EB-2010-0229

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*;

AND IN THE MATTER OF an application by Hydro One Networks Inc. for an Order or Orders approving exemptions to certain sections of the Distribution System Code

BOARD STAFF SUBMISSION

I INTRODUCTION

This is the Written Argument of Board Staff in the application by Hydro One Networks Inc. ("Hydro One") to the Ontario Energy Board (the "Board") making specific requests to address the costs associated with the mitigation of certain technical issues described in Part A[1] of its application and for an order or orders approving exemptions to certain sections of the Distribution System Code ("DSC") to address specific issues described in Part B[2] of its application that are related to the connection and capacity allocation process for certain large generators that have applied to connect to Hydro One's distribution system.

II BACKGROUND

Hydro One filed an application dated June 30, 2010, with the Board under section 74 of the *Ontario Energy Board Act, 1998* (the "Act") for an order of the Board amending Hydro One's electricity distribution licence (ED-2003-0043) to allow exemptions from certain sections of the DSC.

The Board issued a Notice of Application and Hearing on July 30, 2010. Intervention requests were filed by Energy Probe, the Association of Power Producers of Ontario ("APPrO"), the Independent Electricity System Operator ("IESO"), the Ontario Power Authority ("OPA"), and International Power Canada Inc. North Bay Hydro Distribution Limited filed a request for observer status. The Board granted all the intervention requests and the observer request.

On August 25, 2010, the Board issued Procedural Order No. 1, setting out an interrogatory process to provide the Board with additional information that is relevant for its consideration of the application. An oral hearing was held on October 6, 2010 providing parties with a further opportunity for examination of the application. The Board then directed parties to file their written arguments by specified dates.

Board staff is filing this submission having reviewed all of the evidence placed on the record to date.

[1] EB-2010-0229, Exh. B
[2] EB-2010-0229, Exh. C

III RELIEF REQUESTED

During the oral hearing of this matter, Board staff asked that Hydro One clarify and consolidate its requests of the Board in respect of Part A of its application, the portion pertaining to technical issues. Hydro One restated this portion of its application as part of its argument in chief.[3] The submissions of Board staff are therefore based on Hydro One's new request for relief which does not include a request for an exemption to its distribution licence in respect of Part A of its application.

With respect to Part B of Hydro One's application, Board staff understands that the request for relief has been changed only to remove section 6.2.18 from the list of sections of the DSC from which it seeks exemption.

IV HYDRO ONE'S LICENCE

Hydro One Distribution is licensed by the Board for its electricity distribution activities under Electricity Distribution Licence (ED-2003-0043). As a licensed entity, Hydro One Distribution is required to comply with the Act, the *Electricity Act, 1998*, regulations under these Acts and with the Affiliate Relationships Code for Electricity Distributors and Transmitters, the DSC, the Retail Settlement Code, and the Standard Supply Service Code.

In its original application, Hydro One framed its request as an application for an Order or Orders approving exemptions from specific obligations in Section 5.1 of its Electricity Distribution Licence and specifically as particular exemptions from the DSC.

The relief sought under Part B of Hydro One's application is still framed as request for an order or orders exempting Hydro One from specific obligations in Section 5.1 of its licence.

V UNFORESEEN TECHNICAL ISSUES AND COSTS

(A) INTRODUCTION

In Part A of its application, Hydro One describes certain technical problems that it has encountered with the connection of renewable generation to Hydro One's distribution

[3] At page 3.

system. For convenience, and consistent with the general structure of Hydro One's application, Board staff has placed the issues in three Categories as follows:

- Category #1: Excessive voltage fluctuations in the case of generators connecting at a distance from the station ("Distance Limitation");
- Category #2: Over-voltage condition identified with generators using a step-up transformer with a Delta-Y winding configuration ("Delta-Y Transformers"); and
- Category #3: Inability to sustain reverse flow associated with some dual secondary winding power transformers ("Dual Secondary Winding Transformers") at Transformer Stations.

According to Hydro One, these problems could not have been reasonably foreseen and Hydro One states that the costs to mitigate these issues could be significant. Hydro One is proposing that the investments required to resolve these problems be classified as "eligible investments" under section 79.1 of the Act by deeming these investments to be renewable energy expansions that would qualify for distributor funding. This is the regulatory mechanism that would allow the relevant investments to be recorded in variance accounts and recovered from provincial consumers under Ontario Regulation 330/09 and the Board's policy issued on June 10, 2010.[4]

Specifically, section 79.1 of the Act and subsections 1(2) and 1(3) of Ontario Regulation 330/09 (with reference to the definitions of "renewable energy generation facility" and "renewable energy source" found in subsection 2(1) of the *Electricity Act, 1998*)[5] set up a mechanism which, broadly speaking, does two things.

First, by reference in section 1.2(1) of Ontario Regulation 330/09 to the Board's DSC and to the amendments to the DSC which came into force on October 21, 2009, the previous rules with respect to cost responsibility were changed, as between the generator that seeks to be connected and the distributor that owns and operates the system to which the generator seeks to connect, for investments made for the purpose of connecting or enabling the connection of a renewable energy generation facility.

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[4] EB-2009-0349 – Report of the Board, Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09, June 10, 2010.
[5] These sections are reproduced in Appendix A for convenience.

