# Bulk and Regional Tariff Design Stakeholder Engagement Session 5

March 25, 2021

# Notice

In accordance with its mandate to operate in the public interest, the AESO will be audio recording this session and making the session recording available to the general public at www.aeso.ca. The accessibility of these discussions is important to ensure the openness and transparency of this AESO process, and to facilitate the participation of stakeholders. Participation in this session is completely voluntary and subject to the terms of this notice.

The collection of personal information by the AESO for this session will be used for the purpose of capturing stakeholder input for the Bulk and Regional Tariff Design engagement sessions. This information is collected in accordance with Section 33(c) of the *Freedom of Information and Protection of Privacy Act*. If you have any questions or concerns regarding how your information will be handled, please contact the Director, Information and Governance Services at 2500, 330 – 5th Avenue S.W., Calgary, Alberta, T2P 0L4, by telephone at 403-539-2528, or by email at privacy@aeso.ca.

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- Two ways to ask questions if you are accessing the webinar using your computer or smartphone
  - Click "Raise Hand" and the host will be notified that you would like to ask a question. The host will unmute your microphone, you in turn will need to unmute your microphone and then you can ask your question. Your name will appear on the screen, but your camera will remain turned off.
  - Click "Lower Hand" to lower it if needed.
  - You can also ask questions by tapping the "Q&A" button and typing them in. You're able to up-vote questions that have been already asked.
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# Stakeholder participation

The participation of everyone here is critical to the engagement process. To ensure everyone has the opportunity to participate, we ask you to:

- Listen to understand others' perspectives
- Disagree respectfully
- Balance airtime fairly
- Keep an open mind

# Welcome and Introductions

# Session purpose and objectives

- The purpose of this session is to present and discuss the AESO's preferred rate design. The session objectives include:
  - Present preferred rate design, including energy storage treatment, to stakeholders
  - Present and discuss path to achieving minimal disruption
  - Present bill impact summary and assumptions
  - Provide Bill Impact Tool
  - Begin to discuss implementation considerations

# Agenda (morning)

| Time | Agenda Item | Presenter |
|---|---|---|
| 8:00 – 8:10 | Welcome, introduction, purpose, and session objectives | AESO / Stack'd |
| 8:10 – 8:30 | Opening remarks<br>• Case for change<br>• Key highlights | AESO |
| 8:30 – 8:50 | What we heard<br>• Cost responsibility<br>• Efficient price signals<br>• Embedded and marginal approaches | AESO |
| 8:50 – 10:30 | Methodology and analysis<br>• Summary of rate design<br>• Review and elimination of marginal approach<br>• Improvement to embedded approach | AESO / NERA |
| 10:30 – 11:00 | Break | |
| 11:00 – 12:30 | What we heard, methodology and analysis<br>• Q&A | AESO / NERA |
| 12:30 – 1:00 | Break | |

# Agenda (afternoon)

| Time | Agenda Item | Presenter |
|---|---|---|
| 1:00 – 1:45 | Bill impact summary<br>• Summary<br>• Methodology and assumptions<br>• Impacts<br>• Bill Impact Tool<br>Q&A | AESO |
| 1:45 – 2:15 | Path to achieve minimal disruption<br>• Targeted engagement<br>• Mitigation proposal principles<br>• Mitigation options assessment<br>• Q&A | AESO |
| 2:15 – 2:30 | Break | |
| 2:30 – 3:30 | Energy Storage tariff treatment<br>• What we heard<br>• Non-firm rate conclusions<br>• Demand Opportunity Service (DOS)<br>• Q&A | AESO |
| 3:30 – 3:50 | Implementation Considerations<br>• Considerations<br>• Flexibility<br>• Q&A | AESO |
| 3:50 – 4:00 | Session close-out and next steps | AESO |

# Registrants (as of March 18, 2021)

- Acestes Power
- Alberta Direct Connect Consumers Association (ADC)
- Alberta Newsprint Company (ANC)
- Alberta Utilities Commission (AUC)
- AltaLink Management Ltd.
- AltaSteel Inc
- Arcus Power
- ASCENT Energy Partners Ltd.
- ATCO Electric Ltd.
- BECL and Associates Ltd.
- Best Consulting Solutions Inc.
- BluEarth Renewables
- Boost
- Brubaker and Associates, Inc. on behalf of Alberta Direct Connect
- Canadian Renewable Energy Association (CanREA)
- Cement Association of Canada
- Cenovus Energy
- Chapman Ventures Inc.
- Chymko Consulting on behalf of Cities of Red Deer and Lethbridge
- City of Lethbridge
- City of Medicine Hat
- City of Red Deer
- Consumers Coalition of Alberta (CCA)
- Customized Energy Solutions
- DePal Consulting Limited
- Dow Chemical Canada ULC
- Dual Use Customers (DUC)
- EDF Renewables
- Enbridge Pipelines Inc.
- Enel
- Energy Storage Canada (ESC)
- ENMAX Corporation
- EPCOR Distribution & Transmission Inc.
- EQUS
- ERCO Worldwide
- FortisAlberta Inc.
- Government of Alberta
- Guidehouse
- Heartland Generation Ltd.
- Imperial Oil ExxonMobil Canada
- Independent Power Producers Society of Alberta (IPPSA)
- Industrial Power Consumers Association of Alberta (IPCAA)
- Inter Pipeline Ltd
- Invinity Energy Systems
- Lehigh Cement
- Lionstooth Energy Inc.
- Matt Ayres Consulting
- Millar Western Forest Products Ltd
- NextEra Insights Inc.
- North American Environmental Markets Inc.
- NRGCS
- Osler, Hoskin & Harcourt LLP
- Perimeter Solar Inc.
- Power Advisory LLC
- Prairie Sky Strategy
- QUEST – Quality Urban Energy Systems of Tomorrow
- Rodan Energy Solutions
- Stantec
- Suncor Energy Inc.
- TC Energy
- TransAlta Corporation
- Turning Point Generation
- Utilities Consumer Advocate (UCA)
- URICA Asset Optimization
- Versorium Energy Ltd.
- VIDYA Knowledge Systems / CWSAA
- Voltus Energy Canada, Ltd.
- West Fraser Mills Ltd.
- Weyerhaeuser
- Whitecourt Power LP
- Wolf Midstream Inc.

