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NOTICE OF PROPOSAL TO AMEND A CODE

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* of proposed amendments to the Transmission System Code (TSC) and the Distribution System Code (DSC).

A. Background

On January 7, 2016, the OEB issued a letter (January 7th letter) initiating a policy consultation aimed at ensuring the cost responsibility provisions for load customers in the OEB's TSC and DSC are aligned and facilitate the implementation of regional plans.

Proportional Benefit and Upstream Transmission Investment Issues

A primary reason for initiating this consultation was a leave to construct (LTC) application – Supply to Essex County Transmission Reinforcement (SECTR) – which was filed with the OEB by Hydro One Networks Inc. (Hydro One) in January 2014. That LTC application included a proportional benefit approach to cost apportionment that involved apportioning some transmission connection asset costs to all ratepayers.

Hydro One's proposed methodology is not currently contemplated in the TSC.[1] It also differed in some respects from the proportional benefit approach that had been previously proposed in an OEB Supplementary Proposed TSC Amendment that was issued for comment in August 2013 but was not concluded by the OEB.[2] Those two proportional benefit approaches are discussed below.

Hydro One's SECTR application also included a proposal to allocate upstream transmission connection costs to distribution-connected customers (including embedded distributors) in a manner that was not consistent with the current cost responsibility rules in the DSC.

The OEB determined that those cost allocation issues should be reviewed from a *policy* perspective. A policy process allows for a consideration of the issues from a broader perspective (i.e., not based on one specific project). It also provides the opportunity for a more holistic review of the cost responsibility provisions in the TSC and the DSC to ascertain if other issues needed to be addressed.[3]

Other Issues – Regional Distribution Solutions, Code Gaps & Inconsistencies

The following additional issues were identified in the January 7th letter for this policy initiative:

- Consider whether changes to the DSC are needed to facilitate regional planning and the implementation of regional infrastructure plans
- Identify potential inconsistencies between the TSC and the DSC and, to the extent any exist, determine whether those inconsistencies should be aligned or whether they remain appropriate
- Identify potential gaps in the TSC and the DSC related to cost responsibility and regional planning that should be addressed

Working Group Process

In June 2016, the OEB issued a letter announcing the formation of a Working Group comprised of various stakeholders – representing consumer groups, distributors, a

[1] Under the current TSC rules, the costs associated with investments in connection assets are recovered from only the customer(s) that caused the need for the investment.
[2] The consultation process involving the Proposed Supplementary TSC Amendment was placed *on hold* when the SECTR application was submitted by Hydro One.
[3] On August 28, 2015, the OEB issued a letter to all parties in the SECTR case explaining the OEB would not continue to proceed with Phase 2 – cost allocation phase.

transmitter and the IESO – to provide input to OEB staff on issues and potential solutions that would help inform which revisions to the TSC and DSC may be desirable.

The OEB held three Working Group meetings during which a number of issues were identified.[4] Materials related to the Working Group are available on the OEB's website. The OEB notes that not all of the issues raised by the Working Group can be addressed through a code amendment. However, the OEB has identified in this Notice where that is the case.

B. Proposed Amendments to the TSC and the DSC

Attachments A and B to this Notice contain the proposed amendments to the TSC and the DSC, respectively. The following is a high level summary of the proposed Code amendments. Preceding the high level summary are guiding principles that provided the basis for the proposed Code amendments.

Guiding Principles

The OEB is of the view that the following guiding principles should be used to determine the appropriate approach to allocating the costs associated with distribution and transmission connection investments:

- *Optimal Infrastructure Solution* – Optimal solutions are infrastructure investments that meet regional needs at the lowest cost; i.e., most cost effective solution. The optimal infrastructure investment will be identified in a Regional Infrastructure Plan (RIP) and will typically be supported by an Integrated Regional Resource Plan (IRRP)

- *Beneficiary Pays* – Beneficiaries of an infrastructure investment will contribute to the cost of an investment. Cost allocation will be determined based on the customer's proportional use of the connection asset set out in a regional plan. Costs should not be allocated to any load customer (consumer or distributor) or generator that will not benefit from the investment[5]

[4] Materials from the Working Group meetings can be found on the following OEB web page: www.oeb.ca/industry/policy-initiatives-and-consultations/regional-planning-and-cost-allocation-review

[5] In the RRFE Report (p. 43), the OEB identified that "a shift in emphasis away from the 'trigger' pays principle to the 'beneficiary' pays principle is appropriate".

- *Open, Transparent and Inclusive* – The process used to determine the cost of an infrastructure investment and the appropriate allocation of those costs to the beneficiaries should be transparent and include all affected parties

Organization of Notice

The proposed TSC and DSC amendments are described below in the following five sections:

- The first section discusses a proposed proportional benefit approach to apportion costs associated with transmission connection investments between the transmission network pool and customers directly connected to the transmission system that caused the need for the connection investment

- The second section includes proposed changes that relate to the apportionment of costs to customers of distributors (including *embedded* distributors and other ‘large’ load customers), where they benefit from investments in upstream transmission connection facilities. A new proposed *threshold* for determining what size of load constitutes a ‘large’ customer for this and other purposes is also proposed in that section of the Notice

- The third section proposes an approach to cost apportionment between a load customer(s) and all ratepayers,[6] where a connection asset requires replacement at its end-of-life. Also included in this section is a proposed approach to facilitate a regional distribution solution, where more than one distributor is involved, and it would avoid a more costly upstream transmission connection investment. The proposed cost apportionment between the distributors is discussed

- The fourth section proposes an approach that is intended to facilitate the implementation of regional infrastructure plans relative to the status quo. The proposed approach would achieve that goal by mitigating consumer bill impacts through smoothing mechanisms and/or provide advanced funding to distributors to reduce their borrowing requirements. Those bill impacts result from the large lump sum capital contribution amounts that may be required under the current rules

- The final section is comprised of proposed amendments to address inconsistencies between, and gaps within, the TSC and DSC

[6] 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.

1. PROPOSED TSC AMENDMENTS: APPROACHES TO 'APPORTION' TRANSMISSION CONNECTION INVESTMENT COSTS TO THE NETWORK POOL

One of the two major issues raised in the SECTR proceeding, which is discussed in the OEB's January 7th letter, is whether it is appropriate to allow for a *portion* of the costs associated with a transmission *connection* investment that is triggered by a specific customer(s) to be recovered from all ratepayers (like a *network* investment).

Currently, under the TSC, the costs associated with transmission *connection* (line and transformation) investments are recovered only from a load customer or group of load customers that caused the need for the investment. On the other hand, except in exceptional circumstances, the costs associated with transmission *network* investments are recovered from all ratepayers since all Ontario consumers benefit.[7] There was a provision in the TSC (section 6.3.6) that allowed for apportionment of *connection* asset costs to the network rate pool. However, that provision was eliminated in a previous OEB proceeding (EB-2011-0043) for a number of reasons. First, it allowed for the apportionment of 100% of the cost to all ratepayers (i.e., non-beneficiaries), even if the primary reason for the investment was to serve a customer's needs. It was therefore inconsistent with the beneficiary pays principle. It was also incompatible with the OEB's approach to regional infrastructure planning, as it was premised on the transmitter planning investments to connect transmission customers (including distributors) without obtaining input from those customers.

The OEB generally believes a specific customer should not be required to pay all of the costs associated with a connection investment where the investment also addresses a broader network system need (e.g., reliability). This is consistent with the beneficiary pays principle, since both the customer(s) that caused the need for the investment and the broader system benefit.

While the OEB is generally supportive of recovering a portion of the costs in such cases from all ratepayers, the OEB has some concerns related to implementation within the context of ensuring fair and equitable apportionment. For example, there is a potential incentive to apportion more than the appropriate amount to all ratepayers (i.e., network pool).

[7] There may be exceptional circumstances where a capital contribution is required for network investment.

Two approaches were identified for addressing the apportionment of costs where both system and connection benefits will be realized, both of which are described below. Based on a consideration of both methods, the OEB is of the view that the proportional benefit approach is more appropriate, for reasons that are discussed below. That approach is similar to the methodology that Hydro One and the IESO had proposed in the SECTR proceeding.

In that SECTR case, the proposed investment met the needs of certain customers (i.e., three distributors connected to Hydro One) and also addressed a broader network need – meeting load restoration criteria set out in the IESO's ORTAC requirements, which are related to restoring power to consumers after an outage within a reasonable period of time.[8] This proposed methodology was used to determine the proportional benefit between the customer(s) and the broader system. The proposed allocation of costs between the customers and all ratepayers was based on the lowest cost solutions to address the customer and broader system needs *separately*. See sidebar for an illustrative numerical example reflecting this proportional benefit methodology.