Second, it makes certain qualifying costs incurred by a distributor to connect renewable generation facilities to its distribution system recoverable from all ratepayers in the province rather than exclusively from that distributor's ratepayers.

Hydro One seeks, in this application, to have this mechanism apply to a number of investments that would not otherwise qualify for this treatment. In particular, for all three categories of technical problems described in Exhibit B of the application, the investments are being or will be made in respect of projects for which the applications to connect to Hydro One's distribution system were made well before October 21, 2009. This was the date that the amendments to the DSC, that shifted responsibility from the generator to the distributor for certain types of investment came into force. It is also the date that was specifically articulated by this Board in its Notice accompanying the relevant amendments to the DSC as the date that should be used by all parties to determine what projects would qualify for the new treatment in the DSC.

Hydro One does not dispute the fact that the proponents of all of the projects described in its application applied to connect to Hydro One's distribution system prior to October 21, 2009.[6] In fact, Hydro One has said that all of the projects already have connection cost agreements and many of them are already connected to Hydro One's system.[7]

Essentially, Hydro One is asking that the Board treat these projects as though they had applied to connect to Hydro One's system after October 21, 2010. Hydro One is of the view that the investments that it is making or intends to make to address the technical issues described in the application would otherwise qualify as "eligible investments" as that term is defined in the Act. Specifically, the applicant wants this Board to "deem" that the investments to be made to resolve all three categories of technical problems be considered to be "expansions" for purposes of the DSC. The net effect of such a classification is that the costs, which would otherwise be the responsibility of the generator, become the responsibility of the distributor and are, therefore, eligible to be socialized in accordance with the mechanism provided in section 79.1 of the Act.

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[6] Hydro One Networks Inc., Argument in Chief, October 20, 2010, p.2.
[7] Ibid.

(B) BOARD STAFF SUBMISSION

Appropriateness of Deeming the Investments to be Eligible for Socialization

Board staff sees several issues with Hydro One’s suggested approach. Specifically Board staff believes that the relief sought in the Part A of Hydro One’s application should be denied for three main reasons, which are discussed below.

Inequitable Treatment/Fairness

First and perhaps most importantly, the Board was explicit in the October 21, 2009 Notice that accompanied the final changes to the DSC that altered cost responsibility for certain investments made by distributors to connect or enable the connection of renewable generation facilities that the amendments would apply only to projects that had applied to connect to the distributor’s distribution system prior to that date. The Board went further to provide a definition of the “date of application” and to indicate that a renewable generator that has already applied to connect would, if it wanted to take advantage of the new mechanism created by Ontario Regulation 330/09, be required to withdraw its earlier application, rescind any earlier connection impact assessments and forfeit any earlier capacity allocation before it could re-apply to connect and thereby take advantage of the new cost responsibility and socialization mechanisms.

The implication of the language used in the October 21, 2009 Notice is that the Board wanted to leave no room for ambiguity with respect to the application of the new rules and wanted to ensure that generators understood that in order to gain the benefits associated with the new regulatory mechanism, they would be required to relinquish the certainty associated with having a guaranteed capacity allocation on the distribution system.

To now grant an exemption to one distributor in respect of all those projects that could derive a benefit from the new regulatory mechanism while still allowing those projects to keep their capacity allocation on the distribution system, is manifestly unfair to all those generators that operated under the principles clearly articulated when the new regulatory mechanism came into force.

Ontario Regulation 330/09

Second, the new DSC provisions which create the categories of investment for which a distributor will be responsible were created as a result of the reference in section 2(1) of

Ontario Regulation 330/09 which states:

> “The prescribed criterion for falling within the definition of an “eligible investment” under subsection 79.1(5) of the Act is that the costs associated with the investment are determined to be the responsibility of the distributor in accordance with the Board’s Distribution System Code.”

Ontario Regulation 330/09 was filed on September 9, 2009. Prior to the existence of that regulation, there was no ability to spread the costs associated with the connection of renewable generation to the distribution system across all provincial ratepayers. All of the projects for which Hydro One now seeks this treatment have already been through the connection assessment process and have connection cost agreements (or connection cost recovery agreements, as the case may be) and many of the projects are actually connected to Hydro One’s distribution system. To now allow the investments associated with these projects to have the benefit of a regulatory treatment that did not exist when these projects were initiated is to reach back and give application to a regulation that was never intended. Accordingly, Board staff is of the view that this Board does not have the jurisdiction to “deem” the investments proposed to be made to mitigate the technical issues as renewable expansion investments in accordance with the DSC. To do so would, in Board staff’s view, effectively be providing an exemption to the regulation itself.

It can be argued, however, that the costs associated with the investments for which Hydro One now seeks recovery are, for the most part, prospective. Hydro One has not yet incurred many of the costs that are the subject of Part A of its application. In fact, many of the costs that it describes are still high level estimates since the scope of work actually required to be completed to address the issues is still not determined in a definitive way. It is possible therefore, to argue that although the generators in question applied to connect to Hydro One’s system well prior to October 21, 2009, which is the important milestone articulated by the Board as being required to qualify for eligibility under section 79.1 of the Act, the costs associated with the investment will not be incurred until after that date. If the Board was inclined therefore to grant some relief to Hydro One and by extension the renewable generators that are or will be connected to its distribution system, the Board would have the ability to do so based on the prospective nature of the costs involved.

