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Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

June 30, 2010

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

Dear Ms. Walli:

Hydro One Networks Request for Exemption from Certain Sections of the Distribution System Code and Approval of New Rates and Fees Related to Distribution Generation Projects

Hydro One Networks Inc. has gained considerable experience over the past few years in the processing and assessment of generator connection applications, and especially in the activities related to the connection of renewable energy generators. Hydro One's experience with generation proponents under both the RESOP and the FIT programs has afforded Hydro One Distribution an opportunity to apply the recently-revised Distribution System Code.

It is in the context of this experience that Hydro One is submitting for the Board's review and approval two sets of applications.

One is a request for certain exemptions from Hydro One's Electricity Distribution Licence as it applies to obligations under the Distribution System Code requirements. The exemptions, if granted would ensure that (i) cost responsibility is assigned fairly for mitigating certain unforeseen technical issues related to generator connections and (ii) that generators do not risk losing their capacity allocation in cases where they are subject to the IESO's Connection Assessment and Approval process.

The other application is for additional miscellaneous fees that Hydro One Distribution has identified to be levied from generation proponents for Connection Impact Assessments and for Joint Use of the distribution system assets.

Hydro One respectfully submits to the Board that both these applications need to be dealt with in an expeditious manner to allow generation connections to proceed without delay and to afford project proponents the certainty they require in planning their projects. Hydro One further requests that, if a hearing is deemed appropriate, these matters be dispensed with through a written hearing.

Hydro One would be pleased to provide any further information that would assist the Board in assessing the merits of this request. Please feel free to contact Carolyn Russell at (416) 345-5914 for further assistance in this regard.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

EXHIBIT LIST

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.

APPLICATION

1. The Applicant is Hydro One Networks Inc. (Hydro One Networks), a subsidiary of Hydro One Inc. Hydro One Networks is an Ontario corporation with its head office at Toronto. The Applicant carries on the business, among other things, of owning and operating distribution facilities in Ontario. The distribution business of Hydro One Networks will be referred to as "Hydro One Distribution".

2. Hydro One Networks hereby applies on behalf of its Distribution business ("Hydro One Distribution") to the Ontario Energy Board (the "Board"), for an Order or Orders approving exemptions from specific obligations in Section 5.1 of its Electricity Distribution Licence (ED-2003-0043), as they pertain to the following sections of the Distribution System Code and the Board's amendments to it:

    a) the Board's October 21, 2009 Amendments to the Distribution System Code (EB-2009-0077), page 10, which stipulates that date as the official date for the application of new cost responsibility rules.

    b) 6.2.4.1e(i), which directs the removal of a proponent's capacity if the CCA has not been executed within six months of that capacity having been allocated.

c) 6.2.4.18a, which directs that the connection cost deposit for 100% of the total allocated project cost be paid at the time the CCA is executed.

d) 6.2.4.1c, which states that the CIA will not be considered complete unless the in-service date for the generation facility is within three years (for non-water power projects) after the initial application date or in accordance with the timelines in an executed OPA contract.

e) 6.2.16, which directs the distributor to provide the full costs of distribution and transmission upgrades within 90 days after receipt of payment from the generator.

5. These exemptions, if granted would ensure that generators do not risk losing their capacity allocation in cases where they are subject to the IESO's Connection Assessment and Approval process, and that cost responsibility is assigned fairly for mitigating certain unforeseen technical issues related to generator connections.

6. Hydro One Distribution requests a written hearing on this issue.

7. The written evidence filed with the Board may be amended from time to time prior to the Board’s final decision on the Application. Further, the Applicant may seek meetings with Board staff in an attempt to identify and reach agreements to settle issues arising out of this Application.

8. The persons affected by this Application are distributed generators who are making application to connect to Hydro One Networks’ Distribution system.

9. Hydro One Distribution requests that a copy of all documents filed with the Board by each party to this Application be served on the Applicant and the Applicant’s counsel as follows:

a) The Applicant:

Ms. Anne-Marie Reilly
Senior Regulatory Coordinator – Regulatory Affairs
Hydro One Networks Inc.

Address for personal service:	8th Floor, South Tower 483 Bay Street Toronto, ON M5G 2P5
Mailing Address:	8th Floor, South Tower 483 Bay Street Toronto, ON M5G 2P5
Telephone:	(416) 345-6482
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b) The Applicant's counsel:

Mr. Michael Engelberg
Assistant General Counsel
Hydro One Networks Inc.

Address for personal service:	15th Floor, North Tower 483 Bay Street Toronto, Ontario M5G 2P5
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DATED at Toronto, Ontario, this 30th day of June, 2010.

REQUEST FOR EXEMPTIONS FROM THE DISTRIBUTION LICENCE WITH RESPECT TO THE DISTRIBUTION SYSTEM CODE AND UNFORESEEN TECHNICAL ISSUES WITH RENEWABLE ENERGY GENERATION PROJECTS

Hydro One Networks Inc. ("Hydro One") applies to the Board for an exemption from its Electricity Distribution Licence (ED-2003-0043) as it pertains to certain obligations set out in Section 5.1 of the licence. Specifically, Hydro One is requesting exemptions from the Notice of Amendments to the DSC (EB-2009-0077), page 10 which stipulates the applicability of the new cost responsibility rules to generator applications made after October 21, 2009) in relation to the cost treatment of designated renewable energy generation projects, for which, unforeseen technical issues have arisen and connections to Hydro One's Distribution system are underway. Hydro One requests that the Board amend Schedule 3 of said licence accordingly.

1.0 INTRODUCTION

Hydro One has committed to connect a number of generators under the terms of Connection Impact Assessments ("CIAs") and the (then) Connection Cost Recovery Agreements ("CCRAs," currently referred to as Connection Cost Agreements or "CCAs") made prior to Hydro One's discovery of technical problems with these connections. These problems are excessive voltage fluctuations in the case of generators connecting at a distance from the station ("distance limitations"), over-voltage conditions identified with generators using a step-up transformer with a Delta-Y winding configuration ("Delta-Y transformers") and an inability to sustain reverse flow associated with some dual secondary winding transformers ("dual secondary winding transformers.") All of these technical issues have the potential to adversely affect the provision of distribution services to other customers connected to Hydro One's distribution system. Each of these issues arose as a result of the unique circumstances with the implementation of the renewable generation connections program. Hydro One has not experienced these types of problems previously and they could not have been reasonably foreseen.

Some of the generators have Renewable Standard Offer Program ("RESOP") contracts from the Ontario Power Authority and currently are in the process of connecting to Hydro One's distribution system. Under the current rules, because the generators in question applied for a CIA prior to October 21, 2009, the generation proponents must bear the cost of resolving issues related to the connection of their assets to Hydro One's systems. However, the cost to remedy or mitigate these issues could be significant, and yet these costs were unknown to both Hydro One and the proponents, and hence not included in any CIAs, Connection Cost Estimates, or Connection Cost Agreements. These generators have already committed considerable investment to comply with terms and conditions specified in their contracts. Hydro One believes that it would not be fair for Hydro One to request additional funding from these generators in order to resolve technical issues which could not be foreseen and became apparent only at a much later date. Yet, Hydro One also cannot recover the costs of such investments from either its distribution ratepayers or from Provincial Consumers (per Ontario regulation 330/09) , under the current rules in the DSC.

