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**Susan Frank**
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

July 4, 2013

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

Dear Ms. Walli:

**EB-2013-0246 – Hydro One Networks' Section 92 – Niagara Region Wind Generation Connection Project– Application and Evidence**

I am attaching two (2) copies of the Hydro One Networks' Application and Prefiled Evidence in support of an Application pursuant to Section 92 of the Ontario Energy Board Act for an Order or Orders granting leave to upgrade 25 km of transmission line facilities in the Niagara region.

An electronic copy of the complete application has been filed using the Board's Regulatory Electronic Submission System (RESS) and the proof of successful submission slip is attached.

Hydro One Networks' contacts for service of documents associated with this Application are listed in Exhibit A, Tab 2, Schedule 1.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.

c. Darren Croghan

# 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 granting leave to upgrade transmission line facilities in the Niagara region of Ontario (the "Niagara Region Generation Connection Project" or the "Project").

## APPLICATION

1. The Applicant is Hydro One Networks Inc. ("Hydro One"), a subsidiary of Hydro One Inc. The Applicant is an Ontario corporation with its head office in the City of Toronto. Hydro One carries on the business, among other things, of owning and operating transmission facilities within Ontario.

2. Hydro One hereby applies to the Ontario Energy Board (the Board) pursuant to section 92 of the *Ontario Energy Board Act*, *1998* for an order or orders granting leave to upgrade a section of transmission circuit in the Niagara region. This upgrade is required to increase capacity by replacing existing idle conductor with a new 115KV overhead conductor for a 25 kilometer section of line Q5G from Hamilton Beach Transformer Station to Structure Number 154 near Mountainview Road in the Town of Lincoln.

3. The need for the project is described in detail in **Exhibit B, Tab 1, Schedule 4**. The need for the proposed upgrade to a 115 kV transmission circuit in the Niagara region arises from the planned addition of a new wind power generation farm in the area by Niagara Region Wind Corporation ("NRWC"). The existing single circuit 115kV Q5G line can only accommodate approximately 180 MW, which is insufficient as the NRWC

wind farm project will add 230 MW to the system. NRWC has therefore requested that Hydro One upgrade the circuit to accommodate their project. The proposed addition is to be fully paid for by NRWC by means of a capital contribution consistent with the *Transmission System Code*. The target in-service date is September 2015. Although construction is not scheduled to begin until May 2014, Hydro One is seeking approval at this time in order to facilitate timely and orderly planning of the project.

4. As part of NRWC's generation project, NRWC plans to construct 34 kilometres of 115 kV line. As such, NRWC has filed a Leave to Construct application with the Ontario Energy Board (docket number EB-2013-0203). It should be noted that although the two Leave to Construct projects (Hydro One's and NRWC's) are separate projects, Hydro One will not proceed with construction of the Q5G upgrade project until NRWC obtains all necessary approvals on its own project. More information on the sequencing of both projects is provided within the application at **Exhibit B, Tab 5, Schedule 2.**

5. The IESO has carried out its System Impact Assessment (SIA) of the proposed addition in accordance with the Grid Connection Requirements of the Market Rules and the associated IESO Connection Assessment and Approval Process. The IESO's SIA indicates that Hydro One's proposed transmission solution is adequate and does not adversely impact the IESO-controlled grid. The SIA is filed as **Exhibit B, Tab 6, Schedule 3**.

6. Hydro One has completed a Customer Impact Assessment ("CIA") in accordance with its customer connection procedures, and results confirm there are no adverse impacts on transmission customers as a result of this project. The document is filed as **Exhibit B, Tab 6, Schedule 4**.

7. The necessary land rights (easements) for the project consist of existing easement rights Hydro One holds on the provincially-owned corridor lands, as well as permanent easements rights on private property. No new land rights beyond temporary access rights are needed to construct the required line and station facilities. A map showing the general location of the proposed transmission facilities may be found in **Exhibit B, Tab 2, Schedule 2**.

8. Hydro One will be seeking approval of the proposed transmission facilities in accordance with the *Class Environmental Assessment for Minor Transmission Facilities* ("Class EA") approved by the Ministry of Environment ("MOE")

9. Hydro One has notified stakeholders and local First Nations and Metis communities that may have an interest in this proposed line addition. Hydro One will ensure stakeholders' issues are addressed. Hydro One will continue to inform area elected officials, and relevant provincial government ministries and agencies of the project status. During the construction and commissioning stages of the proposed addition, Hydro One will consult with the local community and other interested stakeholders to ensure potential concerns are addressed.

10. This Application is supported by written evidence. This evidence includes details of the Applicant's proposal for the construction of the proposed transmission line facilities. The written evidence is pre-filed as attached and may be amended from time to time, prior to the Board's final decision on this Application. Further, the Applicant may seek meetings with Board Staff and intervenors in an attempt to identify and reach agreements to settle issues arising out of this Application.

11. Hydro One requests a written hearing for this proceeding.

12. Hydro One requests that a copy of all documents filed with the Board be served on the Applicant and the Applicant's counsel, as follows:

13. The Applicant:

Mr. Jamie Waller
Senior Regulatory Coordinator - Regulatory Research and Administration
Hydro One Networks Inc.
Mailing Address: 8th Floor, South Tower
483 Bay Street
Toronto, Ontario
M5G 2P5

Telephone: (416) 345-6948
Fax: (416) 345-5866
Electronic access: regulatory@HydroOne.com

b) The Applicant's counsel:

Michael Engelberg
Assistant General Counsel
Hydro One Networks Inc.

Mailing Address: 15th Floor, North Tower
483 Bay Street
Toronto, Ontario
M5G 2P5

Telephone: (416) 345-6305
Fax: (416) 345-6972
Electronic access: mengelberg@HydroOne.com

# SUMMARY OF PREFILED EVIDENCE

Hydro One Networks Inc. ("Hydro One") has applied to the Board for an order granting leave to upgrade existing transmission line in the Niagara region of Ontario pursuant to Section 92 of the *OEB Act, 1998* (the *"OEB Act"*).

The proposed facilities to be constructed, owned and operated by Hydro One are described in **Exhibit B, Tab 2, Schedule 1.** A map showing the location of the proposed transmission facilities is provided in **Exhibit B, Tab 2, Schedule 2.**

The planned in-service date for the Niagara Region Wind Generation Connection Project (**"the Project"**) is September 2015. A construction schedule for the project is shown at **Exhibit B, Tab 5, Schedule 2.** This schedule is contingent on the outcome of NRWC's related s. 92 application (EB-2013-0203).

The proposed facilities are in the public interest because it satisfies the needs proposed below:

- It will connect the Niagara Region Wind Project, presently before the Board in proceeding EB-2013-0203, and that project, in alignment with the provincial government's policy objective, will increase the amount of renewable energy generation in Ontario.

- It will not have a material impact on the price of electricity as the Project is being undertaken at Niagara Region Wind Corporation's **("NRWC")** request and NRWC is expected to pay for all costs of the Project via a capital contribution as per the requirements of the Transmission System Code **("TSC"**).

Further evidence on the need of the proposed facilities is found at **Exhibit B, Tab 1, Schedule 4**.

The Independent Electricity System Operator (**"IESO"**) has granted conditional approval for the connection of the Niagara Region Wind Farm proposed by NRWC in its final System Impact Assessment Report of July 27, 2012. The document is filed as **Exhibit B, Tab 6, Schedule 3**.

Hydro One has completed a Customer Impact Assessment (**"CIA"**) in accordance with its customer connection procedures and results indicate that the Niagara Region Wind Farm project can be incorporated without any adverse impacts. The document is filed as **Exhibit B, Tab 6, Schedule 4**.

The total cost of this project is estimated to be approximately $16 million. The proposed circuit will be added to the Line Connection pool as an asset with zero Net Book Value, as the cost is to be fully funded by a customer capital contribution, consistent with TSC requirements. Details of the project economics are filed in **Exhibit B, Tab 4, Schedule 2.**

The design of the proposed facilities is in accordance with good utility practice and meets the requirements of the TSC for licenced transmitters in Ontario.

Hydro One will notify stakeholders in the Niagara region of the proposed connections. Hydro One will hear stakeholder concerns and ensure they are addressed, as well as ensure that public authorities are kept informed of the project status. Details regarding the consultation process are filed in **Exhibit B, Tab 6, Schedule 6.**

Hydro One is undertaking an engagement process with neighbouring First Nations communities to provide information about the Project. However, the Ministry of Energy has advised that the project will not result in any appreciable adverse impacts on the rights of any Aboriginal communities so as to trigger the duty to consult. Further information on Hydro One's engagement process for First Nations and Métis is filed in **Exhibit B, Tab 6, Schedule 5.**

This project is subject to the Class Environmental Assessment (EA) for Minor Transmission Facilities under the *Environmental Assessment Act.* Given the low-impact nature of the project, it will be assessed under the Class EA Screening Process. This screening is planned to be filed with the Ministry of Environment once NRWC obtains approval of its Renewable Energy Approval application.

