

July 30, 2015

AESO Stakeholders

Dear Stakeholder:

Re: **Invitation to Participate in Consultation on AESO 2017 Tariff Application**

The AESO is beginning development of its 2017 ISO tariff application, to be filed with the Alberta Utilities Commission (“AUC”) by June 30, 2016. The AESO invites stakeholder to a consultation meeting to discuss the scope of proposed changes to be included in the application.

Date: Wednesday, August 19, 2015
Time: 9:00 AM to 11:00 AM
Place: AESO Boardroom, 25th Floor, 2500, 330 – 5th Avenue SW, Calgary, Alberta
Teleconference: Phone number 1-866-835-7781 and code 8215976118#
RSVP: By **Wednesday, August 5, 2015** to Brenda Hill, 403-539-2850 or
brenda.hill@aeso.ca

The AESO is interested in hearing stakeholder views on topics to be reviewed for the 2017 tariff application, as discussed further below, as well as appropriate processes to use to review those topics and determined what, if any, related tariff changes should be proposed.

The AESO expects to focus on the following topics in the development of its 2017 tariff application:

- (a) transmission cost causation study methodology to reflect current transmission system costs and configuration;
- (b) point of delivery (“POD”) cost function database update;
- (c) directions 5-8 from AUC Decision 2014-242 *2014 ISO Tariff Application and 2013 ISO Tariff Update*, which concerned congestion and the classification of the costs of advancing transmission facility projects at the request of a market participant;
- (d) method for cost classification of facilities that are shared by one or more market participants;
- (e) charging a market participant for incurred system-related costs when a connection projects is cancelled; and
- (f) structure of Rider C to minimize deferral account imbalances among customers.

The AESO is interested in hearing stakeholder views on the above list of topics to be addressed in the 2017 tariff application, as well as any additional topics stakeholders feel should be included. The AESO has used small working groups for consultation on other recent applications, and suggests working groups may also be appropriate to review at least some of these topics.

If you intend to participate in this consultation meeting, please RSVP by **Wednesday, August 5, 2015** to Brenda Hill, 403-539-2850 or brenda.hill@aeso.ca. If you are unable to attend this meeting and would still like to provide comments to the AESO, please contact me to discuss other ways to become involved in the consultation.

All information relating to the AESO's 2017 tariff consultation will be available on the AESO website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2017 Tariff. As well, new information posted by the AESO on this topic will be mentioned in the AESO stakeholder newsletter, which you can subscribe to by clicking "Sign-up for our stakeholder newsletter" at the lower right of the AESO's home page at www.aeso.ca.

If you need any additional information related to this consultation, please contact me at 403-539-2555 or by email to larhonda.papworth@aeso.ca

Yours truly,

[original signed by]

LaRhonda Papworth
Manager, Tariff Applications

cc: Doyle Sullivan, Director, Regulatory Transmission, AESO
Lee Ann Kerr, Manager, Tariff, AESO
Raj Sharma, Senior Regulatory Analyst, AESO

Consultation on Scope of AESO 2017 Tariff Application

LaRhonda Papworth, Manager, Tariff Applications

Lee Ann Kerr, Tariff Manager

Raj Sharma, Senior Analyst

John Martin, Senior Tariff and Regulatory Advisor

August 19, 2015 — AESO Office, Calgary

Agenda

- Introduction and objectives (slides 1-3)
- Topics Currently in Progress (slides 4-8)
- 2014 Tariff Application Background (slides 9)
- Topics proposed for 2017 Tariff Application (slides 10-17)
- Cost Causation Study (slides 18-20)
- Rates Update (slides 21-24)
- Rider C and Deferral Accounts (slides 25-28)
- Other topics? (slide 29)
- Consultation process and next steps (slides 30-31)
- Discussion and wrap-up (slides 32-33)

Please feel free to ask questions during presentation

Objectives

- Familiarize stakeholders with topics identified by AESO for 2017 tariff application
- Identify additional topics (if any) for 2017 tariff application
- Identify concerns to be addressed for those topics
- Decide consultation process for development of application

Topics Currently in Progress

- Topics currently in progress will be included as approved in decisions resulting from those processes
- Directions 5-8 on advancement costs and related provisions
 - Currently before the Commission in Proceeding 3473
 - Decision expected in late August 2015
- Transmission constraint rebalancing charge
 - Currently before the Commission in Proceeding 20623
 - Decision expected by December 2015
- Interim loss factors in Rates STS, DOS, IOS, XOS
 - Currently before the Commission in Proceeding 790
 - Final loss factors expected to become available in 2016

Topics Currently in Progress (cont'd)

- Changes to ISO rule 505.2 (previously 9.5) on performance criteria for generating unit owner's contribution refund
 - Revision of the rule to adopt an availability criteria rather than energy production as the primary performance criteria
 - Pre-consultation notice to stakeholders posted August 6, 2015
 - Revised rule to be posted in late August in line with existing consultation process for development of ISO rules
 - Revised rule expected to become effective in late 2015
- 2015 tariff update
 - Update of rate and investment levels to reflect 2015 costs
 - Filed on August 18 (Proceeding 20753)
 - Proposed to be effective January 1, 2016

Topics Currently in Progress (cont'd)

- 2013-2014 deferral account reconciliation application
 - Reconciliation of deferral account balances for 2013 and 2014
 - To be filed by end of August
 - Request for interim settlement in November 2015
- 2016 tariff update
 - Update of rate and investment levels to reflect 2016 costs
 - To be filed Q1 2016
 - Expected to be effective April 2016

Topics Currently in Progress (cont'd)

- Terms and conditions alignment filing
 - Revision of tariff provisions to align with AESO initiatives and internal process refinements
 - Improving system access service agreement language
 - Updating provisions to accommodate the market participant choice initiative
 - Revisions to support transmission connected customers of distribution system owners
 - Revisions to support the abbreviated needs approval process
 - To be filed in Q4 2015
 - Expected to be effective April 2016

Topics Currently in Progress (cont'd)

- Energy storage initiative
 - AESO working with the University of Calgary to study the differences between storage and conventional load and generators – target completion is Q4 2015
 - Results from the study will inform study of cost and other impacts in order to accommodate energy storage in ISO tariff
 - Depending on outcome, potential revisions to accommodate energy storage in 2017 tariff application

2014 Tariff Application Background

- 2014 ISO tariff filed with the Commission in July 2013 and became effective July 1, 2015
- Some items to be discussed are in response to Commission directions in Decision 2014-242 on the 2014 ISO tariff application
- Directions 5-8 are still outstanding with a decision from the Commission expected in August 2015

Topics Proposed for 2017 Tariff Application

- Not proposing any major changes
- In response to Commission directions the AESO will address:
 - Contract capacity versus installed capacity for point of delivery cost function
 - 2017-2019 cost causation update
 - Rider C and deferral accounts
- 2017 revenue requirement will initially be a high-level estimate
 - Later updated with transmission facility owners' 2017 tariff applications
 - Later updated with AESO 2017 budget

- **Reason:** Respond to Commission directions
- The AESO sought clarification in the 2014 tariff compliance filing on the Commission Directions 5 to 8
- The Commission established a separate module in Proceeding 3473 in its clarifying letter on February 9, 2015
- Decision expected in late August
- AESO will implement and post revised tariff as required

- **Reason:** Respond to Commission directions
- In Decision 2014-242 the Commission directed:

The AESO is directed to use the full increased capacity made possible by an upgrade project. If the AESO cannot reasonably determine this capacity level for any given project, then the project should be excluded from the database.
- The AESO complied with this Direction but acknowledged that compliance had resulted in unanticipated impacts, as explored in certain information requests, and that the full impact would not have been clear during the 2014 tariff proceeding

Point of Delivery Cost Function (cont'd)

- The Commission found that the direction had “resulted in unanticipated effects” and implementation should be delayed until “the matter can be thoroughly explored”
- AESO considers two options should be explored
 - Cost function based on contract capacity
 - Cost function based on installed capacity
- Either option should apply to both greenfield and upgrade projects
- Must also consider impact of projects contracting for 0 MW capacity increases
- Should consider implications for cost recovery through rates and investment

- **Reason:** Update study that underlies tariff
- Update final costs where available for all projects in the connection project database
- Add new projects that have been granted permit and licence
- Update capacities based on outcome of option exploration
- The resulting point of delivery cost function will be used to update:
 - Rate DTS, *Demand Transmission Service*
 - Rate PSC, *Primary Service Credit*
 - Investment levels in section 8 of ISO tariff

Recovery of system-related costs if connection project is cancelled

- **Reason:** Address issue raised in proceeding
- The current ISO tariff provides the authority to collect from a market participant any connection project costs that were classified as system-related if the connection project is subsequently cancelled
- AESO will review and determine if additional clarification is needed
 - Further guidance may come from Commission decision on Directions 5 to 8

Reclassification of Participant-Related Costs as System-Related

- **Reason:** Add clarity to tariff provision
- The current ISO tariff provides the authority to reclassify participant-related costs as system-related and vice versa
- The tariff does not specify details of how the costs are to be classified as participant-related or system-related
- The AESO is proposing to add details on the calculation that are similar to the calculation when facilities are shared between two or more market participants
 - Based on years and MWs

Provision of Historical Billing Data

- **Reason:** Address issue raised in proceeding
- The AESO will provide market participants with multi-year historical billing volume and service detail to enable consultation participants to analyze rate structure and impacts on a quantitative and objective basis
 - Raised in discussions after the 2014 tariff proceeding
 - Would include
 - Volume data (MWh, MW, coincident demand, substation fraction)
 - Service details (DTS, STS, direct-connect)
 - What data fields and what structure should be included?

- **Reason:** Update study that underlies tariff
- The AESO included a 2014-2016 cost causation study prepared by London Economics International in its 2014 tariff application
 - The study established the inputs and methodology for a comprehensive cost causation study that used both capital and operating and maintenance cost data
 - A negotiated settlement process was used with participants and approved by the Commission
- The AESO proposes to update the study inputs itself using the identical methodology used for the 2014-2016 cost causation study
- Suggest consideration of negotiated settlement process

2017-2019 Cost Causation Study Update (cont'd)

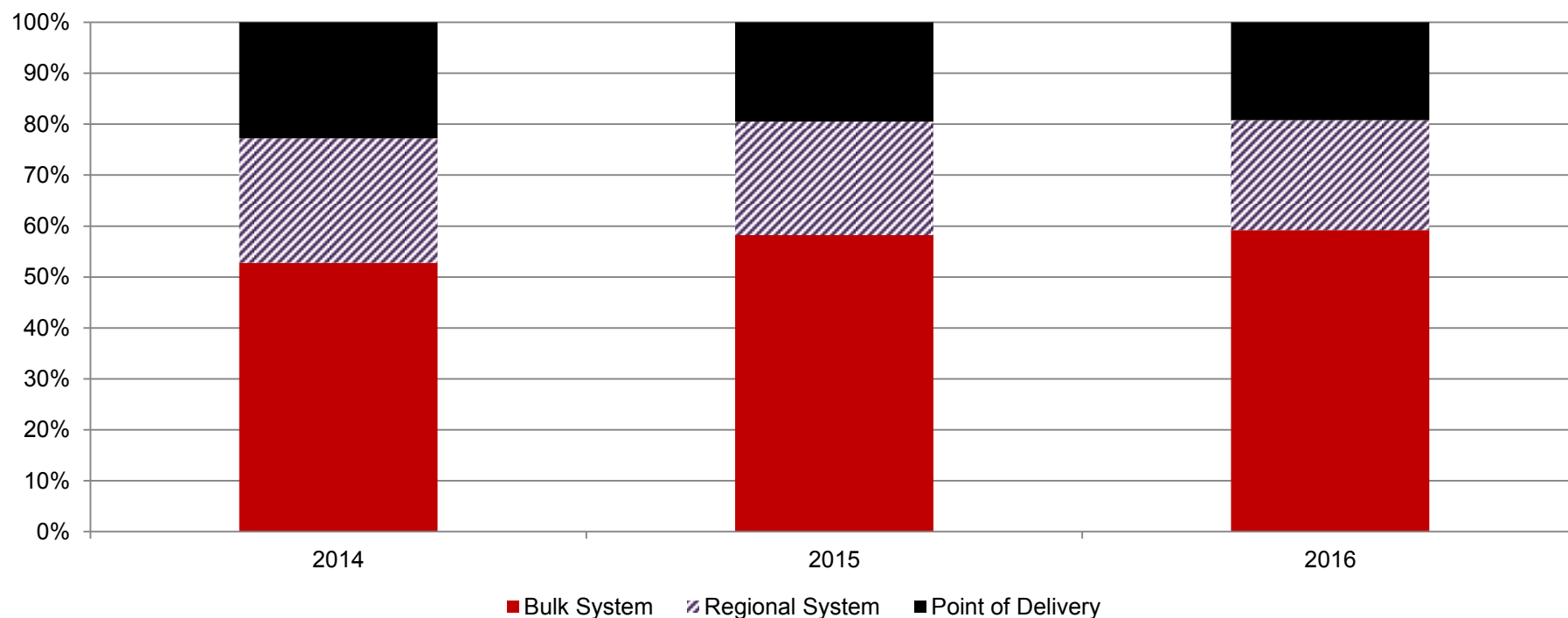


- Proposed process
 - AESO update inputs for 2017-2019 cost causation study in Q4 2015
 - AESO presents results to stakeholders in January 2016
 - AESO files application to begin negotiated settlement process in February 2016 (in advance of 2017 tariff application)

Cost Causation Study History (cont'd)

- *The 2014-2016 Cost Causation Negotiated Settlement Agreement* was approved as filed November 27, 2013
- In accordance with agreement, an updated study was filed January 2014

2014-2016 Functionalization

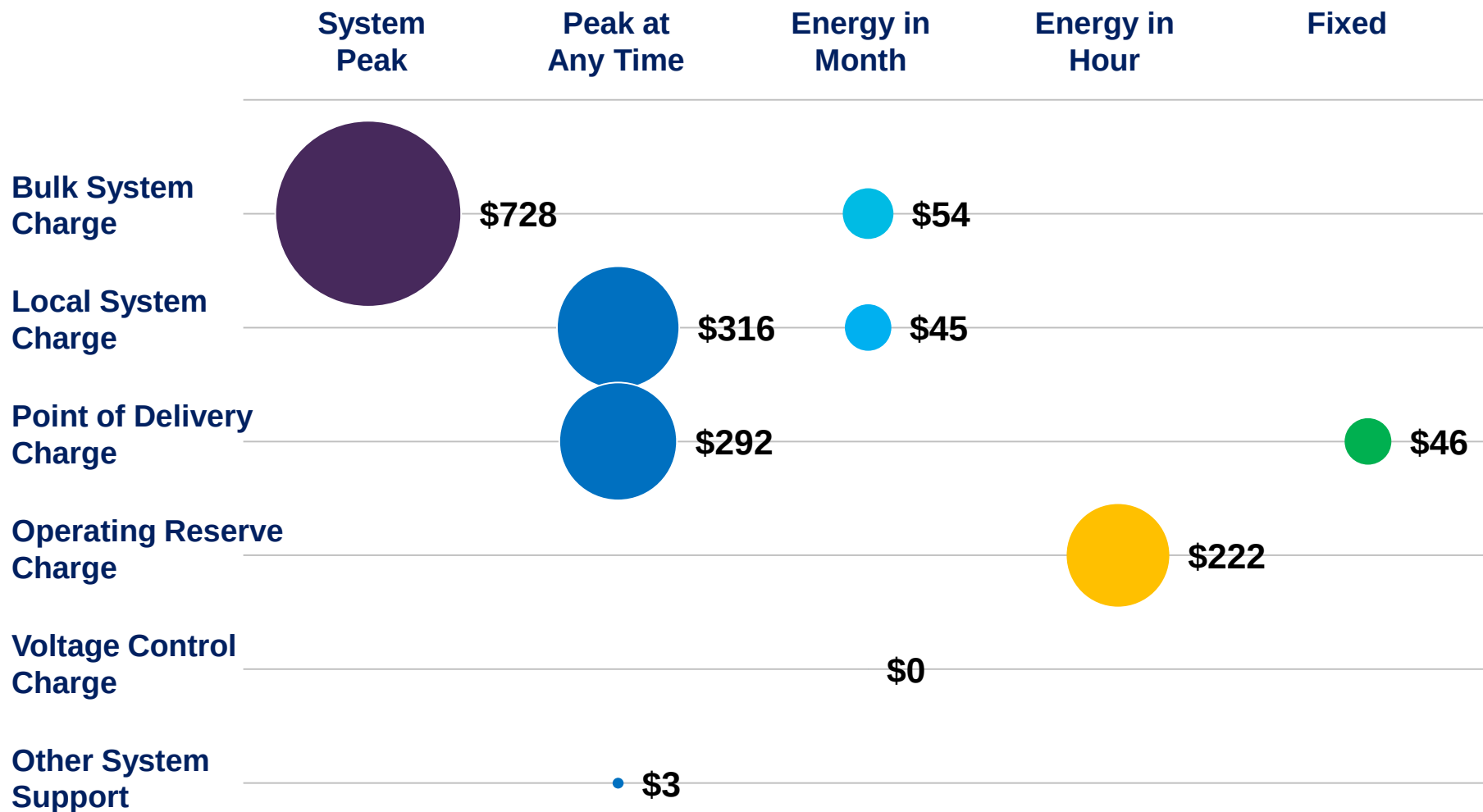


Cost Causation Study History (cont'd)

- 2014-2016 cost classification between demand and energy

2014-2016 Classification	Function	
	Bulk	Regional
Demand	93.1%	87.4%
Energy	6.9%	12.6%

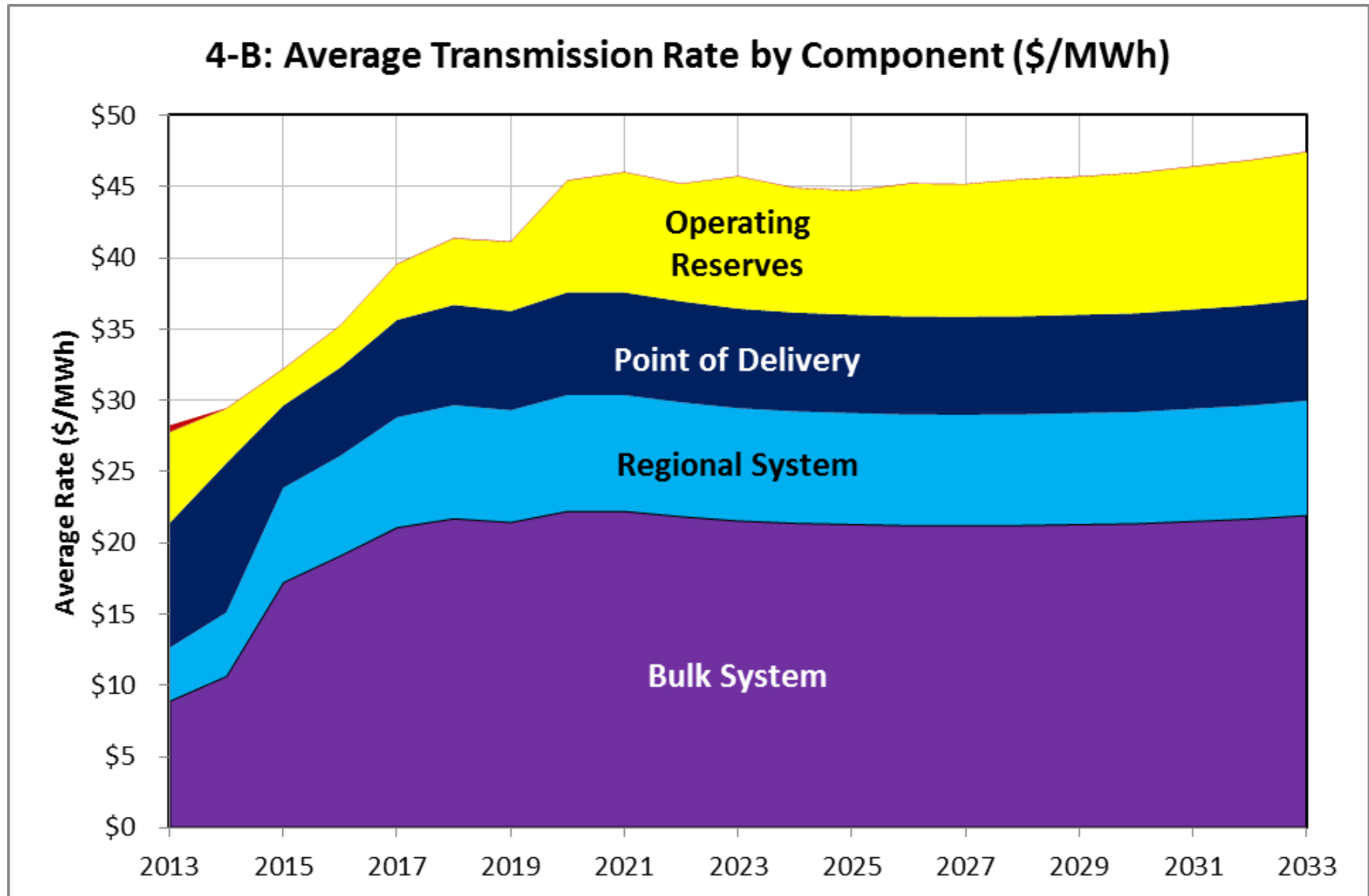
Current 2014 Rate DTS Structure



Transmission Rate Impact Projection

- **Reason:** Update information provided with tariff application
- AESO will include updated long-term transmission rate impact projection (TRIP) in 2017 tariff application
- AESO reviewing TRIP workbook development process of providing periodic updates
- Updating and posting now would not result in significant changes to rate impact

Transmission Rate Impact Projection (cont'd)



*Current posted TRIP Model

- **Reason:** Respond to Commission directions
- In 2014 ISO tariff proceeding, participants submitted that the AESO further examine the Rider C structure to minimize imbalances between market participants
- The Commission directed the AESO to discuss with stakeholders prior to filing its next general tariff application
- The AESO identified the following potential causes of large individual deferral account reconciliation charges or refunds:
 - Different bases for Rider C and Rate DTS components
 - Timing differences between Rider C collections and refunds as compared to production month deferral account reconciliations
 - Variance from forecasts of costs and revenues

Rider C History



- Regular tariff update applications reduce the magnitude of Rider C
 - 2015 tariff update and 2016 tariff update (discussed earlier) should help
- The AESO's initial investigation suggests a change in Rider C structure (from \$/MWh to % of connection charge) would not significantly affect imbalances between market participants

- Rider C has kept deferral account balances small but reconciliations still result in material transfers between customers
- 2013-2014 deferral account reconciliation application planned to be filed late August 2015

Additional topics?

- How would stakeholders like to be involved?
 - Small working groups? On which topics?
 - Written comment process?
 - General stakeholder sessions?
- Potential stakeholder meetings
 - Late January
 - Written comment process
 - Application preview meeting
 - April?
 - Other comment opportunities?

2017 Tariff Application Schedule

2015

- Aug 1st Stakeholder consultation
- Sep Comment matrix

2016

- Jan 2nd Stakeholder session
- Feb File cost application
- Apr 3rd session/Application preview
- Jul File 2017 Tariff Application
- Jul-Dec Regulatory review process
- Dec Refile application with 2017 revenue requirement

- Questions?

For More Information

- LaRhonda Papworth
Manager, Tariff Applications
403-539-2555 or larhonda.papworth@aeso.ca
- Lee Ann Kerr
Tariff Manager
403-539-2741 or leeann.kerr@aeso.ca
- Raj Sharma
Senior Analyst
403-539-2632 or raj.sharma@aeso.ca
- All consultation documents can be found on AESO website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2017 Tariff

Thank you

August 26, 2015

AESO Stakeholders

Dear Stakeholder:

Re: **Additional Information for Consultation on AESO 2017 Tariff Application**

On Wednesday, August 19, 2015, the AESO and stakeholders participated in a consultation meeting to discuss the scope of changes to be included in the AESO's 2017 tariff application. This letter follows up on some of the matters discussed at the meeting, provides additional information on the consultation processes tentatively proposed by the AESO, and requests written comments from stakeholders on the tariff consultation.

1 Transmission System Cost Causation Study

In the 2014 tariff application, the AESO included a 2014-2016 Transmission System Cost Causation Study prepared by London Economics International. The study established the inputs and methodology for a comprehensive transmission system cost causation study that used both capital cost and operating and maintenance cost data. A negotiated settlement process was established and the resulting negotiated settlement was approved by the Commission.

- (a) In its presentation, the AESO proposed to update inputs to the study while using the identical methodology used in the study included in the 2014 tariff application. The AESO would then present results of the updated study to stakeholders in January 2016.
- (b) As well, the AESO proposed to file an application to begin a negotiated settlement process for the study-only portion in February 2016.

2 Point of Delivery Cost Function

In Decision 2014-242 at paragraph 260, the Commission directed the AESO:

... to use the full increased capacity made possible by an upgrade project. If the AESO cannot reasonably determine this capacity level for any given project, then the project should be excluded from the database.

The Commission subsequently found, in Decision 3473-D01-2015 at paragraph 31, that the direction had "resulted in unanticipated effects" and implementation should be delayed until "the matter can be thoroughly explored". In light of the foregoing:

- (a) The AESO considers that two options should be explored: (i) cost function based on contract capacity and (ii) cost function based on installed capacity. Either option should apply to both greenfield and upgrade projects. The AESO also noted that the impact of projects with zero MW incremental contract capacity must be considered. As well, implications for cost recovery through rates and investment need to be considered.

- (b) In consideration of the results from 2(a) above, the AESO will update the connection project database for final costs where available, add new projects for which permit(s) and license(s) under the *Hydro and Electric Energy Act* have been issued, and update capacities. The resulting point of delivery cost function will be used to update Rate DTS, *Demand Transmission Service*, Rate PSC, *Primary Service Credit* and investment levels in section 8 of the tariff.

3 *Rider C and Deferral Accounts*

In the 2014 tariff proceeding, participants submitted that the AESO should further examine the Rider C structure to minimize imbalances between market participants. The Commission directed the AESO to discuss with stakeholders prior to filing its next general tariff application. The AESO identified the following potential causes of large individual deferral account reconciliation charges or refunds in its 2014 tariff application:

- Different bases for Rider C and Rate DTS components;
- Timing differences between Rider C collections and refunds as compared to production month deferral account reconciliations; and
- Variance from forecasts of costs and revenues.

Regular tariff update applications reduce the magnitude of Rider C and therefore potentially reduce large transfers. The AESO's filing of tariff updates in a timely manner should therefore alleviate stakeholder concerns.

The AESO's initial investigation suggests a change in Rider C structure (from \$/MWh to % of connection charge) would not significantly affect imbalances between market participants. The AESO has not identified any improvements to the tariff update, Rider C and deferral account reconciliation processes. The AESO indicated that it could present detailed results of the initial investigation in an upcoming stakeholder session.

4 *Other Topics*

The AESO also indicated as follows at the consultation meeting:

- (a) The AESO will review and determine if additional clarification is needed to the tariff regarding the recovery of system-related costs if a connection project is cancelled. The Commission may provide further guidance on this topic in its decision, expected shortly, to address the AESO's compliance with directions 5 to 8 from Decision 2014-242.
- (b) The AESO is proposing to add details of investment calculations upon reclassification of participant-related costs as system-related costs (and vice versa). These calculations would be similar to calculations performed when facilities are shared between two or more marked participants (based on contracted years and MWs)
- (c) The AESO will provide market participants with multi-year historical billing detail to enable stakeholders to analyze rate design and its impacts on a quantitative and objective basis. This data could include volume data (MWh, MW, coincident demand, substation fraction) and service details (DTS, STS, direct-connect). The AESO is requesting feedback on the data fields and data structure that will be required.

- (d) The AESO is currently reviewing the transmission rate impact project (TRIP) workbook development process, including providing periodic TRIP updates. A TRIP update today would not result in significant changes to rate projections. The AESO is proposing to post an updated TRIP with the 2017 Tariff Application in July 2016.

5 *Suggestions from Consultation Meeting*

Participants provided initial comments and suggestions on some questions asked by the AESO during the meeting. In particular, the AESO noted the following suggestions:

- (a) The current operating reserve charge rate design was identified as an issue by a distribution facility owner (DFO). The DFO explained that regulatory lag results in it holding significant balances for a significant period of time. Some participants were supportive of current operating reserve charge rate design and commented that this is a distribution regulatory process issue.
- (b) A participant raised the issue of investment levels not covering 60% of the similar average project costs. The AESO advised that it would not put this forward as a topic for the 2017 tariff application but that it would provide requested information to stakeholders enabling them to develop their proposals, if any.
- (c) Participants commented that they support the AESO's focus on filing the comprehensive tariff application and the tariff update applications as soon as possible.

6 *Preliminary Proposal for Consultation Process*

The AESO will invite written comments on the information presented at the August 19 meeting, using a standard stakeholder comment form. More information is provided in section 7 below.

In addition, based on discussion at the meeting, the AESO proposes the following consultation process for the development of its 2017 tariff application:

- (a) The AESO will hold a technical session in January 2016 to present:
 - i. results of the updated transmission cost causation study for the 2017 tariff application, including capital-related costs, operating and maintenance costs, cost functionalization, and cost classification;
 - ii. results of the thorough exploration of point of delivery cost function and update of the point of delivery cost database; and
 - iii. results from AESO's investigation of alternative Rider C structure.
- (b) The AESO will use a written comment process and, potentially one or two small working groups to consult on other changes to the tariff. The AESO will provide draft revisions to the tariff with relevant discussion and would then invite stakeholder comments on these draft revisions.
- (c) The AESO will hold a general stakeholder consultation meeting in April 2016 to update stakeholders on the progress of the development of the 2017 tariff application.

7 Request for Written Comments

The AESO invites written comments from stakeholders on this discussion of the tariff application scope. The [comment form](#) is attached and includes specific topics discussed at the meeting. Stakeholders may provide comments on other tariff application topics using the “Other Comments” section of the [comment form](#).

The AESO requests stakeholders to provide comments by returning the form to larhonda.papworth@aeso.ca by **Friday, September 11, 2015**.

All information relating to the AESO’s 2017 tariff consultation will be available on the AESO website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2017 Tariff. As well, new information posted by the AESO on this topic will be mentioned in the AESO stakeholder newsletter, which you can subscribe to by clicking “Sign-up for our stakeholder newsletter” at the lower right of the AESO’s home page at www.aeso.ca.

If you need any additional information related to this consultation, please contact me by phone (403-539-2555) or by email (larhonda.papworth@aeso.ca).

Yours truly,

[original signed by]

LaRhonda Papworth
Manager, Tariff Applications

cc: Lee Ann Kerr, Tariff Manager
Raj Sharma, Senior Analyst

Stakeholder Comments and AESO Responses on Scope of AESO 2017 Tariff Consultation

Background

On August 19, 2015, the AESO and stakeholders participated in a consultation meeting to discuss the scope of matters to be addressed in the AESO's 2017 tariff application. Based on discussion at the meeting, the AESO invited written comments from stakeholders on the information presented at the meeting and additional information provided by the AESO in a letter on August 25, 2015.

Comments were received from:

- ATCO Electric;
- AltaLink Management Ltd.;
- Capital Power;
- EPCOR Distribution & Transmission Inc. (EDTI);
- Industrial Power Consumers Association of Alberta (IPCCA); and
- Office of the Utilities Consumer Advocate (UCA).

The written comments from stakeholders are consolidated below, together with responses from the AESO, where applicable.

Both the meeting presentation and the letter are posted on the AESO website and can be accessed at www.aeso.ca by following the path Tariff ► Current Consultations ► 2017 Tariff.

Consultation Dates

Date of Request for Comments:	August 25, 2015
Period of Consultation:	August 25 – October 30, 2015

Stakeholder Comments on AESO Information

Stakeholder Comment	AESO Response
1(a) <i>In its presentation for the 2017 tariff application, the AESO proposed to update inputs to the past study while using the identical methodology used in the 2014 tariff application. The AESO would then present results of the updated study to stakeholders in January 2016.</i>	
ATCO Electric: Indifferent ATCO Electric is interested in reviewing and understanding the AESO's updated study. While ATCO Electric supports this approach, ATCO Electric still reserves the right to test the methodology used in the tariff application.	The AESO acknowledges ATCO Electric's comment.
AltaLink: Support If there are no material changes for 2017 that would result in a	The AESO acknowledges AltaLink's

Stakeholder Comment	AESO Response
material impact to the AESO's 2014 approved study then it would be cost and time effective for all stakeholders if the AESO uses the current approved study with updated inputs.	support.
Capital Power: Support Capital Power looks forward to reviewing the updated cost causation study and attending the January 2016 stakeholder session.	The AESO acknowledges Capital Power's support.
EDTI: No comments.	
IPCAA: No comments.	
UCA: Support The UCA was active in the NSA in the previous tariff and agreed to the voltage based functionalization.	The AESO acknowledges UCA's support.
1(b) As well, the AESO proposed to file an application to begin a negotiated settlement process for the study-only portion in February 2016.	
ATCO Electric: Indifferent At this point, it is difficult for ATCO Electric to support or oppose a negotiated settlement process without having the opportunity to review the application.	The AESO acknowledges ATCO Electric's comment.
AltaLink: Support Efficient, if no one objects to using the same study methodology as used in the 2014 tariff application.	The AESO acknowledges AltaLink's support.
Capital Power: Support Capital Power supports a negotiated settlement process for the study-only portion on the basis that it may streamline the regulatory approval process. Capital Power will determine the extent of its participation, if any, in the negotiated settlement process after reviewing the results of the study.	The AESO acknowledges Capital Power's support.
EDTI: No comments.	
IPCAA: No comments.	
UCA: Support The UCA felt the NSP increased efficiencies in the previous tariff application.	The AESO acknowledges UCA's support.
2(a) In order to thoroughly explore point of delivery cost function impacts, the AESO considers that two options should be explored, (i) cost function based on contract capacity and (ii) cost function based on installed capacity. Either option should apply to both greenfield and upgrade projects. The AESO also noted that impact of projects with zero MW incremental contract capacity must be considered. As well, implications for cost recovery through rates and investment need to be considered.	
ATCO Electric: Support ATCO Electric supports this approach and looks forward to	The AESO acknowledges ATCO Electric's support.

Stakeholder Comment	AESO Response
understanding the merits of the two options and how the outcome may impact transmission access service payments.	
AltaLink: Support Both options should be reviewed with stakeholders to fully understand the pros and cons of each before establishing a position.	The AESO acknowledges AltaLink's support.
Capital Power: Support Capital Power supports the AESO's proposal to explore point of delivery cost function impacts.	The AESO acknowledges Capital Power's support.
EDTI: No comments.	
IPCAA: No comments.	
UCA: Support The UCA supports the exploration of POD cost function impacts and inquiry into installed capacity measures.	The AESO acknowledges UCA's support.
2(b) <i>In consideration of the results from 2(a) above, the AESO will update the connection project database for final costs where available, add new projects for which permit(s) and license(s) under the Hydro and Electric Energy Act have been issued, and update capacities. The resulting point of delivery cost function will be used to update Rate DTS, Demand Transmission Service, Rate PSC, Primary Service Credit and investment levels in section 8 of the tariff.</i>	
ATCO Electric: Indifferent	
AltaLink: Support See response to 2(a).	The AESO acknowledges AltaLink's support.
Capital Power: Support Capital Power supports the AESO ultimately using the results from stakeholder consultation regarding 2(a) above to update the connection project database and relative items in the tariff.	The AESO acknowledges Capital Power's (qualified) support.
EDTI: No comments.	
IPCAA: No comments.	
UCA: Support The UCA supports the use of the most recent data in determining the POD cost function.	The AESO acknowledges UCA's support.
3(a) <i>The AESO's initial investigation suggests a change in Rider C structure (from \$/MWh to % of connection charge) would not significantly affect imbalances between market participants. The AESO has not identified any improvements to the tariff update, Rider C and deferral account reconciliation processes.</i>	
ATCO Electric: Oppose ATCO Electric proposes that the AESO continue working on finding a Rider C structure to minimize imbalances and volatility	The AESO will form a working group to examine and further investigate Rider C structure and Deferral Accounts

Stakeholder Comment	AESO Response
to market participants as there is still significant impact in Rider C adjustments to customers. ATCO Electric would support a consultation process to deal with Rider C redesign.	reconciliation methodology.
AltaLink: Support The AESO and stakeholders should continue to find ways to make improvements to Rider C.	The AESO acknowledges AltaLink's support. Please see AESO's response to ATCO Electric's comment above.
Capital Power: Indifferent Capital Power seeks to review the results from the AESO's initial investigation and understand the basis for this decision prior to taking an initial position.	The AESO acknowledges Capital Power's comment. Please see AESO's response to ATCO Electric's comment above.
EDTI: Oppose It is not clear to EDTI how " a change in Rider C structure (from \$/MWh to % of connection charge) " will impact the DFO's ability to accurately recover Rider C costs in the DFO's quarterly Transmission Access Charge rider applications.	Please see AESO's response to ATCO Electric's comment above.
IPCAA: No comments.	
UCA: Indifferent.	
3(b) The AESO indicated willingness to present some detailed results from the initial investigation at an upcoming stakeholder session.	
ATCO Electric: Support ATCO Electric supports this initiative in an effort to find a more appropriate mechanism to deal with deferral account reconciliations.	The AESO acknowledges ATCO Electric's support. As stated in the AESO response to 3(a) above, the AESO would form a working group for this purpose.
AltaLink: Support See response to 3(a).	The AESO acknowledges AltaLink's support. Please see the AESO response 3(a).
Capital Power: Support Capital Power supports the AESO's offer to share the detailed results from its initial investigation of potential changes to the structure of Rider C at an upcoming stakeholder session and looks forward to reviewing the results.	The AESO acknowledges Capital Power's support. Please see the AESO response 3(a).
EDTI: Support EDTI would like to fully understand the impacts of the AESO's proposed change in Rider C structure.	The AESO acknowledges EDTI's support. Please see the AESO response 3(a).
IPCAA: No comments.	
UCA: Support The UCA supports this as it will keep participants informed.	The AESO acknowledges UCA's support. Please see the AESO response 3(a).

Stakeholder Comment	AESO Response
4(a) <i>The AESO will review and determine if additional clarification is needed to the tariff regarding the recovery of system-related costs if a connection project is cancelled. The Commission may provide further guidance on this topic in its decision, expected shortly, to address the AESO's compliance with directions 5 to 8 from Decision 2014-242.</i>	
ATCO Electric: Oppose ATCO Electric will participate in the AUC's forthcoming proceeding covering this issue given Decision 3473-D02-2015	Subsequent to the issuance of Decision 3473-D02-2015, the Commission issued Bulletin 2015-15 on October 22, 2015, announcing the initiation of Proceeding 20922 to address the customer advancement cost component of the ISO tariff. The Commission also indicated the proceeding will not be heard until late in Q1 or early in Q2 of 2016. The AESO, in developing its 2017 Tariff Application, will seek to schedule activities to reflect the Proceeding 20922 schedule and avoid overlap and conflict between the proceeding and its consultation activities.
AltaLink: Support AltaLink supports further clarification. However, the Commission indicated in its decision it will provide this guidance as part of its own initiated proceeding on advancement costs.	The AESO acknowledges AltaLink's support. Please see the AESO response to 4(a)
Capital Power: Support Several aspects of AUC Decision 3473-D02-2015 may have implications for the 2017 AESO Tariff Application. Capital Power is interested in the AESO's proposed process for 4(a) in light of Decision 3473-D02-2015 and the Commission's decision to initiate its own proceeding to "address whether and how customer advancement costs can be used to ensure that the future development of transmission projects is achieved in both a timely and an economic manner." Capital Power requests that the AESO provide stakeholders with an update on 4(a) that includes, but is not limited to, the AESO's response to following questions: • How will the 2017 Tariff consultation interface with the Commission-initiated proceeding resulting from 3473-D02-2015? • How will the Commission-initiated proceeding impact the scope of the proposed 2017 Tariff Consultation? • Will project cancellation costs, system project advancement costs, and/or any items pertaining to the AUC directions 5 to 8 from Decision 2014-242 be included in the scope of the 2017 Tariff Consultation?	The AESO acknowledges Capital Power's support. Please see the AESO response to 4(a).
EDTI: No comments.	

Stakeholder Comment	AESO Response
IPCAA: No comments.	
UCA: Support The UCA supports additional clarification on these items.	The AESO acknowledges UCA's support. Please see the AESO response to 4(a).
4(b) <i>The AESO is proposing to add details of investment calculations upon reclassification of participant-related costs as system-related costs (and vice versa). These calculations would be similar to calculations performed when facilities are shared between two or more marked participants (based on contracted years and MWs).</i>	
ATCO Electric: Support ATCO Electric supports this in the context of the work that will be undertaken in 4(a) above.	The AESO acknowledges ATCO Electric's support. The AESO will provide detailed calculations of the methodology for carrying out the calculations. The calculation will be similar to that performed when market participants share facilities, as outlined in subsection 5 of section 9 of the 2014 ISO tariff.
AltaLink: Support It would be helpful for all participants to understand the detailed calculations.	
Capital Power: Support Any reclassification of participant-related costs as system-related costs (and vice versa) should be accompanied with a before and after perspective to provide stakeholders with a view of the impact/re-allocation of costs/charges resulting from the changes. Further, any reclassification of system-related costs should be considered with respect to the Commission's findings in Decision 3473-D02-2015 regarding the application of advancement system costs to generators, and specifically, that "the only recovery of non-radial transmission facility costs from generator market participants that can occur is in accordance with Section 29 of the Transmission Regulation."	The AESO acknowledges Capital Power's support. Please see AESO's response to 4(a) in regards to alignment with Decision 3473-D02-2015.
EDTI: No comments.	
IPCAA: No comments.	
UCA: Support The UCA is concerned with the reclassification of participant-related costs as system-related costs, as system-related costs are borne by the consumers.	The AESO acknowledges UCA's support. Please see AESO's response to 4(a) in regards to alignment with Decision 3473-D02-2015.
4(c) <i>The AESO will provide market participants with multi-year historical billing detail to enable stakeholders to analyze rate design and its impacts on a quantitative and objective basis. This data could include volume data (MWh, MW, coincident demand, substation</i>	

Stakeholder Comment	AESO Response
<i>fraction) and service details (DTS, STS, direct-connect). The AESO is requesting feedback on the data fields and data structure that will be required.</i>	
ATCO Electric: Support This information will assist in understanding the impacts of the proposed changes to the tariff design.	The AESO acknowledges ATCO Electric's support. The AESO continues to solicit feedback on the data fields and data structure required by market participants prior to beginning the data compilation exercise.
AltaLink: Support See response to 4(b).	The AESO acknowledges AltaLink's support. Please see AESO's response to ATCO Electric's comment above.
Capital Power: Support Capital Power supports the AESO providing market participants with multi-year historical billing data to enable stakeholders to analyze rate design and its impacts. Capital Power has no suggestions regarding data fields and structure at this time.	The AESO acknowledges Capital Power's support. Please see AESO's response to ATCO Electric's comment above.
EDTI: No comments.	
IPCAA: No comments.	
UCA: Support The UCA supports having additional data to run their own analysis	The AESO acknowledges UCA's support. Please see AESO's response to ATCO Electric's comment above.
<i>4(d) The AESO is currently reviewing the transmission rate impact projection (TRIP) workbook development process, including providing periodic TRIP updates. A TRIP update today would not result in significant changes to rate projections. The AESO is proposing to post an updated TRIP with the 2017 Tariff Application in July 2016.</i>	
ATCO Electric: Indifferent Updates to TRIP will depend on timing of updated ISO Long-Term Plan expected in January 2016.	The AESO acknowledges ATCO Electric's comment.
AltaLink: Support Updating the model based on material changes makes sense from a practical and resource standpoint.	The AESO acknowledges AltaLink's support.
Capital Power: Support Capital Power supports the AESO updating the TRIP workbook as early as practical in the 2017 Tariff Consultation process, and continuing to provide periodic TRIP updates whenever changes necessitate. The TRIP workbook is a useful document and helps market participants to analyze future transmission cost trends and the impacts of changes to consumer behavior.	The AESO acknowledges Capital Power's support.
EDTI: No comments.	
IPCAA: No comments.	

Stakeholder Comment	AESO Response
UCA: Support Updates to the TRIP model are encouraged by the UCA.	The AESO acknowledges UCA's support. Please see AESO's response to Capital Power's comment above.
5(a) <i>The current operating reserve charge rate design was identified as an issue by a distribution facility owner (DFO). The DFO explained that regulatory lag results in it holding significant balances for a significant period of time. Some participants were supportive of current operating reserve charge rate design and commented that this is a distribution regulatory process issue.</i>	
ATCO Electric: Support ATCO Electric supports a review of the current operating reserve charge rate design in an effort to minimize volatility.	The AESO considers that the current flow-through nature of the operating reserve charge reflects cost causation and avoids cross-subsidies between market participants. However, the AESO is willing as part of consultation to explore alternatives that may be beneficial to distribution-connected consumers, to assess whether changes to the operating reserve charge should be considered.
AltaLink: Indifferent	
Capital Power: Indifferent Capital Power has no comment on 5(a).	
EDTI: Support This issue impacts EDTI. While this issue is related to the regulated nature of the DFO's business, it is a direct result of the rate design that the AESO uses to recover operating reserve costs. EDTI seeks a solution that addresses the issues that impact the DFOs and is not opposed to maintaining the current operating reserve charge rate design for other DTS customers.	The AESO acknowledges EDTI's comment. Please see the AESO response to ATCO Electric's comment above.
IPCAA: No comments.	
UCA: Indifferent The UCA is concerned with increase or decrease in reserves charges.	The AESO acknowledges UCA's comment assuming that "increase or decrease" was intended.
5(b) <i>A participant raised the issue of investment levels not covering 60% of the similar average project costs. The AESO advised that it would not put this forward as a topic for the 2017 tariff application but that it would provide requested information to stakeholders enabling them to develop their proposals, if any.</i>	
ATCO Electric: Support ATCO Electric intends to participate with other TFO's in raising this issue during the hearing and it appreciates the AESO's suggestion to provide requested information to help develop a potential proposal on this issue.	The AESO acknowledges ATCO Electric's support.

Stakeholder Comment	AESO Response
AltaLink: Support Even though the investment level issue is important to AltaLink, having the AESO being open to provide information that will enable AltaLink and others to develop their proposals for the AESO's 2017 tariff will be helpful.	The AESO acknowledges AltaLink's support.
Capital Power: Support Capital Power supports the AESO's offer to provide information to stakeholders to enable them to develop their own proposals, if they so choose.	The AESO acknowledges Capital Power's support.
EDTI: No comments.	
IPCAA: No comments.	
UCA: Indifferent.	
5(c) Participants commented that they support the AESO's focus on filing the comprehensive tariff application and the tariff update applications as soon as possible.	
ATCO Electric: Support ATCO Electric considers timely updates of AESO tariffs results in better reduced true-up balances for ATCO Electric and improves rate signals to customers.	The AESO acknowledges ATCO Electric's support.
AltaLink: Support Filing the AESO's update applications for 2015 and 2016 and a comprehensive application for 2017 as soon as possible would mitigate regulatory lag.	The AESO acknowledges AltaLink's support.
Capital Power: Support Capital Power supports the AESO's expediency in filing the comprehensive tariff application and the tariff update applications.	The AESO acknowledges Capital Power's support.
EDTI: No comments.	
IPCAA: No comments.	
UCA: Support As this proceeding is typically very large, anything to streamline the process is encouraged.	The AESO acknowledges UCA's support.
6(a) In regards to the 2017 tariff application consultation process, the AESO proposed to hold a technical session in January 2016 to present: <i>i. results of the updated transmission cost causation study;</i> <i>ii. results of the thorough exploration of point of delivery cost function and the update of point of delivery cost database; and</i> <i>iii. results from AESO's investigation of alternative Rider C structure(s).</i>	
ATCO Electric: Support As the cost study and Rider impact ATCO Electric and end-use	The AESO acknowledges ATCO Electric's support.

Stakeholder Comment	AESO Response
customers, ATCO Electric is interested in participating in the AESO's technical session in January 2016.	
AltaLink: Support Holding a technical session will allow stakeholders an opportunity to discuss and understand these three points.	The AESO acknowledges AltaLink's support.
Capital Power: Support Capital Power supports the AESO's proposal to hold a technical session in January 2016 to present the above items and encourages the AESO to hold meetings and technical sessions whenever practical to introduce changes, proposals, or technical results (such as to introduce the updated TRIP Workbook in July 2016). These types of sessions are helpful to stakeholders and allow them to better understand the context and reasoning behind various updates and changes.	The AESO acknowledges Capital Power's support.
EDTI: No comments.	
IPCAA: No comments.	
UCA: Support Technical meetings are welcome as they will assist the UCA in their understanding of the issues.	The AESO acknowledges UCA's support.
6(b) <i>The AESO will use a written comment process and potentially one or two small working groups to consult on other changes to the tariff. The AESO will provide draft revisions to the tariff with relevant discussion and would then invite stakeholder comments on these draft revisions.</i>	
ATCO Electric: Oppose To promote efficiency, ATCO Electric would recommend a number of dedicated working groups for each major issue with each working group to develop consensus based draft revisions. Revisions for all issues to then be shared and commented on by all stakeholders. This would allow for flexibility in working group participation based on individual expertise for a given issue.	The AESO acknowledges ATCO Electric's comment. As stated in the AESO response to 3(a) above, the AESO will form a working group to examine matters related to Rider C and Deferral Account reconciliations. The AESO intends to hold technical sessions for matters related to the POD cost function and to present the results of the update to the Cost Causation Study. The AESO also intends to solicit written comments, similar to this process, after the conclusion of above mentioned working group and technical sessions.
AltaLink: Support AltaLink supports an AESO led written comment process, but would recommend that stakeholders have the option to participate in any working groups proposed.	The AESO acknowledges AltaLink's support. Please see the AESO response to ATCO Electric's comment above.
Capital Power: Support	The AESO acknowledges Capital

Stakeholder Comment	AESO Response
Capital Power supports the proposed written process and the idea of using smaller working groups on issues where it makes sense.	Power's support.
EDTI: No comments.	
IPCAA: If there are committees / working groups etc. set please include [IPCAA].	Please see the AESO response to ATCO Electric's comment above.
UCA: Support The proposal seems like a reasonable attempt to streamline the process while maintaining the ability for stakeholders to provide input.	The AESO acknowledges UCA's support.
6(c) The AESO will hold a general stakeholder consultation meeting in April 2016 to update stakeholders on the progress of the development of the 2017 tariff application.	
ATCO Electric: Support For reasons explained above, ATCO Electric is interested in participating in upcoming consultation meetings.	The AESO acknowledges ATCO Electric's support.
AltaLink: Support Understanding if the AESO is on track for filing its 2017 tariff by June 30, 2016 will help AltaLink with allocating resources.	The AESO acknowledges AltaLink's support.
Capital Power: Support Capital Power supports this proposal.	The AESO acknowledges Capital Power's support.
EDTI: No comments.	
IPCAA: No comments.	
UCA: Support Progress updates are encouraged.	The AESO acknowledges UCA's support.
Additional comments	
ATCO Electric: None.	
AltaLink: AltaLink supports the AESO continuing to provide advance notice for filing their tariff applications which allows stakeholders the opportunity to provide input into these applications prior to being filed.	The AESO acknowledges AltaLink's support.
Capital Power: Capital Power has no additional comments at this time.	
EDTI: None.	
IPCAA: IPCAA suggested that the AESO begin to immediately capitalize on some of the new features of the EMS system which is to be in place in 2017.	The AESO notes that dynamic line ratings and dynamic scheduling are not dependent on the EMS system (upgrade). The AESO is striving to

Stakeholder Comment	AESO Response
The suggestions were to begin to focus on: – Dynamic Line ratings to increase the utilization of the Alberta Transmission System and – Dynamic Scheduling to increase the efficient utilization of the inter-ties. IPCAA suggested that the AESO consider these in the development of its 2017 tariff application. As the AESO can realize with the downturn in the Alberta economy and likely stalled growth in electrical consumption costs and how they are allocated are of great importance to IPCAA.	implement and utilize these tools subject to resource constraints. The AESO expects that such utilization would be phased-in, beginning in 2017. The AESO considers that such utilization would not significantly affect cost causation and rate design in the 2017 to 2019 period. The AESO expects such utilization to possibly reduce transmission system costs and likely increase transmission system utilization and market efficiency.
UCA: None.	

November 25, 2015

AESO Stakeholders
AESO 2017 ISO Tariff Consultation Participants

Dear Stakeholder:

Re: **Invitation to Participate in Consultation on Deferral Account Reconciliations and Rider C**

As part of consultation for development of its 2017 ISO tariff application, the Alberta Electric System Operator (AESO) is initiating discussion with market participants of annual tariff updates, deferral account reconciliation processes and Rider C design. The AESO is holding a consultation meeting on these topics and invites you to become involved in this consultation.

The meeting is scheduled as follows:

Date:	Monday, December 14, 2015
Time:	9:30–11:30 AM
Place:	AESO Meeting Room 2539, 25th Floor, 330 – 5th Avenue SW, Calgary, Alberta
Teleconference:	Phone number 1-866-835-7781 and code 5565714323
RSVP:	By 5:00 PM on Wednesday, December 9, 2015 to Brenda Hill, brenda.hill@aeso.ca or 403-539-2850

The AESO expects to discuss the following topics during the meeting:

- interrelationships between annual tariff updates, deferral account reconciliations, and Rider C;
- summary of recent deferral account reconciliations;
- magnitude and frequency of refunds and charges to individual market participants in deferral account reconciliations;
- concerns to potentially be addressed through future changes to Rider C; and
- possible approaches to minimizing impacts of deferral account reconciliations.

The AESO plans to present information on these topics to facilitate discussion, and will post the presentation before the meeting if possible. Stakeholders may provide feedback in person during the meeting or by contacting the AESO after the meeting.

All information relating to the 2017 tariff consultation will be available on the AESO website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2017 Tariff. As well, new information posted by the AESO on this topic will be mentioned in the AESO stakeholder newsletter, which you can subscribe to by clicking “Sign-up for our stakeholder newsletter” at the lower right of the AESO’s home page at www.aeso.ca.

If you have any questions on the AESO's 2017 tariff consultation, please contact me at 403-539-2465 in Calgary or by e-mail to john.martin@aeso.ca.

Sincerely,

John Martin
Senior Tariff and Regulatory Advisor

cc: Carol Moline, Director, Accounting & Treasury
LaRhonda Papworth, Manager, Tariff Applications
Raj Sharma, Senior Tariff Analyst

Consultation on Deferral Account Reconciliations and Rider C

LaRhonda Papworth, Manager, Tariff Applications
John Martin, Senior Tariff and Regulatory Advisor
Carol Moline, Director, Accounting & Treasury

December 14, 2015 – Calgary, Alberta

- Introductions (slides 1-2)
- Objectives and background (slides 3-6)
- Potential impacts of early filing of tariff updates (slides 7-13)
- Seasonality effects of quarterly Rider C (slides 14-17)
- Potential changes to Rider C (slides 18-21)
- DFO concern with operating reserve hourly flow-through charge (slides 22-23)
- Next steps and discussion (slides 24-26)

Please ask questions during presentation!

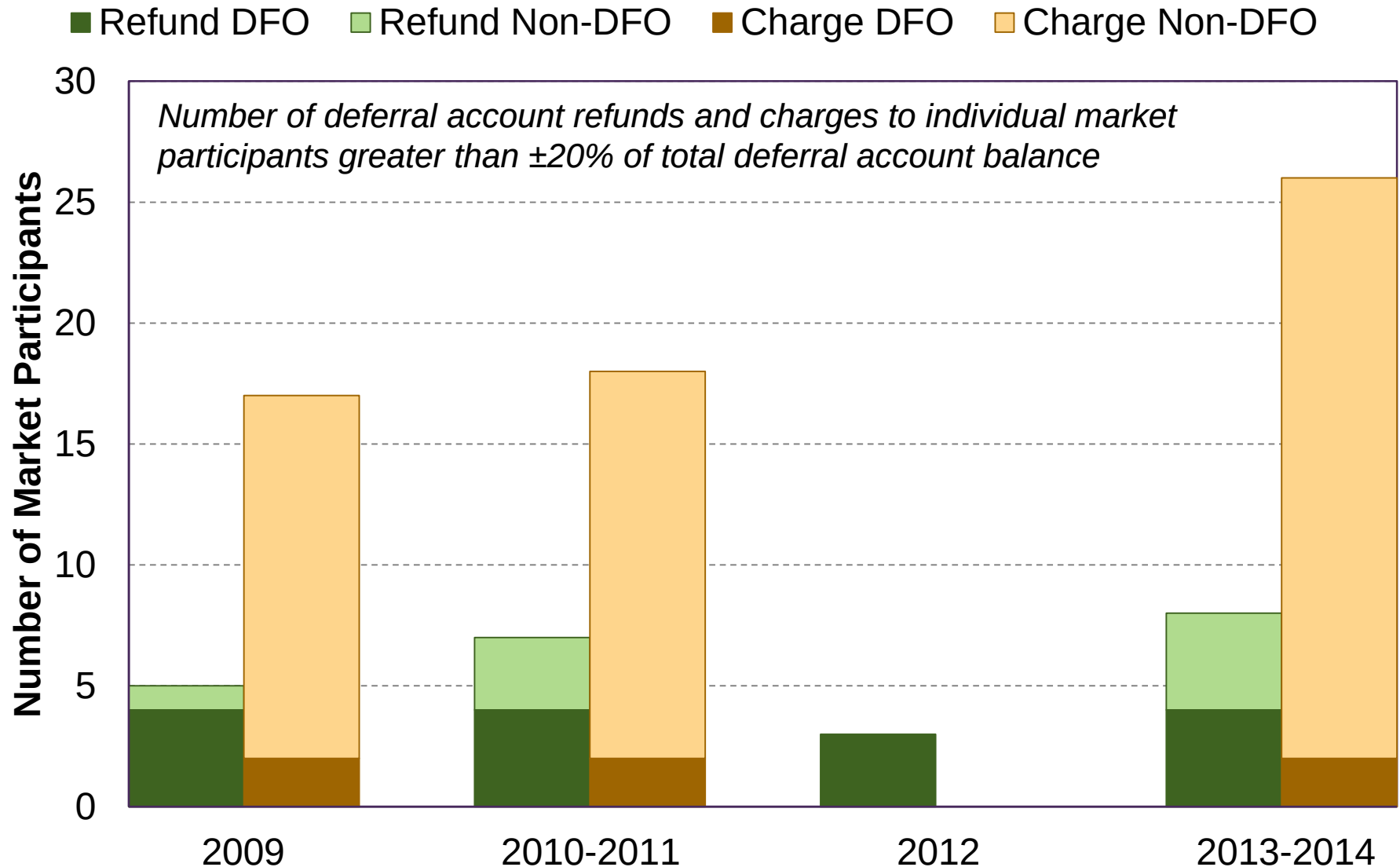
Objectives

- Stakeholders to understand relationships between annual tariff updates, Rider C, and deferral account reconciliations
- AESO to understand concerns to potentially be addressed through future changes to tariff updates, Rider C, and deferral account reconciliations
- Exploration of possible approaches to minimizing impacts of deferral account reconciliations

Why are we talking about deferral account reconciliations and Rider C?

- **Reason:** Respond to Commission directions
- During the AESO's 2014 ISO tariff proceeding, participants submitted that the AESO should further examine the structure of Rider C to minimize imbalances between market participants
- In Decision 2014-242, the Commission directed the AESO “to discuss the related matters of annual tariff updates, deferral account reconciliation processes and Rider C design with stakeholders prior to filing its next comprehensive GTA, and to provide a report on the outcome of any such discussions, including any recommended changes (if any) within its next comprehensive GTA” [paragraph 704, page 139]

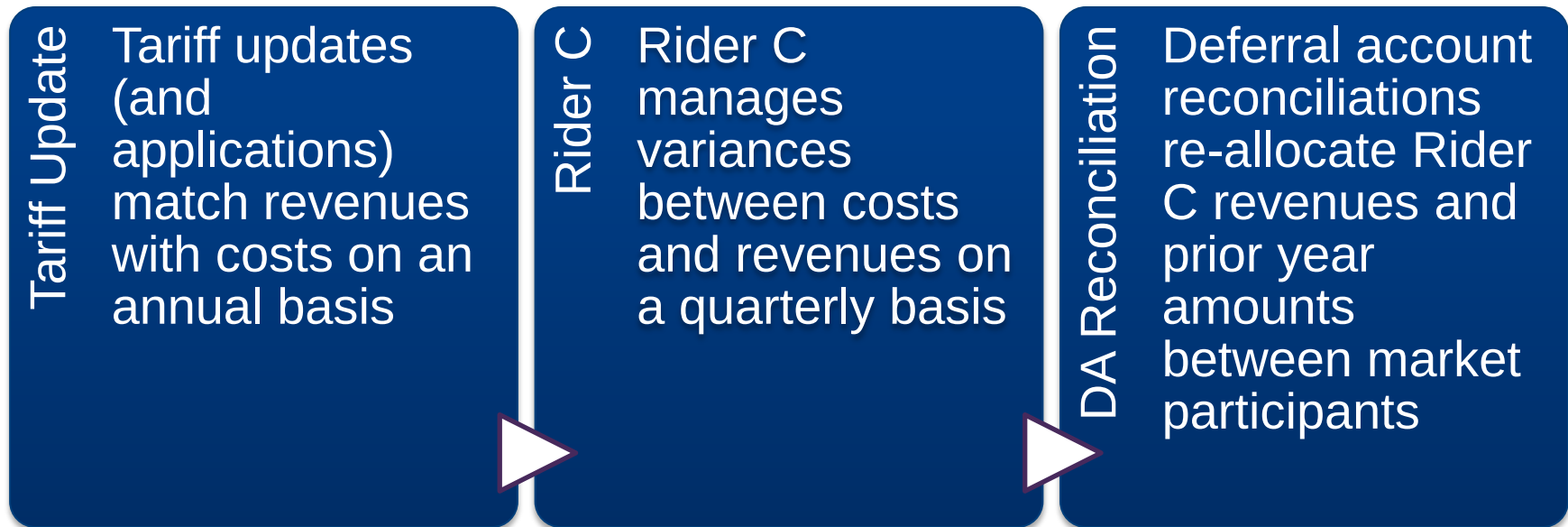
Individual refunds and charges frequently exceed 20% of deferral account balance



The AESO investigated potential Rider C changes for its 2014 ISO tariff application

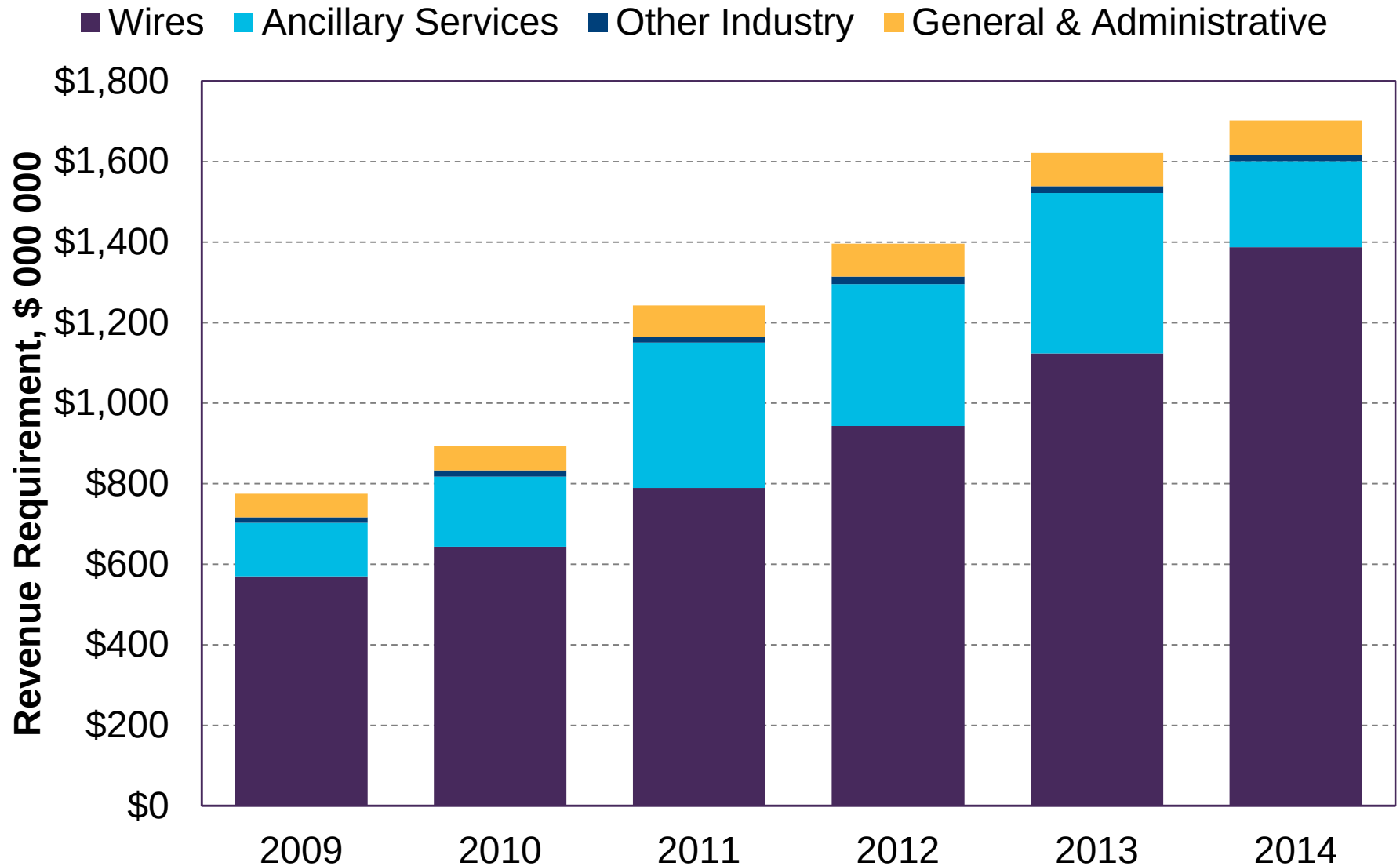
- The AESO considered three facets of the deferral account process may lead to individual charges and refunds being large compared to the net deferral account balance
 - Different bases for Rider C and rate components
 - Timing differences between Rider C collections and refunds compared to production-month reconciliations
 - Variances from forecasts of costs and revenues
- After investigation, the AESO concluded that there do not appear to be any straightforward changes to Rider C that would materially reduce the magnitude of individual charges and refunds that result from a deferral account reconciliation

Tariff updates, Rider C, and deferral account reconciliations are interrelated

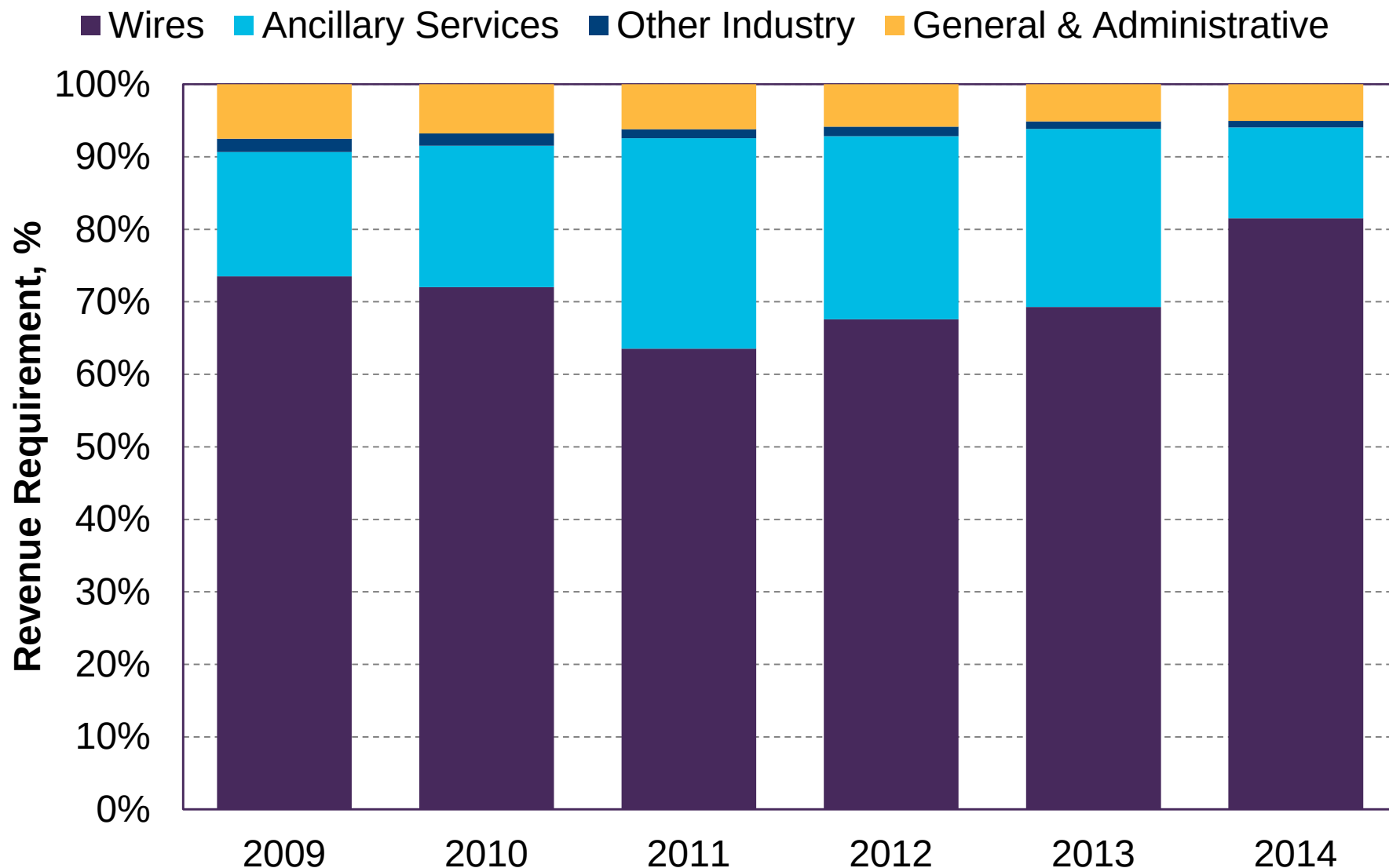


- Regular tariff update applications should reduce the magnitude of Rider C
 - The AESO filed a 2015 tariff update in August 2015
 - The AESO plans to file a 2016 tariff update in early 2016

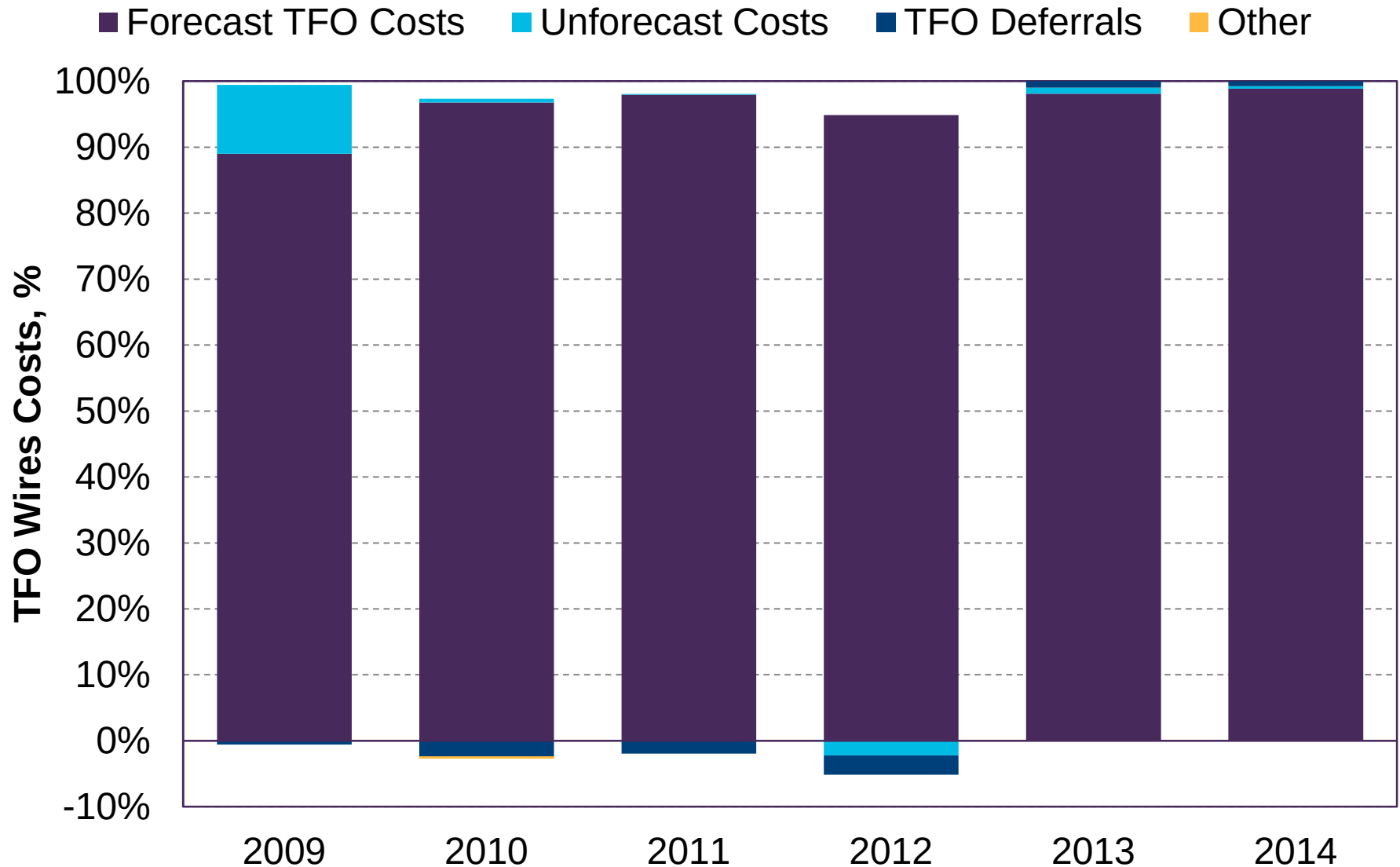
Revenue requirements are established on an annual basis



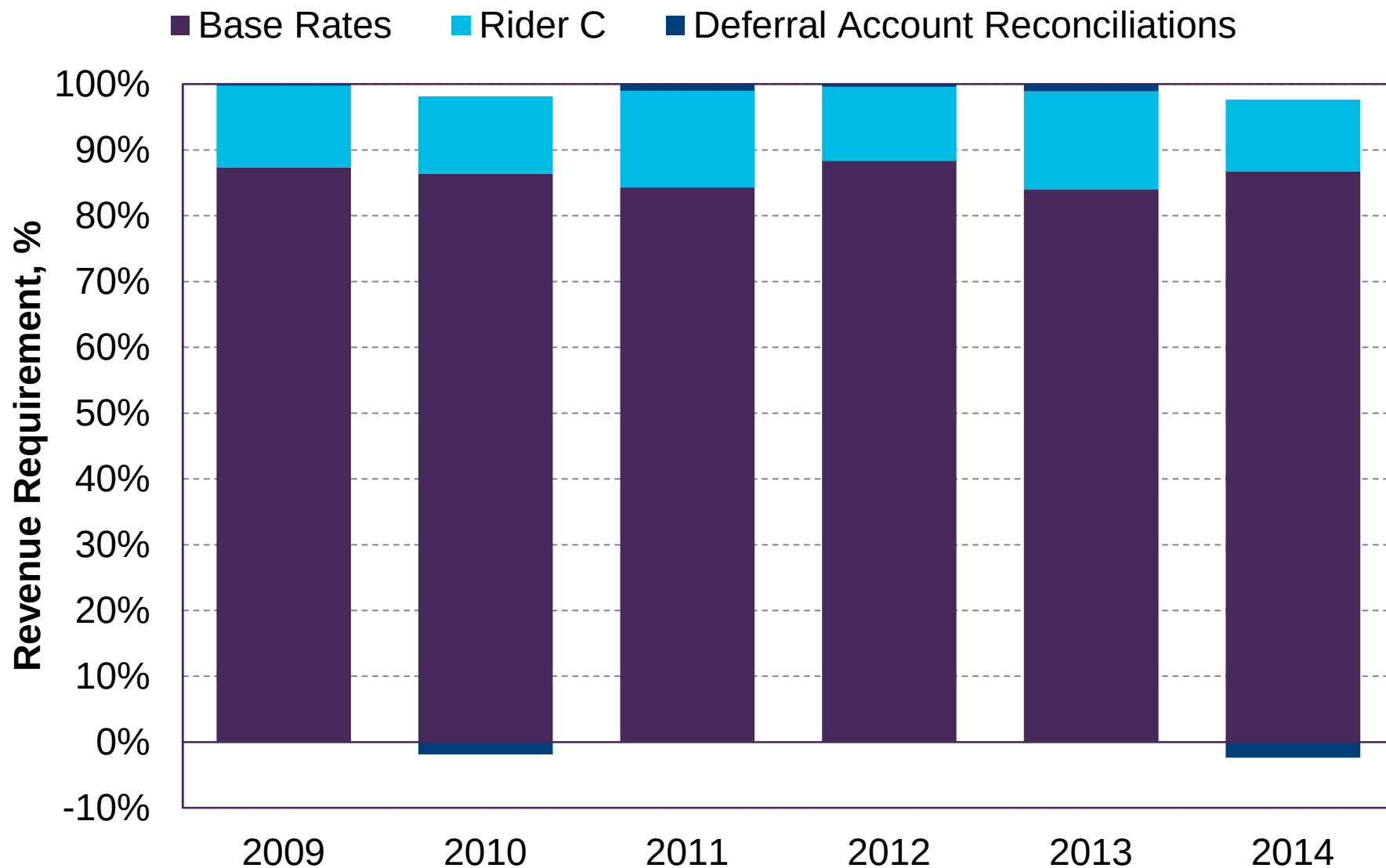
Wires costs represent 70% to 80% of total annual revenue requirement



Annual wires costs can be reasonably forecast



Rates are not keeping pace with costs



Tariff lag results in about 20% shortfall in wires cost recovery

Test Year	2007	2008	2009	2010	2011	2012	2013	2014
Wires Cost	\$458.5		\$523.7		\$786.2		\$1,113.4	\$1,371.7
Effective Dates		Aug 2008 - Sep 2009		Oct 2009 - Jun 2011		Jul 2011 - Sep 2013		Oct 2013 - Jun 2015
								J-D 15

Wires Cost Shortfall

Cost Basis for Rates

Forecast Costs for Year

Inherent Shortfall (\$)

Inherent Shortfall (%)

2009	2010	2011	2012	2013	2014
\$474.8	\$523.7	\$654.9	\$786.2	\$868.0	\$1,113.4
\$523.7	\$645.3	\$786.2	\$973.5	\$1,113.4	\$1,371.7
(\$48.8)	(\$121.6)	(\$131.3)	(\$187.3)	(\$245.4)	(\$258.3)
(9%)	(19%)	(17%)	(19%)	(22%)	(19%)

- Wires costs represent most of the revenue collected through Rider C
- Wires cost shortfalls have varied from 17% to 22% over the past five years

Early filing of tariff updates should reduce amounts collected through Rider C

- Filing tariff updates to achieve an effective date of January 1 of the test year could significantly reduce the amounts collected through Rider C
- Tariff updates would need to be filed in July or August to be approved and implemented by January 1
 - Filing would be at beginning of Budget Review Process, prior to approval of AESO budget
 - Changes that occur during the Budget Review Process would be addressed in deferral account reconciliation
- Early filing may reduce accuracy of wires cost forecasts
- Update approval process may be shortened if filing template can be implemented (similar to distribution system owner transmission deferral account rider process templates)

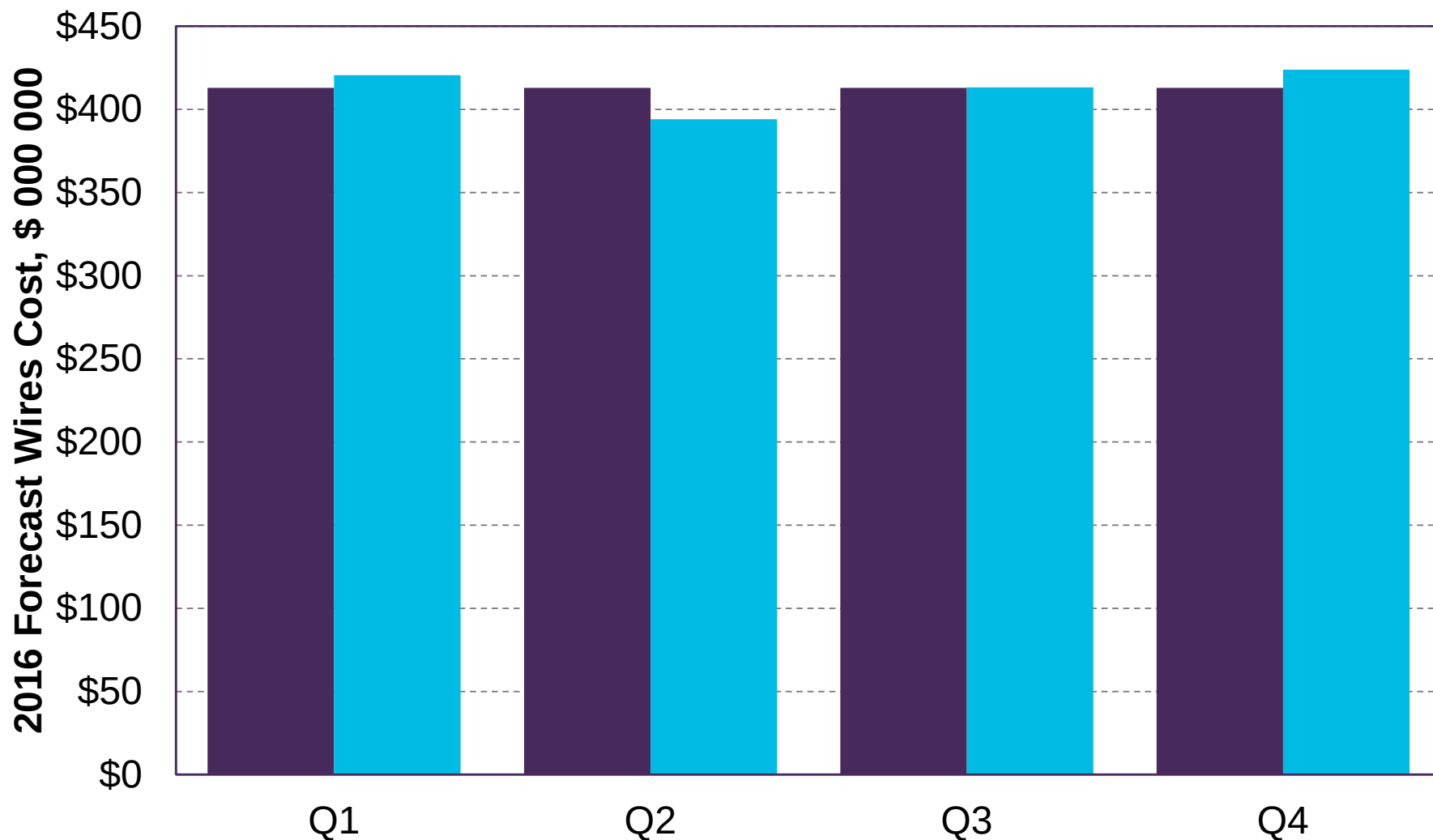
AESO's deferral account reconciliation model currently includes 2011-2013



- AESO will update model to include 2014
- Model may be able to be used to assess impact of early tariff updates
- Model has so far not revealed any straightforward changes to Rider C that would materially reduce the magnitude of reconciliation charges and refunds
- However, there may a seasonality effect in Rider C that may be easily addressed

Wires cost revenue exhibits seasonal patterns while costs do not

■ Costs ■ Revenue



Basing Rider C on forecast year-end balances may reduce seasonal effect

- Rider C must currently be calculated “to restore the deferral account balance to zero (0) over the following calendar quarter, or such longer period as determined by the ISO to minimize rate impact”
- Calculating Rider C to restore the year-end deferral account balance to zero may reduce Rider C amounts
 - AESO may be able to assess impact of change through reconciliation model
- Annual reconciliation approach may also need to be modified
 - Current approach reconciles revenues to costs on a production month basis, which ignores seasonal volume variation

Basing Rider C on year-end balances would not mitigate prior year adjustment impacts

- Prior year adjustments resulting from Commission decisions are currently recovered in one quarter
 - Such adjustments affect forecast deferral account balances at the end of the upcoming quarter
- Even if Rider C was based on year-end balances, prior year adjustments would continue to impact one or two quarters if occurring after Q2 Rider C is posted at beginning of March
 - Should balances from prior year adjustments instead be carried forward to year-end deferral account reconciliations?

Converting Rider C to a percentage basis did not have expected impact

- Rider C is a \$/MWh charge or credit, by rate component
- Using the deferral account reconciliation model, converting Rider C to a percentage charge or credit, by rate component, did not have the expected effect
 - Percentage charge or credit would reflect the \$/MW basis of the Rate DTS connection charge
 - Percentage charge or credit would also be consistent with impact of cost increases or decreases in a tariff update
- Converting to a percentage basis mitigated reconciliation charges and refunds to some extent, but primarily affected who received charges or refunds
 - Impacts likely limited by timing variances and variances between costs and revenues

Rider C is interim in nature

- Rider C revenues are re-allocated between months and between market participants in deferral account reconciliations
- Is interim nature of Rider C an issue?
- Should Rider C be made final and not reconciled?
 - That is, should Rider C be a prospective rider not subject to retrospective reconciliation?

Rider C is interim in nature (cont'd)

- Should Rider C be eliminated and deferral account balances dealt with solely through reconciliations after year-end?
 - Balances would need to be small as a result of early tariff updates
 - AESO would likely convert Rider C to an emergency cash call rider to be available, for example, if deferral account balances were forecast to exceed a specified year-end threshold

Matters for further exploration and potential quantification

- Impact of early tariff updates
- Impact of seasonal effects
- Impact of converting Rider C to a percentage basis
- Possibility of eliminating quarterly Rider C
- Possibility of moving to prospective Rider C
- Other matters?

DFOs have raised concern with operating reserve hourly flow-through charge

- Distribution facility owners have raised concern with difficulty in forecasting operating reserve charges
 - Results in volatile DFO deferral account balances and volatile DFO quarterly riders
 - Have suggested operating reserve component to DFOs could revert back to a percentage of pool price basis
- AESO considers the issue to primarily be whether the DFO or the AESO should hold operating reserve deferral account balances

DFOs have raised concern with operating reserve hourly flow-through charge (cont'd)

- Reverting to a percentage of pool price basis would likely still result in volatile Rider C charges to DFOs from quarter to quarter and volatile deferral account reconciliations
 - Charges would also reflect pool price volatility
- In general, rates and riders should not differentiate between DFOs and direct connect market participants
 - In particular, transmission-connected customers served through DFO should be charged similarly to direct connect market participants served by AESO
- Direct connect market participants previously expressed preference for hourly flow-through charge
- AESO is unclear of benefits of reverting to percentage of pool price basis for operating reserve charge

Next steps

- AESO to further explore impacts of early tariff updates and seasonal effects
 - Including quantification, if possible
- Based on results, AESO may also consider eliminating quarterly Rider C or moving to prospective Rider C
- Based on results, AESO may also consider converting Rider C to a percentage basis
- AESO will report results of exploration in future 2017 tariff consultation process
 - Will also report on findings in tariff application

Future applications

- AESO will file 2016 tariff update early in Q1 of 2016
- AESO expects to file 2017 tariff update in Q3 of 2016
 - Will be filed independently of 2017 comprehensive tariff application
- 2015 deferral account reconciliation application will be filed in Q2 of 2016
 - AESO proposing to “collapse” application sections for prior years with few adjustments, for efficiency in preparing and reviewing application
 - 2015 reconciliation application will follow methodology of other recent reconciliation applications
- Rider C and process changes, if any are proposed, would be part of 2017 comprehensive tariff application

Questions and discussion

For more information

- Contact:

LaRhonda Papworth
Manager, Tariff Applications
403-539-2555, larhonda.papworth@aeso.ca

John Martin
Senior Tariff and Regulatory Advisor
403-539-2465, john.martin@aeso.ca

- Presentation and other consultation documents will be posted on www.aeso.ca ► Tariff ► Current Consultations ► 2017 Tariff

Thank you

June 21, 2016

AESO Stakeholders
AESO 2017 ISO Tariff Consultation Participants

Dear Stakeholder:

Re: **Invitation to Participate in Consultation on AESO 2017 ISO Tariff Application**

As part of consultation for development of its 2017 ISO tariff application, the Alberta Electric System Operator (AESO) is continuing discussion with market participants on topics to be reviewed for the 2017 ISO tariff application as well as an update on work undergone to date. The AESO is holding a consultation meeting on these items and invites you to become involved in this consultation.

The meeting is scheduled as follows:

Date:	Thursday, July 7, 2016
Time:	2:00–4:00 PM
Place:	AESO Main Boardroom 2539, 25th Floor, 330 – 5th Avenue SW, Calgary, Alberta
Teleconference:	Within Calgary calling area: 403-410-3051, Conference ID 4366631 Outside Calgary calling area: 1-855-453-6957, Conference ID 4366631
RSVP:	By 5:00 PM on Monday, July 4 2016 to Brenda Hill, brenda.hill@aeso.ca or 403-539-2850

The AESO expects to discuss the following items during the meeting:

- update on annual tariff updates, deferral account reconciliations, and Rider C;
- update on point of delivery (“POD”) cost function database and transmission cost causation study methodology;
- consult on list of topics to be reviewed for the 2017 tariff application, including review of initial work on energy storage tariff treatment including a summary of the two reports attached here:
 - [*Modeling Dispatch Operations of Energy Storage Facilities in the Alberta Wholesale Electricity Market*](#), University of Calgary, May 2016; and
 - [*Comparison between Electricity Storage and Existing Alberta Site Dispatch Files*](#), AESO, January 20, 2016; and
- timeline and next steps for 2017 ISO tariff application.

The AESO plans to present information on these topics to facilitate discussion, and will post the presentation before the meeting if possible and has included the above mentioned reports for review prior to the meeting. Stakeholders may provide feedback in person during the meeting or by contacting the AESO after the meeting.

All information relating to the 2017 ISO tariff consultation will be available on the AESO website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2017 Tariff. As well, new information posted by the AESO on this topic will be mentioned in the AESO stakeholder newsletter, which you can subscribe to by clicking “Sign-up for our stakeholder newsletter” at the lower right of the AESO’s home page at www.aeso.ca.

If you have any questions on the AESO’s 2017 ISO tariff consultation, please contact me at 403-539-2555 in Calgary or by e-mail to larhonda.papworth@aesoc.ca.

Yours truly,

LaRhonda Papworth
Manager, Tariff Design

cc: Doyle Sullivan, Director – Market and Tariff Design

AESO 2017 ISO Tariff Consultation

July 7, 2016
AESO Office, Calgary

Teleconference Details

Within Calgary calling area:

403-410-3051, Conference ID 4366631

Outside of Calgary calling area:

1-855-453-6957, Conference ID 4366631

- Introduction and objectives (slide 4)
- Applications Currently in Progress (slide 5)
- Topics proposed for 2017 Tariff Application (slides 6-10)
- Energy Storage – Tariff Treatment (slides 11-33)
- Rider C/DAR/Rates Update (slides 34-36)
- Consultation process and next steps (slides 37-39)
- Discussion and wrap-up (slide 40)

Please feel free to ask questions during presentation

Stakeholder Session Objectives

- Enhance understanding of ISO tariff application
- Share information prior to filing of 2017 ISO tariff application
- Feedback to ensure tariff application provides all information stakeholders require
- Identify timeline risks for early 2017 filing

Applications Currently in Progress

- Directions 5-8 on advancement costs and related provisions
 - Decision 3473-D02-2015 issued on August 26, 2015
 - Process letter issued on October 22, 2015 with additional information on process in the new year [2016]
 - Awaiting Commission follow-up
- AESO's 2015 Deferral Account Reconciliation Application
 - Currently before the Commission in Proceeding 21735
 - Interim settlement requested for August 2016
 - Two issues: timing and treatment of primary service credit
- Interim loss factors in Rates STS, DOS, IOS, XOS
 - Currently before the Commission in Proceeding 790
 - New methodology expected to become available in 2016

Topics Proposed for 2017 Tariff Application

- Not proposing any rate structure changes
- Refinements to connection process in Sections 4 and 5 of terms and conditions
 - Associated refinements to Sections 8 and 9
- In response to Commission directions the AESO will address:
 - Contract capacity versus installed capacity for point of delivery cost function
 - Rider C and deferral accounts
 - Cost responsibility for generator compliance with the CIP Alberta reliability standards

Update Rates and Investment Levels

- Update transmission cost causation study using previous 2014 ISO tariff application methodology – initiated
 - For years 2018-2020
- Update point-of-delivery (POD) database – initiated
 - Update primary service credit ratio
- Tariff application will be based on 2017 revenue requirement
 - Will be updated with 2018 revenue requirement in compliance filing
- Bill impact analysis
- Rider J – Wind Forecasting Service Cost Recovery Rider

Terms and Conditions

Sections 4, 5, 8 and 9

Reason: Alignment with Commission Decision 3473-D02-2015 (Compliance with Directions 5 through 8)

- Address implications for system access, planning and forecasting
- AESO's continuing process to improve and refine the connection process
- Will defer to Commission-initiated proceeding (proceeding #) if started before filing of 2017 tariff application

Terms and Conditions

Miscellaneous Revisions

- Update section 10 to include Generating Unit Owner's Contribution (GUOC) rates
- Sections 4 and 5 to address revisions to tariff to align with Market Participant Choice (MPC) and Abbreviated Need Identification Document (ANID) programs
- Clarify for energy storage
- To provide transmission-connected distribution service customer an opportunity to deal directly with a TFO for a connection project
 - Financial obligation and construction contribution provisions that refer to the obligation of the TFO and the market participant
- Updates to Proformas (Appendix B) to reflect current AESO processes

- Section 11 – Ancillary Services
 - Review given fairly recent Commission decision on Transmission Constraint Management and length of time since negotiation
- Rider A1 – Transmission Duplication Avoidance Adjustment, Dow Chemical Canada Inc. / Dow Hydrocarbons / ASU2
 - Review given the “Forecast Benefit to ISO” year ends at 2021
- Climate Leadership Plan / Renewables Procurement
 - No knowledge of impact on tariff and will update if necessary when policy impacts are known

Application of ISO tariff to energy storage was identified as an issue early in initiative

- AESO launched energy storage integration initiative in September 2012
- AESO published issue identification paper in June 2013
 - Technical standards for connection and operation of energy storage
 - Application of ISO tariff to energy storage
 - Technical requirements for provision of ancillary services
 - Asset classification
 - Application of market rules to energy storage

AESO established energy storage work group to discuss and prioritize issues

- Work group identified top three priority issues
 - Develop technical and operating requirements to connect and operate energy storage
 - Determine appropriate tariff treatment for energy storage
 - Review technical requirements for provision of operating reserve by energy storage

Priority issue options were summarized in discussion paper published May 2014

- AESO began developing rules for technical and operating requirements
 - Battery facility rules became effective in April 2016
 - Existing rules applicable to other energy storage technologies
- AESO proposed review of requirements for ancillary services
 - Ensure technology neutrality
 - Consider reducing minimum unit size requirements
 - Consider shortening continuous real power requirement
 - Consider new ancillary services products
 - Consider energy storage providing inertia restoration services
 - Assess application of energy offer submission rules
 - Assess asset classification for energy storage

Discussion paper included review of tariff treatment

- ISO tariff reflects legislative requirements and Commission decisions
- Rates DTS and STS apply to sites with load and generation facilities
- Separate class of service for energy storage justified only if different costs are imposed on transmission system
- No justification to treat energy storage solely as generators
- Application of Rates DTS and STS to energy storage would need demonstration of appropriate cost causation basis
- Energy storage could not rely on Rate DOS to be a commercially viable operation

Further tariff work proposed in recommendation paper in June 2015

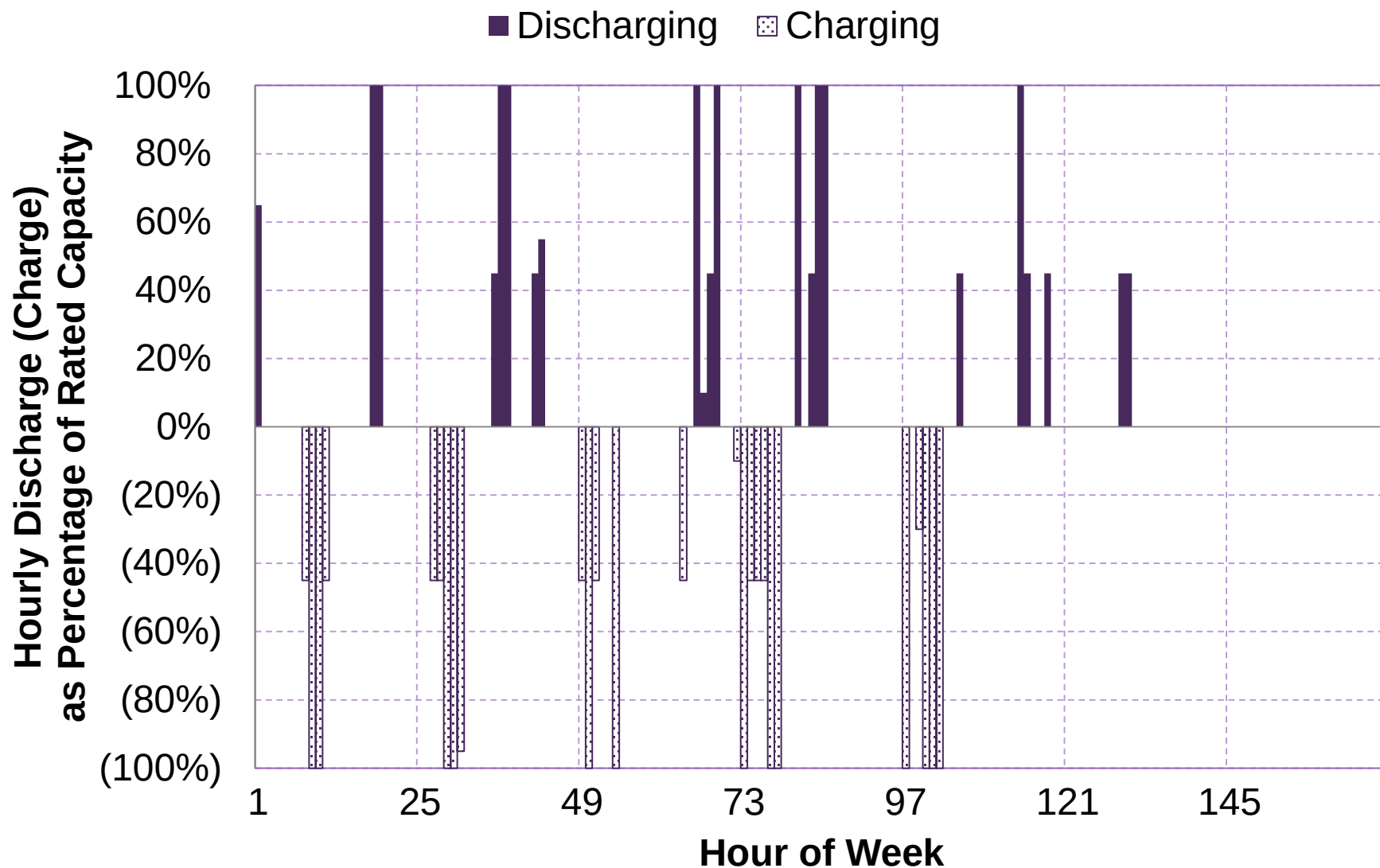
- Legislation review concluded that energy storage which offers in energy or ancillary services market cannot be a rate regulated transmission facility
 - Energy storage could be a transmission facility to meet reliability requirements but would not offer in markets
- Further study required to assess if Rates DTS and STS would be appropriate for energy storage
- Operational and economic dispatch study proposed to examine how costs should be attributed to energy storage
 - Technical parameters based on input from energy storage project proponents
 - Dispatch modelling completed by University of Calgary
 - Assessment of cost causation completed by AESO

University of Calgary completed dispatch modelling study in May 2016

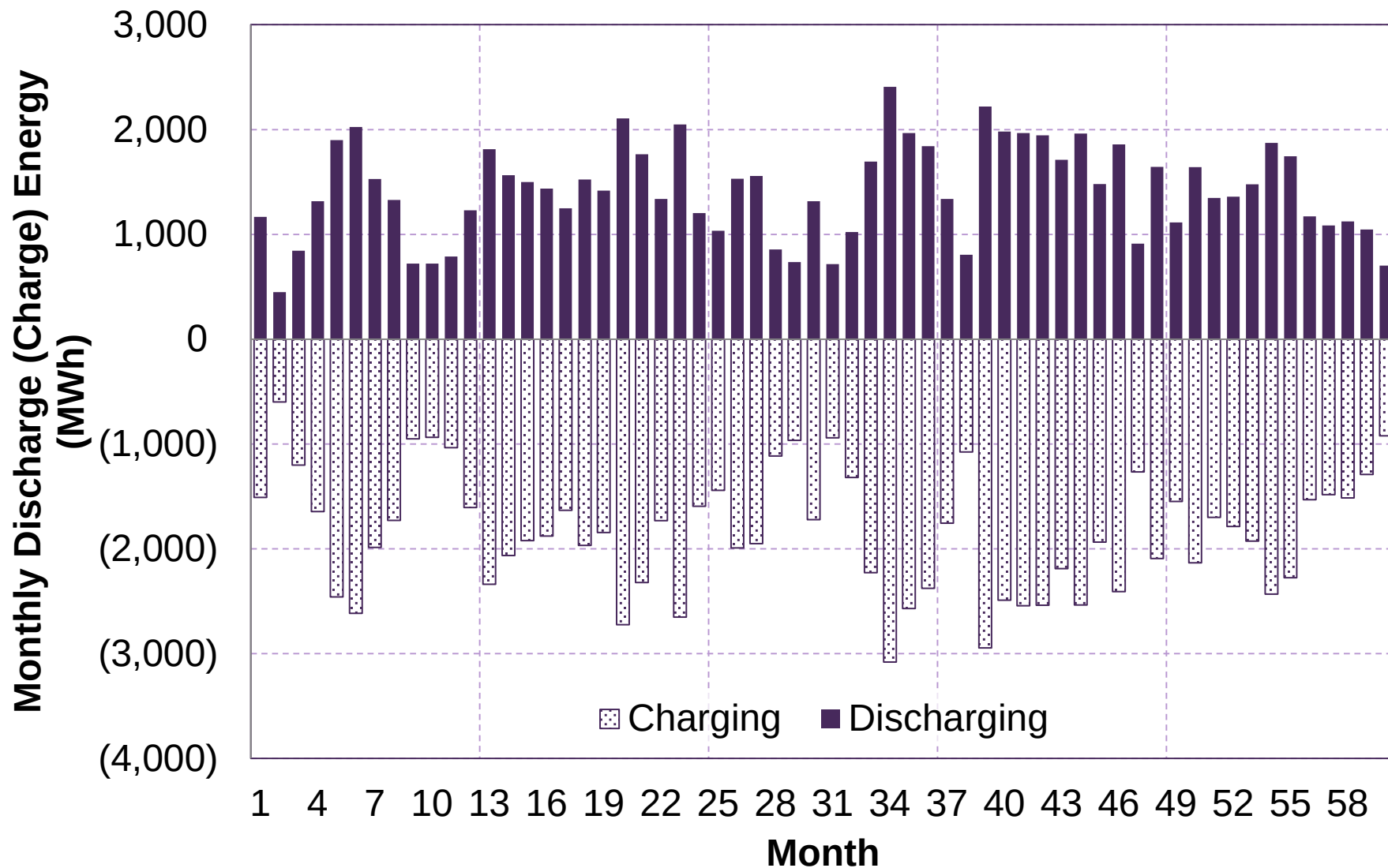


- Dispatch modelling study report posted in June 2016
 - Modelled the operation of eight energy storage facilities comprising different technologies and sizes
 - Based on actual hourly merit orders over 260 weeks from January 2010 to December 2014
 - Predicted operation of energy storage attempting to maximize profit through energy price arbitrage
- Comprehensive set of results provided to AESO
- Examples, trends, and observations provided in report

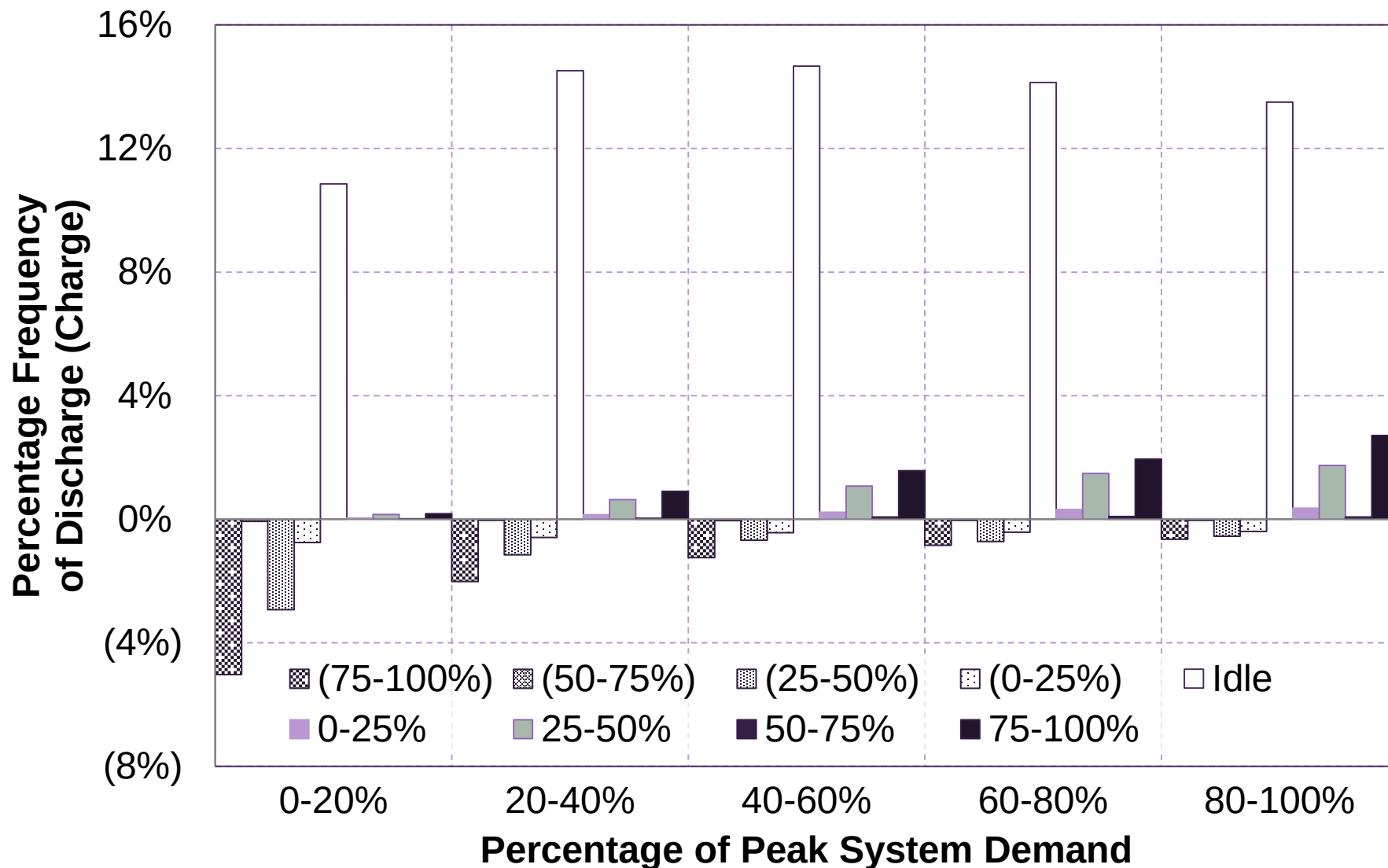
Dispatch modelling showed typical daily discharge-charge cycle



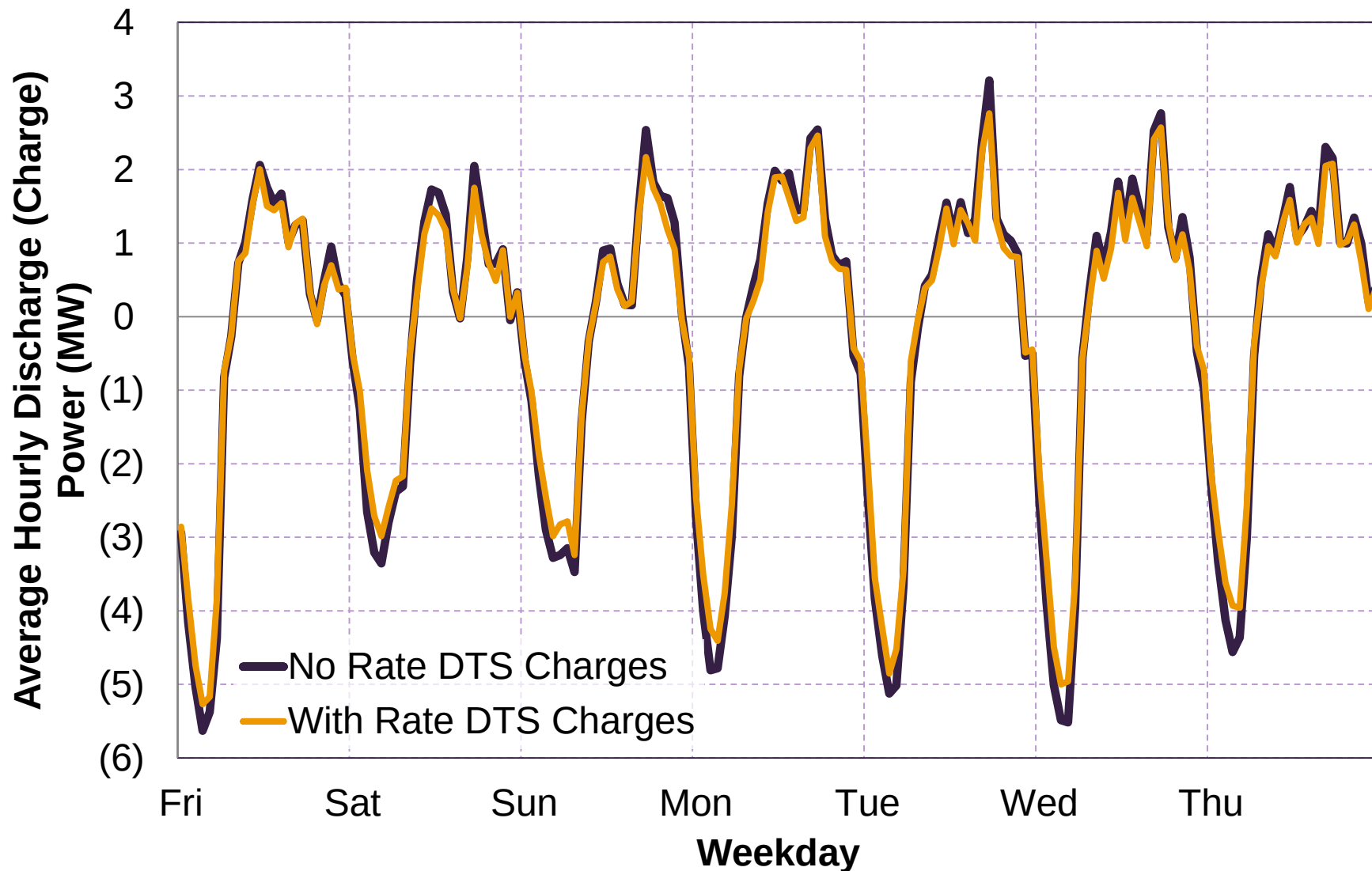
Dispatch modelling showed large monthly variability with no strong seasonal pattern



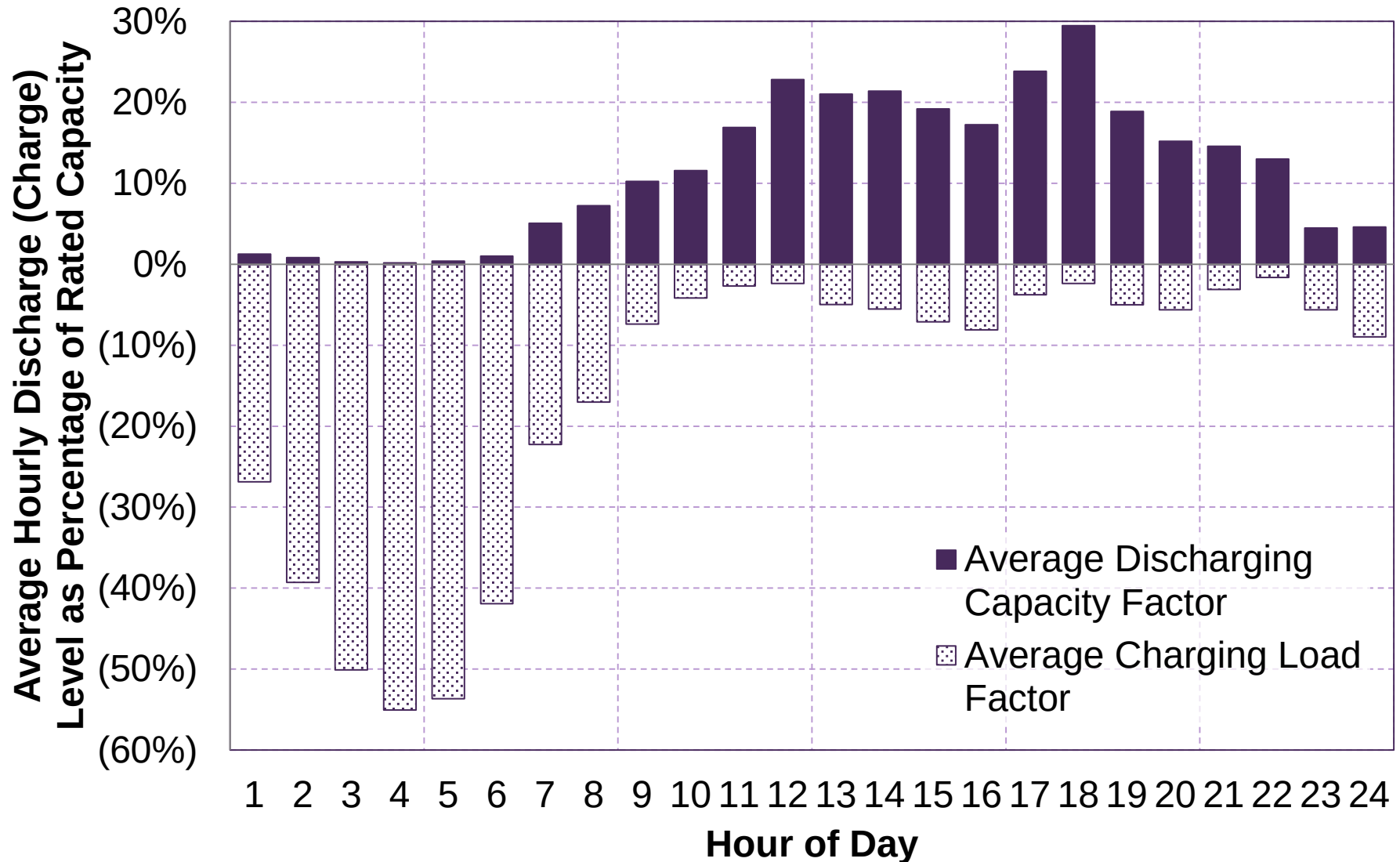
Dispatch modelling showed indirect correlation with system demand



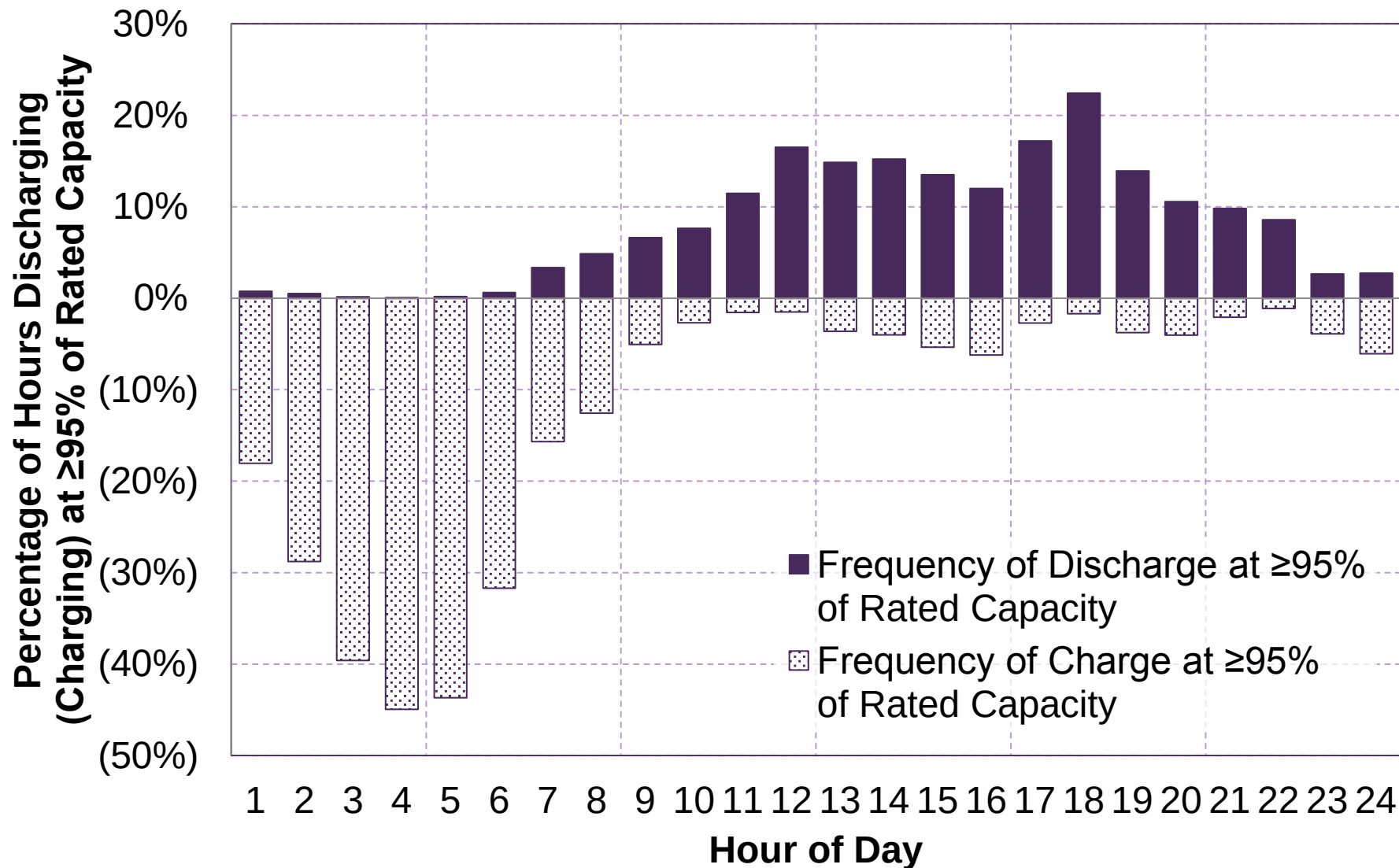
Rate DTS charges had a small impact on power flow



Hourly load factor when charging averaged from less than 10% to more than 50%



Charging at rated capacity occurred for up to 6% of daytime hours



Cost causation considerations for energy storage are similar to those for load

- Cost causation basis for bulk system charge is coincidence with system peak
 - The Commission has found that system peaks are important in the planning of the bulk transmission system [Decision 2007-106]
 - If an energy storage facility charges during system peak, it could cause bulk system costs
- Cost causation basis for regional system charge is load in any hour
 - The Commission has directed the AESO to use NCP [non-coincident peak] demand, together with a ratchet, to collect regional system costs [Decision 2007-106]
 - If an energy storage facility charges in any hour, it could cause regional system costs

Cost causation considerations for energy storage are similar to those for load (cont'd)

- Cost causation basis for point of delivery charge is load in any hour
 - The Commission has directed the AESO to use a multi-tiered NCP [non-coincident peak] demand, together with a ratchet, to collect point of delivery costs [Decision 2007-106]
 - If an energy storage facility charges in any hour, it could cause point of delivery costs
- Cost causation basis for operating reserve charge is load in the hour in which costs are incurred
 - The Commission has approved the hourly allocation of operating reserve costs [Decision 2010-606]
 - Contingency reserve volumes vary directly with hourly load and hourly generation [Reliability Standard BAL-002-WECC]

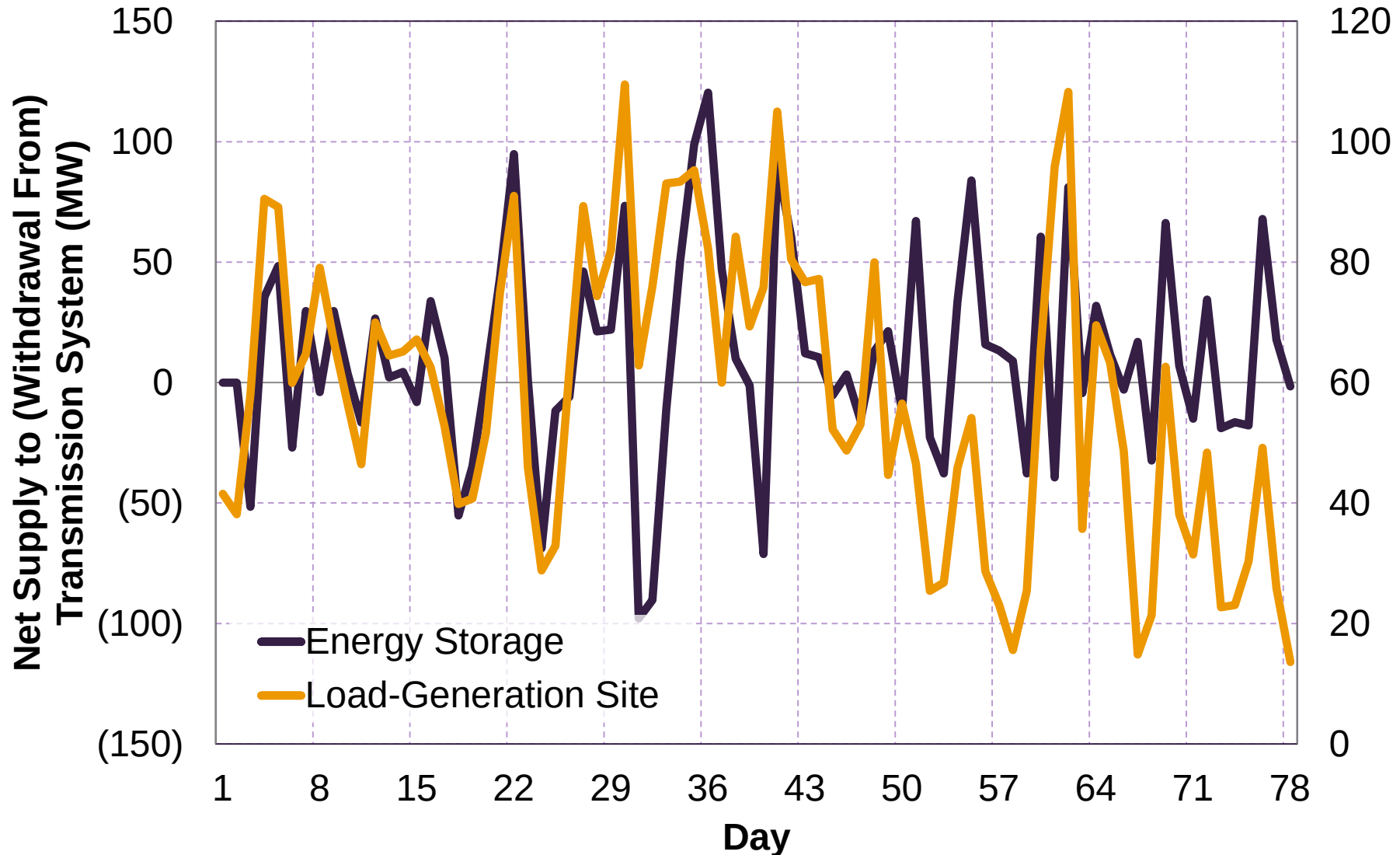
Cost causation considerations for energy storage are similar to those for load (cont'd)

- Cost causation basis for transmission constraint rebalancing charge is load in the hour in which costs are incurred
 - The Commission has approved the hourly allocation of constraint rebalancing costs [Decision 20623-D01-2015]
- Voltage control charge recovers transmission must-run costs as a variable cost through a \$/MWh energy charge [Decision 2005-096]
 - Cost causation basis reflects variable nature of transmission must-run costs that are impacted by many factors
- Other system support services charge recovers miscellaneous fixed costs through a \$/MW demand charge [Decision 2005-096]
 - Cost causation basis reflects fixed nature of costs

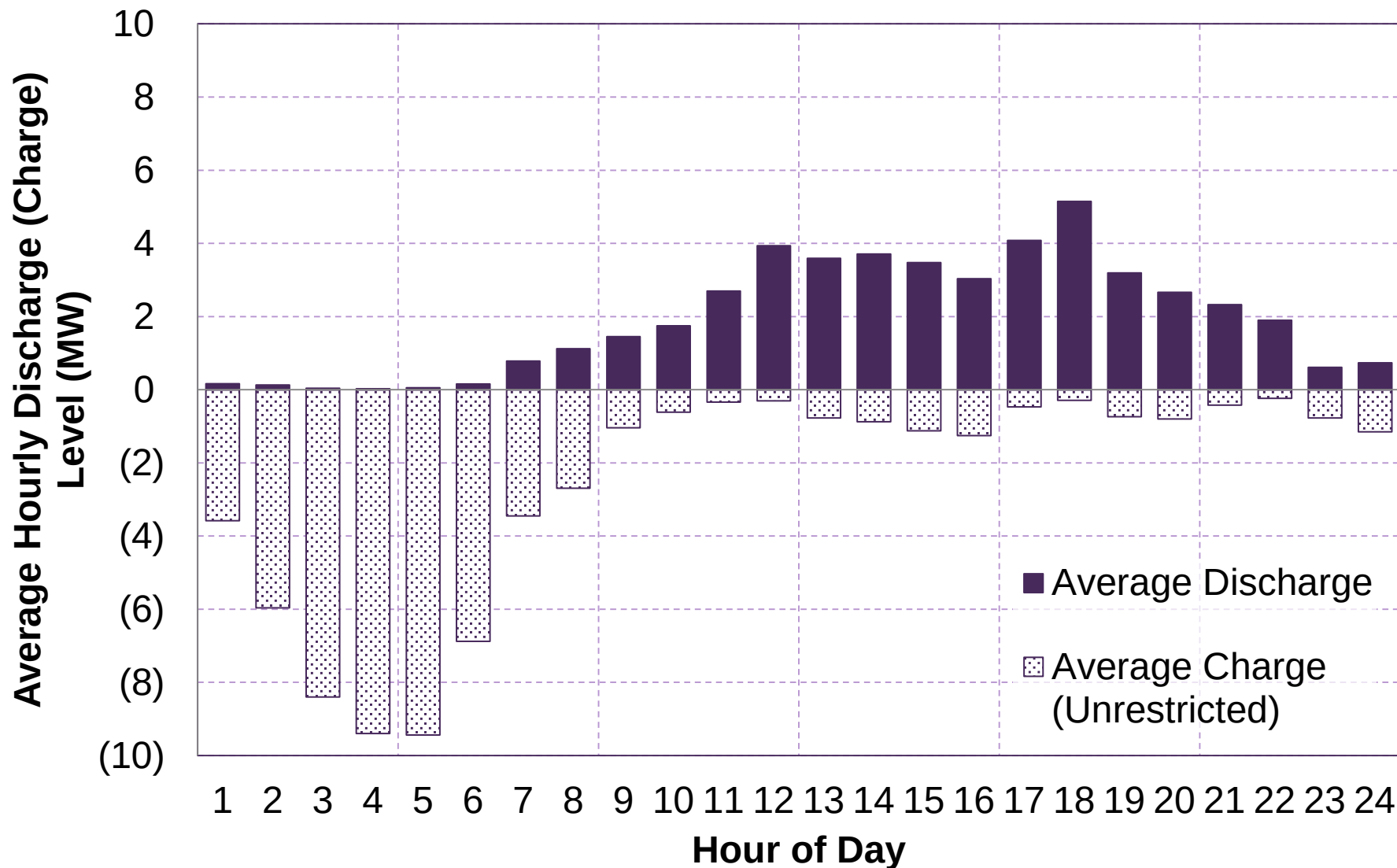
Cost causation review suggests Rate DTS appropriately applies to energy storage

- Rate DTS would apply only in hours in which an energy storage facility is charging
 - Rate STS would apply in hours in which it is discharging
- Many of the components of Rate DTS can be avoided or reduced by the energy storage participant
- The Commission has previously found the combination of Rates DTS and STS to be appropriate for sites that include load and generation
 - The Commission expressed concerns that a standby rate may not accurately reflect the costs that may be imposed by standby loads [Decision 2007-106]

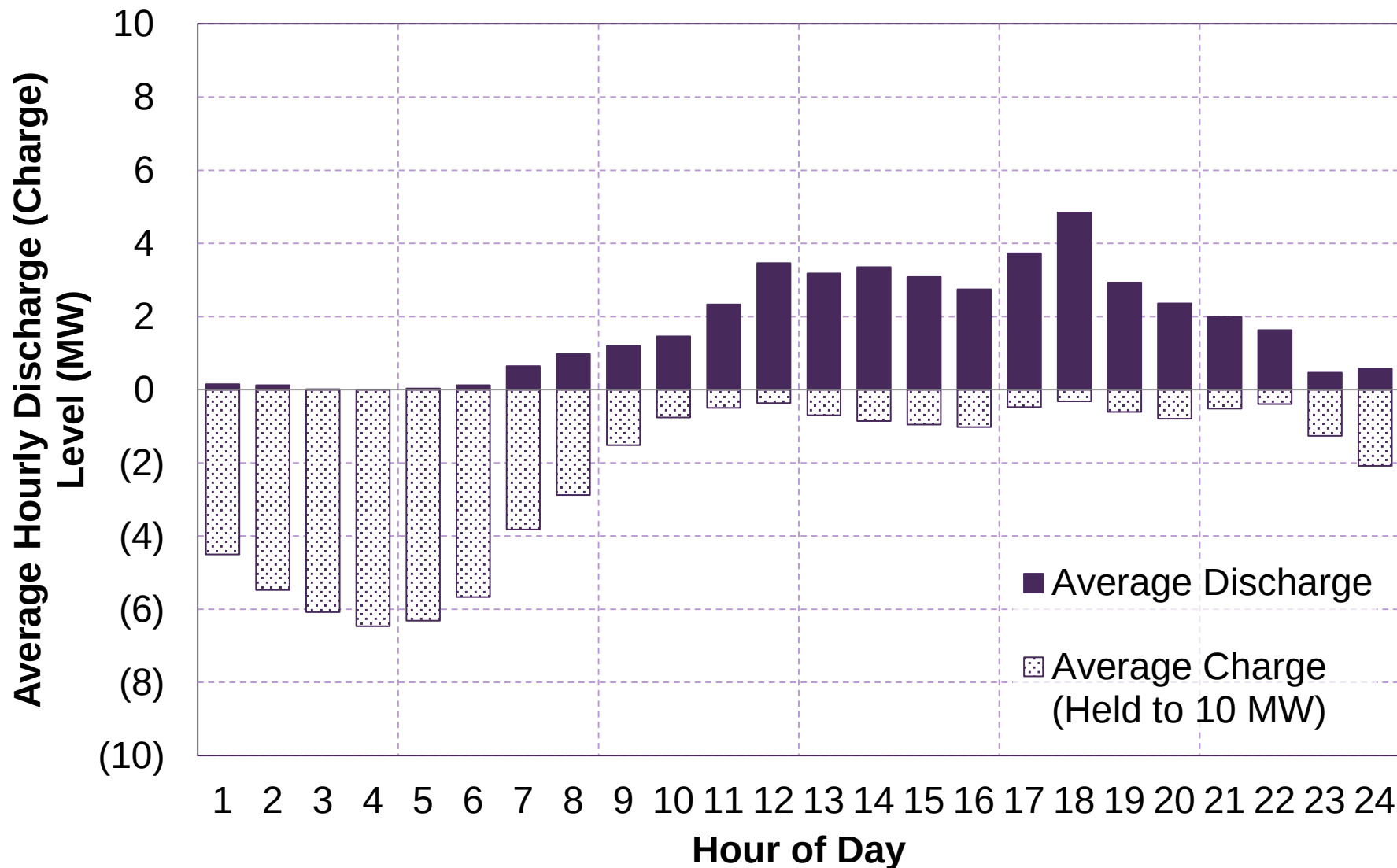
AESO comparability study found similarities between storage and load-generation sites



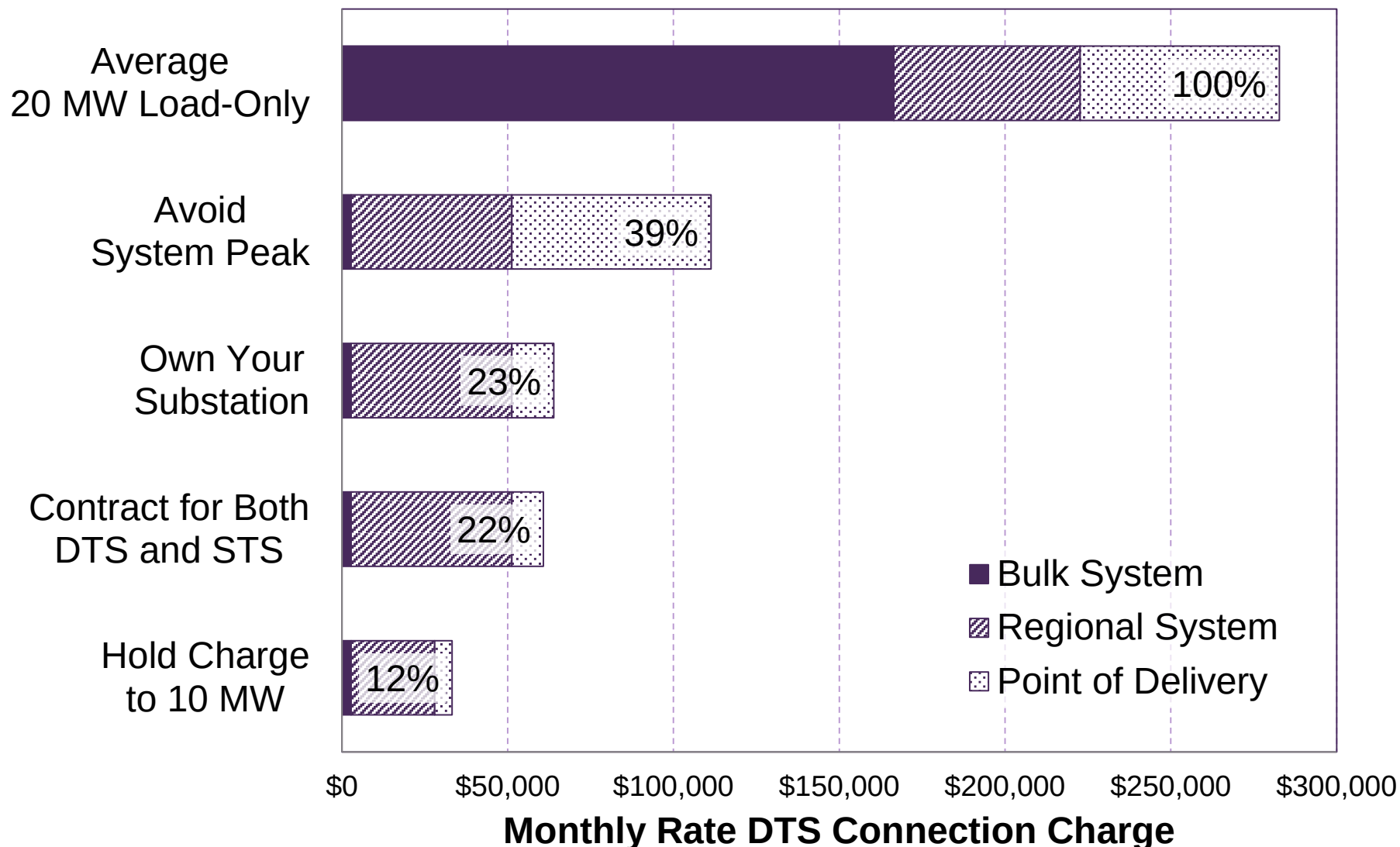
20 MW energy storage facility had average discharge-charge pattern with no restrictions



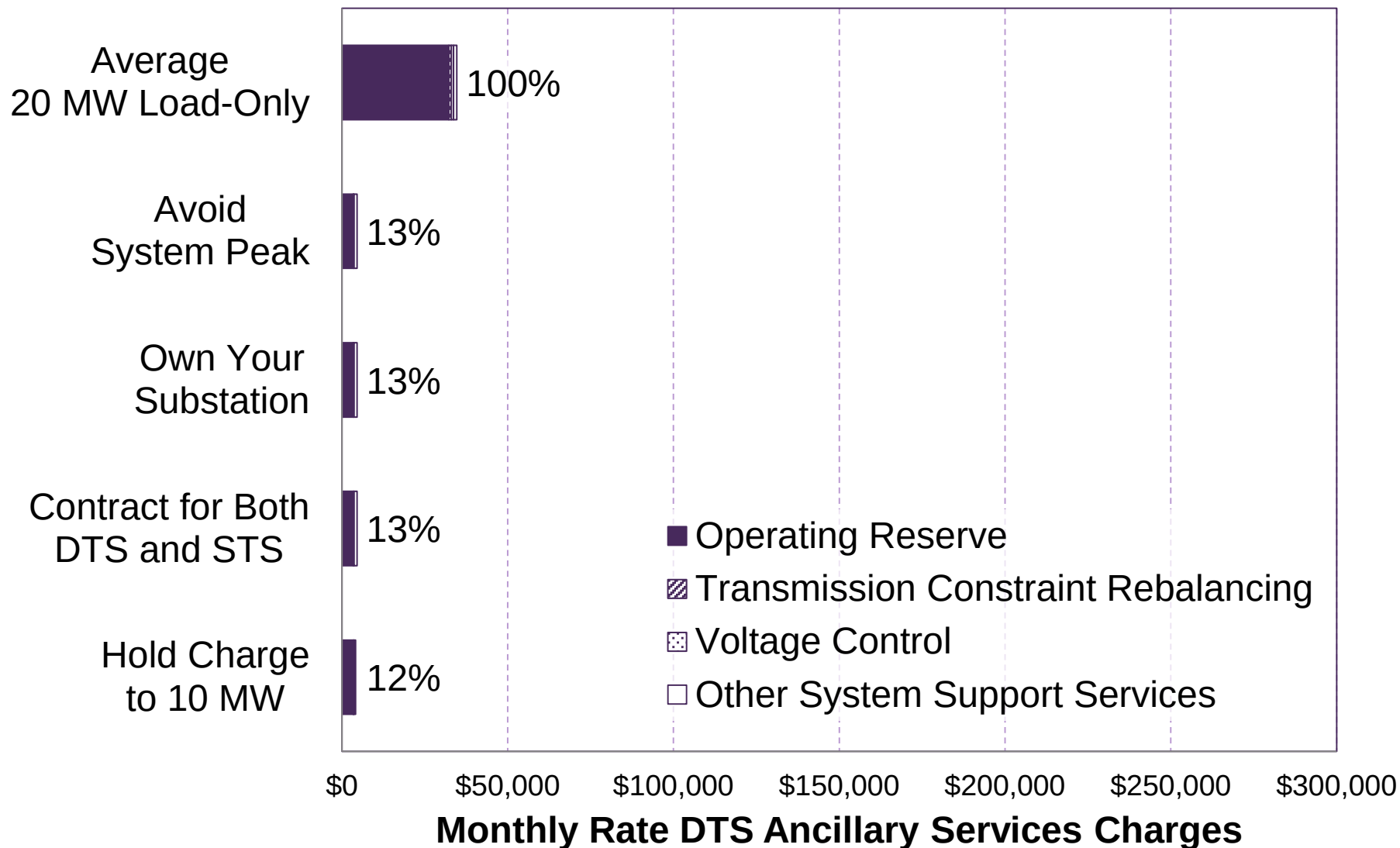
Discharge-charge pattern remained similar when charge level was held to 10 MW



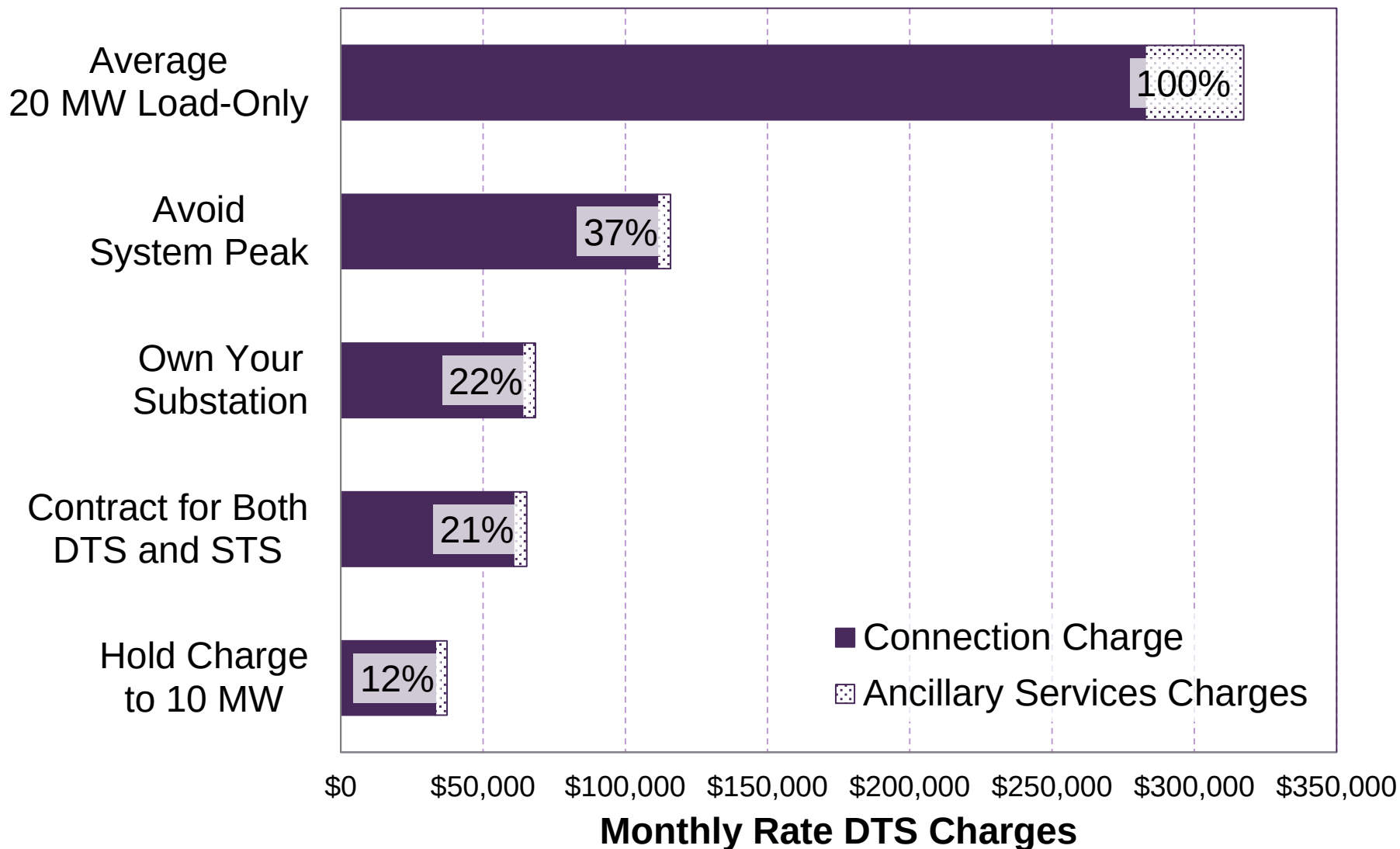
Connection charge for 20 MW storage could be 12% of charge for load-only service



Ancillary services charges for 20 MW storage could be 12% of load-only



Total Rate DTS charges for 20 MW storage could be 12% of total charges for load-only



AESO will propose Rate DTS apply to energy storage facilities when charging

- AESO will discuss use of Rates DTS and STS for energy storage facilities when charging and discharging, respectively, in its tariff application
- Rates and terminology in tariff will be updated to address energy storage facilities
 - Primarily affects applicability subsections in tariff
- Stakeholders will have opportunity to ask information requests and submit evidence on other approaches during regulatory proceeding before the Commission

- Identified in prior work that regular tariff update applications should reduce the magnitude of Rider C
 - The AESO filed 2015 tariff update in August 2015, approved by the Commission and effective January 1, 2016
 - The AESO filed 2016 tariff update in February 2016, approved by the Commission and effective April 1, 2016
- The AESO plans to file upcoming 2017 tariff update in Q3 2016
 - Update of rate and investment levels to reflect 2017 costs
 - Proposed to be effective January 1, 2017

Further work required to investigate other Rider C structure impacts – to the end of 2016:

- Impact of early tariff updates
- Impact of seasonal effects
- Impact of converting Rider C to a percentage basis
- Possibility of eliminating quarterly Rider C
- Possibility of moving to prospective Rider C

- Incorporation of primary service credit (Rate PSC) amounts in deferral account reconciliation and allocation methodology has been questioned in 2015 deferral account reconciliation proceeding
- AESO is reviewing whether modifications of Rider C or deferral account reconciliation methodology are needed to clarify treatment of Rate PSC amounts
 - Current tariff only includes Rates DTS and FTS in deferral account reconciliation and allocation methodology

Consultation Process Plan

- Consultation on Scope
 - Share information on topics to be covered in ISO tariff application (to end of July 2016)
- Specific Topic Consultation
 - Begin in September 2016 to address transmission cost causation study results
 - POD cost function database results
 - Sections 4, 5, 8 and 9 of terms and conditions
 - Rider C/DAR
 - CIP Standards cost recovery
- Application Preview
 - Early 2017

2017 ISO Tariff Application Schedule

2016

- Jul 7 2nd general consultation session
- Jul – ? 2015 DAR Regulatory Process
- Q3 File 2017 Tariff Update Application
- Q4 Specific topic consultation

2017

- Q1 Application preview
- Q1 File 2017 Tariff Application
- Q2 File 2016 DAR Application
- Q2 – Q3 Regulatory review process
- Q4 Compliance filing

Next Steps

- The AESO will invite participants to respond to this presentation through a comment matrix in the next few weeks. To allow transparency, the AESO will post all comments on AESO's website following the receipt of participants' input.
- For more information:
Contact LaRhonda Papworth - Manager, Tariff Design
403-539-2555 or larhonda.papworth@aeso.ca
- All consultation documents can be found on AESO website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2017 Tariff

Discussion

- Questions?