2.0 HYDRO ONE'S PROPOSAL

With the Board's approval, Hydro One proposes to recover these investments from Provincial consumers by:

- re-classifying the investments required to resolve these problems as "eligible investments" under Section 79.1 of the *Ontario Energy Board Act, 1998,* notwithstanding the fact that these investments relate to generators who applied for connection prior to October 21, 2009.
- deeming these investments as distribution expansion investments for renewable

energy generation.

These steps would enable treatment of these projects under the cost responsibility rules of the DSC and thereby allow related investments to benefit from the renewable energy expansion cost cap. Hydro One requests that the Board consider Hydro One's Green Energy Plan, approved in EB-2009-0096, to now be amended to include the investments that are detailed in Exhibits B, Tab 1, Schedule 2, Exhibit B, Tab 1, Schedule 3 and Exhibit B, Tab 1, Schedule 4. All of these investments would be deemed renewable energy expansions that would therefore qualify for distributor funding, would be recorded in variance accounts and recovered from Provincial consumers under O. Regulation 330/09 and the Board's policy issued June 10, 2010. The cost recovery is expected to be addressed in a future Hydro One Distribution filing.

This proposal, however, would require that Hydro One obtain certain exemptions from the DSC.

3.0 APPROVALS REQUESTED

With respect to the designated generation projects, Hydro One respectfully requests the Board's approval of the following:

- An exemption from the Board's October 21, 2009 Amendments to the Distribution System Code (EB-2009-0077), page 10, which stipulates that date as the official date for the application of new cost responsibility rules.
- The classification of all investments related to the resolution or mitigation of the distance limitation and transformer issues described in this Application as renewable energy expansion investments.

The scope of this request is limited to the designated renewable energy generation projects, for which applications to connect were made prior to October 21, 2009 and which are or are anticipated to be, affected by the identified issues.

Further details of, and Hydro One's actions to address, the distance limitation, Delta-Y transformer and dual secondary winding transformer issues are provided in Exhibit B, Tab 1, Schedule 2 through Exhibit B, Tab 1, Schedule 4, respectively.

4.0 HYDRO ONE'S RATIONALE FOR COST RECOVERY FROM PROVINCIAL CONSUMERS

4.1 The Rationale for Exempting Distributed Generators from Cost Responsibility

Prior to October 21, 2009, the Distribution System Code dictated that cost responsibility for all investments made by distributors to connect generators to the distribution system is to be borne by the generators. These cost responsibility rules apply to all generators who applied for a CIA prior to that date.

Further, Section 6.2.26 of the DSC indicates that the generator must bear the responsibility for damages and increased operating costs to the distribution system resulting from their connection. Hydro One believes that this rule is appropriate when it is clear that the generator's actions have contributed to the creation of such problems. In Hydro One's view, however, this section of the Code would normally apply when a proponent has not complied with the utility's specifications and standards in the connection of its facility.

Hydro One submits that this is not the case here. All of the projects identified in this Application had been issued positive CIAs by Hydro One that indicated the generator would be allowed to connect and operate if the conditions of the CIAs were fulfilled.

The technical issues covered by this exemption application were not included in said CIAs. These generators have subsequently either complied or committed to comply with the requirements set out in the CIAs and have invested their resources in bringing the projects to various levels of completion. Hydro One submits that, under these conditions, the generators should not be required to bear the costs of remedying problems which were not known to or anticipated by the distributor or the generation proponent, and which are not attributable to the generator's failure to comply with their obligations to the distributor.

4.2 Hydro One's Fulfillment of its Responsibilities

It is Hydro One's position that it could not have foreseen these issues, and in response, undertaken more stringent planning, developed better work specifications or imposed higher standards of connection, to address these issues in the generators' connection requirements.

Hydro One submits that the requirements established in the CIAs and the executed CCRAs were based on proper planning, good utility practice and approved standards for safe and reliable operation of the distribution system and for generation facilities connecting to it. The issues documented in this Application became apparent only after a number of generators had been connected to Hydro One's distribution system (and more were contracted to do so, according to the same standards and requirements).

Exhibits B, Tab 1, Schedule 2 through B, Tab 1, Schedule 4 describe in detail, the emergence and identification of these issues, as well as Hydro One's actions to address them. Hydro One submits that the problems documented in these exhibits are unprecedented. No other jurisdiction has reported similar issues and little or no information on these issues has been available in mainstream industry journals. The apparent reason for this is that no other jurisdiction has attempted to connect, in such a short period of time, a similar volume of distributed generators, characterized by not only a variety of energy types and sizes, but also the freedom to choose the location of their connection, all on the distribution system. In addition to these factors, Hydro One is a rural distributor with long, lightly loaded feeders, a characteristic which renders its distribution system particularly sensitive to changes in the power injected onto it from a renewable generator, depending on the location of the connection. Also, many generators chose to connect at locations where the station capacity is impacted by transformers with dual secondary windings, some of which are at risk of imbalance caused by the connecting generation, and others which cannot sustain any reverse flow.

Section 6.2.26 of the DSC obliges a distributor to ensure that the safety, reliability and efficiency of its distribution system is not materially adversely affected by the connection of a generation facility to it. The Company submits that the conditions and requirements in its CIAs and contracts reflected good utility practice and all approved standards. It also submits that once these technical issues became apparent, Hydro One's actions to address them, as well as ensure the continued safe connections of future generators, were prudent.

4.3 The Rationale for Recovery from Provincial Consumers

The Board's October 21, 2009 Notice of Amendment to the DSC (EB-2009-0077) identified that the new cost responsibility rules apply to investments associated with renewable generation projects for which an application to connect was made on or after October 21, 2009. As a consequence, investments to connect a RESOP generator remain the cost responsibility of the generator. Hydro One recognizes that the generators associated with this application have all made an application to connect before the October 21, 2009 date, and would therefore be subject to the previous cost responsibility rules – namely "generator pays". However, because the both costs in question and the need for them were unknown at the time, and as stated earlier, Hydro One maintains that it would be inappropriate to apply the "generator pays' rules to these costs.

It is Hydro One's view that recovering these costs from <u>distribution ratepayers</u> would be equally inappropriate. Distribution customers should rightly be allocated the costs of investments that directly benefit them – either individually or in rate pools. Consistent with the Board's policy in EB-2009-0349 ("Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09",or the "Framework for Direct Benefits"), Hydro One believes that distribution customers should fund investments only if they benefit "the customers of the distributor making the investment". This is not the case for the investments in question, which are only intended to hold the distributor's existing customers harmless and to protect them from the adverse impacts of certain technical issues that have emerged recently.

It can, however, be argued that the investments in question should rightly qualify as "eligible investment" costs, as set out in O. Reg. 330/09 and section 79.1 (5) of the Act, as they are for the purpose of "enabling the connection of a qualifying generation facility", that is one that satisfies the criteria necessary to be a renewable energy generation facility under the *Electricity Act, 1998*. The benefits resulting from the connection of these facilities accrue to all provincial consumers. And were it not for the fact that the generators in question applied for connection prior to October 21, 2009, these generators would have been treated under the amended distribution connection cost responsibility rules.