The other approach to addressing the apportionment of connection costs to the network pool was identified in the OEB's January 7th letter. This approach is premised on a transmitter making incremental transmission *connection* investments that exceed the capacity needs of those customer(s) because they would *avoid* a more expensive upstream transmission *network* asset upgrade (i.e., avoided cost methodology). Under this approach, it was proposed that the incremental connection investment costs would be apportioned to

Proposed Proportional Benefit Approach: An Illustrative Example

The cost of each *separate* solution to meet the two regional needs is first determined. In this example, the cost is $30M to address the *system* need and $90M to meet the *customer(s)* need. The aggregate cost of the two solutions is therefore $120M ($30M + $90M). The relative proportion (i.e., percentage allocation of aggregate cost) attributed to each solution is as follows: *system* need ($30M / $120M = 25%) and *customer(s)* need ($90M / $120M = 75%).

Those relative proportions are then applied to the cost of the *single integrated optimal* solution that addresses both needs at a lower cost (e.g., $100M or $20M lower): *system* need is 25% * $100M = $25M and *customer* need is 75% * $100M = $75M. As a result, applying the proportional benefit to the cost of the optimal solution would result in *$25M* being recovered from *all ratepayers* (rather than $30M under the sub-optimal solution) via the network pool and *$75M* would be recovered from the *benefiting customer(s)* – rather than $90M.

[8] Ontario Resource and Transmission Assessment Criteria (ORTAC), IESO.

the network pool (like the avoided network investment costs would have been). In such instances, this would reduce the amount apportioned to the applicable network pool (i.e., all ratepayers) relative to the cost of the network solution. It was consistent with the OEB's goal for regional planning – the lowest cost wires solution that addresses the need. However, the OEB has determined that the 'proportional benefit' methodology could also be used for apportionment scenarios that are limited to addressing 'capacity' needs. That would include cases where incremental connection investments would avoid a higher cost network solution, as described above. In other words, the proportional benefit methodology would solve for all scenarios where proposed connection facilities could also provide network benefits.

The OEB is of the view that the *proportional benefit* approach achieves the objective of ensuring that the cost of a proposed connection facility that addresses a network requirement or provides network benefits is properly shared according to the beneficiary pays principle. Unlike the provision discussed above that was removed from the TSC (section 6.3.6), the proportional benefit approach is compatible with the OEB's approach to regional infrastructure planning by encouraging the optimal investment in transmission assets. In fact, the OEB would expect such an integrated solution to be reflected in a regional plan.

The OEB is therefore proposing to amend the TSC by adding sections 6.13A and 6.13B to allow costs associated with transmitter-owned connection investments to be apportioned between the customer(s) that caused the need for the connection investment and all ratepayers, based on the proportional benefit between the connecting customer(s) and the overall system.

The OEB believes there would be a need for an OEB adjudicative process to review requests for such apportionment, on a case by case basis, to ensure there is not an over-allocation to the network pool (i.e., all consumers).

A case by case application approach would also be necessary as the apportionment would be expected to change based on the specific circumstances. The methodology relies on a proxy to estimate the cost to address each need individually, which provides the basis to determine the apportionment. The OEB expects the proxy and/or associated values to differ in each case. The proxy is therefore critical to this methodology. Whether the proxy used was the most appropriate (and the associated estimated cost) would therefore need to be tested.[9] Such applications should be supported by three documents: a regional infrastructure plan (RIP), an integrated regional resource plan (IRRP), where applicable, and an independent assessment by the IESO that is similar in nature to the assessment that was provided in support of Hydro One's SECTR application.

[9] For example, the proxy used in the SECTR proceeding as the most cost effective 'separate' solution to address the broader load restoration need was a natural gas generation facility.

2. PROPOSED TSC AND DSC AMENDMENTS: APPROACHES TO 'APPORTION' UPSTREAM TRANSMISSION CONNECTION INVESTMENT COSTS

Upstream Transmission Connection Investments – Treatment of Embedded Distributors

There is an inconsistency between the TSC and the DSC where an investment involves an upstream transmission connection asset and both the host and embedded distributor(s) have contributed to the need for that investment. One code requires a capital contribution from a distributor, while the other does not. That results in an inconsistent treatment among distributors. This was the second major issue raised in the SECTR LTC proceeding that related to cost responsibility.

In the TSC, a distributor is treated like all directly connected transmission customers and must provide a capital contribution (based on an economic evaluation) to the transmitter in relation to a connection investment where it is the beneficiary. However, the DSC does not allow a *host* distributor that provided the capital contribution to the transmitter to, in turn, require a capital contribution from an *embedded* distributor where the latter is also a beneficiary of the same upstream transmission connection investment. As a consequence, the customers of the host distributor subsidize the customers of the embedded distributor under the status quo.

The OEB is of the view that the beneficiary pays principle should apply to all distributors, regardless of whether they are connected to the transmission system or embedded within a distribution system, and the allocation of the costs should reflect the extent each distributor (and its customers) caused the need for and benefit from a connection facility investment. In other words, all distributors should be treated the same in terms of cost responsibility, with the costs apportioned based on the relative capacity needs of the host and embedded distributor(s) that benefit from the connection investment.

The OEB is therefore proposing to amend section 3.2.4 of the DSC so that embedded distributors are no longer exempt from providing a capital contribution.[10] Section 3.2.4 would be further amended to change “may” to “shall” to further ensure consistent treatment of customers across distributors. The OEB does not believe it should be left to each distributor to decide whether to apply the beneficiary pays principle.

[10] Where a capital contribution is required based on an economic evaluation.

Upstream Transmission Connection Investments – Treatment of Large Load Customers

The same concept described above applies to all large load customers (e.g., industrial). That is, the OEB also believes all large load customers should be treated the same in terms of cost responsibility whether they are connected to the system of a transmitter, host distributor or embedded distributor.

At the same time, the OEB does not believe it is practical for distributors to require a capital contribution from all load customers (e.g., residential, small business) related to upstream transmission connection investments. The OEB believes there is a need to strike a balance between precision and administrative burden. The OEB is therefore of the view that a materiality threshold for 'large' load customers of distributors is needed for this purpose.

Various potential materiality thresholds were discussed during the Working Group process. Consumer group representatives and distributors both advised OEB staff that 3 MW seemed the most appropriate. It was noted that customers with demand below that level (e.g., 500 kW, 1 MW) may *contribute to* the need for an upgrade, as residential customers similarly do, but they would *not drive* (i.e., cause) the need for an upstream transmission investment.

The proposed threshold for 'large' load customers (that are not distributors) is based on non-coincident peak demand that meets or exceeds 3 MW. Under this proposed approach, a capital contribution would not be required from customers that are below that threshold, including those considered low volume consumers (i.e., residential, small business). The OEB believes this threshold would strike that appropriate balance between precision in terms of allocating costs and administrative burden for distributors.

The OEB is therefore proposing to add new section 3.2.4A to the DSC reflecting the above.

The OEB notes that the proposed 3 MW threshold is also being proposed for other purposes, which are discussed below. Those include: *bypass compensation, capital contribution true-ups and capital contribution (and expansion deposit) refunds*.

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 Connection Assets: Not Like-for-Like

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). That provision is section 6.7.2 of the TSC. Under that section, the transmitter must replace the asset at no cost to the distributor or commercial customer since the cost of the asset has been recovered through the rates they have paid.

During the Working Group process, the IESO suggested a change to the TSC related to cases where a connection asset reaches its EOL but the customer does *not* want a like-for-like replacement. Instead, the customer requires an *upgrade* (e.g., additional capacity) to replace the EOL connection asset. Currently, the customer pays 100% of the cost where it involves an upgrade. The IESO suggested the customer should only be required to pay the *incremental* cost (i.e., amount that exceeds the cost of a like-for-like replacement) to the transmitter.

The OEB is of the view that a change to the TSC to implement this approach would result in greater fairness among all load customers as they would be treated the same – all load customers would essentially receive a credit equal to the cost of a like-for-like replacement asset which could be applied to the cost whether it is the same capacity (*fully* offset) or an upgraded connection (*partially* offset).

On the other hand, if the customer *requests* the replacement of a connection asset that has *not* reached its EOL, the OEB is of the view that the customer should pay. However, the OEB is also of the view that the amount they pay should be limited to the remaining net book value (NBV) – not the full cost – since the asset being replaced remains 'used and useful' but it has also been partially (or fully) paid for by that customer through rates. This NBV-approach is consistent with the OEB's current approach to Bypass Compensation (i.e., NBV approach), in the TSC, which is discussed below.