# Overview of Engagement Process

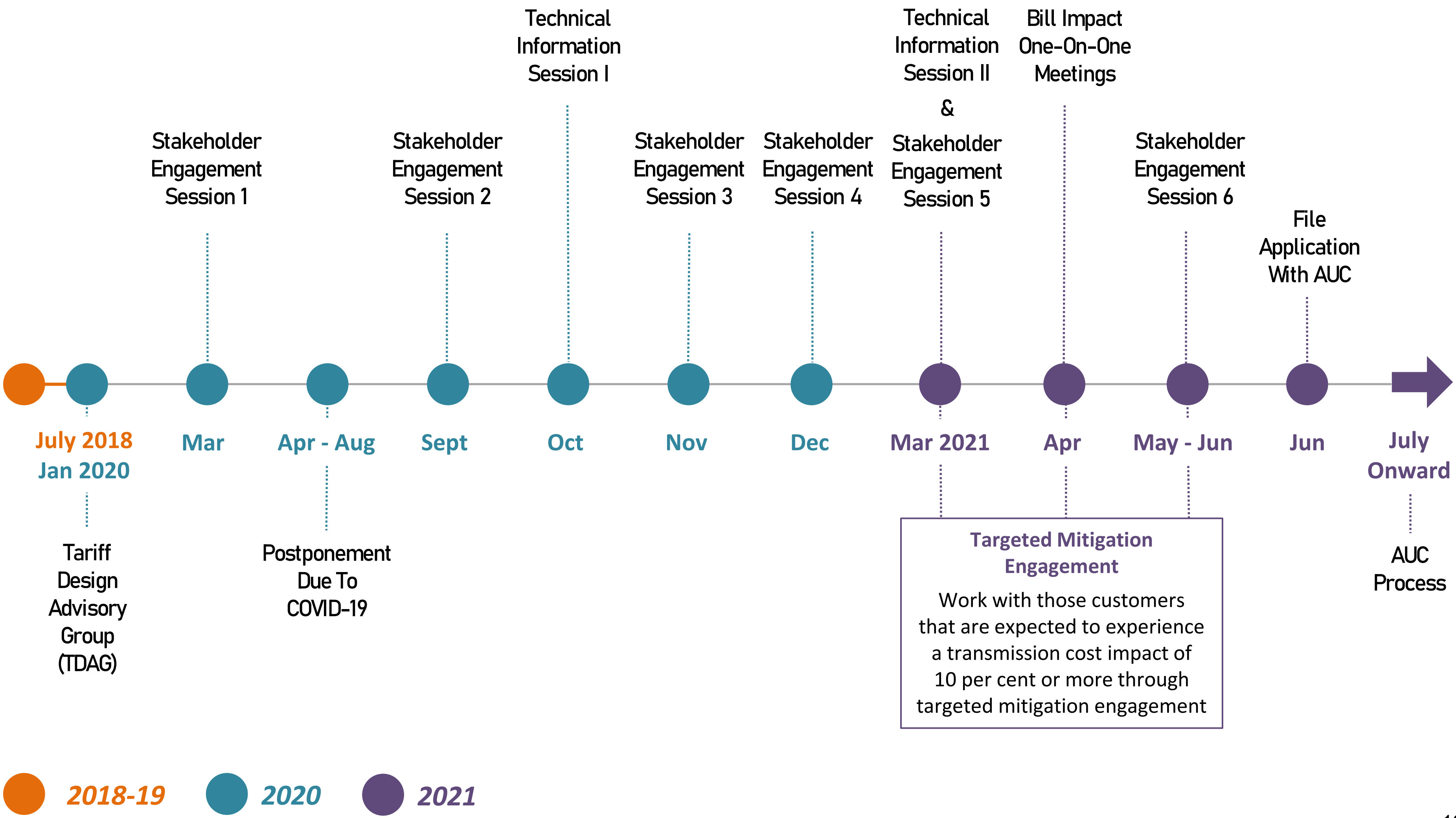
# AESO Stakeholder Engagement Framework

# Stakeholder engagement

The AESO’s stakeholder engagement will:

- Ensure that stakeholders’ needs and interests are consistently, transparently and meaningfully considered in the development of a rate design proposal for bulk and regional cost recovery;
- Provide clear objectives to be examined and evaluated in the development of a rate design proposal for bulk and regional cost recovery;
- Assist stakeholders in understanding and evaluating the AESO’s preferred rate design;
- Supply stakeholders with tools that will allow them to consider and assess the impact of the AESO’s preferred rate design; and
- Identify areas of alignment in order to support an efficient regulatory process.

# Stakeholder engagement timeline



# Opening Remarks

# Case for change

- Since its introduction, the 12-CP rate has increased substantially with significant new investments in the grid to support economic growth and integrate new resources
  - Costs to be recovered are sunk, need to recover these costs to pay for the transmission system
- Substantial peak rate increase has resulted in an increasing risk of cost avoidance at peak hours by customers who can change when they consume power
  - With the current rate design, seeing a negative feedback effect
- The current design is no longer sending effective pricing signals
  - As the transmission system is reinforced and available for use, the weighting of the 12-CP price signal has diverged from the value it creates for the system
- Current rate design does not reflect the drivers of transmission costs to adjust with changes occurring in the landscape of Alberta's electricity system
- Improvements need to be made now so that any future investment decisions are made under the new rate design

# Key highlights

- Sharing our preferred rate design today to build understanding and seek input
  - The preferred rate design strikes the right balance moving forward by allocating costs more appropriately to better reflect a customer's use of the system, putting the appropriate long-term price signals in place while also providing for a transition path of minimal disruption
  - Preferred rate design has shifted away from the bookends and stakeholder proposals presented in the fall
- Rate impact is much less impactful than previously estimated
  - Nearly all customers facing an increase will see a rate impact of less than a 10 per cent increase (to both total bill and transmission bill)
  - AESO seeking to mitigate challenges for the few customers who would see a 10 per cent or greater increase in transmission costs through a targeted engagement
  - Many customers (including residential, commercial, and industrial customers) can expect a reduction in transmission costs relative to today

# Design objectives

| Objective | Description |
|---|---|
| **Reflect Cost Responsibility** (updated) | Cost recovery is based on cost causation, reflecting how transmission customers use the existing grid* |
| **Efficient Price Signals** | Price signal to alter behavior to avoid future transmission build |
| **Minimal Disruption** | Customers that have responded to the 12-CP price signal and invested to reduce transmission costs are minimally disrupted |
| Simplicity | Simplicity and clear price signals while achieving design objectives |
| Innovation and Flexibility | ISO tariff provides optionality for transmission customers to innovate while not pushing costs to other customers |

*AUC Decision 22942-D02-2019

**Proposed rate design must fit within current legislative framework

# Your participation

- Your participation to date has been very insightful to the AESO in understanding your perspectives and helping the AESO develop its preferred rate design proposal
- Your continued participation in this engagement is critical to help us prepare a well-informed application to the AUC for the benefit of Albertans
- We are looking for collaborative solutions to minimize the disruption for customers who are impacted by these changes, and your continued engagement is critical for our success
- AESO recognizes the importance of providing clarity on this initiative for all of Alberta's electricity consumers

# What We Heard

# Session 4 feedback on cost responsibility

- What we heard
  - Cost causation is primary principle that proposed tariff design must meet
  - Embedded approach is likely to best meet cost causation principles
  - Cost recovery must be based on the drivers of the costs to provide transmission service to customers
- In developing the preferred rate design and taking into account stakeholder feedback, preferred rate design is rooted in cost causation, therefore meeting cost responsibility objective

# Session 4 feedback on efficient price signals

- What we heard
  - Current tariff design provides price signals allowing customers to manage costs
  - Price signals should be widely available to be adopted by different types of customers
  - Marginal cost approach might be appropriate (including in combination with embedded approach), but relies on forecasts and additional complexity which hamper ability to achieve a more efficient outcome
- AESO views that the embedded approach to cost allocation remains appropriate in that rates based on cost causation will provide cost reflective price signals

# Session 4 feedback on approaches

### Embedded Approach

- Most appropriately aligns with AESO's design objectives around cost responsibility and would cause the least disruption (several)
- More likely to achieve rate design objective of minimal disruption as AUC and stakeholders more familiar with this approach (several)

### Marginal Approach

- Support but would require reallocating existing costs to ensure cost recovery (one)
- May more fully meet rate design objective of sending efficient price signals (several)

### Combined Approach / Trade-offs

- Promoted a combination of both to cover past and future investments as well as both incremental (covered by marginal) and embedded costs (several)
- Trade-offs between the two approaches need to be considered as each approach may more fully meet different rate design objectives (several)
- Removing price signals completely will result in inefficient behaviour (several)

