February 14, 2020

Alberta Utilities Commission (AUC)
Bulletin 2020-01
Exploring market concerns and tariff issues related to self-supply and export reform
Dual Use Customers (DUC) Responses to Alberta Utilities Commission (AUC) Questions

Preamble

The DUC members are AESO "Direct Connect" customers. The DUC members receive service from the transmission grid at 14 facilities with Industrial Service Designations ("ISDs"). What makes the members of the DUC "dual use" is that load and generation are both present at each location. The members of the DUC have contracted for or are planning to contract for approximately 1,350 MW of Demand Transmission Service ("DTS") contract capacity (over 10% of the total DTS contract capacity).

At each DUC member site natural gas fired cogeneration is present. Of the 5,043 MW of cogeneration that has been developed in Alberta, 3,413 MW have been developed at DUC member sites.[1] DUC members, and their generation partners, have invested billions of dollars in these cogeneration facilities.

There were several key factors present, starting in the late 1990s, that lead to this significant investment in cogeneration:

- Alberta government policy allowing for and encouraging private investment in generation, including
  - Need for generation does not require regulator approval
  - Creation of an open wholesale electricity market (Power Pool of Alberta) where net exports can be freely sold
  - Non-discriminatory transmission system access (via creation of an Independent System Operator)
  - Significant forecast load growth from resource sectors, primarily oil sands
  - Competitive markets for generators to support the transmission system (ancillary services markets)
- Cogeneration was (and still is) more efficient, more economic and reduced risk than stand-alone boilers and purchasing electricity from the grid
- Ability to site generation next to industrial loads to minimize future transmission assets
- Industrial System Designations (ISD) to[2]
  - Extend geographic extent (*HEEA* s. 24)
  - Multiple owners (*EUA* s. 2.1)

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[1] From the AESO's Current Supply Demand Report, 5,043 MW (MC) of cogeneration capacity is available to supply Alberta electricity consumers. 3,413 MW has been developed at DUC member sites. See http://ets.aeso.ca/ets_web/ip/Market/Reports/CSDReportServlet

[2] Please see 24116-X0534, Distribution System Inquiry

- Transmission tariff with net billing[3]

All of the above key factors were important in the cogeneration investment decisions made. Unfortunately, we now have some industry participants advocating for utilization of gross metering data in the application of the transmission tariff, or gross billing.

An industry wide move to gross billing would be a fundamental change in how the Alberta's electric energy industry operates and would be grossly unfair to cogeneration investors.

The DUC submits that an industry wide move to gross billing would significantly impact investor confidence for new base load generation, which will be required in this decade as additional base load coal fired units are phased out. The results will be more expensive, less efficient and higher polluting generation development, all to the severe detriment of Alberta.

The DUC encourages the Alberta government to clarify the wording of the current legislation to reflect long standing Alberta government policy, including net billing.

The DUC encourages the Commission not to approve AESO tariffs that mandate gross billing for new dual-use customers.

[3] For clarity, we delineate between net metering and net billing. Gross metering data can be combined to create net metering data. What is important is what metering data is used as the billing determinants in the transmission tariff. Alberta has, for as long as any of our members know of, used net metering data for industrial utility rates, which leads to net billing.

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Question 1

Please provide your views on the concerns expressed by Capital Power about the impact of unlimited self-supply and export on the energy-only market. Please comment on whether, or to what degree, such concerns may be addressed through changes to market rules or to existing transmission and distribution tariffs.

Response:

The DUC disagrees with Capital Power's assertions that unlimited self-supply and export will have a negative impact on the energy only market. There exists today about 5,000 MW of cogeneration capacity at customer sites and until Capital Power's submissions in this process we are not aware of any party raising these concerns.

DUC members understand that sites with self-supply have the option of submitting offers to the Power Pool of Alberta on either a gross or net basis. Please see ADC's response to ADC-AUC-2019Nov29-007 (b) in 24116-X0526 (AUC Distribution System Inquiry).

It is a common practice for sites with self-supply who offer electricity to the Power Pool of Alberta on gross basis to offer the first block of electricity at a size equal to or greater than on-site steam or electricity requirements at a price of $0/MWh. This common practice ensures that the on-site generator(s) are dispatched to a level to match on-site requirements (at a minimum). One or more of the additional six price-quantity offer pairs allowed by the AESO can be priced above $0/MWh allowing for the on-site generation to be dispatched in the same way as any other generator.

This type of bidding behaviour is not limited to customers with on-site generation. For example, a 400 MW coal fired unit that has a minimum stable operation of 150 MW, would offer the first 150 MW at $0/MWh, and subsequent volumes at higher prices.

These so called zero priced offers have been part of the Alberta Power Pool operation and price discovery since the Power Pool started operation in 1996.

If market rules were changed to require all generators to offer on a gross basis the DUC submits that price discovery would not be enhanced. The result would simply be more zero priced offers, which does not provide additional price discovery. However, requiring all offers to be submitted on a gross basis would result in significant issues and new costs related to credit and other factors, as outlined in the Preamble and 24116-X0526.

In summary, the DUC submit that Capital Power's concerns are unfounded and no changes to market rules or tariffs are required.

Question 2

Please comment on the following:

(a) The concerns expressed by AltaLink about allowing unlimited self-supply and export under the current tariff structure.

Response:

(a) The DUC will address AltaLink's submissions noted in Bulletin 2020-01:

12. Under the AESO's current tariff, the services provided by the grid outlined above (reliability, start-up power, voltage quality, efficiency and facilitation of energy transactions) are not explicitly metered or charged. Instead, the only mechanism through which a market participant is charged for these services is by way of a DTS contract.

Tariff Charges to Generators

The DUC notes that generating units with small or no DTS contract capacity (e.g. all generation units not on a dual-use customer site) pay small tariff charges for the "services provided by the grid". The provisions in s. 47 of the *Transmission Regulation* requires that all transmission system costs (except losses[4]) are charged to load customers, and not to generators.

From the AESO's 2018 tariff filing Appendix I[5], contract capacities in MW by customer type were provide and can be summarized:

	DTS Contract	STS Contract
ATCO Electric	2,180	-
Urban DFO	3,329	-
FortisAlberta	4,493	-
Dual	194	3,137
ISD	1,154	1,236
Direct Connect	748	-
Generation	19	1,769
	12,116	**6,142**

The Dual and Generation categorization are primarily the "pure generators" who have relatively small DTS contract capacities to take electricity from the grid during start-up or contingency conditions. These AESO customers have contracted for 212 MW of DTS and 4,906 MW of STS. This means that the AESO has planned and provides 4,906 MW of transmission capacity, but only receives revenues based on 212 MW.

