Subject: **Canadian Solar Solutions Inc. DGC Flow-Through (Substation Fraction) Proposal**

To: **tariffdesign@aeso.ca**

From: **Ryan Tourigny, P.Eng., MBA., Canadian Solar Solutions Inc.**

With support from Capstone Infrastructure, GP Joule, Kalina Clean Power, and Longspur Developments

Date: **April 30, 2020**

A. OVERVIEW OF THE PROPOSAL

This proposal is based on the goals and objectives set by the Alberta Department of Energy (ADOE) in the Transmission Development *The Right Path for Alberta* A Policy Paper, November 2003 (TDP)[1], a policy document that led and shaped the creation of the Transmission Regulation (TReg). Also, the proposal follows the principles of cost causation and cost recovery within the scope and context of the TDP, the TReg as well as the Electric Utilities Act (EUA).

The directional views provided in this proposal were developed in consultation with Mr. Dean Short, a former ADOE consultant and co-author of the TDP and, Mr. Lewis Manning of Lawson Lundell. These two Alberta electricity sector experts were consulted with reference to two key points:

- Local interconnection costs, i.e., the extent of the generator's cost obligation, and;
- Philosophy behind the generator System Contribution Payment (SCP, now called GUOC) and the intent behind the SCP to act as a location signal and a financial commitment towards system upgrades that will be refunded over time subject satisfactory performance by the generator.

This document has been reviewed by both Messrs. Short and Manning to ensure that the historical understanding that serves as the foundation of this proposal and the direction and intent of the TDP have been captured correctly.

To better understand the context of this proposal a brief historical overview is provided.

B. HISTORICAL REVIEW OF LOCATIONAL SIGNAL AND COST ALLOCATION TO GENERATORS

This brief historical synopsis sets the foundation to understand and recollect how we got to where are today, and the efforts put in by Albertans to segregate wires from energy related costs.

1. Alberta's electric industry spent years at hearings on electric deregulation and fought for electricity generators to institute location-based pricing so as to set the groundwork for competitive generation to be able to compete fairly with the then existing "regulated" generation. The intent was to send a signal that by locating where generation was needed and thus saving the system money (by avoiding or deferring the need for new or incremental transmission capacity, or reducing losses *by locating near load*) a credit would be provided –

[1] https://open.alberta.ca/dataset/0db52c69-eed1-4f4a-997c-a47d57cc9788/resource/7238f12e-2a43-41dc-856e-c623a9fc57a3/download/3103222-2003-transmission-development-policy.pdf

conversely, by locating where the system cannot accommodate generation, a charge to reflect that choice of location driving the need for transmission system investment would result and may result in increased losses.

2. Some level of success was achieved when the Transmission Administrator (ESBI), at that time, split the system wires recovery into two (2), i.e., half to be paid for by generation and the other half by load under rates STS and DTS respectively.
3. The Transmission Administrator (ESBI) also developed the System Expansion Related Pricing (SERP)[2] to determine the zonal pricing impact to generators; however, due to its complexity it was not considered and the Regulator directed the Transmission Administrator (AESO) to develop the Zonal Interconnection Charge (ZIC).
4. While SERP was not adopted, the AUC did approve the ZIC[3] that was to apply to generation (both old and new) that chose to locate in generation rich zones.
5. 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.
6. Government policy was embodied in the TDP and the subsequent enactment of the TReg. The TDP, as a foundational document, set the principles and the objectives that the TReg was to accomplish. Therefore, the TDP is in essence an interpretation guide for the TReg;
7. The TDP and TReg are prescriptive with regards 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 generating unit.
8. 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[4].
9. It appears the AESO has adopted ESBI's tariff practice to impose system costs on distribution connected generation. There has been however no change in Alberta government policy that supports this.
10. In the early years the industry and regulators thought it was worthwhile to send a market signal to guide the location of generation on the transmission system. Early attempts were fraught with problems due to their focus being based on the precise costs a new generator imposed on the transmission system (SERP), and then based on ZIC proposals being applied retrospectively to existing generation and new generation projects already underway, creating commercial uncertainty.
11. The government decided against this practice with the TDP and TReg to create greater commercial certainty. It appears that now a new interpretation is getting back to what the old interpretation used to be before the TDP, i.e., to allocate and charge transmission system costs already rolled-in to rate base or "transmission rate base" (TRB) costs to the generator interconnection (in addition to the SCP), above what is deemed to be a generator's local interconnection cost obligation.
12. Over the years, there has been an apparent progression where policy seems to be slowly reverting to allocating TRB costs to new generation through the AESO and AUC with the "reinterpretation" of wire cost allocation in reference to the definition of what a generator *local*

