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NOTICE OF REVISED PROPOSAL TO AMEND A CODE

REVISED PROPOSED AMENDMENTS TO THE TRANSMISSION SYSTEM CODE AND THE DISTRIBUTION SYSTEM CODE TO FACILITATE REGIONAL PLANNING

BOARD FILE NO.: EB-2016-0003

To: All Licensed Electricity Distributors
All Licensed Electricity Transmitters
All Participants in Consultation Process EB-2013-0421
All Other Interested Parties

The Ontario Energy Board (OEB) is giving notice under section 70.2 of the *Ontario Energy Board Act, 1998* (Act) of revised proposed amendments to the Transmission System Code (TSC) and the Distribution System Code (DSC). Written comments are due by *September 13, 2018*.

A. Background

On September 31, 2017, the OEB issued a Notice of Proposal to Amend a Code (September Notice) in which it proposed a number of amendments to the DSC and TSC (September Proposed Amendments) that were aimed at ensuring the cost responsibility provisions for load customers in those Codes are aligned and facilitate the implementation of regional plans. Under the September Proposed Amendments:

- Where a transmission connection investment also addresses a broader network system need (e.g., reliability), the costs associated with such investments would be apportioned between the load customer(s) that caused the need for the connection investment and the transmission network pool (i.e., all ratepayers), based on the proportional benefit between the connecting customer(s) and the overall system

- A capital contribution would be required from embedded distributors and *large* commercial and industrial (C&I) load customers of distributors, where they cause and benefit from investments in upstream transmission connection facilities, based on their *incremental* load requirements. A new threshold would apply for determining what size of load constitutes a large C&I load customer and that threshold would be based on non-coincident peak demand that meets or exceeds 3 MW

- Where a connection asset requires replacement at its end-of-life (EOL), cost apportionment between a load customer and all ratepayers[1] would differ based on the circumstances as follows:

  - Where the replacement is the *same* capacity (i.e., like-for-like) or *right sized* to *lower* capacity, the customer would not be responsible for any replacement costs

  - Where the replacement involves an *upgrade*, the customer would be responsible for only the *incremental* cost i.e., the amount that exceeds the cost of a like-for-like replacement – not the full cost

  - Where the customer requests replacement *before* EOL, the amount the customer would be responsible for would be limited to the remaining net book value (NBV) – not the full cost

- A regional distribution solution would be facilitated, where more than one distributor is involved and it would avoid a more costly upstream transmission connection investment, so that the most cost effective wires investment in a regional infrastructure plan (RIP) can be implemented

- Where a distributor is required to pay a large lump sum capital contribution to a transmitter in relation to a transmission connection investment, the distributor would be permitted to spread the cost by providing the capital contribution in installments over five years. A distributor would also be able to apply for an advanced funding option – *Upstream Capacity Payment or Upstream Connection*

[1] At the transmission level, the reference to all ratepayers is province-wide through the connection pool. At the distribution level, the reference to all ratepayers is limited to customers in the distributor’s service area.

Adder – to provide the distributor with a pool of funds before the new or upgraded connection investment goes into service to draw down the lump sum amount of the capital contribution. These options would be made available to distributors to supplement (not replace) the status quo approach (i.e., single payment), for the purpose of facilitating the implementation of regional plans by mitigating consumer bill impacts

- Other changes involved proposed amendments to address inconsistencies between, and gaps within, the Codes. The proposed changes focused primarily on aligning the DSC with the TSC. Key considerations include improving alignment with the beneficiary pays principle, consistent treatment of customers across the numerous distributors in Ontario and the evolution of the distribution system (as the functions it performs are becoming more similar to those of the transmission system)

Written comments on the September Proposed Amendments were received from 19 participants involved in this consultation, including the Independent Electricity System Operator (IESO) and representatives of business and residential consumers, a transmitter, distributors, storage entities and a coalition of municipalities.

Following a review of those written comments, the OEB issued a letter on January 25, 2018 inviting stakeholders to participate in a Stakeholder Meeting on February 5th. Stakeholders that participated in the meeting were primarily comprised of those that submitted written comments. The goal of the meeting was to further the understanding of the September Proposed Amendments and the related stakeholder comments that had been received in order to better inform consideration of further revisions to the September Proposed Amendments.

The OEB has considered the written comments received (and the discussions at the Stakeholder Meeting) and has determined that revisions should be proposed to the September Proposed Amendments. Attachment A and Attachment B are comparison versions that show all of the proposed revisions to the TSC and DSC (Revised Proposed Amendments), respectively, relative to the September Proposed Amendments. Attachment C and Attachment D have also been included to show the consolidated changes to the TSC and DSC, including those proposed in both the September Notice and the Revised Proposed Amendments in this Notice.

A summary of the comments received and the manner in which they are proposed to be addressed by the OEB is set out in section B below (in the same order the September Proposed Amendments were set out in the September Notice). Subsection 6 below includes further proposed amendments based on stakeholder comments that were not directly related to the September Proposed Amendments.

Attachment E provides a summary of section B of this Notice at a higher level and is organized differently as follows:

- Proposed revisions to the September Proposed Amendments
- Changes considered but not included in the Revised Proposed Amendments

Section B should be relied upon for providing comments on the Revised Proposed Amendments, as it includes the context and the rationale for adopting (or not adopting) a suggested change as part of the Revised Proposed Amendments. Attachment E has been provided for stakeholder convenience.

B. Proposed Revisions to the September Proposed Amendments

1. PROPOSED TSC AMENDMENTS: APPROACH TO 'APPORTION' TRANSMISSION CONNECTION INVESTMENT COSTS TO THE NETWORK POOL (sections 6.3.18A and 6.3.18B of TSC)

There was broad stakeholder support for the concept of allowing for a *portion* of the costs associated with a transmission *connection* investment that is triggered by specific customers to be recovered from all ratepayers (like a *network* investment), where the investment also addresses a broader network system need. The comments received focused on suggested modifications to the proposed approach set out in the September Notice.

Broaden to include Generator Customers

A transmitter suggested that the approach be broadened to include generator customers so that all transmission customers (i.e., load and generator) are treated the same and pay their fair share.

The OEB is of the view that including generator customers would result in better alignment with the beneficiary pays principle. It also aligns with an existing provision in the TSC that addresses cost responsibility in cases where both load and generator customers connect to the same connection asset. The only difference in that provision is it does not address cases where there is a broader system benefit. Since all potential cost responsibility scenarios are taken into account in the existing TSC (e.g., load, generator, mix, etc.), the OEB is proposing to amend section 6.3.18A of the TSC by focusing it on the only change – the introduction of the proportional benefit concept – and referencing all the sections that address the various cost responsibility scenarios.

Appropriate Process to Determine Apportionment

A group of distributors expressed the view that an adjudicative process was not necessary for determining the appropriate apportionment and suggested the OEB should consider a simplified process.

The OEB remains of the view that a case-by-case application approach will be necessary. That is primarily because the methodology relies on a *proxy* to estimate the cost to *address each need* – customer and broader system – *individually*, which provides the underlying basis to determine the apportionment. Whether the proxy used (and the associated estimated cost) was the most appropriate would therefore need to be tested. This approach will be particularly important at the outset. There may be an opportunity to move to a more streamlined approach in the future once the OEB has decided on a number of applications that involve different circumstances.