A letter of support for the proposed addition, including a commitment of the required capital contribution, has been obtained from NRWC and is filed as **Exhibit B, Tab 6, Schedule 2**.

A detailed construction schedule is filed as **Exhibit B, Tab 5, Schedule 2**. This schedule assumes Board leave to construct under Section 92 of the *OEB Act* by January 2014. Although construction is not scheduled to begin until May 2014, Board approval is being sought at this time to facilitate timely and orderly planning of the project. This schedule is also dependent on the outcome of the NRWC s. 92 application in EB -2013-0203.
Hydro One requests a written hearing for this proceeding and submits that the evidence supports granting the requested Order based on the following grounds:

- The need for an additional circuit has been established;
- The project is supported by and will be funded by NRWC;
- The need for the project is endorsed by the IESO;
- The project will support increasing renewable generation in the province;

- There are no adverse system or customer impacts from the project;
- The project is fully compliant with the relevant codes, rules and licences.

For the reasons provided in support of this Application, Hydro One respectfully submits that the proposed upgrade is in the public interest and should be approved under Section 92 of the *OEB Act.* Accordingly, Hydro One requests an Order from the Board pursuant to Section 92 of the *OEB Act* by January 2014, granting leave to construct the proposed transmission line addition.

# PROCEDURAL ORDERS / AFFIDAVITS / CORRESPONDENCE

# NOTICES OF MOTION

# PROJECT LOCATION AND EXISTING TRANSMISSION SYSTEM

## 1.0 PROJECT LOCATION

The study area addressed by this project is located in the Lincoln, Grimbsy and Hamilton Municipalities in the Niagara Region. The currently idle 115kV, 25 Hz Q5G transmission circuit a section of which is to be upgraded spans these municipalities.

The 115kV Q5G transmission line runs roughly 72 km (East-West) south of Lake Ontario from Niagara Falls (Sir Adam Beck Switching Station #1) to Hamilton (Hamilton Gage TS). The capacity of a section of this circuit is being upgraded to address the need for additional transmission capacity to accommodate Niagara Region Wind Corporation's (NRWC) generation connection. Specifically, the circuit section being upgraded is from Tower 154 in the Lincoln Municipality to Beach Jct in Hamilton, a distance of approximately 25 km. The current planned in-service date of this project is September 2015. However, to the extent possible and as requested by NRWC, Hydro One will put forward reasonable efforts to advance the in-service date of the currently idle Q5G circuit to the fourth quarter of 2014. This in-service date is to align with the expected in-service date of the generation facility proposed by NRWC. Further information on the project schedule is described in **Exhibit B, Tab 5, Schedule 2.**

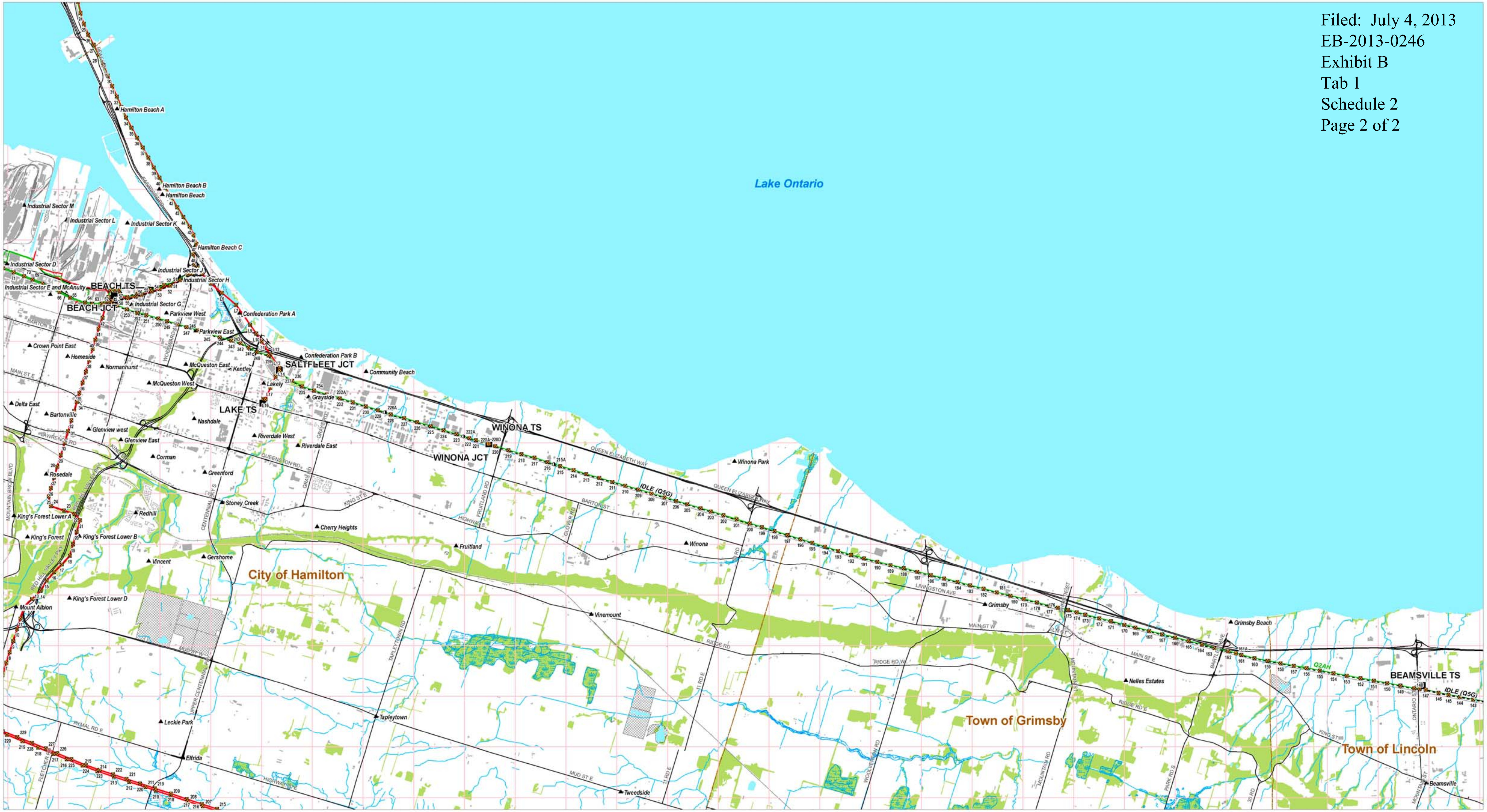
As part of the overall connection requirements for its wind project, NRWC is building a 34 km section of 115 KV transmission line which will connect with Hydro One's upgraded circuit Q5G. That project is the subject of a separate Section 92 application filed with the Ontario Energy Board as EB-2013-0203. Although the NRWC's application is separate from Hydro One's application, Hydro One's plan to proceed with the upgrade work of circuit Q5G is contingent on the outcome of the NRWC application.

## 2.0 EXISTING TRANSMISSION FACILITIES

There are several load customers in the area covered by this project. The 115 kV, 25 Hz line Q5G is currently idle but it shares its towers with the active 115kV Q2AH transmission circuit. The Q2AH circuit services load customers connected to Vineland DS and Beamsville TS located in the project area.

A map of the existing transmission facilities is provided in **Exhibit B, Tab 1, Schedule 2**, and a schematic electrical diagram of the existing facilities is provided in **Exhibit B, Tab 1, Schedule 3**.