Thus the generators associated with these investments, by virtue of having applied for connection before October 21, 2009, and as a result of technical issues that have arisen since then, are "caught" in a regulatory confluence of circumstances beyond their control. Hydro One holds that this situation requires consideration in light of the intent of the relevant legislative and regulatory rules.

In conclusion, Hydro One maintains that the benefits of the investments in question accrue to all provincial ratepayers – not to the customers of the distributor making the investment, and seeks the Board's approval of the recovery of these investments accordingly. Since the Distribution System Code and the Board's Framework for Direct Benefits, prohibit investments to connect generation that was contracted under the RESOP program from being treated as an "eligible investment", Hydro One seeks an exemption from the Code in this respect, and asks that the Board deem the investments in question as eligible investments to be recovered under the principles of the Board's Policy related to O. Reg. 330/09 and consistent with Hydro One's treatment of other eligible investments.

DISTANCE LIMITATIONS:
A DESCRIPTION OF THE ISSUE AND HYDRO ONE'S ACTIONS

1.0 INTRODUCTION

At this time, 22 renewable energy generation projects in various stages of completion are considered likely to be the source of voltage fluctuation issues on distribution feeders, due to their distance from the station. The aggregate capacity of these projects is just over 200 MW and the total cost to address the issue is expected to be about $40 million.

2.0 THE ISSUE

Renewable generation located on some of Hydro One's longer distribution feeders is having an impact on the voltage levels and power quality experienced by customers located on the same feeder. The voltage fluctuations and related power quality problems are dependent on the connection point's distance from the terminal station and effects are amplified on lower voltage distribution lines located in rural areas. Recent experience in one particular case to date has shown that equipment damage has occurred with load customers located on the same feeder as the generator. The problem is exacerbated for projects that have a high degree of variability in voltage output such as wind and solar technologies. The problem can also occur in projects with a more consistent voltage output (such as hydroelectric or biogas) where occasional variability still has a negative impact.

3.0 IDENTIFICATION OF THE PROBLEM

The problem was first identified in early 2009, when customers of Hydro One located on the same long rural feeder as a DG facility experienced problems such as burned-out electrical equipment, consistent with voltage fluctuations. Subsequent monitoring has confirmed that the voltage fluctuations are a result of the connected generation.

Hydro One’s distribution system is mostly rural, with long feeders and small customer loads dispersed along the feeders. These characteristics make Hydro One’s distribution system particularly sensitive to changes in the power injected onto the system from renewable generators located on the feeder. If the generation is intermittent (for example, wind blowing in gusts or intermittent cloud cover for photovoltaic) and as the connection point for the generation moves further away from the TS, the problem is amplified.

Other jurisdictions connecting large amounts of renewable generation to a distribution system with stronger or shorter feeders or with a more densely populated customer base and higher loads may not experience the same problem. Thus, Hydro One was unaware of any similar documented issues in other jurisdictions such as Germany and the Scandinavian countries. The distance limitation problems experienced by Hydro One have not been previously documented in the mainstream industry journals and all prudent measures had been taken when initially considering the impact of the distributed generation on the Hydro One system.

4.0 IMPACTS OF VOLTAGE FLUCTUATIONS

Hydro One’s load customers on affected distribution feeders will experience the impacts of voltage fluctuations, particularly in their electronic equipment. Most electronic devices are designed to operate at a consistent voltage. When the voltage deviates from the rated voltage of the electrical devices, safety- or cost- related problems can occur such as burned-out motors, erroneous motion of robotics, lost data on volatile memory, destruction of hard drives, unnecessary downtime and increased maintenance.

The generators can also be negatively affected by these voltage fluctuations. Each occurrence of the problem could result in tripping off their facility which is problematic for equipment. More importantly, as their equipment warranties often are tied to the number of such trips, many of these events quickly utilize all their warranty during their first few months of operation.

5.0 HYDRO ONE'S ACTIONS TO ADDRESS THE ISSUE

5.1 Future Proponents

Since Hydro One had learned of this issue, it has used computer modeling software to simulate the problem and has identified the conditions, feeders and locations where the problem is likely to occur. Hydro One has incorporated the results of the computer modeling in future Distribution Availability Tests ("DATs") and Capacity Impact Assessments ("CIA's"). Thus, new applicants seeking a generation connection would be subject to an evaluation that would identify the problem and inform the proponent accordingly. Working with the proponent, Hydro One would identify mitigation measures and estimate the costs of these measures, for the proponent's information in making decisions related to the project.

5.2 Current Proponents

Twenty-two projects which all applied for connection prior to October 21, 2009, are likely to experience the distance limitation problems and are listed below in Table 1.

Table 1. Projects Affected by Distance Limitation (Voltage Fluctuations)

Project ID	Size (MW)	Technology	In-Service Date
835	6.7	Hydraulic	Connected
69	6.6	Wind	Connected
1084	9.9	Wind	Connected
1096	9.9	Wind	Connected
1097	9.9	Wind	Connected
1099	9.9	Wind	Connected
281	9.9	Wind	Connected
282	9.9	Wind	Connected
49	10.0	Wind	Connected
76	10.0	Wind	Connected
8	10.0	Wind	Aug. 16, 2010
645	1.3	Hydraulic	Sept. 1, 2010
89	10.0	Wind	Sept. 13, 2010
251	15.0	Hydraulic	Oct. 22, 2010
964	10.0	Solar	Nov. 1, 2010
965	10.0	Solar	Nov. 1, 2010
11bi	6.5	Wind	Nov. 30, 2010
274	9.9	Wind	Nov. 30, 2010
252	9.5	Hydraulic	Dec. 12, 2010
487	8.5	Solar	Dec. 14, 2010
1014	10.0	Wind	Dec. 31, 2010
689	10.0	Solar	Jan. 10, 2011

Hydro One engineering staff have considered various options to mitigate the problem and have identified the most appropriate approaches for each affected project. Further study on possible solutions will continue and will be implemented if determined. To date, only a few effective solutions have been identified, which include:

- the construction of dedicated feeders to isolate the voltage fluctuations from other customers who would otherwise be connected to the same feeder as the generator;
- re-conductoring existing feeders, effectively changing the electrical distance of the connected generator.
- the relocation of the 'point of common coupling' of the project to a point that is closer on the feeder to the terminal station; and
- reducing the installed capacity of the generation project.

The affected projects have been prioritized into groups reflecting their expected commercial in-service dates and Hydro One has taken a phased approach to address the issues, based on in-service date and expected severity, described below:

- Projects with Near-Term In-Service Dates

  A group of six projects totaling 51 MW with near-term in-service dates (Spring and Summer 2010) and having a high probability of exhibiting problems comprise this group. Hydro One is aware of the importance to these generators of meeting their planned in-service dates. Hydro One plans to mitigate the distance issue by such actions as building new dedicated feeders, re-conductoring existing feeders and moving projects to new feeders. The total cost of this work for this set of projects is expected to be $2 million.

