# Participant-Related Costs for DFOs (Substation Fraction) and DFO Cost Flow-Through Technical Session 1 – Feb. 27, 2020

## I. Purpose of this session

The purpose of this session was to:

- Build a common understanding of the purpose and application of participant-related costs for DFOs (substation fraction formula) and DFO cost flow-through; and
- Develop and identify high-level principles applicable to participant-related costs for DFOs and DFO cost flow-through.

## II. Session agenda

| Time | Agenda Item | Presenter |
|---|---|---|
| 9:00 – 9:05 | Welcome, introduction, purpose and session objectives | Stack'd / AESO |
| 9:05 - 9:30 | Overview of engagement process:<br>• Share overall approach and schedule<br>• Clarify what stakeholders can expect as we move through the process<br>• Discussion on approach and schedule | AESO |
| 9:30 – 10:45 | Level-setting: Getting to a common understanding<br>• AESO to present on legislation, terminology, principles, and application of principles for the treatment of local interconnection costs for DFOs<br>• Discussion period to follow presentation | AESO<br><br>All |
| 10:45 – 11:00 | Break | |
| 11:00 – 11:45 | Level-setting: Getting to a common understanding<br>• FortisAlberta to present on local interconnection costs impact and DFO flow-through of costs<br>• Discussion period to follow presentation | FortisAlberta<br><br>All |
| 11:45 – 12:15 | Lunch | |
| 12:15 – 1:45 | Level-setting: Getting to a common understanding<br>• The following to present on local interconnection costs impact and DFO flow-through of costs:<br>  ○ BluEarth Renewables<br>  ○ Innogy Renewables Canada<br>  ○ Siemens Energy<br>• Discussion period to follow presentations | BluEarth Renewables<br>Innogy Renewables<br>Siemens Energy<br>All |



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| Time | Agenda Item | Presenter |
|---|---|---|
| 1:45 – 2:00 | Break | |
| 2:00– 3:45 | Present initially identified principles (AESO)<br>• Discussion on any missing, duplicative or unnecessary principles (All)<br>• Instructions for breakout discussion (Stack'd)<br>• Breakout discussion on principles (All)<br>• Group report back | All |
| 3:45 – 4:00 | Session close out and next steps | Stack'd / AESO |

## III. Attendees

### *In-Person*

| Company |
|---|
| Acestes Power ULC |
| Alberta Electric System Operator |
| AltaLink Management Ltd. |
| ATCO Electric Ltd. |
| Alberta Utilities Commission |
| Best Consulting Solutions Inc. |
| BluEarth Renewables Inc. |
| Canadian Solar Solutions Inc. |
| Capstone Infrastructure Corporation |
| Consumer Coalition of Alberta |
| Clem Geo – Energy Corp. |
| Collicutt Energy |
| Denis Forest Consulting Inc. |
| DePal Consulting Limited |
| Elemental Energy Renewables Inc. |
| ENMAX Corporation |
| FortisAlberta Inc. |
| Green Cat Renewables Canada Corporation |
| Hatch Upside |
| Innogy Renewables US LLC |
| Industrial Power Consumers Association of Alberta |
| Irricana Power Generation |

| Company |
| --- |
| Kalina Distributed Power |
| Lionstooth Energy |
| Longspur Developments |
| Nican International Consulting Ltd. |
| Peters Energy Solutions Inc. |
| Power Grid Specialists Corporation |
| Power Advisory LLC |
| Prairie Sky Strategy |
| Siemens Energy |
| Signalta Resources Ltd. |
| Solar Krafte Utilities Inc. |
| Suncor Energy Inc. |
| TC Energy Corporation |
| Teric Power Ltd. |
| URICA Asset Optimization |
| URICA Energy Management Corporation |
| Wolf Midstream |
| Stack'd Consulting, Inc. |