Such a finding would contradict the Board’s clear policy statements articulated as part of the DSC amendment process. However, the Board could stress that this exceptional treatment is a one-time event and justify the departure by reference to the unusual circumstances in this case. In particular, the need to recognize Hydro One's significant learning curve with respect to renewable generator connections with the need to provide certainty to subject generators with respect to the costs of connection.

Board staff notes however, that the alternative interpretation outlined above should be applied only to investments that clearly meet the definitional requirements of the new provisions of the DSC (i.e., "renewable enabling improvements" or "expansion"). As discussed below, Board staff is of the view that only the investments in Category #1 would meet these definitions.

Not "Expansions" or "Renewable Enabling Improvements" under the DSC

Third, Board staff is of the view that even if the subject generators had applied to connect to Hydro One's distribution system after October 21, 2009, except for the investments related to the distance limitation issue, the types of work required to mitigate the technical problems would not qualify as "expansions" under section 3.2.30 of the DSC or as "renewable enabling improvements" under section 3.3.2 of the DSC.

Board staff's analysis on this point is provided for each of the categories of technical issues below.

Category #1: Distance Limitation Issue

Hydro One has indicated that there are a total of twenty-two projects impacted by the distance limitation issue and of those, ten have already connected to Hydro One's distribution system.[8] Hydro One has estimated that the maximum cost associated with mitigating the distance limitation issue for the 22 projects is $42 million.[9] The applicant has prioritized the 22 projects into 3 groups (projects with near-term in-service dates, projects with longer-term in-service dates and projects with a lower probability of problems) and is proposing to take a phased approach to address the issues.[10] When questioned about the impact of a change in its estimate with respect to the cost for addressing the near-term group of projects, however, the utility indicated that even though the estimated costs for this group had changed from $2 million to more than $5 million, this had no impact on the overall estimate of $42 million to mitigate the problem

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[8] Exh. J1.3, p.1.
[9] Exh. B, Tab1, Sch. 2, p. 6.
[10] Exh. B, Tab 1, Sch. 2, p. 5.

for all groups.[11] By way of clarification, Hydro One's witnesses indicated that while the cost estimate for the near-term group of projects is more or less accurate, the estimates for the other groups are not accurate until the utility undertakes further assessment.[12]

In Board staff's view, the investments described by Hydro One as being required to mitigate the distance limitation issue would, had they been made for projects that applied to connect to Hydro One's distribution system on or after October 21, 2009, fall into the category of an "expansion", in accordance with section 3.2.30 of the DSC. This would have meant that the cost responsibility for those investments would have fallen on the distributor up to the renewable energy generation facility's renewable energy expansion cost cap in accordance with section 3.2.5A of the DSC and the investments would, therefore, be eligible to be socialized.

Hydro One has also indicated that although at this time, there are no other customers that are expected to benefit from the investments made to address the distance limitation issue; new customers might arrive at the time of construction that would benefit from the investments.[13]

Board staff is of the view that at least some of the investments being made under Category #1 have the potential not only to mitigate the existing power quality problems, but also to result in additional capacity being made available to accommodate future additional generation on these feeders that are being relieved.

If Hydro One could demonstrate that a portion of the investment spent could be allocated to the provision of additional capacity for connection of future renewable generation and such capacity is needed to support the OPA's Feed-In Tariff generation procurement program, Board staff is of the view that it could argue that some portion of the costs spent in this category should qualify as being eligible for a future Green Energy Plan expenditure.

In Board staff's submission, such a proposal cannot be addressed in this proceeding both because of lack of certainty around the costs associated with these investments and because the application is not for the purpose of approving a new GEA plan. However, Board staff is of the view that the Board could authorize that some or all of the costs associated with the near-term group of projects that are impacted by this issue be recorded in a deferral account which would be the subject of a future prudence review.

[11] Transcript, Volume 1, October 6, 2010, pp. 115-118.
[12] Transcript, Volume 1, October 6, 2010, pp. 117, line 22 – p. 118, line 3.
[13] Exh. I, Tab 1, Sch. 1, pp. 1-2.

None of these observations negate, however, the fact that these investments are being made in respect of projects that applied for connection (and in many cases were actually connected to) Hydro One's distribution system prior to the filing of Ontario Regulation 330/09 and certainly prior to the coming into force of the relevant portions of the DSC. As such, if this Board decides that the investments are not eligible for section 79.1 treatment under the Act, then a deferral account should not be granted in respect of any of the costs associated with this technical issue.

<u>Category #2: Delta-Y Transformer Issue</u>

Situational Assessment

In its pre-filed evidence, Hydro One indicated that this required investment came about due to Hydro One changing its standard for the transformers from Delta-Y winding to a new configuration of Y-Delta around the fall of 2008[14] in order to mitigate over-voltage conditions. Hydro One further indicated that it began communicating this new requirement to new projects late in 2008,[15] however numerous Connection Impact Assessments ("CIAs") had been issued with the original transformer specifications and generators had committed to purchase the equipment specified in their CIAs.

