Participant-Related Costs for DFOs (Substation Fraction) and DFO Cost Flow-Through Technical Session 2A

May 14, 2020

Notice

In accordance with its mandate to operate in the public interest, the AESO will be audio and video recording this session and making the 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 Participant-Related Costs for DFOs (Substation Fraction) and DFO Cost Flow-Through Technical 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 or by telephone at 403-539-2528.

Welcome and Introductions

COVID-19 update

- The AESO's top priorities are the health and well-being of our employees and stakeholders and continuing to meet the electricity needs of all Albertans
- All business meetings with external stakeholders will be via phone or webinar indefinitely (this includes stakeholder engagement sessions)
- Based on stakeholder feedback, the AESO's own security assessment and the use of Zoom for governments, post-secondary institutions and other companies, the AESO has decided for now to continue using Zoom for our stakeholder engagements until such time that face-to-face engagements are allowed
- The AESO will continue to monitor developments and provide updates to our stakeholders as necessary
- For additional information, please visit the AESO website at www.aeso.ca and follow the path Stakeholder engagement > Covid-19

Purpose of this session

- Purpose
  - Continue to build a common understanding of the purpose and application of participant-related costs for DFOs (substation fraction formula) and DFO cost flow-through;
  - Review proposed changes to high-level principles applicable to participant-related costs for DFOs and DFO cost flow-through; and
  - Present, discuss, and understand stakeholders proposals for participant-related costs for DFOs and DFO cost flow-through.

Agenda

Time	Agenda Item	Presenter
8:00 – 8:10	Welcome, Introduction and Session Objectives	Stack'd / AESO
8:10 – 8:55	Overview • Share revised approach and schedule • Outcomes from Technical Session 1	AESO
8:55 – 9:05	Break	
9:05 – 10:50	Proposal Presentations • DCG Consortium (25 Minutes) • URICA (25 Minutes) • FortisAlberta (25 Minutes) • Joint Q&A (30 Minutes)	Various Stakeholders
10:50 – 11:00	Break	
11:00 – 12:45	Proposal Presentations (continued) • Lionstooth Energy (25 Minutes) • Solar Krafte (25 Minutes) • Canadian Solar Solutions (25 Minutes) • Joint Q&A (30 Minutes)	Various Stakeholders
12:45 – 1:00	Session Close Out and Next Steps	Stack'd / AESO

Registration (updated as of May 13, 2020)

- 1867559 Alberta LD
- Acestes Power
- Alberta Energy
- Alberta Utilities Commission (AUC)
- AltaLink Management Ltd.
- ATCO Electric
- BE
- Best Consulting Solutions Inc.
- Blake, Cassels & Graydon LLP
- BluEarth Renewables
- BowMont Capital and Advisory
- Campus Energy
- Canadian Solar
- Capital Power
- Capstone Infrastructure Corporation
- Carlotta Energy
- Chymko Consulting
- City of Lethbridge
- Clem Geo-Energy Corp
- Customized Energy Solutions
- DCG Consortium
- DePal Consulting Limited
- Denis Forest Consulting Inc.
- Dizrupt Energy
- Elemental Energy
- Enel
- ENMAX Power Corporation
- Enpowered
- EPCOR Distribution and Transmission
- Evolugen (Brookfield Renewable Canada)
- FortisAlberta Inc.
- Green Cat Renewables
- Hatch Upside
- Innogy Renewables Canada Inc.
- IPCAA
- Kalina Distributed Power
- Lionstooth Energy Inc.
- Longspur Developments
- Plains Midstream
- PMC
- Potentia Renewables
- Power Advisory LLC
- RVM Developers
- Siemens Energy Canada Limited
- Signalta Resources Limited
- Solar Krafte
- Solar Power Investment Cooperative of Edmonton
- Suncor Energy Inc.
- TC Energy
- The City of Red Deer
- URICA
- Wolf Midstream

Overview of Engagement Process

AESO Stakeholder Engagement Framework

Overall approach

- The AESO intends to:
  - engage with stakeholders regarding the issues to be examined and the action items to be undertaken, as identified in the technical session(s)
  - work towards the development of a joint proposal with distribution facility owners (DFOs) and distribution connected generation (DCGs) regarding a path forward based on the feedback gathered at the technical session(s)
- A joint proposal, if achieved, or individual proposals regarding the attribution and flow-through of transmission costs to DCGs would then be filed in the consolidated proceeding for consideration and determination by the Commission

Objectives of the overall engagement

- Objectives of the technical sessions(s) include facilitation of:

    i. a common understanding of the purpose and application of the substation fraction formula;

    ii. agreement on high-level principles applicable to the substation fraction formula including, for instance, cost certainty for DCGs, parity between transmission connected generation (TCGs) and DCGs regarding local interconnection costs, and certainty for DFOs regarding the flow-through of costs to be attributed to DCGs; and

    iii. a common understanding of the financial impacts associated with the substation fraction and any associated flow-through of local interconnection costs to different stakeholder groups, including DCGs, TCGs, DFOs, and ratepayer.

Alberta Utilities Commission (AUC) Participation in Working Sessions

Overview of process schedule

Session 1 *Feb. 27, 2020*	Session 2A *May 14, 2020*	Session 2B *May 28, 2020*	Session 3 *June 2020*	Session 4 *If required*
Session objectives: • Clarify intent and understanding of participant-related costs for DFOs (Substation Fraction) and DFO cost flow-through • Review and collect input on high-level principles	**Session objectives:** • Review high-level principles • Summarize learnings from Feb 27 session • Presentations of stakeholder proposals for participant-related costs for DFOs (Substation Fraction) and DFO cost flow-through	**Session objectives:** • Summarize learnings from May 14 session • Stakeholders who presented proposals - address comments and evaluations • Group discussion on evaluation of proposals for participant-related costs for DFOs (Substation Fraction) and DFO cost flow-through	**Session objectives:** • Final discussion and evaluation of proposals • Share process for preparation of report for the AUC	*Session objectives to be shared if additional session required* *This session would be held via webinar if required.*

Next Steps (added)

- We value stakeholder feedback and we invite all stakeholders to provide their evaluation of all of the proposals to the AESO via the questions set out in the **Proposal Evaluation Stakeholder Comment Matrix on or before May 20, 2020**
- Please submit one complete proposal evaluation stakeholder comment matrix per organization
- The AESO will also be completing and posting their evaluation of the proposals
- The AESO will post all evaluations, including the AESO's, on May 21, 2020 on the AESO website at www.aeso.ca

Next Steps (added)

- Technical Session 2B will be hosted on May 28, 2020 from 8:00 a.m. to 12:30 p.m. The session will follow a similar format and registration is now available.
- The purpose of Technical Session 2B is the following:
  - Continue to build a common understanding of the purpose and application of participant-related costs for DFOs (substation fraction formula) and DFO cost flow-through;
  - Stakeholder proposals to respond to evaluation and comments after presentation on May 14 session; and
  - Group discussion to evaluate stakeholder proposals for participant-related costs for DFOs and DFO cost flow-through and determine if alignment on a joint proposal can be made or if multiple proposals will move forward.

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

Using Zoom (updated)

- All attendees will join the webinar in listen-only mode and the host will have attendee cameras disabled and microphones muted
- When asking or typing in a question, please state your first and last name, the organization you work for, and what company you are directing your question to
- Two ways to ask questions during the Q&A portion if you are accessing the webinar using your computer or smartphone
  - If you would like to ask a question during the Q&A portion, click the icon to raise your hand and the host will see that you have raised your hand. 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.
  - You can also ask questions by typing them into the Q&A window. Click the "Q&A" button next to "Raise Hand." You're able to up-vote questions that have been already asked.

Using Zoom – where to access controls

- Using a 2-in-1/PC/MAC Computer
  - Hover your cursor over the bottom area of the Zoom app and the Controls will appear.
  - Click “Raise Hand” and the host will be notified that you would like to ask a question.
  - 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.
- Using Smartphone
  - Tap “Raise Hand.” The host will be notified that you've raised your hand.
  - Tap “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.

Using Zoom – where to access controls

- If you are accessing the webinar via conference call
  - If you would like to ask a question during the Q&A portion, on your phone's dial pad, hit *9 and the host will see that you have raised your hand. The host will unmute your microphone, you in turn will need to unmute your microphone by hitting *6 and then you can ask your question. Your number will appear on the screen.
- Phone controls for attendees
  - To raise your hand, on your phone's dial pad, hit *9. The host will be notified that you've raised your hand.
  - To toggle between mute and unmute, on your phone's dial pad, hit *6.

Technical Session 1 Outcomes

Stakeholder feedback on session 1: Format

- All parties considered the technical session and breakout session to be valuable
  - AESO also agrees that the session was informative and helpful
- Although some concerns were raised about the inability of telephone conference attendees to participate, and expressed interest in the next webinar and its format
  - AESO is using the Zoom video conferencing tool for this session
  - AESO will seek feedback from stakeholders after today’s session

Stakeholder feedback on session 1: Content

- An additional principle is that of simplicity and ease of implementation, which the AESO has incorporated into its level-setting document
  - New Principle 5
- Upfront transparency of costs at the time the investment decision is made is of utmost concern for DCG
  - Addressed in Principle 3 and new Principle 5
- Agreement that the current demand and supply-related cost allocation is not appropriate in many situations and should be replaced
  - Current methodology does not achieve, on balance, the principles identified

Stakeholder feedback on session 1: Content (cont'd)

- Strong support for eliminating "future liabilities" that the DCG has not triggered
  - Addressed in Principle 3
- Questions on whether the AESO would be conducting a jurisdictional review
  - Alberta is unique, there are no comparable jurisdictions
- Further discussion on clear definitions or understanding of key terms
  - Clarity and further understanding added to level-setting document
- All parties discussed the urgency of addressing the topic and expedited resolution
  - The AESO is working towards responding to the AUC's direction as soon as possible and discussed further in next steps

Updates to level-setting document

- The AESO, after review of stakeholder comments and further questions arising from Session 1, has made some updates to the ‘*Summary of Level-Setting Information*’ document
- Updates include and will be discussed further in this presentation:
    1. Principles: further clarity on Principle 3 and an additional Principle 5 added regarding ease of understanding and implementation;
    2. Explanation and illustration of ISO tariff treatment options available to transmission-connected generation for their connection substation, specifically for transformation facilities required to connect to the AIES; and
    3. Minor edits for clarity and consistency.
- The updated ‘*Summary of Level-Setting Information*’ document was posted with edits red-lined on May 7, 2020

Review High-level Principles

Principle 1

- Parity between transmission interconnection costs calculation for transmission connected customers and distribution connected customers while enabling effective price signals to ensure the optimal use of existing distribution and transmission facilities
  - Fairness
  - Effective price signals

Principle 2

- Market participants should be responsible for an appropriate share of the costs of transmission facilities that are required to provide them with access to the transmission system (may include paying a contribution towards facilities paid for by other customers and refund to the customer that paid)
  - Fairness
  - Cost causation

Principle 3

- Costs should not be allocated to a DCG customer after the DCG has energized, if the DCG is not directly causing those costs
  - Certainty of future costs
  - Stability
- **Addition:**
  - DCG participants should have cost certainty when making their final investment decision unless the DCG has caused those costs

Principle 4

- DFOs should be provided with reasonable certainty regarding cost treatment/recovery
  - Certainty of future costs
  - Stability

Principle 5 (added)

- Proposed tariff treatment and implementation should be easily understood
  - Simplicity
  - Stability

Update to Level-setting Document

Updates #1 & 2 to level-setting document

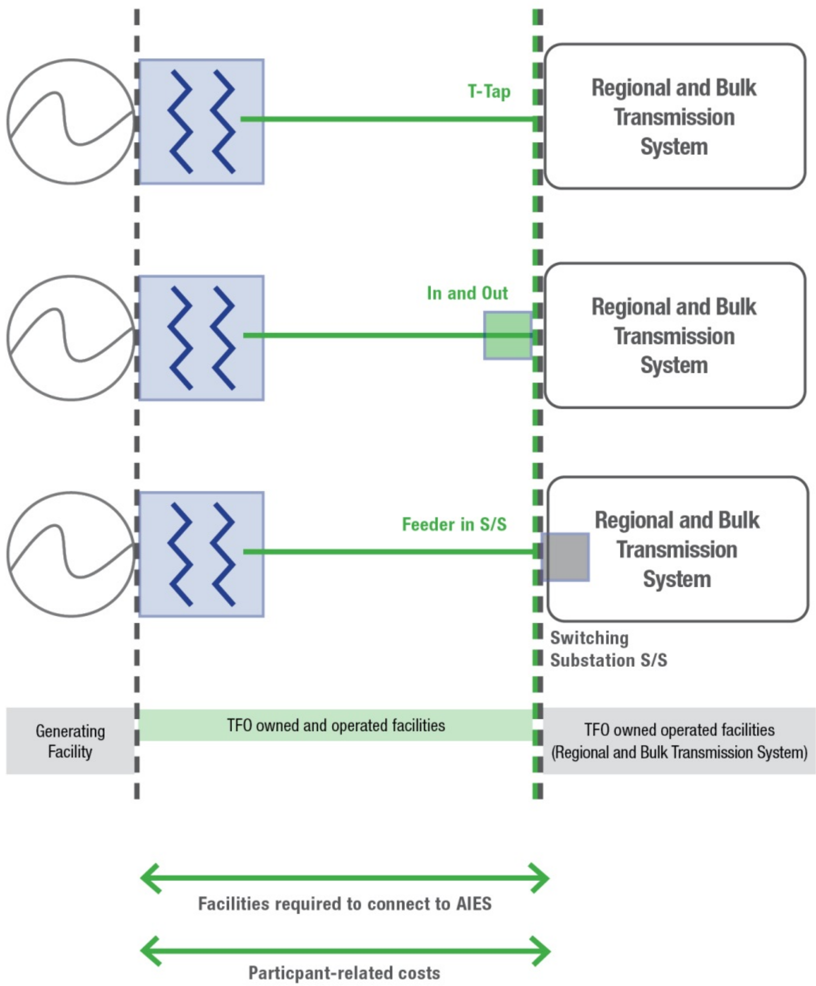
Differentiating two options available to transmission-connected generation for the costs of transformation facilities to enable connecting to the transmission system:

1. Generators can connect to the transmission system by requesting the TFO build the radial line and the stepdown transformation facilities [costs included in CCD]; or

2. Generators can request that the TFO build only the radial line and the generator is responsible (owns, maintains and operates) for the connection substation. [The costs to the generator of building its own facilities are not reflected in a CCD, they are directly incurred by the generator building the connection substation].

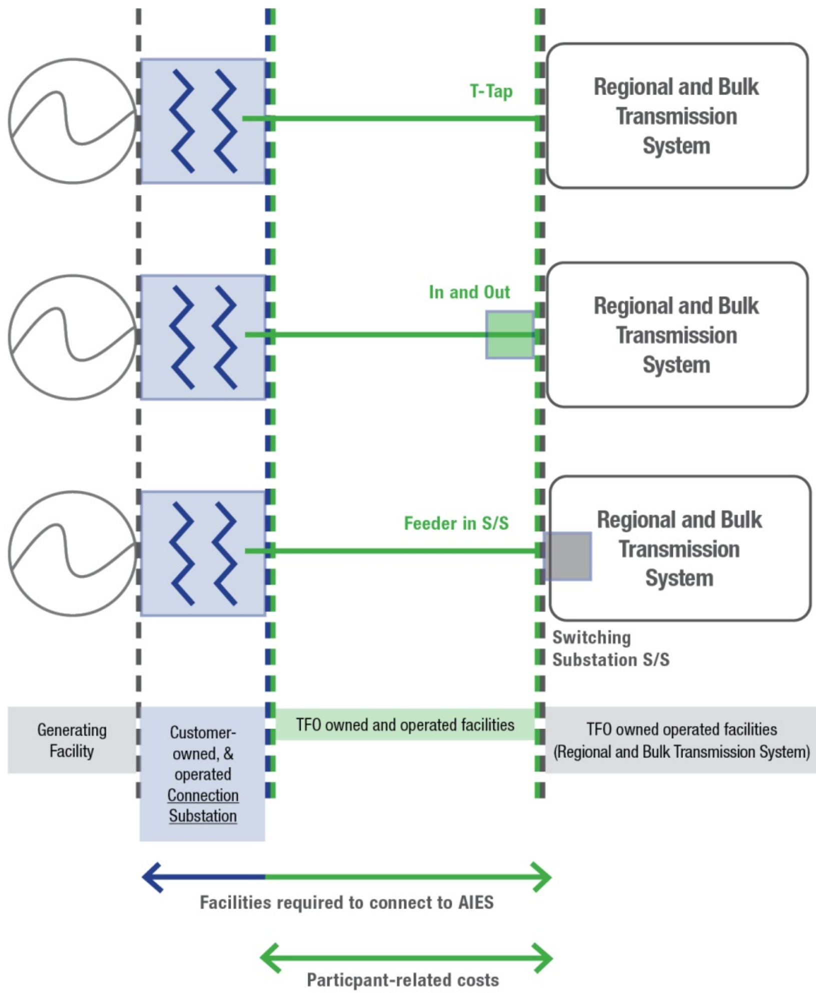
Update #3 to level-setting document

TFO builds owns and operates connection substation



Update #3 to level-setting document (con't)

GFO builds owns and operates connection substation



Break

DCG Consortium Proposal

DCG Consortium Proposal to AESO

May 14, 2020

Power Advisory LLC

www.poweradvisoryllc.com

Submitted to AESO

Companies Supportive of this Proposal

The following companies sponsored the development of this proposal:

- BluEarth Renewables Inc
- Elemental Energy Renewables Inc
- Innogy Renewables Canada Inc
- Irricana Power Generation
- Siemens Energy Canada Limited

The following associations support the content of this proposal:

- Alberta Community and Co-Operative Association ("ACCA")
- Canadian Solar Industries Association ("CanSIA")
- First Nations Power Authority ("FNPA")

Outline

This presentation follows the AESO's requested outline

A. Proposal Summary
B. Principles and Objectives
C. Proposal Details
    i. Your proposal
    ii. What it is (more detailed than the initial overview)
    iii. Process considerations (i.e., how would this solution work?)
    iv. Has the solution been implemented in other jurisdictions? Is there any external validation for your proposal?
D. Proposal Implications
    i. What are the benefits?
    ii. What are the costs?
    iii. What are the risks?
    iv. What is your evaluation of your proposal weighed against the Principles?
    v. Any other Implications (e.g., what is the impact of your proposal on a stakeholder by stakeholder basis?)?

Preamble

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Acknowledging the Constraints

- The DCG Consortium notes that the current cost allocation practice limits new DCG development in Alberta and results in unbounded liabilities for existing DCG. This practice needs to be resolved as soon as possible to allow for certainty so that investment in Alberta DCG can continue. Accordingly, the DCG Consortium is committed to participating in this consultation to come to a mutually agreeable solution that is amenable to the AESO and other stakeholders, if possible, and which can progress through an expedited process before the Commission.
- To achieve that goal, the DCG Consortium needed to recognize and acknowledge a number of constraints that it does not agree with. These constraints are primarily that the *Transmission Regulation* allows the AESO to define local interconnection costs and that the AESO has implied that definition to include both incremental costs to connect and a contribution to shared facilities costs (currently allocated based on substation fractioning).