[2] EUB Decision 2000-1 (February 2, 2000) at page 127 provides the following high level description: *SERP is an element of the EAL tariff, which is designed to send a location based economic signal to the owners and operators of generation units.*
http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2000/2000-01.pdf#search=SERP

[3] EUB Decision 2002-099 (November 5, 2002) at page 83 (Congestion Management Decision) explained ZIC.

[4] Alberta Department of Energy, Transmission Development *The Right Path for Alberta* A Policy Paper, November 2003, Page 5.

interconnection (Participant Related-rate STS) cost is. Therefore, where once the TDP set the principles to strictly define local interconnection charges applicable to a new generator, we now see TRB-like costs above and beyond the "incremental" local interconnection costs being flowed though to generators, in addition to the SCP (GUOC).

13. Historically, the AESO Long Term Plans have had descriptions of the AESO's statutory requirement to build the "transmission" highway and recover the costs from Alberta *load* – specifically from the TReg (2004) onwards and in alignment with TDP principles.
14. Recently however the AESO appears to be departing from this historical position. Now, it appears that the new tariff seeks to take costs that were thought to have been "rolled–in" to rate base and "roll them out" as a participant or flow-through cost to distribution connected generators. This is an additional cost, over and above the SCP and local interconnection cost, and is becoming a financial burden and long-term risk exposure to the generator – particularly when it is being proposed to apply retrospectively.
15. This new interpretation seeks the direct opposite of what the government policy tried to achieve by rolling-in all transmission system costs into the amount load customers had to pay, i.e., rate DTS.

C. PRINCIPLES OF THE 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. In addition to, the principles for access to the transmission system outlined in the EUA and TReg.

From the generator's perspective, this proposal looks at GUOC and the financial certainty that it is expected to offer a generation project. This proposal also looks at the issue of timing with respect to where access to the transmission system is located, for a load customer and DCG, within their differing respective development timeline(s). It also looks at the DFO and DCG relationship with regard to the effects of a unified System Access Service Agreement (SASA) at the POD.

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

The SCP or system contribution payment, a clear and transparent charge known in advance, was put in place to provide a long-term siting signal for new generation that was not related to 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. If a generator were to not perform then no refund would 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[5].

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 DCG and without consideration that load pays for the wires costs—that is how the ADOE's policy, EUA and TReg is 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 rolled-in to and recovered through rate base. Table 1 is presented as a simplified concordance table between TDP, the EUA and TReg to demonstrate the principles under this header.

[5] Transmission Regulation, Part 5 - Local Interconnection Cost and Transmission Contribution Costs, Clause 29(2)(a).