# Methodology and Analysis

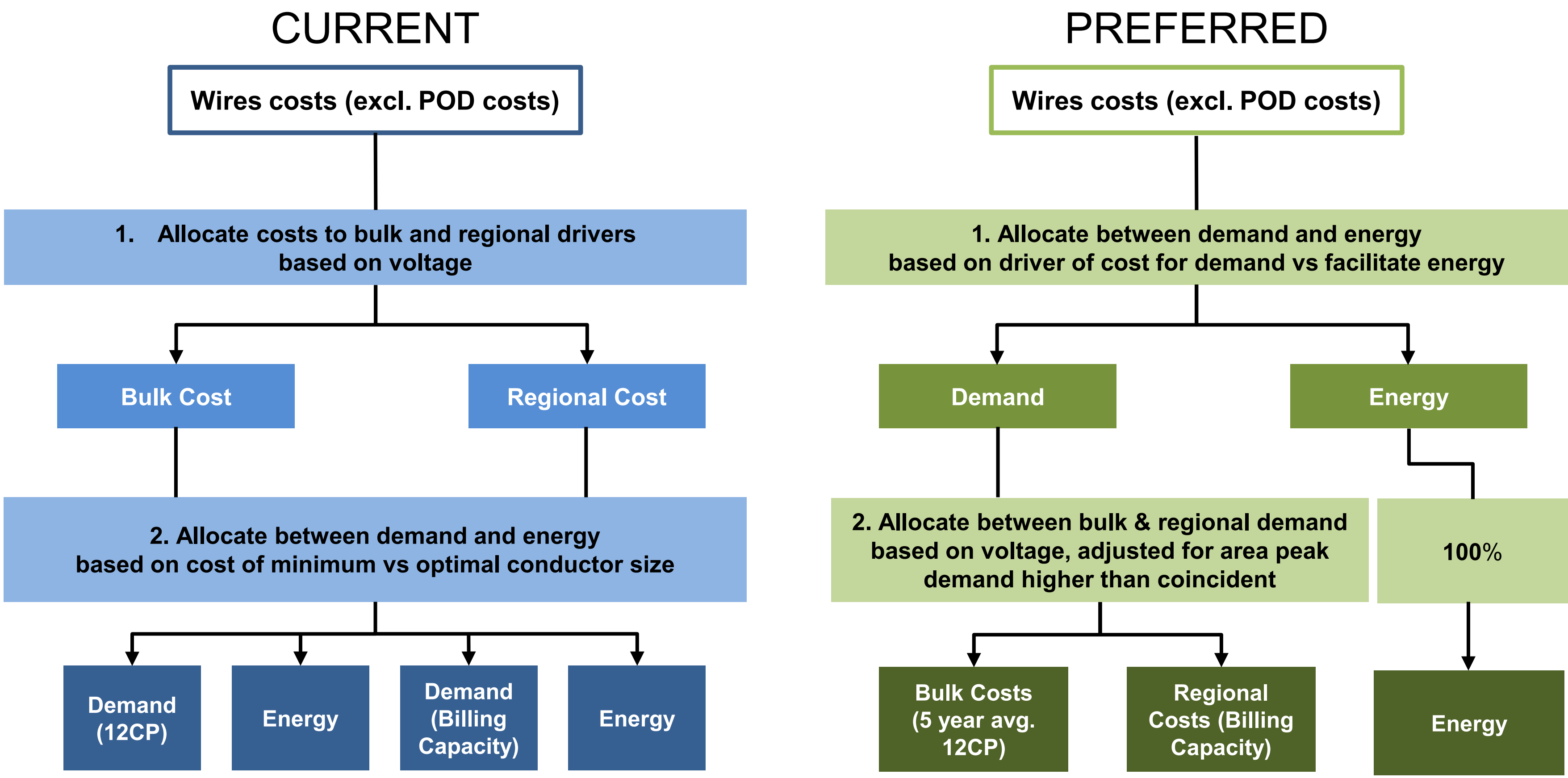
# Tariff redesign process

- NERA Economic Consulting has been retained as an expert
- AESO is adopting and proposing NERA's tariff design
- Richard Druce from NERA is an expert in tariff design and is attending this session to respond to questions from stakeholders on the preferred rate design

# Summary of rate design

- AESO's preferred rate design relies on an embedded approach, with improvements to better reflect cost causation
  - Relies on concept of minimum system in current tariff, which has been improved to align with transmission system use
- Many stakeholders have stated that an embedded approach remains appropriate for Alberta
  - Identified that updating the current embedded approach is likely the best way to meet tariff design objectives
- AESO's preferred rate design reflects an effective balance in meeting our tariff design objectives

# Current and preferred rate design



# Current and preferred rate design

| Type of charge | Cost Allocation (do not sum due to rounding) | | Charges Estimated for 2019 test year | |
|---|---|---|---|---|
| | Current | Preferred | 2019 Test Year | Preferred |
| Coincident Peak ($/MW month) | 47% | 29% | 10,087 | 5,980 |
| Energy* ($/MWh) | 7% | 31% | 2.18 | 10.19 |
| Billing Capacity ($/MW month) | 22% | 17% | 2,668 | 2,055 |
| POD (**out of scope**) ($/MW month) | 24% | 24% | N/A | |
| **Total** | **100%** | **100%** | **N/A** | |

*Current energy charges are the sum of bulk and regional components

# Recommended approach aligns costs with drivers

- The preferred rate design characterizes use of the system to allocate the costs of transmission
  - Divide costs between demand-related cost drivers and costs driven by facilitating in-merit flow of energy-related costs
  - Divide demand costs between costs associated with coincident peak consumption and customer's own peak loads
  - Energy charge will increase; peak and billing capacity charge will decrease relative to current tariff
  - No changes to the current types of charges from current tariff: billing capacity charge, energy charge, peak charge (with five-year trailing average)
- Better aligns charges with use of the system, reducing opportunity for customers to shift costs to others by reducing demand at peak hours
  - Customers who wish to manage costs through peak avoidance remain able to do so, but charges are more reflective of the associated costs

# Review and Elimination of Marginal Approach

# Consideration given to marginal approach

- Discussion in Session 4 about use of embedded and marginal approach to cost allocation
  - Marginal approach is based on estimating the incremental cost of supplying one more unit of demand
    - **Marginal cost**: Change in cost to serve one more customer/MW with next increment of capacity
    - **Residual cost**: Difference between marginal costs recovered and revenue requirement needs to be recovered to minimize distortions
- The suitability of marginal approaches for transmission cost allocation in Alberta was evaluated
  - Applying marginal approach to Alberta context leads to relatively low marginal costs and proportionally higher residual costs
  - Price signal from marginal would be diluted by residual cost recovery
  - Marginal price signal would not encourage efficiency unless pricing is locational since costs vary by location

# Marginal approach does not meet rate design objectives

The AESO has assessed that the marginal approach to cost allocation will not meet our rate design objectives based on the following:

- Reflect Cost Responsibility
  - Cost causation could be achieved to the extent marginal rates appropriately reflect costs, but costs will vary by location
- Efficient Price Signals
  - Efficient price signals would need to vary by location and recovering significant portion of residual costs would undermine efficiency of price signal
- Minimal Disruption
  - Marginal cost allocation requires significant residual cost recovery, limiting the gains from efficient price signals and likely to be more disruptive
- Simplicity
  - Calculation of marginal rates relies on forecasts of future growth and future costs, resulting in a greater degree of complexity relative to the current approach
- Innovation and Flexibility
  - Potential to encourage additional price responsive participation, extent of flexibility depends on the basis for calculations