### *Webinar*

| Company |
| --- |
| Alberta Electric System Operator |
| Alberta Energy |
| AltaLink Management Ltd. |
| ATCO Electric Ltd. |
| Blake, Cassels & Graydon LLP |
| BluEarth Renewables Inc. |
| BowMont Capital and Advisory |
| Bright Diamond Consulting |
| Bullfrog Power Inc. |
| Campus Energy Partners LP |
| Capital Power Corporation |

| Company |
| --- |
| Chymko Consulting Ltd. |
| Coreman Consulting Inc. |
| Customized Energy Solutions |
| EDC Associates Ltd. |
| EPCOR Distribution & Transmission Inc. |
| Evolugen (Brookfield Renewable Canada) |
| FortisAlberta Inc. |
| Horseshoe Power |
| Innogy Renewables US LLC |
| Industrial Power Consumers Association of Alberta |
| Navigatio Capital |
| Saturn Power Inc. |
| Siemens |
| Suncor Energy Inc. |
| TC Energy Corporation |
| TransAlta Corporation |
| Utilities Consumer Advocate |
| URICA Energy Real Time Ltd. |

## IV. Overall outcomes from the day

Attendees spent the session observing presentations to reach a common and shared understanding, to better understand the determination of participant-related costs for distribution connected generation (DCG) interconnection to the transmission system, and participate in breakout discussions with the intention to coalesce on a set of principles to guide future proposals.

Given the volume of questions that remained as we entered the breakout period, we believe the session objective of clarity was partially met, and that some stakeholders may still not have a common and shared understanding of the determination of participant-related costs for DCG intent, design, and implications. Actions to remediate this outstanding gap in understanding have been taken and additional materials will be distributed by the AESO.

Using the overall sentiment of the discussion and comments from participants throughout the day we can initially conclude the following:

1. Stakeholders appear aligned on the need for DCG participants to have cost certainty when making their final investment decision (FID)

   a. In the eyes of many, DCG participants face unlimited and uncertain future risk while transmission connected generation (TCG) participants face one-time connection costs and do not have the same risk uncertainty projected into the future.
2. Some suggested that the application of the substation fraction/cost allocation approach is not flexible enough to accommodate a fair, efficient and openly competitive (FEOC) market that many believe should encourage DCG.
3. Many are looking for greater clarity and/or transparency on how costs are classified and passed through to various stakeholder groups, for example:
   a. Should some of the case studies explored have been better classified as reliability projects and therefore had a higher degree of costs assigned to load?
   b. How should the costs in excess of "good electric industry practice" (GEIP) category of costs be used to support decisions?
4. Some are of the view that cost allocation should follow cost causation strictly based on original impetus, while there was also reference of the benefits provided (aligning with direction previously provided by the Alberta Utilities Commission ("Commission")).
5. Participants are generally aligned with the principles of parity between DCG and TCG, cost certainty for DCGs and cost recovery for Distribution Facility Owners ("DFO"), but expressed varied positions on the necessity for DCG to share in the appropriate costs of the transmission system. Additionally, there was alignment on the potential need for an additional principle along the theme of encouraging investment (e.g., the framework needs to be simple, provide clear signals, and incent future DCG development). There was little alignment on the application of these principles.

## V. Level-setting

### *Objectives and context*

The objective of the level-setting portion of the agenda was to build a common understanding of the AESO's cost allocation and DFO flow-through of participant-related costs for transmission access facilities paid for by a DFO in consideration of the costs of connecting a DCG. Stakeholders representing the AESO, DFOs and DCGs presented on their understanding of the existing tariffs (ISO and distribution) with respect to treatment of DCG, and provided case studies to illustrate the implications. All stakeholders were provided an opportunity to ask clarifying questions during and after each presentation. The discussion commentary can be found below:

### AESO presentation

#### *Clarifying questions from stakeholders, including responses from AESO*

- When will the AESO submit its report to the Commission? How long after the last session?
  - We do not currently have an answer but will confirm once a timeline is established.
- Are costs determined as demand related and supply related? I thought they would be project related?
  - Yes, demand and supply related goes back to 2006, and we did not anticipate how large it would be. Originally it was intended to allocate for a single market participant; don't have history of an example of a market participant that is not a DFO adding generation to its site 10 years later.