Major changes have taken place in the industry since the TSC and DSC were introduced. Increased efficiencies and conservation have lowered the average customer's electricity consumption. The falling cost of distributed (i.e., small scale) generation has encouraged customers to install load displacement generation in order to reduce their total cost of energy. Technology is also evolving quickly which will provide more choice to consumers in terms of their ability to manage demand through various approaches, including generating and storing energy, to better manage their energy costs. These factors are resulting in many distributors experiencing lower customer consumption levels and lower maximum peak demands. EOL conditions provide an opportunity to take that evolution into account in relation to appropriately right-sizing the assets being replaced.

The OEB believes the Codes should reflect that evolution and is proposing to address a third scenario. The OEB expects there will be cases where a customer's load has materially declined from the time the connection facility initially went into service to when it reached its EOL, and there is an expectation that the customer's load will not grow in the future. Currently, the standard industry practice is for the transmitter to replace it with a like-for-like connection asset (i.e., same capacity). The outcome, in such cases, would be an over-investment in capacity since some of it would no longer be needed. As noted above, the customer does not pay for a like-for-like connection asset replacement at its EOL. Instead, all ratepayers pay through the applicable connection pool and, in this instance, they would pay for an over-investment.

As a result, in such cases where a customer's load has materially declined over time, the OEB expects that the transmitter would apply the appropriate judgment and replace the EOL asset with a new connection asset that meets the lower forecast need of the customer at its EOL (i.e., 'right-size'). This approach would reduce the cost allocated to all Ontario consumers and result in a more efficient transmission system by avoiding an investment in unnecessary capacity. The OEB is not proposing to include a code requirement to 'right-size' to a lower capacity. The OEB acknowledges that there will be a need for some transmitter judgment. However, the TSC will be amended to make it clear that a lower capacity replacement connection asset is a potential outcome.

The OEB is therefore proposing that section 6.7.2 of the TSC be amended to include three subsections that address all three EOL scenarios discussed above: *(1) like-for-like, (2) additional capacity, and (3) lower capacity.*

The OEB is also proposing to further amend section 6.7.2 of the TSC to require the transmitter to consult with their customers – distributors and commercial – that are served by a facility before the transmitter replaces it. This proposed requirement is similar to those set out in section 6.2.14 of the TSC, which address the situation where a transmission facility is reaching 75% of its rated capacity. In that case, a transmitter is required to give affected customers notice and seek input from them on their future needs (e.g., forecast demand). The OEB is of the view that similar notice is necessary to ensure the transmitter has engaged in a consultation with its affected customers to be able to identify the future demand on the facility, for the purpose of right-sizing.

The OEB intends to update the transmission filing requirements to ensure transmission system plans that involve the replacement of EOL connection assets include evidence of the assessment of alternatives (i.e., wires and non-wires) in meeting future customer demands on the system. The OEB expects that this approach will ensure replacement decisions and all EOL scenarios are adequately addressed in transmitter planning.

Replacement of End-of-Life Distribution Connection Assets

Unlike the TSC, the DSC does not address cost responsibility in relation to the replacement of a distributor-owned connection asset that has reached its EOL. At the same time, changes in customer expectations and demands on the electricity system, and the evolution of technology are even more pronounced at the distribution system level.

The OEB understands it is standard industry practice not to charge the customer when it involves a like-for-like replacement (i.e., continuation of same level of service) at EOL. The OEB is of the view that is how it should be.

The OEB is therefore proposing to add new section 3.17 to the DSC that aligns with the proposed amendments to section 6.7.2 of the TSC. The proposed new section would capture all three scenarios discussed above involving the replacement of EOL transmission connection assets, to ensure consistency between the two codes. The requirement for distributors to consult with customers, at the time of replacement of an asset, will be limited to those considered to be large customers (3 MW and above), as described in the section above.

The proposed TSC and DSC amendments related to the replacement of EOL assets would achieve the following outcomes:

- Ensure each EOL replacement asset is the most cost effective solution that meets the customer’s needs

- Better recognize the evolution of the distribution system which is resulting in lower customer consumption levels due to factors such as the introduction of new technologies, higher penetration of distribution generation and an increased emphasis on conservation

- Increase regulatory certainty for customers

- Ensure all customers in Ontario are treated the same regardless of:
  - Which distributor serves them
  - Whether they are connected to the distribution system or the transmission system

Regional Distribution Solution – LDC Feeder Transfer

During the Working Group process, the IESO proposed 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 IESO referred to this proposal as ‘LDC Feeder Transfer’. The following is the example that was provided to the Working Group. One distributor – LDC (A) – that requires more transmission connection capacity would make an investment to connect to a distribution line of another distributor – LDC (B) – which has *excess capacity* and *no future growth* is expected. This approach would be taken to avoid a more costly upstream transmission connection investment. The OEB will refer to LDC (A) as the ‘connecting’ distributor and LDC (B) as the ‘facilitating’ distributor below.

The OEB sees merit in this proposal. It would result in achieving the OEB’s goal associated with regional planning of implementing the least cost wires investment that addresses a regional need. This proposed change would also result in less excess capacity on the system, i.e., improved utilization of existing assets since the ‘facilitating’ distributor’s unused capacity would be used by the ‘connecting’ distributor.

The OEB is therefore proposing to amend the DSC to add section 3.1.8. Under this proposed amendment, the non-beneficiary (‘facilitating’ distributor) would be compensated by the beneficiary (‘connecting’ distributor) to the extent the ‘facilitating’ distributor had to make any investments and/or incurred additional costs in the future to facilitate such a solution. The OEB would expect that the two distributors would reach an agreement that would ensure the customers of the ‘facilitating’ distributor were not negatively affected in any way, including from a reliability perspective.

For example, to the extent the ‘facilitating’ distributor had paid the transmitter for capacity (through a capital contribution) in relation to a transmission connection facility that will be used by the ‘connecting’ distributor, the OEB expects the ‘facilitating’ distributor would receive a capital contribution refund from the ‘connecting’ distributor, where applicable. The ‘facilitating’ distributor would also need to be compensated for any incremental charges (e.g., transmission, regulatory charges, etc.) it is required to pay to the IESO due to incremental electricity withdrawn from the grid by the ‘connecting’ distributor. The ‘connecting’ distributor would essentially be treated as an embedded distributor, with the ‘facilitating’ distributor functioning like a host distributor.

From a process perspective, if this proposed amendment is adopted, the OEB believes a joint application involving the ‘connecting’ distributor and the ‘facilitating’ distributor for approval of the proposed investment and the compensation to the ‘facilitating’ distributor would be the appropriate approach. This would confirm the distributors are in agreement and all investments proposed by the distributors have been taken into consideration.

The OEB also expects such a solution would flow from a regional infrastructure plan, since it would require close coordination and agreement among the transmitter and the distributors involved. A regional infrastructure plan would therefore need to be submitted in support of the joint application to demonstrate the distribution solution is more cost effective than a transmission connection upgrade. Distributors would also be required to obtain an assessment from the IESO confirming that the distribution solution is more cost effective than an upgrade to the transmission connection facility that connects the ‘connecting’ distributor to the grid; i.e., confirm the distribution investment is the optimal wires solution from a regional planning perspective.

The OEB would also require that the two distributors demonstrate that there is an adequate amount of excess capacity on the transmission connection facility – connecting the ‘facilitating’ distributor to the transmission network – to meet the forecast needs of both distributors. The OEB does not want to see an outcome whereby the distribution investment is made to avoid a transmission connection investment, while triggering a different transmission connection investment during the forecast period. Under such a scenario, the end result would be an unnecessary distribution investment (i.e., sub-optimal solution). The OEB would look to the IESO to take that potential outcome into account as part of its assessment.

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 transmission connection upgrades discussed above are *lumpy* in nature, while any load growth within the distribution system tends to be *gradual*. Load growth (i.e., *demand*) and the assets to *supply* it are therefore rarely aligned. As a result, when a connection asset upgrade associated with a distributor is implemented, there is often much *excess* capacity.

The disconnect noted above is a concern to the OEB because it can result in significant bill impacts for the customers of distributors and a barrier to the implementation of regional plans due to the capital contribution that must be provided by the distributor to the transmitter. That capital contribution is a one-time lump sum amount representing the shortfall between the revenues to be paid by customers through transmission rates and the total cost of the facility. The capital contribution also reflects both the incremental capacity required by the distributor to meet its near term needs, as well as excess capacity since these investments cannot be sized to exactly match the distributor's forecast needs.[11]

The focus tends to be *line* connections when this issue is raised, as they come in only two discrete sizes – 115 kV and 230 kV – in Ontario.[12] A 230 kV line accommodates about 400 MW of load, while a 115 kV line accommodates only about 150 MW of load – a 250 MW differential. As a consequence, if a 115 kV line comes close but falls short of meeting a distributor's forecast needs, a 230 kV line would be required which would include much excess capacity under such circumstances. The capital contribution would be substantial in such a case since the distributor would not recover any transmission rate revenues on that excess capacity.