# MAP OF EXISTING FACILITIES




## - Circuit Q5G (IDLE) -

hydro one

**Transmission Line Structure**
- 1 Pole
- 2 Pole
- H-Frame
- Lattice

**Transformer / Switching Station**

**Transmission Line**
- 0 kV
- 115 kV
- 230 kV

- Roads
- Railway
- Named Place
- Buildings

- Rivers
- Water Body
- Wetlands
- Species at Risk

- Geographic Township Boundary
- Pit or Quarry
- Wooded Area

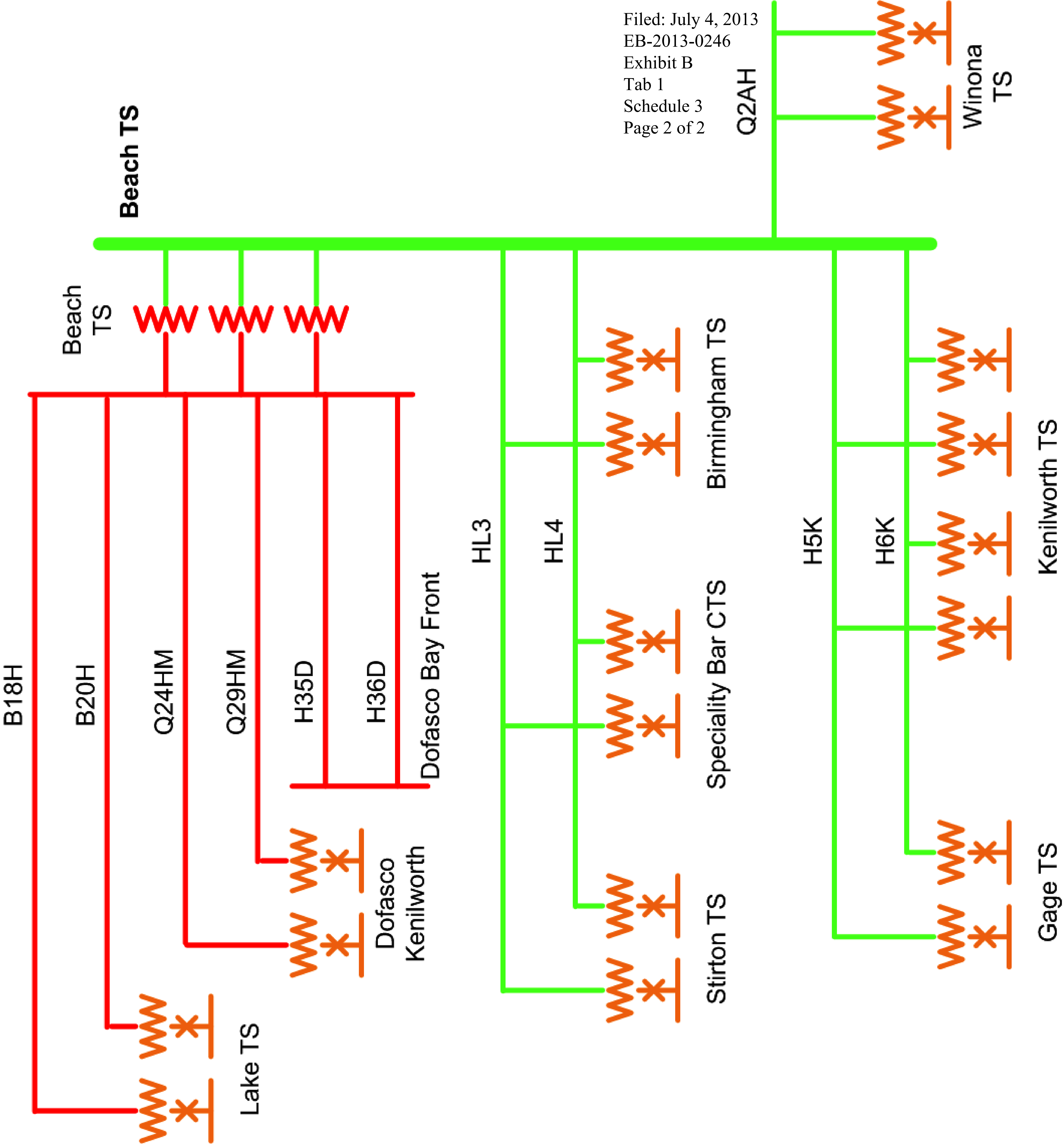
1:35,000

0 1 2 3 4
Kilometers

Produce by: GIS Services, Inergi LP
Date: September 2012
File #: Map12-63_IDLE(Q5G)

inergi

# SCHEMATIC DIAGRAM OF EXISTING FACILITIES


Beach TS
Q2AH
Winona TS
Beach TS
Birmingham TS
Kenilworth TS
HL3
HL4
H5K
H6K
Speciality Bar CTS
Stirton TS
Gage TS
B18H
B20H
Q24HM
Q29HM
H35D
H36D
Dofasco Bay Front
Dofasco Kenilworth
Lake TS

# NEED FOR THE PROPOSED FACILITIES

## 1.0 BACKGROUND

This Schedule describes the need to upgrade a section of the Q5G transmission circuit from Beach TS to Tower 154, approximately 25 km west, to meet the demand for new electricity generation in the area. The existing facilities are described in **Exhibit B, Tab 1, Schedule 1**.

Niagara Region Wind Corporation ("NRWC") is planning to install wind generation facilities in the Niagara Region. NRWC was awarded a Power Purchase Agreement under the Feed-In Tariff ("FIT") program with the Ontario Power Authority on February 24, 2011. The purpose of Hydro One's Niagara Region Wind Corporation Project is to increase capacity to accommodate 230 MW of new generation from NRWC's proposed wind power generation farm. The existing single circuit 25 Hz 115kV Q5G line can only accommodate approximately 181 MW and accordingly it needs to be upgraded. As indicated in **Exhibit B, Tab 4, Schedule 3**, NRWC is expected to provide a 100% capital contribution towards the cost of the project as per the Transmission System Code requirements. In accordance with Hydro One Transmission's Licence (ET-2003-0035), Hydro One is obligated to make an offer to connect or address a change in capacity upon request from a generator.

## 2.0 INVESTMENT CLASSIFICATION

This is a non-discretionary connection project as per the Board's *Minimum Filing Requirements for Transmission and Distribution Rate Applications and Leave to Construct Projects EB-2006-0170.* The project is being undertaken at the generation customer's (NRWC) request.

# 3.0 PROJECT CATEGORIZATION

## 3.1 Project Classification (Development, Connection, Sustainment)

Per the Board's Filing Guidelines, the first stage of project categorization is the classification of a project as development, connection, or sustainment.

- Development projects are for load growth or other changes to the system such as minimizing congestion on the transmission system
- Connection projects are those for providing connection of a customer to the transmission system.
- Sustainment projects are intended to maintain the performance of the transmission network at its current standard or replacing end-of-life facilities.

Based on the above criteria this project is classified as a connection project as it is being undertaken at the generation customer's request.

## 3.2 Need Classification

The second stage of project categorization is to distinguish whether the project need is determined beyond the control of the Applicant ("Non-discretionary") or determined at the discretion of the Applicant ("Discretionary"). Non-discretionary projects may be triggered or determined by such things as:

a) Mandatory requirement to satisfy obligations specified by Regulatory Organizations including NPCC/NERC or by the Independent Electricity Market Operator (IESO);

b) Need to accommodate new load (of a distributor or large user) or new generation (connection);

c) To relieve system elements (transmission lines, circuit breakers, etc.) where the loading exceeded their capacities or where short circuit levels on these systems elements exceeded their withstand capabilities;

d) Projects identified in an approved IPSP;

e) To comply with direction from the Ontario Energy Board in the event it is determined that the transmission system's reliability is at risk.

The NRWC Project is considered a non-discretionary connection project as it required to accommodate new generation in the area.

| | | **PROJECT NEED** | |
|---|---|---|---|
| | | Non-discretionary | Discretionary |
| **PROJECT CLASS** | | | |
| | Connection | **X** | |

# PROPOSED FACILITIES

In order to meet the need described previously in **Exhibit B, Tab 1, Schedule 4**, Hydro One facilities will be upgraded to increase the transmission capability of the power system.

Specifically, Hydro One proposes to re-conductor approximately 25 km of the existing 25 Hz, 115 kV idle single-circuit Q5G from tower 154 to Hamilton Beach TS for an in-service date of 2015. The line will be built to current 115kV standards and operated at 115 kV, and also converted to 60 Hz. As part of the work, circuit Q5G will be extended approximately 100m into Beach TS from Beach Junction to allow connection to the IESO controlled grid. The proposed line facilities are subject to section 92 approval.

In conjunction with the line upgrade, Hydro One is adding a new breaker at Beach TS. This will provide fault protection and isolation of NRWC from the IESO controlled grid when necessary. The proposed station work is not subject to section 92 approval.

The following are the specific work and facilities required by Hydro One to meet the new requirements:

<u>**Line Work**</u>

- Upgrade approximately 25 km of the 115 kV circuit Q5G from tower 154 to Beach Junction on the existing Right of Way by installing higher-capacity conductors.
- Reinforce existing towers
- Extend 115kV circuit Q5G from Beach Junction into Beach TS approximately 100m