- Projects with Longer-Term In-Service Dates

  This group comprises nine projects, totaling 89.4 MW, with a high probability of exhibiting problems but that have projected commercial in-service dates that occur late in 2010 or in 2011. This provides more time to digest the results of on-going monitoring and studies of the problem and provides an opportunity to identify lower-cost alternatives. If necessary, however, these projects would be addressed similarly to the first group. If mitigation at all projects is necessary, the total cost of work for this group of projects is estimated to be $23 million.

- Projects with Lower Probability of Problems

  This group represents seven projects totaling 63 MW, which have a lower probability of exhibiting problems (e.g., hydroelectric projects) or are already connected. Hydro One will install equipment to monitor the power quality and voltage levels on its distribution system to identify the magnitude of the problem. Based on the results of the monitoring, Hydro One will decide, in consultation with the proponent, the steps necessary to mitigate the problem, if any. The estimated cost of monitoring is $100,000. If mitigation is required at all locations, the maximum cost for these projects is estimated to be $17 million.

The maximum estimated costs for the cumulative mitigation proposals are shown in Table 2 below.

Table 2. Estimated Mitigation Costs for Distance Limitation Projects by Grouping

Grouping	Details	Plan	Maximum Estimated Cost
Projects with near-term in-service dates	Spring and Summer 2010	Address immediately	$ 2,000,000
Projects with later in-service dates	Late in 2010 or in 2011.	Study further before addressing	23,000,000
Less problematic projects	Lower probability of exhibiting problems or are already connected	Monitor and study	17,000,000
		Total Maximum Cost	$ 42,000,000

TRANSFORMERS WITH A DELTA-Y WINDING CONFIGURATION: A DESCRIPTION OF THE ISSUE AND HYDRO ONE'S ACTIONS

1.0 INTRODUCTION

Thirty-six (36) RESOP projects in the process of connecting to Hydro One's Distribution System have a Connection Impact Assessment ("CIA") and Connection Cost Recovery Agreement ("CCRA") that was executed prior to October 2008, in which a Delta-Y step-up transformer is specified. Studies undertaken after the completion of the CIA for 18 of these projects showed that the temporary over-voltage values produced by these transformers will be above the acceptable threshold

2.0 THE ISSUE

Distributed Generation projects typically use a step-up transformer to raise the output voltage to a level that is suitable for conveying the electricity from the generator's premise to a suitable point on the distribution system. The step-up transformers are generator-owned assets but must be selected with the distributor's input to ensure that the generator's operation and output are compatible with the distribution system.

Between 2004 and the fall of 2008, the Hydro One connection standard for a distributed generator ("generator") required a generator step-up transformer with a Delta-Y winding configuration. When over-voltage conditions were identified with some generators with this transformer configuration, Hydro One recommended a new configuration standard of Y-Delta in October of 2008. This new standard was established in the Technical Interconnection Requirements document published in March, 2009 and subsequently subjected to comprehensive stakeholder review. All connection assessments after October, 2008 were performed based on the new transformer standard.

A number of RESOP proponents, however, continued to proceed with the original connection process, having already entered into connection cost agreements with Hydro One and some having bought transformers based on the earlier standard.

3.0 IDENTIFICATION OF THE PROBLEM

Prior to the introduction of RESOP, Hydro One had decided that the optimal configuration for anticipated distributed generation connections was that without a high side ground source. Although this configuration runs the risk of over-voltages on four-wire distribution systems, it does not interfere with feeder protections (requiring feeder protection replacement). This meant specifying a delta transformer configuration on the high side and star configuration on the low side (Delta–Y). The following considerations were key to making this determination:

- the small number of connecting generators,
- confidence that the station ground source would be sufficient to control over-voltages and that low cost protection timing adjustments could ensure this,
- confidence that over-voltages on the feeders would not get through the step-down transformers to customer premises and
- cost -- major changes to feeder protection schemes would be costly for generators and would challenge Hydro One protection and control (“P&C”) resources. There would be a higher ongoing feeder protection coordination cost.

Subsequent studies and experience with connecting a large number of distributed generators determined that a high side ground source was required to mitigate the occurrence of over-voltage conditions. Hydro One began communicating this requirement to new projects late in 2008, however numerous CIAs had been issued with the original transformer specifications and generators had committed to purchase the equipment as specified in their CIAs.

4.0 IMPACTS OF VOLTAGE FLUCTUATIONS

Hydro One's load customers on affected distribution feeders will experience the impacts of voltage fluctuations, particularly in their electronic equipment. Most electronic devices are designed to operate at a consistent voltage. When the voltage deviates from the rated voltage of the electrical devices, safety- or cost- related problems can occur such as burned-out motors, erroneous motion of robotics, lost data on volatile memory, destruction of hard drives, unnecessary downtime and increased maintenance.

5.0 HYDRO ONE'S ACTIONS TO ADDRESS THE ISSUE

The solution to the over-voltage problem is to install a grounding transformer.

Hydro One plans to take the following steps:

1. To inform the affected generators directly of the new standard and the associated new requirements to allow them to plan for necessary investments.
2. Where generators have already procured the Delta-Y transformers and a grounding transformer is required, Hydro One is installing a grounding transformer on its distribution system. The cost for this retrofit is about $250,000. Where it is infeasible to do so, Hydro One will make arrangements with the generators to install a Hydro One grounding transformer at the generator's site, at a greater cost, up to $360,000.

The total cost of the program is estimated to range from $4.5 to $6.5 million (to perform the retrofit and associated work on the affected transformers on Hydro One's distribution system).

DUAL WINDING SECONDARY TRANSFORMERS: A DESCRIPTION OF THE ISSUE AND HYDRO ONE'S ACTIONS

1.0 INTRODUCTION

Substation transformers usually consist of two sets of windings – a primary (high side) winding and a secondary (low side) winding. Many station transformers are made with duplicate windings, to permit flexibility in operation. Specifically, dual secondary winding transformers have two identical secondary windings provided on each transformer. These can be connected in series or in parallel, or used as individual windings. Each of the two secondary windings is designed to carry half the rated kVA output of the transformer. The operation of the dual secondaries in conventional transmission and distribution applications has not been particularly problematic but, their increased use with distributed generation has revealed new issues, especially when the electrical flows in the two windings are unbalanced and/or in opposite directions.

2.0 THE ISSUE

Recent experience substantiated by information from one manufacturer has shown that a sub-set of Hydro One's transformers with dual secondary windings cannot withstand power flows in opposite directions on the secondary side and within that group a smaller sub-set also cannot tolerate power flows with a difference greater than a specified amount (referred to as an imbalance). Based on this information, Hydro One has contacted other transformer manufacturers to learn whether they, too share this technical concern. Having researched the problem, Hydro One has developed ratings of acceptable generation for all affected transformers. Exceeding those ratings will greatly increase the risk of transformer failure.

Approximately 13 transformers (see Table 1) are at stations that are over-subscribed with committed distributed generation ("DG") projects while others are expected to be highly subscribed in the FIT program. Reducing the available capacity at these stations would negatively impact DG projects currently underway, as well as substantially limit the success of the FIT program in resource-rich areas for renewable generators. As a cautious measure, monitoring and mitigating action plans should be put in place on all such impacted transformers where a higher capacity is being maintained despite the risk of imbalance.