Request for Stakeholder Comments on Scope of AESO 2017 ISO Tariff Consultation

Background

On July 7, 2016, the AESO and stakeholders participated in a consultation meeting to discuss (1) the scope of changes to be included in the AESO's 2017 ISO tariff application, (2) AESO's proposed energy storage tariff treatment, (3) Rider C/deferral account reconciliation process update, and (4) AESO's consultation plan. Based on discussion at the meeting, the AESO invites written comments from stakeholders on the information presented at the meeting. The meeting presentation is posted on the AESO website and can be accessed at www.aeso.ca by following the path Tariff ► Current Consultations ► 2017 Tariff.

Please use the comment form below when submitting comments to the AESO on the 2017 ISO tariff consultation scope and other matters. Please ensure that your comments represent all interests within your stakeholder organization with respect to the consultation. Please provide comments or questions no later than **September 1, 2016**, to LaRhonda Papworth at larhonda.papworth@aeso.ca or 403-539-2555.

Consultation and Stakeholder Identification

Date of Request for Comments:	July 26, 2016
Period of Consultation:	July 7 – September 1, 2016
Comments From:	
Date:	
Contact:	
Phone:	
Email:	

Stakeholder Comments on AESO Information

Stakeholder Comment	
2017 ISO Tariff Application Topics	
1(a)	<i>In its presentation for the 2017 ISO tariff application, the AESO proposed the following topics would be included in the application:</i>
i.	<i>Not proposing any rate structure changes;</i>
ii.	<i>Refinements to the connection process in Section 4 – System Access Service Requests and Section 5 – Financial Obligations for Connection Projects as well as associated refinements to Section 8 – Construction Contributions for Connection Projects and Section 9 – Changes to System Access Service After Energization; and</i>
iii.	<i>In response to directions from the Commission the AESO will address contract capacity versus installed capacity for point of delivery cost function, Rider C – Deferral Account Adjustment Rider and deferral accounts, and cost responsibility for generator compliance with the CIP Alberta reliability standards.</i>

Stakeholder Comment

Stakeholder Comments:

- 1(b) The 2017 ISO tariff application will also include:**
- i. Updates to the transmission cost causation study (for years 2018 – 2020) using the previous 2014 ISO tariff application methodology;**
 - ii. Updates to the point-of-delivery (POD) database, including an update to the primary service credit ratio;**
 - iii. The 2017 revenue requirement and will be updated with 2018 revenue requirement in compliance filing;**
 - iv. Bill impact analysis; and**
 - v. Update to Rider J – Wind Forecasting Service Cost Recovery Rider**

Stakeholder Comments:

TERMS AND CONDITIONS REVISIONS

- 2(a) The 2017 ISO tariff application will require 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). These changes will have implications for system access, planning and forecasting and are part of AESO's continuing process to improve and refine the connection process. This work will defer to the Commission-initiated proceeding (Proceeding 20922) if the Proceeding 20922 starts before filing of the 2017 ISO tariff application.**

Stakeholder Comments:

- 2(b) Other changes to the ISO tariff's terms and conditions will include:**
- i. Updates to Section 10 – Generating Unit Owner's Contribution (GUOC) to include GUOC rates; and**
 - ii. Changes to sections 4 and 5 to address revisions to align with Market Participant Choice (MPC) and Abbreviated Need Identification Document (ANID) programs;**
 - iii. Clarifications for energy storage;**
 - iv. Allow transmission-connected distribution service customer an opportunity to deal directly with the transmission facility owner (TFO) directly for a connection project; and**
 - v. Updates to proformas (Appendix B) to reflect current AESO processes.**

Stakeholder Comments:

TOPICS ON THE HORIZON

- 3(a) Other topics may be included in the 2017 ISO tariff application. The AESO is determining resources and timeline impacts for these items at this time:**
- i. Section 11 – Ancillary Services review given fairly recent Commission decision on Transmission Constraint Management (TCM) and the length of time since this section was**

Stakeholder Comment

negotiated;

- ii. Rider A1 – Dow Chemical Canada Inc./Dow Hydrocarbons/ASU2 review given the “Forecast Benefit to ISO” year ends at 2021 as written currently; and*
- iii. Climate Leadership Plan / Renewable Electricity Program impacts and tariff are not known at this time. Any tariff revisions required will be made once policy is finalized.*

Stakeholder Comments:

ENERGY STORAGE

4(a) Dispatch Modelling Study results and analysis:

- i. Dispatch modelling showed indirect correlation with system demand;*
- ii. Rate DTS charges had a small impact on power flow;*
- iii. Hourly load factor when charging averaged from less than 10% to more than 50%; and*
- iv. Charging at rated capacity occurred for up to 6% of daytime hours.*

Stakeholder Comments:

4(b) Cost causation considerations for energy storage are similar to those for load:

- i. If an energy storage facility charges during system peak, it could cause bulk system costs;*
- ii. If an energy storage facility charges in any hour, it could cause regional system costs;*
- iii. If an energy storage facility charges in any hour, it could cause point of delivery costs;*
- iv. Load in the hour causes operating reserve charge costs in that hour;*
- v. Load in the hour also causes transmission constraint rebalancing costs in that hour;*
- vi. Variable nature of transmission must-run costs are appropriately recovered through a \$/MWh energy charge; and*
- vii. Fixed nature of other system support services costs are appropriately recovered through a \$/MW demand charge.*

Stakeholder Comments:

4(c) Cost causation review suggests Rate DTS appropriately applies to energy storage:

- i. Rate DTS would apply only in hours in which an energy storage facility is charging and Rate STS would apply in hours in which the facility is discharging;*
- ii. Many of the components of Rate DTS can be avoided or reduced by the energy storage participant; and*
- iii. The Commission has previously found the combination of Rates DTS and STS to be appropriate for sites that include load and generation.*

Stakeholder Comments:

4(d) Rate DTS charges for a 20 MW storage service could be reasonably reduced compared to

Stakeholder Comment

a 20 MW load-only service by the energy storage facility:

- i. avoiding system peak;*
- ii. owning its own substation;*
- iii. contracting for both DTS and STS; and*
- iv. limiting charging rate to 50% of the discharging rate.*

Stakeholder Comments:

Rider C / Deferral Account Reconciliation Process Update

5(a) *In prior work, the AESO identified, and consulted with stakeholders, that regular tariff update applications should reduce the magnitude of Rider C. The AESO plans to file an upcoming 2017 tariff update application in Q3 2016. The 2017 tariff update application will include an update of rate and investment levels to reflect 2017 costs and proposed to be effective January 1, 2017*

Stakeholder Comments:

5(b) *Further work is required to investigate other Rider C structure impacts. This work is ongoing until the end of 2016 and will review the impact of early tariff updates, seasonal effects, converting Rider C to a percentage basis as well as review the possibility of eliminating quarterly Rider C and possibility of moving to prospective Rider C.*

Stakeholder Comments:

5(c) *Incorporation of primary service credit (Rate PSC) amounts in deferral account reconciliation and allocation methodology has been questioned in the 2015 deferral account reconciliation proceeding. AESO is reviewing whether modifications of Rider C or deferral account reconciliation methodology are needed to clarify treatment of Rate PSC amounts.*

Stakeholder comments:

2017 ISO Tariff Application Consultation Process Plan

6(a) *AESO is proposing the following steps for consultation on the 2017 ISO tariff application:*

- i. Consultation on scope;*
- ii. Specific topic consultation to begin in September to address transmission cost causation study results, POD cost function database results, Sections 4, 5, 8 and 9 of terms and conditions, Rider C/DAR process and CIP standards generator cost recovery; and*
- iii. Application preview (early 2017).*

Stakeholder Comments:

Stakeholder Comment
<i>Additional Comments</i>

Please return this form with your comments by **September 1, 2016**, to:

LaRhonda Papworth
Manager, Tariff Design
Email: larhonda.papworth@aeso.ca
Phone: (403) 539-2555
Fax: (403) 539-2524

Consolidated Stakeholder Comments on Scope of AESO 2017 ISO Tariff Consultation

Background

On July 7, 2016, the AESO and stakeholders participated in a consultation meeting to discuss (1) the scope of changes to be included in the AESO's 2017 ISO tariff application, (2) AESO's proposed energy storage tariff treatment, (3) Rider C/deferral account reconciliation process update, and (4) AESO's consultation plan. 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 ► Current Consultations ► 2017 Tariff.

Stakeholder Comments on AESO Information

Stakeholder Comment	
2017 ISO Tariff Application Topics	
1(a)	<i>In its presentation for the 2017 ISO tariff application, the AESO proposed the following topics would be included in the application:</i>
i.	<i>Not proposing any rate structure changes;</i>
ii.	<i>Refinements to the connection process in Section 4 – System Access Service Requests and Section 5 – Financial Obligations for Connection Projects as well as associated refinements to Section 8 – Construction Contributions for Connection Projects and Section 9 – Changes to System Access Service After Energization; and</i>
iii.	<i>In response to directions from the Commission the AESO will address contract capacity versus installed capacity for point of delivery cost function, Rider C – Deferral Account Adjustment Rider and deferral accounts, and cost responsibility for generator compliance with the CIP Alberta reliability standards.</i>

Alberta Direct Connect Consumers Association (“ADC”):

ADC supports the AESO in not proposing any rate structure changes. ADC offers to work collaboratively with the AESO to address concerns with Rider C and deferral account matters.

The Alberta Storage Alliance (“ASA”):

[blank]

Capital Power:

Capital Power supports inclusion of the above topics in the 2017 General Tariff Application (“GTA”).

Ed dePazieux:

A thorough analysis will be required to assess installed capacity vs. contract capacity. Will have comments once the structure of the analysis and outcomes are made clear.

EPCOR Distribution & Transmission Inc. (“EDTI”):

[blank]

ENMAX Corporation (“EEC”):

EEC supports review of the cost responsibility for generator compliance with the CIP Alberta Reliability Standards (“ARS”). Participants who are obligated to comply with CIP ARS should have their costs recovered through the ISO Tariff.

Industrial Power Consumers Association of Alberta (“IPCAA”):

- IPCAA is supportive of the current rate structure in terms of it promoting “user pays” principles.
 - If the AESO is contemplating a working group on Rider C, deferral accounts or cost responsibility for generator compliance with the CIP standards, IPCAA would like to participate.
 - IPCAA does not support consumers being allocated the cost responsibility for generator CIP compliance.
-

NextEra Energy Canada:

[blank]

NRStor Inc.:

[blank]

Renewable Energy Systems Canada Inc. (“RES”):

[Letter submitted by RES. Letter content included in “Other Comments” at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. (“RMP”):

[blank]

Temporal Power Ltd.:

[blank]

1(b) The 2017 ISO tariff application will also include:

- i. Updates to the transmission cost causation study (for years 2018 – 2020) using the previous 2014 ISO tariff application methodology;*
 - ii. Updates to the point-of-delivery (POD) database, including an update to the primary service credit ratio;*
 - iii. The 2017 revenue requirement and will be updated with 2018 revenue requirement in compliance filing;*
 - iv. Bill impact analysis; and*
 - v. Update to Rider J – Wind Forecasting Service Cost Recovery Rider*
-

Alberta Direct Connect Consumers Association (“ADC”):

ADC is supportive of the items included in the 2017 ISO tariff application.

The Alberta Storage Alliance (“ASA”):

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 to assessing the services offered by various energy assets; we believe 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. Further information on the ASA and our initiatives can be found on our website (<http://albertastoragealliance.com/>) and in our recently released White

Paper: Energy Storage – Unlocking the Value for Alberta’s Grid.

The ASA is encouraged to see that the AESO is opening a dialogue on how to best manage the integration of energy storage assets in the Alberta market. However, the ASA believes changes to rate structures should be given further consideration before any final decision is made. 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.

The ASA will continue to work with the AESO and other stakeholders to identify services and applications where energy storage can offer benefits to Alberta’s electric grid. As part of this collaboration, we recommend conducting a technical review to determine what services (existing or new) are required to help maintain a reliable electric grid going forward. Part of this assessment should include a review of whether assets solely providing system stability services should be exempt from certain prohibitive tariffs. For example, a Standard Transmission Service rate for grid-connected storage offering only Operating Reserves would avoid “double charging” such assets under existing regulations and tariffs. Other jurisdictions (CAISO, PJM, IESO, etc.) have introduced legislation to address the perceived “double counting conundrum” whereby storage facilities must pay retail rates for loading and generating, despite operating to provide reliability services to the 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.

Capital Power:

Capital Power supports inclusion of the above topics in the 2017 GTA.

Please provide an estimated date when the updated cost causation study will be provided to stakeholders for review. Capital Power requests that the AESO hold a stakeholder session following the study’s release to review the results and address stakeholder questions.

Capital Power requests that the AESO commit to providing an updated Transmission Rate Impact Projection (“TRIP”) model as part of the AESO’s 2017 GTA. The TRIP model is a comprehensive and detailed document that is helpful to market participants in assessing long-term transmission cost projections and the impacts of rate and tariff design changes. A stakeholder session to review the updated TRIP model would be beneficial.

Ed dePazieueux:

Agree that the AESO should perform the cost causation study in-house.

EPCOR Distribution & Transmission Inc. (“EDTI”):

[blank]

ENMAX Corporation (“EEC”):

[blank]

Industrial Power Consumers Association of Alberta (“IPCAA”):

- Will the updates to the transmission cost causations study require external consultants? What is the expected timeline on this project?
-

NextEra Energy Canada:

[blank]

NRStor Inc.:

NRStor Inc. (NRStor) is a member of The Alberta Storage Alliance (ASA). The 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. NRStor, alongside the ASA, is advocating a technology neutral approach to assessing the services offered by various energy assets; we believe 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. Further information on the ASA and its initiatives can be found on its website (<http://albertastoragealliance.com/>) and in its recently released White Paper: Energy Storage – Unlocking the Value for Alberta’s Grid.

NRStor is encouraged to see that the AESO is opening a dialogue on how to best manage the integration of energy storage assets in the Alberta market. However, NRStor believes changes to rate structures should be given further consideration before any final decision is made. 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.

As a member of the ASA, NRStor will continue to work with the AESO and other stakeholders to identify services and applications where energy storage can offer benefits to Alberta’s electric grid. As part of this collaboration, we recommend conducting a technical review to determine what services (existing or new) are required to help maintain a reliable electric grid going forward. Part of this assessment should include a review of whether assets solely providing system stability services should be exempt from certain prohibitive tariffs. For example, a Standard Transmission Service rate for grid-connected storage offering only Operating Reserves would avoid “double charging” such assets under existing regulations and tariffs. Other jurisdictions (CAISO, PJM, IESO, etc.) have introduced legislation to address the perceived “double counting conundrum” whereby storage facilities must pay retail rates for loading and generating, despite operating to provide reliability services to the 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.

Renewable Energy Systems Canada Inc. (“RES”):

[Letter submitted by RES. Letter content included in “Other Comments” at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. (“RMP”):

RMP has been an advocate for changes to the AESO’s rate structure. Specifically, RMP has advocated that the AESO develop and implement Energy Storage Opportunity Service (“ESOS”) rates. The AESO has refused to do so as indicated in 1(a) i. above. In addition, in the AESO’s 2017 ISO Tariff Consultation held on July 7th, 2017, on slide # 33 the AESO states:

AESO will discuss use of Rates DTS and STS for energy storage facilities when charging and discharging, respectively, in its tariff application

•Rates and terminology in tariff will be updated to address energy storage facilities Primarily affects applicability subsections in tariff

•Stakeholders will have opportunity to ask information requests and submit evidence on other approaches during regulatory proceeding before the Commission

In other words, the AESO has decided that it will NOT consider, discuss nor contemplate any alternative tariff structure, or types transmission rates, that could apply to grid connected energy storage facilities. RMP wonders why the AESO is even asking for comments on its position regarding the appropriateness of the DTS rate for energy storage facilities because clearly the AESO has decided that it will apply a combination of the DTS and STS rates for energy storage facilities without any further discussion.

RMP disagrees with the AESO’s decision to apply DTS and STDS rates to grid connected energy storage facilities without further consultation. RMP recommends that the AESO engage in a true consultative

process regarding the appropriate rates for grid connected energy storage facilities. The Collaborative Industry Dialogue and Issue Resolution (“CIDIR”) process that the AESO is part of would be a good forum for engaging in real consultation regarding the appropriate rates to be applied to energy storage facilities of all types. CODIR consultations could result in substantially reduced time and litigation expenses for the AESO, its ratepayers, storage proponents and all other industry stakeholders.

Temporal Power Ltd.:

Temporal Power Ltd. (Temporal) is a member of The Alberta Storage Alliance (ASA). The 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. Temporal, alongside the ASA, is advocating a technology neutral approach to assessing the services offered by various energy assets; we believe 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. Further information on the ASA and its initiatives can be found on its website (<http://albertastoragealliance.com/>) and in its recently released White Paper: Energy Storage – Unlocking the Value for Alberta’s Grid.

Temporal is encouraged to see that the AESO is opening a dialogue on how to best manage the integration of energy storage assets in the Alberta market. However, Temporal believes changes to rate structures should be given further consideration before any final decision is made. 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.

As a member of the ASA, Temporal will continue to work with the AESO and other stakeholders to identify services and applications where energy storage can offer benefits to Alberta’s electric grid. As part of this collaboration, we recommend conducting a technical review to determine what services (existing or new) are required to help maintain a reliable electric grid going forward. Part of this assessment should include a review of whether assets solely providing system stability services should be exempt from certain prohibitive tariffs. For example, a Standard Transmission Service rate for grid-connected storage offering only Operating Reserves would avoid “double charging” such assets under existing regulations and tariffs. Other jurisdictions (CAISO, PJM, IESO, etc.) have introduced legislation to address the perceived “double counting conundrum” whereby storage facilities must pay retail rates for loading and generating, despite operating to provide reliability services to the grid. Temporal 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.

TERMS AND CONDITIONS REVISIONS

2(a) *The 2017 ISO tariff application will require 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). These changes will have implications for system access, planning and forecasting and are part of AESO’s continuing process to improve and refine the connection process. This will work will defer to the Commission-initiated proceeding (Proceeding 20922) if the Proceeding 20922 starts before filing of the 2017 ISO tariff application.*

Alberta Direct Connect Consumers Association (“ADC”):

No Comment.

The Alberta Storage Alliance (“ASA”):

The ASA recognizes the importance of system access, planning and forecasting and believes the inclusion of energy storage technologies will be crucial in this process. The ASA has released a White Paper outlining its recommendations for the Alberta electricity sector. A key recommendation was for the AESO to collaborate with the ASA in order to conduct a detailed technical review of energy storage technologies to determine what services (existing or new) are required to help maintain a reliable electric grid, and to understand the services and applications where energy storage can offer benefits to the Alberta grid. Ontario’s IESO recently released a technical report on energy storage, which focuses on the reliability needs of the local power system and the potential for energy storage technologies to address those needs, which we believe is worth referencing in this dialogue.

The ASA believes energy storage technologies should be given due consideration as an alternative to incumbent technologies during system planning and forecasting efforts. We look forward to collaborating further with the AESO on this matter.

Capital Power:

Several aspects of the Commission’s Decision 3473-D02-2015 will have implications for the AESO’s 2017 GTA and some elements of that Decision remain unresolved and part of the active AUC Proceeding #20922, as stated above by the AESO. Capital Power asks the AESO to confirm that its proposed approach to deal with these issues ahead of Proceeding 20922 is procedurally correct.

The AESO’s response to the Commission’s directions in Decision 3473-D02-2015 has not been communicated to stakeholders. Capital Power requests 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.

While issues related to the application of system project advancement costs to load remain unresolved, Capital Power submits that the Commission was clear in Decision 3473-D02-2015 that system project advancement costs should not be applied to generators. Section 6.7 of Decision 3473-D02-2015 provides the Commission’s views on this matter and paragraph 191 is particularly helpful in summarizing the Commission’s discussion. Paragraph 191 states that “the only recovery of non-radial transmission facility costs from generator market participants that can occur is in accordance with Section 29 of the Transmission Regulation,” and hence, “AESO tariff provisions designed to allocate the cost of advancing system transmission projects can only be applied to load market participants and not to generator market participants.”

Capital Power asks the AESO to confirm whether or not it has accepted the Commission’s views on the application of advancement costs to generators and whether or not it plans to re-open this issue in the 2017 GTA. Capital Power does not support re-opening the issue of applying system project advancement costs to generators in the 2017 GTA.

Ed dePazieux:

Agree that the Commission needs to clarify its intent. Difficult to start this work without clarification from the Commission on the desired outcome and process.

EPCOR Distribution & Transmission Inc. (“EDTI”):

If Proceeding 20922 has not been initiated prior to filing the 2017 ISO tariff application, does the AESO propose to include amendments to the ISO tariff’s terms and conditions to align with Directions 5-8 of Decision 3473-D02-2015? If yes, will the AESO consult on those proposed amendments prior to filing the 2017 tariff application?

ENMAX Corporation (“EEC”):

[blank]

Industrial Power Consumers Association of Alberta (“IPCAA”):

Agreed. No need to address the same issue in multiple proceedings.

NextEra Energy Canada:

[blank]

NRStor Inc.:

NRStor recognizes the importance of system access, planning and forecasting and believes the inclusion of energy storage technologies will be crucial in this process. The ASA has released a White Paper outlining its recommendations for the Alberta electricity sector. A key recommendation was for the AESO to collaborate with the ASA in order to conduct a detailed technical review of energy storage technologies to determine what services (existing or new) are required to help maintain a reliable electric grid, and to understand the services and applications where energy storage can offer benefits to the Alberta grid. Ontario’s IESO recently released a technical report on energy storage, which focuses on the reliability needs of the local power system and the potential for energy storage technologies to address those needs, which we believe is worth referencing in this dialogue.

NRStor believes energy storage technologies should be given due consideration as an alternative to incumbent technologies during system planning and forecasting efforts. We look forward to collaborating further with the AESO on this matter.

Renewable Energy Systems Canada Inc. (“RES”):

[Letter submitted by RES. Letter content included in “Other Comments” at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. (“RMP”):

RMP recommends that the AESO include grid connected energy storage projects as alternatives to additional transmission capacity in its planning and forecasting processes.

Temporal Power Ltd.:

Temporal recognizes the importance of system access, planning and forecasting and believes the inclusion of energy storage technologies will be crucial in this process. The ASA has released a White Paper outlining its recommendations for the Alberta electricity sector. A key recommendation was for the AESO to collaborate with the ASA in order to conduct a detailed technical review of energy storage technologies to determine what services (existing or new) are required to help maintain a reliable electric grid, and to understand the services and applications where energy storage can offer benefits to the Alberta grid. Ontario’s IESO recently released a technical report on energy storage, which focuses on the reliability needs of the local power system and the potential for energy storage technologies to address those needs, which we believe is worth referencing in this dialogue.

Temporal believes energy storage technologies should be given due consideration as an alternative to incumbent technologies during system planning and forecasting efforts. We look forward to collaborating further with the AESO on this matter.

2(b) Other changes to the ISO tariff’s terms and conditions will include:

- i. Updates to Section 10 – Generating Unit Owner’s Contribution (GUOC) to include GUOC rates; and*
- ii. Changes to sections 4 and 5 to address revisions to align with Market Participant Choice (MPC) and Abbreviated Need Identification Document (ANID) programs;*
- iii. Clarifications for energy storage;*
- iv. Allow transmission-connected distribution service customer an opportunity to deal*

directly with the transmission facility owner (TFO) directly for a connection project; and
v. Updates to proformas (Appendix B) to reflect current AESO processes.

Alberta Direct Connect Consumers Association (“ADC”):

No Comment

The Alberta Storage Alliance (“ASA”):

The ASA is supportive of the AESO’s efforts to clarify and clearly define energy storage technologies and include rule provisions for their participation in the wholesale energy and operating reserves markets. The lack of these rule provisions is currently an important barrier for energy storage (particularly with respect to the ancillary services markets), and revisions to the market rules should consider storage as another capable technology that can satisfy the appropriate technical requirements. We believe this rule development should be accelerated to allow for the inclusion of energy storage in the Alberta market. The ASA believes this is a starting point for the province to understand what services energy storage is capable of providing. The ASA would be pleased to engage with the AESO on building these definitions and providing any further information required.

Capital Power:

Capital Power supports inclusion of these topics and requests that updated GUOC rates and the rationale behind them be provided to stakeholders by the AESO as soon as practical in its 2017 GTA consultation

Ed dePazieux:

Market Participant choice has not been successful in terms of customers choosing this option. It may be time well spent to assess this option and how to make it more compelling as opposed to a simple alignment of sections 4 and 5. Potentially greater tariff changes are required to make this program attractive.

EPCOR Distribution & Transmission Inc. (“EDTI”):

[blank]

ENMAX Corporation (“EEC”):

EEC supports a review of Section 10 to include GUOC rates, and to ensure that any changes align with ISO Rule 505.2, if required.

Industrial Power Consumers Association of Alberta (“IPCAA”):

IPCAA is supportive of allowing transmission-connected distribution customers an opportunity to deal directly with TFOs for connection projects.

NextEra Energy Canada:

[blank]

NRStor Inc.:

NRStor is supportive of the AESO’s efforts to clarify and clearly define energy storage technologies and include rule provisions for their participation in the wholesale energy and operating reserves markets. The lack of these rule provisions is currently an important barrier for energy storage (particularly with respect to the ancillary services markets), and revisions to the market rules should consider storage as another capable technology that can satisfy the appropriate technical requirements. We believe this rule development should be accelerated to allow for the inclusion of energy storage in the Alberta market. The ASA believes this is a starting point for the province to understand what services energy storage is capable of providing. As a member of the ASA, NRStor would be pleased to engage with the AESO on building these definitions and providing any further information required.

Renewable Energy Systems Canada Inc. (“RES”):

[Letter submitted by RES. Letter content included in “Other Comments” at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. (“RMP”):

It would be very helpful to know what “clarifications” the AESO is planning on making to its tariff terms and conditions so that these “clarifications” can be discussed prior to the 2017 rate filing. However, the AESO seems to have precluded ANY further discussion about energy storage rates.

Temporal Power Ltd.:

Temporal is supportive of the AESO’s efforts to clarify and clearly define energy storage technologies and include rule provisions for their participation in the wholesale energy and operating reserves markets. The lack of these rule provisions is currently an important barrier for energy storage (particularly with respect to the ancillary services markets), and revisions to the market rules should consider storage as another capable technology that can satisfy the appropriate technical requirements. We believe this rule development should be accelerated to allow for the inclusion of energy storage in the Alberta market. The ASA believes this is a starting point for the province to understand what services energy storage is capable of providing. As a member of the ASA, Temporal would be pleased to engage with the AESO on building these definitions and providing any further information required.

TOPICS ON THE HORIZON

- 3(a) Other topics may be included in the 2017 ISO tariff application. The AESO is determining resources and timeline impacts for these items at this time:**
- i. Section 11 – Ancillary Services review given fairly recent Commission decision on Transmission Constraint Management (TCM) and the length of time since this section was negotiated;**
 - ii. Rider A1 – Dow Chemical Canada Inc./Dow Hydrocarbons/ASU2 review given the “Forecast Benefit to ISO” year ends at 2021 as written currently; and**
 - iii. Climate Leadership Plan / Renewable Electricity Program impacts and tariff are not known at this time. Any tariff revisions required will be made once policy is finalized.**
-

Alberta Direct Connect Consumers Association (“ADC”):

ADC supports reviewing Rider A1 in this proceeding as Dow Chemical Canada ULC is an ADC member. We offer to work collaboratively with the AESO to ensure clarity beyond 2021 is resolved in this application.

The Alberta Storage Alliance (“ASA”):

The ASA believes the effects of the province’s Climate Leadership Plan / Renewable Electricity Program should be evaluated before finalizing the AESO’s decision on any related energy storage tariff. An influx of variable renewable energy generation may require additional flexibility to maintain system reliability. Energy storage technologies have been deployed and proven in other markets to meet critical reliability needs and defer or avoid major transmission/distribution system upgrades associated with the deployment of renewables. Energy storage can enable renewable generation and also stimulate further GHG emissions benefits to the province. There are four key areas where Alberta’s Electricity System will need solutions as additional renewable generation is built and coal generation is retired, where storage can provide significant value:

1. Renewables integration;
 2. Price volatility;
 3. Supply adequacy; and
-

4. Grid reliability.

We believe the AESO should consider how energy storage technologies can better enable the Climate Leadership Plan when considering the next steps for this consultation process. The ASA would like to see energy storage facilities included in a process to determine the lowest-cost and most efficient infrastructure alternatives going forward

Capital Power:

In regard to 3(a)(i), please confirm exactly what changes or revisions the AESO is considering to Section 11 of the Tariff in light of the Commission decision on TCM.

In regard to 3(a)(iii), Capital Power understands that potential tariff impacts related to the Alberta Climate Leadership Plan (“ACLP”) and the AESO’s Renewable Electricity Program (“REP”) are not known at this time and supports the AESO’s approach to consider such revisions once policy is finalized. Capital Power encourages the AESO to engage and consult with stakeholders in making these determinations once policy is finalized.

Ed dePazieux:

[blank]

EPCOR Distribution & Transmission Inc. (“EDTI”):

[blank]

ENMAX Corporation (“EEC”):

EEC supports a review of Section 11, specifically given the Transmission Constraint Management (TCM) decision, just to ensure there is no redundancy or overlap with the Tariff and the Rule.

Industrial Power Consumers Association of Alberta (“IPCAA”):

- The AESO’s tariff should not be delayed by the REP. Revisions can be incorporated when the REP is formally launched.
 - Re: AS Review – the AESO’s list of what will be considered is fairly comprehensive. Some review is certainly warranted: technology neutrality, reducing minimum unit size requirements are likely easy changes and could (and should) be made quickly. Designing new AS products (perhaps to incorporate wind) will be a much larger project. Consider dividing the options into what can be achieved promptly and what will need a larger consultation process.
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NextEra Energy Canada:

[blank]

NRStor Inc.:

NRStor believes the effects of the province’s Climate Leadership Plan / Renewable Electricity Program should be evaluated before finalizing the AESO’s decision on any related energy storage tariff. An influx of variable renewable energy generation may require additional flexibility to maintain system reliability. Energy storage technologies have been deployed and proven in other markets to meet critical reliability needs and defer or avoid major transmission/distribution system upgrades associated with the deployment of renewables. Energy storage can enable renewable generation and also stimulate further GHG emissions benefits to the province. There are four key areas where Alberta’s Electricity System will need solutions as additional renewable generation is built and coal generation is retired, where storage can provide significant value:

1. Renewables integration;
 2. Price volatility;
 3. Supply adequacy; and
-

4. Grid reliability.

We believe the AESO should consider how energy storage technologies can better enable the Climate Leadership Plan when considering the next steps for this consultation process. NRStor would like to see energy storage facilities included in a process to determine the lowest-cost and most efficient infrastructure alternatives going forward.

Renewable Energy Systems Canada Inc. (“RES”):

[Letter submitted by RES. Letter content included in “Other Comments” at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. (“RMP”):

RMP suggests that the AESO immediately engage in industry consultation regarding the provision and use of ancillary services by energy storage projects. RMP notes that storage projects can provide ancillary services while in both storage and generation modes and therefore can provide a much broader range of ancillary services than can a typical generation facility. A 100MW generating and storage facility can provide a band of 200MW of ancillary services (+100MW in generation mode to -100MW when switched to storage mode) while a 100MW generation facility can provide only a band of 100MW of ancillary services. Allowing energy storage facilities to apply its full band of ancillary services could free up some generation resources to do what they do best, generate electricity. In addition, the AESO should consider the implementation of long term competitively determined contracts for the provision of ancillary services. Ancillary services need not be procured on only a one day forward basis in order to be the least cost service for ratepayers. By entering in to long term AS purchase agreements, the AESO will enable more participants in the AS market thereby potentially leading to lower AS prices. Long term contracts for AS services helps new project entrants by providing creditworthy backed revenue guarantees for project developers which allows them to finance a good portion of their facilities using debt rather having to rely on higher cost equity. Competitively procured long term AS contracts may be just as competitive as day forward or “spot pricing” AS purchase arrangements.

RMP also suggests that the AESO consider potential impacts of the Climate Leadership Plan / Renewable Electricity Program before finalizing its decision on energy storage tariffs. The impacts of the Climate Plans on existing transmission and distribution infrastructure should be considered, particularly when a storage facility might be considered in lieu of reinforcements to existing transmission facilities. In addition, the AESO should consider the impact the Governments Climate Leadership Plan/Renewable Electricity Program will have for new infrastructure requirements to support the influx of variable renewable generation. Energy storage facilities should be included in a process to determine the least cost transmission infrastructure solutions for the future grid.

Temporal Power Ltd.:

Temporal believes the effects of the province’s Climate Leadership Plan / Renewable Electricity Program should be evaluated before finalizing the AESO’s decision on any related energy storage tariff. An influx of variable renewable energy generation may require additional flexibility to maintain system reliability. Energy storage technologies have been deployed and proven in other markets to meet critical reliability needs and defer or avoid major transmission/distribution system upgrades associated with the deployment of renewables. Energy storage can enable renewable generation and also stimulate further GHG emissions benefits to the province. There are four key areas where Alberta’s Electricity System will need solutions as additional renewable generation is built and coal generation is retired, where storage can provide significant value:

1. Renewables integration;
 2. Price volatility;
 3. Supply adequacy; and
 4. Grid reliability.
-

We believe the AESO should consider how energy storage technologies can better enable the Climate Leadership Plan when considering the next steps for this consultation process. Temporal would like to see energy storage facilities included in a process to determine the lowest-cost and most efficient infrastructure alternatives going forward.

ENERGY STORAGE

4(a) Dispatch Modelling Study results and analysis:

- i. Dispatch modelling showed indirect correlation with system demand;*
- ii. Rate DTS charges had a small impact on power flow;*
- iii. Hourly load factor when charging averaged from less than 10% to more than 50%; and*
- iv. Charging at rated capacity occurred for up to 6% of daytime hours.*

Alberta Direct Connect Consumers Association (“ADC”):

No comment.

The Alberta Storage Alliance (“ASA”):

The ASA would like to commend the AESO for commissioning the Dispatch Modelling Study and engaging leading academic institutions in the space. This is an important first step in understanding how energy storage assets will be integrated into the electricity system. However, as a collaboration of industry participants, the ASA believes there is still significant uncertainty around the conclusions inferred from this research. We recommend further dialogue take place with the ASA and industry stakeholders, the AESO, the University of Calgary, and other interested stakeholders to better understand the underlying assumptions and conclusions being drawn from this research. The ASA believes that making impactful market decisions from a single commissioned study is not adequate to reach conclusions on such complex topics.

A primary issue for consideration is that the researchers used a ‘perfect information model’ with 20/20 hindsight of market conditions. While useful for drawing some indicative conclusions, this type of modeling does not accurately reflect how an energy storage facility would be operated on a day-to-day basis under real conditions. There are a number of operational (e.g. state of charge limitations, duty cycle considerations, etc.) and market considerations that specific owners may respond to differently. We recommend the AESO consider following up on this first phase of research to conduct a more detailed technical review and request further input from industry participants including the ASA.

The ASA will continue to work with the AESO and other stakeholders to identify services and applications where energy storage can offer benefits to Alberta’s electric grid. As part of this collaboration, we recommend conducting a technical review to determine what services (existing or new) are required to help maintain a reliable electric grid going forward. Part of this assessment should include a review of whether assets solely providing system stability services should be exempt from certain prohibitive tariffs. For example, a Standard Transmission Service rate for grid-connected storage offering only Operating Reserves would avoid “double charging” such assets under existing regulations and tariffs. 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.

It is imperative that the AESO consider reviewing the stacked benefits or multiple value streams that storage can provide to all levels of the supply chain (from generation to consumption). The ASA’s recently released White Paper details the variety of benefits that storage can provide to the grid. There are four key areas where Alberta’s Electricity System will need solutions as additional renewable generation is built and coal generation is retired, where storage can provide significant value:

1. Renewables integration;
2. Price volatility;

-
3. Supply adequacy; and
 4. Grid reliability.
-

Capital Power:

Capital Power has no comments on the dispatch modeling results.

Ed dePazeieux:

[blank]

EPCOR Distribution & Transmission Inc. (“EDTI”):

[blank]

ENMAX Corporation (“EEC”):

We have no specific comments on the modelling results, other than to note that if the primary use of the storage is commodity price arbitrage, past market conditions may not indicate future dispatch of storage facilities.

Industrial Power Consumers Association of Alberta (“IPCAA”):

No comments.

NextEra Energy Canada:

- i. Dispatch modeling showed indirect correlation with system demand;

Response: The analysis showed that storage devices both supply power to the grid and purchase power from the grid. Given that the modeled operation of storage was based on price arbitrage the results predictably indicate that storage will generally charge during off peak hours and discharge in on peak hours. It is unclear how the specific results are tied to the policy decision that energy purchases from a storage asset trigger DTS charges. The AESO did not appear to consider a charging pattern that would not trigger DTS charges, i.e. it appears as though the concept that power consumption from the grid equates to DTS charges was a foregone conclusion, especially given that the analysis illustrated very little consumption during peak periods.

The dispatch modeling did not reflect the realistic operation of a storage device in the Alberta market for a number of reasons. First, and most importantly, temporal arbitrage in isolation is very unlikely to be the profit maximizing choice for storage facilities. Contingency reserves, regulating reserves, system services such as inertia restoration and potentially renewable integration services will provide market opportunities with dramatically different operating patterns. Second, the analysis presumes perfect knowledge and does not reflect the reality of operating in an uncertain environment. Third, the analysis does not reflect the reality that a storage operator will respond to whatever tariff signals are in place. The current uncertainty around system peak charges would result in a strong aversion to charging during on peak hours due to the risk of incurring system peak costs.

The study also does not compare a storage asset’s operation with that of a peaking generation asset. The study strongly reinforced the conclusion that a storage asset will be motivated by energy market price signals to the extent it is engaging in price arbitrage. While other markets such as regulating reserves are likely to prove more attractive and would result in different operating patterns.

NextEra requests that the AESO provide clarification on whether the storage load pattern study was provided to determine the applicability of DTS to storage charging hours. If yes, can the AESO also clarify what charging pattern would not have indicated DTS charges are appropriate?

- ii. Rate DTS charges had a small impact on power flow;

Response: Even with the concerns raised above regarding the study, it illustrated a material economic inefficiency associated with DTS charges. Further, given the uncertainty associated with coincidental peak charges, a rational operator would respond to DTS charges by entirely avoiding charging during any

hours that approached peak demand, regardless of other economic drivers such as market price.

According to the provincial transmission development policy¹, the transmission tariff should not introduce distortions to the energy only market operation (see page 5). The University of Calgary paper utilized by the AESO suggests that energy market flows from storage devices are reduced by an average of over 11% in each direction due to the tariff. This does not account for uncertainty combined with the fact that energy arbitrage is only a single element of the likely operation.

It is also clear that the tariff treatment sets a strong preference for traditional generators to fill the role of peaking capacity. The analysis indicates profitability for storage assets is reduced by 16% on average via the tariff. The AESO did not provide evidence that traditional generation provides incremental system value that justifies this differential, and further did not value the benefit storage alone can add via temporal arbitrage (amongst other unique attributes).

Clearly, in the instance of storage devices, the tariff introduces a distortion that reduces the overall efficiency of the market. Storage devices facilitate efficient market operations in a manner similar to both export capability and peaking generation combined, yet the AESO did not examine appropriate tariff treatment within this market context.

The most egregious impact of the proposed DTS tariff for storage assets is that it places them at a significant disadvantage in the regulating reserve market when the NRC/AESO study² suggests these assets are uniquely beneficial due to their rapid response times. Other markets have demonstrated the benefits energy storage can provide. PJM for example^{3,4} has added over 280 MW of grid-connected energy storage to their regulation market. PJM used to procure 1% of their peak and valley load (~900 MW of Regulation on average per hour), but as a result of the changes to the performance based regulation market it has been reduced to 700 MW on peak and 525 MW off peak (664 MW on average) which is nearly a 30% drop.

DTS, and in particular the coincident peak demand charge, would effectively become a large random cost faced by a storage device in the regulating reserve market. A storage device selling regulating reserves will logically operate both in a charge and discharge state, driven by AESO automated dispatches in response to variable system conditions. The AESO DTS proposal amounts to systematically discouraging participation from storage assets in the regulating reserve market, and in particular during on peak hours. In this regard, the proposal does not support market fairness and efficiency.

It also must be noted that the AESO's current initiative to develop technology neutral technical standards for system reserves will be moot if the transmission tariff precludes storage participation.

1 (<http://www.energy.alberta.ca/Electricity/pdfs/transmissionPolicy.pdf>)

2 Regulating Reserve Performance Assessment for the Alberta Electric System Operator, March 18, 2016. National Research Council Canada.

3 Regulation Performance Metrics, July 19, 2016, 2016.

4 2010 ISO/RTO Metrics Report PJM Highlights, (<http://www.ferc.gov/EventCalendar/Files/20110120100702-6-PJM-print.pdf>)

iii. Hourly load factor when charging averaged from less than 10% to more than 50%;

The specific operating parameters found by the study are interesting but are flawed for the reasons previously outlined. Further, the AESO does not indicate to what extent these findings influenced its decision to implement DTS charges. To reiterate, it is not clear what charging pattern could have triggered a decision other than that DTS charges would be triggered by charging.

iv. Charging at rated capacity occurred for up to 6% of daytime hours.

See (iii.)

NRStor Inc.:

NRStor would like to commend the AESO for commissioning the Dispatch Modelling Study and engaging leading academic institutions in the space. This is an important first step in understanding how energy

storage assets will be integrated into the electricity system. However, as an industry participant, NRStor believes there is still significant uncertainty around the conclusions inferred from this research. We recommend further dialogue take place with the ASA and industry stakeholders, the AESO, the University of Calgary, and other interested stakeholders to better understand the underlying assumptions and conclusions being drawn from this research. NRStor believes that making impactful market decisions from a single commissioned study is not adequate to reach conclusions on such complex topics.

A primary issue for consideration is that the researchers used a 'perfect information model' with 20/20 hindsight of market conditions. While useful for drawing some indicative conclusions, this type of modeling does not accurately reflect how an energy storage facility would be operated on a day-to-day basis under real conditions. There are a number of operational (e.g. state of charge limitations, duty cycle considerations, etc.) and market considerations that specific owners may respond to differently. We recommend the AESO consider following up on this first phase of research to conduct a more detailed technical review and request further input from industry participants including NRStor and other members of the ASA.

As a member of the ASA, NRStor will continue to work with the AESO and other stakeholders to identify services and applications where energy storage can offer benefits to Alberta's electric grid. As part of this collaboration, we recommend conducting a technical review to determine what services (existing or new) are required to help maintain a reliable electric grid going forward. Part of this assessment should include a review of whether assets solely providing system stability services should be exempt from certain prohibitive tariffs. For example, a Standard Transmission Service rate for grid-connected storage offering only Operating Reserves would avoid "double charging" such assets under existing regulations and tariffs. 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.

It is imperative that the AESO consider reviewing the stacked benefits or multiple value streams that storage can provide to all levels of the supply chain (from generation to consumption). The ASA's recently released White Paper details the variety of benefits that storage can provide to the grid. There are four key areas where Alberta's Electricity System will need solutions as additional renewable generation is built and coal generation is retired, where storage can provide significant value:

1. Renewables integration;
2. Price volatility;
3. Supply adequacy; and
4. Grid reliability.

Renewable Energy Systems Canada Inc. ("RES"):

[Letter submitted by RES. Letter content included in "Other Comments" at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. ("RMP"):

It appears the AESO is using the results of the Dispatch Modeling study to justify their decision not to make any changes to its rate structures, particularly the DTS rate rather than consider the results as the basis for considering other rate structures. RMP believes that by doing so the AESO has missed or glossed over a number of issues that might, if considered, affect the decision that the DTS rate should be applied to grid connected energy storage facilities.

4(a) i. (Please refer to slide # 19 in the AESO's July 7th presentation.) This slide purports to show that under the scenario of storage facility owners maximizing energy price arbitrage revenue, storage operators will more often store energy at their maximum storage rate when system demand is low (presumably because energy prices are low) and will more often generate at close to their maximum generating capacity when system demand is high (presumably because energy prices are high). Please note this slide does NOT show that energy service providers will never store at or near their peak storage

rate when demand is high. (Slide 4 seems to suggest that energy service providers will store at their peak rate about 1% of the time when system demand is at its highest rate.) That means that about 1% of the time, the bulk system charge, by far the largest component of the DTS rate, will apply. One might ask why this would happen. The bulk system charge is calculated as \$10,175/MW/Month multiplied by the maximum rate of energy taken off the system by the storage service operator during the 15 minute Coincident Metered Demand period in a given month. (An energy charge applies as well but for the ease of explanation, that component is ignored here.) Therefore, if a 100MW storage facility charges at its max rate (100MW) during a period of monthly coincident demand, it will be charged \$1,017,500 for bulk system transmission charge in that month, plus all the other components of the DTS rate. Again, why would a storage operator store during a coincident peak demand period? This event could easily occur in a spring, summer or fall month when the 15 minute system peak demand in any of those months is far less than the highest peak demand incurred during the year because energy prices might still be quite low during that spring, summer or fall month high demand 15 minute period. A storage operator looks at energy prices for signals as to whether it should store energy or discharge energy. Low prices during a “shoulder month” could occur because the total amount of generation available during that period did not go down even though average and peak demand in a shoulder month does fall. Therefore, a storage operator seeing low prices acts rationally and stores energy, but in a low demand month could be subject to the bulk system demand charge of in excess of \$1,000,000. However, in a winter period it might happen that the storage operator stored at exactly the same rate at the same energy price but would NOT be subject to the bulk system demand charge. Obviously the “stress” caused to the transmission system by the storage operator taking power off the system during the shoulder month is NOT the same as “stress” caused to the transmission system if the storage operator took energy off the system during the highest peak demand in the year, yet the storage operator will be charged as if it is the same. This seems counter intuitive particularly in light of the Alberta government’s renewable energy policy. Might it not make sense for storage operators to take power off the system during periods of high monthly, but low compared to the annual AIL peak, demand periods in order to preserve some semblance of minimum prices for renewable energy generators. (There are a number of empirical and theoretical studies that show electricity prices will trend to zero for significant periods of time as more renewable generation is added to a marketplace.) It is very conceivable that an event of very low energy prices could be coupled with peak demand in a month and that the storage operator acting rationally, and to the benefit of all generators, could be faced with very large bulk transmission charges as a result. This could occur even though the transmission system was well below its maximum transmission capacity, even taking into account ambient temperature line deratings. Strict application the DTS rate would result in higher transmission rates for storage operators at times when the transmission system is nowhere near peak demand.

4(a) ii – (Please refer to slide #20). This slide needs to be explained or eliminated. There is no explanation about how the DTS rate is applied in the Dispatch Modeling operating algorithm. A Dispatch algorithm might be as simple as - store power when prices are less than \$20/MWH and discharge power when energy prices are greater than \$100/MWH. If the comparable algorithm then becomes store when the energy price plus the DTS rate is less than \$20/MWH and discharge when the energy price plus STS is greater than \$100/MWH, then it might be possible to compare the two scenario’s. As it stands, the AESO seems to be using this slide as a justification for the AESO’s position regarding the DTS rate. However, without an explanation of what algorithms are being compared in slide 20 it is impossible to pass judgement on whether slide # 20 in fact shows what the AESO wants it to show.

RMP as a proponent for the ASIS compressed air energy storage facility has done similar analyses as that performed for the AESO. How the DTS rate is applied in the analysis is crucial to the end result. Since the bulk system charge may be incurred without the storage operator knowing until the end of a month, short term store and generation decisions, which are usually based only on incremental costs, would not be changed. However, after the fact application of the bulk system charge would result in a 100MW storage operator being in excess of \$1,000,000 poorer at the end of the month. Obviously, had the storage operator known or predicted that an additional \$1,000,000 of transmission charges would be

incurred during a 15 minute store decision, that store decision would have been substantially altered.

4(a) iii (Please refer to slide #21.) This slide should be deleted. This slide purports to show that hourly store and discharge capacity factors are low. The implication seems to be that because an hourly average capacity factor is low, the DTS rate charged to the energy storage operator will also be low. RMP has already demonstrated above that a storage operator might charge at its max rate for one hour during a low demand month and therefore incurs the bulk system charge in that month. However, the storage operator may never charge during that hour again for the rest of the year therefore resulting in a very low average capacity factor for that hour, ... even though it had incurred the bulk system charge in that low demand month when it had charged for one hour. Simply put, this slide proves nothing related to the application of the DTS rate and should be eliminated.

4(a) iv – (Please refer to slide # 22.) RMP does not understand the relevance of this slide in the context of the DTS rate discussion.

Temporal Power Ltd.:

Temporal would like to commend the AESO for commissioning the Dispatch Modelling Study and engaging leading academic institutions in the space. This is an important first step in understanding how energy storage assets will be integrated into the electricity system. However, as an industry participant, Temporal believes there is still significant uncertainty around the conclusions inferred from this research. We recommend further dialogue take place with the ASA and industry stakeholders, the AESO, the University of Calgary, and other interested stakeholders to better understand the underlying assumptions and conclusions being drawn from this research. Temporal believes that making impactful market decisions from a single commissioned study is not adequate to reach conclusions on such complex topics.

A primary issue for consideration is that the researchers used a ‘perfect information model’ with 20/20 hindsight of market conditions. While useful for drawing some indicative conclusions, this type of modeling does not accurately reflect how an energy storage facility would be operated on a day-to-day basis under real conditions. There are a number of operational (e.g. state of charge limitations, duty cycle considerations, etc.) and market considerations that specific owners may respond to differently. We recommend the AESO consider following up on this first phase of research to conduct a more detailed technical review and request further input from industry participants including Temporal and other members of the ASA.

As a member of the ASA, Temporal will continue to work with the AESO and other stakeholders to identify services and applications where energy storage can offer benefits to Alberta’s electric grid. As part of this collaboration, we recommend conducting a technical review to determine what services (existing or new) are required to help maintain a reliable electric grid going forward. Part of this assessment should include a review of whether assets solely providing system stability services should be exempt from certain prohibitive tariffs. For example, a Standard Transmission Service rate for grid-connected storage offering only Operating Reserves would avoid “double charging” such assets under existing regulations and tariffs. Temporal 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.

It is imperative that the AESO consider reviewing the stacked benefits or multiple value streams that storage can provide to all levels of the supply chain (from generation to consumption). The ASA’s recently released White Paper details the variety of benefits that storage can provide to the grid. There are four key areas where Alberta’s Electricity System will need solutions as additional renewable generation is built and coal generation is retired, where storage can provide significant value:

-
1. Renewables integration;
 2. Price volatility;
 3. Supply adequacy; and
 4. Grid reliability.

4(b) Cost causation considerations for energy storage are similar to those for load:

- i. If an energy storage facility charges during system peak, it could cause bulk system costs;*
- ii. If an energy storage facility charges in any hour, it could cause regional system costs;*
- iii. If an energy storage facility charges in any hour, it could cause point of delivery costs;*
- iv. Load in the hour causes operating reserve charge costs in that hour;*
- v. Load in the hour also causes transmission constraint rebalancing costs in that hour;*
- vi. Variable nature of transmission must-run costs are appropriately recovered through a \$/MWh energy charge; and*
- vii. Fixed nature of other system support services costs are appropriately recovered through a \$/MW demand charge.*

Alberta Direct Connect Consumers Association (“ADC”):

ADC agrees.

The Alberta Storage Alliance (“ASA”):

Again, the ASA would like to recognize the AESO’s efforts to study and understand the operations of and effects of energy storage facilities. However, we recommend further collaborative dialogue take place between regulators, academics and industry stakeholders to better understand the underlying assumptions and conclusions being drawn from this research. From the ASA’s perspective, we believe the research completed by University of Calgary in many ways supports the notion that modified rates for storage facilities are necessary. We believe the AESO should fully explore diverse perspectives on this research, in collaboration with all stakeholders, prior to finalizing any decisions on rate structures for energy storage facilities.

The ASA also encourages the AESO to consider the many system-wide infrastructure benefits energy storage brings to the system. As Alberta’s grid evolves, Alberta will almost certainly require solutions in four key areas: renewables integration, managing price volatility, maintaining supply adequacy, and ensuring grid reliability. Energy storage can play an important role on the system by providing proven solutions to each of these challenges.

Energy storage technologies can balance the grid by storing excess electricity and reinjecting it at a more optimal time. The successful deployment of energy storage in electricity systems around the world has demonstrated its ability to swiftly react to system needs, making storage a compelling solution for Alberta. The ASA is keen to work with the AESO to better identify how these benefits, and resulting cost savings, are passed through to ratepayers.

Capital Power:

Capital Power supports the AESO’s conclusions above that support the claim that cost causation considerations for energy storage are similar to those for load.

Ed dePazieux:

[blank]

EPCOR Distribution & Transmission Inc. (“EDTI”):

[blank]

ENMAX Corporation (“EEC”):

EEC supports a review of the transmission cost implications of energy storage in the ISO tariff, primarily to ensure that the treatment of energy storage is consistent with FEOC.

Industrial Power Consumers Association of Alberta (“IPCAA”):

Agreed.

NextEra Energy Canada:

Cost causation on the power grid is not a function of the direction of flow. Both load and generation impose similar costs on the system – it is a policy decision that load faces the majority of overall transmission costs in Alberta. The AESO has not presented any evidence that a site that has power flowing in two directions creates materially different physical costs than a site from which power only flows outwards. Both require transmission capacity to reach end use customers and both can be subject to congestion depending on system configuration and power flows. Providing the incremental service of absorbing power for later use should not be viewed as a negative from the system perspective relative to a generator.

The AESO tariff could easily recognize the inherent difference between storage assets and end use load. The AESO already recognizes a range of load types within its tariff structure (DTS, XOS, DOS and behind the fence) so there is a clear precedent that not all types of load are equivalent in terms of treatment.

NextEra requests that the AESO consider cost causation and storage assets in the context of efficient energy market operations. Storage assets purchase power from the grid in support competitive outcomes and within the context of the Alberta transmission policy are not similar to end use customers.

i. If an energy storage facility charges during system peak, it could cause bulk system costs;

Response: Bulk system costs can be created by load or generation for any given hour depending on the system configuration at that time. It is a policy question as to whether charging storage assets DTS supports the development of an efficient system. In effect, does exposing storage assets to DTS costs and behavioral incentives support the market or are other signals such as the spot market price or regulating reserve signal the appropriate driver for storage assets? Further, given a reasonable must offer/bid- must comply rule for storage assets; they can be managed very differently than end use loads.

It must also be recognized that the transmission tariff could incent storage assets to locate in areas that would minimize or even reduce overall transmission costs. This siting signal could easily be implemented through a energy storage tariff similar to STS System Contribution charge that incents efficient siting for generation but modified to recognize that storage has two-way capability.

Storage assets have the potential to create material positive externalities for the market in terms of reduced regulating reserve costs, two-way flexibility to integrate renewables, high ramp rates, improved spot market function with temporal arbitrage, capability to manage congestion more cost effectively and generation capacity for peak load reliability. A barrier to entry for storage assets via tariff design is not in the interest of minimizing system costs and improving the efficiency of the market.

ii. If an energy storage facility charges in any hour, it could cause regional system costs;

See response (i).

iii. If an energy storage facility charges in any hour, it could cause point of delivery costs;

See response (i).

iv. Load in the hour causes operating reserve charge costs in that hour;

Response: It is not clear that this is a reasonable assumption. A tariff and operational construct that treats storage akin to behind the fence load is entirely appropriate. In this instance, the AESO would not be contractually obligated to serve storage as load in the event of a contingency. From a system perspective storage load that can be contractually curtailed can be treated the same as behind the fence load that

does not trigger reserve requirements. This will not create incremental reliability concerns and a tariff construct can be created that is consistent with WECC standards.

v. Load in the hour also causes transmission constraint rebalancing costs in that hour;

Response: Storage devices could easily be integrated into the existing constraint management framework. They could be subject to a must offer/bid - must comply rule that would allow them to be part of the current rebalancing protocol that utilizes the energy market merit order to rebalance the market. A must offer- must bid rule is a very reasonable constraint on storage that would not be reasonable or feasible for all end use customers. This is an important distinction that highlights the fact that storage devices are not similar to end use loads within the market framework and can in fact reduce transmission constraint rebalancing costs rather than cause them.

As an example, without a storage asset in a potential supply constraint zone, the cost of managing the constraint is the cost of paying an out of merit generator to operate. In addition, there is an economic opportunity cost for the generator that did not get to operate, but the market does not price this cost. If a storage asset exists behind the constraint, it could have a bid to purchase electricity that would resolve or reduce the constraint. There would be no out of market payment from load (the storage asset would receive 'discounted' power from constrained generators). In this example, the cost of the constraint is lower for both generators and load. At worst, the storage asset has no impact on congestion costs in the event it does not have the capability to act as a load in a given event.

Similarly, in the event the storage asset is downstream from the constraint it can do nothing but reduce the cost of the resolving the constraint if it has a must bid requirement. In effect, the constraint management framework could be to dispatch down load bids prior to dispatching out of merit generation. In this case again no out of market payment would be made to resolve the constraint, the storage device would not consume power and the cost of constraints would be reduced relative to the status quo. This is akin to opportunity service.

vi. Variable nature of transmission must-run costs are appropriately recovered through a \$/MWh energy charge;

Response: Storage assets will not add to existing transmission must run costs if it is located in a reasonable manner. The AESO can utilize a similar framework to the Generator System Contribution Payment to incent appropriate location of storage assets.

vii. Fixed nature of other system support services costs are appropriately recovered through a \$/MW demand charge;

Response: Presumably this statement is in respect of services such as black start service. This is again an unreasonable cost for a storage asset to bear in the same manner as an end use customer. A storage asset is in the same position as a generator in these conditions, i.e. there is no market in which to sell its product. A storage device will not add to these costs, and, in fact, may be helpful in restoration depending on its state of charge

NRStor Inc.:

Again, NRStor would like to recognize the AESO's efforts to study and understand the operations of and effects of energy storage facilities. However, we recommend further collaborative dialogue take place between regulators, academics and industry stakeholders to better understand the underlying assumptions and conclusions being drawn from this research. NRStor believes the research completed by University of Calgary in many ways supports the notion that modified rates for storage facilities are necessary. We believe the AESO should fully explore diverse perspectives on this research, in collaboration with all stakeholders, prior to finalizing any decisions on rate structures for energy storage facilities.

NRStor also encourages the AESO to consider the many system-wide infrastructure benefits energy storage brings to the system. As Alberta's grid evolves, Alberta will almost certainly require solutions in four key areas: renewables integration, managing price volatility, maintaining supply adequacy, and ensuring grid reliability. Energy storage can play an important role on the system by providing proven

solutions to each of these challenges. Energy storage technologies can balance the grid by storing excess electricity and reinjecting it at a more optimal time. The successful deployment of energy storage in electricity systems around the world has demonstrated its ability to swiftly react to system needs, making storage a compelling solution for Alberta. As a member of the ASA, NRStor is keen to work with the AESO to better identify how these benefits, and resulting cost savings, are passed through to ratepayers.

Renewable Energy Systems Canada Inc. (“RES”):

[Letter submitted by RES. Letter content included in “Other Comments” at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. (“RMP”):

RMP would like to note that the AESO’s cost causation analysis was an internally undertaken analysis. There was no discuss or consultation with energy storage stakeholders. Please see RMP’s comments in to items 1(a) and 1(b). Again, because of the lack of consultation RMP feels compelled to object in the strongest manner to what it perceives as the AESO attempt to justify a decision already taken without really considering the many differences and advantages grid connected storage offers to the transmission system.

4(b) i – The AESO states - energy storage can cause bulk system costs during a system peak. RMP suggests the AESO analysis is flawed. In the storage dispatch analysis, did any store decisions EVER cause a new peak in system demand? The AESO’s Annual Market Statistics shows that the peak AIL in the winter of 2015 was 10,982MW and 10,520 in the summer of 2015. It is RMP’s understanding that transmission systems are built to serve the maximum demand, or peak load demand at any given point in time. The transmission system is not built to serve a lesser number than the highest peak load. Therefore, it is reasonable to ask - in the Dispatch Modeling and in the subsequent internal Cost Causation review, did the store decisions produced by the modeling process ever result in the peak AIL being increased by even 1MW in either the summer or the winter? In theory, of course, any time an individual or a company draws power off the grid there is a chance that it might increase the peak AIL and therefore cause bulk system costs. In reality though, and RMP thought this was what the Dispatch Model study was designed to answer, did simulations ever cause an increase in the peak AIL? A traditional customer has the right to add to overall system demand at any time. A storage operator operating under a transmission opportunity service would never have the right to add to system demand peaks and therefore would never cause bulk system charge costs.

4(b) ii – The AESO states storage operators could cause regional system costs. Of course storage operators could cause regional system costs. That is in part why the AESO requires, as part of its connection process, extensive power flow analyses. Those power flow analyses are designed to determine if regional transmission systems need to be augmented to allow the storage operator to operate within a given region. Simply because that is determined to hold true, does not lead necessarily to a decision to continue to apply the DTS rate unchanged. There are a myriad of other factors and benefits that flow from storage facilities. For example, in item 4 (b) vi the AESO argues that transmission must run balancing costs need to be applied in the DTS rate. Perhaps a storage facility can eliminate the transmission must run generation facility and reduce costs overall. The AESO needs to start thinking about storage as a benefit and a cost to the system and should look at all aspects of its transmission rates in this context.

4(b) iii The AESO states that storage facilities could cause point of delivery costs. Again, of course this is true. It is not clear, however, how the AESO would apply point of delivery interconnection charges as part of the DTS rate AND require the storage facility to provide for transmission costs that are incurred by the TFO to accept the generation or discharge side of the storage facility. It is RMP’s understanding that if point of delivery costs are incurred by the TFO for a generating facility, then the generator pays those costs to the TFO and are rebated those costs over a 10 year period. However, if point of delivery or substation costs are already included in the DTS calculation, why would the generation or discharge side

of the storage facility have to provide for any substation costs. It is NOT clear what the AESO intends. In addition, the AESI has suggested that a storage operator can reduce its DTS charges by reducing its storage rate to half the rate the discharge rate. Under the AESO's construct, a 100MW storage facility would be made up of 100MW of discharge or generation capacity and 50MW of storage capacity. However, if this were to occur how does one calculate the costs that would be chargeable to the discharge side of the facility and therefore payable to the TFO, and what costs should be included in the DTS point of delivery charge?

4(b) iv, v, vi, and vii - Similar comments apply to the remaining components of the DTS rate. At the risk of repetition, the AESO should have consulted with stakeholders before making its decision to retain the DTS rate. The AESO needs to look at storage at more than just a cost to the system. It can also supply substantial benefits and those also need to be taken into account when trying to determine the best rate to be applied for grid connected storage facilities.

Temporal Power Ltd.:

Again, Temporal would like to recognize the AESO's efforts to study and understand the operations of and effects of energy storage facilities. However, we recommend further collaborative dialogue take place between regulators, academics and industry stakeholders to better understand the underlying assumptions and conclusions being drawn from this research. Temporal believes the research completed by University of Calgary in many ways supports the notion that modified rates for storage facilities are necessary. We believe the AESO should fully explore diverse perspectives on this research, in collaboration with all stakeholders, prior to finalizing any decisions on rate structures for energy storage facilities.

Temporal also encourages the AESO to consider the many system-wide infrastructure benefits energy storage brings to the system. As Alberta's grid evolves, Alberta will almost certainly require solutions in four key areas: renewables integration, managing price volatility, maintaining supply adequacy, and ensuring grid reliability. Energy storage can play an important role on the system by providing proven solutions to each of these challenges. Energy storage technologies can balance the grid by storing excess electricity and reinjecting it at a more optimal time. The successful deployment of energy storage in electricity systems around the world has demonstrated its ability to swiftly react to system needs, making storage a compelling solution for Alberta. As a member of the ASA, Temporal is keen to work with the AESO to better identify how these benefits, and resulting cost savings, are passed through to ratepayers.

- 4(c) Cost causation review suggests Rate DTS appropriately applies to energy storage:**
- i. Rate DTS would apply only in hours in which an energy storage facility is charging and Rate STS would apply in hours in which the facility is discharging;*
 - ii. Many of the components of Rate DTS can be avoided or reduced by the energy storage participant; and*
 - iii. The Commission has previously found the combination of Rates DTS and STS to be appropriate for sites that include load and generation.*

Alberta Direct Connect Consumers Association ("ADC"):

ADC agrees that the DTS tariff should apply to all participants with DTS service. The tariff offers significant opportunities to reduce costs through management of load.

The Alberta Storage Alliance ("ASA"):

The ASA believes the DTS and STS rates in their current form do not reflect the true benefits and costs that storage facilities add to the system and can be prohibitive for private sector players looking to deploy energy storage. The University of Calgary research shows that the DTS/STS rates effectively double charge and dis-incentivize storage. The ASA is seeking to engage with the AESO to develop a tariff that

accurately considers both the benefits and costs energy storage can bring to the system. The ASA looks forward to the opportunity to continue this dialogue with the AESO.

Capital Power:

Capital Power agrees with the AESO that its review supports the proposal that Rate DTS would apply to an energy storage facility when charging and that Rate STS would apply in hours in which it is discharging. Capital Power believes that the AESO has demonstrated from a tariff perspective that energy storage facilities should be treated similarly to dual-use customers and that the proposal in 4(c)(i) is the appropriate tariff treatment for energy storage.

Ed dePazieux:

[blank]

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

[blank]

ENMAX Corporation ("EEC"):

[blank]

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

See 4(d) below.

NextEra Energy Canada:

Response: As noted in previous comments, rate DTS is not appropriate for a storage asset for a range of reasons. Cost causation is not similar to end use load customers for the reasons outlined. It is important to recognize that storage load is not responding to the same signals as an industrial site with both load and generation, nor does it create the same requirements for transmission infrastructure or system services. In fact, an appropriately designed storage tariff will result in lower overall system costs and can potentially reduce total infrastructure requirements. The combination of STS and DTS charges for a storage asset creates an entry barrier, distorts appropriate spot market responses in the event they are developed, and materially disadvantages storage in the regulating reserve market, despite evidence these assets are uniquely suited for regulating service.

An appropriate storage tariff must move beyond the simple position that energy consumption by definition creates DTS charges and move towards a tariff model that recognizes the function of storage within the overall policy framework.

NRStor Inc.:

NRStor believes the DTS and STS rates in their current form do not reflect the true benefits and costs that storage facilities add to the system and can be prohibitive for private sector players looking to deploy energy storage. The University of Calgary research shows that the DTS/STS rates effectively double charge and dis-incentivize storage. As a member of the ASA, NRStor is seeking to engage with the AESO to develop a tariff that accurately considers both the benefits and costs energy storage can bring to the system. NRStor and the ASA look forward to the opportunity to continue this dialogue with the AESO.

Renewable Energy Systems Canada Inc. ("RES"):

[Letter submitted by RES. Letter content included in "Other Comments" at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. ("RMP"):

RMP respectfully disagrees with Items 4 (c) i and ii for all of the reasons provided in the preceding

sections.

4(c) iii. Simply because the AUC has previously found the combination of Rates DTS and STS to be appropriate for sites that include load and generation does not mean that it will do so again, ... or has the AESO already discussed this issue with the AUC and been told that the status quo will prevail? It is RMP's belief that well founded arguments in favor of Energy Storage Opportunity Service Rates, particularly in light of the changing power generation and transmission system world, could very well be approved by the AUC. However, without any further discussion the AESO has decided to march forward with no change to its rates forcing energy storage proponents to fight this issue out through a lengthy and costly litigious process.

Temporal Power Ltd.:

Temporal believes the DTS and STS rates in their current form do not reflect the true benefits and costs that storage facilities add to the system and can be prohibitive for private sector players looking to deploy energy storage. The University of Calgary research shows that the DTS/STS rates effectively double charge and dis-incentivize storage. As a member of the ASA, Temporal is seeking to engage with the AESO to develop a tariff that accurately considers both the benefits and costs energy storage can bring to the system. Temporal and the ASA look forward to the opportunity to continue this dialogue with the AESO.

4(d) Rate DTS charges for a 20 MW storage service could be reasonably reduced compared to a 20 MW load-only service by the energy storage facility:

- i. avoiding system peak;**
- ii. owning its own substation;**
- iii. contracting for both DTS and STS; and**
- iv. limiting charging rate to 50% of the discharging rate.**

Alberta Direct Connect Consumers Association ("ADC"):

ADC supports the DTS tariff structure. It has been tested before the AUC and has been demonstrated to reflect cost causation principles.

The Alberta Storage Alliance ("ASA"):

As an industry consortium, the ASA believes that DTS and STS rates in their current form can be prohibitive to the deployment of energy storage facilities. We believe there are challenges with the assumptions used in 4d. Forecasting system peak can be extremely difficult and reducing the charging rate by half may not make sense in many scenarios for asset owners; this would need to be evaluated on a project specific basis. We recommend the AESO explore these items further and conduct additional consultations with industry and academic stakeholders to more thoroughly explore the impacts of the rates on storage facilities from all perspectives. The ASA is seeking to develop a tariff that accurately reflects energy storage technologies' benefits and values them on their unique merits rather than being penalized for their fundamental operational differences relative to incumbent technologies.

Capital Power:

Capital Power agrees with the AESO that many of the components of Rate DTS may be avoided or reasonably reduced by an energy storage participant.

Ed dePazieux:

[blank]

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

[blank]

ENMAX Corporation (“EEC”):

We would like to investigate further whether these results hold true at smaller facilities and if the same opportunities exist. As a note, we hope that the operation of the storage system would be at the discretion of the owner and that the tariff wouldn't limit charge or discharge rates, but rather allow the storage owner to operate in the manner they feel appropriate.

Industrial Power Consumers Association of Alberta (“IPCAA”):

- IPCAA will be interested to hear the perspective of energy storage proponents on this proposal.
 - The AESO should be working to ensure that its tariff structure does not discourage energy storage.
 - Consumers can see significant benefits associated with the use of energy storage.
-

NextEra Energy Canada:

Response: It is not reasonable that the introduction of a tariff that distorts rational energy market behavior for the sole purpose of avoiding said tariff is a logical outcome from a system perspective.

Further, to the extent that these set of statements are true for a storage asset participating entirely in temporal arbitrage, it is not reasonable to assume that a storage asset selling regulating reserves or potential services associated with increased renewable penetration will be afforded the same opportunity. In addition, avoiding the tariff reduces the energy market value of a storage asset from both a system perspective and a profitability perspective. This has the sole impact of making these assets more expensive, and the AESO has not demonstrated a corresponding system benefit.

It is concerning that the AESO suggests a storage asset should limit its charging rate solely as a means to reduce tariff charges. This is clearly an inefficient outcome for the system, as presumably the storage device would be responding to market signals to charge at a greater rate. If the system can accommodate the more rapid rate, and the storage device has the capability to charge at the more rapid rate, it is clearly a poor outcome if tariff design prevents a rational market response.

On the flip side, the AESO has not considered the benefits storage assets create for the system and placed them in the context of generation assets. In particular, the analysis provided by the University of Calgary⁵ illustrates that storage assets can arbitrage prices across time and act as peak capacity. The NRC analysis⁶ illustrates storage assets can improve system performance due to their flexibility. Storage assets could also be used to help integrate renewables, compete with other resource types to supply peak capacity, reduce congestion and generally support the market by bringing a new type of competitor to the system. The AESO is undertaking initiatives in other areas such as the technical standards for reserve providers in an effort to reduce barriers to non-traditional technologies yet the proposed tariff design for storage assets does not recognize this goal.

Overall, the proposed tariff increases the hurdle for storage assets to participate in the market, and it is not clear that the analysis to support the imposition of the DTS tariff extended beyond the concept that power purchased from the grid triggers DTS charges by definition. End use customers are best served by efficient investment signals that do not discriminate between technologies.

⁵ Modeling Dispatch Operations of Energy Storage Facilities in the Alberta Wholesale Market, May 2016.

⁶ Regulating Reserve Performance Assessment for the Alberta Electric System Operator, March 18, 2016. National Research Council Canada.

NRStor Inc.:

As an industry participant, NRStor believes that DTS and STS rates in their current form can be prohibitive to the deployment of energy storage facilities. We believe there are challenges with the assumptions used in 4d. Forecasting system peak can be extremely difficult and reducing the charging rate by half may not make sense in many scenarios for asset owners; this would need to be evaluated on a project specific basis. We recommend the AESO explore these items further and conduct additional

consultations with industry and academic stakeholders to more thoroughly explore the impacts of the rates on storage facilities from all perspectives. NRStor is advocating the development of a tariff that accurately reflects energy storage technologies' benefits, and values them on their unique merits rather than being penalized for their fundamental operational differences relative to incumbent technologies.

Renewable Energy Systems Canada Inc. ("RES"):

[Letter submitted by RES. Letter content included in "Other Comments" at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. ("RMP"):

4(d) i – please see earlier RMP arguments about avoiding system, peak. It is RMP's understanding that system peaks are determined monthly. Under the AESO's strict application of the DTS rate it appears that each storage operator would have to forecast when a monthly system peak might occur in order to reduce the DTS rate to an economically acceptable level. As noted before, storage operators tend to focus on energy prices and incremental transmission costs when making store and discharge decisions. As a result, would it not make more sense to design ESOS rates and have the AESO control those periods storage operators cannot store energy?

4(d) ii – please earlier comments about point of delivery cost complexities associated with the application of both the DTS and STS rates.

4(d) iii – RMP disagrees. RMP strongly believes ESOS rates should be designed and applied for by the AESO. RMP also believes that the ESOS Rate should be no greater than the EOS rate.

4(d) iv – Please see earlier comments about this issue. This seems like an artificial construct that allows the AESO to demonstrate that a storage operators transmission costs are not too high. Does the AESO also suggest that other entities that take power off the grid limit their offtake to half of what they might desire? RMP as a storage project proponent had actually determined some time ago that it could reduce its transmission costs by reducing the rate at which it stores energy. While we thank the AESO for its insight, we fail to understand why it should be necessary to have to do so all the time. Do energy exporters have to reduce the amount of energy that they wish to draw into the neighbouring jurisdictions by 50%? If not, why should storage operators have to do so? Admittedly, EOS users are limited to the amount of capacity that is available to export power. RMP does not have a problem with this concept commonly called in Alberta Opportunity Service. RMP's problem is understanding why the AESO is unwilling to even entertain the same concept for grid connected storage facilities.

Temporal Power Ltd.:

As an industry participant, Temporal believes that DTS and STS rates in their current form can be prohibitive to the deployment of energy storage facilities. We believe there are challenges with the assumptions used in 4d. Forecasting system peak can be extremely difficult and reducing the charging rate by half may not make sense in many scenarios for asset owners; this would need to be evaluated on a project specific basis. We recommend the AESO explore these items further and conduct additional consultations with industry and academic stakeholders to more thoroughly explore the impacts of the rates on storage facilities from all perspectives. Temporal is advocating the development of a tariff that accurately reflects energy storage technologies' benefits, and values them on their unique merits rather than being penalized for their fundamental operational differences relative to incumbent technologies.

Rider C / Deferral Account Reconciliation Process Update

5(a) In prior work, the AESO identified, and consulted with stakeholders, that regular tariff update applications should reduce the magnitude of Rider C. The AESO plans to file an upcoming 2017 tariff update application in Q3 2016. The 2017 tariff update application will include an update of rate and investment levels to reflect 2017 costs and proposed to be effective January 1, 2017

Alberta Direct Connect Consumers Association (“ADC”):

ADC supports timely tariff updates to minimize the revenue collected through Rider C.

The Alberta Storage Alliance (“ASA”):

[blank]

Capital Power:

Capital Power supports the AESO’s approach for the purpose of mitigating Rider C amounts.

Ed dePazieux:

If the TRIP model was up to date Customers would already anticipate the level of rate impact for 2017. Please comment on the AESO’s use of the TRIP model in signaling future rates to its customers.

EPCOR Distribution & Transmission Inc. (“EDTI”):

[blank]

ENMAX Corporation (“EEC”):

[blank]

Industrial Power Consumers Association of Alberta (“IPCAA”):

IPCAA supports regular tariff updates that reduce the magnitude of Rider C.

NextEra Energy Canada:

[blank]

NRStor Inc.:

[blank]

Renewable Energy Systems Canada Inc. (“RES”):

[Letter submitted by RES. Letter content included in “Other Comments” at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. (“RMP”):

No comment.

Temporal Power Ltd.:

[blank]

5(b) *Further work is required to investigate other Rider C structure impacts. This work is ongoing until the end of 2016 and will review the impact of early tariff updates, seasonal effects, converting Rider C to a percentage basis as well as review the possibility of eliminating quarterly Rider C and possibility of moving to prospective Rider C.*

Alberta Direct Connect Consumers Association (“ADC”):

ADC has historically paid millions of extra costs due to the structure of Rider C only to have the dollars returned through the deferral account process much later. ADC supports all efforts to have Rider C changed from an energy charge to something that better reflects the tariff structure.

The Alberta Storage Alliance (“ASA”):

[blank]

Capital Power:

Capital Power looks forward to reviewing the results of the AESO's investigation and will use these results to determine its level of participation in working groups, etc. related to the issue going forward. Capital Power requests that the AESO hold a stakeholder session to review the results of its investigation.

Ed dePazieux:

[blank]

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

[blank]

ENMAX Corporation ("EEC"):

[blank]

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

If the AESO is planning a working group to investigate Rider C structure impacts, IPCAA would participate.

NextEra Energy Canada:

[blank]

NRStor Inc.:

[blank]

Renewable Energy Systems Canada Inc. ("RES"):

[Letter submitted by RES. Letter content included in "Other Comments" at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. ("RMP"):

No comment.

Temporal Power Ltd.:

[blank]

5(c) *Incorporation of primary service credit (Rate PSC) amounts in deferral account reconciliation and allocation methodology has been questioned in the 2015 deferral account reconciliation proceeding. AESO is reviewing whether modifications of Rider C or deferral account reconciliation methodology are needed to clarify treatment of Rate PSC amounts.*

Alberta Direct Connect Consumers Association ("ADC"):

ADC supports that having the tariff collect the right costs with minimal deferral amounts will satisfy all customer concerns regarding deferral account treatment.

The Alberta Storage Alliance ("ASA"):

[blank]

Capital Power:

Capital Power has no comments on 5(c) at this time and will await the results of the AESO's review.

Ed dePazieuz:

[blank]

EPCOR Distribution & Transmission Inc. (“EDTI”):

[blank]

ENMAX Corporation (“EEC”):

[blank]

Industrial Power Consumers Association of Alberta (“IPCAA”):

IPCAA would appreciate seeing the AESO’s analysis on this.

NextEra Energy Canada:

[blank]

NRStor Inc.:

[blank]

Renewable Energy Systems Canada Inc. (“RES”):

[Letter submitted by RES. Letter content included in “Other Comments” at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. (“RMP”):

No comment.

Temporal Power Ltd.:

[blank]

2017 ISO Tariff Application Consultation Process Plan

6(a) AESO is proposing the following steps for consultation on the 2017 ISO tariff application:

- i. Consultation on scope;*
 - ii. Specific topic consultation to begin in September to address transmission cost causation study results, POD cost function database results, Sections 4, 5, 8 and 9 of terms and conditions, Rider C/DAR process and CIP standards generator cost recovery; and*
 - iii. Application preview (early 2017).*
-

Alberta Direct Connect Consumers Association (“ADC”):

ADC appreciates the opportunity to participate in further stakeholder consultation.

The Alberta Storage Alliance (“ASA”):

The ASA commends the AESO’s willingness and leadership in engaging stakeholders in this process. Subsequently, the ASA strongly recommends that the AESO engage in further collaborative dialogue between regulators, academics and industry stakeholders to better understand the underlying assumptions and conclusions being drawn from research conducted on energy storage facilities. The ASA welcomes all opportunities to work with the AESO and engage in constructive dialogue on this topic.

Capital Power:

Capital Power encourages the AESO to hold meetings and technical sessions whenever practical to introduce changes, proposals, or technical results. These types of sessions are helpful to stakeholders

and allow them to better understand the context and reasoning behind various updates and changes. Capital Power reiterates its comments above regarding the value of an updated TRIP model and encourages the AESO to make this part of its 2017 GTA Consultation Process Plan.

Ed dePazieux:

Can the AESO please comment on the form of consultation? In past AESO tariff process, on key items, the AESO has formed stakeholder teams that assess and discuss each item in detail. This type of consultation has been very helpful in minimizing the formal regulatory process. Is the AESO forming these types of teams? If so, when will this process start and which topics will form part of this consultation?

EPCOR Distribution & Transmission Inc. (“EDTI”):

[blank]

ENMAX Corporation (“EEC”):

[blank]

Industrial Power Consumers Association of Alberta (“IPCAA”):

- Regulatory lag is a problem for consumers. IPCAA encourages the AESO to attempt to minimize this.
 - Consumers are waiting for the AESO to publish an updated TRIP model. While this is not necessarily required as a part of the tariff filing, we have not seen an update since June 2014. Consumers need to understand the impacts to their bills.
-

NextEra Energy Canada:

[blank]

NRStor Inc.:

NRStor commends the AESO’s willingness and leadership in engaging stakeholders in this process. Subsequently, NRStor strongly recommends that the AESO engage in further collaborative dialogue between regulators, academics and industry stakeholders including the ASA to better understand the underlying assumptions and conclusions being drawn from research conducted on energy storage facilities. NRStor and the ASA welcome all opportunities to work with the AESO and engage in constructive dialogue on this topic.

Renewable Energy Systems Canada Inc. (“RES”):

[Letter submitted by RES. Letter content included in “Other Comments” at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. (“RMP”):

RMP recommends that the AESO include an opportunity for consultation for the development of alternative transmission rates that may apply to energy storage service operators. The AESO’s dismissal of any further consultative opportunities for this issue appear high handed, arbitrary, and deliberately confrontational.

Temporal Power Ltd.:

Temporal commends the AESO’s willingness and leadership in engaging stakeholders in this process. Subsequently, Temporal strongly recommends that the AESO engage in further collaborative dialogue between regulators, academics and industry stakeholders including the ASA to better understand the underlying assumptions and conclusions being drawn from research conducted on energy storage facilities. Temporal and the ASA welcome all opportunities to work with the AESO and engage in

constructive dialogue on this topic.

Additional Comments

Alberta Direct Connect Consumers Association (“ADC”):

[blank]

The Alberta Storage Alliance (“ASA”):

[blank]

Capital Power:

Capital Power has no additional comments at this time.

Ed dePazieux:

The TRIP model has not seen an update in years, however the assumptions underlying the model have dramatically changed. Customers rely upon this model in making assessments and building longer-term budgets. It is very important that the AESO make updating and publishing the results of the TRIP model a priority. It is disappointing that the AESO was close to publishing these results in as early as March 2016 and then decided to withdraw this work. Please clarify if the AESO views this model as important, and if so, specify a date that it will publish this analysis.

EPCOR Distribution & Transmission Inc. (“EDTI”):

[blank]

ENMAX Corporation (“EEC”):

[blank]

Industrial Power Consumers Association of Alberta (“IPCAA”):

[blank]

NextEra Energy Canada:

[blank]

NRStor Inc.:

[blank]

Renewable Energy Systems Canada Inc. (“RES”):

Renewable Energy Systems Canada Inc. (RES) is a member of the Alberta Storage Alliance (ASA). The 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. RES, alongside the ASA, is advocating a technology neutral approach to assessing the services offered by various energy assets; we believe 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. Further information on the ASA and its initiatives can be found on its website (<http://albertastoragealliance.com/>) and in its recently released White Paper: Energy Storage – Unlocking the Value for Alberta’s Grid.

RES is encouraged to see that the AESO is opening a dialogue on how to best manage the integration of energy storage assets in the Alberta market. However, RES believes changes to rate structures should be given further consideration before any final decision is made. 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.

Please note that RES supports the submission made by the ASA to this consultation and we look forward to a continuing dialogue.

Rocky Mountain Power (2006) Inc. (“RMP”):

[blank]

Temporal Power Ltd.:

[blank]

November 15, 2016

AESO Stakeholders
AESO 2018 ISO Tariff Consultation Participants

Dear Stakeholder:

Re: **Invitation to Participate in Consultation on AESO 2018 ISO Tariff Application**

The AESO continues to consult with market participants on the development of its next comprehensive ISO tariff application, which it now refers to as the 2018 ISO tariff application to reflect the year in which the tariff is expected to become effective (in prior stakeholder communications, this application had been referred to as the 2017 ISO tariff application). The AESO is holding a meeting to provide an update on work completed to date and invites you to attend the following consultation session:

Date:	Monday, December 5, 2016
Time:	1:00 - 4:00 PM
Place:	Meeting Room 6006, 6th Floor, BP Centre, 240 – 4th Avenue SW, Calgary, Alberta Note that the glass doors on the 6th floor are locked; please knock to have them opened.
Teleconference:	Within Calgary calling area: 403-410-3051, Conference ID 4366631 Outside Calgary calling area: 1-855-453-6957, Conference ID 4366631
RSVP:	By 5:00 PM on Wednesday, November 30, 2016 to , Tatiana Aparicio-Caris Tatiana.Aparicio-Caris@aeso.ca or 403-539-2664

The AESO plans to discuss the following items during the meeting:

- progress on annual tariff updates, deferral account reconciliations, and Rider C matters;
- technical update on transmission cost causation study results;
- technical update on point of delivery (“POD”) cost function database; and
- planned timeline and next steps for 2018 ISO tariff application.

The AESO plans to present information on these topics to facilitate discussion, and will post a presentation before the meeting. Stakeholders may provide feedback in person during the meeting or through written comments to the AESO after the meeting.

All information relating to the 2018 ISO tariff consultation will be available on the AESO website at www.aeso.ca by following the path Rules, Standards and Tariff ► Stakeholder engagement ► 2018 ISO tariff application. As well, new information posted by the AESO on this topic will be mentioned in the AESO stakeholder newsletter, which you can subscribe to at the bottom right of the AESO’s home page at www.aeso.ca.

If you have any questions on the AESO's 2018 ISO tariff consultation, please contact me at 403-539-2555 in Calgary or by e-mail to larhonda.papworth@aeso.ca.

Yours truly,

LaRhonda Papworth
Manager, Tariff Design

cc: Doyle Sullivan, Director – Market and Tariff Design

AESO 2018 ISO Tariff Consultation

December 5, 2016
AESO Office, Calgary

- Introduction and objectives (slide 3-5)
- Rider C / Deferral Account Reconciliation (DAR) / Rates Update (slide 6-62)

Break

- Transmission cost causation study update (slide 63-71)
- Point-of-delivery cost function database update (slides 72-76)
- Application process and next steps (slides 77-80)
- Discussion and wrap-up (slide 81)

Please feel free to ask questions during presentation

Stakeholder session objectives

- Enhance understanding of ISO tariff application
- Review technical results of a number of analytical exercises by the AESO
- Share information prior to filing of 2018 ISO tariff application
- Gather feedback to ensure tariff application provides all information stakeholders require
- Review application timeline and next steps

Applications currently in progress

- Directions 5-8 on advancement costs and related provisions
 - Decision 3473-D02-2015 issued on August 26, 2015
 - Process letter issued on October 22, 2015 with additional information on process in the new year *[2016]*
 - Awaiting Commission follow-up
- 2015 Deferral Account Reconciliation application
 - Currently before the Commission in Proceeding 21735
 - Interim settlement was approved and occurred in October 2016
 - Hearing scheduled for December 13 and 14, 2016

Applications currently in progress

- 2017 ISO tariff update
 - Currently before the Commission in Proceeding 22093
 - Interim, refundable approval for January 1, 2017 issued by Commission on December 2, 2016
 - Final approval not expected until 2017
- 2017 Rider F, *Balancing Pool Consumer Allocation Rider*, application
 - Bill 34 passed November 29, 2016
 - Awaiting Balancing Pool notification of annualized amount
 - AESO will file as soon as possible, in December, and applicable for settlement periods from January 1 – December 31, 2017

Evaluation of Potential Changes to Deferral Account Reconciliations and Rider C

John Martin, Senior Tariff and Regulatory Advisor

- Background and overview of evaluation approach
- Impact of early tariff updates
- Impact of changing Rider C structure
- Impact of changing to production year basis
break
- Impact of changing to net revenue allocation methodology
- Possible future changes to Rider C
- Timing and implementation options

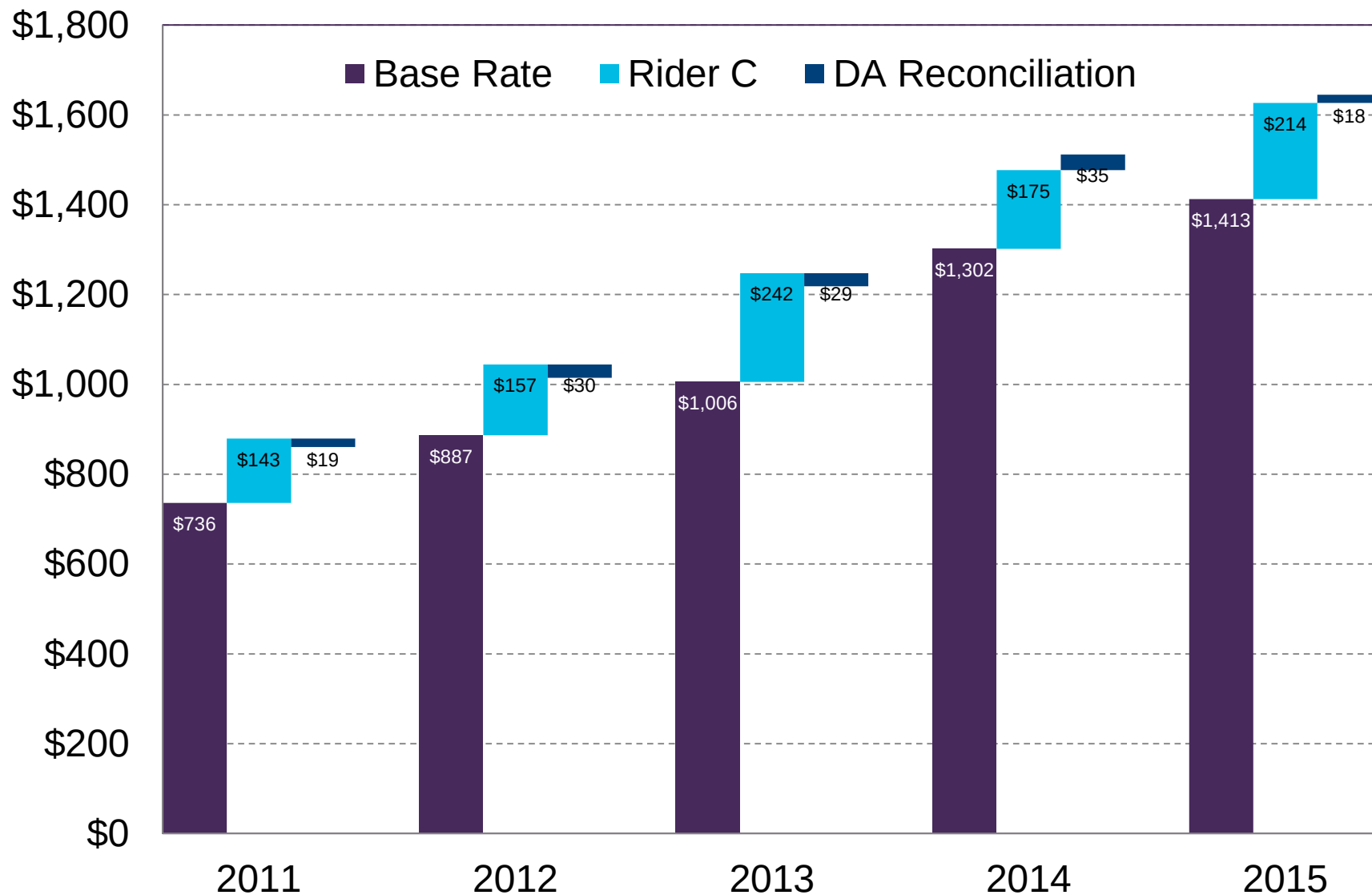
Please ask questions during presentation!

Commission directed AESO to investigate Rider C in Decision 2014-242

- The Commission acknowledges the view expressed by both the ADC and the DUC that the AESO should be directed to examine further the structure of Rider C with an eye to minimizing imbalances among customers. Therefore, the Commission directs the AESO to discuss the related matters of annual tariff updates, deferral account reconciliation processes and Rider C design with stakeholders prior to filing its next comprehensive GTA, and to provide a report on the outcome of any such discussions, including any recommended changes (if any) within its next comprehensive GTA.*

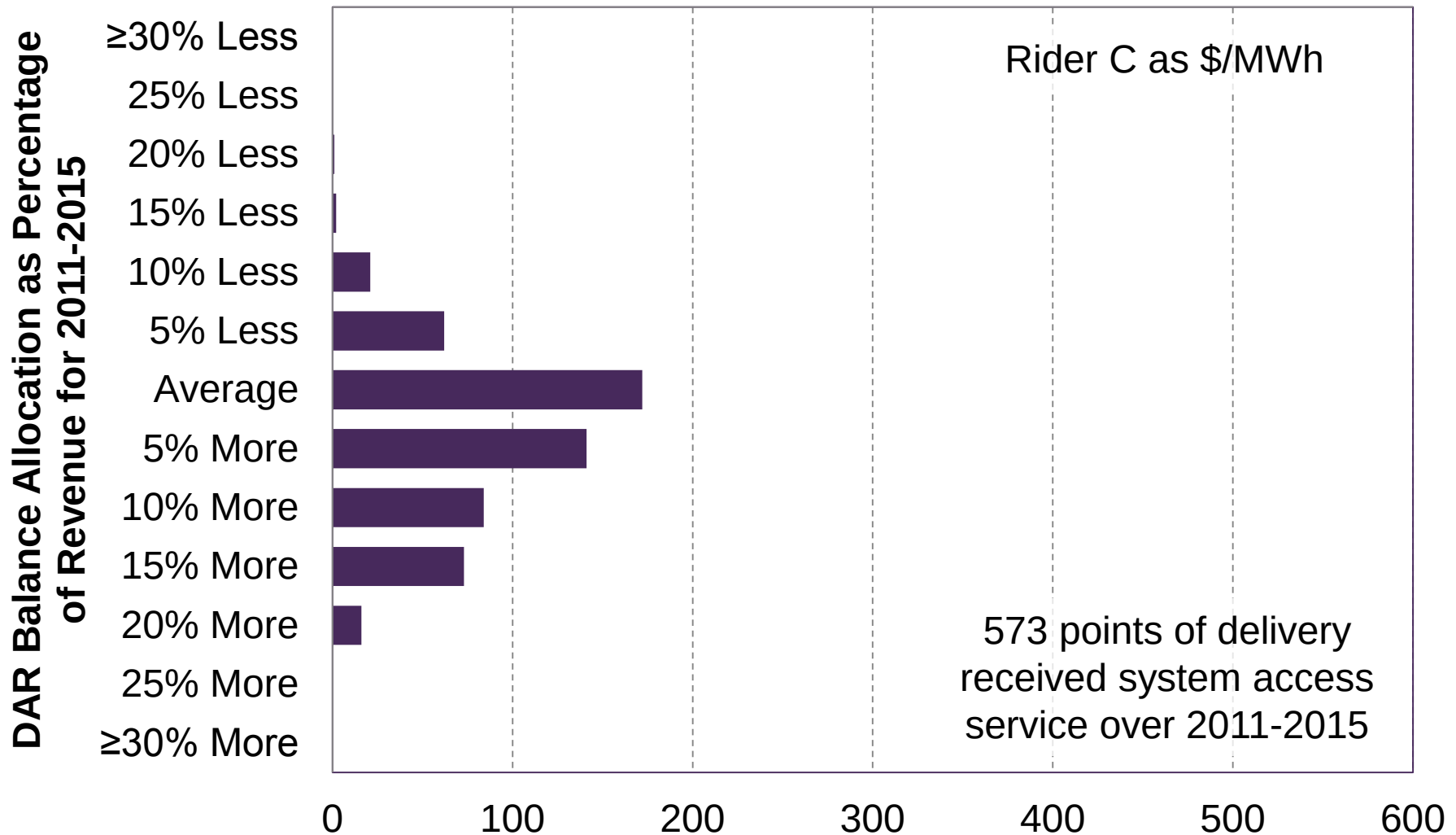
[Decision 2014-242, paragraph 704]

Net amounts allocated through annual reconciliations have been small ...