[4] *Transmission Regulation*, s. 34

[5] 22942_X0005.03

Conversely, the ISD customers have contracted 1,154 MW of DTS and 1,236 MW of STS. ISD customers provide over five times more revenue to the AESO than the "pure generators", even though they have only contracted for a quarter of the export capability.

AltaLink is suggesting that customers with on-site generation do not pay the full cost of the services they receive from the grid. If this is the case, then the same is true for "pure generators" and even to a greater extent. The point is that this is a specifically mandated legislated outcome.

Prior to the enactment of the *Transmission Regulation*, transmission costs were roughly split between generation and load customers (the co-called 50/50 rate design). This rate design was the subject of considerable debate and it was determined that charging generators wires related tariff charges, which the generator could only recover through power pool receipts, was inappropriate and obstructed the fair and efficient operation of the energy only market. The Alberta government dictated in 2004 that the 50/50 rate design be replaced with the current rate design that allocates all transmission costs, except losses, to load customers.

AltaLink's suggestions are contrary to legislation. AltaLink is suggesting the dual-use customers should pay costs that the legislation has deemed they should not. And it appears AltaLink is suggesting the dual-use customers should have discriminatory tariff treatment compared to "pure generators". Both suggestions are highly inappropriate.

DTS Contact Capacity

DTS contact capacity is only one of three components that make up the Billing Capacity billing determinant under the AESO's DTS rate. The peak demand in the current month and the 24-month ratchet are also utilized. This long-standing rate design is intended to provide the appropriate cost recovery mechanism for load customers using the transmission systems, and for loads relying on the transmission system with on-site generation units.

12. … In certain circumstances, where customers self-supply, their DTS contract may not reflect the costs and benefits of being connected to the grid.

The DUC submit this statement is pure conjecture.

The DUC has testified before the Commission that its members select DTS contact capacity amounts that are of the same magnitude as on-site loads that may utilize the transmission system for back-up.[6]

[6] As noted in the response above, the AESO data suggests that ISD customers pay DTS tariff charges based on 1,154 MW of DTS Contract Capacity. In the 2018 AESO Tariff proceeding the DUC advised the Commission that its members hold 1,350 MW of DTS Contract Capacity (22942_X0336, page 5, line 3-10).

13. … The AESO's tariff recovers transmission costs from these self-supplied loads on a net metered basis meaning that these loads are not paying for the full value of being connected to the transmission grid.

The DUC submits that this statement is false.

The AESO tariff recovers costs from all load customers in the same manner, i.e., on a net billing basis. As noted in response the above, the AESO is prohibited from collecting non-losses transmission systems costs from generators. The simple fact is that all generators may not pay for the "full value of being connected to the transmission grid".

If the AESO tariff were changed to bill all customers on a gross metered basis then the DUC submit that customers with on-site generation would receive grossly discriminatory tariff treatment compared to other Alberta generators.

15. In addition, the AESO's tariff recovers transmission costs through three main rate schedules: bulk system; regional system; and point of delivery. The AESO recovers bulk system costs based on a 12-Coincident Peak methodology at the current cost recovery rate of $10,524/MW/month. This bulk recovery rate has provided an economic signal to customers to add generation to their sites in an effort to reduce their metered demand at the time of the monthly coincident peak (which will reduce their transmission costs).

Uneconomic Bypass

AltaLink has suggested that customers building on-site generation to avoid AESO tariff charges is "uneconomic bypass".[7] AltaLink's consultant states "Uneconomic bypass should be reduced to ensure a fully utilized and viable transmission system."

The DUC submit that Alberta's electricity industry was structured to allow, and encourage, economic on-site generation as a substitute for transmission. Investors will not knowingly invest in "uneconomic" generation. The DUC believes that unfettered on-site generation development and unlimited exports will lead to a fully utilized and viable transmission system.

To the extent that AESO customers are building on-site generation to avoid the monthly coincident peak the DUC submit that this is a proper and appropriate response the price signal inherent in the AESO's tariff. The 12 CP rate design was intended to signal to AESO customers to avoid the monthly peak in an effort to minimize the need for additional transmission capacity. The DUC believes that the 12-CP price signal is working as intended.

There is a misconception that on-site generation is built solely to avoid the DTS bulk system demand charge. The potential 12 CP tariff savings offer an inadequate

[7] See https://www.aeso.ca/assets/Uploads/AML-E3-DTS-Reform-Overview-Final-03-12-18.pdf

economic signal to justify the development on-site generation, once tariff and regulatory risks are considered. For example, at $10,524/MW/month, the tariff savings offers a present value of about $500,000/MW over a 5 years period at a 10% discount rate. The DUC submit that new simple cycle generation cannot be economically installed and operated for $500,000/MW.

The 12 CP tariff savings are far from guaranteed. Firstly, on-site generation would need to be operating at the time of every monthly system peak each month to achieve a present value of $500,000/MW. The timing of the system peak is not known in advance and can be unpredictable. In fact, as more customers respond to the 12 CP price signal, the hour of the system peak can move to a different hour. The DUC submit that this is one of the key benefits of the 12 CP rate design - it requires customers to either shed load or operate on-site generation for multiple hours per month in order to have a high probability of avoiding the monthly system peak.[8]

Outside of two winter months, the coincident peak occurs in different hours each month. And of course, the coincident peak could occur on any day of the month. Therefore, the actual present value of the potential 12 CP tariff savings are less than $500,000/MW.

Secondly, additional risk exists due to the fact that the AESO's tariff is not static. The 12 CP rate design could change, resulting in a loss of tariff savings and loss of cost recovery for non-site generation built solely for coincident peak avoidance.

On-Site Generation Drivers

The DUC submit that in the vast majority of cases on-site generation is built for reasons other than coincident peak avoidance. These reasons include, by order of importance:

1. **Requirement for on-site heat source:** Heat recovery from generation units (cogeneration) is very efficient, cost effective and environmentally responsible. For example, cogeneration has a thermal efficiency of 80 to 85%, compared to best in class combined cycle plants with a thermal efficiency of 55 to 60% (e.g. ENMAX Shepard Energy Centre).
2. **Cost Management:** Over the life of a facility, on-site generation provides a consistent and predictable cost of electricity. As history shows, power pool prices in Alberta are subject to supply and demand variants and average power pool prices can vary materially from year to year.

[8] Please see Appendix A, page 17, for a chart that shows the distribution of peak demand hours over the past 14 years.

3. **Reliability:** On-site generation provides a stable and reliable electricity source, which is very important for large industrial facilities and for customers in remote areas where the transmission or distribution system is unreliable (or did not exist when the facility was built).

For DUC members, 12 CP tariff savings are significant; however, a much bigger consideration is political risk, or investor confidence in the Alberta electricity markets framework. Positions taken by AltaLink advocating for revised policies like charging generators for use of the transmission system and gross billing reduce investor confidence and will result in less customer investment in cogeneration facilities.

