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BY EMAIL AND WEB POSTING

December 18, 2018

NOTICE OF AMENDMENTS TO CODES TO FACILITATE REGIONAL PLANNING

AMENDMENTS TO THE TRANSMISSION SYSTEM CODE AND THE DISTRIBUTION SYSTEM CODE

AND

NOTICE OF PROPOSAL TO AMEND A CODE

SUPPLEMENTAL PROPOSED AMENDMENT TO THE DISTRIBUTION SYSTEM CODE

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) has issued amendments to the Transmission System Code (TSC) and the Distribution System Code (DSC) pursuant to section 70.2 of the Ontario Energy Board Act, 1998 (Act), as described in section B.

The OEB is also giving notice of a supplemental proposed amendment to the DSC pursuant to section 70.2 of the Act, as described in section C.

A. Background

On September 31, 2017, the OEB issued a Notice of Proposal to Amend a Code (September Notice) in which it proposed a number of amendments to the DSC and TSC

(September Proposed Amendments) that were aimed at ensuring the cost responsibility provisions for load customers in those Codes are aligned and facilitate the implementation of regional plans.

On August 23, 2018, after considering stakeholder feedback on the September Proposed Amendments, the OEB issued a Notice of Revised Proposal to Amend a Code (August Notice) in which it proposed revisions to the September Proposed Amendments (August Revised Proposed Amendments). Under the August Revised Proposed Amendments:

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

- A capital contribution would be required from embedded distributors and *large* commercial and industrial (C&I) load customers of distributors, where they cause and benefit from investments in upstream transmission connection facilities, based on their *incremental* load requirements. A new threshold would apply for determining what size of load constitutes a large C&I load customer and that threshold would be based on non-coincident peak demand that meets or exceeds 5 MW

- Where a connection asset requires replacement at its end-of-life (EOL), the Codes would be modernized to reflect that wires replacement would need to be determined to be the optimal solution. Where that is the case, cost apportionment between a load customer and all ratepayers[1] would differ based on the circumstances as follows:

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

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

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

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

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

- Where a distributor is required to pay a large lump sum capital contribution to a transmitter in relation to a transmission connection investment, the distributor would be permitted to spread the cost by providing the capital contribution in installments over five years (or longer, with OEB approval)

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

Written comments on the August Revised Proposed Amendments were received from 12 participants involved in this consultation, including the Independent Electricity System Operator (IESO) and representatives of business and residential consumers, a transmitter, distributors, and a residential subdivision developer.

B. Adoption of August Revised Proposed Amendments with Minor Revisions

The comments received from stakeholders generally supported the August Revised Proposed Amendments, although a number of stakeholders suggested the need for certain clarifications and some relatively minor changes. Distributors also provided some suggestions related to implementation of the changes to the Codes after the final amendments are issued.

The OEB has considered the comments received in response to the August Notice and has determined that no material changes are required to the August Revised Proposed Amendments. In light of the comments, however, the OEB has made four minor revisions to the August Revised Proposed Amendments as described below. The OEB is adopting the August Revised Proposed Amendments with those revisions (Final Amendments). Implementation issues identified by distributors are also discussed below under “Coming Into Force”.

The Final Amendments to the TSC and the DSC, as adopted by the OEB, are set out in Attachments A and B to this Notice, respectively. Attachments C and D to this Notice set out, for information purposes only, a comparison version showing the revisions made to the current Codes as reflected in the Final Amendments.

1. *Revisions to the August Revised Proposed Amendments*

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

Upstream Transmission Investments – Capital Contributions

With increased clarity that the capital contribution will be limited to a customer's *incremental* load, a representative of large C&I customers appears to have become more accepting of this requirement in noting that where a “load must pay more without any change in its own consumption appears inherently unfair. So long as [incremental load] remains the sole criterion for defining beneficiaries, there should be little risk that non-benefiting customers will be unfairly assigned cost.” A few stakeholders, primarily some distributors, again expressed concerns that focused predominantly on the negative impact on large load customers and, in turn, economic development in relation to requiring a capital contribution from large load customers within the distribution system based on their *incremental* capacity needs where they cause and benefit from an upstream transmission connection investment.[2]

The OEB remains of the view that beneficiaries should be required to pay the capital contribution whether they are connected to the distribution or transmission system. The OEB agrees that it is inherently unfair for non-beneficiaries (i.e., customers of the distributor that is directly connected to the transmission system) to subsidize the beneficiaries connected to the distribution system.