These transformers are transmission assets, however, since they are directly limiting the generation connections on the distribution system, Hydro One is asking that the classification of all investments related to the resolution or mitigation of the transformer issues described in this Application be considered distribution expansion investments.

3.0 IDENTIFICATION OF THE PROBLEM

Hydro One's transformer fleet includes those with dual secondary windings which had been purchased and installed at a time of few, isolated DG connections to Hydro One's distribution system. In 2009, in response to Hydro One's request for information, one manufacturer of Hydro One transformers, replied that their transformers of pre-1986 vintage could not tolerate any reverse power flows or imbalance between the secondary windings, but those manufactured after 1986 would not demonstrate these issues. Consequently, for this manufacturer's transformers of pre-1986 vintage, Hydro One could no longer allow generation capacity for connection up to the "60%" rule for capacity and instead now had to restrict capacity for generation to minimum load, so as to prevent reverse flow.

Hydro One waited for information from another two manufacturers, and also for confirmation from the one manufacturer regarding the differences between the pre- and post-1986 vintages of equipment. However, this information was not received and the publication of station capacity values was needed for the launch of the FIT program. As a result, Hydro One decided, as a cautionary measure, based on the information that had been received to extend the criteria already applied to the one sub-set of transformers to the entire fleet of pre-1986 transformers with dual secondary windings.

Among the transformers identified as those which could not tolerate any reverse flow due to generation connections were those at several stations that were heavily subscribed during the Renewable Standard Offer Program (“RESOP”) and were also expected to be similarly subscribed during the Feed In Tariff (“FIT”) program. Many served feeders with generation connection projects whose proponents already held RESOP contracts with the Ontario Power Authority (“OPA”) and/or Connection Cost Recovery Agreements (“CCRAs”, later Connection Cost Agreements or “CCA’s”) with Hydro One. These generation projects had applied to Hydro One for connection at a time when the transformer limitations attributable to dual secondary windings and their impacts on the station capacity were unknown; the station capacity had been calculated according to the “60% rule” governing reverse flow conditions, and therefore, was higher.

Hydro One reduced capacity at some affected stations to prevent reverse flow for many transformers. For a small sub-set of affected stations in resource-rich areas (and for which many CCRAs had been executed), capacity was not reduced. Hydro One did not wish to impede generator connections or impose costs for potentially unnecessary mitigation measures in the absence of information from the transformer manufacturers which would have justified a more generic policy decision.

4.0 IMPACT ON LOAD CUSTOMERS AND HYDRO ONE'S DISTRIBUTION SYSTEM

The issues described above have a primary effect on Hydro One's equipment, but not a direct impact (similar to that experienced as a result of feeder voltage fluctuations) on Hydro One's distribution customers. In extreme cases, however, if the reverse flow is allowed to occur for an extended period of time, the transformer may fail, resulting in a risk of outage, with resulting impacts on both Hydro One's station and customer premises.

5.0 HYDRO ONE'S ACTIONS TO ADDRESS THE ISSUE

Based on information already received, Hydro One decided it would be responsible and prudent to extend the criteria, (that is, to restrict generation capacity to minimum load) to the entire fleet of pre-1986 transformers with dual secondary windings.

Hydro One has also identified those transformers with capacity issues and is addressing those that are expected to experience an imbalance or reverse power flows due to pre-FIT or legacy committed projects (the latter are those with existing CCRA's). Connection of projects to these transformers (shown in Table 1) is highly certain and the problem of over-subscription must be addressed immediately.

As a test case, Hydro One has installed real-time monitoring on two of the affected transformers – Modeland and Windsor-Malden. The results of the mitigation measures undertaken at Modeland and Windsor-Malden will be analyzed and a plan to deal with the remaining transformers will be developed. The cost of the mitigation and monitoring measures approved for these stations is approximately $1.5M. In addition, the replacement of a transformer at Windsor-Malden has recently been completed and will help alleviate the reverse flow problem.

In addition, mitigation measures such as rebalancing feeders, curtailing the generators and paralleling the secondaries are being developed and will proceed at these stations as a test of the mitigation measures available to address the problem. The following is a description of each measure:

- Potential re-configuration of a station's feeders to balance the generation ("Balancing the flow"). This requires accurately predicting the operation of connected loads and generators and configuring the connections so that the flow in the windings is essentially balanced at all times. This may help alleviate the problem and may reduce the amount of time that a dangerous imbalance occurs. However, this is not a guaranteed solution as the imbalance may continuously change with changes to load and generation and rebalancing does not fix the reverse flow problem.
- Curtailment - Development of criteria to curtail a certain amount of generation on a temporary basis. Curtailment plans will be negotiated with the affected generators.
- Electrically "paralleling" the two windings (referred to as "paralleling" the secondaries) - Investigation of the option of tying the transformer buses together under certain conditions and on a temporary basis. This effectively balances the flows in the two windings, but also causes the transformer to operate as if it were a single secondary winding unit, and hence eliminates the redundancy and reliability benefit inherent in the dual winding design. Accordingly, the reliability will decrease for a certain period of time as a result of the paralleling, but the imbalance problem will be avoided. Again, this option does not fix the reverse flow problem.

The in-service dates and the connection plans for the DG projects on all projects at highly over-subscribed stations will not be affected unless requested by the generator.

Table 1. Over-Subscribed Stations due to Problematic Dual Secondary Winding Transformers

Station Name	Transformer #	TX - LV Winding S= Single D= Double	Amount of Committed Generation above Acceptable Levels
BRANTFORD TS	T3	D	-2.1
BRANTFORD TS	T4	D	-2.1
BUCHANAN TS	T13	D	-8.0
BUCHANAN TS	T14	D	-8.0
KENT TS	T1	D	-8.0
KENT TS	T2	D	-8.0
MODELAND TS	T4	D	-28.0
ORANGEVILLE TS	T1	D	-3.9
ORANGEVILLE TS	T2	D	-3.9
TALBOT TS	T3	D	-6.8
TALBOT TS	T4	D	-6.8
WINDSOR MALDEN TS	T1	D	-27.6
WINDSOR MALDEN TS	T2	D	-27.6

SECTIONS OF THE DISTRIBUTION SYSTEM CODE COVERED BY HYDRO ONE'S REQUEST FOR AN EXEMPTION

The sections of the Board's Notice of Amendments to the Distribution System Code and the Code, itself, from which Hydro One wishes to be exempted are those in bold text, below.[1]

Excerpt from the Notice of Amendments to the Distribution System Code, EB-2009-0077, page 10

> "As stated in the June Notice and the September Notice, with respect to distribution system investments related to the connection of renewable generation facilities that are intended to be covered by the Final Amendments, **the Board confirms that the Final Amendments apply only to investments associated with renewable generation projects for which an application to connect was made on, or after, today's date"** [October 21, 2009].

3.2.5A Notwithstanding section 3.2.5 but subject to section 3.2.5B, 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.

3.2.5B Where an expansion is undertaken in response to a request for the connection of more than one renewable energy generation facility, a distributor shall not charge any of the requesting generators to construct the expansion:

(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 amount that results from adding the total name-plate rated capacity of**

[1] As there are references to Sections 3.2.5 and 6.2.9 a, these also are included for completeness only.

each renewable energy generation facility referred to in section 6.2.9(a) (in MW) and then multiplying that number by $90,000.