Table 1. Concordance Table Between TDP, EUA and TReg

<table>
<tr><th>ADOE Transmission Development Policy</th><th>Electric Utilities Act</th></tr>
<tr><td rowspan="3">On Page 5 of 19

Generator Cost Responsibility
…

In general, 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. <u>wires</u>, TMR, IBOC/LBCSO, operating reserves, etc.) <u>will be allocated to load</u>.[6]

…

Generator System Contribution Payment

New generators will be required to assume some costs for transmission system upgrades, in addition to their interconnection costs. This will be called a system contribution payment or SCP.
…

Generators who pay local interconnection costs such as radial tie lines may not prohibit interconnection or access to those facilities by other generators or loads. If subsequent projects or loads become interconnected with such facilities, then the line from the new point of interconnection to the system become a part of system facilities and will be reinforced as needed by the ISO and TFO in accordance with this policy and EUB processes. In addition, costs for that portion of the interconnection, which has now become system facilities, will be refunded in accordance with the SCP mechanism.</td>
<td>ISO tariff
30(1) The Independent System Operator must submit to the Commission, for approval under Part 9, a single tariff setting out
(a) the rates to be charged by the Independent System Operator for each class of system access service, and
…

(2) The rates to be charged by the Independent System Operator for each class of service must reflect the prudent costs that are reasonably attributable to each class of system access service provided by the Independent System Operator, and the rates must
(a) be sufficient to recover
(i) the amounts to be paid under the approved tariff of the owner of each transmission facility,
…</td></tr>
<tr><th>Transmission Regulation</th></tr>
<tr><td>Local interconnection costs
28(1) The ISO must include in the ISO tariff
(a) local interconnection costs, as defined by the ISO, payable by an owner of a generating unit for connecting to the transmission system,
…

(3) The owner of a generating unit that interconnects with the transmission system, and who has paid local interconnection costs, may not prohibit interconnection or access to the interconnection facilities by other electricity Market Participants.
(4) If another person makes use of the facilities for which a local interconnection cost has been paid,
(a) local interconnection costs, as defined by the ISO, <u>payable by an owner of a generating unit</u> for connecting to the transmission system,
(b) the original local interconnection cost, or a portion of it, must be refunded to the person who paid it in accordance with the ISO tariff.

Generating unit owner's contribution
29(1) The ISO must include in the ISO tariff
…
(2) The amount payable by owners of generating units is the sum of the following:
(a) for upgrades to existing transmission facilities, a charge of $10 000/MW;
(b) a charge of not more than $40 000/MW, as provided in the ISO tariff, payable by owners of generating units that locate in an area of the transmission system where generation exceeds load, and the amount of the charge is to be determined based

ISO tariff - transmission system considerations
47 When considering an application for approval of the ISO tariff under sections 121 and 122 of the Act, the Commission must
(c) ensure
(i) the just and reasonable costs of the transmission system are wholly charged to DFOs, customers who are industrial systems and persons who have made an arrangement under section 101(2) of the Act, and exporters, to the extent required by the ISO tariff,
and

(ii) the amount payable by a DFO is recoverable in the DFO's tariff,
…</td></tr>
</table>

[6] Alberta Department of Energy, Transmission Development *The Right Path for Alberta* A Policy Paper, November 2003, Page 5.

<u>Local Interconnection Cost vs. Participant Related (Demand / Supply) Cost</u>

The local interconnection costs applicable to generators as proposed in the TDP and the Participant Related cost, in AESO's Tariff, share many similarities with respect to the initial development of radially built transmission infrastructure. The drivers and causation for the 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.

The timing of who sponsors the initial cost for the required infrastructure as a function of (a) driver/causation and (b) Acts and Regulations shaped by the ADOE Policy, requires consideration. At a high level, there are a few basic observations on the radial infrastructure funding at the *inception* of a project:

- 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 are not rolled-in to rate base 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 generation 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. Note, in some instances, generator and load are inextricably linked and are the same Market Participant requiring both STS & DTS. In this case, only AESO's contribution is rolled-in to rate base, the balance of the radial infrastructure cost remains as the capital investment of the generator (non-rate base).

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

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. 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.

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 TReg[7]. 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 cost from both transmission and distribution to convert it 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 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[8], a distribution service provider and an energy supplier. The DFO within its franchise area is responsible for providing electric distribution service[9] as defined by Electric Utilities Act (EUA) to both the load and DCG. EUA Section 105(1)(k) addresses Electric Distribution Service as the connection and disconnection of DCG and does not appear to require a Section 101 release for a DCG to contract with AESO directly for STS services. 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 DTS and STS request is disregarded.