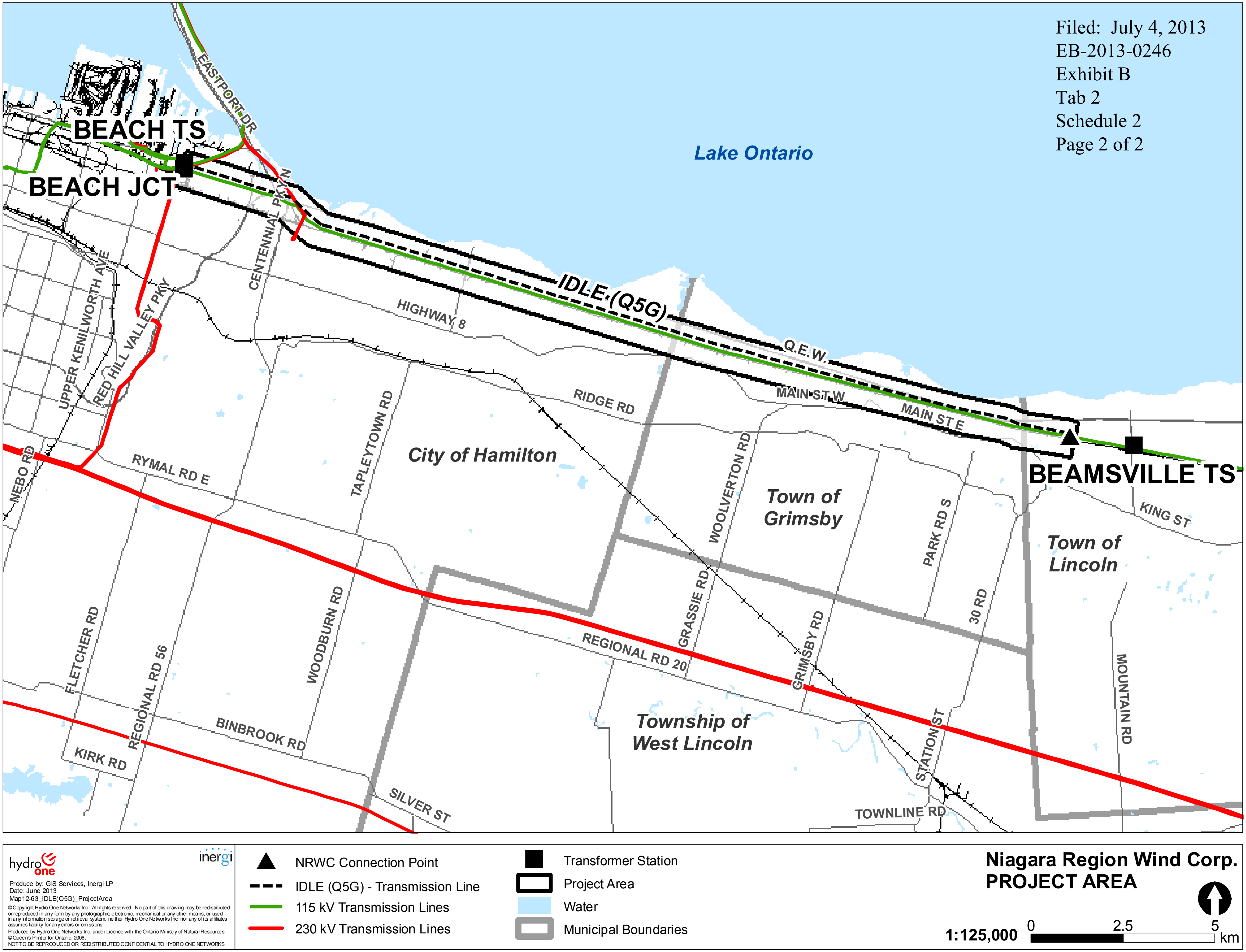
**<u>Station Work</u>**

- Add a new breaker at Beach TS to terminate circuit Q5G into the station.

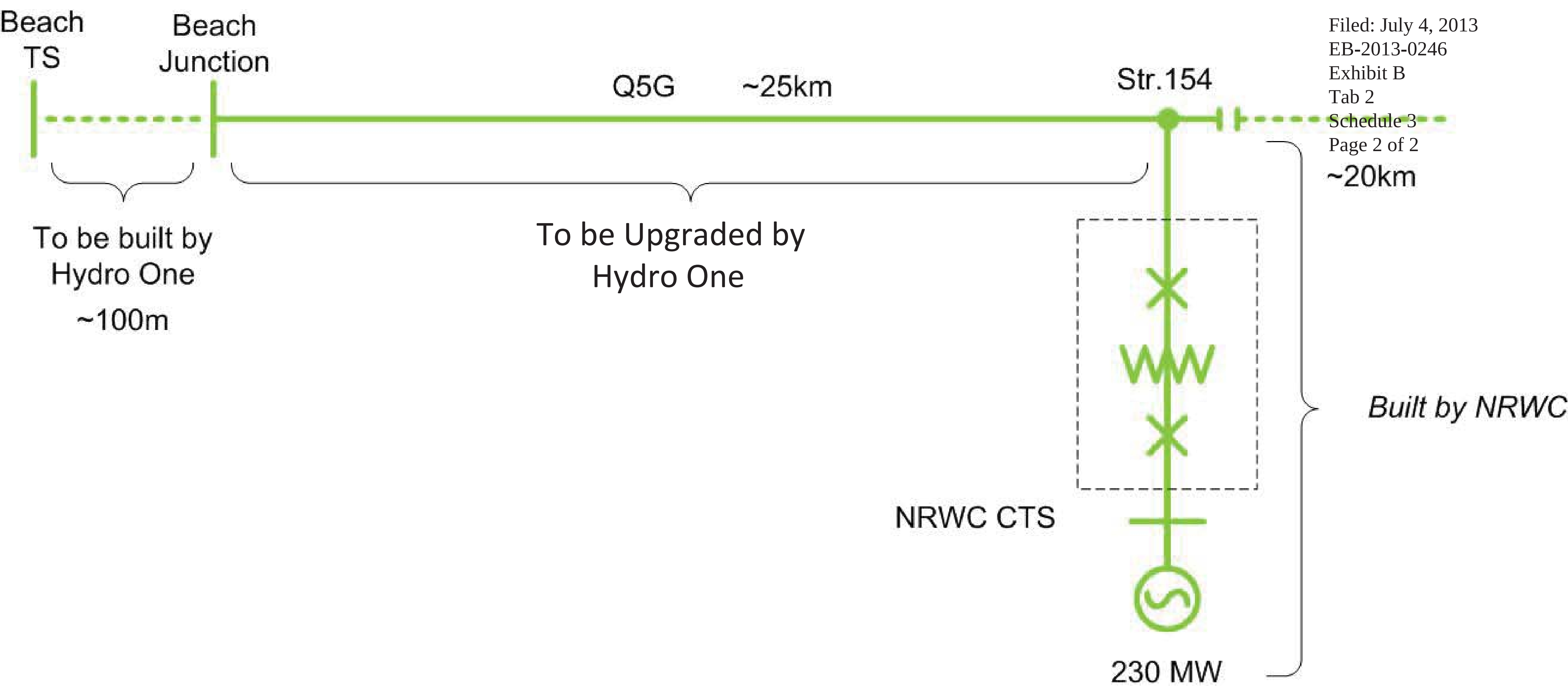
The planned in-service date for the proposed facilities is September 2015. However, at the generator's request, Hydro One will put forward reasonable efforts to advance the in-service date to Q4 2014.

A map showing the proposed transmission facilities is provided at **Exhibit B, Tab 2, Schedule 2.** A schematic electrical diagram of the proposed facilities is provided in **Exhibit B, Tab 2, Schedule 3**. Cross-sections of both the existing and proposed transmission structures on the Right of Way are provided in **Exhibit B, Tab 2, Schedule 4**.

# MAP OF PROPOSED FACILITIES


Lake Ontario
BEACH TS
BEACH JCT
BEAMSVILLE TS
IDLE (Q5G)
EASTPORT DR
CENTENNIAL PKY N
HIGHWAY 8
Q.E.W.
MAIN ST W
MAIN ST E
RIDGE RD
UPPER KENILWORTH AVE
RED HILL VALLEY PKY
NEBO RD
RYMAL RD E
TAPLEYTOWN RD
City of Hamilton
WOOLVERTON RD
Town of Grimsby
PARK RD S
KING ST
Town of Lincoln
30 RD
GRASSIE RD
GRIMSBY RD
REGIONAL RD 20
WOODBURN RD
FLETCHER RD
REGIONAL RD 56
BINBROOK RD
KIRK RD
SILVER ST
Township of West Lincoln
STATION ST
TOWNLINE RD
MOUNTAIN RD
hydro one
inergi
Produce by: GIS Services, Inergi LP
Date: June 2013
Map12-63_IDLE(Q5G)_ProjectArea
NOT TO BE REPRODUCED OR REDISTRIBUTED CONFIDENTIAL TO HYDRO ONE NETWORKS
NRWC Connection Point
IDLE (Q5G) - Transmission Line
115 kV Transmission Lines
230 kV Transmission Lines
Transformer Station
Project Area
Water
Municipal Boundaries
Niagara Region Wind Corp.
PROJECT AREA
1:125,000
0
2.5
5
km

# SCHEMATIC OF PROPOSED FACILITIES


Beach TS
Beach Junction
Q5G
~25km
Str.154
~20km
To be built by Hydro One
~100m
To be Upgraded by Hydro One
Built by NRWC
NRWC CTS
230 MW

# CROSS SECTION OF THE TOWER TYPES

## (Existing and Proposed)

FIGURE A

Existing 1920 Type towers to be modified as required by final design (i.e. re-enforced, raised)

Note: Tower shown below is typical suspension tower for this line section.