# Questions

# Improvements to Embedded Approach

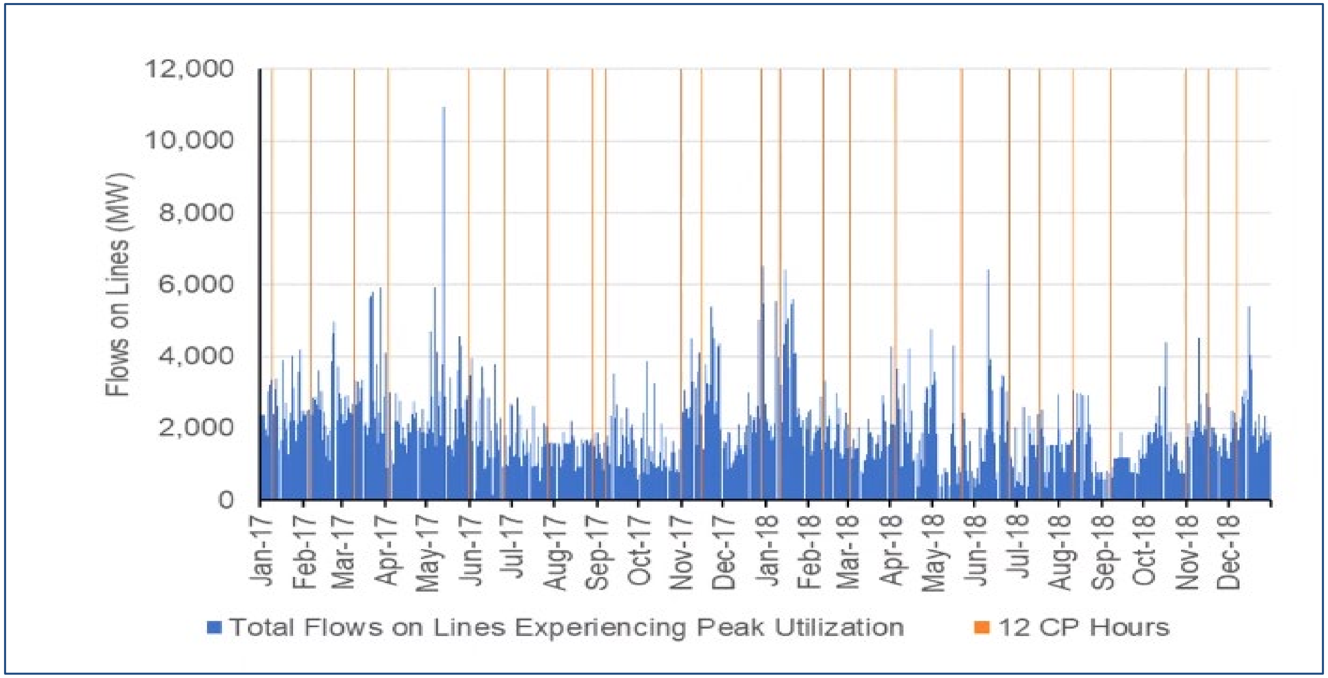
# Overview of embedded approach

- The following context frames the AESO’s preferred rate design
  - High level overview of transmission cost causation as it applies to the Alberta transmission system
  - An explanation of allocating costs between demand and energy
  - An explanation of functionalizing costs between bulk and regional
  - Allocation of costs to billing determinants
  - Evaluation of preferred rate design against objectives
- Design alternatives that were considered and dismissed are described in the Appendix

# Bulk transmission system use

- Demand at times of coincident peak is not the only driver of bulk transmission system utilization
  - Peak bulk line utilization: When a bulk line has flows in an hour greater than 90 per cent of the maximum flow for the year

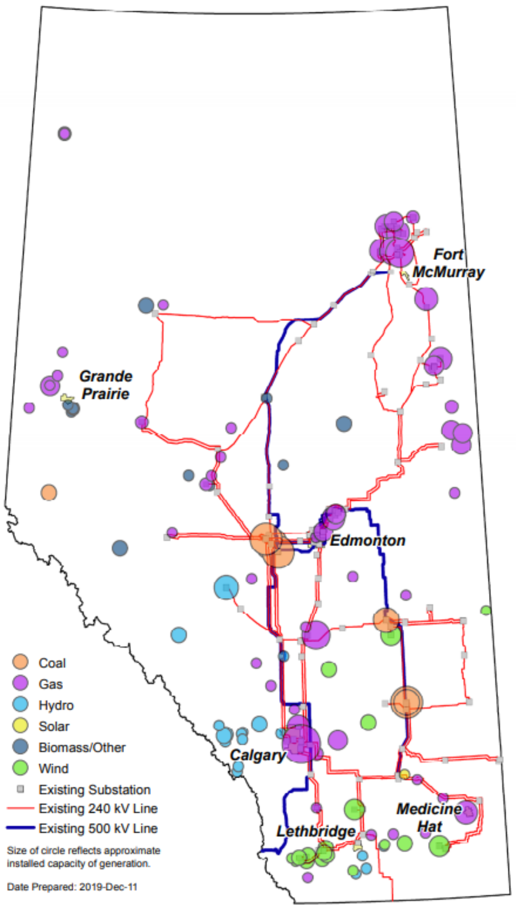
**Hours of 12-CP do not necessarily correspond to hours of peak utilization across high-voltage lines**




*Source: NERA Analysis of SCADA flow data provided by the AESO*

# Other drivers of transmission system costs

- Other drivers of transmission system costs are not adequately reflected in current tariff
- Flows on transmission system associated with seasonal patterns
- Changes in the regional pattern of in-merit energy drive costs
  - When there are changes in generation dispatch in one region, this affects flows to varying degrees in other regions



# Transmission costs associated with energy use

- Energy charges in the current tariff do not explicitly reflect that transmission costs are incurred to enable the flow of in-merit energy
  - Recognizing that transmission costs are allocated to load customers, the costs of facilitating the flow of in-merit energy are not demand related, they are energy related
    - **Demand related**: Costs associated with transmission needed to meet demand
    - **Energy related**: Costs associated with transmission needed to provide in-merit energy
  - The current cost allocation methodology would allocate some of the costs of enabling the flow of in-merit energy to demand

# Minimum and actual system approach

- The AESO's preferred rate design allocates transmission costs between demand and energy prior to functionalization of demand-related costs
  - Better matches the fact that the AESO does not distinguish between voltage levels when planning transmission solutions to enable the in-merit flow of energy
  - Better distinguishes the costs that are demand driven and those that enable the flow of in-merit energy

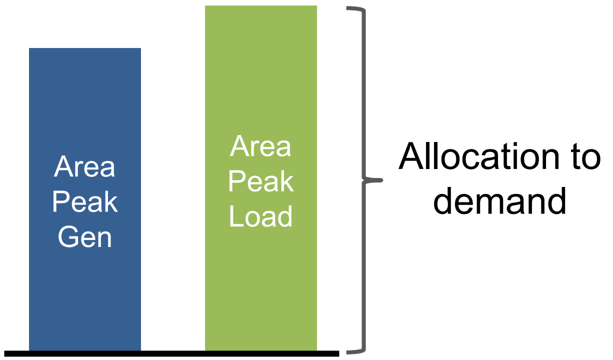
# Minimum and actual system calculation

The following methodology is applied to determine the portion of costs allocated to demand and energy

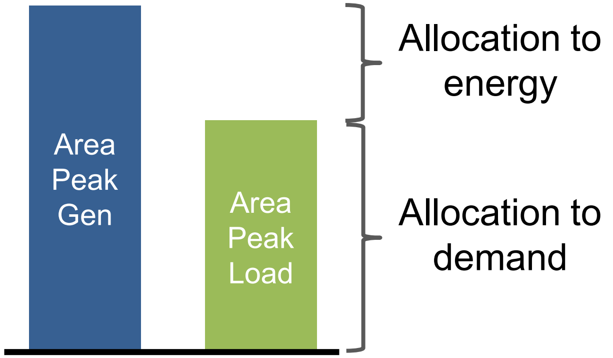
- **Minimum system**: Estimate of the transmission system required to meet peak load (demand)
- **Actual system**: Estimate of the additional transmission system required to facilitate the in-merit flow of energy
- Minimum and actual systems for Alberta are estimated as the sum of the minimum and actual systems across all planning areas
- Calculate the demand-share of costs based on the size of minimum and actual systems for Alberta

The resulting allocations for 2020 are 60 per cent demand and 40 per cent energy, and have changed minimally since 2015

**Example of an area where peak gen < peak load**




**Example of an area where peak gen > peak load**



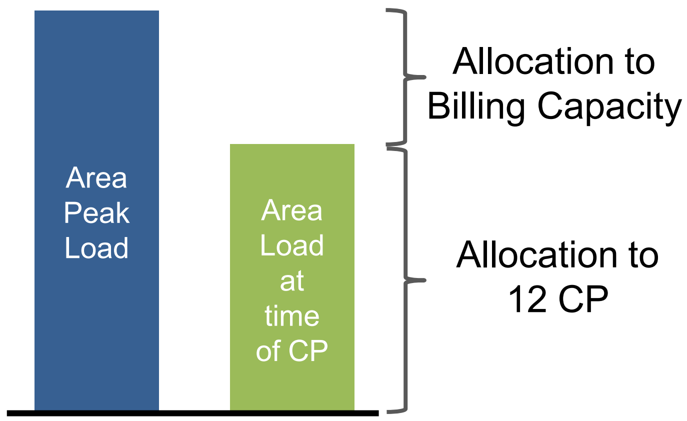
# Functionalize demand share of costs

- Functionalize demand-related costs by proportion of book value of assets on the basis of current voltage threshold (240 kV) as a reasonable approximation of the bulk and regional share of costs
  - Low voltage lines more likely to serve a regional purpose
  - High voltage lines are more likely to serve a bulk purpose
  - Consistent with the approach used today but applied only to the demand portion of costs

# Adjustment to bulk system share of costs

- Size of the bulk system primarily driven by system peak demand, but may need to be larger in areas where the load peaks at times other than the coincident peak
  - The portion of the bulk system that is used to accommodate peaks outside of the coincident peak is allocated to the billing determinant that reflects non-coincident peak (i.e., billing capacity)