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

Upstream Transmission Investments – Capital Contribution True-ups

As noted in the August Notice, the same economic evaluation methodology – transmission discounted cash flow (DCF) in the TSC – will be used for all capital contribution calculations related to the same upstream transmission asset and the same entity (i.e., the transmitter) should do it on behalf of all distributors and large distribution-connected customers. The transmitter would undertake the calculation of the capital contribution for each beneficiary connected to the distributor at the request of a host distributor.

Clarification was requested from a transmitter that the transmitter would also carry out the associated capital contribution *true-ups* that follow the determination of the initial capital contribution. That was the OEB's intent in order to ensure the following outcomes:

- The same entity is responsible for determining the initial capital contributions and the subsequent related true-ups
- Payment is based on *actual* consumption – not the initial load *forecast*
- Alignment with the treatment of transmission-connected distributors and industrial customers

The OEB has therefore further amended section 6.3.20 of the TSC to clarify that the transmitter will be responsible for the calculation of both the initial capital contribution and subsequent related *true-ups*.

Replacement of End-of-Life Transmission and Distribution Connection Assets (section 6.7.2 of TSC, new section 3.1.7 in DSC)

"Right-sizing" to Lower Capacity

Most of the written comments related to end-of-life (EOL) assets continued to focus primarily on the added scenario where a connection asset would be *right-sized* to a *lower* capacity and the OEB included an expectation in the September Notice for transmitters and distributors to right-size, where appropriate, based on utility judgment and consultation with affected customers. While there is increased acceptance that some utility judgment is required, stakeholders expressed the view that some form of further action by the OEB was needed to address the financial incentives for transmitters and distributors not to downsize.

The OEB shares those concerns. As a consequence, the OEB plans to address this issue (i.e., utility incentives to increase rate base) within a broader context. As set out in the OEB's *Strategic Blueprint*, an OEB objective is to change the regulatory framework so it "incents utilities to focus on long-term value for money and least-cost solutions" by changing the approach to remunerating utilities.[3]

ADDRESSING INCONSISTENCIES AND GAPS BETWEEN THE TSC AND DSC

As noted in the August Notice, another purpose of these Code amendments is to address inconsistencies between the TSC and DSC. A key consideration in assessing the need for greater alignment between the Codes is the evolution of the distribution system, as the functions it performs are becoming more similar to those of the transmission system (e.g., many generators connecting, two-way flows on the system, customers becoming more active, etc.).

i) Utility Discretion – Cost Responsibility Code Provisions

The OEB expressed the view, in the August Notice, that the DSC provides distributors with considerable discretion relative to the TSC in relation to cost responsibility. The DSC presently states a distributor "may" *either* recover the costs via a capital contribution from a load customer that causes the need for a distribution investment (i.e., beneficiary pays) *or* recover the costs from all of its customers through its revenue requirement (i.e., non-beneficiary pays). The OEB therefore proposed to remove the latter option by replacing "may" with "shall" for several reasons – to better align with the TSC due to the evolution of the distribution system, ensure the beneficiary pays principle is applied and also achieve more consistent treatment of all load customers across all 67 distributors.

Some distributors continue to object to the removal of that discretion for the same reasons explained in the August Notice.

The OEB remains of the view these changes are necessary due to the distribution system evolving to be more like the transmission system. The OEB also remains concerned that the cost responsibility rules in the DSC would be applied differently across distributors if "may" was retained. In other words, a consumer's cost responsibility would depend on which distributor served them.

