Participant-Related Costs for DFOs (Substation Fraction) and DFO Cost Flow-Through Technical Session 2A – May 14, 2020

I. Purpose of this session

The purpose of this session was to:

- 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 stakeholder proposals for participant-related costs for DFOs and DFO cost flow-through.

II.Session 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

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III. Attendees

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Acestes Power ULC
Alberta Electric System Operator
Alberta Energy
Alberta Utilities Commission
AltaLink Management Ltd.
ATCO Electric Ltd.
Best Consulting Solutions Inc.
BluEarth Renewables Inc.
Blake, Cassels & Graydon LLP
BowMont Capital and Advisory
Campus Energy
Canadian Solar Solutions Inc.
Capital Power
Capstone Infrastructure Corporation
Carlotta Energy
Chymko Consulting Ltd
City of Lethbridge
Clem Geo – Energy Corp.
Customized Energy Solutions
DCG Consortium
Denis Forest Consulting Inc.
DePal Consulting Limited
Dizrupt Energy
Elemental Energy Renewables Inc.
Enel
ENMAX Corporation
Enpowered
EPCOR
Evolugen
FortisAlberta Inc.
Green Cat Renewables Canada Corporation

Company
Hatch Upside
Innogy Renewables Canada Inc (DCG Consortium member)
Industrial Power Consumers Association of Alberta
Irricana Power Generation
Kalina Distributed Power
Lionstooth Energy
Longspur Developments
Nican International Consulting Ltd.
Plains Midstream
PMC
Potentia Renewables
Power Advisory LLC
RVM Developers
Siemens Energy
Signalta Resources Ltd.
Solar Power Investment Cooperative of Edmonton
Solar Krafte Utilities Inc.
Suncor Energy Inc.
TC Energy Corporation
The City of Red Deer
UCA
URICA Asset Optimization
Wolf Midstream
Stack'd Consulting, Inc.

IV. Overall outcomes from the day

Attendees spent the session continuing to build a common understanding of the purpose and application of participant-related costs for DFOs and DFO cost flow-through, reviewing proposed changes to the high-level principles, and observing stakeholder proposals for participant-related costs.

Below you will find the questions and answers as they were asked and answered in the session. Responses are the presenters' own, have not been vetted for accuracy, and are for discussion purposes only.

V. Review of Principles:

Q: What is the TCG responsible for if they are connecting on to an existing transmission line that is feeding a distribution pod?

> **A:** Responsible for cost. TCG, responsible for building own substation

Q: Transmission connected generator would not be sharing any existing costs, is that correct?

> **A:** If a TCG connects to a line that could be a portion that is a shared cost that TCG and DFO share.

Q: [About update #3 to level-setting document]: In the situation described here, how does the generator contribute to the operations and maintenance costs that the TFO occurs over the life of the system?

> **A:** Any ongoing O&M costs TFO allocates in depreciation studies and rate base, no O&M charge in CCD

Q: Is this webinar due to the AUC decision 23393-D01-2019?

> **A:** No

VI. Joint Q&A #1:

Q: [To DCG Consortium] What are you referring to when you say the supply line and why you think it should be excluded from the cost assessment?

> **A:** The radial line that connects the substation into the bulk and regional system. We think it should be excluded in part because it will cause locational signals if you start to think of that on a $/MW/Km basis which is probably a better way to think about supply lines. We would like to exclude the locational component and focus the conversation on the substation equipment itself and not push the conversation outside the substation

Q: [To FortisAlberta] The AESO collects the contributions and then refunds them back to the specific DFO. We are adding a number of tariff steps here and I am a little concerned about transparency, simplicity, is there not a way the DFO collects the contribution directly?

> **A:** We would be invoiced the ASIC contribution by the AESO, we would then package that up with the other interconnection costs to the DCG and provide a quote letter to the DCG, and they would have to pay that before the project could move forward. When they pay that, they would pay that to Fortis. Fortis would effectively pay that to the AESO through the AESO tariff because that is what we are talking about and the AESO essentially directs is back to the TFO much like GUOC. At that point we understood that by keeping the DTS substation fraction at 1 to decouple the supply and demand side that would essentially be inflicting full cost onto our DTS load customers and so by keeping that substation fraction at 1 we essentially, our load customers don't see any value in those assets contributions being made by DCG at those shared substation. We need some way to get the revenue offset dollars from the TFO tariff back to the DFO customers that are responsible for those costs or credits. Open to see how it can be done in a simpler fashion.