In regard to the number of projects affected, during cross examination by counsel for APPrO, Hydro One's witness indicated that at the time of the pre-filed evidence, there were 18 projects impacted by this issue, and after further studies, the number of projects impacted has been reduced to nine.[16] According to Hydro One's evidence, only six grounding transformers are needed, because some of the nine projects share the same feeder. Hydro One witnesses indicated, that to the best of their knowledge, all nine of the generators had already placed equipment orders for the transformers that met the outdated standard when Hydro One communicated the standard change to them.[17] Eight of the 9 generators are already connected to Hydro One's distribution system.[18]

Hydro One indicated that the basic solution to address this issue is to install a grounding transformer. To achieve that, Hydro One will require the generator to install a grounding transformer at the generator's site at an estimated cost of between $450,000 and

[14] Exh. B, Tab 1, Sch. 3, p.1, lines 23 -30.
[15] Exh. B, Tab 1, Sch. 3, p.2, lines 24 -29.
[16] Transcript, Vol. 1, October 6, 2010, pp. 74-75.
[17] Transcript, Vol. 1, October 6, 2010, p. 133.
[18] Exh. J1.4, p. 1.

$500,000.[19] The total cost of this program is estimated by Hydro One to be between $4.5 to $6.5 million.[20]

Classification of Delta-Y Transformer

In its pre-filed evidence, Hydro One requested that investments associated with the Delta-Y transformer issue be deemed as distribution expansion investments and therefore be recoverable from all provincial consumers under Ontario Regulation 330/09.[21] Under cross examination by counsel for APPrO, it was suggested to Hydro One's witness that the investments associated with the Delta-Y transformer standard change could be classified as renewable enabling improvements instead of system expansion. In response, Hydro One's witness indicated that there are some parts of the renewable enabling improvements definition that could be applied to the grounding transformers, because they can be thought of as protection, but that Hydro One felt that the expansion definition was more appropriate.[22]

In its Argument in Chief, Hydro One seems to modify its pre-filed evidence in regard to the classification of the Delta-Y transformer issue where it argues that the work fits both the expansion and the renewable enabling improvements definitions:

> Although the addition of a grounding transformer to address the Delta-Y transformer issue could be considered a renewable enabling improvement due to its protection function, Hydro One submits that this work also meets the definition of expansion investments in section 1.2 of the Distribution System Code, as discussed in the Applicant's interrogatory response at Exhibit I, Tab 1, Schedule 3, page 2.[23]

Board staff submits that the work described in the pre-filed evidence by the applicant as being required to address the Delta-Y issue does not meet the definition of expansion in sections 1.2 and 3.2.30 of the DSC[24]. In Board staff's view, this work by Hydro One does not consist of adding new facilities to its main distribution system to connect new generators as these generators are all already connected or have completed CIAs, and thus any needed expansion would have been completed or described in the CIA.

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[19] Transcript, Vol. 1, October 6, 2010, pp. 92-93.
[20] Transcript, Vol. 1, October 6, 2010, p. 91.
[21] Exh. B, Tab 1, Sch. 1, pp. 2-3.
[22] Transcript, Vol. 1, p. 96, line 11 to p. 97, line 13.
[23] Argument in Chief, by Hydro One Networks Inc., October 20, 2010, page 5.
[24] The sections of the DSC referenced in this discussion are reproduced in Appendix A for convenience.

Board staff also submits that Section 3.3.2 of the DSC is quite prescriptive in describing what constitutes a renewable enabling improvement, and that the work described by Hydro One in the pre-filed evidence does not constitute a modification of the sort described in any of the subsections 3.3.2, in particular, subsections 3.3.2(a) and (b) of section 3.3.2, which read as follows:

> (a) modifications to, or the addition of, electrical protection equipment;
>
> (b) modifications to, or the addition of, voltage regulating transformer controls or station controls;

Board staff notes that the grounding transformers are not classed as electrical protection equipment as stated in (a) above, and are not classed as voltage regulating transformer controls or station controls as stated in (b) above. These grounding transformers are being considered by Hydro One to mitigate against over-voltage conditions where generators already purchased step-up transformers with a Delta-Y winding as was required by the old Hydro One standard[25]. Board staff therefore concludes that the work described by Hydro One which is required to mitigate the Delta-Y issue would not meet the definitional requirements in the DSC even if the applicant could overcome the fairness, timing and legal impediments associated with the application of Ontario Regulation 330/09 and the DSC provisions which came into force on October 21, 2009. The work required to address the Delta-Y issue is essentially retrofitting the generator's step-up transformation facilities with a more appropriate type of transformer.

<u>Category #3: Dual Secondary Winding Transformer Issue</u>

Board Policy

Board staff submits that the work described in the pre-filed evidence for these projects is transmission system work, not distribution system work, which was acknowledged by Hydro One's witness during Board Counsel's cross examination[26]. In Board staff's view, it is not the Board's intent that investments made in the transmission system be attributed to distributors for the purpose of making those investments eligible for socialization across all provincial ratepayers. This principle was clearly articulated in

[25] Exh. B/Tab 1/Sch. 3/p. 1/lines 12-30
[26] Transcript, Vol. 1, October 6, 2010, p. 136, line 24 to p. 137, line 1.

the Board's Notice of Amendments to the Distribution System Code[27]. The Board's policy contained in that Notice was the subject of Board staff Interrogatory No.9.[28] Hydro One's response to Question (i) of Board staff Interrogatory No.9 acknowledged that policy, but indicated that charging generators for that work is inappropriate.

