Energy+Environmental Economics

+ DTS Overview and Proposal

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Outline

- Background
- Proposal
- Conclusion
- Data Needs

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BACKGROUND

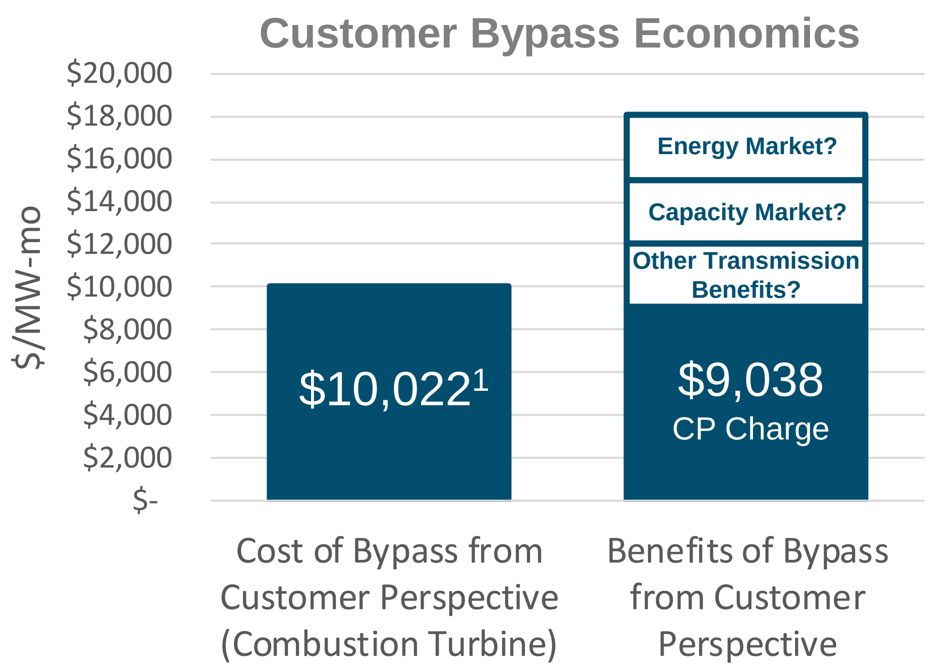
Historical Context

- **In Decision 2007-106[1] (pg 34)**
  - The AESO raised the possibility that a party may be able to avoid the coincident peak (CP) on the system and therefore avoid contribution to fixed costs
  - The AESO posited that this would be unjust and unreasonable when these customers use the system over many other hours
  - However, the "Board finds no evidence has been provided that such a customer exists on the system"… The Board thinks it is "not possible for a customer to generally simply turn the power off and completely avoid the hour of the system peak"
- **Over the last 5 years, we have seen that it is possible and economic for customers to bypass the bulk CP transmission charge by reducing CP load through BTF generation, load shifting, and distributed generation**
- **By reducing their net load during a very few number of hours, these customers can bypass between 40% to 50% of total transmission costs**

[1]http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2007/2007-106.pdf

A Competitive Market

- Efficient price signals are of paramount importance in a market when transmission service is subject to competition from alternative service
- There are many options to reduce CP load and bypass CP charges: BTF generation, DR, DG solar & DG gas
- The cost of a combustion turbine is on-par with CP charges under the current DTS tariff
- When other benefits are layered on, the customer economics of investing in alternative options to bypass the CP charge become very compelling and the potential for more investment continues to grow
- The CP price signal is a value that only accrues to BTF and other distributed resources