Q: [To FortisAlberta] Can you please clarify what you are proposing to include in the equipment costs other than cost of material, materials and installation of equipment on site?

> **A:** Proposal is to work with DFOs and the AESO to determine those average costs but it would be the installed cost so the existing value of the assets in the ground now but I do see the argument that if protection in your SCADA elements is used only for load then maybe those could be excluded. The issue is with doing only doing the materials costs with the transformer and installation costs is that you are missing the project management costs and the AESO connection process costs and then civil grounding. It would be the average project cost to have that installed.

Q: [To All Presenters] The proposal indicates that the calculation of the ASIC would exclude protection control systems, just looking for confirmation in that statement that this is not applied to the incremental protection control systems that would be installed for the purposes of connecting the DCG?

> **A: [FortisAlberta]** We did address in our written submission in more detail. The intention is that any interconnection costs associated directly with the installation of the DCG would be allocated as a separate or additional cost to ASIC, so any of the BTF costs essentially, so protection control, new relays whatever that may be

> **A: [DCG Consortium]** confirm from our end as well. Thinking that all of those costs fit into the incremental cost bucket and one of the major reasons we proposed to exclude all of the protection and control costs from the load substation prospective because the DCG will be paying a good chunk of that anyway as part of its incremental cost so it is duplicative to also charge for load SCADA when the DCG is paying for its own SCADA as part of its incremental charges.

Q: [To DCG Consortium] so you talked about the contribution charge, the megawatts to reflect more of the 8760, how do you think Fortis' calculation of that utilization factor align with what you were thinking?

> **A: [DCG Consortium]** At a high level the approach to utilization factor by Fortis is a step in the right direction as its attempting to calculate on an energy flow basis throughout the year how much is going in reverse, in essence using the transmission assets and how much is going forward using the transmission assets for load customers. The one point where we differ is that we are concerned the utilization factor calculation may not reflect usage on seasonal basis so while you calculate max reverse power flow that might be an instant in time where the rest of the production from the DCG would be netted out by load consumption so most of the flows would be forward. Again, at a high level it is a step in the right direction trying to go to 8760 by how the system is used as a proxy and simplification but there are still some further details needed.

> **A: [FortisAlberta]** We had a few 8760 files that we have done a similar calculation on just as a trial to see how they match for solar they seem to match pretty well. If we had the 8760 files, if we could get those consistently available that probably is a more accurate way to do the calculation. For wind and gas it is more of a challenge to get an assured 8760 profile that we can use for those calculations but we are open to investigating that and we have done it for solar with pretty good results on a trial basis to compare our results with an 8760 analysis

Q: [To DCG Consortium] There are a lot of edge cases to be considered, I believe it was the AESO in the first session spoke and said that if any generator proposed to connect to a substation they would have an opportunity to be their own market participant and wouldn't necessarily have to be a market participant of the TFO whether by means of building their own substation next to the TFO substation or just applying to be their own market participant. In the proposal for system contributions did you do an evaluation to say would that formula be the same for whether or not that DCG connected right next to the POD was a

DFO or TFO customer and flipping that one variable would potentially affect some of those calculations? Seemed to me the premise of your mechanism was to create a brand new section for the CCD and say DFO only. If now you are saying an exact same project but T connected, are you making a big jump in what the potential rate implications would be and did you give any consideration to that type of an edge case.

> **A:** The suggestion here is that there are not any concerns when talking about transmission connected generators so there is nothing to fix on that side. The issue is with distribution connected generators being allocated costs through these CCDs which are costs they don't charge and costs that can be allocated to them at any point during the life of the project which could be years after they connect so those issues don't exist with TCG's. The thought would be that this creates parity along those lines whereas we are getting rid of the issues TCG's don't face when we are looking at DCGs

Q: [To DCG Consortium] Right, so does it create parity with the mechanism the AESO uses presently to insulate separate market participants in that regard or did you give consideration to that?

> **A:** In the first session on of the comments that came up was that DCGs can just become a market a participant and that would shelter them. We thought about that a bit but we went down this path instead which ends up working the same way because no costs will be allocated to them where they are not making changes.

Q: [To FortisAlberta] If a DCGs connection involves the construction of new assets within the POD (e.g., a new 25 kV breaker or even a new transformer), would those components be excluded from the ASIC calculation If so, if in the future another Market participant connects and uses these facilities, will there be a refund to the DCG that funded those equipment?