- What is the distinction between a connection and a behind the fence (BTF) project?
    - A connection is anything that adds transmission assets; for a BTF project there are no transmission assets, coming for a contract change (adding supply transmission service (“STS”) or demand transmission service (“DTS”)).
- In participant related costs, are we not missing a category “in excess”?
    - This is already built into the tariff but we are looking into it further.
- Participant comes in and builds in excess of GEIP, local investment applies to portion that is not in excess of GEIP, but other parts are in excess. Later on down the road would the portion in excess be applied to investment?
    - No answer provided.
- Can you define what you mean by local?
    - Found in transmission regulation and specifies what generating units pay as part of their connection with specific mention of “local interconnection costs”.
- How does the depreciation of an asset get calculated?
    - We do not take depreciation into account, as transformer will be replaced for free after the useful life.
- When a substation fails and it was mentioned the TFO would replace it for free. In this case, it is meant that the TFO will replace the substation which will be paid for by the rate base, correct?
    - Yes.
- Who is the market participant? [Referring to slide 23]
    - Market participant who is not a DFO.
- In this example if DTS increase/decrease with no facility charges [Referring to slide 23], what happens if facility charges are required? (20 MW to 40 MW and a new transformer is needed)
    - It is considered a new project, however, the AESO would re-look at the last project to see if that project was entitled to further investment.
- [Continuation from previous question] Would you then need to figure out which tariff to apply due to two different time frames?
    - BTF means there was no transmission build.
- DTS decreases on point of delivery (“POD”) where the generation facility is connected, load customer disappears, portion of substation fraction has now increased (STS fraction is now higher), would this claw back apply?
    - The fraction number would become higher; DFO would need to pay back contribution.
- How does DTS change with the addition of STS?
    - Substation fraction would change but not DTS.
- What is driving the 20-year period?
    - It is generally how long the assets last.

- Assume there is an old substation built for a load customer and now a new DCG wants to connect, there is a fractioning calculation but no build out or upgrade, what happens in year 21 or 22 when the DFO wants to upgrade substation?
    - TFO will pay for maintenance, if the DFO's system access service require requires the addition of transmission assets they will pay a contribution.
- What happens when the upgrade is completed for a DCG?
    - They will pay for some of the costs.
- [Referring to slide 25] I would like to understand how the split was categorized? There is $5 million in blue and $3 million in green. Is there a sub-category/calculation for the $3 million? How did you decide the difference between the blue and green?
    - Currently the calculator does not calculate the sub-category, we sit down and breakout costs to figure out what they are sharing.
- I think incremental is important, can you explain why there is incremental in appendix 3 of construction contribution decision ("CCD")? It is not cost causation anymore when you take out incremental.
    - Incremental approach worked okay back in 2006 when it was the same market participant.

***Discussion commentary***

- We need to be consistent in how we define terms like participant and market participant.
- One of the key problems is how costs can be reassigned seven years following a project.
- Substation fraction has nothing to do with regional and bulk transmission system.
- Participant made comment on slide 19 and 20 that DFO's don't pay local interconnection costs.
- Another important distinction on slide 20; for a generator to tie into transmission system, there are no upstream costs (regional and bulk transmission system). A DCG is burdened with cost of a substation that is upstream where transmission is not burdened with anything upstream.
- Would just like to point out that in section 8 (3): CCD submitted shows that the capital maintenance cost was a participant-related cost.
    - Acknowledged that this was an error.
- On BTF projects the distribution costs are much lower compared with transmission costs.
- Is it important that the AESO's supply and demand related costs are accurate and reflect reality (i.e. Investment and POD charges have to line up).
- The situation illustrated in Slide 23 is unlikely to occur (i.e. the request to reduce MW).
- [Referring to slide 24] If both are for contracted DTS service, the cost sharing is understandable; if you introduce an STS you begin to apply the substation fraction. Load was there to be served, does not diminish DTS and therefore it doesn't make sense if it is STS.
- When you look at shared costs previously paid, you would apply that to the participant related costs (local interconnection costs). E.g., if costs are $10 million and sufficient funding for $8 million of investment, participant paid $2 million; substation fraction would apply to the $10 million.
    - Substation fraction could apply for the amount paid by the market participant ($2 million) and not the $10 million. This is not how it works today but this is how it could work in the future.

- Basically, on a high-level, you can provide different examples but fundamentally talking about shared costs and differences between transmission connected generation and distribution connected generation.
    - Today we are trying to use the model from the past which does not work today. Current ISO tariff has provision where AESO can treat a DCG with parity.
- As a transmission connected generator, there is an incentive to look on a map and locate as close to regional bulk system to cut down on kilometers and therefore cost.
- With regards to the transmission connected projects, notion that system is not being adequately paid for but now have the generating unit owner's contribution ("GUOC")?
    - GUOC is refunded if you perform what you say you are going to perform.
- Two overarching issues are: at what portion of the substation do you invest in? When should investment be recalculated?