Due to the issue discussed above, stakeholders have noted that many distributors in Ontario may not implement the 'optimal' transmission connection investments identified in regional plans. In those cases, the primary reason for that is the current approach can result in distributor financing issues and significant customer bill impacts.[13] As a

[11] The total system demand of some distributors in Ontario is less than 400 MW including distributors as large as Oakville Hydro and Kitchener-Wilmot Hydro (OEB 2016 Electricity Distributor Yearbook).
[12] There is more flexibility to size *transformation* connection assets to better meet the transmission customer(s) need. However, this issue can also arise in relation to some transformation stations.
[13] Stakeholders often refer to this as an "affordability" issue for the distributor. In the OEB's view, it is a bill impact issue for customers of the distributor, since all of the cost is typically passed on to end use consumers by the distributor under the current regulatory construct.

consequence, concerns have been expressed that the following undesirable outcomes may result:

- Sub-optimal investments being made by distributors within the distribution system to avoid an upstream transmission connection investment
- Existing transmission connection facilities being overloaded to avoid a necessary upstream investment (which reduces the useful life of a connection asset)
- Regional plans cannot be implemented
- Reliability may be impacted

Three approaches are discussed below which are intended to address the issue discussed above. The OEB is proposing the implementation of all three approaches through code amendments and/or changes to other regulatory instruments. A summary of the implementation details associated with the three approaches is set out at the conclusion of the section.

Providing for alternative approaches to fund capital contributions related to connection assets will, in the OEB's view, increase the effectiveness of regional planning by avoiding the unintended consequences noted above.

1. Annual Installment Option (for distributors)

One of the approaches discussed during the Working Group process is referred to as the Annual Installment approach.[14] It would involve a capital contribution being provided via *multiple annual installment payments* over a certain number of years instead of the status quo which is a *single lump sum payment* to the transmitter.

In addition to mitigating bill impacts by spreading the cost over time, the OEB believes this approach would also result in better alignment between incremental revenues received by distributors due to customer load growth and paying the cost of the connection investment to the transmitter. Both would occur over a period of time. It also remains fully aligned with the beneficiary pays principle. It would only be a *timing matter* as to when the beneficiary pays the full cost to the transmitter (including any additional financing costs).

The TSC includes a true-up process related to capital contributions due to the difference between actual load growth and the load forecast. Under this proposed amendment,

[14] During the Working Group process, this approach was referred to as the "Smoothing Option". However, the OEB felt a change in terminology was needed to better describe it and recognize that it is not the only approach that would smooth the costs to reduce bill impacts.

that true-up process would remain in place. The difference between actual and forecast load would be captured by adjusting the final installment payment.

This approach would be limited to regulated distributors since there is virtually no risk that they will not pay the transmitter the full cost of the investment. On the other hand, an industrial customer (e.g., mining company) could cease operations at any time before the investment in the connection asset is paid off. The remaining cost would need to be recovered from all Ontario consumers in all instances where that occurred. As discussed below, there are also a number of other differences between regulated distributors and commercial customers.

The transmitter already finances connection investments under the status quo. The cost is currently recovered through a combination of a capital contribution and through rates over time (as determined by an economic evaluation).As a consequence, under this installment approach, *all* (instead of *part*) of the cost would be recovered over time. The capital contribution portion would just be recovered over a much shorter period of time; e.g., five vs. 25 years.

To strike a balance between minimizing the bill impacts and also minimizing the carrying costs, the OEB is proposing that the period of time over which the full capital contribution would be provided would not be permitted to exceed five (5) years.

Under the current approach, a distributor that makes a lump sum capital contribution will seek to include it in its rate base and thus earn a return on rate base to finance that investment. This proposed installment approach means that a distributor would be recording less upfront and adding to its rate base over time as it makes each installment payment toward the required capital contribution.

The OEB notes this approach represents a relatively minor deviation from the current approach set out in the TSC in relation to recovery of capital contributions. It is only a matter of extending the period over which the full capital contribution is paid. The approach is also consistent with the OEB approved approach used by the natural gas utilities for expansion projects, where cost recovery is spread over a period of time to mitigate bill impacts for the customers of the utility.[15]

[15] In RP-1999-0034, section 6.2, it states *"In many cases this up-front one-time payment was seen as a financial barrier to customers who could not afford such initial outlays. This allowed for the introduction of the periodic contribution charge (PCC) which presented customers with the option of paying a contribution over time. Essentially, the utilities would finance the contribution amounts."* The PCC remains in effect and is typically charged over a 5 year term as a separate line item on the bill.

This approach to addressing the customer bill impact concern discussed above received the most support among Working Group members, particularly the members representing consumer groups.

Advanced Funding Option

The OEB has also considered two approaches that would both provide distributors with a pool of funds before the new or upgraded connection investment goes into service – Upstream Capacity Payment and Upstream Connection Adder.

2. Upstream Capacity Payment Approach

The first approach involves a distributor including in its economic evaluation a payment reflecting future upstream system costs. The payment for capacity ensures the new customer that is connecting to the system and therefore benefitting from existing available capacity (or a new transmission connection asset) pays towards the cost of its future capacity requirements.

Under this approach, distributors would apply a per kW payment reflecting the forecast costs to be paid by customers (e.g., developers) before an upstream transmission investment is made and before a capital contribution is provided to the transmitter. The OEB expects that the forecast cost of the upstream transmission investment would be based on the most recent regional infrastructure plan.

Distributors would hold the funds collected through such charges (including any interest that accrued) in a separate account until the capital contribution related to the new upstream connection asset is provided to the transmitter. The capacity payments collected by the distributor would be included in the capital contribution provided to the transmitter.

The primary benefit associated with this approach is that it ensures those customers who are connecting to transmission connection facilities, where there is existing capacity, would contribute to the next upgrade. In essence, these customers would pay for the use of capacity that would otherwise have been available for other customers, or for general load growth. Since funds would be collected before the capital contribution is due, this would reduce the amount distributors need to borrow to fund the capital contribution. In doing so, it would also reduce the distributor’s incremental financing costs (relative to the status quo). This outcome should therefore facilitate the implementation of regional plans. This approach also aligns with the beneficiary pays principle.

The OEB acknowledges, however, that this approach would not fully eliminate the 'lump sum' issue or mitigate the impacts on all customers of the distributor. To some extent, the cost is being shifted to new customers of the distributor since they would be paying 'in advance' of the date the capital contribution must be provided to the transmitter (i.e., when customers begin to pay under the status quo). In addition, there could be cases where a connection investment was required where there is no new development(s) and, therefore, little or no load growth. A scenario where this may be the case is where an upstream transmission investment has been deferred for a number of years and the connection asset slowly becomes overloaded due to gradual existing customer load growth. If this approach was adopted, there would be a need for cost responsibility rules that support it, as *existing* customers would then be responsible for the full cost.

Any amount collected through the Upstream Capacity Payment would need to be tracked by the distributor and reflected as a future capital contribution offset related to new transmission connection assets.

The capacity payment would also be based on an *estimated* cost rather than an *actual* cost. To eliminate some of the risk, distributors will be expected to calculate the amount of the capacity payment based on the cost estimates included in the most recent regional infrastructure plan. The OEB expects that estimated cost would be developed, in consultation with the lead transmitter and the IESO, during the regional infrastructure planning process.

3. Upstream Connection Adder

The final approach that the OEB is proposing to implement is a funding adder, referred to in this Notice as the Upstream Connection Adder.

It would be similar to the Upstream Capacity Payment approach in that it would provide advance funding to the distributor before the upstream connection asset goes into service and before a capital contribution needs to be provided to the transmitter.[16] Where it differs is it would collect the funds by adding a rate rider to the bills of all the

[16] It typically takes about two years for a line connection and three years for a transformation station from confirmation of the 'need' for the new asset to the date construction is completed and it goes 'into service'. Various factors can affect the amount of time (e.g., environmental approvals, whether land needs to be acquired, whether leave to construct approval is required, etc.).

distributor’s customers, rather than applying a per kW charge to new and expansion customers. Other differences are discussed below.

Similar to the Upstream Capacity Payment approach, the funds collected through the Upstream Connection Adder would be kept in a separate deferral account. Any interest that accrues in relation to the funds collected would remain in that deferral account. The pool of funds in the account would be used to reduce the amount of the capital contribution paid to the transmitter for the upgrade to upstream transmission connection assets. As a result, it would reduce the amount the distributor would need to borrow to finance the capital investment. In doing so, it would also reduce the associated financing costs. However, like the Upstream Capacity Payment, this outcome is possible because some of the cost is being shifted to customers of the distributor, since they would be paying ‘in advance’ of the date the capital contribution is due to the transmitter.