Acknowledging the Constraints

- The *Electric Utilities Act* defines a substation as part of the transmission system. The AESO successfully reinforced this definition with its adjusted metering practice that no longer allows load and generation to be totalized on the high side of the substation, but rather requires totalization at the feeder.
- The *Transmission Regulation* requires that generators only pay for their local interconnection costs (plus GUOC and line losses), while load pays for the remainder of the system costs.
- Local interconnection costs should be defined as incremental costs to connect to the transmission system (i.e. to add or upgrade infrastructure such that the power generated can make it to the substation). Everything beyond this should be paid for by load customers.
- For TCGs, there may be instances where interconnection facilities are shared and costs can be charged to the newly connected TCG and refunded to the first TCG. In the case of DCG, the facilities that have been already constructed have been built to accommodate load and have already become a part of TFO and DFO rate bases (and effectively systemized). Accordingly, DCGs should not be charged any shared facility costs as the substation is part of the transmission system and is not incrementally required for the local interconnection.

A. Proposal Summary

Proposal Summary

Proposal: DCGs pay (1) 100% of their incremental connection costs to connect; plus (2) an additional upfront charge to contribute towards the costs of shared facilities between their point of connection and the regional system.

The second charge requires replacement of the current substation fractioning methodology with a new $/MW charge which contributes towards the costs of shared facilities.

- The upfront charge is a $/MW charge that is the same across Alberta and is known in advance of connection as it will be listed in the tariff.
- The total cost of the upfront contribution towards shared facilities costs ($/MW * MW) will be finalized in the DFO quote letter regarding incremental connection costs and will have the same payment timelines and terms.
- After paying the incremental connection costs and the contribution towards the costs of shared facilities, DCGs will not be assessed additional costs.
- The contribution towards the costs of shared facilities will be assessed based on expected exports to the AIES past the high side of the transformer.
- The contribution towards the costs of shared facilities would only be invoiced on a go forward basis after the effective date of the new tariff provisions and existing CCDs would need to be recalculated in the manner set out below.

B. Principles and Objectives

AESO Principles

Principle 1: Parity between transmission interconnection costs calculation for transmission connected customers and distribution connected customers ….

- Just as TCGs are not assessed costs after connection, neither should DCGs be.
- True parity would suggest that DCGs should not pay for systemized costs that have already been added to the TFO or DFO rate base.

Principle 1: … while enabling effective price signals to ensure the optimal use of existing distribution and transmission facilities

- Optimal use of distribution facilities requires that connection costs for DCGs do not prevent development of DCG in Alberta. If the contribution towards shared facilities costs were to climb too high, this could prevent any future development of DCG. A balance needs to be struck.

AESO Principles

Principle 2: Market participants should be responsible for an appropriate share of the costs of transmission facilities that are required to provide them with access to the transmission system (may include paying a contribution towards facilities paid for by other customers and refund to the customer that paid)

- Notwithstanding our concerns around charging transmission costs to generation customers, the Transmission Regulation grants the AESO the authority to define "local interconnection costs" and the AESO has defined these costs to include both incremental connection costs and shared facility costs.
- Accordingly, this proposal works within the existing legislative framework and AESO definition in an attempt to find resolution and progress a proposal through a regulatory process as quickly and efficiently as possible.

AESO Principles

Principle 3*: DCG participants should have cost certainty when making their final investment decision

- The DCG Consortium strongly agrees with the need to prevent future liabilities by stopping the allocation of costs at the final investment decision.
- After the DFO quote letter regarding the DCG's incremental connection costs is issued to the DCG, the DCG has 30 days to indicate its intention to move forward with the project and a further 30 days to pay the invoice.
- This proposal submits that the final investment decision is made when the DCG indicates its intention to move forward to the DFO. After this point, DCGs should not be allocated any further costs, except for any true-ups required to the final incremental connection costs per the terms of the quote letter.
- The contribution towards shared facility costs should be assessed as a part of the quote letter and should have the same payment timeline and terms.

**This principle was revised in the draft AESO Stakeholder Proposal Evaluation and this slide reflects this new language.*

AESO Principles

- Today, DCGs face three risks regarding their connection costs:
    1. The magnitude of their incremental costs to connect;
    2. The magnitude of the shared facility costs that will be allocated to them immediately through recalculation of CCDs based on a new STS contract size; and
    3. The unmitigable future risk associated with having shared facility costs associated with future upgrades allocated to a project after its final investment decision is made.
- This proposal aims to minimize the risk associated with #2 as it looks to create a postage stamp rate that will be known in the early stages of development (note that there will still be some risk as the number of MW to which the rate applies may be unclear for some time).
- This proposal also eliminates the risk associated with #3 by preventing allocation of costs after the final investment decision. This aspect of the proposal is directly tied to principle 3.
- However, it is important to note that #1 may continue to pose a high level of risk for projects. Technical studies and functional specifications must also be completed and finalized in order to obtain an incremental connection cost quote from the TFO and DFO. The magnitude of incremental connection costs may not be known by the DCG until a significant amount of time has passed following the completion of those studies. By the time this information is known, it can also be the case that DCG projects may have already obtained their permit and licence from the Commission. Accordingly, certainty regarding connection costs is may not be obtained until late in the development process, after much has been invested in designing the project.

AESO Principles

Principle 4: DFOs should be provided with reasonable certainty re: cost treatment/recovery

- This proposal will resolve any CCDs/invoices that are currently being held in abeyance by the Commission, pending the resolution of this consultation and subsequent regulatory proceeding (See Exhibit 25058-X0030). (This resolution is further outlined later in the slides where the practical application of the proposal is discussed.)
- DFOs will no longer be issued CCDs with costs allocated to both DTS and STS for their customers. CCDs previously issued to DFOs with costs allocated to both DTS and STS will be recalculated as "DFO" projects. This will eliminate any cost uncertainty with regards to recovery of costs.
- DFOs will facilitate the flow through of the contribution towards shared facility costs at the same time as the processing of the incremental connection costs. This should not create additional work for the DFO, nor will it cause concerns regarding recovery as it will be a clearly defined flow through item.

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AESO Principles

Principle 5*: Ease of understanding and implementation

- Currently, CCDs need to be recalculated every time the DTS or STS contract size changes. This proposal eliminates that administrative burden.
- This proposal charges the contribution towards shared facility costs at the time of the quote letter. At this point, the DCG is already paying a charge and the DFO is already facilitating this invoice. Accordingly, this does not add any additional burden.
- The use of postage stamp tariff charge makes this cost easy to understand by generators and easy to estimate early in the connection process.

**This principle has been added to the AESO Stakeholder Proposal Evaluation*

Objectives

AESO Question: What are the objectives you are trying to achieve or the challenges you're looking to address with your proposal (i.e., what are you trying to solve?)?

This proposal has the following objectives:

- Effective resolution in a timely manner, including expedited Commission approval
- Prevent the allocation of costs to a DCG after the final investment decision is made
- Prevent the allocation of significant costs to DCGs where the DCG did not cause the costs
- Maximize investor certainty
- Foster investment in Alberta and encourage new market entry for DCG projects

This proposal looks to solve the following issues:

- The current process results in unmitigable risk that will not allow for the development of DCG in Alberta as DCGs can be allocated costs after their final investment decision and which are associated with projects that they have no control over.
- Unmitigable risk makes it impossible for DCG projects to attain financing. There is currently a fairness issue between TCGs and DCGs.
- Prolonged investor uncertainty makes it difficult for projects to move forward with final investment decisions.

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C. Proposal Details

Local Interconnection Costs

- The Transmission Regulation grants the AESO the authority to define “local interconnection costs.”
- Under the ISO Tariff, there are two components of local interconnection costs:
    1. Incremental connection costs
    2. Contributions towards shared facility costs
- These components are included in the definition of participant-related costs (2020 applied for ISO Tariff, Section 4.2(2)).

- This proposal does not suggest any changes to incremental connection costs
- Changes proposed relate to the DCG contribution towards shared facilities

Step 1

Eliminate the current allocation of shared facility costs to DCGs through the substation fractioning methodology and CCDs

Current Calculator

- The 2019 CCD Calculator would designate a project at a DFO substation with both load and DCG as "DTS and STS."
- This designation will result in allocations of costs to both DTS and STS.
- The issue is that this calculation will be done for:
    1. Prior upgrades where a new STS contract has been added or an STS contract has increased
    2. Future upgrades, whether the STS contract changes or not
- A change is required to prevent costs from being allocated to STS, in accordance with AESO principle #3.

Attachment A1: Costs and Contract Details

Participant:	**Name of Market Participant (Customer)**			Tariff:	AESO 2019
Project:	**Project Name**			Effective	1 Jan 2019
Number:	Project Number	Type:	**DTS and STS**	To:	Current
Prepared by:	Name of Preparer	Date:	Date Prepared	Version:	2019.0.0

PROJECT DETAILS

(a)	New Service or Expansion of Existing Service?	New Service
(b)	Is Service at New or Existing Substation?	New Substation
(c)	Will Primary Service Credit Apply to Service?	No
(d)	Any Other Market Participant(s) at Substation?	No

COST OF CONNECTION PROJECT

			Reference
(e)	Cost of New Transmission Facilities:		
(f)	Shared Cost of Existing Transmission Facilities		
(g)	Less: System-Related Costs:		
(h)	Participant-Related Costs:	$0	
(i)	Less: Facilities in Excess of Good Practice:		
(j)	Less: Reduction for Replaced Transformer		
(k)	Balance of Participant-Related Costs:	$0	
(l)	Estimated Operations and Maintenance:		

CONTRACT DETAILS

			Reference
(m)	Date of Commission Permit and Licence:		
(n)	Date of AESO Energization Authorization:	Jan 1, 2019	
(o)	Date of Commercial Operation of Project:	Jan 1, 2019	
(p)	Maximum Investment Term (years):	20	
(q)	Discount Rate for Incremental Capacity:		
(r)	Prior Contribution (for Final Costs or Adjustmen		

Contract Stages			Contract Capacities at Substation (MW)					
			Contracted After Project			Contracted Prior to Project		
	Start	Duration	This Participant		Other	This Participant		Other
No	Date	Months	DTS	STS	Participant	NA	NA	Participant
(1)	Jan 2019	240						
	Total	240						

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Proposed Change

- **Create a new project type called "DFO"**
- This project type will be used for substation upgrades whenever the DFO is the market participant at the substation.
- The AESO will continue to use the "DTS," "STS," and "DTS and STS" project types for transmission connected substations.
- The "DFO" project type will use the same calculations as the "DTS Only" project type, which will ensure that all costs are allocated to load and that all costs are eligible for investments.

Attachment A1: Costs and Contract Details

Participant:	Name of Market Participant (Customer)			Tariff:	AESO 2019
Project:	Project Name			Effective	1 Jan 2019
Number:	Project Number	Type:	DTS Only	To:	Current
Prepared by:	Name of Preparer	Date:	Date Prepared	Version:	2019.0.0

PROJECT DETAILS

(a)	New Service or Expansion of Existing Service?	New Service	
(b)	Is Service at New or Existing Substation?	New Substation	
(c)	Will Primary Service Credit Apply to Service?	No	
(d)	Any Other Market Participant(s) at Substation?	No	

	COST OF CONNECTION PROJECT		Reference
(e)	Cost of New Transmission Facilities:		
(f)	Shared Cost of Existing Transmission Facilities		
(g)	Less: System-Related Costs:		
(h)	Participant-Related Costs:	$0	
(i)	Less: Facilities in Excess of Good Practice:		
(j)	Less: Reduction for Replaced Transformer		
(k)	Balance of Participant-Related Costs:	$0	
(l)	Estimated Operations and Maintenance:		

	CONTRACT DETAILS		Reference
(m)	Date of Commission Permit and Licence:		
(n)	Date of AESO Energization Authorization:	Jan 1, 2019	
(o)	Date of Commercial Operation of Project:	Jan 1, 2019	
(p)	Maximum Investment Term (years):	20	
(q)	Discount Rate for Incremental Capacity:		
(r)	Prior Contribution (for Final Costs or Adjustmer		

Contract Stages			Contract Capacities at Substation (MW)					
			Contracted After Project			Contracted Prior to Project		
	Start	Duration	This Participant		Other	This Participant		Other
No	Date	Months	DTS	NA	Participant	NA	NA	Participant
(1)	Jan 2019	240						
	Total	240						

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If Shared Facility Costs aren't allocated by CCDs, then how?

- With the proposed CCD calculator changes, the DFO will no longer be allocated STS costs from any substation upgrades.
  - This includes (1) that costs will not be allocated to STS for upgrades that occur after the DCG has energized; and (2) that costs associated with historical upgrades will not be re-calculated and re-allocated to STS when a DCG connects.
- In lieu of the contributions towards shared facilities costs that were previously allocated using the substation fraction approach in the CCD calculator, this proposal submits that DCGs would be invoiced a $/MW contribution towards shared facilities at the time of their invoice for the incremental connection costs.

Step 2

Create a new allocation methodology that allocates shared facility costs to DCGs in a reasonable and predictable manner

Contribution Towards Shared Facilities Costs

- The contribution towards shared facilities costs is proposed to be a $/MW postage stamp rate that is applicable to every DCG in Alberta at the same time as its incremental connection costs.
- This is consistent with other aspects of tariff structure in Alberta and avoids the complication of sending location incentives to DCGs based solely on recent and/or expected future costs of substation upgrades for the needs of load.

Considering Costs of a Generation Substation

- Generation substations are fairly simple facilities with lower overall costs than substations that are purpose build for multiple load customers on a DFO network.
- DFO substations are more complex with higher standards and requirements for reliability and resilience (differences that are driven by the load customers)
  - DFO substations are designed typically to a minimum of N-1 redundancy
  - They include complex protection and control schemes to manage system outages and abnormal operating conditions
  - DFO substations can include higher considerations for security and site access
  - Generation substations are designed and built for a specific application, DFO substations must be adaptive to future electricity demand requirements as well as supply capability for distribution network operation and maintenance (e.g., multiple buses and feeders that can support backfeed needs)
- As a part of its incremental connection cost payment, a DCG will pay all costs for facilities only necessary to serve generation. Accordingly, a DCG should not share in the costs of these additional facilities that are only necessary due to the load.

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Core Components

- The DCG Consortium proposes that DCGs should only pay a contribution towards the costs of shared facilities for core components. It proposes these core components to be the transformer and a high voltage breaker for 138 kV service.
- The proposed contribution is only towards the materials and installation costs associated with these two core components.
- The DCG Consortium does not propose to pay for protection and controls, SCADA, engineering, technical studies, etc.
- In many cases, those costs will be duplicative of DCG incremental costs to connect as the DCG will need to pay for its own technical studies and SCADA, for example.

Excluded Components

- The DCG Consortium proposes that DCGs should not pay a share of either the low voltage breakers or the supply line.
- Low Voltage Breakers
  - The number of breakers at a station is determined by the distribution network and existing load customers. Accordingly, the DCG should not be required to contribute towards the costs of the additional feeders.
  - In many cases, a DCG will pay incremental connection costs associated with a new low voltage breaker or the upgrade of an existing low voltage breaker. In these cases, paying a contribution towards the shared facilities costs associated with these would be double counting
- Supply Line
  - A TCG is able to site in a manner that controls supply line costs. A DCG sites near load and connects to existing transmission infrastructure. A DCG cannot control the length of the supply line and should not pay increased connection costs for longer supply lines.
  - Adding a $/MW/km charge for the supply line will send a locational incentive with no associated benefit, i.e. a locational incentive to connect to substations with shorter supply lines to save on connection costs.

Cost Sharing

- Analysis should be completed to determine a typical cost for these two components on an average $/MW basis.
- Next, it should be noted that current flows both ways through a transformer and the use of those facilities by a DCG will not diminish their capability to be used by the load customers. The full capacity of the transformer is available for load to use in the downwards direction and generation to use in the upwards direction. Accordingly, the $/MW costs associated with the costs of a transformer and high voltage breaker should be divided in half in order to attribute 50% of the costs to generation.
- This methodology would continue to be used on a go forward basis, but the output $/MW charge could be revisited on a four year cycle with the tariff applications as component costs may change through time.

High Level Estimate

- In discussion with Fortis, we have developed the following substation component assumptions:
  - Transformer capacity with maximum rating of 42 MVA
  - High voltage breaker for 138 kV service
- In discussion with suppliers,* we understand the following to be appropriate estimates of the installed costs of substation components:
  - 42 MVA Transformer ~$1m-1.6m
  - 138 kV High Voltage Breaker ~ $130-165k
- This leads to the following postage stamp rate that acts as a contribution towards the shared facilities costs:
  - $1.447m * 50% = $724k
  - $724k / 42 MW = $17,232/MW to be paid by generators
- Further, to avoid double-counting, additional consideration will need to be made in the event that the transformer or high voltage breaker are upgraded as a part of the DCG connection (as these costs would then be included in the incremental connection costs)

**The above estimates are based on preliminary quotes from suppliers and the DCG Consortium is working to confirm and obtain these estimates in final written form for use in the AESO consultation sessions.*

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An Upper Limit

- TCG enjoys a competitive advantage over DCG given the economies of scale associated with larger generation projects.
- DCG's competitive advantage is lower connection costs based on use of existing transmission infrastructure.
- There is a threshold above which a contribution towards shared facilities costs will be prohibitively expensive and not allow future development of DCG in Alberta. This threshold will vary depending on the project.
- In order for a proposal to be connection type agnostic (i.e. allow for both TCG and DCG to continue in Alberta in the future), the DCG contribution towards shared facilities costs cannot be so great as to prevent development of DCG.