12 CP Market Responses

The DUC has testified before the Commission that the cost or benefit related to electricity costs (at power pool prices) is a significantly greater economic driver than trying to lower AESO tariff costs via monthly system peak avoidance. For example, when power pool prices are high, increasing on-site generation would reduce the amount and cost of electricity imported from the grid. The converse is true - when power prices are low, generation can be ramped down and imports from the grid increased. These responses are consistent with the Alberta electricity market design where customers respond to market price signals.

DUC members do respond to the 12 CP price signal by scheduling their generation outages at times that are less likely to have a monthly system peak, e.g. during weekends. Similarly, this behavior is beneficial to all Alberta consumers and is an appropriate response to market based AESO tariff price signals.

The DUC submit that installing on-site generation, regardless of the reason for doing so, is appropriate and consistent with Alberta government policy. The key component of Alberta's electricity industry framework is non-regulated investments in generation, without approval for need, and without financial commitments from electricity consumers.

The 12-CP rate design sends an appropriate price signal to encourage customers to avoid system peaks and reduce the costs of the transmission system over the long term. The DUC submit that is should be irrelevant if the peak avoidance is via a reduction in on-site load or an increase in on-site generation output. Both price response mechanisms were considered when the 12 CP rate design was reviewed and approved by the EUB and the Commission.

16. Once transmission facilities are built, these costs become embedded and need to be recovered from customers.

The Overbuilt Problem

The significant increase in transmission rate base (via capital additions) has caused transmission tariff costs to increase fourfold from 2008 to 2018, from about $8/MWh to $35/MWh. This is the key problem – adjusting the transmission tariff will not fix the Overbuilt Problem.

Tariff changes to gross billing may reduce the risk of long term cost recovery for firms like AltaLink; however, doing so will violate the fundamental tenants of the Alberta electricity industry framework and impose irreparable harm on investors who spent billions of dollars on cogeneration in response to government policies.

The DUC submit that the industry focus should be on finding ways to reduce the overall cost of transmission, not on trying to shift the cost burden amongst existing customers. For example, consider financing transmission costs with lower cost government debt, reduced depreciation rates, lower risks to transmission owners to reduce equity rates, deferral options, etc.

The DUC is of the view that regulator approved transmission costs need to be appropriately recovered from electricity consumers. Shifting the cost recovery burden to those customers who have invested in on-site cogeneration will not solve the Overbuilt Problem. Although, discouraging additional cogeneration development will lead to additional transmission investments, to the benefit of firms like AltaLink.

16. …Therefore customers that reduce demands at the time of the monthly peak reduce their transmission costs which end up shifting grid costs to other customers.

This characterization is misleading. By reducing demands at the time of the monthly peak, these customers have reduced the need for current and future transmission and they are rewarded for this by paying comparatively lower rates, which is appropriate and consistent with the Commission approved tariff. Any customer that reduces demand, via operation changes, energy efficiency, market conditions, etc., reduces tariff revenue. Conversely, any increase in demand increases utility revenue. Customers that reduce demands at the time of the monthly peak are responding to the price signal and behaving exactly as the AESO DTS rate intended.

AltaLink's submissions that it is bad to reduce demand would lead to the conclusion that initiatives like demand management and energy management are inappropriate. Clearly, these initiatives have been found by regulators all over the world to be appropriate.

16. … Further, the net-metering practices in the AESO tariff result in material cost shifting and cross-subsidization of the cost of grid services between those that have self-supply generation and those that do not.

Cost Shifting

AltaLink has not provided any evidence, in any AUC proceeding or process, to support this claim. Neither has the AESO provided industry any analysis to suggest that net billing is not appropriate. The AESO supports Option 3: Unlimited self-supply and export.[9]

Net billing for industrial customers with on-site generation has been the practice in Alberta for many decades (included decades before the enactment of the *EUA* in 1995), and is, in the DUC's view, consistent with Alberta government policy and the interpretation of both the *HEEA* and the *EUA*. And while the Commission's decisions in 2019[10] resulted in a change in interpretation regarding net vs. gross metering, we note that these decisions are silent on the issue of net billing.

The DUC submits that net billing is consistent with the intent of the current legislation and does not result in cost shifting or cross-subsidization.

Rather, net billing appropriately puts dual-use customers on the same level playing field as other customers:

- All load customers – dual-use customers pay the same DTS rate, have the same connection investment policy as outlined in the AESO tariff and have the transmission system planned for their needs based on the DTS contract capacity selected and paid for, the same as all other load customers.
- All generation customers[11] – dual-use customers pay the same STS tariff rate, pay the incremental costs to connect to the grid and have the transmission system planned for their export capability based on the STS contract capacity deemed appropriate by the AESO, the same as all other generation customers.

A dual-use customer is either a load customer or a generation customer in each metering interval. The DUC submits that dual-use customers receive no special tariff treatment – the AESO tariff and rules are applied consistently and fairly to dual-use customers as both load and as generation.

As noted above, the Alberta electricity industry was restructuring the mid-1990s to encourage and allow for the development of on-site generation, for the benefit of all Alberta electricity consumers. AltaLink's assertions that it is unfair to customers who <u>have elected not to invest in on-site generation</u> somehow results in cost shifting and cross-subsidisation is completely inconsistent with Alberta government

[9] Bulleting 2019-16, AESO submission

[10] Decisions 23418-D01-2019 (EPCOR Water Services Inc., E.L. Smith Solar Power Plant), 23756-D01-2019, (Advantage Oil and Gas Ltd., Glacier Power Plant Alteration) and 24393-D01-2019 (International Paper Canada Pulp Holdings ULC, Request for Permanent Connection for 48-Megawatt Power Plant).

[11] The DUC note that all generation customers have some on-site load and all generation customers in Alberta are net metered.

policy and every Alberta regulator approved electricity utility tariff issued in the past 40 plus years.

16. … Expanding the current legislation to allow for more self-supply and export will create further incentives to install self-supply generation resulting in an increase in the cost shifting (cross-subsidization) between the customers that can install self-supply generation and those that cannot.

The DUC submit that the intent of Alberta government policy over the past 25 years and the intent of the current legislation is to encourage more self-supply and export to lower generation (power pool prices), transmission and distribution costs for the benefit of all Alberta electricity consumers. There is no cross-subsidization.

37. As discussed previously, the decision to expand the circumstances in which a market participant can self-supply and export beyond those currently allowed under the legislation cannot be made without considering the larger electricity system as a whole. More specifically, the Commission must also consider the current legislation and tariff framework. A key concern, as already discussed, is that under the current tariff, those that self-supply benefit from net-metering and not paying their fair share of the cost for being connected to the grid.