## DFO Commentary – FortisAlberta presentation

### *Clarifying questions from other stakeholders, including responses from Fortis*

- In the event the Rate STS changes, can we sign up for a retroactive agreement with our DFO to get back some of the costs?
    - DCG customer should have full (visibility and) accountability of what they are on the hook for at the ISO tariff level. When DCG customers sign with a DFO, within interconnection agreement the DFO would like to clarify what DCG customers are on the hook for in relation to STS (e.g., 5MW to 10MW).
- In breakdown of DTS related costs, what distinction might a DFO make?
    - DFO pays the contribution up front;
    - For ongoing charges (DTS), prior to the AESO tariff decision, DFO paid DTS contributions on behalf of its load customers and flowed costs through. DTS costs are now brought back up to the TFO level, would become a factor as part of performance-based regulation ("PBR").
- Did the investment change on the first example from the first slide to the second slide?
    - Yes, it did.

### *Discussion commentary from other stakeholders, including responses from Fortis*

- DCG customer also pays GUOC directly to the AESO.
- Believe that system access service request ("SASR") should not impact DCG customers who are already connected.
- Struggled with ruling around "discretion". When given discretion it needs to be exercised reasonably; in light of Commission decision on AltaLink (if it stands), discretion lies with TFO and AESO
    - It was noted that the above stated decision from the Commission does not impact all DFO's.
    - Whether it's the DFO or TFO it ends up on load customers either way.
- Reason bringing up DTS contributions is that substation fraction considers both of them. If you don't lock down contribution and allow for latent/trailing price signals, it poses a significant financial risk for generator that cannot mitigate.

- DFO's are also struggling with the timing of substation fractioning and providing reasonable quotes to its customers in their upfront quote packages.
- Two categories of transmission costs: DTS related charges and market participant related contributions. With regard to all transmission costs: DTS bills at all PODs, creates transmission rates and are flow through dollar for dollar. With regards to distributions, the rates come from distribution rates and are not necessarily flow through (some DFO's use capital trackers) .
- In ISO tariff decisions, DFO organization was given discretion on costs, in phase 2; rate 63 flow through will have similar problems.
- It was noted that the costs, regardless of being STS or DTS are the same. It's more of a question on who should pay.
    - Flow-though to largest load customers and DTS contributions, and was not own initiative: direction from Commission in flowing through some DTS related contributions to largest customer who may be incurring costs.
- Overarching issue is more about energy policy than tariff design. Encourage AESO to reach out to other jurisdictions and explore where there has been deep penetration of DCG and whether they employ cost allocation methodology.

## DCG Commentary – BluEarth Renewables, Innogy Renewables and Siemens Energy presentations

### *Clarifying questions from other stakeholders, including responses from presenters*

- There have been lots of load incidents (thermal conditions n-1 contingencies) in this area, how was it explained to the DCG?
    - It wasn't.
- Why wasn't this project a system reliability project (AESO) and covered through rate-base?
    - The project was identified and conducted from a DFO reliability deficiency and not an AESO identified transmission reliability need.
- In the original project proposal, were the risks of interconnection costs explained to the DCG?
    - No.
- Tariff treatment you are under, is it the existing tariff?
    - Yes, it is the existing tariff.
- How big are the loads on the substations already?
    - It is a big substation with enough capacity.
- What visibility is provided to or requested by the DFO from the AESO in situations with a split STS and DTS portion of a substation fraction?
    - The DFO doesn't have any more detail than what is provided to the DCG on the results of the substation fraction.
    - Appears to be a force fitting exercise in terms of trying to apply substation fraction (historically on single participants who owned both) with the DFO as the intermediary who knows as much about the substation fraction calculations/costs as the DCG.