Step 3

Determine which MWs the $/MW charge is applied

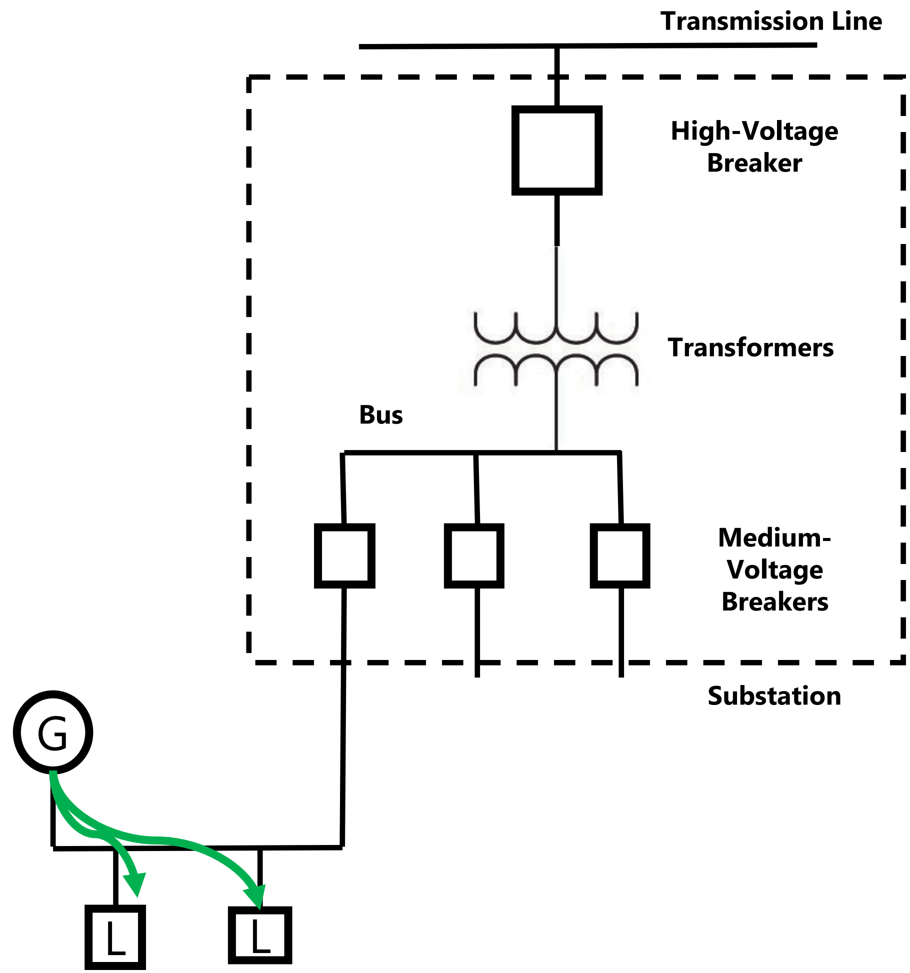
Application of the $/MW Charge

Proposal: To use estimated hourly production data from the DCG combined with historical hourly consumption data to determine an expectation of DCG export to the AIES via the high side of the transformer.

- As the DCG is being charged for the usage of shared transmission facilities (i.e. the substation), it is fair to only apply the charge to energy that may use/benefit from the specific transmission facilities.
- These calculations determine the amount of expected exports past the high side of the transformer.
- This is similar to the methodology used to calculate STS contract capacities, but it is a more accurate estimate of exports.
  - DFOs determine STS contract capacities by comparing the minimum load to the maximum generation in all hours of the day. The exception is solar facilities, where they specifically focus on the period between 9am and 3pm.
  - This does not reflect differences in timing. For example, the minimum load could be at 9am, while the load could be materially higher during the hours when the solar DCG is producing its maximum output.
  - Similarly, for wind and gas DCGs, the minimum load is occurring over night which may not correlate with periods of maximum generation

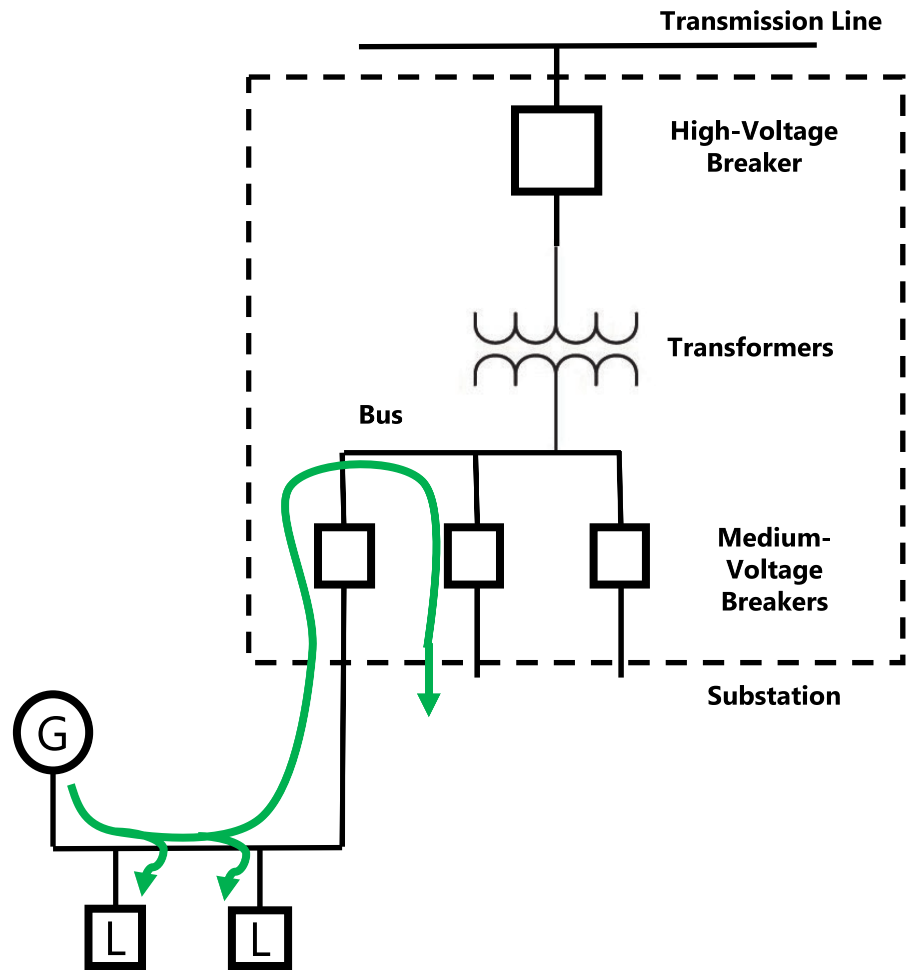
Scenario 1: DCG supplies local load on same feeder

- The diagram to the right shows a simplified typical arrangement for a DFO owned substation
- Under Scenario 1, energy output from the Generator (see green line) is consumed by load on the same feeder for all hours of the year
- Since no DCG output flows to the substation, no costs are allocated to the generator, i.e. 0 MWs are charged the contribution towards shared facility costs



Scenario 2: DCG supplies local load on different feeder

- Under Scenario 2, some energy output from the Generator (green line) is consumed by load on a different feeder
- DCG output flows to the substation and then back out of the substation to a different feeder
- As long as the substation requires imports from the transmission system to serve load on any of the feeders, the power will flow down to the feeders. Accordingly, the DCG will not be exporting power back up to the transmission system
- Since no DCG output flows to the transformer or the high-voltage breaker, no costs are allocated to the generator, i.e. 0 MWs are charged the contribution towards shared facility costs



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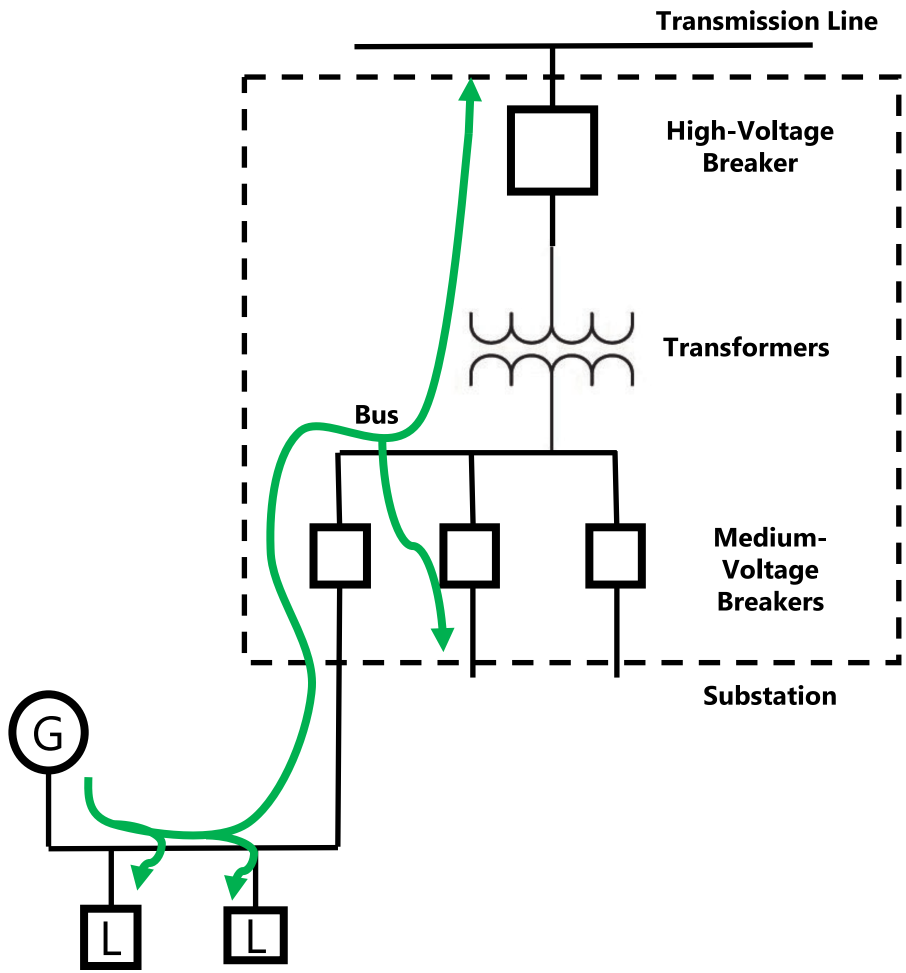
Scenario 3: DCG supplies up to transmission network

- Under Scenario 3, some energy output from the Generator (green line) is supplied to the transmission network
- In this scenario, the DCG would be charged for a contribution towards the costs of the transformers and the high-voltage breakers, i.e. the costs of primary components in the substation to connect to the transmission network.



Step 4

Establish clear timing of the final charges to ensure investor certainty

Restrict Further Charges After the Final Investment Decision

- Under the current connection process, the DFO issues a quote letter to a DCG that notes the incremental costs of connection. This quote letter includes both DFO and TFO incremental connection costs and a 20 year up front payment towards DFO O&M.
- The DCG is given 30 days to accept this quote letter and indicate its intention to move ahead with its connection and a further 30 days to pay its invoice.
- At the point when a DCG accepts the quote from its DFO, it can be considered to have made its final investment decision and will be investing significant capital into the costs of its connection.
- The contribution towards shared facilities costs would be included in the quote letter along side the incremental connection costs. It would then be subject to the same payment timeline and terms as the incremental connection costs. This proposal suggests no changes should be made to the current terms that accompany the quote letter.
- After the DCG accepts this quote, no further costs can be assessed to the DCG over the life of its project, except for costs outlined in the terms and conditions of the quote letter or where the DCG makes changes that require the construction of additional transmission facilities.

Changes to Load and Supply Through Time

- The current substation fractioning methodology reassesses CCDs whenever the DTS or STS contract capacities change. This is one of the primary issues with the current methodology as it prevents investor certainty.
- This proposal assesses a contribution towards shared facilities costs based on moment in time data at the point of connection.
- It could be true that load decreases at a substation, causing an STS contract capacity to increase after its connection. It could be equally true that load growth causes an STS contract capacity to fall after the DCG connection. This proposal does not include any additional charges to be assessed or any contribution towards shared facility costs to be refunded in these cases. This is necessary to have investor certainty.
- Accordingly, changes to STS and DTS contract capacities through time will not impact connection costs.
- A project will not be charged further connection costs except in the case where they add additional generation in a manner that would trigger an increase in the STS contract. In that case, the incremental generation addition should be treated like a new generation project and assessed a contribution towards shared facilities costs accordingly.

Step 5

The transition

Practical Application of this Proposal

- The AESO noted in Session #1 that it considers its CCD calculators have worked for allocating costs to DTS and STS in the case of dual-use customers, but that the calculations were never contemplated to apply to DCGs/DFOs and have not functioned effectively for that purpose.
- Given this, it is necessary to recalculate all CCDs that have been given to DFOs with costs allocated to STS. These CCDs would all be recalculated using the project type “DFO.”
  - This would ensure any existing DCGs are not assessed costs after their final investment decision.
  - DCGs that are still before their final investment decision will be assessed the new $/MW charge in addition to their incremental connection costs.
- As noted in the previous slide, the new $/MW charge would be finalized at the time of the DFO quote letter and paid with the DFO/TFO invoice for incremental connection costs. These invoices would only be sent out on a go forward basis.
- **Grandfathering implication:** Any projects that have already received their quote letter will not be assessed the new contribution towards shared facilities costs charge and will not be assessed any previous or future shared costs under the current substation fractioning approach.

C.iv. Jurisdictional Validation

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Jurisdictional Validation

- The DCG Consortium has not undertaken a jurisdictional review.
- It is our understanding that other jurisdictions only charge DCGs for their incremental connection costs and do not have this concept of shared facility costs where DCGs pay for components previously constructed for load customers. It is also our understanding that other jurisdictions are moving towards policies that foster and encourage non-wires solutions, including DCGs, and, accordingly, are looking to remove existing barriers.
  - This understanding is anecdotal, as the research has not been commissioned.
- Accordingly, we do not expect to find external validation for our proposal; however, we note that our proposal was designed to solve the issue caused by the current substation fractioning methodology while fitting into the AESO's definitions of local interconnection costs (which includes a provision for shared facility costs in addition to incremental connection costs).

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D. Proposal Implications

Benefits

- Investor certainty, i.e. no charges to DCGs past the final investment decision
- The charge is postage stamp and, accordingly, does not provide a locational signal based on historic and expected future costs associated with substation upgrades driven by the needs of load customers.
    - If this was designed based on depreciated costs, there would be a locational signal to site at older substations, which is not ideal.
- Fairness across DCGs
    - Under the current methodologies, some DCGs are assigned significant costs while others could be free from any charges, based on past and unknowable future substation upgrades.
    - This proposal creates increased fairness across different sizes of DCG and across different connections.
- Speedy resolution of this issue will allow projects near their final investment decision to move forward. This is preferable to a drawn out regulatory proceeding.

Costs/Risks

- This proposal will require more up-front work to put in place relative to a proposal that determines shared facility costs on a substation by substation basis,
  - That being said, overall this proposal is likely more simple than having to set the allocation on a case by case basis. Implementation of the cost allocation will be less work each time a DCG discusses connection options with a DFO and the AESO will not have to constantly re-issue CCDs for PODs with changing STS and DTS contract capacity sizes.
  - Further, this proposal will increase investor certainty.

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Assessment of Compliance With Principles

Principle	Does our proposal meet it?
Principle 1: Parity between transmission interconnection costs calculation for transmission connected customers and distribution connected customers while enabling effective price signals to ensure the optimal use of existing distribution and transmission facilities	Yes*
Principle 2: Market participants should be responsible for an appropriate share of the costs of transmission facilities that are required to provide them with access to the transmission system (may include paying a contribution towards facilities paid for by other customers and refund to the customer that paid)	Yes*
Principle 3: DCG participants should have cost certainty when making their final investment decision	Yes
Principle 4: DFOs should be provided with reasonable certainty re: cost treatment/recovery	Yes
Principle 5: Ease of understanding and implementation	Yes

**This proposal meets Principle 1 and 2 as best as possible given the second-best solution. A solution not required to meet the constraints of the Transmission Regulation would better meet both principles.*

Impact of Proposal on Stakeholders

- **DFO** – DFOs will no longer be issued CCDs with costs allocated to both DTS and STS. This will eliminate any cost uncertainty with regards to recovery of costs. Rather, DFOs will facilitate the flow though of a the contribution towards shared facility costs at the same time as the processing of the incremental connection costs.
- **DFO** – This proposal will resolve any CCDs/invoices that are currently being held in abeyance by Fortis, pending the resolution of this consultation and subsequent regulatory proceeding.
- **DFO/AESO/DCG** – The level of this charge will only need to be determined once per tariff cycle (4 years) rather than the current methodology which involves calculations every time a substation is upgraded or every time contract capacities (STS or DTS) change.
- **DCG** – This proposal provides the cost certainty required to continue to invest in DCG development in Alberta.
- **Investors/Financial Institutions** – This proposal provides cost certainty required for financial institutions to provide access to credit.
- **DFO Connected Load Customers** – Load customers will pay the full costs associated with any substation upgrades and other transmission infrastructure as a part of their distribution and transmission rates. DCG contributions to shared facility costs will be remitted to the TFO to offset revenue requirement and associated TFO rates.

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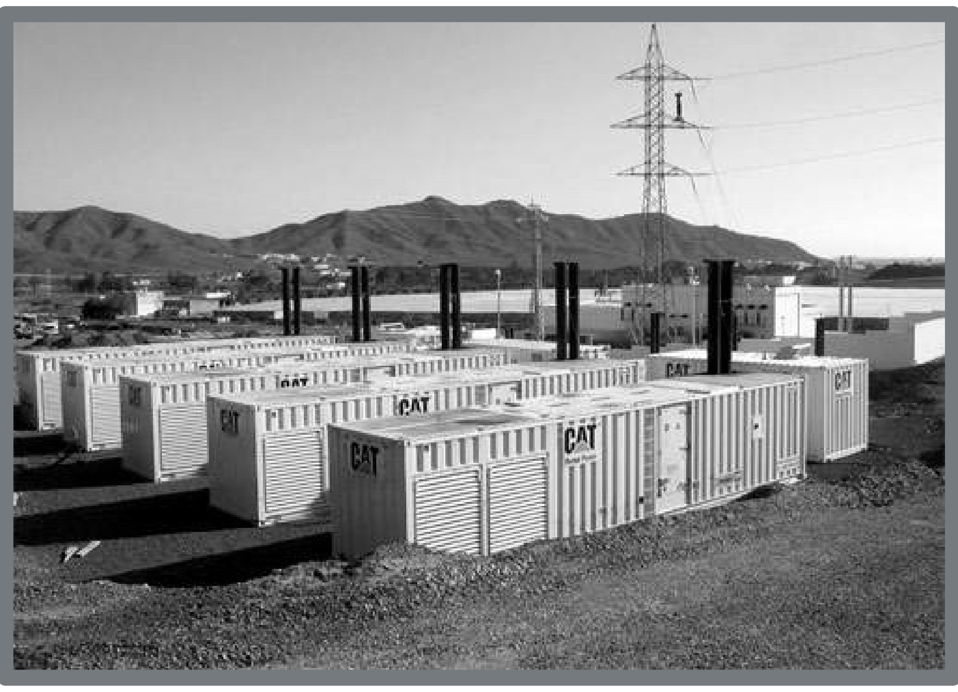
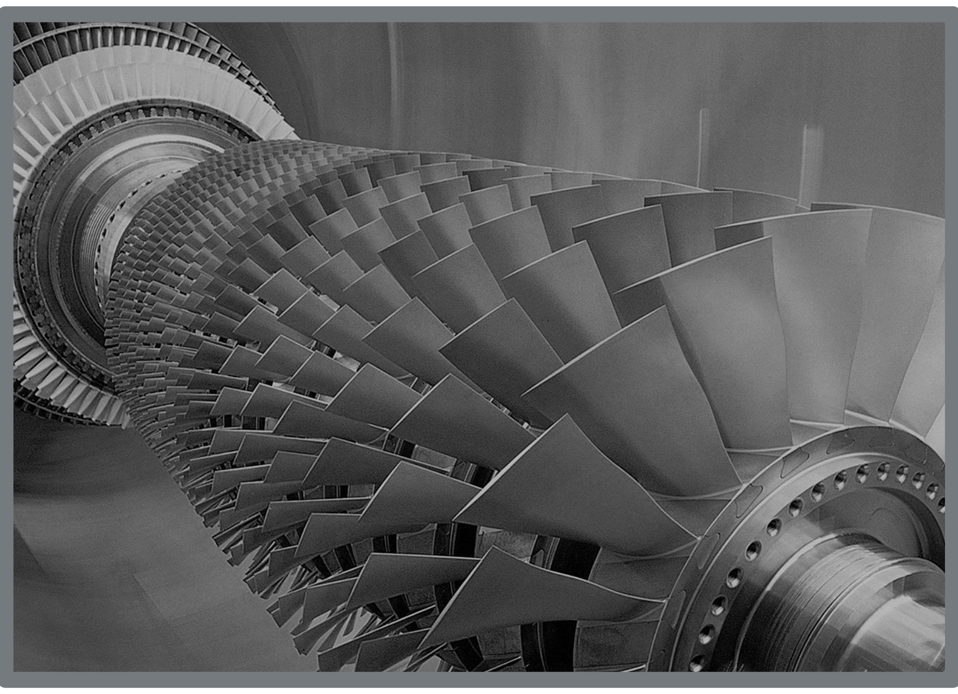
Acronyms

- AESO / ISO – Alberta Electric System Operator
- AIES – Alberta Interconnected Electric System
- CCD – Construction Contribution Decision
- DCG – Distribution Connected Generation / Distribution Connected Generator
- DFO – Distribution Facility Operator
- DTS – Demand Transmission Service
- GUOC – Generator Unit Owners Contribution
- NPV – Net Present Value
- O&M – Operation and Maintenance
- STS – Supply Transmission Service
- TCG – Transmission Connected Generation / Transmission Connected Generator
- TFO – Transmission Facility Operator

URICA Proposal





URICA

URICA PROPOSAL TO THE AESO

Participant-Related Costs for DFOs (Substation Fraction) and DFO Cost Flow-Through

APRIL 30, 2020

URICA Energy Management Corporation

FACILITY DISPATCH

Providing an outsourced, essential service for over 3,000MW of power generation, we provide the plant generation instructions and communicate with the AESO.

