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VIA e-mail: ISOtariffnotice@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.

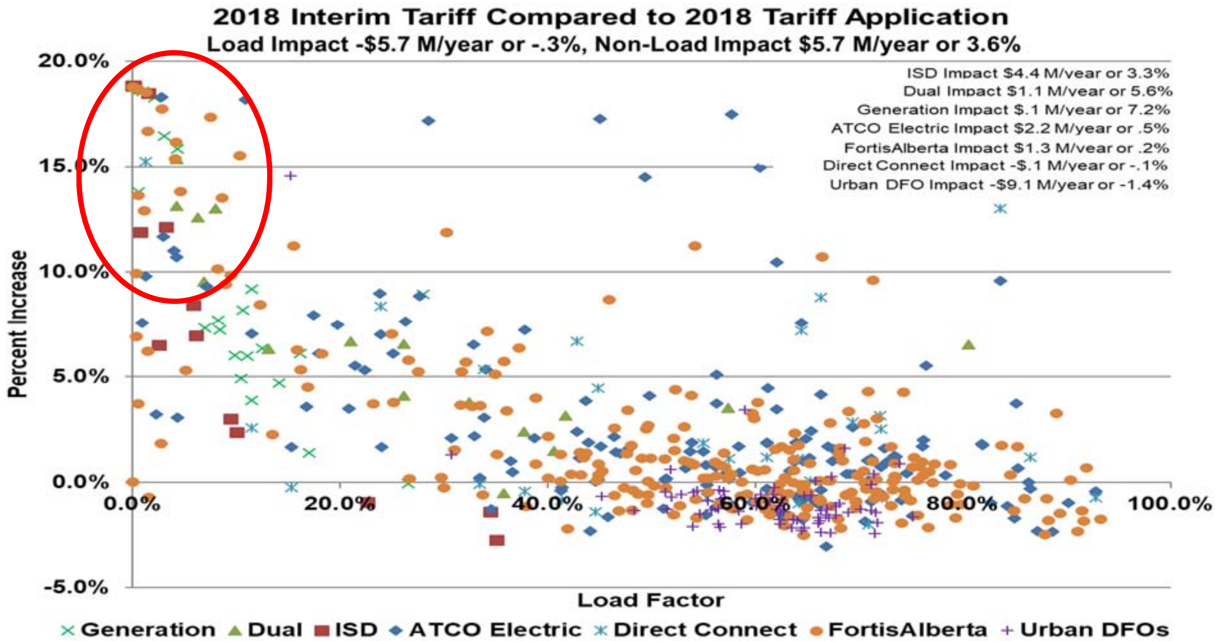
6. In order to quantify the magnitude of the proposed rate increases, we calculated the DTS and PSC charges for every AESO POD using the AESO's current 2018 interim approved tariff, the AESO's proposed 2018 tariff (as filed), and each of the AltaLink, CCA and UCA proposed tariff designs.

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 DFO**s - 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:

    a. 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]

    b. 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.

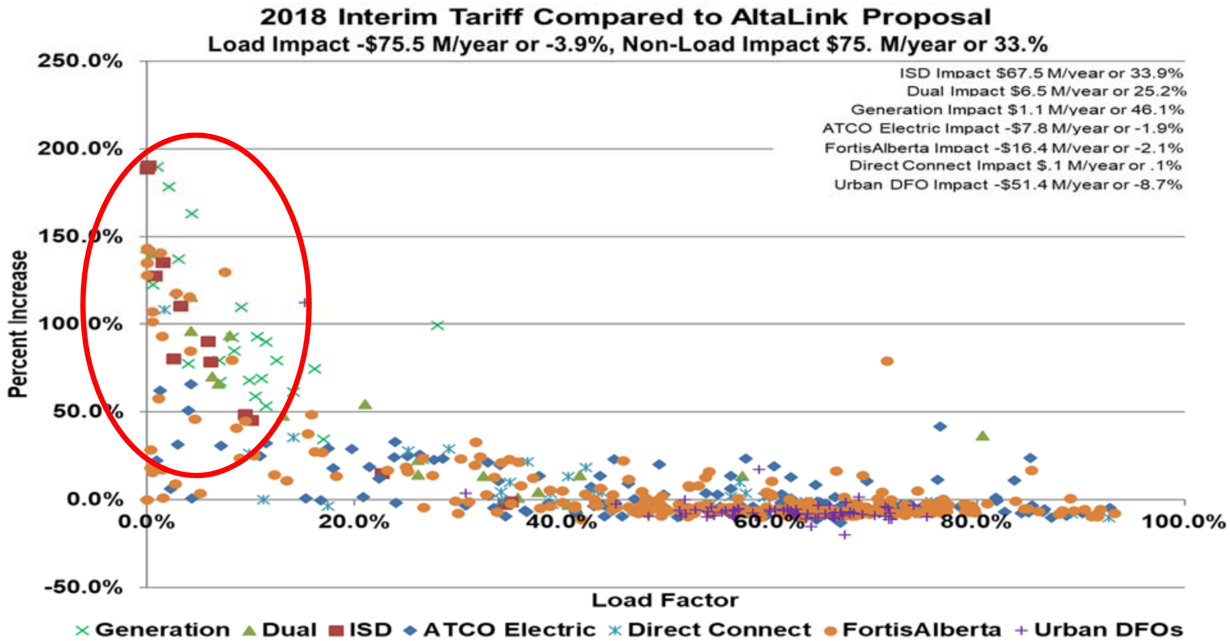
13. We submit that there are two potential price signals that the AESO's bulk demand charge could send to customers:

    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.