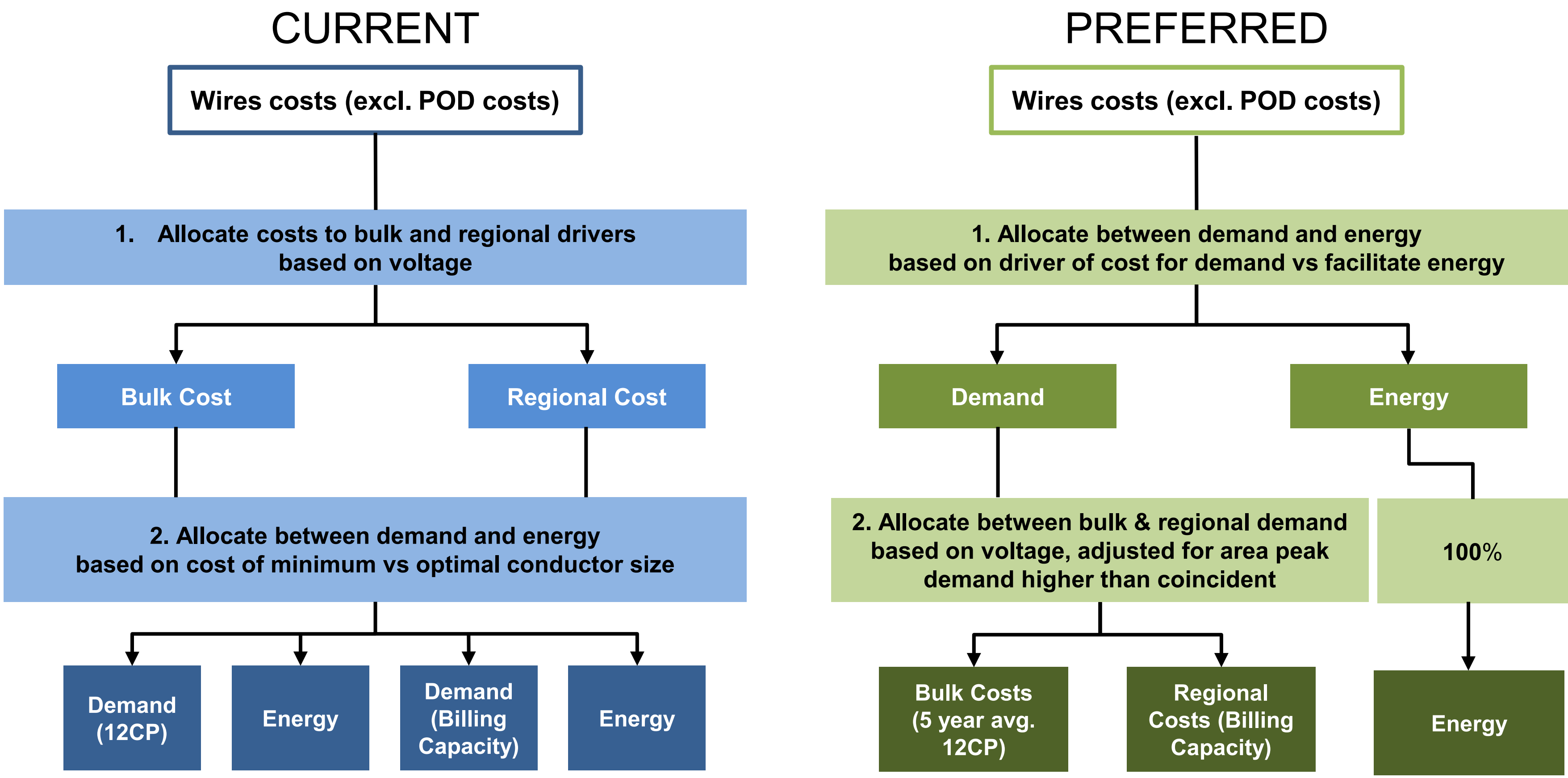
**Example of an area where area peak load > area load at time of coincident peak (CP)**



# Billing determinants to reflect cost causation

- Majority of bulk demand-related costs recovered on five-year trailing average of monthly coincident peak
  - More appropriately reflects how consumption over the longer-term drives transmission costs
  - Five-year average will be phased-in
- Regional demand-related costs (and remaining bulk costs) recovered on billing capacity charge
  - Regional system is scaled to meet non-coincident peak demand
- Energy-related costs recovered on energy charge
  - Transmission system is planned to facilitate the in-merit flow of energy at all times of the year, so energy use in all hours matters for transmission costs

# Review: Current and preferred rate design



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| **Total** | **100%** | **100%** | **N/A** | |

*Current energy charges are the sum of bulk and regional components

# Resulting rates will meet our rate design objectives

- Reflect Cost Responsibility
  - Resulting rates reflect costs of using the transmission system, including costs associated with in-merit flow of energy, local and peak use of the system
- Efficient Price Signals
  - Resulting rates provide transparent price signals to customers that better reflect the cost drivers of the transmission system
- Minimal Disruption
  - Resulting rates are based on similar billing determinants that customers understand (overall cost impacts discussed later in the presentation)
- Simplicity
  - Resulting rates are comparable to current rates in terms of level of complexity
- Innovation and Flexibility
  - Additional flexibility to allow allocations to change over time reflecting evolution in how the transmission system is used

# Break

# Question Period

## What We Heard and Methodology and Analysis

# Break

# Bill Impact Summary

# Overall summary

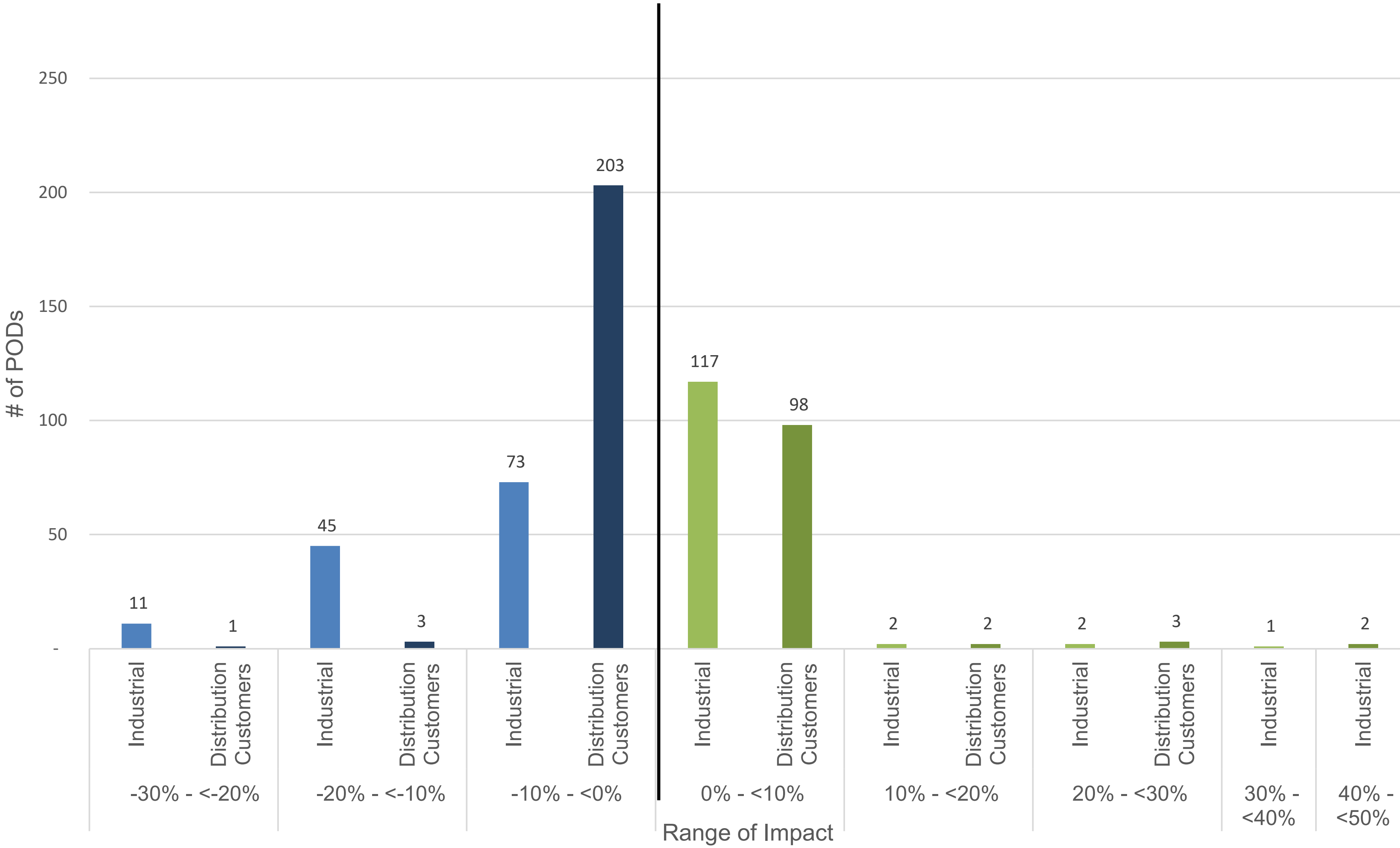
- Total shift in transmission cost recovery will be small
  - Total change less than three per cent of total transmission system costs
- Prior to any mitigation, it is not expected that any customer would have a total bill increase of more than 15 per cent
  - Before we apply any mitigation, a few customers may see up to a 50 per cent increase in transmission costs (15 per cent or less of their total electricity bill)
  - To support a minimally disruptive transition to the new rate design the AESO is exploring mitigation to reduce this impact to no more than a 10 per cent increase in transmission costs
- Many customers (including residential, commercial and industrial customers) can expect a reduction in transmission costs relative to today
  - Changes in bills for customers will depend on how distribution companies pass through transmission costs