The OEB is proposing both this approach and the Capacity Payment approach as they will provide distributors with options to address different circumstances. As noted above, there are some differences between the two approaches.

- Both would be set or be expected to recover a portion of the capital contribution before it is due to the transmitter to use as an offset. The amount recovered through the adder would depend on how it is designed (e.g., portion targeted), while the amount for the capacity payment would depend on the how much capacity is required before the in-service date

- The Upstream Connection Adder would be applied solely to the electricity bill, rather than being reflected in both the cost of new developments and the electricity bill like the Upstream Capacity Payment[17]

- The Upstream Connection Adder would be applied to ‘all’ *existing* customers before the facility goes into service, since it is a rate rider that would be in place before the *new* customers moved into the new development and began to consume electricity. The Upstream Capacity Payment would apply to ‘all’ *new* customers that benefit, with remainder of the cost recovered from ‘all’ *existing* customers until all of the capacity on the connection asset is utilized

[17] For the Upstream Capacity Payment, recovery through the electricity bill would be related to any ‘excess’ capacity.

Since the funds collected through the Upstream Connection Adder would only cover a *portion* of the capital contribution before the upstream asset goes into service, the capital contribution would ultimately be based on *actual* costs. The 'net' capital contribution would cover the outstanding actual cost.

The reason for proposing recovery of only a *portion* of the capital contribution in advance is to limit the extent that there may be a deviation from the beneficiary pays principle, as it would be applied to the bills of existing customers. When the connection asset goes into service, the Upstream Connection Adder would no longer be applied. The economic evaluation would then take into account the actual amount recovered through the Upstream Connection Adder to determine the 'net' remaining capital contribution. There may not be a material deviation from the beneficiary pays principle for the following reasons:

- Background studies prepared for determining municipal development charges that were reviewed by the OEB show a relatively material allocation to *existing* dwellings, where it involves 'hard' services like electricity infrastructure (e.g., water and sewage)
- From an electricity perspective, there may be a reliability-related benefit to existing consumers

The OEB notes both the OEB and distributors have experience with a similar approach, from a process perspective. An example is the funding adder for *Renewable Generation Connection and Smart Grid Development* expenditures which is described in the following guideline: "Deemed Conditions of Licence: Distribution System Planning"(G-2009-0087).[18] The OEB also approved funding adders in the past in relation to smart meters.

In the OEB guideline referred to above, it notes the following:

> Distributors who anticipate substantial expenses related to the qualifying renewable connection or smart grid development investments … may apply for a "Renewable Connection/Smart Grid Funding Adder"… a **tool to provide advance funding** [to the distributor] for these qualifying investments and activities and thus also **to mitigate the anticipated rate impact of the associated costs**. [emphasis added]

[18] www.oeb.ca/oeb/_Documents/EB-2009-0087/Dx_System_Planning_Guidelines_20090616.pdf

This approach also builds on the primary positive attributes associated with the other two approaches discussed above – Upstream Capacity Payment approach (i.e., advanced funding to reduce distributor borrowing requirements) and Annual Installment approach (i.e., smoothing cost recovery over time to mitigate bill impacts). Since this approach would reduce the amount of the capital contribution and associated distributor borrowing requirements, the OEB expects that it would also facilitate the implementation of regional infrastructure plans.

If this approach were to be adopted, the OEB would consider an application for an Upstream Connection Adder through a hearing. This type of application would need to be supported by a Distribution System Plan (DSP) and/or a RIP. The development of filing guidelines would also be necessary that are similar to those referenced above. The OEB expects that would be achieved through changes to the DSP filing guidelines.

Of the approaches discussed above, including the status quo, the OEB expects the advanced funding options would result in the lowest overall cost to consumers, since they would reduce financing costs. It would depend on the distributor’s circumstances and the design of those options in terms of which would result in the lowest overall cost. For example, where a distributor is experiencing high load growth in its service area, it should be the Upstream Capacity Payment approach that achieves that outcome. On the other hand, where there is little load growth (e.g., connection asset has become gradually overloaded over time), the Upstream Connection Adder approach should result in the lowest overall cost. The reason for those different outcomes is the revenues raised through the former are dependent on load growth, while the revenues associated with the latter approach are largely independent of load growth. The OEB expects most new connection investments will be necessary under scenarios involving material load growth. If that is the case, the Upstream Capacity Payment approach would result in the lowest cost option in most instances.

<u>OEB’s Proposed Approach</u>

The OEB has considered the pros and cons associated with all three approaches discussed above and is proposing to implement all of them to provide for flexibility and adaptability to different scenarios of development within distributor territories.

The OEB notes that the status quo (i.e., single lump sum payment) would remain an option for distributors and expects a number of distributors would continue to opt for that approach; particularly, the larger distributors.

Under the OEB's proposed approach, distributors would therefore have a suite of options to choose from that would best address their circumstances (e.g., high vs. low load growth).

The OEB is therefore proposing to amend the TSC by adding new section 6.3.19 which would require transmitters to accept the provision of the capital contribution by distributors in annual installments over a period of time of up to five years. As noted, where a distributor opted to provide installments, the distributor would be responsible for any associated financing costs. This is necessary to ensure the transmitter is not worse off (nor better off). The OEB is therefore also proposing to include in this new section a requirement for the transmitter to include financing costs (from the date the asset goes into service) in each installment payment. In doing so, the transmitter would be compensated in a timely manner for any financing costs that have accrued over the year. The OEB is proposing to use the prescribed construction work in progress (CWIP) rate, which reflects the Mid-Term Bond Index All Corporate yield, for this purpose.[19]

The OEB is also proposing amendments to the appendix in both the TSC and the DSC that addresses the "Methodology and Assumptions for an Economic Evaluation". That is, Appendix B in the DSC and Appendix 5 in the TSC. The proposed amendments would revise the Economic Evaluation methodology to take into account any revenues realized through the Advanced Funding approaches before the 'gross' capital contribution is due to be paid to the transmitter to determine the 'net' remaining capital contribution that needs to be financed. The purpose of these proposed Code amendments is therefore to *accommodate* these Advanced Funding approaches. A Code is not the appropriate regulatory instrument for *implementation* purposes, as a funding adder and a capacity charge involve a *rate.*

To that end, following the completion of this Code amendment process, the OEB will develop Filing Guidelines related to the Upstream Connection Adder and the Upstream Capacity Payment that are similar to those that have been issued in the past for funding adders (e.g., smart meters), if the proposed approach discussed above is adopted by the OEB. Once that process is completed, distributors would be able to apply for an Upstream Connection Adder or the Upstream Capacity Payment. The OEB would also update reporting and accounting guidance with respect to tracking the Upstream Capacity Payment amounts collected through expansions.

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[19] www.oeb.ca/industry/rules-codes-and-requirements/prescribed-interest-rates

The OEB acknowledges that this issue – requirement to provide a relatively large capital contribution in a single lump sum payment – can also impact large commercial (e.g., industrial) customers. However, the OEB is proposing that the financing mechanisms discussed above would only be made available to regulated distributors. The only approach that would seem to be viable for commercial customers is the Annual Installment approach. The OEB's primary concern is the non-payment risk associated with such customers paying the capital contribution over time. That risk would be shifted to all other customers of the distributor. The OEB also believes commercial customers differ from regulated distributors in a number of ways. For example, their additional capacity needs tend to be 'lumpier' in nature (e.g., due to a planned plant expansion). In contrast, distribution systems grow in an 'organic' fashion (e.g., new residential customers in new subdivisions connected).

To summarize, the OEB is proposing amendments to the TSC to *implement* the Annual Installments related to capital contributions. Further amendments are proposed to the Economic Evaluation appendices of the TSC and DSC to *accommodate* the *advanced funding options* – Upstream Connection Adder, Upstream Capacity Payment – as a capital contribution offset.

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

This section discusses the proposed code amendments that are intended to address inconsistencies between and gaps within the TSC and DSC.

A key consideration in assessing the need for alignment between the Codes in relation to the inconsistencies discussed below 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 DSC provides much more discretion to distributors than the TSC provides to transmitters within the context of allocating costs associated with connection asset investments. For example, in the TSC, it notes the transmitter "shall" require a capital contribution from load customers that cause the need for and benefit from a connection investment. In contrast, the DSC provides distributors with the discretion to recover such costs via a capital contribution from the load customer or through its revenue requirement (i.e., from all of its customers). There are a number of sections where that is the case.[20]

As discussed earlier, the evolution of the distribution system is resulting in it operating in a similar way to the transmission system. As a result, the OEB now believes the DSC needs to be revised to achieve greater consistency with the TSC to ensure that all customers are treated equitably (i.e. beneficiary pays), whether they are connected to the transmission or distribution system. With about 70 distributors in the province, the OEB also expects that some distributors are applying the beneficiary pays principle (i.e., requiring a capital contribution), while other distributors are not. To the extent that is the case, there is inconsistent treatment of load customers across the province.[21]

[20] Examples of that contrast between the Codes are set out below.