The DUC agrees that any change to Alberta government policy needs to come from the Alberta government. We are not aware of any communications from the Alberta government to change the policy intent, whereby the need for and the recovery of costs from generation is non-regulated. To further diminish investor confidence in developing new generation sources will have dire consequences for Alberta, including higher power pool prices, grid stability issues and potentially the need for customer backed generation developments.

Attempting to alter Alberta government policy via changes to the AESO’s tariff is not appropriate.

38. Until a comprehensive review is completed of the current tariff design and legislation is completed, and cross-subsidization is addressed then the status quo (albeit not optimal) should continue (Option 1).

The DUC vehemently disagrees.

While it is truly unfortunate that the AUC’s current interpretation of the EUA has the side effect of billing practices that are contrary to well established Alberta government policy, the appropriate course of action is to amend the legislation such that the legal interpretation matches historical precedents and clearly established Alberta government policy intent or to correct the tariff to re-establish net-billing, which has been inappropriately eliminated as a collateral effect of the Commission’s decisions regarding net vs. gross metering.

The DUC applauds the AUC for its initiatives to resolve these issues via the Bulletin 2019-16 and 2020-01 processes. However, Option 1 alone is clearly not optimal and should not be allowed to continue without a corresponding amendment to the AESO tariff that re-establishes net billing. Option 3 could be re-established until a full review of this issue can be undertaken, should the Alberta government be of the view that a change in policy may be appropriate.

Please comment on the following:

(b) The potential impacts of changing existing tariff structures to eliminate net billing for transmission-connected generation, transmission credits for distributed-connected generation, and the Alberta Electric System Operator's use of the 12-coincident peak methodology to recover bulk transmission costs.

Response:

(b) The DUC will address the potential impacts:

eliminate net billing for transmission-connected generation

DUC members, other industrial customers and generation developers, responded to the Alberta's government's policies to encourage on-site generation development by investing billions of dollars in over 5,000 MW of new cogeneration since 1998. These investments were made based on repeated assurances from the Alberta government that the industry structure and framework set out in the legislation in the mid-1990s would continue over the life of these assets.

Changing from net to gross billing would be a fundamental shift in the viability of these investments and would be paramount to a regulator cutting a utility's rate base after the investments were made, approved as useful and put into service.

If the AESO's tariff were altered to gross billing for all transmission-connected generation then investor confidence in the Alberta electricity market could be reduced to a point where no new cogeneration investments will be made (which is likely AltaLink's motivation). Once investor confidence in Alberta's electricity industry is lost, new base-load generation investment, to replace the retiring coal assets, will likely require government and/or customer financial guarantees and Alberta's electricity restructuring and de-regulation policies implemented in the 1990s would be deemed to be a failure.

The DUC disagrees with changes to tariffs that would mandate gross billing. The DUC is anecdotally aware through consultations with the

AESO[12] and DFOs that transmission and distribution planning is based on contract capacities and net metering data. Therefore, the AESO and DFOs plan the transmission and distribution systems based on the contract capacities customers elect and pay for under the respective tariffs.

Since the AESO and DFOs use net metering data to plan the transmission and distribution systems, electricity generated and consumed within a customer's site is not (and should not) be taken into consideration. Both transmission and distribution assets are not built to serve behind the fence loads in excess of contract capacities. Therefore, the DUC submit that since the transmission and distribution systems are not planned based on gross metering it would be inappropriate and unfair to charge electricity consumers based on gross metering data.

Further, Alberta customers with on-site generation have always been net billed. This includes both "pure" generators and generation at load customer (dual-use) sites.

The DUC submit that moving to gross billing will be counter intuitive and discriminatory and could result in prolonged legal challenges from investors who will suffer considerable financial harm.

eliminate the AESO's use of the 12-coincident peak methodology to recover bulk transmission costs

Rate Design Considerations

There are two key considerations in designing an appropriate bulk system transmission cost recovery mechanism:

How are bulk system costs defined?

The cost of service study prepared by London Economics for the 2013 AESO tariff reviewed different functionalization methodologies to define bulk system costs. The report stated:

> In order to functionalize capital costs, LEI performed analysis using the following three methods of functionalization: voltage, economics, and MW-km. After reviewing strengths and weaknesses of the different approaches, LEI recommends using the voltage method. The voltage method is the most straightforward and simple to understand.[13]

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[12] And through our member's and consultant's knowledge of the industry, some of which was gained as former utility and Alberta government agency employees.

[13] Decision 2013-421,pdf page 40, lines 208-214

London Economics determined that all transmission lines at a voltage of 500 kV, 240 kV and High Voltage Direct Current, and associated substations with a secondary voltage of 240 kV or higher, be functionalized as bulk.[14] This study was supported by all interested parties and has been part of the AESO's tariff rate design since 2014.

The DUC submits that the current definition of bulk assets is appropriate and should continue.

How are bulk system costs recovered?

The tariff in place since 2006 recovers bulk systems costs via monthly coincident peak demand charge and an energy charge. The consequences of eliminating the 12-CP based rate design will be a function of what bulk cost recovery mechanism is used instead.

Rate Design Impacts

During the 2018 12 CP consultation process[15] AltaLink, CCA and UCA issued proposals to have all or a portion of the bulk system demand related costs recovered via a non-coincident demand (NCP) charge. The DUC analyzed these proposals and submitted the following written comments to the AESO:

> All of the AltaLink, CCA and UCA proposals will result in severe rate shock.[16] 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.

The rate designs proposed by AltaLink and others utilizing NCP is regressive. NCP was reviewed by the EUB and the Commission and determined to be inappropriate for bulk cost recovery in the 2006 AESO tariff proceeding and subsequent tariff proceedings. As noted below, DUC's experts surveyed several jurisdictions similar to Alberta and found that NCP is not used to allocate bulk transmission costs.

The clear results from the rate designs proposed by AltaLink and others would be unprecedented rate increases to dual-use cogeneration customers.

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[14] Ibid, pdf page 57, lines 599-601, pdf page 83, lines 1186-1191, and pdf page 85, lines 1225- 1228

[15] Held during proceeding 22942

[16] Historically in Alberta, rate shock has been defined as a rate increase of over 10%.

Rate Design Enhancement

During consultations with the AESO and other interested parties[17] the DUC suggested an alternative bulk system rate design option that could address some parties concerns and may provide a better price signal to AESO customers that could lead to a higher probability of future transmission assets being not required or deferred:

> Now that the bulk system is built (over-built), new transmission expenditures will be driven primarily by generation contingencies. The tightest hours (tightest supply cushion or TSC) may be better billing determinants than CP (or multiple CPs). From discussions with planners, often generation contingencies cause concerns with the transmission system that lead to justifications for upgrades. There is a strong correlation between the historic CP hours (2006 to 2018 data) and tightest hours or TSC (2008 to 2017 data).[18]

The DUC submits that using TSC instead of 12 CP may provide better alignment to cost causation and will not result in rate shock to low load factor AESO customers.