*A customer's total electricity bill depends on transmission costs, energy price, and distribution costs (if applicable)

# Bill impact methodology and assumptions

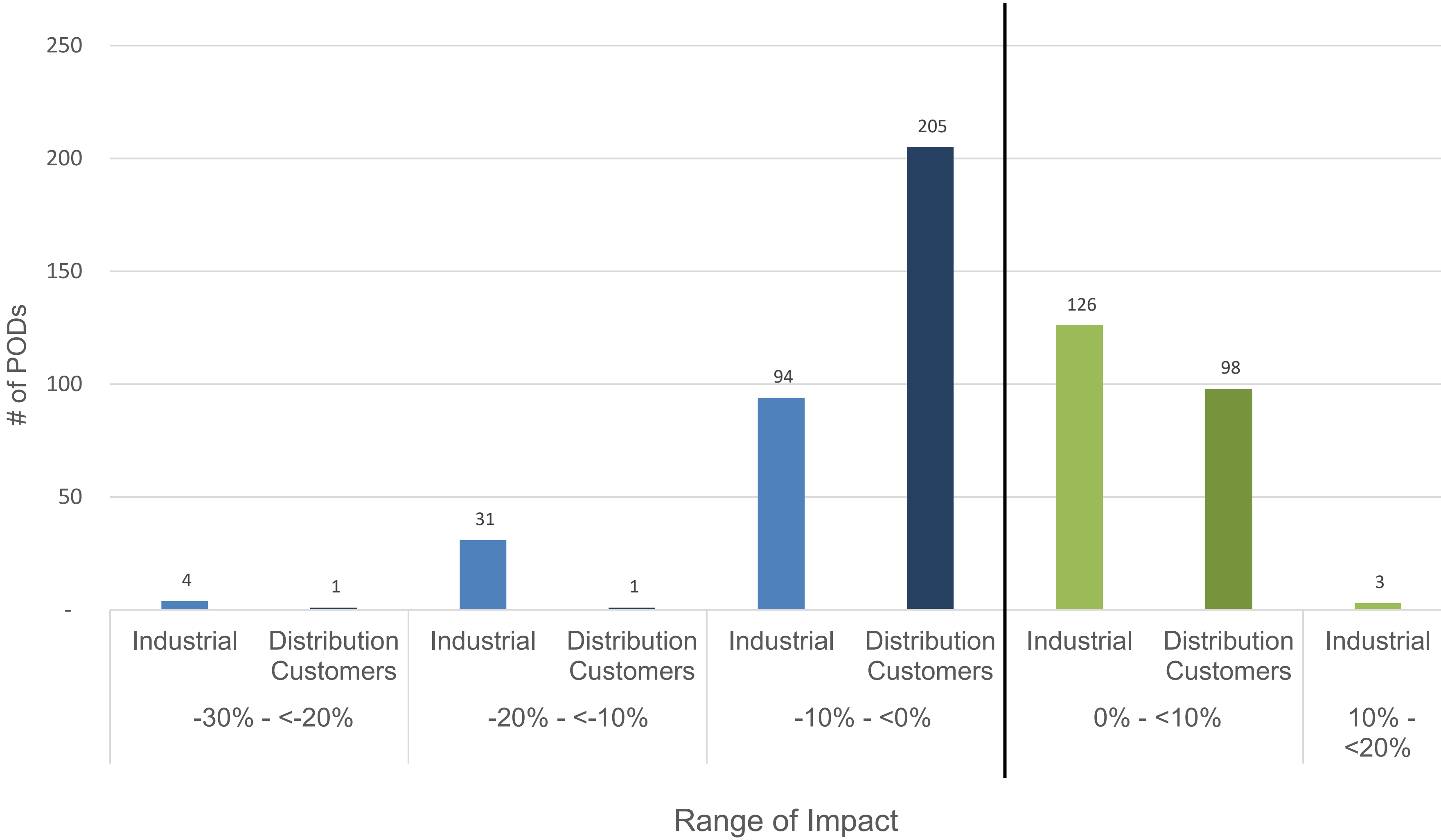
- Calculate the impact of changes in bills attributable to Rate DTS (Demand Transmission Service) changes
  - Proposed and current rates were applied to the same billing determinants (for the 2019 test year) at each **point-of-delivery** (POD) for the bulk and regional charges
    - Transmission bill for each POD includes POD costs, Operating Reserve (OR) charges and other tariff charges
    - Total bill for each POD includes transmission bill and energy commodity costs
  - Estimated per cent impact based on change in transmission costs and total bill by POD under current and proposed tariff
  - Assumed 12-CP consumption maintained at current levels (i.e., no retroactive averages)
- Bills for an individual Rate DTS point-of-delivery will be different from estimates depending on actual demand and usage at the point-of-delivery and actual effective rates

# Number of PODs by transmission cost per cent impact (2019 test year)




Industrial: AESO and DFO Transmission connected customers

# Number of PODs by total bill per cent impact (2019 test year)




Industrial: AESO and DFO Transmission connected customers

# Estimated average transmission cost impact (by Load Factor, 2019)

| Billing Capacity (MW) | Load Factor (energy use / capacity) | | | | |
|---|---|---|---|---|---|
| | 0-20% | 20%-40% | ~~20~~ 40%-60% | 60%-80% | 80%-100% |
| **0-7.5** | -12% | -1% | 0% | 2% | 5% |
| **7.5-15** | -9% | -4% | 1% | 2% | 5% |
| **15-22.5** | -11% | -2% | -1% | 2% | 5% |
| **22.5-30** | -13% | -4% | 1% | 2% | 5% |
| **30-37.5** | -19% | -3% | -1% | 4% | 9% |
| **37.5-45** | -20% | — | -2% | 3% | — |
| **>45** | -16% | 5% | 0% | 2% | 7% |
| **Total Accounts** | **95** | **66** | **170** | **204** | **28** |

# Estimated average total bill impact
## (by Load Factor, 2019)

| Billing Capacity (MW) | Load Factor (energy use / capacity) | | | | |
|---|---|---|---|---|---|
| | 0-20% | 20%-40% | ~~20~~ 40%-60% | 60%-80% | 80%-100% |
| **0-7.5** | -9% | -1% | 0% | 0% | 1% |
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| **15-22.5** | -8% | -1% | -1% | 0% | 1% |
| **22.5-30** | -11% | -2% | 0% | 0% | 1% |
| **30-37.5** | -13% | -2% | -1% | 1% | 2% |
| **37.5-45** | -17% | — | -1% | 1% | — |
| **>45** | -13% | 1% | -1% | 0% | 2% |
| **Total Accounts** | **95** | **66** | **170** | **204** | **28** |