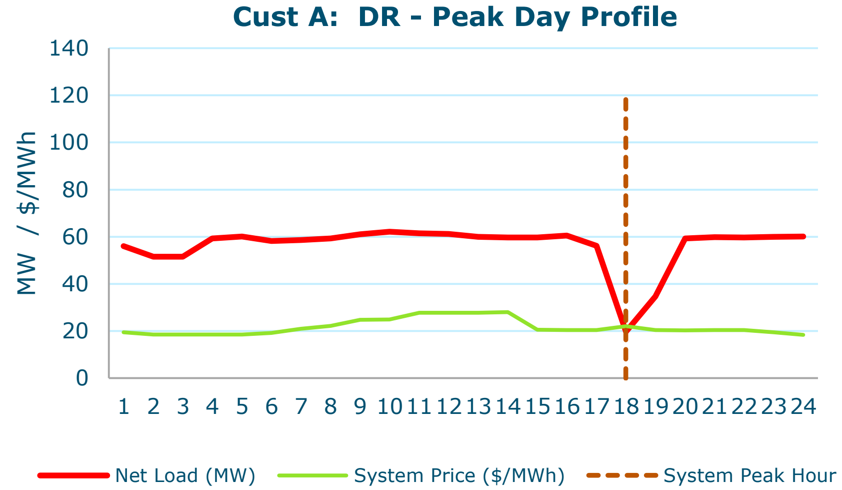
[1]Combustion Turbine Levelized Cost Assumptions

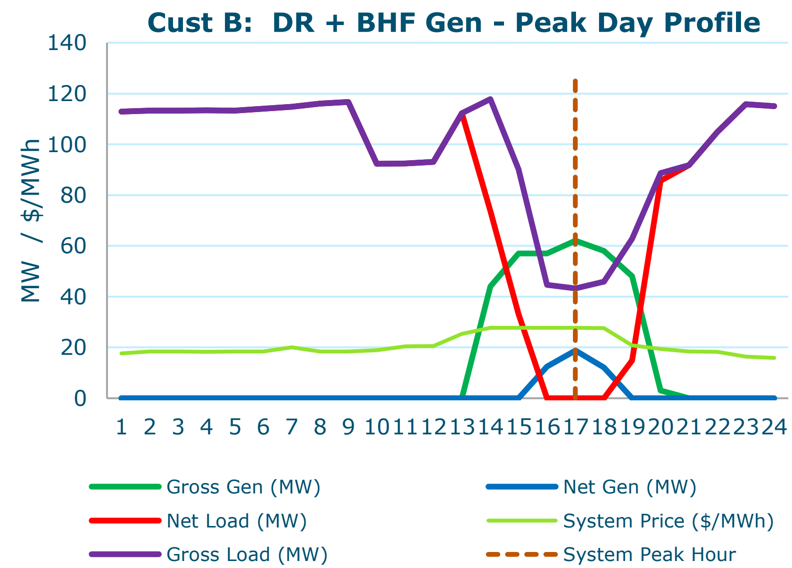
$1,000 overnight capital cost
20 year lifetime
7% cost of capital
$3.00/GJ natural gas
20 operating hours/month
9.6 GJ/MWh
$18/kW-yr fixed O&M
$4/MWh var O&M