ASSET OPTIMIZATION

Collaborating with owners of over 500MW of power generation, we work to maximize the return from their generating facilities through sophisticated commercial management.

PORTFOLIO MANAGEMENT

Whether a generator or consumer, we develop and execute strategies to procure energy, shed load, and balance the customer's position.

CONSULTING & ADVISORY

Utilizing our market knowledge and in-depth experience, we work with clientele to analyze, educate, and effectively participate in the market.

CONTENTS

PROPOSAL SUMMARY

URICA's Proposal achieves cost certainty necessary to support continued investment in DCG in Alberta, but also assigns equitable costs for the connection to the system.

- DCG pay 100% of the Incremental Connection Costs to Connect;
- DCG would be charged a System Contribution Charge:
  - Applied to costs of shared facilities between DCG point of connection and the regional system;
  - Essentially a charge for access and use of the transmission system; and
  - The charge would be reviewable each tariff cycle or less depending on AESO tariff methodology moving forward.
- DCGs will <u>not</u> be assessed additional costs moving forward for future system upgrades.

AESO PRINCIPLES

Principle 1:

Parity between transmission interconnection costs calculation for transmission connected customers and distribution connected customers.

URICA PROPOSAL ADHERENCE

- Neither DCGS not TCGs should be assessed costs after connection.
- Parity cannot be viewed through the lens of interconnection costs only.
- Many decisions go into determination of TCG versus DCG not just interconnection costs. Should be viewed holistically.
- Substation fraction methodology was not contemplated to apply to DCGs/DFOs and does not function effectively for that purpose.
    - URICA proposal eliminates this issue because we are replacing the substation methodology with a system contribution methodology.

AESO PRINCIPLES

Principle 2:

Market participants should be responsible for an appropriate share of the costs of transmission facilities that are required to provide them with access to the transmission system.

URICA PROPOSAL ADHERENCE

- The contribution towards the costs of shared facilities will be assessed based on STS contract. DCG pays STS charges based on flows onto the transmission system.
- Will require transparency ease of access to feeder level details to ensure that STS values are accurate based on DCG levels and actual feeder load to ensure that are responsible only for costs properly attributed to DCG.
- Upfront transmission access charge would create a standardized $/MW charge, regardless of substation connection point in Alberta.
- Cost would be known in advance of connection so DCG has clarity of costs prior to energization.

AESO PRINCIPLES

Principle 3:

Costs should not be allocated to a DCG customer after the DCG has energized, if the DCG is not directly causing those costs.

URICA PROPOSAL ADHERENCE

- After paying the incremental connection costs and the contribution towards the costs of shared facilities, DCGs will not be assessed additional costs moving forward.
  - This provides investment certainty.
- However, further costs to the system based on DCG facility additions or amendments would be a flow through incremental cost to DCG.
  - Additional or incremental costs to the system caused by the DCG will be paid for by the DCG.

AESO PRINCIPLES

Principle 4:

DFOs should be provided with reasonable certainty re: cost treatment/recovery.

URICA PROPOSAL ADHERENCE

- DFOs will facilitate the flow through shared facility costs at the same time as the processing of the incremental connection costs.
  - Does not create a large amount of additional work for the DFO. In fact, the process for integrating power generation facilities should be unchanged from the historical protocol.
- Historical wires costs remain in DFO rate base and there is no removal of investment from the rate base.
  - Because it is a clearly defined cost allocation at the time of connection estimation costs, there should be no issue with cost recovery from the DFO side.

AESO PRINCIPLES

Principle 5:

Ease of understanding and implementation.

URICA PROPOSAL ADHERENCE

- Assures all charges are known in advance of energization.
  - Economic analysis and financing can be completed with a high level of certainty prior to the outlay of significant capital.
- The use of a standardized system contribution charge makes cost easy to quantify and account for by generators in planning stages.
- The line is clearly established for what the DFO and TFO are responsible for prior to integration of a generator to the system.

PROPOSAL OBJECTIVES

The current methodology allows for the allocation of unknown costs throughout the life of the asset / project creates un-mitigatable risk which make continued investment in DCG extremely unlikely. Updated substation fraction methodology needs to create a stabile platform and known variables for DCG investment in Alberta.

- Prevent allocation of costs to DCG that they did not cause or exacerbate.
- Prevent allocation of future costs to DCG that they are not responsible for.
- Create visibility and transparency of expected costs that cultivate investor certainty and encourage rational DCG project additions in Alberta.
- Time is of the Essence: effective resolution in a timely manner including expedited AUC approval of the solution.
- Best efforts under existing Transmission Regulation.

PROPOSAL DETAIL

- Incremental connection costs – DCG should pay for the incremental cost for transmission upgrades caused by the DCG connection.
  - Attempt to right size or limit sizing of DCG projects based on associated additional costs that these types of projects may induce via cost causation.

- Exchange the existing substation fraction methodology a shared facilities contribution cost towards the facilities costs that were previously allocated using the substation fraction approach in the CCD calculation.

- DCGs would be invoiced a standardized contribution cost towards shared facilities at the time of their invoice for incremental connection costs.
  - Standardized rate at all connection points avoids sending confusing locational incentives to DCG and creating separate arguments regarding substation depreciations etc.

PROPOSAL DETAIL, CONTINUED

- As a part of its incremental connection cost payment, a DCG will pay all costs for facilities only necessary to serve generation.
  - DCG should not share in the costs of additional facilities that are specifically needed to serve load.
  - Propose that DCGs should only pay a contribution towards the costs of shared facilities for core components.
    - Transformer / Voltage Breakers
  - DCGs would be not be charged a standardized contribution cost towards protection and controls.
    - Limit duplication of cost allocation to components that are required to serve load and should be recovered via rate base.
  - The DCG should not pay for supply line costs as unlike a TCG they have no control over how the substation was sited.
    - Would create locational signals not aligned and not correlated to any benefit.

COST ALLOCATION

- Analysis should be completed to determine a typical cost for the transformer and breakers on an average $/MW basis.
  - Current flows both ways through a transformer and therefore full capacity of the transformer is available for both load and generation to use.
  - Costs of transformer and high voltage breaker should be allocated to attribute 50% of the costs to generation.

- Costs need to be reasonable and justifiable.
  - Would be reviewable at each ISO tariff application.

- The contribution towards the costs of shared facilities will be assessed based on STS contract.
  - DCG pays STS charges based on flows onto the transmission system.
  - Requires transparency ease of access to feeder level details to ensure that STS values are accurate.

BENEFITS

- **Alignment to AESO Principles in the hopes of an expedited resolution that will:**
  - Creates a stabile investment environment
  - Creates visibility to costs up front
  - Eliminate the potential for unmitigable future costs

- **Fair allocation of system contributions to DCG versus DFO.**
  - Payment for necessary system upgrades, not protection and controls, not supply line length

- **Creation of proper incentives to DCG to ensure that they are locating in the correct location for the correct reasons.**
  - Do not want DCG making location decisions based on advantageous supply line length or age of substation.
  - Does not provide the correct locational signal based on historic and expected future costs associated with substation upgrades driven by the needs of load customers.

IMPLEMENTATION CONSIDERATIONS

- **The URICA proposal, as with every other proposal, will require DFO effort.**
  - All stakeholders must expend effort to make any resolution workable.

- **Put in place and develop a standardized contribution rate on a per MW basis.**
  - Regulatory burden and effort.

- **Access to Substation and Feeder level data.**
  - Information is key in good decision making.

- **Time is of the Essence.**
  - Delays and drawn out efforts to develop contribution rates leaves Developers and DFOs in limbo for planning and investment.

CONTACT COORDINATES

URICA Energy Management

The future of outsourced electricity generation operational and commercial services is here.

Send us a message or visit us:

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Calgary, Alberta T2R 0T9

403.457.4699

www.urica.ca

FortisAlberta Proposal

AESO STAKEHOLDER ENGAGEMENT

PARTICIPANT-RELATED COSTS FOR DFOs (SUBSTATION FRACTION) AND DFO COST FLOW-THROUGH

SESSION 2A

PROPOSAL OF FORTISALBERTA INC.

Miles Stroh & Kevin Noble

May 14, 2020

FORTIS ALBERTA

MISSION ZERO Bring it Home Preventable Injuries

Outline of Presentation

1.0 Overview of Proposal
2.0 Principles

3.0 Proposal Details
- 3.1 Timing
- 3.2 Process Flow
- 3.3 Examples

4.0 Implications of Proposal
- 4.1 Benefits
- 4.2 Risks
- 4.3 Impacts by Stakeholder

1.0 Overview:
Contribution Allocation Method for DFO-contracted PODs

- For all DFO-contracted PODs, the AESO should abandon its existing substation fraction method

- Replace it with a more direct allocation method:

  Average Supply-related Interconnection Contribution ("ASIC")

- Requires decoupling of the load (DTS) and supply (STS) side of the ISO tariff's customer contribution policy
  - DFO's load side carries on as is but with a DTS fraction = 1.0

Contribution Timing, Process and Flow-through to DCG

- AESO to determine and assess ASIC at the time of DCG grid entry
  - @ time of establishment, or any change to, the STS contract capacity at the interconnecting POD (in excess of 1 MW), along with GUOC, STS losses, Distribution interconnection costs
- ASIC: Full flow-through the DFO's distribution tariff & charged to DCG:
  - Retains the integrity of the transmission contribution price signal that the AESO wishes to send to supply
  - Supports cost causation, parity with treatment of transmission-connected generation (TCG)
- ASIC amounts paid by DCG would be returned to the TFO via the ISO and distribution tariffs, resulting in an offset to TFO rate base
  - AESO/TFO to design a DTS POD-specific credit rider to be returned to load

Determination of Magnitude/Level of ASIC Contribution to DCG

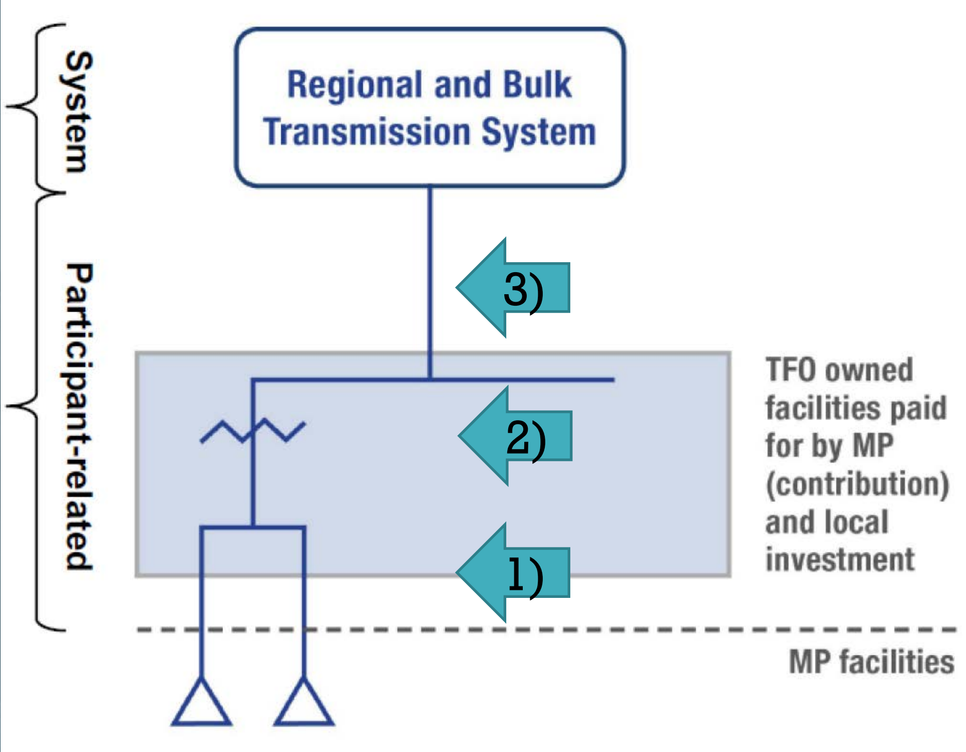
- AESO designs ASIC to satisfy the principles of cost causation & attaining parity between DCG and TCG

- Based on a case-by-case technical cost analysis and allocation (direct assignment) at the time of DCG grid entry (STS contracting)

- AESO should work with the TFOs and DFOs to develop an average province-wide supply-related contribution schedule
  - per unit ASIC $ /supply-related capacity (MW)

- Forms part of the ISO tariff and could be reviewed/adjusted annually in the AESO's annual tariff update applications

Determination of Magnitude/Level of ASIC Contribution to DCG



- ASIC schedule could be comprised of two or three local transmission cost components, based on supply's (DCG's) use of participant-related facilities:

  1) the distribution voltage feeder breaker and bus;

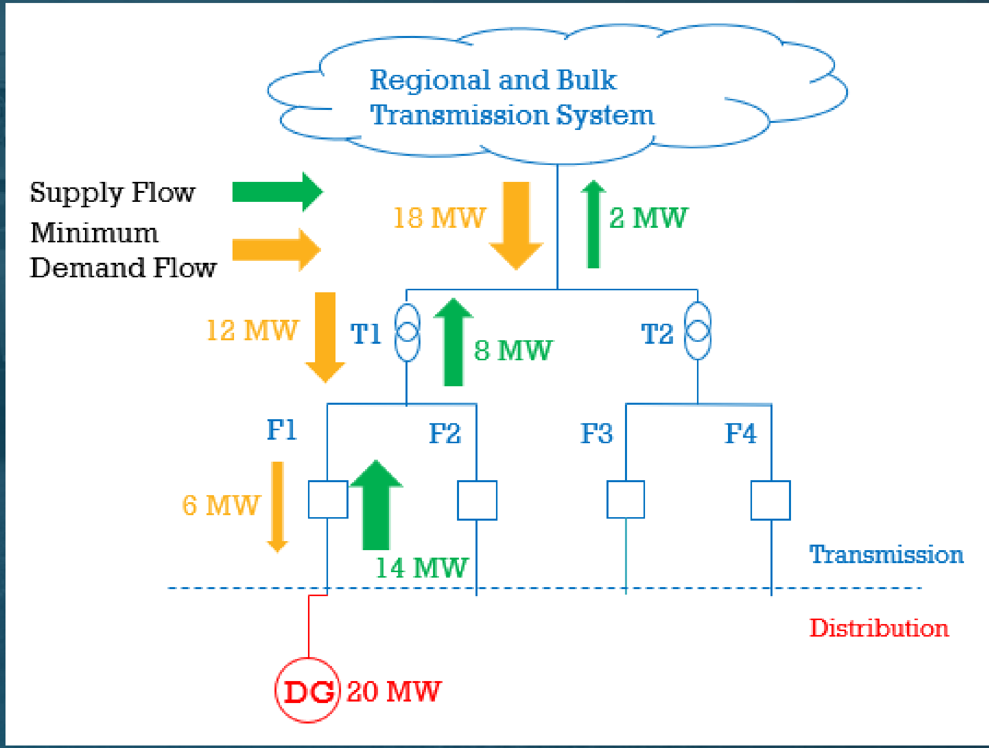
  2) the POD substation transformer, breakers and bus; and

  3) the local transmission line* that connects the POD substation to the AIES bulk and regional transmission system.

* Included for illustration, not recommended for inclusion by FAI

Determination of Magnitude/Level of ASIC Contribution to DCG

- AESO supported by TFOs and DFOs to determine these average POD costs by component and determine the forecast reverse power flows (i.e. Supply's (DCG's) use of each of the POD components).
- Projected power flows for supply and demand through each POD component considering average load factors and supply capacity factors through each component.
- Consistent with the levels used in the establishment of the STS contract capacity levels at the interconnecting POD as per the ISO tariff.



2.0 Principles

- Principles by stakeholders largely aligned with ratemaking principles applied for tariff design throughout the regulated utility industry.
- AESO overarching principle - should facilitate a fair, efficient and openly competitive market (FEOC).
- Leading to the principles that contributions should reflect cost causation, parity between the transmission interconnection costs calculation for transmission-connected customers and distribution-connected customers, both in terms of fairness and providing effective price signals.
- FortisAlberta agrees with this principle and as such, its proposal is designed to meet the objective of achieving parity between transmission and distribution-connected generation when assessing transmission contributions for DCG.

3.1 Timing

- DCG customers should be provided with a transparent preliminary supply-related POD cost allocation price signal during the initial project planning stages of their DCG projects.

- Costs should not be, subsequently, added to the upfront supply-related price signals provided at the time of DCG connection.

- Similarly, additional costs should not be allocated to DCG customers as a result of local transmission system upgrades, driven by load, after the interconnection of the DCG.
  - An exception to this would be when a DCG proponent implements an increase in exported power onto the grid.

3.2 Process Flow

- (1) determination by the DFO of the forecast magnitude of reverse power flow on individual local transmission system components;
- (2) determination by the DFO of historical load factors for individual local transmission system infrastructure components;
- (3) determination by the AESO of forecast capacity factor of the individual DCG;
- (4) determination by the AESO in collaboration with TFOs average installed costs of the individual local transmission system infrastructure components;
- (5) determination by the AESO in collaboration with TFOs the average reverse power flow capability of the individual local transmission system components;
- (6) calculation of a supply-related cost allocation per MW for individual local transmission system infrastructure components.