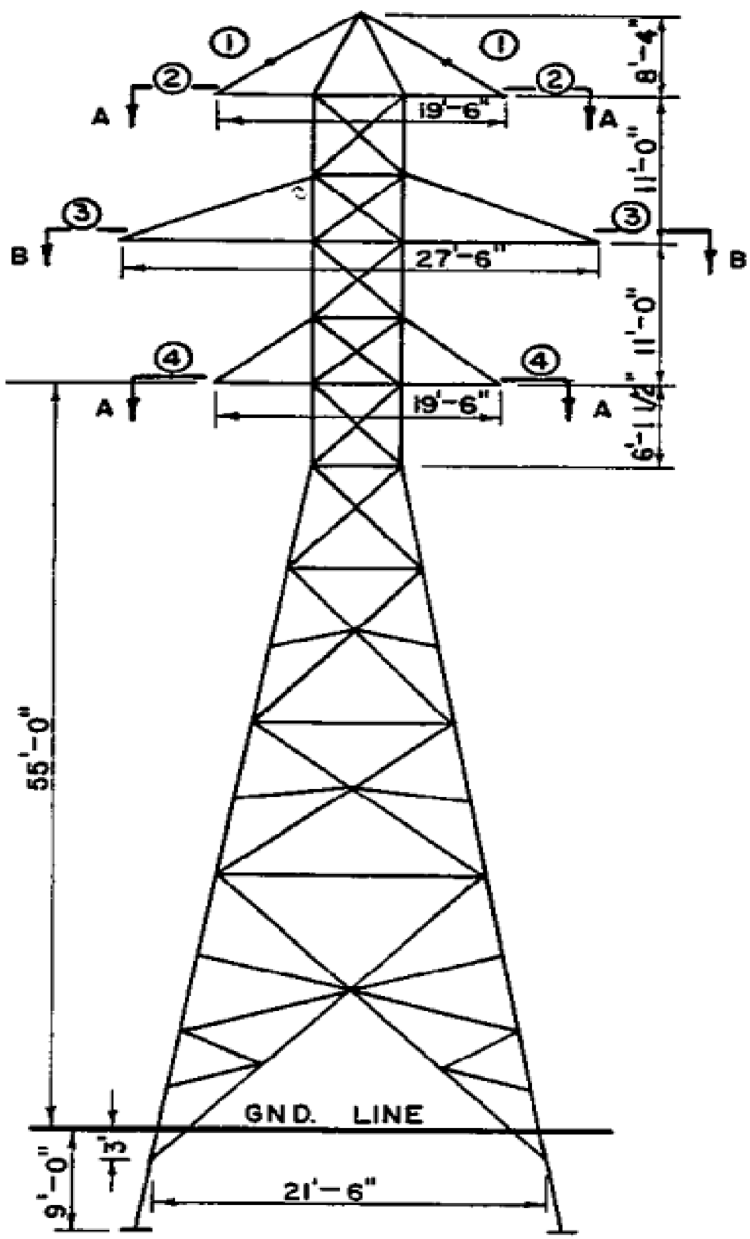
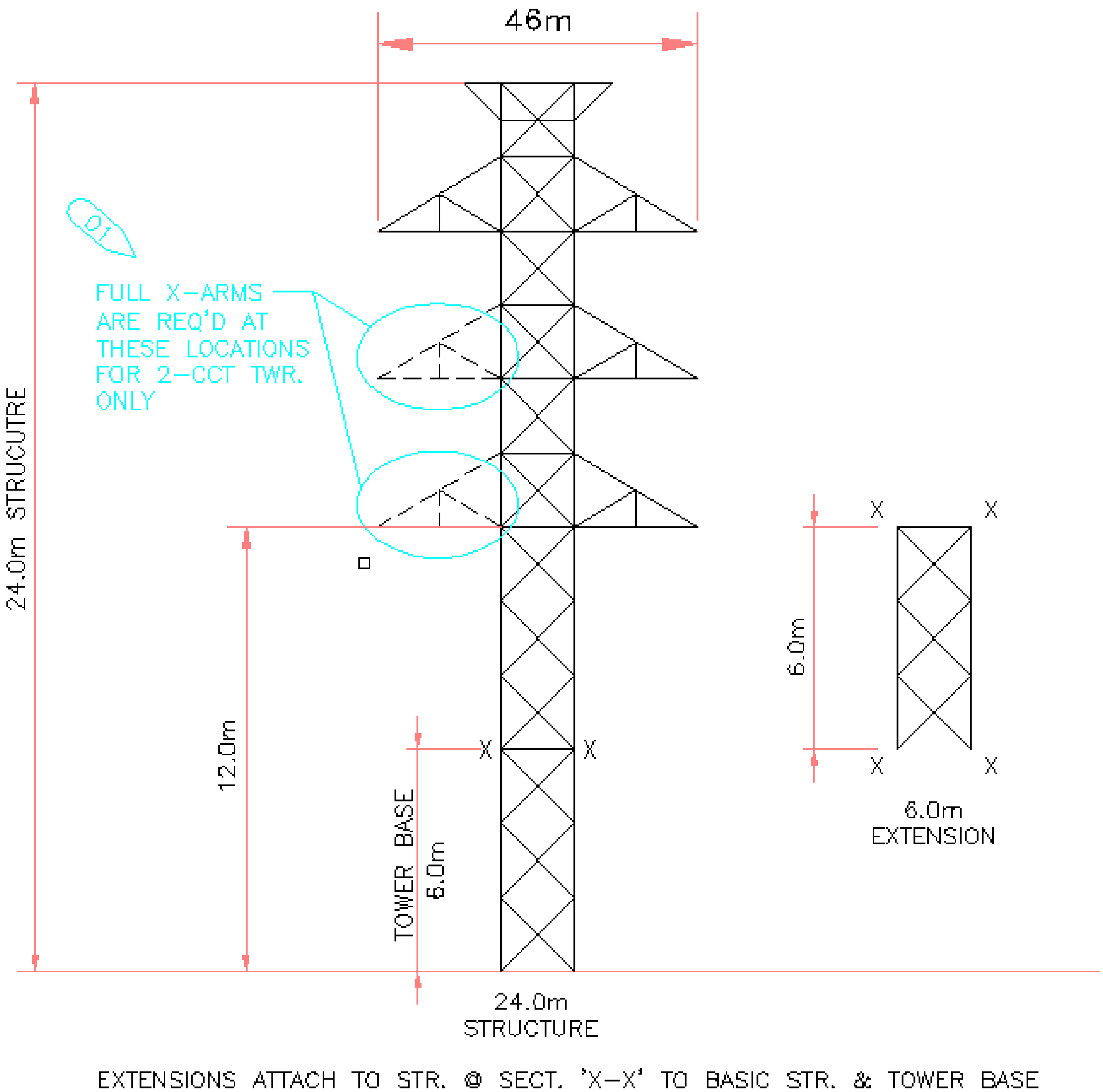


FIGURE B

New structure 154A – HAT type tower with two circuit configuration



# TRANSMISSION ALTERNATIVES CONSIDERED

## 1.0 TRANSMISSION ALTERNATIVES

The "Do Nothing" Alternative was discarded due to the Transmitter's obligation under the Transmission System Code to provide new capacity when requested to do so by customers. In addition, the load at the existing facilities will exceed their capacity with the connection of the NRWC project. For both reasons above, a do nothing alternative was not considered as it would not be feasible to complete this specific project.

The two remaining alternatives available to transmit the Niagara Region Wind Farm generation to the network via Beach TS would be:

**Alternative 1 –** Connect and upgrade the currently idle 25 Hz, 115kV Q5G transmission circuit.

**Alternative 2 –** Connect and upgrade the currently idle 25 Hz, 115kV A8G transmission circuit.

Alternative 2 was not recommended since portions of A8G's towers are shared with three other heavily loaded circuits through high residential and commercial areas. Outages are required to all three circuits to upgrade the A8G circuit. The construction costs for Alternative 2 will be considerably higher than Alternative 1 since temporary bypass circuits will be required for the adjacent circuits in the residential and commercial corridors. Additionally, Alternative 2 is approximately 40 kilometres in length and comparatively longer than Alternative 1.

Alternative 1 has been chosen in order to minimize construction costs, outages and transmission upgrade length. NRWC has agreed to pay 100% of the associated costs.

# PROJECT COSTS, ECONOMICS, AND OTHER PUBLIC INTEREST CONSIDERATIONS

This set of exhibits describes the costs of the proposed facilities and the economics of the project including the economic feasibility, rate impacts, and benefits to Ontario electricity consumers. Other public interest considerations are also discussed.

Under the *OEB Act, 1998,* "public interest" is defined to mean the interest of consumers with respect to prices and the adequacy, reliability and quality of electricity service, and the promotion of the use of renewable energy sources in a manner consistent with the policies of the Government of Ontario. Consumers are defined as those who use electricity that was not self-generated for their own consumption.