- Section 6.3.1 of **TSC**, it states *"… transmitter <u>shall require a capital contribution</u> from the load customer to cover the cost of a connection facility"*.
- Section 6.3.2 states "… transmitter <u>shall require</u> the load customer to make a <u>capital contribution</u> to cover the cost of the modification… "
- Section 3.2.4 of **DSC** states: "The <u>capital contribution</u> … a distributor <u>may charge</u> a customer …."
- Section 3.2.5 states "The <u>capital contribution</u> that a distributor <u>may charge</u> a generator …."

[21] The DSC includes a provision (s. 3.3.3) – Enhancements – that addresses where the OEB has determined cost recovery from all the distributor's customers is appropriate (i.e., capital contribution cannot be required). It relates to investments where the benefits accrue to all customers of the distributor.

The OEB is therefore proposing to amend the DSC to be consistent with the TSC by replacing “may” with “shall” in all sections of the DSC related to cost responsibility (including expansion deposit provisions). In doing so, it will ensure a consistent approach in relation to distributors allocating costs and therefore consistent treatment of all load customers in Ontario.

The OEB is not contemplating a broader review of the DSC at this time given the breadth of this consultation and potential unintended consequences of a wholesale change of sections throughout the DSC from “may” to “shall”.

Capital Contribution Refund / Rebate to Initial Customer(s)

Under the TSC, the initial load customer that requires a new or upgraded transmitter-owned connection asset must provide a capital contribution to the transmitter to fund it. Where there is excess capacity and it is assigned to a subsequent load customer that connects, they must also pay their share in the form of paying a capital contribution refund to the initial customer(s). The same approach is taken in the DSC except where the load customer is an embedded distributor. As noted earlier in this Notice, the host distributor currently cannot require a capital contribution from an embedded distributor and the OEB is proposing to change that.

Both Codes require a refund. However, there is an inconsistency between the TSC and DSC in terms of the timeframe for the refund requirement.

The TSC was amended, in 2013, to increase the timeframe from five (5) to 15 years for the transmitter to require a capital contribution from the subsequent customer(s) that are assigned capacity in order to provide the refund to the initial customer. That change was made due to ‘gaming’ concerns, as five years is a relatively short timeframe.[22]

Those gaming concerns are equally applicable at the distribution level. However, the timeframe currently remains at five years in the DSC. The OEB is therefore proposing to amend section 3.2.27 of the DSC to increase the timeframe to 15 years, subject to the threshold condition discussed below. This change would better align the DSC with the TSC, which the OEB believes is appropriate given the increasing similarity between the two systems.

[22] A distributor could make lower cost ‘*sub-optimal*’ investments until the five year threshold is met, to avoid providing a capital contribution for available capacity (AC) on a transmission connection facility. Once that five year timeline is met, they are assigned that AC at no cost (i.e., free) and the initial customer(s) is not compensated for that capacity. That outcome is incompatible with the OEB objectives for regional planning and two of the *Guiding Principles – Beneficiary Pays and Optimal Investment*.

The OEB notes that distributors have a much larger number of customers than transmitters and the majority are relatively small compared to those connected to the transmission system. It would therefore be a significant administrative burden for distributors to track all customers for 15 years and, for most, the refund would be immaterial.

The OEB therefore proposes that section 3.2.27 of the DSC be further amended to include a materiality threshold of 3 MW, where the 15 year timeframe would apply. For customers below that materiality threshold, the OEB proposes that the status quo of five (5) years would be maintained. This would include developers of residential subdivisions since none would remain for 15 years.

The OEB is also proposing to amend that section to make the DSC more user-friendly and clear for stakeholders by including the reference to 15 years directly in section 3.2.27 rather than referring to a separate document (Appendix B). As a result, references to the customer connection horizon “as defined in Appendix B” would be replaced with the number of years whether the timeframe is changed or not. The OEB is also proposing to add clarity by changing the various references to the *same* term (“parties”) to identify *different* types of customers – “generator” and “load”.

Due to the proposed changes above, there would also be a need to revise section 3.2.23 of the DSC and Appendix B. Section 3.2.23 sets out the process for returning the expansion deposit collected from customers in the case of a distribution system expansion. The annual calculation for returning the expansion deposit must be done for the duration of “the connection horizon as defined in Appendix B”. Since the OEB is proposing to amend section 3.2.27 to make specific reference to the applicable timeframes – rather than Appendix B – section 3.2.23 would similarly be amended to directly reflect the different number of years (five or 15) based on the proposed materiality threshold. This change would affect only new projects where a capital contribution is required after the date the DSC amendments come into force.

Appendix B defines a maximum customer connection horizon of five (5) years, calculated from the energization date of the facilities. It would similarly be amended to make a change that is consistent with section 3.2.27, as explained above. The TSC already references the timeframes directly in the applicable sections.

Capital Contribution True-Ups and Load Forecasts

One factor that contributes to the amount of a capital contribution that a customer must provide to a transmitter or a distributor is a load forecast. For example, if the load *forecast* is *higher* than the customer's *actual* load, the *capital contribution* would have been *too low* because the lower actual consumption results in a *shortfall* of *rate revenues* for the distributor. If the load forecast is too low, the outcome is the opposite.

As a consequence, the TSC includes true-up provisions to address this issue by ensuring the capital contribution reflects the customer's actual load and is therefore consistent with the beneficiary pays principle. This is particularly important where multiple customers are connected to the same connection facility and share the cost. The true-up requirements ensure all customers pay their fair share (i.e., one customer does not subsidize another). It also removes the inappropriate incentive to provide a higher load forecast in order to reduce the capital contribution that must be provided to the transmitter.

The DSC contains its own true-up mechanism in the form of an 'expansion deposit' as set out in sections 3.2.20 to 3.2.26. Section 3.2.20 currently states, for customer expansions that require a capital contribution, a distributor may require the customer to provide an expansion deposit for up to 100% of the present value (PV) of the forecasted revenues as described in Appendix B. For customer expansions that do *not* require a capital contribution, a distributor may require the customer to provide an expansion deposit for up to 100% of the PV of the projected capital costs and on-going maintenance costs of the expansion project.

The DSC permits the distributor to require an expansion deposit even where no capital contribution is required because the distributor can still be at risk if the customer does not deliver on the forecast revenue.[23] To cover the distributor's risk, the DSC permits them to require an expansion deposit, until it is demonstrated that the customer is going to deliver on the revenue. That said, since no capital contribution is required, the OEB considers the risk to be lower and is proposing to maintain "may" in this instance.

Section 3.2.23 provides direction related to how the distributor is to return the expansion deposit to the customer. The distributor must annually return a percentage in proportion to the actual connections (for residential developments) or actual demand (for

[23] There would be no capital contribution required because the customer is committing to a load forecast and an associated amount of revenue that is more than enough to cover all of the costs.

commercial and industrial developments) that materialized in that year (i.e., if 20% of forecasted connections or demand materialized in that year, the distributor is required to return 20% of the deposit). Currently, this annual calculation is only done for five years. As noted, the OEB is proposing to introduce a 3 MW materiality threshold. The return of the expansion deposit would therefore be extended to 15 years for those over that threshold.

The OEB is proposing to amend the sections of the DSC related to expansion deposits to be consistent with the TSC by replacing “may” with “shall”, except for the one instance noted above. This applies to sections 3.2.20 and 3.2.24. All other sections related to expansion deposits already use the term “shall”. This proposed amendment is consistent with the OEB’s view that there is a need for greater consistency between the DSC and TSC, given that distribution systems and transmission systems are becoming more similar in the nature.

Mix of load and generator customers on a connection asset

The TSC and the DSC are currently not consistent in their approach to cost responsibility in cases where a connection asset involves both load and generator customers.

In the TSC, costs are allocated based on a ‘trigger’ pays approach. For example, if a load customer connects first and a generator customer subsequently connects, the generator customer does *not pay* a capital contribution refund to the initial load customer (via the transmitter). On the other hand, if the subsequent customer was a load customer, they would be required to *pay* a refund to the initial load customer.

In contrast, in the DSC refund provision, costs are allocated based on the ‘beneficiary’ pays principle where a load customer connects first and a generator customer subsequently connects. In other words, regardless of the type of customer that subsequently connects, the DSC requires the provision of a capital contribution and the initial customer receives a refund. The ‘apportioned benefit’ is determined considering factors such as the relative *name-plate rated capacity* (generator customer) and the relative *load level* (load customer). The OEB believes this approach is more appropriate. The initial customer should be compensated for the capacity they paid for and do not need, regardless of what type of customer connects after them.