Source: Generation Costs tab from 2017 LTO Data File

Coincident Peak Avoidance

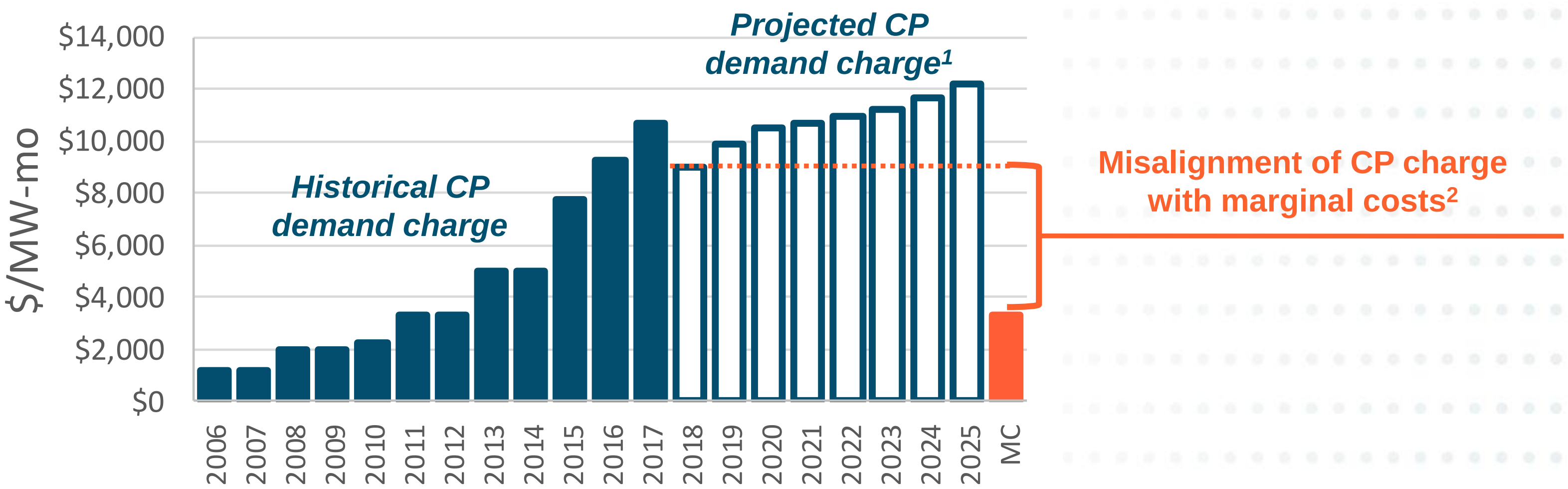
- Historical data indicates certain customers can effectively predict CP and minimize CP based charges through load shedding and DG
- By reducing their net loads by very few hours, they can reduce their transmission costs by between 40 and 50 percent





Need for Change

- Recent investment in the transmission system has increased the bulk system transmission coincident peak (CP) charge such that it is now misaligned with system marginal costs



- This incorrect price signal is being sent to customers and incents uneconomic bypass (credit exceeds benefit) of the CP charge for the transmission system
  - Large quantity of industrial customers in Alberta makes this a particularly acute problem
- Uneconomic bypass should be reduced to ensure a fully utilized and viable transmission system
- Cost-shift is already ~20% of total CP transmission costs[3] and likely to escalate without immediate reform

[1]Source: 2018 AESO TRP workbook Appendix J
[2]See slide 7 for calculation
[3]See slide 8 for calculation

Transmission Marginal Costs

+ **Simple and transparent estimates of transmission marginal costs that can be avoided by reducing CP are needed**

+ **Total Investment Method (DTIM)[1] using publicly available information from the 2017 LTO and 2017 LTP**

  - Total approximate transmission NPV capital investments 2017-2022 = $1000 MM[2]
  - Total NPV AIL peak load growth 2017-2022= 645 MW[3]
  - Assumption: 50%[4] of transmission CapEx is CP load growth related. This value would rely on additional information from the AESO
  - Real economic carrying cost (RECC) = 5.3%
    - 40 year transmission asset life
    - 6.4% WACC, 2% inflation = 4.3% real discount rate

$$MC_{DTIM} = RECC \times \frac{\sum_{t=1}^{N} \frac{I_t}{(1+r)^t}}{\sum_{t=1}^{N} \frac{L_t}{(1+r)^t}}$$

$$RECC = \frac{r(1+r)^N}{(1+r)^N - 1}$$

Where:

It = capital investment in year t

Lt = additional load in year t

r = discount rate or WACC

N = number of years in the planning horizon

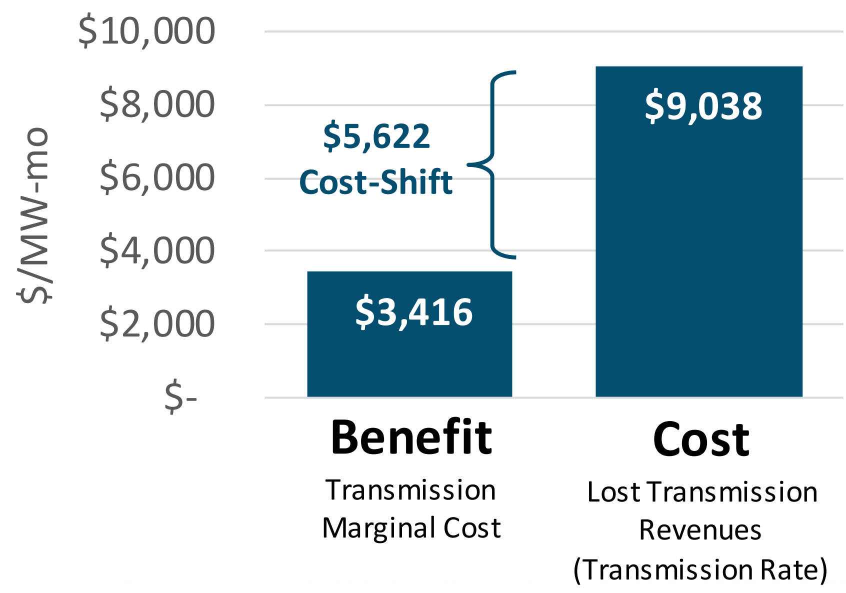
RECC = real economic carrying cost

$$\text{Transmission Marginal Cost} = \frac{\$1000\text{ MM}}{645\text{ MW}} * 5.3\% * 50\% * 1/12\text{ months} = \$3{,}416/\text{MW-mo}$$

[1] https://www.aer.gov.au/system/files/Ausgrid%20-%20Appendix%203%20Summary%20of%20Methodologies%20for%20Estimating%20Marginal%20Cost%20-%20November%202015.pdf
[2] https://www.aeso.ca/assets/Uploads/AESO-2017-Long-termTransmissionPlan-Final.pdf
[3] https://www.aeso.ca/download/listedfiles/2017-LTO-data-file.xlsx
[4] Actual % will be dependent upon which projects are causally related to CP load – currently ~50% of transmission CapEx is allocated to CP

Cost-Shift Today

- The difference between the calculated marginal or "avoided" cost of transmission and the existing DTS CP rate can be used to estimate the cost-shift per MW-month
- Multiplying the cost-shift by the expected MW of bypass yields an estimate of the total cost-shift
- **Cost-Shift = $5,622/MW-mo**
- **Monthly bypass = 2,830 MW/mo**
  - BTF energy served by on-site generation during AIL peak (2,530 MW[1])
  - MW of estimated load shedding that is responsive to the CP (300 MW[2])
- **Annual Cost-Shift = $191 MM**
  - $5,622 * 2,830 * 12 months
- **Cost-Shift = 21%**
  - $191 MM / $900[3] MM



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[1] 2017 LTO Data File (BTF Energy at AIL Peak in 2017)
[2] Mentioned during 2017 AESO LTP Consultation Session on Feb 7, 2018
[3]$900 MM = bulk system CP classified costs from 2018 AESO TRP workbook Appendix J

Cost-Shift Growth Potential

+ **Without action, today's estimated cost-shift of $191 MM could plausibly grow by upwards of 64%**

+ **Sources of additional bypass potential**

  1. **AESO Direct Customers**
     - Potential: **350 MW**
       - The 2017 average of monthly metered coincident peak in Alberta is about 7,790 MW (AESO TRIP Model)
       - The aggregated monthly CP from DFO rate applications is about 7,080 MW (DFO filing data)
       - 50% of the difference between these two yields 350 MW
  2. **DFO settled Direct Customers**
     - Potential: **465 MW**
       - 50% of the 930 MW load that are subject to CP charge but settled through DFOs.
  3. **New DER Participants**
     - Potential: **1000 MW** of distribution connected solar, distributed connected gas generation, gas fired cogen, demand response, or other CP avoidance deployed through aggregation
       - There is an incremental 3000 + MW of incremental solar in the Queue

+ **Incremental CP bypass in 5 years = 1815 MW, which causes a 64% increase to the $191 MM in cost-shift today**

+ **New plausible 2022 cost-shift = $313 MM**

Principled Approach

- E3/AltaLink believe that there are a multitude of rate design reforms that improve the status quo and more closely align with AUC rate design principles