# PROJECT COSTS

The estimated capital cost to upgrade the 115 kV circuits Q5G between tower 154 and Beach TS including overheads and Allowance for Funds Used during Construction ("AFUDC") is as follows:

**Table 1**
**Cost of Upgrade Line Work**

| | ***Estimated Cost ($000's)*** |
|---|---|
| Planning & Estimating | 0 |
| Project Management [1] | 202 |
| Engineering | 198 |
| Procurement | 4,092 |
| Construction | 4,070 |
| Commissioning | 0 |
| Contingencies | 1,632 |
| **Costs before Overhead and AFUDC** | **10,194** |
| Overhead [2] | 1,151 |
| AFUDC [3] | 231 |
| **Total Line Work** | **$ 11,576** |

[1] Project Management includes costs for temporary rights along the ROW.

[2] All overhead costs allocated to the project are for asset management and corporate services costs. These costs are charged to capital projects through a standard overhead capitalization rate. As such they are considered "Indirect Overheads". Hydro One does not allocate any project activity to "Direct Overheads" but rather charges all other costs directly to the project.

[3] AFUDC is calculated using the Board's approved interest rate methodology (EB-2006-0117) to the projects' forecast monthly cash flow and the carry-forward closing balance from the preceding month.

**Table 2**
**Cost of Upgrade Station Work**

| | ***Estimated Cost ($000's)*** |
|---|---|
| Planning & Estimating | 304 |
| Project Management [4] | 199 |
| Engineering | 686 |
| Procurement | 915 |
| Construction | 1,028 |
| Commissioning | 201 |
| Contingencies | 534 |
| **Costs before Overhead and AFUDC** | **3,866** |
| Overhead [5] | 431 |
| AFUDC [6] | 135 |
| **Total Line Work** | **$ 4,433** |
| **Total expenditure upfront (station +Line)** | **$ 16,009** |
| Removals OM&A (includes overheads) | - $ 12 |
| | |
| **Total Project Costs** | **$ 15,997** |

The cost of the upgrade line / station work provided above allows for the schedule of approval, design and construction activities provided in **Exhibit B, Tab 5, Schedule 2**.

[4] Project Management includes costs for temporary rights along the ROW.

[5] All overhead costs allocated to the project are for asset management and corporate services costs. These costs are charged to capital projects through a standard overhead capitalization rate. As such they are considered "Indirect Overheads". Hydro One does not allocate any project activity to "Direct Overheads" but rather charges all other costs directly to the project.

[6] AFUDC is calculated using the Board's approved interest rate methodology (EB-2006-0117) to the projects' forecast monthly cash flow and the carry-forward closing balance from the preceding month.

## 1.0 RISKS AND CONTINGENCIES

As with most projects, there is some risk associated with estimating costs. Hydro One's cost estimate includes an allowance for contingencies in recognition of these risks.

Based on past experience, the estimates for this project work include allowances in the contingencies to cover the following potential risks:

- Cancellation or delays in obtaining required power and telecommunications system outages (needed for upgrading the lines work and commissioning activities);
- Construction equipment failures;
- Delay relating to receipt of material at site on time;
- Activities or materials of a minor nature, not included in the estimate preparation;
- Labour hours deviating from the estimate

Cost contingencies that have not been included, due to their uncertainty of occurrence, include:

- Delays resulting from delivery of long lead materials; and
- Delays in obtaining regulatory approvals, permits and licences;
- Deviations from the project plan arising from unforeseen EA conditions of approval for this project or that of the proponent
- Safety or environmental incidents
- Delays in any property rights negotations
- Significant changes in costs of materials since the estimate preparation.

## 2.0 COSTS OF COMPARABLE PROJECTS

This is not relevant as the entire project capital cost is to be recovered through the capital contribution resulting in zero net cost to the pool.

# PROJECT ECONOMICS

## 1.0 ECONOMIC FEASIBILITY

The proposed transmission reinforcement facilities for Hydro One's Niagara Region Wind Generation Connection project (**"the Project"**) comprise line assets and related station assets, both of which will be classified as Line Connection assets. As this Line Connection will connect generation facilities to the transmission system, it will be allocated to the Network Pool for rate making purposes, consistent with cost allocation rules. Please refer to **Exhibit B, Tab 2, Schedule 1**, for information on the proposed work and to Section 2.0 below for more information regarding the allocation to the Network Pool.

The Line Connection will be 100% customer funded as the requirement is directly related to capacity to accommodate new generation from NRWC's proposed wind power generation farm. Hydro One is requiring NRWC to pay the fully allocated cost excluding incremental operating and maintenance costs, consistent with the economic evaluation requirements of Section 6.5.1 of the Transmission System Code concerning generation connections. Also, there is no incremental cost associated with periodic verification and testing of fault protection equipment of the generation facility. As a result, a capital contribution of $16.0 million, excluding HST, equal to the up-front capital cost of the project, is required.

## 1.1 Cost Responsibility

Line Connection

In determining the capital contribution regarding the line connection assets, the costs assigned to customers for cost responsibility purposes are $16.0 million. This amount covers the cost of re-conductoring and re-energizing the idle Q5G 115 kV circuit by reinforcing approximately 20 existing steel lattice towers, installing 3 single pole structures, stringing from customer substation to single pole structures, and installing shaft extensions on 10 suspension towers. This amount also covers the cost installing a new 115kV breaker at Beach TS, as it will be part of the Line Connection along with the existing 115kV Beach TS switchyard. This work is being done for a generator connection, and as such, it has been assigned to the customer for cost responsibility purposes. The table below indicates the cost responsibility for the elements of work to be done on the project.

| **Cost Responsibility** *in $ million, excluding HST* | Cost of Work (per B-4-2) | Cost Responsibility | | Capital Contribution |
|---|---|---|---|---|
| | | Customers | Pool | |
| **Transmission Line Facilities** | 11.6 | 11.6 | - | 11.6 |
| **Station Facilities** | 4.4 | 4.4 | - | 4.4 |
| **Total** | 16.0 | 16.0 | - | 16.0 |

## 1.2 Line Connection

A 20-year discounted cash flow analysis for the Line Connection facilities, consistent with the term of the NRWC generation contract with OPA, is provided in Table 1. The capital contribution, based on Transmission System Code requirements will be $16.0 million.

## 2.0 RATE IMPACT ASSESSMENT

The analysis of the Network Pool rate impact has been carried out on the basis of Hydro One's transmission revenue requirement for the year 2013, and the most recently approved Ontario Transmission Rate Schedules. The Line Connection Pool and Transformation Connection Pool revenue requirement would be unaffected by the new facilities. As per the transmission cost allocation methodology approved by the Board, any Line Connection or Transformation Connection assets that are used to connect generation facilities to the transmission system will, for rate making purposes, be included in the Network Pool. The cost allocation process associated with generation connection assets is detailed in Section 4.1.2 of Exhibit G1, Tab 2, Schedule 1 of the evidence filed under Hydro One's Transmission Application EB-2012-0031.

<u>Network Pool</u>

Based on the incremental cash flows associated with the project, and after setting the capital contribution against the project's capital cost, there will be only a minor change in the Network Pool revenue requirement once the project's impacts are reflected in the transmission rate base at the projected in-service date in September of 2015. The maximum revenue deficiency related to the proposed Line Connection facilities will be $0.1 million in any given year, which will result in a 0% (after rounding) impact on the provincial Network Pool rates. The revenue deficiency is related to the incremental annual operating and maintenance costs, which are included in the rate impact analysis in Table 2. These costs are excluded from the DCF analysis used to determine the project's capital contribution requirement and shown in Table 1, as they are not subject to recovery from generator customers per TSC section 6.5.1. The detailed analysis illustrating the calculation of the incremental network revenue deficiency and rate impact is provided in Table 2 below. As with the economic feasibility analysis, a 20-year study horizon has been used, consistent with the term of the NRWC generation contract with OPA.

As noted above, adding the costs of the new facilities will cause no change to the Network Pool rate after rounding, and therefore there will be no impact on a typical residential bill.