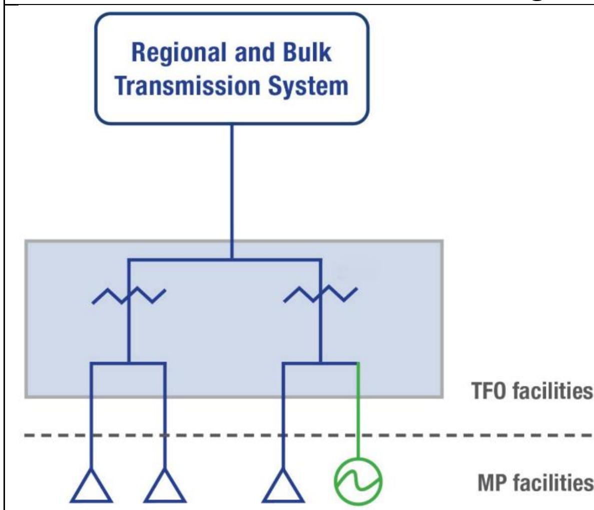
A quick test to differentiate that the DFO and DCG are separate and distinct Market Participants is as follows, a DFO does not require a STS contract with AESO to complete its legislated function to serve load, and the converse is true, the DCG does not require a DTS contract to operate according its legislated requirements.

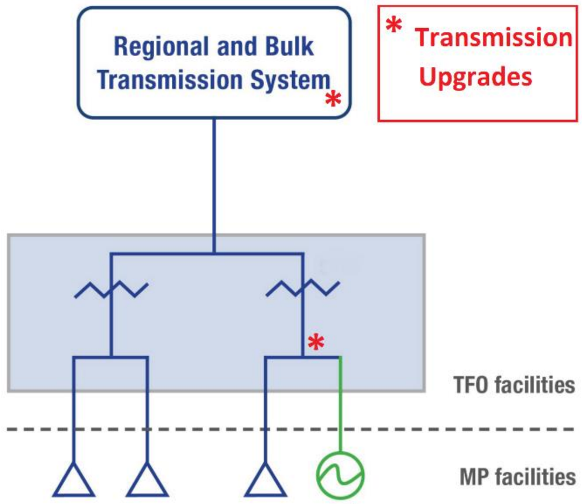
D. PROPOSAL OUTLINE

[7] Transmission Regulation, Part 5 - Local Interconnection Cost and Transmission Contribution Costs, Clause 28(4)(b).
[8] Electric Utilities Act, Part 1, Application and Purpose, Interpretation, Section 1(1)(p.2)(i)
[9] Electric Utilities Act, Part 1, Application and Purpose, Interpretation, Section 1(1)(l.1)

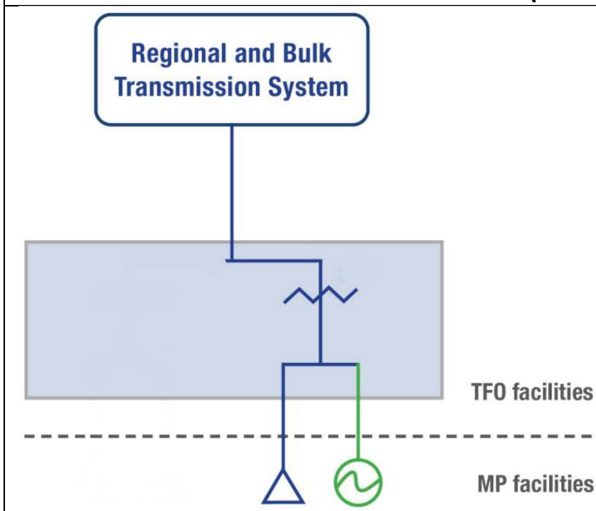
The proposal outlined below considers four (4) scenarios. Each scenario is based on the historical evolution of the electric industry regulatory process. The scenarios seek to establish alignment between ADOE Policy, EUA and TReg.