3.2 Process Flow

- ASIC Calculation

- $ASIC = ASIC_{breaker} + ASIC_{trans}$
- $ASIC = [(RP_{breaker} \times \$/MW_{breaker}) \times UF_{breaker}] + [(RP_{trans} \times \$/MW_{trans}) \times UF_{trans}]$

- Where:
- RP = Reverse power flow on transmission component
- $/MW = Average cost per MW of reverse power flow on transmission component
- UF = Utilization factor on transmission component

3.2 Process Flow

- Utilization Factor Calculation

- $UF = (CF_{DCG} \times MRP)/[(CF_{DCG} \times MRP)+(LF \times PL)]$

- Where:
- UF = Utilization factor of the transmission component
- CF_{DCG} = Capacity Factor of the DCG
- MRP = Maximum reverse power on transmission component
- LF = Load factor on transmission component
- PL = Peak load on transmission component

3.2 Process Flow

Upon application of DCG to interconnect and establish STS:

- AESO provides a supply-related contribution document similar to a CCD that identifies the total required supply-related contribution.
- AESO/TFO invoices DFO, for all supply-related contributions required.
- DFO invoices the DCG developer for all supply-related contributions prior to connection and energization of DCG.
- AESO/ TFO establishes a POD specific credit rider for ASICs paid to be returned to DTS load customers.

3.3 Example

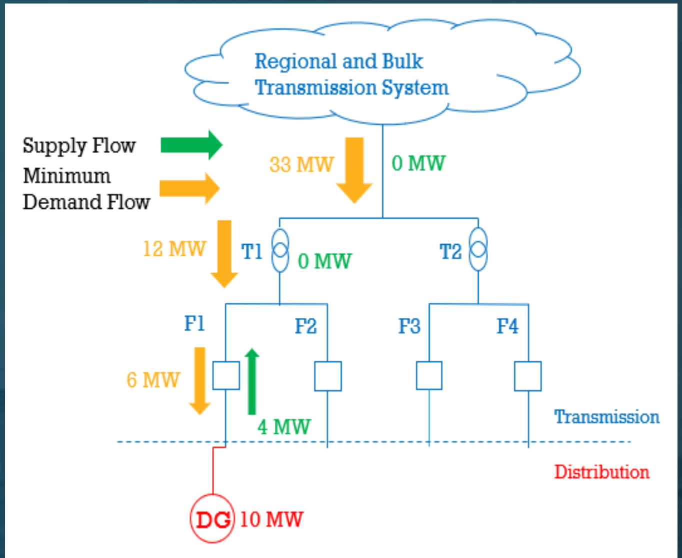
- The example assumptions used to monetize the DCG usage include:

Transmission Component	Average cost	Average maximum reverse power flow capacity
Distribution voltage feeder breaker and bus	$1.0M	25 MW
Substation stepdown transformer, breakers and bus	$3.6M	40 MW

* Numbers are for illustrative purposes only.

3.3 Example #1 – Breaker Level Reverse Power

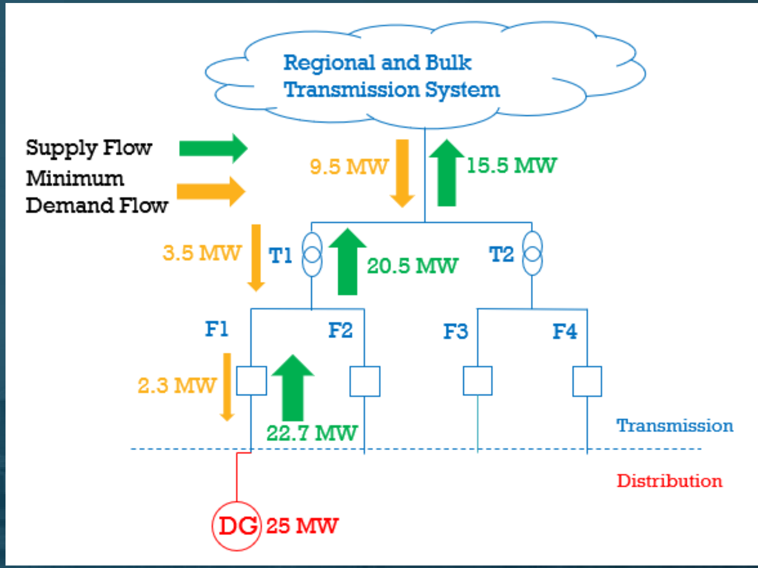
Component	(w)	(x)	(y)	(z)	(w*x)/[(w*x)+(y*z)]
	Maximum Component Reverse Power (MW)	DCG Capacity Factor	Peak Component Load	Load Factor	Utilization Factor
(1) Distribution voltage feeder breaker	4.0	0.33	12.0	0.64	0.15
(2) POD Substation Transformer	0.0	0.33	27.0	0.77	0.00



Component	(a) Step 1	(b) step 4	(c) Step 5**	(d) Step 6	(e) Step 7 (c/d)	(e) Step 8 (a x b x e)
	Magnitude of Reverse Power flow (MW)	Utilization Factor	Ave installed cost ($k)	Capacity (MW)	Installed cost per MW ($k)	Required DCG Usage Contribution ($k)
(1) Distribution voltage feeder breaker	4.0	0.15	$1,000	25	$40	$24
(2) POD Substation Transformer	0.0	0.14	$3,600	40	$90	$0
Total required DCG usage contribution of all components ($k)						$24

3.3 Example #2 – POD Level Reverse Power

Component	(w)	(x)	(y)	(z)	(w*x)/[(w*x)+(y*z)]
	Maximum Component Reverse Power (MW)	DCG Capacity Factor	Peak Component Load	Load Factor	Utilization Factor
(1) Distribution voltage feeder breaker	22.7	0.33	5.0	0.71	0.68
(2) POD Substation Transformer	20.5	0.33	12.0	0.87	0.39



Component	(a) Step 1	(b) step 4	(c) Step 5	(d) Step 6	(e) Step 7 (c/d)	(e) Step 8 (a x b x e)
	Magnitude of Reverse Power flow (MW)	Utilization Factor	Ave installed cost ($k)	Capacity (MW)	Installed cost per MW ($k)	Required DCG Usage Contribution ($k)
(1) Distribution voltage feeder breaker	22.7	0.68	$1,000	25	$40	$616
(2) POD Substation Transformer	20.5	0.39	$3,600	40	$90	$725
Total required DCG usage contribution of all components ($k)						$1,342

4.0 Implementation of Proposal

4.1 Benefits

- Provides a pathway for the AESO to effectively resolve the stated DFO/DCG concerns.
- Improves harmonization and timing of transmission price signals sent by ISO tariff for flow-through distribution tariffs to end-use DCG customers.
- Eliminates the risk, and the resulting adverse impact on DCG development.
- Provides investor and cost certainty for DCG proponents and confirms full DFO flow-through with respect to transmission costs.
- Eliminates the possibility of transmission contributions being assessed to DCG after they have interconnected or the local investment claw-back to DFO load customers.

FORTIS ALBERTA

MISSION ZERO Bring it Home Preventable Injuries

4.2 Risks

- Risks are primarily implementation risks and costs associated with the AESO's implementation of the ASIC proposal and tariff mechanisms.

- AESO would also have to design POD specific riders in its ISO tariff as a means to compensate the DFO's load customers in the form of lower DTS POD charges for the DCGs' payment of ASIC (offsetting TFO rate base at these DFO-contracted PODs).

- Transition plan required for application to DCGs in queue / connected.

- Helpful for the AESO to develop an Information Document (ID) to make its CCD timing and contracting practices and policies more clear, consistent and transparent for its DFO and DCG customers.

4.3 Impacts on Stakeholders

- **DCG:** Removes the risk and the resulting adverse impact on DCG development, that was imposed by the AESO's current practice of applying its substation fraction approach

- **DFOs:** Harmonizes and synchronizes timing of transmission price signals sent by the ISO tariff to DCG;
  - Confirms flow-through treatment of transmission costs per s.47(a) of *T- Reg*.
  - Requires DFOs to assist AESO in identifying reverse power flows by component

4.3 Impacts on Stakeholders

- **AESO:** Requires amendments and approvals to ISO tariff to
  - Differentiate between the application of its customer contribution policy to DFO-contracted PODs versus non-DFO-contracted PODs
  - Codify the ASIC levels and mechanism, and POD-specific credit riders, in its tariff
  - Transition / Grandfathering Plan to ASIC mechanism
  - Develop an Information Document (ID) re: same.

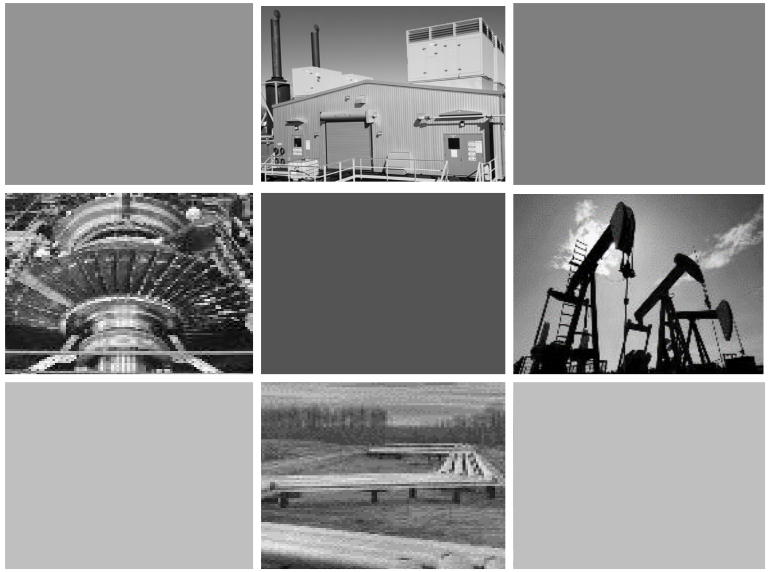
- **TFOs:** Requires TFOs to assist the AESO to determine the average transmission costs by component and POD-specific credit riders for DCG payment of ASIC contributions.

End

Joint Q&A

Break

Lionstooth Energy Proposal



Lionstooth Energy Proposal

April 30th, 2020

Agenda & Overview

Agenda

- Introduction to Lionstooth Energy
- Level-Setting & the Principles the Proposal is based on:
  - The Problem as LTE sees it
  - Key Policy & Principles
- Proposal
- Implications of Proposal
- Summary

Lionstooth Energy Proposal

Proposal	Policy / *Principle*
1. Historical costs remain in TFO/DFO rate base	• "Load Pays" Policy • Recovery of revenue requirement *principle* • Investor Certainty *principle*
2. DCG pays for incremental cost for Tx upgrades caused by DCG	• Locational signal Policy • Cost causation *principle* • No future risks *principle* • Investor Certainty *principle* • Parity between TCG & DCG *principle*
3. Refund to DCG as load increases	• "Load Pays" Policy • Cost causation *principle*

Lionstooth Energy

Lionstooth Energy

Experienced Generation Developer

- Developing Alberta-based projects since 2009
- Over 100 MW of projects designed, constructed and operated
- Focused on natural gas fired distributed generation
- Also providing advisory consulting for other developers

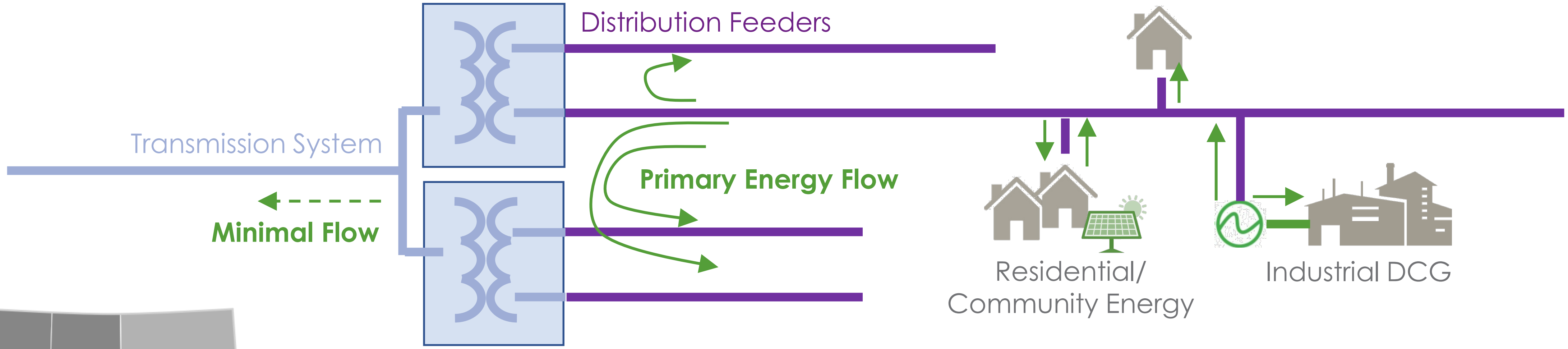
Active Advocate for DCG

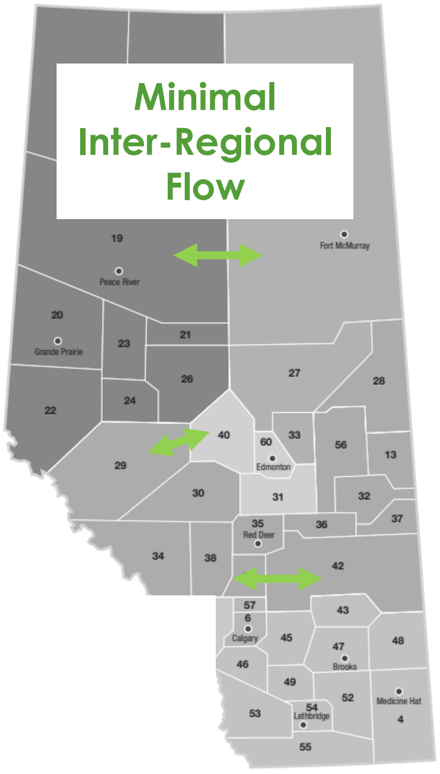
- Participating in DCG consultations & proceedings since 2017 Dx Inquiry

Location	Cadotte	Judy Creek	Galloway	Cadotte	Judy Creek	Carson Creek	Swan Hills	Swan Hills	Karr	Gold Creek
Capacity	4 MW	2 MW	4 MW	20 MW	15 MW	15 MW	5 MW	7 MW	3 MW	3 MW
In-Service Date	2012	2012	2013	2013	2014	2014	2015	2016	2016	2017
Grid Connected	•	•	•	•	•	•	•	•		
Isolated									•	•
Sales / Produced Gas					•	•			•	•
Flare Gas	•		•	•			•	•		
Waste Heat		•								•
Technology	Micro-Turbines	ORC	Micro-Turbines	Recips	Turbine	Turbine	Recips	Recips	Recips	Micro-Turbines
Industry Partner	•	•	•	•			•	•	•	•
Independent					•	•				
Still Operating?	•	•	•	•	•	•		•	•	•

Lionstooth Energy

Future Vision for Alberta Electricity





The future is being driven by customer choice.

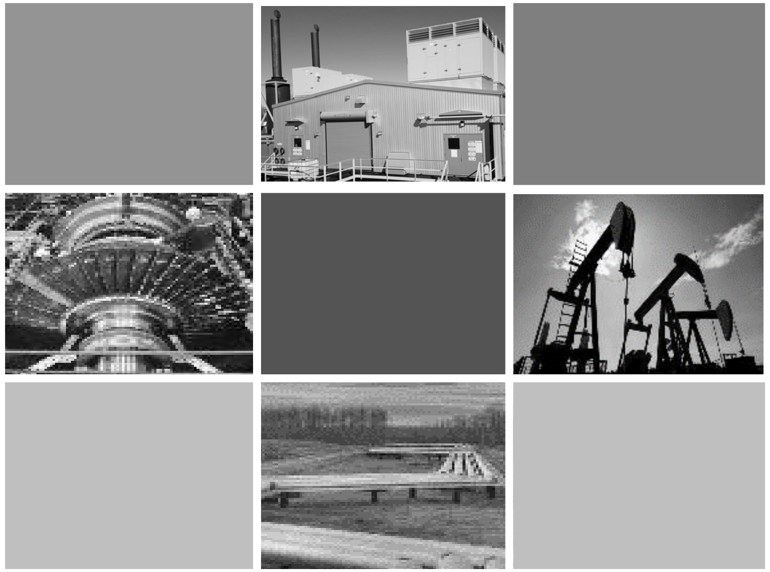
- Electricity consumption & supply will become increasingly more democratized and personalized
- Local Distribution systems/planning regions will become more self-contained
- Distribution utilities will become the enabler of intra-regional energy flows
- Transmission Utilities will still support:
  - Location-specific loads (large industrials) and generators (wind, nuclear) that exceed the capacity of the distribution system
  - Inter-regional and inter-provincial energy flows (still important, relied on less frequently)
- Policy and principle development should:
  - Continue to look at what best enables customers
  - Protect customers from further growth of "sunk assets" that no longer fit what customers want

Lionstooth Energy

Proposal Collaboration

- As an experienced developer of DCG, Lionstooth's business is directly and materially impacted by the outcome of these Technical Sessions and the total cost for DCG interconnection
- To support LTE's proposal development, we engaged the following entities to gain an increased understanding of their concerns, motivations, & comments on Lionstooth's proposal
  - AESO
  - ATCO Electric
  - FortisAlberta
  - Kalina Power
  - URICA Energy Mgmt
  - DCG Consortium
  - BluEarth Renewables
  - Razor Energy
  - Campus Energy
  - Peters Energy Solutions
  - Aura Power Renewables
  - Montana First Nation
  - Ermineskin Cree Nation
  - Métis Nation of Alberta
  - Solar Krafte
  - EDC Associates
  - IPCAA