> **A:** They would be excluded; we note in the submission that we need to be aware of the risk of double counting. So if a DCG drives a transformer upgrade or a breaker addition they would pay for that component to be added so then they shouldn't be further allocated an ASIC cost for that. So the second part of that, if another market participant connects in the future I don't have an answer for that right now but it is something that needs to be looked at. As far as ASIC calculation goes that is for existing or pre-existing substation or POD facilities that were installed to swerve load. In terms of interconnection costs which is a separate stream, we need to be careful that we don't create a duplication of that cost allocation but in terms of ASIC and price signal being only sent at the time of connection – as far as the ASIC calculation goes I think we would make sure that it is a one-time cost upfront to the connecting generator and that there would be no additional costs or refunds thereafter. When it comes to the interconnection facilities, if those facilities whether it be a transformer or feeder breaker were handled initially as an interconnection cost then I think there might be some room to create a refund to the existing DCG customer if those incremental interconnection costs are assessed at the second DCG generator. Need to make sure there is not double counting but as far as the ASIC calculation goes we would not see any additional charges or refunds after grid entry.

Q: [To FortisAlberta] Would elimination of option M in anyway effect your calculation?

> **A:** We view option M as a separate issue. The DFOs were directed to provide those credits to DCG back in the year 2000 for entirely different reasons. At that time it was a metering change, and adjusted metering practice at that time by the transmission administrator so it really has nothing to do with contributions assessed through the AESO tariff to the DCG or supply generally. The answer is no.

Q: [To FortisAlberta] To go back to other CCDs where substation fraction was split between DTS and STS and I'm just curious if Fortis has put thought to that how they would go back and treat past DCGs that have already connected and already paid a supply related cost or been invoiced?

> **A:** We believe that is something the AESO needs to determine in terms of that transition plan as part of the proposal that goes to the Commission. It is the AESO who issues those CCDs in accordance with its AESO tariff and from our perspective, being the middle man between the AESO and the DCGs, we see a lot of different revision and corrections to these CCDs and we are not quite sure which is the final CCD which should be flowed through to the DCGs or not, so we do believe that is something that needs to be looked at. As much as we generally would not propose not to look retroactively, the fact of the matter there is in the last couple of years by the AESO applying its adjusted metering practice and being rigorous in trying to charge STS contributions to DCG or supply that is going to have to be remedied because that is the reason for the complaints that we have seen which led to this engagement with the AESO. Yes, that needs to be determined and would leave up to AESO to determine what is fair to these DCG customers. And we also know the DCG consortium has made a proposal which we would not object to.

Q: If the AESO issued CCDs for something from 2 years that you could enable all of the financial transactions resulting from that?

> **A: [FortisAlberta]** Yes, to the extent that there is some sort of transitioning or grandfathering provision put in place as part of the AESO's proposal to the commission that we would expect that the AESO would give us guidance through an information document, how they plan to handle that. It has been the issue all along is ensuring the harmonization and synchronization between the AESO and distribution tariffs to the benefit of their DCG customers
>
> **A: [DCG Consortium]** I would like comment that although it sounds like retroactive ratemaking, I don't think it is as much down that path. For all of my members, none of the CCD costs have been paid yet and very few have even been invoiced. There is a lot of regulatory delay where the AESO has taken a lot of time to calculate the CCDs, Fortis has taken a while to pass them through and in many cases haven't invoiced them yet. We are looking to saying is that there are necessarily any financial refunds the need to happen its more invoices that have been sent and held in advance by the commission or CCD that have been issued but not invoiced should be recalculated.

Q [To FortisAlberta]: You say that the AESO should abandon the substation fraction calculation and clarify if it just for distribution facility owned facilities?

> **A:** Yes, correct.

Q: Heard an undertone that the optimization of existing distribution and transmission facilities comes from sending the signal to size the DCG to the local load either at the feeder or substation. Am I correct in that interpretation?

> **A: [DCG Consortium]** I agree with that. One of the great benefits the DCG provides over TCG is that you don't have to build all of these lines to get the power from where its generated to where its supplied and so as soon as you have distribution connected generator that's 200MW you are not reaping those benefits anymore. If you are sizing the generator similar to the load on that particular substation then the DCG is providing all of those benefits.