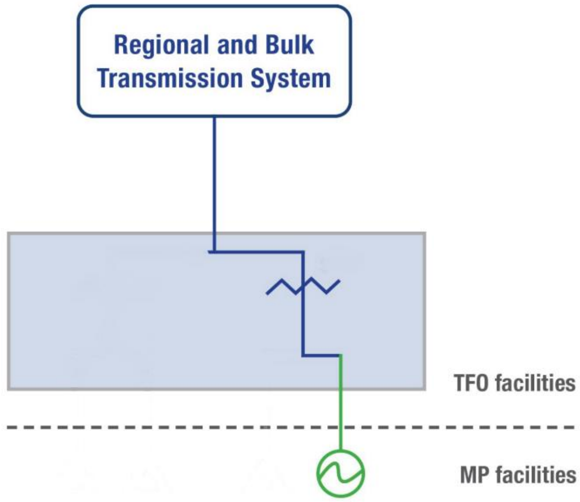
No proposals are provided for the handling of future flow-through costs. A future flow-though cost to address transmission facility capacity improvement, upgrades, corrections to voltage deficiencies, etc., is in fact nothing more than absence of transmission planning where AESO ought to have relied 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 GUOC. A future flow-through while a GUOC is in place essentially constitutes double counting to recover the future cost of transmission facility upgrades.

<table>
<tr><th colspan="2">Scenario 1 – Existing POD, No Transmission Upgrades</th></tr>
<tr><td>
</td><td>DGC Pays for:
• Connection to the dist. system,
• Revenue meter / SCADA as required,
• Protection coordination, upgrades (dist. & trans.),
• Direct Trip (sub. to project site as required)
• Transfer Trip (if required).</td></tr>
</table>

<table>
<tr><th colspan="2">Scenario 2 – Existing POD + DCG Related Transmission Upgrades</th></tr>
<tr><td>
</td><td>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.
Note: transmission upgrades or modifications will only be covered by the DCG if it can be proven through engineering studies that the DCG integration drives the need and hence the cause of the upgrade as a result of the interconnection as pre-interconnection assessments. After interconnection, any upgrades to the transmission system fall under AESO's duty to plan and expand the transmission system and covered by rolled-in costs and the GUOC.</td></tr>
</table>

<table>
<tr><th colspan="2">Scenario 3 - New POD with STS (Load and STS are the same Market Participant)</th></tr>
<tr><td>
</td><td>DGC Pays for:
• If the load that drives the need for a POD <u>concurrently</u> 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.
• The initial load and DCG interconnection have a likeness to transmission connected generation; however, the main driver and causation of the POD construction is the load component.
• In the future, subsequent DCG connections, whether third party are not, are not subject to further cost flow-through allocation and are treated as Case 1 or Case 2.</td></tr>
</table>

Scenario 4 - New POS with no DTS	
	First DGC pays for: • No cost is rolled-in to rate base, the DCG pays[10] all costs and the DCG is treated as a transmission connected generator—assume no load contract required. • The DFO may have plans in the area to serve load; however, the DFO's load interest lags or has an uncertain timeline with regards to the DCG development requirements. This scenario may represent a pilot project that generates its own source of energy and sells the surplus to the grid. The site may be an ISD or initially operate with an exemption. Then DFO pays for: • Once the pilot project is proven successful, and after some time load develops in the surroundings, and the DFO elects to serve its franchise area; then, the DFO can request access to the POS. The DFO's access to the POS will trigger a contribution[11] to the non-rate base investment the DCG made on the radial transmission infrastructure in proportion to the DFO's DTS contract at the POS thereby converting it to dual-use. The next DCG pays for: • Contrary to Scenario 3, after some time the next DCG proposes to connect to the dual-use transmission facility. In this case, the new DCG pays a contribution to the residual value of the remaining cost to the first DCG, i.e., that component of the transmission infrastructure that was never rolled-in to rate base.