- When you get the bill and considering the needs document, it is conceivably possible that most of the t-costs was simply flown through to the customer, is that a possibility?
    - Would agree that DTS has not changed, there was an STS introduced and DFO does not have responsibility as they do not have generation on the system and would not be needed.
- Who requested the SASR that increased STS?
    - The DCG requested the SASR.
- When AESO initiates a transmission project for reliability etc. no cost flow through to the transmission connected generator right?
    - There are two streams:
        i. No classification of costs when system transmission project (i.e., a project for the construction of non-radial/networked transmission facilities); TFO pays and then bills AESO who then bills DFO, Rate 101 customers, industrial customers Etc. through DTS rates.
        ii. Connection project that is radial; all costs are classified as participant related costs; costs for the upgrade of the system will not be allocated to a generator's connection. Costs for upgrades of the system are not allocated to a generator's connection.
- Are we treating TCG and DCG on a level playing field?
    - DCGs do appear concerned with sharing the costs previously incurred and paying for the costs that it causes in some cases. The main concerns appear to stem from unforeseen future costs
- When a DCG connects there is an interconnection cost (or incremental costs to connect plus interconnection costs to the distribution system) that is paid; is the AESO under the impression that these existing costs are inadequate?
    - ISO tariff says have to pass through any supply-related costs to DCG in addition to incremental costs and distribution system interconnection costs

### *Discussion commentary from other stakeholders, including responses from presenters*

- One additional risk not highlighted is that investments will flee the province and if they were hit with an additional bill of this magnitude.
- There shouldn't be additional costs to DFO if DCG's show up there. Should DCG's pay something? CCD should be used as a price signal.
- When erosion on transmission system's reliability impacts the distribution system reliability and the DFO asks for system improvements, do market participants believe it is a reasonable and prudent cost that should be viewed as a system cost, or that it is a cost in excess and unnecessary for the benefit it drives?
- AESO's role in this case was to administer the substation fraction; as it was not an AESO directed project.
- There is a provision already in place regarding 2 market participants in the AESO tariff.
- With further clarity around costs in excess of good utility practice, DFO reliability projects that don't require contract change should maybe fall in excess.

- Are we allocating costs in the right buckets?
- Am I correct in my understanding that the substation fraction calculator pumps out a number that calculates what a DFO should be paid back for its existing infrastructure (i.e. contribution received from another participant)?
- Feel that STS is over simplified and based on only capacity and not real energy flow which disproportionately impacts the DCG (which are often renewable resources that rarely flow at nameplate capacity which is what STS is calculated on).
- Still trying to figure out where the $2 million is coming from.
- Biggest concern is the future liability.
- System costs should be passed through to the customer.
- Want to make it clear why DCG's bring up incremental costs; DCG wants the same treatment as TCG, prepared to pay the cost (even if $2 million or $3 million) to connect to the system.
- Themes we heard: How are we defining system costs vs. participant costs and there is no intention to leave out unmitigated error from the AESO.
- Seems that the primary tension is between fairness and efficiency: questions around fairness and what people should pay (what is equitable contribution), primary motivation for the market is open competition will lead to efficient outcomes, if does not lead to efficiency why do it? (maybe other reasons why).

## VI. Breakout on principles

### *Context*

Participants used the principle reconciliation as basis for discussion and did not discuss the similarities or differences between the three sets of principles.

### *Principles*

The following principles were put forward by the AESO to help guide the breakout group discussion:

> **Principle #1:** Parity between transmission interconnection costs calculation for transmission connected customers and distribution connected customers
>
> **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) (e.g., 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)

**Principle #4:** DFOs should be provided with reasonable certainty re: cost treatment/recovery (certainty of future costs/stability)

### *Breakout summary*

Across all of the breakout groups, participants generally supported the principles of parity, cost certainty, and cost recovery for DFOs (principles 1, 3, and 4), and were also generally aligned on additional principles to incent investment (e.g. a simple framework, with clear signals). Principle 2, focused on whether DCG's should share in the appropriate share of costs showed significant divergence with some participants believing the DCG should not share in existing facilities costs, with others permitting that existing costs should be shared but that the DCG should be insulated from future costs (that they are not causing), which would also align with the parity principle in how TCG is treated.

Each of the groups suggested that participants differed in how the principle should be applied, suggesting that there will be various approaches / solutions provided in subsequent sessions.

Some of the groups spent additional time on level-setting and terminology, suggesting that more work needs to be done to reach a common understanding of the challenges and issues the technical sessions are seeking to resolve.

Detailed discussion from each breakout group is offered below.

### *Breakout Results*

## Purple Group

### *Summary of breakout group*

Participants were generally aligned on the consolidated high-level principles, however, differed in the application of the principles. For example, participants felt that distributed connected generation costs should be a similar magnitude and timing as transmission connected generation which they felt was not occurring today. Additionally, some of the group members felt there were a few other important principles that were not addressed in the consolidated principles set including: financial transparency and grounded by policy/Commission principles.