Scope of Benefits

The IESO suggested that the assessment of benefits should be broader than addressing system needs (e.g., reliability) and therefore include other benefits such as a reduction in system losses. On the other hand, a group of distributors suggested parameters to limit the scope in relation to the type of benefits similar to the criteria used for Z-factor applications, such as identifiable, quantifiable, and material.

The OEB believes there is merit in relation to both suggestions and views them as complementary in that the benefits considered could be broader but certain criteria would need to be met for them to be considered for cost responsibility purposes. The OEB is of the view that electricity consumers would need to directly benefit through a reduction in their electricity bill and/or an increase in reliability for it to be considered. Reduced system losses are a good example of a benefit that should be considered, as long as they are material, because they would result in lower electricity bills for consumers. That said, the OEB does not intend to codify the types of benefits that would be considered. Instead, they would be proposed in utility applications (with supporting evidence from the IESO). This is another reason the OEB is of the view that an adjudicative process would be needed, particularly at the outset.

Appropriate Pool – Network vs. Connection

A transmitter suggested that the costs related to the broader system benefits should be attributed to the *connection* pool (rather than the *network* pool) due to implementation challenges, as use of the network pool would require manual tracking of the connection costs. It was noted that approximately 92% of transmission customers pay both network and line connection pool charges.

The OEB acknowledges that it would be less of an administrative burden to allocate the costs to the connection pool. However, the OEB remains of the view that allocating the costs to the *network* pool is more appropriate as it better aligns with the beneficiary pays principle. In doing so, it also avoids shifting almost 10% of the costs to consumers within the distribution system that are primarily low volume in nature (i.e., residential and small business).

2. Proposed TSC and DSC Amendments: Approaches to 'Apportion' Upstream Transmission Connection Investment Costs

Upstream Transmission Connection Investments – Treatment of Embedded Distributors and Large Load Customers (section 3.2.4A of DSC, new section 6.3.20 in TSC)

Concerns focused primarily on the negative impact on large load customers and, in turn, economic development in relation to requiring a capital contribution from *embedded* distributors and large load customers within the distribution system based on their *incremental* capacity needs where they cause and benefit from an upstream transmission connection investment.[2] Representatives of large C&I customers and some distributors therefore expressed the view that a capital contribution should not be required from large C&I customers.

The OEB remains of the view that beneficiaries should be required to pay the capital contribution whether they are connected to the distribution or transmission system (i.e., customers of the distributor directly connected to the transmission system should not be required to subsidize them). At the Stakeholder Meeting, it was noted that some new customers locating closer to the transmission system are currently connecting to the distribution system to avoid the capital contribution required by the TSC. An example that was identified by a utility would advance the need for upgrades to a transformation station by over 10 years based on current forecasts (i.e., investment triggered a decade earlier than planned / needed). The OEB is of the view that the cost responsibility rules in the DSC should not create incentives that result in such inappropriate outcomes (e.g., unnecessary wires investments).

Concerns and a wide range of views were also expressed in the written comments related to the use of 3 MW as a materiality threshold, for the purpose of determining which C&I customers of distributors are considered *large* load customers. The concerns that were raised included much different treatment for customers within the same OEB rate class that are *just above* and *just below* 3 MW and a lack of empirical analysis demonstrating that 3 MW is the appropriate level. Other options were suggested, in the written comments, that ranged significantly, from well above to well below 3 MW –

[2] For large C&I customers, a capital contribution may not be required or it may not be significant. Their incremental capacity needs would be driven by an expected increase in load, which would result in higher rate revenues for the distributor. The distributor undertakes an economic evaluation based on the C&I customer's load forecast. That will determine if the increase in rate revenues paid by the customer would cover their allocated cost or if a capital contribution is needed to cover the shortfall and, if so, how much.

alignment with the threshold used for *Class A* customers (1 MW or 500 kW) under the Industrial Conservation Initiative (ICI) program to use of the OEB's *large user* rate class threshold (5 MW) that is utilized for setting distribution rates. Another proposed approach involved moving away from an *absolute* load threshold to use of an *incremental* load threshold for capital contribution purposes. At the stakeholder meeting, there was broad support for using 5 MW as the threshold.

The OEB is of the view that changing the threshold from 3 MW to 5 MW is appropriate. It is more comparable to the size of customers connected to the transmission system for which alignment is being sought, as the typical transmission customer is over 10 MW. As noted above, it is also an existing threshold used by the OEB to represent the size of a large customer for the purpose of determining the appropriate distribution charges. Since it is an existing threshold, it also avoids the issue of customers within the same rate class being treated differently in terms of how they are charged. It would further avoid additional administrative costs that distributors would need to incur to track customers against a new threshold.

In terms of the proposed new section 3.2.4A where large C&I customers would be required to pay a capital contribution, a comment received from a utility was the proposed DSC amendment should refer to "new", as well as "modified", transmission assets. Within a cost responsibility context, the OEB is of the view that whether the customer's incremental capacity needs are met using a "modified" *existing* transmission asset or a "*new*" transmission asset is irrelevant. The determining factor is whether a large C&I customer has indicated that they need incremental capacity and the utility cannot meet that need without making an investment. The OEB is also therefore of the view that adding a reference to "new" would be appropriate.

A transmitter noted a process issue arises in the event the OEB does require embedded distributors and large distribution-connected customers to provide a capital contribution in relation to upstream transmission connection investments through the addition of section 3.2.4A to the DSC. Under the status quo, the economic evaluation methodology – including discounted cash flow (DCF) calculation – in an appendix of both the TSC (Appendix 5) and the DSC (Appendix B) would be used for the same asset, which would result in different outcomes, as the methodologies in the two Codes are not exactly the same. The transmitter added that use of only the TSC DCF would align the DCF calculation with the type of assets (i.e., transmission). Two possible options to implement that approach were also identified:

i. The transmitter could perform the calculation for all distributors (including embedded distributors); or
ii. Each host distributor could do it using the TSC DCF with assistance and information from the transmitter (after the transmitter calculates the capital contribution to be paid by the host distributor)

The OEB believes that the same economic evaluation methodology should be used for all capital contribution calculations related to the same upstream transmission asset, it should be the transmission DCF (in the TSC) and the same entity (i.e., transmitter) should do it on behalf of all distributors and large distribution-connected customers for the following reasons:

- It would ensure consistent treatment across all beneficiaries that are required to provide a capital contribution
- It would be more efficient to calculate the amount owed by each distributor – embedded and host – at the same time relative to a two-step process (whereby the host distributor would do the calculation in relation to embedded distributors after the transmitter does it for the host distributor)
- The DCF would align with the type of asset for which it was intended
- The costs and revenues would match

The OEB is therefore proposing to amend the TSC to require the transmitter to undertake the DCF calculation at the request of a host distributor by adding section 6.3.20. The OEB is also proposing to revise the September Proposed Amendment to section 3.2.4A of the DSC as follows:

- To reflect that the host distributor would be required to request that the transmitter calculate the amount of the capital contribution for each beneficiary connected to the distributor using the DCF methodology in Appendix 5 of the TSC
- To take “new” transmission assets into account
- To adjust the large C&I customer threshold to 5 MW

The OEB notes that the proposed change in the threshold from 3 MW to 5 MW also applies where the OEB is continuing to propose use of a large customer threshold for other purposes (i.e., not limited to the requirement to provide a capital contribution). Those other purposes are discussed below.

