12CP Method:
DRAFT Discussion Document

Given that **cost causation** should drive the allocation of bulk transmission costs, a 'big picture' **reflection o**n 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]

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[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 pooling[9], 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 Policy[13] 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.
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> 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

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[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]

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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.

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[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.

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[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.

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[24] LTP, p.8

[25] ADC/DUC/IPCAA March 12 Presentation, slide 8