# Estimated average transmission cost impact by coincident peak response

- Customers with low load factors are less likely to be consuming during coincident peaks
- Customers with higher load factors tend to consume during coincident peaks
- Customers with higher load factors and who respond to coincident peaks will have a larger rate impact under the AESO's preferred design **before mitigation**

| Response to Coincident Peak (%) | Load Factor (energy use / capacity) | | |
|---|---|---|---|
| | 0-33% | 33%-66% | 66%-100% |
| 0-33% | -12% | -2% | 2% |
| 33%-66% | -5% | 2% | 16% |
| 66%-100% | -13% | 22% | 42% |

# Further information about bill impact

- The AESO has posted the Bill Impact Tool to allow stakeholders to calculate the estimated bill impact for their sites
  - Stakeholders can request from the AESO their specific site data input for the tool. The AESO will provide the data to the Rate DTS market participant for the site.
  - The AESO is hosting a **Technical Information Session on March 31, 2021** to provide further information on how to use the Bill Impact Tool. Registration details are available on our website.
- Ratepayers can also request a one-on-one meeting with the AESO to ask questions about how the Bill Impact Tool works for your site. These bill impact one-on-one meetings will be scheduled during April 1-14, 2021.
- **Email us at tariffdesign@aeso.ca** to request your site-specific data input for the Bill Impact Tool and/or to request your one-on-one bill impact meeting

# Questions

# Path to Achieve Minimal Disruption

# Session 4 feedback on minimal disruption

- What we heard
  - Gradual implementation over time is preferrable given current economic circumstances
  - Mitigation options can only be evaluated alongside the AESO’s preferred rate design
  - Mitigation of rate increases that occur at the bill level allows for quick adoption and allows tariff price signals to become effective
  - Mitigation at bill level is difficult to implement fairly, especially if permanent
  - Major changes to current tariff design are premature at this time
  - Changes to rates cannot be delayed indefinitely
- We are including a pathway to achieve minimal disruption that is targeted at those loads who will see a transmission cost impact of 10 per cent or more

# What we mean by minimal disruption

- Minimal disruption means transitioning to the new tariff design in a way that balances two risks
  1. Continuation of current tariff incentives risks increasing the cost shifting between customers who can respond to incentives and those who cannot
  2. If the changes to the tariff design are so significant that some customers choose to leave the grid, costs to remaining customers would increase
- Preferred rate design addresses first risk in a manner that minimizes the second risk for many, with additional mitigation to support the few that are significantly impacted
- Path to change should allow customers to adapt to new tariff design
  – We have an opportunity to develop and put forward to the Commission a mutually acceptable mitigation approach that will allow for a successful transition to the new tariff design

# Targeted engagement plan for mitigation

- Rate impact assessment indicates significant increases only to limited number of consumers
  - The Bill Impact Tool will assist all impacted stakeholders in assessing their rate impact to identify concerns to the AESO
- The AESO is initiating a targeted engagement to develop a mutually acceptable set of mitigation options with this small impacted group
- Agreed upon proposal, or identified options*, will be shared with the broad stakeholder group for Session 6
- The AESO will provide both information from the targeted engagement and the broad engagement to the AUC to support regulatory efficiency
- The AESO intends to include a mitigation proposal as part of its application for approval by the AUC
  - The AUC has ultimate authority to decide whether or not to approve the proposal or any identified option

* If unable to agree upon a proposal, options identified by involved parties will be shared

# Scope of targeted mitigation

- Parties with an estimated transmission cost impact of greater than 10 per cent increase have been invited to this targeted engagement
  - Includes seven sites / customers across four industries
  - Total estimated impact of roughly $8 million
  - The five distribution facility owners (DFOs) PODs with an estimated transmission cost impact of greater than 10 per cent that are not DFO Transmission connected customers are excluded, as the rate impact is incorporated into overall DFO rates and will not be POD specific

# AESO mitigation proposal starting principles

The AESO is seeking to develop a mutually acceptable mitigation proposal with the small group of impacted loads that will:

1. **Limit the rate impact for customers**: Mitigate rate impact to under 10 per cent increase to a party's transmission bill for initial stage of transition
2. **Adapt with design and rates**: Ensure options are adaptable to changes to the proposed design and forecast rates
3. **Consistent application**: Mitigation options can be applied consistently across all impacted loads and not be individually defined
4. **Administrative simplicity**: Feasible to implement with current tools and systems
5. **Mutually acceptable**: Account for feedback from broad stakeholder group

# Mitigation options assessment

The AESO's initial evaluation of options forms a starting point for targeted mitigation engagement

- Other options may be identified by impacted loads in targeted engagement

| Type | Category | Description | Assessment |
|---|---|---|---|
| **Rate Design** | Transition Rate Design | Phase in tariff changes | Given the small number of load customers with rate impacts over 10 per cent a phase-in of new rates not needed, targeted mitigation more effective |
| | | Adjustment period | Limited effectiveness as a mitigation option as greater portion of rates based on usage and not billing capacity |
| | Rate Classes | Set rates by customer size/type/class | Preferred rate design provides customers with similar flexibility to today, better reflecting how differences in behavior correspond to transmission costs |
| **Bill Adjustment** | Transition bill impacts | Bill increase of no more than X% per year for Y years | Continues to be an available option for consideration in the targeted engagement |
| | Permanent bill reduction | Bill increase of no more than X% | Mitigation is to support a minimally disruptive transition to getting the appropriate long-term price signals in place. |

# Targeted approach – Schedule

- **March 19-31 |** One-on-one meetings with impacted loads
  - Describe estimated bill impact
  - Respond to questions on targeted engagement process
- **April 15 |** Stakeholder feedback due on mitigation options and proposal principles from broad stakeholder group
- **April 1 to late May |** Facilitated group meetings
  - Explore options, seek agreement
  - Notes from meetings will be shared (excluding commercially sensitive information)
- **Late May |** Outcomes of targeted engagement will be shared with broad stakeholder group for feedback
- **June |** Adjust mitigation proposal for feedback received from broad stakeholder group

# Questions

# Break

# Energy Storage Tariff Treatment

# Session 4 feedback on energy storage tariff treatment

- What we heard
  - Current rates reflect one class of service: firm load
  - Consideration should be given to rates that reflect the different types of uses of the system: non-firm rates
  - Types of tariff treatment that could reflect different use of the system:
    - Rates that allow additional use of available capability that would not otherwise occur
    - Rates that reflect transmission cost savings from interruptions to relieve constraints
    - Rates that encourage participation in markets or provision of ancillary services

# Summary of non-firm rate assessment

| | Rates that reflect transmission cost savings from interruptions to relieve constraints | Rates that encourage participation in markets or provision of ancillary services | Rates that allow additional use of available capability that would not otherwise occur |
|---|---|---|---|
| **Description** | • Demand reduction (or increase) beneficial to reduce transmission constraints, value of which is reflected in rates | • Reduced DTS rate available everywhere to eligible loads / storage that participate in markets or reliability services (energy, OR) | • Discount relative to DTS for curtailable service to enable use of the system that would not otherwise occur to offset costs for other customers |
| **Rationale** | • Identify need in specific location<br>• Interrupt load to manage transmission constraints<br>• Lower future transmission costs | • Available everywhere<br>• Encourage participation in market / service through additional bids and offers | • Encourage efficient use of capability without incurring additional transmission costs (AESO can recall and load must curtail) |
| **Conclusions** | • Rates that reflect transmission cost savings from interruptions to relieve constraints have a strong locational component | • Rates that encourage participation in markets or provision of ancillary services do not impose different transmission costs than those that do not, and provision of services is compensated through those markets / contracts | • Rates that allow additional use of available capability that would not otherwise occur are beneficial for all stakeholders provided the use of this capability would truly not otherwise occur under Rate DTS |

# Rates that allow additional use of available capability

- The AESO has considered options to reflect different use cases of the grid and has identified that energy storage could make use of transmission capability that would not otherwise occur for benefit of other customers or drive the need for additional transmission capacity
- Demand Opportunity Service (DOS) is one such rate
  - Allows customers connected to the grid to draw additional power over and above the amount they are contracted for under DTS as a means of reducing DTS charges for all customers
  - The current service is interruptible, temporary and available only when there is surplus transmission capacity
    - Term is 12 months
    - Three types based on interrupt-ability: Seven-minute, One hour, Term
    - Loss charges are applied to MW under this rate
  - Participants need to pre-qualify for DOS