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 number that results from the calculation referred to in (b).

3.2.5 The capital contribution that a distributor may charge a generator to construct an expansion to connect a generation facility to the distributor's distribution system shall not exceed the generator's share of the present value of the projected capital costs and on-going maintenance costs for the facilities. Projected revenue and avoided costs from the generation facility shall be assumed to be zero, unless otherwise determined by rates approved by the Board. The methodology and inputs that a distributor shall use to calculate this amount are described in Appendix B.

6.2.9 Where a person who is considering applying for the connection of a generation facility to the distributor's distribution system requests a preliminary meeting with the distributor and provides the required information, the distributor shall provide a time when it is available to meet with the person which is within 15 days of the person providing the required information. For the purposes of this section, the following is the required information:

a. the name-plate rated capacity of each unit of the proposed generation facility and the total name-plate rated capacity of the generation facility at the connection point;

REQUEST FOR EXEMPTIONS FROM THE DISTRIBUTION LICENCE WITH RESPECT TO THE DISTRIBUTION SYSTEM CODE TO ADDRESS PROCESSING ISSUES FOR LARGE RENEWABLE ENERGY GENERATION PROJECTS

Hydro One Networks Inc. ("Hydro One") applies to the Board for exemptions from Hydro One's Electricity Distribution Licence ED-2003-0043 as it pertains to certain sections of the Distribution System Code ("DSC") in relation to the obligation on distributors to remove an applicant's capacity allocation if a connection cost agreement has not been signed in relation to the connection of the embedded generation facility within the 6-month timeframe specified in the DSC. This exemption is requested in light of the timelines required to process applications from and perform assessments for large embedded renewable energy generators ("large generators") to connect to Hydro One's distribution system.

1.0 INTRODUCTION

At this time, Hydro One is processing applications from over ten large generation proponents who have applied to connect to its distribution system under the FIT program. The DSC requires that an applicant's capacity be removed if, within six months after the project capacity has been allocated:

- a Connection Cost Agreement ("CCA") has not been executed (Section 6.2.4.1 e i), or
- the appropriate deposits have not been paid at the time that the CCA is executed for post-October 21, 2009, applicants (Section 6.2.18 a).

Hydro One believes that this six-month timeline is generally feasible for small and mid-sized generators, as their review consists of a distribution connection impact assessment ("distribution CIA") and a potential Transmission Station ("TS") review (where needed). However, the IESO's Market Rules require that large generator connection applications must also undergo a System Impact Assessment ("SIA") by the IESO and a Transmission Customer Impact Assessment by Hydro One Transmission. Ontario Regulation 326/09 made under the *Electricity Act. 1998*, stipulates up to 150 days to accommodate these studies. Should upgrades to the transmission system be required as a result of these assessments, further time is needed to develop the scope of work and detailed cost estimates. These additional time requirements could result in the removal of the proponent's capacity allocation well before the completion of the cost estimates and the CCA.

Hydro One believes that this issue can be resolved through exemptions from certain sections of the DSC.

2.0 THE CURRENT SITUATION

2.1 Hydro One's Understanding of the Current Situation

Under the current rules, it is Hydro One's understanding that the application process for a large generator is the following:

<u>Phase 1 (3 Months)</u> – The distributor completes a distribution CIA and provides it to the proponent within 90 days after the receipt of the application (according to DSC Section 6.2.13). Subject to a successful review, capacity may be allocated to the proponent at that time (DSC Section 6.2.4.1). The six-month timeline for the proponent to execute the CCA and pay the relevant deposits begins upon completion of the Connection Impact Assessment. (DSC Sections 6.2.4.1 (a), 6.2.4.1(e)(i) and (iii) and 6.2.18 (a).

<u>Phase 2 (5 Months)</u> -- The distributor collects payment from the proponent for the SIA and Transmission Customer Impact Assessment (if not done previously), then prepares the SIA application and conveys the distribution CIA, SIA application and payment on

the proponent's behalf, to the IESO. The IESO will, upon completing the SIA, forward it, with the distribution CIA, to the transmitter. The distributor also forwards the generator's payment for the Transmission Customer Impact Assessment to the transmitter, enabling the transmitter to commence work. The Transmission Customer Impact Assessment, once complete, is then delivered to the distributor.

Hydro One's experience is that the steps in this phase are sequential, that is, that the IESO cannot begin the SIA until it receives the distribution CIA and similarly, that a prerequisite for beginning the Transmission Customer Impact Assessment is the receipt of the prior two reviews. The allowed time period for this phase is 150 days (O. Reg. 326/09).

<u>Phase 3 (Variable)</u> – Section 6.2.16 of the DSC states that "In the case of an application for the connection of a mid-sized or large embedded generation facility, once the impact assessment is provided to the applicant, the distributor and the applicant have entered into an agreement on the scope of the project and the applicant has paid the distributor for the cost of preparing a detailed cost estimate of the proposed connection, the distributor shall provide the applicant with 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 transmitter or distributor that has been advised under section 6.2.17."

Hydro One interprets "the impact assessment" referred to in Section 6.2.16 above, to be the Transmission Customer Impact Assessment and believes there may be a few scenarios at this stage:

- If, as a result of all the studies, a need for only distribution upgrades has been determined:
    - Should a generator request a simple cost estimate, the distributor has 30 days from the completion of the Transmission Customer Impact Assessment to prepare and deliver this with an offer to connect.

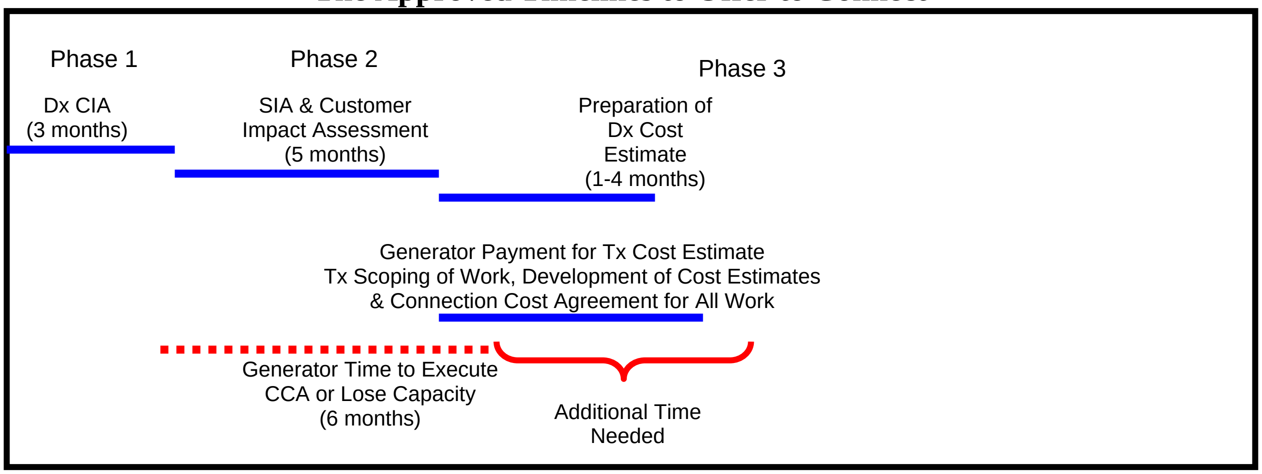
- ◦ Should a generator request a detailed cost estimate, Hydro One interprets Section 6.2.16 as providing the generator some time (perhaps a couple of weeks to a month) after receipt of all the studies to enter into an agreement with the distributor and make a payment for a detailed cost estimate. The distributor then has up to 90 days after that payment to provide the detailed cost estimate and offer to connect.
- If there is a need for *both* distribution and transmission upgrades:
  - ◦ The same timelines above, apply to the processes for developing and delivering cost estimates for both distribution and transmission upgrade work. That is, the distributor has up to 90 days after payment from the generator, to prepare the detailed cost estimate for distribution upgrades, request and receive the transmitter's cost estimate and provide the total package with the offer to connect (that is, the CCA) to the generator.