Lionstooth Energy



Level-Setting & the Principles the Proposal is Based On

Lionstooth Energy

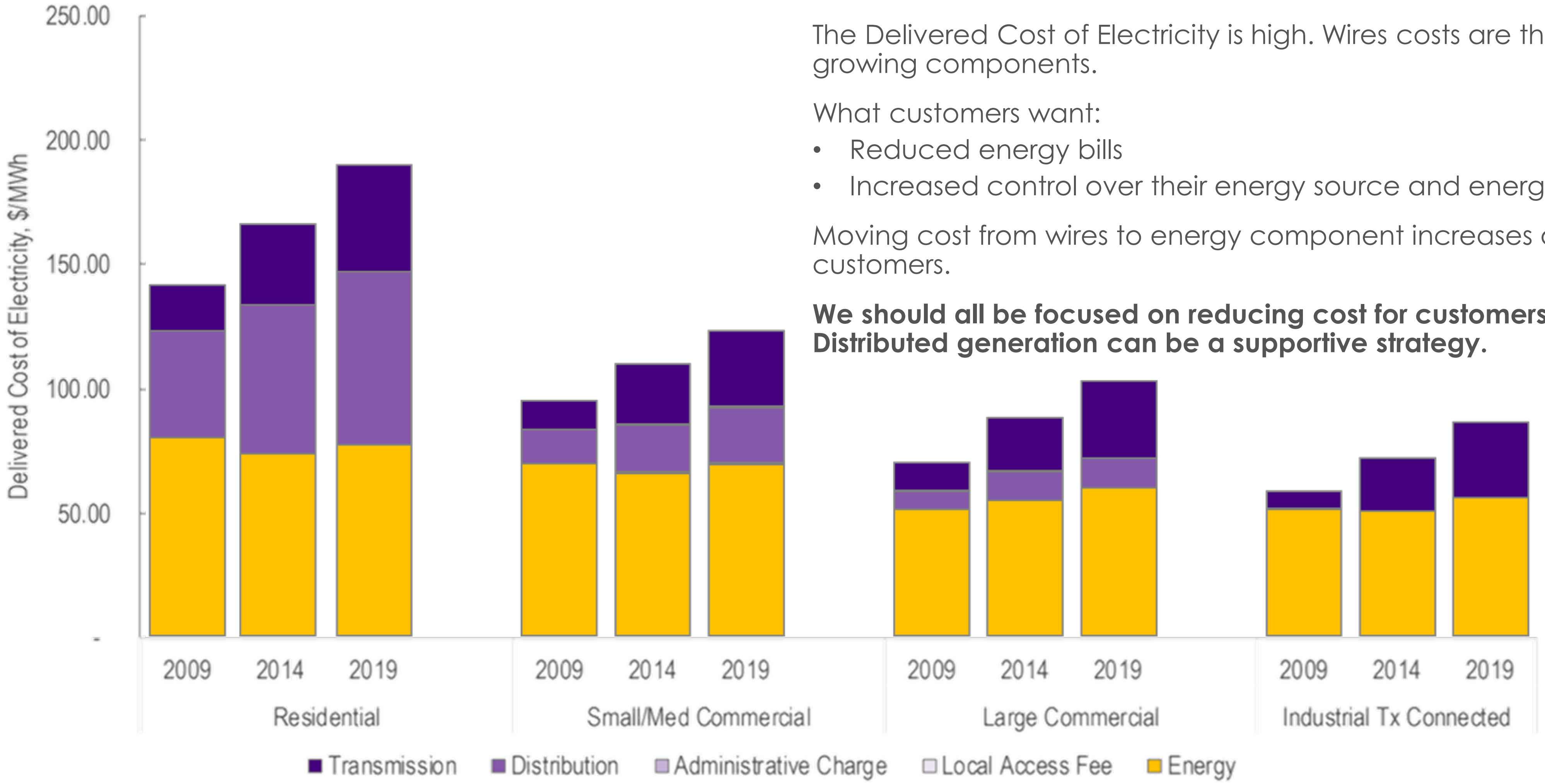
Level-Setting: Focus is on Participant-related Costs

	Transmission Costs: Bulk and Regional	Transmission Costs: Participant-related	Distribution: Connection to distribution grid costs	DCG Project Costs: DCG incurred costs
AESO Terminology →	Transmission Costs: Bulk and Regional	Transmission Costs: Participant-related	Distribution: Connection to distribution grid costs	DCG Project Costs: DCG incurred costs
TReg Terminology →	aka **System Costs**	aka **Local Interconnection Costs**		
	BULK AND REGIONAL No impact to DCG	**SUBSTATION** Supply related costs based on the last project at the substation in the past 20 years	**DISTRIBUTION GRID** DCG invoiced directly by DFO	**DCG PROJECT** DCG project facility costs plus TFO protection and controls. TFO invoices the DFO who invoices the DCG.
			In this scenario, the DFO is the Market Participant (MP)	
DCG cost impact	Z No cost	A A = Supply related cost	B B = DFO interconnection costs	C + D C = TFO protection and controls costs D = DCG owners costs
	GUOC A System Contribution Payment, calculated by the AESO, by region, for generation access to Bulk & Regional system.	**Substation Fraction** This component is the subject of discussion.	**DFO Interconnection Cost** Incremental connection costs paid to the DFO to connect to the distribution system.	**TFO Protection & Controls + DCG Site Connection Costs** Costs paid to the TFO for connecting to Tx system plus on-site DCG connection costs.

DCG Total Interconnection Cost: Z + A + B + C + D
Focus of this discussion is A cost only.

Lionstooth Energy

Level-Setting: Impacts to the Delivered Cost of Electricity



The Delivered Cost of Electricity is high. Wires costs are the fastest growing components.

What customers want:

- Reduced energy bills
- Increased control over their energy source and energy consumption.

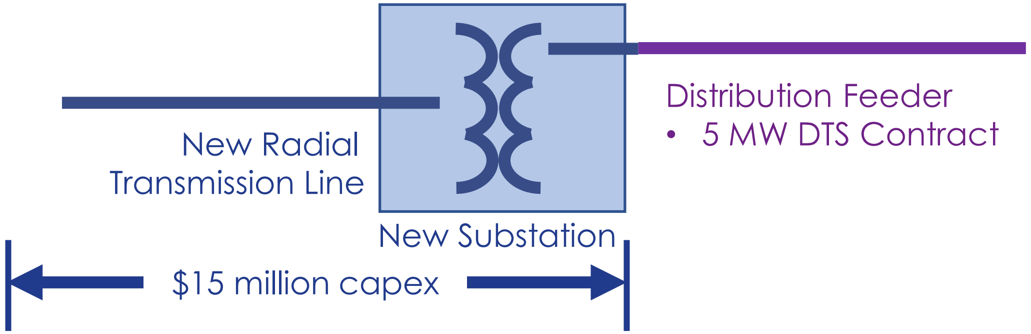
Moving cost from wires to energy component increases overall bill for customers.

We should all be focused on reducing cost for customers. Distributed generation can be a supportive strategy.

*Graph reproduced from "AESO Delivered Cost of Electricity Estimates Presentation" posted with Bulk & Regional engagement (09 Mar 2020).

The Problem as Lionstooth sees it

New “Radial” Substation



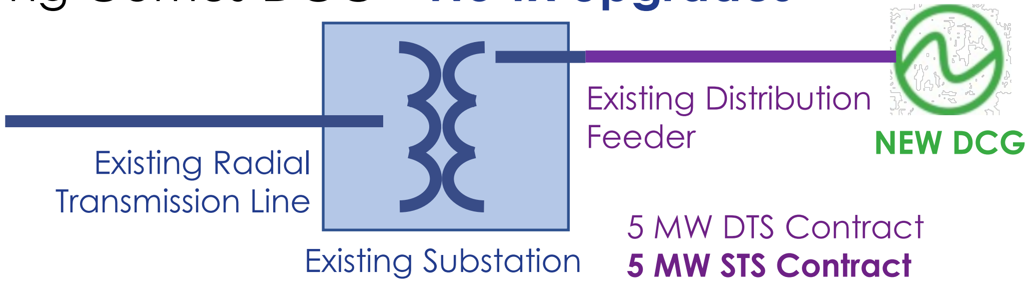
TFO
- $10 million allowable investment
- Rolled into rate base, earns regulated return (8 ¾% return)
- Recovered through DTS tariff

DFO
- $5 million capital contribution
- $5 million rolled into DFO rate base, earns regulated return (8 ¾% return)
- Recovered through Dx tariffs

Load Customers
- Wires bills increase to pay for increased Tx & Dx rate bases*

***Example Footnotes:**
- High-level example for illustrative purposes
- Does not account for timing imbalances in rate design
- Does not account for significant amount of time between “new radial substation” and “addition of DCG”

Along Comes DCG – **No Tx Upgrades**



5 MW DTS Contract
5 MW STS Contract
50% Substation Fraction Each

TFO
- $5 million allowable investment (decreased due to changes in substation fraction)
- $5 million removed from TFO rate base (de-systemizing)
- **TFO NOT HAPPY**

DFO*
- $2.5 million capital contribution (decreased due to changes in substation fraction)
- $2.5 million removed from DFO rate base (de-systemizing)
- **DFO NOT HAPPY**

Load Customers
- Wires bill decreases*
- Energy bill increases, likely <u>increasing more than wires goes down</u>
- **Load Customers NOT HAPPY**

DCG Customer
- $7.5 million capital contribution
- 25-50% increase in CAPEX
- Recovered through energy market (15-20% return)
- **DCG NOT HAPPY**

No one should be HAPPY with this allocation methodology!

Key Policy & Regulation

Transmission Development Policy & Transmission Regulation

- Tx policy must contribute to a stable investment climate
- Tx should not be a barrier to generation development

Policy 1 – Load Pays for Transmission

- Payment for Tx is primarily borne by loads, recovered through regulated tariffs (rather than energy market)
- TDP recognizes wires charges allocated to generators will ultimately be passed onto customers through energy price

↓ ↓

Sec 47: Costs of the Tx system are wholly charged to DFOs, ISDs, etc., & the amount payable by DFOs is recoverable in the DFO's tariff

Policy 2 – Generator Locational Signals

- To align interests, a financial contribution from generators is required based on their size and proximity to load centres
- Wholesale electricity market should not be unduly distorted with allocated Tx costs

↓ ↓

Sec. 28: Generators [TCG] pay **local interconnection costs**
Sec. 29: Generators pay **GUOC** (recovery for system costs)

Rate Design *Principles*

FEOC:*

- Fair – participants are working with a leveling playing field
- Efficient – transactions between willing parties are not impeded
- Openly Competitive – competition is not impeded

- Refers to market and economic efficiencies and outcomes, not perceived inequities or leveling of physical conditions

Tariff Design *Principles* (Bonbright)

- *Principle 1* – Recovery of Revenue Requirement
- *Principle 2* – Cost Causation
  - Provision of appropriate price signals that reflect all costs and benefits

*With support from Kalina Distributed Power, Proceeding 24116 Exhibit 24116-X0599.01 "Written Submission" (March 2020).

Load pays & generators are incented to locate close to load.
Design *principles* cannot override TReg & TDP Policies.

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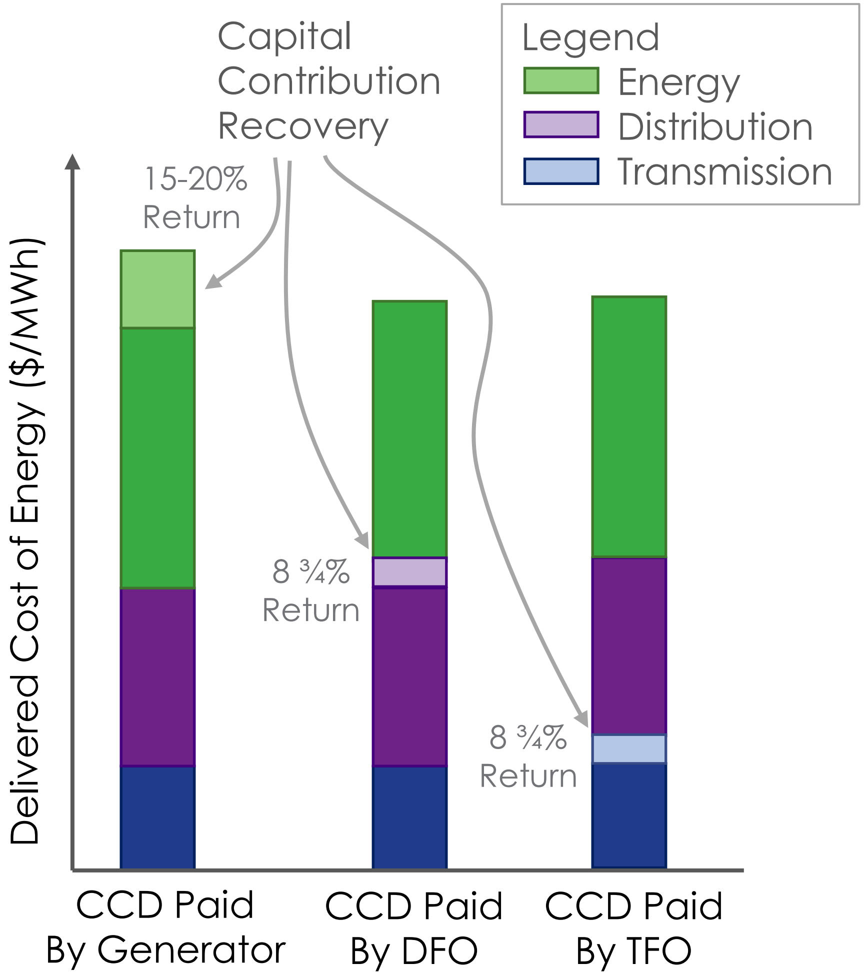
Impact of Current Allocation Methodology

- Starting with the TDP, there was a conscious shift to removing embedded costs of the wires system from generators. The TDP noted that removing this approach will:
  - Ensure regulated Tx price distortions are not introduced into the wholesale market
  - Provide transparent pricing for Tx service to customers
  - Align with neighboring jurisdictions

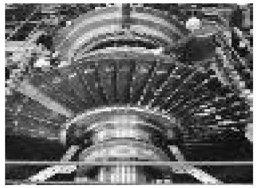
- The TDP also acknowledged and recognized the flow-through relationship between wires-based generation charges and the energy market
  - Example: customers ultimately pay for losses through their energy price

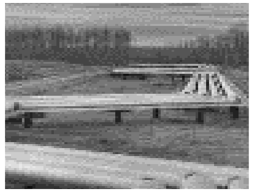
- This approach was aligned with FEOC, in that it pursued efficient market outcomes, not settling for perceived inequities or recovering costs based on benefits



The current Allocation Methodology is leading us back to a market where, **Tx price signals will distort the energy market,** and load, which ultimately pays, will see **further increases in the total delivered cost of energy**.

Lionstooth Energy

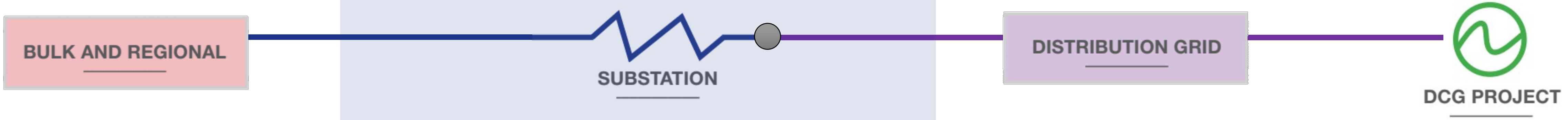





Proposal Detail

Lionstooth Proposal

System Costs Z	Tx Local Interconnection Cost A	Dx Local Interconnection Cost B	DCG Project Cost C+D



System Costs (Z)

GUOC
No Change

Tx Local Interconnection Cost (A)

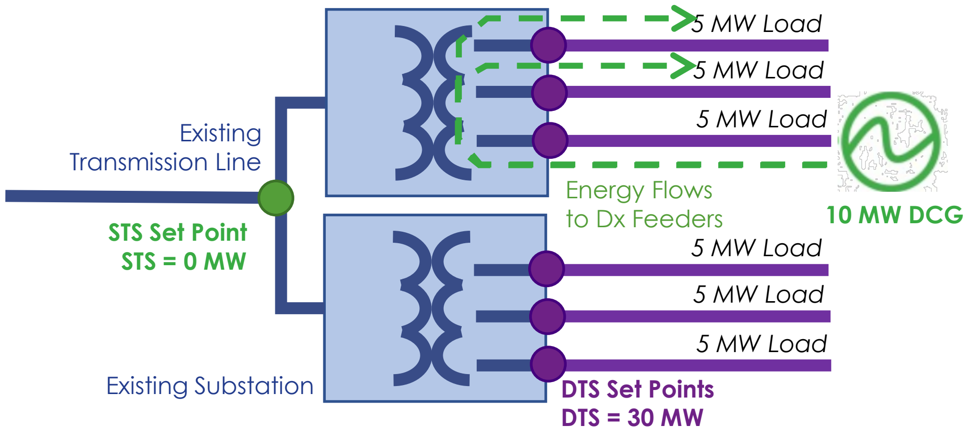
- Historical wires costs remain in TFO/DFO rate base
    - No removal of investment from rate base
    - No Tx distortion of energy market
- DCG should pay for the **incremental cost** for Tx upgrades caused by the DCG connection
    - Costs known up-front
    - Paid at time of connection
    - Principle of cost-causation
    - No need for substation fractioning
- As load increases, refund to DCG (just like TCG)
    - DCG cannot claim exclusive right to incremental Tx / Dx capacity
    - Refund based on actual demand flows on Dx system, not necessarily DTS contract demand
- DCG pays STS charges based on actual supply flows onto Tx system

Dx Local Interconnection Cost (B)

No Change

DCG Project Cost (C+D)

No Change



The cost of the wires system continues to be primarily borne by load.
DCG pays local interconnection cost, including both Tx & Dx costs, calculated on a cost causation basis.