E. IMPLICATIONS OF PROPOSAL

The following table summarizes key implications of the proposal.

Proposal Scenario	Comments
Scenario 1	**Benefits:** This option does not require the rolling-out of costs from rate base. The TFO and DFO rate base, as well as, their return on investment remains unharmed. In this case the DCG only pays the true local interconnection cost and it is not financially burdened when rate base from transmission system recovery is rolled-out (delegitimizing) to flow-through a Participant Related cost (Rate STS). The load, as an end client, is not impacted by changes in wires cost, and there are no interconnection cost excesses that need be recovered through DCG energy costs. Impact to energy pricing remains unaffected. **Cost:** No impact, no change.

[10] Transmission Regulation, Part 5 - Local Interconnection Cost and Transmission Contribution Costs, Clause 28(1)(a).
[11] Transmission Regulation, Part 5 - Local Interconnection Cost and Transmission Contribution Costs, Clause 28(4)(b).

	Risks: None observed. However, note that if any wire flow-through cost is applied, if it does not cripple a project, the cost will be recovered over time through the sale of energy at a rate expected to be higher than the rate of return had the costs stayed in rate base. **Principles Applied:** Cost causation – Load triggered the initial POD construction and effectively moved the Transmission System, as an access point, from the Bulk/Local system to the 25 kV bus in the substation. Tariff cost recovery – AESO's contribution and the DFO's supplemental payment are costs rolled-in to rate base to recover "system" cost be it transmission or distribution. The recovery cost is consistent with TDP, EUA and TDP.
Scenario 2	**Benefits:** Same as Scenario 1 **Cost:** Same as Scenario 1; however, minor upgrades to the transmission system would be part of the local interconnection cost provided that the transmission upgrades are identified as part of an engineering study and show causation attributable to the DCG MW injection prior to the interconnection of the DCG. **Risks:** Same as Scenario1 **Principles Applied:** Same as Scenario 1
Scenario 3	**Benefits:** Similar to AESO's proposed flow through process. **Cost:** No impact to rate base. **Risks:** None. However, it is necessary to be aware that once the Participant Related (Rate DTS) costs are entered into rate base and energization of the POD has occurred, any subsequent DCG, third party or not, thereafter is treated as per Scenario 1 or Scenario 2 **Principles Applied:** Cost causation – Load triggered or caused the POD construction; however, DCG is a concurrent driver but not the primary driver for this need; therefore, it is part of the cost causation. Cost allocation to the DCG would be based on a one-time DTS/STS ratio cost allocation. Tariff cost recovery – AESO's contribution and the DFO's supplemental payment are costs rolled-in to rate base to recover "system" cost be it transmission or distribution for the costs attributable to Participant Related costs (Rate DTS and STS). The recovery cost is consistent with TDP, EUA and TDP.
Scenario 4	**Benefits:** known process, similar to a Transmission connected generator (with or without ISD) **Cost:** DCG, acting as a transmission connected generator, pays 100% of the cost and these costs are not entered into rate base. Future interconnections at the POS are subject to cost sharing. **Risks:** None. **Principles Applied:** Cost causation – the generator, as a market participant, triggered or cause the POS construction. Same rules as a transmission connected generator apply. Tariff cost recovery – Local Interconnection cost consistent with TDP, EUA and TDP.

F. CONCLUSION

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.

This proposal is consistent with policy framework and should be adopted as soon as possible to bring investment certainty to the industry.

G. COMPANIES WITH SUPPORTIVE VIEWS OF PROPOSAL

Canadian Solar Solutions Inc. shared this proposal with the companies shown below. These companies have expressed support for the views presented herein:

Capstone Infrastructure

GP Joule

Kalina Distributed Power

Longspur Developments