A: **[URICA]** Conceptually to me that is where we are talking about, the availability of data would make the decision a lot easier and however we look at this going forward whether we use utilization factor or capacity factor or stick to something similar to the STS, the availability of that data pretty easy to use and the availability to put these assets to offset load correctly or as correctly as possible under the assumption they are helping makes sense. Being able to right size an asset and not put something in way larger than the load or the substation maxes would make a lot more sense.

Q: [To FortisAlberta] How does the use of the ASIC methodology (specifically the utilization factor and capacity factor) fit into the AESO principle 4 of simplicity and stability of implementation?

A: In terms of simplicity, you can go to various levels of complexity or detail. Have talked about an 8760 per year analysis both the supply and demand at a particular POD, we don't know whether we need to go there initially so what we have proposed is the utilization factor. To the last question, incentivize the generator to maximize use of an existing POD which is to basically match the load so there is not any reverse power flow and they are to track any additional contribution. In terms of simplicity we believe that utilization factor is a good way to start out with and then over time perhaps things could be refined and small amount of complexity introduced to refine the calculation. We believe that the utilization factor is sufficient in sending the right incentives and price signals to a DCG.

Q: [To AESO] Comment or consideration directed partially at AESO, I think in their planning documents they have noted that some high penetrations of DCG, there is a reduction in the transmission capacity. That is obviously a cost that gets born by someone, how does that principle fit into this sort of cost allocation methodology.

A: Sort of what I was getting at with the optimization of transmission and distribution facilities. If a price signal is sent that tells the DCG to connect in the part of the province to build on outflow issue then that is a problem so it is having that conversation about price signal for local load. So in these proposals…I am not ready to understand at how the $/MW would impact that but when you look at flows on the transmission system out of the substation are those priced appropriately so that the DCG gets the signal to look at that. The GUOC has a regional charge and I hear from the proposal that the simplicity should be an Alberta wide thing so it is something to consider and think about. Should be included in the evaluations that people send in. [Yes, it is a consideration that is worthy of discussion, but you don't have a point of view on how that would flow through]

A: I think that probably gets to the principle around the parity of treatment for transmission and distribution connected generation and why that's of importance to the AESO and that comes back to what was described in that maybe there is an incremental amount of DCG that causes an outflow constraint that would require transmission reinforcement in the AESO requirements to have an unconstrained transmission system it is important to address. Where the importance in respect to the parity of treatment for TCG and DCG is making sure the most efficient generation is developed and that requires they face similar cost or price signals when connecting to the transmission system so that it is factor into those investment decisions

Q: [To FortisAlberta] If optimization of locating DCGs is about locating it at places where there is an equal or large amount of load on the distribution system my question is there the ability for DFOs to provide that information to market participants to inform their siting decisions or is that something that is commercially sensitive or has securities issues with it?

A: We have the load information as does the AESO at each POD to the extent that it's serves multiple customers I don't think confidentiality is an issue. To the extent that it only serves one at that distribution pod then that may be an issue but there are likely ways to deal with that. What you are talking about is the availability of load data 8760 hours at all of the Pods in the province and maybe it would be something the AESO could provide to market participants to determine where best to locate to match load. We do share on individual applications when asked by the DCG developer. Have to keep in mind that we have feeders where one customer drives majority of load so that can be sensitive. But generally speaking at a feeder or POD level there is enough customers that you can't pick out individual commercial information. Could it be shared universally probably more of a legal/regulatory question.

VII. Joint Q&A #2:

Q: [To Canadian Solar] Slide 7 of LionsTooth presentation – To help me better understand your use of the word system cost. Can you speak to that using this visual?

A: First part of the test, if it has been entered into the rate base it is a system cost. Recovering through rate base. At its core it is a definition of a system/system cost. If a DFO grabs from working capital and pays supplementary component not covered by…. rolled into their rate of recovery. Whether systemizing on transmission or distribution it is a system cost as it is experiencing a rate of recovery

Q: [To All participants] On the sub-station fraction there is an asymmetric incentive in which the DCG has an unhedged risk while a transmission connected generator does not. But, it seems your proposals do not recognize the other asymmetric incentive between transmission connected generators and DCG. A transmission connected generator will pay a contribution towards the substation cost where your proposal does not. Shouldn't the incentives be symmetric between both classes of generation for efficient investment?