[3] OEB's Strategic Blueprint: Keeping Pace with an Evolving Energy Sector, page 11.

The OEB is therefore making the change from “may” to “shall” as reflected in the August Revised Proposed Amendments, except in two sections of the DSC, as discussed below.

In relation to section 3.1.5 of the DSC, the OEB has reconsidered the change from “may” to “shall”. That section contemplates distributors defining a basic connection for each *non-residential* customer rate class and recovering the cost of connection through its revenue requirement or a basic connection charge.

For residential customers, defining a basic connection is relatively straightforward as residential customers have connections that are similar in nature. On the other hand, for most distributors, the types of connections for non-residential customers vary significantly, which would make defining a ‘basic’ connection a challenge. The OEB is also of the view that, for large customers, an economic evaluation based on the specific circumstances of the customer will be more precise and therefore better reflect the beneficiary pays principle. The OEB has therefore decided to maintain distributor discretion in relation to this provision by retaining the term “may”. [4]

ii) Expansion Deposit Refunds (section 3.2.23 of the DSC)

In the August Notice, the OEB proposed to amend the sections of the DSC related to expansion deposits to be consistent with the TSC by making an expansion deposit a requirement (i.e., replacing “may” with “shall”), but only where a capital contribution is required. The expansion deposit would be returned over a period of up to five years.

The OEB remains of the view that distributor discretion to require an expansion deposit should be removed (where a capital contribution is required), as non-beneficiaries should not bear the risk of non-payment.

There also appeared to be some confusion in some of the stakeholder comments that the distributor is required to retain some portion of the expansion deposit for the full five-year period. The OEB notes that is not the intent under section 3.2.23 of the DSC. For example, if 100% of the customer’s forecast demand has materialized by the end of the second year, the distributor should be returning the entire expansion deposit at that time.

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[4] While section 3.2.20 was amended to change “may” to “shall” in relation to a distributor requiring an expansion deposit where a capital contribution is required, the OEB also maintained distributor discretion (i.e., retained “may”) where a capital contribution is <u>not</u> required.

iii) Bypass Compensation (new section 3.5.3 of DSC, section 11.2.3 of TSC)

In the August Revised Proposed Amendments, the OEB proposed including bypass compensation provisions in the DSC in a manner that is consistent with the TSC to address both *full* and *partial* bypass. The OEB is of the view this change is necessary to ensure all customers of a distributor are not required to pay the stranded cost associated with the bypassed assets when an individual load customer chooses to bypass a distributor-owned facility that was built to meet that customer's needs.

Two issues were identified in the comments, which are discussed below.

Potential Gaming Issue

A transmitter raised a concern related to customers with substantial variations in load within the context of how bypass compensation is calculated (that is, based on the customer's average peak load over the most recent three months following bypass). The transmitter provided an example of an actual customer's peak demand, which ranges from about 300 kW for 6½ months out of the year to about 6 MW for 5½ months. As a result, if such a customer is planning to bypass the system, there is a strong incentive to do so when their peak demand falls to 300 kW, as it would result in a 20-fold reduction in bypass compensation.

The OEB is of the view that a relatively minor change to the way bypass compensation is calculated is appropriate to address this potential 'gaming' issue, as the system needs to be built to accommodate a customer's peak demand (i.e., 6 MW). The OEB will retain a three-month period; however, rather than the *most recent* three months, the highest three-month *rolling average* of non-coincident peak demand over the *most recent 12 months* will be used.

Three years was suggested for the rolling average, however, no rationale was provided for extending it over such a long period. The OEB is of the view that one year is appropriate since the issue relates to variations within a year. In addition, where calculations over a period of time are required in OEB Codes, an annual calculation tends to be the norm.

The approach discussed above will better ensure the customer will pay an amount that is more representative of the actual capacity they have historically required (i.e., beneficiary pays). In doing so, it will better ensure all other customers of the transmitter or distributor will not be negatively impacted due to bypass. Section 11.2.6 (of the TSC) and section 3.5.3 (of the DSC) will be amended to reflect this revision.