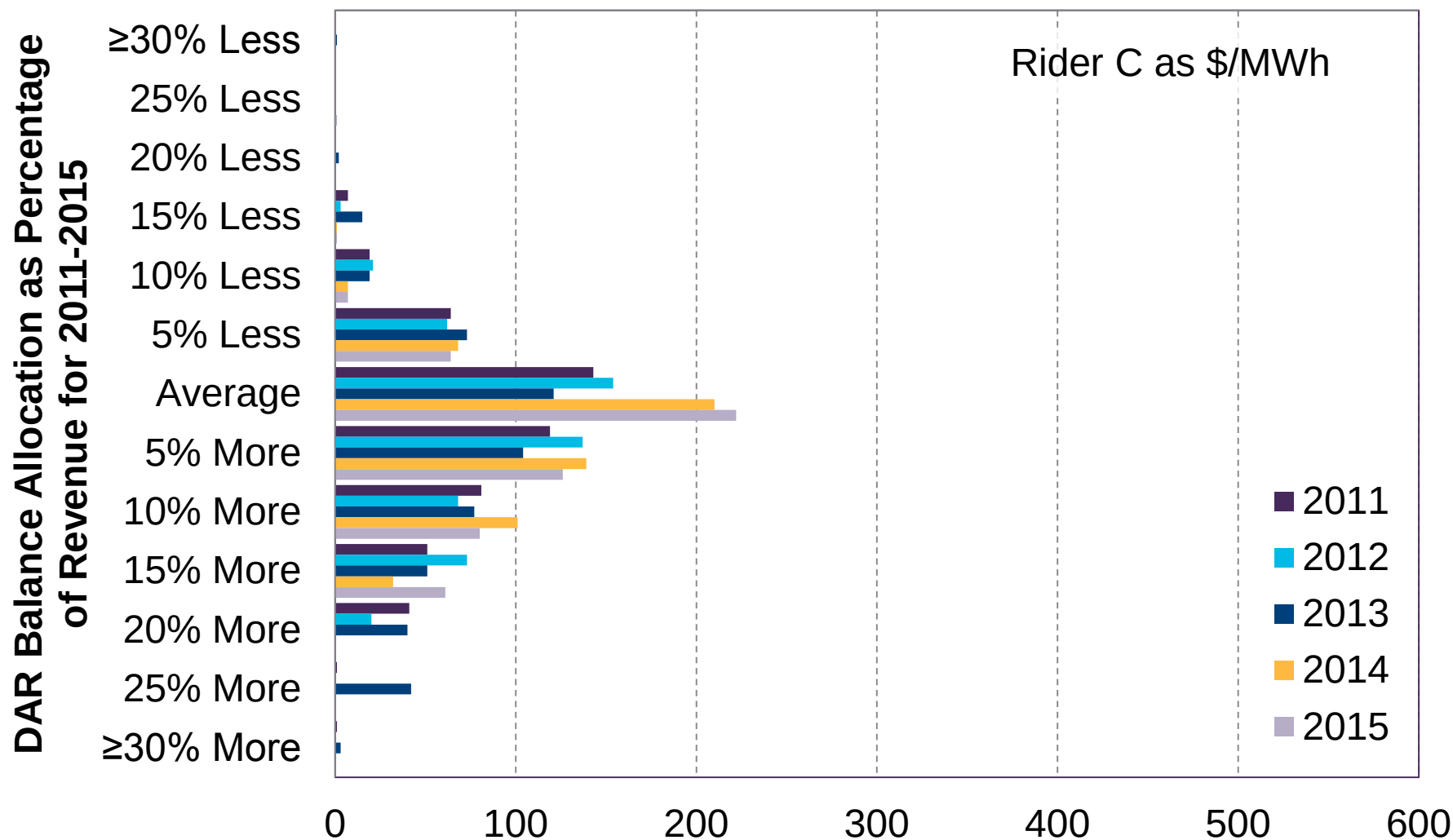
But allocations to individual services have varied over a much wider $\pm 20\%$ range

Number of Services per 5% Interval Less or More Than Average



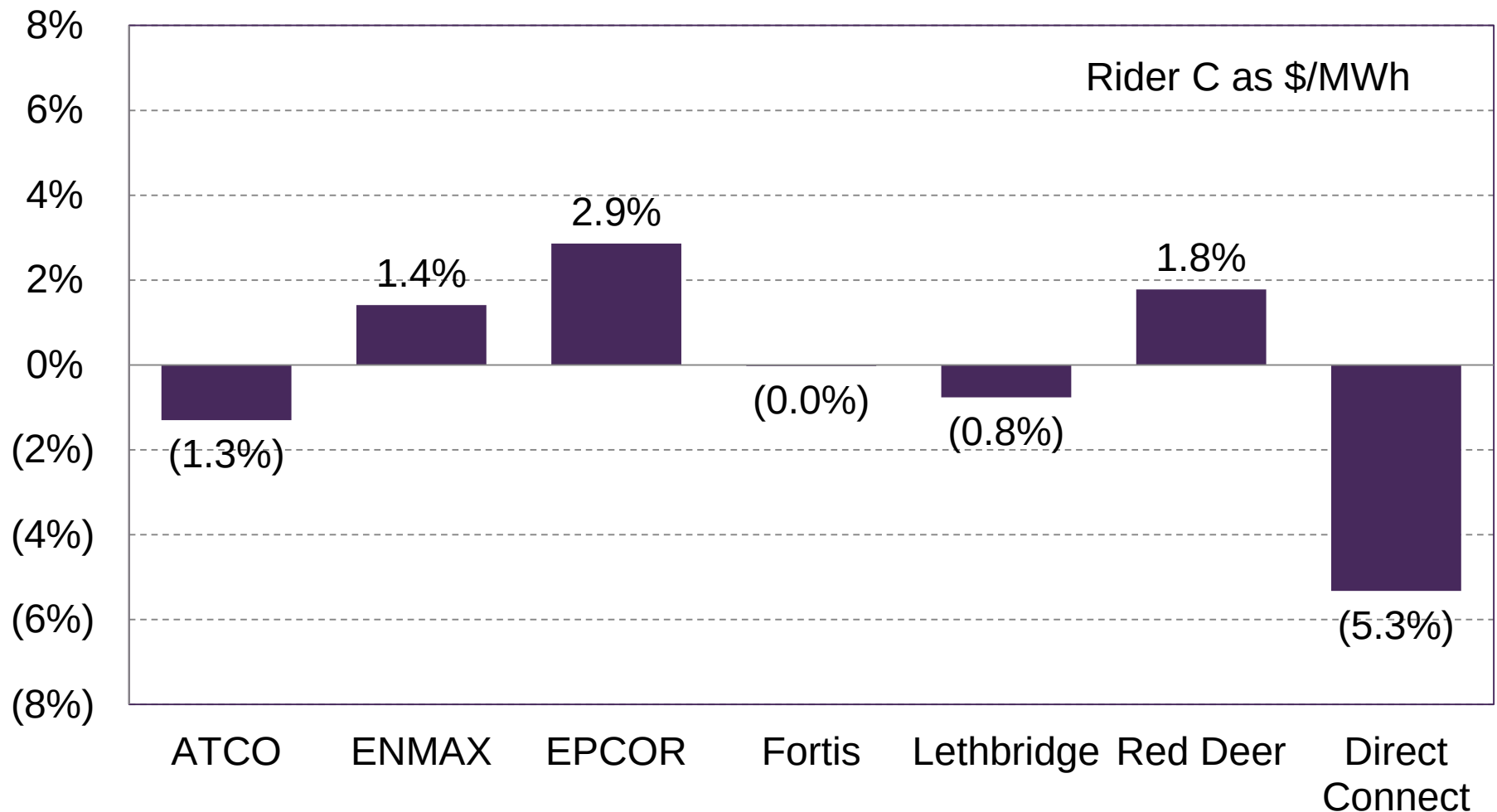
Variability has been similarly wide for individual years

Number of Services per 5% Interval Less or More Than Average



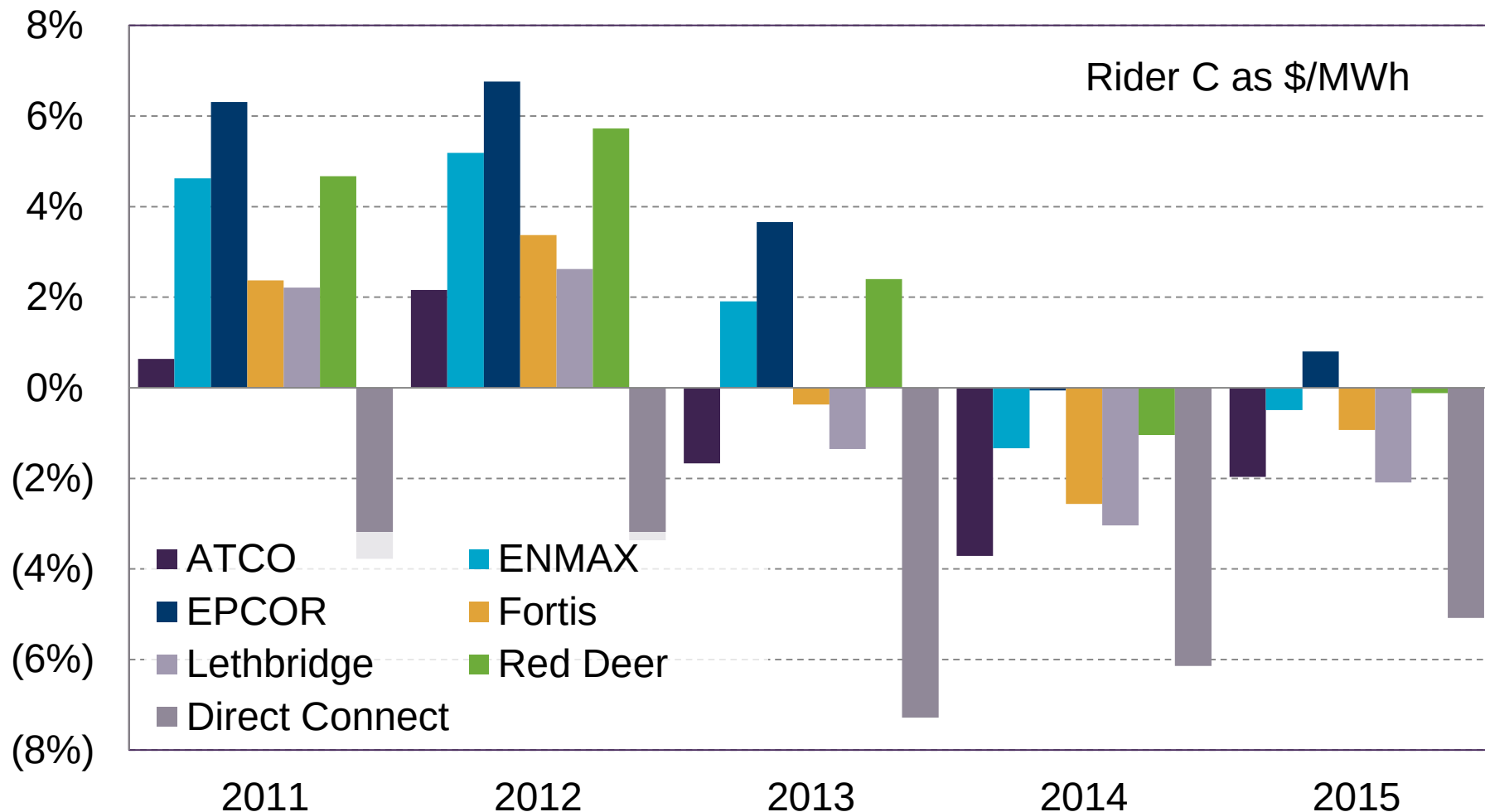
Allocations have also varied between customers

**DAR Balance Allocation Refund (Charge)
as Percentage Less or More Than Average for 2011-2015**



Variability in allocation has similar pattern in individual years

**DAR Balance Allocation Refund (Charge)
as Percentage Less or More Than Average by Year**



In consultation for 2018 tariff application, AESO proposed Rider C evaluation



- Develop model of deferral account reconciliation for 2011-2015
- Assess impact of early tariff updates
- Evaluate potential changes to Rider C structure
 - Convert to percentage basis (from current \$/MWh basis)
- Consider annual basis for Rider C and annual reconciliation to eliminate seasonal effects
- Possibility of eliminating Rider C or moving to prospective Rider C
- Note that this discussion addresses only connection charge component of deferral account balance
 - Connection charge account for 95% of deferral account balance

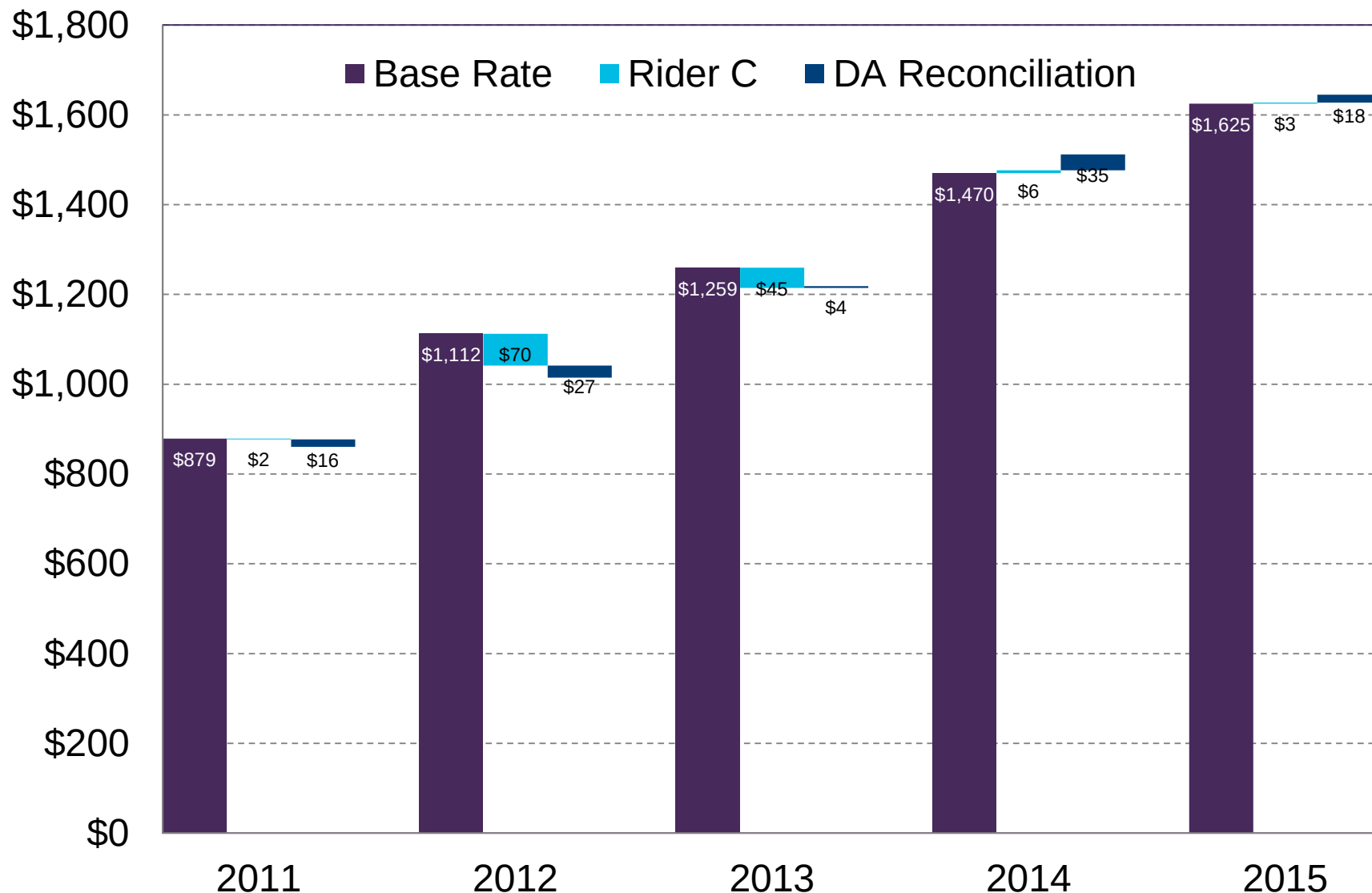
AESO has simulated Rider C and deferral account reconciliation in Excel

- Simulation model covers five years (2011-2015)
- Includes charges and allocations to over 570 individual services
- Closely replicates deferral account reconciliation for 2011, 2013, and 2014
 - Uses calculated instead of “frozen” Rider C during 2012
 - Uses final settlement data for all months of 2015
 - Simulation matches deferral account balance allocation over all settlement points within $\pm 2\%$
- Allows assessment of impact of changes to Rider C and to deferral account reconciliation methodology
- Will not be made public as data is commercially sensitive



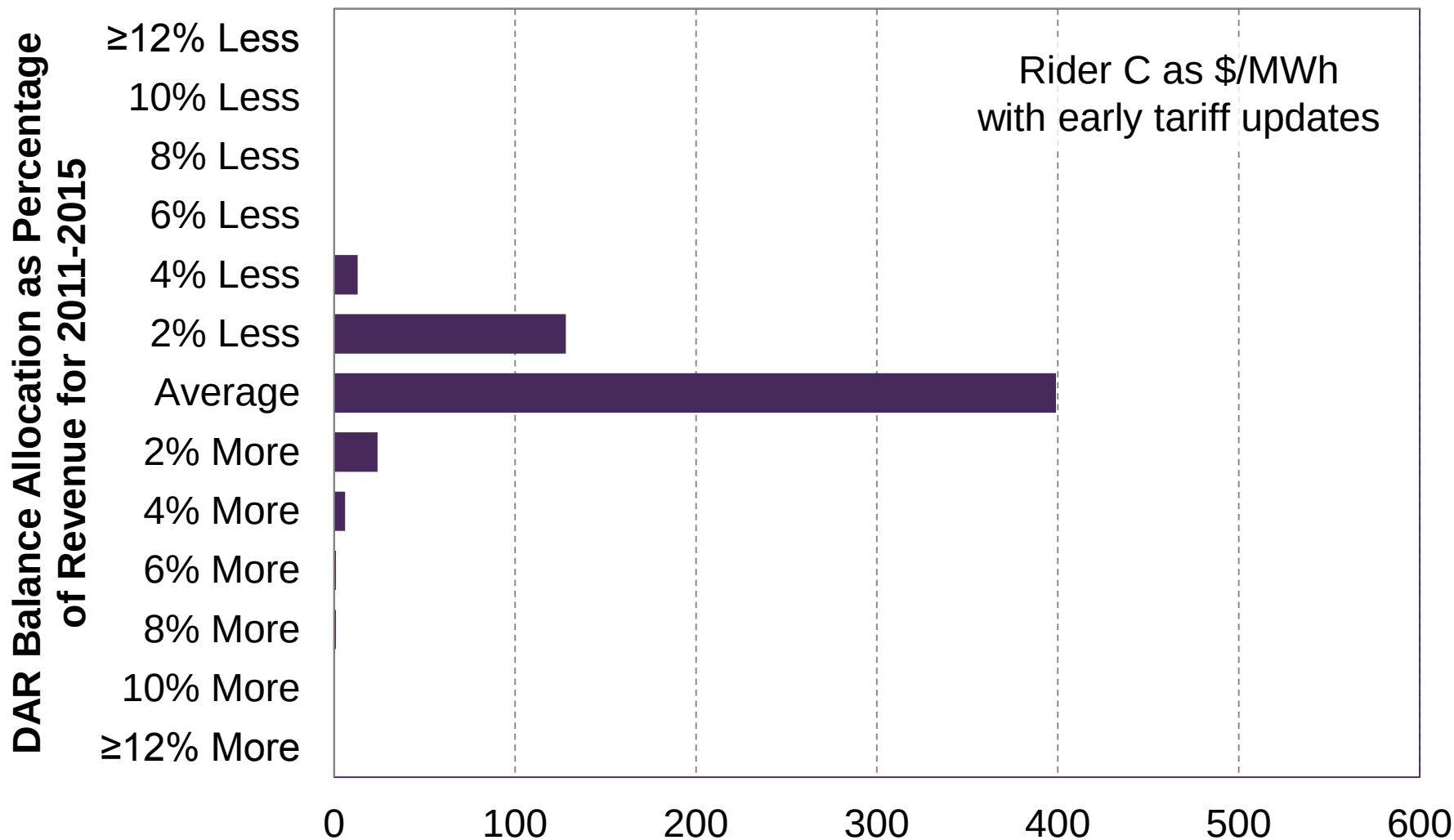
Impact of Early Tariff Updates

Early tariff updates can significantly reduce Rider C charges and credits



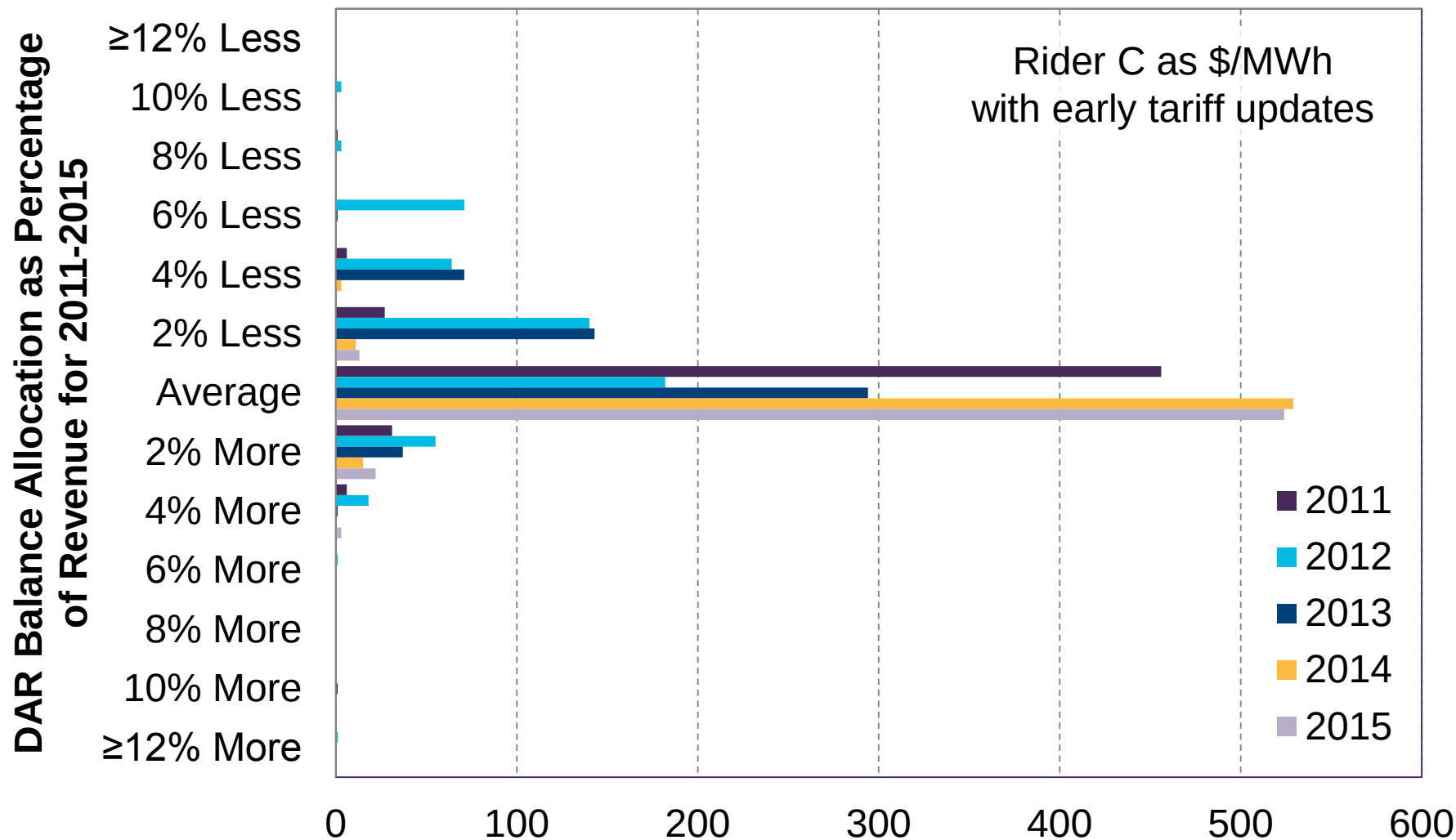
Early tariff updates also reduces variability of allocations to individual services

Number of Services per 2% Interval Less or More Than Average



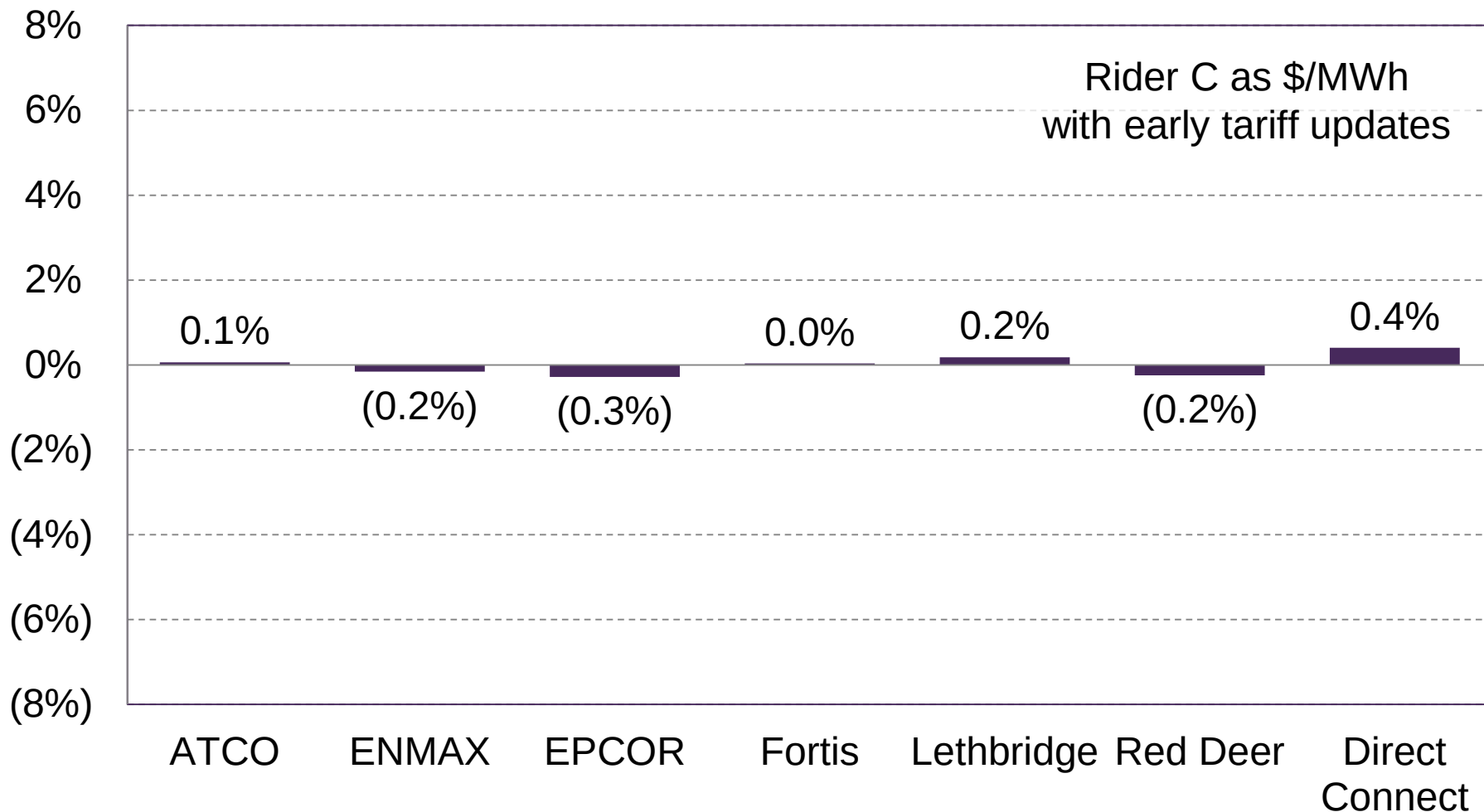
Variability depends on amounts collected through Rider C each year

Number of Services per 2% Interval Less or More Than Average



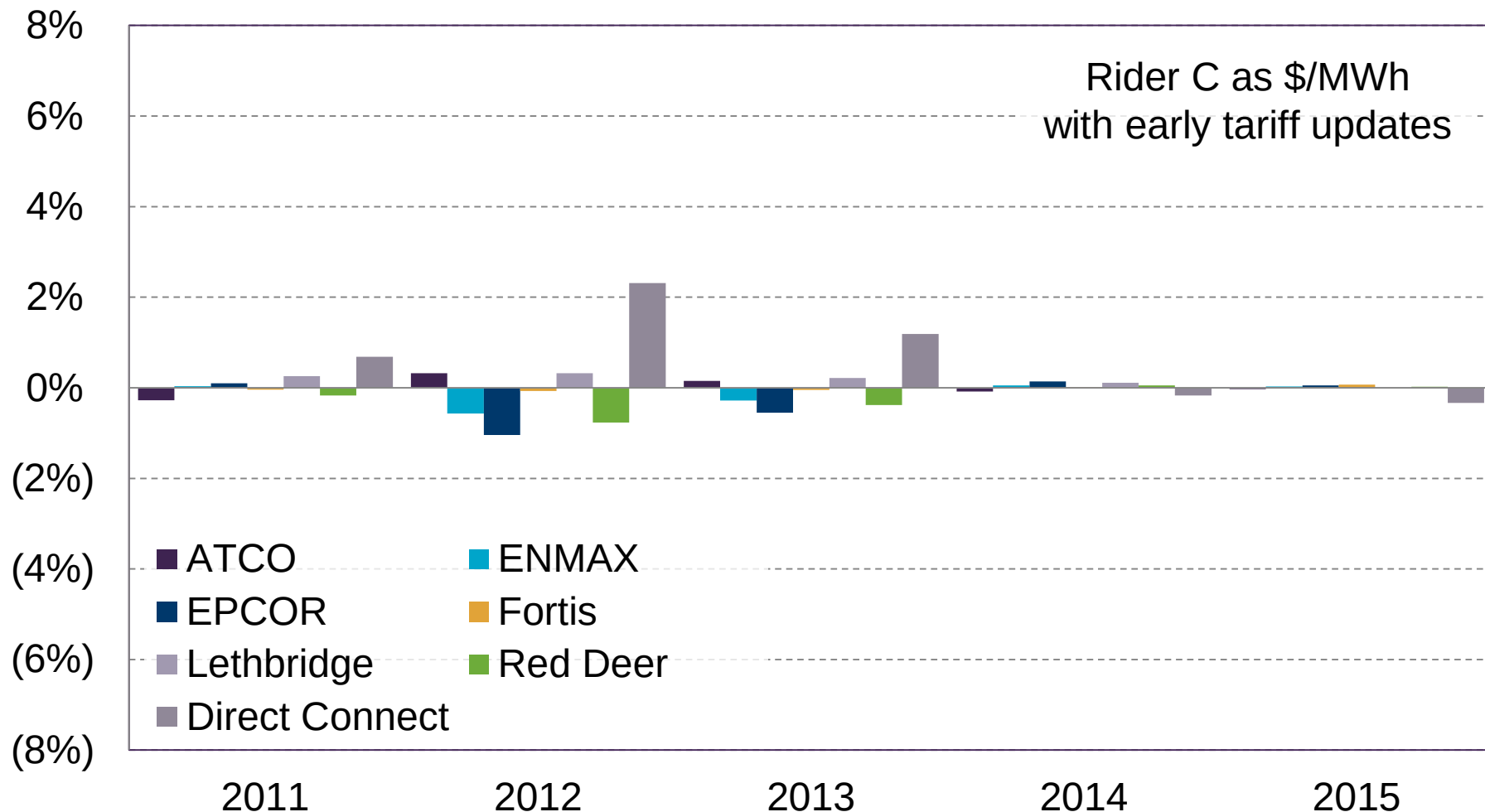
Early tariff updates similarly reduce allocation variability between customers

DAR Balance Allocation Refund (Charge) as Percentage Less or More Than Average for 2011-2015



Allocation variability between customers is reduced in individual years as well

DAR Balance Allocation Refund (Charge) as Percentage Less or More Than Average by Year



Conclusion: Early tariff updates significantly reduce transfers between services

- Early tariff updates significantly reduce transfers between services in a deferral account reconciliation
- Early tariff updates do not entirely eliminate transfers between services
- AESO needs to better manage tariff update process
 - Approval of 2017 tariff update prior to January 1 was uncertain due to introduction of issues beyond the scope of a tariff update application



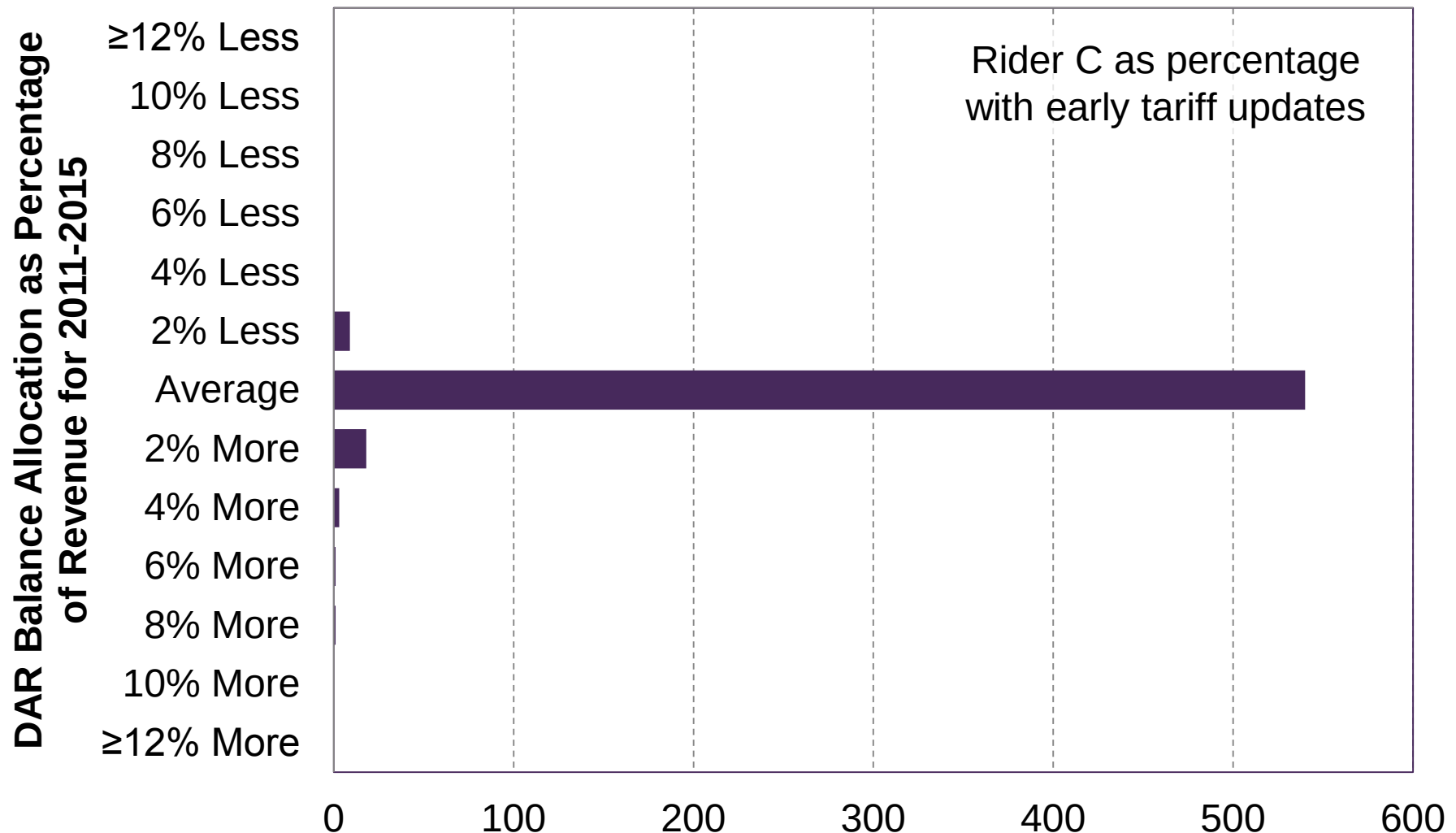
Impact of Changing Rider C Structure

Converting Rider C to a percentage basis primarily impact transfers between services

- Changing the structure of Rider C would have little impact on total amounts collected through Rider C or determined in a deferral account reconciliation
 - Potential small impact from differences in ability to forecast revenue under different structures
- Changing Rider C to a percentage of revenue should reduce transfers in deferral account reconciliation by aligning Rider C with the deferral account balance allocation methodology
 - Previous higher-level analysis had found limited reduction to transfers

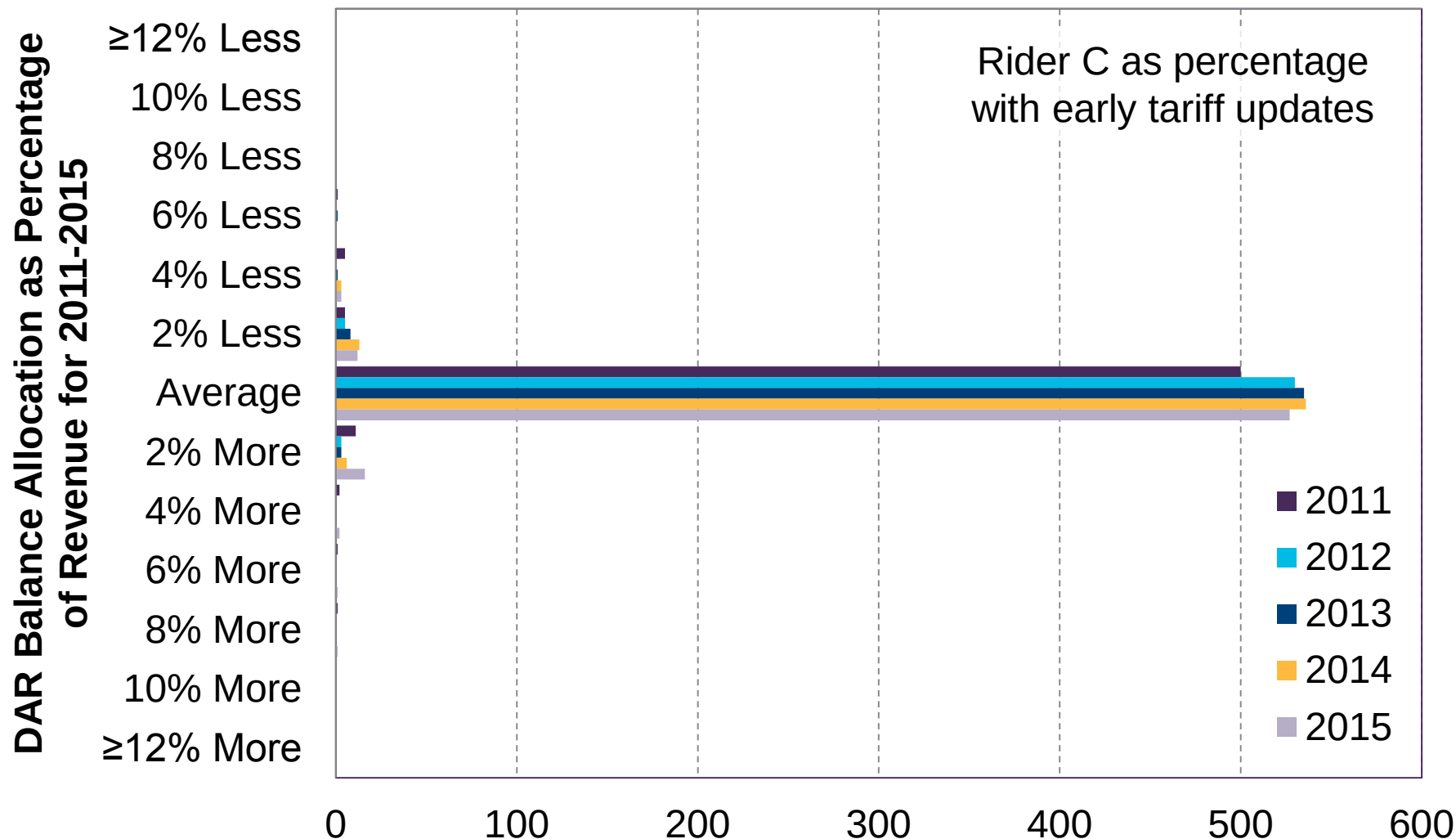
Rider C as percentage significantly reduces variability of allocations to services

Number of Services per 2% Interval Less or More Than Average



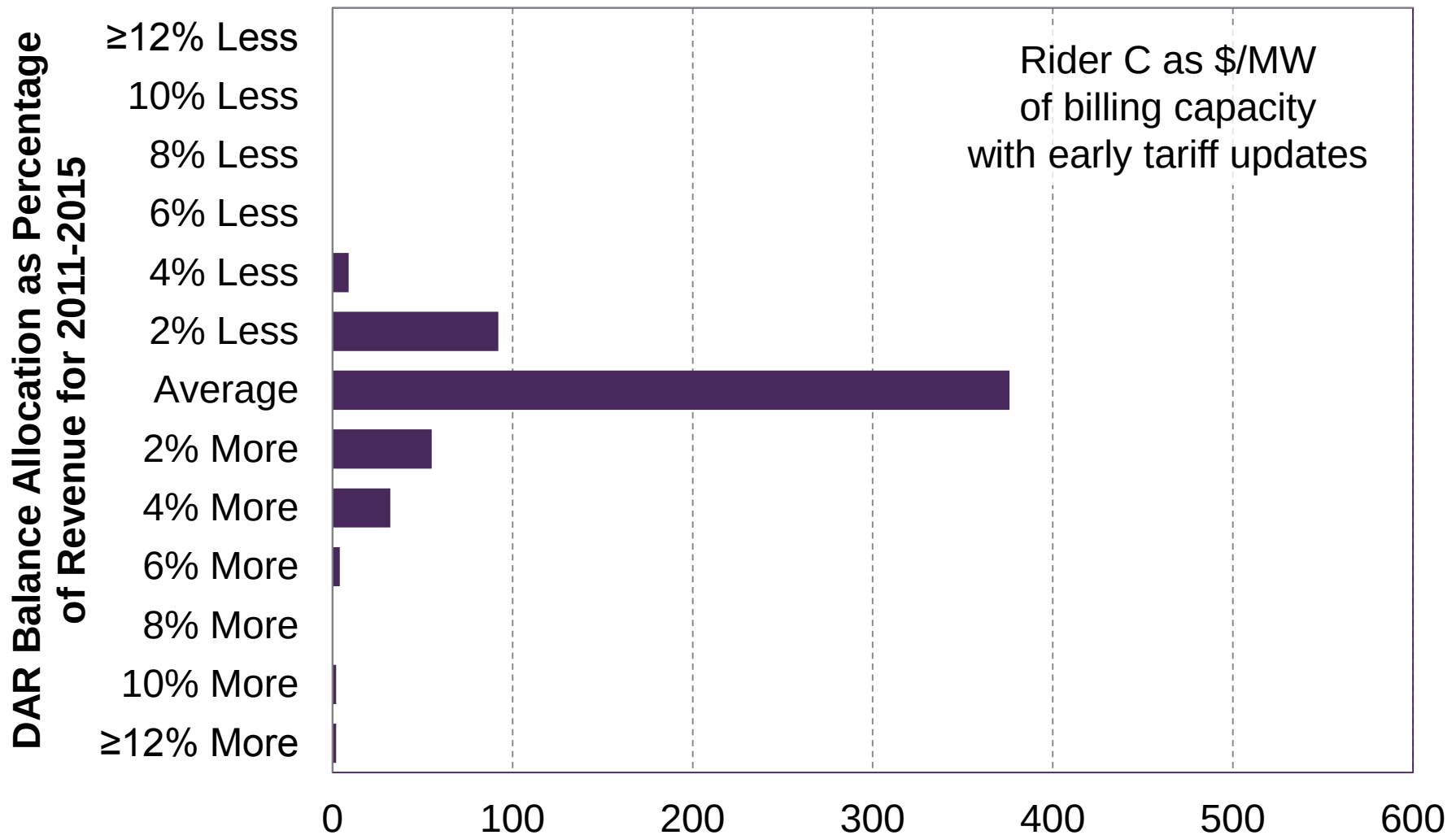
Reduction to variability between services occurs in every year

Number of Services per 2% Interval Less or More Than Average



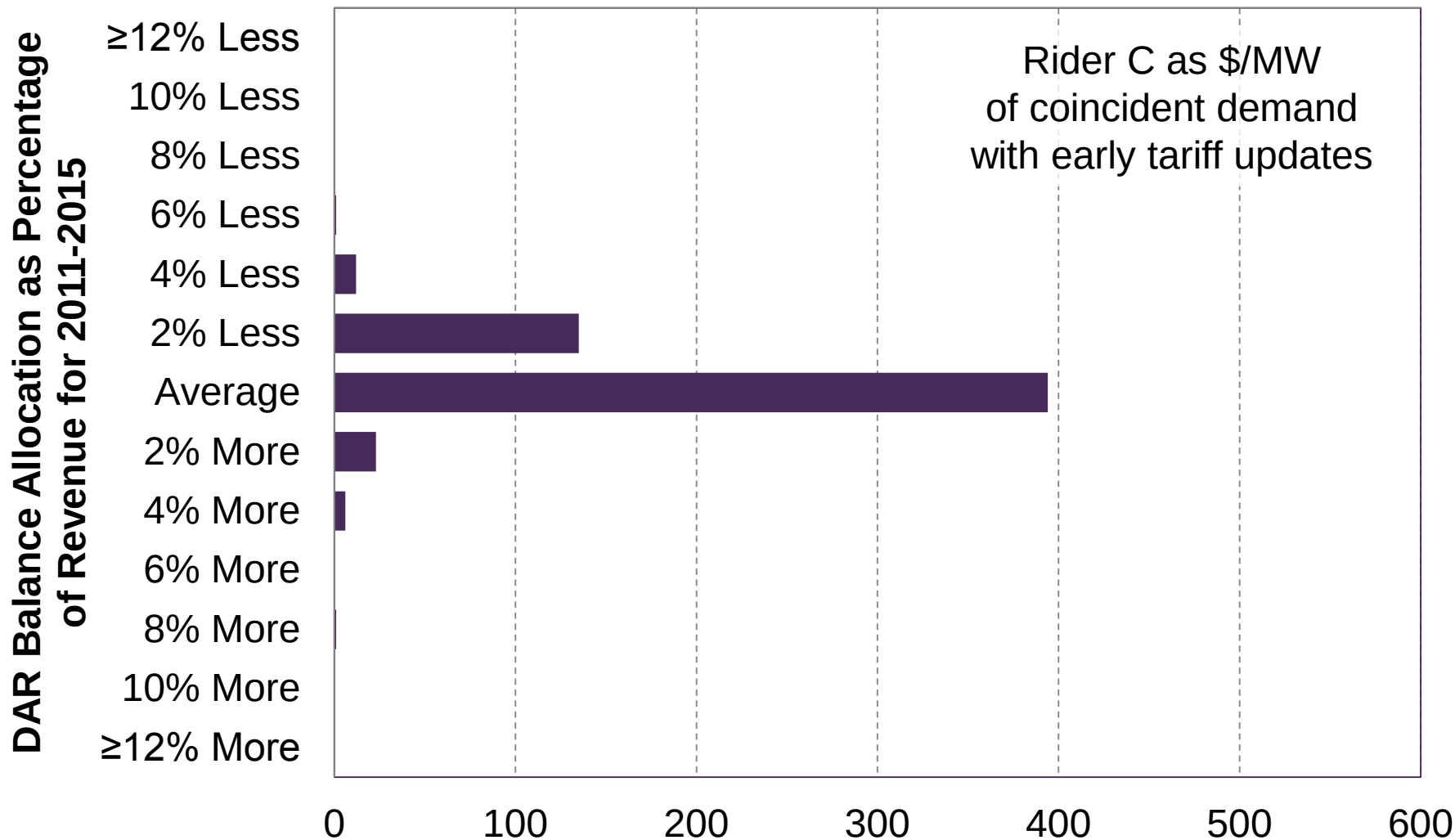
Rider C as \$/MW of billing capacity reduces some variability of allocations to services

Number of Services per 2% Interval Less or More Than Average



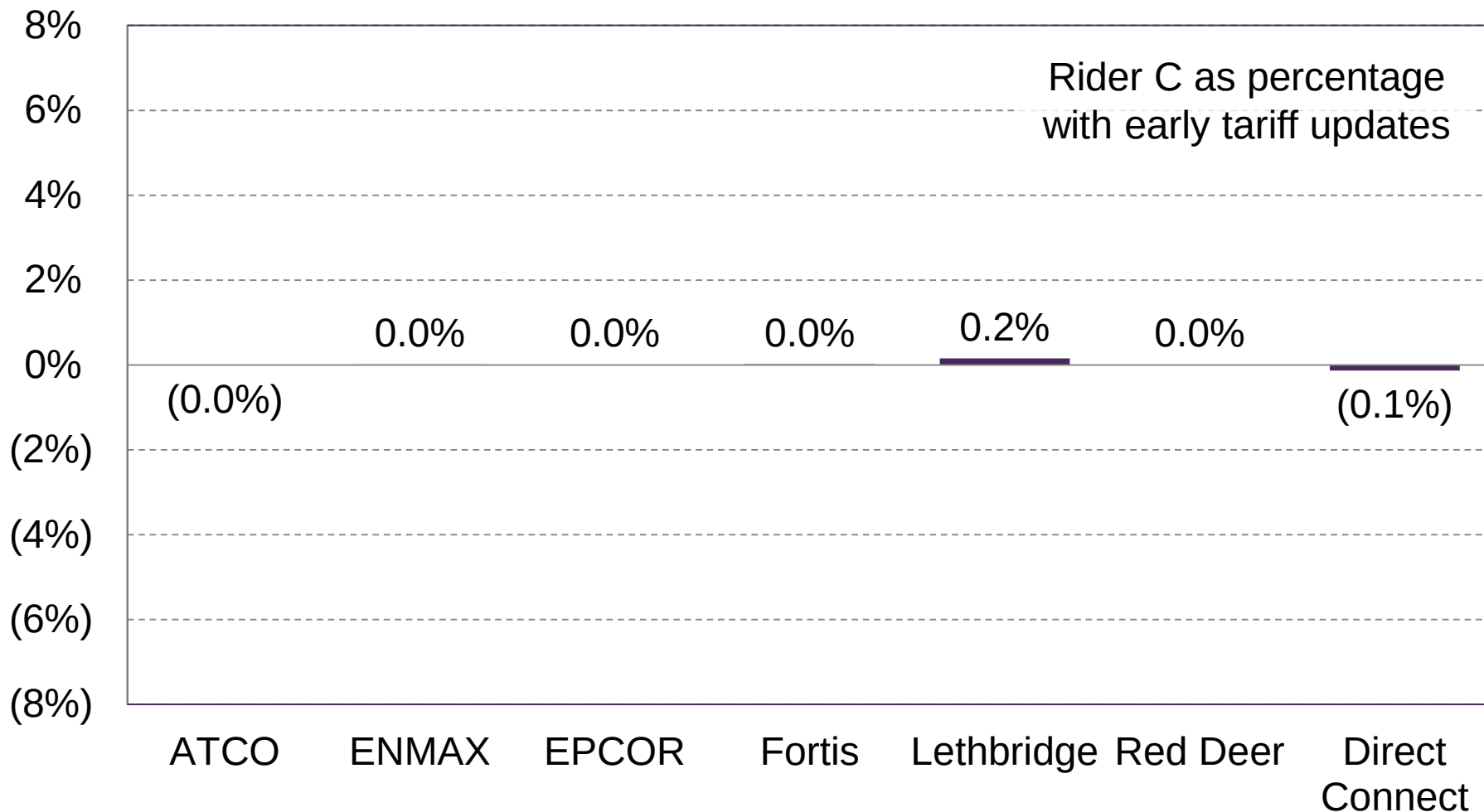
Rider C as \$/MW of coincident demand provides minimal reduction to variability

Number of Services per 2% Interval Less or More Than Average



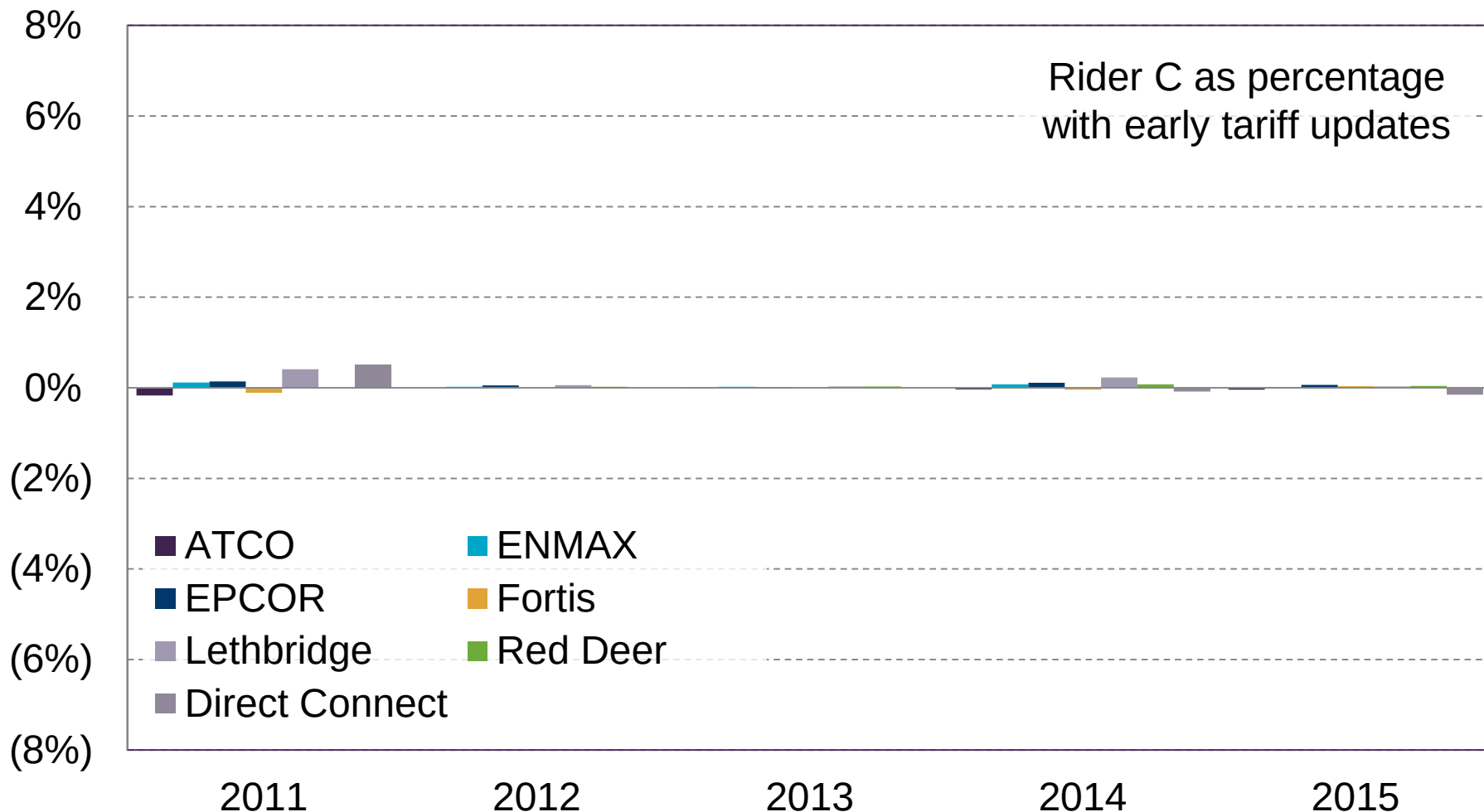
Rider C as percentage also reduces allocation variability between customers

DAR Balance Allocation Refund (Charge) as Percentage Less or More Than Average for 2011-2015



Reduction to variability between customers occurs in every year

**DAR Balance Allocation Refund (Charge)
as Percentage Less (More) Than Average by Year**



Conclusion: Rider C as percentage almost eliminates transfers between services

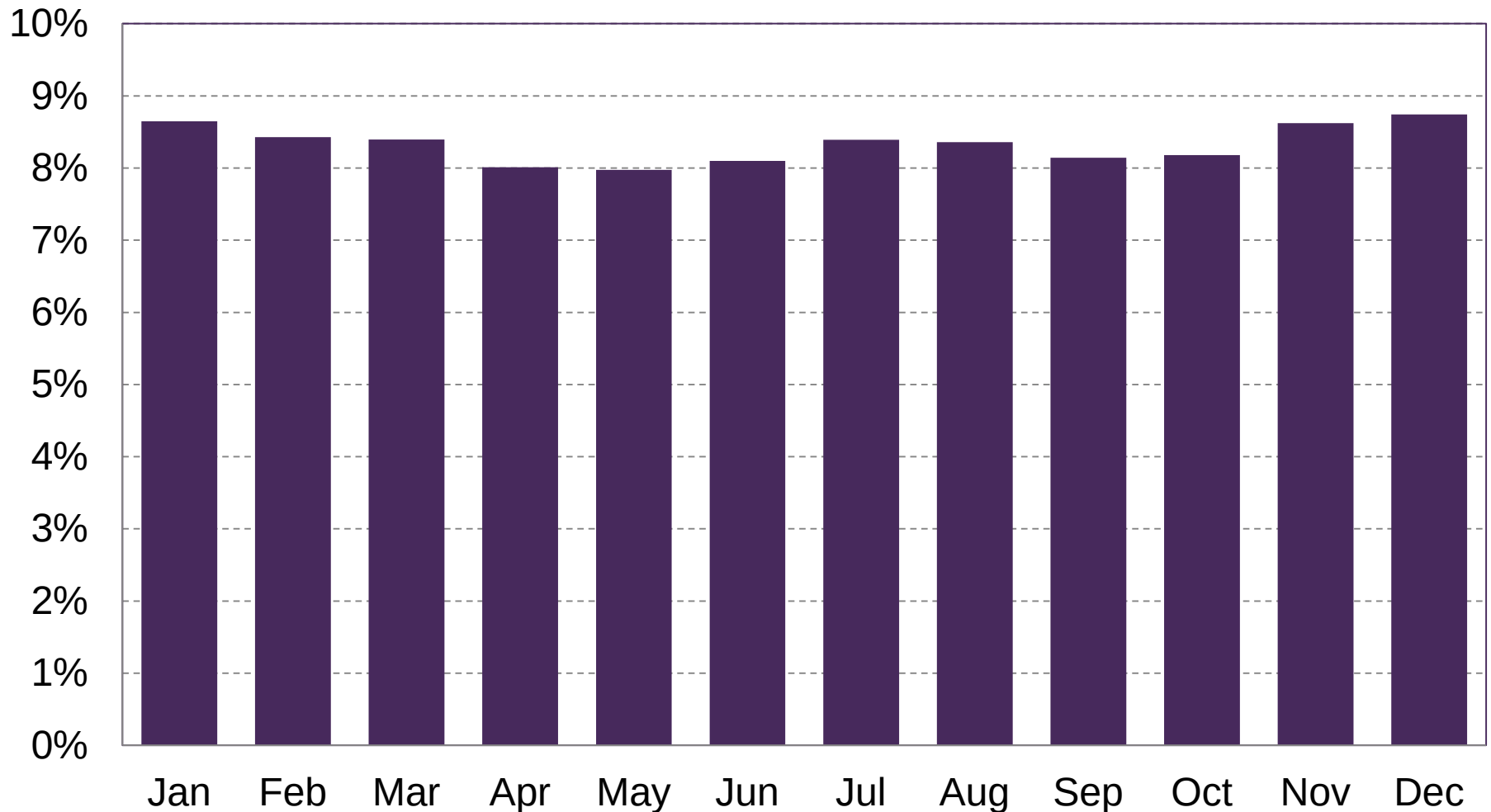
- Rider C as percentage almost eliminates transfers between services in a deferral account reconciliation
- Some transfers between services still exist but are small



Impact of Changing to Production Year Basis

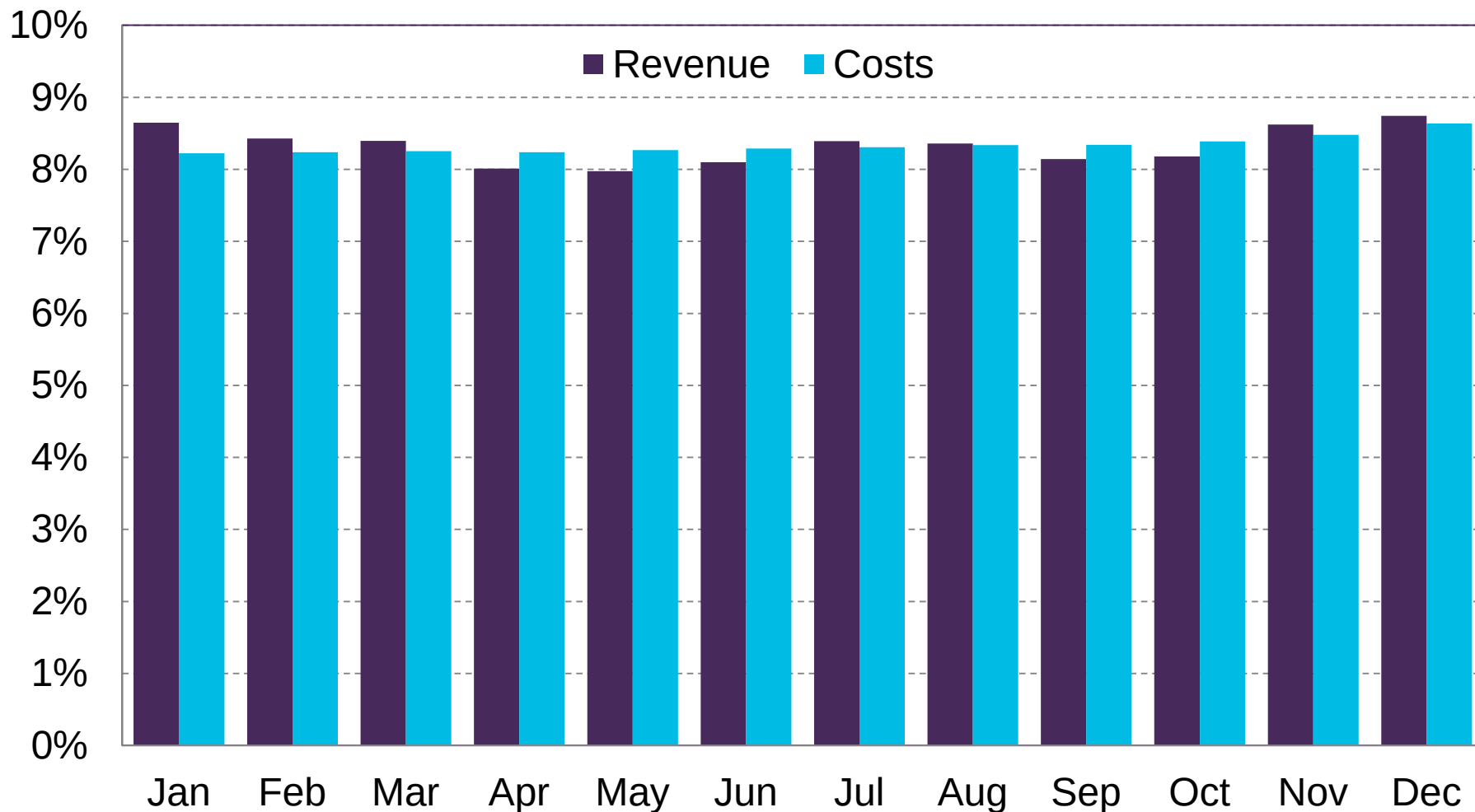
Monthly revenue exhibits a pattern of winter and summer peaks

**Monthly Revenue as Percentage of Annual Total
Average Over 2011-2015 With Early Tariff Updates**



Costs do not exhibit the same seasonal pattern

**Monthly Revenue and Costs as Percentage of Annual Totals
Average Over 2011-2015 With Early Tariff Updates**



Costs are determined on an annual basis for the AESO's revenue requirement

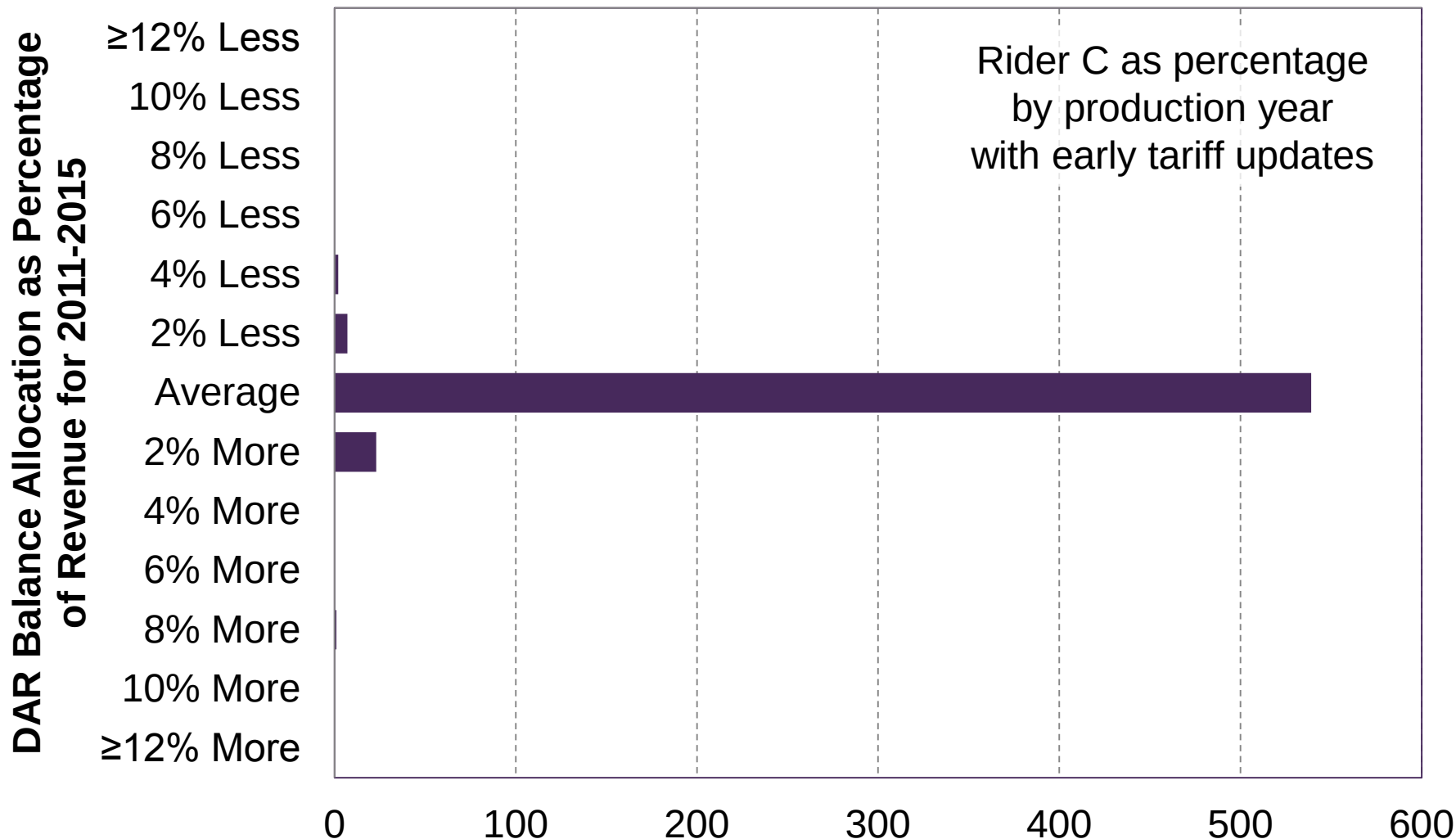
- Transmission facility owner costs are established on an annual basis
 - Annual amount is simply divided by 12 to get monthly amount
- AESO's own administrative costs are not attributable to specific production months
 - Comprise general and administrative costs, other industry costs, and capital costs of the AESO
 - Are simply attributed to month in which they occur
 - Account for 6% to 9% of the AESO's annual revenue requirements
- Connection charge amount in Rate DTS is calculated on an annual basis in tariff applications and tariff updates

Allocating shortfalls and surpluses by month is inconsistent with rate design approach

- Allocating deferral account balances on a production month basis indirectly establishes a monthly connection charge
 - Lower per-unit charge in winter and summer when volumes are higher
 - Higher per-unit charge in spring and fall when volumes are lower
- Effect is to levelize revenue over all months
 - Inconsistent with cost causation as peak volumes result in lower charges
 - Lowers allocations in peak months compared to off-peak months
- Allocating shortfalls and surpluses on a monthly basis results in different annual allocations between services that have different load patterns between months

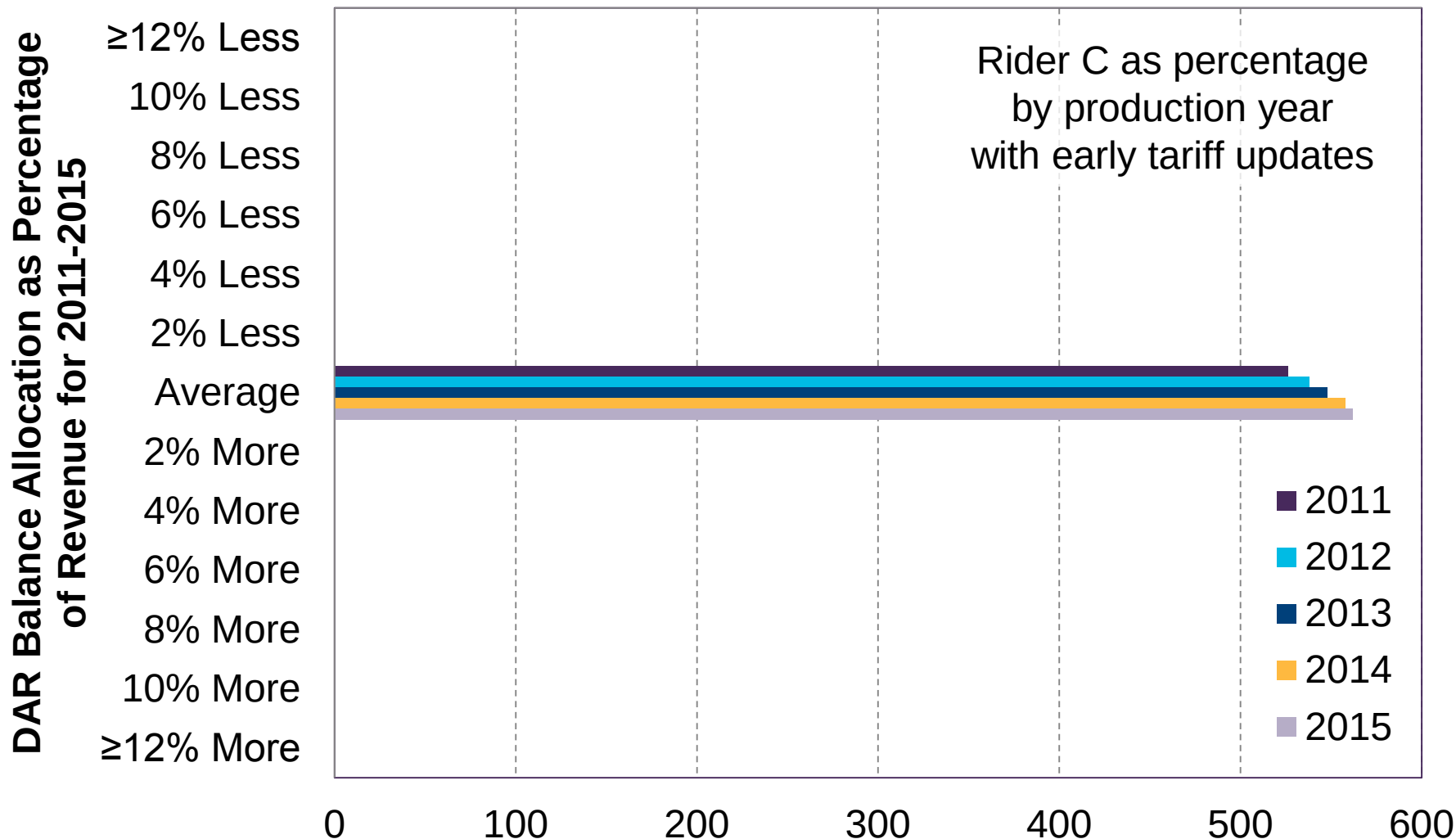
Five-year view obscures impact of Rider C as percentage by production year

Number of Services per 2% Interval Less or More Than Average



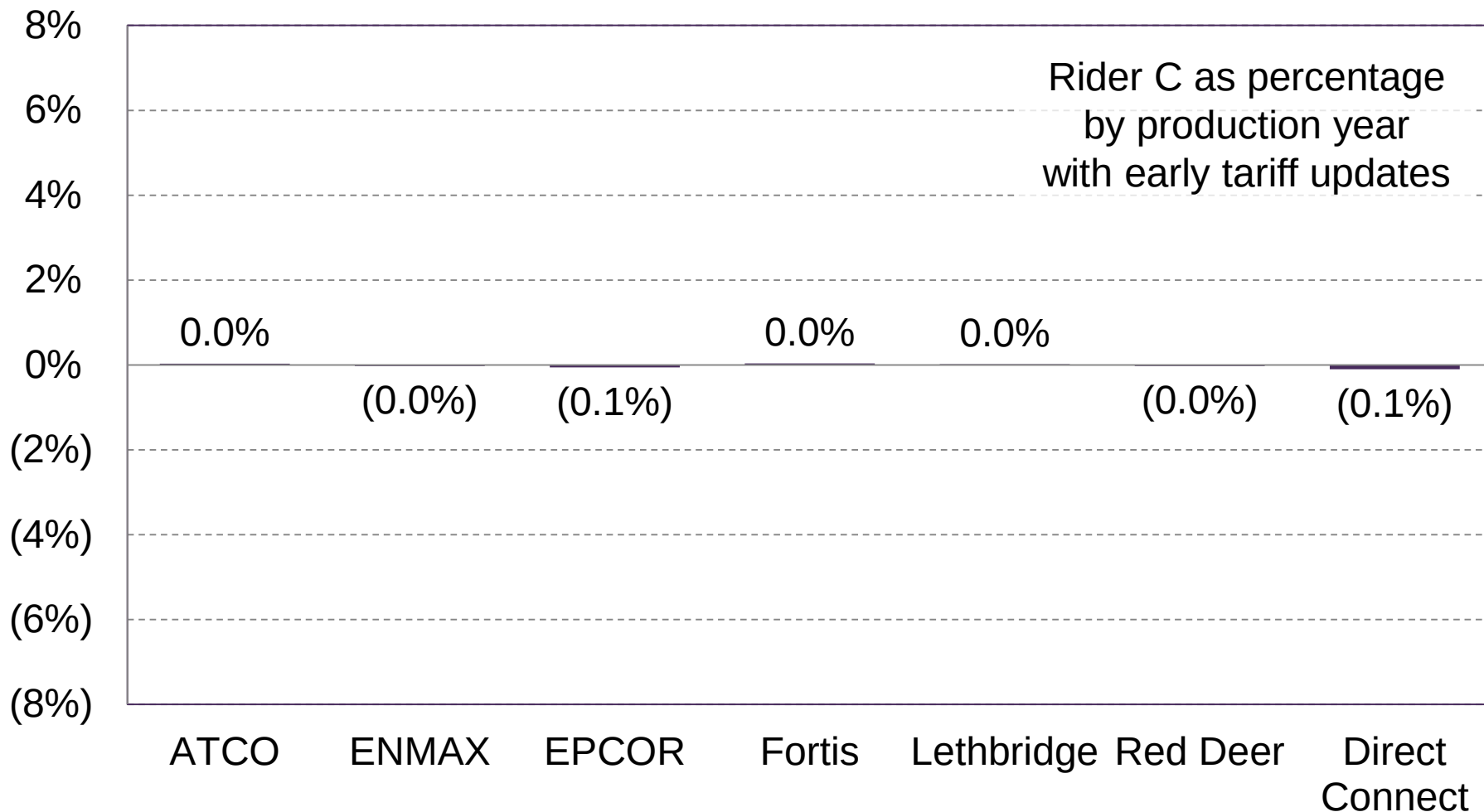
Rider C as percentage by production year eliminates remaining variability

Number of Services per 2% Interval Less or More Than Average



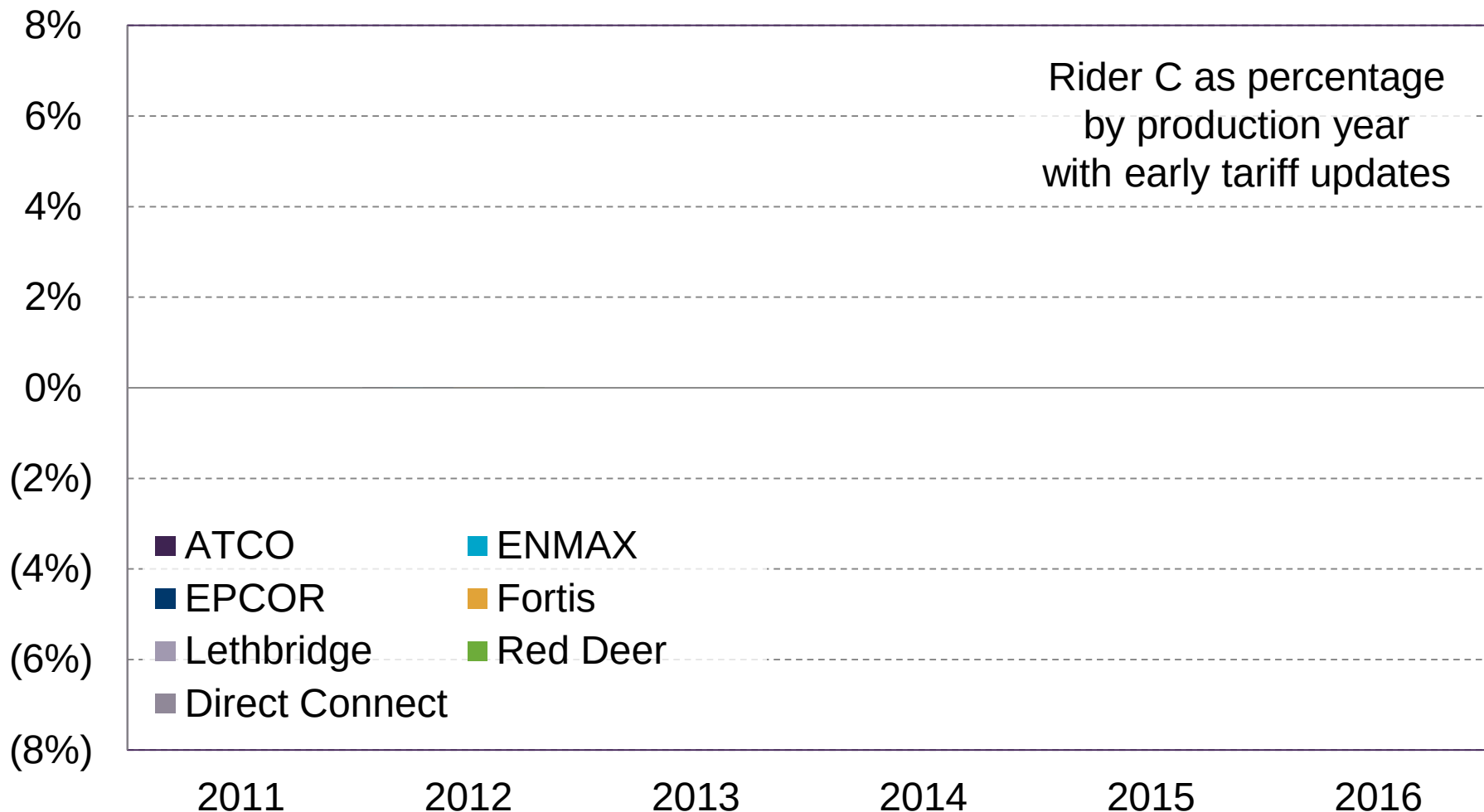
Five-year view also obscures impact by customer

DAR Balance Allocation Refund (Charge) as Percentage Less or More Than Average for 2011-2015



Rider C as percentage by production year eliminates variability between customers

DAR Balance Allocation Refund (Charge) as Percentage Less (More) Than Average by Year



Conclusion: Rider C as percentage by production year eliminates transfers

- Rider C as percentage by production year eliminates transfers between services in a deferral account reconciliation
- In practice there will still be some transfers resulting from timing impacts, such as if an annual cost becomes known partway through year
 - Such costs would be recovered through Rider C in remaining months of year then allocated over full production year in deferral account reconciliation application

break



Impact of Changing to Net Revenue Allocation Methodology

PS Group has proposed deferral account balances be allocated on net revenue

- Existing methodology allocates deferral account balances on Rate DTS “base rate” revenue only
 - Similar approach for Rate FTS
 - “Base rate” revenue does not include any revenue attributed to the service under other rates and riders, such as Rate PSC, *Primary Service Credit*, or Rate UFLS, *Under Frequency Load Shedding Credits*
- Group of market participants who receive Rate PSC (PS Group) has proposed change in allocation methodology in 2015 deferral account reconciliation application proceeding
- PS Group proposal allocates deferral account balances on Rate DTS “base rate” revenue net of Rate PSC credits
 - Results in smaller allocations to Rate DTS services with Rate PSC and larger allocations to all other Rate DTS services

Matter is being reviewed in 2015 deferral account reconciliation proceeding

- PS Group has submitted evidence
- Oral hearing is currently scheduled for December 13-14, 2016
- PS Group has requested proposed change in methodology be applied to 2008 to 2015 production years
- AESO has submitted any change in methodology should be made on a go-forward basis only
 - For 2017 deferral account year
 - After market participants are made aware of proposed change
 - With review in an ISO tariff application proceeding
- Commission decision on issue expected in mid-March 2017

AESO is considering merits of net revenue methodology on a go-forward basis

- Currently-approved methodology allocates deferral account balance in proportion to Rate DTS revenue for a service

$$\left[\begin{array}{l} \text{Costs} \\ - \text{Rate DTS Revenue} \\ - \text{Other Tariff Revenue} \end{array} \right] \times \frac{\text{Rate DTS Revenue}_{\text{one service}}}{\text{Sum of Rate DTS Revenue}_{\text{all services}}}$$

- Deferral account balance includes revenue from Rate DTS and from other tariff components, while allocation includes only “base rate” revenue from Rate DTS
- Net revenue allocation methodology would allocate deferral account balance in proportion to Rate DTS netted with other revenue for a service

$$\left[\begin{array}{l} \text{Costs} \\ - \text{Rate DTS Revenue} \\ - \text{Other Tariff Revenue} \end{array} \right] \times \frac{\text{Net Tariff Revenue}_{\text{one service}}}{\text{Sum of Net Tariff Revenue}_{\text{all services}}}$$

AESO is considering merits of net revenue methodology on a go-forward basis (cont'd)

- Net tariff revenue for a service would include charges and credits related to contracted load service
 - Rate DTS and Rate FTS, *Demand Transmission Service*
 - Rate UFLS, *Demand Underfrequency Load Shedding Credits*
 - Rate PSC, *Primary Service Credit*
 - Riders A1-A4, *Transmission Duplication Avoidance Adjustments*
 - Payments in lieu of notice (PILONs) for reductions or terminations of contract capacity under section 9 of ISO tariff
- Net tariff revenue for a service would not include charges under Rate DOS, *Demand Opportunity Service*
- Net tariff revenue for a load service would not include charges or credits related to non-load service

Net revenue methodology would impact deferral account balance allocations

- Impact primarily on deferral account balance allocated to an individual service rather than on transfers between services in a deferral account reconciliation
 - Deferral account balance is settled through both Rider C during year and deferral account reconciliation after year-end
- Using deferral account reconciliation simulation for 2014-2015, net revenue methodology would impact allocation of \$61.8 million deferral account balance
 - Deferral account balance represents about 2% of revenue requirement over 2014-2015

Net revenue methodology would impact deferral account balance allocations (cont'd)

Rate DTS Netted With:	Affected Services	2014-2015 Deferral Account Balance Increase (Decrease)	
Rate UFLS	240	(\$3.9 million)	(9%)
Rate PSC	43	(\$0.5 million)	(13%)
Riders A1-A4	3	\$0.01 million	1%
PILONs	8	\$0.1 million	9%

- Services that include no additional charges or credits would see an increase in deferral account balance allocations, compared to existing methodology
 - Remaining \$4.3 million would be allocated over all services
 - All services would see an average 7% increase in deferral account balance allocation
 - Including services with no additional charges or credits

Net revenue methodology would require changes to ISO tariff

- Rates UFLS and PSC, Riders A1-A4, and PILONs would need to indicate they are subject to deferral account adjustment
 - Rider C would need to indicate it applies to amounts under those tariff components, in addition to Rates DTS and FTS
- Consistent with Commission directions in recent decisions, a change in deferral account reconciliation methodology should be reviewed in a comprehensive tariff application

AESO invites stakeholder feedback on net revenue allocation methodology

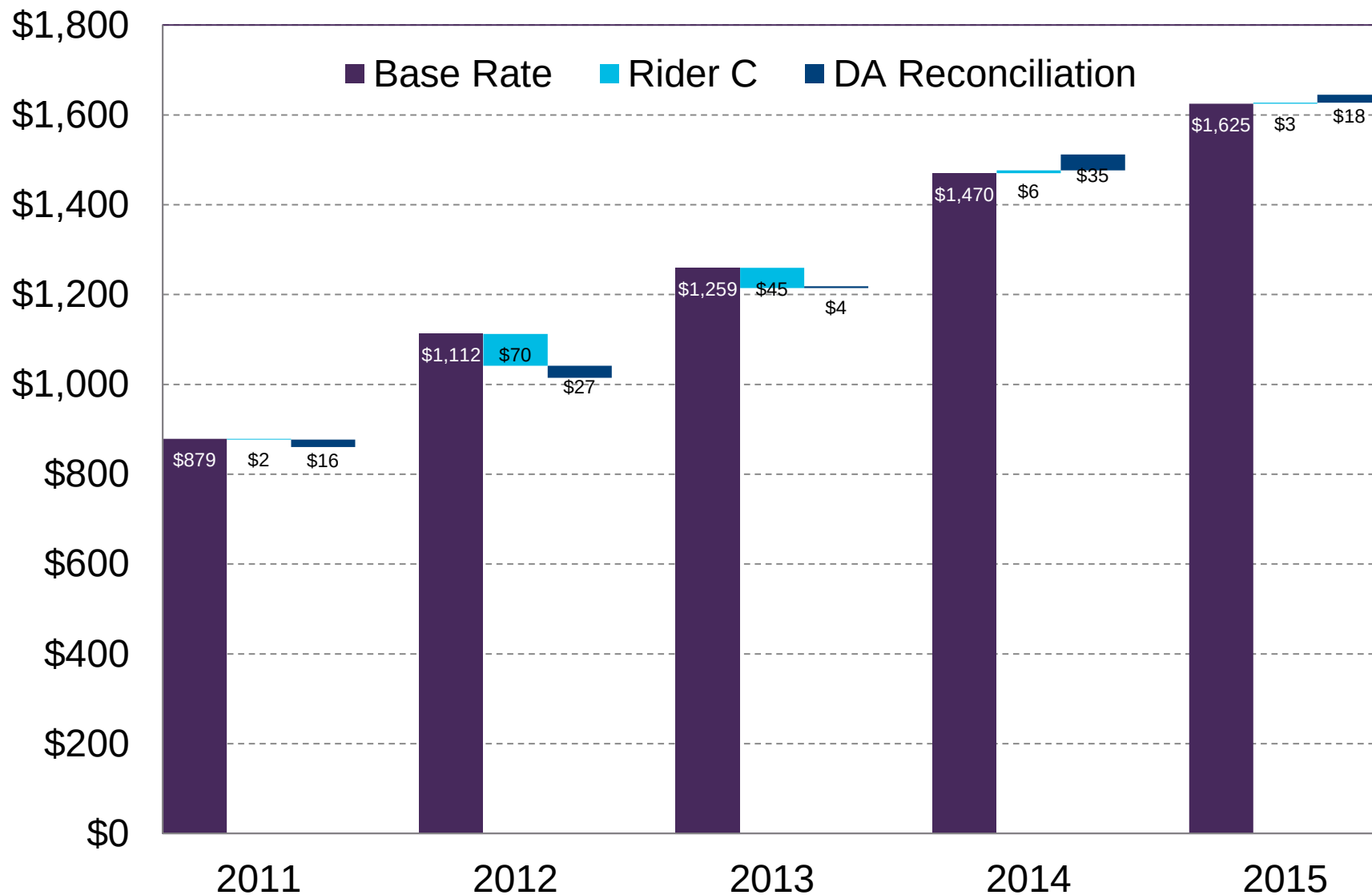


- AESO is seeking stakeholder comments on net revenue allocation methodology



Possible Future Changes to Rider C

Early tariff updates can significantly reduce Rider C charges and credits



Could Rider C be eliminated?

- Early tariff updates can significantly reduce Rider C charges
- However, simulation included \$70 million refund through Rider C in 2012
- Success at maintaining early tariff update process is uncertain
- AESO would likely want to maintain an “emergency” rider of some sort

Could Rider C be converted to a prospective rider?

- Early tariff updates can significantly reduce deferral account balances
- A prospective rider would eliminate deferral account reconciliations
- But prior year adjustments could still be significant
- Impact of “real time” costs incurrence during year is unknown

Conclusion: Maintain use of Rider C and deferral account reconciliations

- 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



Timing and Implementation Options

How should Rider C and reconciliation methodology changes be implemented?

- Commission has directed the AESO to report on tariff updates, deferral account reconciliation processes, and Rider C design in next comprehensive tariff application
 - Would allow comprehensive review with broad stakeholder representation
 - Would allow implementation on a go-forward basis
 - Tariff not expected to be effective until mid-2018
- AESO considers changes to Rider C design should be implemented as soon as practical
 - Expected to nearly eliminate transfers between services in deferral account reconciliation
 - Would require, at a minimum, changes to Rider C in the ISO tariff

What changes should be proposed?

- Early tariff updates already implemented
 - 2018 tariff update planned to be filed in Q3 2017
- Changes to Rider C
 - Will require changes to AESO billing system
 - Convert to percentage of revenue (instead of \$/MWh)
 - Target zero deferral account balance at end of year (instead of end of quarter)
 - Potentially apply to net revenue
- Changes to deferral account reconciliation methodology
 - Will require changes to deferral reporting system used for applications
 - Reconcile on production year basis
 - Potentially allocate deferral account balance on net revenue

AESO considers three options are available for Rider C and methodology changes

1. Include Rider C and deferral account reconciliation methodology changes in 2018 tariff application in Q2 2017
 - Aligns with Commission direction in Decision 2014-242
 - Changes likely effective in mid-2018 on go-forward basis
 - Allows comprehensive review with broad representation
2. File separate application in Q1 2017 for Rider C and deferral account reconciliation methodology changes
 - Changes likely effective in late 2017 on go-forward basis
 - Limits review to some extent; representation uncertain
 - Preparing complete separate application may delay completion of tariff application

AESO considers three options are available for Rider C and reconciliation changes (cont'd)



3. File application in Q1 2017 for interim Rider C changes with request to make existing reconciliation methodology interim
 - Full review would occur as part of 2018 tariff proceeding
 - Changes likely effective mid-2017, on interim basis
 - Would need to allow sufficient time for AESO billing system changes
 - Limited review of interim application; comprehensive review in tariff application
 - Minimal impact on 2018 tariff application
- AESO also considered negotiated settlement approach but concluded it had no significant advantages

AESO invites stakeholder feedback on three options for implementation



- Are there other practical options?

Transmission Cost Causation Study Update

Raj Sharma

Public

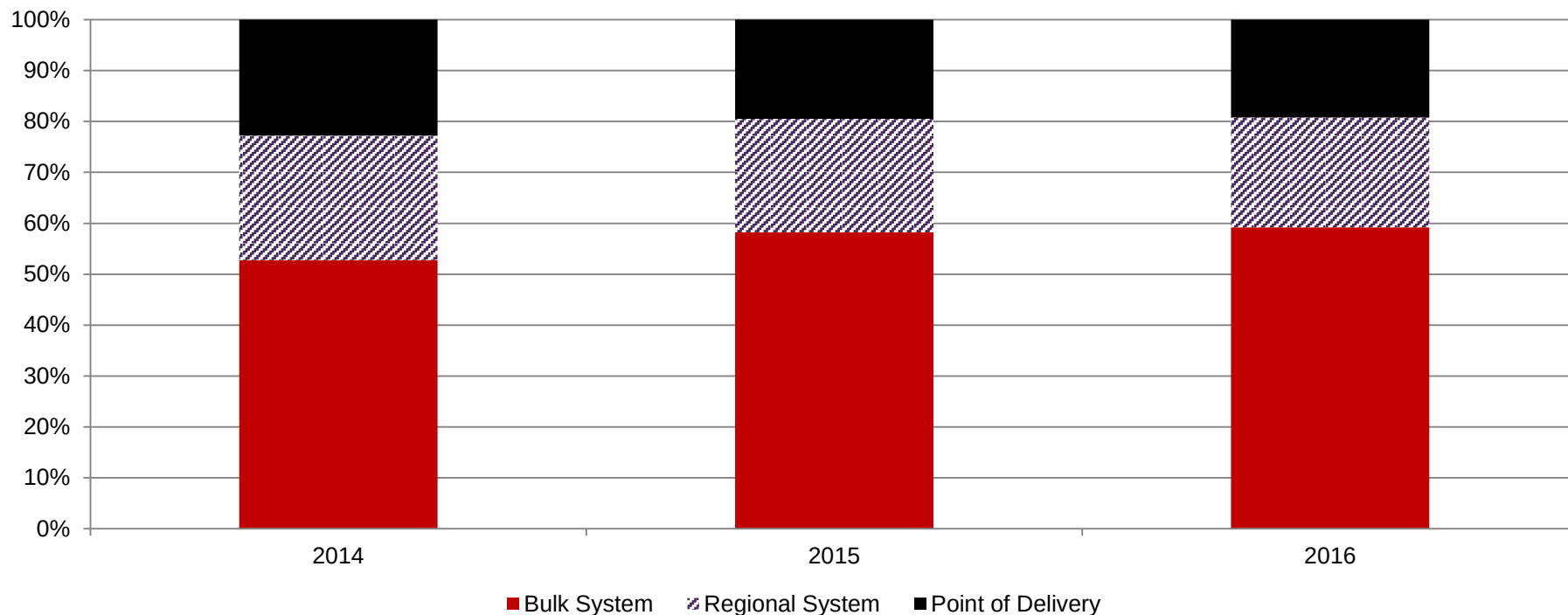
Plan for 2018 – 2020 transmission cost causation study

- The AESO included a 2014-2016 transmission cost causation study prepared by London Economics International (“LEI”) in its 2014 ISO tariff application
 - The study established the inputs and methodology for a comprehensive cost causation study that used both capital cost and operating and maintenance cost data
 - A negotiated settlement process was used with participants and approved by the Commission
- The AESO proposed to update the LEI study itself using identical methodology with functionalization by voltage and classification by minimum system approach (in August 2015)

History of functionalization in transmission cost causation study

- *The 2014-2016 Cost Causation Negotiated Settlement Agreement* was approved as filed November 27, 2013
- In accordance with agreement, an updated study was filed January 2014

2014-2016 Functionalization

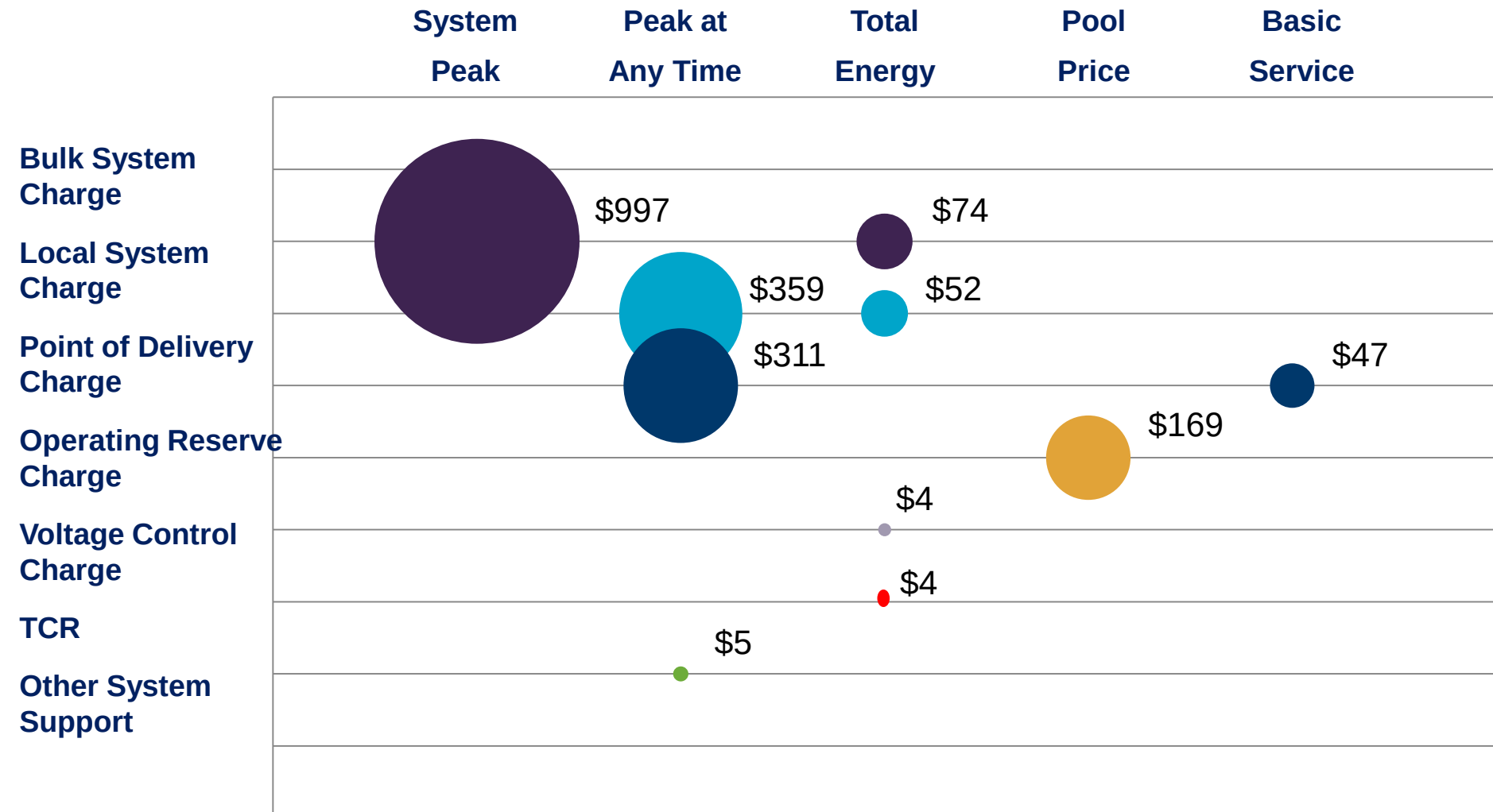


History of classification in transmission cost causation study

2014-2016 cost classification between demand and energy

2014-2016 Classification	Function	
	Bulk	Regional
Demand	93.1%	87.4%
Energy	6.9%	12.6%

Applied for Rate DTS structure in 2017 ISO tariff update application (\$ million)



Scope of 2014-2016 transmission cost causation study

Scope included:

- Functionalization of capital costs by voltage methodology (including use of low-side voltage to functionalize substation costs)
- Functionalization of operating and maintenance (O&M) costs by specific allocators for most cost components, and functionalization of non-capitalized general and administration (G&A) costs in proportion to O&M costs
- Weighting of capital and O&M costs over 2014-2016
- Classification of bulk system and regional system costs by minimum system methodology

Scope of 2018-2020 transmission cost causation study

Update of 2014-2016 transmission cost causation study:

- Using identical methodology
- Using same data sources, plus a few additional sources
- For years 2018-2020

Process for 2018-2020 transmission cost causation study

AESO's proposed process:

- update inputs for 2018-2020 transmission cost causation study in Q4 2016
- Present draft results to stakeholders in January 2017
- Include the study in the 2018 ISO tariff application

Point-of-delivery (POD) Cost Function Update

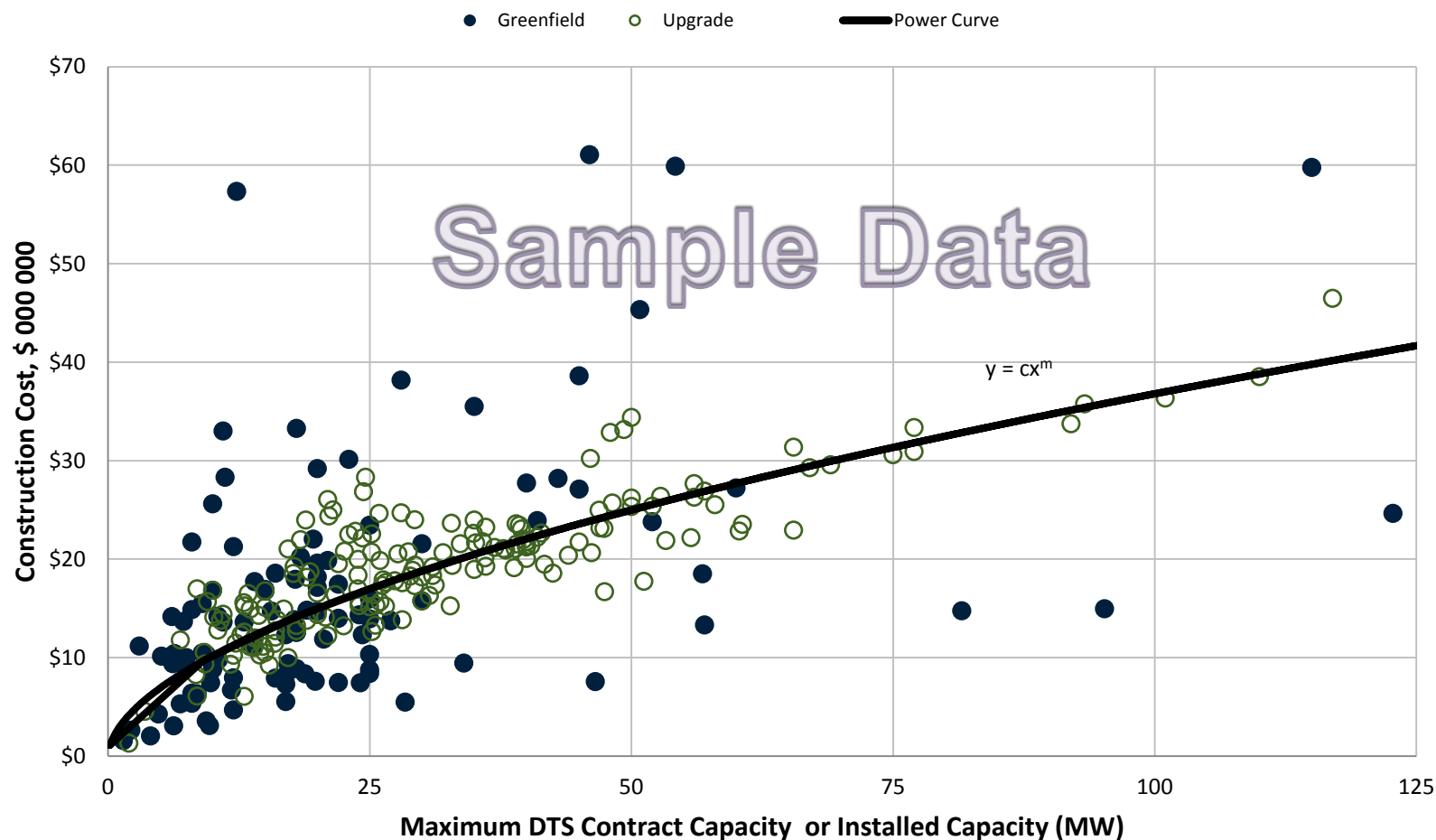
LaRhonda Papworth

Public

POD cost function database input into cost curves

- POD cost function database includes connection project (demand only) attributes: cost data, contract levels, installed capacity, connection type, location, substation number, project type, etc.
- For the 2018 tariff application, AESO will update POD cost function database with projects data since last update in 2014
- After Decision 2014-242 and Decision 3473-D01-2015 from the Commission in regards to project inclusion and criteria, the AESO was directed to “use ‘Greenfield and Update Excluding 0 MW’ until the matter can be thoroughly explored”
 - contract vs installed capacity
 - upgrade projects with 0 MW increase

POD cost function database – cost curves



POD cost function database – cost curves

Cost Curve Options	Greenfield	Upgrade	0 MW Contracts
#1 Pre-2014 Practice	Contract	Contract	Include
#2 Current Interim Practice	Contract	Contract	Remove
#3 As requested in Decision 2014-242	Contract	Installed	By using installed, 0 MW projects <u>are</u> included
#4 Not asked	Installed	Installed	
#5 AESO not considering (Not asked, not debated)	Installed	Contract	?

Potential evaluation criteria for cost curve options

1. Maintaining alignment between POD cost function, maximum investment levels and the POD charge in Rates DTS and PSC
2. Consistency with past practice (post-2007)
3. Maximize number of projects in database
4. Statistical criteria for project exclusion
5. Degree of relationship between installed capacity and contract capacity
6. “Lumpiness” of installed capacity and standard transformer sizes
7. Number of assumptions required to determine the MWs
8. Behavior of market participant’s relationship to MWs
 - encouraging staging to contract appropriately
 - planning signal from contract capacity vs installed capacity
9. Potential to eliminate substation fraction
10. Treatment of split between DTS and STS shared costs
11. Rates reflect true costs per MW
12. Equal services treated equally, unequal services treated unequally
13. Sending the “right” price signal
14. Fairness of treatment of customers with charges based on two different approaches

Application Process, Timeline and Next Steps

LaRhonda Papworth

Checklist for 2018 ISO tariff application

Scope item	Status
Rider C / DAR / Tariff updates	95% complete
POD cost function work	75% complete
Transmission cost causation study	75% complete
Terms and conditions: Sections 4, 5, 8 and 9	75% complete
Clarify tariff for energy storage	100% complete
Updates to Proformas	80% complete
Clarify Rider A-1 – Dow duplication avoidance tariff	75% complete
Address direction from Commission regarding cost recovery from Critical Infrastructure Protection (CIP) work	75% complete
Long-term transmission rate projection model	75% complete

Tariff tentative timeline

Session	Date
1 st Technical Session	December 5, 2016
2015 DAR Hearing	December 13 & 14, 2016
Stakeholder comment matrix posted	December 16, 2016
2017 tariff update effective (interim, refundable basis)	January 1, 2017
Stakeholder comments due	mid-January 2017
2 nd Technical Session	Tentative: January 30, 2017
3 rd Technical Session	February 2017
Application Preview	April 2017
Application writing	Q1 – Q2 2017
Application filing	Q2 2017
2016 DAR Filing	Q3 2017
2018 tariff <u>update</u> application	Q3 2017
Regulatory review process for 2018 tariff application	Q4 2017 - Q1 2018
Compliance filing	Q2 2018

Next steps

- The AESO will invite participants to respond to this presentation through a comment matrix in the next few weeks. To allow transparency, the AESO will post all comments on AESO's website following the receipt of participants' input
- For more information:
 - LaRhonda Papworth – Manager, Tariff Design
 - 403-539-2555
 - larhonda.papworth@aeso.ca
- All consultation documents can be found on AESO website at www.aeso.ca by following the path:
 - Rules, Standards and Tariff ► Stakeholder engagement
 - 2018 ISO tariff application

Further Discussion? Questions?

Request for Stakeholder Comments on AESO 2018 ISO Tariff Consultation

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 invites written comments from stakeholders on the information presented at the meeting. 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.

Please use the comment form below when submitting comments to the AESO on the 2018 ISO tariff consultation. Please ensure that your comments represent all interests within your stakeholder organization with respect to the consultation. Please provide comments or questions no later than **January 20, 2017**, to LaRhonda Papworth at larhonda.papworth@aeso.ca or 403-539-2555.

Consultation and Stakeholder Identification

Date of Request for Comments:	December 20, 2016
Period of Consultation:	November 15, 2016 – January 20, 2017
Comments From:	
Date:	
Contact:	
Phone:	
Email:	

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.*

Stakeholder Comments:

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

- i. *Rider C as percentage almost eliminates transfers between services in a deferral account*

Stakeholder Comment

reconciliation; and

- ii. Some transfers between services still exist but are small.*

Stakeholder Comments:

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.*

Stakeholder Comments:

****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 Comments:

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.*

Stakeholder Comments:

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.**

Stakeholder Comment

- (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?**

Stakeholder Comments:

(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.**

Stakeholder Comments:

(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;**

Stakeholder Comments:

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

(13) Sending the “right” price signal;	☐ Support ☐ Oppose ☐ Indifferent	(14)
(14) Fairness of treatment of customers with charges based on two different approaches; and	☐ Support ☐ Oppose ☐ Indifferent	(15)
(15) Any others?		(16)

Stakeholder Comments:

(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.

Stakeholder Comments:

Additional Comments

Please return this form with your comments by **January 20, 2017**, to:

LaRhonda Papworth
 Manager, Tariff Design
 Email: larhonda.papworth@aeso.ca
 Phone: (403) 539-2555

January 18, 2017

AESO Stakeholders
AESO 2018 ISO Tariff Consultation Participants

Dear Stakeholder:

Re: **Invitation to Participate in Consultation on AESO 2018 ISO Tariff Application**

The AESO continues to consult with market participants on the development of its next comprehensive ISO tariff application, which it now refers to as the 2018 ISO tariff application to reflect the year in which the tariff is expected to become effective (in prior stakeholder communications, this application had been referred to as the 2017 ISO tariff application). The AESO will be holding the following consultation session to provide an update on work completed to date and invites you to attend:

Date:	Monday, January 30, 2017
Time:	1 p.m. to 4 p.m.
Place:	Meeting Room 6006, 6th Floor, BP Centre, 240 – 4th Avenue SW, Calgary, Alberta Note that the glass doors on the 6th floor are locked; please knock to have them opened.
Teleconference:	Within Calgary calling area: 403-410-3051, Conference ID 4366631 Outside Calgary calling area: 1-855-453-6957, Conference ID 4366631
RSVP:	By 5 p.m. on Wednesday, January 25, 2017 to, Tatiana Aparicio-Caris Tatiana.Aparicio-Caris@aeso.ca or 403-539-2664

The AESO plans to discuss the following items during the meeting:

- technical presentation on transmission cost causation study results;
- technical presentation on point of delivery (POD) cost function database results;
- progress on annual tariff updates, deferral account reconciliations, and Rider C matters; and
- planned timeline and next steps for 2018 ISO tariff application.

The AESO plans to present information on these topics to facilitate discussion, and will post a presentation before the meeting. Stakeholders may provide feedback in person during the meeting or through written comments to the AESO after the meeting.

All information relating to the 2018 ISO tariff consultation is available on the AESO website at www.aeso.ca by following the path Rules, Standards and Tariff ► Stakeholder engagement ► 2018 ISO tariff application. As well, new information posted by the AESO on this topic will be mentioned in the AESO stakeholder newsletter, which you can subscribe to at the bottom right of the AESO's home page at www.aeso.ca.

If you have any questions on the AESO's 2018 ISO tariff consultation, please contact me at 403-539-2555 in Calgary or by e-mail to larhonda.papworth@aeso.ca.

Yours truly,

LaRhonda Papworth
Manager, Tariff Design

cc: Doyle Sullivan, Director – Market and Tariff Design

AESO 2018 ISO Tariff Consultation

January 30, 2017
AESO Office, Calgary

Agenda

- Introduction and objectives (slide 1-4)
- Transmission cost causation study preliminary results (slide 5-36)
- Point-of-delivery cost function database preliminary results and discussion (slides 37-61)
- Rider C / Deferral Account Reconciliation (DAR) / Rates Update (slide 62-80)
- Summary of comments from previous session (slides 81-82)
- Application process and next steps (slides 83-85)
- Discussion and wrap-up (slide 86)

Please feel free to ask questions during presentation

Stakeholder session objectives

- Enhance understanding of ISO tariff application
- Review technical results of a number of analytical exercises by the AESO
- Share information prior to filing of 2018 ISO tariff application
- Gather feedback to ensure tariff application provides all information stakeholders require
- Review application timeline and next steps

Applications currently in progress

- Directions 5-8 on advancement costs and related provisions
 - Decision 3473-D02-2015 issued on August 26, 2015
 - Process letter issued on October 22, 2015 with additional information on process in the new year *[2016]*
 - Awaiting Commission follow-up
- 2015 Deferral Account Reconciliation application
 - Currently before the Commission in Proceeding 21735
 - Interim settlement was approved and occurred in October 2016
 - Hearing held on December 13 and 14, 2016
 - Decision expected mid-March

Applications currently in progress

- 2017 ISO tariff update
 - Currently before the Commission in Proceeding 22093
 - Interim, refundable approval for January 1, 2017 issued by Commission on December 2, 2016
 - Still some matters before the Commission
 - Final approval expected in 2017

Transmission Cost Causation Study Preliminary Results

Raj Sharma

Plan for 2018–2020 Transmission Cost Causation Study

- The AESO included a 2014-2016 transmission cost causation study prepared by London Economics International (“LEI”) in its 2014 ISO tariff application
 - The study established the inputs and methodology for a comprehensive cost causation study that used both capital cost and operating and maintenance cost data
 - A negotiated settlement process was used with participants and approved by the Commission
- The AESO proposed to update the LEI study itself using identical methodology with functionalization by voltage and classification by minimum system approach (in August 2015)

2014-2016 Transmission Cost Causation Study

- *The 2014-2016 Cost Causation Negotiated Settlement Agreement* was approved as filed November 27, 2013
- In accordance with agreement, an updated study was filed January 21, 2014
- Results of this study set functionalization and classification values for ISO tariff for 2014, 2015, 2016 (and 2017).

Scope of 2014-2016 Transmission Cost Causation Study

Scope included:

- Functionalization of capital costs by voltage methodology (including use of low-side voltage to functionalize substation costs)
- Functionalization of operating and maintenance (O&M) costs by specific allocators for most cost components, and functionalization of non-capitalized general and administration (G&A) costs in proportion to O&M costs
- Weighting of capital and O&M costs over 2014-2016
- Classification of bulk system and regional system costs by minimum system methodology

Capital Functionalization Method in 2014-2016 Transmission Cost Causation Study

- Functionalizing individual line and individual substation facilities:
 - Point of Delivery: radial line and delivery substation
 - Bulk: remaining facilities 240kV and over
 - Regional: remaining facilities below 240kV

Capital Functionalization in 2014-2016

Transmission Cost Causation Study

Year	Function			Total
	Bulk	Regional	POD	
2014	\$6.4 billion	\$2.2 billion	\$1.9 billion	\$10.5 billion
2015	\$9.3 billion	\$2.6 billion	\$2.1 billion	\$14.0 billion
2016	\$9.9 billion	\$2.7 billion	\$2.2 billion	\$14.7 billion

O&M Functionalization Method in 2014-2016 Transmission Cost Causation Study

- Capital related costs: depreciation, return, income tax, structure payments, linear and property taxes and capital related offsets
- Non-capital costs: labour, G&A, fuel and variable O&M for isolated generation and revenue offsets to labour costs
 - Isolated generation cost as regional and POD using capital cost functionalization ratio
 - Control center operations cost based on number of lines and transformers
 - Vegetation management cost based on line brushing allocator
 - Substation cost based on transformers
 - Overhead line and miscellaneous cost based on km of line
 - Net salaries and wages allocated to groups using proportion of full time equivalents (FTEs) and then further to functions

O&M Functionalization in 2014-2016

Transmission Cost Causation Study

Year	Function			Total
	Bulk	Regional	POD	
2014	\$35.3 million	\$66.6 million	\$68 million	\$169.9 million

Combined (Capital and O&M) Functionalization in 2014-2016 Transmission Cost Causation Study

Ratio of Non-Capital to Capital Costs

Type	2014	2015	2016
Non-Capital	19.5%	18.0%	16.3%
Capital	80.5%	82.0%	83.7%

Combined Functionalization

Year	Function		
	Bulk	Regional	POD
2014	53.2%	24.2%	22.6%
2015	58.4%	22.2%	19.4%
2016	59.4%	21.5%	19.1%

Functionalization in 2014-2016 Transmission Cost Causation Study – Other Items



- Deduct Regulated Generating Unit Connection Charge (RGUCC) revenue from bulk function revenue requirement for the year

Functionalization in 2014-2016

Transmission Cost Causation Study

Year	Function		
	Bulk	Regional	POD
2014	52.8%	24.4%	22.8%
2015	58.2%	22.3%	19.5%
2016	59.2%	21.6%	19.2%

Classification Methodology in 2014-2016 Transmission Cost Causation Study



- Bulk classification:
 - Ratio of per kM cost of 2x795 ACSR and 2x1033 ACSR 240kV conductor
 - Ratio of per kM cost of 3x1590 ACSR and 2x2156 ACSR 500kV conductor
 - Ratio of cost of basic and high efficiency transformer
- Regional classification:
 - Ratio of per kM cost of 1x266 ACSR and 1x477 ACSR 138kV conductor
 - Ratio of cost of basic and high efficiency transformer

Classification in 2014-2016 Transmission Cost Causation Study

Classification	Function	
	Bulk	Regional
Demand	93.1%	87.4%
Energy	6.9%	12.6%

Scope of 2018-2020 Transmission Cost Causation Study

- Update of 2014-2016 transmission cost causation study
- Using identical methodology
- Using same data sources, plus a few additional sources
- For years 2018-2020

Process for 2018-2020 Transmission Cost Causation Study



- Update inputs and conduct 2018-2020 transmission cost causation study in 2016
- Present draft results to stakeholders in January 2017
- Include the study in the 2018 ISO tariff application

Capital Cost Functionalization

Function			TOTAL
Bulk	Regional	POD	
\$10.6 billion	\$4.4 billion	\$3.1 billion	\$18.1 billion

2014 O&M Cost Functionalization

Function			Total
Bulk	Regional	POD	
\$37.3 million	\$64.3 million	\$67.1 million	\$168.8 million

Preliminary 2018 Functionalization – Combined (Capital and O&M)

Ratio of Non-Capital to Capital Costs	
Non-Capital	13.2%
Capital	86.8%

Combined Functionalization		
Function		
Bulk	Regional	POD
53.5%	26.2%	20.3%

Preliminary 2018 Functionalization – Other Items



- Deduct Regulated Generating Unit Connection Cost (RGUCC) revenue from bulk function revenue requirement for the year

Preliminary 2018 Functionalization

Function		
Bulk	Regional	POD
53.4%	26.3%	20.3%

Capital Cost Functionalization

Function			TOTAL
Bulk*	Regional	POD	
\$10.5 billion	\$4.5 billion	\$3.3 billion	\$18.3 billion

2014 O&M Cost Functionalization

Function			Total
Bulk	Regional	POD	
\$37.3 million	\$64.3 million	\$67.1 million	\$168.8 million

Preliminary 2019 Functionalization – Combined (Capital and O&M)

Ratio of Non-Capital to Capital Costs	
Non-Capital	12.2%
Capital	87.8%

Combined Functionalization		
Function		
Bulk	Regional	POD
53.2%	26.1%	20.7%

Preliminary 2019 Functionalization – Other Items

- Deduct Regulated Generating Unit Connection Cost (RGUCC) revenue from bulk function revenue requirement for the year
- Add Fort McMurray West 500kV transmission project (“CP” project) revenue requirement to bulk function revenue requirement for the year

Preliminary 2019 Functionalization

Function		
Bulk	Regional	POD
55.0%	25.1%	19.9%

Capital Cost Functionalization

Function			TOTAL
Bulk*	Regional	POD	
\$10.4 billion	\$4.8 billion	\$3.5 billion	\$18.7 billion

O&M Cost Functionalization

Function			Total
Bulk	Regional	POD	
\$37.3 million	\$64.3 million	\$67.1 million	\$168.8 million

Preliminary 2020 Functionalization – Combined (Capital and O&M)

Ratio of Non-Capital to Capital Costs

Non-Capital	11.2%
Capital	88.8%

Combined Functionalization

Function		
Bulk	Regional	POD
51.8%	27.2%	20.9%

Preliminary 2020 Functionalization – Other Items



- Deduct Regulated Generating Unit Connection Cost (RGUCC) revenue from bulk function revenue requirement for the year
- Add Fort McMurray West 500kV transmission project (“CP” project) revenue requirement to bulk function revenue requirement

Preliminary 2020 Functionalization

Function		
Bulk	Regional	POD
53.7%	26.2%	20.1%

Preliminary 2018-2020 Functionalization

Year/Function	Bulk	Regional	POD
2018	53.4%	26.3%	20.3%
2019	55.0%	25.1%	19.9%
2020	53.7%	26.2%	20.1%
Average	54.0%	25.9%	20.1%

Questions and Discussion

Point-of-delivery (POD) Cost Function Preliminary Results and Discussion

LaRhonda Papworth

POD cost function database input into cost curves

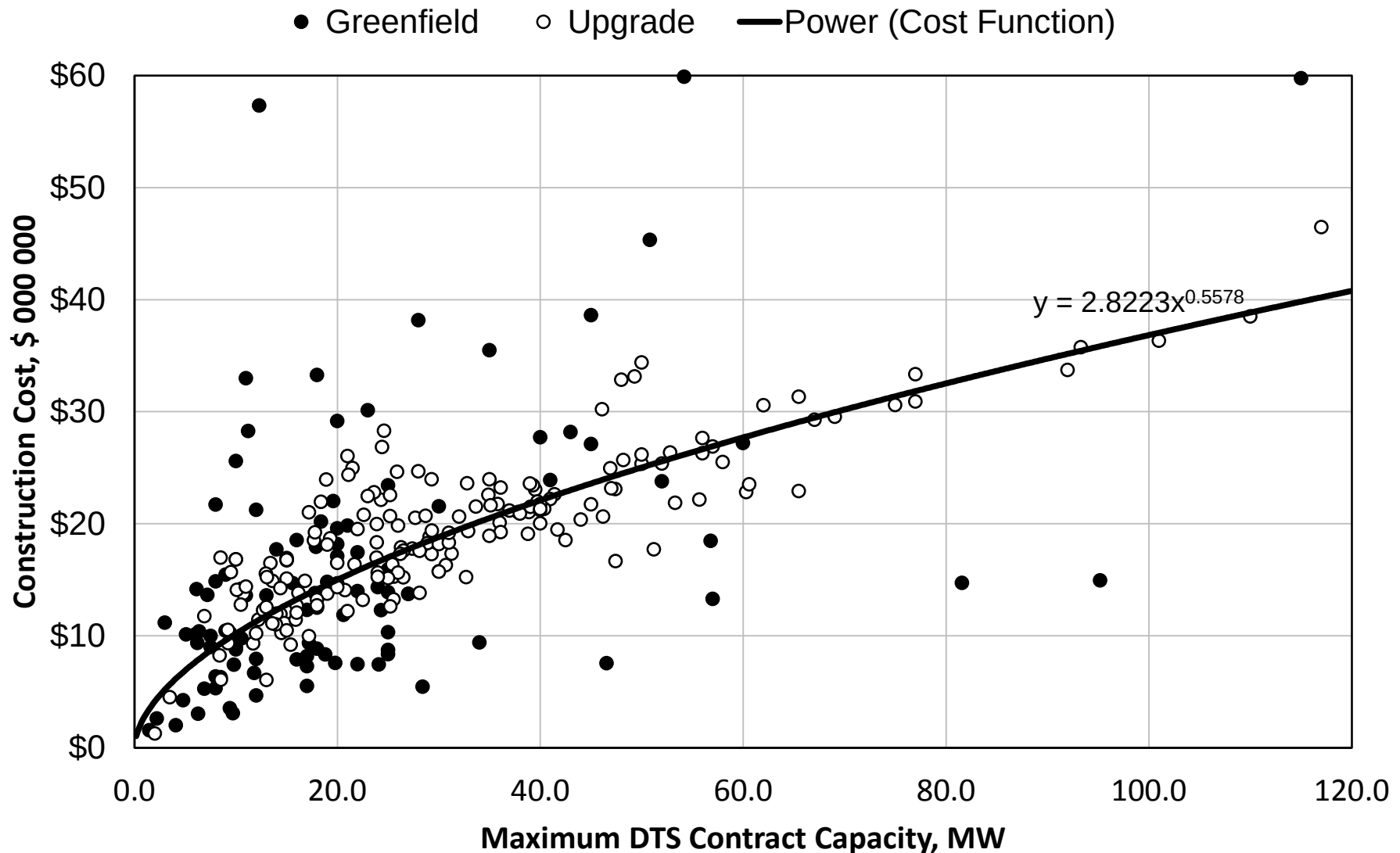
- POD cost function database includes connection project (demand only) attributes: cost data, contract levels, installed capacity, connection type, location, substation number, project type, etc.
- For the 2018 tariff application, AESO will update POD cost function database with projects data since last update in 2014
- After Decision 2014-242 and Decision 3473-D01-2015 from the Commission in regards to project inclusion and criteria, the AESO was directed to “use ‘Greenfield and Update Excluding 0 MW’ until the matter can be thoroughly explored”
 - contract vs installed capacity
 - upgrade projects with 0 MW increase

POD cost function database – cost curves

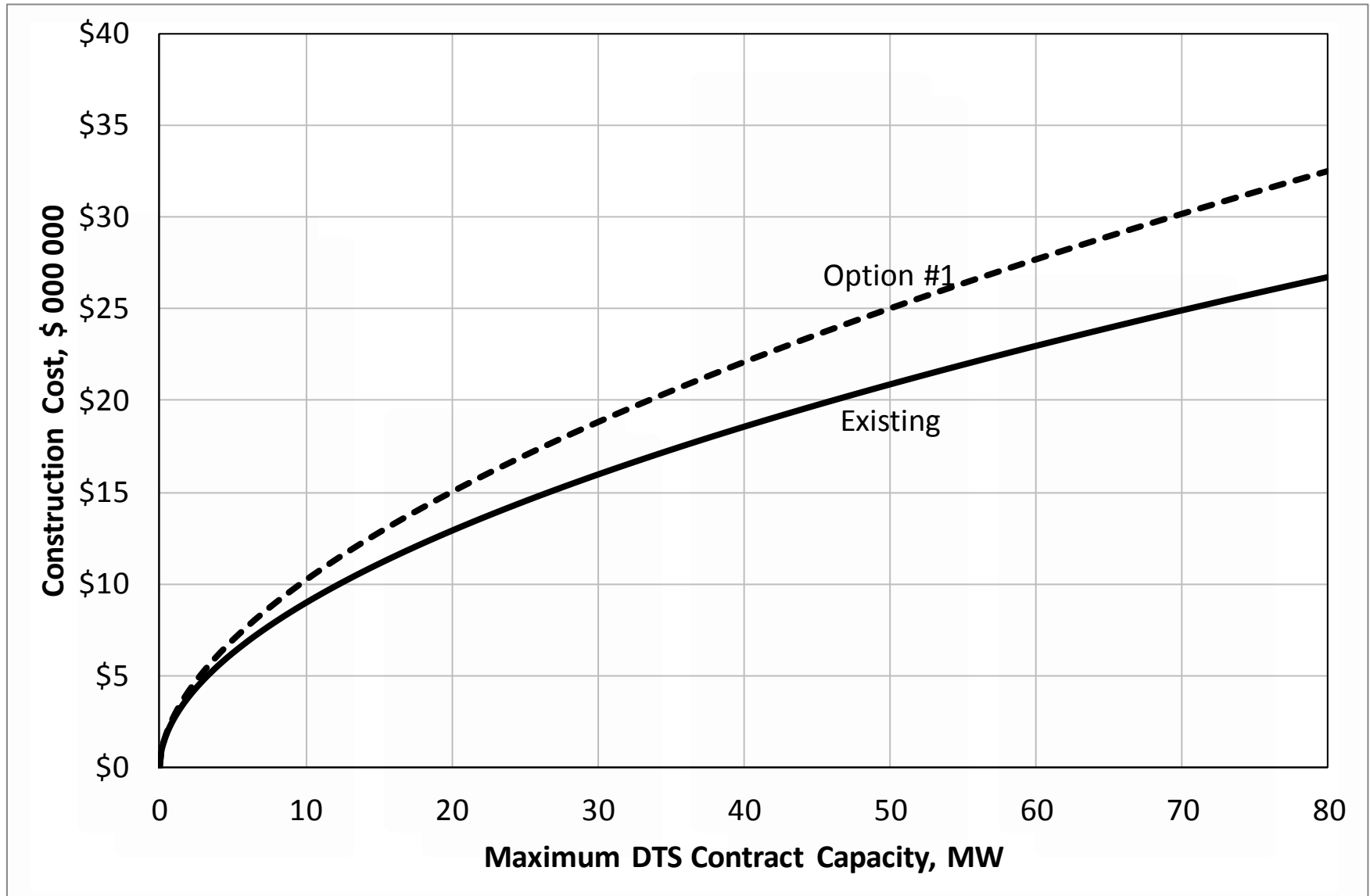
Cost Curve Options	Greenfield	Upgrade	0 MW Contracts
#1 Pre-2014 Practice	Contract	Contract	Include
#2 Current Practice (until thoroughly explored)	Contract	Contract	Remove
#3 As requested in Decision 2014-242	Contract	Installed	By using installed, 0 MW projects <u>are</u> included
#4 Not asked	Installed	Installed	
#5 ~~AESO not considering~~ (Not asked, not debated)	Installed	Contract	?

Preliminary POD Cost Function Database

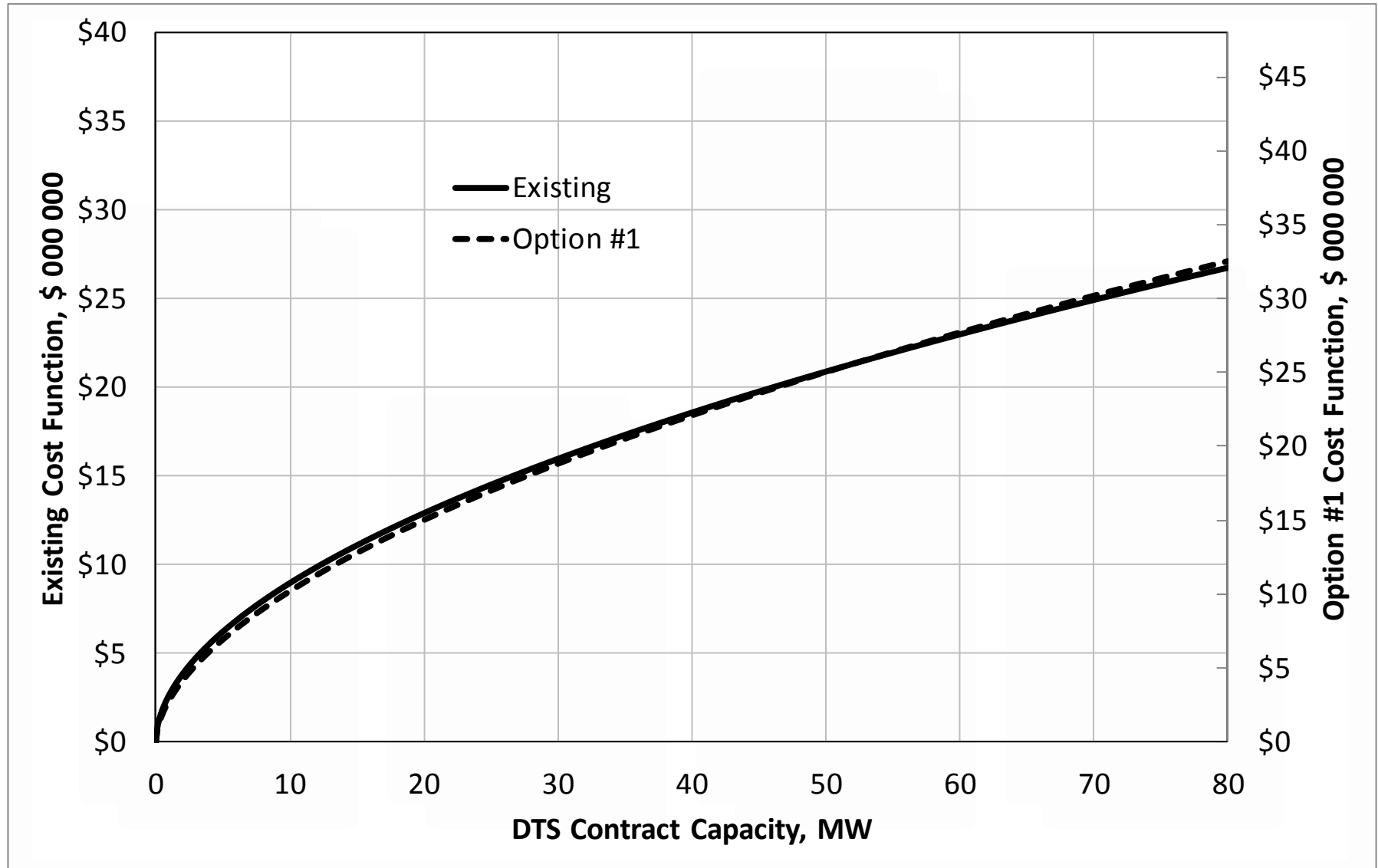
Option #1 – Greenfield & Upgrade Contract, 0 MW Upgrade projects included



Comparison of Option #1 to Existing (2014 ISO Tariff) Cost Function Curve

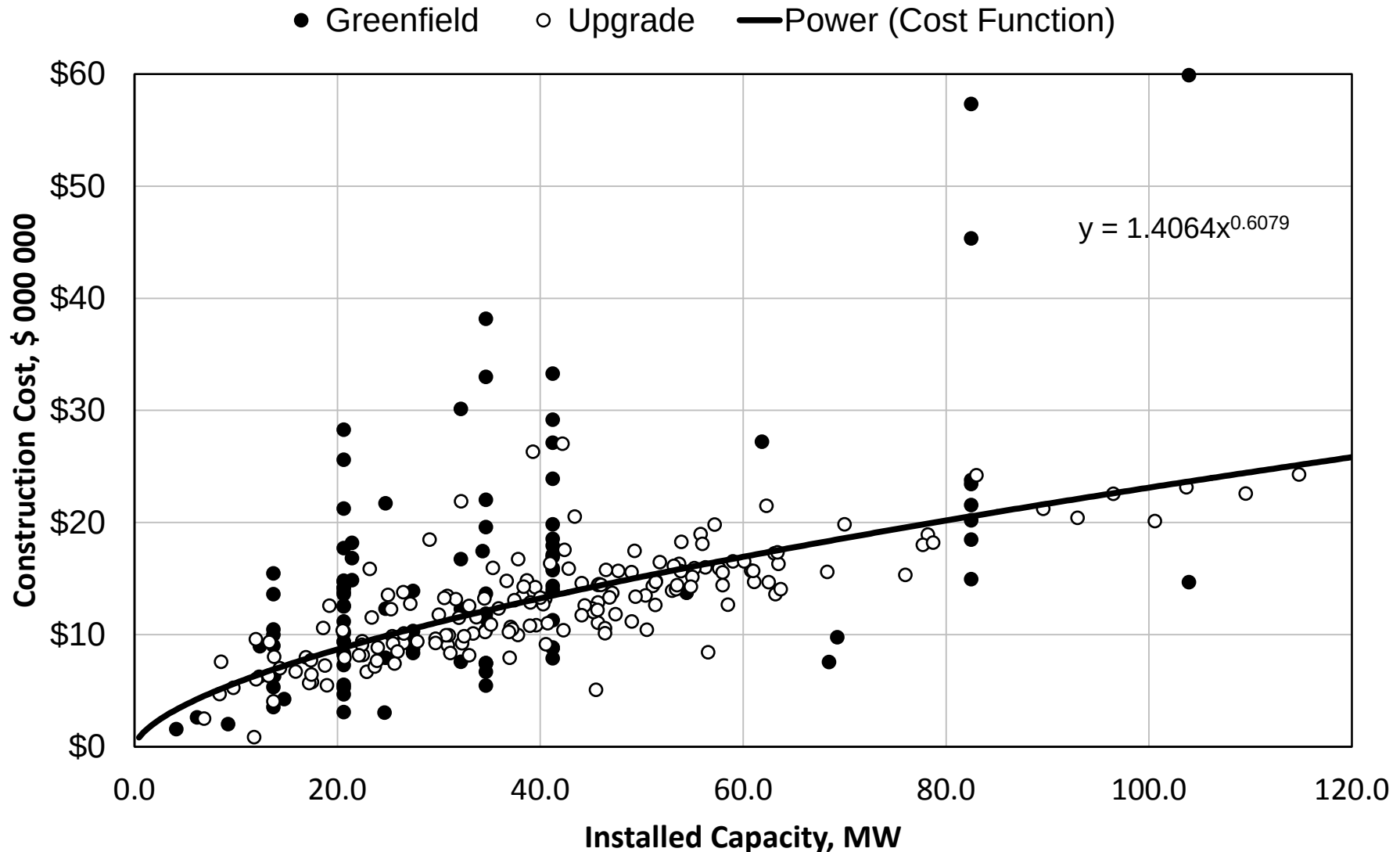


Impact of Update on Shape of Cost Function Curve

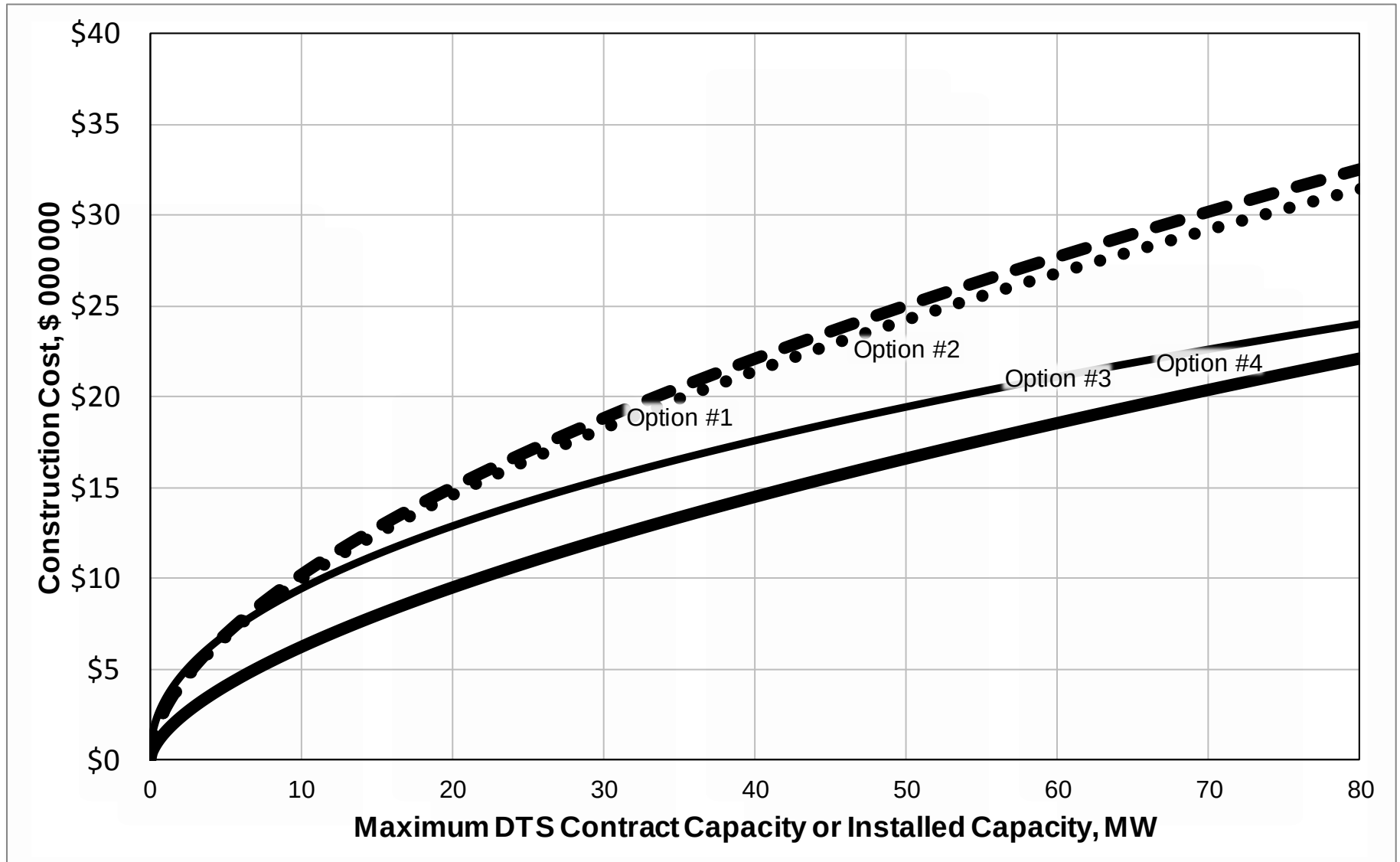


Preliminary POD Cost Function Database

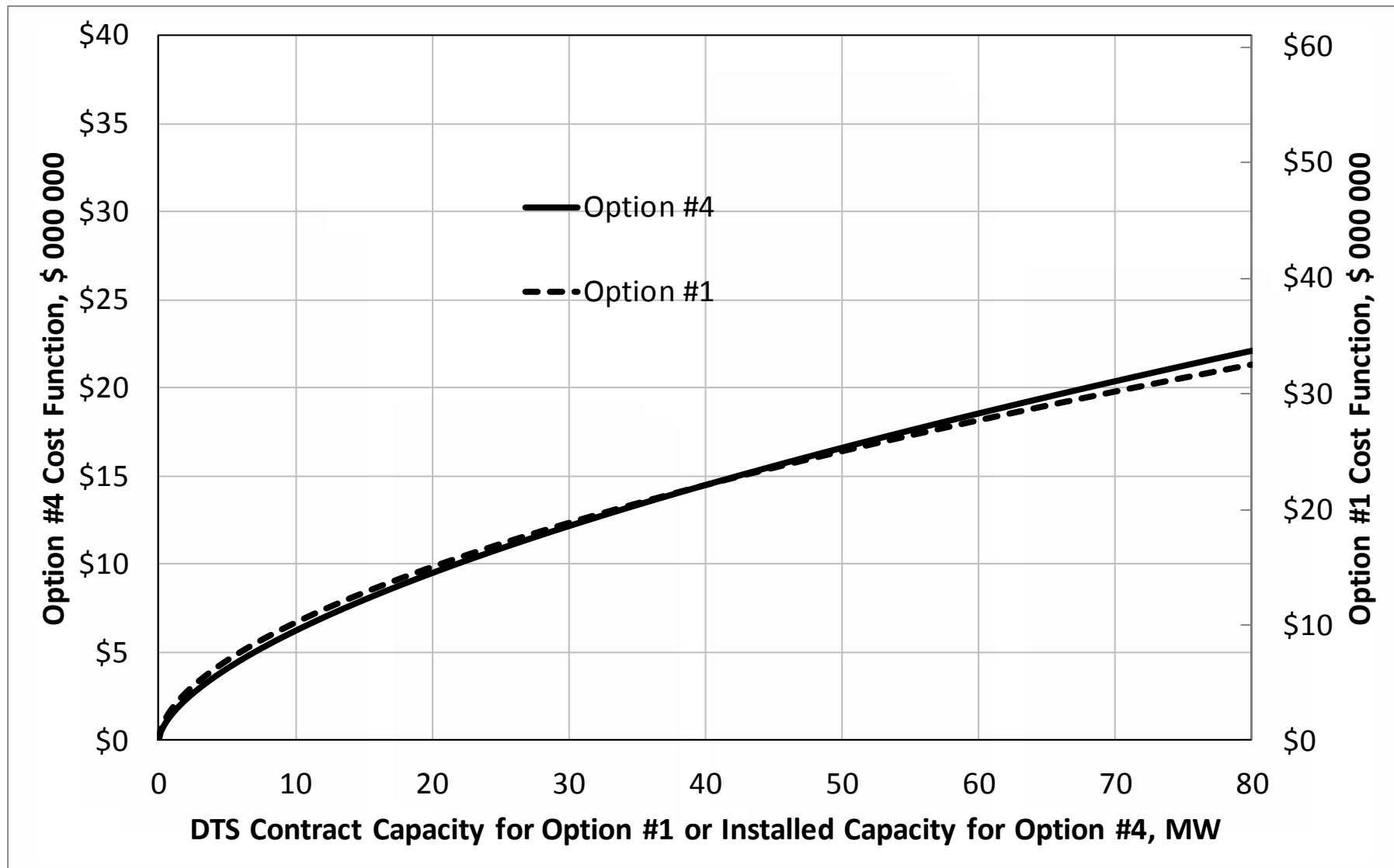
Option #4 – Greenfield & Upgrade Installed Capacity



Impacts of Updates and Options on Cost Function Curves



Impact of Installed Capacity to Shape of Cost Function



Potential evaluation criteria for cost curve options

1. Maintaining alignment between POD cost function, maximum investment levels and the POD charge in Rates DTS and PSC
2. Consistency with past practice (post-2007)
3. Maximize number of projects in database
4. Statistical criteria for project exclusion
5. Degree of relationship between installed capacity and contract capacity
6. “Lumpiness” of installed capacity and standard transformer sizes
7. Number of assumptions required to determine the MWs
8. Behavior of market participant’s relationship to MWs
 - encouraging staging to contract appropriately
 - planning signal from contract capacity vs installed capacity
9. Potential to eliminate substation fraction
10. Treatment of split between DTS and STS shared costs
11. Rates reflect true costs per MW
12. Equal services treated equally, unequal services treated unequally
13. Sending the “right” price signal
14. Fairness of treatment of customers with charges based on two different approaches

Maintaining alignment between POD cost function, maximum investment levels and the POD charge in Rates DTS and PSC

Current ISO Tariff:

- POD cost function determines a relationship between **contract capacity** of a project and the construction cost
- Investment is calculated using investment levels from the POD cost function multiplied by the **contract capacity**
- POD charge in rates is charged based on billing capacity which is the highest of highest-metered demand, 90% of highest metered demand in previous 24-month period or 90% of the **contract capacity**.