A: [Canadian Solar] Let start with the transmission connected generator. First of all they don't drive any investment policy from the AESO it's a dollar for dollar investment from the generator, its non-rate base so basically they are flipping the bill to connect to what would otherwise be the local or regional system. From a DG day 1 of the POD formation, the DG does not exist and we need to follow rules where consumers pay for wires. Through an investment mechanism be it from AESO or the Distribution investment policy, a radial line in a point of deliver is synthesized and brought to the consumer to gain access to electrical services. If we follow policy and regulation we have now caused the consumer to pay for that investment that was once a transmission system voltage at 240 or 138 has now been rolled in through a rate based investment all the way to the 25kv, from our perspective, our understanding how these principles evolved, we don't see any asymmetry other than the wires paid to bring a service closer to systemize what was otherwise far away to a nearby 25kv connection. Based on this principle, a DER connects to a 25kv distribution feeder, we don't see asymmetry or true up, this is just the physics of the interconnection mechanism.

A: [LionsTooth] To address the first point, current allocation methodology has been applied had the effect of unhedged future risk against DCG. Across the board all 90 people generally agree that unhedged risk needs to go away. Pablo was very eloquent, in saying look at AIES as a whole and don't necessarily differentiate too much between voltages so much, both TCG and DCG pay their local interconnection costs, just so happens that DCG connects to distribution the system, TCG pay for a substation and radial line just by the fact that is where they have chosen to locate.

In fact, if TCG was able to locate 5 ft away from existing substation, I would have substantially less cost which is locational signal. At the end of the day everything that is rolled into an individual utility rate base whether it is a distribution or transmission utility it does not make any sense, either from who should pay nor does it make sense for the delivered cost of electricity to a customer. So no it is not an asymmetry because locational signal over time drives generators to locate closer to load. It is not an incentive it is not a benefit, it is responding to how the grid works.

A: [Solar Krafte] I don't see any asymmetry. Both TCG and DCG need to build transformation capacity to tie into their respective distribution and/or transmission lines. A bigger generator/centralized generator is going to need more transformation capacity to tie into a higher voltage transmission line. On the flip side, commercially, it would benefit from economies in terms of how big it is and building that system out. From a connection perspective there is complete parity. They both pay the incremental cost to connect to the system.

A: [LionsTooth] As we showed on our TCG versus DCG slide there are in fact other disparities as well in that right size DCG uses very little of the AIES to get generation to load so that is a disparity. We are happy to pay GUOC for the voltage support and those sorts of things that we get from the AIES. The other disparity, and we do not want to open this can of worms is that we as DCG developers accept that we do not have congestion free access to the AIES and we are not in any way proposing in order to create parity between TCG and DCG that we should have an unconstrained distribution system because that would put the cost for load customer through the roof. Let's be clear there are some disparities but there are also locational benefits the DCG causes as well. All of those things need to be taken into consideration when we look at it.

Q: [To Solar Krafte] Can you comment on how not changing the tariff or the discretion the AESO has solves the investor certainty issue with current proposal? The way I see your proposal is that on a case by case basis we have to take it on faith that the AESO will continue to exercise that discretion.

A: That is not really what I am proposing but thank you for pointing that out. The AESO would need to crystalize their position in relation to DFOs in respect of that discretion. It might be one-line item added to the particular section (subsection 10 of section 8) however they choose to do it I defer completely to them. I agree with you it needs to be clear and unequivocal so we don't end up going forward with this whether or not to opt out or in on whether they exercise discretion so it would effectively not be discretion then would it.

Q: [To LionsTooth] On slide 16 you commented on the increase reliability from a DCG connecting on the distribution system and this sort of conversation came up in the 2018 tariff preceding and I am wondering if you could expand on that because I think that would be really helpful. Maybe the DFOs could help capture the increase in reliability of a DCG connecting on a distribution system.

A: [LionsTooth] That is a great question. At the end of the day, we have transfer trip protection that is required for a DCG to make sure that when a DFO does not want the generator supporting the electric system that they can turn us off. By the same token if you had an issue with a transmission radial line to the individual substation, there is in fact a potential that you could isolate a distribution feeder from the transmission system and you could power that distribution feeder with a distributed generator. In fact, load customers do this all of the time across Alberta where in fact there are customers that are islanded from the grid. We have in fact entire isolated systems that exist in the Alberta system. Concepts exist, what is interesting, as part of distribution system inquiry, AltaLink posted a 2014 paper that goes into much more detail about the various benefits that a properly integrated DCG can provide to a distribution system.