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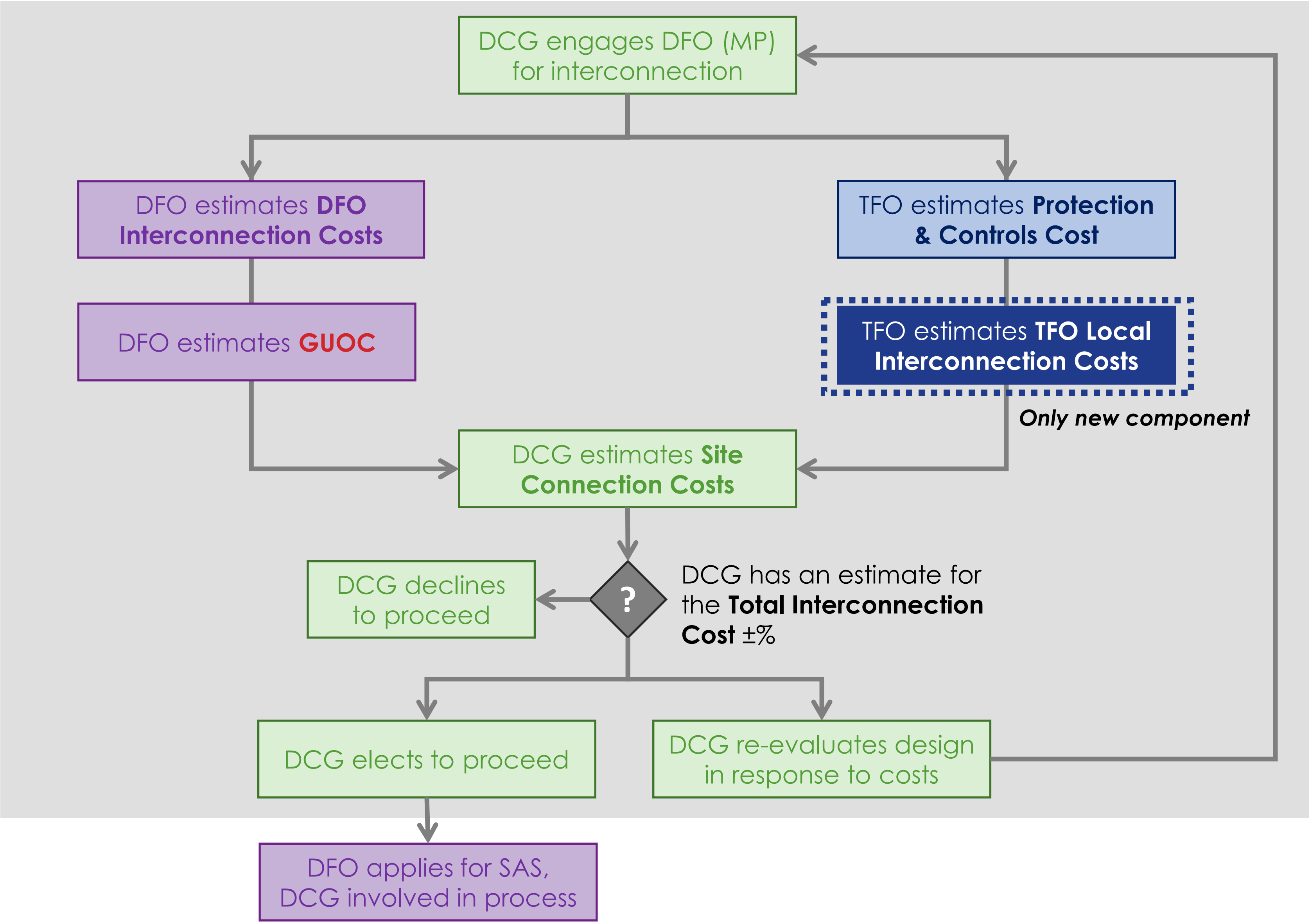
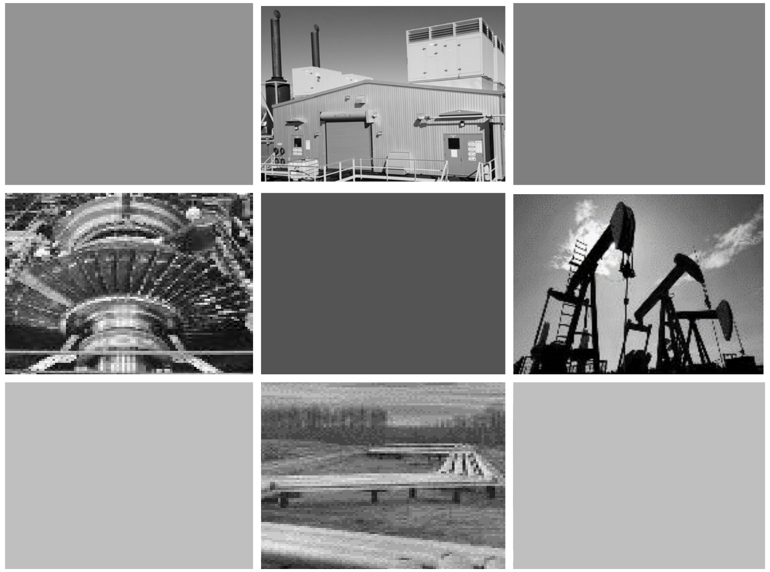
DCG Connection Process



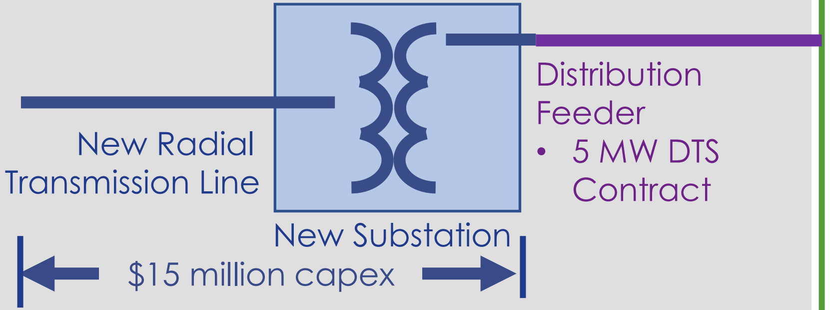
- Lionstooth proposal does not require significant changes to ISO Ts & Cs or the Connection Process
  - DCGs are provided with cost estimates before DCG enters the Queue
  - Opportunity for DCG to respond to market signals (i.e. connection costs)
- DFOs enable the DCG connection



Proposal Implications

Applying the Lionstooth Proposal

New "Radial" Substation



TFO
- $10 million allowable investment
- Rolled into rate base, recovered through DTS tariff

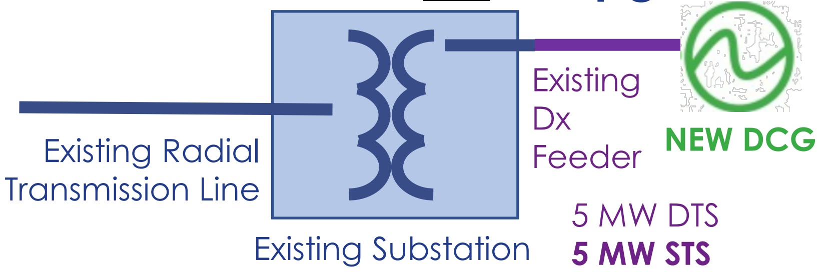
DFO
- $5 million capital contribution
- Rolled into rate base, recovered through Dx tariffs

Load Customers
- Wires bills increase to pay for increased Tx & Dx rate bases*

No change to these assumptions

***Example Footnotes:**
- High-level example for illustrative purposes
- Does not account for timing imbalances in rate design
- Does not account for significant amount of time between "new radial substation" and "addition of DCG"

DCG Connects – No Tx Upgrades



TFO
- No change to TFO investment or rate base
- **TFO kept whole**

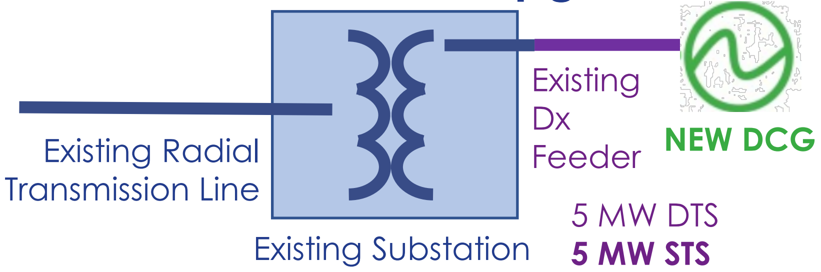
DFO
- No change to DFO contribution or rate base
- Dx Feeder improvements to allow for DCG
- **DFO kept whole**

Load Customers
- No change to wires bills*
- Increased reliability for direct Dx loads & grid wide
- **Load Customers indifferent**

DCG Customer
- Signal to "right-size" DCG
- No Tx upgrades = no local interconnection costs
- **DCG indifferent**

No one harmed, at most indifferent.

DCG Connects – Tx Upgrades



TFO
- No change to TFO investment or rate base
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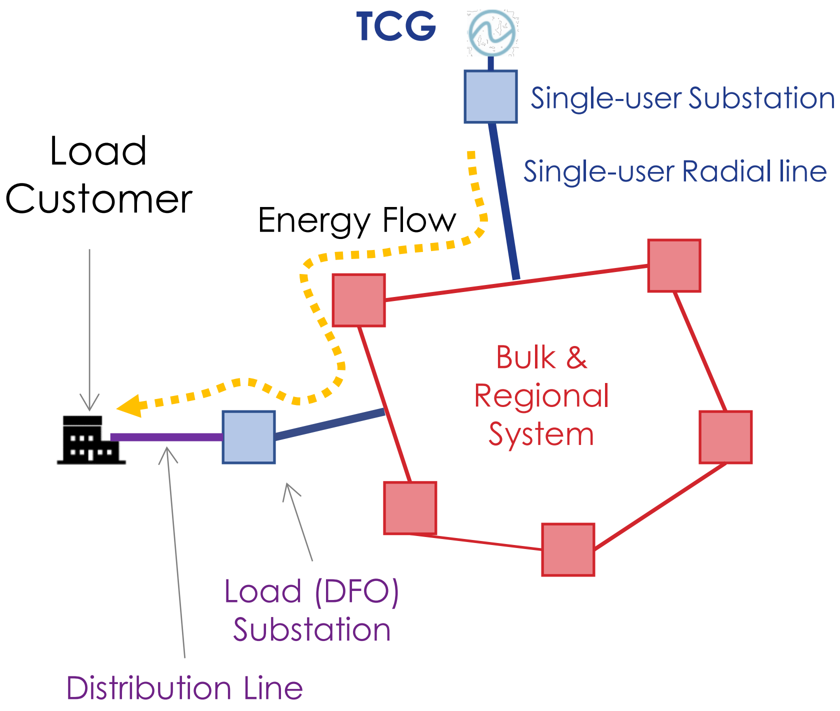
DFO
- No change to DFO contribution or rate base
- Dx Feeder improvements to allow for DCG
- **DFO kept whole**

Load Customers
- No change to wires bills*
- Increased reliability for direct Dx loads & grid wide
- **Load Customers indifferent**

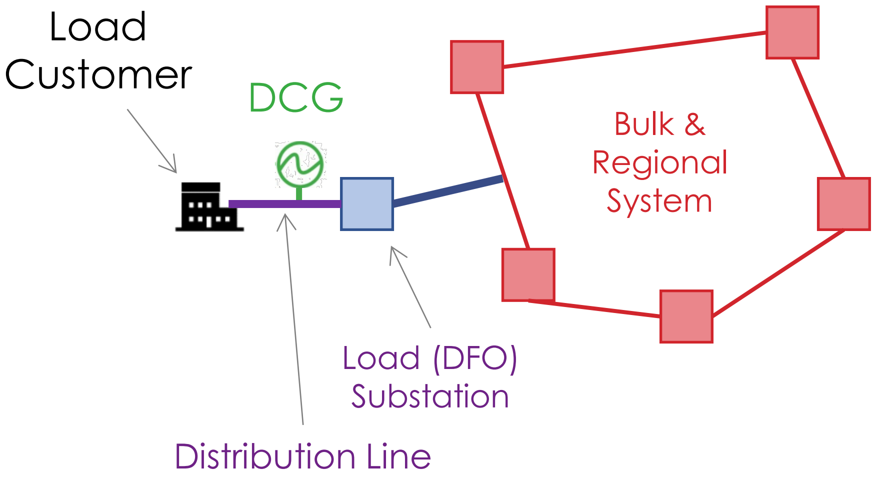
DCG Customer
- Incremental **local interconnection costs** due to DCG
- DCG able to evaluate design in response to market signal
- **DCG pays for costs caused**

DCG locational signal.

Comparison – TCG vs DCG



- Energy flow from TCG to a Dx connected load requires:
  - TCG's radial line & substation
  - Bulk & Regional System
  - Radial line to the DFO substation
  - DFO substation
  - DFO Dx line
- The TCG pays for their radial line as a locational signal, and GUOC to pay for bulk/regional use
- **TCG does not pay for use of radial line to DFO, fraction of DFO substation, distribution line use – these are all accommodated in GUOC**



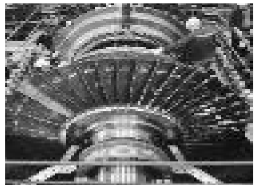
- Energy flow from a DCG to a Dx connected load requires:
  - DFO distribution line
- The DCG pays for their **Dx interconnection** as a locational signal, and **GUOC** (although "right-sized" DCG may not use regional/bulk)
- **Right-sized DCG does not use the substation, and does not use the radial line, but under current methodology could be assessed a cost associated with these.**
- **The Lionstooth proposal accommodates the disparity of TCG benefiting from using the radial lines, substations and distribution lines that were paid for by load.**
- **In addition, there is a need to acknowledge the benefits of DCG as a "load sink" which increases the capacity of the Dx system at DCG's cost**

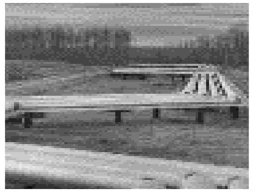
Summary

Lionstooth Energy Proposal

Proposal	Policy/Principle
1. Historical costs remain in TFO/DFO rate base	• "Load Pays" Policy & Regulations • Recovery of revenue requirement *principle* • Investor Certainty *principle*
2. DCG pays for incremental cost for Tx upgrades caused by DCG	• Locational signal Policy • Cost causation *principle* • No future risks *principle* • Investor Certainty *principle* • Parity between TCG & DCG *principle*
3. Refund to DCG as load increases	• "Load Pays" Policy • Cost causation *principle*

Lionstooth Energy





Supplemental Information

Questions to Resolve

AESO Proposal Guideline Questions	Lionstooth Response
1. Should the AESO or the ISO tariff make a distinction for DCG as being different from a DFO or a TCG or load?	The AESO needs to continue to view DCGs as a generator. This proposal does not require significant changes to ISO Ts & Cs or the Connection Process. However, the ISO tariff may need amendments to better reflect an increase in two-way energy flows between the Tx and Dx systems. See Slide 14.
2. How can DCG optimize Dx or Tx facilities by either their connection or their supply?	DCGs benefit the system through their role as "load sinks." A right-sized DCG can reduce local congestion, increase system capabilities, increase utilization, and defer more costly investment, as a non-wires alternative. Sending locational signals to DCG achieves this and is aligned with the TDP & TReg. This does require stable signals and additional planning of two-way energy flows. See Slides 4, 13, & 17.
3. How can the value or optimization of Dx or Tx facilities be determined?	In collaboration with a specific DCG and associated DFO, the AESO should be able to quantitatively model, on an hourly basis, the available load-serving capacity of the Dx feeder, associated substation, and associated Tx line resulting from the presence of a DCG. For example, this would show during peak demand hours the ability of an operating DCG to reduce congestion. It is also our view that this can be used as a long-term planning tool. Just as the AESO models forecast loads, it can model the impact of DCG in specific planning areas. Publishing these locational signals would help DCG to locate where able to better support the system.

Questions to Try to Answer

AESO Proposal Guideline Questions	Lionstooth Response
1. What is the fair or appropriate methodology to determine minimum facilities required to allow DCG to access the Tx grid? Is the fairness methodology an on average calculation across all DCGs in the province or should the fairness methodology account for differences throughout the province?	It's important to note fair should refer to market and economic efficiencies and outcomes, not leveling of physical conditions. The appropriate methodology is to assess DCGs impact on Tx facilities on a direct cost-causation basis at time of connection. Averaging across all DCGs or sites does not send the right locational signal. See slides 10 & 13.
2. How should ISO tariff local investment be implemented given increasing amount of generation added to traditionally load-only point-of-deliveries?	The TDP and TReg are clear in our view. Load pays and generators should be incented to locate close to load. Historical wires costs remain in TFO/DFO rate base and DCG should pay for the incremental cost for Tx upgrades caused by the DCG connection. See slides 10 & 13.
3. Can the proposal be implemented within the existing ISO tariff provisions? If not, what will need to be changed.	We believe so. This proposal is not intended to have significant changes to ISO Ts & Cs or the Connection Process. See Slide 14.

Solar Krafte Proposal

PARTICIPANT-RELATED COSTS FOR DFOS (SUBSTATION FRACTION) AND DFO COST FLOW-THROUGH PROPOSAL

solarkrafte

OVERVIEW OF PROPOSAL

- To connect to the AIES, Transmission-connected Generation (TCG) pays only its incremental costs to connect.

- To connect to the AIES, Distribution-connected Generation (DCG) pays not only its incremental costs to connect but also costs that flow through from the Distribution Facilities Owner (DFO) related to transmission system substation projects, past and future, that were or will be initiated by the DFO to address load servicing distribution reliability deficiencies.

- To reconcile this incongruity, the AESO need only exercise the legal discretion it has within the existing ISO tariff provisions to determine the non-incremental costs in question to be system-related and not participant-related.

PRINCIPLES PROPOSAL BASED ON

1. Consistent Treatment under the AESO BTF Connection Process

2. Encourage DCG (Without Subsidy)

3. Consistent and Fair Treatment Between TCG and DCG, Through Equal Access to the AIES

1. Consistent Treatment under the AESO BTF Connection Process

DCG should not bear transmission system upgrade costs. As Behind-The-Fence (BTF) projects, DCG is explicitly and categorically barred from requiring or effecting such upgrades.

Flowing through these costs, whether retroactively or in the future, for transmission system changes, that are forbidden for a DCG project to participate in, is patently nonsensical.

This treatment becomes increasingly egregious considering that such transmission system changes were and/or are specifically vetted as necessary and entirely unrelated to the DCG project.

2. Encourage DCG (Without Subsidy)

The flow-through of substation fraction allocations to DCG projects defeats, discourages and terminates DCG projects, confining them to aging, no load growth PODs. DCG needs to go where the load growth is, and bring with it the tangible benefits that DCG brings to the AIES:

- Offsets to investments in transmission, or distribution facilities that would otherwise be recovered through rates

- Increased electric system reliability

- Reduced reliance on the high voltages and currents and the complex delivery systems that are conducive to grid failures, particularly in Alberta's high wind and other climatological conditions

- Islanding localizes the impact of transmission system failures, giving local distribution systems and customers the ability to ride out major or widespread outages
- Flexibility and fuel source diversity with DG gas peaker, DG solar, and DG storage all very competitive in Alberta now, offering an ideal stand-alone DG generation mix
- Emergency supply of power
- Reduction of peak power requirements
- Efficiency, eliminating entirely complete transmission line loss equivalents
- Improvements in power quality, and provision of ancillary services

- Inverter based DG (solar PV) systems use capacitors that innately provide reactive power up to the nameplate capacity of the generator
- Inverter based DG (solar PV) actively cancels/ mitigates transients in real time at or near the customer level, improving grid stability
- Inverter based DG (solar PV) provides extremely fast ramping to follow sudden increases or decreases in load, improving system stability and component lifetimes
- Reductions in land-use effects and rights-of-way acquisition costs
- Reduction in vulnerability to terrorism and improvements in infrastructure resilience

3. Consistent and Fair Treatment Between TCG and DCG, Through Equal Access to the AIES

There needs to be consistent and fair treatment between TCG and DCG. If TCG pays only its incremental costs to connect to the AIES then DCG should pay only its incremental costs to connect to the AIES also.

PROPOSAL

1. Backdrop
2. How This Plays Out
3. How To Reconcile This Incongruity
4. What Mechanism To Use

1. Backdrop

To connect to the AIES, TCG connects to the transmission system. To connect to the transmission system, TCG pays only its incremental costs to connect. Beyond these incremental costs, TCG does not pay or contribute to the costs of the transmission system. Load customers pay these transmission system costs and the AESO characterizes these non-incremental costs as “system-related”.

To connect to the AIES, DCG connects to the distribution system. To connect to the distribution system, DCG pays not only its incremental costs to connect but also costs that flow through from the DFO related to transmission system substation projects, past and future, that were or will be initiated by the DFO to address load servicing distribution reliability deficiencies. The AESO characterizes these non-incremental flow-through costs (i.e., substation fraction costs) as “participant-related”.

2. How This Plays Out

TCG benefits from the deeming of construction costs related to the transmission system substation facilities that TCG tie into, as system-related, effectively shielding TCG from the construction costs of these facilities, whether existing or new, notwithstanding TCG's full use and access to such facilities at no cost to them.

DCG enjoys no such privilege where construction costs of transmission system substation facilities flow-through to them.

3. How To Reconcile This Incongruity

DCG needs to be treated no differently than TCG. TCG is shielded from non-incremental transmission system costs (i.e., "system-related costs"), paying only the incremental costs to connect to the AIES. DCG too needs to be shielded from transmission system costs, including transmission system costs attributable to DFO initiated projects to address load servicing distribution reliability deficiencies, and like TCG, pay only its incremental costs to connect to the system. This is parity. This is the fair and balanced approach, and this is the approach taken by every reasonably competitive jurisdiction on the planet.