Mitigation Cost - Dual-Secondary Winding Transformers

During cross examination by counsel for APPrO at the Oral hearing, a Hydro One witness updated the number of transformers that are impacted by the dual secondary winding issue. Mr. D'Arcey indicated that a maximum number of nine transformers located in five stations[29] could be involved. In regard to the potential cost to mitigate this aspect of the application, the same Hydro One witness also indicated it would cost $5 million per transformer to a maximum of nine transformers, if need was established for each such transformer.[30] During cross examination of the same Hydro One witness by Board counsel,[31] the witness clarified additional expenditures related to the commissioning of manufacturer's studies and monitoring for the various transformer locations[32] which amounted to approximately $700,000. The response to Board staff Interrogatory No.9, (iii) states in part that:

> The following table gives a summary of the costs associated with the measures that the Company anticipates will be required to address the individual transformer limitations at the present time.
>
> Although the table identifies relatively low-cost measures, there is still a residual risk that one or more of the manufacturers' studies that Hydro One has commissioned will identify a requirement to replace one or two individual transformers at a cost of approximately $5 million each. This will not be known, however, until all of the studies have been completed and the results analyzed.

Board staff notes that once the studies are complete and the results of the monitoring, which is described in Board Staff Interrogatory No. 9 is complete, there is a risk that all nine transformers could be identified as needing replacement which amounts to $45 million in addition to the approximately $700, 000 identified above.

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[27] Notice of Amendment to a Code – Amendments to the Distribution System Code, EB-2009-0077, October 21, 2009, Part III "Summary of Comments……" - Sec B "Cost Responsibility for Transformer Stations".
[28] Exh. I, Tab 1, Sch. 9, pp. 2-3, Response to Question (i).
[29] Transcript, Vol. 1, October 6, 2010, pp. 93 – 94.
[30] Transcript, Vol. 1, October 6, 2010, p. 94, lines 8-16.
[31] Transcript, Vol. 1, October 6, 2010, pp. 138 – 139.
[32] Exh. I, Tab 1, Sch.9, p. 4.

Cost Responsibility under the Transmission System Code ("TSC")

The TSC approach is based on a User Pay principle for any reinforcement, upgrade, or new investment in transmitter owned connection assets unless the assets are at end of life. Board staff agrees with Hydro One that requiring the generators to pay for the investments related to dual secondary winding is unfair, however, Board staff submits that Hydro One's proposal related to this category of investment is not only non-compliant with the Board policy related to investments in the transmission system, but also it is non-compliant with the TSC's User Pay principles for connection facilities.

Risk to Provincial Ratepayers

Board staff submits that there are two aspects of risk to ratepayers related to Hydro One's request in relation to dual secondary transformers.

The first is that granting the exemption requested by Hydro One would establish a precedent for a large number of transformer stations on the system[33] which could have dual secondary winding transformers that may have the same limitation as those for which Hydro One seeks special treatment in this application.

The second aspect is that under the current rules, the Economic Connection Test that the OPA will be using to determine which renewable generators can be economically connected considers only network investments, not investments in connection facilities. There is no corresponding economic evaluation by the OPA for connection facilities that includes transformers owned by Hydro One Transmission as is the case in this Application.

The combination of the two risks could lead to permitting recovery of such investments first by deeming them to be distribution expansions, and then by socializing a large portion of the investment across all provincial rate payers. In Board staff's submission, this would have the effect of moving the risk of uneconomic connections from the connecting generators onto the provincial ratepayers.

Board staff also notes that based on the evidence provided, the costs of the proposed investments are still not clearly defined. Board staff is aware that Hydro One is still in the process of undertaking various monitoring studies to study some of the technical issues that have arisen and to determine the most appropriate course of action. Hydro

[33] Exh B, Tab 1, Sch. 4, p. 2.

One's witnesses indicated that the studies and monitoring described at Board Staff Interrogatory No.9 had only just begun for some of the transformers at issue and that these assessments would be used to determine future capital expenses.[34]

In conclusion, Board staff submits that the work required to mitigate the dual secondary winding transformer issue should not be recognized as a renewable energy expansion investment in accordance with section 3.2.30 of the DSC and that these investments should not be included as an addendum to Hydro One's provisionally-approved Green Energy Plan or otherwise be deemed to be eligible for socialization across all provincial ratepayers.

<u>Allocation of Costs to Generators in Absence of Exemption</u>

Hydro One indicated that while it thinks that it would be unfair to do so,[35] if the Board does not grant the exemptions that it is requesting in Part A of its application, it will have no option but to charge the generators, in full, for these costs.[36] Hydro One has further indicated that it is of the view that the provisions of the contracts that it has with the generators will allow it to push the costs of the investments that are the subject of this application onto the generators.[37] At the request of the Board panel members in this proceeding, Hydro One provided excerpts of the contracts on which it may rely, should it seek to visit these costs upon the generators.[38] Hydro One also referenced sections 6.2.25 and 6.2.26 of the DSC as a potential basis for requiring the generators to absorb the costs associated with the mitigation of the technical issues described in Part A of the application.

Board staff agrees with Hydro One that it would not be fair to allocate these mitigation costs to generators, particularly, on the basis of section 6.2.26 of the DSC. Board staff's view is that such an allocation would not be consistent with the intent of this section. Sections 6.2.25 and 6.2.26 of the DSC place responsibility on the distributor to ensure that generation connections do not affect the safety, reliability and efficiency of the distribution system. In the case at hand, any potential negative impact on the distribution system or its customers should have been examined as part of the connection assessment process and any mitigation measures identified as part of that process should have been included in the connection cost (recovery) agreements.