2.2 Implications

2.2.1 <u>If Only Distribution Upgrades Are Needed</u>

Should all parties take their maximum allowed time allotments to complete these tasks, as noted above, Phases 2 and 3 extend beyond the proponent's six-month deadline for capacity removal. Diagram 1 below, shows a simplified version of Hydro One's interpretation of this timeline, where the top line in Phase 3 represents the timeline for a distributor to either prepare a simple cost estimate, or, should the proponent want a detailed cost estimate, to reach agreement with the generators on the scope of work, receive payment for the detailed cost estimate, then prepare and deliver that with the offer to connect. The bottom line in Phase 3 represents the time required for the transmitter to undertake a similar process to develop a detailed scope of work and cost estimate for any required transmission upgrades.

Diagram 1
The Approved Timelines to Offer to Connect



3.0 HYDRO ONE’S PROPOSAL

To help resolve these issues, Hydro One proposes the following:

<u>Phase 1</u> – The distributor completes a CIA within the 90-day deadline and delivers it to the proponent. Capacity is allocated to that project *on a provisional basis*, until the SIA and Transmission Customer Impact Assessment and relevant other information are complete.

<u>Phase 2</u> – Work on the SIA and Transmission Customer Impact Assessment proceeds as described in Section 2.1, and, once these are finished:

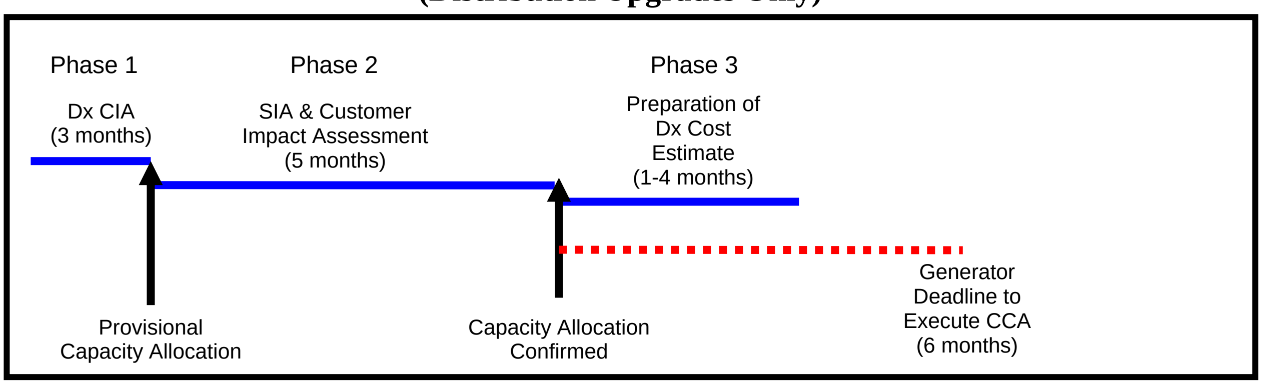
- The distributor packages all the studies and provides these to the generator with notice that:
  - Its capacity allocation is confirmed (as of the date that the SIA and CIA are completed); and
  - the timeline to execute the CCA and pay the relevant deposits begins on the same date.

- Hydro One proposes that:
    - Should only distribution upgrades be needed, the time for the generation to sign a CCA remains six months, but begins from the date that the capacity allocation has been confirmed.
    - Should both distribution and transmission upgrades work be needed, the time for the generator to sign a CCA would be extended by one month beyond the date that the scope of work and cost estimate for the transmission upgrades are provided to the proponent.

Phase 3

If Only Distribution Upgrades Are Needed – The distributor prepares the cost estimate for the distribution upgrades and delivers this with the offer to connect to the generator, within the month after the issuance of the SIA and Transmission Customer Impact Assessment, as per Hydro One's understanding of the intent of Section 6.2.16. The proposed timeline is shown below, in Diagram 2.

Diagram 2
Hydro One's Proposed Timelines to Offer to Connect
(Distribution Upgrades Only)



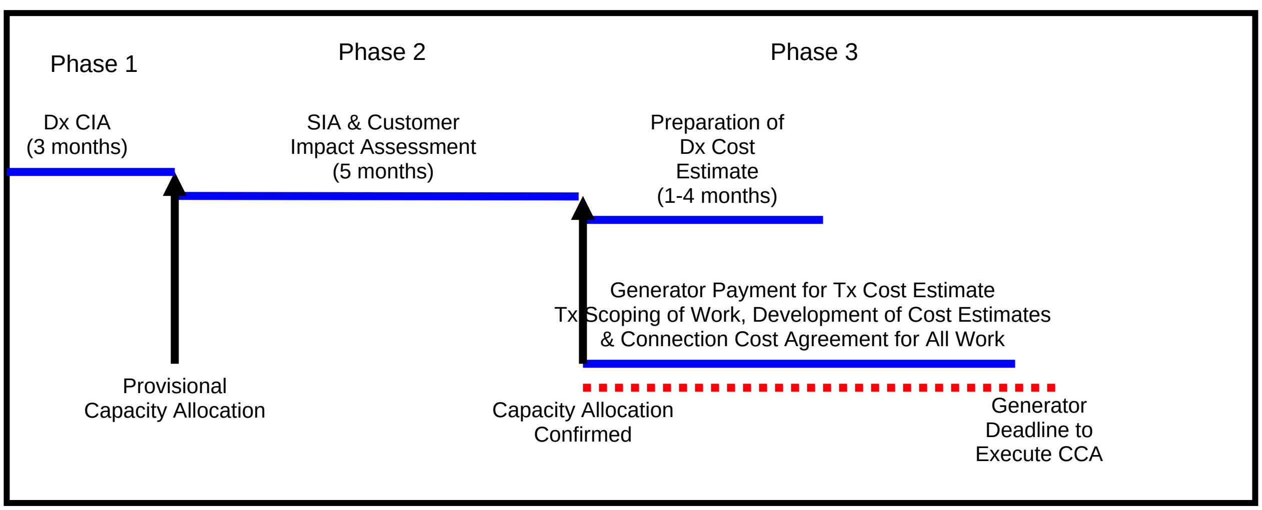
If Both Distribution and Transmission Upgrades are Needed – The distributor prepares the cost estimate for any needed distribution upgrades and provides the generator a package which includes:

- the distribution cost estimate; and
- further information on obtaining a detailed scope of work and cost estimate for the transmission upgrades.