Please comment on the following:

(c) Whether other tariff-based solutions exist to ensure that the transmission and distribution costs are fairly allocated between users.

Response:

(c) The DUC does not believe that other tariff-based solutions, like NCP, are appropriate, and submits that transmission and distribution costs, assuming re-establishment of net-billing, are currently fairly allocated between users.

The DUC is of the strong view that the existing AESO tariff, utilizing 12 CP and net billing, ensures that transmission costs are fairly collected from Alberta electricity consumers. The DUC submits that the defining 240 kV and 500 kV transmission assets as bulk and collecting the demand related costs via 12 CP, along with defining lower voltage transmission costs as Regional and POD and collecting via NCP and energy charges, fairly allocates transmission costs between all transmission systems users, within the confines of the existing legislation (i.e. *Transmission Regulation* requiring only losses related costs be collected from generators).

Please comment on the following:

(d) If you believe that no changes to the current tariff framework are required please provide your rationale for that position.

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[17] The AESO struck a Transmission Design Advisory Group (TDAG) to provide industry feedback and advise on Capacity market design and transmission tariff issues. A subcommittee of the TDAG, the Transmission Tariff Working Group (TTWG), was struck to review 12 CP. The AESO disbanded the TTWG in early 2020.

[18] Please Appendix A entitled TTWG DUC 12 CP Rate Design Thoughts Oct 8 19

Response:

(d)

Current Tariff is Working

The DUC submits that the 12 CP rate design has fulfilled its objective of encouraging AESO customers to reduce the monthly AIL peak demand. We believe that the system peak as been reduced by about 400 to 500 MW, or about 4%.

The DUC submits that AESO planners may not have adequately and appropriately taken the sustained reduction in system peak demand into account when recommending new bulk system additions. The 12 CP tariff design has worked; unfortunately, the AESO may have been too conservative in their planning to take full advantage of lower system peaks.

Support for 12 CP

The DUC retained experts to review transmission tariffs from several different jurisdictions across North America. CP is the common method used to allocate bulk transmission costs.[19]

> 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 anticipated system peaks and promoting more efficient grid utilization. This in turn lowers the need for new transmission investment. Coincident peak is a deciding factor when AESO planning contemplate new transmission assets and thus 12 CP encourages efficient investment.
>
> These and many other arguments have been cited by ISOs and utilities as reasons for implementing the CP approach.

Many jurisdictions allocate transmission costs through a monthly coincident peak methodology, ranging from ISOs and utilities of comparable size to the AESO.

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 for bulk system cost recovery.

[19] An excerpt from the export's report is provided under Appendix B.

12 CP not needed due to the Overbuilt Problem

Parties have also stated that now that the bulk system has undergone a significant built-out, there is no longer a requirement for a tariff design to reduce or defer the need for bulk system additions. The DUC submits that this view is dangerously short-sighted. The AESO continues to bring bulk system expansions to the Commission for approval as noted in their recently released long term plan.[20]

As noted above, the high transmission costs in Alberta are a direct result of both the AESO advocating for and the Alberta government dictating via Bill 50[21] the over development of the bulk system. The four-fold increase in transmission costs from 2008 to 2018 is a result of the Overbuilt Problem. The Overbuilt Problem cannot be solved by attacking dual-use customers. The AESO's tariff design is and continues to be appropriate for all Alberta electricity consumers.[22]

AltaLink's suggestions that extracting significantly more tariff revenue from dual-use customers and discouraging additional on-site generation development is injudicious, and we submit, inappropriately self-serving.

[20] In the AESO's recently released 2020 long term plan five additional bulk system expansion projects are identified as required in the near term, AESO 2020 Long-term Transmission Plan, page 10, at https://www.aeso.ca/assets/downloads/AESO-2020-Long-termTransmissionPlan-Final.pdf

[21] *Electric Statutes Amendment Act*, 2009, see http://www.assembly.ab.ca/ISYS/LADDAR_files/docs/bills/bill/legislature_27/session_2/20090210_bill-050.pdf

[22] Please see Appendix A - DUC 12 CP Rate Design Thoughts, for additional reasons on why the DUC submits that the current 12 CP rate design continues to be appropriate.

Appendix A - DUC 12 CP Rate Design Thoughts

AESO Current Rate Design – DUC Support for 12 CP

1. The significant increase in transmission rate base (via capital additions) has caused transmission tariff costs to increase fivefold from 2008 to 2018, from about \$8/MWh to \$35/MWh. This is the key problem – adjusting the transmission tariff will not fix this problem. Focus should be on finding ways to reduce the overall cost of transmission, not on trying to shift the cost burden amongst existing customers. For example, consider financing with lower cost government debt, reduced depreciation rates, lower risks to transmission owners to reduce equity rates, deferral options, etc.
2. The AESO tariff design has little to no price signal to Distribution Facility Owner (DFO) customers as the DFO transmission costs (AESO DTS charges) are allocated by DFO rate class and collected on DFO rates using energy and/or NCP. About 75% of DTS rate revenue is collected from DFO customers who do not see AESO tariff price signals. The 12 CP price signal (or any other price signal) really only matters to direct connect, dual-use and DTS rate flow through customers. We need to focus on the impact to these key customers.
3. Planners use a peak demand forecasts to model the transmission system to determine where upgrades are required. These studies were typically triggered by load or generation additions. These studies may find that the scenario that justifies the transmission expansion is a generation related contingency. For every transmission assets that serves load, without the need to serve the peak load the transmission expansion may not be required. Therefore, collecting a portion of both historical and future transmission costs based on CP is appropriate.
4. The current AESO tariff has an appropriate mix of CP, NCP and energy:

Tariff Cost

AESO 2018 Appendix H Rate Design		
DTS wires costs		
Coincident Demand	\$916	42%
Non-Coincident Demand	\$820	37%
Energy	\$404	18%
Customer	\$61	3%
	\$2,201	100%

Delivered Cost

AESO 2018 Appendix H Rate Design		
DTS wires costs + pool price		
Coincident Demand	\$916	18%
Non-Coincident Demand	\$820	16%
Energy	\$3,402	65%
Customer	\$61	1%
	\$5,199	100%

5. Saskatchewan has a similar transmission system to Alberta based on historical coal, newer gas and now renewables. 100% of transmission costs are allocated to rate classes based on 1 CP. Using CP to allocate transmission costs is used in many jurisdictions.
6. The AESO's 2018 revenue requirement forecast (from 2018 tariff filing) and long term plans suggests increases from new bulk transmission additions. Any AESO tariff price signals that will reduce transmission investment and lower the cost of operating reserves (i.e. pool prices) should be encouraged. We believe that 12 CP has, over the past 13 years, provide an appropriate price signal and customers have responded. Without 12 CP, the transmission build would have been even greater and transmission rates would be higher.
7. 12 CP sends a strong price signal to encourage the continued development of behind the fence generation, which will lower transmission investment and reduce pool prices. Additional

cogeneration is the most efficient and cost effective generation option for Alberta and should be encouraged to replace the coal fleet for base load generation.