A transmitter suggested moving section 3.2.4A in the September Proposed Amendments to a separate section of the DSC that is dedicated to upstream transmission connection assets. The OEB believes that suggestion has merit. It would separate cost responsibility rules related to upstream *transmission* connection assets from “Expansions” (section 3.2) which has always been focused on *distribution* assets. However, the OEB believes it would be more appropriate to move any sections when the OEB issues Final Code amendments. In doing so, that will maintain consistent numbering throughout the notice and comment stages of this consultation. It will therefore avoid the potential for confusion. It may also be appropriate to move other provisions and the OEB believes doing so in a holistic and coordinated manner would be a better approach in addressing this administrative matter.

3. PROPOSED TSC AND DSC AMENDMENTS: APPROACHES TO 'APPORTION' COSTS FOR END-OF-LIFE CONNECTION REPLACEMENTS AND MULTI-DISTRIBUTOR REGIONAL SOLUTIONS

Replacement of End-of-Life Transmission and Distribution Connection Assets (section 6.7.2 of TSC, new section 3.1.17 in DSC)

As noted in the September Notice, the TSC includes a provision that addresses when an upstream transmission connection asset reaches its end-of-life (EOL) and needs to be replaced with a like-for-like connection asset (i.e., same capacity). The transmitter must replace the asset at no cost to the distributor or C&I customer because the cost of the asset has been recovered through the rates they have paid. The September Notice also identified that the DSC does not currently address EOL assets. The OEB therefore proposed amending both Codes to address all three potential EOL replacement scenarios: *(1) like-for-like, (2) additional capacity, and (3) lower capacity.*

The OEB also expressed the view in the September Notice that the customer should pay, if the customer *requests* the replacement of a connection asset *before* it has reached its EOL. However, the amount they pay would be limited to the remaining net book value (NBV) – not the full cost. Transmitters and distributors would also be required to consult affected customers on how the EOL asset is planned to be replaced before a final decision is made.

<u>*General*</u>

The IESO suggested certain wording changes to section 6.7.2 (TSC) of the September Proposed Amendments to reflect a linkage to the planning process by adding the transmitter's assessment would need to be integrated with the regional planning and bulk planning processes.

The OEB does not believe every EOL assessment will need to be addressed through a regional or a bulk planning process. Based on experience to date with regional planning, some EOL needs are addressed through a local planning process involving only one distributor (and the transmitter). That said, where there are regional considerations, the OEB expects that the regional planning process will always be used to determine the optimal solution. That is the OEB's expectation in relation to any type of investment, whether it involves an EOL asset or not.

Within that context, the OEB believes certain changes should be made to modernize the Codes from an EOL perspective. The OEB is concerned that the current wording in the TSC can imply that wires replacement is the only option when an asset reaches EOL. That is not consistent with the OEB's vision.

The OEB is therefore of the view that the September Proposed Amendments should be revised to reflect that section 6.7.2 (TSC) and new section 3.1.17 (DSC) only apply where *wires* replacement at EOL is the determined to be the *optimal* solution. Since the OEB's underlying rationale for instituting a more structured regional planning process across Ontario was to better ensure the optimal solution to meet the need is implemented, the OEB believes this proposed change is consistent with the spirit of the comments provided by the IESO.

'Right-sizing' to Lower Capacity

Most of the written comments focused on the added scenario where a connection asset would be *right-sized* to a *lower* capacity and the OEB included an expectation in the Notice for transmitters and distributors to right-size, where appropriate, based on utility judgment and consultation with affected customers. A number of stakeholders expressed the view that the Codes should obligate *right-sizing* due to the financial incentives for transmitters and distributors not to downsize (i.e., not limit it to an expectation in a Notice).

At the Stakeholder Meeting, stakeholders acknowledged that there are issues associated with not allowing for any utility judgment. The OEB notes it also needs to be able to enforce compliance with code obligations and that would be problematic with judgment involved. As a consequence, the OEB is proposing to maintain the approach proposed in the September Notice.

The OEB will consider if and to what extent further action is necessary once work related to EOL is completed that is currently underway including the following:

- The OEB established the Regional Planning Process Advisory Group (RPPAG) to make improvements to the regional planning process based on "lessons learned". Following the first cycle of addressing all the regions, EOL asset replacement was identified as an area that required improvement. As discussed in the OEB's Implementation Plan (in response to a Directive from the Minister of Energy), the RPPAG was already in the process of developing guidance on the information that the lead transmitter should provide to the other members of a regional Study Team (i.e., IESO, applicable distributors) in relation to EOL Among other things, that RPPAG guidance document will also identify the transmission assets to focus on and replacement options for the assets at EOL[3]

- The IESO also received a Directive from the Minister of Energy related to developing a coordinated, cost-effective, long-term approach to addressing the need to replace transmission assets at EOL

Replacement Before EOL

There was broad support in relation to not requiring payment of the full replacement cost in cases where the customer requests replacement *before* EOL. However, two issues were raised in the written comments. A number of stakeholders suggested this fourth scenario should also be reflected in the Codes and the customer should be required to also pay the *advancement* cost – not only the NBV.

The OEB has considered the comments and concluded that this scenario should be captured in the Codes rather than relying on an explanation in the Notice, as a Code requirement should better achieve a consistent approach by all distributors and transmitters. The OEB is also of the view that a customer requesting replacement before EOL should also be required to pay the *advancement* cost for the following reasons. Not waiting until the connection asset reaches EOL is a choice made by an individual customer and all ratepayers (in the transmission connection pool) should not be required to pay for reinvestment that is earlier than needed, for the benefit of one specific customer.

Other End-of-Life Issues

Distributors raised concerns regarding an obligation to consult before every distributor-owned asset is replaced due to the large number of customers they serve. Distributors noted this would result in significant administrative burden. Limiting the requirement to consult to distribution stations, where the cost of replacement is material, was therefore suggested.

The OEB acknowledges that there is a substantial difference between the transmission and distribution systems in this regard as a transmitter has a relatively limited number of connection assets and related customers to consult. Line connections at the

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[3] The OEB's Implementation Plan for the 2017 Long-Term Energy Plan.

transmission level also tend to be much longer and more costly to replace. The OEB therefore believes this is an area where there is a need to strike a balance between the materiality of the assets and the administrative burden placed on distributors, by focusing the obligation to consult in the DSC on distribution stations connected to the transmission system and distribution lines connecting large C&I customers (5 MW and above). This approach will better align with the same proposed TSC obligation.