	AUC Rate Design Principles	E3/AltaLink Perspective
1	Recover of the total revenue requirement	We agree
2	Provision of appropriate price signals that reflect all costs and benefits, including comparison with alternative sources of service	A coincident peak charge equal to the marginal cost of transmission sends the correct price signal to loads and prevents uneconomic bypass
3	Fairness, objectivity, and equity that avoids undue discrimination and minimizes inter-customer subsidies	Minimization of uneconomic bypass (achieved through correct price signal) minimizes inter-customer subsidies and maximizes equity
4	Stability and predictability of rates and revenue	E3/AltaLink are looking for stakeholder input on appropriate need and design of transition mechanism
5	Practicality, such that rates are appropriately simple, convenient, understandable, acceptable, and billable	Simple to understand and implement

PROPOSAL

AltaLink/E3 Proposal

+ **Step 1: Rate Design Modification (this case)**
  1) Set coincident peak DTS charge to align with the marginal cost of bulk CP transmission service
  2) Collect the remaining transmission revenues through billing demand
+ **Step 2: Tracking Account (this case)**
  - If a transition mechanism is needed, a tracking account administered by the AESO should measure and track the levels of cost-shifting that is occurring over time
+ **Step 3: Cost of Service Study (subsequent design cases)**
  - Conduct a cost of service study that properly allocates assets by their function
  - The study should not allocate the cost of high voltage lines that are not built to serve CP to the CP charge

Rate Reform Options & Criteria

- **AltaLink considered a number of rate design reforms that would address the issue of uneconomic bypass**

Rate Reform Options

1) CP = marginal cost, remainder = NCP, or billing demand
2) 2-Part rate (baseline billed at embedded cost, deviations billed at marginal cost)
3) Standby charge based on marginal cost (applies only to BTF generators who avoid CP or only to new BTF generators)

- **Each option was evaluated under a range of criteria**

Rate Design Criteria

1) Align CP rate with marginal cost to send correct price signal
2) Recover remaining embedded costs through a billing determinant that is difficult for customers to uneconomically bypass
3) Eliminate cost-shift from existing & potential future BTF generators
4) Limit bill impacts for customers who cannot avoid the coincident peak
5) Maximize stakeholder support for rate reform proposal
6) Avoid large, complex rate overhaul