# DOS rates refresher

| Rate DOS Type | Cost Allocation to Rate DOS[1] | Opportunity Service Obligations |
|---|---|---|
| DOS 7 Minute | • Costs converted to $/MWh amounts<br>• Variable components of the bulk and regional system (i.e., energy charge) | Recallable within 7 minutes of a directive |
| DOS 1 Hour | • Costs converted to $/MWh amounts<br>• Variable components of the bulk and regional system (i.e., energy charge)<br>• + 50% of the non-energy bulk and regional system charges | Recallable within 60 minutes of a directive |
| DOS Term (Available to loads with generation, when generation unavailable) | • Costs converted to $/MWh amounts<br>• Variable components of the bulk and regional system (i.e., energy charge)<br>• + 100% of the non-energy bulk system charges<br>• +1200% of the non-energy regional system charges | Recallable within 7 minutes of a directive |

[1]As filed in the AESO's 2010 ~~2020~~ ISO tariff application (paragraphs 229 - 233) and approved in Decision 2010-606, released on Dec. 22, 2010

# Key terms and conditions for DOS

- Current DOS pre-qualification
  - Non-refundable $5000 fee (annual fee)
  - Requires anticipated frequency of use
  - Estimate of MWhs per month
- Eligibility criteria
  - Use would not occur under any other rate
  - Sufficient transmission capacity
  - Is temporary or repeated short-term use
  - Must have alternative energy source or a “market opportunity” where the cost of receiving additional electric energy under Rate DTS renders the opportunity uneconomic
- Transaction request
  - 45 days after pre-qualification
  - Prior to use the participant must submit a formal transaction request + $500/month if approved

# Modernizing DOS

- The AESO's revised view is that the DOS rate may be revised to allow for expanded eligibility (i.e. energy storage)
  - Overall structure and rate design considerations can remain as is
  - Energy storage may be able to meet DOS eligibility criteria
- Must resolve outstanding questions regarding eligibility, visibility and use of energy under the DOS rate for greater use
  - How to validate that the energy would not have been used under a DTS rate?
    - Any adjustments to expand application need to maintain the balance of allowing customers to draw additional power that otherwise would not be used under Rate DTS, while eliminating any potential for customers to rely on DOS as a means of avoiding DTS charges
  - How to modernize the DOS transaction information so that the AESO has clarity on when energy will be used? And how it is curtailed?
    - Confirm what information is used or needed by the AESO relating to DOS energy and eliminate any unnecessary requirements

# Next steps

- We are seeking feedback with respect to:
  - Is DOS a suitable rate for a portion of energy storage charging capacity?
  - And if so, your thoughts on assessing eligibility?
- AESO will continue to explore noted questions
  - AESO will present recommendation at Session 6

# Questions

# Implementation Considerations

# Implementation considerations

- To support the transition, the AESO will provide a forecast of rates in advance of them coming into effect
- The AESO will reduce red tape through administrative changes to rate sheets
- Updates to underlying data and transparent information
  - The AESO will propose to update the data underlying the cost allocations every five years
    - Calculations underlying the demand and energy allocations
    - Calculations underlying the allocations of demand to bulk and regional categories
  - Timing of highest coincident metered demand to hourly from 15-minute interval
    - Provides participants with more transparent information
    - Simpler calculation aligns with public information
    - More appropriately reflects information used for transmission planning

# Feedback requested on implementation changes to increase flexibility

- Should the AESO provide participants with more flexibility to contract capacity?
  - Contract reset period
    - Allow participants to change their contract capacity once new rates come into effect, without payment in lieu of notice (PILON), to better reflect their needs given the change in rate design
  - Expand PILON waiver provisions
    - Allow for changes to contract capacity without a PILON, provided the contract level has not changed in the previous five years
    - Encourage participants to provide more accurate information about contract level to the AESO by removing PILON under certain circumstances

# Next Steps

# Engagement schedule

- **March 31, 2021 |** Host technical information session to go over Bill Impact Tool to ensure understanding and enable stakeholders to understand how to navigate and determine their bill impact
- **March to May 2021 |** Work with those customers that are expected to experience a transmission cost impact of 10 per cent or more through an approach of targeted mitigation engagement
- **April 1-14, 2021 |** Host bill impact one-on-one meetings with interested ratepayers to assist with using the Bill Impact Tool and ensure understanding on how the impact can be calculated
- **April 15, 2021 |** Stakeholder feedback due on questions set out in stakeholder comment matrix
- **Late May/Early June 2021 |** Host stakeholder engagement session to provide an overview and seek stakeholder input on mitigation discussion outcomes, energy storage assessment recommendation, Session 5 stakeholder feedback or follow-up, and areas of alignment
- **June 2021 |** File application with AUC for public proceeding and approval

# Session feedback

- We want to thank you for attending the Bulk and Regional Tariff Design Stakeholder Engagement Session 5 and we would appreciate your feedback on the session
- To limit stakeholder fatigue, we are collecting your initial feedback on the session by conducting a Zoom poll during the session rather than emailing you a short session survey following the session
- Zoom poll

# Session feedback (cont.)

- We value stakeholder feedback, and we invite all interested stakeholders to provide their input on this session via the questions set out in the **Stakeholder Comment Matrix Tariff Session 5 on or before April 15, 2021**. The matrix will be available on March 25, 2021 on our website at www.aeso.ca.
  - Path: Stakeholder Engagement > Rules, standards and tariff consultations > Tariff (filter) > Bulk and Regional Tariff Design > March 25, 2021 Session 5
- Within this comment matrix we are looking for your feedback on the following:
  - Preferred rate design
  - DOS rate eligibility
  - Targeted approach on mitigation discussions
  - AESO mitigation principles and options
  - Areas of alignment
  - Implementation considerations

# Next session

- The next session (Session 6) will be hosted in late May or early June 2021. Notice will be provided three weeks in advance in our Stakeholder Newsletter and on our website.
- Session 6 purpose
  – The purpose of the session is to engage stakeholders in a discussion of the AESO’s mitigation discussion outcomes, energy storage assessment recommendation, Session 5 stakeholder feedback or follow-up, and areas of alignment
- Session 6 objectives
  – Provide an overview and seek stakeholder input on the outcomes of the targeted mitigation engagement
  – Present and discuss the energy storage assessment recommendation for the purpose of getting stakeholder feedback
  – Share our learnings and seek stakeholder input on Session 5 stakeholder feedback or follow-up and areas of alignment
  – Understand outstanding stakeholder concerns

# Questions

# Contact the AESO

- ***Twitter:*** *@theAESO*
- ***Email:*** *tariffdesign@aeso.ca*
- ***Website:*** *www.aeso.ca*
- Subscribe to our stakeholder newsletter

# Thank you

# Appendix

# Tariff design alternatives considered and dismissed

1) Approach to allocating between demand and facilitating the free flow of in-merit energy:

a) Generation capacity compared to contractual demand

**Rejected**: Does not account for differences in transmission costs that arise from how load and in merit energy use the transmission system at different times

a) Peak net generation compared to peak load

**Rejected**: Does not account for diversity amongst customers, nor does it account for the fact that transmission is needed to accommodate in merit energy even if load is there to offset.

2) Functionalization of demand-driven costs:

a) Functionalizing based on length or capacity of transmission wires

**Rejected**: no systematic correspondence between length or capacity and function

3) Consideration of time period for billing determinants for bulk costs to coincident demand:

a) 1CP and 4 CP:

**Rejected:** if selected, would not capture other times in the year where marginal in merit energy and demand are in different places.

b) 12-CP (in its current form):

**Rejected:** average is more reflective of how longer- term consumption patterns drive transmission costs

# List of Acronyms

# Acronyms

- AUC = Alberta Utilities Commission
- CP = Coincident Peak
- DFO = Distribution Facility Owner
- DOS = Demand Opportunity Service
- DTS = Demand Transmission Service
- OR = Operating Reserve
- PILON = Payment in Lieu of Notice
- POD = Point-of-Delivery