> **A: [FortisAlberta]** Currently it is all anti-island standards so the DCG would be the disconnect is the source is not on. It is technically viable with the right generator at least and controls in place you could island load it up and increase reliability. It is a future state and being looked at in the DSI; I think solar and wind without battery are less capable whereas synchronous gas is more capable of those types of island operations. Current connections of the DCG do not increase the reliability of the grid but in the future state it is a possibility. From a reliability perspective, DFOs basically request system access to serve its gross load because we cannot count on non-wires alternatives where generators are actually obligated to fill a wire deficiency if you will so until there provisions within regulatory framework to allow DFOs to contract with DCG to fill a wire alternative it is really difficult to rely on that increased reliability to the extent it exists.

Statement: [AUC] Wanted to put at odds two of the comments, one from LionsTooth and one from Canadian Solar. The idea that the AIES includes both the transmission system and the distribution system. DCG does in fact benefit from the AIES in that, the AIES is not just the transmission system. There seem to be differing positions here, I believe the enactments are pretty clear as to that and I wanted to ensure we were all on the same page because LionsTooth may have had a different definition of what benefits were received from the AIES and might have been referring to the transmission system as opposed to the AIES.

Statement: [Canadian Solar] Way back a long time ago when the transmission administrator's investment policy was invented, an important thing was going on. The purpose of the investment policy was to prevent pioneering. There were big concerns in the day that if you had unlimited transmission investment, distribution would want new POD all over and there had to be some mechanism to keep construction happening from building freeways down to parking lots. In the particular situation you are talking about the distribution utility if they paid a contribution, they made a business case inside that the extra money they put on the table and put in their own rate base was appropriate. At this point, once that is done and dusted and that POD is in place, it is in place. A DCG wouldn't connect there if they knew that connecting came with some big price tag. He is fine with the incremental costs associated with it but if you red circle pods and say this POD comes with so many $/MW contributions, you will send them somewhere else. The point that was made is that it is in the system it is in the rate base you are done.

Q: [To LionsTooth]: Question stems from one of the principles that we have around parity for treatment around transmission connected generation and distribution connected generation. You are presenting here the costs of return that is required for some of the infrastructure investment, Can I interpret with this argument that you would go so far as to say that the interconnection costs for transmission connected generators should also be systemized and that would results in the lower delivered cost of electricity for consumers.

> **A:** I would recommend against it, as you have to play the two policies that came out of TDP in the same manner that say load should primarily pay but we also need to incent generators to locate close to load. Otherwise generators will run all over the place. Need to have both in place but the intent is facilities that serve load should be paid for by load.

Statement: [Canadian Solar] Until the rules change and GOA tells us otherwise, here is what I know, there are very clear rules on interconnecting generators, there are very clear rules on where consumers pay for wires and we should not be afraid of saying that's what it is and until the rules change, those are the rules. We have to stop inventing new terminology to skirt the rules we have been given TDRs have a lot of value it has been broadly documented. I believe there is no room for flow through in the future, it pierces through the meaning of GUOC. It is a form of double counting and those are the two points. Locational drivers, the signal that was meant to be sent from the transmission network came though the old system contribution payment, that was it. There was intended to be no other signal. I am all for finding value points and trying to recognize them because one thing that everybody needs to recognize is that when people do write policy like that they may not have the foresight to take in every possible scenario that is out there but can safely say that there was no intention outside of the SEP for there to be there be any costs unbundled from rate base or system improvements being down in an area to serve load was going to spill over onto DCGs.

Statement: [Solar Krafte] What could be done, subsection 10 of section 8 where it talks expressly talk about the discretion the AESO has. It is titled ‘Limitations’. You could add a paragraph 11 where you carve out this exemption in relation to DFO. Beyond that, I am realistic. I don’t know what’s going to unfold from here, because we need to move quickly here, investment capital is mobile and moves around and no good reason for Alberta to be different then every other jurisdiction in North America. We need to be competitive and we need to resolve quickly and simply.

Statement: [LionsTooth] First is that this is for all intents and purposes a negotiated settlement, so we need all try to come to consensus; we are really close. Agreed on future costs should not be included. Generally agreed on our definition on what is a transformer in the new metering practice. Agreed that DCG should not be paying for radial transmission line. There is still some misalignment as to whether or not we should be removing costs from rate base and assigning to customers. I hear clear messages that the government has given us policy and rules to follow and I hear clear messages with people saying that assessing some form of shared cost is not the best solution or downright unacceptable. Needs to be taken into account. Need to look at what drives lowest cost of electricity for load customers.