8. Now that the bulk system is built (over-built), new transmission expenditures will, at least in the near term, be driven primarily by generation contingencies. The tightest hours (tightest supply cushion or TSC) may be better billing determinants than CP (or multiple CPs). From discussions with planners, often generation contingencies cause concerns with the transmission system that lead to justifications for upgrades. There is a strong correlation between the historic CP hours (2006 to 2019 data) and tightest hours or TSC (2008 to 2017 data):

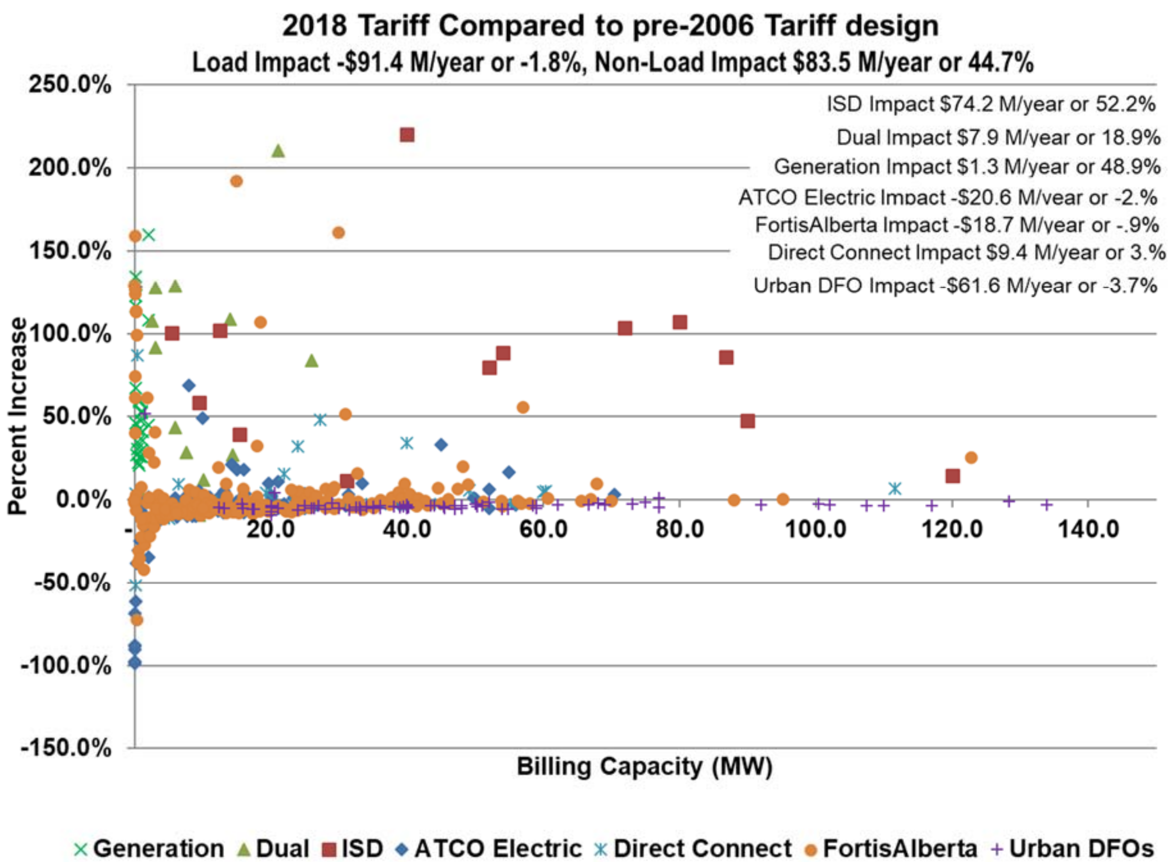
Coincident Peaks												
Hour / Month	1	2	3	4	5	6	7	8	9	10	11	12
1												
2												
3												
4												
5												
6												
7												
8										7.1%		
9				7.1%						7.1%		
10										7.1%		
11				7.1%								
12				14.3%	7.1%	7.1%			7.1%			
13				7.1%	7.1%		7.1%					
14				7.1%	7.1%	14.3%	14.3%	14.3%	14.3%			
15				7.1%	7.1%	50.0%	28.6%	21.4%	14.3%			
16				7.1%	14.3%	21.4%	28.6%	35.7%	14.3%			
17				21.4%	57.1%	7.1%	21.4%	21.4%	21.4%			7.1%
18	100.0%	28.6%		7.1%				7.1%	14.3%	7.1%	100.0%	92.9%
19		64.3%	71.4%							50.0%		
20		7.1%	21.4%						7.1%	21.4%		
21			7.1%	14.3%					7.1%			
22												
23												
24												

Tightest Supply Cushion Hours

Hour / Month	1	2	3	4	5	6	7	8	9	10	11	12
1												
2												
3												
4												
5												
6												
7	6.7%					2.2%						
8	6.7%					2.2%						
9			33.3%		6.7%	6.5%						
10			33.3%		6.7%	10.9%	3.7%	9.1%	1.9%	11.1%		
11					10.0%	15.2%	7.4%	9.1%	1.9%			
12				16.7%	6.7%	10.9%	7.4%		3.8%			
13				16.7%	6.7%	10.9%	11.1%	9.1%	13.5%			
14				16.7%	13.3%	6.5%	11.1%	18.2%	13.5%	11.1%		
15				16.7%	16.7%	10.9%	14.8%	27.3%	13.5%	11.1%		
16	6.7%			16.7%	16.7%	10.9%	14.8%	27.3%	15.4%	11.1%	5.6%	
17	33.3%			16.7%	13.3%	8.7%	22.2%		19.2%	11.1%	72.2%	37.5%
18	33.3%	66.7%			3.3%	2.2%	7.4%		7.7%	11.1%	22.2%	37.5%
19	13.3%	33.3%							3.8%	22.2%		25.0%
20			33.3%						5.8%	11.1%		
21												
22						2.2%						
23												
24												

9. The 2006 tariff that moved from cost recovery from 50% load / 50% generation to load pays all wires costs under bulk (CP), regional (NCP) and POD (NCP) tariff design was justified in part by not imposing significant rate shock to dual use customers. Cogeneration development was encouraged by the Alberta government as a clear policy directive (since 1993) and significant non-regulated co-generation investments were made (about 5,000 MW). Without the cogeneration build over the past 20 years delivered prices to Alberta consumers would have been much higher. It is plainly unfair and inappropriate after the major transmission build to implement a revised tariff design that would cause large rate increases for dual-use customers, who made investments to reduce their reliance on the bulk transmission system.