Concerns:

Provision of Price Signals

Fairness, Objectivity, and Equity

- Moving the POD cost function to relationship between **installed capacity** and the construction cost would require investment levels based on installed capacity and POD charge in rates to installed capacity
- This would result in potentially different determinants for POD charges vs bulk and regional

Consistency with past practice (post-2007)

- Since 2007 investment levels and POD portion have rates has been determined using **contract capacity**

Concerns:

Fairness, Objectivity, and Equity

Stability and Predictability

- Moving to new approach would have to be given some consideration of intergenerational equity
- Potential for unintended consequences

Maximize number of projects in database / statistical criteria for project inclusion

- Currently there are 94 greenfield projects, 18 pre-AESO projects and 285 upgrade projects

Concerns:

Fairness, Objectivity, and Equity

Stability and Predictability

- Removing projects does have an impact on statistical results
- Slippery slope argument for exclusion

Degree of relationship between installed capacity and contract capacity

- Measure the relationship between installed capacity and contract capacity

Concerns:

Provision of Price Signals

- Customer consideration of future expectation of load growth and operation flexibility
- TFO considerations for properly sizing transformers to minimize long-term costs (replace smaller transformer with larger transformer could be larger cost than a larger transformer at the start of a project)
- TFO considerations for standardization and back-up requirements
- Is there a price signal for installed capacity?

“Lumpiness” of installed capacity and standard transformer sizes

- There are efficiencies in the practice of transmission facility owners standardizing transformer sizes

Concerns:

Fairness, Objectivity, and Equity

Provision of Price Signals

- Difficult for a market participant to perfectly match load requirements to standard transformer sizes

Number of assumptions required to determine installed vs contract capacity

- Contract capacity is easily determined and tracked
- Installed capacity requires a number of assumptions along with extremely detailed research between the AESO and DFOs to estimate

Concerns:

Fairness, Objectivity, and Equity

Stability and Predictability

Practicality

- Data could be considered subjective and time-consuming to gather
- Will billing on installed capacity require strong validation?

Behavior of market participant's relationship to installed vs contract capacity

- Market participants “billing” behavior would not change from month to month with a rate based only on installed capacity
- A “billing capacity” calculation including highest-metered demand, past 24-month highest-metered demand and installed capacity would likely maximize to installed capacity

Concerns:

Provision of Price Signals

Fairness, Objectivity, and Equity

- No monthly price signal to market participants for POD charge

Encouraging staging to contract appropriately / planning signal from contract capacity vs installed capacity

- Market participant behavior could be to match installed capacity request exactly to standard transformer size
- Potentially less upgrade projects and larger greenfield projects

Concerns:

Provision of Price Signals

- Would installed capacity investment levels and rates encourage behavior of market participants to provide accurate loading levels to allow planning of the transmission system
- Is the price signal for staging strong in tariff today given the present value calculation?

Potential to eliminate substation fraction / Treatment of split between DTS and STS shared costs

- Installed capacity at a substation could potentially remove the requirement to allocate costs and investment by substation fraction

Concerns:

Practicality

- Additional clarity for each market participant at a shared substation
- No substation fractions could result in simpler billing structure and would be easier to understand to new stakeholders

Rates reflect true costs per MW / Sending the “right” price signal

- Are customer connection costs driven by installed capacity or contract capacity

Concerns:

Provision of Price Signals

Fairness, Objectivity, and Equity

- Adding “installed capacity” as a new billing component could introduce conflicting or dampening signal in contrast to existing “billing capacity”

Equal services treated equally, unequal services treated unequally

- For Option #3, for example, a site that contracted for 25 MWs as a greenfield project would be treated differently than a site that contracted for 15 MWs, then upgraded to 25 MWs

Concerns:

Fairness, Objectivity, and Equity

Bridging the “gap” / Fairness of treatment of customers with charges based on two different approaches

- A market participant could have investment based on a contract capacity approach but rates determined by installed capacity

Concerns:

Fairness, Objectivity, and Equity

Criteria Summary

Criteria	Rate Design Principles	Stakeholder Votes
Maintaining alignment between POD cost function, maximum investment levels and the POD charge in Rates DTS and PSC	Fairness, Objectivity, and Equity Provision of Price Signals	Support – 5 Oppose – 0 Indifferent - 1
Degree of relationship between installed capacity and contract capacity	Provision of Price Signals	Support – 4 Oppose – 1 Indifferent – 1
Rates reflect true costs per MW	Fairness, Objectivity, and Equity Provision of Price Signals	Support – 4 Oppose – 1 Indifferent – 1
Treatment of split between DTS and STS shared costs		Support – 3 Oppose – 1 Indifferent - 0
Sending the “right” price signal	Provision of Price Signals	Support – 4 Oppose – 0 Indifferent - 1

Criteria Summary (cont'd)

Criteria	Rate Design Principles	Stakeholder Votes
Maximize the number of projects in database	Fairness, Objectivity, and Equity Stability and Predictability	Support – 3 Oppose – 0 Indifferent – 3
Fairness of treatment of customers with charges based on two different approaches	Fairness, Objectivity, and Equity	Support – 3 Oppose – 0 Indifferent – 1
Consistency with past practice (post-2007)	Fairness, Objectivity, and Equity Stability and Predictability	Support – 1 Oppose – 1 Indifferent – 4
Statistical criteria for project exclusion	Fairness, Objectivity, and Equity	Support – 0 Oppose – 2 Indifferent – 4
Behavior of market participants relationship to MWs	Fairness, Objectivity, and Equity Provision of Price Signals	Support – 2 Oppose – 0 Indifferent – 3

POD Cost Function

Next Steps

- Gather more information from stakeholders in order to develop subjective and objective comparisons of Option #1 and Option #4
- Provide additional analysis to stakeholders on Option #1 and Option #4 to illustrate preliminary rates and investments under each option
- Present AESO's position at upcoming stakeholder session in March or April

Proposal to Apply for Interim Changes to Rider C and Deferral Account Reconciliations

John Martin, Senior Tariff and Regulatory Advisor

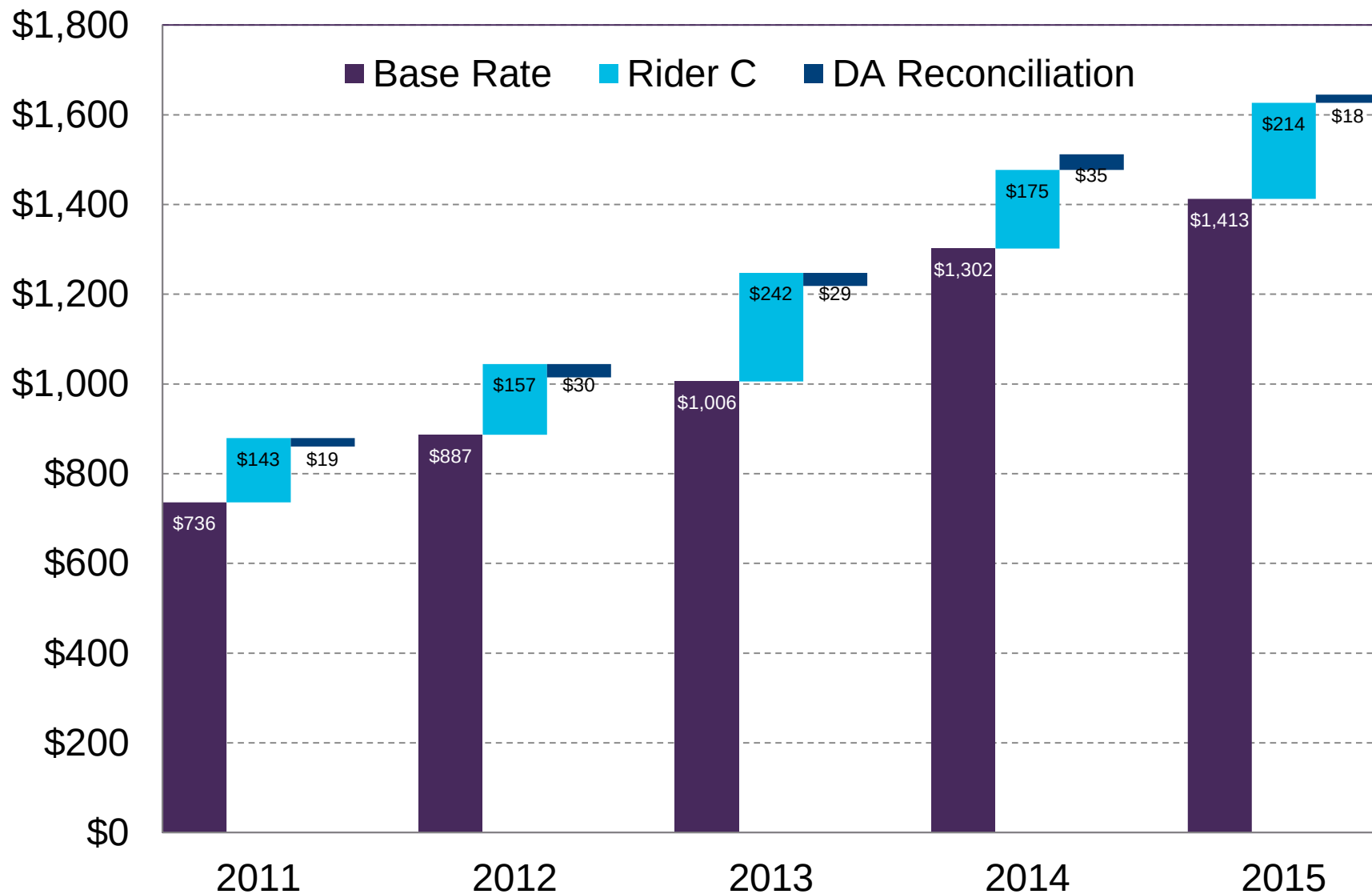
January 30, 2017 – Calgary, Alberta

Commission directed AESO to investigate Rider C in Decision 2014-242

- The Commission acknowledges the view expressed by both the ADC and the DUC that the AESO should be directed to examine further the structure of Rider C with an eye to minimizing imbalances among customers. Therefore, the Commission directs the AESO to discuss the related matters of annual tariff updates, deferral account reconciliation processes and Rider C design with stakeholders prior to filing its next comprehensive GTA, and to provide a report on the outcome of any such discussions, including any recommended changes (if any) within its next comprehensive GTA.*

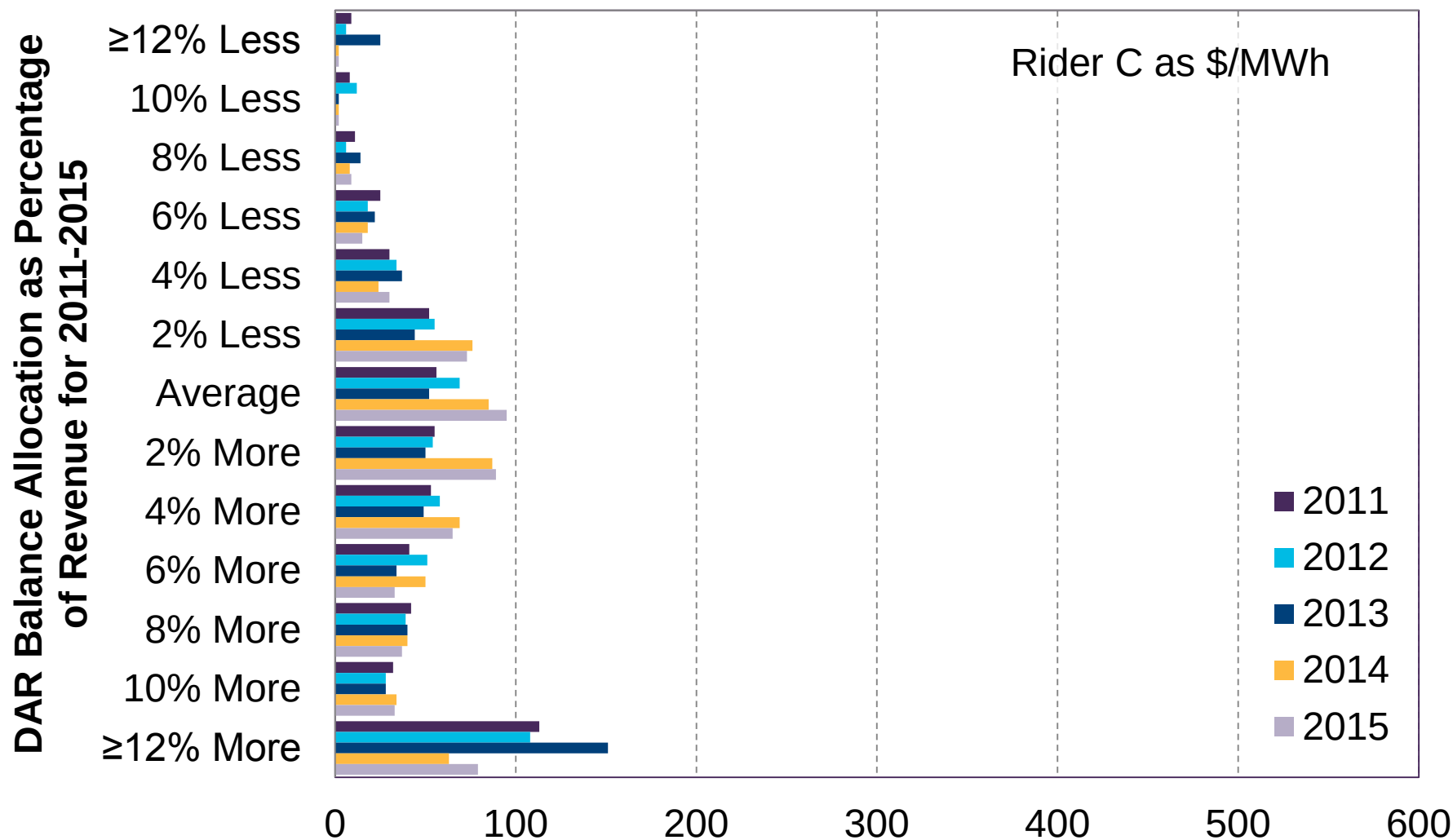
[Decision 2014-242, paragraph 704]

Net amounts allocated through annual reconciliations have been small ...



But allocations to individual services have varied over a much wider $\pm 20\%$ range

Number of Services per 2% Interval Less or More Than Average

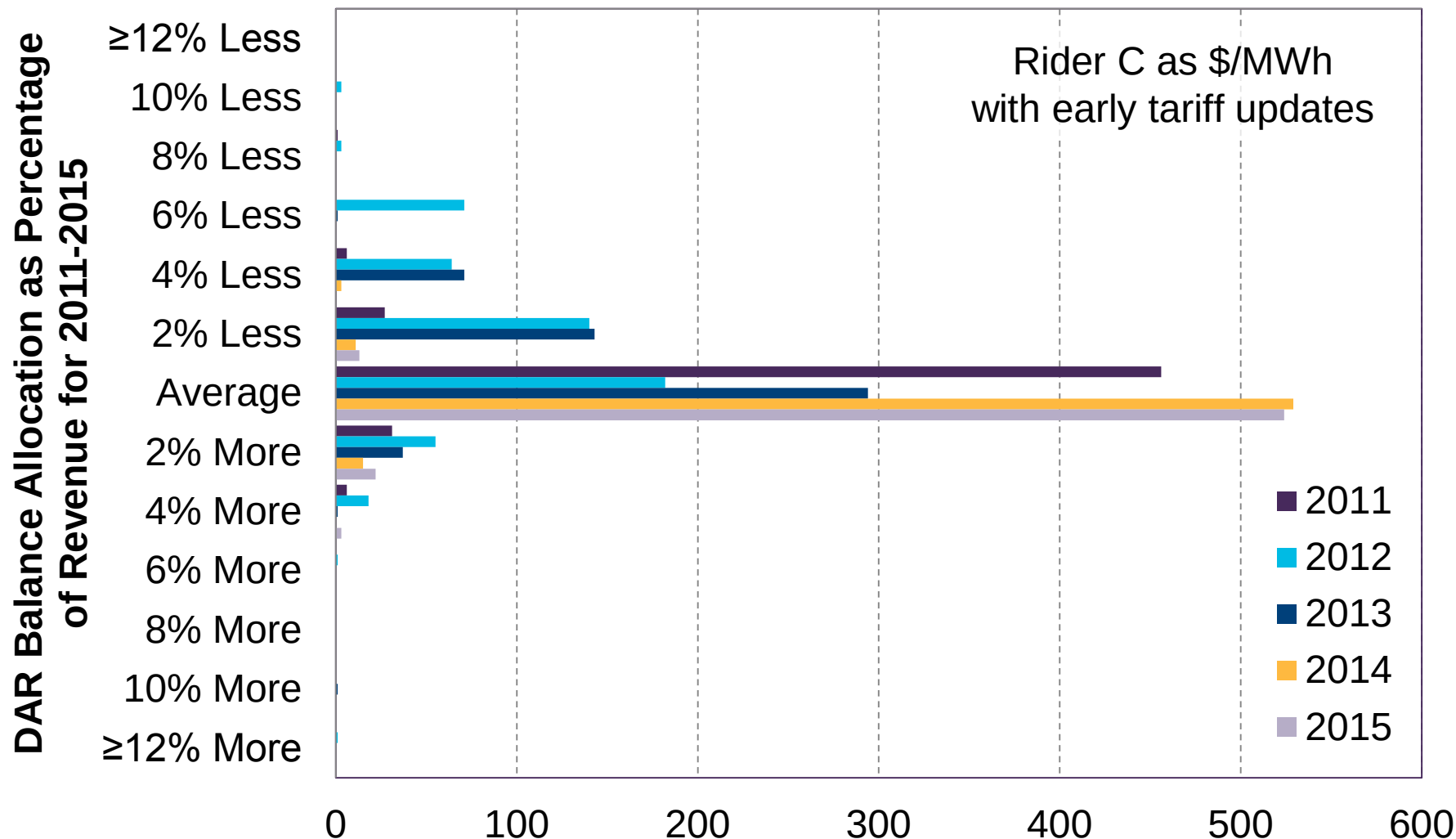


At December consultation meeting, several potential changes were discussed

- To reduce transfers between services in deferral account reconciliation applications:
 - Early tariff updates
 - Rider C as percentage (rather than as \$/MWh)
 - Rider C calculated on production year (rather than quarter)
- To address issues raised by Primary Service Group in AESO 2015 deferral account reconciliation proceeding:
 - Allocation of deferral account balances on both Rate DTS and Rate PSC amounts
- AESO proposes to apply for interim approval of these changes to be effective in 2017

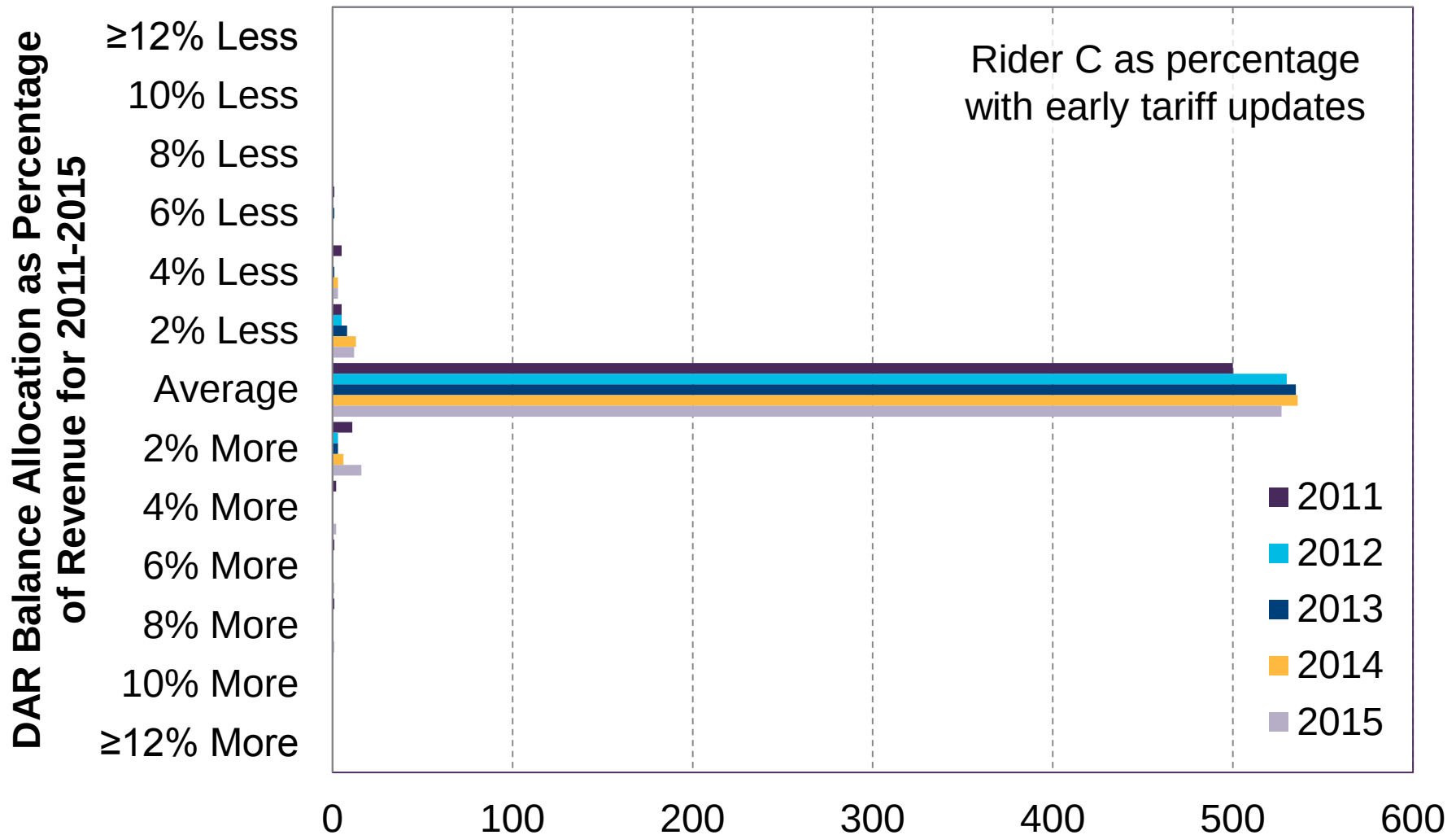
Early tariff updates reduce variability of allocations to individual services

Number of Services per 2% Interval Less or More Than Average



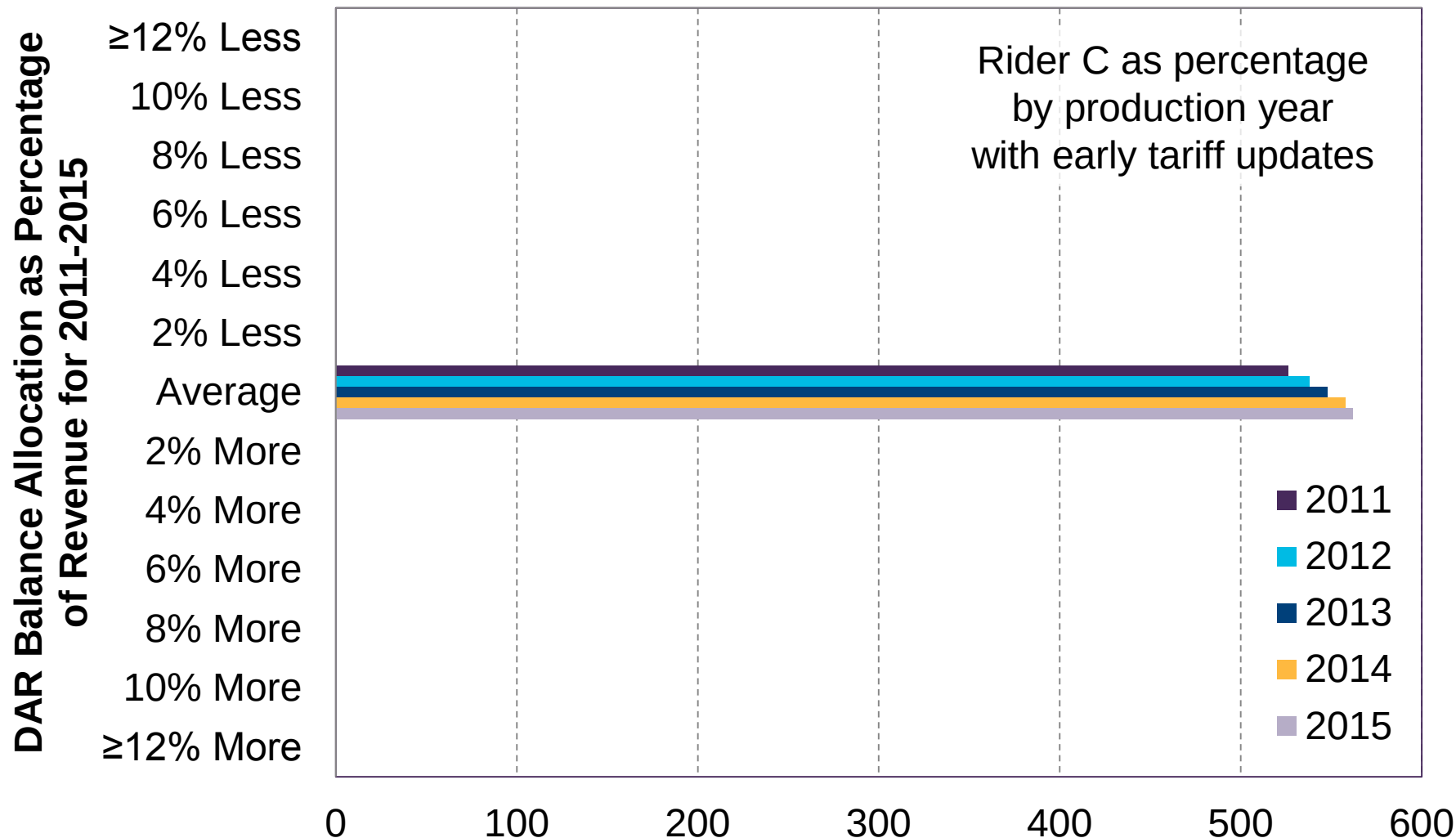
Rider C as percentage further reduces variability of allocations to services

Number of Services per 2% Interval Less or More Than Average



Rider C calculated on production year eliminates remaining variability

Number of Services per 2% Interval Less or More Than Average



Allocating DA balance on Rates DTS and PSC improves alignment with DA balance

- Currently-approved methodology allocates deferral account balance in proportion to Rate DTS revenue for a service

$$\left[\begin{array}{l} \text{Costs} \\ - \text{Rate DTS Revenue} \\ - \text{Other Tariff Revenue} \end{array} \right] \times \frac{\text{Rate DTS Revenue}_{\text{one service}}}{\text{Sum of Rate DTS Revenue}_{\text{all services}}}$$

- Deferral account balance includes revenue from Rate DTS, Rate PSC, and other tariff components, while allocation currently includes only “base rate” revenue from Rate DTS
- Allocating deferral account balance in proportion to Rates DTS and PSC would result in allocation being more closely aligned with deferral account balance

$$\left[\begin{array}{l} \text{Costs} \\ - \text{Rate DTS Revenue} \\ - \text{Other Tariff Revenue} \end{array} \right] \times \frac{\text{Rates DTS and PSC Revenue}_{\text{one service}}}{\text{Sum of Rates DTS and PSC Revenue}_{\text{all services}}}$$

AESO considered three alternatives for applying for approval of proposed changes

- Include changes in 2018 tariff application in Q2 2017
 - Changes likely effective in mid-2018 on go-forward basis
- File separate application in Q1 2017 for changes
 - Changes likely effective in late 2017 on go-forward basis
 - Potentially limited review and potential conflict with Commission direction to report in comprehensive tariff application
- File application in Q1 2017 for interim changes
 - Changes likely effective mid-2017, on interim basis
 - Changes would be comprehensively reviewed as part of 2018 tariff application

Stakeholders supported moving forward with proposed changes on timely basis



- Almost all stakeholders who commented supported early tariff updates, Rider C as percentage, and Rider C calculated on production year
 - One party suggested Rider C be determined separately for bulk system, regional system, and point of delivery rate components
 - Costs are not recorded by those components and separate deferral account balances cannot be determined
 - One party asked for more information on Rider C changes
 - The AESO will include some additional information in interim application, but information was essentially summarized in December consultation meeting

Stakeholders supported moving forward with proposed changes on timely basis (cont'd)



- Support was more limited for allocation of deferral account balances on both Rate DTS and Rate PSC amounts
 - Some parties will await decision on allocation issue in AESO 2015 deferral account reconciliation proceeding
 - AESO acknowledges that the decision may affect proposal
- Stakeholders generally supported an application for changes to be effective in 2017 on an interim basis
 - One party requested timing be coordinated with the quarterly deferral account riders of distribution system owners
 - AESO will try to maintain publishing Rider C 30 days before start of quarter

AESO currently proposing application at end of February for approval of interim changes



- Early tariff updates already implemented
- Proposed application would request interim approval of three changes
 - Rider C as percentage (rather than as \$/MWh)
 - Rider C calculated on production year (rather than quarter)
 - Allocation of deferral account balances on both Rate DTS and Rate PSC amounts
- Application would be filed at end of February
 - Decision on AESO 2015 deferral account reconciliation proceeding is expected in mid-March
- Interim approval would be requested by end of May
- Interim changes to Rider C would be effective July 1, 2017

Preliminary proposed changes to Rider C

- 1 Rider C applies to system access service provided under ... (c) Rate PSC, *Primary Service Credit*.
- 2(2) The ISO must determine Rider C for each calendar quarter as an additional percentage charge or credit
 - Currently: additional \$/MWh charge or credit
- 2(4) The ISO must calculate the Rider C charge or credit as the sum of amounts ... required to restore the deferral account balance to zero (0) at the end of the calendar year ... in each of the following rate components: (a) connection charge and primary service credit
 - Currently: over the following calendar quarter ... (a) connection charge
 - Will also affect 2017 deferral account reconciliation process

- 3(3) The ISO must apply Rider C, *Deferral Account Adjustment Rider*, to system access service provided under this rate.
 - Will also affect 2017 deferral account reconciliation process

Is interim approval by end of May practical?

- Interim approval seems best approach to accomplish early implementation
- Three-month proceeding for approval is tight
 - Application will include limited information
 - Full report will be filed with 2018 ISO tariff application
- Interim approval is subject to change or reversal, and does not establish precedent
 - Rider C charges themselves are effectively interim and subject to change in deferral account reconciliations
 - 2017 deferral account reconciliation application will not be filed until Q2 of 2018 at the earliest, and much of 2018 ISO tariff proceeding will be completed by then

Is interim approval by end of May practical?

(cont'd)

- Stakeholder opposition will put end-of-May approval at risk
 - Substantial information requests or raising of tangentially-related issues may be viewed as opposition
 - Assigning AESO resources to respond to information requests or prepare substantial argument and reply could delay filing of 2018 ISO tariff application
- Delaying effective date for Rider C changes to October 1, 2017 would eliminate much of the benefit of interim approval
- AESO will request stakeholder feedback on practicality of request for interim approval by end of May

Request for final approval of changes will be included in 2018 ISO tariff application



- AESO plans to include full report on tariff updates, deferral account reconciliation processes, and Rider C design in 2018 ISO tariff application
 - Responds to Commission direction in Decision 2014-242
 - Report would address whether net revenue allocation should include other tariff components like Rate UFLS, Riders A1-A4, and payments in lieu of notice (PILON)
- Full review of proposed changes would occur in that proceeding
 - Would also reflect outcome of 2015 deferral account reconciliation proceeding
- Changes would be expected to be confirmed as final or otherwise modified in mid-2018

Further discussion?

- Comments or questions

Application Process, Timeline and Next Steps

LaRhonda Papworth

December 5, 2016 Session – Stakeholder Comments Review



- Generally keep deferral account reconciliation filings and tariff updates on schedule with communication to stakeholders on timing
- Concern on keeping 2018 ISO tariff application on schedule
- Updates on some scope items that haven't been discussed yet in a stakeholder technical session . AESO will discuss in relation to schedule on upcoming slides
- Transmission rate projection model will be filed with the 2018 ISO tariff application
- AESO tariff treatment of energy storage continued concerns raised

Checklist for 2018 ISO tariff application

Scope item	Status
Rider C / DAR / Tariff updates	100% complete
POD cost function work	90% complete
Transmission cost causation study	95% complete
Terms and conditions: Sections 4, 5, 8 and 9	50% complete
Clarify tariff for energy storage	100% complete
Updates to Proformas	90% complete
Clarify Rider A-1 – Dow duplication avoidance tariff	80% complete
Address direction from Commission regarding cost recovery from Critical Infrastructure Protection (CIP) work	75% complete
Long-term transmission rate projection model	75% complete

Tariff tentative timeline

Session	Date
2 nd Technical Session	January 30, 2017
Stakeholder comment matrix posted	February 3, 2017
Stakeholder comments due	February 17, 2017
3 rd Technical Session	Tentative: March 1, 2017
4 th Technical/Information Session	March/April 2017
Application Preview Session	April/May 2017
Application writing	Q1 – Q2 2017
Application filing	Q2 2017
2016 DAR Filing	Q3 2017
2018 tariff <u>update</u> application	Q3 2017
Regulatory review process for 2018 tariff application	Q4 2017 – Q1 2018
Compliance filing	Q2 2018

Next steps

- The AESO will invite participants to respond to this presentation through a comment matrix in the next few weeks. To allow transparency, the AESO will post all comments on AESO's website following the receipt of participants' input
- For more information:
 - LaRhonda Papworth – Manager, Tariff Design
 - 403-539-2555
 - larhonda.papworth@aeso.ca
- All consultation documents can be found on AESO website at www.aeso.ca by following the path:
 - Rules, Standards and Tariff ► Stakeholder engagement
 - 2018 ISO tariff application

Further Discussion? Questions?



Request for Stakeholder Comments on AESO 2018 ISO Tariff Consultation

Background

On January 30, 2017, the AESO and stakeholders participated in a consultation meeting to discuss (1) technical presentation on transmission cost causation study results; (2) technical presentation on point of delivery (POD) cost function database results and discussion on criteria; (3) progress on annual tariff updates, deferral account reconciliations, and Rider C, *Deferral Account Adjustment Rider* ("Rider C") matters; and (4) application process and next steps. Based on discussion at the meeting, the AESO invites written comments from stakeholders on the information presented at the meeting. 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.

Please use the comment form below when submitting comments to the AESO on the 2018 ISO tariff consultation. Please ensure that your comments represent all interests within your stakeholder organization with respect to the consultation. Please provide comments or questions no later than **February 17, 2017**, to LaRhonda Papworth at larhonda.papworth@aeso.ca or 403-539-2555.

Consultation and Stakeholder Identification

Date of Request for Comments:	February 6, 2017
Period of Consultation:	November 15, 2016 – February 3, 2017
Comments From:	
Date:	
Contact:	
Phone:	
Email:	

Stakeholder Comments on AESO Information

Stakeholder Comment
(1) Transmission Cost Causation Study – Preliminary Results (Slides 6 – 36)

A. Scope of 2018-2020 Transmission Cost Causation Study (Slide 18):

1. Update of 2014-2016 transmission cost causation study;
2. Using identical methodology
3. Using same data sources, plus a few additional sources; and
4. For years 2018-2020.

Stakeholder Comments:

Stakeholder Comment

B. Process for 2018-2020 Transmission Cost Causation Study (Slide 19):

- i. Update inputs and conduct 2018-2020 transmission cost causation study in 2016
- ii. Present draft results to stakeholders in January 2017; and
- iii. Include the study in the 2018 ISO tariff application.

Stakeholder Comments:

C. Preliminary Functionalization - 2018 (Slides 20 – 24):

<i>Bulk</i>	<i>Regional</i>	<i>POD</i>
53.4%	26.3%	20.3%

Stakeholder Comments:

D. Preliminary Functionalization - 2019 (Slides 25 – 29):

<i>Bulk</i>	<i>Regional</i>	<i>POD</i>
55.0%	25.1%	19.9

Stakeholder Comments:

E. Preliminary Functionalization - 2020 (Slides 30 – 34):

<i>Bulk</i>	<i>Regional</i>	<i>POD</i>
53.7%	26.2%	20.1%

Stakeholder Comments:

F. Preliminary Functionalization – 2018-2020 3-year Average (Slide 35):

<i>Bulk</i>	<i>Regional</i>	<i>POD</i>
54.0%	25.9%	20.1%

Stakeholder Comments:

**(2) Point-of-delivery (“POD”) Cost Function – Preliminary Results and Discussion
(Slides 38 – 61)**

A. Background and POD Cost Function Cost Curve Options (Slides 38 - 39):

Cost Curve Options	Greenfield	Upgrade	0 MW Contracts
#1 – Pre-2014 practice	Contract	Contract	Include
#2 Current practice (until thoroughly explored)	Contract	Contract	Remove
#3 As requested in Decision 2014-242	Contract	Installed	By using installed, 0 MW projects <u>are</u> included
#4 Not asked for	Installed	Installed	
#5 AESO not considering (not asked, not debated)	Installed	Contract	?

Stakeholder Comments:

B. POD Cost Database and Cost Curves - Preliminary (Slides 40 – 45):

- i. **Option #1 Cost Curve;**
- ii. **Option #1 Cost Curve comparison to existing tariff;**
- iii. **Option #4 Cost Curve;**
- iv. **Options #1, #2, #3 and #4 Cost Curves comparison; and**
- v. **Impact on curve from Option #1 and Option #4**

Stakeholder Comments:

C. Potential evaluation criteria for cost curve options (Slides 46 – 58):

- i. **Maintaining alignment between POD cost function, maximum investment levels and the POD charge in Rates DTS and PSC;**
- ii. **Consistency with past practice (post-2007);**
- iii. **Maximize number of projects in database / statistical criteria for project inclusion;**
- iv. **Degree of relationship between installed capacity and contract capacity;**
- v. **“Lumpiness” of installed capacity and standard transformer sizes;**
- vi. **Number of assumptions required to determine installed vs contract capacity;**
- vii. **Behavior of market participant’s relationship to installed vs contract capacity;**
- viii. **Encouraging staging to contract appropriately / planned signal from contract capacity vs installed capacity;**
- ix. **Potential to eliminate substation fraction / treatment of split between DTS and STS shared costs;**
- x. **Rates reflect true costs per MW / sending the “right” price signal;**
- xi. **Equal services treated equally, unequal services treated unequally; and**
- xii. **Bridging the “gap” / fairness of treatment of customers with charges based on two different approaches.**

Stakeholder Comments:

D. Criteria Summary / Ranking (Slides 59 – 60):

Rank	Criteria	Rate Design Principles
1	<i>Maintaining alignment between POD cost function, maximum investment levels and the POD charge in Rates DTS and PSC</i>	<i>Fairness, Objectivity, and Equity Provision of Price Signals</i>
2	<i>Degree of relationship between installed capacity and contract capacity</i>	<i>Provision of Price Signals</i>
3	<i>Rates reflect true costs per MW</i>	<i>Fairness, Objectivity, and Equity Provision of Price Signals</i>
4	<i>Treatment of split between DTS and STS shared costs</i>	
5	<i>Sending the “right” price signal</i>	<i>Provision of Price Signals</i>
6	<i>Maximize the number of projects in database / statistical criteria for project exclusion</i>	<i>Fairness, Objectivity, and Equity</i>
7	<i>Fairness of treatment of customers with charges based on two different approaches, consistency with past practice (post-2007)</i>	<i>Fairness, Objectivity, and Equity Stability and Predictability</i>
8	<i>Behavior of market participants relationship to MWs</i>	<i>Fairness, Objectivity, and Equity Provision of Price Signals</i>
9	<i>Number of assumptions required to determine installed vs contract capacity</i>	<i>Fairness, Objectivity, and Equity Stability and Predictability Practicality</i>

Stakeholder Comments:

E. POD Cost Function Next Steps (Slide 61):

- i. Gather more information from stakeholders in order to develop subjective and objective comparisons of Option #1 and Option #4;***
- ii. Provide additional analysis to stakeholders on Option #1 and Option #4 to illustrate preliminary rates and investments under each option; and***
- iii. Present the AESO’s position at upcoming stakeholder session in March or April.***

Stakeholder Comments:

(3) Proposal to Apply for Interim Changes to Rider C and Deferral Account Reconciliations (Slides 63 – 80)

- A. The AESO anticipates filing an application before the end of February for interim approval of changes to address the following issues (Slide 66):**
- i. To reduce transfers between services in deferral account reconciliation applications:**
 - 1. Determine Rider C as percentage (rather than as \$/MWh);**
 - 2. Determine Rider C based on production year (rather than quarter); and**
 - ii. To address issues raised by Primary Service Group in the 2015 deferral account reconciliation proceeding:**
 - 1. Allocate deferral account balances on both Rate DTS and Rate PSC amounts.**

Stakeholder Comments Regarding Included Issues:

- B. The AESO does not plan to address in its interim application the following matters raised in stakeholder comments (Slides 72-73):**
- i. To determine Rider C separately for bulk system, regional system, and point of delivery rate components;**
 - ii. To provide more extensive information beyond the analysis presented to stakeholders;**
 - iii. To address the allocation of deferral account balances for years prior to 2017 (which is under consideration in the 2015 deferral account reconciliation proceeding);**
 - iv. To allocate deferral account balances on amounts other than Rates DTS and PSC (such as Rate UFLS, Riders A1-A4, or payment in lieu of notice amounts); or**
 - v. To modify the timing of publishing Rider C quarterly charges or credits.**

Stakeholder Comments Regarding Excluded Issues, Including Identification of Any Issues Stakeholder Considers Should Be Included:

C. Application timing (Slides 74 and 79):

- i. Application would be filed at end of February;**
- ii. Interim approval would be requested by end of May;**
- iii. Interim changes to Rider C would be effective July 1, 2017; and**
- iv. Request for final approval of changes will be included in 2018 ISO tariff application.**

Do you support the AESO's plan to apply for interim changes to Rider C and deferral account reconciliations?

- ☐ Support
- ☐ Oppose
- ☐ Indifferent

Stakeholder Reasons for Position:

(4) Application Process, Timeline and Next Steps (Slides 82 – 85)

- A. The AESO discussed the status of a number of 2018 ISO tariff application scope items (Slide 83) and a 2018 ISO tariff tentative timeline.**

Stakeholder Comments:

Additional Comments

Please return this form with your comments by **February 17, 2017**, to:

LaRhonda Papworth
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Phone: (403) 539-2555

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 1 st 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.

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.

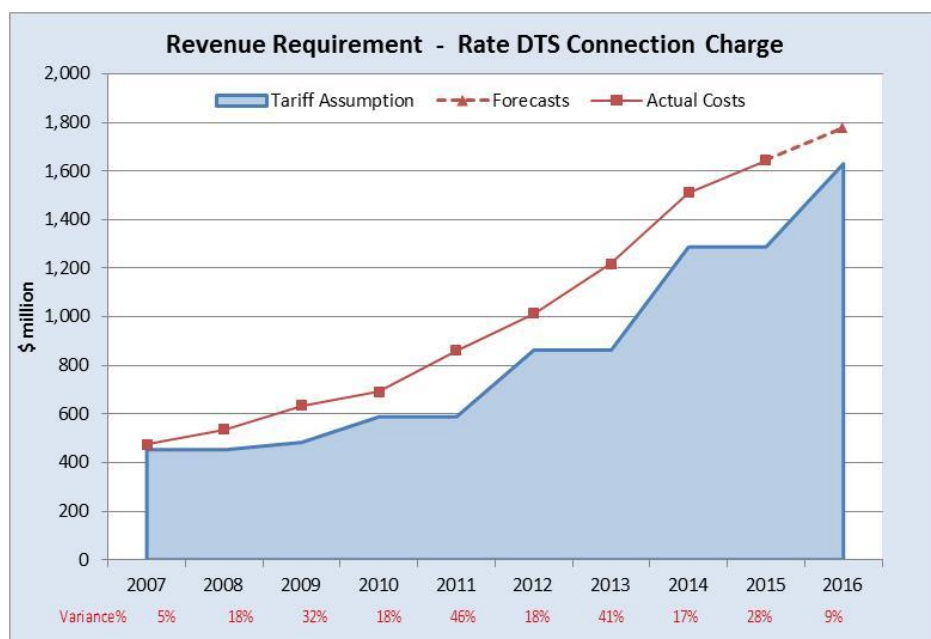
2) In the past decade, the Connection Charge forecasts used to prepare tariff rates have been materially lower than actual costs, in some years by more than 40%. The approved rates were accordingly too low and the AESO relied materially on collecting monies using Rider C (temporarily) and material billing 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

Stakeholder Comment

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:

$$\text{Final Revenue Collected (fr)} = r + [r/R]D$$

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

$$\text{Final Revenue Collected (fr)} = qP * ((R+D)/R)$$

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

$$\text{Final Revenue Collected (fr)} = qP * (110\%)$$

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 were 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:

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

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

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

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

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

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:

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

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

Stakeholder Comment

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 to be superior to an energy charge, 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

Stakeholder Comment

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 line 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 provide 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 AES 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 AES, 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.

February 14, 2017

AESO Stakeholders
AESO 2018 ISO Tariff Consultation Participants

Dear Stakeholder:

Re: **Invitation to Participate in Consultation on AESO 2018 ISO Tariff Application**

The AESO continues to consult with market participants on the development of its next comprehensive ISO tariff application, which it now refers to as the 2018 ISO tariff application to reflect the year in which the tariff is expected to become effective (in prior stakeholder communications, this application had been referred to as the 2017 ISO tariff application). The AESO will be holding the following consultation session to provide an update on work completed to date and invites you to attend:

Date:	Wednesday, March 1, 2017
Time:	1 pm to 4 pm
Place:	Meeting Room 6006, 6th Floor, BP Centre, 240 – 4th Avenue SW, Calgary, Alberta Note that the glass doors on the 6th floor are locked; please knock to have them opened.
Teleconference:	Within Calgary calling area: 403-410-3051, Conference ID 4366631 Outside Calgary calling area: 1-855-453-6957, Conference ID 4366631
RSVP:	By 5 pm on Friday, February 24, 2017 to, Tatiana Aparicio-Caris Tatiana.Aparicio-Caris@aesO.ca or 403-539-2664

The AESO plans to discuss the following items during the meeting:

- potential proposed changes to the ISO Tariff's Terms and Conditions;
- cost responsibility for compliance with the Critical Infrastructure Protection ("CIP") Alberta reliability standards;
- potential proposed changes to Rider A-1 – *Transmission Duplication Avoidance Adjustment Dow Chemical Canada Inc. / Dow Hydrocarbons / ASU2*;
- continued work on the AESO's point of delivery (POD) cost function database results and analysis; and
- planned timeline and next steps for the 2018 ISO tariff application.

The AESO plans to present information on these topics to facilitate discussion, and will post a presentation before the meeting. Stakeholders may provide feedback in person during the meeting or through written comments to the AESO after the meeting.

All information relating to the 2018 ISO tariff consultation is available on the AESO website at www.aeso.ca by following the path Rules, Standards and Tariff ► Stakeholder engagement ► 2018 ISO tariff application. As well, new information posted by the AESO on this topic will be mentioned in the

AESO stakeholder newsletter, which you can subscribe to at the bottom right of the AESO's home page at www.aeso.ca.

If you have any questions on the AESO's 2018 ISO tariff consultation, please contact me at 403-539-2555 in Calgary or by e-mail to larhonda.papworth@aesoc.ca.

Yours truly,

LaRhonda Papworth
Manager, Tariff Design

cc: Doyle Sullivan, Director – Market and Tariff Design

AESO 2018 ISO Tariff Consultation

March 1, 2017
AESO Office, Calgary

- Introduction and objectives (slide 1-5)
- ISO Tariff Terms and Conditions Proposals (slides 6-30)
- Rider A1 – proposed changes (slide 31-33)
- Summary of comments from previous session (slides 34-35)
- Application process and next steps (slides 36-38)
- Discussion and wrap-up (slide 39)

Please feel free to ask questions during presentation

Stakeholder session objectives

- Enhance understanding of ISO tariff application
- Review technical results of a number of analytical exercises by the AESO
- Share information prior to filing of 2018 ISO tariff application
- Gather feedback to ensure tariff application provides all information stakeholders require
- Review application timeline and next steps

Applications currently in progress

- Directions 5-8 on advancement costs and related provisions
 - Decision 3473-D02-2015 issued on August 26, 2015
 - Process letter issued on October 22, 2015 with additional information on process in the new year *[2016]*
 - AESO will proceed with addressing matters in the 2018 ISO tariff application unless Commission provides further guidance
- 2015 Deferral Account Reconciliation application
 - Currently before the Commission in Proceeding 21735
 - Interim settlement was approved and occurred in October 2016
 - Hearing held on December 13 and 14, 2016
 - Decision expected mid-March

Applications currently in progress

- 2017 ISO tariff update
 - Currently before the Commission in Proceeding 22093
 - Interim, refundable approval for January 1, 2017 issued by Commission on December 2, 2016
 - Commission considered close of record for this proceeding to be February 15, 2017
 - Commission final decision expected on or before April 11, 2017
- Upcoming Rider C Amendment application
 - Amending Rider C to apply to Rate PSC, *Primary Service Credit*, change to percentage charge or credit and restore deferral account balance to zero at the end of the calendar year
 - AESO now planning to file Rider C Amendment application in early March 2017

ISO Tariff Terms and Conditions Proposals

Lee Ann Kerr

Public

Matters for consideration in Commission-initiated proceeding

#	Matter
6.1	Price signals and system transmission project advancement costs
6.2	Effect of <i>Transmission Regulation</i> sections 15(1)(e) and (f) on classification of advancement costs
6.3	AESO discretion and need to develop clear criteria when applying advancement costs in respect of system transmission projects
6.4	Materiality threshold for applying advancement cost provisions to system projects
6.5	Application of advancement cost provisions to non-radial system transmission projects
6.6	Application of advancement cost provisions to upgrades/enhancements of existing system transmission facilities
6.7	Application of system project advancement costs to generator
6.8	Application system project advancement costs to distribution utilities
6.9	Time limitations on participant-related classification of system project advancement
6.10	Impact of system transmission project advancement cost provisions on transmission system planning and project execution
6.11	Adequacy of market participant accountability mechanisms in tariff
6.12	Application of Good Electric Industry Practice to staged loads

Other Commission Decisions

Decision	Summary
2005-096	“The underlying purpose of the contribution policy is to send price signals (reflective of the AESO’s economics) to market participants when they are considering siting alternatives for their facilities.”
2005-096	“With respect to the request of AE that the Board should provide clear directions respecting the classification of system and customer costs, the Board considers that the AESO should approach any situation in which there may be “shades of grey” in this designation exercise, with the position that a debatable interconnection project cost should be presumed initially to be customer-related unless clearly demonstrated otherwise.”
2005-096	“The Board, however, considers that a general stance that system enhancement costs are customer costs unless demonstrated otherwise is consistent with the expectation that the AESO adopt a more proactive stance in respect of its overall system planning and transmission system upgrade responsibilities, as detailed in the <i>Transmission Regulation</i> .”

Other Commission Decisions(cont'd)

Decision	Summary
2010-606	“The Commission considers that Article 9.3(c)(ii) of the current T&Cs provides a reasonable balance between the attribution of incremental costs caused by a connecting customer and the designation of costs as system costs where the AESO was already contemplating a system planning driven expenditure prior to the connection request. Article 9.3(c)(iii) already provides broad discretion to designate costs that would otherwise be classified as customer costs to be classified as system costs.”
3473-D02-2015	“...the Commission intended that the AESO would develop tariff provisions that would induce the market participant on the critical path to either consent to a shifting of the requested in-service date or absorb relevant incremental costs that would arise from a decision not to shift the requested in-service date.”

Principles for Load Customers

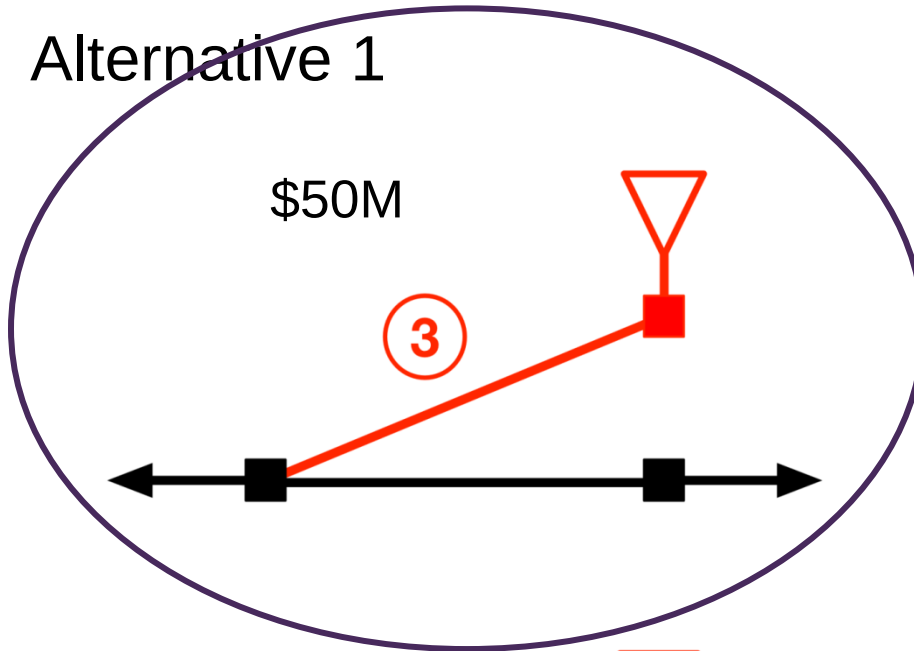
- Provide a price signal
 - Unconstrained alternative selection
 - ISDs for system transmission projects should be moved if they can't be met without incurring significant increases to project costs (or the market participant can pay)
 - Where the construction of system transmission facilities are triggered, the market participant needs to provide some form of commitment
- System transmission facilities aren't built as the result of a connection(s) not proceeding
 - We need sufficient certainty that projects will “show up”
 - Don't construct system transmission facilities if market participants don't show up
- General high-level alignment with Decision 3473-D02-2015

Alternatives to connect to transmission system

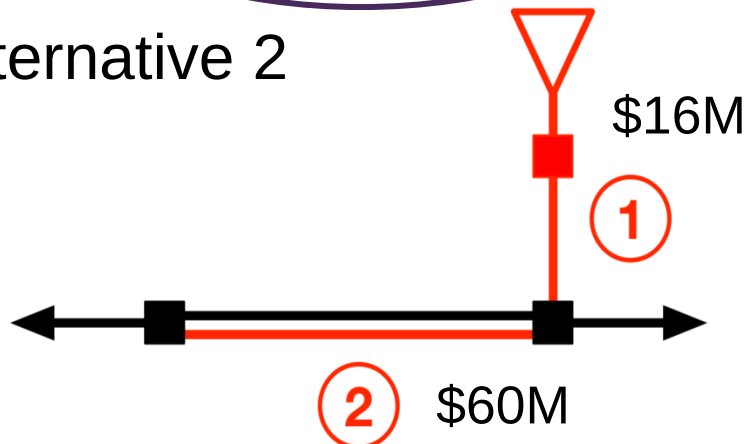
- a) most load connection projects will be radial facilities to existing transmission facilities with capacity
 - b) in some cases load connection projects may require an enhancement of existing system facilities or creation of looped facilities
- Load connection alternative must be unconstrained and
 - Alternative selected will be lowest overall costs

Alternative Selection - “Lowest Overall Costs”

Alternative 1



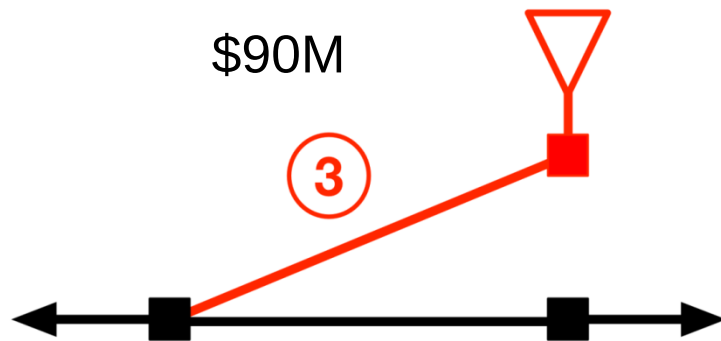
Alternative 2



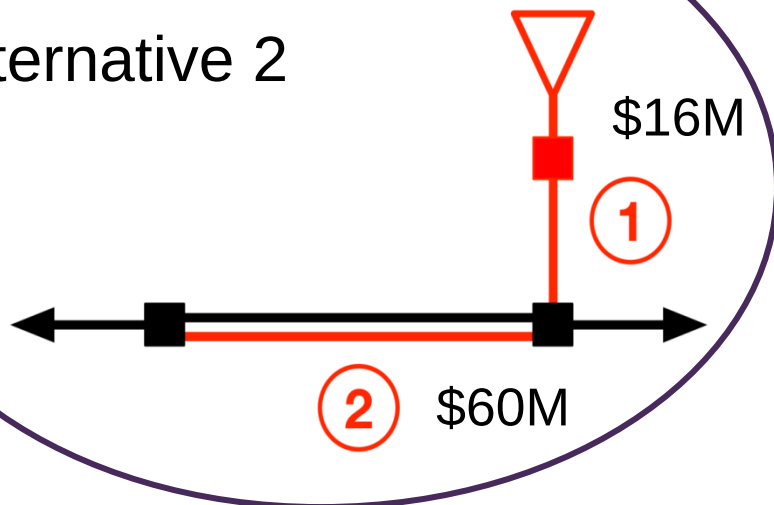
- Both Alternative 1 and 2 are unconstrained
- Alternative 1 is a radial connection to a strong source
- Alternative 2 is a radial to a weaker source ① with a required system upgrade ②
- Alternative selection would result in Alternative 1 as it is the lowest overall costs (system upgrade required)

Alternative Selection - “Lowest Overall Costs”

Alternative 1

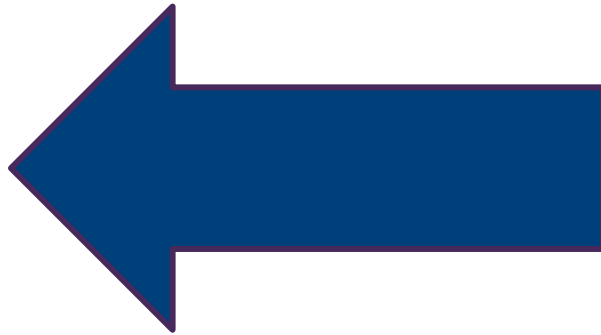


Alternative 2



- Both Alternative 1 and 2 are unconstrained
- Alternative 1 is a radial connection to a strong source
- Alternative 2 is a radial to a weaker source ① with a required system upgrade ②
- Alternative selection would result in Alternative 2 as it is the lowest overall costs (with system upgrade required)

System Transmission Facilities Required for a Load Connection



Connection Alternative Selection



Majority of projects

- Radial connection to a strong source
- 100% participant-related costs

Few projects

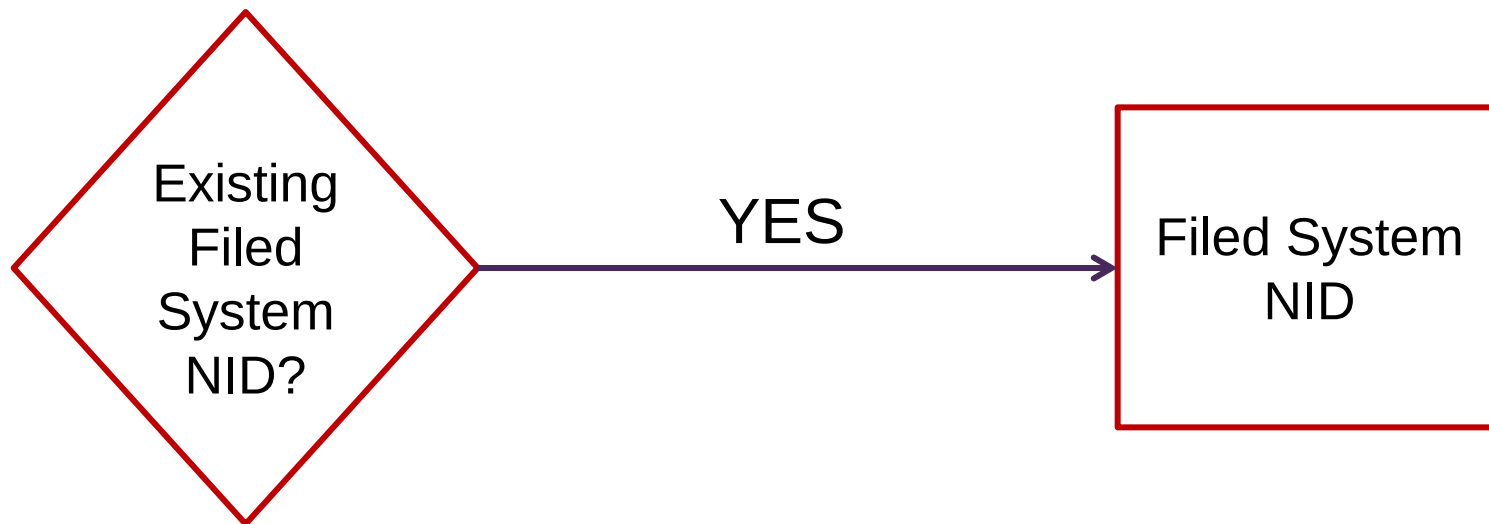
- Lowest overall costs include looped facilities (system transmission facilities)
- System-related cost component

System Transmission Facilities Required for a Load Connection

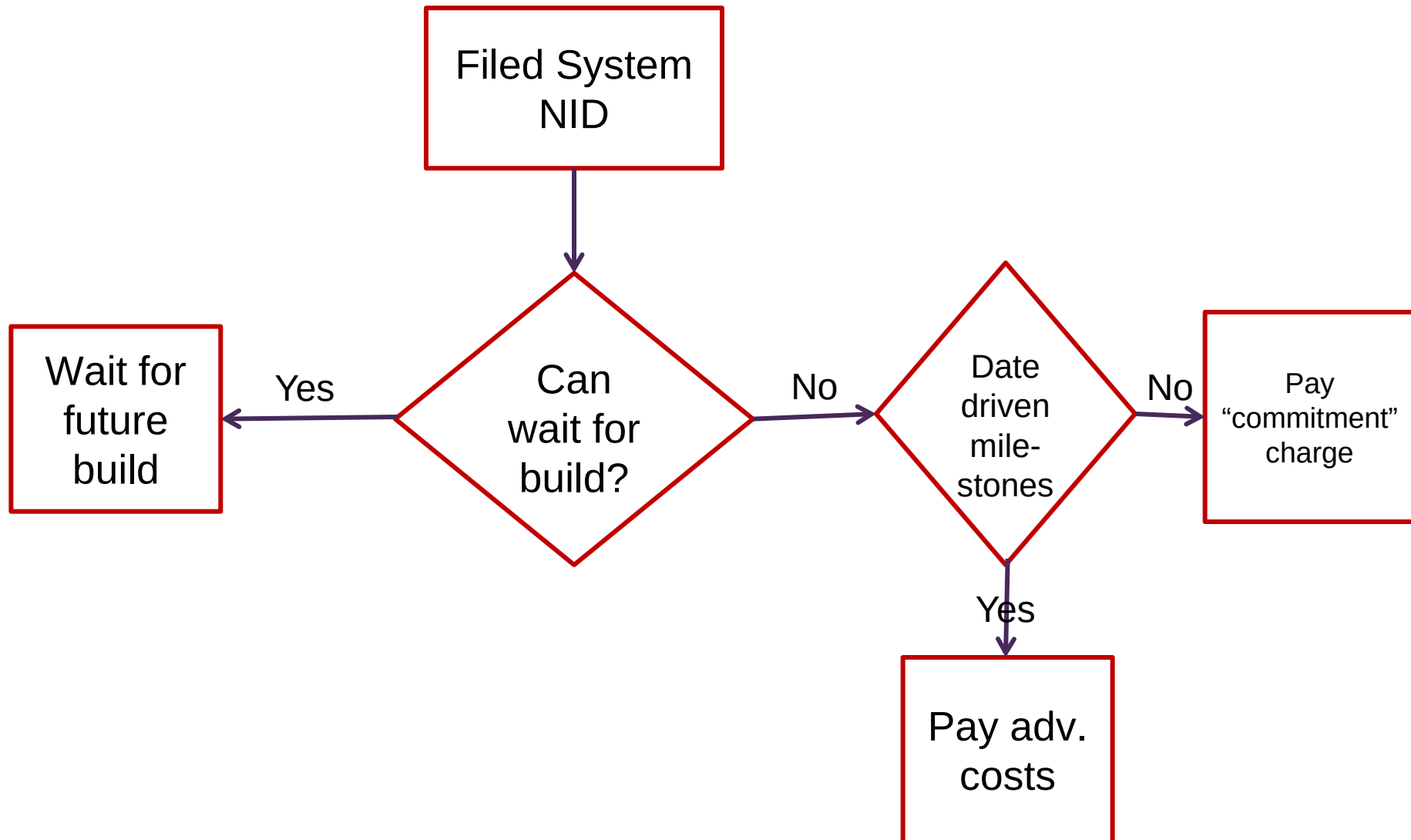


- Current tariff refers to long term plan and “as reasonably expected” by the AESO
- “While the AESO’s intention to complete a loop of a new radial transmission line within five years can point to various types of documents, the Commission is unaware of any mechanism to ensure that planned loops are actually completed in accordance with the above noted planning documents. The Commission considers a five-year planning horizon to be arbitrary.”

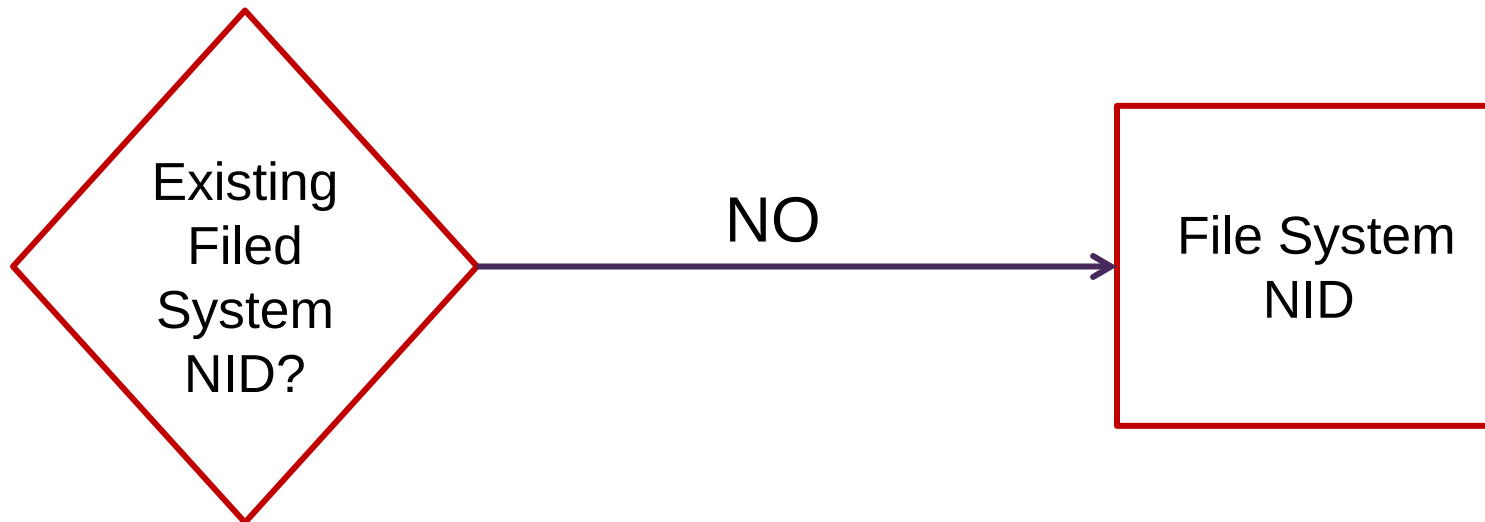
System Transmission Facilities Required for a Load Connection



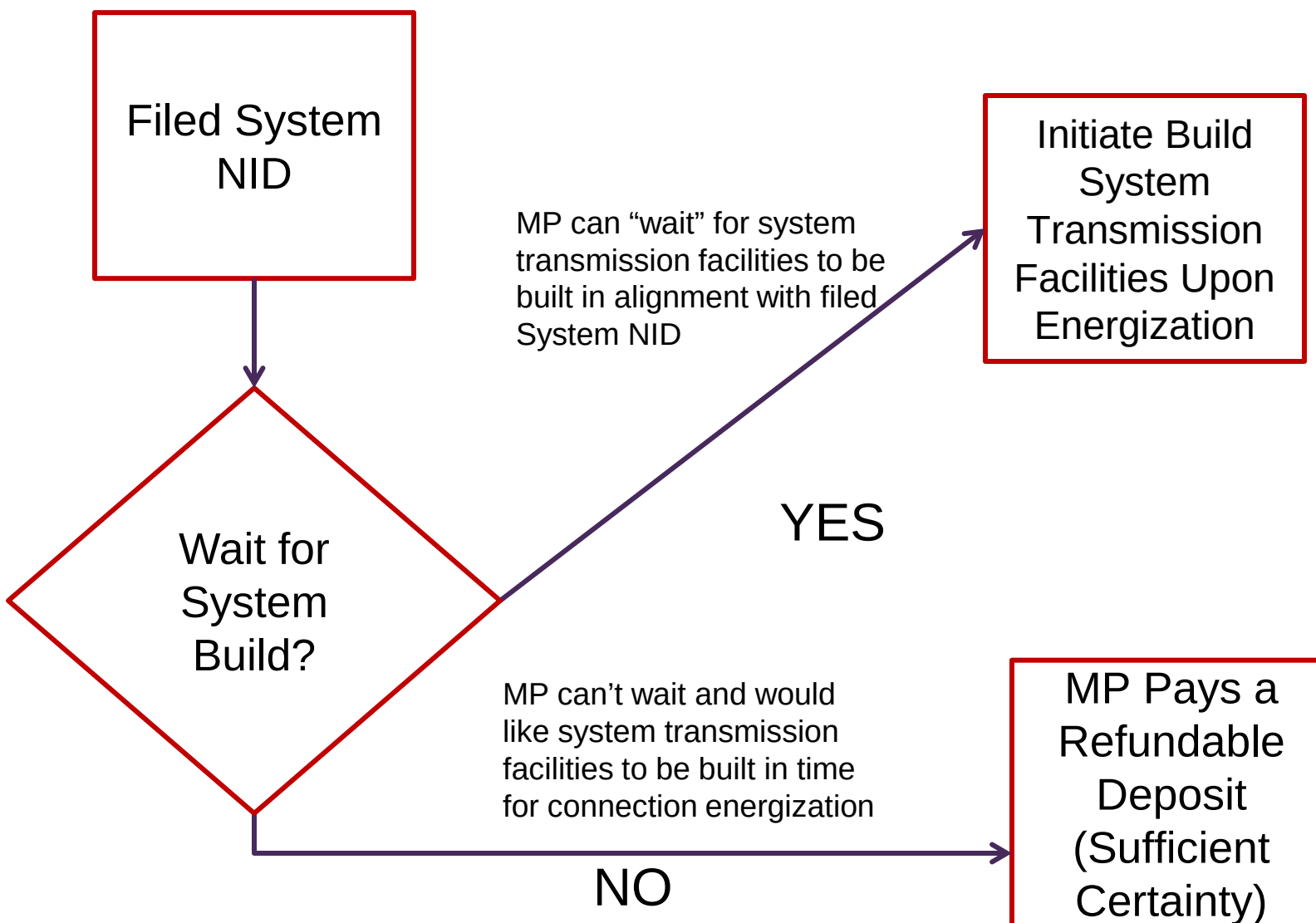
System Transmission Facilities Required for a Load Connection



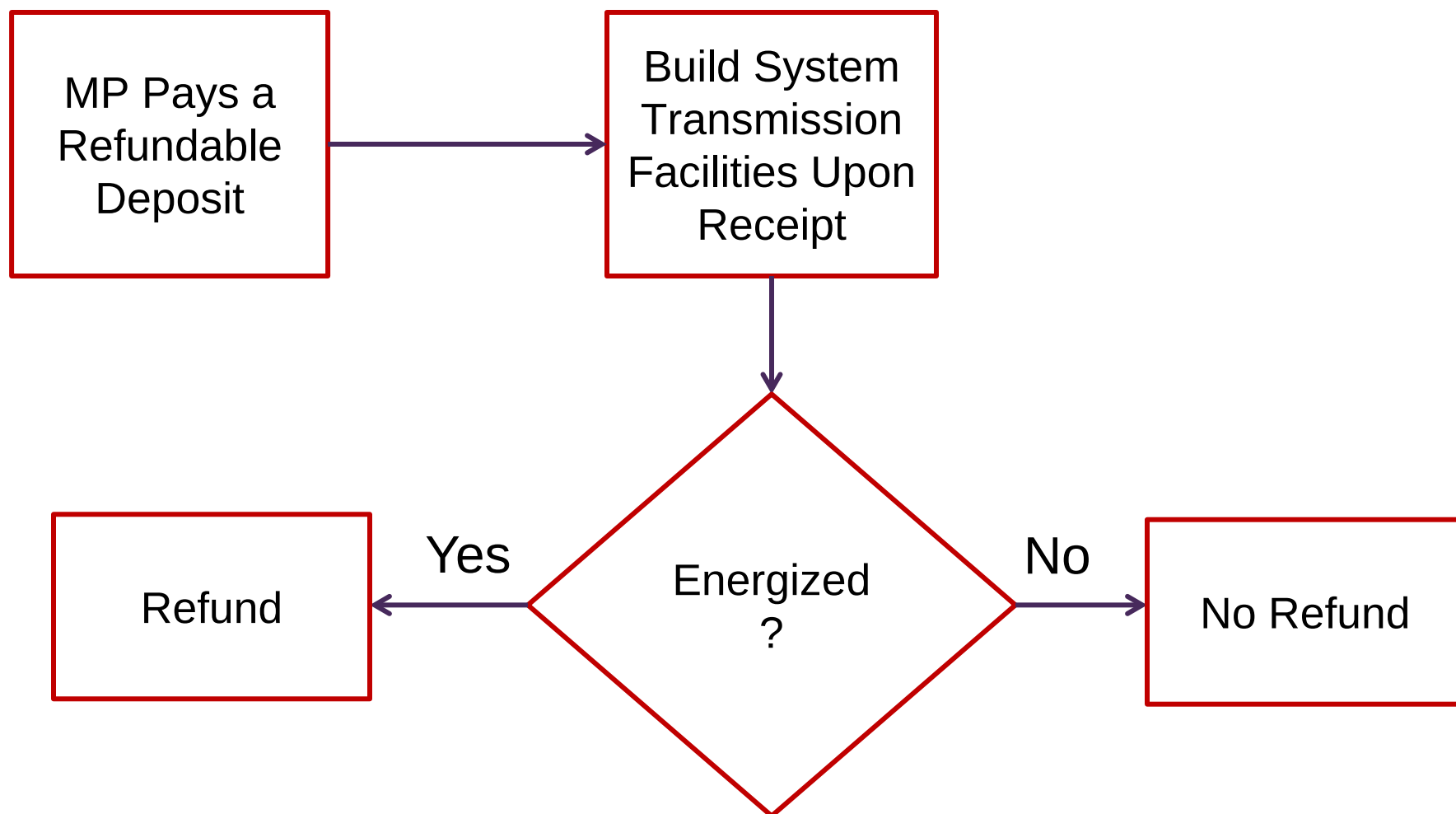
System Transmission Facilities Required for a Load Connection



System Transmission Facilities Required for a Load Connection – Concept 1 -“Refundable Deposit”



System Transmission Facilities Required for a Load Connection – Concept 1 – Refundable Deposit



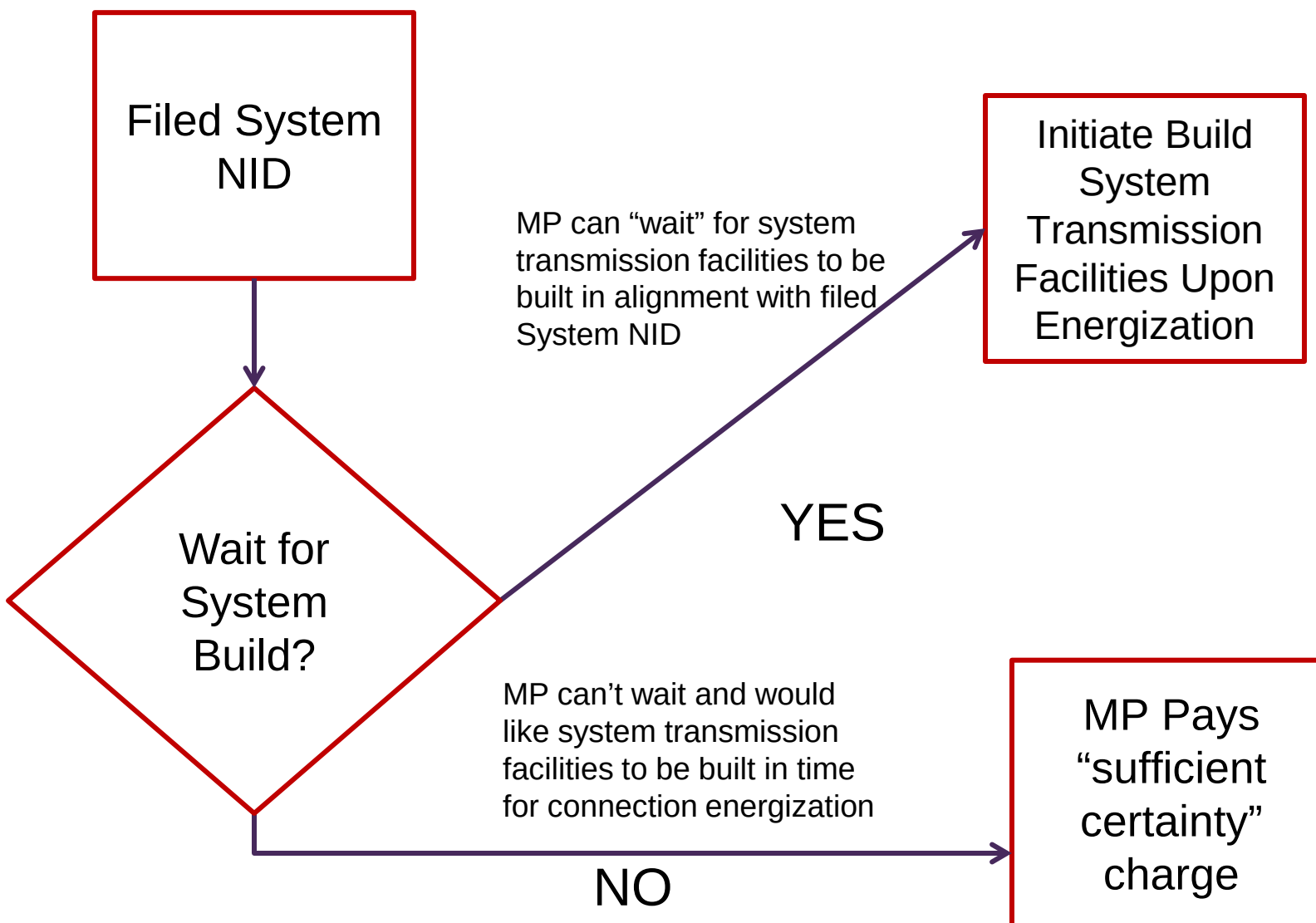
“Refundable Deposit” – What does it provide for the AESO?

- Provides the AESO with sufficient certainty that the connection project will energize
- Not building system transmission assets that will not be used
- Provides a price signal where there is limited capacity
- Only applies when the MP can't “wait” for system transmission facilities

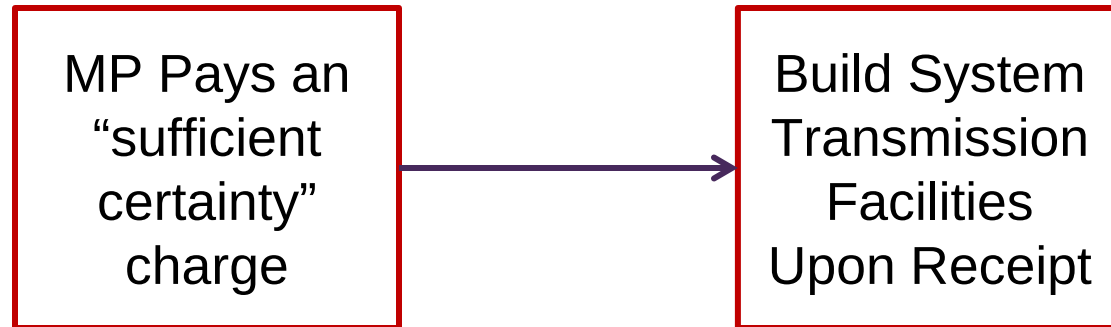
Pros and Cons – Concept 1 – Refundable Deposit

- Pros
 - Strong price signal (if you can't wait)
 - Aligns with GUOC incentives (“performance” = “energization”)
 - Encourages timely energization (the AESO is holding a large deposit)
 - The MP can choose to “wait”, stage their contract to accommodate current system capacity and construction will begin after energization
- Cons
 - System transmission facility costs might be prohibitively high
 - Delay in cost estimates (creation of system NID)

System Transmission Facilities Required for a Load Connection – Concept 2 – “Pay a Share”



System Transmission Facilities Required for a Load Connection – Concept 2 – “Pay A Share”

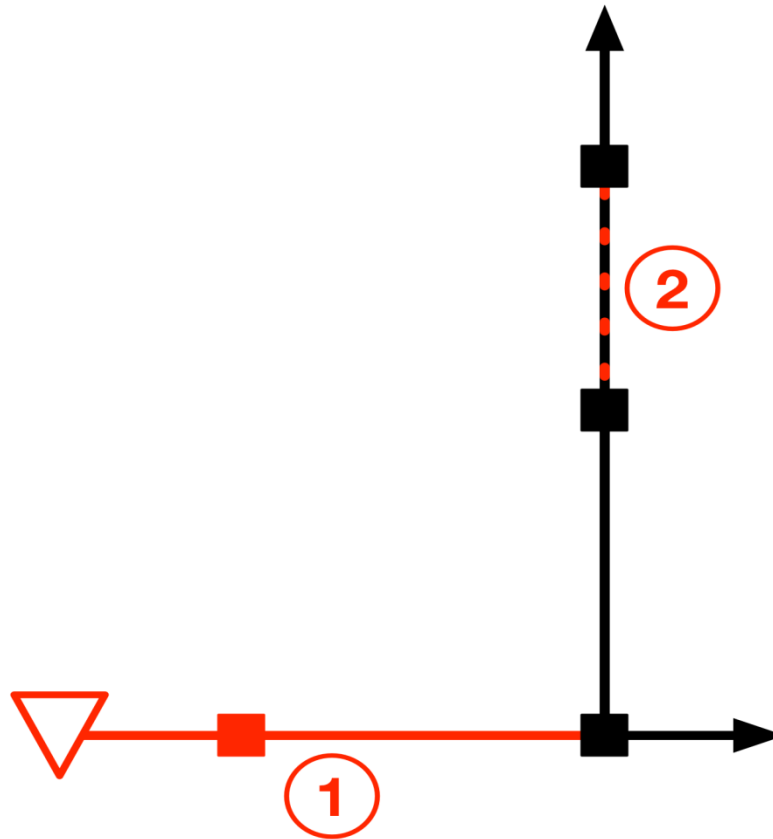


“Pay A Share” – What does it provide for the AESO?

- Restores a reasonable balance between certainty and price signals
- Provides the AESO with sufficient certainty that the connection project will energize
- May calculate in accordance with the current tariff provisions
- Provides a price signal where there is limited capacity
- Only applies when the market participant can't “wait” for system transmission facilities
- Intended to address system build required that is not anticipated or planned in the AESO near term planning horizon (5 years)

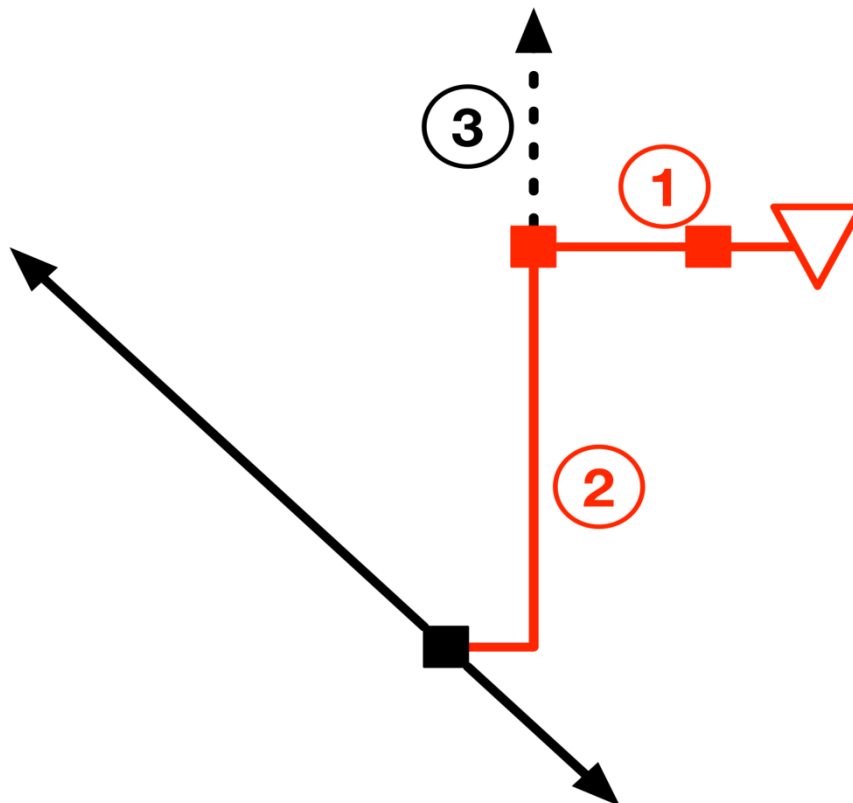
- Pros
 - Market participant pays a share of the system transmission facilities for causing advancement of unplanned facilities
 - Strong price signal (if you can't wait)
 - The MP can choose to “wait”, stage their contract to accommodate current system capacity (considering forecast growth) and initiation of the system transmission facility project will begin after energization
- Cons
 - “Commitment” cost charge might be high

Example – Wait or Pay



- Advancement costs apply to all system transmission facilities required for a load connection, not solely radial facilities planned to be looped (section 8 subsection 3(3)(b))
- “Accelerated Construction Costs” as contemplated in Decision 3473-D01-2015
- Filed system NID (with MW milestones) required, current tariff refers to the long term plan, or as ISO reasonably expects will be required in the future
- Differentiation between generation and load connections
- “Shared with system” cost provisions

Examples – Initially Radial then “Shared”



Next Steps

- Allow stakeholders to review presentation and concepts
- Gather stakeholder feedback and incorporate in to further work
- Follow up in next stakeholder session
- Work towards recommended approach for application

Rider A1 – Dow Chemical Canada Inc. / Dow Hydrocarbons / ASU2 Changes

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Rider A1 - Dow Duplication Avoidance Tariff (DAT) Issues

- Rider A1 inconsistent with other Rider A's with language and detail
- Forecast benefit table ends in 2021 – what happens after 2021?
 - 25 year business case assumption in original application does not reflect the expectation of asset life for a transmission line
- What is required in the ISO tariff to provide clarity on future duplication avoidance sites?

Rider A1 - Dow Duplication Avoidance Tariff (DAT) Next Steps

1. The AESO plans to update Rider A1 to authoritative language
2. High-level test of some criteria considered in original AEUB decision U98125 (available capacity, credible bypass threat, service life of transmission facilities)
3. Consideration of Rider A1 continuing to a reasonably expected transmission life period with recovery of O&M and losses annual/monthly payments from Dow
4. Add “expiry” or “term” to clarify what happens after a certain date, i.e. re-application for duplication avoidance tariff

Application Process, Timeline and Next Steps

LaRhonda Papworth

January 30, 2017 Session – Stakeholder Comments Review

- Clarification of transmission cost causation study results, specifically around regional assets costs – next session
- POD cost function work – next session
 - POD cost function translated to rates and investment
 - Concerns around installed capacity assumptions
 - One preference for Option #4 – installed capacity basis
 - Stakeholders request to see more data and results before deciding on preferred approach
- Request for transmission rate projection model on a timely basis – to be filed with application in Q2 2017

Checklist for 2018 ISO tariff application

Scope item	Status
Rider C / DAR / Tariff updates	100% complete
POD cost function work	90% complete
Transmission cost causation study	95% complete
Terms and conditions: Sections 4, 5, 8 and 9	65% complete
Clarify tariff for energy storage	100% complete
Updates to Proformas	90% complete
Clarify Rider A-1 – Dow duplication avoidance tariff	80% complete
Address direction from Commission regarding cost recovery from Critical Infrastructure Protection (CIP) work	75% complete
Long-term transmission rate projection model	75% complete

Tariff tentative timeline

Session	Date
3 rd Technical Session	March 1, 2017
Stakeholder comment matrix posted	March 6, 2017
Stakeholder comments due	March 20, 2017
4 th Technical/Information Session	late March/ early April 2017
Application Preview Session	April/May 2017
Application writing	Q1 – Q2 2017
Application filing	Q2 2017
2016 DAR Filing	Q3 2017
2018 tariff <u>update</u> application	Q3 2017
Regulatory review process for 2018 tariff application	Q4 2017 – Q1 2018
Compliance filing	Q2 2018

Next steps

- The AESO will invite participants to respond to this presentation through a comment matrix in the next few weeks. To allow transparency, the AESO will post all comments on AESO's website following the receipt of participants' input
- For more information:
 - LaRhonda Papworth – Manager, Tariff Design
 - 403-539-2555
 - larhonda.papworth@aeso.ca
- All consultation documents can be found on AESO website at www.aeso.ca by following the path:
 - Rules, Standards and Tariff ► Stakeholder engagement
 - 2018 ISO tariff application

Further Discussion? Questions?

Request for Stakeholder Comments on AESO 2018 ISO Tariff Consultation

Background

On March 1, 2017, the AESO and stakeholders participated in a consultation meeting to discuss (1) potential changes to the ISO tariff's terms and conditions; (2) potential changes/amendments to Rider A1 – *Transmission Duplication Avoidance Adjustment Dow Chemical Canada Inc. / Dow Hydrocarbons / ASU2*; and (3) application process and next steps. Based on discussion at the meeting, the AESO invites written comments from stakeholders on the information presented. The meeting presentation is posted on the AESO website and can be accessed at www.aeso.ca by following the path Rules, Standards and Tariff ► Stakeholder engagement ► 2018 ISO Tariff Application.

Please use the comment form below when submitting comments to the AESO on the 2018 ISO tariff consultation. Please ensure that your comments represent all interests within your stakeholder organization with respect to the consultation. Please provide comments or questions no later than **March 17, 2017**, to LaRhonda Papworth at larhonda.papworth@aesoc.ca or 403-539-2555.

Consultation and Stakeholder Identification

Date of Request for Comments:	March 7, 2017
Period of Consultation:	November 15, 2016 – March 7, 2017
Comments From:	
Date:	
Contact:	
Phone:	
Email:	

Stakeholder Comments on AESO Information

Stakeholder Comment
(1) ISO Tariff Terms and Conditions Proposals (Slides 6 – 30)
A. Principles for Load Customers (Slide 10): • <i>Provide a price signal;</i> • <i>System transmission facilities are not built as the result of a connection(s) not proceeding; and</i> • <i>General high-level alignment with Decision 3473-D02-2015.</i>
Stakeholder Comments:
B. Alternative Selection for Load Connections (Slides 11-13):

Stakeholder Comment

- *Load connection alternative must be unconstrained; and*
- *Alternative selected will be lowest overall costs alternative.*

Stakeholder Comments:

C. System Transmission Facilities Required for a Load Connection – “Filed System NID” (Slides 14 – 16):

- *AESO is proposing to change language in the ISO tariff terms and conditions to add clarity regarding “long term transmission system plan” and “as the ISO reasonable expects will be required in the future” (section 8, subsection 3(3)(b)).*

Stakeholder Comments:

D. System Transmission Facilities Required for a Load Connection – with a Filed System NID (Slide 17):

- *Market participant can wait for build?*
- *If not, a System NID with date driven milestones – customer would pay advancement costs calculated in accordance with current ISO tariff provisions*
- *If not, and a System NID without date driven milestones – customer would pay “commitment” charge*

Stakeholder Comments:

E. Concept 1: System Transmission Facilities Required for a Load Connection – without a Filed System NID (Slides 18 - 21):

- *Market participant can wait for build?*
- *If market participant can wait for system development (with milestones), the system transmission development will be initiated upon market participant’s energization;*
- *If market participant cannot wait for system development (with milestones), market participant pays a refundable deposit in order to provide “sufficient certainty” of project going ahead.*
 - *Market participant will be refunded deposit upon connection project energization*

Stakeholder Comments:

F. Concept 1: Refundable Deposit – What does it provide for the AESO? (Slide 21):

- *Provides “sufficient certainty” that connection project will energize;*
- *Will not build system transmission assets that will not be used;*
- *Provides a price signal where there is limited capacity; and*
- *Only applies when the market participant cannot wait for system transmission facilities.*

Stakeholder Comments:

Stakeholder Comment

G. Concept 1: Refundable Deposit – Pros and Cons (Slide 22):**Pros:**

- *Strong price signal if market participant cannot wait;*
- *Aligns with Generator Unit Owner's Contribution ("GUOC") incentives, (i.e. "performance" = "energization");*
- *Encourages timely energization as the AESO is holding a large deposit;*
- *The market participant can choose to wait or stage their contract to accommodate current system capacity and system facilities construction will begin after connection project energization.*

Cons:

- *System transmission facility costs might be prohibitively high;*
- *Delay in cost estimates (may not occur until the creation of the system NID).*

Stakeholder Comments:

H. Concept 2: System Transmission Facilities Required for a Load Connection – without a Filed System NID (Slides 23 - 24):

- *Market participant can wait for build?*
- *If market participant can wait for system development (with milestones), the system transmission development will be initiated upon market participant's energization;*
- *If market participant cannot wait for system development (with milestones), market participant pays a "sufficient certainty charge" in order to provide "sufficient certainty" of project going ahead.*
 - *System transmission facilities will be initiated upon receipt of the "sufficient certainty charge".*

Stakeholder Comments:

I. Concept 2: Sufficient Certainty Charge – What does it provide for the AESO? (Slide 25):

- *Restores a reasonable balance between certainty and price signals;*
- *Provides the AESO with sufficient certainty that the connection project will energize;*
- *May calculate in accordance with the current tariff provisions;*
- *Provides a price signal where there is limited capacity;*
- *Only applies when the market participant cannot wait for system transmission facilities; and*
- *Intended to address system build required that is not anticipated or planned in the AESO near-term planning horizon (5 years).*

Stakeholder Comments:

J. Concept 2: Sufficient Certainty Charge – Pros and Cons (Slide 26):**Pros:**

- *Market participant pays a share of the system transmission facilities for causing*

Stakeholder Comment

advancement of unplanned facilities;

- *Strong price signal if market participant cannot wait;*
- *The market participant can choose to wait or stage their contract to accommodate current system capacity (considering forecast growth) and system facilities construction will begin after connection project energization.*

Cons:

- *“Sufficient certainty charge” cost might be high.*

Stakeholder Comments:

K. Tariff Alignment – Other items (Slides 28 - 29):

1. *Advancement costs apply to all system transmission facilities required for a load connection, not solely radial facilities planned to be looped (section 8, subsection 3(3)(b));*
2. *“Accelerated construction costs” as contemplated in Decision 3473-D02-2015;*
3. *Filed system NID (with MW milestones) required, current tariff refers to the long-term plan, or as ISO reasonable expects will be required in the future;*
4. *Differentiation between generation and load connections; and*
5. *“Shared with system” cost provisions.*

Stakeholder Comments:

L. Next Steps (Slide 30)

- *Allow stakeholders to review presentation and concepts;*
- *Gather stakeholder feedback and incorporate in to further work;*
- *Follow up in next stakeholder session; and*
- *Work towards recommended approach for application.*

Stakeholder Comments:

(2) Rider A1 – Dow Chemical Canada Inc. / Dow Hydrocarbons / ASU2 Changes (Slides 31 – 33)

A. Rider A1 – Dow Duplication Avoidance Tariff (DAT) Issues (Slide 32):

- *Rider A1 is inconsistent with other Rider A's with language and detail;*
- *Forecast benefit table ends in 2021 – what happens after 2021; and*
 - *25-year (approx.) business case assumption in original application does not reflect the expectation of asset life for a transmission line.*
- *What is required in the ISO tariff to provide clarity on future duplication avoidance sites' treatment.*

Stakeholder Comments:

B. Rider A1- Dow Duplication Avoidance Tariff (DAT) – Next Steps (Slide 33):

Stakeholder Comment

1. *The AESO plans to update Rider A1 to authoritative language;*
2. *High-level test of some criteria considered in original AEUB decision U98125 (available capacity, credible bypass threat, and service life of transmission facilities);*
3. *Consideration of Rider A1 continuing to a reasonable expected transmission life period with recovery of O&M and losses annual/monthly payments from Dow; and*
4. *Add “expiry” or “term” to clarify what happens after a certain date, i.e. re-application for duplication avoidance tariff? Other?*

Stakeholder Comments:

(3) Application Process, Timeline and Next Steps (Slides 34 – 39)

- A. *The AESO discussed the status of a number of 2018 ISO tariff application scope items (Slide 36) and a 2018 ISO tariff tentative timeline.*

Stakeholder Comments:

Additional Comments

Please return this form with your comments by **March 17, 2017**, to:

LaRhonda Papworth
 Manager, Tariff Design
 Email: larhonda.papworth@aeso.ca
 Phone: (403) 539-2555

Consolidated Stakeholder Comments on AESO 2018 ISO Tariff Consultation Session – January 30, 2017



Background

On January 30, 2017, the AESO and stakeholders participated in a consultation meeting to discuss (1) a technical presentation on transmission cost causation study results; (2) a technical presentation on point of delivery (POD) cost function database results; (3) progress on annual tariff updates, deferral account reconciliations, and Rider C, *Deferral Account Adjustment Rider*, matters; and (4) the process and next steps for the 2018 ISO tariff application. The AESO invited written comments from stakeholders on the information presented at the meeting. The written comments received from stakeholders are consolidated below.

A copy of the presentation provided by the AESO at the January 30, 2017 meeting 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) Transmission Cost Causation Study – Preliminary Results (Slides 6 – 36)
A. Scope of 2018-2020 Transmission Cost Causation Study (Slide 18): i. Update of 2014-2016 transmission cost causation study; ii. Using identical methodology iii. Using same data sources, plus a few additional sources; and iv. For years 2018-2020.
Alberta Direct Connect Consumers Association (“ADC”): ADC supports this approach.
ATCO Electric: While ATCO Electric understands that the AESO’s 2018 Transmission Cost Causation Study methodology is similar to the Cost Study methodology approved in the AESO’s 2014 ISO Tariff application, ATCO Electric will require more time to review and understand the updated Cost Study as well as associated Rate Design implications once the AESO submits its 2018 application.
Dual Use Customers (“DUC”): DUC supports the proposed methodology to update the transmission cost causation study.
EPCOR Distribution & Transmission Inc. (“EDTI”): EDTI is supportive and has no concerns at this time.
ENMAX Power Corporation (“EPC”): No comment.
FortisAlberta Inc.: No comment.

Stakeholder Comment

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

IPCAA supports the use of identical methodology to update the transmission cost causation study.

Primary Service Group ("PSG"):

No comment.

B. Process for 2018-2020 Transmission Cost Causation Study (Slide 19):

- i. Update inputs and conduct 2018-2020 transmission cost causation study in 2016**
- ii. Present draft results to stakeholders in January 2017; and**
- iii. Include the study in the 2018 ISO tariff application.**

Alberta Direct Connect Consumers Association ("ADC"):

ADC Supports this approach.

ATCO Electric:

No comment.

Dual Use Customers ("DUC"):

No comment.

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

EDTI is supportive and has no concerns at this time.

ENMAX Power Corporation ("EPC"):

No comment.

FortisAlberta Inc.:

No comment.

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

IPCAA supports the AESO's proposed process.

Primary Service Group ("PSG"):

No comment.

C. Preliminary Functionalization - 2018 (Slides 20 – 24):

Bulk	Regional	POD
53.4%	26.3%	20.3%

Alberta Direct Connect Consumers Association ("ADC"):

Slide 21 indicates that there has been an increase of regional assets in the order of \$1.7B since 2016. Can the AESO provide a list of the key projects that are included in the total?

ATCO Electric:

No comment.

Dual Use Customers ("DUC"):

We are surprised with the Regional cost increases. The DUC looks forward to the opportunity to review

Stakeholder Comment

the proposed COS models.

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

EDTI has no concerns at this time.

ENMAX Power Corporation ("EPC"):

No comment.

FortisAlberta Inc.:

No comment.

Industrial Power Consumers Association of Alberta (IPCAA):

These results seem reasonable. However, the presentation raises the following question:

Slide 21 indicates that the 2018 Regional Costs are \$4.4 Billion. Slide 11 indicates that 2016 Regional Costs were \$2.7 B. Can the AESO provide a list of the regional projects that make up this increase of \$1.7 B over the 2-year timeframe?

Primary Service Group ("PSG"):

No comment.

D. Preliminary Functionalization - 2019 (Slides 25 – 29):

<i>Bulk</i>	<i>Regional</i>	<i>POD</i>
<i>55.0%</i>	<i>25.1%</i>	<i>19.9</i>

Alberta Direct Connect Consumers Association ("ADC"):

No comment.

ATCO Electric:

No comment.

Dual Use Customers ("DUC"):

No comment.

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

EDTI has no concerns at this time.

ENMAX Power Corporation ("EPC"):

No comment.

FortisAlberta Inc.:

No comment.

Industrial Power Consumers Association of Alberta (IPCAA):

These results seem reasonable

Primary Service Group ("PSG"):

No comment.

E. Preliminary Functionalization - 2020 (Slides 30 – 34):

Stakeholder Comment

<i>Bulk</i>	<i>Regional</i>	<i>POD</i>
53.7%	26.2%	20.1%

Alberta Direct Connect Consumers Association ("ADC"):

No comment.

ATCO Electric:

No comment.

Dual Use Customers ("DUC"):

No comment.

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

EDTI has no concerns at this time.

ENMAX Power Corporation ("EPC"):

No comment.

FortisAlberta Inc.:

No comment.

Industrial Power Consumers Association of Alberta (IPCAA):

These results seem reasonable.

Primary Service Group ("PSG"):

No comment.

F. Preliminary Functionalization – 2018-2020 3-year Average (Slide 35):

<i>Bulk</i>	<i>Regional</i>	<i>POD</i>
54.0%	25.9%	20.1%

Alberta Direct Connect Consumers Association ("ADC"):

No comment.

ATCO Electric:

No comment.

Dual Use Customers ("DUC"):

No comment.

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

EDTI has no concerns at this time.

ENMAX Power Corporation ("EPC"):

No comment.

FortisAlberta Inc.:

No comment.

Stakeholder Comment

Industrial Power Consumers Association of Alberta (IPCAA):

These results seem reasonable.

Primary Service Group ("PSG"):

No comment.

(2) Point-of-delivery ("POD") Cost Function – Preliminary Results and Discussion (Slides 38 – 61)

A. Background and POD Cost Function Cost Curve Options (Slides 38 - 39):

Cost Curve Options	Greenfield	Upgrade	0 MW Contracts
#1 – Pre-2014 practice	Contract	Contract	Include
#2 Current practice (until thoroughly explored)	Contract	Contract	Remove
#3 As requested in Decision 2014-242	Contract	Installed	By using installed, 0 MW projects <u>are</u> included
#4 Not asked for	Installed	Installed	
#5 AESO not considering (not asked, not debated)	Installed	Contract	?

Alberta Direct Connect Consumers Association ("ADC"):

Valid to examine the various approaches.

ATCO Electric:

No comment.

Dual Use Customers ("DUC"):

The DUC supports Option 4 as installed capacity (e.g. mid-transformer size) is much better aligned to cost causation than contract capacity. As our evidence in the last proceeding clearly showed, some market participants do not have the proper incentives to contract for capacity upgrades. Upgrade projects with 0 MW contract capacity increase are a clear indication that contract capacity is not appropriate for the development of the POD cost function.

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

EDTI has no concerns at this time.

ENMAX Power Corporation ("EPC"):

No comment.

FortisAlberta Inc.:

No comment.

Industrial Power Consumers Association of Alberta (IPCAA):

IPCAA has two main concerns: (1) the intergenerational equity issues associated with changing the POD function cost curve at this point; and (2) the AESO's ability to assemble accurate installed capacity data, in order to create an accurate curve. These issues should be examined thoroughly.

Stakeholder Comment

Primary Service Group ("PSG"):

No comment.

B. POD Cost Database and Cost Curves - Preliminary (Slides 40 – 45):

- i. Option #1 Cost Curve;**
- ii. Option #1 Cost Curve comparison to existing tariff;**
- iii. Option #4 Cost Curve;**
- iv. Options #1, #2, #3 and #4 Cost Curves comparison; and**
- v. Impact on curve from Option #1 and Option #4**

Alberta Direct Connect Consumers Association ("ADC"):

It would be helpful to see how the curves translate into the POD tariff.

ATCO Electric:

No comment.

Dual Use Customers ("DUC"):

The DUC supports Option #4. The DUC suggests the AESO consider the following:

- Develop a cost curve that correlates capital costs and installed capacity
- Develop a correlation between installed capacity and contract capacity (IC/CC ratio) using all AESO PODs (with potentially excluding those services where market participants do not the incentive to fully contract for capacity)
- Use the IC/CC ratio to determine which slopes of the cost curve line are used to develop the POD rates. For example, instead of using the slope between 7.5 MW and 17 MW on a capital cost vs. contract capacity curve, use 9 MW to 20 MW from the Option #4 capital cost vs. installed capacity curve, where the 9 MW and 20 MW values are derived using the IC/CC ratio. The DUC submits that using the IC/CC ratio will introduce less inaccuracy to the development of the POD cost function than using Options #1 to #3 with contract capacities.
- Only use projects from the past 5 years – older project data is likely not as accurate and influenced by the accuracy of cost escalators. A valid sample set should be obtainable from using project cost data from the past ~5 years.

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

EDTI has no concerns at this time.

ENMAX Power Corporation ("EPC"):

No comment.

FortisAlberta Inc.:

No comment.

Industrial Power Consumers Association of Alberta (IPCAA):

Can the AESO provide additional information on how the curves translate into the POD portion of the tariff?

Primary Service Group ("PSG"):

No comment.

Stakeholder Comment

C. Potential evaluation criteria for cost curve options (Slides 46 – 58):

- i. *Maintaining alignment between POD cost function, maximum investment levels and the POD charge in Rates DTS and PSC;*
- ii. *Consistency with past practice (post-2007);*
- iii. *Maximize number of projects in database / statistical criteria for project inclusion;*
- iv. *Degree of relationship between installed capacity and contract capacity;*
- v. *“Lumpiness” of installed capacity and standard transformer sizes;*
- vi. *Number of assumptions required to determine installed vs contract capacity;*
- vii. *Behavior of market participant’s relationship to installed vs contract capacity;*
- viii. *Encouraging staging to contract appropriately / planned signal from contract capacity vs installed capacity;*
- ix. *Potential to eliminate substation fraction / treatment of split between DTS and STS shared costs;*
- x. *Rates reflect true costs per MW / sending the “right” price signal;*
- xi. *Equal services treated equally, unequal services treated unequally; and*
- xii. *Bridging the “gap” / fairness of treatment of customers with charges based on two different approaches.*

Alberta Direct Connect Consumers Association (“ADC”):

Does the AESO have an estimate of the difference between installed capacity and contract capacity in the provinces POD facilities? Has there been a great number of POD upgrades where the contract capacity hasn’t increased?

ATCO Electric:

No comment.

Dual Use Customers (“DUC”):

DUC submits that response to B. above best meets these criteria.

EPCOR Distribution & Transmission Inc. (“EDTI”):

No comment.

ENMAX Power Corporation (“EPC”):

No comment.

FortisAlberta Inc.:

No comment.

Industrial Power Consumers Association of Alberta (IPCAA):

The AESO has listed some fair concerns.

Primary Service Group (“PSG”):

No comment.

D. Criteria Summary / Ranking (Slides 59 – 60):

Rank	Criteria	Rate Design Principles

Stakeholder Comment		
1	<i>Maintaining alignment between POD cost function, maximum investment levels and the POD charge in Rates DTS and PSC</i>	<i>Fairness, Objectivity, and Equity Provision of Price Signals</i>
2	<i>Degree of relationship between installed capacity and contract capacity</i>	<i>Provision of Price Signals</i>
3	<i>Rates reflect true costs per MW</i>	<i>Fairness, Objectivity, and Equity Provision of Price Signals</i>
4	<i>Treatment of split between DTS and STS shared costs</i>	
5	<i>Sending the “right” price signal</i>	<i>Provision of Price Signals</i>
6	<i>Maximize the number of projects in database / statistical criteria for project exclusion</i>	<i>Fairness, Objectivity, and Equity</i>
7	<i>Fairness of treatment of customers with charges based on two different approaches, consistency with past practice (post-2007)</i>	<i>Fairness, Objectivity, and Equity Stability and Predictability</i>
8	<i>Behavior of market participants relationship to MWs</i>	<i>Fairness, Objectivity, and Equity Provision of Price Signals</i>
9	<i>Number of assumptions required to determine installed vs contract capacity</i>	<i>Fairness, Objectivity, and Equity Stability and Predictability Practicality</i>

Alberta Direct Connect Consumers Association (“ADC”):
Criteria seems reasonable.

ATCO Electric:
No comment.

Dual Use Customers (“DUC”):
DUC submits that response to B. above best meets these criteria.

EPCOR Distribution & Transmission Inc. (“EDTI”):
EDTI has no concerns at this time.

ENMAX Power Corporation (“EPC”):
No comment.

FortisAlberta Inc.:
No comment.

Industrial Power Consumers Association of Alberta (IPCAA):
These Rate Design Principles have been stated fairly.

Stakeholder Comment

Primary Service Group ("PSG"):

No comment.

E. POD Cost Function Next Steps (Slide 61):

- (1) Gather more information from stakeholders in order to develop subjective and objective comparisons of Option #1 and Option #4;**
- (2) Provide additional analysis to stakeholders on Option #1 and Option #4 to illustrate preliminary rates and investments under each option; and**
- (3) Present the AESO's position at upcoming stakeholder session in March or April.**

Alberta Direct Connect Consumers Association ("ADC"):

ADC agrees that further analysis is required before deciding on a preferred option.

ATCO Electric:

No comment.

Dual Use Customers ("DUC"):

DUC supports these next steps. The DUC asks the AESO to consider our response to B. above.

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

No comment.

ENMAX Power Corporation ("EPC"):

No comment.

FortisAlberta Inc.:

No comment.

Industrial Power Consumers Association of Alberta (IPCAA):

IPCAA supports the proposed next steps.

Primary Service Group ("PSG"):

No comment.

(3) Proposal to Apply for Interim Changes to Rider C and Deferral Account Reconciliations (Slides 63 – 80)

A. The AESO anticipates filing an application before the end of February for interim approval of changes to address the following issues (Slide 66):

- i. To reduce transfers between services in deferral account reconciliation applications:**
 - a. Determine Rider C as percentage (rather than as \$/MWh);**
 - b. Determine Rider C based on production year (rather than quarter); and**
- ii. To address issues raised by Primary Service Group in the 2015 deferral account reconciliation proceeding:**
 - a. Allocate deferral account balances on both Rate DTS and Rate PSC amounts.**

Alberta Direct Connect Consumers Association ("ADC"):

ADC supports the timely filing of the Rider C changes by the end of February and will lend its support in

Stakeholder Comment

the AUC process.

ATCO Electric:

ATCO Electric is supportive of the AESO's approach and timing towards making changes with respect to its Rider C.

Dual Use Customers ("DUC"):

DUC supports the AESO's proposal.

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

It is not clear to EDTI whether the calculation of Rider C as a percentage will be on total DTS charges or DTS charges net of pool price impacted charges such as operating reserve. EDTI is concerned that if Rider C is calculated as a percentage of total DTS charges including operating reserve, a spike in actual pool price may cause Rider C revenues to grossly exceed the forecast amounts. To avoid this potential problem, the proposal to calculate Rider C as a percentage should specify calculation based on DTS charges net of pool price impacted charges. EDTI supports this proposal subject to resolution of this concern.

ENMAX Power Corporation ("EPC"):

EPC supports changes which reduce the magnitude for Rider C.

FortisAlberta Inc.:

FortisAlberta supports calculating Rider C as a percentage of revenue rather than as \$/MWh.

FortisAlberta supports interim changes to the Rider C as long as the timing of the approval and the changes to the Rider C provides FortisAlberta with sufficient time to update, file and receive its approval from the Commission with regard to the standardized Quarterly AESO DTS Deferral Account Rider templates to accommodate the changes to Rider C.

In addition to the approval of the standardized templates, as per Decision 2012-304, FortisAlberta is directed to file its Quarterly AESO DTS Deferral Account Rider Application within 3 business days of the AESO's Rider C publication. FortisAlberta would like to ensure that any interim approvals requested by the AESO considers FortisAlberta and the other utilities' quarterly applications filing deadlines.

Industrial Power Consumers Association of Alberta (IPCAA):

IPCAA supports the AESO's proposal.

Primary Service Group ("PSG"):

The Primary Service Group supports the AESO promptly filing an application for interim approval to address the issues identified.

B. The AESO does not plan to address in its interim application the following matters raised in stakeholder comments (Slides 72-73):

- i. To determine Rider C separately for bulk system, regional system, and point of delivery rate components;***
- ii. To provide more extensive information beyond the analysis presented to stakeholders;***
- iii. To address the allocation of deferral account balances for years prior to 2017 (which is under consideration in the 2015 deferral account reconciliation proceeding);***

Stakeholder Comment

- iv. To allocate deferral account balances on amounts other than Rates DTS and PSC (such as Rate UFLS, Riders A1-A4, or payment in lieu of notice amounts); or*
- v. To modify the timing of publishing Rider C quarterly charges or credits.*

Alberta Direct Connect Consumers Association ("ADC"):

ADC agrees that the interim tariff should be limited in scope.

ATCO Electric:

ATCO Electric is supportive of the AESO's plan to exclude the above noted items as part of its Rider C process.

Dual Use Customers ("DUC"):

The DUC agrees that these issues are more appropriately dealt with in the upcoming GTA proceeding.

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

See EDTI's response to part A. EDTI requires more information regarding the calculation of Rider C as a percentage, specifically whether the calculation will be net of pool price related charges.

ENMAX Power Corporation ("EPC"):

No comment.

FortisAlberta Inc.:

No comment.

Industrial Power Consumers Association of Alberta (IPCAA):

IPCAA has no concerns with this approach.

Primary Service Group ("PSG"):

The Primary Service Group supports the AESO proposal to exclude the above issues from the interim application.

C. Application timing (Slides 74 and 79):

- i. Application would be filed at end of February;*
- ii. Interim approval would be requested by end of May;*
- iii. Interim changes to Rider C would be effective July 1, 2017; and*
- iv. Request for final approval of changes will be included in 2018 ISO tariff application.*

Do you support the AESO's plan to apply for interim changes to Rider C and deferral account reconciliations?

Support / Oppose / Indifferent

Alberta Direct Connect Consumers Association ("ADC"): **Support**

All high load factor loads incur a real cost (both in lost use of capital and foregone interest) with the current Rider C methodology. The timely change of methodology will result in a fair allocation of deferral amounts for all DTS customers.

ATCO Electric: **Support**

ATCO Electric is supportive of the AESO's plan with respect to interim changes to Rider C and deferral account reconciliations. ATCO Electric is of the view that the AESO's proposal to change Rider C

Stakeholder Comment

recovery from a \$/MWh to a Percentage basis should help reduce true-up balances amongst market participants. ATCO Electric considers, however, that it will need to review the AESO's proposal to understand the mechanics of the new Rider C calculation as it pertains to billing Transmission Direct Customers. As well, ATCO Electric will need to coordinate and be consistent with the other DFOs to make any necessary changes to the DFO's Quarterly Rider process for flowing through AESO costs.

Dual Use Customers ("DUC"): **Support**

A quick, interim solution to the Rider C issues is required. Rider C is becoming more of an issue for some DUC members. Rider C as a percentage of revenue is likely a much better way to allocate additional base rate charges / credits.

EPCOR Distribution & Transmission Inc. ("EDTI"): **Oppose**

At this time EDTI opposes the proposed interim changes to Rider C due to the concerns described in the responses to parts A and B of this section. If these concerns can be resolved to the satisfaction of EDTI then EDTI will support the AESO's plan to apply for interim changes to Rider C and deferral account reconciliations.

ENMAX Power Corporation ("EPC"): **Support**

EPC supports interim changes to Rider C effective July 1, 2107 on the assumption that the DFOs can incorporate the changes necessary to the TAC Deferral Account Reconciliation Applications to accommodate the change in Rider C from a \$/MWh to a percentage

FortisAlberta Inc.: **Support**

FortisAlberta supports the AESO's plan to apply for interim changes to Rider C as long as consideration is made for filing deadlines of FortisAlberta's Quarterly AESO DTS Deferral Account Reconciliation

Industrial Power Consumers Association of Alberta (IPCAA): **Support**

This is the fastest way to implement the proposed changes, so the AESO should move forward with this approach.

Primary Service Group ("PSG"): **Support**

The Primary Service Group supports the prompt resolution of these issues. The Group requests the AESO consider all opportunities to advance the effective date before July 1, 2017.

(4) Application Process, Timeline and Next Steps (Slides 82 – 85)

A. The AESO discussed the status of a number of 2018 ISO tariff application scope items (Slide 83) and a 2018 ISO tariff tentative timeline.

Alberta Direct Connect Consumers Association ("ADC"):

ADC supports the scope and timeline.

ATCO Electric:

ATCO Electric is supportive of the AESO's Application Process, Timeline, and Next Steps.

Dual Use Customers ("DUC"):

If possible, the DUC would like the opportunity to review the COS and rate projection models prior to the GTA filing.

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

- i. Timing of changes to calculation of Rider C - Any changes to Rider C timing needs to be

Stakeholder Comment

coordinated with timing requirements of the DFO's quarterly transmission access charge deferral account rider process (Decision 2012-304). A change to Rider C from \$/MWhr basis to a percentage basis will likely require AUC approval of corresponding changes to the DFO's quarterly transmission access charge deferral account rider process (approved in Decision 2012-304). Accordingly, a change to the calculation of Rider C with an effective date of July 1, 2017 will require approval by the AUC of any corresponding changes to the quarterly rider process prior to June 1, 2017. The AESO should inquire whether the AUC would contemplate approving changes to the quarterly rider template as part of the proceeding to decide the AESO's application for interim approval of the Rider C changes.

- ii. Timing of DAR Applications - 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).
- iii. Timing of AESO Tariff Updates and Tariff Applications - 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 or applications for interim approval of proposed rates prior to September 10th of each year to allow the DFOs to reflect the AESOs tariff update in their respective annual rate adjustment filings.

ENMAX Power Corporation ("EPC"):

No comment.

FortisAlberta Inc.:

No comment.

Industrial Power Consumers Association of Alberta (IPCAA): Support

When the AESO states: "Transmission rate projection model will be filed with the 2018 ISO tariff application" does this mean an update of the previous "TRIP model" (last updated in June 2014 and recently removed from the AESO's website) or the less robust "TRP" (introduced in 2016)?

IPCAA members support the publication of a robust transmission rate forecast.

Primary Service Group ("PSG"):

No comment.

Additional Comments

Alberta Direct Connect Consumers Association ("ADC"):

ADC appreciates the timely publishing of the Transmission rate projection model.

March 27, 2017

AESO Stakeholders
AESO 2018 ISO Tariff Consultation Participants

Dear Stakeholder:

Re: **Invitation to Participate in Consultation on AESO 2018 ISO Tariff Application**

The AESO continues to consult with market participants on the development of its next comprehensive ISO tariff application, which it now refers to as the 2018 ISO tariff application to reflect the year in which the tariff is expected to become effective (in prior stakeholder communications, this application had been referred to as the 2017 ISO tariff application). The AESO will be holding the following consultation session to provide an update on work completed to date and invites you to attend:

Date:	Monday, April 10, 2017
Time:	1:00 pm to 4:00 pm
Place:	Meeting Room 6006, 6th Floor, BP Centre, 240 – 4th Avenue SW, Calgary, Alberta. Note that the glass doors on the 6th floor are locked; please knock to have them opened.
Teleconference:	Within Calgary calling area: 403-410-3051, Conference ID 4366631 Outside Calgary calling area: 1-855-453-6957, Conference ID 4366631
RSVP:	By 5 pm on April 3, 2017 to, Tatiana Aparicio-Caris Tatiana.Aparicio-Caris@aesO.ca or 403-539-2664.

The AESO plans to discuss the following items during the meeting:

- proposed changes to the ISO Tariff's Terms and Conditions;
- cost responsibility for compliance with the Critical Infrastructure Protection ("CIP") Alberta reliability standards;
- results on the AESO's point of delivery (POD) cost function database results and analysis; and
- planned timeline and next steps for the 2018 ISO tariff application.

The AESO plans to present information on these topics to facilitate discussion and will post a presentation before the meeting. Stakeholders may provide feedback in person during the meeting or through written comments to the AESO after the meeting.

All information relating to the 2018 ISO tariff consultation is available on the AESO website at www.aesO.ca by following the path Rules, Standards and Tariff ► Stakeholder engagement ► 2018 ISO tariff application. As well, new information posted by the AESO on this topic will be mentioned in the AESO stakeholder newsletter, which you can subscribe to at the bottom right of the AESO's home page at www.aesO.ca.

Public

If you have any questions on the AESO's 2018 ISO tariff consultation, please contact me at 403-539-2555 in Calgary or by email to larhonda.papworth@aeso.ca.

Yours truly,

LaRhonda Papworth
Manager, Tariff Design

cc: Doyle Sullivan, Director – Market and Tariff Design

Consolidated Stakeholder Comments on AESO 2018 ISO Tariff Consultation Session – March 1, 2017



Background

On March 1, 2017, the AESO and stakeholders participated in a consultation meeting to discuss (1) potential changes to the ISO tariff's terms and conditions; (2) potential changes/amendments to Rider A1 – *Transmission Duplication Avoidance Adjustment Dow Chemical Canada Inc. / Dow Hydrocarbons / ASU2*; and (3) application process and next steps. The AESO invited written comments from stakeholders on the information presented at the meeting. The written comments received from stakeholders are consolidated below.