### *1. Principle #1*

### *Definition*

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

### *Summary and overall thoughts*

Participants were generally aligned on the parity principle but differed on the application when compared with how the principle has been applied historically. Most of the discussion was around the uncertainty and future risk of distributed connected generation and the differences when compared with transmission connected generation.

### *Commentary*

Please find a more detailed build out of the discussion below:

- Cost parity around the future risk is the heart of the issue
- Costs for distributed connected generation is out of their control while it appears that transmission connected generation is under control
    - There is a metering cost allocated to the generator that does not occur on the transmission side
- With the current application of the principle, increases or decreases in DTS could greatly impact distributed connected generation
- A novel idea was brought forward by a participant that distributed connected generators should deal directly with the AESO. Concerns were raised that new challenges would arise if distributed facility owners were left out of the process
    - What would it look like if DCG dealt with AESO directly for STS?
- Unknown external cost drivers for distributed connected generation but not for transmission connected generation
- Discussion around the way STS is calculated occurred with suggestions that it could potentially be calculated at a POD versus a feeder
    - This will ensure that you will only be responsible for the costs you bear, not the load-driven costs of the substation.
    - One challenge for this approach may be an increased cost for generators
- It was generally accepted that price signals should be given at the time of investment and/or before investment occurs
    - A novel suggestion was brought forward by one participant that it could also be linked to locational value with the goal being to drive efficiency
- How do you insulate distributed connected generation from the activity of distribution partners?
- Distributed connected generator's should pay the same magnitude and timing as transmission connected generation
- A discussion point was raised about how "contract capacity" is not the best approach for DCG's to get charged whereas this approach may still adequately serve TCG's
- A discussion point was raised around how it felt like substation fraction was force fit and capacity as a parameter is not correct
- As it related to the application of the principle, should the rules differ for distributed facility owners and dual use market participants?
- If metering was used as a way to calculate the tariff, infrastructure would need to be in place
- An idea was brought forward that if a transmission facility owner can compete in the distributed connected generation space, why can't we compete in theirs
    - An example of how AltaLink could build a solar farm was used

## *2. Principle #2*

### *Definition*

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) (e.g., fairness, cost causation)

### *Summary and overall thoughts*

While there was agreement that market participants should be responsible for an appropriate share of costs, participants concluded that upfront cost-certainty was of utmost importance and suggested a signal be added to ensure efficiency

### *Commentary*

- Only pay for interconnection costs and not benefits deriving from the system
    - Not everyone was in agreement on what "benefits" entailed in this scenario
- If AESO keeps the same application of the principle, everyone would connect to transmission systems instead of the distribution system
- There needs to be balance about market participants paying an appropriate share of costs
- *Likes*
    - Distributed connected generators should not be responsible for the costs properly attributed to load (DTS)
- *Dislikes:*
    - Substation fraction calculation is too simplistic
    - Application of principle chases away investors
    - Get rid of substation costs and load pays
    - Distributed connected generators should not have to pay substation fraction
- Efficient system would be what is needed to keep feeder going
- Transmission costs limited to cost of distributed connected generator to connect
- Potential location signal to ensure efficiency and an appropriate share of costs are transferred

## *3. Principle #3*

### *Definition*

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)

### *Summary and overall thoughts*

Participants were generally aligned that costs should not be allocated to a distribution connected generator after energization, however there may be an exception for future cost-sharing for STS.

### *Commentary*

- There needs to be an improvement in the fairness of cost sharing
- In addition to costs, account refunds also need to be taken into consideration

- Future cost-sharing for STS among distributed connected generation would be an exception for this principle

### *4. Principle #4*

#### *Definition*

DFOs should be provided with reasonable certainty re: cost treatment/recovery (certainty of future costs/stability)

#### *Summary and overall thoughts*

The fourth principle was not discussed in the breakout due to a time constraint

### *5. Other Principles*

The following principles were briefly mentioned as other principles that should be taken into consideration but a detailed discussion was not conducted:

- Financial Transparency is important
- Grounded by policy/Commissions principles

## Orange Group

#### *Summary of breakout group*

Participants were generally aligned with principles 1, 3, and 4, but differed on principle 2 specifically whether or not DCG customers should be responsible for a share of cost for delivery. Suggestions for additional principles focused largely on improving investor confidence (e.g., process must be simple, provides clear efficient signals, technology agnostic, and incents future DCG activity). Additionally, the group spent additional time on ‘level setting’ and ensuring a common understanding of current tariff application.