The issue arises from the treatment of the DFO and DCG as though they are one and the same, as equivalents, and from the delineation of the AIES into two separate systems (transmission and distribution).

4. What Mechanism To Use

The ISO tariff, as it is currently written and approved, provides a mechanism to protect DCG (and equally important the DFO) and allow for viable DCG where transmission system substation upgrades are (or were) implemented to address load servicing distribution reliability deficiencies: The AESO need only exercise the legal discretion it has under subsection 10 of section 8 of the Tariff to determine the costs to be system-related and not participant-related.

Subsection 10 of section 8 of the Tariff:

ISO Tariff – Section 8
Construction Contributions for Connection Projects (continued)

aeso

Limitations

10 The **ISO** may exercise discretion in the application of the **construction contribution** provisions in the **ISO tariff**, including the determination of costs to be system-related in certain circumstances that might, under strict application of the **construction contribution** provisions, have been classified as participant-related.

Through equal access to the AIES, this is the only approach that gives rise to consistent and fair treatment between TCG and DCG.

IMPLICATIONS OF PROPOSAL

- Establishes consistent treatment of DCG under the AESO BTF connection process
- Encourages DCG (without subsidy)
- Establishes consistent and fair treatment between TCG and DCG, through equal access to the AIES

Canadian Solar Proposal

CANADIAN SOLAR

DGC FLOW-THROUGH PROPOSAL

May 2020

Introduction

Canadian Solar retained:

- Pablo Argenal (Nican International Consulting)
- Lewis Manning (Lawson Lundell)
- Dean Short (former ADOE advisor and co-author of *Transmission Development The Right Path for Alberta A Policy Paper (the TDP)*, November 2003)

To (1) obtain a detailed understanding of the history and evolution of cost allocation between loads and generators in Alberta as well as (2) the foundational principles that led to the creation of the Transmission Regulation (TReg)—refer to Canadian Solar's white paper for additional detail

These discussions came to focus on two main items:

- **Local interconnection costs, i.e., the extent of a generator's cost obligation and**
- **The purpose of the generator System Contribution Payment (SCP, now called GUOC)**

Pertinent Background

- Leading to and following Alberta's electricity market deregulation, discussion was ongoing between the Transmission Administrator (ESBI), the EUB and others relating to various forms locational pricing signals for generators (SERP, ZIC)
- In 2003, the ADOE expressly overruled the direction that the Transmission Administrator was taking to allocate system transmission costs to generators on the basis of the policy of the Government of Alberta
- Government policy was embodied in the TDP and the subsequent enactment of the TReg
  - The TDP, as a foundational document, set out the principles and the objectives that the TReg was to accomplish
  - **The TDP effectively remains an interpretation guide for the Treg**

Foundational Principles

- Tariffs that were designed as a 50/50 wires cost recovery, through STS and DTS tariffs, where generation paid half of the Bulk, Local and Point of Delivery (POD) components all part of system charges were EXPRESSLY OVERRULED as a matter of government policy
- The TDP and TReg are prescriptive with regard to the segregation of wires costs from energy costs, cost allocation and in establishing what system costs and local interconnection costs are with reference to the interconnection of a generator
- **The SCP (now GUOC) was to be the sole system contribution of a generator based on clear objectives and attributes set out in the TDP and reflected in the TReg**

System Contribution Payment (SCP) vs. Generator Unit Owner Contribution (GUOC)

- The SCP or system contribution payment is:

  A clear and transparent charge, known in advance to provide a long-term siting signal for new generation that is not related to location or precise system costs

- The SCP was made refundable over time subject to satisfactory performance over a 10-year period based on established performance metrics by generator technology type
- Were a generator unable to perform, refunds would not occur and that generator's SCP would have contributed to system costs

The ADOE's views on the SCP and GUOC under the TReg remain the same, i.e., for upgrades to the existing transmission facilities

Principles Of This Proposal

- This proposal considers the historical developments of the regulatory framework on cost allocation and cost causation principles that propelled the ADOE's policy for transmission development as well as the principles for access to the transmission system outlined in the EUA and Treg

- This proposal considers:
  - GUOC as mechanism to provide financial certainty to generators and to serve a generator's only obligation towards transmission system costs
  - Development timing of load and generation relative to cost causation
  - DFO and DCG relationship with regard to unified a System Access Service Agreement (SASA) at a given Point of Delivery (POD)

Cost Recovery of the Transmission System and Fairness

The issue of fairness has been raised in the context of the DCGs using transmission and distribution wires at no cost to DCGs and without consideration that load pays for the wires costs:

- That is how the ADOE's policy, the EUA and TReg are expected to work
- Fairness cannot be added as an act of kindness to circumvent ADOE Policy, EUA and TReg

In short, it has been established that load, *not DCGs*, pay for wires cost that were rolled-in to and recovered through rate base

Local Interconnection Cost vs. Participant Related Cost

The drivers and causation for radial infrastructure are in general initially established as:

- Point of Delivery (POD) – to supply DFO load
- Point of Supply (POS) – to provide access to a generator
- POS/POD – to provide service to a generator to access the energy market (Rate STS) and receive transmission system support (Rate DTS) when the local site generation is out of service

Radial infrastructure funding at the inception of a project is accepted to be:

- **Point of Delivery** – funding covered by AESO's investment policy, and from time to time by a small supplemental contribution from the DFO. In either case, these costs are rolled-in to their respective rate bases for recovery

- **Point of Supply** – funding covered fully by the generator since there is no investment policy for generators. The funds <u>are not rolled-in to rate base</u> and are indeed a transmission asset paid for exclusively by the generator

- **Point of Supply / Point of Demand** (dual use) – initial funding covered by the generator. However, for instances where the generator project has a load component requiring DTS, in this case, AESO concurrently applies a contribution in proportion to (a) size and (b) duration of the DTS contract the generator wishes to carry

Local Interconnection Cost vs. Participant Related Cost

- From a generator's perspective the local interconnection cost is a function of where the "transmission system" connection will occur and how far it is from the project site.
  - Therefore, it matters where a generator's access point to the transmission system is and where the transmission facility point of connection will occur

Timing and causation of the interconnection drivers also matter to assess who pays for the radial connection

It would appear that as a first mover:

- For a Point of Delivery – It is a Customer Related cost (rate DTS)
- For a Point of Supply – It is a Local Interconnection cost (rate STS)
- For a Point of Supply requiring a DTS service - It is a combination of Local Interconnection cost (rate STS) with an AESO contribution for the DTS level contracted

The question that remains is, for a situation where after some time a DCG shows up, at PODs for which costs have been rolled-in to rate base, **what is the first connection or access point to the transmission system or transmission facility? Is there a test to determine this?**

Local Interconnection Cost vs. Participant Related Cost

- AESO advised in its February 27, 2020 Technical Session, that the transmission system classification is limited to “Bulk” and “Local” transmission components; however, the “POD” component does not classify as transmission system. However, rate DTS as a transmission system wires recovery mechanism has been functionalized to recover or “roll-in” to rate base “all” transmission system components; hence, by definition Bulk, Local and POD are all system cost components once rolled-in to rate base
  - To confirm the above statement, the functionalization definitions for rate DTS were compared between the 2005 ISO Tariff and 2018 ISO Tariff filings and it appears that the functionalization scope and intent has remained essentially unchanged between the Tariff filings

- **From a DCG’s perspective, at a POD, the 25 kV bus fits the definition of transmission system where it will indirectly contract with AESO for STS, through the DFO, and directly contract with AESO for GUOC payment and performance management of the generator asset**

Local Interconnection Cost vs. Participant Related Cost

- It would appear that causation and sequence of development, load or generation, does matter:
  - If the first mover is a generator, a cost sharing will occur when the next generator (or load) connects to its radial investment—this principle is supported by the TReg
  - However, if the first mover is a load (DFO), and some time in the future a DCG contracts for STS and pays GUOC, it appears that the GUOC functions as the system payment for upgrades as seen from the 25 kV upstream into transmission

Therefore, to apply a flow-through cost in this instance, AESO would have to roll-out costs from both transmission and distribution rate bases to convert them into an incremental cost to the DCG's local interconnection

There are no principles in the TDP, EUA or TReg that empower AESO to defeat the purpose of the GUOC, to roll-out cost from rate base and convert it to a flow-through charge to the DCG interconnection

DFO Combined SASA Request

- The treatment of the DFO's SASA, carrying a DCG STS contract, as a single Market Participant may also be a culprit in the perception that a cost flow-through to the DCG is warranted and justified by AESO
  - There are in fact two Market Participants, a distribution service provider and an energy supplier. The DFO within its franchise area is responsible for providing electric distribution service as defined by Electric Utilities Act (EUA) to both the load and DCG
  - However, it appears that AESO's need or sense of obligation to flow-through cost stems from the perception that the DFO is a single market participant under one SASA
- The treatment of the DFO's SASA, containing a DCG STS request, as single Market Participant leads to a disconnect in cost allocation where the generator then experiences an incremental flow-through, in addition to its local interconnection cost, under the definition of Participant Related (Rate STS) costs
- Within the definition of Participant Related cost, as it pertains to DCG, the AESO treats both the DFO load and DCG as a common driver to establish need or causation of the POD, and on this basis, allocate flow-through cost—**the relevance of sequence and timing between the original DFO DTS and the present DCG STS request is disregarded**

Proposal Outline

Four (4) scenarios were considered and each scenario is based on the historical evolution of the electric industry regulatory process

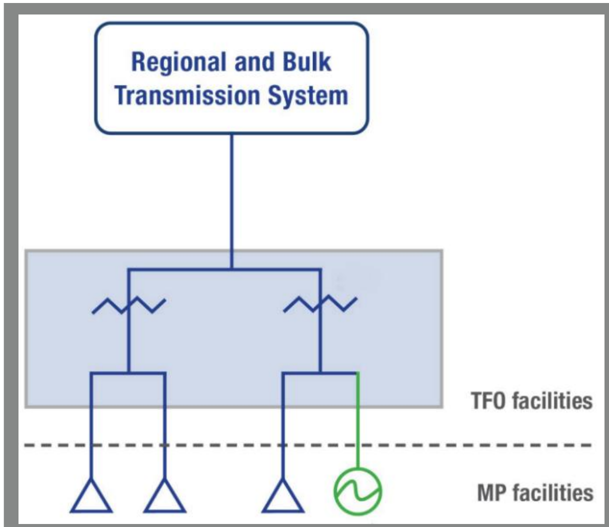
- The scenarios seek to establish alignment between ADOE Policy, EUA and TReg

No proposals are provided for the handling of future flow-through costs for the following reasons:

- A future flow-though cost to address transmission facility capacity improvement, upgrades, corrections to voltage deficiencies, etc., is in fact nothing more than absence of transmission planning where AESO ought to have relied on load and generation forecasts to plan the transmission system in fulfillment of their legislated obligations
- This type of transmission system flow-through does not appear to have an ADOE Policy basis or align with EUA or TReg as it pertains to flowing through a future cost in presence of a GUOC

A future flow-through to a DCG while a GUOC is in place essentially constitutes double counting to recover the future cost of transmission facility upgrades

Scenario 1 – Existing POD, No Transmission Upgrades



DGC Pays for:

- Connection to the dist. system,
- Revenue meter / SCADA as required
- Protection coordination (dist. & trans.)
- Direct Trip (sub to project site as required)
- Transfer Trip (if required)

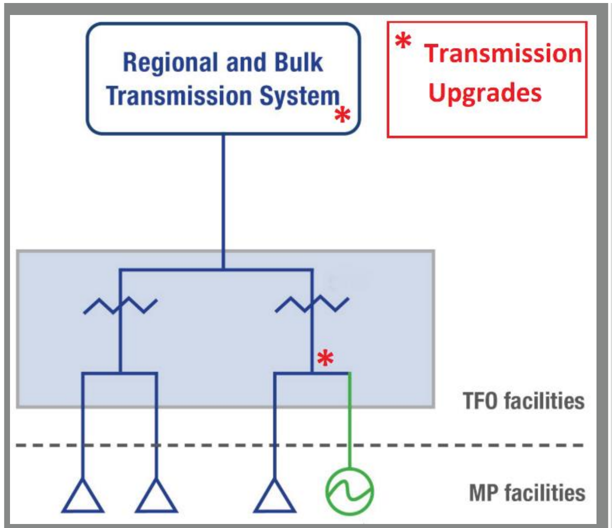
Pros:

- No cost impact to rate base by DCG
- Local Interconnection Costs principles align with TDP, EUB and TReg.

Cons:

- May be subject to a run-back curtailment signal in lieu of transmission upgrade costs

Scenario 2 – Existing POD + DCG Related Transmission Upgrades



DGC Pays for:

- Connection to the dist. system,
- Revenue meter / SCADA as required
- Protection coordination (dist. & trans.)
- Direct Trip (sub to project site as required)
- Transfer Trip (if required).
- Limited Transmission Upgrades (at time of interconnection)
- 25 kV switches and breakers in the subs
- Deep RAS modifications (soft costs not infrastructure)
- Minor transmission modification, i.e., jumpers, CTs, PTs, etc.

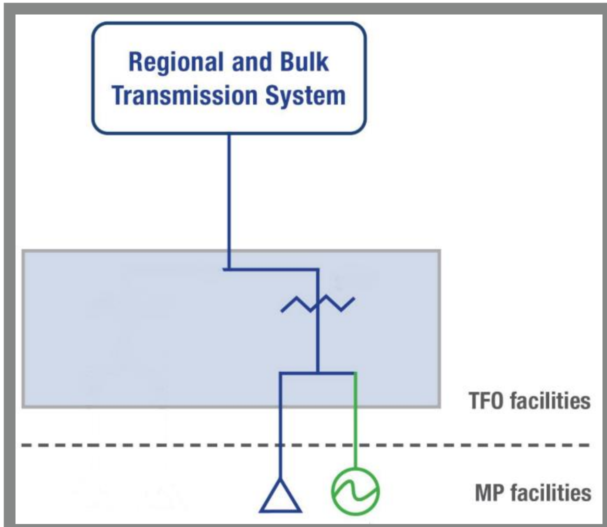
Pros:

- No cost impact to rate base by DCG
- Local Interconnection Cost principles align with TDP, EUB and TReg

Cons:

- Back end transmission RAS costs may resemble transmission like capacity management principles and potentially costly to the DCG

Scenario 3 - New POD with STS
(Load and STS are the same Market Participant)



GC Pays for:

- If load that drives the POD need and concurrently develops onsite DCG, and the DCG requires an STS contract at the time of first POD energization, and before the POD costs are rolled-in to rate base, then the DCG will contributed in proportion to DTS (DFO) and STS (DCG) ratio in addition to its Local Interconnection cost
- The initial load and DCG interconnection have a likeness to transmission connected generation; however, the main driver and causation is the load
- In the future, DCG connections, are not subject to further cost flow-through allocation and are treated as Case 1 or Case 2

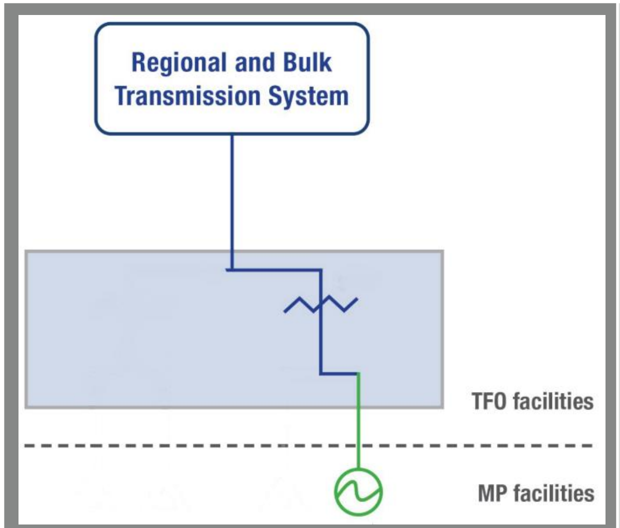
Pros:

- No cost impact to rate base by DCG
- Clear contribution requirement by a generator
- Both Local Interconnection and Customer Related Cost principles align
- Aligns with TDP, EUB and TReg

Cons:

- Could be difficult to establish causation, i.e., if load or generation is the driver and may trigger Scenario 4 cost allocation

Scenario 4 - New POS with no DTS



First DGC pays for:

- All costs—no cost is rolled-in to rate base—assume no DTS contract

Then DFO pays for:

- If the DFO requests access to the POS, it triggers a contribution to the non-rate base investment and refundable to the first DCG

Then next DCG pays for:

- Contrary to Scenario 3, the next DCG pays a contribution to the residual value of the remaining cost to the first DCG for costs that were not rolled-in to rate base

Pros:

- No cost impact to rate base by DCG
- Follows TCG model
- Clear contribution process to a generator investment
- Aligns with TDP, EUB and TReg

Cons:

- Reimbursement settlement may be complex with multiple parties, and with the additional complexity of multiple contract vintage

Summary

TDP Policy and TReg are clear that: "generators will be responsible to pay for several elements of transmission including:

a. Local interconnection charges,
b. Location-based loss charges, and
c. A financial commitment and payment towards transmission system upgrades.

The balance of remaining transmission costs (i.e. wires, TMR, historical IBOC/LBCSO, operating reserves, etc.) will be allocated to load."

Nowhere is it contemplated that pre-existing assets (in whole or in part) are rolled-out from the transmission rate base and charged to distribution connected generators

Summary

It is critical that the cost causation and allocation principles of the TDP and TReg be adhered to

- This provides much needed commercial clarity and cost certainty to generators
- Ensures that generators are not adjusting site selection behavior to the detriment of load
- **One party should not cause a cost that is allocated to another (generators should not drive increases to rate base; rate base should not be retroactively rolled-out and imposed on generators)**

  (i.e. locating so as to minimize flow-through costs, despite indisputable technical rationale for generators to site near load to support the transmission system)


CanadianSolar
THANK YOU

Joint Q&A

Session Close-out and Next Steps

Next Steps (updated)

- We value stakeholder feedback and we invite all stakeholders to provide their evaluation of all of the proposals to the AESO via the questions set out in the **Proposal Evaluation Stakeholder Comment Matrix on or before May 20, 2020**
- Please submit one complete proposal evaluation stakeholder comment matrix per organization
- The AESO will also be completing and posting their evaluation of the proposals
- The AESO will post all evaluations, including the AESO's, on May 21, 2020 on the AESO website at www.aeso.ca

Next Steps

- Technical Session 2B will be hosted on May 28, 2020 from 8:00 a.m. to 12:30 p.m. The session will follow a similar format and registration is now available.
- The purpose of Technical Session 2B is the following:
  - Continue to build a common understanding of the purpose and application of participant-related costs for DFOs (substation fraction formula) and DFO cost flow-through;
  - Stakeholder proposals to respond to evaluation and comments after presentation on May 14 session; and
  - Group discussion to evaluate stakeholder proposals for participant-related costs for DFOs and DFO cost flow-through and determine if alignment on a joint proposal can be made or if multiple proposals will move forward.

Contact the AESO

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- Subscribe to our stakeholder newsletter

Thank you