[34] Transcript, Vol. 1, October 6, 2010, pp. 139, lines 5-7.
[35] Exh. B, Tab 1, Sch. 1, p. 2, lines 12-17 & Exh. I, Tab 1, Sch. 2.
[36] Exh. I, Tab 1, Sch. 2, p. 1.
[37] Transcript, Vol. 1, October 6, 2010, page. 122, line 17-23.
[38] Hydro One Networks Inc. Argument in Chief, EB-2010-0229, October 20, 2010, Schedule "A", pp. 15-18.

VI EXTENSION OF TIMELINE - LARGE RENEWABLE GENERATION PROJECTS

(A) INTRODUCTION

Hydro One is requesting an exemption from sections 6.2.4.1e(i), 6.2.4.1c and 6.2.16 of the DSC as it considers the timeline specified in the DSC insufficient for the processing of connection applications from twelve specific large generators that have applied for connection to Hydro One's distribution system. According to the application, large generators wishing to connect to the distribution system are first required to apply for a distribution connection impact assessment ("CIA" - Distribution). They are then required to apply to the IESO for a System Impact Assessment ("SIA"), and a Customer Impact Assessment ("CIA" - Transmission) from the licensed transmitter, (for these projects, the licensed transmitter is Hydro One Transmission). Hydro One states that if upgrades to the transmission system are needed as a result of these assessments, additional time is required for the transmitter to develop the scope of work and detailed cost estimates. Hydro One indicates that the transmitter is not able to provide definitive timelines within which it can commit to provide the detailed cost estimates for required transmission upgrades.

The issue, as Hydro One has described it in its evidence, is that when upgrades to the transmission system are determined to be required, it may not be possible for the cost estimates for those upgrades to be provided in time for the parties to sign a connection cost agreement within the timelines prescribed by section 6.2.4.1(e)(i) of the DSC. That section requires that a distributor remove the capacity allocation of a generator that applied to connect to the distributor's system unless a connection cost agreement has been signed with the distributor within 6 months of the date that the applicant received a capacity allocation. Hydro One is concerned that for some or all of the twelve generators that are the subject of Part B of Hydro One's application, this timeline may not be met and Hydro One will be required by the provision of the DSC to remove their capacity allocation.

Hydro One indicates in its evidence that the reason that it needs an open-ended timeline is that it has no way of predicting how long it will take the transmitter, in this case Hydro One Transmission, to provide the required cost estimates, which then feed into the connection cost estimate required to be signed for purposes of section 6.2.4.1(e)(i) of the DSC.

Hydro One is also requesting that provisional allocation of capacity on its distribution system occur only once the SIA and CIA-Transmission are complete rather than when the distribution CIA is complete as is required by section 6.2.4.1(a) of the DSC. The stated rationale for this position is first, that only once the SIA study is completed and no issues are found, can that capacity be confirmed and second, that larger generation projects that require SIAs and CIAs at the transmission level could, under their proposal, lose their "provisional" capacity allocation to smaller projects whose applications to connect are submitted subsequently, but do not require the same level of review.

(B) Submission

Board staff is of the view that it is appropriate to allow additional time for the completion of the connection process, culminating in the signing of a connection cost agreement for the twelve large size generators for which Hydro One has made application in this matter. Board staff submits, however, that to provide certainty with respect to the capacity allocation process for all generators who are in the process of connecting or who may wish to connect to Hydro One's distribution system, the extension of time to finalize a connection cost agreement must not be open ended.

At the hearing, Hydro One's witnesses confirmed that all twelve of the projects for which Hydro One is seeking an exemption to the DSC have completed distribution connection impact assessments and they have all, therefore, been granted capacity allocations on Hydro One's distribution system.[39]

Board staff submits that Hydro One should be granted an extension of 5 months in addition to the 6 month time limit specified in section 6.2.4.1e(i) of the DSC for a total of 11 months from the time a distribution CIA is completed, to sign a connection cost agreement. In this scenario, there would be 5 months for the processing of the transmission connection assessments (i.e., the IESO SIA and the Hydro One Transmission CIA) in accordance with the timeline in Ontario Regulation 326/09, followed by an additional 6 months which would be used for the preparation of detailed cost estimates at both the distribution and transmission levels and for the preparation, negotiation and signing of the connection cost agreement.

Based on information included in Section 5.0 of Hydro One's Transmission Connection Process, Board staff is of the view that no additional time needs to be granted for the

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[39] Transcript, Vol. 1, October 6, 2010, pp. 48-49.

preparation of transmission cost estimates. Board staff suggests that any necessary transmission cost estimates can be developed concurrently with the preparation of distribution cost estimates (in section 6.2.16 of the DSC).

To illustrate the reasonableness of the 90 day time period for the preparation of the transmission cost estimates, Board counsel introduced Exhibit No. K1.2[40] during the Oral hearing, which is an extract from a document entitled "Transmission Connection Procedures". In the last page of that document it shows "Timelines for Connection Process", and against phase 3, which is the connection estimate phase under the heading Timeline "On Best Effort Basis", it indicates 45 Calendar Days. A Hydro One witness indicated that the 45 day timeline may be for load rather than generator connections.[41] Board staff suggested that the document applied to all customers, including load and generation. Board staff has confirmed that the referenced document has been approved by the Board[42] and is applicable to all transmission customers, as defined in the TSC,[43] which includes generator customers.