### *1. Principle #1*

#### *Definition*

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

#### *Summary and overall thoughts*

Participants were generally aligned on the parity principle but differed on the application when compared with how the principle has been applied historically. Most of the discussion was around the uncertainty and future risk of distributed connected generation and the differences when compared with transmission connected generation.

#### *Commentary*

Please find a more detailed build out of the discussion below:

- Cost parity around the future risk is the heart of the issue

- Costs for distributed connected generation is out of their control while it appears that transmission connected generation is under control
- Parity between Transmission Connected and Distribution Connected should be 'similar', but it was agreed that it may not be the 'same'. There is a distinction here.

### 2. Principle #2

#### Definition

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).

#### Summary and overall thoughts

In general this principle was the most controversial amongst the team. Some members agreed, while others did not. It was very clear that this principle was the least understood by the team.

In response to this differing level of understanding, the group spent additional time on 'level setting' and ensuring a common understanding of current tariff application.

#### Commentary

- Generally, the group felt this was important, however there was concern that a solution could be too complicated or risked the market participant in incurring additional costs
- Key question comes down to: should the generator share in the local interconnection cost of a DFO driven project (whether it is load or reliability)?
- If there is a benefit to the DCG, then the DCG should share in the cost. If there is no benefit to the DCG, then no cost should be shared
- Novel Idea: Can all DFO driven reliability projects (e.g. Provost) be classified as facilities in excess of good engineering practice? These are projects that the DFO is initiating; the AESO has not determined a TPL-002 violation. Therefore, the DCG should be insulated from sharing any cost.
- Cost signals must be timely in order for DCGs to determine cost impact

### 3. Principle #3

#### Definition

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

#### Summary and overall thoughts

In general this principle was agreed upon by the entire team. All DCGs and DFO representatives firmly believe that DCGs should not be exposed to additional costs after they have energized.

#### Commentary

- Energized is not an appropriate time in which costs are 'locked down'. This needs to be determined earlier in the connection process to align with when DCGs make their investment decision.

### *4. Principle #4*

#### *Definition*

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

#### *Summary and overall thoughts*

In general, it was agreed that the DFOs should have a predetermined methodology in which to recover costs. Additionally, there was alignment with participants that DFOs should have a predetermined methodology in which to treat costs.

### *5. Other Principles*

- Keep it Simple:
    - This is a very complicated process overall. It is very difficult for DCGs to explain to their investors or stakeholders. Whatever solution is determined going forward, it must be simple and easy to explain to others
- Must be technology agnostic (able to support any type of generator or technology)
- Utilize existing infrastructure before building new (DCGs can help avoid system build)
- Alberta is an attractive place for DCGs. If we don't solve this issue soon, investors will lose confidence and look elsewhere

## Blue Group

#### *Summary of breakout group*

Participants were generally aligned on the consolidated high-level principles, however, differed on the options for implementation of them.

#### *Conversation notes*

- "System Cost" must be clearly defined. How is AESO defining this and how is the DCG's defining this?
- While aligned on the principles, we need to look at the consistent application of them
- Substation fractions – important considerations around timing and when facilities are needed.
- DFO as "default" market participant and contract holder versus Market Participant (SAS) – Should this remain? Should the Generation Facility Owner (GFO) be the contract holder instead?
- Carefully consider cost allocation along the lines of "triggers" and who is deriving the value, to help eliminate retroactive or significant forward looking changes.
- Different service needs, under "1" Market Participant…
- Cost sharing, and timing and size – ATCO does delineate this on the Distribution side too.
- It's all in the specific details of how the costs should be shared. Get right down to bus apportionment, etc.