Clarification Requested

A transmitter identified that, in some cases, where a customer of a distributor bypasses a distribution asset, that customer will also bypass a transmission asset. A transmitter requested clarification that the transmitter can recover bypass compensation through the distributor where that occurs.

The OEB is of the view that a customer should provide bypass compensation in relation to all utility assets they have historically relied on to be supplied and then choose to bypass. Since only the distributor can bill the customer, it is appropriate for the transmitter to recover bypass compensation through the distributor. The OEB is of the view that this clarification does not require a code amendment.

That said, the transmitter will need to demonstrate that the customer also bypassed a transmission facility. The OEB notes that bypass of a distribution asset does not automatically mean a transmission asset has also been bypassed.

Relationship to Capacity Reserve Charge (CRC)

As noted in the August Notice, the OEB will clarify the relationship between the bypass compensation charge and the capacity reserve charge (CRC), once the OEB has reached a conclusion on the CRC as part of the C&I policy consultation on rate design.[5]

Other Code Amendments

In the August Notice, the OEB agreed with the suggestion to move the proposed new provision on upstream transmission connections (originally numbered 3.2.4A in the September Proposed Amendments) to a new, separate section of the DSC that is dedicated to upstream transmission connection assets. Accordingly, 3.2.4A has been renumbered as section 3.6.1, and will fall under the heading “Upstream Transmission Connections”. This will separate the cost responsibility rules related to *distribution expansions* (section 3.2) and *transmission connection* investments.

[5] EB-2015-0043.

The OEB also made some other non-substantive housekeeping changes to clarify the intent of the related Code amendments.[6] Those changes are identified (i.e., highlighted) in Attachments C and D.

2. *Anticipated Costs and Benefits*

The anticipated costs and benefits associated with the Final Code Amendments are primarily set out in the September Notice and the August Notice. Interested parties should refer to those Notices for further information in that regard.

The OEB believes that the revisions made to the August Revised Proposed Amendments, as described above in this Notice, will not result in material incremental costs to distributors, transmitters or ratepayers and will provide the following benefits:

- The revision to the bypass compensation provision will protect ratepayers from a consumer shifting the costs associated with a stranded asset due to gaming and therefore result in better alignment with the beneficiary pay principle

- The change from “shall” to “may” in relation to creating a basic connection for each non-residential rate class will avoid administrative costs for distributors

- The clarifications provided should increase regulatory predictability for transmitters and distributors

3. *Coming into Force*

All of the submissions from distributors suggested there was a need for a transition period before the DSC amendments come into force. However, few reasons were provided and only one submission included a suggested timeline, which was when the IESO’s Market Renewal project is implemented. The OEB is of the view that waiting until Market Renewal is implemented is unreasonable, as that is currently expected to be in 2023. Two groups of distributors also raised questions about the application of the Code amendments to the Supply to Essex County Transmission Reinforcement (SECTR) project.[7]

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[6] For example, “host” distributor was previously used in section 6.3.20 of the TSC. However, the intent was to capture all distributors that are directly connected to the transmission system and not all such distributors are also connected to an embedded distributor. The term “host” was therefore replaced with “transmission-connected” distributor to achieve the intent.
[7] EB-2013-0421.

Reasons provided by distributors in relation to why they felt a transition period was necessary included the need to communicate the changes to large customers (5 MW) and embedded distributors who will be affected by a number of changes, and distributors will need to revise their Conditions of Service to reflect the amendments to the DSC.

The OEB notes this has been an extensive consultation process and it has been relatively clear what the OEB was planning to change in the Codes. AMPCO and other C&I customer representatives, such as Canadian Manufacturers and Exporters, have been engaged throughout this consultation process and the OEB expects their members have been informed. The materiality threshold was also increased to 5 MW, so the number of customers that are impacted is limited, and it is only a subset of those customers that are contemplating an increase in load that will be affected by the changes. The OEB also expects that embedded distributors, who may be affected by changes in cost responsibility, should have been following this consultation. Therefore, it is the OEB's view that distributors should be able to inform their customers in a relatively short time. The OEB also has 'gaming' concerns associated with delaying certain DSC changes such as the new Bypass Compensation and Capital Contribution requirements. Given the benefits that will come from greater predictability and consistency in relation to cost responsibility and the fact that transmitters, distributors and the affected customers have had considerable knowledge of the planned changes, the implementation of the Code amendments should not be delayed.