A group of distributors also requested guidance on how to determine when an asset is at its EOL. The OEB believes distributors are better positioned to determine when their assets reach EOL based on their past experience. The life of an asset depends on many factors. For example, how an asset is used by a utility would affect its service life. The OEB expects how assets are utilized would differ across about 60 distributors. The OEB also believes it would be premature to provide any form of guidance at this time – in advance of the RPPAG finalizing its EOL guidance document and the IESO completing its EOL review initiative triggered by the Government's LTEP Directive, as discussed above.

As a consequence, the OEB proposes to revise the proposed new section 3.1.17 of the DSC and further amend section 6.7.2 of the TSC by adding a third subsection to address cost responsibility where a customer requests replacement before EOL. In such cases, the customer would be required to compensate the distributor or transmitter based on the remaining NBV and the advancement costs.[4] The OEB also proposes to revise section 3.1.17 of the DSC to limit the obligation for distributors to consult to distribution stations and, for distribution lines, only where large C&I customers are connected (5 MW and above).

Regional Distribution Solution – LDC Feeder Transfer (new section 3.1.18 of DSC)

There was general support for the proposed amendment which would allow for a distribution solution – involving more than one distributor – that would *avoid* a higher cost *upstream* transmission connection upgrade, as a way to further leverage regional planning. The solution specifically involved a *connecting* distributor making an investment to connect to a distribution line of a *facilitating* distributor, with the latter distributor fully compensated by the former.

[4] Calculating the advancement cost is not a new concept. Transmitters have done it for many years, as required under section 6.5.2 of the current TSC.

The OEB continues to believe this proposal has merit, as the least cost *wires* solution that addresses a need (i.e., optimal investment) should be made. That is the underlying reason the OEB introduced a more formal approach to regional planning across Ontario and requires a regional infrastructure plan to support all electric utility applications.

Distributors noted in the written comments that the September Proposed Amendments focused on addressing *new and modified* distribution assets, but there may also be a need for investment in *existing* assets. The OEB believes all asset investments need to be reflected to achieve the intent of this proposed provision; i.e., customers of facilitating distributor are not to be negatively impacted. To the extent that includes existing assets of the facilitating distributor, they should be captured. The OEB therefore proposes to also reflect *existing* distribution assets in this proposed DSC amendment.

A group representing consumers expressed the view that the opportunity for such a distribution solution may not be limited to two distributors and the DSC amendment should be worded to allow for multiple distributors. The OEB is uncertain about the likelihood of such a solution involving more than two distributors. That said, the OEB does not want the DSC to be a barrier to the ability to consider a multiple distributor scenario. The OEB further believes the wording in the September Proposed Amendment can be used without any changes to allow for such a scenario. Each distributor connecting to the same “facilitating distributor” would be considered separately, as a “connecting distributor” under the proposed DSC amendment. The “facilitating distributor” would in turn have a separate agreement with each “connecting distributor”. Since an application is required, any additional complexities could be addressed in the OEB’s adjudicative process.

The OEB is also proposing to maintain the process described in the September Notice. That is, a joint application – supported by a regional infrastructure plan (RIP) – would be required. The distributors would also be required to obtain an assessment from the IESO confirming that this type of distribution investment is the optimal wires solution from a regional planning perspective.

The OEB is therefore proposing to revise the proposed new section 3.1.18 of the DSC to also take into account cases where an investment in *existing* assets is required. The OEB has also made a minor proposed revision to clarify that the agreement between the distributors would require approval. As discussed above, the OEB is of the view that there is no need to change the wording in the September Proposed Amendment to accommodate such an arrangement between more than two distributors.

4. PROPOSED TSC AND DSC AMENDMENTS: FACILITATING REGIONAL PLAN IMPLEMENTATION AND MITIGATING ELECTRICITY BILL IMPACTS

Distributor ‘incremental’ load growth vs. ‘lumpy’ transmission connection investments

The September Notice discussed the disconnect between *lumpy* transmission connection upgrades and *gradual* load growth within the distribution system. That disconnect often results in a large capital contribution that must be provided by the distributor to the transmitter due to much *excess* capacity. The September Notice further identified that this disconnect is a concern to the OEB because it could result in significant bill impacts for the customers of distributors and a barrier to the implementation of regional plans.

The OEB therefore proposed three approaches to assist in funding capital contributions in order to address the issue:

- An *Annual Installment* option that would allow distributors to provide a capital contribution in annual payments over a period of up to five years

- Two advanced funding options – *Upstream Capacity Payment* and *Upstream Connection Adder* – that would provide distributors with a pool of funds before the new or upgraded connection investment goes into service to reduce the capital contribution when it is due to be paid

Annual Installment Option (section 6.3.19 of TSC)

There was broad support for the Annual Installment option. Some consumer groups suggested that this option should be modified to allow the capital contribution to be recovered over a longer period of time than five years, where the distributor can make a case that it is necessary.

The OEB believes the suggested modification to allow for an extended period of time has merit. The OEB therefore proposes that an application would need to be submitted by a distributor for an extension to pay in installments beyond five years. As a result, this proposed revision to the September Proposed Amendment to the TSC would incorporate flexibility to *allow* for an extension. An OEB Decision approving an extension would still be required on a case-by-case basis for the installment period to exceed five years. The OEB currently foresees only one justification for an extended period. That is, where the consumer bill impacts are still too high and continue to present a barrier to the implementation of a regional plan.

A transmitter expressed the view that distributors should pay interest to the transmitter at the transmitter's OEB approved cost of capital on the unpaid balance, rather than the OEB's prescribed construction work in progress (CWIP) rate proposed in the September Proposed Amendments. The OEB does not agree, as only the amount that has been paid in installments will be included in the distributor's rate base. The outstanding balance will remain in the transmitter's rate base until the distributor pays the full cost for which it is responsible, and will continue to attract the full return on rate base. As such, at any point in time, 100% of the total cost will be in rate base (e.g., 40% distributor, 60% transmitter). Under the transmitter's proposed approach, to some extent, it would get paid the cost of capital twice. The CWIP rate is being proposed to address the incremental *financing* costs the transmitter will need to incur in receiving the capital contribution over time rather than through a single payment at the time the asset goes into service. The OEB's intent is to hold the transmitter (and its customers) harmless.

The OEB is therefore proposing to revise section 6.3.19 of the September Proposed Amendments to the TSC to require the transmitter to allow the capital contribution to be paid over a longer period of time than five years, on a case-by-case basis, where the OEB has approved an application from a distributor to do so.

Advanced Funding Options

In relation to the two advanced funding options, there were a number of questions and concerns raised by stakeholders. For example:

- What would happen to the funds collected by the distributor if the infrastructure investment is cancelled?
- Some customers would pay the charge over a period of time and then move outside the distributor's service area before they could benefit; i.e., asset goes into service

A number of stakeholders also stated that further consultation was required due to too many uncertainties to provide informed feedback and/or to support implementation.

As stated in the September Notice, the purpose of these proposed Code amendments was only to *accommodate* the two advanced funding options. A further process related to the development of Filing Guidelines would then be required to address design and implementation issues. It is therefore within that subsequent consultation process on the Filing Guidelines that more details related to these proposed options would be provided. That said, since these two options could not be implemented before revised Filing Guidelines are in place, the OEB has decided to defer further consultation on both advanced funding options until changes to the Filing Guidelines are considered.