- Perhaps limit the change risk exposure to 3 years? 5 years? Rather than 20 years, similar to other jurisdictions.
- Perhaps there could be a base cost/charge/fee based on size and connection?
- Look at other incentives/disincentives/signals for placement/investment for both the DFO and GFO.
- Consider a General Rate for GFOs in the DFO tariff? Incremental generation versus average load?
- Ensure consideration of generation displacing load, or otherwise increasing load capacity at a substation previously not possible (or problematic) without generation present.
- The big question remains: where does discretion best lie? With DFO or AESO? Must consider events even where the principles are codified. Participants generally want it left with the AESO.
- Concentrate on cost causation and the split – who “needs” what and where – detailed allocation of specific costs.
- Separate the investment erosion from the CCD calculation, while still ensuring GFOs and Loads pay their fair shares.
- Balance calculations and cost assignment with relative impacts.
- Codification of the principles may need to be done on scenarios to ensure clarity of treatment in the future.
- Suggestion: if there’s no STS change, don’t recalculate.
- Limits on upgrades, timing and “value” of them to the DCG (and loads for that matter).
- Consider when decisions are “locked in” for participants (and where in the connection process) to ensure low risk of changes and thus accurate investment decisions by DCGs. Consider closely where things will be Grandfathered based on new decisions, as well as decisions yet to come to help add clarity for investors.
- Consider closely how the STS is set.
- Cost causation based on the metering point, timing and justifications.
- Carefully consider the ‘cost causation’ of all these DFO “reliability projects”.

## Green Group

### *Summary of breakout group*

Participants were generally aligned on the consolidated principles 1, 3, and 4, but disagreed with principle 2, suggesting that DCG should not pay for a share of existing facilities. Participants within this group also differed on the how the principles should be implemented. This group also stressed the importance of a simple solution that attracts investment and provides the right signals to result in an optimized grid.

### *1. Principle #1*

### *Definition*

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

### *Commentary*

- The group did not think that there was parity between distribution and transmission connected generation as it exists today. Mainly because of the unlimited potential for future costs.
- Distribution credits would be a good price signal to incent DCG to connect in areas that are beneficial to the system. Agreed that finding the cheapest connection to the grid doesn't necessarily correlate to one that benefits the system.
- Parity is an ambiguous term.
- DCG and transmission connected generation don't necessarily have to have parity; it should be based on the benefit that they are providing.
- Connecting generation for the lowest cost to all Albertans should be a consideration. This includes not just the dollar amounts but also optimizing the grid.

### *2. Principle #2*

#### *Definition*

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) (e.g., fairness, cost causation)

#### *Commentary*

- Agreement among the group that all the costs to connect the project should be made known upfront so that the generator can make an informed decision.
- The group did not believe that DCG should pay for a share of the existing costs for transmission facilities.
- Policies, rules and practices should be created to attract investment to Alberta and certainly not to incent 'defecting' from the grid (could be its own principal).
- Transparency and simplicity should be factored into any decisions and could be its own principal.

### *3. Principle #3*

#### *Definition*

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)

#### *Commentary*

- Agreement among the group that no costs should be allocated to DCGs after the project has energized. This was flagged as absolutely critical so that generators could have certainty in their decision before investing anything.

### *4. Principle #4*

#### *Definition*

DFOs should be provided with reasonable certainty re: cost treatment/recovery (certainty of future costs/stability)

***Commentary***

- The group agreed that DFOs should be able to recover their costs. We discussed how those costs were recovered was the underlying issue but we didn’t get into the details.

## VII. Additional webinar questions

- Would you please define what you mean by Local?
    - The T-Reg says "local interconnection costs", as defined by the ISO, are payable by the owner of a generating unit for connecting to the transmission system. The ISO tariff identifies them as connection costs, most often for a radial configuration
- The green color in the previous slide, is that Distribution or Transmission network?
    - These would be the costs solely paid for by the generator to connect to the feeder.
- If Fortis requests a new DTS connection where it did not exist one and it requires new step-down substation, who pays for such new substation?
    - The TFO builds the substation and owns and maintains it. However the DFO pays a contribution towards the costs of the construction.
- Will this webinar be recorded?
    - Yes
- Do Transmission Connected Generators receive Distribution Credits?
    - No
- So DCG receive the credit that Transmission connected don't
    - Yes
- Is that compensation?
    - DCG credits are revenues for DCG
- Comment: What is not hi-lighted in the principles is the other side of the coin the benefits that DCG's receive that create inefficiencies and discrimination
- If the main concern of the DCG generators is the unhedged risk the way to avoid that is to locate on the Bulk system, is that not correct
    - These sessions are attempting to come up with a solution so that this is not the case.
- How is the amount eligible for "Local Investment" determined
    - Only the demand related costs for a connection project are eligible for local investment.