A copy of the presentation provided by the AESO at the March 1, 2017 meeting 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) ISO Tariff Terms and Conditions Proposals (Slides 6 – 30)

A. Principles for Load Customers (Slide 10):

- **Provide a price signal;**
- **System transmission facilities are not built as the result of a connection(s) not proceeding; and**
- **General high-level alignment with Decision 3473-D02-2015.**

Alberta Direct Connect Consumers Association ("ADC"):

ADC supports the principles.

AltaLink Management Ltd. ("AML"):

AltaLink agrees that load customers should have some form of a price signal that ties their commitment for connection to the system, if their connection project drives transmission system development. The price signal should not be punitive to the customer as load customers drive economic growth in the province.

Capital Power Corporation:

Capital Power has no comments at this time.

Dual Use Customers ("DUC"):

Agreed. The AESO should ensure that system transmission facilities are built in time to meet customer requirements.

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

No comments.

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

IPCAA agrees with the principles listed here..

Stakeholder Comment

TransCanada Energy Ltd. ("TCE"):

No comments.

B. Alternative Selection for Load Connections (Slides 11-13):

- **Load connection alternative must be unconstrained; and**
- **Alternative selected will be lowest overall costs alternative.**

Alberta Direct Connect Consumers Association ("ADC"):

Agree.

AltaLink Management Ltd. ("AML"):

AltaLink generally agrees that the load connection alternative must be unconstrained and will be based on the lowest overall cost. However, in determining the overall lowest cost solution, the AESO needs to consider the benefits provided to the system and therefore other customers when system related investments are part of an alternative being considered. In Alternative 2, slide 12, the \$60M represented by "2" provides benefits to customers connected to both the right and left of the connection, as the investment is a networked system asset. The benefits to the network, the region and to the customers in the region should all be considered in the selection process. AltaLink does not agree with the view that in Alternative 2 the customer being connected receives the only benefit.

Capital Power Corporation:

Capital Power wishes to better understand the AESO's proposal for connection alternative selection as presented on Slides 11-13, particularly in respect to whether or not the proposal is consistent with previous determinations of the Commission regarding transmission rights in Alberta. Capital Power requests more details from the AESO regarding its proposal and the rationale behind the proposed change.

Dual Use Customers ("DUC"):

Appears to align with T-reg..

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

The AESO clarified at the meeting that cost is not the only factor it considers when selecting a preferred alternative. Other factors include environmental and social impacts. Also, when considering locations of new transmission facilities or enhancements of existing facilities, section 15.1(2)(b) of the *Transmission Regulation* require the ISO to consider maximizing the efficient use of right of ways, corridors or other routes that already contain or provide for utility or energy infrastructure. A more accurate statement than "Alternative selected will be lowest overall costs alternative" would be "The total project cost, including both participant-related and system-related component costs, will be used for the purpose of cost comparisons."

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

IPCAA has no major concerns with this..

TransCanada Energy Ltd. ("TCE"):

.

C. System Transmission Facilities Required for a Load Connection – "Filed System NID" (Slides 14 – 16):

- **AESO is proposing to change language in the ISO tariff terms and conditions to add**

Stakeholder Comment

clarity regarding “long term transmission system plan” and “as the ISO reasonably expects will be required in the future” (section 8, subsection 3(3)(b)).

Alberta Direct Connect Consumers Association (“ADC”):

No comment.

AltaLink Management Ltd. (“AML”):

The AESO has the responsibility to forecast the future requirements for the transmission system. The long term plan is the forecast of that future and there is uncertainty around this forecast. A connecting customer should not be penalized for any inaccuracy in the AESO’s forecast. In other words, the connecting customer should not bear the cost of uncertainty in the AESO’s forecast.

As the demand in a region grows there will be a requirement for transmission infrastructure which should be reflected in the AESO’s long term plan. If a customer wants to be connected and their load requirements have been generally incorporated into the AESO’s long term transmission plan from a load growth forecast or through ongoing discussions with the AESO that the customer’s load is specifically included in the AESO’s load growth forecast, the AESO should accommodate the customer without any additional costs to the customer other than their own connection costs. If the customer’s load has not been incorporated into the AESO’s long term plan then there should be a cost to the customer for advancing the transmission system infrastructure.

Capital Power Corporation:

Capital Power has no comments at this time.

Dual Use Customers (“DUC”):

The DUC is uncomfortable with tariff terms like “reasonably expects”. What requirements exist for the AESO to initiate a system NID?

EPCOR Distribution & Transmission Inc. (“EDTI”):

No comments.

Industrial Power Consumers Association of Alberta (“IPCAA”):

Does the AESO plan on elaborating on what “reasonably expects” means? Are there any quantifiable metrics associated with this term?

TransCanada Energy Ltd. (“TCE”):

TCE supports the AESO’s proposal to provide additional clarity and looks forward to reviewing the AESO’s proposed language.

D. System Transmission Facilities Required for a Load Connection – with a Filed System NID (Slide 17):

- a. Market participant can wait for build?***
- b. If not, a System NID with date driven milestones – customer would pay advancement costs calculated in accordance with current ISO tariff provisions***
- c. If not, and a System NID without date driven milestones – customer would pay “commitment” charge***

Alberta Direct Connect Consumers Association (“ADC”):

No comment.

Stakeholder Comment

AltaLink Management Ltd. (“AML”):

AltaLink agrees that if the customer’s load was not included in the AESO’s long term planning process, the customer should pay for advancing an already identified system project with a NID in service date or planned milestone driven in service date in order to meet the customer’s earlier project ISD. The commitment charge must be refundable once their project has been energized. See AML’s comments to C above.

The AESO should consider updating its plan on an annual basis for ISDs which would set a reasonable expectation for connecting customers.

Capital Power Corporation:

Capital Power has no comments at this time.

Dual Use Customers (“DUC”):

Unlike generation customers, load customers typically can’t wait for service. One bad experience should not cause an overreaction. Perhaps the AESO should review project management practices to ensure that system facilities are not built in advance of need. The DUC does not object to having connecting customers pay deposits for advancing system projects, within commercially reasonable parameters.

EPCOR Distribution & Transmission Inc. (“EDTI”):

No comments..

Industrial Power Consumers Association of Alberta (“IPCAA”):

Is the AESO concerned that this new process will encourage customers to be more aggressive about their in-service dates in order to avoid advancement costs and commitment charges?

IPCAA agrees that customers should be accountable for building what they say they will build. Particularly when other ratepayers are taking on system costs on their behalf..

TransCanada Energy Ltd. (“TCE”):

TCE is of the view that the AESO should provide the necessary information to market participants that would allow them to make an informed decision whether they should wait for a system build or not. The necessary information would include both the cost to advance or accelerate a project and the time that a market participant may have to wait for the system facilities to be built. In those cases where an existing NID does not have date-driven milestones, TCE understands that the NID will have MW-driven milestones. In this circumstance, TCE submits that the AESO should provide a forecast as to when it expects the MW-driven milestones to be met.

TCE will be able to provide further comments once the AESO provides clarity as to the details of the “commitment charge”.

E. *Concept 1: System Transmission Facilities Required for a Load Connection – without a Filed System NID (Slides 18 - 21):*

- a. *Market participant can wait for build?***
- b. *If market participant can wait for system development (with milestones), the system transmission development will be initiated upon market participant’s energization;***
- c. *If market participant cannot wait for system development (with milestones), market participant pays a **refundable deposit** in order to provide “sufficient certainty” of project going ahead.***

Stakeholder Comment

i. Market participant will be refunded deposit upon connection project energization

Alberta Direct Connect Consumers Association (“ADC”):

No comment, might be valuable to test the concept with a load that is looking to build or has recently built and can identify how this may have been viewed for their project..

AltaLink Management Ltd. (“AML”):

AltaLink generally agrees with customer costs being tied to the NID being filed by the AESO and supports a fully refundable deposit (including carrying costs). If a deposit is required, the deposit should be determined based on a percentage of the amount of the forecast incremental system project costs due to advancing the system project, not the entire system project costs, and should be refundable upon the customer signing a DTS contract. The AESO should consider staging the deposit to align with the actual incurrence of incremental project costs, not a lump sum at the start.

AltaLink’s support of these principles relies upon the AESO initiating timely need project applications to meet the forecast planning of the transmission system per their long term plans.

Capital Power Corporation:

Capital Power has no comments at this time.

Dual Use Customers (“DUC”):

The DUC is not comfortable with the “Filed System NID” test / concept. The DUC prefers Concept 2 over Concept 1 at this time.

EPCOR Distribution & Transmission Inc. (“EDTI”):

In situations where system development is required to meet a customer’s load connection, but there is no system NID currently filed, all options appear to have the AESO create a system NID separate from the customer connection NID (slides 18-26). An additional option would be for the system component to be included in the customer connection NID and include a portion of the system component cost in the financial security currently required by the market participant as per Section 5 of the existing T&Cs. This would achieve the same objectives as the two concepts proposed at the session, but require fewer changes to the existing approved T&Cs.

Industrial Power Consumers Association of Alberta (“IPCAA”):

This is an interesting test to apply. What happens when the customer project has been in the works for a while, and perhaps should have triggered a system NID, but the AESO did not consider the project “real” enough to warrant a system NID being filed?

What level of refundable deposit would this be? Does the AESO have an estimate or range available for discussion purposes?

TransCanada Energy Ltd. (“TCE”):

Please define “sufficient certainty”.

TCE will be able to provide more comments regarding Concept 1 once the AESO provides clarity as to the terms of the proposed refundable deposit and of the refund. With respect to the deposit, TCE is interested in knowing what the AESO is proposing in terms of the magnitude, timing and form of payment that would be required. With respect to the refund, TCE is interested in knowing the proposed timing of the refund and, in the case where the market participant’s project does not energize, whether the AESO would propose that the market participant receive a refund (or partial refund) if the system facilities

Stakeholder Comment

become needed at some future point in time.

F. *Concept 1: Refundable Deposit* – What does it provide for the AESO? (Slide 21):

- a. *Provides “sufficient certainty” that connection project will energize;***
- b. *Will not build system transmission assets that will not be used;***
- c. *Provides a price signal where there is limited capacity; and***
- d. *Only applies when the market participant cannot wait for system transmission facilities.***

Alberta Direct Connect Consumers Association (“ADC”):

No comment.

AltaLink Management Ltd. (“AML”):

AltaLink agrees that if the customer is required to pay any advancement costs, they should be 100% refundable upon the customer signing a DTS contract.

Capital Power Corporation:

Capital Power has no comments at this time.

Dual Use Customers (“DUC”):

Please see response to E. above.

EPCOR Distribution & Transmission Inc. (“EDTI”):

See comments to E.

Industrial Power Consumers Association of Alberta (“IPCAA”):

See comments above.

TransCanada Energy Ltd. (“TCE”):

No comments.

G. *Concept 1: Refundable Deposit* – Pros and Cons (Slide 22):

Pros:

- a. *Strong price signal if market participant cannot wait;***
- b. *Aligns with Generator Unit Owner’s Contribution (“GUOC”) incentives, (i.e. “performance” = “energization”);***
- c. *Encourages timely energization as the AESO is holding a large deposit;***
- d. *The market participant can choose to wait or stage their contract to accommodate current system capacity and system facilities construction will begin after connection project energization.***

Cons:

- e. *System transmission facility costs might be prohibitively high;***
- f. *Delay in cost estimates (may not occur until the creation of the system NID).***

Alberta Direct Connect Consumers Association (“ADC”):

No comment.

AltaLink Management Ltd. (“AML”):

Stakeholder Comment

See AltaLink's comments in F.

Capital Power Corporation:

Capital Power has no comments at this time.

Dual Use Customers ("DUC"):

Please see response to E. above.

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

See comments to E.

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

See comments above.

TransCanada Energy Ltd. ("TCE"):

When the AESO states "[e]ncourages timely energization as the AESO is holding a large deposit", is the AESO referring to the timely energization of the market participant's project or the system project? If the latter, please explain the rationale for the statement.

H. *Concept 2: System Transmission Facilities Required for a Load Connection – without a Filed System NID (Slides 23 - 24):*

- a. *Market participant can wait for build?***
- b. *If market participant can wait for system development (with milestones), the system transmission development will be initiated upon market participant's energization;***
- c. *If market participant cannot wait for system development (with milestones), market participant pays a "sufficient certainty charge" in order to provide "sufficient certainty" of project going ahead.***
 - i. *System transmission facilities will be initiated upon receipt of the "sufficient certainty charge".***

Alberta Direct Connect Consumers Association ("ADC"):

This method seems to strike the right balance of protecting customers from projects that are not advanced, while not being a barrier for new load to grow in the province..

AltaLink Management Ltd. ("AML"):

AltaLink does not support any concept where the customer pays an amount for certainty that is not refundable. Additionally, it would be very difficult for the AESO to determine the amount of a fair "sufficiency charge" given the high degree of uncertainty of the overall cost and timeline to build the system (filing of applications, approvals and construction) without a filed System NID.

AltaLink would be very concerned with the punitive price signals that this may send to load customers and the disincentive this will create in Alberta for economic growth from connecting load customers. Please see AltaLink's response to C above.

Capital Power Corporation:

Capital Power has no comments at this time.

Dual Use Customers ("DUC"):

Please see response to E. above.

Stakeholder Comment

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

See comments to E.

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

What level of sufficient certainty charge would this be? Does the AESO have an estimate or range available for discussion purposes?

TransCanada Energy Ltd. ("TCE"):

TCE will be able to provide more comments regarding Concept 2 once the AESO provides clarity as to the terms of the proposed sufficient certainty charge. TCE is interested in knowing what the AESO is proposing in terms of the magnitude, timing and form of payment that would be required.

I. Concept 2: Sufficient Certainty Charge – What does it provide for the AESO? (Slide 25):

- a. Restores a reasonable balance between certainty and price signals;**
- b. Provides the AESO with sufficient certainty that the connection project will energize;**
- c. May calculate in accordance with the current tariff provisions;**
- d. Provides a price signal where there is limited capacity;**
- e. Only applies when the market participant cannot wait for system transmission facilities; and**
- f. Intended to address system build required that is not anticipated or planned in the AESO near-term planning horizon (5 years).**

Alberta Direct Connect Consumers Association ("ADC"):

No comment.

AltaLink Management Ltd. ("AML"):

See AltaLink's response to H above.

Capital Power Corporation:

Capital Power has no comments at this time.

Dual Use Customers ("DUC"):

Please see response to E. above.

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

See comments to E.

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

See comments above.

TransCanada Energy Ltd. ("TCE"):

No comments.

J. Concept 2: Sufficient Certainty Charge – Pros and Cons (Slide 26):

Pros:

- a. Market participant pays a share of the system transmission facilities for causing advancement of unplanned facilities;**
- b. Strong price signal if market participant cannot wait;**

Stakeholder Comment

- c. *The market participant can choose to wait or stage their contract to accommodate current system capacity (considering forecast growth) and system facilities construction will begin after connection project energization.***

Cons:

- d. *“Sufficient certainty charge” cost might be high.***

Alberta Direct Connect Consumers Association (“ADC”):

No comment.

AltaLink Management Ltd. (“AML”):

See AltaLink’s response to H above.

Capital Power Corporation:

Capital Power has no comments at this time.

Dual Use Customers (“DUC”):

Please see response to E. above.

EPCOR Distribution & Transmission Inc. (“EDTI”):

See comments to E.

Industrial Power Consumers Association of Alberta (“IPCAA”):

See comments above.

TransCanada Energy Ltd. (“TCE”):

No comments.

K. *Tariff Alignment – Other items (Slides 28 - 29):*

- 1. *Advancement costs apply to ally system transmission facilities required for a load connection, not solely radial facilities planned to be looped (section 8, subsection 3(3)(b));***
- 2. *“Accelerated construction costs” as contemplated in Decision 3473-D02-2015;***
- 3. *Filed system NID (with MW milestones) required, current tariff refers to the long-term plan, or as ISO reasonable expects will be required in the future;***
- 4. *Differentiation between generation and load connections; and***
- 5. *“Shared with system” cost provisions.***

Alberta Direct Connect Consumers Association (“ADC”):

No comment.

AltaLink Management Ltd. (“AML”):

AltaLink is unclear of what the AESO is requesting as it relates to these Other Items and therefore has no specific additional comments.

Capital Power Corporation:

Differentiation between load and generation connections must prevail.

Dual Use Customers (“DUC”):

No comment at this time.

Stakeholder Comment

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

No comments.

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

IPCAA has no comments at this time.

TransCanada Energy Ltd. ("TCE"):

The AESO has presented two concepts to address accelerating system projects. TCE recommends that the AESO include both options in its tariff. The financial positions and circumstances of AESO's load customers vary significantly. Including both options in the tariff may allow a market participant to accelerate a system project, whereas limiting the tariff to only one of the options may unnecessarily preclude this.

L. Next Steps (Slide 30)

- **Allow stakeholders to review presentation and concepts;**
- **Gather stakeholder feedback and incorporate in to further work;**
- **Follow up in next stakeholder session; and**
- **Work towards recommended approach for application.**

Alberta Direct Connect Consumers Association ("ADC"):

ADC will review the concepts at our next Board meeting and provide any further thoughts at the next stakeholder session..

AltaLink Management Ltd. ("AML"):

AltaLink recommends that the AESO incorporate stakeholder feedback into a recommended approach and provide an explanation for those stakeholder suggestions not adopted. This should then enable a future effective stakeholder session prior to finalizing its decision on this matter.

Capital Power Corporation:

Capital Power notes verbal indication from the AESO at the March 1, 2017 stakeholder session that the AESO generally agrees with the views of the Commission presented in Section 6.7 of Decision 3473-D02-2015 concerning the application of advancement costs to generators, specifically that system project advancement costs should not be applied to generators. For clarity, Capital Power requests that the AESO confirm its position on the application of system advancement costs to generators at its next stakeholder session and include discussion of the item in its written presentation materials. Capital Power considers the issue of applying system project advancement costs to generators closed and does not support re-opening the issue in the 2018 GTA.

Dual Use Customers ("DUC"):

We look forward to reviewing additional material on this topic.

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

No comments.

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

IPCAA would be happy to invite the AESO to present at a Board meeting to run these concepts by members directly. It would be beneficial to have estimates of potential deposits and charges for customers to consider.

Stakeholder Comment

TransCanada Energy Ltd. ("TCE"):

No comments.

(2) Rider A1 – Dow Chemical Canada Inc. / Dow Hydrocarbons / ASU2 Changes (Slides 31 – 33)

A. Rider A1 – Dow Duplication Avoidance Tariff (DAT) Issues (Slide 32):

- **Rider A1 is inconsistent with other Rider A's with language and detail;**
- **Forecast benefit table ends in 2021 – what happens after 2021; and**
 - **25-year (approx.) business case assumption in original application does not reflect the expectation of asset life for a transmission line.**
- **What is required in the ISO tariff to provide clarity on future duplication avoidance sites' treatment.**

Alberta Direct Connect Consumers Association ("ADC"):

ADC submits that the circumstances that arose to justify this treatment still exist and that the table should be updated to reflect the life of the assets.

AltaLink Management Ltd. ("AML"):

AltaLink has not had time to consider this issue fully and will provide the AESO comments in the future should we have any.

Capital Power Corporation:

Capital Power has no comments at this time.

Dual Use Customers ("DUC"):

The DUC submits that a Rider A should result in tariff treatment as if the transmission substation and/or line was built and remains in service. Under no circumstances should net metering/totalization cease at the end of a Rider A term. If the Rider A transmission facilities are equivalent to "customer owned" assets, then the customers should be responsible for maintenance and losses costs. If equivalent to "system" assets, then all AESO customers should be responsible for maintenance and losses costs. The DUC submits that it may be appropriate to re-evaluate maintenance costs and losses costs at the end of a Rider A term, and set for another term, e.g. 20 years.

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

No comments.

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

IPCAA has no comments at this time.

TransCanada Energy Ltd. ("TCE"):

No comments.

B. Rider A1- Dow Duplication Avoidance Tariff (DAT) – Next Steps (Slide 33):

- 1. The AESO plans to update Rider A1 to authoritative language;**
- 2. High-level test of some criteria considered in original AEUB decision U98125 (available capacity, credible bypass threat, and service life of transmission facilities);**
- 3. Consideration of Rider A1 continuing to a reasonable expected transmission life period**

Stakeholder Comment

with recovery of O&M and losses annual/monthly payments from Dow; and

4. Add “expiry” or “term” to clarify what happens after a certain date, i.e. re-application for duplication avoidance tariff? Other?

Alberta Direct Connect Consumers Association (“ADC”):

While the transmission service is in place, it should retain the same treatment without need to reapply..

AltaLink Management Ltd. (“AML”):

See comments above.

Capital Power Corporation:

Capital Power has no comments at this time.

Dual Use Customers (“DUC”):

1. No issues with updating language, if intent is not altered.
2. The “test” was performed when the Rider was approved. A “re-test” concept is inappropriate and would meet with highest level of objection from the DUC. Retroactive rate making should not be considered.
3. See comments to under A. above
4. See comments to under A. above. The DUC would object to any tariff terms that would result in loss of net metering/totalization and at any time prior to the customer’s facilities being removed from transmission service.

EPCOR Distribution & Transmission Inc. (“EDTI”):

No comments.

Industrial Power Consumers Association of Alberta (“IPCAA”):

IPCAA has no comments at this time.

TransCanada Energy Ltd. (“TCE”):

No comments.

(3) Application Process, Timeline and Next Steps (Slides 34 – 39)

A. The AESO discussed the status of a number of 2018 ISO tariff application scope items (Slide 36) and a 2018 ISO tariff tentative timeline.

Alberta Direct Connect Consumers Association (“ADC”):

ADC is supportive of the timeline and scope items..

AltaLink Management Ltd. (“AML”):

No comments.

Capital Power Corporation:

Capital Power understands that the AESO will be holding a future stakeholder session to review its work to date addressing direction from Commission regarding cost recovery from Critical Infrastructure Protection (CIP) and looks forward to participating.

Dual Use Customers (“DUC”):

Stakeholder Comment

No comments.

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

It is difficult to provide fulsome comments on proposed changes to the Terms and Conditions without reviewing a draft of the proposed changes. Additional consultation will likely be needed once revised T&Cs have been drafted.

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

Thank you for the update.

TransCanada Energy Ltd. ("TCE"):

No comments.

Additional Comments

Capital Power Corporation:

Capital Power has no additional comments at this time.

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

None at this time.

AESO 2018 ISO Tariff Consultation

April 10, 2017
AESO Office, Calgary

- Introduction and objectives (slides 1-5)
- ISO Tariff Terms and Conditions Proposals (slides 6-29)
 - Certainty Charge Workshop (slides 30-36)
- POD Cost Function Database (slides 37-46)
- Transmission Cost Causation Study follow-up (slides 47-53)
- Critical Infrastructure Protection (“CIP”) Alberta reliability standards cost responsibility (slides 54-56)
- Application process and next steps (slides 57-63)
- Discussion and wrap-up (slide 64)

Please feel free to ask questions during presentation

Stakeholder session objectives

- Enhance understanding of ISO tariff application
- Review technical results of a number of analytical exercises by the AESO
- Share information prior to filing of 2018 ISO tariff application
- Gather feedback to ensure tariff application provides all information stakeholders require
- Review application timeline and next steps

Applications currently in progress

- Directions 5-8 on advancement costs and related provisions
 - Decision 3473-D02-2015 issued on August 26, 2015
 - AUC letter issued March 29 “Issues list and closure of Proceeding 20922”
 - “...*the Commission has determined that matters anticipated to be addressed within proceeding 20922 should instead be considered as part of a comprehensive tariff application*”
- 2015 Deferral Account Reconciliation application
 - Hearing held on December 13 and 14, 2016
 - Decision 21735-D02-2017 issued on March 14, 2017, ordered that the application is approved as filed.
 - “...*the Commission directs the AESO to address whether changes to the deferral account allocation methodology and to Rider C are warranted given the concerns raised by the PS Group, as part of its next ISO tariff application*”

Applications currently in progress

- 2017 ISO tariff update
 - Interim, refundable approval for January 1, 2017 issued by Commission on December 2, 2016
 - Commission final decision 22093-D02-2017 issued on April 4, 2017 approving 2017 rates and investment levels as filed
- Upcoming Rider C Amendment application
 - Amending Rider C to apply to Rate PSC, *Primary Service Credit*, change to percentage charge or credit and restore deferral account balance to zero at the end of the calendar year
 - AESO now planning to file Rider C Amendment application in April 2017
 - The AESO will request an effective date of July 1, 2017 but given the delay in filing, the AESO will be able to handle a mid-quarter change to Rider C methodology, i.e. August 1, 2017

ISO Tariff Terms and Conditions Proposals

Lee Ann Kerr

Public

Proceeding 20922 Closure March 29, 2017

Commission “Issues List”

#	Issue
Issue 1	Legislative framework
Issue 2	Advanced system-related classification of radial transmission projects
Issue 3	Load forecasting

Commission “Issues List”

Issue 1 - Legislative framework

- The Commission suggests that one way to interpret the legislation is that there is a distinction between the construction of transmission to serve generation and to serve forecast load
- The planning restrictions affect the ability of the AESO to set and alter in-service dates, affecting the cost of achieving its congestion and planning mandates

Issue 2 – advanced system-related classification of radial transmission projects

- The “in-advance system-related classification” can affect the magnitude and timing of entry into the transmission system by load customers
- A market participant may have an incentive to overstate its long-term requirements as it is not responsible for system-related costs
- The AESO should balance between the preferences for certainty among market participants and the desire to minimize the costs of transmission development

Commission “Issues List”

Issue 3 - Load forecasting

- “Because the information used by the AESO for transmission system planning and development decisions currently relies on information provided by the large industrial customer group, the forecast inaccuracy identified by interveners could be related to the incentives built-in to the provision of information to the AESO”
- There is no financial reason for the market participant to be accurate or conservative when providing forecast information
- Establish a target rate of load growth? Load connections who want to connect more quickly can do so only if there is no net cost to other market participants

Other Commission Decisions

Decision	Summary
2005-096	“The underlying purpose of the contribution policy is to send price signals (reflective of the AESO’s economics) to market participants when they are considering siting alternatives for their facilities.”
2005-096	“With respect to the request of AE that the Board should provide clear directions respecting the classification of system and customer costs, the Board considers that the AESO should approach any situation in which there may be “shades of grey” in this designation exercise, with the position that a debatable interconnection project cost should be presumed initially to be customer-related unless clearly demonstrated otherwise.”
2005-096	“The Board, however, considers that a general stance that system enhancement costs are customer costs unless demonstrated otherwise is consistent with the expectation that the AESO adopt a more proactive stance in respect of its overall system planning and transmission system upgrade responsibilities, as detailed in the <i>Transmission Regulation</i> .”

Other Commission Decisions(cont'd)

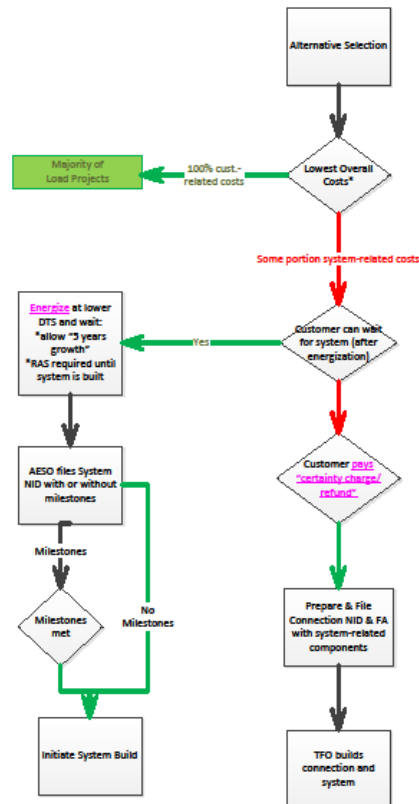
Decision	Summary
2010-606	“The Commission considers that Article 9.3(c)(ii) of the current T&Cs provides a reasonable balance between the attribution of incremental costs caused by a connecting customer and the designation of costs as system costs where the AESO was already contemplating a system planning driven expenditure prior to the connection request. Article 9.3(c)(iii) already provides broad discretion to designate costs that would otherwise be classified as customer costs to be classified as system costs.”
3473-D02-2015	“...the Commission intended that the AESO would develop tariff provisions that would induce the market participant on the critical path to either consent to a shifting of the requested in-service date or absorb relevant incremental costs that would arise from a decision not to shift the requested in-service date.”

Principles for Load Customers

- Provide a price signal
 - Unconstrained alternative selection
 - ISDs for system transmission projects should be moved if they can't be met without incurring significant increases to project costs (or the market participant can pay)
 - Where the construction of system transmission facilities are triggered, the market participant needs to provide some form of commitment
- System transmission facilities aren't built as the result of a connection(s) not proceeding
 - We need sufficient certainty that projects will “show up”
 - Don't construct system transmission facilities if market participants don't show up
- Alignment with Commission's issue list (Proceeding 20922)

System Transmission Facilities Required for a Load Connection

Certainty for LOAD



*All things being equal

Certainty

See pdf file “Certainty for Load” for larger image

Alternatives to connect to transmission system

- a) most load connection projects will be radial facilities to existing transmission facilities with capacity
 - b) in some cases load connection projects may require an enhancement of existing system facilities or creation of looped facilities
- Load connection alternative must be unconstrained and
 - Alternative selected will be lowest overall costs

Market participant can wait for system or pay certainty charge/refund

If lowest overall costs alternative requires some portion system-related costs, customer has a choice

1. Energize at lower DTS and wait for system to be built
 - Will require market participant to lower DTS request and allow “5 years of growth” in the area (planning horizon), energize and upon energization AESO can plan system development
 - RAS will be required on the market participant until system is built

or

2. Customer pays a certainty charge/refund to ensure that at their energization, there are no constraints on the transmission system

“Refundable Deposit” – What does it provide for the AESO?

- Provides the AESO with sufficient certainty that the connection project will energize
- Not building system transmission assets that will not be used
 - If market participant does not show – no refund
 - If market participant only partially shows up (lower DTS), only partial refund
- Provides a price signal where there is limited capacity
- Only applies when the MP can't “wait” for system transmission facilities

Pros and Cons – Refundable Deposit

- Pros
 - Strong price signal (if you can't wait)
 - Aligns with GUOC incentives (“performance” = “energization”)
 - Encourages timely energization (the AESO is holding a large deposit)
 - The MP can choose to “wait”, stage their contract to accommodate current system capacity and construction will begin after energization
- Cons
 - System transmission facility costs might be prohibitively high
 - Delay in cost estimates (creation of system NID)

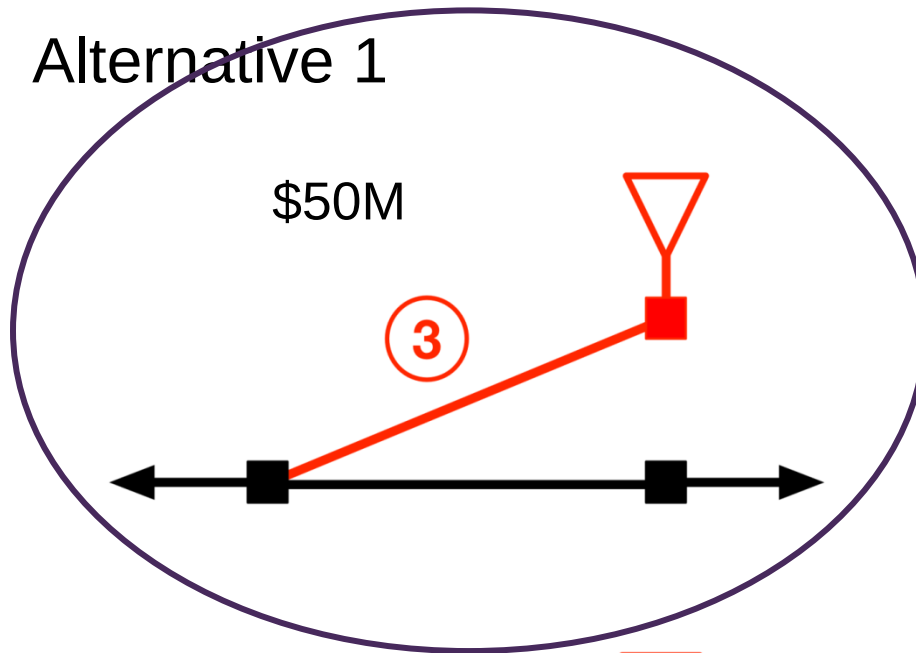
System Transmission Facilities Required for a Load Connection

Option	Pros	Cons	Overall Score
Charge \$/MW	- Easy to understand - Avoids “true” advancement cost calculation	- Facilities may be built and not used - Cliff between waiting and not - MP “pay’s” for system facilities - Sunk costs, MP might “sit”	
Charge Adv. Cost	- Aligns with existing provision - 5 years aligns PILON/planning horizon - Very strong price locational signal (drives economic efficient outcome) - Difficult to determine “actual” adv. Costs - Perception that they are paying for system_in advance	- Facilities may be built and no used - Cliff between waiting and not - MP “pays” for system facilities - Sunk costs, MP might “sit” - Based on O&M cost estimate (+50/-50)-consultant prepared?	
Refund Full System	- No system facilities build that won’t be used/paid for - somewhat strong locational price signal - Avoids MP contributions to system facilities cost - encourages timely energization - Avoids “true” adv. costs calculation	- Delay in cost estimates in order to determine refundable charge - Who holds the \$	
Refund \$/MW	- Like GUOC - Easy to understand - Avoids MP contributions to system facilities cost - Encourages timely energization - Avoids “true” advancement cost calculation	- Facilities may be built and not used	
Refund Adv. Cost	- Somewhat aligns with existing provision - 5 years aligns with PILON/planning horizon - Avoids MP contributions to system facilities cost - Encourages timely energization	- Facilities may be built and not used	

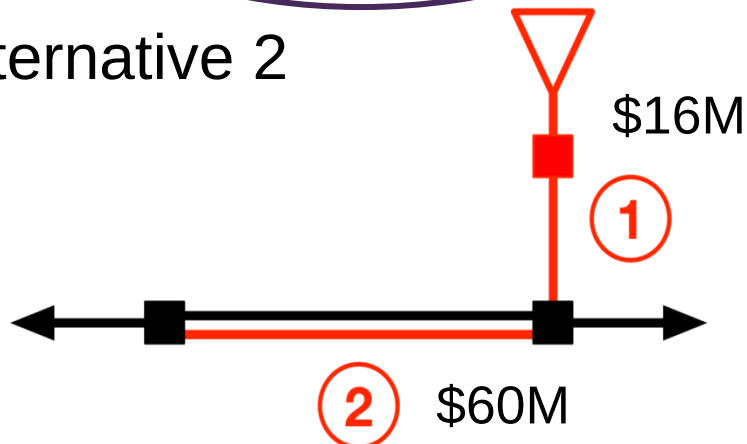
Increasing shade is higher score

Alternative Selection - “Lowest Overall Costs”

Alternative 1



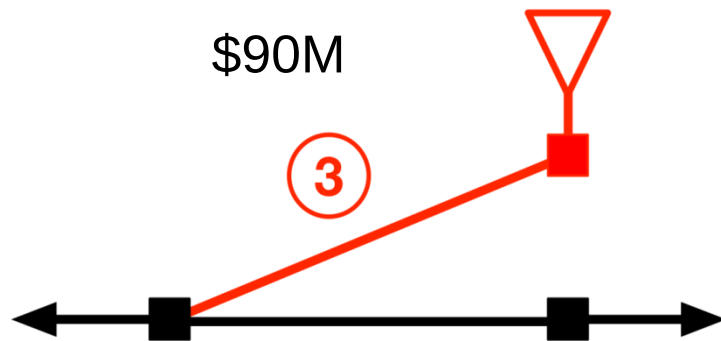
Alternative 2



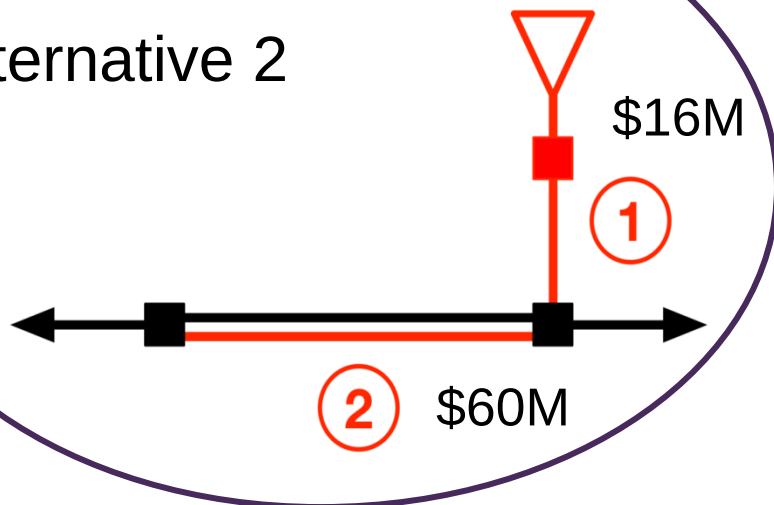
- Both Alternative 1 and 2 are unconstrained
- Alternative 1 is a radial connection to a strong source
- Alternative 2 is a radial to a weaker source ① with a required system upgrade ②
- Alternative selection would result in Alternative 1 as it is the lowest overall costs (system upgrade required)

Alternative Selection - “Lowest Overall Costs”

Alternative 1

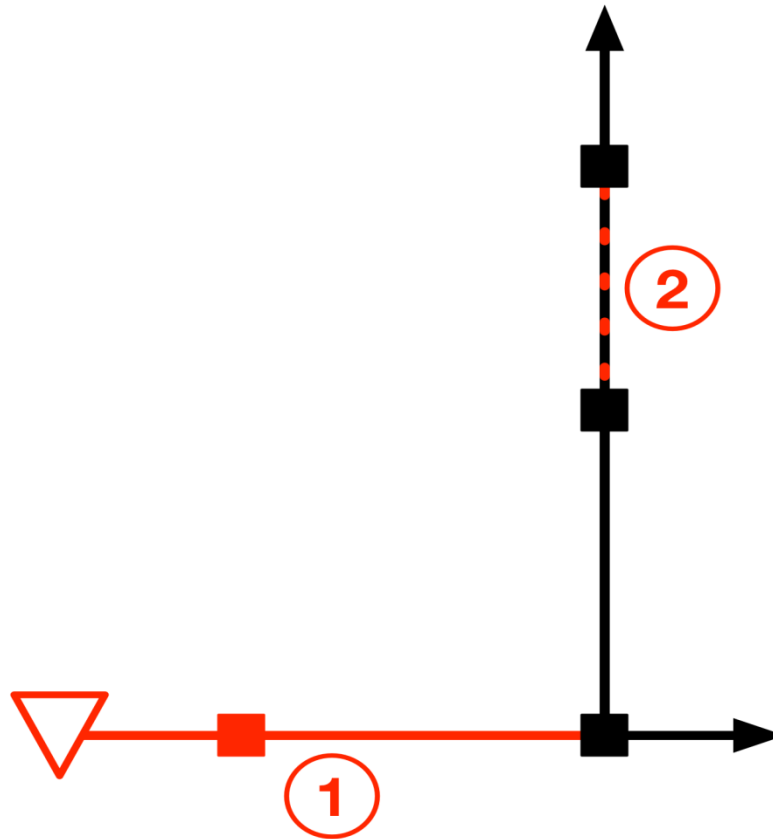


Alternative 2

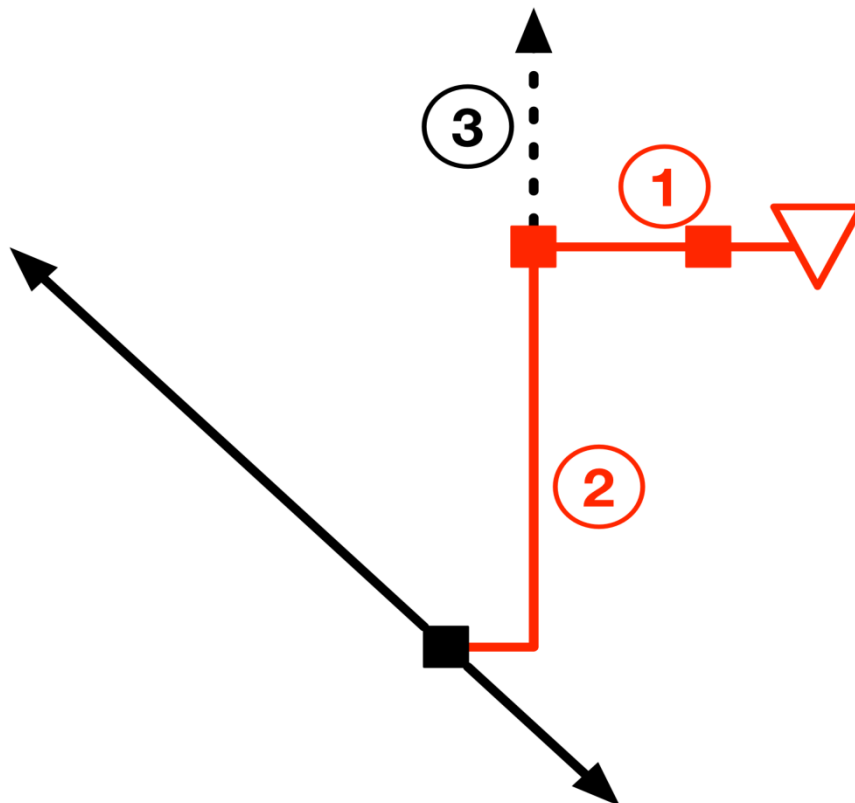


- Both Alternative 1 and 2 are unconstrained
- Alternative 1 is a radial connection to a strong source
- Alternative 2 is a radial to a weaker source ① with a required system upgrade ②
- Alternative selection would result in Alternative 2 as it is the lowest overall costs (with system upgrade required)

Example – Wait or Pay



Examples – Initially Radial then “Shared”



Changes to Sections 4, 5, 8 & 9: What are we proposing to add?

- New provisions that identify how the AESO will determine the preferred alternative
 - Constraint/congestion free
- Revised practices for system access (to replace the AESO's "Practices for System Access Service")
- Defining and enforcing critical requirements for a SASR
 - MWs, in-service date, location
- Identify when connection projects give us "sufficient certainty" that they will materialize
 - Example: GUOC payment, REP award, energization, "load certainty charge"
- New provisions around advancement costs and "accelerated construction" charges

Changes to Sections 4, 5, 8 & 9: What are we proposing to add? (cont'd)

- Differentiation between generation and load
 - New provisions for dual use customers?
- “Shared with system” cost provisions
- Connection that are initially radial are 100% participant-related costs, to be “shared” if loop is closed

Changes to Sections 4, 5, 8 & 9: What are we proposing to revise/remove?

- Remove any provisions that are duplicative of the legislation, Rules, Reliability Standards
- Language in Section 8 referring to a “contiguous” connection project
- Remove provision referring to “planned to be looped” as system-related cost
 - Advancement costs will apply to all system transmission facilities required for a load connection
- Remove connection process references
- Revisit the “Good Electric Industry Practice” to reflect the AESO’s minimum requirements

Other Terms and Conditions Proposals

- Section 1 - Applicability and Interpretation of ISO Tariff
 - Legal review
 - Ensure no duplication of legislation, rules, reliability standards
- Section 2 - Provision of and Limitations to System Access Service (may merge Sections 2 - 4)
 - Make distinction between load and generation
 - Add t-tap expectation of service
 - Remove outage provisions (covered in ISO Rules)
- Section 3 - System Access Service Connection Requirements (may merge Sections 2 - 4)
 - Remove technical requirements (covered in ISO Rules)
 - Move compliance requirements to section 2

Other Terms and Conditions Proposals (cont'd)

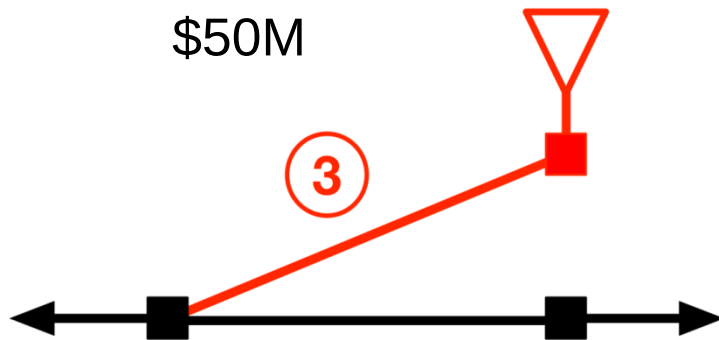
- Section 5 - Financial Obligations for Connection Projects
 - Legal Review
 - Ensure no duplication of other authoritative documents
- Section 6 - Metering
 - Remove altogether (covered in ISO Rules)
- Section 7 - Provision of Information by Market Participants
 - Review for duplication of ADs and legislation
- Section 10 - Generating Unit Owners Contribution
 - Add GUOC rates to the tariff

Other Terms and Conditions Proposals (cont'd)

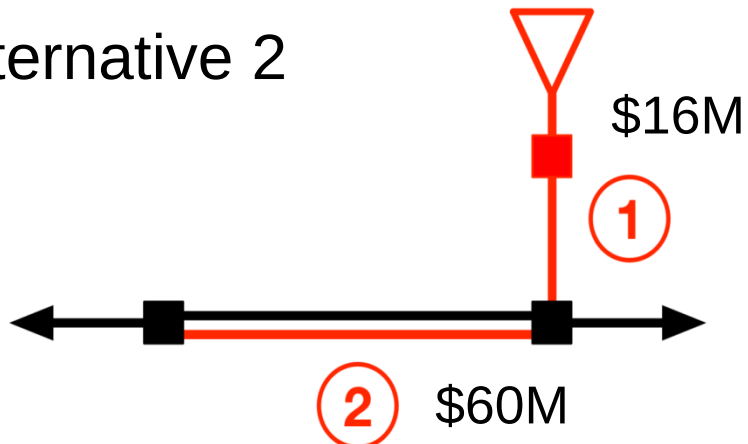
- Section 11 - Ancillary Services
 - No changes proposed
- Section 12 - Demand Opportunity Service
 - No changes proposed
- Section 13 - Financial Security, Settlement and Payment Terms
 - Duplication with ISO Rules?
- Section 14 Peak Metered Demand Waivers
 - No changes proposed
- Section 15 Miscellaneous
 - Confirm with legal

Workshop

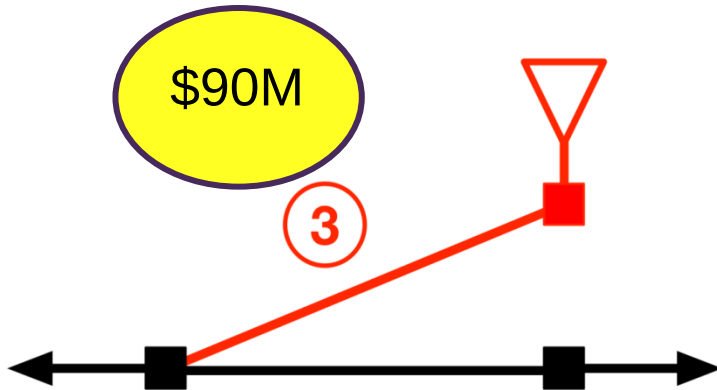
Alternative 1



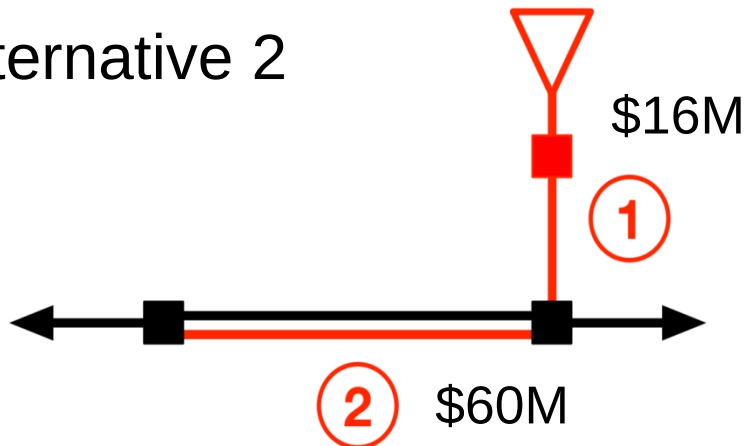
Alternative 2



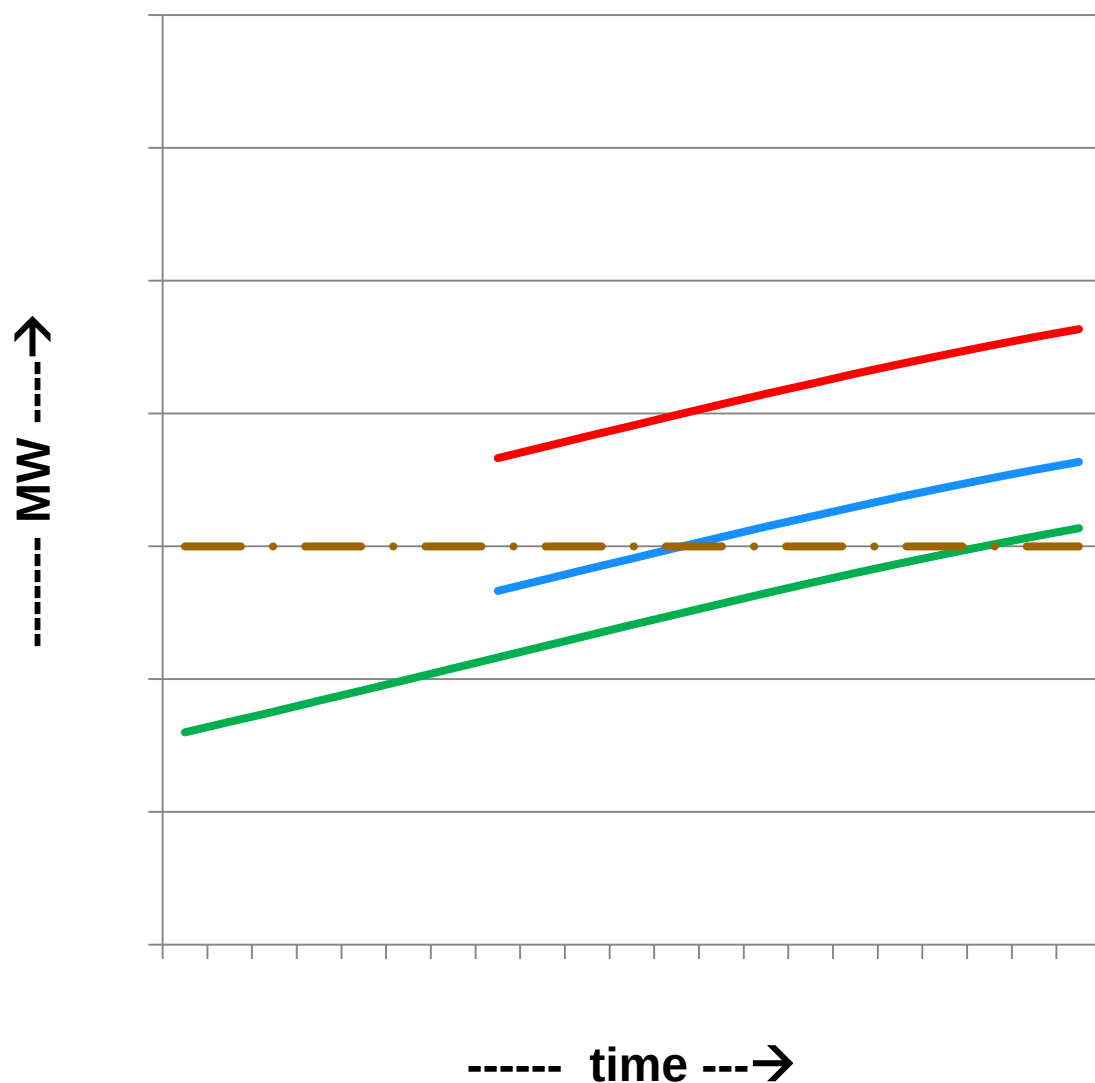
Alternative 1a



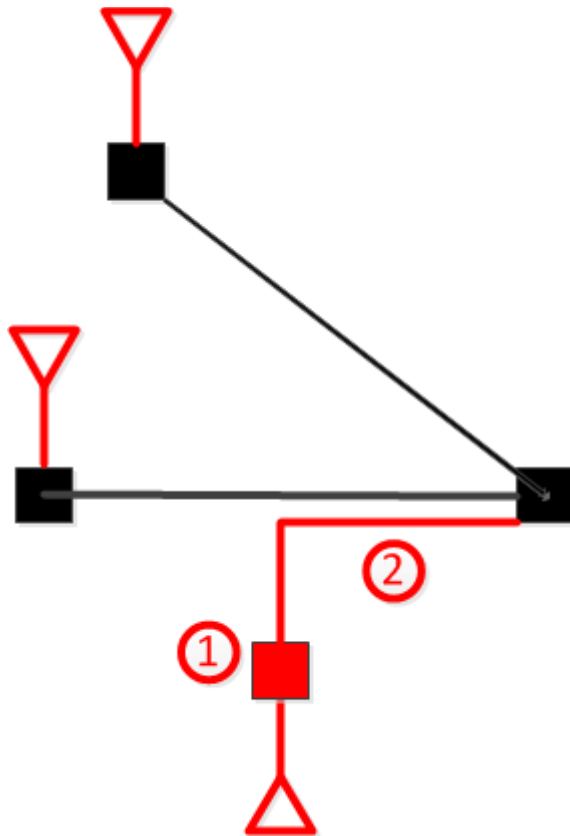
Alternative 2



Example 1 (cont'd)

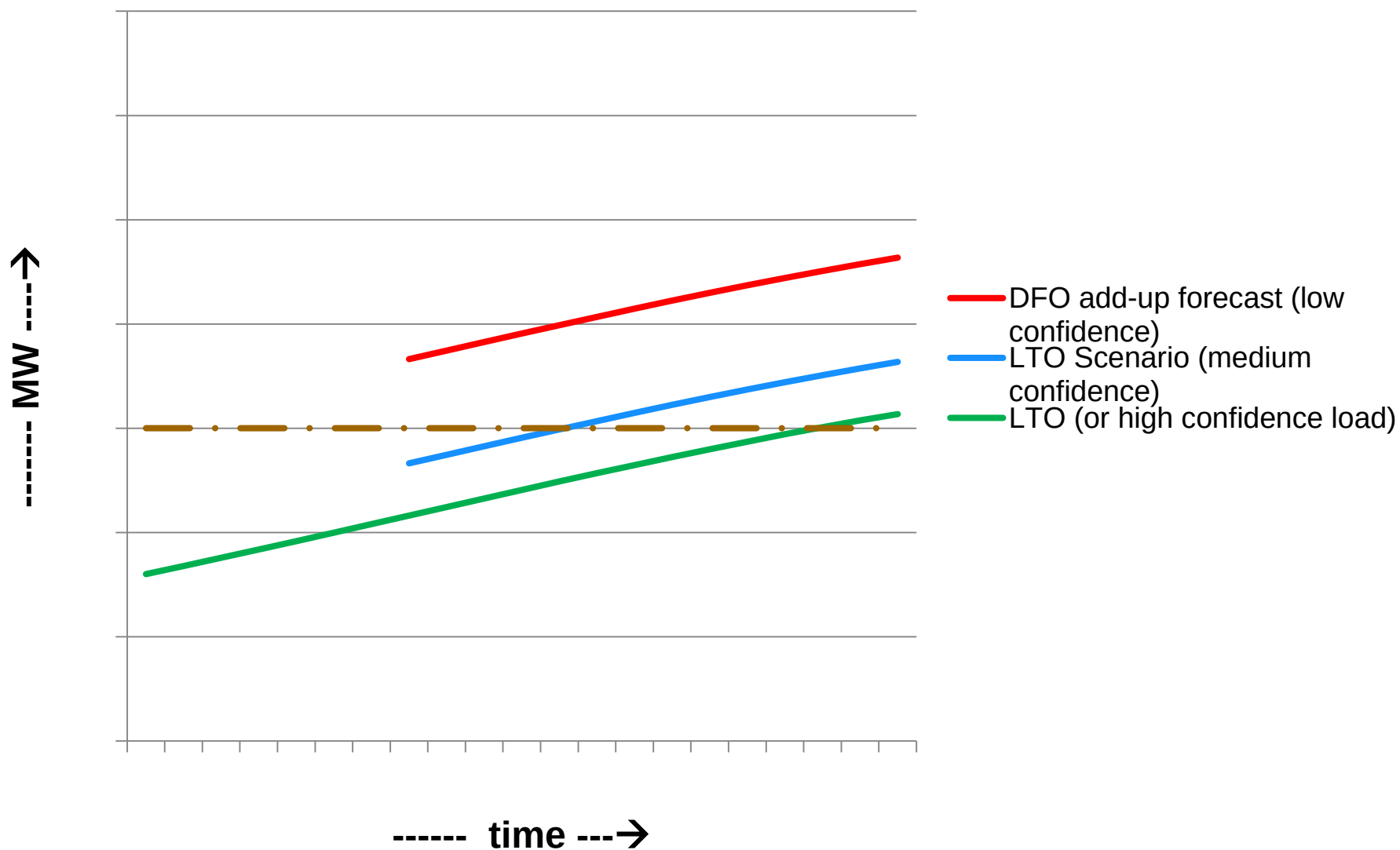


- Market Participant requests 90 MW DTS for 2019
 - Available additional capacity by 2024 is 40 MW
- Original DTS Request
— MP requests reduced DTS
— LTO (or high confidence load)
— Area Capacity



- If all 3 projects energize, system component ② is required.
- If only 2 projects energize and 1 project cancels, system component ② is not required.

Example 2 (cont'd)



Next Steps

- Allow stakeholders to review presentation and concepts and provide feedback
- Prepare application with revised terms and conditions

POD Cost Function Database

LaRhonda Papworth

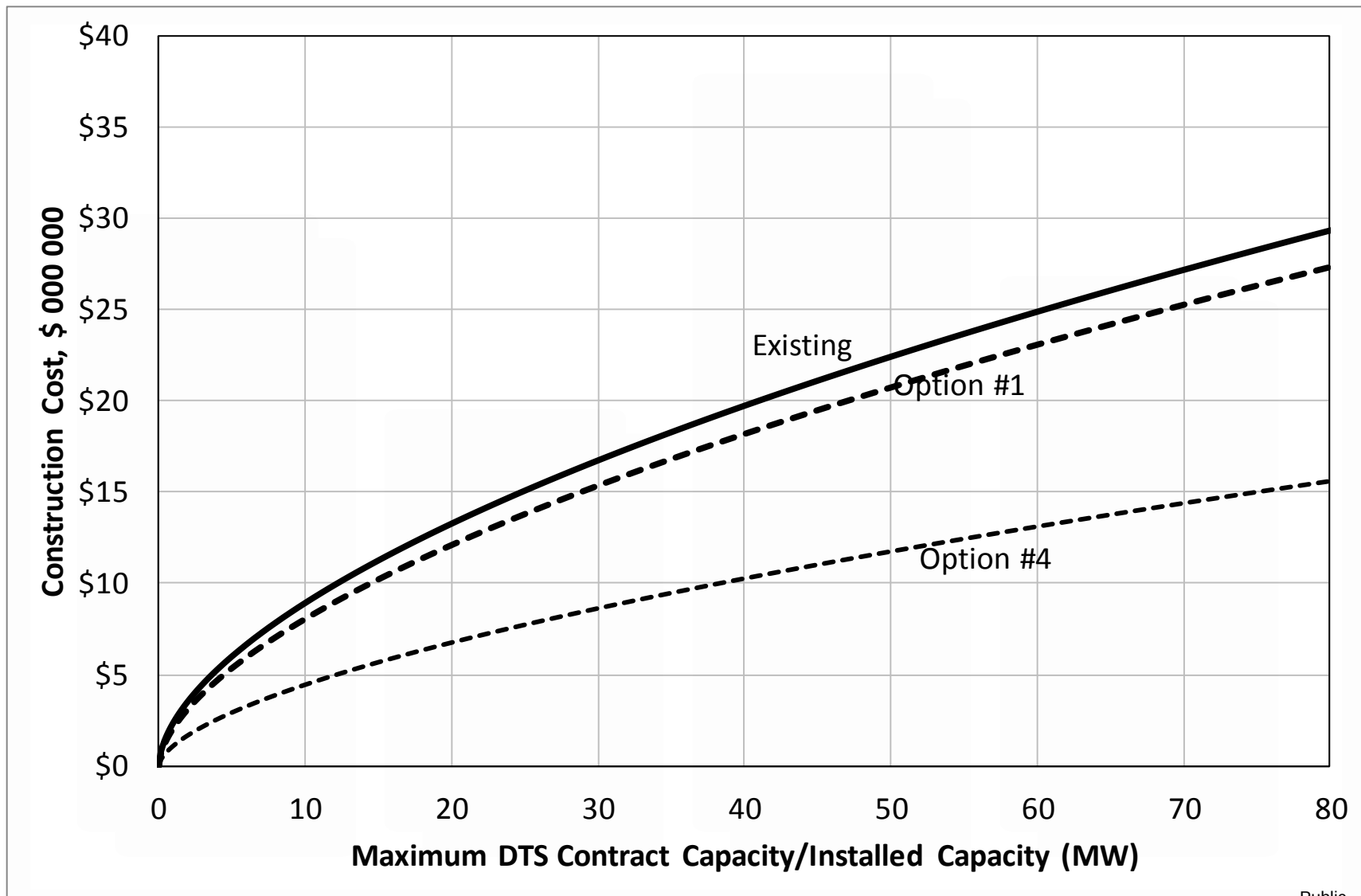
POD cost function database input into cost curves

- POD cost function database includes connection project (demand only) attributes: cost data, contract levels, installed capacity, connection type, location, substation number, project type, etc.
- For the 2018 tariff application, AESO will update POD cost function database with projects data since last update in 2014
- After Decision 2014-242 and Decision 3473-D01-2015 from the Commission in regards to project inclusion and criteria, the AESO was directed to “use ‘Greenfield and Update Excluding 0 MW’ until the matter can be thoroughly explored”
 - contract vs installed capacity
 - upgrade projects with 0 MW increase

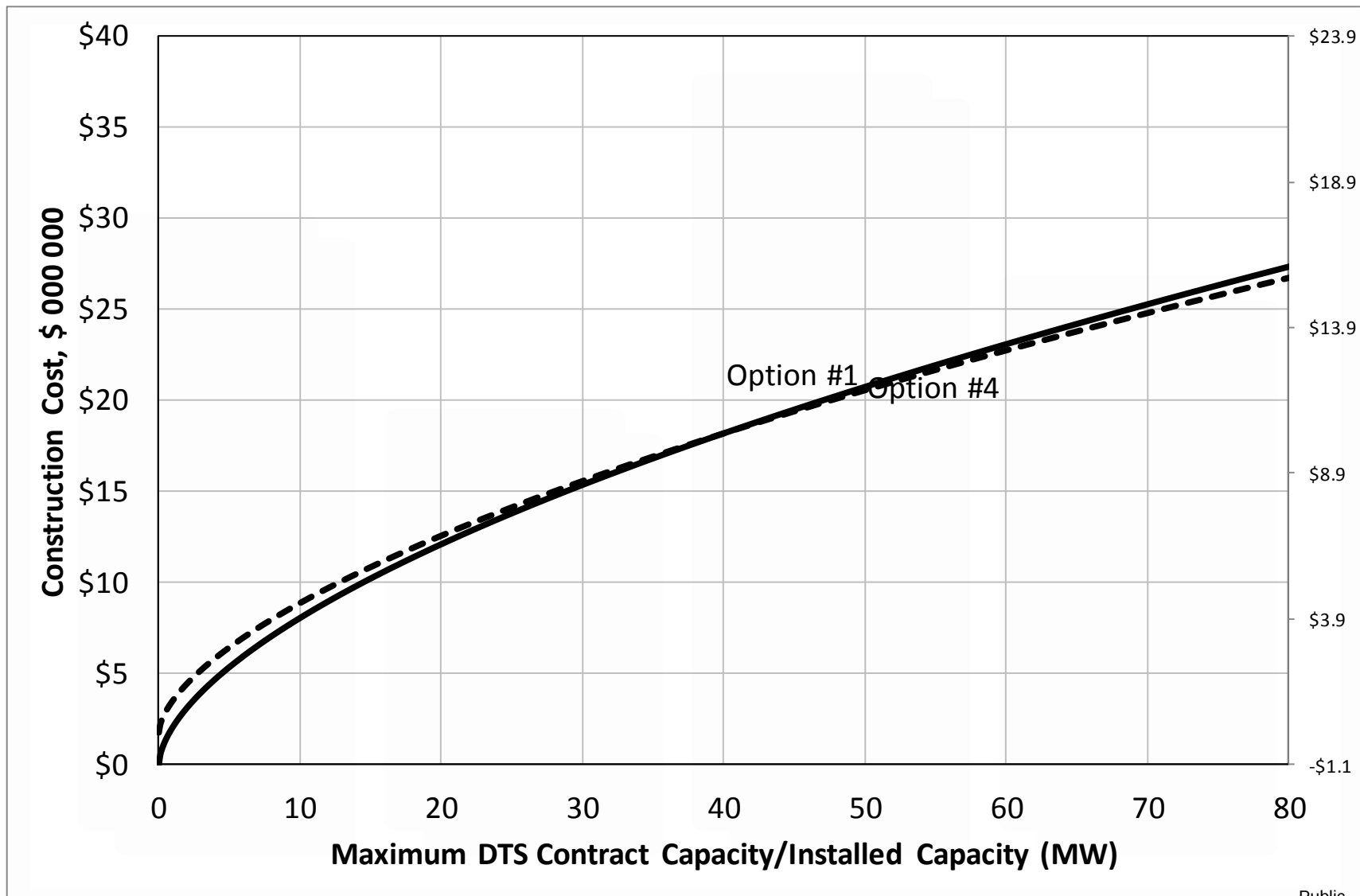
POD cost function database – cost curves

Cost Curve Options	Greenfield	Upgrade	0 MW Contracts
#1 Pre-2014 Practice	Contract	Contract	Include
#2 Current Practice (until thoroughly explored)	Contract	Contract	Remove
#3 As requested in Decision 2014-242	Contract	Installed	By using installed, 0 MW projects <u>are</u> included
#4 Not asked	Installed	Installed	
#5 ~~AESO not considering~~ (Not asked, not debated)	Installed	Contract	?

Comparison of Options to Existing (2014 ISO Tariff) Cost Function Curve



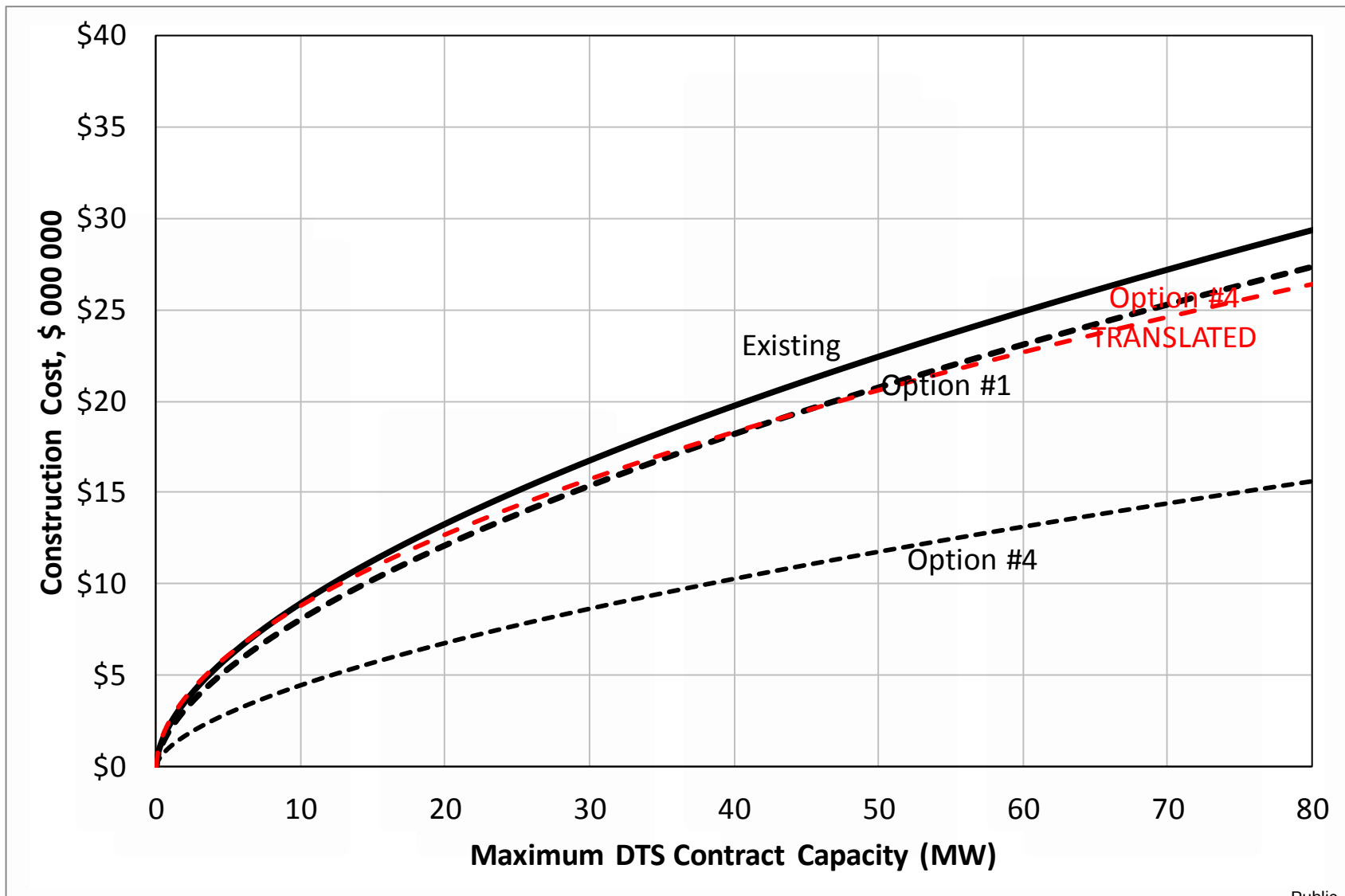
Comparison of Options - Shape



Translated Installed Capacity to Contract Capacity – X axis

- In order to continue to bill based on contract capacity, the cost curve x-axis for installed capacity must be “translated” to contract capacity
- In other words, create the exact same shape and dimensions as previous graph Option #4 which can be graphed against Option #1 without altering the secondary vertical axis

Comparison of Options to Existing (2014 ISO Tariff) Cost Function Curve



Criteria Summary

Criteria	Option #1	Option #4
Variability of relationship between installed capacity and contract capacity		
Number of assumptions and reasonableness of assumptions		
Fairness of treatment of customers with charges based on two different approaches (intergenerational equity)		
Reflect actual cost drivers of projects	R2 = 0.35	R2 = 0.37

Increasing shade is more positive

Impact on POD Rates

POD Charge	2017 ISO Tariff	Option #1 – est.*	Option #4 – est.*
Customer X SF	\$8,789/month	\$8,353/month	\$10,986/month
<= 7.5 MW	\$3,559/MW	\$3,616/MW	\$3,687/MW
>7.5 to <=17 MW	\$2,229/MW	\$2,306/MW	\$2,196/MW
>17 to <=40 MW	\$1,555/MW	\$1,633/MW	\$1,476/MW
>40 MW	\$1,007/MW	\$1,070/MW	\$914/MW

* Estimated using proposed transmission cost study results for 2018 and 2017 wires costs and 2017 billing determinants

POD Cost Function

Next Steps

- Proceed with rates calculations based on Option #1
- Continue to work on translation of Installed Capacity cost curve to a Contract Capacity cost curve to provide analysis to Commission in application in order to thoroughly explore the matter
- Application will include analysis of all 4 options:
 - Option #1 – Contract capacity for both greenfield and upgrade projects, including 0 MW upgrade projects
 - Option #2 – Contract capacity for both greenfield and upgrade projects, excluding MW upgrade projects
 - Option #3 – Contract capacity for greenfield and installed capacity for upgrade projects
 - Option #4 – Installed capacity for both greenfield and installed capacity for upgrade projects

Transmission Cost Causation Study Follow-up

Raj Sharma

Public

Preliminary 2018-2020 Functionalization

Year/Function	Bulk	Regional	POD
2016	59.2%	21.6%	19.2%
2018	53.4%	26.3%	20.3%
2019	55.0%	25.1%	19.9%
2020	53.7%	26.2%	20.1%

Regional System Additions in 2020

- Downtown Calgary (P1456) – about \$145 million
- Grande Prairie (P1784, P1785) – about \$75 million
- Central East (PENV, P1781) – about \$280 million potentially moving to post 2020

Classification by Minimum System Approach

- Demand related cost as ratio of minimum system cost and optimal system cost
- 138kV: minimum system is 1x266 ACSR and optimal system is 1x477 ACSR
- 240kV: minimum system is 2x795 ACSR and optimal system is 2x1033 ACSR
- 500kV: minimum system is 2x2156 ACSR and optimal system is 3x1590 ACSR

Classification Calculations

- Normalize cost to single circuit for 138kV
- Normalize cost to double circuit for 240kV
- Escalate cost to common test year*

Regional System Classification

Conductor	1x266 ACSR	1x477 ACSR
2019 \$ per km	487,202	537,349

Class	Demand	Energy
2014-2016	87.4%	12.6%
2018-2020	93.3%	6.7%

Bulk System Classification

Conductor	2x795 ACSR	2x1033 ACSR
2019 \$ per kM	1,764,083	2,306,910

Class	Demand	Energy
2014-2016	93.1%	6.9%
2018-2020	78.2%	21.8%

Critical Infrastructure Protections (“CIPs”) Cost Recovery

LaRhonda Papworth

Public

- Alberta reliability standard – *Cyber Security – BES Cyber System Categorization CIP-002-AB-5.1* is planned to be come effective on October 1, 2017
- TransAlta's Sundance Facility (units 1-6) would be the only aggregated generating facility classified with a Medium Impact Rating and would be then subject to additional expenditures
- In Proceeding 3443, the Commission directed the AESO to:

“Address as part of its next general tariff application, the issue of cost responsibility for compliance with the CIP Alberta reliability standards. The AESO's application must either state that the AESO is including any such costs in its proposed tariff as recoverable under the AESO's tariff pursuant to section 30(2)(iv) of the *Electric Utilities Act*, or that the AESO does not propose that some or all of such costs are recoverable through its proposed tariff.”

AESO's Proposed Position in Upcoming Application



- Not recoverable under tariff; generators should be individually responsible for the costs of complying with Alberta Reliability Standards, including CIPs
 - Based on AESO's internal FEOC assessment (costs that are directly assigned to the market participant are more efficient than if they are socialized)
 - Consistent with the treatment of other Alberta reliability standards that provide a benefit to the AES and all market participants
- AESO's rationale included in application, may include evaluation of tariff, cost causation and FEOC principles

Application Process, Timeline and Next Steps

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- “In order to present a manageable set of issues, the Commission considers it may be helpful to parties if certain scope issues are communicated to market participants in advance of the submission of the ISO’s tariff application. The scope issues include consideration of issues that arose out of Proceeding 20922 and also incorporate issues that were raised in subsequent proceedings, since Proceeding 20922 was initiated. However, parties are not limited or constrained in any way from submitting evidence on the issues identified below or on any other issues of significance to the operation and construction of the ISO tariff.”

To be investigated after 2018 ISO Tariff Application

- Capacity market cost recovery
- Coincident metered demand as billing determinant for bulk recovery charges
- Export rates

Will be addressed in application but with no proposed changes in rates or terms and conditions in 2018 ISO Tariff Application

- Energy storage tariff
- Isolated generation connections

March 1, 2017 Session – Stakeholder Comments Review

- Rider A1 – Dow - General agreement to approach the AESO is proposing to include in application
 - Revise Rider A1 in ISO Tariff to add clarity regarding the life of the duplication avoidance tariff (DAT) and include a high-level assessment of the continued applicability of the DAT
 - Extend forecast benefit to reflect life of the assets so that O&M and losses payments (only) continue in an extended payment table
- Application preview session will be an opportunity for the AESO to share the complete scope of changes proposed to the ISO tariff
 - Due to the amount time required for legal and language review, the exact provisions will only be provided in the application to the Commission, not in the application preview

Checklist for 2018 ISO tariff application

Scope item	Status
Rider C / DAR / Tariff updates	100% complete
POD cost function work	100% complete
Transmission cost causation study	100% complete
Terms and conditions including Sections 4, 5, 8 and 9	80% complete
Clarify tariff for energy storage	100% complete
Updates to Proformas	100% complete
Clarify Rider A-1 – Dow duplication avoidance tariff	100% complete
Address direction from Commission regarding cost recovery from Critical Infrastructure Protection (CIP) work	100% complete
Long-term transmission rate projection model	75% complete

Tariff tentative timeline

Session	Date
Application Preview Session	June 2017
Application writing	Q2 2017
Application filing	Q2 2017
2016 DAR Filing	Q3 2017
2018 tariff <u>update</u> application	Q3 2017
Regulatory review process for 2018 tariff application	Q4 2017 – Q1 2018
Compliance filing	Q2 2018

Next steps

- The AESO will invite participants to respond to this presentation through a comment matrix in the next few weeks. To allow transparency, the AESO will post all comments on AESO's website following the receipt of participants' input
- For more information:
 - LaRhonda Papworth – Manager, Tariff Design
 - 403-539-2555
 - larhonda.papworth@aeso.ca
- All consultation documents can be found on AESO website at www.aeso.ca by following the path:
 - Rules, Standards and Tariff ► Stakeholder engagement
 - 2018 ISO tariff application

Further Discussion? Questions?

Request for Stakeholder Comments on AESO 2018 ISO Tariff Consultation

Background

On April 10, 2017, the AESO and stakeholders participated in a consultation meeting to discuss (1) proposed changes to the ISO tariff's terms and conditions; (2) cost responsibility for compliance with the Critical Infrastructure Protection ("CIP") Alberta reliability standards; (3) results on the AESO's point of delivery ("POD") cost function database results and analysis; and (4) application process and next steps. Based on discussion at the meeting, the AESO invites written comments from stakeholders on the information presented. The meeting presentation is posted on the AESO website and can be accessed at www.aeso.ca by following the path: Rules, Standards and Tariff ► Stakeholder engagement ► 2018 ISO Tariff Application.

Please use the comment form below when submitting comments to the AESO on the 2018 ISO tariff consultation. Please ensure that your comments represent all interests within your stakeholder organization with respect to the consultation. Please provide comments or questions no later than **May 2, 2017**, to LaRhonda Papworth at larhonda.papworth@aeso.ca or 403-539-2555.

Consultation and Stakeholder Identification

Date of Request for Comments:	April 18, 2017
Period of Consultation:	November 15, 2016 – April 18, 2017
Comments From:	
Date:	
Contact:	
Phone:	
Email:	

Stakeholder Comments on AESO Information

Stakeholder Comment
(1) ISO Tariff Terms and Conditions - Proposals (Slides 6 – 36)
A. Proceeding 20922 Closure Letter, March 29, 2017 (Slides 7-10): Issue 1: Legislative framework; Issue 2: Advanced system-related classification of radial transmission projects; and Issue 3: Load forecasting
Stakeholder Comments:
B. Other Commission Decisions (Slides 11-12)

Stakeholder Comment

Stakeholder Comments:

C. Principles for Load Customers (Slide 13):

- *Provide a price signal;*
 - *System transmission facilities are not built as the result of a connection(s) not proceeding; and*
 - *Alignment with Commission's issue list (Proceeding 20922).*
-

Stakeholder Comments:

D. System transmission facilities required for a load connection (Slides 14-19):

- *Alternative selection for load connections (Slide 15);*
 - *Market participant can wait for system or pay certainty charge/refund (Slide 16);*
 - *"Refundable deposit" – What does it provide for the AESO? (Slide 17);*
 - *Pros and cons – "refundable deposit" (Slide 18); and*
 - *Options (Slide 19)*
-

Stakeholder Comments:

E. Alternative selection example 1 – "lowest overall costs" (Slides 20-23):

- *Diagram - Alternative 1 is "lowest overall costs" (Slide 20);*
 - *Diagram - Alternative 2 is "lowest overall costs" (Slide 21); and*
 - *Diagrams - Other examples (not discussed) (Slides 22-23).*
-

Stakeholder Comments:

F. Changes to Sections 4, 5, 8 & 9: What are we proposing to add? (Slides 24-25):

- *New provisions that identify how the AESO will determine the preferred alternative;*
 - *Revised practices for system access (to replace the AESO's "Practices for System Access Service");*
 - *Defining and enforcing critical requirements for a SASR;*
 - *Identify when connection projects give us "sufficient certainty" that they will materialize;*
 - *New provisions around advancement costs and "accelerated construction" charges;*
 - *Differentiation between generation and load;*
 - *"Shared with system" cost provisions; and*
 - *Connections that are initially radial are 100% participant-related costs, to be "shared" if loop is closed.*
-

Stakeholder Comments:

G. Changes to Sections 4, 5, 8 & 9: What are proposing to revise/remove? (Slide 26):

Stakeholder Comment

- *Remove any provisions that are duplicative of the legislation, rules, & reliability standards;*
- *Remove “contiguous” in Section 8 referring to a “contiguous” connection project;*
- *Remove provision referring to “planned to be looped” as system-related cost;*
- *Remove connection process references; and*
- *Revisit the “Good Electric Industry Practice” to reflect the AESO’s minimum requirements.*

Stakeholder Comments:

H. Other terms and conditions proposals (Slides 27-29):

- **Section 1 – Applicability and interpretation of ISO Tariff;**
 - *Legal Review*
 - *Ensure no duplication of legislation, rules, or reliability standards*
- **Section 2 – Provision of and Limitations to System Access Service (may merge Sections 2 – 4);**
 - *Make distinction between load and generation*
 - *Add t-tap expectation of service*
 - *Remove outage provisions (covered in ISO rules)*
- **Section 3 – System Access Service Connection Requirements (may merge Sections 2-4);**
 - *Remove technical requirements (covered in ISO rules)*
 - *Move compliance requirements to Section 2*
- **Section 5 – Financial Obligations for Connection Projects;**
 - *Legal review*
 - *Ensure no duplication of other authoritative documents*
- **Section 6 – Metering;**
 - *Remove altogether, covered in ISO rules*
- **Section 7 – Provision of Information;**
 - *Review for duplication of authoritative documents and legislation*
- **Section 10 – Generating Unit Owners Contribution;**
 - *Add GUOC rates to the ISO tariff*
- **Section 11 – Ancillary Services;**
 - *No changes proposed*
- **Section 12 – Demand Opportunity Service;**
 - *No changes proposed*
- **Section 13 – Financial Security, Settlement and Payment Terms;**
 - *Duplication with ISO rules?*
- **Section 14 – Peak Metered Demand Waivers; and**
 - *No changes proposed*
- **Section 15 - Miscellaneous;**
 - *Confirm with legal review.*

Stakeholder Comment

Stakeholder Comments:

I. Workshop Slides (Slides 30-36):

- Repeated from Slides 20-21 (Slides 31-32);
- Example 1 background, area load, and area load forecasts (Slide 33);
- Example 2 diagram and background (Slide 34); and
- Example 2 area load and area load forecasts (Slide 35).

Stakeholder Comments:

J. Terms and Conditions' Changes – Next Steps (Slide 36):

- Allow stakeholders to review presentation and concepts, and provide feedback;
- Prepare application with revised terms and conditions.

Stakeholder Comments:

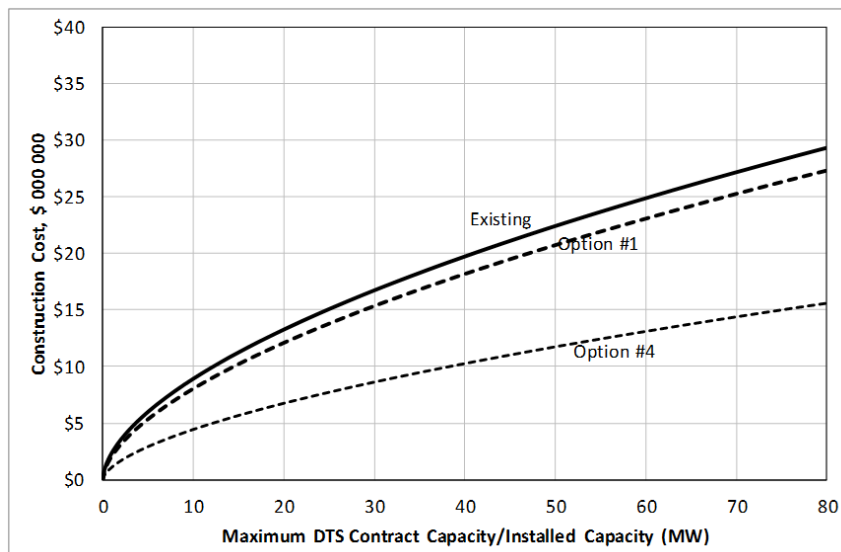
(2) POD Cost Function Database (Slides 37 – 46)

A. POD cost function database input into cost curves and options (Slides 38-39):

- AESO was directed to “use ‘Greenfield and Update Excluding 0 MW’ until the matter can be thoroughly explored” (Slide 38);
- AESO thoroughly exploring four options (Slide 39).

Stakeholder Comments:

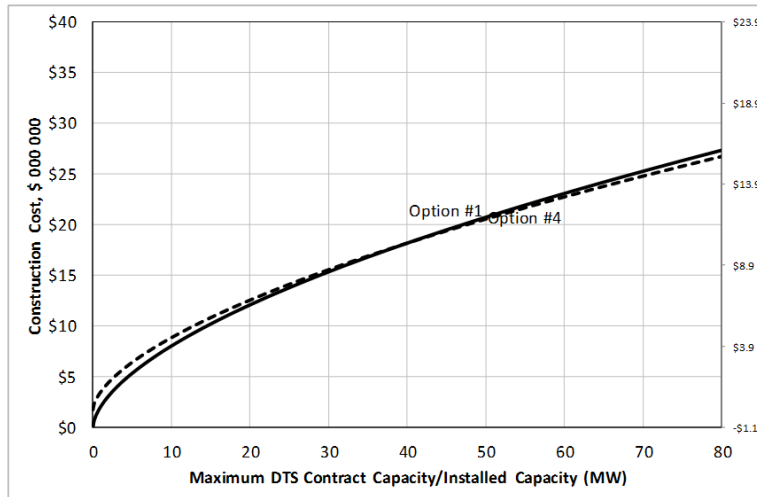
B. Comparison of options to existing (2014 ISO Tariff) Cost Function Curve (Slide 40):



Stakeholder Comment

Stakeholder Comments:

C. Comparison of options shape (Slide 41):



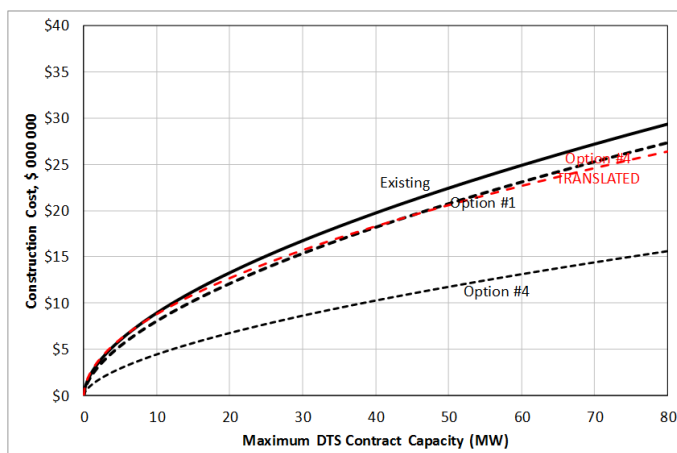
Stakeholder Comments:

D. Translated installed capacity to contract capacity – X axis (Slide 42):

- In order to continue to bill based on contract capacity, the cost curve x-axis for installed capacity must be “translated” to contract capacity;
- In other words, create the exact same shape and dimensions as previous graph Option #4 which can be graphed against Option #1 without altering the secondary vertical axis.

Stakeholder Comments:

E. Comparisons of options to existing (2014 ISO Tariff) cost function curve (Slide 43):



Stakeholder Comment

Stakeholder Comments:

F. Criteria summary (Slide 44):

Criteria	Option #1	Option #4
Variability of relationship between installed capacity and contract capacity		
Number of assumptions and reasonableness of assumptions		
Fairness of treatment of customers with charges based on two different approaches (intergenerational equity)		
Reflect actual cost drivers of projects	R2 = 0.35	R2 = 0.37

Stakeholder Comments:

G. Impact on POD rates (Slide 45)

POD Charge	2017 ISO Tariff	Option #1 – est.*	Option #4 – est.*
Customer X SF	\$8,789/month	\$8,353/month	\$10,986/month
<= 7.5 MW	\$3,559/MW	\$3,616/MW	\$3,687/MW
>7.5 to <=17 MW	\$2,229/MW	\$2,306/MW	\$2,196/MW
>17 to <=40 MW	\$1,555/MW	\$1,633/MW	\$1,476/MW
>40 MW	\$1,007/MW	\$1,070/MW	\$914/MW

Stakeholder Comments:

H. POD cost function – next steps (Slide 46):

- *Proceed with rates calculations based on Option #1 – pre-2014 practice;*
- *Continue to work on translation of “Installed Capacity” cost curve to a “Contract Capacity” cost curve to provide analysis to Commission in application, in order to thoroughly explore the matter; and*
- *Application will include analysis of all four options.*

Stakeholder Comments:

(3) Transmission Cost Causation Study Follow-up (Slides 47 – 53)

A. Preliminary 2018-2020 Functionalization (Slide 48):

Stakeholder Comment			
Year/Function	Bulk	Regional	POD
2016	59.2%	21.6%	19.2%
2018	53.4%	26.3%	20.3%
2019	55.0%	25.1%	19.9%
2020	53.7%	26.2%	20.1%

Stakeholder Comments:

B. Regional system additions in 2020 (Slide 49):

- *Downtown Calgary (P1456) – about \$145 million*
- *Grande Prairie (P1784, P1785) – about \$75 million*
- *Central East (PENV, P1781) – about \$280 million, potentially moving to post-2020*

Stakeholder Comments:

C. Classification by minimum system approach (Slides 50-51):

- *Demand related cost as ration of minimum system cost and optimal system cost (Slide 50)*
 - *138kV: minimum system is 1x266 ACSR and optimal system is 1x477 ACSR*
 - *240kV: minimum system is 2x795 ACSR and optimal system is 2x1033 ACSR*
 - *500kV: minimum system is 2x2156 ACSR and optimal system is 3x1590*
- *Classification calculations (Slide 51):*
 - *Normalize cost to single circuit for 138kV;*
 - *Normalize cost to double circuit for 240kV; and*
 - *Escalate cost to common test year (new improvement for this study).*

Stakeholder Comments:

D. Regional system classification (Slide 52):

Conductor	1x266 ACSR	1x477 ACSR
2019 \$ per kM	487,202	537,349

Class	Demand	Energy
2014-2016	87.4%	12.6%
2018-2020	93.3%	6.7%

Stakeholder Comments:

Stakeholder Comment

E. Bulk system classification (Slide 53):

Conductor	2x795 ACSR	2x1033 ACSR
2019 \$ per kM	1,764,083	2,306,910

Class	Demand	Energy
2014-2016	93.1%	6.9%
2018-2020	78.2%	21.8%

Stakeholder Comments:

(4) Critical Infrastructure Protections (“CIPs”) Cost Recovery (Slides 54-56)**A. Background to CIPS Cost Recover Issue (Slide 55)**

- **Alberta reliability standard – Cyber Security – BES Cyber System Categorization CIP-002-AB-5.1 is planned to be effective on October 1, 2017**
- **TransAlta’s Sundance Facility (units 1-6) would be the only aggregated generating facility classified with a Medium Impact Rating subject to additional expenditures**
- **In Proceeding 3443, the Commission directed the AESO state if these costs would recoverable under the ISO tariff or not**

Stakeholder Comments:

B. AESO’s proposed position in upcoming application (Slide 56)

- **Not recoverable under the tariff; generators should be individually responsible for the costs of complying with Alberta Reliability Standards, including CIPs**
 - **Based on AESO’s internal FEOC assessment (costs that are directly assigned to the market participant are more efficient than if they are socialized);**
 - **Consistent with the treatment of other Alberta reliability standards that provide a benefit to the AIES and all market participants.**
- **AESO’s rationale will be included in the ISO tariff application and may include evaluation of tariff, cost causation and FEOC principles.**

Stakeholder Comments:

(5) Application Process, Timeline and Next Steps (Slides 57 – 62)**C. The AESO discussed the status of a number of 2018 ISO tariff application scope items (Slide 36) and a 2018 ISO tariff tentative timeline.**

Stakeholder Comments:

Stakeholder Comment
<i>Additional Comments</i>

Please return this form with your comments by **May 2, 2017**, to:

LaRhonda Papworth
Manager, Tariff Design
Email: larhonda.papworth@aeso.ca
Phone: (403) 539-2555

Consolidated Stakeholder Comments on AESO 2018 ISO Tariff Consultation Session – April 10, 2017



Background

On April 10, 2017, the AESO and stakeholders participated in a consultation meeting to discuss (1) proposed changes to the ISO tariff's terms and conditions; (2) cost responsibility for compliance with the Critical Infrastructure Protection ("CIP") Alberta reliability standards; (3) results on the AESO's point of delivery ("POD") cost function database results and analysis; and (4) application process and next steps. The AESO invited written comments from stakeholders on the information presented at the meeting. The written comments received from stakeholders are consolidated below.

A copy of the presentation provided by the AESO at the April 10, 2017 meeting 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) ISO Tariff Terms and Conditions - Proposals (Slides 6 – 36)

A. Proceeding 20922 Closure Letter, March 29, 2017 (Slides 7-10):

- **Issue 1: Legislative framework;**
- **Issue 2: Advanced system-related classification of radial transmission projects; and**
- **Issue 3: Load forecasting**

Alberta Direct Connect Consumers Association ("ADC"):

ADC supports the AESO working closely with new customers to have confidence in project scope and timing in order to advance new facilities while not incurring unnecessary costs.

AltaLink Management Ltd. ("AltaLink"):

AltaLink is generally concerned with the direction being proposed related to advancement costs for load customers, as the proposals appear to be quite punitive to new load customers connecting to our system and will create an additional barrier to economic development within Alberta. AltaLink is concerned that Alberta will become an outlier jurisdiction sending punitive price signals to new customer growth at a time

when our economy needs to be welcoming economic development of all kinds. Reasonable and balanced price signals should be considered, for the rare situation that an un-forecast load addition drives the need for earlier than planned system expansion.

It must be recognized that long term transmission planning and load forecasting will always be inaccurate to actual results, it is a forecasting process after all. It is unrealistic and inappropriate to place the risk of the AESO's long term forecast inaccuracy on a single load customer that is helping to drive the economy in Alberta.

Forecasts are a prediction of the future, and by their very nature cannot be accurate especially over long time frames of 10-20 years. It is unreasonable to expect otherwise.

The use of scenarios is important to establish commonalities and triggers in the planning of transmission system reinforcements, and we support the AESO in continuing to refine this approach. It may be beneficial for the AESO to re-explain the planning process to the industry. AltaLink's understanding is that

Stakeholder Comment

the AESO's LTP is based on a long term forecast and scenarios. This does not drive specific transmission development. The AESO brings forward specifically a NID for a specific project with the specific updated local forecast to support the development at that time. It is therefore a low probability that development will occur that much before needed. AltaLink would request the AESO bring forward in its application an analysis that confirms the magnitude of the risk trying to be addressed with the advancement cost proposal.

To address the Commission's concern of load customers being incented to overstate their load requirements (size and timing), the AESO should include over the last 5-10 years, the number of load addition projects, the % of load addition projects that resulted in the need for transmission system projects, the % of load addition projects that resulted in advancing from the AESO's plans the timing of the energization of transmission system projects, and the % of advanced transmission system projects where the last customer in driving the need did not proceed. AltaLink is quite concerned with creating a punitive price signal to all future load customers in order to address a very low probability event or even worse, an outcome that has yet to materialize.

ATCO Electric Ltd. ("ATCO Electric"):

ATCO Electric is concerned that more projects in the AESO connection queue will be delayed significantly if the AESO elects to cancel projects and have them restart at Stage 0 to be re-studied even for the smallest of load forecast differences. ATCO Electric is of the view that a more streamlined process is required to reduce churn otherwise created.

Capital Power Corporation ("Capital Power"):

Capital Power notes and understands that the focus of the presentation, and potential tariff revisions being considered by the AESO for the 2018 GTA, relates to the treatment and allocation of costs relevant to load, and that the potential revisions described are not intended to affect generator costs or those associated with supply transmission service ("STS") contract holders.

In this key respect, Capital Power notes and supports the finding of the AUC noted on slide 8 that there is a distinction between load serving transmission projects and generation serving transmission projects. Capital Power further notes the AESO's continued and ongoing obligation to plan for and maintain a congestion free system [Transmission Regulation section 15(1)(e)(i)] and the AUC's previous findings that "there are no explicit or implicit transmission 'rights' but that the obligation imposed on the AESO is to provide market participants with a reasonable opportunity to access the AES." – Decision 2013-135 at para 96. (slide 8) Any proposed tariff amendments considered by the AESO must be consistent with these principles and directives.

Dual Use Customers:

No comments.

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

IPCAA welcomes the AESO's acceptance of the view that they should adopt a more proactive stance with respect to its overall system planning and transmission upgrade responsibilities for both load and generation.

TransCanada Energy Ltd.:

No comments.

B. Other Commission Decisions (Slides 11-12)

Alberta Direct Connect Consumers Association (“ADC”):

ADC supports that an economic signal be sent to ensure robust planning and that facilities built will be efficiently utilized. There should be some latitude for market participants to stage their DTS contract levels or accept an interruptible service until full system build is completed or pay advancement costs if in service dates are firm.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta (“IPCAA”):

While the AUC indicates that to reduce costs a market participant could either shift its in-service date or absorb incremental costs, IPCAA believes that the market participant should have the opportunity as well to stage its market access, with options such as RAS schemes. This is a fundamental difference from the AESO’s view that it is an all or nothing approach of completely unconstrained access.

TransCanada Energy Ltd.:

No comments.

C. Principles for Load Customers (Slide 13):

- ***Provide a price signal;***
 - ***System transmission facilities are not built as the result of a connection(s) not proceeding; and***
 - ***Alignment with Commission’s issue list (Proceeding 20922).***
-

Alberta Direct Connect Consumers Association (“ADC”):

Principles are fine, however the degree of price signal needs to be established such that it doesn’t discourage new load from locating in Alberta.

AltaLink Management Ltd. (“AltaLink”):

AltaLink is concerned with the implications of adding incremental up front cost to new load connecting customers as this will be an additional barrier to economic development in Alberta. Load connecting customers already make significant upfront capital investments for their own plant or growth project, for the costs of interconnecting to the grid and now may be required to provide additional upfront capital to fund a transmission system development. Transmission system development fundamentally benefits all customers in the region, generation and load, new and existing, and as such it is unfair to place the entire development cost on one customer, the “last in”. AltaLink is not aware of any other jurisdictions in Canada or North America that require a single load customer to fund transmission system developments. AltaLink is concerned with the “last in pays” concept being proposed. Transmission system development is driven by all types of customers: generation, gradual load growth of existing customers, new small load customers, and new larger load customers. System development goes through a process of long term

planning, through to need application, permitting, construction and energization. There are regulatory reviews at the first three stages to reaffirm timing of proceeding to construction and energization. The AESO's role is to plan the system for forecast load and generation as transmission development takes many years. Not having the transmission system in place for actual load customer needs is not the customers issue, it is a forecast inaccuracy in the transmission planning process. Requiring new load customers to pay large upfront "last in pays" contributions to advance transmission system development to meet their needs because the forecasting process did not, is punitive to the customer.

AltaLink would request the AESO bring forward in its application an analysis that confirms the magnitude of the risk trying to be addressed with the advancement cost proposal. This analysis should include over the last 5-10 years, the number of load addition projects, the % of load addition projects that resulted in the need for transmission system projects, the % of load addition projects that resulted in advancing from the AESO's plans the timing of the energization of transmission system projects, and the % of advanced transmission system projects where the last customer in driving the need did not proceed. AltaLink is quite concerned with creating a punitive price signal to all future load customers in order to address a very low probability event or even worse, an outcome that has yet to materialize.

Although AltaLink is concerned with the proposed approach, should the AESO and the AUC determine some price signal is warranted, AltaLink would recommend and support the AESO seeking from the Commission a more principles based approach that the AESO can apply to the rare situation being considered, versus a tariff based approach that is inflexible to changing customer needs or government policy. This is because AltaLink believes the situation will be very rare. The discretionary approach should follow these key principles:

- 1) Advancement costs should not be considered if the system development was in the latest AESO LTP and the in-service date was within 5 years of the now needed in-service date. This addresses the inherent forecast accuracy of the LTP process.
- 2) Should advancement costs be applicable, the following principles should be considered:
 - the pricing signal must be 100% refundable
 - should be related to a % of the carrying costs of the advanced transmission system development, to a maximum of 5 years (as all customers in the region are driving the need not just one)
 - should not be the full cost of the advanced transmission system development
 - should be paid based on the progression of costs incurred and not all upfront
 - should be refunded at the earliest stage of customer commitment such as when its interconnection project begins construction or when a DTS contract is signed
 - should the customer ultimately not proceed, the customer should be refunded all of its deposit less the costs actually incurred for the system development

ATCO Electric Ltd.:

No comment.

Capital Power Corporation:

No comments.

Dual Use Customers ("DUC"):

No comments.

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

IPCAA disagrees with the AESO's concept of only offering an unconstrained alternative selection. While load may have the desire for full access, some load may examine other alternatives such as constrained access using a RAS schema. Considering the implementation of both a capacity market and a carbon

market, load may at times have incentives to construct some behind-the-fence generation or demand response capabilities.

IPCAA agrees that like generation, some form of financial commitment should be made if construction of system transmission facilities is triggered.

TransCanada Energy Ltd.:

No comments.

D. System transmission facilities required for a load connection (Slides 14-19):

- **Alternative selection for load connections (Slide 15);**
 - **Market participant can wait for system or pay certainty charge/refund (Slide 16);**
 - **“Refundable deposit” – What does it provide for the AESO? (Slide 17);**
 - **Pros and cons – “refundable deposit” (Slide 18); and**
 - **Options (Slide 19)**
-

Alberta Direct Connect Consumers Association (“ADC”):

For points D-G: A new load, once they have entered into a DTS contract has an ongoing obligation to pay for the transmission system through the DTS tariff. Appropriate contract timing may reduce the concern for loads advancing system before they are ready to take service as they would start paying effective the contract date. Any treatment of new load connections should not be more onerous than a new generator connection.

AltaLink Management Ltd. (“AltaLink”):

Fundamentally, AltaLink supports enabling customer load as economic development on the grid. New load growth is good for existing customers and the economy in Alberta. AltaLink has provided its principles in C above. AltaLink supports a fully refundable deposit (including carrying costs) and as AltaLink has stated in its last comments to the AESO, the AESO should consider staging the deposits to align with the actual incurrence of incremental project costs. AltaLink does not support a lump sum approach. AltaLink supports a longer term view of least cost in developing the transmission system. The AESO should be looking at long term forecasts in the region when a new customer wishes to connect and should plan the system for the long term accordingly, seeking the least cost solution to interconnect the new customer. AltaLink is concerned with what appears to be a new planning approach that all new load customers will be radially connected as this can be suboptimal development in the region. AltaLink would expect the AESO has the expertise and capabilities to effectively assess what is the best long term development in the region to connect a new customer and justify if any of that development is system based. The AESO should be given deference as the independent system operator in its transmission development plans, for connecting new loads and for long term system development, they have the expertise and it is their role in the industry, not any other agency or entity.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta (“IPCAA”):

IPCAA disagrees with the AESO that load connection alternatives must be unconstrained. By unconstrained, we interpret this to mean that at all times the load has complete access. Since typically

transmission constraints are the result of rare events, such as transmission outages etc. at most times significantly more transmission capacity may be available than the AESO's worst case assumptions. It would be useful for the load to assess the costs of full transmission access versus costs it may incur from having to reduce its consumption.

IPCAA is concerned with the AESO's view that the alternative selected will be the lowest overall cost. IPCAA would like to better understand this term. For example, does the AESO consider a probabilistic assessment of alternatives.

IPCAA agrees that any deposit provided by the load to ensure energization should be fully refundable. If the load does energize within the specified window and the deposit is NOT refundable, there is reduced incentive for the load to meet its commitment.

There should be a reasonableness test to a load only partially showing up (i.e. with a lower DTS capacity). For example, if a load with a 20 MW commitment shows up with 18 MW is not unreasonable. It would be worthwhile understanding the AESO's view on reasonableness.

The concern IPCAA has is that the deposit for the system cost could be prohibitive and load may ultimately decide not to invest. Unlike GUOC in which the generation owner pays a contribution towards a system build, between \$10,000/MW and \$50,000/MW, would the load be on the hook for the whole system build? Can the AESO explain the difference between a system build for a load versus a generator?

TransCanada Energy Ltd.:

The process diagram on slide 14 has changed from the process diagrams on slides 14-24 from the March 1, 2017 consultation session. In the circumstance in which the customer cannot wait for the system build, the earlier slides contemplated a certainty charge/refundable deposit or an advancement cost depending on whether a system NID had been filed and on the form of the milestones. The April 10, 2017 presentation appears to replace the advancement costs associated with advancing a system project for which a NID has already been filed with a refundable deposit. In this case, the magnitude of the refundable deposit should not be for the full system project, but should be commensurate with what the advancement costs would otherwise have been (i.e., the deposit should be relative to the incremental costs associated with advancing the system project). Alternatively, if the deposit is for the full cost of the system project and the customer does not connect, the customer must be refunded all of the deposit less the incremental advancement costs.

E. Alternative selection example 1 – “lowest overall costs” (Slides 20-23):

- **Diagram - Alternative 1 is “lowest overall costs” (Slide 20);**
- **Diagram - Alternative 2 is “lowest overall costs” (Slide 21); and**
- **Diagrams - Other examples (not discussed) (Slides 22-23).**

Alberta Direct Connect Consumers Association:

No comments.

AltaLink Management Ltd. (“AltaLink”):

Based on the discussions at the April 10 stakeholder meeting, it was noted by the AESO that if there was near future benefits in Alternative 2, the AESO would choose Alternative 2 and charge the customer \$50M, the same amount as the AESO would have charged the customer in Alternative 1. AltaLink supports this approach as the AESO should have the long term planning perspective for the region and system development benefits all customers in the region.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta (“IPCAA”):

Slide 20: IPCAA believes that Alternative 2 with the option of a RAS schema for the load may be the cheapest solution until the system build becomes inevitable. Alternative 1 (\$50M of radial connection) may saddle the load with costs that may make the load project uneconomic. Load should be able to assess its options for a constrained versus unconstrained option.

Slide 21: It would be useful understanding what a generators obligation would be under alternative 2 for GUOC versus a load’s obligation. Alternative 2 is certainly more attractive for the load in ultimately only having a financial obligation for element 1 with element 2 socialized across all load.

Slide 23: Can the AESO please expand on the radial then shared component in terms of recovery of costs associated with the radial connection? If 3 is a generator instead of a load would it also share costs?

TransCanada Energy Ltd.:

The determination of lowest overall costs for alternative selections should consider the long-term overall costs by taking into consideration projects already contemplated in the long-term plan. For example, consider the scenario presented on slide 20 in which Alternative 1 (\$50M cost for a radial connection) is deemed to be of lower overall cost than Alternative 2 (\$16M cost for radial connection and \$60M for system upgrade). If the \$60M system upgrade is already in the long-term plan or a NID has been filed, this fact should be taken into consideration. If the incremental advancement cost for this system upgrade is only \$10M, then the \$10M incremental cost should be applied to Alternative 2 rather than the \$60M total cost resulting in the selection of Alternative 2.

F. Changes to Sections 4, 5, 8 & 9: What are we proposing to add? (Slides 24-25):

- ***New provisions that identify how the AESO will determine the preferred alternative;***
 - ***Revised practices for system access (to replace the AESO’s “Practices for System Access Service”);***
 - ***Defining and enforcing critical requirements for a SASR;***
 - ***Identify when connection projects give us “sufficient certainty” that they will materialize;***
 - ***New provisions around advancement costs and “accelerated construction” charges;***
 - ***Differentiation between generation and load;***
 - ***“Shared with system” cost provisions; and***
 - ***Connections that are initially radial are 100% participant-related costs, to be “shared” if loop is closed.***
-

Alberta Direct Connect Consumers Association (“ADC”):

No comment.

AltaLink Management Ltd. (“AltaLink”):

AltaLink would recommend that sufficient certainty occurs when the customer’s interconnection project moves to the construction stage following permit. At this stage the customer will need to commit sufficient funding for the customer contribution payments for the interconnection, and most customer interconnections now require millions in contributions. Other options would be when they sign a DTS contract or upon energization of their interconnection project, whichever is sooner. The customer should

be refunded all costs provided with carrying costs to keep the customer whole.

ATCO Electric Ltd.:

No comment.

Capital Power Corporation:

Section 4: Capital Power agrees with preserving the current distinction between load and generation. Capital Power submits it is not necessary to establish a tariff classification for dual-use customers. The current supply transmission service (“STS”) and demand transmission service (“DTS”) structure appropriately addresses the supply and demand requirements for dual-use customers. A level playing field must be preserved, and is preserved, by having distinct DTS and STS classifications governing the fundamental distinction between whether a site is drawing power from the grid, or delivering power to the grid. Consequently, service connections for dual-use customers (i.e. storage) are properly achieved with STS and DTS contracts like generators and load respectively (slide 25).

Dual Use Customers (“DUC”):

No comments.

Industrial Power Consumers Association of Alberta (“IPCAA”):

IPCAA submits that ultimately dual use customers should not be viewed as both generation and load and be forced to cover costs of both components. Typically, dual use is attractive to electricity consumers as a whole, as these entities shave peak costs for both energy and ancillary services. Considering the capacity market evolution, more discussion should take place with respect to dual use entities.

How are radial costs shared if a loop is “closed”? Can the AESO explain the anticipated cost-sharing mechanism?

TransCanada Energy Ltd.:

With respect to “Defining and enforcing critical requirements for a SASR”, the AESO should strive to develop flexible requirements such that any such enforcements are only implemented if necessary to avoid unnecessary costs being imposed upon customers.

G. Changes to Sections 4, 5, 8 & 9: What are proposing to revise/remove? (Slide 26):

- **Remove any provisions that are duplicative of the legislation, rules, & reliability standards;**
 - **Remove “contiguous” in Section 8 referring to a “contiguous” connection project;**
 - **Remove provision referring to “planned to be looped” as system-related cost;**
 - **Remove connection process references; and**
 - **Revisit the “Good Electric Industry Practice” to reflect the AESO’s minimum requirements.**
-

Alberta Direct Connect Consumers Association (“ADC”):

No comments.

AltaLink Management Ltd. (“AltaLink”):

AltaLink considers any change to “Good Electric Industry Practice” to be a material change to the tariff and as such, the AESO should consult on the specific reasons why the AESO believes the definition needs to change and provide a draft of the changes to enable a stakeholders an opportunity to provide comments on the definition.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

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

Clearer language and intent is always welcome.

IPCAA is concerned with the statement "advancement costs will apply to all transmission facilities for a load connection." Do the same rules apply to generators? If not, what is the rationale for difference between the two groups?

TransCanada Energy Ltd.:

No comments.

H. Other terms and conditions proposals (Slides 27-29):

- **Section 1 – Applicability and interpretation of ISO Tariff;**
 - *Legal Review*
 - *Ensure no duplication of legislation, rules, or reliability standards*
- **Section 2 – Provision of and Limitations to System Access Service (may merge Sections 2 – 4);**
 - *Make distinction between load and generation*
 - *Add t-tap expectation of service*
 - *Remove outage provisions (covered in ISO rules)*
- **Section 3 – System Access Service Connection Requirements (may merge Sections 2-4);**
 - *Remove technical requirements (covered in ISO rules)*
 - *Move compliance requirements to Section 2*
- **Section 5 – Financial Obligations for Connection Projects;**
 - *Legal review*
 - *Ensure no duplication of other authoritative documents*
- **Section 6 – Metering;**
 - *Remove altogether, covered in ISO rules*
- **Section 7 – Provision of Information;**
 - *Review for duplication of authoritative documents and legislation*
- **Section 10 – Generating Unit Owners Contribution;**
 - *Add GUOC rates to the ISO tariff*
- **Section 11 – Ancillary Services;**
 - *No changes proposed*
- **Section 12 – Demand Opportunity Service;**
 - *No changes proposed*
- **Section 13 – Financial Security, Settlement and Payment Terms;**
 - *Duplication with ISO rules?*

-
- **Section 14 – Peak Metered Demand Waivers; and**
 - **No changes proposed**
 - **Section 15 - Miscellaneous;**
 - **Confirm with legal review.**
-

Alberta Direct Connect Consumers Association:

No Comments at this time.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd. (“ATCO Electric”):

ATCO Electric notes that the AESO has not addressed the current challenge associated with connection projects that are not eligible for local investment and are required to provide cash security up to Stage 4 of the AESO connection process. ATCO Electric is seeking clarity whether other financial mechanisms can be used that will still provide the AESO will certainty on the level of the commitment required from Market Participants.

Capital Power Corporation (“Capital Power”):

Capital Power has comments for Section 14 only at this time.

Amendments to Section 14 should be made to accommodate peak metered demand exception requests for generators. The Peak Metered Demand Waiver (“PMDW”) currently addresses load customer events only; for example, the transfer of load between substations in distribution networks without increasing substation DTS contracts. However, there are no provisions in Section 14 that consider a generator’s need to seek PMDW relief due to events that may be beyond their control that may result in exceedances of their peak metered demand. These include forced outages (trips) involving individual or co-located generating units – caused by system events beyond the operator’s control – when the generator(s) are returned to service under abnormal conditions.

Capital Power has experienced such events where rare, unlikely, and unanticipated transmission system events have occurred coincident with a co-located unit’s planned outage and tripped the operating units. No self-supply option was available to return the blacked-out units to service and consequently the tripped units were returned to service with DTS support under abnormal start-up conditions. In those circumstances, and under the current tariff, Capital Power pursued resolution of the issue under the AESO’s dispute resolution processes. However, Capital Power believes it would be beneficial to provide greater clarity with respect to when and how PMDW applies to generators, and provides the following proposed amendments to Section 14 2(1)(c).

Causes Eligible for Peak Metered Demand Waivers

2(1) The ISO may waive peak metered demand for a market participant for the purpose of calculating billing capacity when the peak metered demand was caused by one of the following:

- (a) commissioning;
 - (b) activities required to repair and maintain transmission facilities;
 - (c) load service restoration activities that:
 - (i) for load that follow a forced outage, planned outage or unplanned outage of transmission facilities or facilities that are part of an electric distribution system; or
 - (ii) for load that are caused by an emergency on the transmission system; or
 - (iii) for generators that follow the trip of a generating unit or trip of co-located generating units, beyond the control of the generator, that results in abnormal demand during service restoration that exceeds the DTS contract amount.
 - (A) when the AES is importing from any of the tie lines; and
 - (B) absent the conditions in (d) and (e) below.
 - (d) compliance with a directive the ISO issues during an emergency; or
 - (e) an event of force majeure that impacts the ISO.
-

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta:

Section 2: Please make it clear what the AESO's intent is for a distinction between load and generation.

Section 10: Since the AESO is adding GUOC to the tariff, can it ensure symmetry between generators and loads in terms of connections and financial responsibilities? Can that be provided as a comparison table?

TransCanada Energy Ltd.:

No comments.

I. Workshop Slides (Slides 30-36):

- ***Repeated from Slides 20-21 (Slides 31-32);***
 - ***Example 1 background, area load, and area load forecasts (Slide 33);***
 - ***Example 2 diagram and background (Slide 34); and***
 - ***Example 2 area load and area load forecasts (Slide 35).***
-

Alberta Direct Connect Consumers Association:

No comments.

AltaLink Management Ltd. ("AltaLink"):

The transmission planning process is based on long term forecasts and scenarios to test the robustness of the long term transmission plans. In the rare case that a large new customer, for example a new petrochemical plant of 90 MW comes along as a complete surprise to the AESO plans and was not included in the latest LTP, which occurs every two years, the AESO should accommodate the new customer as new customers drive the economy in Alberta. There should be no punitive charges to the customer for the enablement of transmission to supply its load. Load customers should be uncongested on the transmission system. For the example of the new petrochemical plant, possibly supported by government policy, charging the new customer an additional \$100M up front to provide sufficient regional transmission system capacity to supply this new load may make the project uneconomic.

AltaLink is concerned with any distinction between "natural load growth" and single customer load growth.

Load growth is load growth. It is unfair to be punitive to one large load by charging major advancement costs while other customers do not need to pay for these advancement costs when they trigger the need. As such, AltaLink reemphasizes its principles in C above around any decision to apply advancement costs on single load customers that may require system developments.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta (“IPCAA”):

Slide 32: Because the AESO is only offering unconstrained solutions, the option of the radial connection with a cost of \$16M and a RAS schema is not available to the load.

Slide 33: While the original request was for 90 MW, it is not clear why a load would not be offered the alternative of the full capacity requested with a RAS scheme until the full system capacity was available.

TransCanada Energy Ltd.:

No comments.

J. Terms and Conditions’ Changes – Next Steps (Slide 36):

- **Allow stakeholders to review presentation and concepts, and provide feedback;**
 - **Prepare application with revised terms and conditions.**
-

Alberta Direct Connect Consumers Association:

No comments.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta:

No comments.

TransCanada Energy Ltd.:

No comments.

(2) POD Cost Function Database (Slides 37 – 46)

A. POD cost function database input into cost curves and options (Slides 38-39):

- AESO was directed to “use ‘Greenfield and Update Excluding 0 MW’ until the matter can be thoroughly explored” (Slide 38);
- AESO thoroughly exploring four options (Slide 39).

Alberta Direct Connect Consumers Association:

No comments.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

DUC submits that the AESO was directed to use installed capacities. The POD cost function should be derived using escalated capital costs (to 2018 \$) and installed capacities.

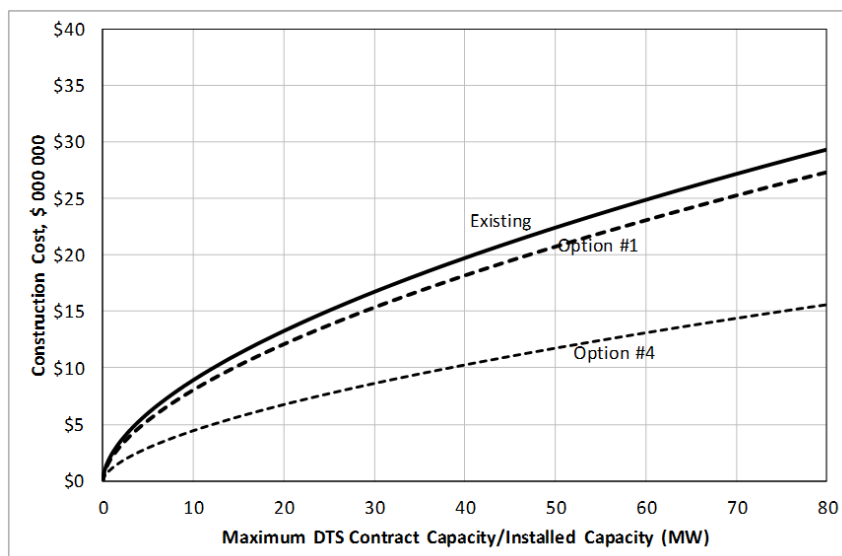
Industrial Power Consumers Association of Alberta:

No comments.

TransCanada Energy Ltd.:

No comments.

B. Comparison of options to existing (2014 ISO Tariff) Cost Function Curve (Slide 40):



Alberta Direct Connect Consumers Association:

From our understanding of the Options, it seems that Option 4 better reflects actual cost drivers of projects.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

The DUC does not support Option 1 or Option 4.

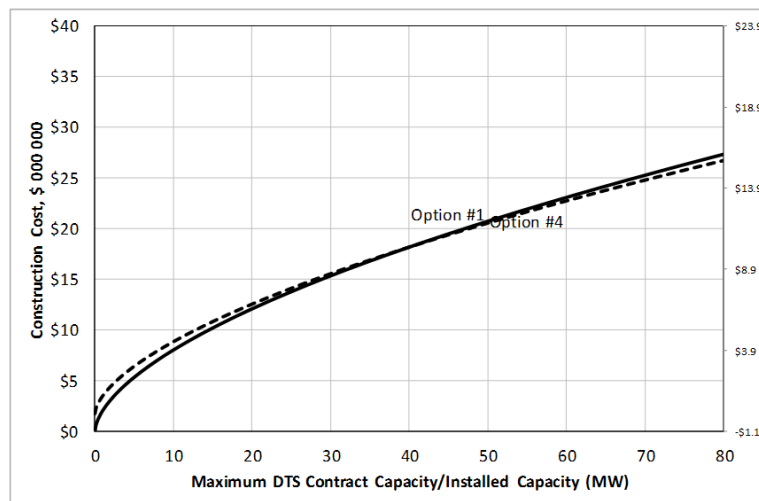
Industrial Power Consumers Association of Alberta ("IPCAA"):

IPCAA submits that capital cost versus installed capacity should be used to develop the pod cost function and then an adjustment should be made to correlate to billing capacity in the rate design. As it presently stands Option #4 better reflects actual cost drivers of projects.

TransCanada Energy Ltd.:

No comments.

C. Comparison of options shape (Slide 41):



Alberta Direct Connect Consumers Association:

No comments.

AltaLink Management Ltd. ("AltaLink"):

No comments.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta:

No Comments.

TransCanada Energy Ltd.:

No comments.

D. Translated installed capacity to contract capacity – X axis (Slide 42):

- ***In order to continue to bill based on contract capacity, the cost curve x-axis for installed capacity must be “translated” to contract capacity;***
 - ***In other words, create the exact same shape and dimensions as previous graph Option #4 which can be graphed against Option #1 without altering the secondary vertical axis.***
-

Alberta Direct Connect Consumers Association:

Agree that if Option 4 is preferred that it needs to be translated to billing capacity.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd.:

No comment.

Capital Power Corporation:

No comments.

Dual Use Customers (“DUC”):

The DUC submits that the capital cost / installed capacity POD cost function should be used, and the conversion to Billing Capacity billing determinants should be used in rate design by adjusting POD rate levels by the average billing capacity to installed capacity ratio for all PODs.

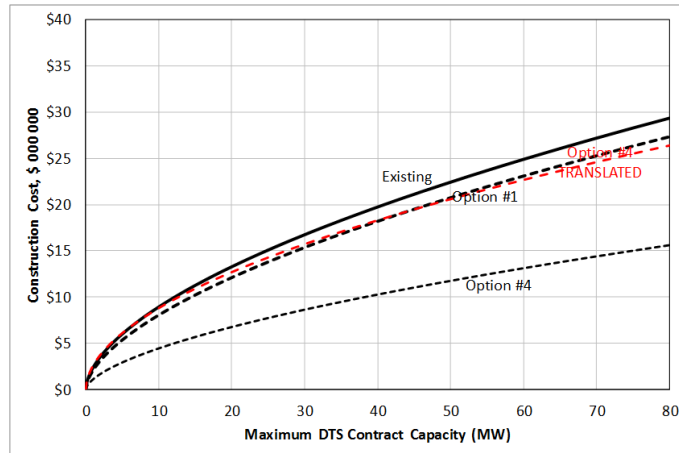
Industrial Power Consumers Association of Alberta:

No comments.

TransCanada Energy Ltd.:

No comments.

E. Comparisons of options to existing (2014 ISO Tariff) cost function curve (Slide 43):



Alberta Direct Connect Consumers Association:

No comments.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta:

No comments.

TransCanada Energy Ltd.:

No comments.

F. Criteria summary (Slide 44):

Criteria	Option #1	Option #4
Variability of relationship between installed capacity and contract capacity		
Number of assumptions and reasonableness of assumptions		
Fairness of treatment of customers with charges based on two different approaches (intergenerational equity)		
Reflect actual cost drivers of projects	R2 = 0.35	R2 = 0.37

Alberta Direct Connect Consumers Association:

No comments.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta:

Option #4 better reflects actual cost drivers of projects.

TransCanada Energy Ltd.:

No comments.

G. Impact on POD rates (Slide 45)

POD Charge	2017 ISO Tariff	Option #1 – est.*	Option #4 – est.*
Customer X SF	\$8,789/month	\$8,353/month	\$10,986/month
<= 7.5 MW	\$3,559/MW	\$3,616/MW	\$3,687/MW
>7.5 to <=17 MW	\$2,229/MW	\$2,306/MW	\$2,196/MW
>17 to <=40 MW	\$1,555/MW	\$1,633/MW	\$1,476/MW
>40 MW	\$1,007/MW	\$1,070/MW	\$914/MW

Alberta Direct Connect Consumers Association:

Option 4 is a better reflection of actual costs.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd. (“ATCO Electric”):

ATCO Electric supports Option #1 - pre-2014 practice.

Capital Power Corporation:

No comments.

Dual Use Customers (“DUC”):

See DUC comments above.

Industrial Power Consumers Association of Alberta:

No comments.

TransCanada Energy Ltd.:

No comments.

H. POD cost function – next steps (Slide 46):

- **Proceed with rates calculations based on Option #1 – pre-2014 practice;**
 - **Continue to work on translation of “Installed Capacity” cost curve to a “Contract Capacity” cost curve to provide analysis to Commission in application, in order to thoroughly explore the matter; and**
 - **Application will include analysis of all four options.**
-

Alberta Direct Connect Consumers Association (“ADC”):

ADC appreciates a thorough analysis of all the options.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd. (“ATCO Electric”):

ATCO Electric supports Option #1 - pre-2014 practice.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta (“IPCAA”):

IPCAA supports including the analysis of all four options as part of the application.

TransCanada Energy Ltd.:

No comments.

**(3) Transmission Cost Causation Study Follow-up
(Slides 47 – 53)**

A. Preliminary 2018-2020 Functionalization (Slide 48):

Year/Function	Bulk	Regional	POD
2016	59.2%	21.6%	19.2%
2018	53.4%	26.3%	20.3%
2019	55.0%	25.1%	19.9%
2020	53.7%	26.2%	20.1%

Alberta Direct Connect Consumers Association:

No comments.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd. (“ATCO Electric”):

ATCO Electric will need more time to review and understand the AESO’s Transmission Cost Causation Study, but generally does not have significant issues with the proposed 2018-2020 functionalization of

costs at this time. ATCO Electric notes that ratepayers in ATCO Electric's service area continue to pay more for transmission chargers than customers in other service areas, which ATCO Electric may consider exploring further in the AESO's upcoming tariff application..

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta:

No comments.

TransCanada Energy Ltd.:

No comments.

B. Regional system additions in 2020 (Slide 49):

- **Downtown Calgary (P1456) – about \$145 million**
 - **Grande Prairie (P1784, P1785) – about \$75 million**
 - **Central East (PENV, P1781) – about \$280 million, potentially moving to post-2020**
-

Alberta Direct Connect Consumers Association:

No comments.

AltaLink Management Ltd. ("AltaLink"):

These planned system additions are an example of the dichotomy being considered for advancement costs. These system additions are based on forecasts. If the projects are built and the load does not materialize on the forecasted time, should the AESO charge the City of Calgary or the City of Grande Prairie an upfront advancement payment for the entirety of the project until it is needed?

AltaLink believes the AESO should not, it is the forecasting accuracy that should be borne by the AESO and all the customers in Alberta. The same principle should be considered for individual customers..

ATCO Electric Ltd.:

No comments.

Capital Power Corporation ("Capital Power"):

Capital Power is concerned with the proposal to delay system transmission projects in the Central region, particularly the deferral of PENV and P1781 to post 2020; currently scheduled for end Q1-2021. Capital Power recognizes the first renewable energy procurement ("REP1") auction will procure 400MW while future auction capacities and timing have yet to be determined. Currently, there are 17 projects, totaling ≈2,275MW with in-service-dates ranging from October 25, 2017 to December 31, 2019 in the Central planning areas (32, 35, 36, 37 39, 42) as reproduced from the AESO Connection Project list below.