Board staff is of the view that if for some reason the extension of 5 additional months for these twelve projects is insufficient in one or more cases, Hydro One should be required to come to the Board to seek an additional extension so that the Board can be made aware of the issues that are causing the significant delay in getting connection cost agreements finalized for these projects. Board staff also notes that at the oral hearing, Hydro One agreed in principle to the concept of quarterly reporting on the status of each of the twelve projects and any anticipated obstacles that Hydro One sees as potentially preventing the project from meeting the timelines outlined in the Board's decision or in the DSC, as applicable.[44] The details of such reporting were not specifically addressed, but Board staff supports the concept of reporting on the progress of the 12 subject projects through the connection assessment process and the identification by Hydro One in its reporting of any real or anticipated obstacles in achieving the connection of the projects in accordance with the timelines set by the Board.

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[40] Exhibit No.K1.2: October 6, 2010, Extracts from Document Entitled "Transmission Connection Procedures", including the Title page, the Table of Content and the last page showing a section entitled "Timelines for Connection Process".
[41] Transcript, Vol. 1, October 6, 2010, p. 143.
[42] The Transmission Connection Procedures, approved by the Board Decision and Order dated February 12, 2008, for a revised TCP filed with the Board October 12, 2007.
[43] Transmission System Code, October 20, 2009 section 2.0.18 states that "customer" means a generator, consumer, distributor or unlicensed transmitter whose facilities are connected to or are intended to be connected to a transmission system.
[44] Transcript, Vol. 1, October 6, 2010, pp. 86-88.

Board staff is of the view that such reporting would be useful to the Board in order to provide some transparency around the connection process and some form of notice to the Board of potential problems that may arise with respect to one or more of the projects that may not be on track to meet the timelines outlined in the DSC or extended in this proceeding, as applicable.

It is not entirely clear to Board staff whether Hydro One's request to allocate capacity on its distribution system provisionally until the SIAs and transmission CIAs are completed, was made in the nature of an exemption request (from section 6.2.4.1(a) of the DSC) with respect only to the twelve larger generation projects that were the subject of Part B of its application or whether the applicant was asking for a broader exemption in this regard. On the assumption that the request relates only to the twelve generators, Board staff notes that this request was not accompanied by an express request for exemption to section 6.2.4.1(a) of the DSC, which would be required to effect the decision that the applicant is seeking. Regardless of this technical omission, however, Board staff is of the view that granting only provisional capacity allocation until the SIA and transmission CIA are complete for larger projects creates a level uncertainty in the capacity allocation process that it not desirable. Board staff believes that generators should be able to proceed with certainty, from the time they receive a distribution level CIA, through the connection process with the knowledge that the capacity required to connect their project has been reserved as required. In Board staff's view, the OPA's various screens for determining whether capacity exists at both the distribution and transmission levels for FIT projects and Section 6.2.4.1 of the DSC which is designed to remove capacity allocation under certain circumstances provide the necessary checks and balances at both the front and back ends of the connection process. As such, Board staff does not support the notion of introducing the concept of provisional capacity allocation until the SIAs and transmission CIAs are completed.

Board staff notes that Hydro One's exemption request is only being sought for twelve specific generators. Hydro One has not indicated how it would deal with other future large size generators seeking to connect to their distribution system. In Board staff's view, the only option, as the DSC is presently drafted, would be another future exemption request, as necessary. Board staff also notes that other distributors may be faced with similar issues in relation to the processing of applications for connection by large size generators and may also need to request a similar exemption.

Finally, Board staff is of the view that if the Board grants an exemption to Hydro One from the requirement in section 6.2.4.1(e) of the DSC in respect of the twelve generators that are the subject of Part B of the application, exemptions to section 6.2.4.1(c) and 6.2.16 are not required.

The rationale for this position is that, according to the evidence, each of the twelve generators has already applied to be connected to Hydro One's distribution system and a distribution level CIA has been completed. Section 6.2.4.1(c) enumerates two requirements that must be met prior to a connection impact assessment being completed. In other words, before a distributor completes a distribution CIA, it must ensure that the application from the generator meets the requirements outlined in section 6.2.4.1(c). This section is no longer relevant to the twelve generators in this proceeding as they have already applied for and received completed CIAs.

Section 6.2.16 of the DSC prescribes timelines for the provision by the distributor of a detailed cost estimate and an offer to connect to the applicant generator. While Board staff is proposing herein that the period of time that the applicant generator has to sign a connection cost agreement be extended, Board staff does not see a need for the Board to provide an exemption from the timelines in section 6.2.16. The distributor should still be required to provide a detailed cost estimate and an offer to connect by the later of 90 days after the receipt of payment from the applicant and 30 days after the receipt of comments from a directly connected transmitter or distributor. In this case, Hydro One has indicated that the most significant unknown in the process that follows the SIA and transmission CIA is the preparation by the transmitter of a detailed cost estimate. Section 6.2.16 gives the distributor 30 days following the preparation of that detailed transmission cost estimate to provide the detailed cost estimates for both distribution and transmission level upgrades and an offer to connect. In other words, this section contemplates that Hydro One will have the detailed cost estimate from the transmitter in hand and will have an additional 30 days to meet the requirements of section 6.2.16. Board staff submits that there is no evidence on the record of this proceeding that suggests that this timeline cannot be met and that, therefore, an exemption is required in respect of this section.