# Table 1 – DCF Analysis, NRWC, page 1

| | |
|---|---|
| Date: | 2-Jul-13 |
| Project # | 21285 |

**SUMMARY OF CONTRIBUTION CALCULATIONS**
**Network Pool - Estimated Cost**

hydro one

Facility Name: NRWC : Generation Connection

Scope: Line Connection

| | | Month / Year | In-Service Date Sep-1 2015 | Sep-1 2016 (1) | Sep-1 2017 (2) | Sep-1 2018 (3) | Sep-1 2019 (4) | Sep-1 2020 (5) | Sep-1 2021 (6) | Sep-1 2022 (7) | Sep-1 2023 (8) | Sep-1 2024 (9) | Sep-1 2025 (10) | Sep-1 2026 (11) | Sep-1 2027 (12) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | <—— Project year ended - annualized from In-Service Date ——> | | | | | | | | | | | |
| **Revenue & Expense Forecast** | | | | | | | | | | | | | | | |
| Load Forecast (MW) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Tariff Applied ($/kW/Month) | | | | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 |
| **Incremental Revenue - $M** | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| OM&A Costs (Removals & On-going Incremental) - $M | | | (0.0) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Municipal Tax - $M | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Net Revenue/(Costs) before taxes - $M** | | | (0.0) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Income Taxes | | | 0.0 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.1 |
| **Operating Cash Flow (after taxes) - $M** | | | (0.0) | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.1 |
| | | Cumulative PV @ 5.70% | | | | | | | | | | | | | |
| **PV Operating Cash Flow (after taxes) - $M** | (A) | 2.3 | (0.0) | 0.2 | 0.3 | 0.3 | 0.2 | 0.2 | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| **Capital Expenditures - $M** | | | | | | | | | | | | | | | |
| Upfront - capital cost before overheads & AFUDC | | | (14.1) | | | | | | | | | | | | |
| - Overheads | | | (1.6) | | | | | | | | | | | | |
| - AFUDC | | | (0.4) | | | | | | | | | | | | |
| Total upfront capital expenditures | | | **(16.0)** | | | | | | | | | | | | |
| On-going capital expenditures | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| PV On-going capital expenditures | | | 0.0 | | | | | | | | | | | | |
| **Total capital expenditures - $M** | | | (16.0) | | | | | | | | | | | | |
| **PV Proceeds on disposal of assets - $M** | | | **0.0** | | | | | | | | | | | | |
| **PV CCA Residual Tax Shield - $M** | | | **0.2** | | | | | | | | | | | | |
| **PV Working Capital - $M** | | | **0.0** | | | | | | | | | | | | |
| **PV Capital (after taxes) - $M** | (B) | (15.8) | (15.8) | | | | | | | | | | | | |
| **Cumulative PV Cash Flow (after taxes) - $M** | (A) + (B) | (13.5) | (15.8) | (15.7) | (15.4) | (15.1) | (14.9) | (14.7) | (14.5) | (14.4) | (14.2) | (14.1) | (14.0) | (13.9) | (13.9) |

**Discounted Cash Flow Summary**
(Based on Economic Study Horizon - Years): 20

**Discount Rate - %** 5.70%

| | | Before Contribution $M | | After Contribution $M | Impact of Contribution $M |
|---|---|---|---|---|---|
| PV Incremental Revenue | | 0.0 | | 0.0 | |
| PV OM&A Costs | | (0.0) | | (0.0) | |
| PV Municipal Tax | | 0.0 | | 0.0 | |
| PV Income Taxes | | 0.0 | | 0.0 | (0.0) |
| PV CCA Tax Shield | | 2.5 | | 0.0 | (2.5) |
| PV Capital - Upfront | (16.0) | | (16.0) | | |
| **Add**: PV **Capital Contribution** | 0.0 | (16.0) | 16.0 | 0.0 | 16.0 |
| PV Capital - On-going | | 0.0 | | 0.0 | |
| PV Proceeds on disposal of assets | | 0.0 | | 0.0 | |
| PV Working Capital | | 0.0 | | 0.0 | |
| PV Surplus / (Shortfall) | | (13.5) | | (0.0) | 13.5 |

Profitability Index* 0.2 (1.0)

*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

| | |
|---|---|
| **Start Date:** | 1-Jan-13 |
| **In-Service Date:** | 1-Sep-15 |
| **Payback Year:** | 2035 |
| **No. of years required for payback:** | 20 |

# Table 1 – DCF Analysis, NRWC, page 2

| | |
|---|---|
| Date: | 2-Jul-13 |
| Project # | 21285 |

**SUMMARY OF CONTRIBUTION CALCULATIONS**
**Network Pool - Estimated Cost**

Facility Name: NRWC : Generation Connection

Scope: Line Connection

| | | Sep-1 | Sep-1 | Sep-1 | Sep-1 | Sep-1 | Sep-1 | Sep-1 | Sep-1 |
|---|---|---|---|---|---|---|---|---|---|
| | Month / Year | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** |
| | | *13* | *14* | *15* | *16* | *17* | *18* | *19* | *20* |
| **Revenue & Expense Forecast** | | | | | | | | | |
| Load Forecast (MW) | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Tariff Applied ($/kW/Month) | | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 |
| **Incremental Revenue - $M** | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| OM&A Costs (Removals & On-going Incremental) - $M | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Municipal Tax - $M | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Net Revenue/(Costs) before taxes - $M** | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Income Taxes | | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| **Operating Cash Flow (after taxes) - $M** | | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| **PV Operating Cash Flow (after taxes) - $M** | (A) | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Capital Expenditures - $M** | | | | | | | | | |
| Upfront - capital cost before overheads & AFUDC | | | | | | | | | |
| - Overheads | | | | | | | | | |
| - AFUDC | | | | | | | | | |
| Total upfront capital expenditures | | | | | | | | | |
| On-going capital expenditures | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| PV On-going capital expenditures | | | | | | | | | |
| **Total capital expenditures - $M** | | | | | | | | | |
| **PV Proceeds on disposal of assets - $M** | | | | | | | | | |
| **PV CCA Residual Tax Shield - $M** | | | | | | | | | |
| **PV Working Capital - $M** | | | | | | | | | |
| **PV Capital (after taxes) - $M** | (B) | | | | | | | | |
| **Cumulative PV Cash Flow (after taxes) - $M** | (A) + (B) | (13.8) | (13.7) | (13.7) | (13.7) | (13.6) | (13.6) | (13.6) | (13.5) |

# Table 2 – Revenue Requirement and Network Pool Rate Impact, page 1

| *NRWC : Generation Connection* | | | Project YE 1-Sep 2016 | Project YE 1-Sep 2017 | Project YE 1-Sep 2018 | Project YE 1-Sep 2019 | Project YE 1-Sep 2020 | Project YE 1-Sep 2021 | Project YE 1-Sep 2022 | Project YE 1-Sep 2023 | Project YE 1-Sep 2024 | Project YE 1-Sep 2025 | Project YE 1-Sep 2026 | Project YE 1-Sep 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Calculation of Incremental Revenue Requirement ($000)* | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| In-service date | 1-Sep-15 | | | | | | | | | | | | | |
| Capital Cost | 15,997 | | | | | | | | | | | | | |
| Removal Cost | 12 | | | | | | | | | | | | | |
| Less: Capital Contribution Required | (16,009) | | | | | | | | | | | | | |
| Net Project Cost | - | | | | | | | | | | | | | |
| Average Rate Base | | | - | - | - | - | - | - | - | - | - | - | - | - |
| Incremental OM&A Costs | | | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 |
| Grants in Lieu of Municipal tax | | | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Depreciation | | | - | - | - | - | - | - | - | - | - | - | - | - |
| Interest and Return on Rate Base | | | - | - | - | - | - | - | - | - | - | - | - | - |
| Income Tax Provision | | | - | - | - | - | - | - | - | - | - | - | - | - |
| **REVENUE REQUIREMENT PRE-TAX** | | | **119** | **119** | **119** | **119** | **119** | **119** | **119** | **119** | **119** | **119** | **119** | **119** |
| Incremental Revenue | | | - | - | - | - | - | - | - | - | - | - | - | - |
| **SUFFICIENCY/(DEFICIENCY)** | | | **(119)** | **(119)** | **(119)** | **(119)** | **(119)** | **(119)** | **(119)** | **(119)** | **(119)** | **(119)** | **(119)** | **(119)** |
| | | Base Year | | | | | | | | | | | | |
| Network Pool Revenue Requirement including sufficiency/(deficiency) | | 887,309 | 887,428 | 887,428 | 887,428 | 887,428 | 887,428 | 887,428 | 887,428 | 887,428 | 887,428 | 887,428 | 887,428 | 887,428 |
| Network MW | | 244,490 | 244,490 | 244,490 | 244,490 | 244,490 | 244,490 | 244,490 | 244,490 | 244,490 | 244,490 | 244,490 | 244,490 | 244,490 |
| Network Pool Rate ($/kw/month) | | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 |
| Increase/(Decrease) in Network Pool Rate ($/kw/month), relative to base year | | | - | - | - | - | - | - | - | - | - | - | - | - |
| **RATE IMPACT relative to base year** | | | **0.00%** | **0.00%** | **0.00%** | **0.00%** | **0.00%** | **0.00%** | **0.00%** | **0.00%** | **0.00%** | **0.00%** | **0.00%** | **0.00%** |

| **Assumptions** | | |
|---|---|---|
| Incremental OM&A | | $1.5 k per new km of overhead line each year and $17.9 k per new km of underground line each year. |
| Grants in Lieu of Municipal tax | 0.50% | Transmission system average |
| Depreciation | 2.00% | Reflects 50 year average service life for towers, conductors and station equipment, excluding land |
| Interest and Return on Rate Base | 6.46% | Includes OEB-approved ROE of 8.93%, 2.08% on ST debt, and 5.01% on LT debt. 40/4/56 equity/ST debt/ LT debt split |
| Income Tax Provision | 26.50% | 2013 federal and provincial corporate income tax rate |
| Capital Cost Allowance | 8.00% | 100% Class 47 assets |