As a result, the OEB is no longer proposing to revise the applicable appendices of the TSC and DSC to accommodate the advanced funding options. As noted in the comments, a code amendment is actually not necessary. The OEB was only proposing to amend the Codes to provide additional clarity. If the OEB decides to proceed with those options, the timing of implementation by the OEB would therefore not be affected since it hinges on the timing of any future changes to the Filing Guidelines under any approach (i.e., whether the Codes are revised or not).

5. PROPOSED TSC AND DSC AMENDMENTS: ADDRESSING INCONSISTENCIES AND GAPS

As noted in the September Notice, another purpose of these proposed Code amendments is to address inconsistencies between the TSC and DSC. A key consideration in assessing the need for greater alignment between the Codes is the evolution of the distribution system, as the functions it performs are becoming more similar to those of the transmission system.

Utility Discretion – Cost Responsibility Code Provisions

The OEB expressed the view, in the September Notice, that the DSC provides distributors with too much discretion relative to the TSC in relation to cost responsibility. The DSC presently states a distributor “may” *either* recover the costs via a capital contribution from a load customer that causes the need for a distribution investment (i.e., beneficiary pays) *or* recover the costs from all of its customers through its revenue requirement (i.e., non-beneficiary pays). The OEB therefore proposed to remove the latter option by replacing “may” with “shall” for several reasons – to better align with TSC due to the evolution of the distribution system, ensure the beneficiary pays principle is applied and also ensure consistent treatment of all load customers with over 60 distributors in Ontario.

Some distributors objected to the removal of that discretion. For one group of distributors, the objection appears to be primarily premised on economic development concerns. One distributor also suggested “more liberal” terminology be used in the DSC such as “*shall, within reason*” to reflect materiality. Another group of distributors sought “*additional information and analysis that demonstrates … how [requiring capital contributions] achieves a better alignment with the beneficiary pays principle versus the current practice of socializing these costs through rates*”.

Distributors also raised concerns in relation to requiring all costs associated with relocation being recovered from the customer requesting it. Those concerns are discussed below under the section that focuses on relocation.

The OEB does not believe it is appropriate to address economic development concerns by adopting rules in its Codes that are intended to subsidize one group of electricity consumers (e.g., businesses) at the expense of other consumers (e.g., residential). In addition, as discussed in the September Notice, the distribution system is evolving to be more like the transmission system. The OEB therefore continues to be of the view that greater alignment between the Codes is necessary due to that evolution. The OEB is also concerned that the cost responsibility rules in the DSC would be applied differently across distributors if more liberal terminology was used, while the goal is to achieve the opposite outcome – more consistent treatment of similar customers.

The OEB does not agree with a group of distributors that additional information and analysis is necessary to demonstrate that requiring payment from the customer that needs additional capacity results in better alignment with the beneficiary pays principle than socializing the costs. The latter approach results in non-beneficiaries and beneficiaries paying the same amount through rates.

The OEB is therefore continuing to propose the change from “may” to “shall” as reflected in the September Proposed Amendments.

Capital Contribution Refund / Rebate to Initial Customer (sections 3.2.27 and 3.2.23 of DSC)

The OEB proposed to amend the DSC to increase the timeframe from five to 15 years in relation to requiring capital contribution rebates to align with the TSC. It was also proposed that the increase to 15 years would be limited to those considered to be large C&I customers to take into account that distributors have a much larger number of customers than transmitters and the majority of those are relatively small.

A general concern raised by distributors is related to the administrative burden associated with the need to track customers for 15 years. A distributor also raised other concerns including the provision of a rebate being based on the size of the customer, as it would result in unfair treatment among customers that contributed to similar investments.

The OEB acknowledges that the need to track customers over 15 years (rather than five years) would result in more administrative effort for distributors. However, the OEB does not believe it would be significant, as the OEB expects it would be relatively infrequent where an unforecasted customer that is over the large customer threshold connects to the same asset as another large customer.

That said, the OEB does share the concern related to the potential for unfair treatment among customers that contributed to similar investments due to the threshold. The OEB is therefore proposing to maintain the status quo in the DSC (i.e., five years for all customers) which does not involve a materiality threshold.

The OEB is continuing to propose to amend section 3.2.27 to:

- Make the DSC more user-friendly and clear for stakeholders by including the reference to five years directly in section 3.2.27 rather than referring to a separate document – Appendix B
- Change the references from the *same* generic term – “parties” – to identify the specific types of customers that are applicable within that section – “generator” and “load”

As discussed in the September Notice, similar consequential revisions would be triggered in relation to section 3.2.23 of the DSC.

Capital Contribution True-Ups and Load Forecasts (sections 3.2.20 and 3.2.24)

The OEB proposed to amend the sections of the DSC related to expansion deposits to be consistent with the TSC by replacing “may” with “shall”, where a capital contribution is required, and to extend the period it was refunded from five to 15 years for those considered to be large C&I customers (based on the threshold). As noted in the September Notice, section 3.2.20 includes two references to “may” and a change to “shall” is not proposed where a capital contribution is *not* required; i.e., discretion maintained in relation to requiring an expansion deposit.

Similar to rebates, distributors raised administrative burden concerns related to returning an expansion deposit over 15 years. The primary reason for extending the timeframe to 15 years in the TSC was associated with *gaming* concerns. A group of distributors suggested that there was a need to take into account certain differences between the distribution and transmission systems. For example:

- On a shared *transmission* connection asset, it is limited to a few customers and they tend to be quite large and sophisticated. An action by one can therefore have a significant impact on the other(s)
- On the *distribution* system, the incentive for gaming is lower because the connection investments tend to be relatively short (i.e., much lower cost)
- If a large customer of a distributor were to try to game by delaying a request for additional capacity that would trigger an investment until a payment (i.e., rebate) is no longer required, the capacity they need can potentially be used up through

> organic load growth with many low volume consumers among the large customers at the *distribution* level. That is not the case on a *transmission* connection asset.

The OEB remains of the view that distributor discretion to require an expansion deposit should be removed (where a capital contribution is required), as non-beneficiaries should not bear the risk of non-payment. However, the OEB believes the points raised in relation to the risk of gaming being lower on the distribution system requires consideration. The OEB is of the view that the incremental risk mitigation, by extending the period to 15 years (as set out in the September Proposed Amendments), would likely not justify the increase in distributor administrative costs that would be passed on to consumers. The OEB is therefore proposing to maintain a five-year return period for all customers.

Mix of load and generator customers on a connection asset (new section 3.1.9 in DSC, section 6.3.16 of TSC)

In the September Proposed Amendments, the OEB proposed to add a new section 3.1.9 in the DSC to address cost responsibility in cases where a connection asset investment meets the needs of both load and generator customers, and they connect at the same time. A distributor suggested moving this new section to section 3.2, which involves “Expansions”. The OEB believes such a move has merit as the related provision that involves a refund is included in section 3.2. However, as noted above, the OEB will consider all potential section reordering in a holistic and coordinated manner (rather than an ad hoc basis), once the comment phase is completed and the OEB issues Final Code amendments.