Hydro One proposes that the generator be provided two weeks to assess the study results, decide whether to proceed further and provide payment to the transmitter for the scope of the transmission work and cost estimate.

Upon receipt of payment from the generator, the transmitter then prepares a detailed scope of work and cost estimate for the required transmission upgrades and returns this to the distributor. The distributor compiles the total costs of all distribution and transmission upgrades and completes the offer to connect. Diagram 3, below, displays Hydro One's proposed timeline.

Diagram 3
Hydro One's Proposed Timelines to Offer to Connect
(Distribution and Transmission Upgrades Required)



4.0 APPROVALS REQUESTED

Hydro One believes that its proposed approach is feasible, but it will require certain exemptions from the DSC. Therefore, with respect to the processing of connection applications from large generators, Hydro One respectfully requests the Board's approval of exemptions from the following sections of the DSC:

- 6.2.4.1e(i), which directs the removal of a proponent's capacity if the CCA has not been executed within six months of that capacity having been allocated. This exemption would allow for a provisional allocation of capacity, with a later confirmation.
- 6.2.4.18a, which directs that the connection cost deposit for 100% of the total allocated project cost be paid at the time the CCA is executed.

  The request for this exemption with the timeline revisions discussed by Hydro One in Phases 2 and 3 of its proposal, would allow sufficient time for the distributor, the IESO and the transmitter to complete all the relevant impact assessments as well as preparation of cost estimates for both distribution and transmission work, which will comprise the total connection cost deposit, enabling proponents to finalize their financing arrangements and make their payments.
- 6.2.4.1c, which states that the CIA will not be considered complete unless the in-service date for the generation facility is within three years (for non-water power projects) after the initial application date or in accordance with the timelines in an executed OPA contract. This acknowledges that the additional time required to complete the SIA, Transmission Customer Impact Assessment and the relevant cost estimates will encroach on the generation facility's construction phase and possibly jeopardize the originally contracted in-service dates. (The proponent may also have to re-negotiate the original in-service date in their contract with the OPA.)
- 6.2.16, which directs the distributor to provide the full costs of distribution and transmission upgrades within 90 days after receipt of payment from the generator.

Exhibit C, Tab 2, Schedule 1, contains all the sections of the DSC from which these exemptions have been requested.

5.0 RATIONALE FOR THIS EXEMPTION REQUEST

5.1 The Need for Provisional Allocation of Capacity

Hydro One supports the intent of the DSC rules to ensure efficient and fair processing of all applications for generator connection to its distribution system. As noted earlier, the direction in the DSC to remove the capacity of generation proponents who have not executed their contract or paid their deposits within the specified timeline is feasible for small and medium-sized generators.

Hydro One submits that this rule does *not* reflect the additional reviews required for large generators, and is not aligned with the timelines stipulated in O. Reg 326/09. Even in the best circumstances, it will likely take a full six months *after* completion of the CIA (and allocation of the capacity) for the IESO and transmitter to complete their reviews. Should transmission upgrades be needed, further time is required to develop the related cost estimates. The generation proponent cannot, in Hydro One’s view, be expected to execute a CCA and/or make a connection cost deposit in the absence of certain information that is simply unavailable within the DSC-stipulated timelines. In these cases, compliance by the distributor with the DSC’s six-month rule results in an action which is ultimately unfair to the proponent – removal of the applicant’s capacity allocation.

However, should a proponent’s capacity not be allocated until the end of all the reviews, the proponent could again lose its “spot” to smaller generators, whose applications have been submitted subsequently, but are not subject to the same degree of review.

For these reasons, Hydro One proposes the concept of *provisional* capacity allocation, with confirmation of this capacity allocation at the date when all studies are complete.

5.2 Other Alternatives Considered

In coming to these proposals, Hydro One contemplated developing a different CCA "template" for large generators only, for execution according to the DSC's timelines (that is, this CCA would be provided, with the distribution cost estimate, to the generator after the CIA is completed). This CCA would recognize that reviews are continuing and that transmission upgrades *may* be required. It would, therefore, contain either:

a) the distribution cost estimate only, with the proviso that any transmission upgrades and related costs estimates be provided later; or
b) the distribution cost estimate, plus a very generic transmission cost estimate (under the assumption that some transmission upgrades may be identified later).

In these cases, the proponent would be required to execute the CCA and provide a deposit for all the stated costs as per the DSC.

Neither of these arrangements is considered feasible. Option a) would work only if distribution upgrades are required. If transmission upgrade work proves necessary, this option will have contravened section 6.2.18a of the DSC, which requires that the connection cost deposit represent 100% of the fully-allocated costs of the facility connection. The cost estimate in Option b) would be highly inaccurate for the transmission portion of work, possibly requiring the proponent to provide up-front funding for unidentified "work" which may prove later to be unnecessary, or requiring the distributor to request additional funding well after the CCA has been executed. For these reasons, Hydro One submits that its proposal of allowing greater flexibility in the six-month timeline is more reasonable and would be preferable to both parties. Hydro One submits that when transmission upgrades are needed, linking a three-month extension to the transmitter's completion of cost estimates is the most appropriate approach, as it recognizes the varying degree of complexity which may be involved for different connections.

Hydro One submits that this overall approach provides the best balance between equitable treatment of large generation proponents with the need to provide all generation proponents with an efficient application process.

SECTIONS OF THE DISTRIBUTION SYSTEM CODE COVERED BY HYDRO ONE'S REQUEST FOR AN EXEMPTION

6.2.4.1 e an applicant shall have its capacity allocation removed if:

i. a connection cost agreement has not been signed in relation to the connection of the embedded generation facility within 6 months of the date on which the applicant received a capacity allocation for the proposed embedded generation facility;

6.2.18 A For any proponent that executed a connection cost agreement prior to the date of coming into force of this section, but is not yet connected to the distributor's distribution system, the distributor shall notify the proponent of that embedded generation facility, within 60 days of this section coming into force, that a connection cost deposit equal to 100% of the total allocated cost of connection and a capacity allocation deposit equal to $20,000 per MW of capacity of the embedded generation facility must be paid within 60 days of the distributor's notice as a condition of the applicant maintaining its current capacity allocation.

6.2.4.1 c a connection impact assessment will not be completed unless the embedded generation facility which is the subject of the application meets the following requirements at the time the application is made:

- demonstrated site control over the land on which the embedded generation facility is proposed to be located and any required adjacent or buffer lands in the form of property ownership (deed), long term lease (lease agreement) or an executed option to purchase or lease the land.

- a proposed in-service date for the embedded generation facility which is no later than 5 years for water power projects or 3 years for all other types of projects from the initial date of application for connection or in accordance with the timelines in an executed OPA contract.

6.2.16 In the case of an application for the connection of a mid-sized or large embedded generation facility, once the impact assessment is provided to the applicant, the distributor and the applicant have entered into an agreement on the scope of the project and the applicant has paid the distributor for the cost of preparing a detailed cost estimate of the proposed connection, the distributor shall provide the applicant with 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 transmitter or distributor that has been advised under section 6.2.17.