Proj #	Project Name	Phase	Queue Type	Planning	Gen MW	Load MW	MW Type	Stage	Planned ISD	Received
635	Suncor Hand Hills Wind Energy Project	1	Connection	42	80.0	0.0	Wind	5	Dec 31, 2018	Oct 6, 2006
678	BlueEarth Hand Hills Wind Project	1	Connection	42	80.0	1.0	Wind	5	Dec 31, 2018	Jan 15, 2007
937	Irma Wainwright Wind	1	Connection	32	90.0	3.0	Wind	3	Sep 30, 2018	Jun 11, 2009
1567	Sharp Hills Wind Farm New Facility Generator Capacity	1	Connection	42	300.0	0.0	Wind	3	Apr 8, 2019	Jun 4, 2014
1704	Paintearth Wind Farm	1	Connection	42	150.0	1.0	Wind	3	Jul 1, 2019	Oct 8, 2015
1710	Capital Power Halkirk 2 Wind	1	Connection	36	150.0	1.8	Wind	3	Jan 15, 2019	Oct 22, 2015
1752	Suncor Braconier Wind Project New POS	1	Connection	42	80.0	0.3	Wind	2	Oct 31, 2019	Feb 23, 2016
1753	Suncor Huxley Wind Project New POS	1	Connection	42	50.0	0.3	Wind	2	Oct 31, 2019	Feb 23, 2016
1761	EDF EN Hand Hills WAGF	1	Connection	42	200.0	0.0	Wind	2	Oct 1, 2019	Mar 7, 2016
1770	NextEra Red Deer Battery Energy Storage System	1	Connection	42	40.0	46.0	Battery	2	Dec 1, 2018	Mar 18, 2016
1780	Sequoia Energy Oyen WAGF	1	Connection	42	100.0	1.0	Wind	2	Dec 14, 2018	Apr 6, 2016
1797	RES Oyen Wind Power Project	1	Connection	42	350.0	2.0	Wind	2	Jun 28, 2019	May 16, 2016
1824	Spirit Pine-Lone Pine WAGF	1	Connection	42	172.8	1.0	Wind	2	Dec 1, 2019	Jul 28, 2016
1893	NextEra Red Deer River Solar	1	Connection	35	150.0	0.5	Solar	2	Mar 26, 2019	Nov 15, 2016
1898	BowArk Energy Lanfne WAGF	1	Connection	42	145.0	0.0	Wind	2	Dec 1, 2019	Dec 2, 2016
1909	TransAlta Garden Plain Wind	1	Connection	42	130.0	4.0	Wind	2	Dec 31, 2019	Dec 22, 2016
1921	FortisAlberta Hayter STS Increase	1	Contract	37	8.0	0.0	STS	1	Oct 25, 2017	Mar 9, 2017

While it is unlikely that all these projects will proceed, it is evident that the Central region provides a strong regime for wind power development. It would be unreasonable to delay the Central region transmission upgrade(s) when considering Alberta's future REP auction capacities and the portfolio of Central region renewable projects currently active in the AESO connection process. Future REP auctions will be reliant upon the availability of transmission capacity. Capital Power encourages the AESO to proceed with the Central region system transmission projects to provide market participants seeking to develop renewable projects in the Central region a fair and reasonable opportunity to compete in future REP auctions..

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta:

Thank you for providing this information.

TransCanada Energy Ltd.:

No comments.

C. Classification by minimum system approach (Slides 50-51):

- **Demand related cost as ration of minimum system cost and optimal system cost (Slide 50)**
 - **138kV: minimum system is 1x266 ACSR and optimal system is 1x477 ACSR**
 - **240kV: minimum system is 2x795 ACSR and optimal system is 2x1033 ACSR**
 - **500kV: minimum system is 2x2156 ACSR and optimal system is 3x1590**
- **Classification calculations (Slide 51):**
 - **Normalize cost to single circuit for 138kV;**
 - **Normalize cost to double circuit for 240kV; and**
 - **Escalate cost to common test year (new improvement for this study).**

Alberta Direct Connect Consumers Association:

Appears to be consistent with the London Economics Study.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta:

No comments.

TransCanada Energy Ltd.:

No comments.

D. Regional system classification (Slide 52):

Conductor	1x266 ACSR	1x477 ACSR
2019 \$ per kM	487,202	537,349

Class	Demand	Energy
2014-2016	87.4%	12.6%
2018-2020	93.3%	6.7%

Alberta Direct Connect Consumers Association (“ADC”):

ADC would appreciate more detail on what has caused the shift to more demand versus energy on the regional system. Which specific projects have contributed to this result?

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta:

No comments.

TransCanada Energy Ltd.:

No comments.

E. Bulk system classification (Slide 53):

Conductor	2x795 ACSR	2x1033 ACSR
2019 \$ per kM	1,764,083	2,306,910

Class	Demand	Energy
2014-2016	93.1%	6.9%
2018-2020	78.2%	21.8%

Alberta Direct Connect Consumers Association:

For the Bulk system classification, what did the AESO use for costs of the 500 kV minimum and optimal system? How does the HVDC facilities get considered, are they already the optimal system because of the losses impact of HVDC? How does this factor into the demand/energy split? Because the demand – energy split is a significant departure from the London Economics study, please provide the details as to what specific projects have influenced the allocation.

AltaLink Management Ltd. (“AltaLink”):

AltaLink requests that the AESO provide stakeholders a reconciliation and detailed explanation of the 2014-16 demand/energy calculation to the 2018-2020 demand/energy calculation given the ~15% change. The reconciliation should include the total costs being recovered by each category.

ATCO Electric Ltd.:

No comment.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta (“IPCAA”):

IPCAA notes a marked increase in the energy / demand split. Can the AESO explain this change from the previous 2014 – 16 classification. Will this have any impact on behaviors in the Capacity market with its focus on demand rather than energy?

TransCanada Energy Ltd. (“TCE”):

No comments.

(4) Critical Infrastructure Protections (“CIPs”) Cost Recovery (Slides 54-56)

A. Background to CIPS Cost Recover Issue (Slide 55)

- **Alberta reliability standard – Cyber Security – BES Cyber System Categorization CIP-002-AB-5.1 is planned to be effective on October 1, 2017**
- **TransAlta’s Sundance Facility (units 1-6) would be the only aggregated generating facility classified with a Medium Impact Rating subject to additional expenditures**
- **In Proceeding 3443, the Commission directed the AESO state if these costs would recoverable under the ISO tariff or not**

Alberta Direct Connect Consumers Association:

ADC agrees with the AESO position that these costs are the responsibility of the market participant, and not load.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

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

IPCAA submits that these CIP costs are better assigned to the market participant that is incurring the costs than socializing them across all consumers.

TransCanada Energy Ltd.:

No comments.

B. AESO's proposed position in upcoming application (Slide 56)

- **Not recoverable under the tariff; generators should be individually responsible for the costs of complying with Alberta Reliability Standards, including CIPs**
 - **Based on AESO's internal FEOC assessment (costs that are directly assigned to the market participant are more efficient than if they are socialized);**
 - **Consistent with the treatment of other Alberta reliability standards that provide a benefit to the AIES and all market participants.**
 - **AESO's rationale will be included in the ISO tariff application and may include evaluation of tariff, cost causation and FEOC principles.**
-

Alberta Direct Connect Consumers Association ("ADC"):

ADC supports.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd.:

No comment.

Capital Power Corporation:

Capital Power disagrees with the AESO's proposed position, and believes it would unfairly impose costs on generators to comply with standards that, by design and intent, are being adopted to provide system benefit. The CIP Standards are being implemented to enhancing the reliability of the AIES. While the benefits will accrue to all users of the AIES, the *Alberta Reliability Standard Cyber Security – BES Cyber System Categorization CIP-002-AB-5.1* states the purpose is "To identify and categorize BES cyber systems and their associated BES cyber assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES cyber systems could have on the reliable operation of the bulk electric system." Therefore, it is not reasonable that the

cost of complying with standards beyond the “low” impact CIP Standard rating be assigned to the affected generators, particularly given that the ability for those generators to recover those costs would be highly uncertain given the competitive dynamics of Alberta’s competitive wholesale market. Capital Power submits that CIP costs beyond a “low impact” rating should be allocated to the system and collected through the AESO Tariff - not charged to the specific generator..

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta (“IPCAA”):

IPCAA supports the AESO’s proposed position.

TransCanada Energy Ltd.:

No comments.

(5) Application Process, Timeline and Next Steps (Slides 57 – 62)

C. The AESO discussed the status of a number of 2018 ISO tariff application scope items (Slide 36) and a 2018 ISO tariff tentative timeline.

Alberta Direct Connect Consumers Association (“ADC”):

ADC agrees that any tariff design considering the Coincident metered demand be investigated after this GTA. This matter has been raised in all GTA’s since 2006 and the AUC has approved this tariff mechanism every time. There is a strong and lengthy evidentiary record as to why the CPD method provides the right economic signal to minimize future system build for the benefit of all ratepayers. The ADC would be happy to share that with any interested parties.

AltaLink Management Ltd. (“AltaLink”):

As AltaLink has expressed to the industry, including the AESO, AltaLink is concerned that the current rate design (i.e. coincident peak charge) is resulting in cross-subsidization of transmission costs between customer classes. This tariff structure needs to be reviewed in 2018 with decisions implemented in 2019 tariff structures. AltaLink is open to a separate module to address this industry issue if it is not addressed within this AESO GTA, in order to enable expedience for the overall AESO tariff decision.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta:

Thank you for providing the update.

TransCanada Energy Ltd.:

No comments.

Additional Comments

ADC appreciates the opportunity to provide comments.

AltaLink requests the AESO confirm with stakeholders that the TRIP model will be updated and filed with the AESO's 2018 application.

Capital Power appreciates the opportunity to participate in the AESO's 2018 Tariff development.

DUC appreciates the opportunity to provide comments.

June 13, 2017

AESO Stakeholders
AESO 2018 ISO Tariff Consultation Participants

Dear Stakeholder:

Re: **Invitation to Attend Information Session on AESO 2018 ISO Tariff Application**

The AESO is finalizing the development of the 2018 ISO tariff application, which the AESO currently anticipates filing with the Alberta Utilities Commission by July 31, 2017. The AESO invites stakeholders to an information session to discuss the proposals that will be included in the application:

Date: Monday, June 26, 2017
Time: 1:00 pm to 4:00 pm
Place: Meeting Room 6006, 6th Floor, BP Centre, 240 – 4th Avenue SW, Calgary, Alberta.
Note that the glass doors on the 6th floor are locked; please knock to have them opened.
Teleconference: Within Calgary calling area: 403-410-3051, Conference ID 9232504
Outside Calgary calling area: 1-855-453-6957, Conference ID 9232504
RSVP: By 5 pm on **June 21, 2017** to, Tatiana Aparicio-Caris Tatiana.Aparicio-Caris@aesO.ca or 403-539-2664.

The AESO will present information on the following topics to be addressed in its 2018 ISO tariff application:

- transmission cost causation study update;
- point of delivery cost function update and options analysis;
- Rate DTS, *Demand Transmission Service*, update to reflect cost causation study and point of delivery function;
- Critical Infrastructure Protection (CIPs) Alberta reliability standard compliance cost recovery;
- tariff treatment of energy storage;
- update on Rider C, *Deferral Account Adjustment Rider*, amendment application;
- updated investment levels;
- terms and conditions amendments;
- response to the Commission's Proceeding 20922 closure letter; and
- application process.

The AESO plans to present information on these topics to facilitate discussion and will post a presentation before the meeting.

All information relating to the 2018 ISO tariff consultation is available on the AESO website at www.aeso.ca by following the path Rules, Standards and Tariff ► Stakeholder engagement ►

Public

2018 ISO tariff application. As well, new information posted by the AESO on this topic will be mentioned in the AESO stakeholder newsletter, which you can subscribe to at the bottom right of the AESO's home page at www.aeso.ca.

If you have any questions on the AESO's 2018 ISO tariff consultation, please contact me at 403-539-2555 in Calgary or by email to larhonda.papworth@aesocanada.com.

Yours truly,

LaRhonda Papworth
Manager, Tariff Design

cc: Doyle Sullivan, Director –Tariff Design

AESO 2018 ISO Tariff Consultation

Application Preview

June 26, 2017

AESO Office, Calgary

Public

- Session objectives_(slide 3)
- Application objectives_(slides 4)
- Transmission Cost Causation Study Results _(slides 6-13)
- Rates and Riders updated_(slides 14-36)
- Revised Terms & Conditions_(slides 37-45)
 - Substantive changes to allow for tariff mechanisms to address past cost allocation issues and Commission's closure letter from Proceeding 20922
 - Issue #1 – legislative framework
 - Issue #2 – advanced system-related classification of radial transmission projects
 - Issue #3 – load forecasting
 - Shift of AESO's position to require a non-refundable advancement charge if a load connection requires a system upgrade

Agenda (cont'd)

- Other matters_(slides 46-51)
 - Other revisions to terms and conditions
 - Include updated GUOC rates into ISO tariff
 - Tariff treatment for energy storage
 - Cost recovery of CIP Alberta reliability standards
 - Riders A1 - Dow Duplication Avoidance Tariff revision
- Tariff target timelines _(slide 52)
- Discussion and wrap-up_(slide 53)

Session objectives

- Provide an overview of upcoming 2018 ISO tariff application
- Provide draft calculated rates and investment based on 2017-2018 Budget Review Proposal, TFO applied-for or approved wires costs, Transmission Cost Causation Study results and results from POD cost function cost curve
- Provide tariff timeline targets

Application objectives

- Close off a number of past tariff initiatives
 - Cost classification proceedings
 - Point-of-delivery cost function (contract vs installed capacity)
 - Rider C, deferral account reconciliation process
- Capacity market and other issues raised by stakeholders during consultation to be addressed post-application:
 - Capacity market cost recovery
 - Export rates
 - Coincident metered demand recovery of bulk transmission
 - Review classification (demand and energy) method
 - Good electricity industry practice/investment policy
- Share with stakeholders as soon as possible the scope and timing of the additional work

Transmission Cost Causation Study Results

Raj Sharma

Preliminary 2018-2020 capital cost functionalization

Year/Function	Bulk	Regional	Point of Delivery
2016	66.9%	18.1%	15.0%
2018	57.5%	23.9%	18.6%
2019	56.5%	23.8%	19.6%
2020	55.1%	24.2%	20.7%

Preliminary 2018-2020 operating and maintenance cost functionalization

Year/Function	Bulk	Regional	Point of Delivery
2014-2016	20.8%	39.2%	40.0%
2018-2020	21.2%	36.5%	42.3%

Preliminary 2018-2020 non-capital costs to capital costs ratio

Year	Non-capital	Capital
2014	19.5%	80.5%
2015	18.0%	82.0%
2016	16.3%	83.7%
2018-2020	17.1%	82.9%

Preliminary combined 2018-2020 functionalization

Year/Function	Bulk	Regional	Point of Delivery
2016	59.4%	21.5%	19.1%
2018	51.3%	26.1%	22.6%
2019	50.5%	26.0%	23.5%
2020	49.3%	26.3%	24.4%

Preliminary final combined 2018-2020 functionalization

Includes revenue from regulated generation unit charge, and cost from Fort McMurray West 500kV project

Year/Function	Bulk	Regional	Point of Delivery
2016	59.2%	21.6%	19.2%
2018	51.2%	26.1%	22.7%
2019	52.4%	25.0%	22.6%
2020	51.2%	25.3%	23.5%

Bulk system classification

Results of update following the same minimum system methodology do not seem reasonable so the AESO is proposing to continue 2016 bulk system classification for 2018 to 2020.

500 kV Conductor	3x1590 ACSR	2x2156 ACSR
Cost per kM	\$2,100,000	\$1,900,000

240 kV Conductor	2x795 ACSR	2x1033 ACSR
Cost per kM	\$1,593,624	\$1,701,334

Class	Demand	Energy
2014-2016	93.1%	6.9%
2018-2020	93.7%	6.3%

Regional system classification

Results of update following the same minimum system methodology do not seem reasonable so the AESO is proposing to continue 2016 regional system classification for 2018 to 2020.

138/144 kV Conductor	1x266 ACSR	1x477 ACSR
Cost per kM	\$362,336	\$442,662

Class	Demand	Energy
2014-2016	88.2%	11.8%
2018-2020	87.4%	12.6%

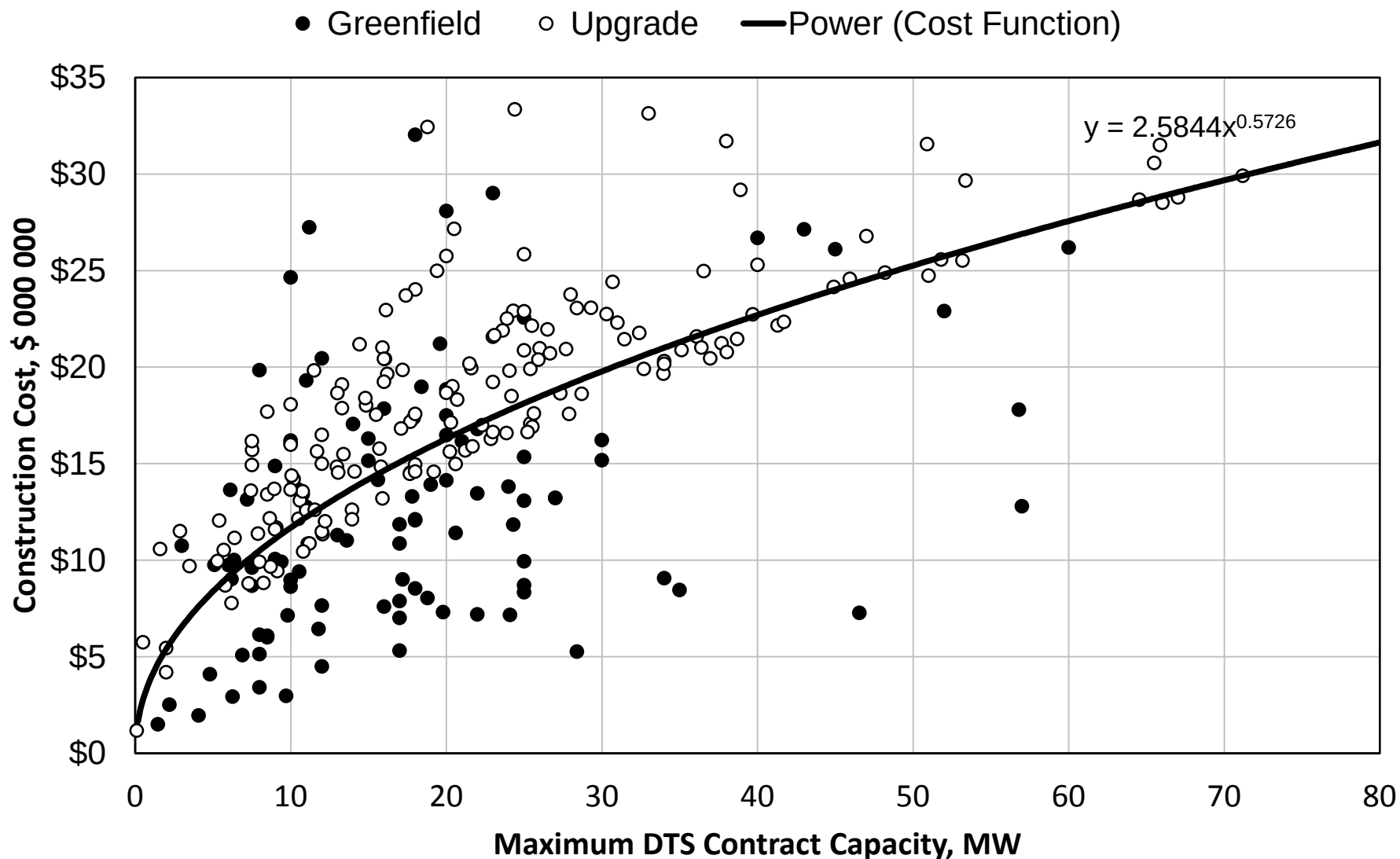
POD Cost Function Database, Rates and Investment

LaRhonda Papworth

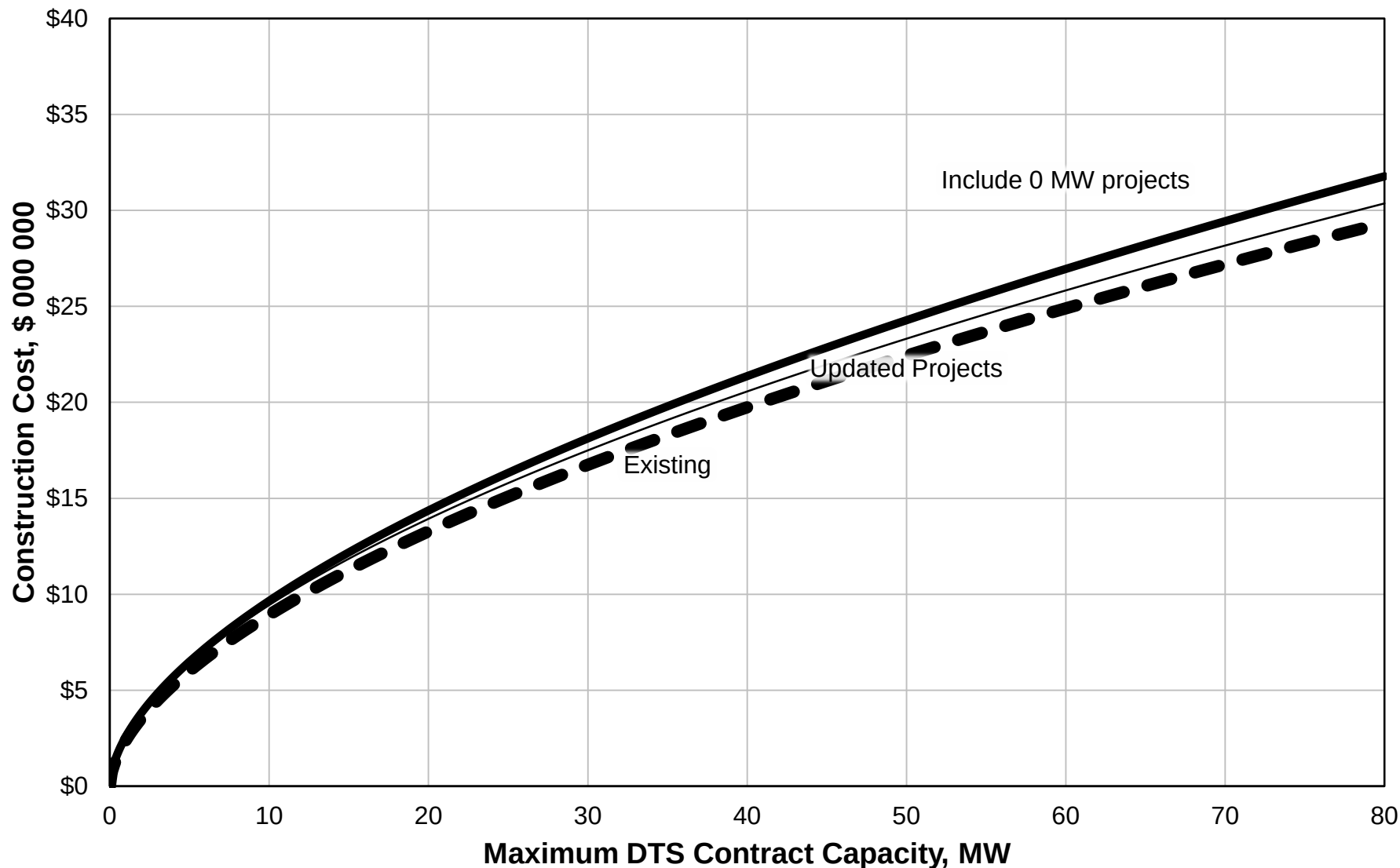
2017 POD cost function database includes a total of 285 projects

Type of Project	Number	Average Contract Capacity (MW)	Total Contract Capacity (MW)	Average Cost (\$ 000 000)	Total Cost (\$ 000 000)
Greenfield	112	21.9	2,017.7	\$14.6	\$1,338.9
Upgrade	173	7.7	1,386.2	\$3.4	\$599.4

Final cost function represents all 285 connection project data points



Updating project data had the largest impact on the existing cost function



Existing and proposed cost functions

- Existing cost function

$$\text{Costs} = \$2,392,400 \times \text{MW}^{0.5721}$$

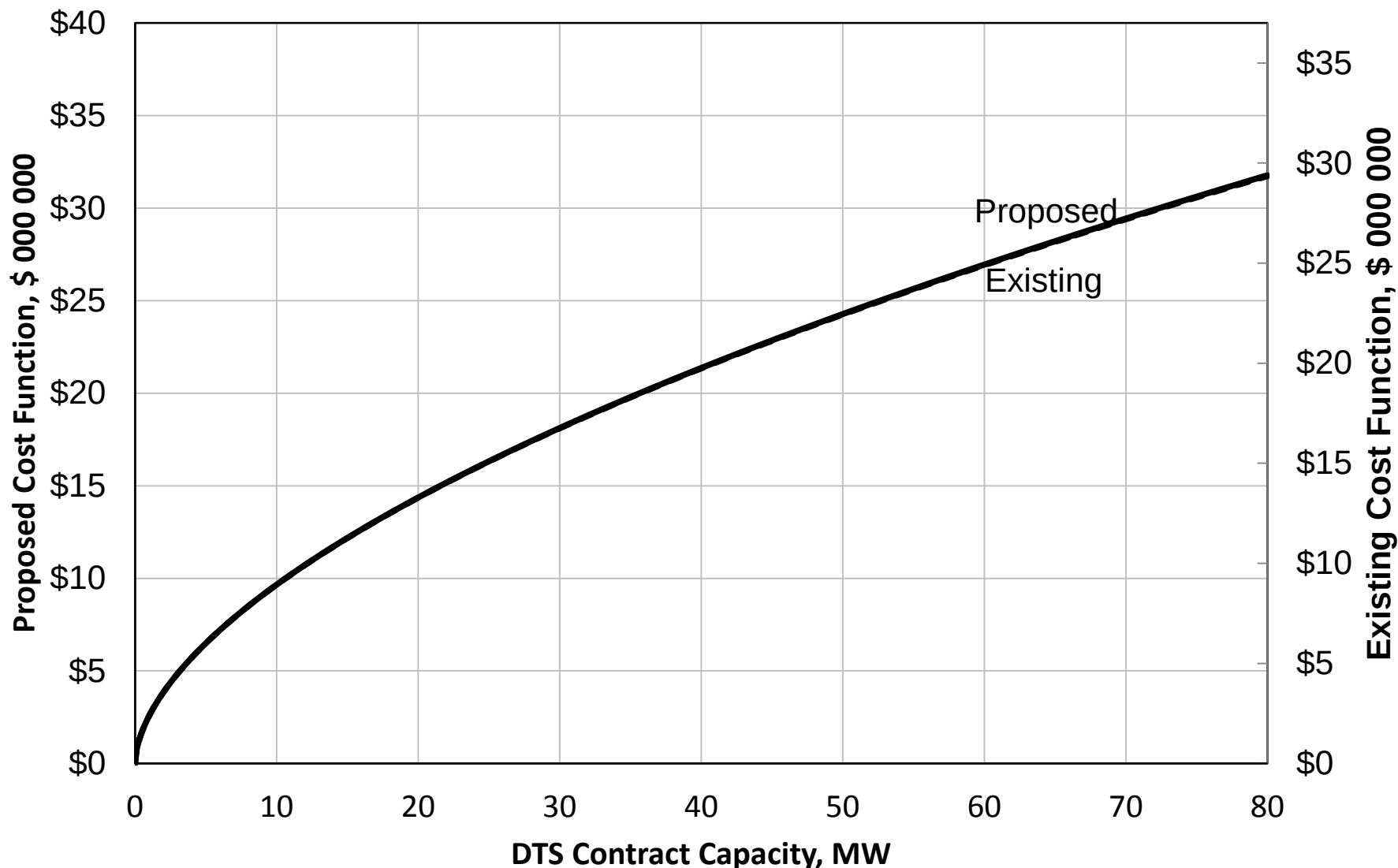
- Proposed cost function

$$\text{Costs} = \$2,584,400 \times \text{MW}^{0.5726}$$

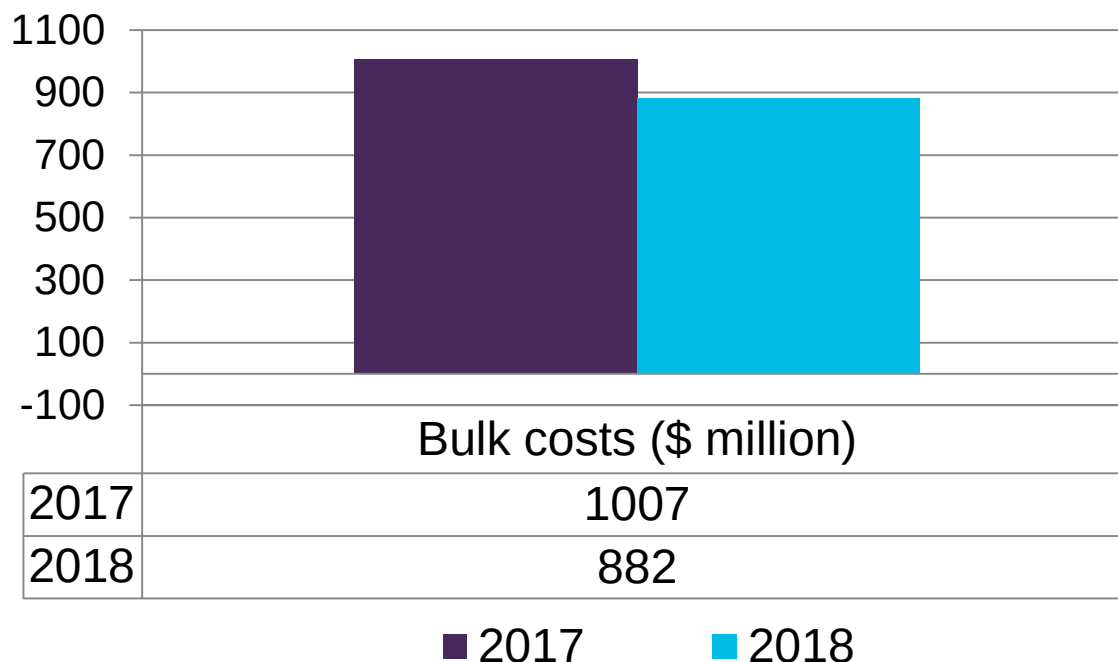
How are rates impacted?

- Revision of the cost function will affect the average rates paid for system access service by all market participants
 - The cost function provides the cost causation basis for the point of delivery charge in Rate DTS
- Point of delivery charge components are affected by the shape of the cost function, not the level

Changes to the shape of the cost function will impact rates



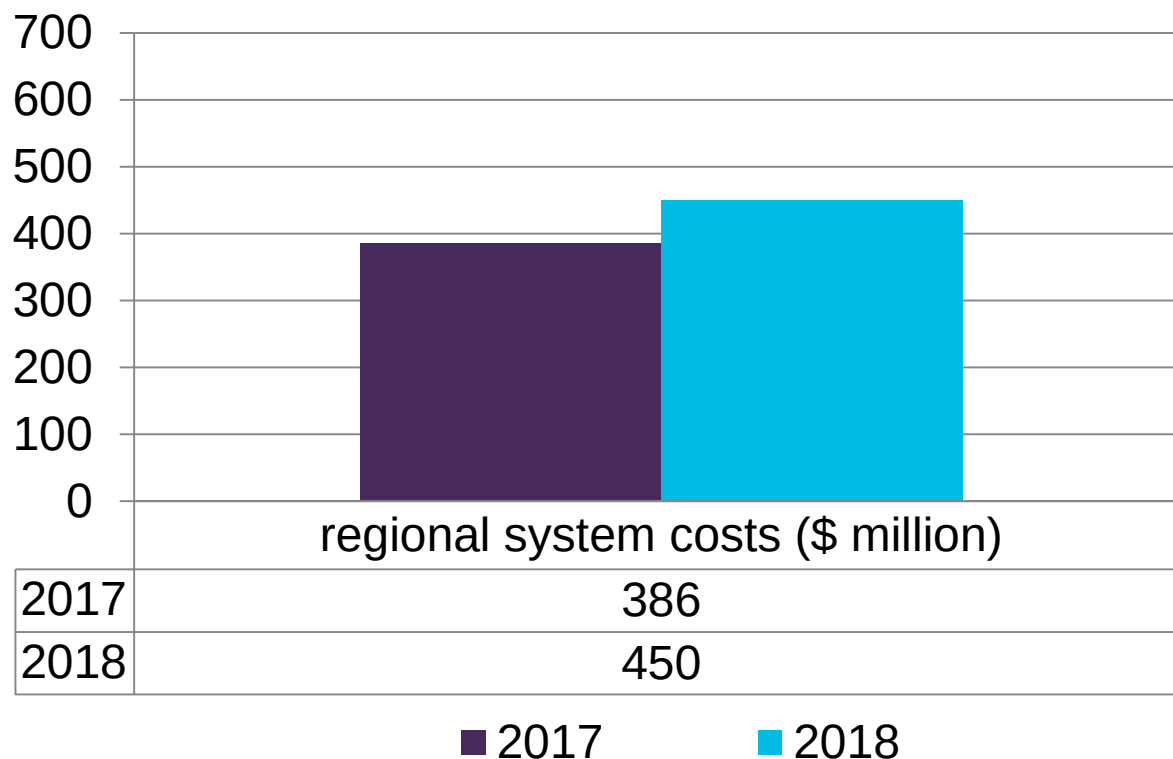
How is Rate DTS bulk system charge changing?



Rate DTS – Bulk system charge	2017	2018
Coincident demand charge (\$/MW/month)	10,670.00	9,219.00
Metered energy charge (\$/MWh)	1.25	0.99

Initial rate calculations. May change for application

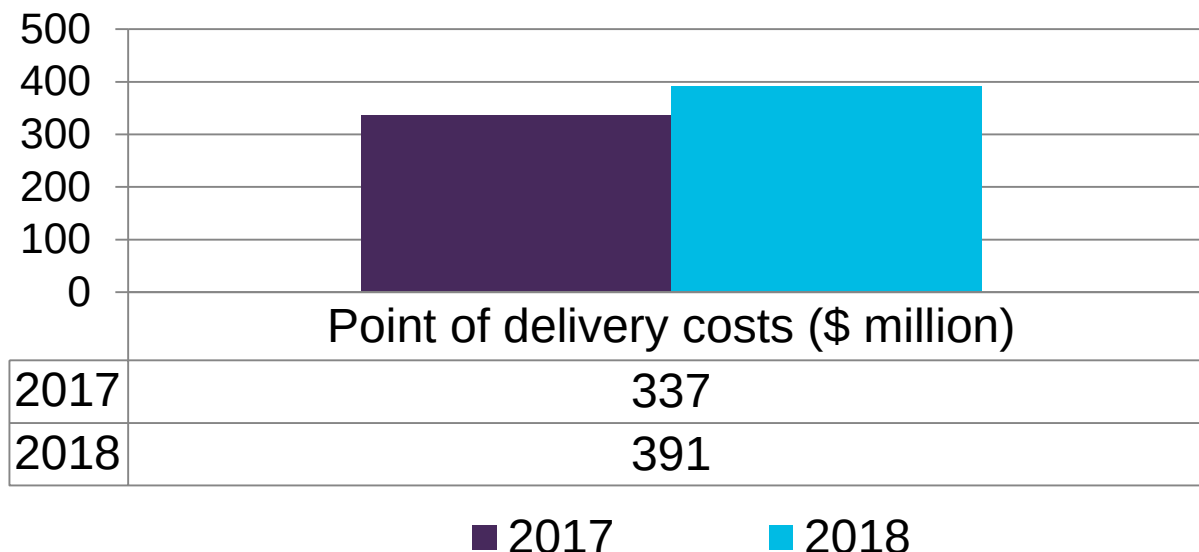
How is Rate DTS regional system charge changing?



Rate DTS – Regional system charge	2017	2018
Billing capacity charge (\$/MW/month)	2,356.00	2,694.00
Metered energy charge (\$/MWh)	0.87	1.01

Initial rate calculations. May change for application

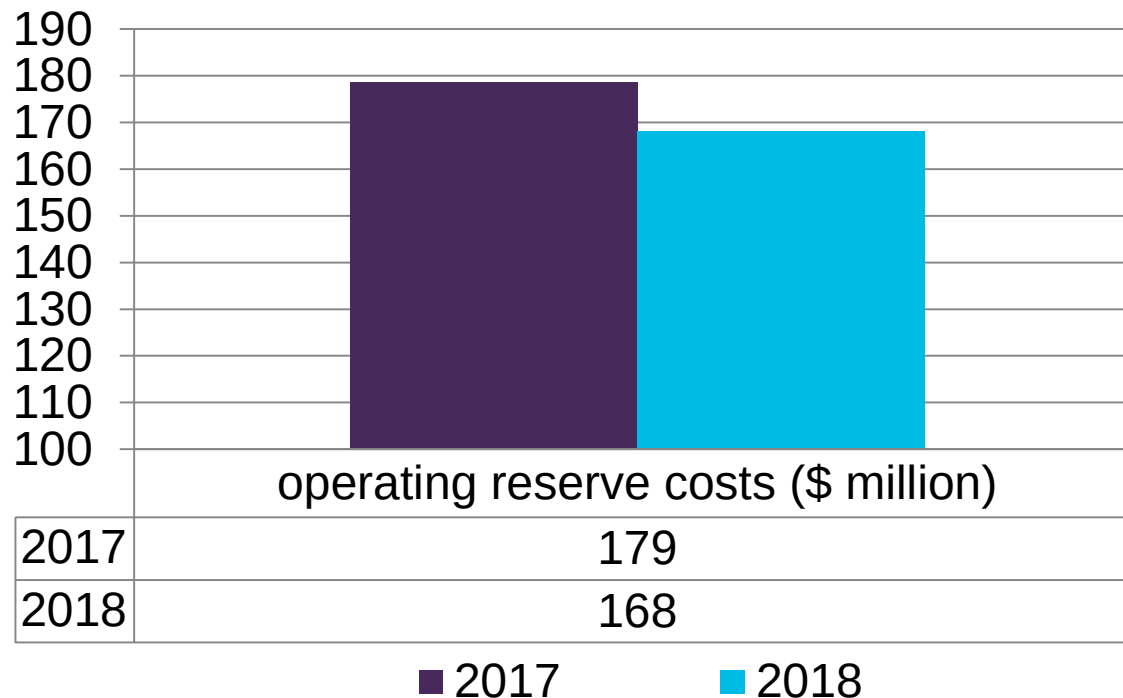
How is Rate DTS point of delivery charge changing?



Rate DTS – Point of delivery charge	2017	2018
Substation Fraction (\$/month)	8,789.00	10,109.00
First (7.5 x SF) MW (\$/MW/month)	3,559.00	4,100.00
Next (9.5 x SF) MW (\$/MW/month)	2,229.00	2,569.00
Next (23 x SF) MW (\$/MW/month)	1,555.00	1,795.00
All remaining MW (\$/MW/month)	1,007.00	1,157.00

Initial rate calculations. May change for application

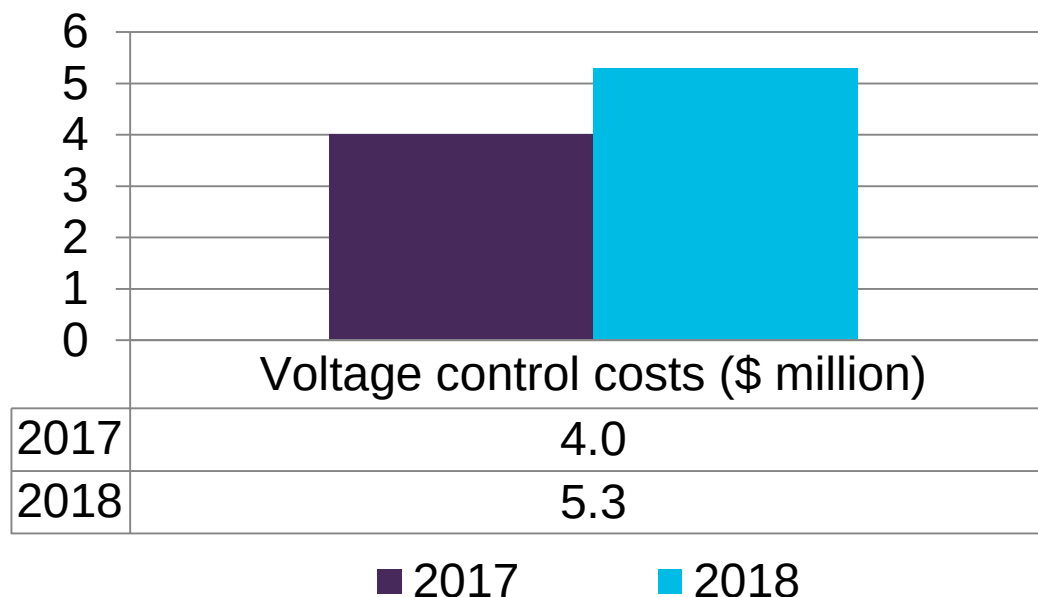
How is Rate DTS operating reserve charge changing?



Rate DTS – Operating Reserve Charge	2017	2018
Operating reserve charge (allocated hourly)	6.99%	6.58%

Initial rate calculations. May change for application

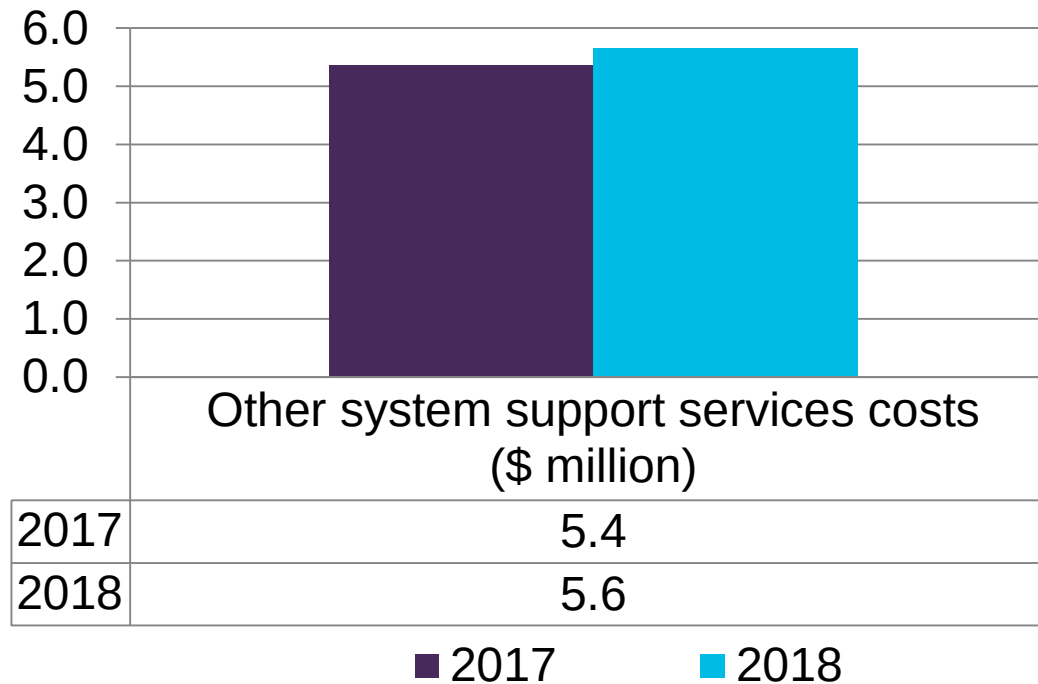
How is Rate DTS voltage control charge changing?



Rate DTS – Voltage control charge	2017	2018
Voltage control charge (\$/MWh)	0.07	0.09

Initial rate calculations. May change for application

How is Rate DTS other system support services charge changing?



Rate DTS – Other system support services charge	2017	2018
Other system support services charge (\$/MW/month)	46.00	47.00

Initial rate calculations. May change for application

How is Rate DOS changing?

- No change to Rate DOS language
- Rate DOS 7 Minute reflects full payment of usage (\$/MWh) components of bulk system and regional system, and operating reserves
- Rate DOS 1 Hour reflects additional contribution to fixed cost of bulk system and regional system over Rate DOS 7 Minute
- Rate DOS Term reflects additional contribution to fixed cost of bulk system and regional system over Rate DOS 1 Hour

Rate DOS	2017	2018
DOS 7 Minutes (\$/MWh)	4.99	4.80
DOS 1 Hour (\$/MWh)	16.47	15.67
DOS Term (\$/MWh)	94.79	103.71

Initial rate calculations. May change for application

How is Rate XOS changing?

- No change to Rate XOS language
- Rate XOS 1 Hour reflects full payment of usage (\$/MWh) cost of bulk system and regional system, plus components of operating reserve and fixed cost of bulk system and regional system

Rate XOS	2017	2018
XOS 1 Hour (\$/MWh)	7.63	7.24

Initial rate calculations. May change for application

How is Rate PSC changing?

- No change to Rate PSC language
- Rate PSC equals 79% of first four tiers and 100% of last tier of Rate DTS point of delivery charge
- Rate PSC compensates market participant whose connection does not include conventional transformation facilities

Rate PSC	2017	2018
Substation Fraction (\$/month)	6,939.00	7,986.00
First (7.5 x SF) MW (\$/MW/month)	2,809.00	3,239.00
Next (9.5 x SF) MW (\$/MW/month)	1,759.00	2,030.00
Next (23 x SF) MW (\$/MW/month)	1,228.00	1,418.00
All remaining MW (\$/MW/month)	1,006.00	1,157.00

Initial rate calculations. May change for application

How is Rate STS changing?

- Rate STS language change to include requirement for all behind the fence generating units must contract for Rate STS

Rate STS	2017	2018
System average loss factor (%)	4.44%	3.65%
Regulated generating unit connection cost charge (\$/MW/month)	95.00	75.28

How is Rate IOS changing?

- No change to Rate IOS language
- Rate IOS losses charge in an hour
 - $(\text{import interchange transaction}) \times (\text{Pool Price}) \times (\text{loss factor for the intertie})$
 - Rate IOS transaction fee of \$500 in a settlement period in which at least one Rate IOS transaction was approved

How big is the 2018 Rate DTS change?

Rate DTS Components	Percentage Change (from 2017)
Connection Charge	
Bulk System Charge — Demand	(13.6%)
Bulk System Charge — Usage	(20.8%)
Regional System Charge — Demand	14.3%
Regional System Charge — Usage	16.1%
POD Charge — Customer $\times$ SF	15.0%
POD — Demand $\leq (7.5 \times \text{SF})$ MW	15.2%
POD — Demand $> (7.5 \times \text{SF})$ to $\leq (17 \times \text{SF})$ MW	15.3%
POD — Demand $> (17 \times \text{SF})$ to $\leq (40 \times \text{SF})$ MW	15.4%
POD — Demand $> (40 \times \text{SF})$ MW	14.9%
Total connection charge	(2.0%)

Initial rate calculations. May change for application

How big is the Rate DTS change? (cont'd)

Rate DTS Components	Percentage Change (from 2017)
Operating Reserve Charge — % of PP	(5.9%)
Voltage Control Charge — Usage	28.6%
OSS Service Charge — Demand	2.2%

Total Rate DTS Tariff % Change	(2.5%)

Initial rate calculations. May change for application

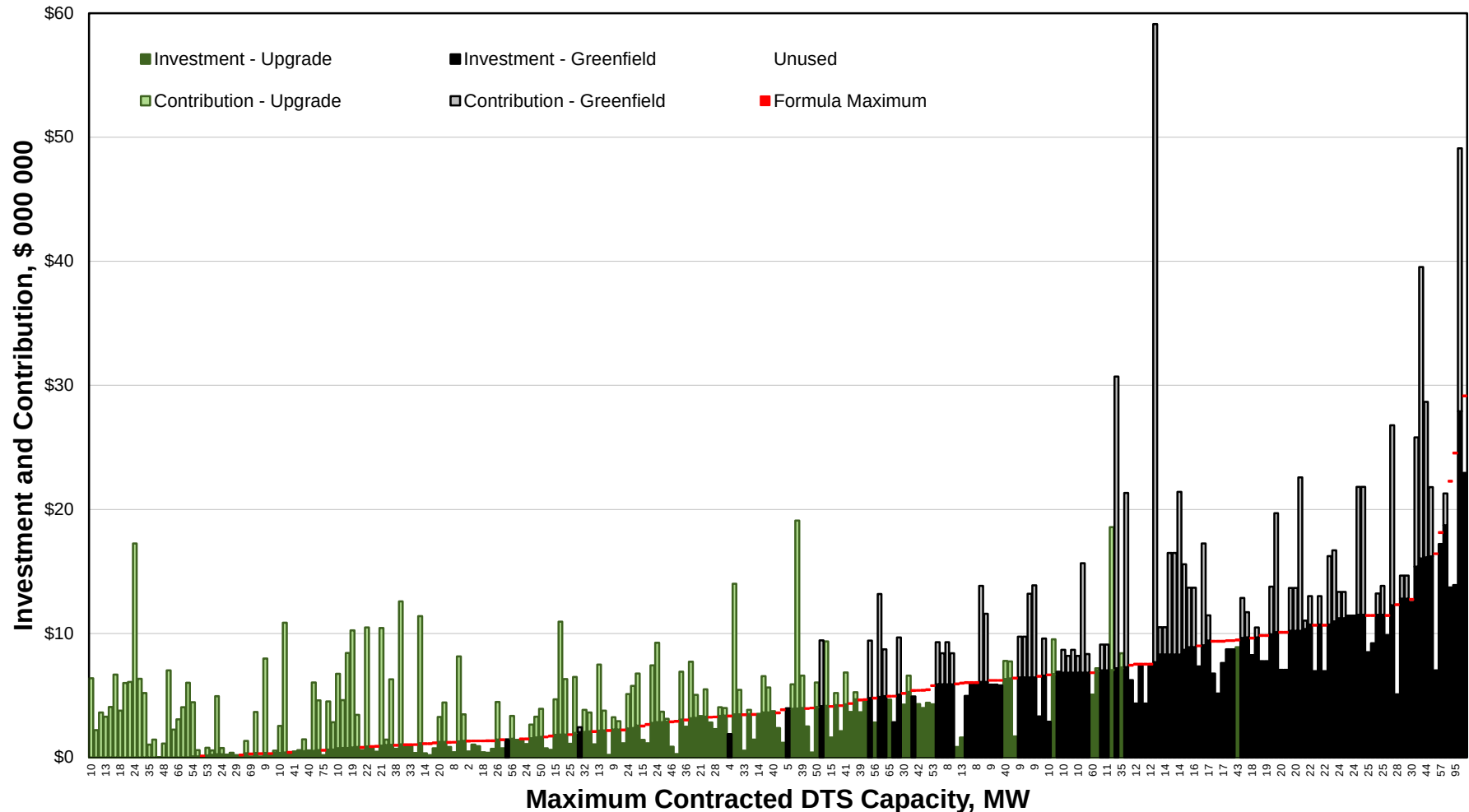
How big is the Rate STS change?

Rate STS Components	Percentage Change (from 2017)
Losses Charge — % of PP	(13.5%)
RGU Connection Costs — Demand	(20.8%)
Total Rate STS Tariff % Change	(13.9%)

Initial rate calculations. May change for application

Multiplier of 0.72 results in 60% investment coverage over all 285 projects

Investment and Contribution Using Proposed Investment Levels



Comparison of investment levels

Tier	2017 Investment	2018 Investment	PSC Investment
Substation fraction	\$80 150/year	\$72 950/year	\$15 320/year
First ($7.5 \times \text{SF}$) MW	\$32 450/MW	\$29 600/MW	\$6 220/MW
Next ($9.5 \times \text{SF}$) MW	\$20 350/MW	\$18 550/MW	\$3 900/MW
Next ($23 \times \text{SF}$) MW	\$14 200/MW	\$12 950/MW	\$2 720/MW
All remaining MW	\$9 150/MW	\$8 350/MW	\$0/MW

Initial calculations. May change for application

Terms and Conditions

Doyle Sullivan

Tariff principles driving cost classification change

1. Strong locational price signal to load and generation
 - Sending adequate price signals reflecting cost causation
 - Greater emphases on adequate price signals as compared to certainty, with respect to the classification of system transmission project costs, in order to restore the balance between these two principles
 - Advancement costs as price signals to market participants.
 - Advancement costs should be actively used, where required.
 - Presumption of customer-related costs if “shades of grey”
2. System facilities are only built when there is sufficient certainty
 - Use AESO discretion to ensure that future development of transmission projects is achieved in both a timely and economic manner
 - AESO’s willingness to exercise its discretion (T-reg s. 15(2) and (3))

Tariff principles driving cost classification change (cont'd)

3. Adjust in-service dates to reduce transmission costs, if possible, or assess “accelerated costs” to market participant
 - Incent change in behavior by the end-use customer to make an economic decision to shift its in-service date
 - Incremental transmission project costs related to the advancement of in-service dates should be borne by the customer
 - In-service dates are reasonable targets that are moveable
4. Increased communication between market participant, TFO and AESO to reduce costs
 - Tariff provisions to clarify the role expected of a TFO in relation to project execution
5. Generation does not pay for system facilities
 - They are only responsible for “local interconnection costs”, the GUOC and losses, per the *Transmission Regulation*
 - Generators not charged for advancement or accelerated costs

Tariff principles driving cost classification change (cont'd)

6. Commission-initiated proceeding closure letter

- Issue #1 – legislative framework

AESO will address this issue in the application. We don't anticipate our responses to Issue #1 will result in changes to the terms and conditions

- Issue #2 – advanced system-related classification of radial transmission projects

To address this issue, the AESO will be proposing revisions to the terms and conditions.

- Issue #3 – load forecasting

AESO will address this issue in the application. In particular, proposed changes to the terms and conditions include project certainty, critical information from market participants regarding projects to ensure that the ISO tariff incents timely and accurate information sharing between the AESO and market participants.

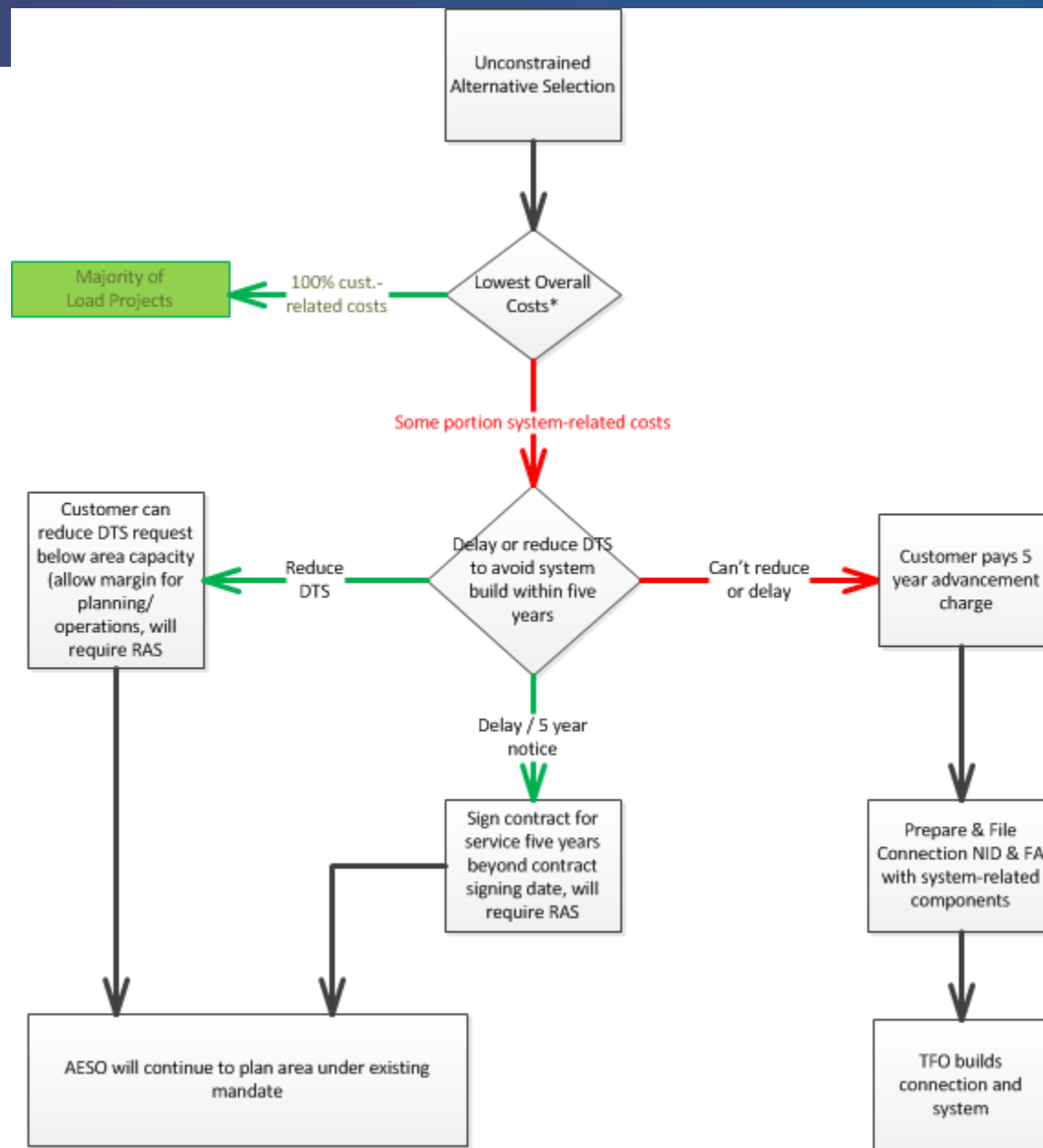
Tariff mechanisms to be applied for in AESO's terms and conditions

- Critical requirements for connection projects to ensure that market participants are applying for projects with high degree of confidence
 - If critical requirements (MWs, ISD or location) change, the AESO must reassess or cancel project
 - Area assessment required if more than one SASR in an area is submitted
- Lowest overall long-term costs (distribution + connection + system-related costs + non-wires costs) evaluation of connection alternatives
 - Unconstrained alternative comparison, generation connections allowable with permanent N-1 RAS
 - AESO may apply discretion to meet its planning obligations

Tariff mechanisms to be applied for in AESO's terms and conditions

- For load, if lowest overall long-term cost alternative includes portion of system-related costs*, market participant will be required to pay 5-year advancement charge, or:
 - Market participant can reduce MWs and allow time for planning and operational flexibility; or
 - Market participant can sign contract for service out 5 years to allow sufficient notice for the AESO to forecast and plan.
- For generation, Generator Unit Owner's Contribution to be paid earlier in connection process

Load evaluation process



Tariff mechanisms to be applied for in AESO's terms and conditions

- Accelerated construction costs provision to ensure that market participants are charged for additional system costs that could have been saved if the market participant had been willing to adjust their in-service date.
 - A choice to adjust in-service date and save costs or be charged the additional cost.

Tariff mechanisms to be applied for in AESO's terms and conditions

- Project certainty definitions to allow the AESO to reasonably forecast and plan
 - Earlier signing of DTS and STS contracts (prior to NID filing) to ensure the commitment of market participants aligns with forecasting, planning and regulatory processes in connecting and planning system reinforcements
 - The market participant will also be required to:
 - For load connections, payment of 5-year advancement cost prior to NID filing (if applicable)
 - For generation connections, payment of Generator Owner's Unit Contribution
 - Therefore, at the time of NID filing, the project will have certainty to be included in AESO forecasting and planning processes

Other Items

LaRhonda Papworth

- Minor changes to terms and conditions beyond discussed earlier
 - To remove “radial . . . plan to be looped”
 - Clarify that generator’s STS connection only pays local interconnection costs, does not pay for system or advancement costs
 - Add provisions to allow shared costs calculations for facilities to be shared with system
 - Update provisions to allow for abbreviated needs approval process, current system access service agreements, market participant choice, and transmission direct connected distribution customers.

- Administrative clean up of other terms and conditions
 - Sections 1, 2, 3, 6, 7, 12, 13, 14 and 15
- Update GUOC rates and include in Section 10 of tariff
 - Regional \$/MWs updated to reflect current expectation of region load and supply (2018 – 2020)
 - Include rates as part of ISO tariff. Currently rates are in a document outside of the tariff
 - Changing terms to be applicable to maximum capability (MC) not Rate STS MWs

- Energy Storage
 - Confirm that Rate DTS and Rate STS will be applicable to these facilities, and these facilities will be considered dual-use
 - Rates and terminology in the tariff will be updated to address energy storage facilities (primarily affects applicability subsections in tariff).

- CIPs Cost Recovery

- Responding to the Commission's request from Proceeding 3443 that the AESO address the issue of cost recovery for CIP reliability standard compliance in its tariff application
- The AESO will propose that the costs of complying to CIP standards should be borne by the market participant, based on the AESO's FEOC analysis
- It is the role of the Commission under Section 30(2)(a)(iv) of the Electric Utilities Act to determine whether this is appropriate.

- Rider A1 – Dow duplication avoidance tariff amendment
 - Modernize and update current Rider A1 to allow for expiry in 2041
 - Include annual forecast benefit amounts from Dow to rate payers to recover annual O&M and losses costs to account for the credible bypass threat option, if it had been built.

Tariff timing targets

Step	Timing
File Rider C amendment application	As soon as possible
File 2018 ISO tariff application	Early August 2017
File 2016 deferral account reconciliation	September 2017
File 2018 ISO tariff update application	September – October 2017

Q&A

The information contained in this document is for information purposes only, and the AESO is not responsible for any errors or omissions. Further, the AESO makes no warranties or representations as to the accuracy, completeness or fitness for any particular purpose with respect to the information contained herein, whether express or implied. Consequently, any reliance placed on the information contained herein is at the reader's sole risk.

January 30, 2018

Dear Market Participants:

Re: Proceeding 22942 – Consultation on 12 Coincident-peak Method and Refunding FortisAlberta Customer Contributions by AltaLink

The Alberta Electric System Operator (AESO) is requesting comments on the following proposed process to address the Alberta Utilities Commission (AUC) direction in its January 19, 2018 letter in Proceeding 22942¹ regarding (1) the coincident metered demand rate design issue and (2) distribution facility owner customer contribution issues.

AESO Proposed Process:

A. The AESO will offer an opportunity to all participants to prepare submissions to be presented in a facilitated stakeholder session or sessions. The AESO will be a participant in the session(s) and will invite AUC staff to attend as observers. The submissions will be made available for all participants' review in advance of the session(s). The submissions should include:

1. **Coincident Metered Demand Issue:**

- a. A summary of each participant's position for the bulk recovery methodology, including:
 - i. A recommendation to change the methodology or maintain the existing coincident metered methodology;
 - ii. Any analysis completed by the participant, as well as noting any further data or data analysis that may be required (by the AESO or others); and
 - iii. If a methodology change is recommended, the recommended timing of when the change should be made.
- b. The participant's proposed weighting of the following five (5) rate design principles applicable to the bulk recovery methodology:²
 - i. Recovery of the total revenue requirement;
 - ii. Provision of appropriate price signals that reflect all costs and benefits, including in comparison with alternative sources of service;
 - iii. Fairness, objectivity, and equity that avoids undue discrimination and minimizes inter-customer subsidies;

¹ Exhibit 29242-X0112.

² Proceeding 29242, 2018 ISO Tariff Application, Exhibit 29242-X0002.01, para 92.

- iv. Stability and predictability of rates and revenue; and
- v. Practicality, such that rates are appropriately simple, convenient, understandable, acceptable and billable.

2. Distribution Facility Owner Customer Contribution Issue:

- a. AltaLink to prepare a summary of its position in regards to FortisAlberta Inc.'s customer contributions as raised in AltaLink's 2017-2018 general tariff application;
 - b. Other interested participants to summarize their position regarding the treatment of FortisAlberta Inc.'s customer contributions as raised in AltaLink's 2017-2018 general tariff application; and
 - c. AltaLink and the other participants to indicate whether AltaLink's proposal should apply to all DFOs or only to Fortis (together with a supporting rationale).
- B. The AESO is initially proposing to address both issues in the same stakeholder sessions, however, depending on the interest and the number of submissions, the AESO may break this into two separate sessions.
- C. After each presentation, there will be a question and answer period for all participants to ask clarifying questions.
- D. Before the close of a facilitated session, next steps can be determined that may include:
- a. Requests for additional facilitated sessions to present further submissions;
 - b. Requests for additional data and analysis; and
 - c. Requests for additional facilitated session(s) to document options, rate design principles' weighting and timing required for any changes.
- E. After the facilitated sessions have concluded, the AESO will host a follow up session to present the recommendations that it proposes to file with the AUC in a revised 2018 comprehensive ISO tariff application.

The AESO intends to inform the AUC before March 30, 2018 of the planned process and any status updates available.

Market participants can submit their comments regarding the proposed process by way of a letter to ISOTariffnotice@aeso.ca by February 8, 2018. In your letter, please advise if you plan to participate in the facilitated session(s), indicate the issue(s) you intend to address, your position in regards to the issue(s) (whether you support a change or not, or whether you are neutral) and whether you intend to present a submission in support of your position.

Yours truly,

Doyle Sullivan, P. Eng
Director, Tariff Design

cc: Miranda Keating Erickson, Vice-President, Markets

February 22, 2018

Dear Market Participants:

Re: Proceeding 22942 – Update Regarding Consultation on 12 Coincident-peak Method and Refunding FortisAlberta Customer Contributions by AltaLink

On January 30, 2018, the Alberta Electric System Operator (“AESO”) posted a letter to its website inviting comments from market participants regarding the AESO’s proposed consultation process to address the Alberta Utilities Commission (“AUC”) direction in its January 19, 2018 letter¹ regarding (1) the coincident metered demand rate design (“12 CP”) and (2) the distribution facility owner (“DFO”) customer contribution issues. The AESO also requested market participants to indicate whether they intend to participate in the proposed process and to what extent.

Twenty (20) parties responded and all, except one who was silent on the issue, indicated that they would participate if the AESO moves forward with the proposed process. Concurrent with posting this letter, the AESO is also posting a matrix that summarizes the comments received by the AESO, either directly or filed with the AUC.²

Only two parties expressed any concern with the proposed process – EPCOR Distribution and Transmission Inc. (“EPCOR”) and the Office of the Utilities Consumer Advocate (“UCA”).

EPCOR suggests that the AESO’s proposed process is not consistent with the AUC’s direction in its January 19, 2018 letter regarding the AESO being given time to conduct an analysis, consult with parties and prepare evidence on the issues of the 12 CP method and, if necessary, the DFO customer contribution issue. EPCOR expresses surprise that the AESO would initiate a process that does not contemplate the AESO providing any analysis to parties. Further, EPCOR claims that the proposed process contemplates steps that appear “to be little more than a duplication of the [AUC’s] regulatory approval process, with participants being subject to questioning by other parties and potentially being required to provide follow-up information.”

The UCA suggests that the AESO is “requiring” parties to “file a written submission and/or analysis in advance of the sessions and prior to the AESO amending its application.”

¹ Exhibit 29242-X0112.

² The Office of the Utilities Consumer Advocate and the Consumers Coalition of Alberta filed their responses in Proceeding 22942, as Exhibit 22942-X0117 and Exhibit 22942-X0118, respectively.

It appears to the AESO that there has been a misunderstanding by these two parties regarding the AESO's intentions for the proposed consultation process. The AESO is not purporting to "require" parties to participate or make presentations in the consultation process, or to duplicate the AUC process.

The high level intention of the consultation process is to provide participants with an opportunity for direct discussions with other participants and the AESO in order to express any concerns they may have and present information that they believe will be of value in supporting their views. The AESO has not conducted any further analyses or developed any alternative position beyond what was presented in the AESO's 2018 comprehensive ISO tariff application. Information and analysis presented by participants will assist the AESO in assessing whether a change to the 12 CP methodology or the DFO customer contribution policy is warranted.

Whether and how participants present information is entirely within their own discretion. There is no requirement for any party to present its views and, for those who wish to make presentations, the degree of participation could range from simply providing high level thoughts in a PowerPoint presentation to providing analysis that could be used in a regulatory filing.

The process proposed by the AESO in its January 30, 2018 letter was seen by the AESO as the most efficient process to:

- (a) engage with interested parties;
- (b) provide participants with the opportunity, but not an obligation, to share their views and, if they wish, explain the reasons for holding those views;
- (c) consider any analysis that participants may have conducted to this point;
- (d) provide participants with the opportunity to ask questions and gain clarity regarding the concerns or positions of other participants;
- (e) provide the opportunity to request additional data from the AESO;
- (f) provide the opportunity to request that the AESO conduct and provide analysis; and
- (g) assist, in the most efficient and timely manner and having regard to the views of participants, the AESO in developing its position regarding the 12 CP and DFO customer contribution issues and prepare and file evidence regarding those matters.

The AESO considers its proposed process to be consistent with the AUC's January 19, 2018 ruling.

Having regard to the level of interest of parties to participate in the process, the AESO has decided to move forward with its proposed approach. The AESO will however be splitting the two issues into two separate sessions. Set out below are the first consultation process steps and dates:

Issue 1: 12 CP Methodology

1. March 12, 2018 - 9 am to 3 pm (detailed agenda to follow)
2. March 26, 2018 - 9 am to 3 pm (agenda to be determined at end of March 12 session)

Issue 2: DFO Customer Contribution Issue

1. March 5, 2018 - 1 pm to 3 pm

Please RSVP to isotariffnotice@aeso.ca with information regarding who will be attending from your company/association and, if you indicated that you were going to present information at the initial session, the amount of time you will require, including allowing time for questions, and the type of audio/visual tools that you will require. A detailed agenda will follow once the AESO has a final listing of attendees and presentation times.

It should also be noted that some parties, in their comments regarding the AESO's proposed process, raised issues that are outside the scope of the 12 CP and DFO customer contribution issues. The AESO will not be addressing these other issues as part of its consultation process.

Yours truly,

Doyle Sullivan, P. Eng
Director, Tariff Design

cc: Miranda Keating Erickson, Vice-President, Markets

Date of Request for Comment: <u>January 30, 2018</u> Period for Comments: <u>January 30, 2018</u> through <u>February 8, 2018</u>	
AESO Request	Market Participant Comments and/or Alternative Proposal
The Alberta Electric System Operator (AESO) is requesting comments on the following proposed process to address the Alberta Utilities Commission (AUC) direction in its January 19, 2018 letter in Proceeding 229421 regarding (1) the coincident metered demand rate design issue and (2) distribution facility owner customer contribution issues. <u>AESO Proposed Process:</u> A. The AESO will offer an opportunity to all participants to prepare submissions to be presented in a facilitated stakeholder session or sessions. The AESO will be a participant in the session(s) and will invite AUC staff to attend as observers. The submissions will be made available for all participants' review in advance of the session(s). The submissions should include: 1. <u>Coincident Metered Demand Issue:</u> a. A summary of each participant's position for the bulk recovery methodology, including: i. A recommendation to change the methodology or maintain the existing coincident metered methodology; ii. Any analysis completed by the participant, as well as noting any further data or data analysis that may be required (by the AESO or others); and iii. If a methodology change is recommended, the recommended timing of when the change should be made. b. The participant's proposed weighting of the following five (5) rate design principles applicable to the bulk recovery methodology:² i.	Access Pipeline Inc. Access Pipeline is responding to your January 30, 2018 request for comments on AESO's proposed process. Access plans to participate; our interest is the Coincident Metered Demand Issue. Currently, we are neutral relative to this issue; however, as a direct-connected load customer this issue has potential to impact our service cost. Our intent is to monitor the proceeding, reserving the right to participate more actively at our discretion. Alberta Direct Connect Consumer's Association (ADC) The Alberta Direct Connect Consumer's Association "ADC" is supportive of the AESO's proposed consultation process. The ADC submits the following comments: 1. The ADC intends to fully participate in the Coincident Metered Demand Issue. 2. The ADC does not intend to participate in the Distribution Facility Owner Customer Contribution Issue. 3. The ADC is supportive of the AESO's Coincident Peak Bulk system rate design and does not support any change to the rate design. Our view is supported by the ample evidence in prior AESO GTA's that has informed AUC decisions on 12 CP. 4. The ADC is prepared to present a submission in support of the AESO position. The ADC requests that the session be scheduled outside the dates of Feb 26th to March 2nd to avoid conflict with holiday schedules. ADC would also appreciate having an option to remotely connect to the session to provide a cost-effective way for our subject matter expert to understand the perspective of other intervenors. AltaGas Ltd. As noted in the proceeding, AltaGas is an energy infrastructure company with significant load, cogeneration, peaking generation, as well as a portfolio of commercial and industrial customers in Alberta.

Recovery of the total revenue requirement; ii. Provision of appropriate price signals that reflect all costs and benefits, including in comparison with alternative sources of service; iii. Fairness, objectivity, and equity that avoids undue discrimination and minimizes inter-customer subsidies; iv. Stability and predictability of rates and revenue; and v. Practicality, such that rates are appropriately simple, convenient, understandable, acceptable and billable. 2. <u>Distribution Facility Owner Customer Contribution Issue:</u> a. AltaLink to prepare a summary of its position in regards to FortisAlberta Inc.'s customer contributions as raised in AltaLink's 2017-2018 general tariff application; b. Other interested participants to summarize their position regarding the treatment of FortisAlberta Inc.'s customer contributions as raised in AltaLink's 2017-2018 general tariff application; and c. Altalink and the other participants to indicate whether AltaLink's proposal should apply to all DFOs or only to Fortis (together with a supporting rationale). B. The AESO is initially proposing to address both issues in the same stakeholder sessions, however, depending on the interest and the number of submissions, the AESO may break this into two separate sessions. C. After each presentation, there will be a question and answer period for all participants to ask clarifying questions. D. Before the close of a facilitated session, next steps can be determined that may include: a. Requests for additional facilitated sessions to present further submissions; b. Requests for additional data and analysis; and c. Requests for additional facilitated session(s) to document options, rate design principles' weighting and timing required for any changes.	Many Alberta market participants including AltaGas manage risks by drawing upon a portfolio. AltaGas considers it important that all power market participants have the opportunity and continued freedom to manage the load profile risks of customers in the most convenient and economically efficient ways possible. Sometimes these load profiles coincide with the AESO's coincident peak metric. As part of risk management it is rational to have generation units dispatched, or in merit, to offset higher demand from customers and any associated costs. AltaGas considers some of AltaLink's positions as unreasonable and AltaGas reserves the right to intervene if necessary to ensure that an AltaLink style tariff doesn't preclude rational risk management practices in the wholesale electricity market. AltaGas intends on monitoring the proceeding primarily as an observer and as an advocate for flexibility in managing risks in the electricity market. Should there be any changes as a result of the consultation and proceeding 22942, AltaGas proposes they be prospective from the date of an AUC decision. I would like an invitation to any facilitated session to monitor any dialogue that would inhibit risk management. I don't anticipate making any submissions in the consultation, but AltaGas reserves the right to do so if it considers it necessary. AltaGas is unlikely to take a strong position on the principles of rate design, bulk recovery methodology, or customer contribution issues unless they limit or prohibit AltaGas' ability to manage its commercial and industrial customers. AltaLink Management Ltd. AltaLink intends to participate in all facilitated session(s) proposed by the AESO in its consultation process. AltaLink is concerned about rate design issues connected to the AESO's Cost of Service Study and the resulting coincident metered demand rate. In addition, AltaLink also has concerns about the Distribution Facility Owner (DFO) Customer Contribution Issue. With respect to the Coincident Metered Demand Issue, AltaLink submits change is required to the current rate design where bulk system transmission costs are recovered through a 12 coincident peak (CP) charge. AltaLink submits that the CP charge sends an improper economic signal which leads to the cost avoidance of bulk system costs. As a result there is inappropriate cost shifting among transmission users so that some users who are taking advantage of the transmission system are not paying their fair share of the embedded costs of the system. With respect to the DFO Customer Contribution Issue, under the AESO rules, the DFO may be required to make a contribution, associated with requested construction of transmission facilities. The contribution from the DFO is an offset to the Transmission Facility Owner's (TFO) rate base. AltaLink submits that the issue with this customer contribution approach for transmission capital investments is that it creates a situation that: 1) provides the DFO, rather than the TFO, with a regulated return on transmission assets that it does not build, own, operate or maintain; 2) results in the TFO incurring all the business risk associated with building, owning, operating and maintaining the transmission assets without any return to compensate for those business risks; and 3) may be

E. After the facilitated sessions have concluded, the AESO will host a follow up session to present the recommendations that it proposes to file with the AUC in a revised 2018 comprehensive ISO tariff application. The AESO intends to inform the AUC before March 30, 2018 of the planned process and any status updates available. Market participants can submit their comments regarding the proposed process by way of a letter to ISOTariffnotice@aeso.ca by February 8, 2018. In your letter, please advise if you plan to participate in the facilitated session(s), indicate the issue(s) you intend to address, your position in regards to the issue(s) (whether you support a change or not, or whether you are neutral) and whether you intend to present a submission in support of your position.	more costly to current DFO customers since, compared to alternative approaches, it fails to provide clear price signals concerning DFO investment decisions in transmission related assets. AltaLink intends to address both issues in its participation in the facilitated session(s), including presenting submissions in support of AltaLink's position as well as proposals that AltaLink submits will alleviate the concerns that it has outlined above. ATCO Electric On January 30, 2018, the AESO posted a letter to its website inviting market participants to provide comments by February 8, 2018 regarding the AESO's proposed consultation process for the 12 CP method and DFO customer contribution issues which have been raised in its 2018 AESO Tariff Application. The AESO's letter also requests information regarding the scope of intended participation by market participants in the process. Accordingly, ATCO Electric submits this letter to indicate its interest in participating in the above noted consultation process addressing both the 12 CP method and DFO contribution issues. At this time, ATCO Electric is not advancing an alternative methodology, but as previously indicated is of the view that the 12 CP method for recovering bulk system costs should be reviewed during the 2018 AESO Tariff to determine whether it continues to remain the appropriate methodology for recovery of bulk system costs. With respect to the second issue regarding the Distribution Facility Owner Customer Contributions, ATCO Electric has yet to determine its position on this matter and will be able to provide further comment once Altalink's position on the issue is known and the implications to other DFOs are understood. ATCO Electric looks forward to participating in these sessions and does not expect to present any formal submissions at this time, however ATCO Electric reserves the right to do so as the sessions proceed. ATCO Power On January 30th, 2018, the AESO posted a notice inviting stakeholders to declare their intention to participate in a facilitated stakeholder session to discuss the 12CP Method and DFO Customer Contributions issues that have been raised as part of Proceeding 22942 – 2018 AESO Tariff Application. ATCO Power is a registered participant in Proceeding 22942 and hereby advises the AESO of our intention to participate in the AESO's facilitated stakeholder session on the 12CP and DFO Customer Contribution matters. ATCO Power does not intend to present any material on the issues at hand and does not have a formal position on either matter.

	BC Hydro and Power Authority BC Hydro is a Market Participant under the Independent System Operator tariff (ISO Tariff) since it purchases Fort Nelson Demand Transmission Service (FTS) at a point of delivery at Fort Nelson, British Columbia. As such, BC Hydro is interested in the coincident metered demand rate design issue. Per the ISO Tariff, the coincident metered demand is established based on the sum of the metered demands for all Demand Transmission Service (DTS) and FTS Market Participants. The Bulk System Charge and the Regional System Charge for the ISO Tariff Rate DTS and Rate FTS are currently the same. Since the ISO Tariff Rate FTS may be affected by the outcome of the consultation process, BC Hydro intends to participate in the consultation and to provide comments as appropriate. With respect to the AESO’s request that Market Participants provide comments on the process proposed in its January 30, 2018 letter, BC Hydro believes that the proposed process will be adequate to address the issues at hand. Since BC Hydro is interested primarily in the Coincident Metered Demand Issue, BC Hydro’s preference is that the process be split into two streams to address the separate issues. Canadian Solar Industries Association CanSIA appreciates the opportunity to participate in a consultation process on the tariff allocation issue. In response to the recent AESO letter, CanSIA would like to note its intent to participate in the AESO consultation process. CanSIA will outline its position at a later date and may choose to present a submission in support of its position at the appropriate step in the consultation process. The tariff allocation methodology is of particular interest to solar producers as it impacts the revenue that distribution connected solar projects are able to earn. The current tariff allocation methodology sends a strong incentive for the development of distribution connected solar as projects are able to earn revenue associated with the tariff cost savings in addition to the energy price. Given that solar resources are able to offset load at peak in a number of months throughout the year, the 12CP methodology is a benefit to distribution connected solar resources. This issue is of particular concern to the province as Alberta transitions to a greener grid and price signals to develop renewable generation in a cost-effective manner, inclusive of transmission and distribution costs, will be vital. It is important that the new tariff allocation methodology, whatever it may be, considers the impact to distribution connected solar and continues to support the Government of Alberta’s climate leadership initiatives which include a goal of 30% renewable generation by 2030. Distribution connected solar can be a meaningful and cost-effective part of that goal, as long as the structure continues to be designed appropriately. CanSIA looks forward to the opportunity to put forward a more detailed submission at a later date.

	Capital Power Corporation Capital Power Corporation ("Capital Power") hereby registers our intent to participate in the facilitated session(s). As a registered party in AUC Proceeding 22942, and an active market participant in Alberta, Capital Power submits that the elements being discussed are important to the long term sustainability of the wholesale market. Capital Power's primary interest relates to the 12 CP Method, on which the company remains neutral. At this time, Capital Power does not take a position on whether changes are needed to the rate design, and does not intend to make a submission to the AESO in advance of the stakeholder session. Capital Power will, however, fully participate and will take the opportunity to ask clarifying questions to evaluate any proposed changes to rate design. Capital Power does not take a position on the issue of distribution facility owner customer contributions and will not make a submission to the AESO in advance of the stakeholder session. However, as an issue that will be tested within AUC Proceeding 22942, Capital Power may ask clarifying questions as needed. Devon Energy Corporation Further to the Alberta Electric System Operator (AESO) letter of January 30, 2018, Devon Canada Corporation ("Devon") registers its intention to participate in the above referenced consultation. Devon has a significant and growing electrical load and has an interest in the outcome of this proceeding. Devon takes no position on the issues at this time and remains neutral. Devon plans on reviewing the consultation presentations and participating in the consultation discussion. Desiderata Energy Consulting Inc. on behalf of Dual Use Customers (DUC) 1. The DUC intends to fully participate in the AESO proposed Coincident Metered Demand Issue (12 CP) consultation process. 2. The DUC will not be participating in consultations on the Distribution Facility Owner Customer Contribution Issue. 3. The DUC has no issues with 12 CP. 4. The DUC supports the AESO's existing and proposed bulk system rate design.

	5. The DUC is prepared to make a presentation, either solely or jointly with other registered parties, on the continued appropriateness of the 12 CP rate design. ENMAX Corporation This email is to advise that ENMAX would like to participate in the AESO's stakeholder sessions as an observer and will not be making any submissions at this time. If this changes, we will be sure to notify the AESO. Energy Storage Canada ESC is generally supportive of the AESO's proposed process as it will give participants an opportunity to share their perspectives and evidence. While the AESO has initially proposed to address both the Distribution Facility Owner Customer Contribution Issue and the Coincident Metered Demand issue together, ESC suggests that they will be more effective if addressed in separate sessions. ESC believes there is little overlap between the two issues and many participants who are focused on the Coincident Peak issue due to the impact the Coincident peak calculations have on the DTS tariff will not be interested in participating in discussions on DFO Customer Contributions. ESC plans to participate in the facilitated sessions covering the Coincident Metered Demand issue as this methodology may continue to be utilized in the AESO's tariff, in rates such as DTS or an Energy Storage Opportunity Service specific rate. At the present time, ESC does not take a position on whether or not 12CP should be changed but ESC may not be neutral depending on the proposals put forward by various stakeholders. At this point in time, ESC does not intend to present a submission in the sessions. EPCOR Distribution & Transmission Inc. In EPCOR Distribution & Transmission Inc.'s ("EDTI's") view, the AESO's proposed process is not consistent with the Commission's direction. The Commission's letter states that the AESO has been given time to submit "a revised application to include the results of its analysis of and evidence on the issues respecting the 12 CP method and, if necessary, the DFO customer contribution". The Commission's letter also anticipates that the AESO should be in a position to file its revised Application by the end of March, 2018. Given the Commission's directions, EDTI is surprised that the AESO would initiate a process that does not contemplate the AESO providing anything to interested parties, but instead envisions a lengthy "consultation" process under which each interested party would be required to share its views, analyses, proposals, etc. on the two issues with all other parties. It also contemplates steps that appear to EDTI to be little more than a duplication of the Commission's regulatory approval process, with participants being subject to questioning by other parties and potentially be required to provide follow-up information. And all of this is in the absence of

	having first been provided with the “analysis” that the Commission has directed the AESO to conduct and file in this proceeding. EDTI notes that issues like the DFO customer contribution have been live for many months if not years, and EDTI does not read the Commission’s letter as contemplating a substantial delay in incorporating these matters into the Commission’s tariff approval process and moving ahead with that proceeding. In fact, EDTI doesn’t believe that the Commission was contemplating anything more than the AESO performing its analysis, perhaps providing it to interested parties for timely feedback, and filing its revised or augmented Application to have these matters addressed by way of the Commission’s regulatory approval process, at or about the end of March. EDTI recommends that the AESO proceed in that fashion. If the AESO does decide to proceed with its proposed process, EDTI will attend and participate to the extent it believes that the process will further the objective of having these issues addressed by the Commission efficiently and in a timely manner. At this point, EDTI does not intend to make any presentations as contemplated in the AESO’s letter. If the AESO chooses to provide its analysis and recommendations contemplated in the Commission’s letter to parties in advance of filing with the Commission, EDTI would be pleased to review them and provide the AESO with its initial comments at that time. EDTI provides the following additional comments on the two issues. <u>Coincident Metered Demand Issue:</u> EDTI does not currently have a firm position on the 12CP method or any other alternative to it to recover bulk system costs. EDTI is interested in this issue and intends to continue to follow it carefully, and will provide input into the Commission’s approval process in respect of this issue as EDTI determines to be warranted. <u>Distribution Facility Owner Customer Contribution Issue:</u> The AESO appears to interpret this issue narrowly, as relating solely to AltaLink’s proposed approach vis-à-vis FortisAlberta. EDTI reads the Commission’s letter as acknowledging that this is an issue that goes beyond the specific proposal by AltaLink to encompass the DFO contribution framework more generally, including the appropriate allocation of transmission system capital costs as between TFOs and DFOs. EDTI considers that this is an important issue raised by the AESO’s 2018 Tariff Application and intends to be an active participant in the proceeding that regard. Fortis Alberta Inc. FortisAlberta Inc. (“FortisAlberta” or the “Company”) is writing to provide its comments regarding matters identified in the AESO’s letter of January 30, 2018, including consultation on the 12 Coincident Peak (12 CP) cost allocation method / rate design for the AESO’s Rate Demand Transmission Service (DTS) Bulk System charge. The Company also writes to provide comments on AltaLink’s proposals regarding AESO contribution policy, and more specifically, its proposal to revisit the imposition of a mandatory Rider I for certain market participants as a

	means of maximizing Transmission Facility Owner (TFO) investment in AESO projects requested by a distribution Facility Owner (DFO) on a prospective basis. FortisAlberta intends to fully participate in whatever consultative or regulatory processes may be initiated to deal with these matters, given their potential impacts on its customers and operations. The Company offers the following preliminary comments on the process proposed by the AESO in its correspondence of January 30, 2018: <u>1. 12 CP Cost Allocation Method / Rate Design</u> FortisAlberta’s customers are charged transmission costs on a flow-through basis as part of the Company’s distribution tariff. This means that, generally speaking, end-use customers ultimately pay all of the transmission tariff costs attributable to arrangement of their system access service. The Bulk System 12 CP charge represents almost half of the AESO’s overall transmission revenue requirement, which is collected as a transmission cost. FortisAlberta submits that, given the size of the 12 CP charge, it is important for the AESO to ensure that the related cost allocation and rate design are correct. In practice, this will require taking steps to ensure that any proposed methods properly reflect generally accepted rate design principles, including cost causation, avoiding undue discrimination/subsidy, and ensuring that economically efficient price signals are sent to transmission market participants. It is also important that DFOs be positioned to fully explain the drivers of these costs, which are ultimately allocated, and flowed-through, to their customers through their distribution tariffs. As such, FortisAlberta supports the review of the cost allocation method and rate design applied to recovery of DTS Bulk System Costs being undertaken at this time. FortisAlberta does not intend to provide a new standalone submission on the 12 CP issue for consideration in the current regulatory process. However, the Company commends Section 5.1.1 of Decision 2006-0991 to the AESO and other participants. In this decision, which addressed FortisAlberta’s 2006/2007 DTA “bulk system” cost allocation method, the Board approved a broader allocation approach of using average on-peak demand across all on-peak hours for purposes of allocating shared distribution system costs. In doing so, the Board, noted that such an approach “reflects a broader recognition of cost causation and, on balance, is more appropriate than the narrower definition ...”² Consistent with this, FortisAlberta submits that the adoption of a more broadly-applied method for allocation and recovery of DTS Bulk System Costs should be considered in the current circumstances, as being more reflective of cost causation principles, generally. <u>Related Rate Supply Transmission Service (STS)/DTS POD Metering Issue</u> The 12 CP rate design issue is also related to an additional metering issue that FortisAlberta has recently identified. The AESO recently advised the Company of its plan to change how an AESO point of delivery (POD) is metered, in terms of the applied metering logic and totalization. The impact of this intended change will depend on whether the market participant’s metering for a given POD is located at either the POD transformer primary

	bus, the POD secondary bus, or at the individual distribution feeder level. It appears that this proposed AESO revenue metering change would affect both the DTS and STS billing determinants for each POD (including CP), and would have the effect of increasing the substation fraction for STS (with a corresponding increase to the applicable AESO transmission contributions flowed-through to distribution-connected generation (DCG)). FortisAlberta also recognizes that the proposed metering change will have the effect of reducing the amount of CP transmission credits available to DCGs through some distribution tariffs, including its own Option M. Further, based on the Company's understanding of the AESO's current implementation plans, the proposed change may actually result in discriminatory application of the AESO tariff, depending on the POD and the location of the metering employed by the market participant. As such, FortisAlberta submits that this consultation provides a timely opportunity for the AESO to enhance transparency regarding this proposed change for all stakeholders. The Company recommends that, in its upcoming consultation on the 12 CP cost allocation method / rate design, the AESO also address this proposed AESO tariff metering change, so that other participants (including DCG customers) understand how the change, if implemented, may financially impact them. FortisAlberta also requests that the AESO include the details around its proposed change to AESO tariff metering in its revised 2018 comprehensive ISO tariff application so that all parties have the opportunity to review this change in that forum. Until this issue is fully vetted, the Company recommends that the AESO refrain from any implementation of this change, as it is already starting to create issues and uncertainty for FortisAlberta and its DCG customers wishing to connect to the system. <u>2. AltaLink's Position on AESO Contribution Policy / Mandatory Rider I Proposal</u> AltaLink's proposal to refund AESO contributions to FortisAlberta, and thereafter charge FortisAlberta (and its customers) a corresponding rider to recover the amortization of those AESO contribution amounts, would effectively result in the imposition of a mandatory Rider I, applied to specific market participant(s) for the benefit of the incumbent TFO (in this case, AltaLink). That is, it effectively translates to 100% TFO investment in AESO projects requested by a DFO on a prospective basis, thereby eliminating any AESO contribution price signal to DFOs when arranging system access service on behalf of their customers. The Company submits that such a proposal presents a risk of unjustly discriminatory application of the ISO tariff to a subset of market participants, and a preferential and inconsistent application of the AESO contribution policy it contains. FortisAlberta submits that this proposal is fundamentally at odds with the provisions of applicable legislation, including the Electric Utilities Act, and, consequently, should not be considered in the revised ISO tariff application contemplated to follow the conclusion of the current consultation process. As the AESO is aware, this is not a new issue; extensive records regarding the topic of AESO contribution policy and the possible forms of Rider I have been before the Commission over the last decade. In fact, this discussion began more than ten years ago when AltaLink hosted its own stakeholder consultation process regarding the AESO's contribution policy, at which point the concept of Rider I was first introduced. Rider I was subsequently

	raised, discussed and proposed in numerous proceedings before the Commission over the following years, as summarized by the attached document entitled “Attachment 1 – AESO Rider I Proceeding History”, which was provided by the AESO in its 2015 Rider I consultation with stakeholders. Based on the Commission’s previous determinations on Rider I, the AESO proposed a nondiscriminatory (voluntary for all) Rider I mechanism in its tariff. However, FortisAlberta understands that this pursuit of Rider I was effectively abandoned in the 2015 timeframe, presumably due to the parties’ inability to agree on satisfactory terms to mitigate Rider I default risk that was imposed on TFOs by the Commission in past decisions. Notwithstanding previous extensive considerations of Rider I, as described above, AltaLink proposed to levy a rider directly on the DFO market participant (FortisAlberta) as part of its 2017/2018 GTA. In response, FortisAlberta filed a motion with the Commission to strike this proposal as being a matter for the ISO tariff in accordance with legislation³. The Commission subsequently directed AltaLink to strike the proposal from its GTA⁴. FortisAlberta agrees with the AESO’s position as described in its Counsel’s January 3, 2018 correspondence to the Commission in this Proceeding, regarding the “dilatory” nature of AltaLink’s behaviour, and confirming that the proper forum for considering any further proposals with respect to this matter was in the 2-year AESO consultation process leading up to the filing of the current application, or, alternatively, in the next comprehensive ISO tariff application. AltaLink had ample opportunity over the last two years to request the AESO to revisit the Rider I matter. Rider I’s storied history belies AltaLink’s suggestion that urgency exists with respect to this matter. To now allow AltaLink to drive the AESO tariff consultation process with a proposal that solely advances its own business interests to the detriment of other market participants is, in the Company’s submission, unacceptable. AltaLink’s proposal neglects consideration of, or context for, the broader structural contribution policy framework, in terms of how the AESO and DFO policies should operate concurrently, and how end-use customers are provided AESO contribution price signals via flow-through of AESO contributions through the respective distribution tariffs. This is regardless of whether these transmission contribution price signals are collected up front or recovered through the tariff(s) over time, and whether the FortisAlberta end-use customers are transmission connected, distribution connected or are distribution-connected generation. As such, if the AESO proceeds with this consultation on this matter, FortisAlberta recommends that the AESO adjust its proposed process to ensure that it, and not AltaLink, plays the lead role in facilitating discussion on this matter, while providing a view of how it proposes to consult and further develop its contribution policy and mechanisms moving forward. This would allow for proposals to be reviewed using a principle-based approach, like the approach that the AESO and stakeholders reached consensus on in the review of the 2012 AESO Construction Contribution Policy⁵. In terms of process, the AESO should ensure that all stakeholders (including AltaLink and FortisAlberta) should be given equal opportunity and standing in terms of providing any submissions on this matter.

	Industrial Power Consumers Association of Alberta In response to the AESO’s letter of January 30, 2018, the Industrial Power Consumers Association of Alberta (IPCAA) provides the following responses regarding the AESO’s proposed consultation process: 1. IPCAA intends to participate in the facilitated session(s). 2. IPCAA intends to address the Coincident Metered Demand Issue. 3. IPCAA supports the AESO’s 2018 tariff application as it relates to bulk system rate design (12 CP). 4. IPCAA intends to present a submission in support of our position. City of Lethbridge and the City of Red Deer The Cities of Red Deer and Lethbridge are pleased to respond to the AESO's January 30, 2018 letter requesting comments on the proposed process to address the Alberta Utilities Commission's direction in Proceeding 22942. As distribution facility owners, the Cities of Red Deer and Lethbridge have an interest in the outcome of the CP 12 review, as well as the Distribution Facility Owner Customer Contribution issue. The Cities do not intend to make a presentation but will be present for all stakeholder sessions. The Cities also intend to engage in the questions and answer period if more clarification is required. Solar Krafte For DG projects, totalizing the metering at the POD level is the current and historical approach, and as such, is a current driver of SASRs for DG projects not dependent on subsidies, such as Solar Krafte's 282 MW AC BTF portfolio of distributed solar PV systems. In the case of Fortis and its "Option M" DG credit (the difference between AESO System Access Service charges to Fortis at the upstream POD with the generator in operation and the charges that would have been incurred if the generator had not been in operation), totalized metering at the POD level rewards and fully recognizes the tangible benefits that DG brings to the AIES: • Increased electric system reliability • Avoidance of the high voltages and currents and the complex delivery systems that are conducive to grid failures • Islanding localizes the impact of transmission system failures, giving local distribution systems and customers the ability to ride out major or widespread outages

	• Flexibility and fuel source diversity (carbon risk comes to mind) • Emergency supply of power • Reduction of peak power requirements • Efficiency, eliminating entirely complete transmission line loss equivalents • Offsets to investments in transmission, or distribution facilities that would otherwise be recovered through rates • Improvements in power quality, and provision of ancillary services • Inverter based DG (solar PV) actively cancels/ mitigate transients in real time at or near the customer level, improving grid stability • Inverter based DG (solar PV) provides extremely fast ramping to follow sudden increases or decreases in load, improving system stability and component lifetimes • Reductions in land-use effects and rights-of-way acquisition costs • Reduction in vulnerability to terrorism and improvements in infrastructure resilience AESO's current and historical approach, totalizing the metering at the POD level, is the sensible approach, and acknowledges the reality that DG attenuates at the POD level, offsetting load on the distribution system first, and only when that load is fully served, regardless of the number of feeders, does the generation flow onto the transmission system. AESO's attempt to use a strict (and oxymoronic) interpretation of the ACT, i.e., "the low voltage terminal", to string, fully encapsulate and colour DG as flowing onto the transmission system when we know the power in question fully serves the load on the distribution system reeks of complicity. AESO asserts that the current Tariff actually supports their proposed approach (i.e., to no longer totalize STS and DTS at the POD level). What? Then why is AESO totalizing the metering at the POD level? Because it's nonsensical to do otherwise. Distributed generation is what Thomas Edison envisioned with his DC generators: a power station on every city block, making long-distance transmission and its associated losses irrelevant. At the time, however, it seemed more feasible to go with Tesla's AC generators and long transmission lines. Now that we've had the AC grid for a century, we're starting to see its shortcomings and a return to the concept of microgrids and distributed energy generation. Boasting Canada's highest solar resource, solar generation no longer needs pricing subsidies in southern Alberta. Solar generation captures daytime-only pool pricing (~150% higher than during the night time low demand periods). Unlike wind, which suffers a night-time pool pricing deficit, solar acts as defacto peaker generation, capturing high demand period daytimeonly pricing. Solar generation offers this crucial daytime-only generation component to Alberta's electricity system. Alberta solar generation is the perfect fit with oil-sands cogen. Oil-sands cogen likes to operate 24/7 with the primary product, heat, needed for 24/7 processes. Oil-sands 24/7 cogen runs into night-time low demand grid

	condition, that wind often generates into as well. Oilsands, and other, Alberta cogen performs well in winter, when additional heat is required. This is perfectly balanced by solar generation that performs much better during our long summer days. Solar is the ideal way to service daytime peak summer irrigation and air-conditioning loads, when heat, the primary product from cogen is not needed as much. Unlike intermittent renewables such as wind, Solar has guaranteed, predictable minimum and maximum daytime generation profiles that provide extremely valuable daytime generation capacity. Daytime summer peak generation can be very expensive to capitalize, as low capacity factor peaker generation is needed. This undesirable, expensive peaker generation is what solar generation supplants. Solar power will never (and cannot) push power into the night-time lows when impacts to the transmission system are most likely to occur. Alberta must not impede the deployment of competitive, grid-parity renewables, and in particular DG renewables. Solar Krafte's DG BTF portfolio alone is estimated to generate over 570 gigawatt hours of electricity per year, offsetting 330,000 tonnes of greenhouse gas emissions annually and generating enough electricity to power more than 75,000 Alberta homes. Additionally, the total capital cost of the proposed projects is expected to approach \$500 million, bringing an important source of direct and indirect economic activity, and revenue, to southern Alberta. And all of this without subsidies. Totalizing the metering at the POD level is integral to our model, and has been from the day we spent our first dollar on development. We are adamantly opposed to any changes to the totalizing approach, and if there must be a change, then those SASRs submitted under the current Tarrieff/ approach must be grandfathered based on the date the SASR was received by the AESO and not the System Access Service Agreement contract date. TransCanada Energy Ltd. TCE supports the AESO's proposal for one or more facilitated stakeholder sessions that provide market participants the opportunity to make submissions and present their positions regarding the coincident metered demand issue. TCE agrees that these submissions should include a summary of the market participant's position that includes whether it recommends that the method be changed or maintained, a summary of the analysis it has or intends to complete, and its recommended timing for any proposed changes. If a market participant is proposing a change to the bulk recovery method, TCE submits that it would be helpful for its submissions to also include the following: 1. a detailed description of its proposed bulk recovery method; 2. the rationale for why its bulk recovery method should be preferred; and

	3. an analysis indicating how its bulk recovery method aligns with rate design principles. TCE intends to participate in the facilitated session(s) related to the coincident metered demand issue. At this point in time, TCE's position is neutral and, as such, does not intend to present a submission. Utilities Consumer Advocate <u>1. Coincident Metered Demand Issue</u> As stated in its letter dated January 19, 2018, "On November 27, 2017, the Alberta Utilities Commission issued a ruling stating AltaLink Management Ltd. may fully participate in this proceeding and that the coincident metered demand rate design issue (12 CP method or DTS rate design) would be considered in the scope this proceeding." Subsequent to that ruling, the Commission provided parties with an opportunity to comment on the process steps necessary to incorporate additional evidence on the 12 CP method. The UCA's submission, filed on December 15, 2018, recommended that a process schedule should be established to provide the AESO with an opportunity to meet and consult with its stakeholders, perform its analysis of the issue, and file supplemental evidence addressing the issue. The UCA further recommended that: Following the AESO's filing of supplemental evidence, the proceeding would simply follow its normal course, which would include the filing of information requests (IRs) and IR responses, intervenor evidence, IRs to intervenors and IR responses followed by rebuttal evidence if necessary, and potentially culminating in an oral hearing, followed by argument and reply argument. In its January 19, 2018 correspondence, the Commission made the following directions: The Commission considers that time is required for the AESO to conduct an analysis and prepare evidence on the issues of the 12 CP method and, if necessary, the DFO customer contribution. The Commission also considers that revisions may be required to the AESO's application as a result. For these reasons, the Commission suspends Proceeding 22942 until the AESO submits a revised application to include the results of its analysis of and evidence on the issues respecting the 12 CP method and, if necessary, the DFO customer contribution. If the AESO is not in a position to file its revised application by March 30, 2018, the Commission directs it to file a status update by the same date. On January 30, 2018, the AESO outlined its proposed process, which would require all participants to prepare and present (at a facilitated stakeholder session or sessions) written submissions, containing the following: A summary of each participant's position for the bulk recovery methodology, including: i. A recommendation to change the methodology or maintain the existing coincident metered

	methodology; ii. Any analysis completed by the participant, as well as noting any further data or data analysis that may be required (by the AESO or others); and iii. If a methodology change is recommended, the recommended timing of when the change should be made. The UCA would be pleased to attend and participate in facilitated stakeholder sessions with the AESO and other participants. As a part of that process, the UCA considers that participants could contribute, orally, to the creation of an issues list to be analyzed and addressed by the AESO in its supplemental evidence. However, the UCA considers that requiring it, and other intervenors, to file a written submission and/or analysis in advance of the sessions, and prior to the AESO amending its application, is inappropriate and results in a reversal of the “normal course” recommended in the UCA’s correspondence of December 15, 2017.⁷ It seems to the UCA that the AESO is in effect requesting intervenors to file evidence on the issue before the applicant does. Further, the AESO is in sole possession of most of the data that would be relevant to any analysis. Thus any process that results in a requirement that intervenors file evidence on their respective positions, before having the opportunity to request, receive and review relevant data in the possession of the Applicant,⁸ puts the intervenors at a marked and unusual disadvantage. The AESO has also proposed that participants provide, in writing, in advance of the stakeholder sessions: b. The participant’s proposed weighting of the following five (5) rate design principles applicable to the bulk recovery methodology: i. Recovery of the total revenue requirement; ii. Provision of appropriate price signals that reflect all costs and benefits, including in comparison with alternative sources of service; iii. Fairness, objectivity, and equity that avoids undue discrimination and minimizes inter-customer subsidies; iv. Stability and predictability of rates and revenue; and v. Practicality, such that rates are appropriately simple, convenient, Again, the UCA considers this request to be inappropriate. The AESO appears to want to dictate what each participant must address in evidence prior to exploring potential changes in the methodology. This should be left to the parties, and to the appropriate time in the process when more relevant information is available. 2. Distribution Facility Owner Customer Contribution Issue Although the UCA has an interest in this issue, it makes no comment on the proposed process other than to note that it does not expect to be in a position to take a definitive position at a stakeholder session. It would, however, be interested in attending such sessions to gain a broader understanding of the issues. The last paragraph in the AESO’s letter of January 30, 2018, requests each party submitting comments to

	provide certain advice. In keeping with the comments above, the UCA plans to attend and participate in stakeholder consultation sessions. The UCA expects to actively participate in at least the 12 CP method and the related bulk system cost allocation issue, and at this point, as indicated in its letter dated October 6, 2017,⁹ it is concerned that the issue should be re-examined “in light of current and expected market conditions to ensure all rates are still fair, objective and equitable, and eliminate inter-customer subsidies.” Finally, the UCA confirms, as stated in its correspondence of December 15, 2017,¹⁰ that “based on its preliminary review of the application, it intends to file evidence in this proceeding, likely limited to the 12-CP Method issue.” However, for the reasons stated above, it does consider it appropriate and does not intend to file a submission in advance of the stakeholder sessions. Finally, the UCA is of the view that the stakeholder consultations should proceed without delay, and without a requirement for premature intervenor evidence, and that a direction be issued from the Commission in this regard.

DFO Customer Contributions Issue #2 in Proceeding 22942

March 5, 2018
Main Boardroom, AESO Offices

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Agenda - DFO contribution issue

March 5, 2018

Topic	Presenter	Schedule
Introduction	Doyle Sullivan	1:00 – 1:05 pm
Session Overview	Matt Gray (Facilitator)	1:05 - 1:15 pm
Background on DFO Contribution Issue	Lee Ann Kerr	1:15 – 1:30 pm
AltaLink (AML) presentation (includes Q & A)	AML	1:30 – 3:00 pm
Break		3:00 – 3:15 pm
FortisAlberta presentation (includes Q & A)	Fortis	3:15 – 4:00 pm
Consumers' Coalition Alberta (CCA) presentation (includes Q & A)	CCA	4:00 – 4:15 pm
Open discussion	All	4:15 – 4:45 pm
Next steps and summary of action items	Matt Gray	4:45 – 5:00 pm

- AUC Direction (January 19 Letter - [link](#))
 - *19. The Commission considers that time is required for the AESO to conduct an analysis and prepare evidence on the issues of the 12 CP method and, if necessary, the DFO customer contribution. The Commission also considers that revisions may be required to the AESO's application as a result.*
- Objectives engagement on DFO customer issue
 - Gather views, supporting information (data and analysis) to help the AESO determine whether to maintain or reconsider status quo
- Scope of session
 - DFO Customer contribution issue
- Proposed timeline

- Structure of AESO engagement on DFO customer contribution issue
 - Facilitated session(s)
 - Initial session or further sessions
 - Opportunities for interested parties or the AESO to:
 - *Present their views and any analysis or assumptions to support their view on the issue*
 - *Ask clarifying questions*
 - Request further data and analysis of the AESO or other parties
 - Assess if further session(s) are required and agenda for future session
 - Written comment period
 - Respond to presentations and discussions from session
 - AESO Response session
 - AESO presents position that it will be filing in GTA

- Manage session agenda
- Ensure all parties are heard
- Agreements
 - Keep an open mind
 - Ask questions (be curious)
 - Share the air time
 - Be specific and succinct
 - Listen generously

Session Documentation

- Meeting minutes will not be taken
- Session presentations will be posted to aeso.ca
- Action items
 - Logged from all session(s)
 - Posted to aeso.ca within two days of session
- Written comments
 - Due March 19
 - No matrix. Send letter to ISOtariffnotice@aeso.ca
 - Posted to aeso.ca by March 21

Timeline for Engagement on 12 CP and DFO issues

- March 5 – DFO Customer Contribution Issue (session 1)
- March 12 – 12 CP methodology (session 1)
- March 29 – Update to AUC
- April 9 – 12 CP methodology (session 2)
- TBD – If required, further sessions for the AESO or other parties to present further information or analysis
- TBD – AESO presentation of position to be filed in GTA

2012 Contribution Policy Principles

- (1) Provide effective price signals
- (2) Maintain intergenerational equity
- (3) Be based on cost causation
- (4) Be based on local costs
- (5) Be robust and sustainable
- (6) Treat all load market participants equitably
- (7) Compensate utilities equitably
- (8) Be simple, consistent, and transparent

AUC Decision on Contribution Policy

[Decision 2012-362]

- The AESO considers the first three principles to be primary principles, and the remaining five secondary principles
- “The Commission considers the list of eight principles to be reasonably consistent with past decisions and directions of the Commission and the board. The Commission finds that the eight principles provide a reasonable basis for the assessment of the AESO’s construction contribution policy”
- “...certain decisions made by the AESO as a result of the construction contribution policy review appear to have significantly elevated the importance of intergenerational equity considerations relative to the goal of providing an effective price signal”

Thank you

Agenda



Date: Monday, March 5, 2018
Location: 25th Floor Calgary Place, Main Boardroom

Time: 1:00 – 5:00 pm

DFO Customer Contribution Issue Session

Time	Agenda Items	Presenter
1:00 – 1:05 pm	Introduction	Doyle Sullivan (AESO)
1:05 – 1:15 pm	Session overview	Facilitator – Matt Gray (AESO)
1:15 – 1:30 pm	Background on DFO Contribution Issue	Lee Ann Kerr (AESO)
1:30 – 3:00 pm	AltaLink (AML) presentation (includes Q & A)	AML
3:00 – 3:15 pm	<i>BREAK</i>	
3:15 – 4:00 pm	FortisAlberta presentation (includes Q & A)	FortisAlberta
4:00 – 4:15 pm	Consumers' Coalition Alberta (CCA) presentation (includes Q & A)	CCA
4:15 – 4:45 pm	Open discussion	All
4:45 – 4:55 pm	Next steps and summary of action items	Matt Gray
4:55 – 5:00 pm	Wrap up	Matt Gray

Public

AESO 2018 Tariff

PROPOSED REFUNDING OF DFO CUSTOMER
CONTRIBUTIONS

MARCH 5, 2018



DFO Customer Contribution Issue

- **Context:**
 - Under the Alberta Electric System Operator's tariff, the regulated Distribution Facility Owner may be required to make a contribution, associated with requested construction of transmission facilities. The contribution from the Distribution Facility Owner is treated as an offset to the Transmission Facility Owner's rate base. Proposal only pertains to contributions made by the regulated DFO, and not an industrial or other customer behind the DFO.
- **The issue: This customer contribution approach for transmission capital investments creates a situation that:**
 1. Provides the regulated Distribution Facility Owner, rather than the regulated Transmission Facility Owner, with a regulated return on transmission assets that it does not build, own, operate or maintain;
 2. Results in the Transmission Facility Owner incurring all the risk associated with building, owning, operating and maintaining the transmission assets without any return to compensate for those business risks; and
 3. Fails to provide clear price signals concerning regulated Distribution Facility Owner investment decisions in regulated transmission related assets.

DFO Customer Contribution Issue

The EUA defines transmission assets is defined as

- (bbb) “transmission facility” means an arrangement of conductors and transformation equipment that transmits electricity from the high voltage terminal of the generation transformer to the low voltage terminal of the step down transformer operating phase to phase at a nominal high voltage level of more than 25 000 volts to a nominal low voltage level of 25 000 volts or less, and includes
 - (i) transmission lines energized in excess of 25 000 volts,
 - (ii) insulating and supporting structures,
 - (iii) substations, transformers and switchgear,
 - (iv) operational, telecommunication and control devices,
 - (v) all property of any kind used for the purpose of, or in connection with, the operation of the transmission facility, including all equipment in a substation used to transmit electric energy from
 - (A) the low voltage terminal,
 - (B) electric distribution system lines that exit the substation and are energized at 25 000 volts or less,
- and
- (vi) connections with electric systems in jurisdictions bordering Alberta, but does not include a generating unit or an electric distribution system;

Proposal

- **Regulated Transmission Assets**
 - The regulated Transmission Facility Owner should make the capital investment in all regulated Distribution Facility Owner related transmission assets.
 - The ensuing charges associated with such investment in DFO driven transmission will be charged to the DFO via the Alberta Electric System Operator.
 - The DFO will pass such charges to its distribution customers.
 - Alberta transmission customers are held whole as are the DFO's distribution customers.

Mechanics of Refunding of DFO Customer Contributions

DFO Customer Contribution - Mechanics:

1. Proposal only pertains to contributions made by the regulated DFO, and not an industrial or other customer behind the DFO.
2. DFO provides upfront contribution to the TFO as per the AESO policy.
3. Upon energization TFO refunds the DFO contribution back to the AESO.
4. TFO includes the revenue requirement related to these new assets in its monthly AESO billing.
5. AESO charges the DFO monthly for the TFO revenue requirement related to the DFO contribution refund and the AESO uses this revenue to offset the TFO tariff increase related to the DFO contribution refund.
6. DFO will then flow through this AESO monthly charge directly to its customers. DFO customers are kept whole by this new arrangement over the life of the assets.

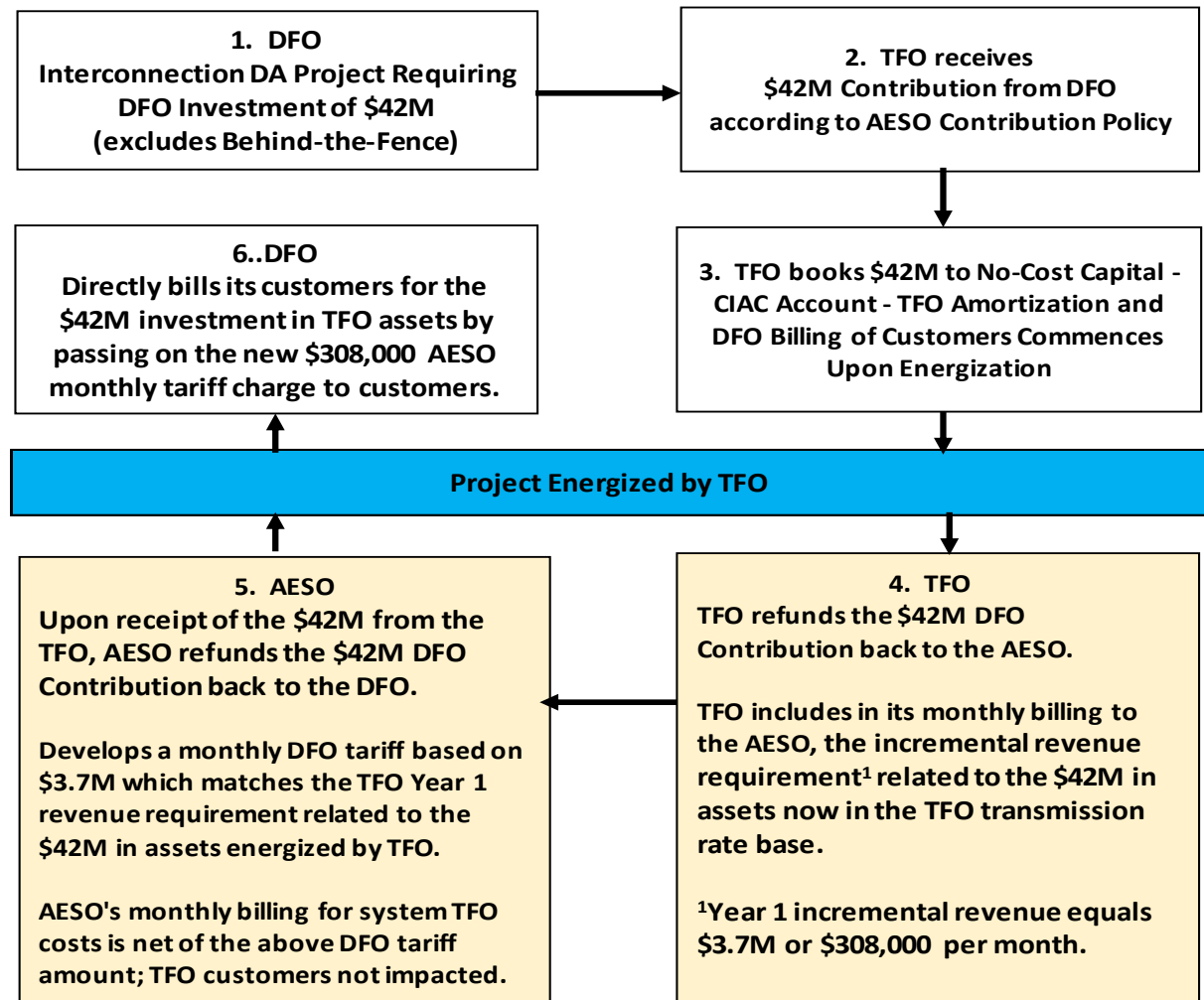
Refunding of DFO Customer Contributions - Financial Flows and Impacts - Using Fortis Provost based on \$42M Refund in Year 1 (\$M)

Provost (DFO customer) project:
138kV
\$42M
100% contributed

AESO monthly charge to DFO based on TFO's approved:

- Capital structure
 - Debt and Equity
- ROE
- Embedded Debt rate
- Depreciation rate(s)
- Income Tax rates/parameters

Each eligible DFO project would be tracked separately



Administration – Simple Process

Proposed Approach

- 2018 AESO Tariff (Section 4) would require modification to:
 - Reflect the TFO refunding the DFO contribution back to the DFO (once project is energized) via the AESO.
 - As well, to provide the monthly invoicing to the DFO regarding the specific project(s) that would be ultimately recovered from its customers.
- In order to assist the AESO, the TFO could provide the AESO (and DFO) with the specific monthly billing calculations (based on the AUC approved TFO tariff components) that would support the calculations and be used to invoice the DFO.
- AltaLink is open to other suggestions with respect to administrative efficiency.

Distribution Facility Owner (DFO) Customer Contributions Summary

Refunding DFO Customer Contributions for Direct Assigned Transmission related Capital Investments:

- Consistent with AUC Ruling and AESO submission that refunding customer contributions should be addressed in the context of an ISO tariff and not in a single TFO GTA, and also consistent with AUC and AESO concerns that it should apply to all DFOs and all TFOs.
- Simply put....It is the regulated TFO that owns and maintains the interconnection transmission asset and therefore should be allowed to make the investment in those assets and not the regulated DFO.
- This proposal does not impact the TFO's system tariff charged to transmission rate payers since the additional revenue requirement, based on the TFO's Weighted Average Cost of Capital (etc.), is recovered from the DFO by the AESO.
- Efficiency of market price signals maintained in the construction and energization of new transmission related assets since DFO customers, like industrial customers, directly pay for the additional TFO assets.
- Administratively simple to employ

DFO Contributions Policy

- DFO Accountability for Costs-incentives for appropriate sizing and engineering of facilities for efficiency
 - Mitigating Impact of second generation PBR
 - Recovery via Tariffs, in place of contributions
- Coordinated Planning by the AESO and DFOs in the face of increasing distributed generation and related tariff issues

AUC Proceeding 22942

2018 ISO Tariff Application Consultation

AESO / Distribution Facility Owner (DFO)

Customer Contribution Issue

March 5, 2018





- Rider I is not a new issue; debate has extended over last decade
- ISO tariff must be applied in an open access, non-discriminatory manner
- Any reconsideration of Rider I needs to be evaluated within:
 - Broader ISO tariff contribution policy and industry tariff framework
- All about retaining efficient **Price Signals** to DFOs / End-Use Customers as they connect
 - Balance between pay now (contributions) or pay later (rates over time)
 - DFO value comes from acting as “conduit” for those transmission signals
- No ISO tariff application amendment or delay required within this AESO tariff proceeding process
- Recommend AESO pursue other avenues to reduce the magnitude of the AESO contribution price signal using principle-based approach



- Rider I - Amortization of AESO customer contributions; equates to 100% investment level for transmission facility owners (TFOs) / AESO
- Concept first introduced in a 2007 AML consultation on AESO tariff contribution policy, followed by:
 - 2009/2010 TFO General Tariff Applications, 2009 and 2011 Generic Cost of Capital Proceedings, AESO 2010 ISO Tariff Application, Utilities R&V of Decision 2011-474, AESO 2012 Rider I Application, AUC 2013 Utility Asset Disposition Proceeding...
- Debates around management fees; default / stranded asset risk to TFOs / other customers; mandatory/voluntary or opt-out/in terms, amortization/depreciation periods, and utility asset disposition (UAD) ensued.
- 2015 AESO Rider I consultation – proposed a non-discriminatory (voluntary for all) form of Rider I, pending default risk terms with TFOs...
- AML 2017/2018 GTA proposal; AUC struck on motion from FortisAlberta.



Distribution Wires

- Operate and maintain distribution (D) system
- Construct new and upgrade existing D facilities
- Connect load and generating customers

System Access Service (SAS)

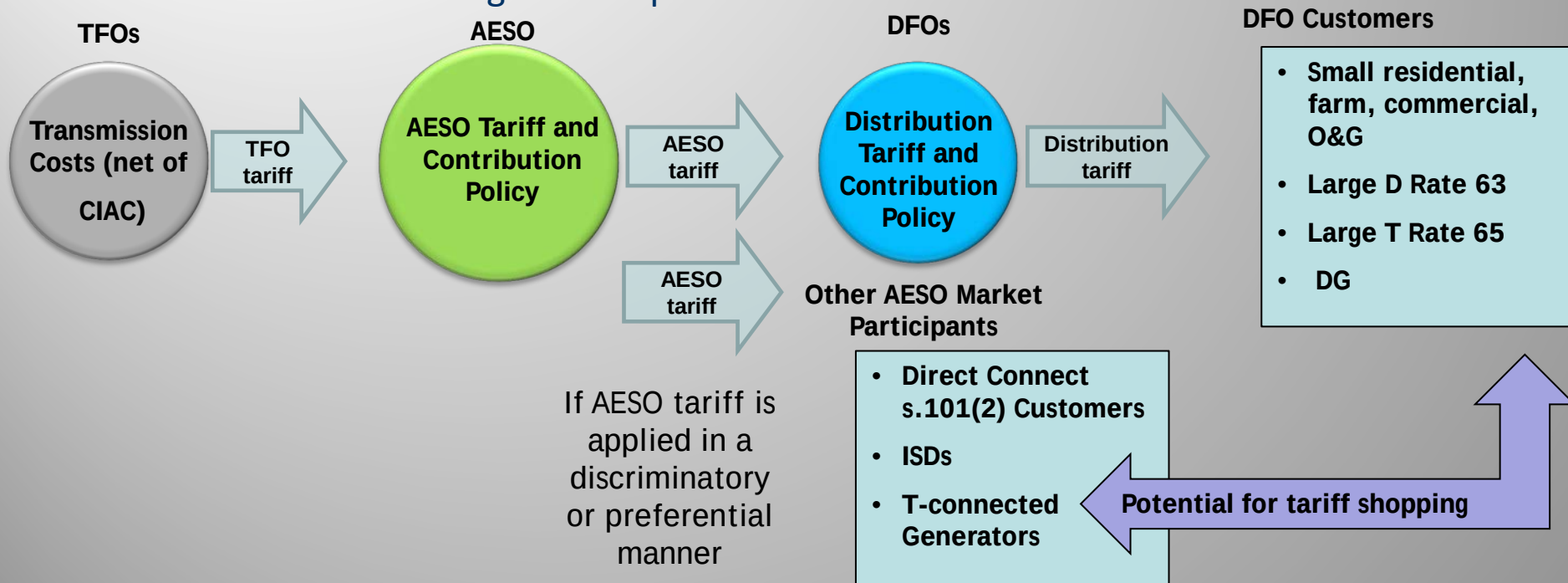
- **Arrange access to transmission for customers**
- **Financial settlement with AESO for SAS**

Meter Reading, Load Settlement and Distribution Tariff Billing

- Responsible for reading meters and sending consumption transactions to retailers.
- Determines the hourly energy usage from the power pool for each site for each retailer
- **Bill Retailers for their customers' T and D charges (Distribution Tariff)**



- Rider I proposal neglects consideration of, or context for, the broader tariff and contribution policy framework, in terms of how the AESO / DFO tariffs and policies should operate concurrently, and how AESO contribution price signals flow-through to end-use customers through the respective tariffs:





- **Balance** is required between paying now (contributions, leading price signal) and paying later (rates, lagging price signal)
- DFO's are in the closest proximity, to understanding the needs of its end-use customers.
- Value of DFO comes from acting as “conduit” for the AESO tariff price signals: Contracting for AESO SAS, optimized based on the transmission load/capacity requirements of the distribution system and its customers.
- If DFOs are singled out for mandatory Rider I treatment, effectively results in:
 - 100% TFO investment in all new DFO initiated projects
 - removes all leading price signals to DFOs/end-use customers.
- In the absence of a leading contribution price signal, potential for inefficiencies in system development; opens the door for larger market participants to:
 - request transmission facilities beyond their need, or
 - engage in “tariff shopping” between the AESO and distribution tariffs



- Review the principle-based approach and stakeholder consensus achieved in Proceeding 1162: 2012 AESO Construction Contribution Policy Proceeding, as a means of reducing the severity of the contribution price signal sent to all market participants (including DFOs).
- Decision 2012-362: “...the Commission remains of the view that, at the end of the day, providing an efficient price signal is considered a more important policy objective...”; others being intergenerational equity, cost causation.
- Industry should address the root cause of AML’s issue: i.e. underlying trend of rising contribution levels /insufficient transmission investment levels.
- DFOs can further investigate flowing through AESO contributions to large D-connected customers, to retain leading price signals to large connecting customers.



- Comments/Questions

March 5, 2018

Dear Market Participants:

Re: **Proceeding 22942 - Consultation on 12 Coincident-peak Method and Refunding FortisAlberta Customer Contributions by AltaLink**

On February 22, 2018, the AESO posted on its website an update letter regarding its proposed consultation process for the 12 CP and DFO customer contribution issues.¹

Subsequently, the AESO has been made aware of scheduling conflicts by parties wishing to participate in the planned March 26, 2108 session regarding the 12 CP issue. In order to accommodate these parties, the March 26, 2018 session has been rescheduled to April 9, 2018.

A detailed agenda for the April 9, 2018 session, regarding the 12 CP issue, will be provided to interested parties following the first 12 CP session on March 12, 2018.

Sincerely,

< *Electronically Submitted* >

Doyle Sullivan, P. Eng
Director, Tariff Design

¹ Exhibit 22942-X0120

12 COINCIDENT PEAK (12 CP) METHODOLOGY

ALBERTA DIRECT CONNECT CONSUMER ASSOCIATION (ADC)

DUAL USE COALITION (DUC)

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA (IPCAA)

Vittoria Bellissimo - IPCAA

Colette Chekerda - ADC

Dale Hildebrand - DUC

March 12th, 2018



PRESENTATION OUTLINE

- About ADC, DUC and IPCAA
- Recommendation
- Rate Design Principles
- CP Methodology
- Stability
- Aligning Cost Elements
- Historical Review
- Questions?



ABOUT ADC



- The ADC was established in 2002 to represent the interests of large industrial consumers directly connected to the transmission system.
- Membership includes: Alberta Newsprint Company, Dow Chemical, ERCO Worldwide, Lehigh Inland Cement, MEGlobal, Millar Western, Praxair, Sherritt International, and West Fraser Timber.
- ADC members represent approximately 600 MW of peak load and 4,000 GWh of annual energy.
- ADC members are global competitors. Affordable and reliable electricity is essential to our viability. On average, electricity represents about 30% of members operating costs, but is as high as 80% for some.
- ADC members are active participants: price response, ancillary services, LSSi, and on-site generation.
- ADC member facilities are located in Northern and Central Alberta

ABOUT DUC

- DUC was formed in 2004 to represent industrial cogenerators in Transmission Administrator (AESO) tariff proceedings
- Members include Alberta's largest oil sands and industrial cogenerators
 - 1,300 MW DTS contract capacity
 - 3,000 MW installed cogeneration capacity
- Currently ten members, 15 sites

ABOUT IPCAA



- IPCAA was formed in 1983 as a membership-based society representing Alberta's large industrial electricity consumers.
- Our members are involved in key Alberta industries, including Oil & Gas, Pipelines, Petrochemicals, Agriculture and Steel.
- Our mission is to take a leadership role in ensuring that a competitive marketplace exists for electrical services.