Cost Functionalization

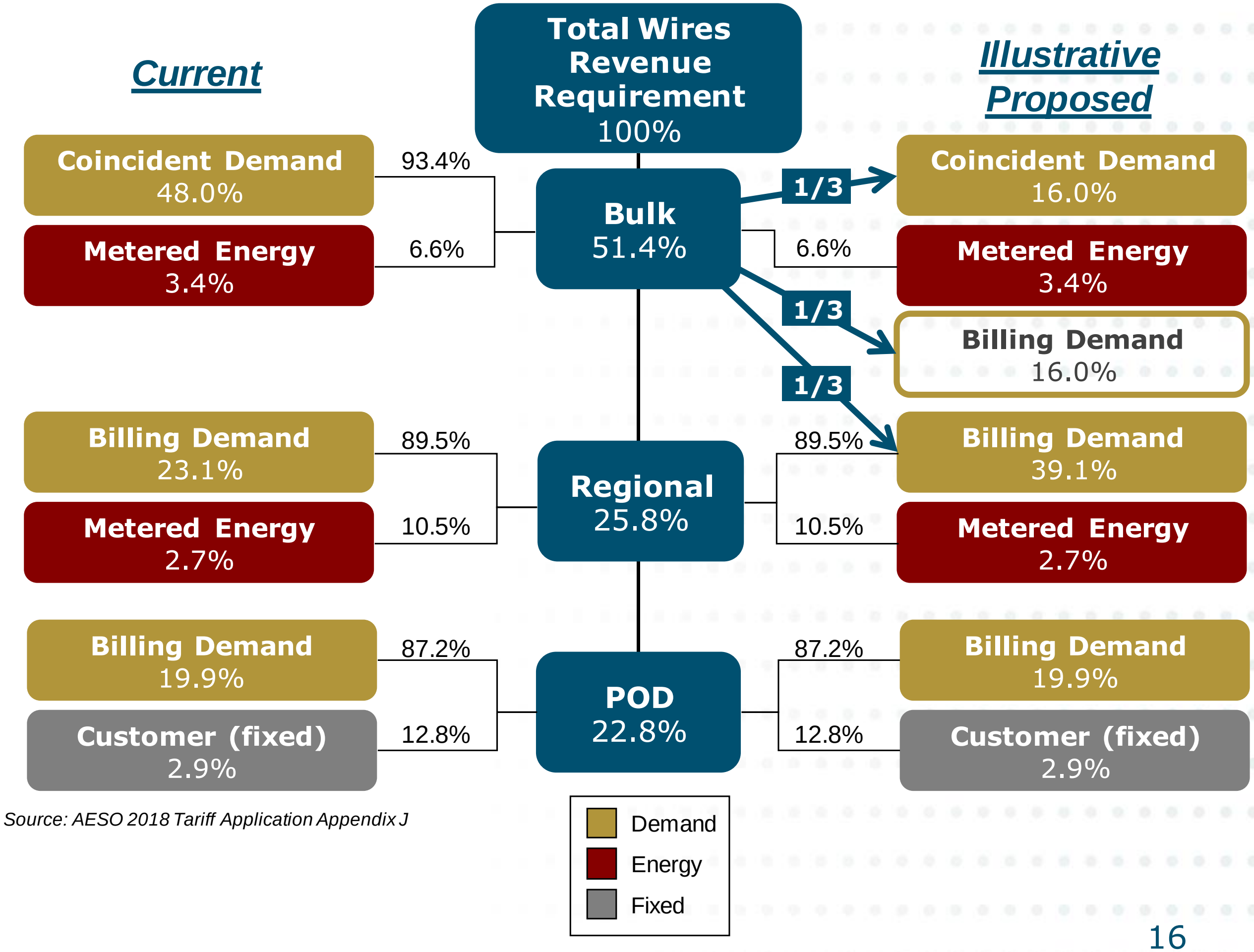
- **The costs of the transmission system are functionalized into three categories by voltage**

Category	Bulk	Regional	Point of Delivery (POD)
Criteria	*>= 240 kV*	*69/72-138/144 kV*	*25 kV or POD Tap*

- **Voltage is becoming increasingly insufficient to determine the function of many lines, particularly as more high voltage lines are being built to**
  - Interconnect renewables
  - Meet regional transmission needs
  - Accomplish other provincial energy goals
- **These lines are not driven by the need to meet the system CP and thus their costs should not be recovered through this charge**
- **Properly allocating costs and reducing the CP charge will reduce the cost-shift**

Cost of Service Study

- AltaLink also believes The AESO should engage in a new and improved cost of service study based on causality
- This improvement would more accurately functionalize each transmission asset beyond simply voltage to determine whether it primarily serves system load (CP) or other functions such as regional load, renewable integration, or provincial policy



Source: AESO 2018 Tariff Application Appendix J

Conclusion

+ **Bad News– We have a problem**
  - Changes in energy policy, slower bulk system growth and an increasing reliance on both BTF and DERs are putting downward pressure on the marginal cost of Bulk Transmission
    - Drives a bigger gap between embedded (historical) and marginal (future) cost of transmission
    - Today, this problem is the largest single source of upward pressure on the transmission portion of customers' bills who have not bypassed the bulk transmission charge
    - If untreated, uneconomic bypass could trigger the need to substantially restructure transmission rates, relying on some form of non-bypassable transmission access fees
+ **Good News- There are many workable solutions**
  - If you act now in anticipation of this growing problem, there are a variety of ways to align transmission ratemaking with both market forces and government policy

Data Needs

+ **The following items are needed from the AESO to assess the full extent of cost-shifting due to uneconomic bypass of the transmission system bulk charge in Alberta**
  - MW of bypass during CP
    - BTF generation
    - Load shedding
    - Other
  - Transmission marginal costs
    - List of projects in 2020-2025 period that could be avoided or deferred through a reduction in the CP