All of which is respectfully submitted.

Appendix A

To Board Staff Submissions

EB-2010-0229

Ontario Energy Board Act, 1998

79.1(1) The Board, in approving just and reasonable rates for a distributor that incurs costs to make an ***eligible investment*** for the purpose of connecting or enabling the connection of a ***qualifying generation facility*** to its distribution system, shall provide rate protection for prescribed consumers or classes of consumers in the distributor's service area by reducing the rates that would otherwise apply in accordance with the prescribed rules. [Emphasis added]

(5) "eligible investment" means an investment in the construction, expansion or reinforcement of a distribution line, transformer, plant or equipment used for conveying electricity at voltages of 50 kilovolts or less that meets the criteria prescribed by regulation.

"qualifying generation facility" means a generation facility that meets the criteria prescribed by regulation.

Ontario Regulation 330/09

1(2) The prescribed criterion for falling within the definition of an "eligible investment" under subsection 79.1(5) of the Act is that the costs associated with the investment are determined to be the responsibility of the distributor in accordance with the Board's Distribution System Code.

(3) The prescribed criterion for falling within the definition of a "qualifying generation facility" under subsection 79.1(5) of the Act is that the generation facility satisfies the criteria necessary to be a renewable energy generation facility under the *Electricity Act, 1998*.

Electricity Act, 1998

2(1) "renewable energy generation facility" means a generation facility that generates electricity from a renewable energy source and that meets such criteria as may be prescribed by regulation and includes associated or ancillary equipment, systems and technologies as may be prescribed by regulation, but does not include an associated waste disposal site, unless the site is prescribed by regulation for the purposes of this definition.

“renewable energy source” means an energy source that is renewed by natural processes and includes wind, water, biomass, biogas, biofuel, solar energy, geothermal energy, tidal forces and such other energy sources as may be prescribed by the regulations, but only if the energy source satisfies such criteria as may be prescribed by the regulations for that energy source.

<u>Distribution System Code</u>

1.2 “renewable enabling improvement” means a modification or addition to the main distribution system identified in section 3.3.2 that is made to enable the main distribution system to accommodate generation from renewable energy generation facilities

“renewable energy expansion cost cap” means, in relation to a renewable energy generation facility, the dollar amount determined by multiplying the total name-plate rated capacity of the renewable energy generation facility referred to in section 6.2.9(a) (in MW) by $90,000, reduced where applicable in accordance with section 3.2.27A or section 3.2.27B

1.7 Any amendments to this Code shall come into force on the date the Board publishes the amendments by placing them on the Board’s website after they have been made by the Board, except where expressly provided otherwise.

3.2.5A …a distributor shall not charge a generator to construct an expansion to connect a renewable energy generation facility:

(a) if the expansion is in a Board-approved plan filed with the Board by the distributor pursuant to the deemed condition of the distributor’s licence referred to in paragraph 2 of subsection 70(2.1) of the Act, or is otherwise approved or mandated by the Board; or

(b) in any other case, for any costs of the expansion that are at or below the renewable energy generation facility’s renewable energy expansion cost cap.

For greater clarity, the distributor shall bear all costs of constructing an expansion referred to in (a) and, in the case of (b), shall bear all costs of constructing the expansion that are at or below the renewable energy generation facility’s renewable energy expansion cost cap.

3.3.2 Renewable enabling improvements to the main distribution system to accommodate the connection of renewable energy generation facilities are limited to the following:

(a) modifications to, or the addition of, electrical protection equipment;

(b) modifications to, or the addition of, voltage regulating transformer controls or station controls;

(c) the provision of protection against islanding (transfer trip or equivalent);

(d) bidirectional reclosers;

(e) tap-changer controls or relays;

(f) replacing breaker protection relays;

(g) Supervisory Control and Data Acquisition system design, construction and connection;

(h) Any other modifications or additions to allow for and accommodate 2-way electrical flows or reverse flows; and

(i) Communication systems to facilitate the connection of renewable energy generation facilities.

3.3.3 Subject to section 3.3.4, the distributor shall bear the cost of constructing an enhancement or making a renewable enabling improvement, and therefore shall not charge:

(a) a customer a capital contribution to construct an enhancement; or

(b) a customer that is connecting a renewable energy generation facility a capital contribution to make a renewable enabling improvement.

3.3.4 Section 3.3.3(a) shall not apply to a distributor until the distributor's rates are set based on a cost of service application for the first time following the 2010 rate year.

3.2.30 An expansion of the main distribution system includes:

(a) building a new line to service the connecting customer;

(b) rebuilding a single-phase line to three-phase to serve the connecting customer;

(c) rebuilding an existing line with a larger size conductor to serve the connecting customer;

(d) rebuilding or overbuilding an existing line to provide an additional circuit to serve the connecting customer;

(e) converting a lower voltage line to operate at higher voltage;

(f) replacing a transformer to a larger MVA size;

(g) upgrading a voltage regulating transformer or station to a larger MVA size; and

(h) adding or upgrading capacitor banks to accommodate the connection of the connecting customer.