   If ones uses the pre-2006 rate design (NCP and energy) and increases the rates by about 6.8 times, such that the AESO 2018 Bill Impact workbook generates equivalent revenue requirements to the current 2018 tariff, the resulting rate impacts are as follows:



The resulting 50+% increase to ISD customers from going back to a NCP rate design clearly violates rate design principles and would not be in the public interest.

	# PODS	$ Annual Impact (million)	Average Delivered Cost / POD ($M/y)	Average % Impact	# PODs > 10.% increase	Ave. Billing Capacity > 10.% increase (MW)	Average Delivered Cost / POD ($M/y)
ISD	16	$74	$8.9	52%	16	72.1	$4.64
Dual	20	$8	$2.1	19%	12	9.5	$0.69
Generation	24	$1	$0.1	49%	24	0.8	$0.05
ATCO Electric	150	($21)	$6.8	-2%	9	20.5	$0.99
FortisAlberta	242	($19)	$8.3	-1%	24	16.5	$1.02
Direct Connect	30	$9	$10.4	3%	5	22.7	$0.87
Urban DFO	70	($62)	$23.9	-4%	1	1.5	$0.20
	552	**($8)**	**$9.4**	**0%**	**91**	**21.8**	**$1.34**

For most AESO & DFO customers, moving from CP to NCP (or some other tariff design) will have relatively little impact on DFO bills. Non-load customers will experience significant rate shock, and dual-use (cogeneration) customers will be hit the hardest. Therefore, any rate design change (other than perhaps replacing CP with TSC) will not pass rate design principle rate-shock tests.

Options to implement this rate shock over time to dual-use customers[23], are simply not fair as there is no justification to move away from the historical relative share of cost recovery by the various types of transmission customers in Alberta. We have had large dual-use customers in Alberta since the 1970's.

[23] As suggested by AltaLink

Appendix B – DUC Experts Draft Report Excerpt on 12 CP

3.1 Definitions of 12 CP

The National Association of Regulatory Utility Commissioners ("NARUC") defines monthly coincident peak, or 12 CP, as using "*an allocator based on the class contribution to the 12 monthly maximum system peaks. This method is usually used when the monthly peaks lie within a narrow range; i.e. when the annual load shape is not spiky. The 12 CP method may be appropriate when the utility plans its maintenance so as to have equal reserve margins, [loss of load probabilities] or other reliability index values in all months.*" In terms of minimum data requirements, the 12 CP method necessitates "*reliable monthly load research data for each class of customers and for the total system... The data can be recorded and/or estimated.*"[10]

For its purposes, the AESO defines 12 CP as follows: "*[t]he monthly coincident system peak is the greatest sum in any 15-minute interval in the month. The 15-minute interval in which this peak occurs establishes the interval in which coincident metered demand is measured at each Rate [Demand Transmission Service ("DTS")] and Rate [Fort Nelson Demand Transmission Service ("FTS")] point of delivery.*"[11]

3.2 Arguments for and examples of 12 CP in other jurisdictions

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. As

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[10] National Association of Regulatory Utility Commissioners. *Electric Utility Cost Allocation Manual*. January 1992.
[11] AESO. *Information Document – Coincident Metered Demand*. November 2015.

coincident peak is a deciding factor when contemplating new build, and thus encourages efficient investment.

These and many other arguments have been cited by ISOs and utilities as reasons for implementing the 12 CP approach. The proceeding examples illustrate a variety of jurisdictions currently allocating transmission costs through a monthly coincident peak methodology, ranging from ISOs and utilities of comparable size to the 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, and are summarized in Figure 11 below.

Figure 11. Applications of 12 CP in various jurisdictions

Entity	Application of 12 CP
PacifiCorp	Demand-related costs are allocated using each class' contribution to the 12 monthly peaks coincident with the PacifiCorp system peak.
ISO-New England	Each network customer's monthly regional network load is its hourly load coincident with the coincident aggregate load of all network customers served in each local network in the hour in which the coincident load is at its maximum for the month.
SPP	Network customers are required to pay a monthly demand charge based on their monthly network load ratio share of transmission service, determined as their hourly load coincident with the monthly peak for each network zone or customer area.
MISO	Transmission customers taking Network Integration Transmission Service shall pay the firm monthly zonal rate or a monthly demand charge for the zone based upon where the load is physically located. MISO charges network customers based upon their monthly network load ratio share of transmission service, which is based upon their hourly load coincident with the monthly peak for each network zone or customer area.

Sources: PacifiCorp Cost of Service 2016; ISO-NE Open Access Transmission Tariff; SPP Open Access Transmission Tariff; MISO Network Integration Transmission Service, Schedule 9.

PacifiCorp operates across the Western US with approximately 26,600 km of transmission lines; operating as Pacific Power in Oregon, Washington and California; and as Rocky Mountain Power in Utah, Wyoming and Idaho.[12] PacifiCorp allocates its demand-related costs according to each class' contribution to the 12 monthly peaks, coincident with the utility's system peak. PacifiCorp justifies this methodological choice since *"capacity is important each month for meeting peak loads, load following, and accommodating plant maintenance."*[13]

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[12] PacifiCorp. *PacifiCorp Facts*. 2017.
[13] PacifiCorp. *Cost of Service: Functionalization Classification & Allocation Procedures.* 2016.

ISO-New England, which operates approximately 14,500 km of high-voltage transmission lines across all six New England states, defines customers' monthly regional network load as their hourly load that coincides with the coincident aggregate load of all network customers served in each local network, in the hour in which the coincident load is at its peak for the month.[14,15]

SPP and MISO implement similar 12 CP methodologies, whereby each customer's monthly demand charge is determined by their monthly network load ratio share of transmission service, which is based on their hourly load coincident with the monthly peak for each network zone or customer area.[16,17] SPP operates the bulk electric grid and wholesale power market in the central US, with over 96,600 km of high-voltage transmission lines, while MISO operates across 15 American states and the province of Manitoba, with approximately 110,600 km of high-voltage transmission lines.[18,19]

In terms of rationale, ISO-New England, SPP, and MISO have implemented their 12 CP methodologies as a result of FERC's Order No. 888 (1996), which reaffirmed the use of the 12 CP allocation method. At that time, FERC determined that the majority of utilities planned their systems to meet their 12 monthly peaks. FERC found that *"because network service is load based, it is reasonable to allocate costs on the basis of load for purposes of pricing network service. This method is familiar to all utilities, is based on readily available data, and will quickly advance the industry on the path to non-discrimination."*[20]

3.3 Wider-usage of CP

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 strong price signals to customers and has the intended effect of reducing consumption peaks when the demand placed on the system is highest.