The September Proposed Amendment involving section 6.3.16 to the TSC included the term “proportional benefit”. A transmitter suggested the reference to “proportional benefit” should be removed from this section because the concept of proportional benefit does not apply to the attribution of costs between load and generator customers, as they are not based on avoided investments.

The OEB does not agree that the reference to “proportional benefit” should be removed. Under this section, costs would be apportioned based on the same underlying principle as section 6.3.18A – proportional benefit (between the load and generator customers, as opposed to a customer and the Network pool). Proportional benefit simply describes the degree one customer (or group of customers) benefits relative to another customer.

Only the factors used to determine the proportional benefit differ under those two sections. The OEB is therefore not proposing any revisions.

Bypass Compensation (new section 3.5.1 of DSC, section 11.2.1 of TSC)

In the September Proposed Amendments, the OEB proposed including bypass compensation provisions in the DSC in a manner that is consistent with the TSC. This change would ensure all customers of a distributor are not required to pay the stranded cost associated with the bypassed assets when an individual load customer chooses to bypass a distributor-owned facility that was built to meet that customer's needs.

Relationship to Capacity Reserve Charge (CRC)

A number of stakeholders requested clarification in relation to how the proposed bypass compensation charge (in this consultation) would work with the capacity reserve charge (as proposed in the C&I customer consultation – EB-2015-0043). The primary concern was the potential for a customer being required to pay both charges to compensate the distributor for the same bypassed capacity (i.e., charged twice).

Bypass compensation is broader in scope. Unlike the capacity reserve charge (CRC), it is not limited to cases of bypass involving generation. For example, bypass can be achieved through wires reconfiguration, where the customer shifts *existing* load from the distributor's facilities to its own duplicative facilities.

The comments requesting clarification appear to be limited to one bypass scenario under the current proposals. The scenario involves the customer installing behind-the-meter non-renewable generation (e.g., natural gas CHP).[5] That clarification is not possible at this time, since both bypass compensation and the CRC are at the proposal stage and could therefore change before a final approach is adopted by the OEB. As a consequence, the OEB will clarify the relationship between the two charges, once the OEB has reached a conclusion on the CRC as part of the C&I policy consultation.

Partial Bypass

A distributor suggested that the proposed addition related to bypass compensation focused on only *full* bypass; i.e., requiring bypass compensation in cases where the customer fully disconnects from the distributor's system. The distributor noted that bypass compensation should also apply to *partial* bypass.

[5] Under the current proposal set out in this Notice (new section 3.5.2), a distributor would not be permitted to require bypass compensation for any reduction in a customer's existing load served by the distributor's distribution system that has resulted from embedded *renewable* generation.

The OEB's intent was to capture all types of bypass in the September Proposed Amendment, subject to certain exceptions.[6] Whether a C&I customer or embedded distributor shifts all or most of its existing load, it results in bypass, as distribution assets will be stranded. In both cases, existing load will be removed from the system and supplied by other means.

Cases involving a portion of the customer's existing load have triggered bypass compensation in the past based on the current TSC provisions.[7] For example, a distributor was connected to a transmitter-owned transformation station (TS) and needed more capacity. The distributor, in turn, built its own TS and shifted *existing* load from the transmitter-owned TS to its own TS. Without bypass compensation in such a case, all ratepayers in the transmission connection pool would be negatively impacted. The OEB also believes such a scenario would be relatively common without bypass compensation, which would result in much under-utilized capacity on the system. The same issues can arise at the distribution level and the OEB expects the potential for it to increase as the distribution system continues its evolution and customers become more active and engaged.

Clarification – Load Management

In the September Proposed Amendments, "load management" is one of the activities that was proposed to be exempt from bypass compensation. Clarification was requested in relation to what was specifically considered "load management" for bypass compensation purposes.

In striving to align with the TSC, the OEB used the same terminology. "Conservation" is also identified as exempt. For clarification, the OEB's intent was "load management", in conjunction with "conservation", would capture all distributor CDM programs administered by the IESO and all activities identified in the OEB's CDM Guidelines, which includes those that would defer infrastructure investments.

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[6] Indicative of that intent is the proposed addition of section 3.5.2 which includes actions that customers would be able to take to partially reduce their demand on the system without triggering bypass compensation (e.g., conservation). The September Notice also explained that, in the OEB's view, there is only one circumstance that involves *existing* load where it can be shifted without triggering bypass compensation; that is, where the existing facility is overloaded, as reflected in proposed section 3.5.2(c).

[7] The TSC does not currently include a specific reference to *partial* bypass. The bypass provisions were added over a decade ago.

As a consequence, the OEB is proposing to revise section 3.5.1 of the DSC in the September Proposed Amendments to clarify bypass compensation would also apply to partial bypass. The OEB is also proposing to provide the same clarification in the TSC by amending section 11.2.1 to achieve the OEB's goal of consistency between the Codes.

Relocation of Connection Assets (new sections 3.1.20 and 3.1.21 of DSC)

The OEB proposed the addition of two new sections in the September Notice to clarify the circumstances under which a customer or a distributor should pay for the relocation of distribution assets. Where the customer requested relocation, they would be responsible for all the costs incurred by the distributor. If the distributor relocated assets and there was no customer request to do so, the customer would not pay.

In the written comments, distributors identified that they were only permitted to recover some of the costs (e.g., 50%) incurred from a customer in certain cases, such as under the *Public Service Works on Highways Act, R.S.O. 1990*.

The OEB is therefore proposing to amend section 3.1.20 of the DSC to clarify that, where the customer requests relocation, the amount to be recovered from the customer should either be all of the costs or the maximum amount permitted under law (e.g., government legislation), where the full amount is not permitted.

In response to a comment from a distributor, the OEB is proposing to replace the existing provision related to relocation with the revised proposed new sections. The existing provision only addressed one scenario in relation to cost responsibility. It also referred to relocation of distribution "plant", which is the only reference to "plant" throughout the DSC and distribution "plant" is not a defined term. It was therefore open to interpretation. The OEB is therefore also proposing to remove the provision related to relocation from section 3.4.

Definition of "Customer"

The OEB proposed to revise the definition of "customer" in the September Notice. A distributor raised concerns in relation to including "embedded distributor" in the definition of "customer". It was noted that an embedded distributor needed to be treated differently than a load or generator customer in relation to some sections of the DSC. An example that was identified relates to the treatment of costs involving distribution system "enhancements" (section 3.3). A distributor cannot require a customer to pay a capital contribution under that section and the enhancement may be required due to normal load growth within the systems of both the host and embedded distributor. As a result, if “embedded distributor” is included in the definition, only the host distributor (and its customers) would pay. Other concerns identified related to DSC provisions that do not involve cost responsibility.

An alternative approach was suggested – *deem* embedded distributors to be customers in relation to the cost responsibility sections (except section 3.3) which would also include the proposed EOL, bypass compensation and LDC feeder transfer sections discussed in this Notice.