RECOMMENDATION

The 12 CP methodology for bulk system cost recovery continues to be appropriate for Alberta.

Considerations:

- How one pays for transmission infrastructure is a key piece in ensuring efficient infrastructure development
- The strong price signal is, in our view, working and is leading to reduced bulk transmission investments over the long term
- The cost causation principle holds and leads to longer-term efficiency gains

AESO 5 RATE DESIGN PRINCIPLES

1. Recovery of the total revenue requirement;
2. Provision of appropriate price signals that reflect all costs and benefits, including in comparison with alternative sources of service;
3. Fairness, objectivity, and equity that avoids undue discrimination and minimizes inter-customer subsidies;
4. Stability and predictability of rates and revenue; and
5. Practicality, such that rates are appropriately simple, convenient, understandable, acceptable and billable.

RANKING

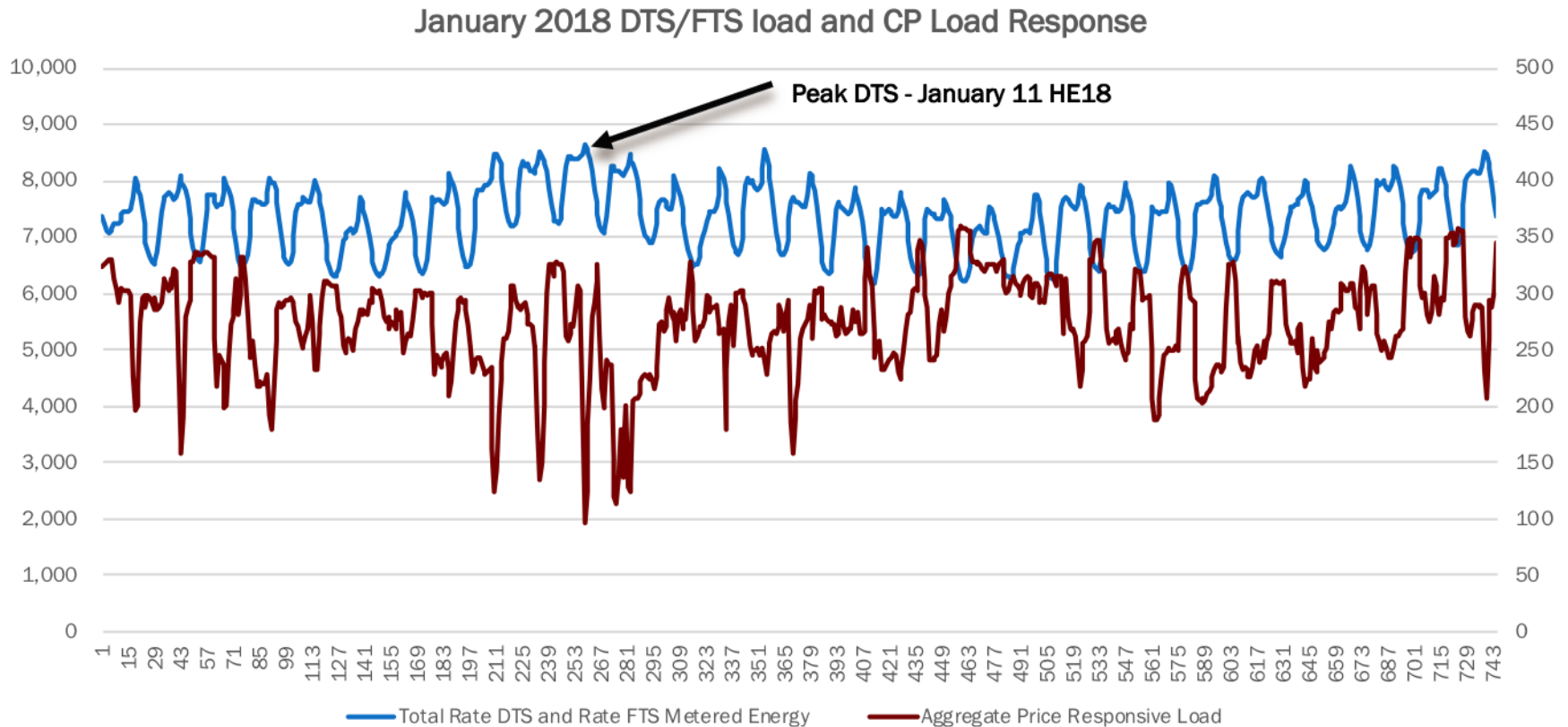
All of the rate design principles are important; however, we would suggest the following weighting from 1 to 10 (10 = most important):

Principle	Weighting	Comments
1. Recovery of the total revenue requirement	N/A	This is a requirement for the AESO
2. Provision of appropriate price signals that reflect all costs and benefits, including in comparison with alternative sources of service	10	We submit that the 12 CP price signal is strong and appropriate for Alberta
3. Fairness, objectivity, and equity that avoids undue discrimination and minimizes inter-customer subsidies	7	“undue discrimination and minimizes inter-customer subsidies” are extremely difficult to measure making this principle difficult to apply
4. Stability and predictability of rates and revenue	9	Especially important for Market Participants who have invested significant capital to respond to the 12 CP price signal
5. Practicality, such that rates are appropriately simple, convenient, understandable, acceptable and billable	8	The AESO’s tariff is quite complex; however, its sophistication supports Principle 2.

12 CP METHODOLOGY

- 12 CP Methodology sends a strong price signal to flatten consumption, in doing so, creating a need for less:
 - Future transmission
 - Generation capacity
- This is not a short-term effect - it takes time. To achieve this, significant levels of investment are required.
- 300 – 400 MW of Demand Response already exists

JANUARY 2018 CP RESPONSE

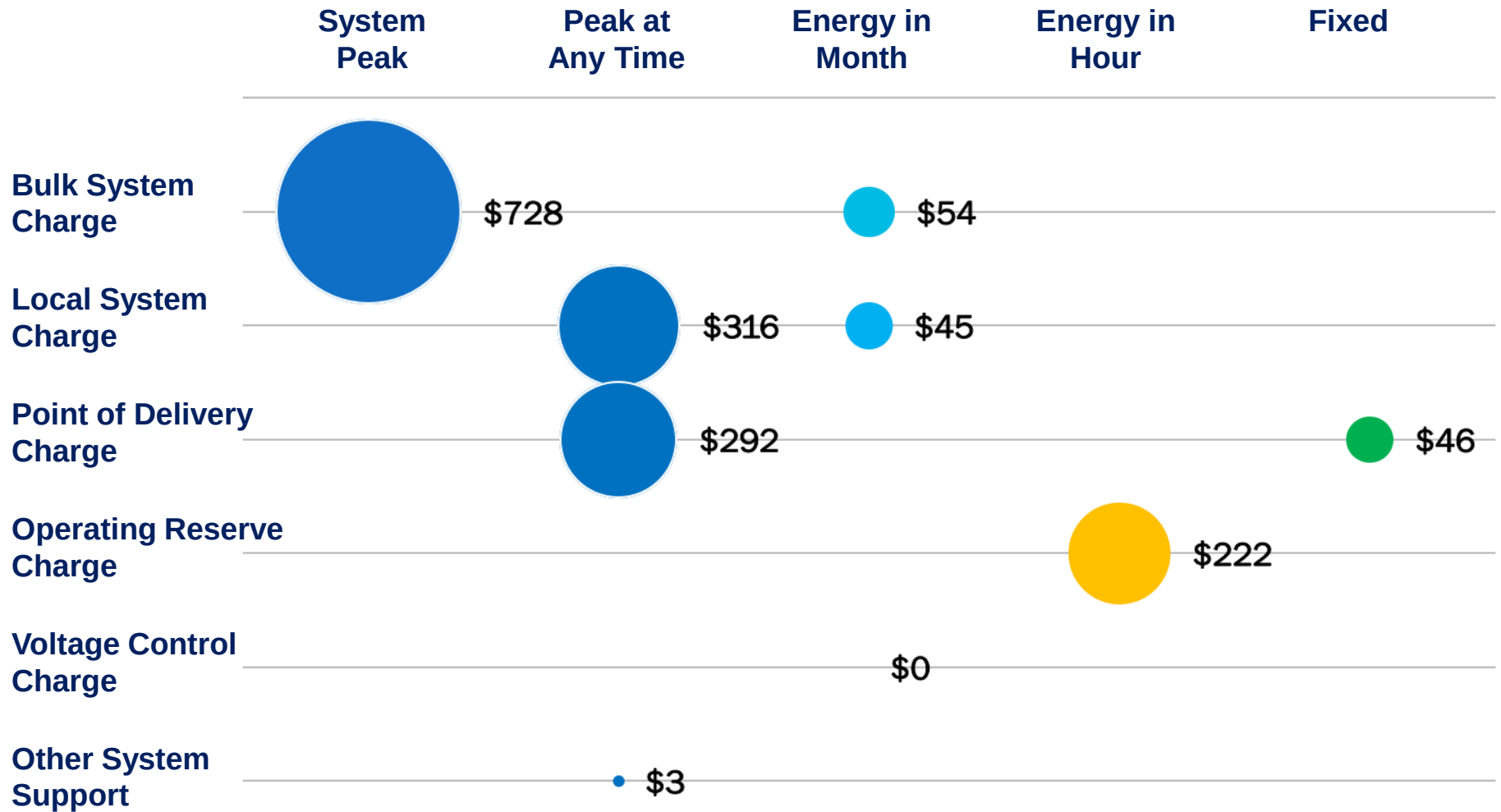


- 12 CP results in a sustainable response behavior by flexible loads
- In order to achieve CP benefit, loads need to interrupt their business operation several times during a month – the idea that a load can respond in one 15 min interval to reduce costs is simply not true. Facilities incur significant production losses in order to manage costs.
- January Peak DTS would have been at least 200 MW higher without this important price signal (this data includes behavior of only 7 price responsive loads).

12 CP METHODOLOGY

- Cost allocation for transmission infrastructure is a key component in ensuring efficient infrastructure development
- A strong price signal is required to influence participant behavior
- A review of billing determinants shows that CP is the best option to influence participant behaviour

RATE DTS STRUCTURE



STABILITY

- One of the principles of rate making is **stability** and **predictability** of rates and revenue
- In 2014, interveners reached a negotiated settlement on the cost causation study. Parties included:
 - AltaLink Management (AML)
 - The Consumers' Coalition of Alberta (CCA) and
 - The Office of the Utilities Consumer Advocate (UCA)
- The settlement included the classification of bulk system and regional system costs into demand-related and energy-related components
- Why the current proposals for change?
- In order to incent investment by consumers we need **stability** and **predictability** of rates.

REVIEW OF CONCERNS

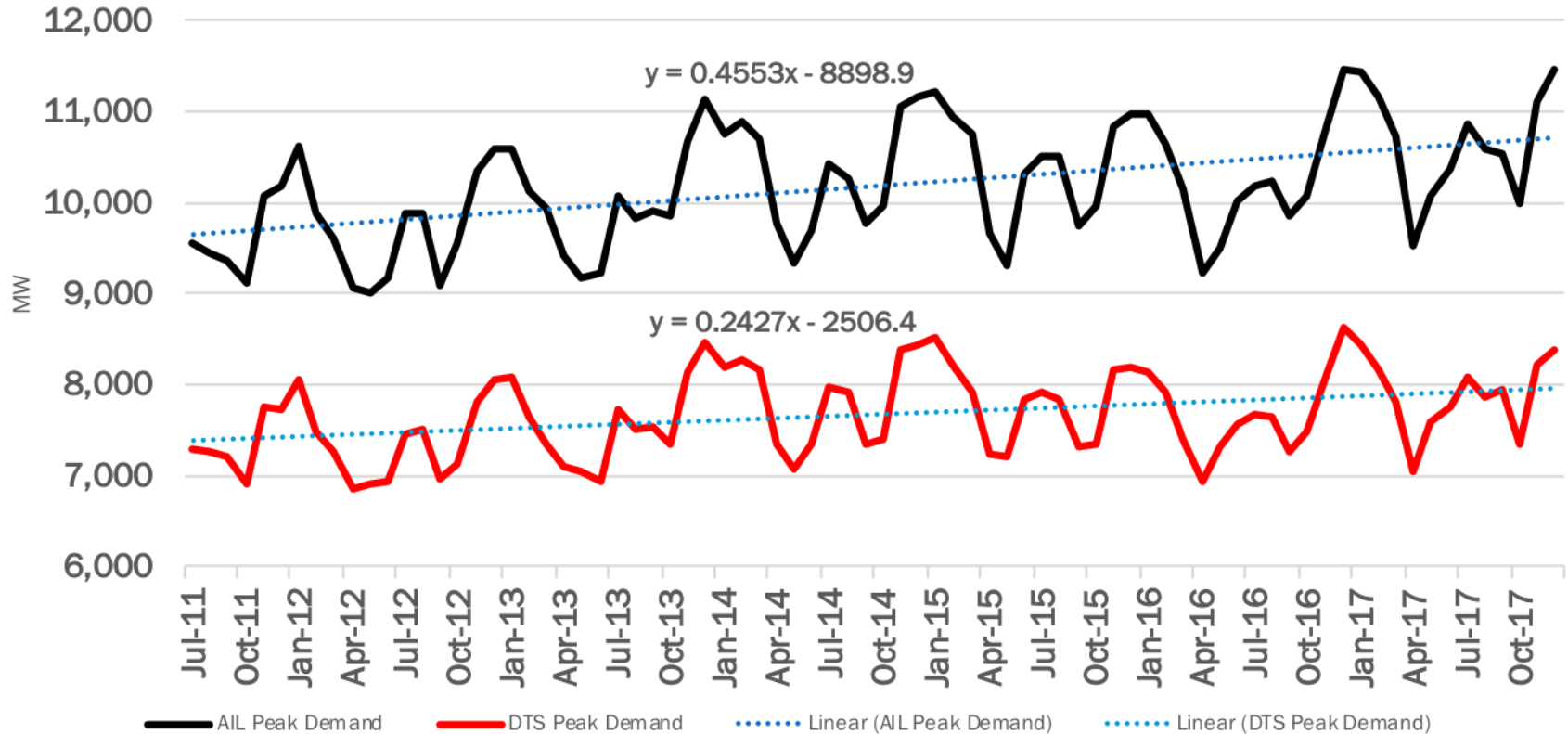
1. Stranded asset risk?
2. Cross-subsidization?
3. Inability for some customer classes to respond to price signals?

Counterpoints:

- Ultimately, having to build less transmission benefits all consumers. There are significant efforts required to reduce demand during peak periods and this leads to a reduced need for transmission and capacity in Alberta. This behaviour enhances the efficiency of Alberta's electricity infrastructure for the benefit of all customers.
- There are other mechanisms which would enable more customers to respond to price signals. i.e. distribution tariffs that flow through the CP rate design.

MONTHLY PEAK DEMAND AIL AND DTS

(JULY 2011 TO DEC 2017)



- Peak AIL has grown by 2,145 MW versus Peak DTS growth of 1,329 MW since July 2011
- Without the CP price signal, the 816 MW difference would need to be served by the transmission system resulting in more transmission infrastructure.
- The notion of “death spiral” in declining DTS load is not supported by the data – Jan 2018 was the highest peak in history.

ALIGNING COST ELEMENTS

- All aspects of the electricity market should act in concert, including:
 - Transmission policy
 - Rate design
 - Electricity market (and capacity market) design
- Overall goal is efficiency - the signal to flatten demand and increase the utilization of the existing transmission and generation assets.

HISTORICAL REVIEW

- Report for Alberta government March 1992 suggested 3,357 MW of cogeneration potential in Alberta by 2005
 - Part of the rationale / justification to move to wholesale energy market and transmission administrator (open access)
- Industry restructuring was intended to reduce transmission costs by putting generation closer to loads
- Result:
 1. 5,000 MW of low cost cogeneration built at no cost to electricity consumers
 2. Significant transmission investment was delayed until 2008+
- Bill 50 mandated “critical” transmission infrastructure – We will have transmission costs >\$40/MWh by 2021

OTHER CONSIDERATIONS

If 12 CP is under review then regional transmission rate design also needs to be reviewed. Key questions include:

- Why should customers connected at 240 kV pay the full costs associated with the 138 / 144 kV transmission system?
- Why should customers located close to the bulk transmission system pay the same rates as customers located at a greater distance?

CONCLUSION

- Continue with the current plan. It works.
- We need to understand and critically assess the various options proposed by other interveners
- We need to assess the efficiency implications of each option

QUESTIONS?

Please feel free to contact us:

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Colette@carmal.ca
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Vittoria.Bellissimo@IPCAA.ca

Fire safety: AESO building evacuation procedures

Calgary Place

Slow alarm:

- Stand by
- Listen to announcements

Fast alarm:

- Evacuate to muster point

Muster point:

- Courtyard at 5th Ave Place

BP Centre

Slow alarm:

- Stand by
- Listen to announcements

Fast alarm:

- Evacuate to muster point

Muster point *South*:

- Courtyard at 5th Ave Place

Muster point *West*:

- Courtyard by Chinese Cultural Center

SCC

When alarm sounds:

- Proceed to Guard House
- Wait for further instruction
(From your fire captain or fire department)



12-Coincident Peak (CP) Bulk Recovery Methodology Issue #1 in Proceeding 22942

March 12, 2018

Main Boardroom, AESO Offices

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Agenda – 12-Coincident Peak Issue

March 12, 2018

Topic	Presenter	Schedule
Introduction	Doyle Sullivan	9:00 – 9:05 am
Session Overview	Karla Reesor (Facilitator)	9:05 - 9:15 am
AESO position I 2018 ISO tariff application	LaRhonda Papworth	9:15 – 9:30 am
Facilitated discussion on bulk recovery methodology principles	Karla Reesor	9:30 – 10:00 am
AltaLink (AML) presentation (includes Q & A)	AML	10:00 – 11:30 am
Lunch		11:30 am – noon
ADC, DUC and IPCAA (includes Q & A)	ADC, DUC, IPCAA	noon – 12:30 pm
Consumers' Coalition Alberta (CCA) presentation (includes Q & A)	CCA	12:30 – 12:45 pm
Utilities Consumer Advocate (UCA) presentation (includes Q & A)	UCA	12:45 – 1:15 pm
Open discussion	All	1:15 – 2:15 pm
Break		2:15 – 2:30 pm
Next steps and summary of action items	Karla Reesor	2:30 – 3:00 pm

- AUC Direction (January 19 Letter - [link](#))
 - *19. The Commission considers that time is required for the AESO to conduct an analysis and prepare evidence on the issues of the 12 CP method and, if necessary, the DFO customer contribution. The Commission also considers that revisions may be required to the AESO's application as a result.*
- Objectives engagement
 - Gather views, supporting information (data and analysis) to help the AESO determine whether to maintain or reconsider status quo
- Scope of session
 - 12-Coincident peak issue
- Proposed timeline

AESO Engagement on 12-CP Issue

- Structure of AESO engagement on 12-Coincident Peak (CP) Methodology issue
 - Facilitated session(s)
 - Initial session or further sessions
 - Opportunities for interested parties or the AESO to:
 - *Present their views and any analysis or assumptions to support their view on the issue*
 - *Ask clarifying questions*
 - Request further data and analysis of the AESO or other parties
 - Assess if further session(s) are required and agenda for future session
 - Written comment period
 - Respond to presentations and discussions from session
 - AESO Response session
 - AESO presents position that it will be filing in GTA

- Manage session agenda
- Ensure all parties are heard
- Agreements
 - Keep an open mind
 - Ask questions (be curious)
 - Share the air time
 - Be specific and succinct
 - Listen generously

Session Documentation

- Meeting minutes will not be taken
- Session presentations will be posted to aeso.ca
- Action items
 - Logged from all session(s)
 - Posted to aeso.ca within two days of session
- Written comments
 - Due March 26
 - No matrix. Send letter to ISOtariffnotice@aeso.ca
 - Posted to aeso.ca by March 28

Timeline for Engagement on 12 CP and DFO issues

- March 5 – DFO Customer Contribution Issue (session 1)
- March 12 – 12 CP methodology (session 1)
- March 29 – Update to AUC
- April 9 – 12 CP methodology (tentative session 2)
- TBD – If required, further sessions for the AESO or other parties to present further information or analysis
- TBD – AESO presentation of position to be filed in GTA

2018 ISO tariff application - Summary and Principles

EUB Decision on 12-Coincident peak

[Decision #2007-106, December 21, 2007]



- “The Board also concurs with the evidence of Dr. Rosenberg noted above that NCP and contract demand do not recognize this diversity and are not appropriate allocation factors for bulk costs” [Page 34]
- “The AESO is directed to continue to unbundle bulk and local wires costs and to use 12 CP method as the allocator for collecting the demand portion of bulk wire costs” [Page 35]

12-Coincident Peak (CP) Methodology

2018 ISO tariff application summary

- Of total wires costs, bulk system costs are 51.4%. Of the total bulk system costs, 93.4% are classified as demand-related. [Section 4-1 of application]
- As a result, 48% of total wires costs is recovered through the monthly coincident metered demand
- The AESO stated that “any significant change in transmission system composition or transmission system usage would necessitate a thorough review” [Section 5.3]
- The AESO provided evidence that no significant change has occurred to the coincident metered demand billing determinant [Figure 5-1]
- The AESO committed to review the 12-coincident peak methodology at close of this proceeding and, additionally, analysis and work on capacity market cost recovery mechanism could be helpful in reviewing the bulk recovery methodology

Principles for bulk wires costs recovery methodology

In its 2006 ISO tariff application, the AESO identified five rate design principles applicable to a utility (adapted from Principles of Public Utility Rates by Bonbright, Daniels, and Kamerschen, 2nd ed., 1988, pp. 385-389):

- i. recovery of the total revenue requirement;
- ii. provision of appropriate price signals that reflect all costs and benefits, including in comparison with alternative sources of service;
- iii. fairness, objectivity, and equity that avoids undue discrimination and minimizes inter-customer subsidies;
- iv. stability and predictability of rates and revenue; and
- v. practicality, such that rates are appropriately simple, convenient, understandable, acceptable, and billable.

Principles for bulk wires costs recovery methodology (continued)

Further:

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

Principles for bulk wires costs recovery methodology (continued)

- Decision 2010-606 regarding the 2010 ISO tariff application reaffirmed that after the principle of full recovery of the revenue requirement, a rate design reflecting cost causation should generally prevail over other secondary considerations, including rate shock considerations, when assessing the AESO's rate design
- The AESO has continued to apply these cost causation principles in the 2018 ISO tariff application

Bulk System Recovery Principles Facilitated Discussion

Thank you



Energy+Environmental Economics

+ DTS Overview and Proposal

March 12, 2018

Ren Orans
Managing Partner
E3



Outline

- + Background**
- + Proposal**
- + Conclusion**
- + Data Needs**



Energy+Environmental Economics

BACKGROUND



K I L O W A T T H O U R S

SINGLE-STATOR WATTHOUR METER

TYPE AB1 S.

200 CL 240 V 3 W 60 Hz TA 30

MADE
IN



Historical Context

+ In Decision 2007-106¹ (pg 34)

- The AESO raised the possibility that a party may be able to avoid the coincident peak (CP) on the system and therefore avoid contribution to fixed costs
- The AESO posited that this would be unjust and unreasonable when these customers use the system over many other hours
- However, the “Board finds no evidence has been provided that such a customer exists on the system”... The Board thinks it is “not possible for a customer to generally simply turn the power off and completely avoid the hour of the system peak”

+ **Over the last 5 years, we have seen that it is possible and economic for customers to bypass the bulk CP transmission charge by reducing CP load through BTF generation, load shifting, and distributed generation**

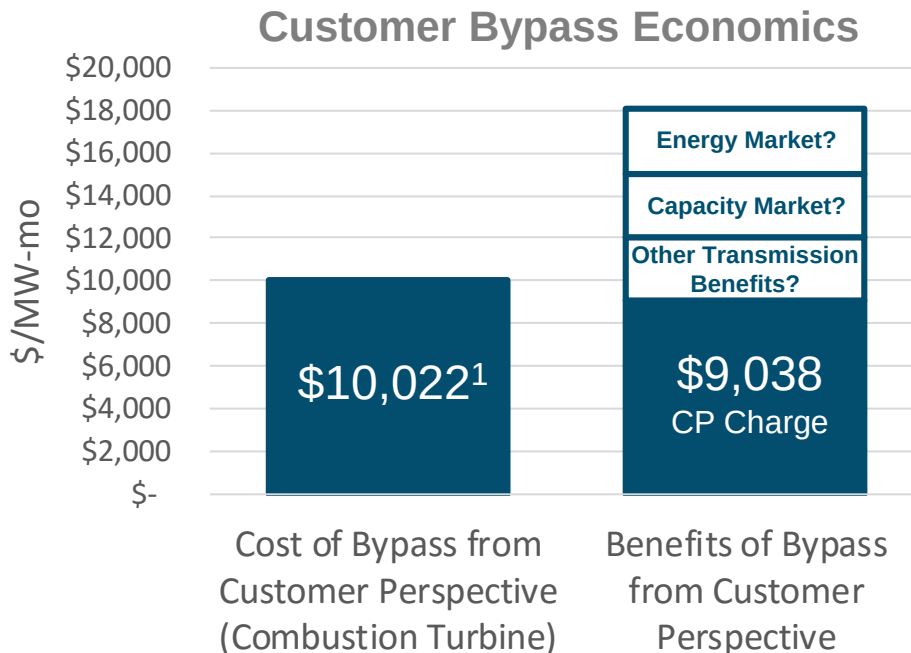
+ **By reducing their net load during a very few number of hours, these customers can bypass between 40% to 50% of total transmission costs**

¹http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2007/2007-106.pdf



A Competitive Market

- + Efficient price signals are of paramount importance in a market when transmission service is subject to competition from alternative service
- + There are many options to reduce CP load and bypass CP charges: BTF generation, DR, DG solar & DG gas
- + The cost of a combustion turbine is on-par with CP charges under the current DTS tariff
- + When other benefits are layered on, the customer economics of investing in alternative options to bypass the CP charge become very compelling and the potential for more investment continues to grow
- + The CP price signal is a value that only accrues to BTF and other distributed resources



¹Combustion Turbine Levelized Cost Assumptions

\$1,000 overnight capital cost
20 year lifetime
7% cost of capital
\$3.00/GJ natural gas
20 operating hours/month
9.6 GJ/MWh
\$18/kW-yr fixed O&M
\$4/MWh var O&M

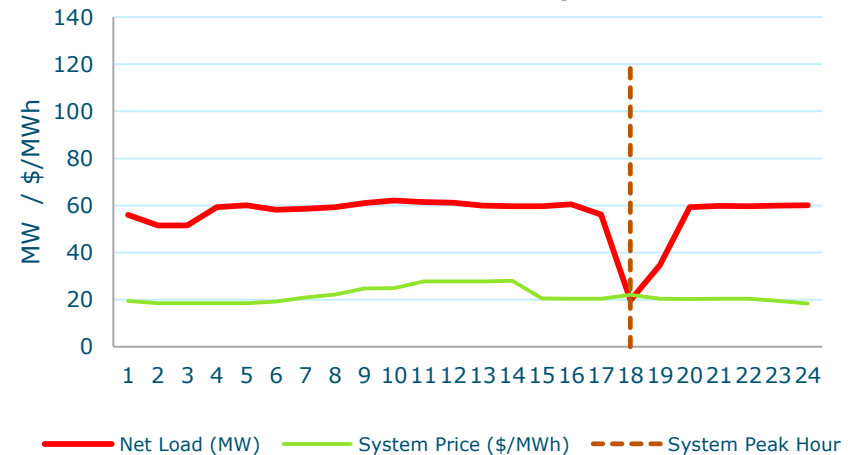
*Source: Generation Costs tab
from 2017 LTO Data File*



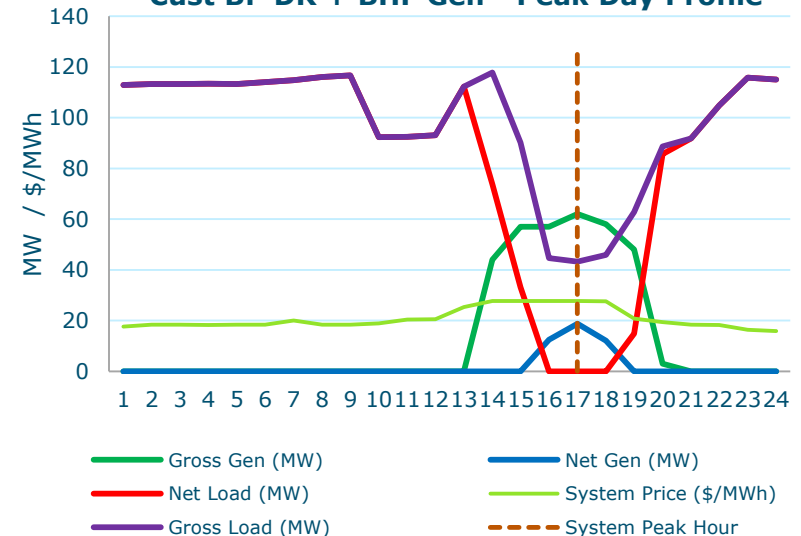
Coincident Peak Avoidance

- + Historical data indicates certain customers can effectively predict CP and minimize CP based charges through load shedding and DG**
- + By reducing their net loads by very few hours, they can reduce their transmission costs by between 40 and 50 percent**

Cust A: DR - Peak Day Profile



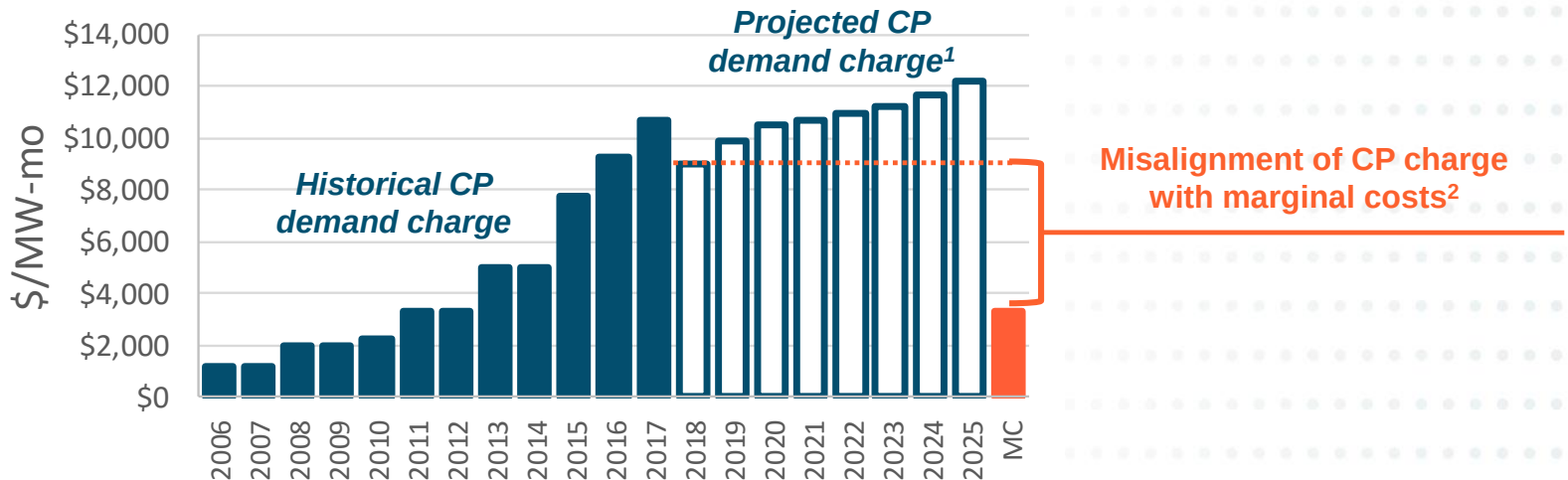
Cust B: DR + BHF Gen - Peak Day Profile





Need for Change

- + Recent investment in the transmission system has increased the bulk system transmission coincident peak (CP) charge such that it is now misaligned with system marginal costs



- + This incorrect price signal is being sent to customers and incents uneconomic bypass (credit exceeds benefit) of the CP charge for the transmission system
 - Large quantity of industrial customers in Alberta makes this a particularly acute problem
- + Uneconomic bypass should be reduced to ensure a fully utilized and viable transmission system
- + Cost-shift is already ~20% of total CP transmission costs³ and likely to escalate without immediate reform



Transmission Marginal Costs

+ Simple and transparent estimates of transmission marginal costs that can be avoided by reducing CP are needed

+ Total Investment Method (DTIM)¹ using publicly available information from the 2017 LTO and 2017 LTP

- Total approximate transmission NPV capital investments 2017-2022 = \$1000 MM²
- Total NPV AIL peak load growth 2017-2022 = 645 MW³
- Assumption: 50%⁴ of transmission CapEx is CP load growth related. This value would rely on additional information from the AESO
- Real economic carrying cost (RECC) = 5.3%
 - 40 year transmission asset life
 - 6.4% WACC, 2% inflation = 4.3% real discount rate

$$MC_{DTIM} = RECC \times \frac{\sum_{t=1}^N \frac{I_t}{(1+r)^t}}{\sum_{t=1}^N \frac{L_t}{(1+r)^t}}$$

$$RECC = \frac{r(1+r)^N}{(1+r)^N - 1}$$

Where:

I_t = capital investment in year *t*

L_t = additional load in year *t*

r = discount rate or WACC

N = number of years in the planning horizon

RECC = real economic carrying cost

$$\text{Transmission Marginal Cost} = \frac{\$1000 \text{ MM}}{645 \text{ MW}} * 5.3\% * 50\% * 1/12 \text{ months} = \$3,416/\text{MW-mo}$$

¹ <https://www.aer.gov.au/system/files/Ausgrid%20-%20Appendix%203%20Summary%20of%20Methodologies%20for%20Estimating%20Marginal%20Cost%20-%20November%202015.pdf>

² <https://www.aeso.ca/assets/Uploads/AESO-2017-Long-termTransmissionPlan-Final.pdf>

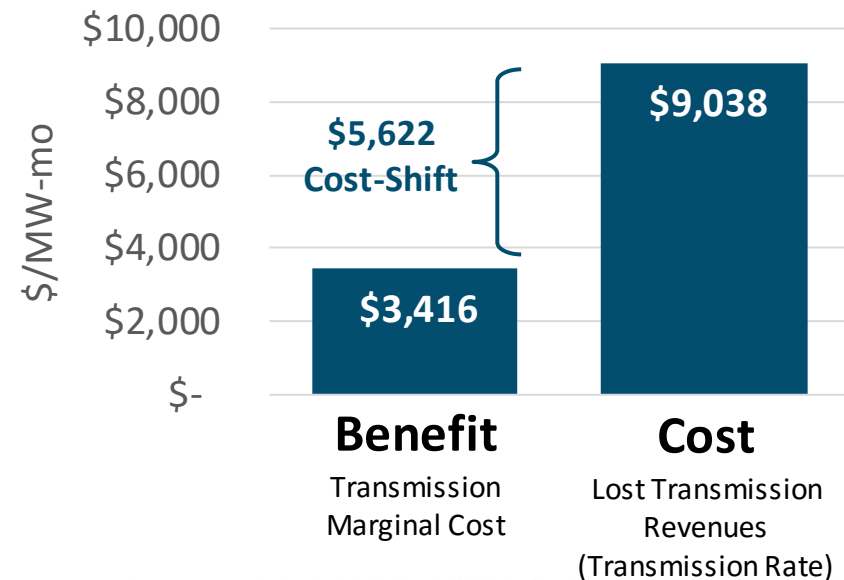
³ <https://www.aeso.ca/download/listedfiles/2017-LTO-data-file.xlsx>

⁴ Actual % will be dependent upon which projects are causally related to CP load – currently ~50% of transmission CapEx is allocated to CP



Cost-Shift Today

- + The difference between the calculated marginal or “avoided” cost of transmission and the existing DTS CP rate can be used to estimate the cost-shift per MW-month
- + Multiplying the cost-shift by the expected MW of bypass yields an estimate of the total cost-shift
- + **Cost-Shift = \$5,622/MW-mo**
- + **Monthly bypass = 2,830 MW/mo**
 - BTF energy served by on-site generation during AIL peak (2,530 MW¹)
 - MW of estimated load shedding that is responsive to the CP (300 MW²)
- + **Annual Cost-Shift = \$191 MM**
 - $\$5,622 * 2,830 * 12 \text{ months}$
- + **Cost-Shift = 21%**
 - $\$191 \text{ MM} / \$900^3 \text{ MM}$





Cost-Shift Growth Potential

- + **Without action, today's estimated cost-shift of \$191 MM could plausibly grow by upwards of 64%**
- + **Sources of additional bypass potential**
 1. **AESO Direct Customers**
 - Potential: **350 MW**
 - The 2017 average of monthly metered coincident peak in Alberta is about 7,790 MW (AESO TRIP Model)
 - The aggregated monthly CP from DFO rate applications is about 7,080 MW (DFO filing data)
 - 50% of the difference between these two yields 350 MW
 2. **DFO settled Direct Customers**
 - Potential: **465 MW**
 - 50% of the 930 MW load that are subject to CP charge but settled through DFOs.
 3. **New DER Participants**
 - Potential: **1000 MW** of distribution connected solar, distributed connected gas generation, gas fired cogen, demand response, or other CP avoidance deployed through aggregation
 - There is an incremental 3000 + MW of incremental solar in the Queue
- + **Incremental CP bypass in 5 years = 1815 MW, which causes a 64% increase to the \$191 MM in cost-shift today**
- + **New plausible 2022 cost-shift = \$313 MM**



Principled Approach

- + E3/AltaLink believe that there are a multitude of rate design reforms that improve the status quo and more closely align with AUC rate design principles**

	AUC Rate Design Principles	E3/AltaLink Perspective
1	Recover of the total revenue requirement	We agree
2	Provision of appropriate price signals that reflect all costs and benefits, including comparison with alternative sources of service	A coincident peak charge equal to the marginal cost of transmission sends the correct price signal to loads and prevents uneconomic bypass
3	Fairness, objectivity, and equity that avoids undue discrimination and minimizes inter-customer subsidies	Minimization of uneconomic bypass (achieved through correct price signal) minimizes inter-customer subsidies and maximizes equity
4	Stability and predictability of rates and revenue	E3/AltaLink are looking for stakeholder input on appropriate need and design of transition mechanism
5	Practicality, such that rates are appropriately simple, convenient, understandable, acceptable, and billable	Simple to understand and implement



Energy+Environmental Economics

PROPOSAL

MADE
IN



AltaLink/E3 Proposal

+ **Step 1: Rate Design Modification (this case)**

- 1) Set coincident peak DTS charge to align with the marginal cost of bulk CP transmission service
- 2) Collect the remaining transmission revenues through billing demand

+ **Step 2: Tracking Account (this case)**

- If a transition mechanism is needed, a tracking account administered by the AESO should measure and track the levels of cost-shifting that is occurring over time

+ **Step 3: Cost of Service Study (subsequent design cases)**

- Conduct a cost of service study that properly allocates assets by their function
- The study should not allocate the cost of high voltage lines that are not built to serve CP to the CP charge



Rate Reform Options & Criteria

+ AltaLink considered a number of rate design reforms that would address the issue of uneconomic bypass

Rate Reform Options

- 1) CP = marginal cost, remainder = NCP, or billing demand
- 2) 2-Part rate (baseline billed at embedded cost, deviations billed at marginal cost)
- 3) Standby charge based on marginal cost (applies only to BTF generators who avoid CP or only to new BTF generators)

+ Each option was evaluated under a range of criteria

Rate Design Criteria

- 1) Align CP rate with marginal cost to send correct price signal
- 2) Recover remaining embedded costs through a billing determinant that is difficult for customers to uneconomically bypass
- 3) Eliminate cost-shift from existing & potential future BTF generators
- 4) Limit bill impacts for customers who cannot avoid the coincident peak
- 5) Maximize stakeholder support for rate reform proposal
- 6) Avoid large, complex rate overhaul



Cost Functionalization

- + The costs of the transmission system are functionalized into three categories by voltage

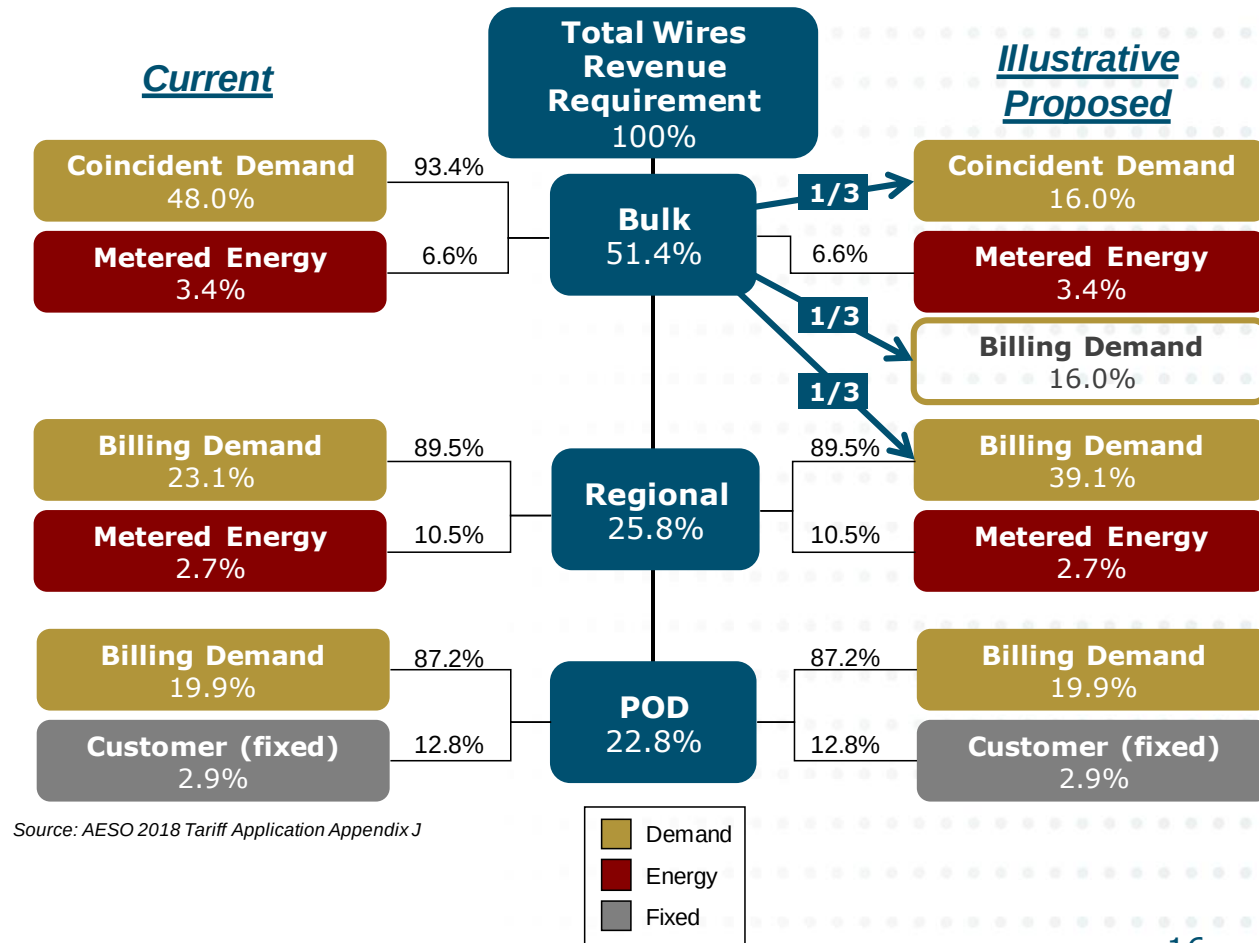
Category	Bulk	Regional	Point of Delivery (POD)
Criteria	≥ 240 kV	69/72-138/144 kV	25 kV or POD Tap

- + Voltage is becoming increasingly insufficient to determine the function of many lines, particularly as more high voltage lines are being built to
 - Interconnect renewables
 - Meet regional transmission needs
 - Accomplish other provincial energy goals
- + These lines are not driven by the need to meet the system CP and thus their costs should not be recovered through this charge
- + Properly allocating costs and reducing the CP charge will reduce the cost-shift



Cost of Service Study

- + AltaLink also believes The AESO should engage in a new and improved cost of service study based on causality
- + This improvement would more accurately functionalize each transmission asset beyond simply voltage to determine whether it primarily serves system load (CP) or other functions such as regional load, renewable integration, or provincial policy





Conclusion

+ **Bad News– We have a problem**

- Changes in energy policy, slower bulk system growth and an increasing reliance on both BTF and DERs are putting downward pressure on the marginal cost of Bulk Transmission
 - Drives a bigger gap between embedded (historical) and marginal (future) cost of transmission
 - Today, this problem is the largest single source of upward pressure on the transmission portion of customers' bills who have not bypassed the bulk transmission charge
 - If untreated, uneconomic bypass could trigger the need to substantially restructure transmission rates, relying on some form of non-bypassable transmission access fees

+ **Good News- There are many workable solutions**

- If you act now in anticipation of this growing problem, there are a variety of ways to align transmission ratemaking with both market forces and government policy



- + The following items are needed from the AESO to assess the full extent of cost-shifting due to uneconomic bypass of the transmission system bulk charge in Alberta**
 - MW of bypass during CP
 - BTF generation
 - Load shedding
 - Other
 - Transmission marginal costs
 - List of projects in 2020-2025 period that could be avoided or deferred through a reduction in the CP

CCA Presentation-Review of 12 CP Method for Allocation/Recovery of Transmission Bulk System Costs March 12, 2018

Changing System

- The Appendix to the December 2017 Alberta Energy paper describes the changing characteristics of the Alberta electricity system as follows:
 - In Alberta, periods of system stress do not generally occur at the same time as peak demand, with approximately 50 per cent of stress periods occurring between July and September, while peak demand commonly occurs in either December or January. This disconnect is expected to widen as renewable penetration increases. System stress periods in Alberta can also have significant annual variance with zero occurrences in some years (2015 and 2016) and up to eight occurrences in other years (2011 and 2013).

Peak Load No Longer the Primary Driver

- In the past, periods of system stress occurred during times when peak load conditions existed. In other words load (or demand) was the primary driver for expansion of the system.
- In a vertically integrated world, it was important to size bulk system additions in order to ensure adequacy of transmission capacity during peak load conditions when the probability of system stress was relatively high.
- Under the old planning paradigm for supply and use of electricity, the use of the loss of load expectation method for determining reserve requirements, and the allocation of capacity costs on the basis of a single or multiple coincident peaks or weighted energy approaches would have been appropriate since load, or demand, was the primary driver of system stress and therefore of system expansion. Under those circumstances it made sense to provide strong incentives to reduce demand during peak periods in order to optimize system costs

High System Stress Periods Not Correlated with high Load Periods

- The current and go forward bulk system planning would need to consider net demand variability and frequent cycling of units due to significant intermittent renewable resources, multi directional and multitemporal load flows, increasing use of integrative smart grid technologies and demand time shifting as a result of the deployment of storage.
- Net demand variability and multidirectional load flows would not be correlated with high demand periods and can occur in any hour. This means planning of bulk system must recognize the need for adequate bulk system capacity in any hour.

A Principled Approach Must Consider Relative Probability of a Load Increment Causing System Stress if added during peak vs outside peak hours

- Rather than providing strong incentives under the coincident peak method to shift demand from peak demand hours to all other hours or even providing somewhat weaker incentives under an energy based methods such as use of on-peak/ off-peak energy, a more nuanced approach is required where by fixed bulk system costs are allocated/recovered recognizing the probability of a load increment causing bulk system additions (on a planning basis), if incurred during peak load hours versus the hours outside peak load hours.
- If there is equal probability that an increment of load would cause bulk system additions (on a planning basis), if incurred during peak load hours versus the hours outside peak load hours, then a non coincident peak or NCP recovery of bulk system costs from all connected loads would be appropriate

Data requirements

- Load analysis by major bulk system lines based on recent historical data:
 - A. Probability of highest 5 hours for each line (planning system) occurring at the same time as the system coincident peak hour, by month (include summary statistics)
 - B. Based on A, calculate the probability of the peak hours for all lines occurring at the same time as the system coincident peak hour, by month
- Simulated analysis of go forward system with increase in frequency of cycling and increasing NDV
- Provide an estimate of the probability of bulk system line peaks occurring at the same time as the 12 CP hours

Possible Reforms to Bulk System Cost Recovery

- Bulk system cost recovery based on higher of CP or NCP times X% (Probability of line peaks occurring at the same time as 12 CP hours; Ontario uses 85%).
- Increasing self generation with multi directional, multitemporal flows means price signals reflecting cost causation should be provided to generation in as much as to load
- All market participants must pay injection and withdrawal charges to access the bulk system.
- All generators including behind the fence (BHF) would have separate contracts to access the bulk system
- Bulk system considered as the physical system where primarily all inflows and outflows occur
- Generator access charges or credits should reflect cost causation in relation to regional system (no wires charges/credits for Generation directly connected to bulk system)
- Load would continue to pay 100% of bulk system wires costs

Rate Making is a forward Looking Concept

- Transmission pricing must provide forward looking price signals consistent with current and go forward planning
- Historical planning may help inform the future; however, this should not be determinative since future cost causation may differ substantially from the past
- Need for gradualism in giving effect to changes in rate design
- Imposing separate contracts and access tariffs for BHF generation may stem load defections
- Steps toward reform ought to commence now-to provide right price signals for those contemplating new generation additions

**Alberta Electric System Operator
2018 ISO Tariff Application**

Proceeding 22942

AESO Consultation on 12 Coincident-Peak Method

Submitted on behalf of:

**The Office of the Utilities Consumer Advocate
(UCA)**

March 9, 2018

Introduction

1. The AESO, in its January 30, 2018 letter¹, proposed a consultation process on the allocation of transmission costs, and in particular the 12CP cost allocator used in the tariff setting process. the AESO described the intent of this specific consultation process as follows:
 - (a) engage with interested parties;
 - (b) provide participants with the opportunity, but not an obligation, to share their views and, if they wish, explain the reasons for holding those views;
 - (c) consider any analysis that participants may have conducted to this point;
 - (d) provide participants with the opportunity to ask questions and gain clarity regarding the concerns or positions of other participants;
 - (e) provide the opportunity to request additional data from the AESO;
 - (f) provide the opportunity to request that the AESO conduct and provide analysis; and
 - (g) assist, in the most efficient and timely manner and having regard to the views of participants, the AESO in developing its position regarding the 12 CP and DFO customer contribution issues and prepare and file evidence regarding those matters.
2. In this submission the UCA responds in particular to the AESO's offer (b) to share its views and explain the reason for holding those views; and (f) to request that the AESO conduct and provide analysis of alternative approaches to the attribution of transmission costs inherent in the use of a 12CP allocator.

The Basic Transmission Cost Allocation Issue

1. Altalink, in its September 28, 2017 letter², and other parties including EDTI³, CCA⁴, the UCA⁵, ATCO Electric⁶ and the Cities of Red Deer and Lethbridge⁷ had expressed concerns over the AESO's transmission cost allocation approach that forms the basis of its proposed transmission tariff design. Concerns over the fairness and stability of tariff

¹ Exhibit 22942-X0114

² Exhibit 22942-X0036

³ Exhibit 22942-X0055

⁴ Exhibit 22942-X0063

⁵ Exhibit 22942-X0064

⁶ Exhibit 22942-X0066

⁷ Exhibit 22942-X0071

revenues have been presented as a desire to modify the 12CP allocator used to allocate that portion of transmission costs defined as comprising the high voltage “bulk” system.

2. The process of allocating the costs of a single and fully integrated transmission system into portions that will be recovered by specific elements of the final tariff from the various customer classes is known as a fully allocated cost of service study. Within the cost of service study there are three dependent and closely related and sequential steps:
 - a) Functionalization of total cost into the defined service provided by each element;
 - b) Classification of the functionalized cost as being driven by power demanded (MW), energy volume consumed (MWh) or the number of customers served; and
 - c) Allocation of the classified cost to be recovered by a specific tariff design.
3. The selection of the specific allocator used in the final step of the three step process of cost allocation must be informed by the preceding steps. The relative merit of any particular allocator such as a multiple CP in all of its possible variants cannot be determined without examining the manner in which the portion of costs operated on by that allocator are functionalized and classified in the preceding steps of the cost allocation process.
4. In terms of allocated transmission “wire” costs, the UCA does not have any concerns over the currently used classification methodology that define costs in relation to power demand, energy volumes, and administrative costs or losses. The UCA does however have significant concerns over the functionalization procedure forming the very first step of the wire-cost allocation process as explained below.
5. In short we believe that the role of transmission wire costs currently functionalized for cost allocation purposes⁸ as “bulk” system and “area” or regional systems need to be reconsidered in the light of the current industry structure and recent transmission system developments. Such reconsideration requires a fresh approach to functionalization and the selection of singular or multiple CP or NCP allocators.

Historical Background and Explanation of Concerns

6. The justification of allocating demand related costs using various forms of singular or multiple coincident peak (CP), or non-coincident peak (NCP) allocators was developed in the early 20th Century for application to vertically integrated and centrally planned utilities, many years prior to the development of today’s desegregated retail electricity markets.

⁸ The system may be functionalized slightly differently for regulatory purposes other than cost allocation such as the application of mandatory reliability standards.

7. In this vertically integrated monopoly model, all generation, transmission and distribution costs were planned and built by the same entity to serve end-use loads. All costs were therefore deemed to be “caused” solely by the end-use customer placed conceptually at the foot of a stack of costs ascending to the generation sources. A convenient topological fiction running linearly from generators via transmission and distribution systems to terminate at loads was then employed for cost allocation purposes. This conceptual model for cost allocation bore little relationship to the physical disposition and operation of the integrated system elements.
8. In this conceptual model, the transmission and distribution network were assumed to radiate from a single representative bus where all cumulative generation on the system was injected. As the adequacy of system generation capacity is determined by coincident system load demands, the generation costs functionalized as demand related were generally allocated using some form of single or multiple CP. At the other end of this conceptually radial system, the more local and lower voltage delivery wires, sized to carry the maximum demand regardless of peak generation coincidence, were allocated on an NCP basis.
9. Within the vertically integrated utility, the transmission system provided the nexus between the CP allocated generation and the NCP allocated distribution. The appropriate method of transmission allocation was therefore considered to shift from a CP relationship at the “sending” end of this linear model to NCP at the “receiving” end where substations provided the distribution system interface.
10. At the time these universal functionalization and allocation procedures were developed there was little in the way of distributed or independent generation, and the entire system was centrally planned and integrated. There was therefore little need to parse out the transmission system itself based on a more realistic topology or functionalization, or to examine allocators that better matched cost causation for a desegregated and more broadly distributed market system serving both independent generators and load distribution systems.
11. Alberta now has a desegregated system where generation is not centrally planned and has become more widely distributed, connected by a regional transmission network that connects a number of regional load centres and is not consistent with the centrally located source and radial transmission nexus that lingers as the conceptual basis for a cost allocation model.

An Improved Cost Allocation Model

12. Following the Alberta industry restructuring the fully de-segregated transmission system has been considered to comprise a central high voltage “bulk” system connecting independent generators at points of supply (POS) and load distribution centres at points of delivery (POD) with these dualities driven by market rather than central planning considerations.

13. In the current conceptual cost model, load POD are considered to be connected to the bulk system via a significant local regional system, while generator POS are considered to connect directly to the bulk system without need of an intervening regional transmission system. This functional and allocation model may have been influenced by legislated directions to not impose transmission wire costs beyond the local POS on independent generators in order to encourage the rapid development of new generation following Alberta industry restructuring.
14. Unfortunately, the cost paradigm shift to a decentralized market system is not complete. It does not recognize that generators are no longer planned to connect directly to the bulk system and are more widely distributed than the old vertically integrated model. This is reflected in the functionalization of regional transmission cost responsibility entirely to POD with the bulk system interface beginning at POS producing an asymmetrical functionalization of bulk system costs. The concept that generators always feed directly into the “upstream” bulk system as if the network is completely radial has been retained, even though the de-centralized system that integrates new generation is now far more regional in nature.
15. The advent of two North to South HVDC lines in 2015 was a major physical and economic change that greatly increased the transmission rate base and completed the transition of the Alberta system to a market based model reliant on broadly distributed generation and cross-border trade. This significantly changed role with the displacement of 240KV lines to fulfil a more regional purpose now requires reconsideration of the definition of “bulk” and “area” transmission for purely cost allocation purposes, and how these common costs are to be fairly and stably functionalized and allocated in accordance with principles of cost causation.
16. The UCA therefore proposes that the AESO develop and file a new cost of service model and resultant tariffs where only HVDC lines and AC transmission in **excess** of 240KV are considered to be bulk transmission and these transmission costs are allocated using a modified multiple CP that reflects the current use of system as described below.
17. Transmission lines designed to be operated at 240KV or below would be functionalized as regional, reflecting the evolution of this transmission as more local wire services intended to integrate both loads and more distributed generation sources. The allocator chosen would also be NCP to better reflect the more non-coincident nature of local cost causation.

Request for the AESO to conduct and provide analysis

18. In summary the UCA views the current approach to transmission cost functionalization and allocation based on vertically integrated utility concepts and monopoly characteristics to be outdated and inconsistent with the evolving nature of the de-

segregated transmission system that now provides the armature for a growing distributed generation and market system.

19. The UCA requests the AESO to please provide three sensitivity analyses showing how the fully allocated cost of service model, resultant tariff and billing distribution between types of customer would change if:

- a) The cost of the bulk transmission system is redefined as comprising the HVDC system and AC lines operated above 240KV, all allocated to POD on the current 12CP basis.

All AC lines operating at 240KV or below are considered to be area or regional transmission and allocated to POD on an NCP basis.

- b) Without any change to the definition of bulk or area transmission, allocate all bulk costs using a 12CP allocator ***where the peak contribution for each of the 12 months is determined as the mean of the 12 highest aggregate peak demand hours within each calendar month.***

- c) ***Both*** of the bulk/area functionalization definition, and the determination of the 12CP contributions in A and B above are combined.

20. By incorporating the suggested changes the AESO would develop and file an updated transmission cost allocation model better reflecting current topology and functionality, where only HVDC lines and AC transmission in excess of 240KV are functionalized as bulk, and allocated using a form of 12 CP stabilized using 12 hourly averages.

21. Transmission lines designed to be operated at 240KV or below would be functionalized as regional, reflecting their evolution as regional wire services intended to integrate both loads and more local distributed generation sources. The appropriate allocator would be NCP to better reflect the more non-coincident nature of more local cost causation.

22. The UCA looks forward to reviewing the revised cost of service studies and is available to discuss and provide clarifications where necessary.

AESO 2018 ISO Tariff

Transmission Wire Cost Allocation Issues

utilitiesconsumer
advocate

Current Approach

- Bulk system defined as lines operating at 240kV and above.
 - Allocated using a 12 monthly Coincident Peak Allocator (with each of 12 months based on a single hour)
- Regional system defined as lines operating below 240kV
 - Allocated using Non-Coincident Peak (NCP) Allocator

Concerns with Current Approach

- Does resulting allocation fairly reflect cost causation?
 - Based on old vertically integrated centrally planned concepts
 - Alberta now de-segregated with distributed independent generation
 - HVDC is part of significant changes to system topology and trade
- Does allocation method provide stable results?
 - The use of CP based on single hour allows gaming and instabilities.

Requested Sensitivity Analysis

1. For cost allocation purposes redefine “bulk” and “regional” system so that:
 - The bulk system comprises HVDC and AC lines operating above 240kV only
 - Regional systems AC lines operating up to and including 240kV
 - Provide the resulting cost allocation and tariff change distributions by customer class

Requested Sensitivity Analysis

2. Modify the existing 12 CP allocators:
 - So that the allocations for each of the 12 months are based on the mean of the 12 highest hourly peak demands within that month.
 - Provide the resulting cost allocation and tariff change distributions by customer class

Requested Sensitivity Analysis

3. Combine both modifications suggested in 1 and 2, and provide:
 - the resulting costs allocation
 - Tariff change distributions by customer class

Conclusion

It is the UCA's view that completion of the requested analyses will assist in the review of a functionalization and cost allocation process that better reflects the nature of Alberta's evolving transmission.

Questions

March 15, 2018

AltaLink Management Ltd.
Zora Lazic, SVP Law & Regulatory, General Counsel
2611 – 3rd Avenue SE
Calgary, AB T2A 7W7

Dear Ms. Lazic:

Re: **Alberta Electric System Operator (AESO)
2018 ISO Tariff Application
Proceeding 22942
Consultation on DFO Customer Contribution Issue**

Further to the consultation session held on March 5, 2018 with respect to the DFO Customer Contribution Issue, the AESO has the following questions that will further assist the AESO in understanding the AltaLink Management Ltd. (AltaLink) proposal.

1. Please provide a process graphic illustrating the ongoing payment/transaction flows that would occur on a monthly basis and include in the graphic how these rates would be adjusted if capital structure, ROE, depreciation rates, or income tax rates change.
2. Please explain in detail what would happen and provide numerical examples when a CCD adjustment is required for
 - a) a 5 MW contract increase and a 5 MW contract decrease, including how the PILON would be calculated; and
 - b) when connection project costs change.

Use the parameters provided in the presentation where a \$42 million project would result in a \$308,000/month (\$3.7 million/yr) cost to the DFO. Assume an initial DTS contract level of 20 MW and current AESO investment policy and adjust the initial monthly payment accordingly.

3. Please explain the “risk [to a TFO] associated with building, owning, operating and maintaining” where the customer is a regulated DFO.
4. The following is set out on AltaLink Slide 5, bullet 3: “Upon energization TFO refunds the DFO contribution back to the AESO”. As the AESO is currently not a party to the contribution transaction, please explain why a refund to the AESO is being proposed? Could arrangements not be made such that the TFO works directly with the DFO when DFO contributions are required?
5. Please explain why DFO participation would be mandatory. Would this also be applicable to all DFOs in Alberta and if not, identify the DFOs to whom it would be applicable? Additionally, please comment on paragraph 526 of Decision 2011-474, reproduced below:

“526. In response to the submission by the UCA that Rider I should be mandatory for all DFOs, the Utilities stated that there is no rational basis for creating a distinction between standalone and integrated utilities. The Utilities submitted that all utilities are subject to the standalone principle; and

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therefore corporate affiliations should not necessitate use of Rider I any more than they should be a determinant of the appropriate compensation for CIAC. Therefore, the Utilities submitted that Rider I should be optional for all market participants.”

6. AltaLink's proposal does not comply with the following subsections of the current ISO tariff:
- Section 8: 7(2) - A market participant must pay construction contribution amounts to the legal owner of the transmission facility in accordance with the financial obligation provisions of section 5 of the ISO tariff, *Financial Obligations for Connection Projects*.
 - Section 9: 2(2) - The ISO must review the construction contribution determination and may determine a construction contribution adjustment is required when ... [the listed conditions do not include anything that reflects AltaLink's proposal].
 - Section 9: 6 - The ISO must determine the amount of an adjustment to a construction contribution paid for a connection project in accordance with the construction contribution provisions described in the ISO tariff as applied to the transmission facilities when constructed.
 - Section 9: 7(2) - The legal owner of the transmission facilities must refund a construction contribution adjustment ... [the listed circumstances do not include anything that reflects AltaLink's proposal].

Does AltaLink have suggestions for revisions to these provisions that would allow for a refund of DFO customer contributions to the AESO?

7. Aside from mandatory participation in the AltaLink proposal and only offering the proposal to a DFO, can AltaLink explain how AltaLink's proposal differs from Rider I?
8. During the session on March 5, AltaLink indicated that it may pursue the application of their proposal retroactively to 2006. Please confirm this possibility and provide details.

AltaLink may respond to these action items as part of its written comments or as a separate response, either of which will be due by the written comment deadline of March 19, 2018.

Please do not hesitate to contact the undersigned if you have any questions.

Sincerely,

< Electronically Submitted >

Doyle Sullivan, P. Eng
Director, Tariff Design

March 15, 2018

FortisAlberta Inc.
Janine Sullivan, Vice President, Finance and Chief Financial Officer
320 – 17th Avenue SW
Calgary, AB T2S 2V1

Dear Ms. Sullivan:

Re: **Alberta Electric System Operator (AESO)
2018 ISO Tariff Application
Proceeding 22942
Consultation on DFO Customer Contribution Issue**

Further to the consultation session held on March 5, 2018 with respect to the DFO Customer Contribution Issue, the AESO has the following questions that will further assist the AESO in understanding Fortis's concerns regarding the AltaLink Management Ltd. (AltaLink) proposal.

1. Do Rate 63 customers or other customers pay a contribution to Fortis? If so, please show how is it calculated? In the calculations please indicate how transmission contributions are reflected or flowed through.
2. Please provide further details about the "tariff shopping" concern raised during the session and give an example.
3. AltaLink Management Ltd. (AltaLink) claims that "it is the regulated TFO that owns and maintains the interconnection transmission asset and therefore should be allowed to make the investment in those assets". Is it true that a regulated DFO owns the distribution assets but does not make investment in those assets? Please elaborate.
4. Does Fortis anticipate that implementing the AltaLink approach would have implications on the PBR process? If so, please explain those implications.
5. The following is set out on Fortis Slide 3, first bullet: "Rider I - Amortization of AESO customer contributions; equates to 100% investment level for transmission facility owners (TFOs) / AESO". Please explain what is meant by this statement?

Fortis may respond to these action items as part of its written comments or as a separate response, either of which will be due by the written comment deadline of March 19, 2018.

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Please do not hesitate to contact the undersigned if you have any questions.

Sincerely,

< *Electronically Submitted* >

Doyle Sullivan, P.Eng
Director, Tariff Design

March 23, 2018

Alberta Electric System Operator
Calgary Place,
2500, 330-5th Avenue S.W
Calgary AB, T2P 0L4

Attention: Doyle Sullivan, P.Eng.
Director, Tariff Design

Dear Mr. Sullivan:

Re: 2018 ISO Tariff Application
Proceeding 22942
Consultation on DFO Customer Contribution Issue

On March 5, 2018, AltaLink Management Ltd. (AltaLink) attended a DFO Customer Contribution session at the Alberta Electric System Operator (AESO). On March 15, 2018, the AESO posted the following Action Items:

- **Action Item 1 – AltaLink** - AltaLink to provide detail on its process for retroactively assessing projects and to use specific project examples; and
- **Action Item 2 – AESO** - AESO to make specific requests to AltaLink and FortisAlberta Inc. in regards to further clarification it may require.

On March 15, 2018, AltaLink received a letter from the AESO with eight questions regarding AltaLink's proposal on DFO Customer Contribution. Enclosed is AltaLink's responses to these questions from the AESO. For Action Item 1, AltaLink provides its response in AESO question eight which includes a proposal for addressing historical contributions. The proposed method is not proposing to retroactively adjust historical contributions, but is instead proposing to address the unamortized DFO only customer contributions as at December 31, 2017 on a go forward basis. This method does not involve a specific project due to the method proposed. As a result, AltaLink considers Action Item 1 and 2 closed.

Yours truly,

(Original signed by)

Zora Lazic
Senior Vice President Law & Regulatory, General Counsel

Request:

1. Please provide a process graphic illustrating the ongoing payment/transaction flows that would occur on a monthly basis and include in the graphic how these rates would be adjusted if capital structure, ROE, depreciation rates, or income tax rates change.

2. Please explain in detail what would happen and provide numerical examples when a CCD adjustment is required for

- a) 5 MW contract increase and a 5 MW contract decrease, including how the PILON would be calculated; and

- b) when connection project costs change.

Use the parameters provided in the presentation where a \$42 million project would result in a \$308,000/month (\$3.7 million/year) cost to the DFO. Assume an initial DTS contract level of 20 MW and current AESO investment policy and adjust the initial monthly payment accordingly.

3. Please explain the “risk [to a TFO] associated with building, owning, operating and maintaining” where the customer is a regulated DFO.
4. The following is set out on AltaLink Slide 5, bullet 3: “Upon energization TFO refunds the DFO contribution back to the AESO”. As the AESO is currently not a party to the contribution transaction, please explain why a refund to the AESO is being proposed? Could arrangements not be made such that the TFO works directly with the DFO when DFO contributions are required?
5. Please explain why DFO participation would be mandatory. Would this also be applicable to all DFOs in Alberta and if not, identify the DFOs to whom it would be applicable? Additionally, please comment on paragraph 526 of Decision 2011-474, reproduced below:

“526. In response to the submission by the UCA that Rider I should be mandatory for all DFOs, the Utilities stated that there is no rational basis for creating a distinction between standalone and integrated utilities. The Utilities submitted that all utilities are subject to the standalone principle; and therefore corporate affiliations should not necessitate use of Rider I any more than they should be a determinant of the appropriate compensation for CIAC. Therefore, the Utilities submitted that Rider I should be optional for all market participants.”

6. AltaLink’s proposal does not comply with the following subsections of the current ISO tariff:
 - Section 8: 7(2) - A market participant must pay construction contribution amounts to the legal owner of the transmission facility in accordance with the financial obligation provisions of section 5 of the ISO tariff, *Financial Obligations for Connection Projects*.
 - Section 9: 2(2) - The ISO must review the construction contribution determination and may determine a construction contribution adjustment is required when ... [the listed conditions do not include anything that reflects AltaLink’s proposal].
 - Section 9: 6 - The ISO must determine the amount of an adjustment to a construction contribution paid for a connection project in accordance with the construction contribution provisions described in the ISO tariff as applied to the transmission facilities when constructed.

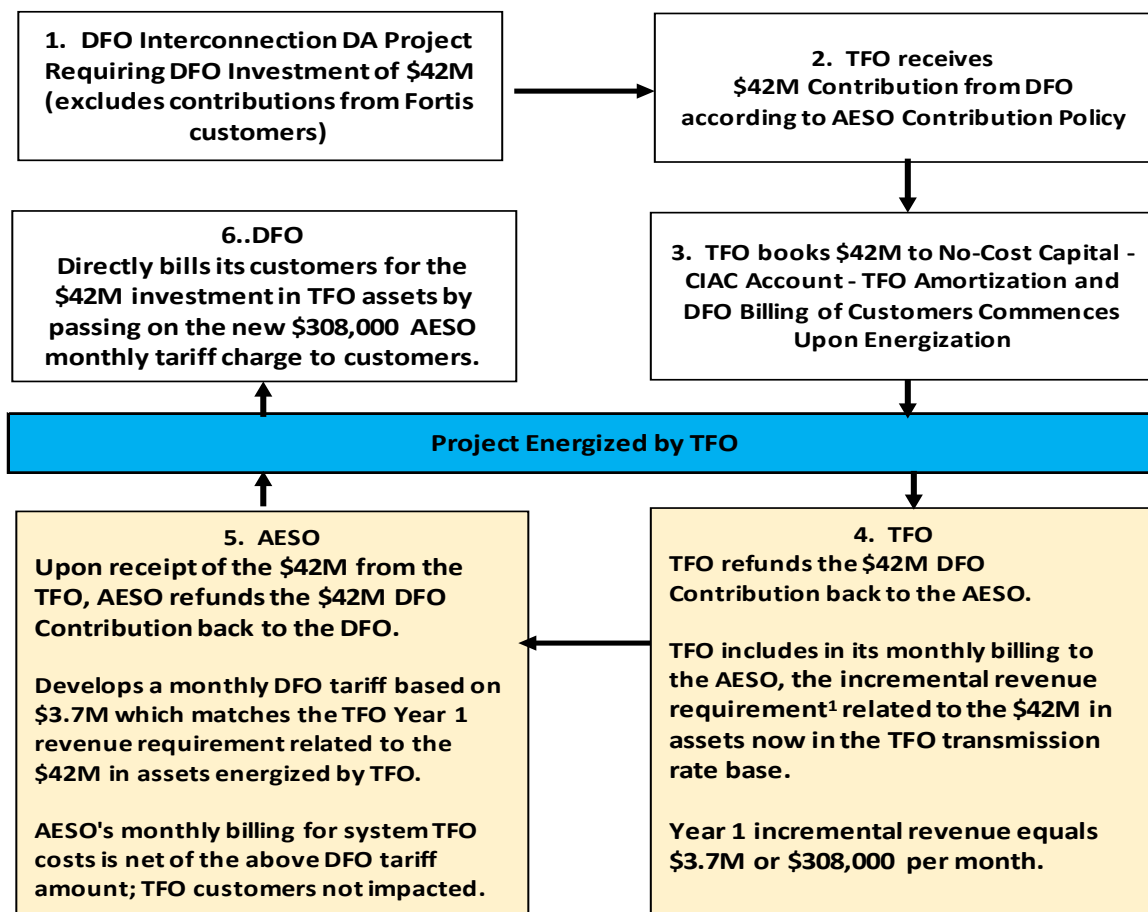
- Section 9: 7(2) - The legal owner of the transmission facilities must refund a construction contribution adjustment ... [the listed circumstances do not include anything that reflects AltaLink's proposal].

Does AltaLink have suggestions for revisions to these provisions that would allow for a refund of DFO customer contributions to the AESO?

- Aside from mandatory participation in the AltaLink proposal and only offering the proposal to a DFO, can AltaLink explain how AltaLink's proposal differs from Rider I?
- During the session on March 5, AltaLink indicated that it may pursue the application of their proposal retroactively to 2006. Please confirm this possibility and provide details.

Response:

- The schematic shown on Slide 7 of AltaLink's March 5, 2018, presentation to the AESO shows the payment and transaction flows that would result from AltaLink's proposed refund of DFO customer contributions using, as an example, the Fortis Provost Line Project with a \$42.0 million DFO contribution.



Description of the process flows as set out in the schematic above reflects:

- Steps 1 to 3: The DFO contributions to the TFO from initiation of project to its energization;
- Step 4: The refunding of the DFO contribution from the TFO to the AESO. As a result, the TFO rate base increases by the amount of the DFO contribution refund and therefore its tariff increases by the amounts attributable to the amortized amounts from the customer contribution refunds to the DFO (via the AESO). At this step the series of amortized amounts will always be calculated and adjusted to reflect final AUC decisions as they arise regarding capital structure, ROE, depreciation rates, or income tax rates changes. This is consistent with how the TFO currently reflects changes to the monthly tariff it charges the AESO. For instance if a generic cost of capital decision is issued, and to the extent any of the capital structure and/or ROE parameters are changed, adjustments would be applied in the determination of AltaLink's tariff to the AESO as well as to the amortized payments determination applicable to the DFO. The changes to those parameters would be applied to the effective period of the decision; and
- Steps 5 to 6: A refund of the DFO contribution from the AESO to the DFO. The AESO in this step converts the DFO contribution into a series of amortized payments (based on the TFO's approved rates) invoiced monthly to the DFO.

To summarize the flow as reflected in Slide 5 of AltaLink's March 5, 2018 presentation to the AESO DFO Customer Contribution – Process Steps and Mechanics:

- i. Proposal only pertains to contributions made by the regulated DFO, and not an industrial or other customer behind the DFO;
 - ii. DFO provides upfront contribution to the TFO as per the AESO policy;
 - iii. Upon energization TFO refunds the DFO contribution back to the AESO;
 - iv. TFO includes the revenue requirement related to these new assets in its monthly AESO billing;
 - v. AESO charges the DFO monthly for the TFO revenue requirement related to the DFO contribution refund and the AESO uses this revenue to offset the TFO tariff increase related to the DFO contribution refund; and
 - vi. DFO will then flow through this AESO monthly charge directly to its customers. DFO customers are kept whole over the life of the assets.
- 2(a) When a CCD adjustment is required, it is important to note that the current proposal does not impact the adjustment levels required for either contract capacity increases or decreases, or with respect to PILON adjustments as they would continue to be determined by the terms and conditions of the AESO tariff. Under the current situation, the financial adjustments arising from such changes would consist of customer contributions being either charged or refunded to the DFO. The only change arising out of this transaction is adjustments reflected through changes to the monthly invoice issued to the DFO and not through a lump sum invoice.

Under AltaLink's proposal, the DFO contribution is refunded post project energization, subsequent changes arising from changes to the CCD contract capacity would take place under the same terms and conditions that currently exist. The difference arises in that the refund amount would no longer be accomplished through a single lump sum payment to the DFO via the TFO. Instead, the capacity adjustment is reflected through lower monthly invoicing amounts to the DFO as a result of lowering the contribution investment that determines the billing amount. Therefore, as a result of

this adjustment arising from a DFO contract capacity increase, the DFO ratepayers would see a reduction to their monthly charges while the transmission system ratepayers would see an offsetting increase. In summary, the recovery of the total costs associated with the transmission asset(s) follow the AESO's tariff in determining the amount to be recovered from Transmission System ratepayers and Distribution ratepayers.

The following simplified example assumes the initial DFO Customer Contribution was \$42.0 million based on a DTS contract capacity of 20 MW:

- In the event contract capacity was increased by 25 percent from 20 MW to 25 MW, we have assumed for simplicity that the DFO's required contribution would also be adjusted downward by 25 percent from \$42.0 million down to \$31.5 million;
- Under the current environment, this \$10.5 million as determined by the AESO, would be refunded by the TFO to the DFO and would result in lower charges to DFO ratepayers. Conversely, according to the AESO tariff, the TFO rate base would increase by the \$10.5 million (due to reduced contribution levels). This increase to the TFO rate base would result in increased and equal offsetting charges to the transmission ratepayers;
- Under the proposed approach, a change to the contracted amount would result in no change to the TFO rate base as it would have already reflected the refund of the DFO contribution. What would change is the amount the AESO charges the DFO. Specifically, the determination of what portion of the TFO total tariff is to be invoiced by the AESO to the regulated DFO would decrease by the amortized payment associated with the \$10.5 million adjustment arising from this example; and
- As a result of decreasing the DFO contribution refund amount by the \$10.5 million, the amount the AESO would now invoice the DFO falls from \$3.7 million in year 1 down to \$2.8 million or approximately \$232,000 per month. The offsetting difference would be charged to the Transmission System ratepayers.

The same mechanics and approach would apply for decreases in CCD contract capacity (from 20 MW to 15 MW). The DFO contribution principle amount in this example would be adjusted upward by 25 percent from \$42.0 million to \$52.5 million and amounts to \$3.7 million per year to \$4.6 million per year or approximately \$385,000 per month. This resulting adjustment as calculated by the AESO would be charged to the DFO. Again, in this instance, instead of a further lump sum contribution from the DFO reflecting this adjustment being made to the TFO under the current environment, the proposed approach would have an increase in the monthly amount (from \$307,000/month to \$385,000/month) that the AESO would invoice the DFO (who would collect these amounts from their ratepayers). This would result in lower offsetting amounts being charged to transmission system ratepayers. Any adjustments with respect to PILON related charges as determined by the AESO tariff would also be treated in similar fashion.

- 2(b) When connection project costs change, the appropriate adjustments to the required DFO contribution amounts would be calculated (as they are currently being done) under the AESO tariff. Upon energization of the project (under the proposed approach), the DFO customer contribution would be refunded to the AESO who would in turn refund those contributions to the DFO. As explained above, the TFO monthly charge to the AESO would increase and consequently the AESO's monthly charge to the DFO would increase by a corresponding amount. In all of these instances

that give rise to changes to DFO contributions, the TFO would assist the AESO in calculating the monthly charges to the DFO.

- (3) The TFO is responsible for the design, permitting, construction and integration of those transmission projects. These assets are then required to be operated and maintained in a reliable and efficient manner. These activities must be performed prudently and subjects TFO's to construction, operating and decommissioning risk. This can be summed up as business risk of owning and operating transmission assets as a TFO.
- (4) The AESO is currently not a direct party to the Customer Contribution Agreement, however, the template and process is a mechanism reflected in the AESO's approved tariff. The refund of the DFO contribution through the AESO is proposed due to the AESO being the sole provider of transmission system access, inclusive of charges for access to market participants. The TFO does not have the authority to make contribution arrangements directly with a DFO without authority from the AESO/AUC. To the extent the TFO is permitted to directly work with the DFO regarding DFO contributions, AltaLink (TFO) would agree to do so.
- (5) This is not a Rider I issue and the Rider I proposal was not adopted in Alberta. AltaLink's proposal is designed to only be applicable to regulated DFOs to address a long standing tariff structure issue between regulated TFOs and regulated DFOs and should be applicable to all Alberta DFOs. This proposed change should be mandatory regarding contributions made by the regulated DFO only, and not an industrial or other customer behind the DFO.

For additional context, this is a tariff matter that does not change who ultimately pays for transmission assets. Under this proposal, transmission assets as defined in the EUA and their related costs that are determined by the AESO tariff are part of the transmission system and are paid by transmission system ratepayers. In AltaLink's proposal, transmission assets built by the TFO for the DFO have costs recovered through the DFO customers. In other words, the end customers are not impacted by this proposal. This proposal places the rate base into the regulated party (the TFO in this instance) that is accountable for the design, permitting, construction and integration of those transmission projects and not the regulated DFO. It effectively stops the DFO from earning returns on the regulated TFO's transmission assets.

The regulated TFO should be allowed to make the investment in TFO assets because it is the entity that owns and maintains the AIES and not the regulated DFO. Left unchanged, this situation results in the TFO incurring business risk, as discussed above, without return while providing the DFO with the regulated returns on the risk.

Furthermore, the current arrangement fails to provide clear economic signals concerning regulated DFO's investment decisions in regulated transmission related assets. Unlike industrial customers that are not regulated, the regulated DFO finances the customer contributions it makes to the TFO with respect to transmission assets, and then recovers those costs inclusive of a regulated return on equity from the DFO ratepayers. Effectively, encouraging the DFO to pursue the construction of transmission assets by the TFO. By shifting the return on transmission to the TFO, it provides economic signals on when transmission assets are required by a DFO.

Overall, allowing TFO's to earn a fair return on the design, permitting, construction and integration of transmission assets in Alberta properly balances the business risk and creates proper economic signals for the construction of transmission assets.

- (6) AltaLink's proposal does comply with the current subsections listed above. In AltaLink's view, there would be no requirement to change the Sections listed above in regards to the determination, collection of the upfront contribution or any financial settlements/true-ups associated with the DFO contributions. The AltaLink proposal contemplates the refunding of such DFO contributions post energization of those assets. Also, any changes to elements, such as DFO contracted amounts on a go forward basis, would continue to be subject to the existing AESO tariff adjustments. Those ensuing adjustments, as explained in response 2 above, would be reflected as a change in the level of recovery of costs from the DFO through the proposed monthly invoicing process.

With respect to changes/additions to the AESO tariff sections, AltaLink proposes to work with the AESO and other interested parties to determine the appropriate revisions regarding its DFO contribution proposal. Specifically, tariff sections would need to be drafted to reflect the refunding of the DFO contributions post project energization and the conversion to a monthly billing amount that would see the AESO invoicing the regulated DFO who would in turn collect such amounts from its customers.

- (7) Rider I was specifically focused at all stakeholders industry wide and provided an option for enrolment. As explained in response 5 above, AltaLink's proposal is about correcting the issue of TFOs bearing the risk for DFOs, while DFOs effectively earn the return on the transmission asset. However, a similarity does exist between the Rider I and the DFO contribution refund proposal, as the mechanical calculation in determining the monthly charge to the DFO adopts the approved TFO cost of service rates and methods in determining the amortized monthly amounts to be charged to the DFO.
- (8) AltaLink intends to pursue the application of its proposal to the unamortized DFO only customer contributions as at December 31, 2017. This is a go forward approach that would refund those unamortized balances in the same fashion as described in AltaLink's proposal. The unamortized DFO contributions will be refunded to the AESO who in turn passes those amounts back to the regulated DFO. The AESO would then charge the DFO, on a monthly basis, the TFO's cost of service associated with those contributions. The DFO would then collect those invoiced amounts from its customers and would pay the AESO.



WACHOWICH & COMPANY
— Barristers & Solicitors —

March 23, 2019

Alberta Electric System Operator (AESO)
2500, 330-5th Avenue SW
Calgary, AB
T2P 0L4

Attn: Brenda Hill
Regulatory Coordinator
Legal & Regulatory Affairs

Dear Madam:

Re: Alberta Electric System Operator (“AESO”)
2018 ISO Tariff Application ID22942-Distribution Facility Owner (DFO)
Contributions

CCA representatives participated in the March 5, 2018 consultation meeting respecting the above. In accordance with the schedule established by the AESO following that meeting, CCA is pleased to provide the following comments:

- a) In CCA’s view a contribution is a tariff. Therefore, an approach where DFO’s are subject to a monthly site-specific tariff, in place of an upfront contribution to the Transmission Facility Owner (TFO), for facilities not covered by the AESO’s investment policy, is a change in form of the tariff and not in substance. CCA agrees with AltaLink that the replacement of contributions by a tariff should not apply to large industrial customers due to potential issues around prudential requirements.
- b) A site-specific tariff could be based on the levelized cost of the facility over its expected service life and reflect the applicable TFO cost of capital and depreciation rates. Replacing a contribution by an equivalent tariff for recovery of the capital costs of a facility may facilitate greater accountability on the part of DFOs for the facilities they request, particularly since contributions would no longer be rate based.
- c) The change in tariff method as described above must include all TFOs and DFOs and any changes should be on a go forward basis and not involve any refund of historical contributions to the TFOs as this may potentially have a shock effect on the DFO’s balance sheet, financing and capital structure and may amount to retroactive rate making. Certain adjustments to DFO PBR capital tracker assumptions may be necessary if the above change in tariff method is implemented on a go forward basis.

James A. Wachowich Robert J. Wachowich

d) There should be a systematized process for planning and coordination between the AESO, the TFOs and the DFOs and the exercise of due diligence and oversight responsibilities by the AESO to ensure the optimum solution is chosen in all situations including ones where choosing a distribution facility solution may be in the interest of the DFO owners but not necessarily in the public interest.

If you have any questions with respect to the above, please contact the writer.

Yours truly,

WACHOWICH & CO.

PER:

JAMES A. WACHOWICH, Q.C.

CCA Legal Counsel



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T5H 0E8 Canada
epcor.com

March 23, 2018

Alberta Electric System Operator
Calgary Place, 2500, 330 – 5th Avenue SW
Calgary, AB T5P0L4

Attention: Doyle Sullivan
Director, Tariff Design

Dear Mr. Sullivan:

Re: Proceeding 22942 – DFO Customer Contribution Issue Session

1. EPCOR Distribution & Transmission Inc. (“EDTI”) provides the following comments on the DFO Customer Contribution Issue Session held by the Alberta Electric System Operator (“AESO”) on March 5, 2018.
2. EDTI is in general agreement with the eight principles listed as being important considerations in an optimal construction contribution policy.¹
3. EDTI does not have any specific comments on AltaLink Management Ltd.’s (“AML”) proposal other than that the treatment of all DFOs in the province should be equal. If AML’s proposal is accepted, it should apply to all DFOs, not only FortisAlberta. With respect to FortisAlberta’s presentation, EDTI agrees that the AESO tariff must be applied in an open access, non-discriminatory manner, and that there is a need to address the underlying issue of rising contribution levels and/or insufficient transmission investment levels.
4. EDTI highlights that any proposed changes to the treatment of customer contributions must also consider the impact on cost recovery under both transmission cost of service regulation as well as distribution performance-based regulation. More specifically, EDTI is concerned that any change in customer contribution treatment include mechanisms to ensure that the utility in question is provided with a reasonable opportunity to recover its capital investment including a fair return on that investment under each form of regulation.

¹ Decision 2012-362, pdf page 8: (1) Provide effective price signals (2) Maintain intergenerational equity (3) Be based on cost causation (4) Be based on local costs (5) Be robust and sustainable (6) Treat all load market participants equitably (7) Compensate utilities equitably (8) Be simple, consistent, and transparent

5. EDTI remains concerned that AML's proposal highlights a deeper underlying issue of increasing Customer Contribution amounts being paid by DFOs for transmission facilities without verification that these allocations are just and reasonable and in the public interest, and whether contributions are being allocated to all DFOs in the province consistently.
6. EDTI also notes that there appears to be a flaw in either the contribution policy, or the AESO's application of it. Generally, new transmission facilities, or modifications to existing facilities, that are required for the AESO to meet its obligations under sections 15(1)(e) and (f) of the *Transmission Regulation* and to comply with Alberta Reliability Standard TPL-002-AB1-0 should be classified as system-related components regardless of who initiated the project for which the components were determined to be necessary. There may be advancement costs required if a customer did not provide proper notice or requires the facilities sooner than can be reasonably scheduled, and thus increase the construction cost. But barring those rare occasions, a properly designed contribution policy should be one where system-related components are classified as such regardless of who initiated the project. This does not appear to be the case for either the AESO's proposed tariff, or the manner in which the AESO applies its currently approved tariff. To illustrate this issue, EDTI provides the following examples.
7. In the Needs Identification Document for 138 kV Transmission System Reinforcement in Downtown Calgary² filed with the AUC in 2015, the AESO stated that an outage to one of the 138 kV transmission lines (2.3L) serving downtown Calgary during summer peak loading conditions would cause a thermal overload to another 138 kV transmission line (2.82L) serving downtown Calgary. It identified this as a violation of Alberta Reliability Standard TPL-002-AB-0, and therefore required transmission system reinforcement to alleviate the constraint. This project was classified as a *system project*, with no customer contribution from the DFO.
8. In 2015, EDTI's distribution function submitted a System Access Service Request ("SASR") and Distribution Deficiency Report ("DDR") to the AESO to address reliability concerns of the transmission system in south-central and west Edmonton. In the DDR, EDTI identified a number of existing TPL-002-AB1-0 violations, where an outage to an existing transformer or transmission line would cause another transmission line serving the area to be overloaded. The AESO's preferred solution includes the installation of a new 240/72 kV transformer and a 72 kV transmission line. The costs to install both facilities have been classified by the AESO as *participant-related*.
9. The driver of these two projects is the same. The only difference is that one was identified by the AESO through a system study, the other was identified by EDTI and then confirmed by the AESO through a system study, but the treatment of the costs for transmission development to resolve the issues is entirely different in both cases. Under a principled approach, such inconsistent cost

² Exhibit 21038-X0009

treatment should not occur. The classification of a transmission development required to address an overheating/overloading violation of TPL-002-AB1-0 should be consistent in the province, regardless of who identified the violation or in which load center the violation occurs.

10. Please contact me directly at 780-441-7109 if you have any questions with respect to this letter.

Sincerely,

[Electronically Submitted]

Saqib Chaudhary
Director, Regulatory Affairs
EPCOR Distribution & Transmission Inc.



Janine Sullivan
Vice President,
Finance and Chief Financial Officer

FortisAlberta Inc
320 – 17th Avenue SW
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Janine.sullivan@fortisalberta.com

March 23, 2018

VIA EMAIL

Alberta Electric System Operator
Calgary Place
2500, 330 – 5th Avenue SW
Calgary, Alberta T2P 0L4

Attention: Doyle Sullivan
Director, Tariff Design

Dear Mr. Sullivan:

**Re: FortisAlberta Comments on Alberta Electric System Operator (AESO) 2018
Independent System Operator (ISO) Tariff Application Proceeding 22942
Consultation on DFO Customer Contribution Issue**

Introduction

FortisAlberta Inc. (“FortisAlberta” or the “Company”) provides the following comments for the consideration of the Alberta Electric System Operator (AESO) in connection with its current consultation regarding scoping for its 2018 ISO tariff application (the Tariff Application).

The scope of the Tariff Application should not be amended at this late date to include consideration of substantial revisions to the AESO’s customer contribution policy (the Contribution Policy). In FortisAlberta’s view, there is no valid reason to embark upon an *ad hoc* reconsideration of this important tariff issue. None of the issues identified by the parties that participated in the March 5, 2018 meeting reveal a pressing, public interest-based, need to consider fundamental changes to the Contribution Policy at this time. There is no indication that the Contribution Policy is being implemented in a manner that is inconsistent with the ISO tariff, or that its implementation is not otherwise in the public interest.

AltaLink’s *ad hoc* proposal neglects consideration of, or context for, the broader structural contribution policy framework, in terms of how the AESO and DFO policies should operate concurrently, and how end-use customers are provided AESO contribution price signals via flow-through of AESO contributions through the respective distribution tariffs. This is regardless of whether these transmission contribution price signals are collected up-front or recovered through the tariff(s) over time, and whether the FortisAlberta end-use customers are transmission connected, distribution connected or are distribution-connected generation.

The ISO tariff does not operate in isolation. Any consideration of the Contribution Policy that might be undertaken in the 2018 ISO Tariff Application must necessarily include an assessment of whether, and to what extent, proposed changes may affect the Commission's overall ratemaking approach for both distribution and transmission utilities. The Company submits that these impacts have the potential to be complex, especially when the interplay between the Performance-Based Regulation (PBR) approach applied to distribution utilities and Cost of Service (COS) ratemaking for transmission utilities is considered.

Response to follow-up Questions posed by the AESO

FortisAlberta is in receipt of the AESO's correspondence of March 15, 2018, in which the AESO asked a number of follow-up questions. The AESO questions and the Company's responses are as follows:

1. Do Rate 63 customers or other customers pay a contribution to Fortis? If so, please show how is it calculated? In the calculations please indicate how transmission contributions are reflected or flowed through.

Yes, there are provisions within the FortisAlberta distribution tariff which permit the flow-through of a "Customer Transmission Contribution" to Rate 63 Large General Service customers. Specifically, *Section 7.2.2 – Other Contributions* of FortisAlberta's currently approved *Customer Terms and Conditions of Electric Distribution Service* states:

Customer Transmission Contribution

FortisAlberta may incur Transmission Costs as a result of entering into contracts with the Independent System Operator for provision of System Access Service in support of a Customer's electricity supply requirements. Transmission Costs include but are not limited to contributions and application fees made by FortisAlberta to the Independent System Operator in respect of a Point of Delivery providing System Access Service to a Customer. Transmission Costs are allocated to Customers as follows:

- (a) for a Customer other than a Temporary Service Customer, with an Expected Peak Demand initially 2000 kW or less, no Customer Transmission Contribution will be levied;
- (b) for a Customer other than a Temporary Service Customer with an Expected Peak Demand initially greater than 2000 kW, or at any time thereafter, a Customer Transmission Contribution may be required as follows:
 - i. where a single Customer is served from a new Point of Delivery, the Customer Transmission Contribution equals the Transmission Cost associated with the Customer-requested Optional Facilities (which are Transmission Facilities) as reasonably determined by FortisAlberta;
 - ii. where a number of new Customers are served from a new Point of Delivery, each Customer is allocated a portion of the Transmission Cost associated with the Customer-requested Optional Facilities (which are Transmission Facilities) as reasonably determined by FortisAlberta, based on the proportion of their Expected Peak Demand to the total expected demand at the Point of Delivery. This allocated cost becomes the Customer Transmission Contribution; and

- iii. where an expansion of an existing Point of Delivery is required to provide System Access Service to a Customer or several Customers with increased electricity requirements, any resulting Transmission Cost associated with the Customer-requested Optional Facilities (which are Transmission Facilities) as reasonably determined by FortisAlberta, is allocated to each such Customer based on the proportion of their increase in Expected Peak Demand relative to the total increase in expected demand at the Point of Delivery. This allocated amount becomes the Customer Transmission Contribution; and
- (c) for a Temporary Service Customer, regardless of Expected Peak Demand, the Customer Transmission Contribution is equal to the Transmission Cost plus an amount equivalent to the present value of any additional ongoing AESO tariff costs attributable to the Customer as determined by FortisAlberta.

Any obligations associated with the Customer-requested Optional Facilities (which are Transmission Facilities) as reasonably determined by FortisAlberta, undertaken by FortisAlberta in connection with the Independent System Operator's Construction Commitment Agreements become the obligations of the Customer to FortisAlberta.

Any refunds of contributions received by FortisAlberta from the Independent System Operator may be passed on to Customers as described in Section 7.2.3.

The above provisions within the distribution tariff allow the Company to flow-through the price signal associated with the AESO contribution on a whole, or partial *pro rata* basis, to large distribution connected (Rate 63) customers if the Company determines that the transmission facilities requested by the customer are "optional" in nature.

A current example of where a Rate 63 customer may be assessed an AESO contribution is the Grist Lake project. In this case, FortisAlberta has demonstrated to the AESO and the customer that the end-use load can be served cost effectively from an existing POD. However, the customer prefers to be connected to a new POD (Grist Lake Substation) for reliability reasons. The AESO has calculated the resultant AESO contribution for the Grist Lake project per the AESO Contribution Policy. For its part, FortisAlberta has determined that it would treat the customer-requested transmission facilities and resultant AESO contribution as "Customer-requested Optional Facilities" per its tariff with the corresponding AESO contribution being flowed through to the Rate 63 customer as a "Customer Transmission Contribution." Consequently, the customer is able to receive the system access service it requires and is willing to pay for, and other DFO customers are kept whole.

The Company's distribution tariff also requires the flow-through of AESO contributions to Rate 65 Transmission Connected Service customers for their dedicated PODs, and the partial *pro rata* flow-through of AESO contributions to DG customers based on the AESO's DTS/STS substation fraction for the respective POD.

With respect to the issue of flowing through AESO contribution price signals to distribution connected customers, the AESO should also be made aware of a recent direction from the Alberta Utilities Commission (the Commission or AUC) in Decision

21538-D01-2017 with respect to FortisAlberta's 2015 PBR Capital Tracker True-up Proceeding, which stated:

Direction 10:

In view of concerns noted above, the Commission directs Fortis, in its next Phase II application, to discuss whether some form of pro rata sharing of AESO contributions by end-use customers that drive the need for an AESO contributions project is warranted, including a proposal for an alternate pro rata sharing scheme; or Fortis's views, including a detailed rationale in light of all considerations that Fortis may consider to be relevant, as to why pro rata sharing of AESO contributions by customers other than Rate 65 would not be warranted.

The above direction requires the Company to investigate expanding the flow-through of AESO contribution price signals to end-use distribution connected customers. AltaLink's proposed approach, which would effectively prevent the communication of AESO contribution price signals to DFOs and their customers, appears to be fundamentally at odds with the Commission determination to investigate the *pro rata* sharing of AESO contributions to end-use distribution connected customers. It is also contrary to the Commission endorsed-principle of sending economically efficient price signals to connecting customers (as addressed in the AESO's last comprehensive review of its Contribution Policy).

2. Please provide further details about the “tariff shopping” concern raised during the session and give an example.

FortisAlberta uses the term “tariff shopping” to describe the potential phenomena of an end-use customer having the ability to choose among different regulated tariff provisions (whether that be the ISO tariff or a distribution tariff) for provision of the same regulated service.

Differential application of the ISO tariff to Market Participants will incent “tariff shopping”. For example, a large transmission or distribution connected customer (e.g., Rate 63, Rate 65 or an *Electric Utilities Act (EUA)* s.101(2) AESO direct-connect customer) may choose to apply to connect as a FortisAlberta transmission or distribution connected customer, or as an AESO direct-connect AESO customer, depending on how AESO contributions may be assessed and collected from that customer (either upfront *pro rata* collection of the AESO contribution from the customer or recovered over time through an allocation of increased ISO tariff rates/riders). Any potential for large customers to exercise this kind of choice creates a risk of inappropriate shifting of costs and risks among other customers connected to the Alberta Interconnected Electric System (AIES).

AltaLink clarified in the March 5th session that it did not contemplate applying its proposal to finance AESO contributions in respect of contribution amounts flowed through the distribution tariff to end-use customers (as described above for a Rate 63 customer or a Rate 65 transmission connected service). This would mean that the ISO tariff would be differentially applied depending on the terms of the approved distribution tariffs of its downstream DFO market participants and permits ISO Contribution Policy to

be dictated, and altered, by the treatment of AESO customer contributions in specific downstream distribution tariffs. In the Company's view, the ISO tariff should be applied to all market participants in an open and non-discriminatory manner. Failure to ensure non-discriminatory application of the ISO tariff will likely make the Company's tariff shopping concerns a reality.

3. AltaLink Management Ltd. (AltaLink) claims that “it is the regulated TFO that owns and maintains the interconnection transmission asset and therefore should be allowed to make the investment in those assets”. Is it true that a regulated DFO owns the distribution assets but does not make investment in those assets? Please elaborate.

Yes, similar to the ISO tariff Contribution Policy, which informs the maximum investment levels (MILs) for which the TFO can invest in customer-related transmission assets, DFOs also have a distribution tariff contribution policy, which establishes the MILs for which a DFO can invest in customer-related distribution assets.

In FortisAlberta's *2010/2011 Distribution Tariff Application – Common Approach to MILs*¹ (which resulted from a stakeholder consultation on customer contribution / investment policies and MILs of the major DFOs in the province), it was recognized by the DFOs that the purpose of an investment (or customer contribution) policy is to establish rules and guidelines that govern a utility's investment in customer extensions. These guidelines must allow new customers to receive a fair level of utility investment in their service, while still ensuring that ratepayers are not unduly burdened by the cost of such new extensions.

In the simplest terms, MILs and customer contributions form part of the utility's investment policy and, from the utility's perspective, are the maximum amounts that the Company is willing, or is allowed, to invest towards the cost of extending service to new customers. From the customer or rate class perspective, it is important that the MILs are set to achieve a reasonable and acceptable balance of what an individual customer pays upfront through a customer contribution versus what customers (or rate classes) pay through ongoing average rates.

In reality, what AltaLink has characterized as an unfairness issue at the transmission level occurs at the distribution level and is a natural and necessary part of any utility tariff. That is, each utility tariff typically has a customer contribution and utility investment policy that ensures that balanced price signals are sent to connecting customers to provide economic discipline in the extension of the system. The result is that DFOs, like TFOs, own and operate assets for which a customer contribution was collected for amounts above the MILs, and the DFO does not earn a rate of return on the customer contributed portion of those customer-related costs. This is a natural and necessary feature of any utility tariff that ensures the communication of economically efficient price signals to customers.

¹ FortisAlberta Inc. 2010/2011 Phase I Distribution Tariff Application, Proceeding 212, Appendix O – Common Approach to MILs, June 16, 2009.

4. Does Fortis anticipate that implementing the AltaLink approach would have implications on the PBR process? If so, please explain those implications.

Yes, the Commission's decisions and approvals with respect to the 2018-2022 Performance Based Regulation (PBR) Plans for Alberta DFOs address incremental "K-Bar" capital funding for the second PBR term using an historical average of AESO contributions experienced by the DFOs under the current AESO Contribution Policy in place during the first PBR term. This fixed "K-Bar" funding approach for AESO contributions effectively eliminates any perverse incentive to DFOs to over-invest in the arrangement of system access service that may have existed under COS and replaces it with an economic incentive to the DFO to efficiently manage AESO contribution costs over the PBR term.

To the extent that the AESO were to propose a significant shift in AESO Contribution Policy (i.e., removal of AESO contribution price signals to DFOs and their customers, as proposed by AltaLink), FortisAlberta anticipates that the Commission would likely have to review and adjust its determinations for the DFO's PBR plans/rates to align with such a material ISO tariff change.

5. The following is set out on Fortis Slide 3, first bullet: "Rider I – Amortization of AESO customer contributions; equates to 100% investment level for transmission facility owners (TFOs) / AESO". Please explain what is meant by this statement?

The statement highlights that AltaLink's proposed approach to financing DFO AESO contributions is a "Rider I" -like proposal, in that the TFO would not only finance and earn a return on, and of, the costs of the customer-related transmission facilities up to the AESO tariff's maximum investment levels (as recovered through the AESO rates/riders over time), but would also earn a return on, and of, the AESO contribution amounts (also collected through AESO rates/riders over time). This results in the TFO investing 100% in the cost of interconnection facilities being requested by the DFO and/or its customers. In the Company's view, this dynamic provides no incentive to the TFO to manage the costs of customer-related facilities, and eliminates the economically efficient price signals communicated to DFO market participants and their customers.

This issue was also addressed in FortisAlberta's *2010/2011 Distribution Tariff Application – Appendix O – Common Approach to MILs*, where the following principles, among others, were agreed to for purposes of establishing MILs for the distribution tariffs:

1. MILs should be set to achieve a reasonable balance of what an individual customer pays upfront through a customer contribution versus what all customers in a particular rate class pay through ongoing rates. In other words, new customers should receive a fair and sufficient level of investment such that the majority of customers do not pay contributions for connecting, while still ensuring that existing customers are not unduly burdened by the cost of such new services.

2. MILs should provide economic discipline and price signals to new customers as they are connected to the interconnected transmission and distribution system, and these levels should be aligned with encouraging the best long term economic and technical solution to meet standard service requirements.

Concluding Comments

In summary, AltaLink's proposal to refund AESO contributions to DFOs and thereafter charge DFOs (and their customers) a corresponding rider to recover the amortization of those AESO contribution amounts would effectively result in the imposition of a mandatory Rider I, applied to specific market participant(s) for the benefit of the incumbent TFO (in this case, AltaLink). In application, this would result in 100% TFO investment in AESO projects requested by a DFO on a prospective basis, thereby eliminating any AESO contribution price signal to DFOs when arranging and financially settling system access service on behalf of their customers, as required by section 105 of the *EUA*.

The Company submits that such a proposal presents a risk of unjust discriminatory application of the ISO tariff to a subset of market participants, and a preferential and inconsistent application of the Contribution Policy it contains. FortisAlberta submits that this proposal is fundamentally at odds with the provisions of applicable legislation, including the *Electric Utilities Act*, and, consequently, should not be considered in any revised ISO tariff application that may follow the conclusion of the current consultation process.

To the extent that either the AESO or the AUC determines that a comprehensive assessment of the Contribution Policy is required, such an assessment should not be undertaken in the absence of a complete and well-considered consultation process, as was done using a principle-based approach that the AESO and stakeholders reached consensus on in the review of the 2012 AESO Construction Contribution Policy² and in the DFO's / FortisAlberta's 2010/2011 DTA – Common Approach to MILs. In FortisAlberta's view, any such process should include, at a minimum, input from all affected customers, market participants and industry stakeholders. The Company does not view the scope or depth of analysis completed at the AESO's March 5, 2018 consultation session, or the subsequent comment process, as being sufficient to support the material reconsideration of ISO Contribution Policy being requested by certain parties.

Please contact me directly at (403) 514-4992 or Miles Stroh at (403) 514-4229, if you have any questions with respect to these comments.

Sincerely,

"Original signed by"

Janine Sullivan
Vice President, Finance and Chief Financial Officer

² Commission Initiated Application – Electric Transmission Contribution Policy, Proceeding 1162, April 13, 2011.



Industrial Power Consumers Association of Alberta

1117 22 Avenue NW
Calgary AB, T2M 1P6

March 19th, 2018

Alberta Electricity System Operator
330 5 Ave SW, Calgary, AB
T2P 0L4

Attention: Brenda Hill - ISOTariffNotice@aeso.ca

**Re: ISO Tariff Consultation – DFO Customer Contributions
IPCAA Submission**

The Industrial Power Consumers Association of Alberta (IPCAA) appreciates the opportunity to comment on the ISO Tariff consultation regarding DFO customer contributions. As you may know from previous discussions and regulatory filings, IPCAA does have concern over both the increasing distribution costs as well as checks and balances in the process.

The solution proposed by AltaLink may, in fact, provide an appropriate incentive to both the DFO and TFO (when they are separate entities) in ensuring the need for projects. IPCAA believes there is merit in further exploration of the concept.

IPCAA is more than happy to meet with the AESO and other parties if further discussions are warranted.

Sincerely,

A handwritten signature in black ink, appearing to read "R. Penn", is written above the printed name.

Richard Penn
Senior Policy and Regulatory Consultant,
Industrial Power Consumers Association of Alberta

March 30, 2018

Mr. Doyle Sullivan, P.Eng.
Director, Tariff Design
Alberta Electric System Operator
Via e-mail – ISOTariffnotice@aeso.ca



RE: Proceeding 22942 – Consultation on 12 CP Method

Dear Doyle,

The Alberta Direct Connect Consumer's Association "ADC" participated in the March 12th Stakeholder session and provides the following comments for the AESO's consideration.

The ADC continues to support the AESO 2018 GTA bulk system 12 CP cost methodology as applied for in the 2018 GTA. We remain convinced that there is no immediate issue needing resolution on 12 CP in this GTA period.

Significant effort will be required by the AESO and stakeholders to consult on the scope, studies, and analysis needed to move forward with any change to the tariff structure. There are other significant efforts underway that may also impact the tariff design process such as the requirement for the AESO to develop the capacity cost allocation tariff and possible changes to the transmission regulation. It seems inefficient to the ADC that we would tackle the DTS tariff design without consideration of these other key developments.

ADC is very concerned about the cost of transmission and the competitiveness of our energy intensive trade exposed industries. In order to remain competitive, our members have made significant investments to manage their electricity costs within the current market structure and tariff design. Any change that results in rate shock to these industries must be carefully considered and transitioned in over a sufficient period of time commensurate with any notice requirements of DTS contract changes.

The ADC suggests that the AESO leave the 2018 interim DTS tariff in effect and proceed with the rest of the items in the 2018 GTA proceeding. This will allow the other elements to get resolved in a timely manner and provide adequate time to strike a workgroup to begin consultation on both the transmission and capacity tariffs.

Regards,

A handwritten signature in black ink that reads 'Colette Chekerda'. The signature is written in a cursive, flowing style.

Colette Chekerda, P.Eng.
ADC Executive Director

March 29, 2018

Alberta Electric System Operator
Calgary Place,
2500, 330-5th Avenue S.W
Calgary AB, T2P 0L4

Attention: Doyle Sullivan, P. Eng.
Director, Tariff Design

Dear Mr. Sullivan:

Re: 2018 ISO Tariff Application
Proceeding 22942
Consultation on 12-Coincident Peak Issue

On March 12, 2018, AltaLink attended a 12-conincident peak (CP) session at the Alberta Electric System Operator (AESO). On March 14, 2018, the AESO requested participants submit comments and responses, and any detail to help the AESO understand the additional data or data analysis requested on the issue of CP. On March 21, 2018, the AESO extended the deadline for submission to March 30, 2018.

CP is an important issue for rate design in Alberta and AltaLink appreciates the AESO taking active steps to involve all parties to help ensure a proper outcome. AltaLink participated in the session held on March 12, 2018 to help contribute and understand all parties' positions. AltaLink understands a further session on the CP issue will be held on April 9, 2018 and AltaLink confirms that it will be in attendance. Ren Orans, Zachary Ming, Zora Lazic, and Gary Hart plan to attend in person on AltaLink's behalf at the AESO. Others from AltaLink may call in on an as needed basis.

As requested, AltaLink's general comments on the 12-coincident peak issue and session are as follows.

AltaLink's immediate concern is with the unintended incentives resulting from the current Bulk System Rate (BSR) Design. Through the March 12, 2018 stakeholder session at the AESO, AltaLink's consultant provided evidence that the Bulk CP rate is no longer aligned with the incremental BSR and has reached a level where it is economic to bypass the bulk transmission rate. Due to the strong bypass signal provided by the current Bulk Transmission System Rate Design, AltaLink is concerned customers may be actively taking steps to bypass or load shed to avoid costs.

AltaLink understood from the March 12, 2018 stakeholder session that parties disagree on the following:

1. Is the bulk CP rate sending an appropriate economically efficient price signal?
2. Does the bulk CP rate reflect a fair cost allocation based on the causal relationship between embedded bulk costs and bulk transmission usage?

Economically Efficient Price Signal

AltaLink agrees with IPCAA, ADC and DUC that the most important rate design goal in this case is the reflection of appropriate price signals. These parties argue the current 12 CP cost allocation methodology is sending appropriate price signals because customers are responding to it.

AltaLink respectfully disagrees. The goal of an efficient and appropriate price is not solely to induce behavior, but to induce behavior that saves costs for all customers and is fair to all market participants. To incent economically efficient behavior by saving costs for all customers and fairly allocating these savings, prices should be set as close to the incremental costs of service as possible. Based on AltaLink's preliminary analysis,

the incremental costs of serving new CP loads is substantially less than the current embedded-cost-based level. Further, based on using the AESO's long term forecast, the incremental costs of serving new CP loads could stay that way for some time.

Embedded Costs and Transmission Usage

AltaLink agrees with the UCA and the CCA that the bulk system service rate is probably higher than would be justified by a fair cost allocation of embedded costs. Allocating some of the Bulk system costs to more causally linked charges, for example attributing 240 kV facilities to the regional charge, might provide a more equitable cost allocation. However, AltaLink remains of the view that large levels of new uneconomic bulk system bypass are imminent, and is concerned that new studies that might be required to develop a completely new cost of service study might be time consuming and would unnecessarily delay bringing this important issue before the commission.

Transition period and Timeline

AltaLink is also keenly aware that many existing industrial customers could have increases in their transmission service bills should its proposal be adopted without a transition mechanism. To immediately stop this impact, AltaLink proposes a mechanism that will shift no costs between existing customers and focus on preventing new uneconomic bypass. AltaLink proposes to apply a more efficient marginal-cost-based rate solely to customers with new, behind the fence generation that becomes operational after January 1, 2019. All existing BTF generation would continue to be billed on a 12-coincident peak basis for bulk transmission service. Customers installing new BTF generation after January 1, 2019, would be billed on a new rate that is based on the incremental cost of transmission service on a 12-coincident peak basis, with the remaining transmission costs collected from a non-coincident peak or NCP charge. This proposed change would minimize system costs by preventing new uneconomic bypass immediately. A more comprehensive cost-of-service study can be used in a full rate design review in the future.

AltaLink's proposal as described above is a reasonable compromise between existing parties that can be easily implemented without the need for substantial new work or analysis. If there is no problem with the existing design and there is no pending large amounts of uneconomic bypass on the immediate horizon, the rate modification will have no impact on any customer or stakeholder. Conversely, if the bypass threat is large, this modification will assure that the costs saved from the BSR bypass are in line with the bulk transmission related benefits provided.

Data Request

In order to estimate the appropriate incremental cost of service for the Bulk CP charge and to verify the current levels of uneconomic cross subsidization among customers, AltaLink requires further information on AESO's transmission planning, drivers of new transmission needs, and projections for behind the fence generation. AltaLink has attached data requests to ascertain this information.

AltaLink looks forward to working further with parties to resolve the 12-coincident peak issue with the hope that the Commission can expeditiously act to modify the rate to realign it with its original design objectives.

Yours truly,

(Original signed by)

Gary Hart
Executive Vice President and Chief Operating Officer

Reference: 2017 Long-term Outlook data file ("2017-LTO-data-file.xlsx"), August 17, 2017

Issue: AltaLink seeks further information regarding the AESO's estimate of bypass of the DTS bulk CP charge.

Quote: i) First table of "AIL and System Load Energy" worksheet in reference file:

System Load Annual Energy by Scenario (GWh)				
Reference Case				
Year	Total AIL Energy	Total On-site Generation Energy	BTF Energy (Energy Served by On-site Generation)	System Load Energy**
	[A]		[B]	[A] - [B]
2014*	79,950	-	17,370	62,580
2015*	80,257	-	17,780	62,477
2016*	79,560	-	17,449	62,112
2017	82,607	34,392	18,757	63,850
2018	83,884	35,480	18,940	64,944
2019	85,467	35,328	19,246	66,221
2020	86,536	35,529	19,643	66,892
2021	87,295	36,323	20,239	67,056
2022	87,872	36,635	20,553	67,319
2023	88,253	36,543	20,477	67,776
2024	89,223	36,614	20,567	68,657
2025	89,939	36,603	20,496	69,442
2026	90,677	36,879	20,554	70,123
2027	91,682	36,810	20,552	71,130
2028	92,708	36,598	20,423	72,284
2029	93,389	36,525	20,586	72,803
2030	94,304	36,512	20,805	73,499
2031	95,287	36,850	21,014	74,273
2032	96,350	37,062	21,144	75,205
2033	96,809	37,167	21,369	75,440
2034	97,586	37,062	21,319	76,267
2035	98,216	37,436	21,698	76,518
2036	98,967	37,585	21,814	77,153
2037	99,209	37,699	22,023	77,186
*Actuals				

ii) First table of "AIL and System Load Peak" worksheet in reference file:

<u>System Load at AIL Peak (MW)</u>				
<u>Reference Case</u>				
Season Year	Total AIL Peak Load	Total On-site Generation	BTF Energy (Energy Served by On-site Generation)	System Load at AIL Peak**
	[A]		[B]	[A] - [B]
2014*	11,229	-	2,243	8,986
2015*	10,982	-	2,400	8,582
2016*	11,458	-	2,362	9,096
2017	11,539	4,493	2,530	9,009
2018	11,737	4,498	2,560	9,177
2019	11,939	4,507	2,605	9,333
2020	12,018	4,528	2,648	9,370
2021	12,144	4,563	2,687	9,458
2022	12,260	4,809	2,807	9,453
2023	12,321	4,590	2,725	9,596
2024	12,428	4,594	2,735	9,693
2025	12,557	4,840	2,811	9,746
2026	12,678	4,893	2,825	9,853
2027	12,814	4,893	2,826	9,988
2028	12,945	4,662	2,754	10,191
2029	13,089	4,667	2,764	10,325
2030	13,231	4,675	2,812	10,419
2031	13,354	4,975	2,913	10,442
2032	13,486	4,975	2,914	10,573
2033	13,603	4,748	2,849	10,754
2034	13,721	4,748	2,849	10,872
2035	13,815	4,763	2,870	10,945
2036	13,881	4,984	2,951	10,931
2037	13,947	5,025	2,992	10,955
*Actuals				

Request:

- Please explain the relationship between Total On-site Generation, BTF Energy, and System Load at AIL Peak in the tables above.
- If on-site generation at net-load customers is not included within the referenced table, please provide a comparably annual forecast summary that quantifies this generation during AIL peak from 2017 to 2037.
- What types of generation technologies are included within on-site generation and BTF energy? Are all generation sources (e.g. distribution connected generation including solar and small gas-fired generation units) counted towards these categories or is on-site generation limited to controllable power (e.g. gas combustion turbines)? Is there a minimum or maximum nameplate capacity necessary for inclusion in the forecasts for on-site generation? Is cogeneration considered to be on-site generation? Is load shedding considered to be on-site generation? If any generation technologies are excluded from the definition of on-site generation, please explain why they are excluded.
- For any technologies such as load shedding that may not be included in "On-site Generation", please provide an estimate of the MW generation of these resources during the AIL peak.

- (e) Please confirm that the forecasts for “On-site Generation” and “BTF Energy” do not include planned BTF facilities announced in AESO’s monthly project lists. For example, the March 2018 project list¹ includes a multitude of new projects in the “BTF” category with a total capacity of over 2000 MW, but the average annual growth in BTF energy at AIL peak is 23 MW per year from 2017 to 2037 according to the LTO.
- (f) If the 2017 LTO forecast for on-site generation and BTF energy is based on a list of planned or announced BTF facilities, please provide this list and the corresponding data for expected generation and load at these facilities. If the BTF Energy forecast is not calculated using expectations for new BTF facilities that have been announced, please provide the methodology used to produce this forecast and the forecasted levels (energy produced and installed capacity) of behind the fence generation and distributed connected generation through to the year 2030.
- (g) Is the impact of the level of the DTS coincident metered demand charge a factor in forecasted BTF energy? If yes, how is this impact incorporated into the forecast? If not, does the AESO think it is reasonable and meaningful to incorporate this effect into the BTF forecast?

¹ 2018 March Project List located at: <https://www.aeso.ca/assets/Uploads/Final-March-2018-Project-List2.xls>

Reference: AESO 2018 ISO Tariff Application, Section 2, paragraph 23.

Issue: AltaLink requires information regarding the extent of bypass of the DTS rate that has occurred in the past and would be reasonable to occur in the future.

Quote: “Other matters raised during consultation that are not addressed in this application include:

(a) bulk transmission system cost recovery through coincident metered demand (one hour in a month) raised by certain stakeholders as it relates to shifting bulk transmission cost burden from market participants that can avoid the highest coincident metered demand hour in a month to market participants who cannot avoid the highest coincident metered demand hour. As a result of this and other related issues, the bulk system demand charge may require a more extensive review and, as may be necessary, associated revisions to the ISO tariff.”

Request:

- (a) Please provide a table of total installed nameplate capacity (MW) of on-site generation and distributed generation by technology type, by year, for the years 2006 to 2017.
- (b) Please provide a table of total gross system load, by hour, for the years 2006 to 2017. Within this table, Please identify the hour of coincident monthly peak for each month.
- (c) Please provide a table of total on-site generation and distributed generation, by hour, for the years 2006 to 2017. If it is less cumbersome to provide disaggregated facility-level data, please do so.

Reference: AESO 2018 ISO Tariff Application, Appendix J.

Issue: AltaLink requests the AESO to provide stakeholders with updated rate projections and cost studies.

Request:

- (a) Please provide an updated Appendix J with the latest data on the forecasted costs of future transmission projects included in the AESO 2017 Long-Term Transmission Plan and the latest forecasted billing determinants.

- Reference:**
- 1) AESO 2018 ISO Tariff Application, Section 7.1, paragraphs 191 and 192.
 - 2) AESO 2017 Long-Term Transmission Plan
 - 3) AESO 2017 Long-Term Outlook
- Issue:**
- AltaLink is looking for the AESO to disaggregate and categorize forecasted transmission project costs according to drivers of need in order to better understand, in light of the new outlook for load and generation, the extent to which coincident system peaks will likely determine the need for transmission investment going forward
- Quote:**
- Reference 1
- “The AESO notes that its system NIDs are based on forecasts of relevant total load and generation within a given study area, and not on a forecast system load energy (previously referred to as AES energy).”
- “The AESO undertakes project-specific assessments of the underlying drivers of load and generation to ensure that any filed system NIDs contain the most up-to-date information. As the AESO develops its long-term outlook based on broad economic assumptions, it is prudent for the AESO to conduct a more detailed review of a smaller geographic area to ensure that the specific area drivers of load and generation are fully understood before recommending a system transmission facility upgrade. For example, in a recent system NID34 for a 138-kV transmission system facility upgrade in downtown Calgary, the AESO utilized a load forecast that was less than the AESO’s corporate forecast, following the completion of the AESO’s detailed area review of specific load drivers in downtown Calgary, along with recent trends of load growth.”
- Reference 2
- “Overall, the 2017 LTO Reference Case load forecast is significantly lower than the 2016 LTO Reference Case.” (2017 Long-term Outlook, Section 5.24, page 15, paragraph 1)
- Reference 3
- “The 2017 LTP identifies 15 transmission developments proposed over the next five years and valued at approximately \$1 billion.” (2017 Long-Term Transmission Plan, page 4)

Request:

- (a) Is the AESO transmission planning criteria and methodology posted publicly on the AESO website? If not, would the AESO provide a document describing AESO transmission planning criteria and methodology employed when developing transmission system plans (e.g. the planning criteria used for the 2017 Long-Term Transmission Plan)?
- (b) Please identify the primary driver of need for all AESO system project needs identification applications from 2006 to 2017.
- (c) How is the \$1 billion from page 54 of the 2017 Long-Term Transmission Plan disaggregated among the 15 projects it is based on.

- (d) Which, if any, of these 15 projects could be deferred or eliminated due to a reduction in the coincident peak?
- (e) For each of the 14 projects that are listed on page 70 of the Long-Term Transmission Plan, what is projected estimated cost by project?
- (f) Which of these 14 projects listed on page 70 could be deferred or eliminated due to a reduction in the coincident peak?
- (g) Please confirm the projects driven by generation investment will proceed regardless, whether or not behind the fence generation results in lower coincident system peak levels. If projects driven by generation investment are dependent upon coincident peak levels, please explain how.
- (h) For projects identified on page 70 with a driver as Renewables Integration, would lower load levels at coincident system peak have any impact on those transmission costs?
- (i) For projects identified as Load/Transfer-in, would lower load levels at coincident system peak have any impact on those transmission costs?



Reference: 1) Utilities Consumer Advocate presentation to the 12 CP working group on March 12, 2018

Issue: A number of parties are looking for a solution to the present high levels of the DTS bulk coincident metered demand charge.

Quote: Slide 4: "For cost allocation purposes, redefine 'bulk' and 'regional' system so that: the bulk system comprises HVDC and AC lines operating above 240 kV only; Regional systems AC lines operating up to and including 240 kV"

Request:

- (a) Please provide an updated TRIP model that reflects the requested re-functionalization of the 240 kV assets proposed by the UCA. This update should reflect all changes to aggregate billing determinants, all changes to cost functionalization, all changes to cost classification, and all changes to all rate components of the DTS tariff including bulk system coincident metered demand, bulk system coincident metered energy, regional system billing capacity, and regional system metered energy.

Doyle Sullivan, Director, Tariff Design

Alberta Electric System Operator (AESO)

Transmitted electronically to: ISOtarriffnotice@aeso.ca

March 29, 2018

Dear Mr Sullivan,

Re: Consultation on 12 Coincident Peak Method

CanSIA appreciates the opportunity to participate in a consultation process on the tariff allocation issue and intends to continue to participate throughout the remainder of this process.

Further Process: CanSIA agrees with the comments made by a number of parties at the stakeholder session on March 12, that this is a complex topic and it requires significant analysis if a change is to be made to the tariff cost allocation structure. Accordingly, this process should not be rushed. CanSIA would support resumption of the AESO tariff proceeding with this issue ruled out of scope while the AESO continues its consultation process on the allocation methodology.

At a minimum, CanSIA supports holding another consultation roundtable, currently scheduled for April 9, 2018. CanSIA further suggests that a number of additional consultation sessions are likely necessary if the AESO has appetite to consider changes to the cost allocation methodology. If the consultation process continues beyond April 9, and if no other party addresses the implications of a change in allocation methodology on the development of solar (with or without the co-location of energy storage) in the April 9 session, then CanSIA would also request the ability to make a presentation at a future session.

AltaLink's Proposal: CanSIA agrees that it is important to incent individual market participant behaviour that has overall system benefits. Alberta benefits greatly from a high load factor that is the direct result of (1) large penetration of relatively flat industrial load; and (2) the response of industrial load to price signals wherein reductions in industrial load reduces the total system load during the tightest hours and the coincident peak hours. The tariff allocation and the real time energy price are currently the two signals that market participants respond to in today's

market, which results in the high load factor that is the envy of other jurisdictions. This interaction between demand and supply will become increasingly important as the penetration of variable renewable electricity increases in Alberta's supply-mix.

AltaLink has proposed that the system benefit of peak-shaving or peak-shifting are less than the current tariff charge. CanSIA would propose that further analysis needs to be completed before reaching this conclusion. CanSIA would suggest there are flaws with a number of AltaLink's assumptions, most notably with (1) the assumption that only transmission costs avoided over the next five years should be a part of the system benefits and; (2) the assumption that all existing transmission infrastructure is used and useful and belongs in rate base.

Transmission development must be considered over a longer time frame than five years. Behaviours that prevent a new transmission line from being constructed in the next few years and behaviours that allow us to operate within the constraints of the existing transmission infrastructure for decades longer than it could have been expected to be sufficient are both behaviours that the tariff structure should be designed to incent. CanSIA submits that a much lower cost network can be developed over time if it allows distributed resources (including solar electricity generation with or without the co-location of energy storage) to be developed at or proximal to load sites. Short-term analysis of potential upgrades deferred fails to capture the full value of longer term benefits.

Solar electricity generation (with or without the co-location of energy storage) has the ability to play a significant role in the latter of those two behaviours. Distributed solar generation has the ability to combat load growth without requiring any additional transmission infrastructure to connect the generation assets to the load assets and may in fact allow the overall rate base to be reduced over time. It is incorrect to presume that the transmission system can only grow and that other emerging technologies, including distribution-connected solar, are not viable options to avoid future transmission needs.

CanSIA would note that the current Long Term Outlook does not consider any solar electricity generation smaller than 5MWs in its forecasting and yet CanSIA anticipates a minimum of 50MW of such solar electricity generation facilities will be in-service in Alberta by 2020. It is a mistake to ignore the potential impact of facilities at this scale on the system as incenting these types of projects (along with energy efficiency, demand response, energy storage etc) can significantly reduce the future costs of new transmission in Alberta. The tariff signal needs to reflect the value that these technologies and applications are able to bring.