The only change that may have a material impact on computer information systems (CIS) is related to the rule changes for expansion deposits due to the broader group of customers for which collections and refunds will be required. The OEB will therefore provide distributors with three months to implement the expansion deposit related DSC amendments because of those CIS changes.

The OEB will also provide distributors with six months to revise their Conditions of Service. However, the OEB notes that, as the revisions to their Conditions of Service will reflect the amendments to the DSC, distributors will be expected to implement the DSC amendments before a revised Conditions of Service is issued in all cases where there is a new customer connection or increase in a load (i.e., expansion) for a customer above the 5 MW threshold.

As a result, with the exception of the DSC amendments related to expansion deposits, all of the final amendments to the TSC and the DSC, as set out in Attachments A and B, will 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. The amendments will apply on a go forward basis to all new projects (i.e., a signed agreement addressing cost responsibility has not yet been executed).[8]

C. <u>Supplemental Proposed Amendment to the Distribution System Code</u>

1. *Proposal to Revise Section 3.2.4 of the DSC*

Upstream Transmission Connection Investments – Treatment of Residential Subdivision Developers

The issue discussed below was not raised in the comments that were received. It was identified by OEB staff in responding to an Industry Relations Enquiry (IRE) and is related to residential developers within the context of upstream transmission investments and the requirement to provide a capital contribution.

For upstream transmission investments, under new section 3.6.1 (formerly section 3.2.4A) of the DSC, the requirement to provide a capital contribution has been focused on large C&I customers throughout this consultation, from the initial stage involving the working group. The focus of most of the discussion during the consultation process has been related to what MW threshold to use to determine which customers should be considered a large customer, for cost responsibility purposes, under the DSC. In that regard, the OEB decided on a 5 MW threshold, which was broadly supported. At the same time, residential developers have always paid a capital contribution in relation to distribution expansions under section 3.2.4 of the DSC.

Section 3.6.1 applies where the upstream *transmission* investment involves a transmitter-owned facility (e.g., transformation station) and developers would not pay a capital contribution (unless that section was to be broadened to also apply to residential developers). The new issue arises where a distributor owns the upstream *transmission* asset (e.g., the transformation station). Where that is the case, it becomes a <u>deemed</u> *distribution* asset and would therefore be considered a distribution expansion under

[8] Terminology tends to differ at the transmission and distribution level. For distributors, it is the Connection Agreement. For transmitters, it is typically referred to as the Connection Cost Recovery Agreement (CCRA).

existing section 3.2.4 of the DSC. As noted above, under that section, residential developers typically pay a capital contribution.

The OEB has concluded there is a need to propose this supplemental DSC amendment because the OEB is of the view that it would not be appropriate to have *different* cost responsibility rules for residential developers under the *same* Code depending solely on what type of utility owns the *same* asset. In other words, 'who owns' the asset should not be the determinant of 'who pays' as set out below:

- Distributor-owned (developer pays) under section 3.2.4
- Transmitter-owned (developer does not pay) under section 3.6.1

The OEB considered two options to address this issue:

- Revise new section 3.6.1 to also apply to residential developers (as well as large customers)
- Revise existing section 3.2.4 to exempt residential developers from paying a capital contribution where the distribution expansion is an upstream transmission asset that has been deemed to be a distribution asset

The OEB is proposing the latter option above (i.e., exemption) because it aligns with the OEB's intent to date, as set out in the two previous OEB's Notices; that is, only large C&I customers within the distribution system should pay a capital contribution in relation to upstream transmission investments. The alternative – broadening section 3.6.1 to apply to residential developers – would deviate from that C&I customer focus, and the OEB expects that the developer will ultimately pass through most or all of the costs to residential consumers.