The OEB shares the view that a more targeted approach involving *deeming* would be appropriate and is therefore proposing to remove “embedded distributor” from the definition of customer and, instead, *deem* them to be customers for the purpose of section 3 of the DSC (with the exception of section 3.3).

The OEB is therefore proposing to revise the definition of “customer” to reflect that deeming approach. For clarity, the OEB proposes to also reflect the deeming approach at the beginning of section 3 of the DSC.

Distributor-Owned Assets

At the Stakeholder Meeting, one of the issues discussed was the standard type of distribution assets used in a number of proposed DSC amendments. The specific term used in the September Proposed Amendments was “distributor-owned asset”.

Some distributors expressed the view that “distributor-owned asset” is too broad and it should be limited to distribution “connection” assets. At the other end of the spectrum, there was some distributor support for “distributor-owned asset” because distribution “connection” would be too narrow since customers sometimes cause and pay for upgrades in the main distribution system. Concerns were also expressed by distributors in relation to the administrative burden associated with addressing all distributor-owned assets and, as a result, suggested some degree of materiality should be reflected. In the written comments, a specific dollar threshold was suggested – $100K. A round number such as that amount seems somewhat arbitrary.

The OEB believes any *new* materiality threshold would be arbitrary and questions the need for such a *new* threshold. However, the OEB is of the view that an *existing* form of materiality threshold in the DSC would be appropriate – basic connection. As a consequence, the OEB is proposing a new definition of "distributor-owned asset" which would exclude all assets that are installed as part of a basic connection. [8]

In addition, many of the distributor comments and concerns related to the requirement to consult with affected customers where end-of-life (EOL) distributor-owned assets are involved. As discussed above, for that purpose, the OEB is proposing to further limit the scope of applicable assets to distribution stations that are connected to the transmission system and distribution lines that connect large customers (at or above 5 MW).

An important consideration that did not seem to be taken into account in some of the written comments is the frequency that the proposed DSC amendments involving distributor-owned assets will be triggered and, in some cases, no distributor action is required. "Distributor-owned assets" is referenced in the following sections:

- 3.1.17A – NBV and advancement cost calculation where a customer requests replacement before the asset reaches its EOL
- 3.1.19 – Cost attribution where a mix of load and generator customers require a new or modified asset at the same time
- 3.1.20 – Asset relocation at customer request and related cost attribution
- 3.1.21 – No distributor action required (as it relates to asset relocation in the absence of a customer request and therefore no cost attribution)
- 3.5.2(c) – No distributor action required (as it relates to not charging bypass compensation in relation to the overload portion of existing load)
- 3.5.3 – NBV calculation to determine bypass compensation

6. Other Proposed TSC and DSC Amendments

Hydro One suggested some other amendments to the Codes that were not triggered by the September Proposed Amendments. A new issue was also raised at the Stakeholder Meeting, as part of a broad discussion involving multiple stakeholders, related to *overloaded* facilities that had not been identified in the written comments.

Definition of "Embedded Distributor" (section 9.7.1 of DSC)

One suggested change is related to the existing definition of "embedded distributor" in the DSC. Hydro One identified that some embedded distributors do not meet the current

[8] Section 3.1.5 of the DSC allows distributors to define a basic connection by rate class for *non-residential* customers.

definition due to the reference to them not being a “wholesale market participant”. It was noted that a number of embedded distributors are now market participants and only one DSC provision (section.9.7.1) requires a reference to their status in that regard.

The OEB shares the view that a change is required and is therefore proposing that the definition of “embedded distributor” in the DSC be amended by removing the reference to not being a “wholesale market participant” (so that all embedded distributors will technically meet the definition) and also amend section 9.7.1 of the DSC to add their market participant status.

Clarification on Capital Contribution Refunds (section 6.3.17A of TSC)

In the TSC, section 6.3.17A addresses capital contribution refunds. Hydro One raised a concern related to a sentence that could be interpreted to mean the load forecasts of the initial customer and subsequent customer should be added together to perform the Economic Evaluation and the related DCF, in determining the appropriate capital contribution amount for each customer (including the rebate to the initial customer). It was suggested that section 6.3.17A be revised and a new section 6.3.17B be added to clearly delineate the capital contribution calculation of the initial customer from the subsequent customer.

The OEB confirms that it is not the intent for the load forecasts to be aggregated and the potential for misinterpretation should be eliminated to ensure the DCF calculations are done separately for each customer.

The OEB is therefore proposing a similar approach to what was suggested, except by amending section 6.3.17A of the TSC through the use of separate bullets to add clarity on how each customer is treated (rather than by introducing a second new section). While the calculations should be performed separately, there is still a connection between the calculations for the two customers. As a consequence, the OEB believes both calculations should be reflected in the same section.

Treatment of ‘Overload’

At the Stakeholder Meeting, there was a relatively lengthy discussion related to *overload* within the context of cost responsibility, when the beneficiary pays issue was the topic of discussion.

A stakeholder suggested that constant material overloading should be avoided and that incremental revenues associated with overloading a facility should be used to help pay for a new facility, like a capital contribution. In response, another stakeholder noted that it is not that simple because there are also additional offsetting costs that need to be taken into account. Such costs include higher maintenance costs and those associated with a reduction in the service life of the facility. Not accounting for those incremental costs (along with the incremental revenues) would result in rate increases for customers in the pool.

The OEB is of the view that material overloading of a facility should be avoided, particularly where it is on a constant basis (i.e., as normal day-to-day operations) and/or the limited time rating (LTR) is exceeded. The OEB is also of the view that the focus should not be on an incremental revenue scheme associated with overload. Such a scheme may create inappropriate incentives that exacerbates overload situations and ignores the associated incremental costs discussed above. Instead, the focus should be on managing the load on the assets in an appropriate manner to ensure customer reliability is not negatively impacted and asset end-of-life is not advanced.

C. Anticipated Costs and Benefits

The anticipated costs and benefits associated with the September Proposed Amendments were set out in the September Notice, and interested parties should refer to the September Notice for further information in that regard.

The OEB believes that the Revised Proposed Amendments will result in the same costs and benefits as the September Proposed Amendments, with the exceptions discussed below.

Based on the comments submitted, the Revised Proposed Amendments would have a substantially lower impact in terms of additional administrative costs for distributors. Examples include the following:

- Not increasing the timeframe from five to 15 years in relation to administering capital contribution rebates and expansion deposits
- The increase in the large customer threshold from 3 MW to 5 MW (since the changes to the applicable DSC provisions would apply to a substantially lower number of customers)
- The need for distributors to consult affected customers in relation to end-of-life distributor-owned assets would also be limited to a relatively small subset of

assets – distribution stations connected to the transmission system and only distribution lines that connect large load customers (at or above 5 MW)
- The scope of the distribution assets that are applicable under the Revised Proposed Amendments would also be reduced by excluding all distributor-owned assets installed as part of a basic connection

The OEB further believes the Revised Proposed Amendments will provide greater clarity in terms of the implementation of the proposed changes in the cost responsibility rules relative to the September Proposed Amendments.