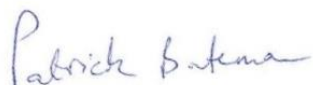
Solar is simultaneously able to help solve future transmission issues and also to aid the province in meeting its legislated 30% by 2030 renewable electricity target. There is a significant system benefit to distribution-connected solar preventing future transmission needs. There is also a significant benefit to Albertans if merchant or bi-laterally contracted solar facilities enter the market in a greater extent in response to market price signals and a lesser extent to out-of-market payments. To meet the goals of the Climate Leadership Plan, substantial investment in renewable electricity generation capacity is required. CanSIA suggests that the minimization of this investment, and those associated with transmission infrastructure expansion, needs to be considered as a system marginal benefit under AltaLink's proposal, as removing the current tariff signal will have the effect of halting the development of distribution-connected solar.

Lastly, CanSIA would note that AltaLink had a detailed argument as to why a portion of the current bulk system charge needs to be moved away from the 12CP allocator. However, AltaLink did not provide an adequate argument for its proposal to move those charges into a non-coincident peak charge. If it is determined that some of the bulk system charge needs to be reallocated away from the 12CP allocator, there are a number of alternatives, including total energy usage or super-peak weighted energy broadly as have been contemplated in the capacity market cost allocation consultation with the Department of Energy.

CanSIA agrees with the AESO's statement at the consultation session that the onus is on AltaLink to convince the AESO and the AUC that the current allocation methodology needs to change. CanSIA would also propose that, if successful, the burden of proof also falls to AltaLink to defend its proposal of non-coincident peak as a replacement allocator.

Conclusion: In conclusion, CanSIA proposes that the current 12CP allocation methodology should continue. It simultaneously incents behaviours that will reduce the future need for transmission expenditures and supports the Government's goals in the Climate Leadership Plan.

Best regards,



Patrick Bateman
Director of Policy & Market Development
Canadian Solar Industries Association (CanSIA)

A decorative graphic consisting of two thin, curved lines that intersect and extend across the top left of the page.

Capital Power Corporation
1200 – 10423 101 Street NW
Edmonton, AB T5H 0E9
www.capitalpower.com

March 29, 2018

FILED ELECTRONICALLY

Alberta Electric System Operator
Calgary Place
2500, 330 – 5th Avenue SW
Calgary, AB T2P 0L4

Attention: Doyle Sullivan, Director, Tariff Design

Dear Mr. Sullivan:

**Re: Alberta Utilities Commission (“AUC” or “Commission”) Proceeding 22942
Alberta Electric System Operator (“AESO”) Consultation on 12 Coincident-Peak Method (“12 CP Method”)**

On March 12th, the AESO hosted a stakeholder session to discuss the application of the 12 CP method in the recovery of bulk system charges under the current AESO Tariff. At the conclusion of the session, the AESO requested feedback from stakeholders to inform the next steps of the process. Capital Power submits the following comments in respect of this request.

Capital Power believes there is merit in further exploring the analytical approach advanced by AltaLink LP and its consultant, Energy & Environmental Economics (“E3”), however before determining detailed process steps, Capital Power believes that further context is required concerning the magnitude of the issues at hand. To advance the discussion with stakeholders and allow for a more informed determination of process, Capital Power recommends that the AESO perform its own independent assessment of the magnitude of the 12 CP issue and present it to stakeholders.

In completing the preliminary analysis there should be consideration of questions which include but are not limited to the following:

- Does the current DTS rate design satisfy the Commission's design principles?
- Has there been a material change in the system composition or system usage?
- Is there evidence of uneconomic bypass in the system, and what is the magnitude?
- To what degree are costs being shifted between customer classes, and who is bearing additional cost?
- Is a new cost of service study required to address the issue?

In establishing a scope for the preliminary analysis, and a framework for subsequent analysis, Capital Power expects that the AESO will gain a better understanding of the time required to address the application of the 12 CP method in the recovery of bulk system charges. With this information, the AESO would be better able to establish a path forward for the current AUC Proceeding.

If, in the opinion of the AESO, the scope of the work necessary to support a refiled application exceeds what can reasonably be completed within the current AUC Proceeding, Capital Power would support a separate process



or module to address the 12 CP issue. Alternatively, if the AESO is confident that such analysis can be completed in a reasonable timeframe, the work should be expedited to avoid further delays to the current proceeding.

Whether through a separate module or the current proceeding, the AESO should endeavor to present alternative rate design options to stakeholders to address identified issues. Over a period not greater than eight weeks, the AESO should undertake consultation on the options prior to advancing a preferred alternative for consideration by the Commission. Capital Power does not support a negotiated settlement, and would request the application be considered through a regulatory process.

Capital Power appreciates the opportunity to provide feedback on this issue. Should you have additional questions please contact the undersigned.

Regards,



Colin Robb, Senior Advisor, Regulatory and Environmental Policy
Capital Power Corporation

Cc:

Jason Comandante, Vice President, Regulatory and Environmental Policy

Alan Ross, Borden Ladner Gervais LLP

March 30, 2019

Alberta Electric System Operator (AESO)
2500, 330-5th Avenue SW
Calgary, AB
T2P 0L4

**Re: Alberta Electric System Operator (“AESO”)
2018 ISO Tariff Application ID22942-Consultations on 12 Coincident Peak (12CP)
Method of Cost Recovery**

1. CCA representatives participated in the March 12, 2018 consultation meeting respecting the above. In accordance with the schedule established by the AESO following that meeting, CCA is pleased to provide the following comments.

Comment on 12 CP Presentations:

2. Both the UCA and CCA presentations alluded to the lack of cost accountability on the part of co- generators under the existing transmission tariff structure. The UCA approach seeks cost accountability through changes to the cost of service study (moving 240 kV into regional system) while the CCA approach requests cost accountability through rate design (higher of 12 CP or a fraction of NCP based on coincidence factors). Both approaches suggest taking steps towards tariff reform to reflect cost accountability on the part of co-generators as well as all other customers. In CCA’s submission comprehensive tariff reform must proceed sooner rather than later in order to provide the right price signals to suppliers of capacity prior to the capacity auctions scheduled to commence in 2019.

3. In CCA’s view the UCA proposed change in the functionalization of 240kV lines in the cost of service study would reflect the true functional nature of the bulk system and this step could potentially be achieved without significant administrative effort. Reclassifying 240 KV lines as part of the regional system would allow the AESO to consider injection tariffs for supply and thereby capture cost causation on the part of supply resources connected to the regional system. With increasing behind the fence generation (BTF), both at the transmission and distribution levels, it is important to consider injection tariffs, based on the costs or benefits to the system arising from the supply side in order to provide the necessary price signals prior to the capacity auction scheduled for 2019. While the CCA does not agree there is any need or justification to consider load retention type rates focused on large co generators, injection tariffs for supply, may largely address AltaLink’s and other TFO’s concerns about load defections.

4. The AML, IPCAA/ADC/DUC presentations referred to the potential for uneconomic bypass by co-generation customers if the existing tariff structure were changed to require improved cost accountability by co generators. However, the potential for uneconomic bypass would be credible if it can be demonstrated that the estimate of costs for providing back up generation entirely through self-generation (islanded system) and the foregone revenue to BTF generation from inability to access the grid in order to supply services such as energy, ancillary services and

capacity (in the future), are lower than the costs to co generators arising from improved cost accountability under a reformed tariff structure designed to improve cost accountability.

5. Further, the IPCAA/ADC/DUC view that interruptible loads help to reduce bulk system additions, needs to be considered in the context of planning of the bulk system. If the planning of the system does not recognize interruptible loads, there are likely no savings on bulk system fixed costs arising from interruptible loads.

6. It would be helpful if the IPCAA/ADC/DUC could provide further analysis and support with respect to the above matters.

Process:

7. CCA notes the next meeting respecting the 12 CP topic is scheduled for April 9, 2018. At this meeting, CCA suggests that a schedule for further consultations on the topic of transmission tariff reform be put forward by the AESO for consideration by the group. The schedule could include milestones for reaching agreement on issues with cost of service issues being dealt with first followed by rate design. Due consideration should be given to gradualism and rate stability without unduly distorting price signals going forward. The timing of this process should ensure the necessary tariff reforms are in place before the capacity auction scheduled for 2019.

8. In order to not delay proceeding ID22942, a step could be included in the above schedule to put forward a proposed approach to dealing with the 12CP issue for the purposes of that proceeding pending broader tariff reform to be completed prior to the capacity auction in 2019.

9. A facilitated process would be effective in this regard and, if agreement cannot be reached on certain issues, then a mechanism should be established to take those specific contentious issues for speedy resolution by the AUC so that the remaining process may continue uninterrupted.

Yours truly,

Raj Retnanandan
CCA Consultant

12CP Method: DRAFT Discussion Document

Given that **cost causation** should drive the allocation of bulk transmission costs, a 'big picture' **reflection** on the physical and social factors driving bulk transmission development is essential. This reflection leads to three initial hypotheses for discussion:

- Alberta's current legislative and regulatory **framework impedes** the use of cost causation in bulk transmission rate design.
- Changes in the 12 Coincident Peak methodology should only be implemented once the new capacity market and renewables policy **framework is fully defined**.
- In the interim, an **AESO-led consultative** process should be convened, to share objective data regarding system planning and operation, customers' 12-CP response and the occurrence of uneconomic bypass.

1 The Nature of Bulk Transmission

1.1 Bulk Transmission Driven by Separation of Generation & Load

A bulk transmission system is only required if there is **geographic separation** between generation facilities and consumer load.

Most types of generation rely on an **energy source** whose location is highly constrained. The further that energy source is from customer load locations, the greater the cost of bulk transmission.

The locational flexibility of Alberta's generation resources is:

- **Hydro** generation's location is completely determined by geography. "Large hydro sites are limited to advantageous topography along major rivers. As such, the scope for large-scale dammed hydro in Alberta is limited to a few key rivers and specific sites."¹
- **Coal** generation's location was primarily constrained by the depth of coal's coverage, the availability of a large volume of cooling water, and the location of previous units. Coal to gas conversion is limited to coal units' current location.
- **Cogeneration**'s location is driven by the location of its heat sink. "The majority of cogeneration in Alberta is related to oilsands production, which requires large amounts of steam used in the steam-assisted gravitational drainage process."²

¹ AESO 2017 Long-Term Transmission Plan, p.74

² Ibid, p.73

- **Wind and solar** generation facilities are most economically located in regions of high resource potential.³
- **Gas** generation in Alberta can in principle be located in proximity to load.
 - “...simple-cycle units are often smaller than other gas technology types, and typically have a higher degree of flexibility in terms of where they can locate within the province.”⁴
 - “From a fuel availability perspective, combined-cycle units have a relatively high degree of flexibility in terms of where they can locate.” “However, fuel availability is not the only locational consideration.” “Locating at existing sites can reduce costs and regulatory requirements, and often achieve community acceptance more readily than at greenfield sites. Consequently, the 2017 LTO assumes most combined-cycle development will occur at brownfield coal sites.”⁵

In the long-term planning horizon, the integration of renewables will be a major driver of bulk transmission facility development.

“Alberta’s current renewable electricity target–30 per cent of electricity generated using renewable resources by 2030–requires the addition of approximately 5,000 MW of renewable generation and assumes wind and solar resources are the most economical renewables that will develop. Currently, the existing transmission system has an upper-limit capacity of approximately 2,600 MW.”⁶

1.1.1 Origins of Bulk Transmission in Alberta (1891 – 1995)

“The justification of allocating demand related costs using various forms of singular or multiple coincident peak (CP), or non-coincident peak (NCP) allocators was developed in the early 20th Century for application to vertically integrated and centrally planned utilities, many years prior to the development of today’s desegregated retail electricity markets.”⁷

In the late 19th and early 20th century, the first ‘islanded’ municipal power systems were developed. In the 1930’s, “Calgary Power [later TransAlta Utilities] was developing a province-wide system of generation and transmission.” “Under the terms of the [1930] agreement, Calgary Power sold [hydro-electric] energy to Edmonton during the summer, and Edmonton sold surplus [coal-fired] power to Calgary power during the low water season.”⁸

³ Ibid, p.27-28, Figure 3.0-2: Alberta’s wind resource potential, Figure 3.0-3: Alberta’s solar resource potential

⁴ Ibid, p.72

⁵ Ibid, p.73

⁶ Ibid, p.27

⁷ Submission of UCA, AESO Consultation on 12 Coincident Peak Method, March 9, 2018, p.3 para.6

⁸ Candles to Kilowatts: The Story of Edmonton’s Power Company, 2002, p. 25, 29

As in future decades, the bulk power system's development was primarily driven by generation resource location, surplus hydro energy being seasonally available in the Calgary region and surplus coal power being seasonally available in the Edmonton region.

Beginning in the late 1950's, the development of large coal units in the Wabamun area led to the development of a province-wide transmission system. In the 1980's, province wide 'one system planning' was integrated with province wide generation and transmission cost pooling⁹, treating the entire province as a single operationally and financially integrated entity. This legislative fabrication served to support a traditional but factually unfounded conceptual model:

"In this vertically integrated monopoly model, all generation, transmission and distribution costs were planned and built by the same entity to serve end-use loads. All costs were therefore deemed to be "caused" solely by the end-use customer placed conceptually at the foot of a stack of costs ascending to the generation sources. A convenient topological fiction running linearly from generators via transmission and distribution systems to terminate at loads was then employed for cost allocation purposes. This conceptual model for cost allocation bore little relationship to the physical disposition and operation of the integrated system elements."¹⁰

The financial and operational predominance of generation has led to an unfortunate conceptual confusion between the 'physical disposition and operation' of generation versus transmission.

If Alberta's (relatively weak) external tie lines are out of service, generation capacity must exactly match load at all times. In a generation context, the 'system peak' is a very meaningful single number, which generators absolutely must be able to meet in the moment when it occurs.

The transmission 'system' presents an entirely different reality, being a network whose individual elements may experience peak loads and other operating constraints at any time. There is no 'single peak' that has to be met by the 'system' as a whole; there are only local and regional conditions to be managed. Particularly given Alberta's renewables policies, most of those conditions will in future be driven by generation, not load.

Given that "physical disposition and operation' of transmission is highly local in nature, local cost allocation would more accurately reflect cost causation. But even though EEMA cost pooling ended two decades ago, its 'province wide' cost allocation framework lingers on in the Electric Utilities Act's statutory constraint that:

30 (3) "The rates set out in the [ISO] tariff

⁹ EEMA, the Electric Energy Marketing Agency, in operation from 1982 to 1996.

¹⁰ Ibid, p.4, para.7

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

It is understood that this provision was put in place in large part to shield Alberta’s remote loads (particularly in the north) from the high cost of the long transmission lines needed to serve them from the southern coal units. But as further discussed below, this historic legacy also acts to prevent a more cost-causation based bulk transmission allocation method.

1.1.2 Fundamental Tradeoff: Higher Transmission Costs for Lower Generation Costs (1996 – 2017)

In a 2000 conference speech, Dale McMaster articulated a fundamental economic tradeoff implicit in the competitive generation market, a reality which until that time had been largely overlooked by much of the industry.

When generation was centrally planned, sited and dispatched, it was possible to plan to minimize the costs of the transmission system.

But in a competitive market, generation cannot be centrally planned, sited and dispatched. Generating units will locate themselves as they see fit, and operate in response to unpredictable competitive market conditions, all of which requires a considerably more robust transmission system.

1.1.2.1 Implementation of 50/50 Generation / Load Allocation

Generation’s role in cost causation was explicitly recognized in the 1999-2000 transmission tariff. In its 1990-2000 GTA, the Transmission Administrator (EAL), “proposed allocating all embedded costs, with the exception of the Remedial Action Scheme costs (RAS), on a 50/50 basis between supply and demand customers.”¹¹

The Board approved this allocation, stating:

“The Board considers that both supply and load customers use the transmission system and both classes of customers benefit from their use of the system. System access service provides load customers the benefit of access to generation within Alberta and the opportunity to access power imported into the province and sold into the Power Pool. Conversely, system access service enables generators to sell into the Power Pool (and, in accordance with the EU Act, to sell directly to intra-Alberta load demand customers in the future) and to export power from Alberta. The Board agrees with ENMAX that, in a competitive marketplace, supply customers require access to load in the same manner as demand customers require access to supply.”¹²

¹¹ Decision 2000-1, p.76 The final allocation was 48.8% to Load and 51.3% to Supply (p.122)

¹² Decision 2000-1, p.119

Generation cost recovery was based on energy.

“The Board concludes that the STS rate should be an energy charge to avoid unintentionally negatively affecting the PPA process and discriminating against a certain class of generation.”

1.1.2.2 Policy Termination of 50/50 Allocation

However the 2003 Transmission Development Policy¹³ overrode this reasoned analysis of cost causation, stating:

“The 50/50 pricing regime currently used for embedded costs will be discontinued effective January 1, 2006. Three important objectives are met by removing this pricing regime;

- (a) price distortions are not introduced into the wholesale market from the regulated transmission business,
- (b) consumers receive transparent pricing for transmission service, and
- (c) the market and pricing rules of Alberta are further aligned with those of neighboring jurisdictions.”

It is noteworthy that this policy change was not stated to have a goal of better reflecting cost causation.

1.1.2.3 Separation of Need & Facilities Applications

The policy also separated the regulatory approval process into two components:

“The ISO may bring forward a “need application” to the EUB for approval to proceed with preconstruction activities for a particular project or area development. This approach is different than the current regulatory process for need assessment before the Board.”¹⁴

“Prior to deregulation, a single application would be filed by a utility company and the EUB would consider both the need and the facility stages together. If a hearing was necessary, both issues would be addressed in one proceeding.

As a result of deregulation, this has become a two-stage process.

The first stage requires the ISO (presently AESO) to establish the need for the proposed transmission facilities and seek approvals from the EUB.

Upon the approval of the needs identification document, the ISO would assign the project to a utility company or a market participant to proceed with the second stage, i.e., to apply to the EUB for the construction and operation of the transmission facilities. It is during this

¹³ TDP, p.5, dated December 22, 2003, available at: <https://open.alberta.ca/dataset/0db52c69-eed1-4f4a-997c-a47d57cc9788/resource/7238f12e-2a43-41dc-856e-c623a9fc57a3/download/3103222-2003-transmission-development-policy.pdf>

¹⁴ TDP, p.7

second stage of facility applications that location and routing issues are dealt with in detail.”¹⁵

This separation of “need” and “facilities” applications led to controversy and conflict in respect of the Edmonton-Calgary 500 kV transmission line.

“The Board considered, in respect to the first step, high level options as to the potential line’s location. It favoured what is called “The West Corridor”. Certain parties objected to the result, claiming a lack of notice and a lack of an opportunity to express their views on the question of need and location. The Board heard a request to reconsider but the resulting decision left several parties dissatisfied. Among other issues they raised bias and a lack of notice as part of their grounds for appeal...”

“The Board began the second phase hearings. The hearings, partly as a result of ongoing discontent over alleged lack of notice and too narrow a scope for participation became difficult to manage and were disrupted and violence broke out. Hearings were adjourned and resumed in a new location. Officials of the Board hired an outside contractor to assist in Board security. The persons thus hired attended the hearings in plain clothes and engaged in activities that some parties say interfered with their solicitor client privilege. One of the persons hired, a private investigator, by obtaining a password, participated in a telephone conference call where participants discussed their concerns. This participation in the phone call was authorized by a senior EUB official. It has risen suspicions about what other activity of a similar kind may have occurred.”¹⁶

Decision 2007-075 concluded

“that, for this case, and in these circumstances, the reasonably informed person would indeed hold a reasonable apprehension about the EUB’s ability to decide this matter fairly and impartially and that, as a result, jurisdiction has been lost.” [p.2]

This decision thereby voided the entire regulatory process respecting this major transmission reinforcement, which was considered by many to be critical for Alberta’s transmission system reliability. The controversy also led to the termination of the Energy and Utilities Board (EUB) and the creation of the Alberta Utilities Commission (AUC).¹⁷

1.1.2.4 Designation of “Critical Transmission Infrastructure” [CTI]

At this point, there was considerable apprehension that necessary transmission system reinforcements could not be approved in a timely fashion, and that the Alberta electric system was at risk. “No major transmission line has been added to the existing N-S transmission system for more than 20 years.”¹⁸

¹⁵ EUB Decision 2005-031 (April 14, 2005), p.8

¹⁶ Decision 2007-075, p. 4

¹⁷ The process of creating the AUC is discussed in Bulletin 2007-043

¹⁸ Decision 2005-031, p.28

To break up this apparent impasse, in 2009 the Government of Alberta assumed the power to designate a project as **Critical Transmission Infrastructure (CTI)** if it

“...is, in the opinion of the Lieutenant Governor in Council, critical to ensure the safe, reliable and economic operation of the interconnected electric system.”¹⁹

This eliminated regulatory proceedings to determine ‘need’, allowing the AESO to direct the construction of these facilities ‘in a timely manner.’ (EUA 41.3)

1.1.2.5 Cost Causation and Critical Transmission Infrastructure

“Critical Transmission Infrastructure” projects represent the largest-ever expansion of Alberta’s bulk transmission system.

What is these projects’ ‘cost causation’ ?

Only the elected officials comprising ‘the Lieutenant Governor in Council’ know what considerations led to a specific bulk system project being designated as ‘Critical Transmission Infrastructure.’

To assess these projects’ “cost causation”, a review of their current and future function is needed.

1.1.3 The New Policy & Market Environment – Coal Retirement & Renewables

As the 2003 Transmission Development Policy anticipated:

“The Board will therefore be required to take a more comprehensive and longer-term view of need, including approval of likely transmission corridors when there is still some uncertainty about the precise nature of the future load and generation configuration on the system.”²⁰

The AESO’s 2017 Long Term Outlook (LTO) and Long Term Transmission Plan (LTP) provides an authoritative and objective view of factors impacting bulk system transmission planning.

“The longer term transmission developments will be primarily influenced by coal-fired generation retirement and the pace/magnitude at which renewable generation is added to the interconnected electric system.” [LTP p.57]

In the next 20 years, load growth is not the primary driver of bulk system costs. The 2017 LTO forecasts that Alberta’s electricity demand will grow at an annual rate of 0.9 per cent until 2037, an increase of under 2,000 MW during the 20 year period.

The only load scenario in the LTO is a low load growth scenario.

¹⁹ Electric Statutes Amendment Act, 2009 [aka ‘Bill 50’] (modifying Electric Utilities Act, 41.1(1)(e))

²⁰ TDP, p.7

“The Low Load Growth Scenario was not studied as it was not expected to have a major influence on identified transmission enhancements due to identified load-driven enhancement being captured in the near-term assessments.”²¹

Consider the changes in generation type forecast in the LTO Reference Case:

20 Year - Reference Case Changes	Coal-fired	Cogen.	Combined Cycle	Simple Cycle	Coal-to-Gas	Hydro	Wind	Solar	Other	Total
Reference Case	-6,299	405	5,005	1,853	790	350	5,000	1,000	0	8,104

Some 6,000 MW of coal is to be removed from service, replaced by 6,000 MW of wind and solar renewables, primarily backed up by simple and combined cycle gas generation and a range of smaller energy resources. In total, some 14,400 MW of new generation resources have to be integrated with the transmission system in the next 20 years, more than seven times the < 2,000 MW of expected load growth.

Scenario volatility is primarily driven by generation resource uncertainties:

20 Years - Reference Case & Differences	Coal-fired	Cogen.	Combined Cycle	Simple Cycle	Coal-to-Gas	Hydro	Wind	Solar	Other	Total
Reference Case	-6,299	405	5,005	1,853	790	350	5,000	1,000	0	8,104
Low Growth	0	-405	-910	-380	0	0	-700	0	0	-2,395
High Coal-to-Gas	0	0	-910	-1,853	3,059	0	0	0	0	296
No Coal-to-Gas	0	0	0	95	-790	0	0	0	0	-695
Large-hydro Addition	0	0	-910	-285	0	1,170	0	0	0	-25
Western Integration	0	0	-455	-618	0	0	0	0	0	-1,073
High Cogeneration	0	1,320	-1,365	-333	0	0	0	0	0	-378

²¹ LTO, p.57

These uncertainties are also regional in nature, which adds great complexity to the AESO's scenario planning.

20 Year Changes from Reference Case						
	Northwest	Northeast	Edmonton	Central	South	Calgary
Low Growth	-95	-818	-645	-290	-547	0
High Coal-to-Gas	-617	-693	1,084	302	410	-190
No Coal-to-Gas	0	47	-790	0	0	48
Large-hydro Addition	-95	545	-597	170	-47	0
Western Integration	-142	-95	-645	-95	-47	-47
High Cogeneration	-95	730	-1,100	135	-47	0

1.1.4 Transmission Planning is Network-Driven, Not Peak-Driven

Nowhere in the AESO's bulk transmission system planning documentation is there a stated requirement to "meet the transmission system coincident peak." The LTP focuses on individual planning areas and their interactions, not on some one single event.

The transmission system is a complex network, with complex and often unexpected interactions.

"Integration of incremental generation in the central east area would be sub-optimal, leading to a reduced system-wide total capacity to integrate new renewable generation by an amount greater than that added in the central east area.

Specifically, for every 100 MW of incremental renewable generation added in the central east area, the southeast area renewable generation integration capacity would be reduced by 160-190 MW.

The planned transmission transfer out reinforcement in the central east area will address this constraint."²²

As the CCA presentation of March 12 observes,

"The current and go forward bulk system planning would need to consider net demand variability and frequent cycling of units due to significant intermittent renewable resources, multi directional and multitemporal load flows, increasing use of integrative smart grid technologies and demand time shifting as a result of the deployment of storage.

Net demand variability and multidirectional load flows would not be correlated with high demand periods and can occur in any hour. This means planning of bulk system must recognize the need for adequate bulk system capacity in any hour."

²² LTP, p.32

1.1.5 Load Based Allocators Cannot Reflect Cost Causation

This extensive (and exhaustive) reflection on bulk system cost causation leads to tentative conclusions:

- Future bulk system costs will be primarily driven by generation location
 - BUT the Transmission Regulation currently prohibits sending a new cost-based locational signal to new generators
- Bulk system costs are driven by local area factors (e.g. incremental generation in the central east area)
 - BUT the EUA currently forbids different local charges in Alberta
- Load-based allocators are very poorly correlated with Alberta's impending bulk system development
 - BUT this is the traditional and most accepted approach to bulk system cost allocation.
 - AND since load-based allocations are little grounded in fact, their selection is largely arbitrary and capricious

2 Potential Changes in Market Structure

The constraints that impede cost-causation based bulk system cost allocation may change during the ongoing electric market restructuring.

The analysis presented by E3 on behalf of AltaLink indicates that transmission is reaching a cost threshold at which on-site generation is becoming more economic than central station service via the bulk transmission system. The current policy of unconstrained generator location may no longer be sustainable, possibly leading to its review.

Similarly, the potential for reconsidering the EUA's prohibition against local transmission pricing may be revisited in the light of this potential transmission 'death spiral.'

ADC/DUC/IPCAA have posed fundamental questions that merit analysis:²³

"Why should customers connected at 240 kV pay the full costs associated with the 138 / 144 kV transmission system?

Why should customers located close to the bulk transmission system pay the same rates as customers located at a greater distance?"

Given the arbitrary nature of bulk system transmission allocators, it would be imprudent to drift into a new alternative when the rules of the game are potentially open to change. For the moment, the current 12 CP method is as (un)reasonable as any other load-based allocator.

²³ ADC/DUC/IPCAA March 12 Presentation, slide 17

3 Consultative Process re: Bulk System Cost Allocation

An industry-wide consultative process may identify a cost allocation method better adapted to Alberta's new gas and renewables based future.

“Moving through the LTP's forecast period, the province's generation mix will shift from 38 per cent coal and 17 per cent renewable generation to 63 per cent natural gas and 37 per cent renewable generation.”²⁴

The traditional utility model is not appropriate for this new world, and it will take time for the industry to adapt to the new approaches that will be required. A consultative process, led by the AESO to build a shared understanding, would be far superior to a litigated process leading to yet another arbitrary and cost-irrelevant allocator.

Suggestions to modify the transmission classification process appear to be forms of 'tinkering with the controls', proposing changes that have no discernable benefit in signaling behaviors beneficial to the system.

As part of this process, it would be prudent to monitor the level of 12CP demand response, which ADC/DUC/IPCAA have stated is on the order of 300 – 400 MW.²⁵

The concerns raised by AltaLink regarding potential uneconomic bypass also merit monitoring. All transmission system users would be adversely impacted if large amounts of load left the system, and remedial responses should be considered in a timely fashion.

Fixed cost allocation is a problem that demonstrably has no single best solution. What is needed is an approach which fits Alberta's unique and rapidly evolving market structure, with input from the broad range of stakeholders knowledgeable and engaged in this ongoing journey.

Rick Cowburn

Vidya Knowledge Systems

Friday, March 23, 2018

²⁴ LTP, p.8

²⁵ ADC/DUC/IPCAA March 12 Presentation, slide 8

Feedback – AESO CP Bulk charge

This paper by Depal Consulting Limited (Depal) provides feedback and recommendations on the Bulk Charge coincident peak issues discussed with the AESO and Stakeholders at the AESO consultation session held on March 12, 2018. It primarily provides feedback regarding the issues raised by Altalink through its consultant, E3.

It is the view of Depal that modifying the Bulk charge on this early analysis is inappropriate. The AESO should hold a separate module to discuss this significant issue since the analysis required to change over 50% of the AESO tariff costs should be much more rigorous, inclusive and complete.

In its presentation, Altalink, the CCA and the UCA presented the following Argument and solutions:

- Customers have a strong signal to generate to eliminate the Bulk Charge. Generation costs are \$10K MW/month, while the AESO Bulk tariff costs are \$9K MW/month.
- Altalink estimates that the correct marginal cost of new bulk transmission is \$3.4K MW/month.
 - Cost shift from Cogen and price responsive loads to other customers is \$191 Million/year
 - New Customers of 1815 MW over the next 5 years will cause a cost shift of \$313 Million/year.
- Altalink proposes to fix this issue by:
 - Creating a new bulk charge for incremental bulk costs (1/3 of bulk costs)
 - Collect the remaining 2/3 on billing capacity (including contract level)
 - Do a cost of service study. Altalink is proposing to move 240 kV lines to regional costs, keep only 500 kV in bulk
- CCA proposes to collect bulk costs on an NCP basis.
- UCA advocates for shift from bulk to regional and using CP for bulk, but top 12-hours/ month (instead of only one hour).

Depal provides the following feedback on the Altalink argument and alternate proposals.

Review and Feedback

It is appropriate to review the Bulk capacity charge allocation method. However, the proposals from Altalink, the UCA and CCA are being provided very late in the 2018 tariff process. There is inadequate time within this process to conduct a new cost of service study or to closely examine the price signal provided by the CP method. Therefore, Depal advocates that the AESO should again propose to hold a separate stakeholder discussion and module on this issue, distinct from the 2018 tariff process. It is better to be thoughtful than to rush this important issue.

Altalink is proposing to use billing demand, which includes contract capacity, to allocate Bulk costs. Additionally Altalink and the UCA are advocating for transferring 240 kV lines from Bulk to Regional.

Depal disagrees that DTS contract levels should be used as a billing factor for Bulk charges. The AESO does not use DTS contract levels in its demand forecast.¹ The AESO 2017 LTO does not explicitly use DTS contract levels in its bottom up Point of Delivery load forecast but rather uses “historical load values”.² Finally, if DTS contract levels were used for Bulk charges it would certainly lead many customers to renegotiate DTS contracts, reducing the aggregate level of DTS in Alberta and creating less of an overall reduction in bulk charges than some parties expect. Therefore moving from CP to the use of contract capacity is inappropriate.

This stakeholder consultation process encourages a discussion on the cost allocation methodology for “the CP method and, if necessary, the DFO customer contribution”³. The Allocation of Bulk and Regional charges is clearly not in-scope. The AESO has confirmed, for over a year, its methodology in this regard and therefore modifying the split between Bulk and Regional should be discussed at a later date, in conjunction with a new cost of service study.

¹ AESO rebuttal evidence, Proceeding 22244, page 2-3

² AESO 2017 Long term - Outlook.pdf – page 13

³ Exhibit 22942-X0112, paragraph 19

² AESO 2017 Long term - Outlook.pdf – page 13

⁴ AESO System Reliability and Energy Revenue Modeling, Jan 26, 2018 – Capacity

³ Exhibit 22942-X0112, paragraph 19

While the argument of Altalink is well presented, the assumptions leading to Altalink's conclusions are incomplete. For example:

- Altalink has proposed that the levelized cost of a simple cycle generation unit is \$10K/MW- month. However the AESO in its capacity work has forecasted this cost at 12.3 K/MW – month.⁴ The difference is likely due to Altalink's use of the low end of the range of capital costs while the AESO used the mid-range. If the high end of capital costs is utilized, the cost could increase to 14.6 K/MW- month.
- This cost forecast is for one unit. Given forced and planned maintenance of the generator, it is likely that a by-pass customer would still be subject to Bulk charges in 1 or 2 months per year. This could increase the overall cost for the simple cycle alternative by about \$1 K/MW- month.
- Given this analysis, the high-end cost of a simple cycle unit could be over \$15 K/MW – month. While benefits of installing this capacity are significant with the Bulk charge of \$9K/MW- month, it is by no means a risk free to recoup a BTF investment. Customers that choose to install a generator to eliminate the bulk charge still face significant risks including: Construction costs, regulatory change, capacity and energy market revenues, operating costs and risks, maintenance risks, etc.
- Altalink has estimated the incremental cost of Bulk transmission is \$3.4K/MW- month. However, this assumes that only \$500 Million is added to Bulk costs. The AESO recently put out a rate impact sheet showing over \$6 Billion in total system cost additions in the next 10 years⁵. If only \$1.3 Billion is added to Bulk, using Altalink's methodology, the incremental Bulk charge is equal to the existing level of bulk charges. The level of Bulk additions is uncertain since it is highly dependent on Government policy and generator additions; therefore, the appropriate level of incremental bulk tariff costs is variable. At this time, there is inadequate proof that the incremental Bulk charge identified by Altalink is correct.
- The other issue with the cost shift is the assumed level of Behind the Fence (BTF) Generation and price responsive load receiving benefit.

⁴ AESO Summary of Integrated Capacity and Energy Revenue Modeling, Jan 26, 2018 – Capacity market CMD 1.

⁵ https://www.aeso.ca/assets/Uploads/TRP-Factsheet-2018.pdf?utm_source=Stakeholder+Newsletter&utm_campaign=5d4d9513c5-EMAIL_CAMPAIGN_2018_03_13&utm_medium=email&utm_term=0_4de5e0990d-5d4d9513c5-237959201

Using the total MW of consumption for BTF units is inappropriate since required grid back up is likely less than total load. Also, the cost shift will only occur if the load still exists. If the Bulk charge proposed by Altalink occurred it is likely that some price responsive load may leave the Province. It is similarly likely that some Cogen may reduce its level of grid back up or choose to Island. A lower level of MW for this load reduces the level of cost shift that is either present or that will occur.

While the structure of the Altalink argument has appeal, the analysis and assumptions do not clearly support the conclusions. Restructuring the allocation of 51.4% of the AESO tariff based upon this analysis is inappropriate and premature.

Altalink has outlined a concern that higher bulk charge may create an incentive for more customers leaving the grid. This is a serious concern that requires monitoring. Depal has discussed the issue with the AESO's capacity market team and the AESO will be monitoring the types of projects that receive capacity payments. If BTF generators become the common technology type that wins new capacity contracts, the AESO will consider using this technology to calculate Gross and Net Cost of New Entry (CONE). This change in reference technology would then reduce capacity costs and align the capacity market with the Bulk Tariff charges. Using the capacity market as the tool to monitor and address this concern reduces the likelihood of fewer customers paying system Bulk charges.

Conclusions

The appropriate cost allocation methodology for bulk system costs is important and an analysis on this issue should not be rushed. The work completed to date is insufficient and inconclusive. Depal recommends deferring this topic to a separate module to allow adequate time for the analysis and to enable the 2018 AESO tariff process to proceed.

In any event, Depal advocates that it is inappropriate to use the DTS contract level to allocate bulk system costs. Bulk system planning is not based upon the level of executed DTS contracts.

March 30, 2018

VIA e-mail: ISOtariiffnotice@aeso.ca

Alberta Electricity System Operator (AESO)
330 5 Ave SW, Calgary, AB T2P 0L4

Attention: Doyle Sullivan, P. Eng.
Director, Tariff Design

Re: Proceeding 22942 – Consultation on 12 Coincident-Peak (12 CP) Method

In response to the AESO's e-mail of March 14, 2018, and on behalf of the Dual Use Customers (DUC), we appreciate the opportunity to provide the following comments and responses to the AESO's application and the materials presented on March 12, 2018 at the AESO's offices.

1. At the March 12, 2014 session AltaLink, the UCA and the CCA presented alternate proposed bulk transmission rate designs. We have evaluated each of these proposed rate designs and confirm that if approved rate increases to certain AESO customers would be egregiously high and cause significant financial harm to many AESO customers, most of whom are direct connection customers.
2. All of the AltaLink, CCA and UCA proposals will result in severe rate shock.¹ Rate increases up to 240% to individual resource production facilities, and in some cases individual companies, will be devastating. The ramifications to these proposals, if implemented, would be damaging for all Alberta electricity consumers. It is anticipated that Alberta will lose industrial output, tax base, jobs and investment. The proposals will materially impact about 10% of the AESO PODs with average rate increases over 30%, while providing a 3 to 5% rate reduction for other load customers; surely these proposals are not in the public interest.
3. The proposed tariff changes will have the greatest impact on behind the fence (BTF) generators, the majority of which are DUC members and industrial cogenerators. We submit that the development of 5,000 MW of cogeneration since 1998 has been extremely positive for Alberta in terms of lower power prices, reduced emissions, non-consumer backed investment, industrial expansion, taxes and jobs. Targeting companies who have made significant cogeneration investments with material cost increases is inappropriate and will stymie future cogeneration investment. The result will be the development of new generation with higher costs and greater emissions.
4. The AESO asked parties to bring forth evidence to support and quantify the problem they are proposing to address. We have considered the information shared during the March 12, 2018 session and have found no compelling evidence nor rationale to consider changes to the bulk

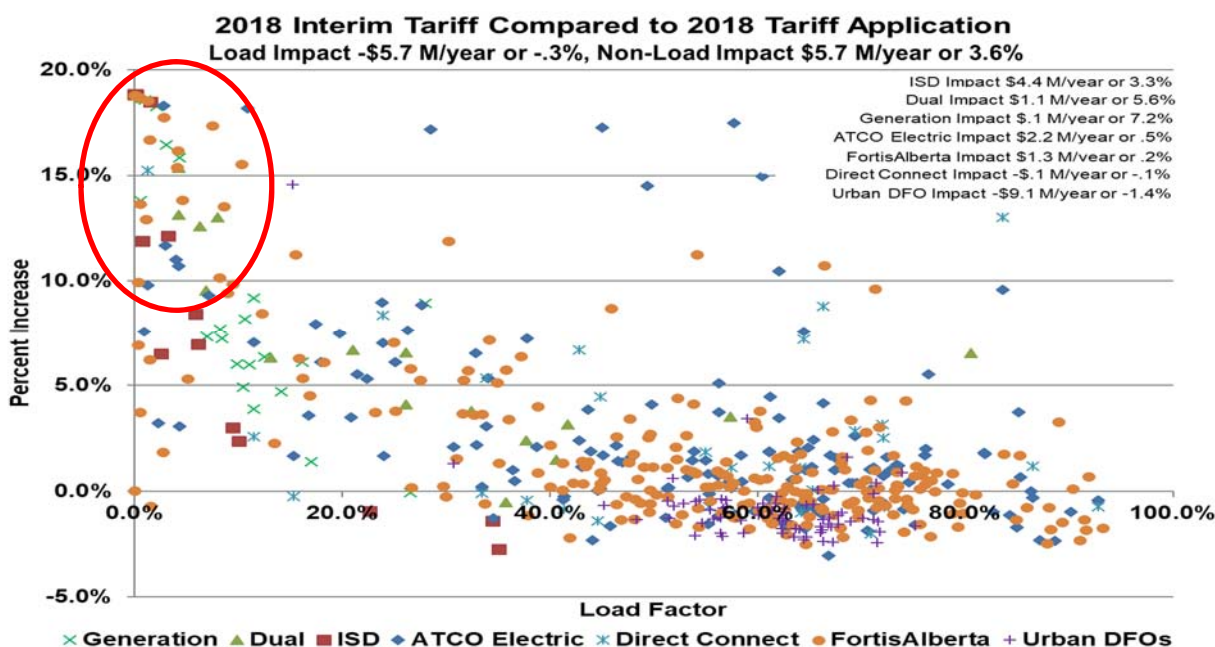
¹ Historically in Alberta, rate shock has been defined as a rate increase of over 10%.

transmission rate design. Having heard the other party's proposals, we are not prepared at this time to consider any bulk transmission tariff design changes which will result in the large proposed tariff cost increases. **We encourage the AESO and interested parties to proceed with the current proceeding without litigating the 12 CP issue.**

5. Notwithstanding, the DUC is prepared to participate in a working group to review the 12 CP issue, including in depth data analysis, to ensure Alberta has the right long-term transmission tariff design. This complex issue will require dedicated resources over a long period of time (1 -2 years). The working group's recommendations to the AESO could be incorporated into the next AESO GTA.
6. In order to quantify the magnitude of the proposed rate increases, we calculated the DTS and PSC charges for every AESO POD using the AESO's current 2018 interim approved tariff, the AESO's proposed 2018 tariff (as filed), and each of the AltaLink, CCA and UCA proposed tariff designs.
7. The billing determinants provided by the AESO in Appendix I of their filing were used.² The AESO in Appendix I categorized PODs as **Load**, **Dual** (dual use, 50% of which are PODs that serve DFOs with distribution connected generation, the other 50% are Direct Connect customers), **Generation** (transmission connected generators, all Direct Connect customers) and **ISD** (AUC approved designations, mainly Direct Connect customers). Further, the Load PODs can be distinguished between **Direct Connect** customers and PODs serving Distribution Facility Owners or DFOs (**ATCO Electric & FortisAlberta**, and the **Urban DFOs** - ENMAX, EPCOR, Lethbridge and Red Deer). We have used these categorizations to compare the proposed rate increases.
8. We note that the AESO's proposed 2018 tariff will materially shift costs to non-load customers, with proposed rate increases to certain PODs of up to 18%. This level of rate increase is, in our view, rate shock, and is not acceptable.
9. The AESO's proposed 2018 tariff, compared to the current 2018 interim tariff, will shift costs from high load factor customers to low factor customers (mainly generators and customers with behind-the-fence generation, Dual use and ISDs).³ The AESO is proposing rate increases to PODs supporting generation up to 18%, with all non-load PODs proposed to receive an average 3.6% increase. All load PODs in aggregate are proposed to receive a 0.3% reduction. Please see the chart below:

² Ex. 22942_X0005, Appendix I, 2018 Bill Impact Analysis. To ensure that the total revenue requirement for each tariff comparison were equal some rates were adjusted by a few percent.

³ Some very small PODs will also see proposed increases over 15%.



10. We do not believe that AltaLink's theoretical assumption that "un-economic by-pass" has or will occur is a valid reason to alter the bulk transmission rate design. AltaLink suggests the current "cost shift" is \$191 million per year or about 21% of the bulk system demand costs of \$900 million.⁴ This analysis is flawed due to:

- The estimated Transmission Marginal Cost of \$3,416/MW-mo is based on a 5-year projection from the AESO's 2017 Long Term Plan.⁵ For transmission investments a long term (40 year) Transmission Marginal Cost should be utilized.⁶
- The "Monthly Bypass" includes 2,530 MW of existing BTF generation. This generation should be excluded from the analysis since transmission infrastructure was not necessarily built for BTF load – the AESO plans for and builds transmission to serve fully contracted DTS load.⁷ To suggest that non-contracted BTF load is by-passing the AESO tariff is incorrect.

We are of the view that if any cost shift exists, it is not material, and is appropriate to reduce long term transmission costs for the benefit of all AESO customers.

11. AltaLink (and the CCA and the UCA) proposals ignores the fact that bulk transmission was not planned nor built to serve many AESO customer's full behind the fence load. The AESO, and Transmission Administrators and integrated electric utilities before them, used contract capacities as the metric to plan and seek regulatory approval to build bulk transmission capacity. For those AESO customers who not need (or want to pay for) transmission capacity to support their entire on-site load, they have elected lower DTS contract capacities. To suggest that it now appropriate

⁴ AML-E3 DTS Reform Overview Final 03-12-18, slide 9

⁵ AML-E3 DTS Reform Overview Final 03-12-18, slide 8

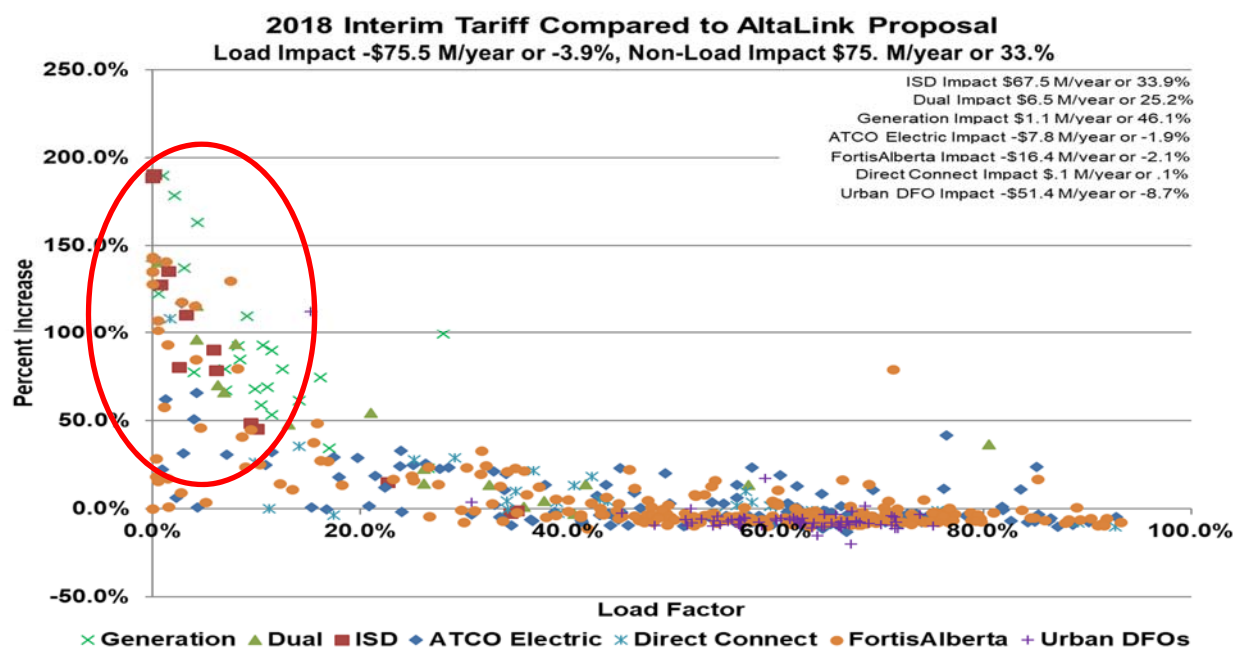
⁶ AltaLink conceded that using 5 years of data is a short-fall in their analysis and agreed a longer term forecast of transmission costs should be utilized. AML-E3 DTS Reform Overview Final 03-12-18, slide 18

⁷ See paragraph 11.

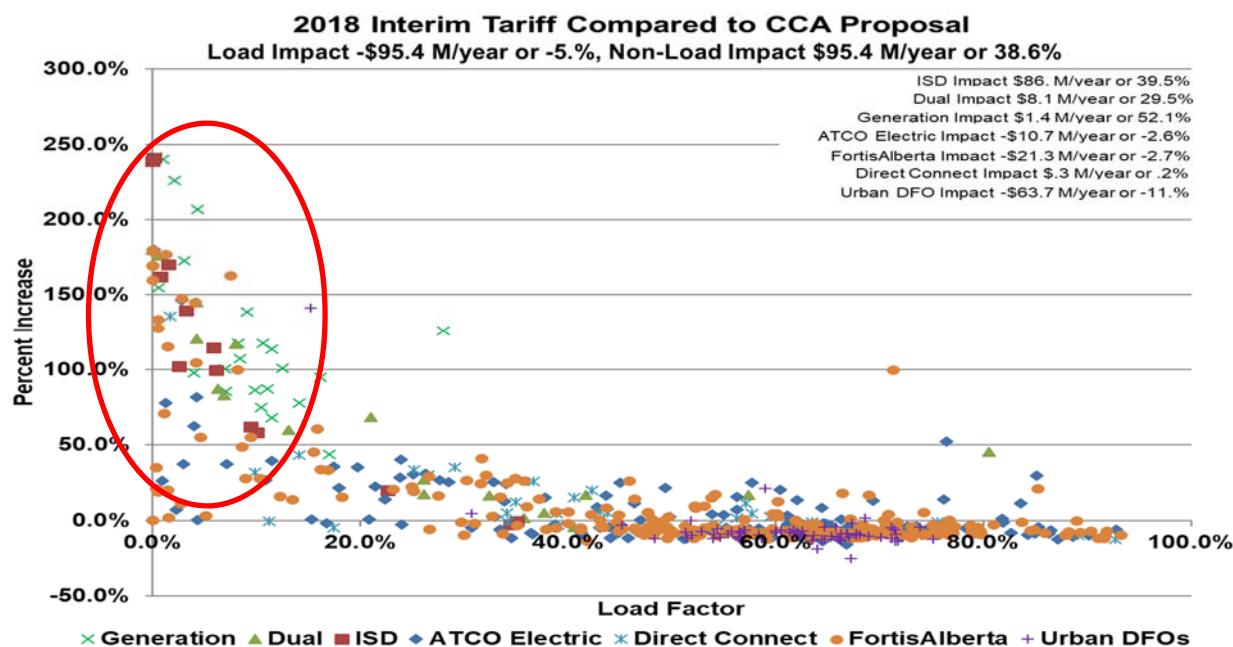
to charge these customers for bulk transmission based on the NCP or the Billing Capacity billing determinant would be fundamentally unfair and unreasonable.

12. AltaLink also suggests that the benefits of bypass from a customer perspective are greater than the cost of by-pass and therefore customers have an economic incentive to build generation behind the fence. This analysis does not consider the inherent risks any customer would face from recovering a generation investment over the life of the asset based on a short-term transmission tariff cost reduction. In Alberta, there have been several periods of time where it would have been economic for customers to build on-site simple cycle generation to avoid higher delivered electricity prices. However, no industrial customer to our knowledge has ever built on-site simple cycle generation to avoid either high power pool prices or “high” bulk system demand charges. AltaLink’s theoretical propositions do not reflect the realities Alberta industrial electricity consumers face.
13. We submit that there are two potential price signals that the AESO’s bulk demand charge could send to customers:
 - a. **Price signal to build on-site generation** – as noted above, we submit that the existing and proposed benefits from trying to avoid the CP and lower transmission tariff costs are not great enough for AESO customers to build simple cycle generation behind the fence. However, even if the price signal was high enough to encourage behind the fence generation development, we do not agree with AltaLink that this presents a problem.
 - b. **Price signal to alter operations to try and avoid the CP** – to the extent AESO customers are responding to the price signal inherent in the tariff, utilizing existing assets, we submit this is behavior was contemplated when the tariff was changed in 2006, is appropriate, should be encouraged and is beneficial to all AESO customers.
14. AltaLink’s proposal is for Bulk system demand costs to be recovered 1/3 via coincident peak (CP) demand and 2/3 via non-coincident peak (NCP) billing demand or Billing Capacity.⁸ This proposed rate design will shift \$75 million per year from load customers to non-load customers, with some ISD and Generation customers impacted by proposed rate increases up to 180%. On average, PODs supporting generation would be impacted by a 33% rate increase. Please see the chart below:

⁸ AML-E3 DTS Reform Overview Final 03-12-18, slide 16



15. The CCA suggests that Bulk system cost recovery be based on the higher of CP or NCP times X%, where X is the probability of line peaks occurring at the same time as 12 CP hours (Ontario uses 85%).⁹ Using an X of 85%, the CCA proposal would shift even more costs from load to generator PODs than AltaLink's proposal. CCA's proposed rate design will shift \$95 million per year from load customers to non-load customers, with some ISD and Generation customers impacted by proposed rate increase of almost 250%. On average, PODs supporting generation would be impacted by a 39% rate increase. Please see the chart below:



⁹ CCA 12 CP Presentation 2018-03-12, slide 7

16. The CCA also suggests that all generators, including behind the fence, should have separate contracts to access the bulk system.¹⁰ All AESO customers, including those with BTF generation, have DTS contracts. This provision of the tariff ensures that all customers, including generators, make a contribution to fixed transmission costs even when they only utilize the transmission system periodically (i.e. low load factor). The following table shows the DTS contract capacity coverage and billing load factors by AESO customer type:¹¹

All PODs					
	DTS Contract (MW)	Bill Capacity (MW)	Contract Coverage	Billing Load Factor	# PODs
Load	10,862	11,211	97%	59%	493
Dual	194	221	88%	21%	20
ISD	1,855	2,142	87%	11%	22
Generation	19	24	76%	10%	24
	12,929	13,598	95%	50%	559

Load PODs					
	DTS Contract (MW)	Bill Capacity (MW)	Contract Coverage	Billing Load Factor	# PODs
ATCO Electric	2,180	2,305	95%	56%	150
FortisAlberta	4,493	4,496	100%	58%	242
Direct Connect	859	936	92%	54%	31
Urban DFO	3,329	3,474	96%	62%	70
	10,862	11,211	97%	59%	493

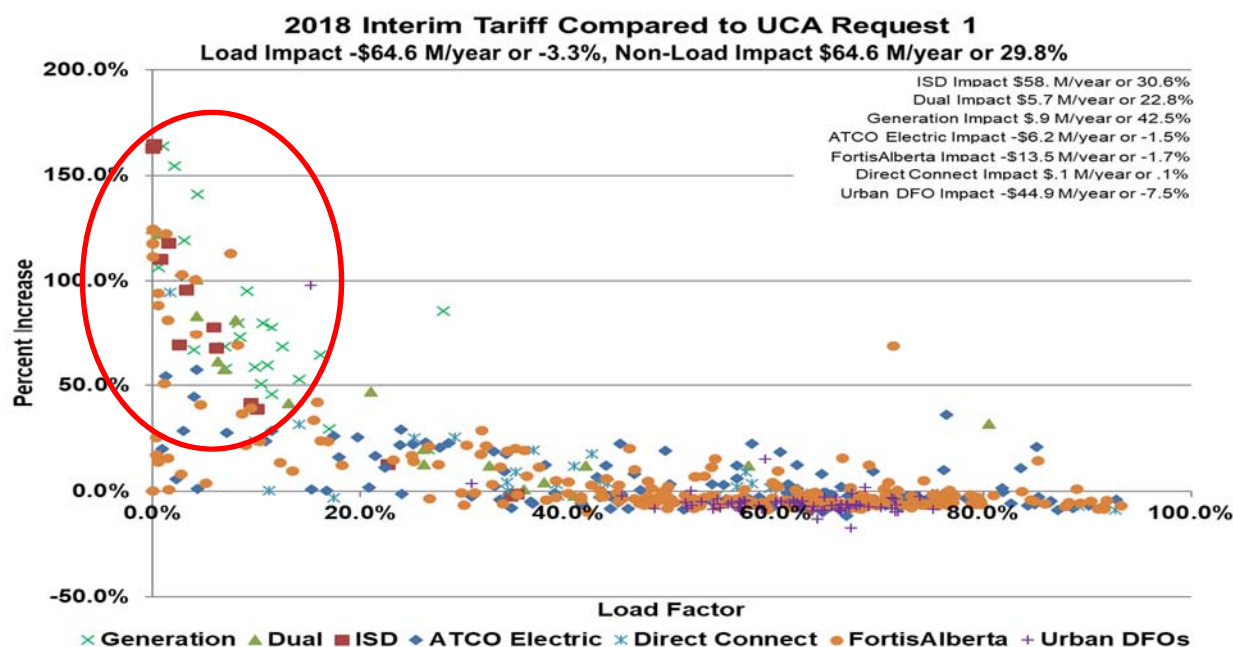
17. The UCA's first sensitively analysis requests that all 240 kV assets be defined as Regional and the resulting costs collected via NCP billing capacity determinants.¹² From the AESO's proposed cost of service study 57% of the existing and forecasted bulk costs are 240 kV.¹³ This proposed rate design will shift \$64 million per year from load customers to non-load customers, with some ISD and Generation customers impacted by proposed rate increase of 170%. On average, non-load customers would be impacted by a 30% rate increase. Please see the chart below:

¹⁰ ibid

¹¹ Summarized billing determinants from Ex. 22942_X0005, Appendix I, 2018 Bill Impact Analysis, tab I-3 Per POD Bill Det

¹² UCA - 12 CP Presentation 2018-03-09, slide 4

¹³ Ex. 22942_X0026, Appendix E, Transmission System Cost Causation Study, tab 2018UpdateClassification



18. The UCA's second sensitively analysis requests that the monthly CP demand be modified from the highest peak in a calendar month to the average of the 12 highest peaks in a calendar month.¹⁴ Presumably this modified rate design is intended to make it harder for AESO customers to "game" the current tariff and avoid the monthly CP. If there is any evidence that AESO customers are successfully and inappropriately gaming the tariff we would not object to this tariff modification (and the inherent increase in administrative costs from a more complex tariff). In our experience, those AESO customers who are responding to the CP price signal are reducing their net load for several hours per month. In addition, over time as more customers are responding to the CP price signal, the actual CP hour is becoming harder to predict. We are not convinced this proposed rate design change will have the desired result or materially change customer behavior.
19. Finally, the DUC's experts¹⁵ have reviewed tariffs from several different jurisdictions across North America and CP is the common method used to allocate bulk transmission costs. The use of NCP is an outdated rate design that does not send any price signal to alter consumer behaviour and will result in higher costs in the longer term, and is in our view, not appropriate for Alberta.
20. The 12 CP approach is a widely-accepted industry practice, due to its simple and non-discriminatory method of factoring in all months without prejudice. This allows for greater stability, as it captures capacity usage across the year and across customer classes. Allocating transmission costs in this way also provides a strong price signal to customers, incentivizing them to reduce their consumption during system peak and promoting more efficient grid utilization. This in turn lowers the need for new generation and transmission investment among utilities. Coincident peak is a deciding factor when contemplating new build, and thus encourages efficient investment.
21. These and many other arguments have been cited by ISOs and utilities as reasons for implementing the 12 CP approach. Many jurisdictions allocate transmission costs through a monthly coincident peak methodology, ranging from ISOs and utilities of comparable size to the

¹⁴ UCA - 12 CP Presentation 2018-03-09, slide 5

¹⁵ Paragraphs 20 to 23 are excerpts from a DUC expert's draft report.

AESO, as well as those that are significantly larger. PacifiCorp, ISO-New England, Southwest Power Pool ("SPP"), and Midcontinent ISO ("MISO") are all examples of entities that implement the 12 CP methodology.

22. Although 12 CP is the industry norm, some jurisdictions choose to implement a variation of the CP approach, such as 2, 3, and 4 CP. These variations retain their linkage to system peaks, which are the underlying investment drivers for utilities. Many of the other benefits of 12 CP carry over to jurisdiction-specific variations, including promoting efficient grid utilization among customers. For example, in the case of a winter peaking system, a 4 CP approach using peaks for winter months still sends a stronger price signals to customers and has the intended effect of reducing consumption peaks when the demand placed on the system is highest.
23. Utilities such as Manitoba Hydro, BC Hydro, Nova Scotia Power Inc. ("NSPI"), SaskPower, and ISOs such as Electric Reliability Council of Texas ("ERCOT"), and PJM are all examples of jurisdictions implementing variations of the CP approach.

Sincerely,

Desiderata Energy Consulting Inc.



W. Dale Hildebrand, P.Eng., M.B.A.
President

copy: DUC Management Team



2000 – 10423 101 St NW, Edmonton, AB
T5H 0E8 Canada
epcor.com

March 29 2018

Alberta Electric System Operator
Calgary Place, 2500, 330 – 5th Avenue SW
Calgary, AB T5P0L4

Attention: Doyle Sullivan
Director, Tariff Design

Dear Mr. Sullivan:

Re: 12 Coincident Peak Issue Session
Proceeding ID 22942

1. EPCOR Distribution & Transmission Inc. (“EDTI”) provides the following comments on the 12 Coincident Peak Issue Session held by the Alberta Electric System Operator (“AESO”) on March 12, 2018.
2. EDTI is in general agreement with the five rate design principles listed by the AESO in its presentation on March 12th.
3. EDTI does not have any specific comments on the positions presented by each of the other parties.
4. EDTI remains concerned that, given the diverse positions put forward by the other parties, issues may be present with the 12 coincident peak method and that further analysis including updating of the relevant portions of the cost of service study by the AESO are warranted.
5. Please contact me directly if you have any questions with respect to this letter.

Sincerely,

[Electronically Submitted]

Saqib Chaudhary
Director, Regulatory Affairs
EPCOR Distribution & Transmission Inc.



Industrial Power Consumers Association of Alberta

1117 22 Avenue NW
Calgary AB, T2M 1P6

March 29, 2018

Alberta Electricity System Operator
330 5 Ave SW, Calgary, AB
T2P 0L4

Attention: Doyle Sullivan, P. Eng.
Director, Tariff Design
ISOTariffNotice@aeso.ca

Re: **Proceeding 22942 – 2018 ISO Tariff – 12 CP Methodology**

In response to the AESO's request for comments, the Industrial Power Consumers Association of Alberta (IPCAA) provides the following comments and responses to materials presented by interested stakeholders on March 12, 2018.

IPCAA Perspective

IPCAA submits that none of the parties that presented on March 12th (AltaLink, CCA, UCA) provided any convincing evidence that there is a problem with the current AESO rate design. All of their proposed changes would result in rate shock for some Alberta electricity customers, large industrials included, with corresponding economic consequences such as reduced capital investment and job losses for Alberta.

IPCAA has historically supported the 12 Coincident Peak (12 CP) methodology for bulk system cost recovery, and submits that it remains appropriate. The 12 CP method has been tested over the last four AESO tariff applications, and has repeatedly been approved by the Commission. The current rate design is intended to provide an appropriate price signal to drive consumer behaviour towards reducing demand during transmission system peaks. Over the long-term, this rate design reduces or delays future transmission infrastructure build, which benefits all electricity customers. In order to allow customers to react to this price signal, we need rate stability.

AltaLink Proposal

In its presentation, AltaLink suggested that due to the fact that distributed generation has become economic, there is a cost shift that is occurring between those who can invest in on-site generation and those who cannot. IPCAA has concerns with the material presented and submits that there is insufficient analysis at this point to draw a firm conclusion that there is a problem with the current AESO tariff or rate design. Much more data and analysis is required, and the issue needs to be examined holistically, along with other changing market conditions, such as carbon pricing, the transition to a capacity market, and distribution costs and cost allocation.

In its “Illustrative Proposed” example, AltaLink is suggesting that bulk system costs be recovered on the following basis: 1/3 CP demand and 2/3 billing or non-coincident peak (NCP) demand. This change would dull the price signal significantly. NCP does not provide a price signal to consumers and does not incent any constructive behaviour that would reduce overall system load, nor does it reflect cost causation. The AltaLink proposal would have a markedly negative impact on Alberta co-generators, which is problematic considering that Alberta is currently working towards closing its coal-fired electricity generators and cogeneration is expected to play a large role in facilitating this transition.

CCA Proposal

In its proposal, the CCA is suggesting using the higher of CP or a ratio (possibly 85%) times NCP to establish bulk system cost recovery. IPCAA has significant concerns regarding the use of NCP. As stated above, NCP does not provide a price signal to consumers and does not incent any constructive behaviour that would reduce overall system load, nor does it reflect cost causation. IPCAA submits that the CCA proposal would be both inefficient and unfair to all Alberta ratepayers.

UCA Proposal

One of the UCA’s major concerns was with the cost causation study. This study was agreed to by negotiated settlement in the previous AESO tariff. The UCA was one of the signatories to that settlement. IPCAA submits that it is inefficient to be conducting a new study every tariff application.

Rate Design Working Group

The electricity industry is undergoing a significant transformation with the implementation of a capacity market. It would be much more appropriate to conduct any review of cost allocation and rate design in concert with the design and ultimate implementation of the capacity market. Making changes before the capacity cost allocation system is fully scoped out is inherently inefficient, will send cross-purposed investment signals and will cause massive duplication of resources for the AESO, the AUC, and stakeholders.

IPCAA would be supportive of striking a committee or working group to analyze the concerns of all stakeholders and the impact of possible rate design changes on all Alberta ratepayers. This work could feed into both the AESO capacity cost allocation analysis and the next AESO GTA.

Recommendation

Acting quickly and without sufficient consideration of the consequences on this issue is not efficient or fair to Alberta electricity consumers. Many consumers have made significant investments under the current rate structure and require rate stability in order to realize the benefits of these investments. Rate shock can have some fairly dire consequences, including loss of capital investment in Alberta and job losses for Albertans.

IPCAA is willing to allocate time to fully understand and analyze all stakeholder concerns; however, in the interest of moving forward in a responsible manner, we respectfully request that the AESO defer this issue to its next tariff application, allowing for a coordinated, holistic examination in the interim.

Thank you for the opportunity to comment and please feel free to contact us with any questions.

Sincerely,

A handwritten signature in black ink, appearing to read 'V. Bellissimo', written in a cursive style.

Vittoria Bellissimo
Executive Director,
Industrial Power Consumers Association of Alberta



Infrastructure Services (Electric)

CITY OF
Lethbridge



ELECTRIC, LIGHT & POWER DEPARTMENT

March 29, 2018

Doyle Sullivan Regulatory
Alberta Electric System Operator (AESO)
2500, 330 – 5th Avenue SW
Calgary, AB T2P 0L4

Dear Mr. Sullivan,

SUBJECT: 2018 AESO Tariff Application – 12 Coincident Peak Allocation Issue

As per the AESO's request for feedback on the March 12, 2018 presentations related to the coincident peak allocation method, the Cities of Red Deer and Lethbridge are pleased to provide the following comments.

As distribution facility owners and DTS customers, the Cities have an interest in a fair and efficient AESO tariff that provides the greatest reward to customer behaviour that is the most beneficial to the system. In other words, the Cities support prioritizing the rate-making principles of cost recovery, appropriate price signals, and fairness. That said, the Cities are also aware that consensus on rate-making principles does not meaningfully facilitate consensus on the specific methods of cost-allocation and rate design.

Indeed, the March 12, 2018 meeting demonstrated that there is much disagreement over whether a new tariff is required, the risks of changing (or not changing) the tariff, and what an alternative to the new tariff should look like. Only the suggestion that the AESO complete additional analysis sparked general agreement from the stakeholders present. While the Cities are not necessarily opposed to further study and analysis, they also are not convinced that further information is necessary to address immediate deficiencies in the current tariff. Nor are they optimistic that more detailed studies will lead to any sort of agreement or consensus on the fairness of the tariff.

Regardless of what further studies are or are not completed, the Cities take the high-level view that the transmission tariff must provide the greatest reward for behaviour that is the most beneficial to the system overall. Based on their

experience as electric utilities, the Cities know that lower load factors use existing wires capacity more efficiently and help to defer the need to build more capacity.

A simple test of any proposed tariff is to calculate DTS charges for a hypothetical customer with a finite capability to produce MWhs of behind-the-fence generation. For two scenarios of otherwise equal MWhs of generation, the lower net load factor customer should have the lower DTS invoice. If not, the DTS is rewarding inefficient configurations of behind-the-fence generation that will lead to a poorer utilization of wires capacity in the future.

The current AESO tariff provides a greater reward to a customer that shifts or reduces load for short periods of system peak compared to a customer that flattens its load over a larger number of hours. Further study might help to quantify the incremental benefits and set a more precise signal, but the Cities submit that the necessary first step is to ensure the tariff is at least directionally correct. The current and last-proposed tariff does not meet the basic requirement of providing the largest reward to a customer who deploys its behind-the-fence generation resources to flatten its net load factor.

As an interim measure and to mitigate rate shock, the price differential for different load factors can be conservatively small. However, the Cities submit that the tariff can and should be immediately revised to at least be directionally correct pending any further research and study that the AESO deems appropriate.

Thank you for the opportunity to provide feedback on this issue. If you have any questions, please don't hesitate to call Jim Jorgenson at (403) 342-8341 or Stewart Purkis at (403) 315-9962.

Sincerely,

<submitted electronically>

Jim Jorgenson, City of Red Deer Electric Manager
Stewart Purkis, City of Lethbridge Electric Manager

cc. Michael Turner, Chymko Consulting



450 - 1st Street S.W.
Calgary, Alberta, Canada T2P 5H1

Tel: (403) 920-5005
Fax: (403) 920-2364
Email: markj_thompson@transcanada.com

March 30, 2018

Via email

Alberta Electric System Operator
Suite 2500, 330 – 5th Avenue SW
Calgary, AB T2P 0L4

**Attention: Mr. Doyle Sullivan,
Director, Tariff Design**

Dear Doyle,

Re: Proceeding 22942 – Consultation on 12-Coincident Peak Method

TransCanada Energy Ltd. (TCE) writes in response to the AESO's request for comments with respect to the March 12, 2018 consultation session regarding the 12-Coincident Peak issue. TCE participated in the March 12, 2018 session and appreciated the presentations made by the AESO and other stakeholders. Overall, the presentations were helpful and provided a better understanding of the issues certain parties have with the current allocation methodology. Based on these presentations, TCE provides the following comments.

TCE supports further analysis to determine whether the current 12-Coincident Peak method will facilitate uneconomic bypass, and if so, what allocation method, or blend of methods, would provide the appropriate price signal while providing for fair treatment of historical investments intended to reduce bulk transmission costs. In this regard, TCE recommends that the AESO conduct its own assessment as to the potential for uneconomic bypass.

TCE also supports the request made during the consultation session for an additional presentation from the AESO at the next consultation session explaining the drivers the AESO uses when planning new bulk transmission builds.

Based on the March 12, 2018 presentations by stakeholders, TCE expects that the time required to complete this analysis would be significant. TCE recommends that the AESO create a tentative timeline that includes the time required for: (i) data collection; (ii) analysis to determine potential for economic bypass; and (iii) if potential for uneconomic bypass exists, assessment of options to resolve issue. If time required is significant, the 12-CP issue should be severed from the other issues being considered in the 2018 ISO Tariff proceeding to allow this proceeding to continue without unreasonable delay.

TCE further recommends that this issue be considered in parallel with the AESO's consultation on the allocation of capacity market costs among load participants. A parallel process is important to ensure the two allocation methodologies are established using the same principles and to ensure they do not operate at cross purposes. While the DOE has determined the general allocation method to be used to allocate capacity market costs, the AESO must still determine the details that could significantly alter the nature of the allocations.

If you would like to discuss this further, please feel free to contact me at (403) 920-5005 or via e-mail at markj_thompson@transcanada.com.

Yours truly,

Original Signed by

Mark Thompson
Manager, Market Services & Regulatory

March 29, 2018

UCA Position on the 12 Coincident Peak Transmission Cost Allocation Issues

Introduction

1. The UCA was an active participant in the facilitated stakeholder consultation session hosted by the AESO on March 12, 2018. After listening to the various presentations made by the AESO, AML, ADC, DUC, IPCAA, and the CCA, on that occasion, along with responses to pertinent questions, the UCA believes that a system economic problem has developed that is exacerbated by the transmission cost allocation procedures currently used. This problem requires immediate reconsideration and development of corrective measures that will reach beyond a simple adjustment to the 12 Coincident Peak (CP) transmission cost allocation methodology.
2. The 2005 transmission regulation relieved generators of any responsibility for transmission wire costs whereas previously one half of total transmission wire costs had been allocated to them. This change in the regulatory framework exposed load customers directly to the full cost of transmission wires comprising what is defined as the “bulk” system. This also removed effective price signals for new generator location that were based on the cost of transmission reinforcements necessary to accommodate them.
3. An alternative attempt to use energy loss factors as a price signal for generator location has been the cause of much confusion and dispute for many years. Marginal loss factors are not effective as a price signal. They are highly unstable, and bear little relationship to the costs of expanding the transmission system to accommodate new generation.
4. The more recent completion and addition to rate base of two HVDC lines added substantially to the costs of the bulk system that can now only be recovered from net load customers.

5. Given the escalation of transmission wire costs that must now be borne solely by load customers, it is not surprising that serious concerns have been raised over the cost allocation procedures in circumstances that now invite uneconomic transmission bypass and suboptimal developments in the absence of integrated generation and transmission system planning and efficient price signals.
6. As described in the UCA's March 9, 2018 Submissions ("March 9th Submissions") such reconsideration must include what transmission line elements comprise the definition of "bulk" versus "regional" transmission subsystems, as well as the precise form of CP or other allocator used.

The Position of the UCA

7. The interest of the UCA is to find an approach that will address the identified problems of transmission cost allocation without causing hardship to any user of the transmission system. The approach should also provide better long term price signals for efficient development of a reliable electricity supply system that is affordable for all customers, especially given the changes that the electricity system is facing today.
8. To be clear, the UCA is not motivated by a desire to shift costs from one class of transmission customer to any other class. Should a cost allocation approach be found that better addresses the identified problem but also causes a significant cost shift to a particular group, the UCA would urge that a long term mitigation strategy be adopted for existing customers.
9. For instance, the UCA is sensitive to the concerns of the Energy Intensive Trade Exposed (EITE) industrial customers (i.e. members of ADC/DUC/IPCAA) who rely on control of monthly coincident peaks in order to avoid some transmission costs. It has been recognized historically in Alberta that the reduction of peak loads that are coincident with peaks of generation reduces the costs of aggregate generating capacity required, and is of value to the overall system.
10. It is not clear to the UCA however that such peak "clipping" at times of generation stress results in any material reductions in bulk transmission costs, as the elements of this transmission subsystem are designed to meet very different stresses and stability criteria than that of aggregate generation capacity.

11. In terms of signaling behavior that provides value to the system, and the mitigation of any potential shift of wire cost allocations, it is important that reconsideration of transmission cost allocations be conducted in concert with the development of the generation capacity market. If transmission tariff adjustments reflecting more appropriate cost allocations were to be made coincident with the introduction of a credit for reducing the level of aggregate generation capacity, then EITE customers would not be disadvantaged by refining the allocation of transmission costs to better reflect cost causation.
12. The UCA would like to remind all parties that cost allocation is a distinct and separate process to rate design. They are not to be treated as an identity and changes in cost allocation may not always translate directly into tariff changes.
13. The principles of James Bonbright that may conflict are intended to be considered as a whole. It is not helpful to consider Bonbright principles as a set of “weighted” factors to be applied mechanically to the results of a cost allocation study. Any single Bonbright principle (such as rate stability) may at times be determinative and override an entrenched consideration such as exactly recovering the cost of service by class.

Information that will assist in evaluating Alternative Allocations

14. In its March 9th submissions, the UCA outlined concerns with the current definition of bulk system and the specific version of 12 CP allocator in use. In summary the current allocation approach was developed for a previous vertically integrated monopoly structure where the allocation of generation costs was paramount, and errors made in the allocation of smaller transmission costs did not have the consequences that they now have for a desegregated structure where generation development is determined by market forces and transmission costs are driven as much by the locational decisions of independent generators as they are by traditional load customers.
15. In order to better reflect cost causation in the current desegregated structure as well as mitigate the price signals problems noted by others, the UCA has suggested redefining the division between bulk and regional systems as well as a broadening of the application of the CP allocator to encompass more hours matched to the load duration curves and coincidence with bulk transmission system elements. To inform this discussion and the exploration of transmission

cost causation and improved definitions of transmission subsystems, the UCA would like to receive responses from the AESO to the following requests for information:

- a) Please identify and explain any potential cost reductions in the **bulk** transmission system (or any elements thereof) as a result of POD (Point of Delivery) load reductions made during the 12 hours coincident with monthly peak aggregate generation without making any reductions to the NCP (Non-Coincident Peak) loads at the same POD.
 - b) Please identify and explain any potential cost reductions in the **bulk** transmission system (or any elements thereof) as a result of reductions of NCP load at any POD.
 - c) Please identify and explain any potential cost reductions in **regional** transmission systems (or any elements thereof) as a result of POD load reductions made during 12 hours coincident with peak aggregate generation without making any reductions to the NCP loads at the same POD.
 - d) Please identify and explain any potential cost reductions in **regional** transmission systems (or any elements thereof) as a result of reductions of NCP load at any POD.
 - e) Please provide a table indicating the changes to cost allocations that would result from the changed definition of bulk system, and the use of 12 hourly averages to determine each monthly CP as requested in the UCA's March 9th Submissions.
 - f) Would the UCA proposed change to bulk system definition referenced in (e) above change any of the responses to questions a) through d) above?
 - g) Please identify and explain your understanding of the potential cost reductions (in MW) of aggregate generation capacity that could result from POD load reductions made during the 12 hours coincident with peak aggregate generation but that do not reduce NCP loads at the same POD.
16. In addition, the UCA would be appreciative if the ADC/DUC/IPCAA group could provide some analyses of the bill increases that would be incurred by the recently suggested changes to transmission cost allocation assuming that these would translate into changes in the tariff and/or billing practices. Could ADC/DUC/IPCAA differentiate between bill increases that could result from CP to NCP allocation

from the bill increases that would result from a change from the billing of net loads for owners of BTF (Behind the Fence) generation to the billing of gross loads?

Process and Timing

17. While the UCA considers the transmission cost allocation problems identified in this and other submissions to be serious concerns that require both thorough and immediate study, we also recognize that an adequate and comprehensive study will take some time.
18. The UCA does not wish to unnecessarily delay approval of the AESO's current tariff application. It is for this reason that we have requested sensitivity studies and more general information that could all be completed and provided relatively quickly and without delaying the tariff application.
19. Comprehensive studies that may be necessary to resolve these cost allocation issues could be completed in parallel with the tariff process on the understanding that they will be completed in the same timeframe as the current application and will then inform future tariff applications. In the UCA's view, it is important that the Commission direct a specific schedule in this regard so that momentum is maintained on the important initiative to analyze and address the identified system problem.

2nd Session
12-Coincident Peak (CP) Bulk Recovery
Methodology
Issue #1 in Proceeding 22942

April 9, 2018
BP Main Boardroom, AESO Offices

The information contained in this presentation is for information purposes only. While the AESO strives to make the information contained in this presentation as timely and accurate as possible, the AESO makes no claims, promises, or guarantees about the accuracy, completeness, or adequacy of the information contained in this presentation, and expressly disclaims liability for errors or omissions. As such, any reliance placed on the information contained herein is at the reader's sole risk.

AESO Inventory of Data/Analysis Requests

Requests for Raw or Processed Data

Engineering data

- Flow levels on major bulk system lines
- Drivers of need for all system projects to date
- Bulk and Regional system cost reduction due to various forms of load reductions

Forecasting data

- Alberta Internal Load (AIL) peak and co-incident peak
- Forecast generation during AIL peak
- Installed capacity of on-site generation and distributed generation by type by year
 - On-site generation and distributed generation by hour
- Gross system load by hour

Cost of Service data

- Allocator (i.e., bulk system cost billing determinant) using mean of 12 highest peak demands per month

Requests for Studies and Analysis

Planning analysis

- Future flow/scenario analysis on major bulk system lines
- Drivers for future system projects
- MW of bypass during co-incident peak (CP)
- List of assets that could have been deferred through reduction in CP

Forecasting analysis

- Forecast flow analysis with increasing net demand variability
- Forecast probability of flow peak occurring at CP

Cost of Service analysis

- Adjust bulk and regional functionalization using alternate definitions (i.e., should all 240 kV lines be considered bulk)
 - Utilize this alternate functionalization with existing rate design and billing determinants
 - Assess the reaction of load to the shift of costs to non-coincident peak (NCP) (i.e., will this result in a reduction in load)

1. Is CP response “uneconomic bypass”?

- Analysis required to reasonably answer this question
- If uneconomic bypass exists then development and assessment of remedial options (along with bill impact mitigation)

2. Assess the impact of moving from net load to gross load treatment

3. Reassess the appropriateness of existing functionalization, rate design and determinants in meeting future needs

- Assess alternate functionalization definitions
- Assess alternate rate designs
- Assess alternate billing determinants
- Assess impact a new rate price signal will have on future transmission costs and on existing and future loads

Common Themes in Submissions

Complexity

- This is a very complex topic that will require significant analysis and stakeholder engagement
- A proper/thorough analysis is critical
- There are diverse perspectives amongst the parties and the process/scope for this exercise will require significant effort
 - Will more detailed studies lead to any sort of agreement or consensus?

Timing

- The data, analysis and re-work that may be required cannot be finished within the existing proceeding
- Should not be rushed
- Set schedule/timeline if managed through a separate process

Scope

- Transmission tariff reform will have to include a review of effectiveness of the current bulk and regional design (not just 12-CP)
- New structures should be evaluated
- Cost of service needs to be re-evaluated

Separate Process

- If the scope of work/analysis cannot be completed in a timely fashion then the Bulk and Regional components should be removed from the current AUC proceeding
- A separate process or module with a set timeline/schedule should be developed that is outside the current AUC proceeding

Alignment with Capacity Market

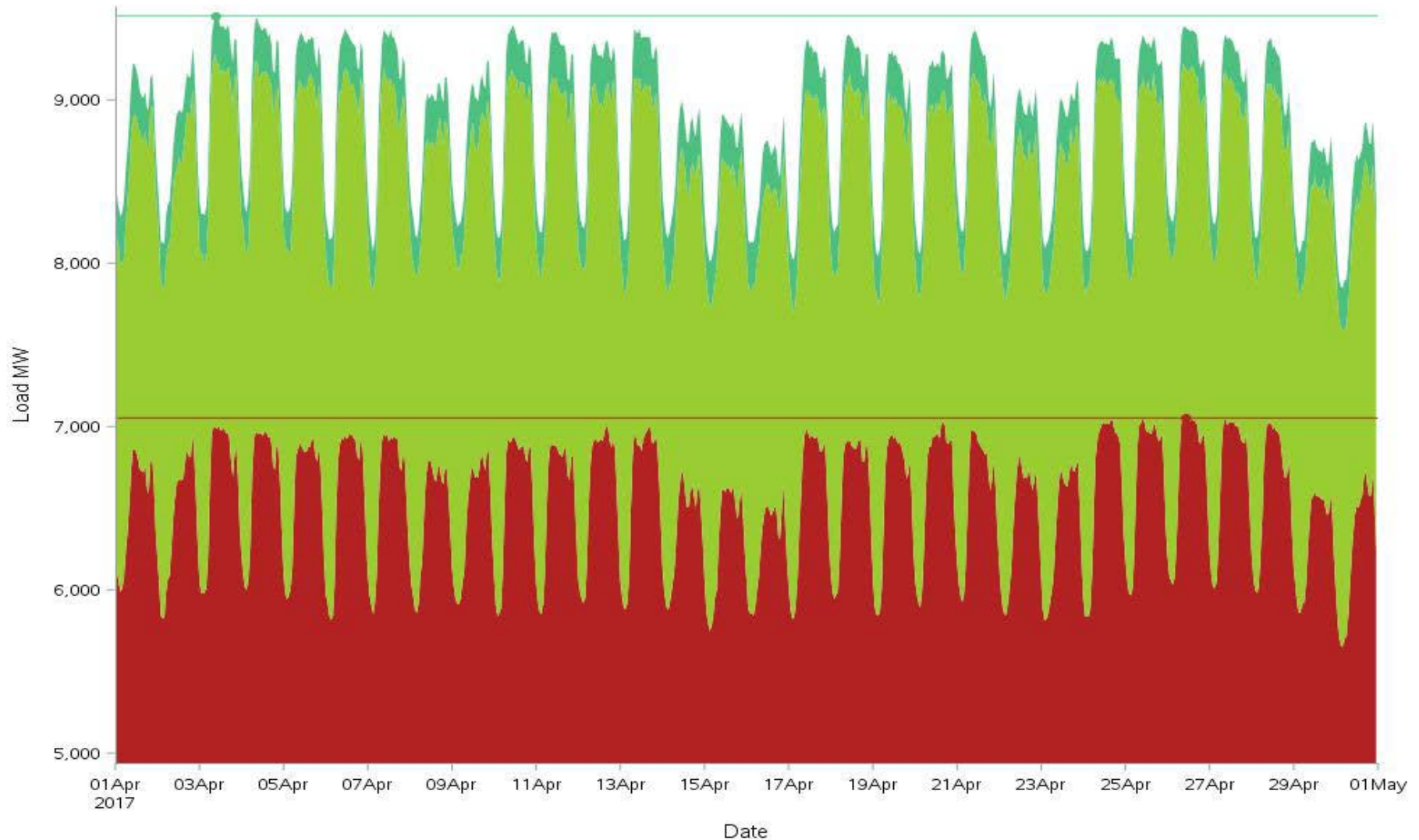
- Capacity market tariff design should be done in parallel or through a joint initiative with this transmission cost tariff design process
- There are other significant processes underway that may impact the transmission tariff and impact the recommendations

Other comment:

- Implement a temporary measure/rate to prevent un-economic bypass by new BTF generation until a more thorough review can be completed

AESO Information Presentation

Many Potential Co-incident Peak Periods Occur in Each Month



Monthly CMD peaks for 2017

Month	CMD (MW)	MW difference between CMD and 10 th highest	MW difference between CMD and 150 th highest	# of 15 min intervals within 200 MWs of the CMD	# of 15 min intervals within 500 MWs of the CMD
2017-01-09 17:15	8,439	44	277	81	465
2017-02-06 18:00	8,196	66	263	87	462
2017-03-08 19:15	7,837	<u>82</u>	192	159	791
2017-04-26 10:45	7,069	<u>11</u>	<u>66</u>	<u>844</u>	<u>1,642</u>
2017-05-31 16:15	7,598	70	<u>442</u>	<u>25</u>	208
2017-06-26 15:30	7,744	68	370	<u>25</u>	432
2017-07-27 15:45	8,107	51	285	76	387
2017-08-28 17:00	7,881	31	197	155	619
2017-09-07 17:15	7,962	71	434	34	<u>194</u>
2017-10-30 7:45	7,384	52	210	136	1,164
2017-11-21 17:30	8,223	60	291	60	579
2017-12-28 17:15	8,401	49	256	83	574

Thank you

Bulk Transmission Cost Allocation

~~~~~

## ***History & Policy***

# ***Why* bulk transmission ?**

**Because generation energy sources are  
distant from the load they serve**

**HYDRO**

**COAL & CONVERSION**

**COGEN**

**WIND & SOLAR**

**SIMPLE-CYLE GAS**

**COMBINED CYCLE GAS**



# The Old World

- **Generators** - central station service
  - Must meet instantaneous system peak
  - CP methods fit generation *reasonably well*
- **Transmission** - uses generator method
  - Province wide Gen & Trans cost pooling
  - Same costs everywhere *by law*
    - EUA 30(3)(a) Rates not locationally different
  - Shields remote loads from true costs

# Interlude: 1999 - 2005

- **Transmission 50/50 to Generators / Load**
  - Generator STS rate = *energy charge*
  - Common cost reduction incentive
- **BUT 2003 Transmission Policy changed:**
  - ~ All costs to load
  - Split NEED & FACILITIES applications

***The dance of unintended consequences***

# **Critical Transmission Infrastructure ( CTI )**

- **Edmonton-Calgary line sparks protest**
  - EUB ‘spying’, decision voided, AUC formed
- **Government concerned about delay**
  - Cabinet determines ‘CTI’ facilities
  - Largest ever bulk transmission additions

**BUT**

**CTI “Cost causation” not public**



# Renewables Policy

**“The longer term transmission developments will be primarily influenced by coal fired generation retirement and the pace/magnitude at which renewable generation is added to the interconnected electric system.”**

**[LTP p.57]**

# Bulk Cost Causation

**13,900 MW of new capacity by 2037**  
(excludes CTG conversions)  
**2,400 MW Peak demand forecast growth**  
**from 11,458 MW in 2016**  
**to 13,947 MW in 2037** AESO LTO p.3

**“What’s load got to do with it ?”**

( T. Turner )

# If all you have is a hammer...

- **Effective cost causation tariff is blocked**
  - No *generation* location signals
  - No *transmission* local marginal pricing
- **Fair cost sharing is the goal**
  - *Fairness* is subjective
  - *Everyone talks their book...but*
  - The community often finds consensus, given enough time

## Attachment 1

### Tariff Design - Proposed Process and Timelines

#### Principles

1. The proposed consultation and design process for bulk and regional ISO tariff design will take place outside of Proceeding 22942.
2. The AESO and interested stakeholders will collaborate to develop consultation scope and terms of reference (TOR), and to identify data needs, identify and review required analysis, and identify and propose solutions.
  - a. The AESO's Straw Alberta Market (SAM) working group TOR will be used as an initial template/starting point.
3. The proposed consultation and design process is estimated to be 12-18 months in length:
  - a. The AESO, in consultation with stakeholders, will strive to shorten this timeline. However, this will be dependent on the amount of analysis required and the availability of additional resources (AESO, stakeholders or consultants) required to assist in data analysis.
  - b. It is anticipated that some of the activities mentioned below can be done in parallel to assist with shortening the timeline.
4. Transparency – all agendas, discussion materials, data analysis, work product and high level meeting summaries (completed by facilitator approved by AESO) will be posted to [www.aeso.ca](http://www.aeso.ca).
5. The AESO will update the Commission on the progress of the consultation every six months.
6. The AESO will file its conclusions with the Commission.
7. The AESO received an extensive number of data requests and data analysis requests in the March and April 2018 sessions, regarding the current 12 CP methodology for the recovery of bulk transmission costs. These requests will form part of and be completed in the proposed consultation process, with the exception of the following that will be completed prior to commencement of the consultation and design process:
  - a. The AESO will make available to all stakeholders historical hourly behind-the-fence energy and provide reasonable ongoing updates to this data; and
  - b. The AESO will provide explanations to all stakeholders for the types of load/generation included in the behind-the fence energy.
8. The AESO will develop any other principles applicable to the proposed consultation and design process jointly in consultation with stakeholders.

#### Structure of Consultation

The AESO will invite interested stakeholders to express their interest in participating in an advisory group. Once formed, this advisory group will identify action items and form working groups to carry out the action items and report back to the advisory group. Preliminary details are listed below, which will be further developed with stakeholders as part of the TOR.

#### Advisory Group:

- The advisory group will determine the mandate and action items to be carried out by working groups, as well as the required level of technical expertise (AESO, stakeholder or consultant), project management, and facilitation that may be required



- Advisory group meetings will be facilitated, will be self-directed with regard to the advisory group's activities and the facilitator will attempt to resolve impasses for which consensus cannot be achieved as the need arises. If consensus cannot be achieved, the AESO will have the final decision.
- Membership will be open to all interested stakeholders who RSVP to the AESO initial notice. Those who RSVP will be expected to participate in all advisory group meetings.
- A balanced membership from all industry stakeholders will be encouraged. If it is observed that one industry group is over or under represented then the AESO will consider re-balancing the membership.
- Commission staff will be invited to attend advisory group meetings as an observer.
- Advisory group members will be encouraged to participate in person (preferred) but accommodation will be made for remote attendance.
- Potential tariff design changes will be considered within the context of the existing legislative framework. However, adjustments to the consultation and design process may be made by the advisory group as a result of Government policy, or legislative changes.
- The advisory group has no decision-making authority with regards to the content of any future ISO tariff application.

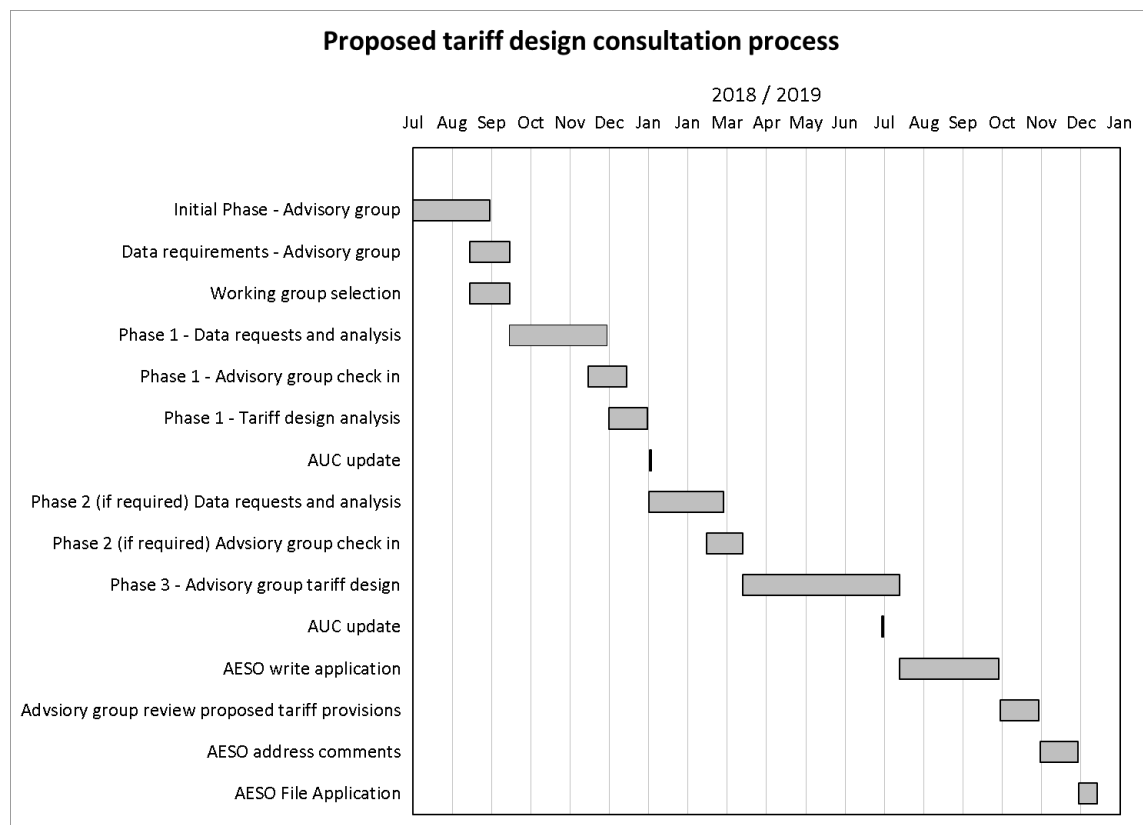
#### Working Groups:

- Will be formed on an ad hoc basis as determined by the advisory group.
- Membership in a working group will occur by self-selection among industry stakeholders. Size will be encouraged to be less than 10 and a balanced representation from industry is preferred.
  - o The AESO will propose other mechanisms if an efficient working group size or process cannot be achieved.
- Consultants may be utilized for assisting with working group activities.

#### **Proposed process and timeline**

- Initial Phase: Determination of scope and process (two months)
  - o Step one: Invite parties to express their interest in participating in the Bulk/Regional and weighted energy methodology (WEM) tariff design stakeholder advisory group ("advisory group").
  - o Step two: Host facilitated stakeholder sessions to gather feedback on:
    - Initial scope of AESO-stakeholder examination of Bulk/Regional and WEM tariff design.
    - TOR for this engagement (i.e., objectives, principles, criteria governance).
    - Milestones.
    - Meetings every two weeks may be required through the initial phase.
  - o Step three: finalize scope, TOR and process.
- Initial Phase: Advisory Group determines data requirements and analysis (one month)
  - o Includes confirming inventory of data requests received to date and confirming with advisory group data requirements in light of confirmed scope from Initial Phase.
  - o Identify and create working groups to address data and data analysis requests.
  - o Review resources available to complete data analysis.
- Phase One: Working Groups complete data requests and analysis (two and half months)
  - o Complete data requests and data analysis as directed by advisory group.
  - o Working group meetings are anticipated to be on a weekly basis.
  - o Report back to advisory group upon completion.

- Phase One: Advisory group review (one month)
  - o Review data requests and data analysis completed by working groups.
- Phase One: Advisory group tariff design (one month)
  - o Upon review of data and analysis, identify any tariff design issues and questions, and identify if further analysis is required to be completed by working groups.
- Phase Two (if required): Working groups complete further data requests and analysis (two months)
  - o Complete data requests and data analysis as directed by advisory group.
  - o Working group meetings are anticipated to be on a weekly basis.
  - o Report back to advisory group.
- Phase Two (if required): Advisory group review (one month)
  - o Review data requests and data analysis completed by working groups.
- Phase Three: Advisory group tariff design (four months)
  - o Upon review of data and analysis, identify tariff design solutions and review impact.
  - o Additional analysis may be required by working groups to determine impacts on market participants and rate payers.
- AESO drafts application (two and half months)
  - o AESO to commence writing application based on recommendations from advisory group.
  - o AESO to discuss potential new or revised ISO tariff provisions with advisory group.
  - o Once complete, the AESO to file application.



## **Further update of the AESO regarding the 12 CP and DFO CC consultation Alberta Utilities Commission Proceeding 22942**

**April 30, 2018**

### **The consultation sessions and AESO's determinations**

1. Regarding the 12 coincident peak methodology ("12 CP") issue, the Alberta Electric System Operator ("AESO") conducted consultation sessions with interested stakeholders on March 12, 2018 and April 9, 2018. Regarding the distribution facility owner customer contribution ("DFO CC") policy issue, the AESO conducted a consultation session on March 5, 2018. On April 24, 2018, the AESO conducted a consultation session for both matters.
2. The views of stakeholders were presented during the sessions and, in some cases, in writing prior to or following a session.
3. Based on the AESO's own assessment and the views presented by stakeholders, the AESO has determined as follows:
  - (a) 12 CP Issue
    - (i) The 12 CP issue requires further consultation, associated with a robust and thorough analysis over a longer timeframe, before conclusions can be reached regarding whether the 12 CP methodology should be continued, modified or replaced by an alternative methodology.
    - (ii) The regional tariff design should also be the subject of consultation in conjunction with consultation regarding the bulk (12 CP) tariff design.
    - (iii) Stakeholders do not oppose further consultation and analysis of the bulk (12 CP) and regional ("Bulk/Regional") tariff design. The AESO's proposed consultation process was broadly supported by stakeholders and Attachment 1 to this Update is the AESO's initial draft of the proposed process, which includes an initial statement of principles, structure of the consultation, and proposed process and potential timeline. The final design of the process will be determined through the AESO's engagement with participating stakeholders. The AESO will provide updates to the Commission on 6 month intervals. Attachment 1 is being filed for informational and transparency purposes only (i.e., the AESO is not requesting Commission approval of the final consultation process design).
    - (iv) There is broad stakeholder support for the proposition that interim measures in relation to the 12 CP and Bulk/Regional design are not appropriate at this time.
    - (v) As a result of the time required to conduct and conclude the required analysis, it is readily apparent to the AESO and stakeholders that it is not feasible to have the Bulk/Regional tariff design issue considered in Proceeding 22942, as part of the AESO's 2018 comprehensive ISO tariff application ("2018 Comprehensive Application"), and should

be considered outside of Proceeding 22942, in the proposed consultation process.

- (vi) Therefore, and subject to the Commission granting the AESO's motion set out in the Stikeman Elliott LLP cover letter filing this further update, the AESO does not intend to file an amendment to the 2018 Comprehensive Application in respect of alternatives to the 12 CP methodology.

(b) DFO CC Issue

- (i) The AESO will not propose a change to the existing DFO CC policy. The AESO's reasons for reaching this decision are set out below.
- (ii) It follows that the AESO does not intend to file an amendment to the 2018 Comprehensive Application regarding an alternative approach to the current DFO CC policy.

### **Proposed future consultation process**

4. In the event that the Commission grants the AESO's motion to be relieved from filing an amendment to the 2018 Comprehensive Application regarding the issue of whether the 12 CP methodology should be continued, modified or replaced by an alternative methodology, the AESO anticipates that the Bulk/Regional tariff design consultation process will require approximately 12-18 months to bring it to conclusion, regarding whether it should be changed and, if so, to file the requisite application with the Commission.
5. The AESO will endeavor to work with stakeholders to determine whether timeline efficiencies can be achieved for each phase and completion of the process.
6. The proposed scope of the consultation process will involve consideration of a comprehensive tariff design and the analysis will include the following matters, among others:
  - (a) historical analysis of load served by on-site, distribution connected generation or coincident metered demand "bypass";
  - (b) revised transmission cost causation methodology and study;
  - (c) load analysis of major bulk system lines;
  - (d) an understanding of forecast and planning processes;
  - (e) probability of coincident metered demand avoidance;
  - (f) analysis of other bulk and regional cost recovery mechanisms;
  - (g) bypass analysis; and
  - (h) any other analysis that may be warranted.
7. Revisions to existing tariff design could involve changes to functions, functionalization of costs, classification of costs, rate classes, rate design and rates.



8. Additional rate classes such as interruptible, standby, or energy storage will be considered in the comprehensive tariff design consultation process.
9. In the event that the AESO determines that the Bulk/Regional tariff design should not be changed, the AESO will file its conclusions and supporting reasons with the Commission. The AESO expects that stakeholders would wish to provide comments to the Commission regarding the AESO's determination, and supports the Commission providing stakeholders with an opportunity to do so.
10. The tariff design proposed in the 2018 Comprehensive Application, if approved, would remain in effect until the Bulk/Regional issues are resolved through the AESO's proposed consultation process and either a changed tariff design is approved by the Commission or the current tariff design, as applied for, continues in effect.
11. As explained in section 4 of the 2018 Comprehensive Application, the AESO has applied for approval to continue to use the methodology of the 2014-2016 Alberta Transmission System Cost Causation Study, approved by the Commission in Decision 2014-242 regarding the 2014 comprehensive ISO tariff Application.<sup>1</sup> That is, the AESO has, in the applied-for 2018 ISO tariff, used the same tariff design consisting of function definitions, functionalization, classification, rate classes, allocation and rate design. The AESO has used the latest data as inputs into the same tariff design, including data in respect of existing transmission facilities, proposed transmission facilities, operation and maintenance costs, and historical and forecast billing determinants.
12. The AESO's 2018 ISO tariff update, approved by the Commission in Decision 23065-D01-2017 (November 28, 2017), will remain in effect until such time as the Commission approves the 2018 Comprehensive Application. The AESO will apply for approval of its 2019 ISO tariff update application in the third or early fourth quarter of 2018 to be effective on January 1, 2019. As explained in paragraph 10 of this update, if, following the conclusion of the comprehensive tariff design consultation process, the AESO applies for a changed tariff design, it would, if approved by the Commission, replace the current rate design.

### **Combined consultation regarding the WEM and Bulk/Regional tariff designs**

13. In light of the Government of Alberta having determined, as a matter of policy, that the allocation of costs for the capacity market will be based on a weighted energy methodology ("WEM")<sup>2</sup> and recovered through the ISO tariff,<sup>3</sup> the AESO has, in consultation with stakeholders, concluded that it would be more efficient to consider the Bulk/Regional tariff design issues and the WEM tariff design through the same consultation stream, as many of the Bulk/Regional tariff design stakeholders are also interested in the WEM tariff design.
14. Although the Bulk/Regional tariff design relates to transmission system cost recovery and the WEM tariff design relates to capacity market cost recovery, there may be some commonality regarding the cost recovery principles related to the transmission system and the capacity market that can be

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<sup>1</sup> Decision 2014-242, *2014 ISO Tariff Application and 2013 ISO Tariff Update*.

<sup>2</sup> Policy Direction for Alberta's Capacity Market, March 1, 2018, page 2:  
<http://www.energy.alberta.ca/AU/electricity/AboutElec/Documents/PolicyDirectionCapacity%20Market.pdf>.

<sup>3</sup> Bill 13, *An Act to Secure Alberta's Electricity Future*, Part 2.2, which adds new section 41.45(2) to the *Electric Utilities Act*.

considered through a combined consultation process.

15. While the process will be combined, the AESO recognizes that implementation of the potential methodologies may have different timeframes and that issues related to each may be advanced at different paces during the combined consultation process.

### **Reasons why the AESO will not propose a change to the DFO CC policy**

16. The AESO arrived at its decision that it will not propose a change the DFO CC policy primarily because the issue raised by AltaLink Management Ltd. (“AltaLink”) involves a choice between continuing to include a contribution in the rate base of the DFO or changing the policy to include it in the rate base of the transmission facility owner. The AESO does not consider itself to be the appropriate party to make that policy decision and that it is more appropriate for the Commission to determine the issue. Additional reasons to support the AESO’s decision include:
  - (a) The AESO is concerned that AltaLink’s proposal could be discriminatory and unfair as it would be applied only to DFOs and not direct connect customers.
  - (b) Even if AltaLink’s proposal were applied to all DFOs and direct connect customers, it would resemble Rider I, which the Commission decided in Decisions 2012-364 and 2013-417 should not proceed due to the concerns raised by AltaLink and ATCO Electric Ltd. in Proceeding 1982 regarding credit default risk.
  - (c) AltaLink’s proposal would have to be considered in the context of cost recovery under both transmission system cost of service regulation and distribution system performance-based regulation.
  - (d) The adoption of AltaLink’s proposal by the AESO would be administratively burdensome, including initial design which would require further consultation, as well as implementation and compliance considerations.
17. The AESO notes that AltaLink will have the opportunity to present evidence in Proceeding 22942 in support of its proposed change to the DFO CC policy and any party opposed to AltaLink’s position will have the corresponding opportunity to file evidence in support of its position.

### **Possible revisions to the 2018 Comprehensive Application**

18. Given the passage of time from when the 2018 Comprehensive Application was filed with the Commission on September 14, 2017, and in light of comments received from some stakeholders, the AESO intends to thoroughly review the 2018 Comprehensive Application to determine whether any of the content should be updated and the 2018 Comprehensive Application revised accordingly.
19. The AESO requests that the Commission continue the suspension of Proceeding 22942 while the AESO completes that process. If the AESO determines that the 2018 Comprehensive Application should be revised, it anticipates being able to file an amended application with the Commission by the end of June 2018. The AESO will advise the Commission and parties if the AESO anticipates a change to the expected filing timeline.

May 17, 2018

Dear Market Participants:

Re: AESO 2018 ISO Tariff Application - AESO Consultation Invitation

The AESO is considering amendments to its 2018 comprehensive ISO tariff application, which was filed with the Alberta Utilities Commission on September 11, 2017.<sup>1</sup> The AESO invites stakeholders to an information session to discuss the potential amendments to the AESO's application:

|                 |                                                                                                                                                                             |
|-----------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Date:           | Tuesday, May 29, 2018                                                                                                                                                       |
| Time:           | 1:30 pm to 3:40 pm                                                                                                                                                          |
| Place:          | Meeting Room 6006, 6th Floor, BP Centre, 240 – 4th Avenue SW, Calgary, Alberta.<br>Note that the glass doors on the 6th floor are locked; please knock to have them opened. |
| Teleconference: | Within Calgary calling area: 403-410-3051, Conference ID 4366631<br>Outside Calgary calling area: 1-855-453-6957, Conference ID 4366631                                     |
| RSVP:           | By noon on <b>May 28, 2018</b> to, <a href="mailto:ISOtarriffnotice@aeso.ca">ISOtarriffnotice@aeso.ca</a> or to Brenda Hill at 403-539-2850.                                |

At the information session, the AESO intends to present on the following issues, which could result in amendments to the AESO's 2018 comprehensive ISO tariff application:

- Additional consultation for the "12-CP" issue that has occurred since January 19, 2018, as well as additional rate classes potentially including standby, interruptible, or energy storage rates
- Additional consultation for the DFO customer contribution issue that has occurred since January 19, 2018;
- A potential requirement for the earlier execution of system access service agreements for both Rate DTS, *Demand Transmission Service*, and Rate STS, *Supply Transmission Service*;
- Calculation of avoidable construction costs;
- Distribution energy resources and contract levels;
- Point-of-delivery cost curve;
- Treatment of isolated communities seeking to connect interconnected electric system; and
- Peak metered demand waivers.

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<sup>1</sup> AUC Proceeding 22942.

Information relating to the AESO's consultation on its 2018 comprehensive ISO tariff application is available on the AESO website at [www.aeso.ca](http://www.aeso.ca) by following the path Rules, Standards and Tariff ► Stakeholder engagement ► 2018 ISO tariff application, and will also be addressed through the AESO's stakeholder newsletter, which can be subscribed to at the bottom right of the AESO's home page at [www.aeso.ca](http://www.aeso.ca).

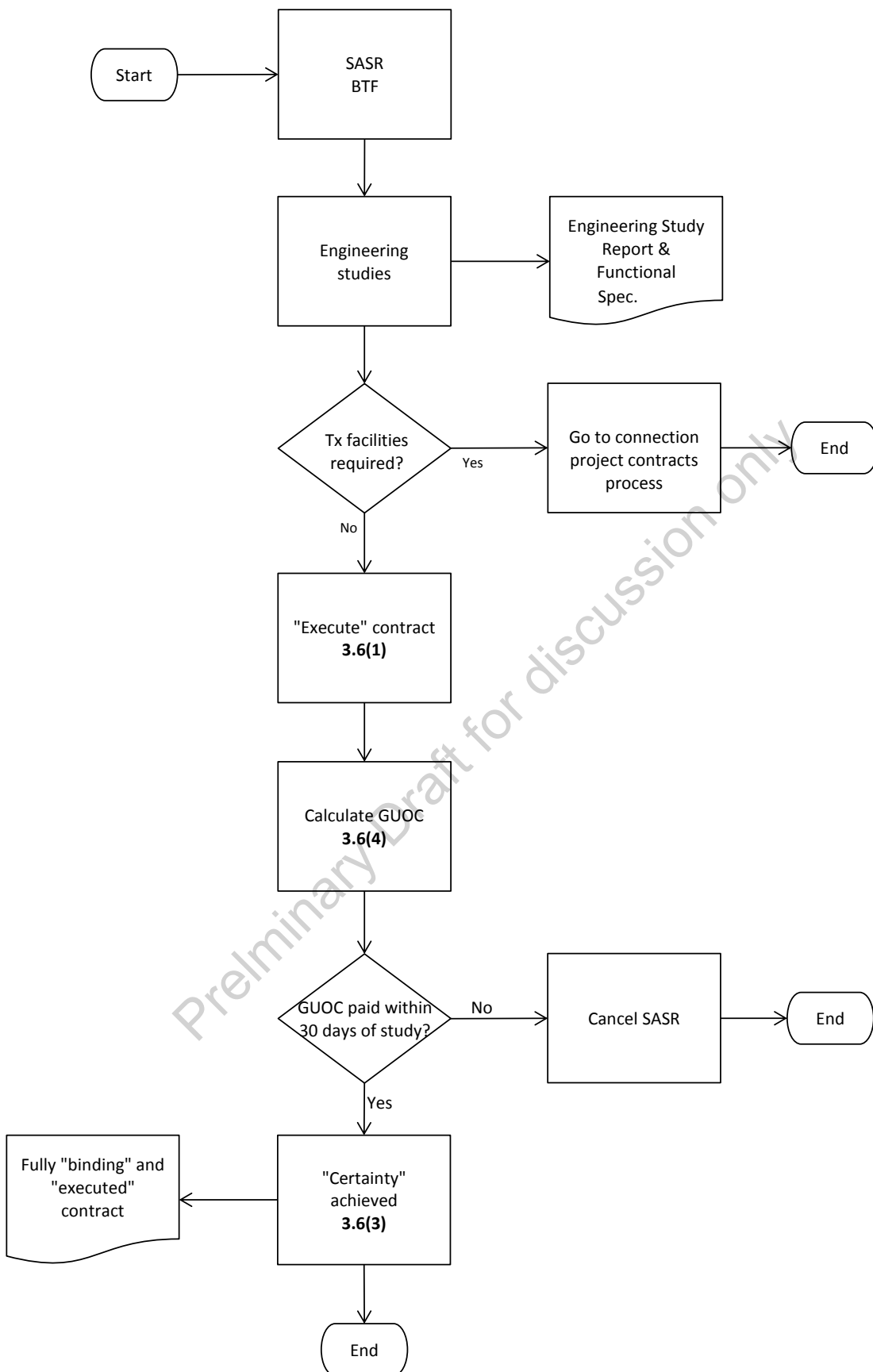
If you have any questions on the AESO's 2018 ISO tariff consultation, please contact the undersigned at 403-539-2555 in Calgary or by email to [larhonda.papworth@aesoc.ca](mailto:larhonda.papworth@aesoc.ca).

Yours truly,

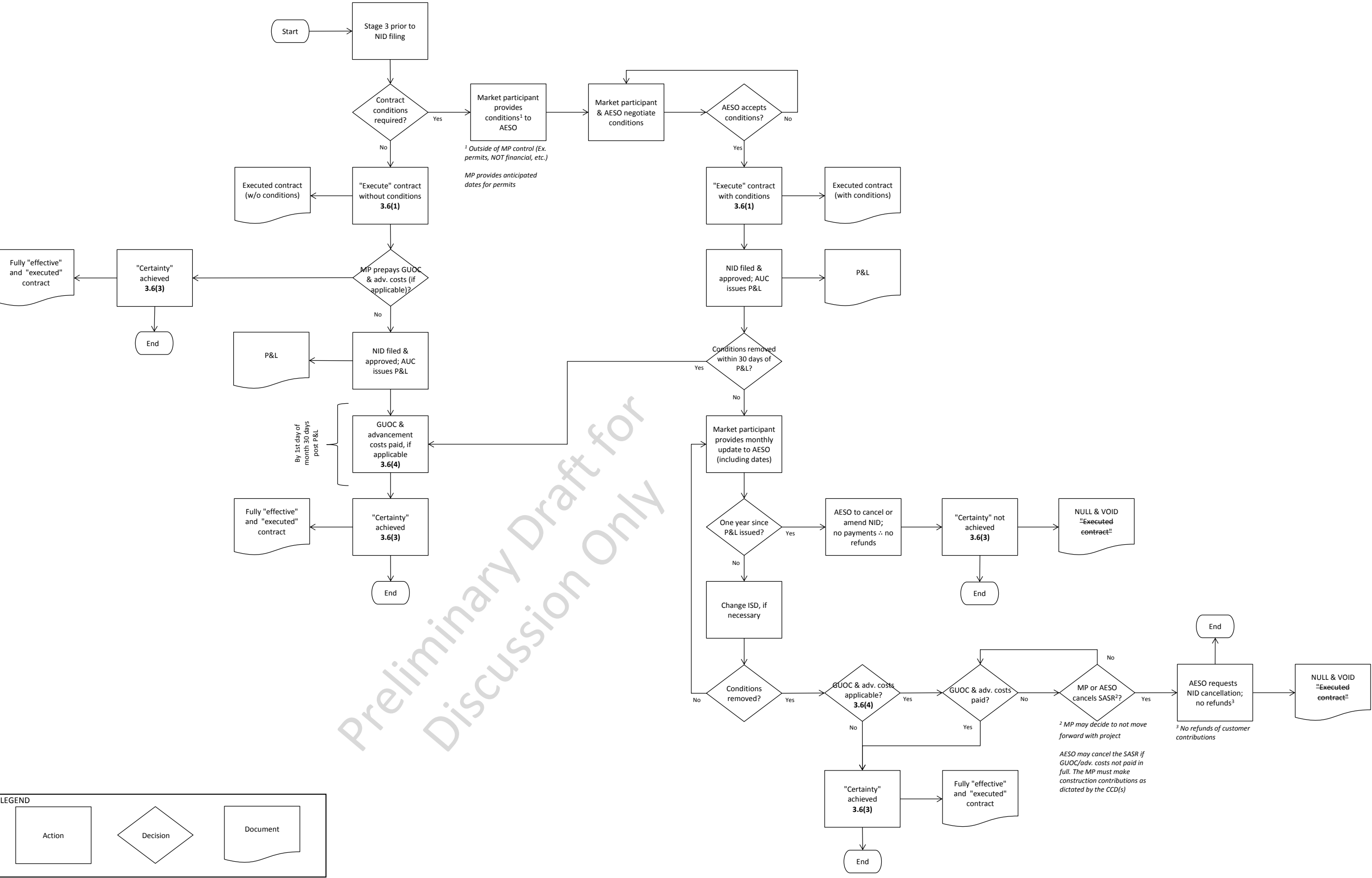
LaRhonda Papworth  
Manager, Tariff Design

cc: Doyle Sullivan, Director –Tariff Design

## Contract Execution and Effective Timing - BTF Project



Contract Execution and Effective Timing - connection project (requires NID filing)



# Updated 2018 ISO tariff application

May 29, 2018  
BP Main Boardroom, AESO Offices

Public

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# Updated 2018 ISO Tariff Application

# 2018 ISO tariff application timeline review

| September 2017                                     | AESO files the 2018 ISO tariff application                                                                                                                                                                             |
|----------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| January 19, 2018                                   | The Commission suspends the 2018 ISO tariff application proceeding to direct the AESO to consult with stakeholders on (1) 12-coincident peak (cp) methodology and (2) DFO contribution issues                          |
| March 5, March 12, 2018<br>April 9, April 24, 2018 | AESO consults on two issues                                                                                                                                                                                            |
| April 30, 2018                                     | AESO files an update on consultation with the Commission and requests time to file an updated 2018 ISO tariff application given the amount of time passed since original filing and other items raised by stakeholders |
| May 29, 2018                                       | AESO updates stakeholders on scope of application updates                                                                                                                                                              |

# Commission directed consultation from January 19, 2018

- AESO is proposing no changes to 2018 ISO tariff design resulting from the consultation since January 19 on tariff redesign
  - All tariff redesign or design work to occur in new consultation process outlined in April 30, 2018 closing letter to the Commission
- Revise consultation section to document or summarize consultation since January 19, 2018 Commission process letter regarding 12-cp methodology and DFO contribution issue
- Revise application to move tariff treatment of energy storage section and reports to tariff redesign process

# Proposed amendments to application and terms and conditions

- The AESO is proposing to make a number of updates to the provisions in the ISO tariff terms and conditions
- The AESO is also proposing to update the application to provide background and context to all proposed amendments to the terms and conditions

# List of updates

| Proposed tariff           | Original application                                                                                                                                                               |
|---------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Subsection 3.2 and 3.6    | <u>Critical requirements</u> and for <u>contract amounts</u> to include maximum anticipated net flow by individual feeder into the transmission system                             |
| Subsection 3.4(1)         | <u>ISO preferred alternative</u>                                                                                                                                                   |
| Subsection 3.6            | <u>Earlier contract execution</u> prior to Need Identification Document (NID) filing<br><u>Planning certainty</u> at time of NID filing and any GUOC or advancement costs payments |
| Subsection 4.2(2)         | No provision for <u>connecting isolated communities</u> to the AIES as participant-related costs                                                                                   |
| Subsection 4.3(3)(b)      | Defines <u>avoidable construction costs</u>                                                                                                                                        |
| Subsections 5.3 and 5.5   | Require additional clarity on <u>Rate DTS contracts stage delay</u> and impact on payment in lieu of notice (PILON) or Shared Costs                                                |
| Subsections 11.2 and 11.3 | Require additional clarity on <u>causes eligible</u> for peak metered demand waivers and process for the AESO to <u>make determination</u> on a waiver request                     |

# Rate STS contracts on DFO substations

## Original application:

- In Section 3.2(2)(c) to require critical requirements including maximum anticipated flows by feeder in SASR
- In Section 3.6(2)(b) to require Rate STS contract levels to approximate maximum anticipated flows on feeders

## Updated application:

- Additional clarity regarding background to maximum anticipated flows into transmission facilities
- Update application for high-level issues including POD function database and highlighting question of “what are local interconnections for DER”

## Original application:

- In Section 3.4(1) the AESO determines the ISO's preferred connection alternative taking into account relevant factors

## Updated application:

- Additionally, for Rate STS requests, require the AESO to consider **economic efficiency** as a relevant factor

**Economic efficiency** means the optimal deployment and utilization of resources to achieve maximum overall value and least-cost production over the long term. Achieving economic efficiency may include comparing alternatives by assessing:

- least-cost production [effective operation]
- cost allocation based off of cost-causation [cost]
- maximizing social welfare [public interest]
- minimizing barriers to entry for market participants [competition]

## Original application:

- Subsection 3.6(1) - a Rate DTS or Rate STS must be executed before the AESO submits a Needs Identification Document (NID)

## Updated application:

- Rate DTS or Rate STS contract must be executed before AESO submits a NID. Contract not effective until:
  - 30 days post permit & licence (P&L); and
    - Upon payment of Generator Unit Owner Contribution (GUOC) for Rate STS or advancement costs for Rate DTS (if applicable)
    - Contract can be cancelled before fully effective with no penalty
  - Additional conditions may be requested (and agreed to by the AESO) for any regulatory conditions beyond the market participant's control
    - Conditions can allow for an extension for up to one year post P&L



# Early contract execution (cont'd)

## *Flow charts handout*

- 1. Connection project*
- 2. Behind-the-fence project*

## Original application:

- Subsection 3.6(3) - a specific connection project must be included in forecasts and system plans upon the execution of a Rate DTS or Rate STS contract

## Updated application:

- As above but additionally a MP can achieve “planning certainty” by executing a Rate DTS or Rate STS contract, and paying any GUOC amounts or advancement costs
  - As early as just prior to NID filing
  - And in the case of a BTF project, execute contract 30 days post study (confirmation of no tx facilities required)

# Isolated communities connection as participant-related costs

- Decision 22125-D01-2018:

*The Commission understands ATCO Transmission's submissions in this proceeding and in Proceeding 22093 to suggest that the ISO tariff terms and conditions require amendment in order to grant it the relief it seeks in terms of cost classification. The Commission agrees and, consistent with its previous ruling in Proceeding 22093, the AESO's cost classification determination that all costs associated with the project are participant-related is approved on an interim basis, pending the final determination of the terms and conditions, related to Section 8, in the AESO's 2018 ISO tariff application.*

- Revise 2018 ISO tariff application to include discussion and background to AESO's position in the Sheridan 2085S connection NID
- Include provision in subsection 4.2(2) to classify the costs to connect isolated communities (as identified in *Isolated Generating Units and Customer Choice Regulation*) as participant-related costs

## Original application:

- In subsection 4.2(3)(b) - a MP could pay “avoidable construction costs” in order to maintain an in-service date while system transmission facilities are under construction

## Updated application:

- As above but a change in the calculation of “avoidable construction costs”:
  - Costs from the earlier in-service date of projects under construction;
  - Costs from the additional revenue requirement resulting from the system transmission facilities being in place at an earlier in-service date; and
  - A credit from the additional monthly Rate DTS bulk and regional revenue resulting from the earlier in-service date (up to the avoidable construction costs amount).

# Avoidable construction costs (cont'd) - Case 1

|                                                                             |                     |                 |                                                                                                             |
|-----------------------------------------------------------------------------|---------------------|-----------------|-------------------------------------------------------------------------------------------------------------|
| <b>Case 1: \$25,000,000 project -&gt; \$5,000,000 savings "found"</b>       |                     |                 |                                                                                                             |
| <b>30 MW Project (75% coincident factor, 65% capacity factor)</b>           |                     |                 |                                                                                                             |
| <b>(add how many months/years of delay as an input to automate further)</b> |                     |                 |                                                                                                             |
|                                                                             |                     |                 |                                                                                                             |
|                                                                             | <b>Feb-2020</b>     | <b>Feb-2021</b> | <b>Comment</b>                                                                                              |
| Initial Project                                                             | \$ 25,000,000       | \$ 25,000,000   |                                                                                                             |
| Additional cost                                                             | \$ 5,000,000        | \$ -            |                                                                                                             |
| Total Project Capital Cost                                                  | \$ 30,000,000       | \$ 25,000,000   |                                                                                                             |
| Additional rev req for \$25 M                                               | \$ 2,500,000        | \$ -            | portion ( for the ISD timing difference only)                                                               |
| Total Cost Impact                                                           | \$ <b>7,500,000</b> | \$ -            |                                                                                                             |
| DTS Revenue Credit                                                          | \$ (4,072,800)      | \$ -            | Extra monthly bills paid due to earlier in service date<br>(includes only Bulk and Regional portion of DTS) |
| Net Charge to Cust                                                          | \$ <b>3,427,200</b> | \$ -            | Calculated to keep all others customers neutral                                                             |
| Rate Payer Impact                                                           | \$ 25,000,000       | \$ 25,000,000   |                                                                                                             |

# Avoidable construction costs (cont'd) - Case 2

|                                                                          |                       |                 |                                                                               |
|--------------------------------------------------------------------------|-----------------------|-----------------|-------------------------------------------------------------------------------|
| <b>Case 2: \$800,000,000 project -&gt; \$186,000,000 savings "found"</b> |                       |                 |                                                                               |
| <b>30 MW Project (75% coincident factor, 65% capacity factor)</b>        |                       |                 |                                                                               |
|                                                                          |                       |                 |                                                                               |
| <b>ISD</b>                                                               | <b>Feb-2020</b>       | <b>Feb-2021</b> |                                                                               |
| Initial Project                                                          | \$ 800,000,000        | \$ 800,000,000  |                                                                               |
| Additional cost                                                          | \$ 186,000,000        | \$ -            |                                                                               |
| Total Project Capital Cost                                               | \$ 986,000,000        | \$ 800,000,000  |                                                                               |
| Additional rev req for \$800 M                                           | \$ 80,000,000         | \$ -            |                                                                               |
| Total Cost Impact                                                        | \$ <b>266,000,000</b> | \$ -            |                                                                               |
| DTS Revenue Credit                                                       | \$ (4,072,800)        | \$ -            | DTS Credit to Rate Payers is very small and much smaller than avoidable costs |
| Net Charge to Cust                                                       | \$ <b>261,927,200</b> | \$ -            |                                                                               |
| Rate Payer Impact                                                        | \$ 800,000,000        | \$ 800,000,000  |                                                                               |

# Avoidable construction costs (cont'd) - Case 3

|                                                                       |                     |               |                                                                 |
|-----------------------------------------------------------------------|---------------------|---------------|-----------------------------------------------------------------|
| <b>Case 3: \$25,000,000 project -&gt; \$1,000,000 savings "found"</b> |                     |               |                                                                 |
| <b>30 MW Project (75% coincident factor, 65% capacity factor)</b>     |                     |               |                                                                 |
|                                                                       |                     |               |                                                                 |
| <b>ISD</b>                                                            | <b>Feb-20</b>       | <b>Jun-20</b> |                                                                 |
| Initial Project                                                       | \$ 25,000,000       | \$ 25,000,000 |                                                                 |
| Additional cost                                                       | \$ 1,000,000        | \$ -          |                                                                 |
| Total Project Capital Cost                                            | \$ 26,000,000       | \$ 25,000,000 |                                                                 |
| Additional rev req for \$25 M                                         | \$ 2,500,000        | \$ -          |                                                                 |
| Total Cost Impact                                                     | \$ <b>3,500,000</b> | \$ -          |                                                                 |
| DTS Revenue Credit                                                    | \$ (4,072,800)      | \$ -          |                                                                 |
| Net Charge to Cust                                                    | \$ -                | \$ -          | Avoidable Construction Charge is zero because DTS               |
| Rate Payer Impact                                                     | \$ 24,427,200       | \$ 25,000,000 | *Rate Payer Impact is less with MP choosing to not delay<br>ISD |

- Delay of Rate DTS stage
  - Payment in lieu-of-notice to add clarity regarding a market participant's request to delay a phase contract increase (subsection 5.3)
  - Share costs calculation to add clarity for calculations for when one market participant delays a phase contract increase and the increase of costs on the other market participant (subsection 5.5)
- Peak metered demand waivers to add clarity that load restoration activities refers to DFOs (subsection 11.2) and to make waiver request process more efficient (subsection 11.3) and



# POD cost function (Option 4 – installed capacity) - Appendices F and G

- Fix up Option 4 to fix to Contract over Installed Capacity
- A number of other ‘installed capacity conversion’ errors to finalize Option 4 to meet the Commission's direction in Decision 3473-D01-2015 to thoroughly explore a POD cost curve to reflect installed capacity, rather than contract capacity
- Appendix F – *POD Cost Function Report* updated to reflect changes above

- The AESO is not proposing any change in bulk/regional tariff design in this application
- The AESO does not plan to update the 2018 ISO tariff application for rate design
- The applied for update was a mechanical update of 2014 Study and the AESO has used latest available information to update the 2014 Study.

# Discussion

# Next Steps

# Next Steps

| Timing                  | Step                                                                                                      |
|-------------------------|-----------------------------------------------------------------------------------------------------------|
| June 1                  | AESO and CCA responses to CCA motion responses due                                                        |
| July 3-6                | AESO plans to file updated application                                                                    |
| Timing to be determined | AESO to kick off new consultation process as described in April 30 <sup>th</sup> update to the Commission |

**Thank you**