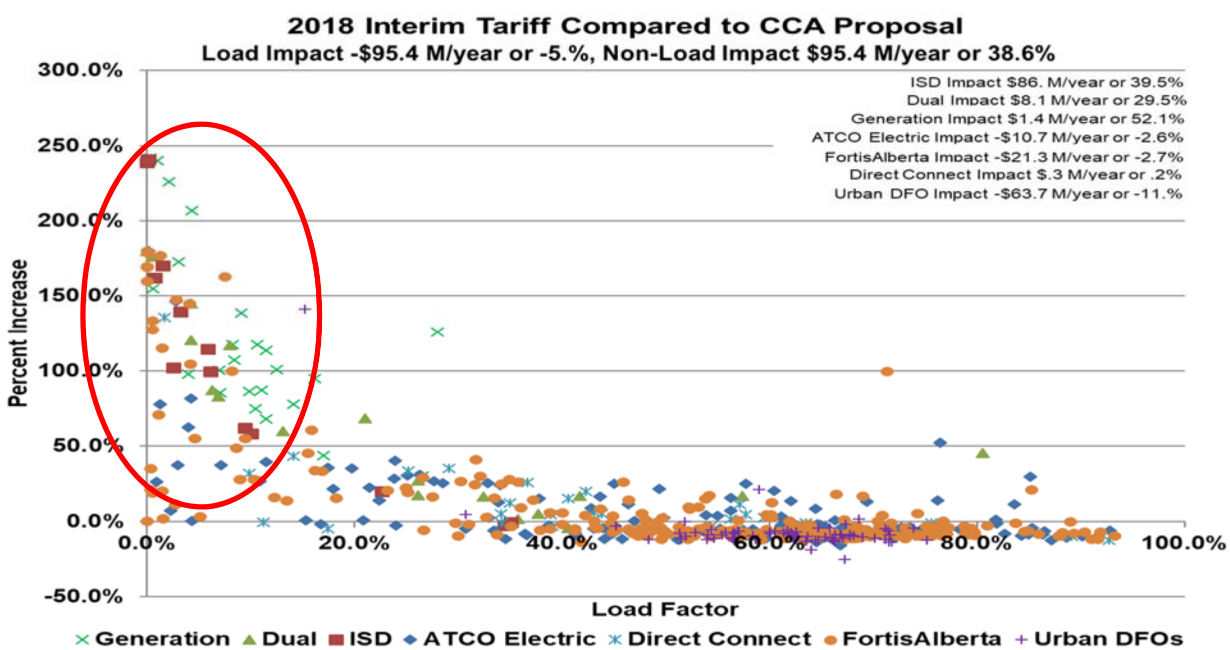
    b. **Price signal to alter operations to try and avoid the CP** – to the extent AESO customers are responding to the price signal inherent in the tariff, utilizing existing assets, we submit this is behavior was contemplated when the tariff was changed in 2006, is appropriate, should be encouraged and 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

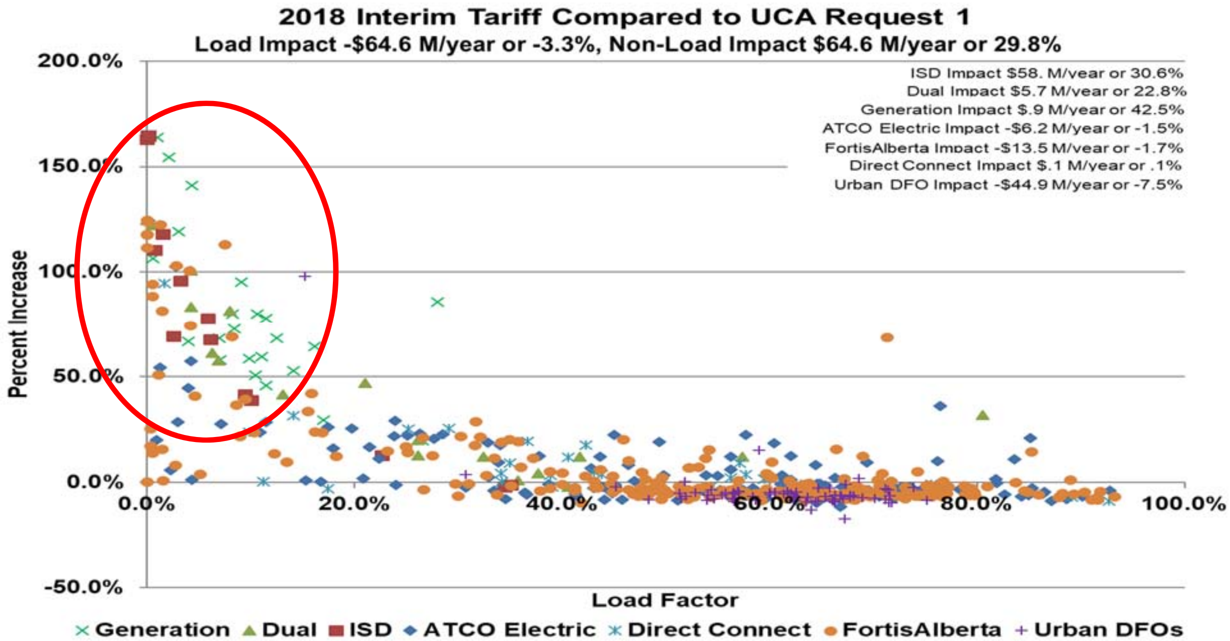
17. The UCA's first sensitively analysis requests that all 240 kV assets be defined as Regional and the resulting costs collected via NCP billing capacity determinants.[12] From the AESO's proposed cost of service study 57% of the existing and forecasted bulk costs are 240 kV.[13] This proposed rate 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 administrate 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 experts[15] 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

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[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.

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President

copy: DUC Management Team