While the OEB is deferring further consultation on the advanced funding options, the OEB believes the benefits involving smoothing consumer bill impacts and facilitating the implementation of regional plans will continue to be achieved through use of the capital contribution installment option, particularly with the added flexibility to extend the period beyond five years, where determined to be necessary.

The OEB does not believe that the Revised Proposed Amendments will result in incremental costs for distributors, transmitters or ratepayers relative to the costs associated with implementation of the September Proposed Amendments.

D. Coming into Force

As was the case with the September Proposed Amendments, the OEB proposes that the Revised Proposed Amendments to the TSC and the DSC, as set out in Attachments C and D, come into force on the date that the final Code amendments are published on the OEB's website after having been made by the OEB.

A stakeholder requested clarification related to the impact of the Code amendments on existing agreements and contracts between distributors and their customers. The OEB's intent is that the Code amendments would only apply on a prospective basis, as existing agreements were entered into based on the current rules in the Codes,[9] with the exception of allocating the costs associated with the SECTR project which triggered this consultation. As the OEB noted in its Phase 1 Decision and Order related to that leave

[9] If, however, the customer required additional capacity and the existing agreement therefore needed to be revised, the *new code provisions* would apply to the *new incremental* load. Any *existing* load under the existing agreement would remain subject to the *previous cost allocation rules* under such a scenario.

to construct case, “a deferral account should be established to facilitate the allocation of project costs as later determined”.[10]

E. Cost Awards

Cost awards will be available under section 30 of the Act to those that are eligible to receive them in relation to written comments provided on the Revised Proposed Amendments to the TSC and DSC in this Notice. Cost awards will be available to a **maximum of 10 hours** per eligible participant.

F. Invitation to Comment

Anyone interested in providing written comments on the Revised Proposed Amendments to the Codes are invited to submit them by **September 13, 2018**.

Your written comments must be received by the Board Secretary by **4:45 p.m.** on the required date. They must quote file number **EB-2016-0003** and include: *your name, address, telephone number and, where available, your e-mail address and fax number.*

One paper copy of your written comments must be provided, and should be sent to:

Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

The OEB requests that you make every effort to provide electronic copies of your written comments in a searchable/unrestricted Adobe Acrobat (PDF) format, and to submit them through the OEB’s web portal at https://www.pes.oeb.ca/eservice/. A user ID is required to submit documents through the OEB’s web portal. If you do not have a user ID, please visit the “e-filings services” webpage on the OEB’s website at www.oeb.ca, and fill out a user ID password request. Participants are also requested to follow the document *naming conventions* and document *submission standards* outlined in the document entitled “RESS Document Preparation – A Quick Guide”, which is also

[10] Decision and Order on Phase 1, EB-2013-0421, Hydro One Networks Inc., Leave to construct a new transmission line and facilities in the Windsor-Essex Region, July 16, 2015, page 10 (emphasis added).

found on the e-filing services webpage. If the OEB’s web portal is not available, electronic copies of your written comments may be provided by e-mail at boardsec@oeb.ca**.**

Those that do not have internet access should provide a CD containing their written comments in PDF format.

If the written comment is from a private citizen (i.e., not a lawyer representing a client, not a consultant representing a client or organization, not an individual in an organization that represents the interests of consumers or other groups, and not an individual from a regulated entity), the OEB will remove any personal (i.e., not business) contact information from those written comments (i.e., address, fax number, phone number, and e-mail address) before making the written comment available for viewing at the OEB's offices or posting it on the OEB's website. However, the private citizen’s name and the content of the written comment will be available for viewing at the OEB's offices and will be placed on the OEB's website.

This Notice, including the Revised Proposed Amendments to the TSC and DSC in Attachments C and D, and all related written comments received by the OEB will be available for public viewing on the OEB’s web site at www.oeb.ca and at the OEB’s office during normal business hours.

If you have any questions regarding the Revised Proposed Amendments to the Codes described in this Notice, please contact Chris Cincar at Chris.Cincar@oeb.ca or at 416-440-7696. The OEB’s toll free number is 1-888-632-6273.

DATED at Toronto, **August 23, 2018**

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Attachments:

Attachment A: Revised Proposed Amendments to the TSC – *Comparison Version to September Proposed Amendments*
Attachment B: Revised Proposed Amendments to the DSC – *Comparison Version to September Proposed Amendments*
Attachment C: Revised Proposed Amendments to the TSC – *Comparison Version to current TSC reflecting Consolidated Proposed Amendments*
Attachment D: Revised Proposed Amendments to the DSC – *Comparison Version to current DSC reflecting Consolidated Proposed Amendments*
Attachment E: Summary of Code Revisions – Proposed / Not Proposed

Attachment A
to
Notice of Revised Proposed Amendments to the Transmission System Code and the Distribution System Code

August 23, 2018

EB-2016-0003

Comparison Version of Revised Proposed Amendments to the Transmission System Code relative to the September Proposed Amendments
(for information purposes only)

Note: Underlined text indicates proposed additions to the September Proposed Amendments to the Transmission System Code and strikethrough text indicates proposed deletions from the September Proposed Amendments. Where sections include no such changes, no revisions are proposed to the September Proposed Amendments. Numbered titles are included for convenience of reference only.

[see separate document attached]

Attachment B
to
Notice of Revised Proposed Amendments to the
Transmission System Code and the Distribution System Code

August 23, 2018

EB-2016-0003

Comparison Version of Revised Proposed Amendments to the Distribution System Code relative to the September Proposed Amendments
(for information purposes only)

Note: Underlined text indicates proposed additions to the September Proposed Amendments to the Distribution System Code and strikethrough text indicates proposed deletions from the September Proposed Amendments. Where sections include no such changes, no revisions are proposed to the September Proposed Amendments. Numbered titles are included for convenience of reference only.

[see separate document attached]

Attachment C
to
Notice of Revised Proposed Amendments to the Transmission System Code and the Distribution System Code

August 23, 2018

EB-2016-0003

Comparison Version of Revised Proposed Amendments relative to the current Transmission System Code
(for information purposes only)

Note: This attachment consolidates both sets of proposed amendments relative to the current Transmission System Code, with yellow shading indicating proposed revisions to the original September Proposed Amendments. Underlined text indicates proposed additions and strikethrough text indicates proposed deletions. Numbered titles are included for convenience of reference only.

[see separate document attached]

Attachment D
to
Notice of Revised Proposed Amendments to the Transmission System Code and the Distribution System Code

August 23, 2018

EB-2016-0003

Comparison Version of Revised Proposed Amendments relative to the current Distribution System Code
<u>(for information purposes only)</u>

Note: This attachment consolidates both sets of proposed amendments relative to the current Distribution System Code, with yellow shading indicating proposed revisions to the original September Proposed Amendments. Underlined text indicates proposed additions and strikethrough text indicates proposed deletions. Numbered titles are included for convenience of reference only.

[see separate document attached]

Attachment E
to
Notice of Revised Proposed Amendments to the Transmission System Code and the Distribution System Code

August 23, 2018

EB-2016-0003

Summary of Code Revisions – Proposed / Not Proposed

[see separate document attached]