Given the OEB’s shift in emphasis from the ‘trigger’ pays to the ‘beneficiary’ pays approach in relation to cost responsibility, the OEB is proposing to amend section 6.16

of the TSC to be consistent with section 3.2.27 of the DSC. The OEB believes this proposed change to the TSC would achieve the following desirable outcomes:

- Better ensure that all transmission customers are treated the same (i.e., all beneficiaries pay)
- Eliminate the potential for cross-subsidization between load and generator customers
- Result in a consistent approach to cost responsibility between the TSC (transmission level) and DSC (distribution level) in this regard

The OEB is proposing to create new section 3.1.9 in the DSC, since section 3.2.27 is specific to refunds. Unlike the TSC, the DSC does not currently contemplate a scenario where load and generator customers connect at the same time to a new connection facility. This new section would combine the positive attributes of both sections – 3.2.27 (DSC) and 6.16 (TSC). For example, use the beneficiary pays approach in the DSC. On the other hand, the terminology in section 3.2.27 of the DSC refers to "*relative load level*" while the TSC is much more specific in referring to "*respective non-coincident incremental peak load requirements*" for apportioning costs. It is the "peak" load requirements that drive the need and size of the investment, and best reflects the relative benefits. The "relative load level" can also be interpreted differently by distributors (e.g., average, peak, etc.). The OEB is therefore also proposing to amend section 3.2.27 of the DSC to add "non-coincident peak" before "load". The OEB is proposing to replicate the proposed wording for the DSC in the TSC; i.e., current wording in section 6.1.6 would be replaced.

Under the OEB's proposed approach, the end result would be the same wording in both Codes.

Bypass Compensation

Under the TSC and the DSC, transmitters and distributors construct a load customer's connection facility based on the customer's load forecast. Where the load customer subsequently constructs its own connection facility to supply *existing* load before the utility-owned connection facility reaches its end-of-life, it is considered bypass because the dedicated connection asset becomes stranded. Unlike a shared network asset, a dedicated connection asset cannot be used by other customers. If the customer disconnects and does not compensate the utility for the bypass, the stranded cost must be borne by all of the other ratepayers in the connection pool that remain connected to the system of the utility. The customer that disconnected would be the only beneficiary but they would not pay.

Bypass compensation from a load customer to a transmitter is therefore required under section 6.7.7 of the TSC in certain circumstances to ensure all consumers are not required to pay the stranded cost when a load customer bypasses a transmitter-owned connection facility. Bypass compensation is calculated based on the remaining net book value (NBV) associated with the connection facility in the TSC. Where the NBV is zero, the connection facility is considered to be fully depreciated.

There is only one circumstance in the TSC where existing load can be shifted from a transmitter-owned connection asset *without* triggering bypass compensation to the transmitter; that is where the existing connection facility is *overloaded*, since overloading any facility reduces the economic efficiency of the transmission system and should be avoided. However, in such cases, only the overload portion of *existing* load does not constitute bypass.

The DSC is not consistent with the TSC. It does not require bypass compensation under any circumstances. The OEB believes that is a gap in the DSC that should be addressed. A key reason for that is related to changes in how the distribution system is being used. For many years, consumers were largely passive and the distribution system was used almost exclusively to deliver power to consumers. However, similar to the transmission system, consumers have recently become more active in terms of undertaking various measures that are resulting in customers of distributors reducing their use of the distribution system (i.e., distribution assets that were put in place to specifically serve them). As the distribution system evolves into an extension of the transmission system, the need for alignment between the DSC and TSC has become much more evident, in this regard.

During the Working Group process, some members expressed the view that a separate consultation process was necessary, in the future, to address this inconsistency. It was suggested this issue was too significant to include in this consultation.

The OEB is of the view that a separate consultation process is not required. Bypass compensation at the transmission level was addressed in the TSC, as part of broader consultation than this consultation process, and there were no bypass provisions in the OEB’s codes that could be leveraged to inform the added bypass provisions at that time. The bypass provisions in the TSC can now be leveraged to inform any DSC amendments.

The OEB is therefore proposing to add sections 3.5.1 and 3.5.3 to the DSC to identify the circumstances where bypass compensation should be required and to identify how it should be determined (i.e., based on NBV of bypassed capacity). The bypass provisions in the TSC have been used to amend the DSC.

The OEB is also proposing that the 3 MW materiality threshold would apply in relation to bypass compensation, for the same reason reasons discussed above.

Similar to the TSC, the OEB is not proposing that bypass compensation be provided to the distributor due to all actions that result in a load reduction. The OEB is therefore also proposing to add new section 3.5.2 to the DSC to specify the circumstances under which a customer of a distributor could take action to reduce the amount of electricity it withdraws from the distribution system *without* triggering the need to provide bypass compensation – *embedded renewable generation (e.g., rooftop solar), energy conservation, energy efficiency, or load management activities (e.g., net metering)*.

The OEB is not proposing any material changes to the provisions in the TSC related to bypass compensation. However, the OEB does see an opportunity to make the TSC more user-friendly for stakeholders. Bypass compensation is currently addressed in two separate sections of the TSC – section 6 and section 11. The OEB is proposing to consolidate all bypass compensation related provisions under section 11.2, which is entitled "Bypass Compensation". Current sections 6.7.5 to 6.7.11 would be moved to become new sections 11.4 to 11.10. Any changes to the wording would be limited to affected cross references between sections.

Except for cases where proposed section 3.5.2 would apply, the OEB is of the view that the customer that chooses to bypass and benefits from reduced or no distribution charges should be solely responsible for the related stranded costs – not all other consumers, who have no control over that decision and do not benefit. The OEB believes the proposed changes to the DSC set out above would achieve that outcome.

Relocation of Connection Assets

The DSC does not address cost responsibility where a distribution asset connecting a customer is relocated at the customer's request. Most distributors therefore have provisions in their Conditions of Service that require the customer to pay for relocation.

However, in some cases, it is the OEB's understanding that some distributors do not apply a relocation charge. In such cases, all customers of the distributor – not the requesting customer – are responsible for the cost. The OEB does not believe that outcome is appropriate.

Unlike the DSC, the TSC includes a section (6.7.3) that addresses this issue and identifies that the transmitter must recover the cost of relocating the connection facility solely from that requesting customer.

In order to achieve consistency between the DSC and the TSC and to ensure all customers in the province are treated the same, the OEB is proposing to add section 3.1.10 to the DSC that would achieve the same outcome as section 6.7.3 of the TSC; i.e., allocate the full cost of relocating a connection asset to the customer where the customer requested the relocation. That proposed change would eliminate the potential for the customer requesting the relocation to be subsidized by other consumers. The OEB is also proposing to add section 3.1.11 to clarify the customer does not pay where they do *not* request the relocation – the distributor pays.

Definition of "Customer"

The definition of "customer" is different in the TSC and the DSC. The definition in the DSC is less specific and could be interpreted differently for cost responsibility purposes. In particular, the TSC specifically refers to each type of customer – "*generator, consumer, distributor or unlicensed transmitter*" – whereas the DSC is more general in referring to "*a person*".

The OEB is proposing to amend the DSC to be more specific and clear like the TSC so that the definition of "customer" is not open to different interpretations. The OEB believes this will provide greater regulatory certainty to distributors and their customers, particularly within context of allocating costs.

Community desire for more than 'optimal' solution in regional plan – No mechanism in place to fund Local Choices

The IESO has established a local advisory committee (LAC) in each region where it has been determined that an Integrated Regional Resource Plan (IRRP) is required. LACs are comprised of stakeholders from the affected local community. One purpose of the LACs is to provide input related to the local preferences in terms of the solution to meet a regional need.

As a consequence, there may be instances where a community desires a ‘premium’ solution that is *preferred*, but is *not necessary* (i.e., higher cost than the ‘optimal’ solution). For example, the undergrounding of transmission wires for only *aesthetic* reasons. Currently, neither code (TSC or DSC) addresses how costs should be allocated in relation to such ‘premium’ wires solutions. Some members of the Working Group expressed the view that this represents a gap in the Codes that should be addressed.

The OEB believes that, where such an unnecessary premium wires solutions is desired, the incremental cost of the investment should be funded through other means, rather than through distribution rates (e.g., by the municipal shareholder through municipal property taxes similar to the approach recently used in Ottawa). This approach is consistent with the optimal infrastructure solution principle discussed above, as the ‘premium’ solution would not be the ‘optimal’ solution identified in the regional infrastructure plan.