The OEB views this as a clarification to achieve alignment with new section 3.6.1 (i.e., only large C&I customers pay). The OEB is therefore proposing to amend section 3.2.4 to exempt residential developers from paying a capital contribution, where the *distribution expansion* involves an upstream *transmission* asset that has been *deemed* to be a *distribution* asset.

2. *Anticipated Costs and Benefits*

The primary anticipated benefit associated with the Proposed Supplemental Amendment is to ensure residential developers receive consistent treatment in relation to cost responsibility regardless of which utility owns the asset. It may also avoid confusion among developers where they could be required to pay a capital contribution within the service area of one distributor and not in another distributor's service area and/or avoid investment decisions being made by developers based on that confusion (i.e., assumed no capital contribution due to prior experience).

The OEB does not anticipate any incremental costs. The Proposed Supplemental Amendment may avoid administrative costs for distributors in applying two different cost responsibility rules and customer service representatives addressing any developer confusion that may arise as discussed above.

3. *Coming Into Force*

The OEB proposes that the Supplemental Proposed Amendment to the DSC, as set out in Attachment E, come into force on the date that the final DSC amendment is published on the OEB's website after having been made by the OEB.

4. *Cost Awards*

The OEB will not be awarding costs for the purpose of commenting on the Proposed Supplemental Amendment to the DSC.

5. *Invitation to Comment*

Anyone interested in providing written comments on the Supplemental Proposed Amendment to the DSC is invited to submit them by **January 9, 2019**.

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 Final Amendments to the TSC and DSC set out in Attachments A and B, respectively, and the Supplemental Proposed Amendment to the DSC set out in Attachment E (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 Final Code Amendments or the Supplemental Proposed Amendment to the DSC, as 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, **December 18, 2018**

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Attachments:

Attachment A: Final Amendments to the Transmission System Code
Attachment B: Final Amendments to the Distribution System Code
Attachment C: Comparison Version of Final Amendments relative to the current Transmission System Code
Attachment D: Comparison Version of Final Amendments relative to the current Distribution System Code
Attachment E: Supplemental Proposed Amendment to the Distribution System Code

Attachment A
to
Notice of Amendments to Codes and Notice of Proposal to Amend a Code

December 18, 2018

EB-2016-0003

Final Amendments to the Transmission System Code

[see separate document attached]

Attachment B
to
Notice of Amendments to Codes and Notice of Proposal to Amend a Code

December 18, 2018

EB-2016-0003

Final Amendments to the Distribution System Code

[see separate document attached]

Attachment C
to
Notice of Amendments to Codes and Notice of Proposal to Amend a Code

December 18, 2018

EB-2016-0003

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

Note: This attachment consolidates all three sets of amendments relative to the current Transmission System Code, with yellow shading indicating the initial revisions to the original September Proposed Amendments and grey shading indicating the final revisions set out in this Notice. Underlined text indicates additions and strikethrough text indicates deletions. Numbered titles are included for convenience of reference only.

[see separate document attached]

Attachment D
to
Notice of Amendments to Codes and Notice of Proposal to Amend a Code

December 18, 2018

EB-2016-0003

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

This attachment consolidates all three sets of amendments relative to the current Distribution System Code, with yellow shading indicating the initial revisions to the original September Proposed Amendments and grey shading indicating the final revisions set out in this Notice. Underlined text indicates additions and strikethrough text indicates deletions. Numbered titles are included for convenience of reference only.

[see separate document attached]

Attachment E
to
Notice of Amendments to Codes and Notice of Proposal to Amend a Code

December 18, 2018

EB-2016-0003

Note: This attachment sets out the proposed amendments relative to the current Distribution System Code. Underlined text indicates proposed additions and strikethrough text indicates proposed deletions. Numbered titles are included for convenience of reference only.

Supplemental Proposed Amendment to the Distribution System Code

[see separate document attached]