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. Their methodologies are outlined in the proceeding Figure 12.

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[14] "Key Grid and Market Stats: Transmission." *ISO-New England.* <https://www.iso-ne.com/about/key-stats/transmission>

[15] ISO New England. *Section II: Open Access Transmission Tariff.*

[16] Southwest Power Pool. *Open Access Transmission Tariff, Sixth Revised Volume No. 1.* August 2012.

[17] MISO. *Schedule 9: Network Integration Transmission Tariff.* April 18, 2018.

[18] "About Us." *Southwest Power Pool.* <https://www.spp.org/about-us/>

[19] MISO. *Level 200 – Energy & Operating Reserve Market Pricing.* February 1, 2018.

[20] Federal Energy Regulatory Commission. *Order No. 888.* April 24, 1996.

Figure 12. Applications of other forms of CP in various jurisdictions

Entity	Application of other forms of CP
Manitoba Hydro	100% of transmission functionalized system costs are classified as demand and allocated using the top 50 winter coincident peak hours.
BC Hydro	100% of transmission costs are classified as demand and allocated using the 4CP approach, using a 5-year average of 4 monthly peaks for November through February, from data for the five most recent preceding years.
Nova Scotia Power	Since 1995, NSPI uses a system load factor ("SLF") methodology for classification and a 3CP method to allocate the demand cost among customer classes according to the average of the three highest months of energy use.
SaskPower	All of the transmission functions are classified as demand and are allocated using the average seasonal peak (2CP) methodology, effective January 1, 2014. The winter seasonal peak load is SaskPower's largest demand calculated on an hourly interval basis during November to February, with the summer seasonal peak load calculated over June to September.
ERCOT	Uses the average of coincident peak demand for June through September (4CP), excluding the portion of coincident peak demand attributable to wholesale storage load.
PJM	PJM charges a daily demand charge for network transmission service (aggregated into a monthly charge) based on the network customer's daily network service peak load contribution (including losses), coincident with the zonal peak for the 12 months ending October 31 of the preceding year.

Sources: MPUB Order 164/16; BCUC Order G-47-16; Decision 2014 NSUARB 53; SaskPower 2017 Cost of Service Study; Texas Administrative Code, Section 25.192; PJM Open Access Transmission Tariff Accounting.

Manitoba Hydro is a provincial Crown Corporation and one of the largest vertically integrated electricity and natural gas distribution utilities in Canada, owning approximately 18,500 km of transmission lines.[21] Manitoba Hydro classifies all of its transmission functionalized system costs as demand, and allocates these costs using the top 50 winter coincident peak hours. Regarding the reasons for selecting this allocation methodology, Manitoba Hydro states: *"[t]he winter coincident peak allocator reflects the proportional share that each customer class contributes to these peaks... Allocating by winter coincident peak reflects the shape of the domestic load over the course of a year."*[22]

BC Hydro, operating more than 18,000 km of high-voltage transmission lines, also takes a winter peaking approach, classifying 100% of transmission costs as demand and allocating this using a

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[21] Manitoba Hydro. *Building A Strong Energy Future: Annual Report 2016-17.* July 2017.
[22] Manitoba Public Utilities Board. *Order No. 164/16.* December 20, 2016.

4 CP methodology, whereby a 5-year average of 4 monthly peaks is taken for November through February.[23,24]

NSPI, owning 5,300 km of high-voltage transmission lines in Nova Scotia, allocates demand costs among customer classes according to the average of the three highest months of energy use, a 3 CP approach.[25, 26] During a hearing to approve NSPI's Cost of Service Study, which was last updated in 2013, stakeholders cited cost causation as one of the reasons for continuing with the 3 CP methodology, which has been in effect since 1995. [27, 28] An industrial stakeholder also supported continuation of the 3 CP methodology since *"[t]he demand patterns of the NSPI system strongly indicate that it is appropriate to use demand classification and a 3CP allocator."*

Unlike the three aforementioned Canadian utilities, SaskPower uses an average seasonal peak, 2 CP, methodology to allocate all transmission functions that are classified as demand. SaskPower is Saskatchewan's main energy supplier with nearly 14,400 km of high-voltage transmission lines.[29] SaskPower's winter seasonal peak load is the utility's largest demand calculated on an hourly interval basis during November through February, while the summer seasonal peak load is calculated over June to September.[30] Although SaskPower previously implemented a 1 CP approach, 2 CP was deemed to better suit the utility's operations: *"for some facilities, even though SaskPower is a winter peaking utility, it is the summer capacity that determines the required installed capacity of certain facilities."*[31]

ERCOT, a summer peaking market that operates over 74,800 km of transmission lines, utilizes a 4 CP approach, using the average of coincident peak demand for June through September, excluding the portion of coincident peak demand attributable to wholesale storage load.[32,33] *"The exclusion of wholesale storage from the 4 CP calculation that [transmission service providers ("TSPs")] use to bill wholesale transmission costs to [distribution service providers] should ensure that TSPs do not under collect their transmission costs of service."*[34]

Finally, PJM uses a variable CP approach, charging a daily demand charge for network transmission service, which is aggregated into a monthly charge. This is based on the network customer's daily network service peak load contribution, coincident with the zonal peak for the

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23 "Transmission." *BC Hydro.* <https://www.bchydro.com/energy-in-bc/operations/transmission.html>

24 British Columbia Utilities Commission. *Order Number G-47-16.* April 11, 2016.

25 "How We Deliver Electricity." *Nova Scotia Power.* <https://www.nspower.ca/en/home/about-us/how-we-deliver-electricity/default.aspx>

26 Nova Scotia Utility and Review Board. *Decision 2014 NSUARB 53 (M05473).* March 11, 2014.

27 "Electricity." *Nova Scotia Utility and Review Board.* <https://nsuarb.novascotia.ca/mandates/electricity>

28 Nova Scotia Utility and Review Board. *2014 NSUARB 53.* March 11, 2014.

29 SaskPower. *Powering Saskatchewan to a Cleaner Energy Future: 2016-17 Annual Report.* 2017.

30 SaskPower. *2017 Fiscal Test Embedded Cost of Service Study.* June 1, 2016.

31 Elenchus Research Associates Inc. *Review of Cost Allocation and Rate Design Methodologies.* January 25, 2013.

32 "About ERCOT." *ERCOT.* <http://www.ercot.com/about>

33 Texas Administrative Code. *Section 25.192: Transmission Service Rates.* July 5, 2016.

34 Public Utility Commission of Texas. *Order Adopting Amendments to Section 25.192 and Section 25.501.* March 2012.

12 months ending October 31 of the preceding year.[35] PJM operates in 13 states and the District of Columbia, with over 132,800 km of transmission lines.[36]