While the OEB is of the view that only the cost associated with the ‘optimal’ wires solution (as identified in a regional plan) should be recoverable in rates, the OEB considers that the issue identified by the Working Group should be addressed on a case by case basis, in an adjudicative process, rather than through a change to the Codes. The distributor or transmitter would need to justify any proposed investment that deviates from the optimal solution identified in the regional infrastructure plan as part of a rate or LTC application.

The LAC preference may be DG and/or CDM, in some cases. Those alternative solutions are discussed in the next section of this Notice under “None-Wires Solutions”.

<u>**Out of Scope**</u>

Non-Wires Solutions – No Mechanism for Local Cost Recovery

An issue raised during the Working Group process is that the costs associated with *wires* (i.e., distribution solutions) are recovered *locally* through the distribution rate approved by the OEB. On the other hand, it was suggested that where a *non-wires* option (e.g. distributed generation or CDM) represents the optimal solution, there is no mechanism to similarly allocate costs locally (via distribution rates) to the same group of customers in relation to much of the generation that is procured in Ontario.[24]

[24] Instead, it is recovered provincially (i.e., allocated to all consumers) through the Global Adjustment charge.

The OEB notes that there is a mechanism in place in relation to some non-wires options where they defer the need for wires investments; specifically, in 2014, the OEB made changes to its CDM Guidelines which provides distributors with the ability to fund certain non-wires investments (e.g., storage, eligible generation) in distribution rates.[25] However, the OEB has not yet received an application from a distributor to include such generation in rate base.

The OEB believes the most cost effective solution in a regional plan should be implemented regardless of the 'type' of solution (i.e., wires or non-wires). That is one of the reasons for the above noted change to the CDM Guidelines and the OEB's intent to further consider this issue as part of a separate initiative to implement optimal investment planning decisions by distributors and transmitters. That future initiative is intended to assess the need for regulatory reforms which support the evolution of the sector (e.g., technological innovation).[26]

C. Anticipated Costs and Benefits

The OEB believes the Code amendments set out in this Notice will result in benefits that exceed any additional costs.

The OEB expects that aligning the cost responsibility provisions in the Codes and addressing the gaps that have been identified will achieve the following beneficial outcomes:

- Ensure that transmitters and distributors have clear and common requirements for allocating costs
- Better align with the beneficiary pays principle which would ensure that all beneficiaries pay their fair share of connection investments
- More consistent treatment of consumers and distributors across the province
- Reduce the potential for cross-subsidization by non-beneficiaries
- Facilitate new technological developments by recognizing that distribution systems are evolving and becoming more dynamic (i.e., no longer limited to delivering electricity to consumers)

[25] Guidelines for Electricity Distributor CDM (EB-2014-0278), section 4.1 (Applications for Rate-Funded Activities to Defer Distribution Infrastructure), p.4 – 6.
[26] This future initiative is discussed in the OEB's Business Plan (2017-2020).

- Ensure that embedded distributors and large consumers connected to the distribution system are accountable for the costs related to upstream transmission connection investments they contribute to and benefit from
- Enhance cost discipline among distributors and transmitters
- Enhance regulatory predictability, which is particularly important within the context of large capital investments

The OEB also believes the proposed Code amendments associated with addressing the ‘lumpy’ connection investment and related ‘affordability’ issue will result in the following benefits:

- Facilitate the implementation of regional infrastructure plans and therefore the most cost effective wires investments
- Recovery of large capital contributions would be smoothed over time to reduce consumer bill impacts, to the extent distributors adopted the smoothing mechanisms
- The above would result in lower electricity bills for consumers

The OEB expects that some of the proposed amendments to the TSC and the DSC, particularly those related to capital contribution true-ups and extending the capital contribution refund period (for some customers) in the DSC, will result in distributors incurring additional administrative costs. The OEB expects the magnitude of such costs will differ across distributors. It will depend on how many customers they have that exceed the 3 MW materiality threshold.

The proportional benefit approach to apportioning some costs to the network pool would also impose new costs on all Ontario ratepayers. For example, Hydro One proposed apportioning $22.5 million in costs to all Ontario ratepayers in its SECTR application. As discussed above, under the status quo, all costs associated with transmission connection investments can only be recovered from the specific customers that caused the need for the connection investment; i.e., no allocation to all ratepayers.[27]

[27] The total estimated SECTR project cost was $77.4 million. It did not exceed the needs of the customers that caused the need for the project. It is also uncertain if that load restoration need would have been addressed in isolation at a total cost of $22.5 million. The triggering customers would be responsible for the full cost ($77.4 million) under the existing cost responsibility rules. All of the cost estimates can be found in IESO’s (then OPA) supporting evidence – *Recommended Cost Allocation Treatment for the [SECTR] project (page 9)* – included in Hydro One’s SECTR application.

D. Coming into Force

The OEB proposes that the proposed amendments to the TSC and the DSC, as set out in Attachments A and B, 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.

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 proposed TSC and DSC amendments in this Notice. Cost awards will be available to a **maximum of 20 hours** per eligible participant.

The OEB's January 7, 2016 letter noted that the OEB would determine later how costs will be apportioned. The OEB has now determined that costs will be recovered from all rate-regulated licensed electricity distributors (65% of the costs awarded) and all rate-regulated licensed transmitters (35% of the costs awarded). Within the distributor class, costs awarded will be apportioned based on respective customer numbers. Within the transmitter class, apportionment will be based on respective revenues (using the most recent three year average from their audited financial statements or similar documentation).

Attachment C contains important information regarding cost awards for this Notice and comment process, including in relation to eligibility requests and objections. The deadlines for filing cost eligibility requests and objections will be strictly enforced to facilitate a timely decision on cost eligibility.

F. Invitation to Comment

Anyone interested in providing written comments on the proposed TSC and DSC amendments in Attachments A and B are invited to submit them by **October 23, 2017**.

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 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 proposed TSC and DSC amendments in Attachments A and B, 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 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, **September 21, 2017**

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Attachments:

Attachment A — Proposed Amendments to the Transmission System Code
Attachment B — Proposed Amendments to the Distribution System Code
Attachment C — Cost Awards

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

September 21, 2017

EB-2016-0003

Proposed Amendments to the Transmission System Code

Note: Underlined text indicates proposed additions to the Transmission System Code and strikethrough text indicates proposed deletions from the Transmission System Code. Numbered titles are included for convenience of reference only.

[see separate document attached]

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

September 21, 2017

EB-2016-0003

Proposed Amendments to the Distribution System Code

Note: Underlined text indicates proposed additions to the Distribution System Code and strikethrough text indicates proposed deletions from the Distribution System Code. Numbered titles are included for convenience of reference only.

[see separate document attached]

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

September 21, 2017

EB-2016-0003

Cost Awards

Cost Award Eligibility

The OEB will determine eligibility for cost awards in accordance with its *Practice Direction on Cost Awards*. Any participant in this process intending to request cost awards (and has not already been determined eligible for cost awards in the OEB's Decision issued on June 13, 2016) must file a written submission with the OEB by **October 2, 2017,** identifying the nature of their interest in this process and the grounds on which they are eligible for cost awards (addressing the OEB's cost eligibility criteria in section 3 of the OEB's *Practice Direction on Cost Awards*). An explanation of any other funding to which the participant has access must also be provided, as should the name and credentials of any lawyer, analyst or consultant that the person intends to retain, if known. All requests for cost eligibility will be posted on the OEB website.

Licensed electricity distributors and licensed electricity transmitters will be provided with an opportunity to object to any of the requests for cost award eligibility. If an electricity distributor or transmitter has any objections to any of the cost eligibility requests, those objections must be filed with the OEB by **October 12, 2017**. Any objections will be posted on the OEB website. The OEB will then make a final determination on the cost eligibility of the requesting participants.

Eligible Activities

Cost awards will be available in relation to providing comments on the proposed TSC and DSC amendments in Attachments A and B, to a **maximum of 20 hours.**

Cost Awards

The OEB will apply the principles in section 5 of its *Practice Direction on Cost Awards,* when determining the amount of the cost awards. The maximum hourly rates in the OEB's Cost Awards Tariff will also be applied. The OEB expects that groups representing the same interests or same type of participant will make every effort to communicate and co-ordinate their participation in this process. Cost awards are made available on a per eligible participant basis, regardless of the number of professional advisors that an eligible participant may wish to retain.

The OEB will use the process in section 12 of its *Practice Direction on Cost Awards* to implement the payment of the cost awards; i.e., the OEB will act as a clearing house for all cost award payments in this process. For more information on this process, please see the OEB's *Practice Direction on Cost Awards* and the October 27, 2005 letter regarding the rationale for the OEB acting as a clearing house for the cost award payments. These documents can be found on the OEB website at www.oeb.ca on the "Rules, Codes, Guidelines & Forms" webpage.