## Table 2 – Revenue Requirement and Network Pool Rate Impact, page 2

| *NRWC : Generation Connection* | | | Project YE 1-Sep 2028 | Project YE 1-Sep 2029 | Project YE 1-Sep 2030 | Project YE 1-Sep 2031 | Project YE 1-Sep 2032 | Project YE 1-Sep 2033 | Project YE 1-Sep 2034 | Project YE 1-Sep 2035 |
|---|---|---|---|---|---|---|---|---|---|---|
| *Calculation of Incremental Revenue Requirement ($000)* | | | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
| In-service date | 1-Sep-15 | | | | | | | | | |
| Capital Cost | 15,997 | | | | | | | | | |
| Removal Cost | 12 | | | | | | | | | |
| Less: Capital Contribution Required | (16,009) | | | | | | | | | |
| Net Project Cost | - | | | | | | | | | |
| Average Rate Base | | | - | - | - | - | - | - | - | - |
| Incremental OM&A Costs | | | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 |
| Grants in Lieu of Municipal tax | | | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Depreciation | 2.00% | | - | - | - | - | - | - | - | - |
| Interest and Return on Rate Base | 6.46% | | - | - | - | - | - | - | - | - |
| Income Tax Provision | 26.50% | | - | - | - | - | - | - | - | - |
| **REVENUE REQUIREMENT PRE-TAX** | | | **119** | **119** | **119** | **119** | **119** | **119** | **119** | **119** |
| Incremental Revenue | | | - | - | - | - | - | - | - | - |
| **SUFFICIENCY/(DEFICIENCY)** | | | **(119)** | **(119)** | **(119)** | **(119)** | **(119)** | **(119)** | **(119)** | **(119)** |
| | | Base Year | | | | | | | | |
| Network Pool Revenue Requirement including sufficiency/(deficiency) | | 887,309 | 887,428 | 887,428 | 887,428 | 887,428 | 887,428 | 887,428 | 887,428 | 887,428 |
| Network MW | | 244,490 | 244,490 | 244,490 | 244,490 | 244,490 | 244,490 | 244,490 | 244,490 | 244,490 |
| Network Pool Rate ($/kw/month) | | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 | 3.63 |
| Increase/(Decrease) in Network Pool Rate ($/kw/month), relative to base year | | | - | - | - | - | - | - | - | - |
| **RATE IMPACT relative to base year** | | | **0.00%** | **0.00%** | **0.00%** | **0.00%** | **0.00%** | **0.00%** | **0.00%** | **0.00%** |

## Table 3 – DCF Assumptions

**Hydro One Networks -- Transmission Connection Economic Evaluation Model**
**2013 Parameters and Assumptions**

**Transmission rates** are based on current OEB-approved uniform provincial transmission rates.

| | | | |
|---|---|---|---|
| | Monthly Rate ($ per kW) | | |
| | Network | 3.63 | |
| **Income taxes:** | | | |
| Basic Federal Tax Rate - % of taxable income: | 2013 | 15.00% | Current rate |
| Ontario corporation income tax - % of taxable income: | 2013 | 11.50% | Current rate |
| **Capital Cost Allowance Rate:** Class 47 | 2013 | 8.0% | Current rate |
| **After-tax Discount rate:** | | 5.70% | Based on OEB-approved ROE of 8.93% on common equity and 2.08% on short-term debt, 5.01% forecast cost of long-term debt and 40/60 equity/debt split, and current enacted income tax rate of 26.5% |

# OTHER PUBLIC INTEREST CONSIDERATIONS

There are no other customers in the area. This project is being executed at the request of a single generator customer (NRWC). As a result, there are no other public interests to consider in this application.

# CONSTRUCTION AND PROJECT ADMINISTRATION

Hydro One is targeting to achieve a September 2015 in-service date for the proposed line upgrade. Section 92 approvals is being sought in 2013 in order to allow for the orderly planning and execution of the project, including the procurement of long-lead time materials and equipment. Hydro One has also agreed to make reasonable efforts to meet NRWC's proposed generation in-service date of Q3 2014 contingent on the outcome of NRWC's related s.92 application (EB-2013-0203).

To complete the project Hydro One will undertake the following activities:

- Carry out line construction activities that include setting up construction yards, building access roads on the right-of-way (if required), clearing trees and brush from the right-of-way, inspecting existing foundations and installing new foundations, erecting new structures, upgrading existing structures, stringing new conductor, removing unused/waste construction materials from the site plus restoration of the area.

- Install new 154A structure to accommodate line tap connection, 90m west of structure 154 using a Heavy Angle Tower Semi Anchor with 2 circuit configuration. Hydro One will also install 3 single pole structures. The work will proceed to tap each phase of structure 154A to the dead end insulator connected to the tower shaft and then to each single pole structure. The line will then be strung from the single pole structures to the customer substation and a counterpoise will be installed from structure 154A to the three single pole structures.

- To accommodate the generation facility, the existing conductor must be removed and replaced with a larger conductor. The insulators will be re-used, unless they are damaged, but new vibration dampers and phase spacers must also be installed. Furthermore, several structures might need to have some members upgraded to carry the load of the new conductor which is heavier than the existing conductor, while other structures may require body extensions and upgraded foundations.

- Q5G will be re-energized from tower 154 to Beach TS, a run of approximately 25km. The existing termination of Q5G is a junction (Beach Jct.) on the south side of Beach TS, across the railroad tracks. The line continues from there as underground cables to Beach TS. The existing Beach Jct. will be modified to accommodate new underground cables that will go north and cross underneath the railway line, terminating at Beach TS. The cables will cross the railway line in ducts that will be installed via HDD (Horizontal Directional Drilling).

- Build 3 foundations for extended steel support structures as well as the installation of 3 extended steel support structures for cable terminals and 3 lightning arresters.

- These construction activities will involve significant line outages which will require close coordination with generation production schedules and other construction work in the area. The longest outage requirement will be to enable upgrading of the towers for two-circuit use. This will be followed by a further significant outage to re-string the existing conductors onto the newly configured towers.

A Project Schedule showing the tasks leading up to the in-service date is provided in **Exhibit B, Tab 5, Schedule 2**.

# LINE CONSTRUCTION AND IN-SERVICE SCHEDULE

| TASK | START | FINISH |
|---|---|---|
| | | |
| Submit Section 92 | | July, 2013 |
| Projected Section 92 Approval | | January, 2014 |
| Detailed Engineering * | March 2014 | August 2014 |
| Tender & Award Structural Steel | March 2014 | May-2014 |
| Receive Structural Steel | May 2014 | June 2014 |
| Construction ** | May 2014 | August 2015 |

* Commencement of Detailed Engineering and further tasks is contingent on NRWC receiving s. 92 approval for its own transmission line. Should NRWC agree to reimburse required expenditures to advance and complete the work as requested, Hydro One may have the option to complete the Detailed Engineering component of the line construction prior to NRWC s. 92 approval.

** Hydro One is aware of the Q3 2014 proposed in-service date provided by Niagara Region Wind Corporation ("NRWC") in EB-2013-0203. Contingent on the Board's timeline for approval in that case, as well as NRWC receiving approval for its Renewable Energy Application before the Ministry of Environment, Hydro One will work with the generation proponent and put forward reasonable efforts to mobilize resources and align the two schedules accordingly.

# OTHER MATTERS / AGREEMENTS / APPROVALS

## 1.0 SYSTEM IMPACT ASSESSMENT

Under the market rules, any party planning to construct a new or modified connection to the IESO-controlled grid must allow for an IESO assessment of these facilities. The IESO has completed the System Impact Assessment (SIA) of the proposed facilities included in the Niagara Region Wind Project under the IESO Connections Assessment and Approval process.

The IESO assessment addresses the impact of the proposed facilities on system operating voltage, system operating flexibility, and on the ability of other connections to deliver or withdraw power supply from the IESO-controlled grid. The IESO's SIA filed at **Exhibit B, Tab 6, Schedule 3** confirms the need for this project and indicates that Hydro One's proposed transmission solution maintains system adequacy and has no material adverse impact on the reliability of the transmission system.

## 2.0 CUSTOMER IMPACT ASSESSMENT

Hydro One has carried out a CIA in accordance with its customer connection procedures to determine the impact of the proposed facilities on other customers. The CIA provided in **Exhibit B, Tab 6, Schedule 4** confirms that the Niagara Region Wind Project will not adversely impact customers in the area.

## 3.0 STAKEHOLDER AND COMMUNITY CONSULTATION

Hydro One has notified stakeholders and local First Nations and Metis communities that may have an interest in this proposed line upgrade. Hydro One will ensure stakeholders' issues are addressed. Hydro One will inform area elected officials, and relevant provincial government ministries and agencies of the project status. During the construction and commissioning stages of the proposed addition, Hydro One will consult with the local community and other interested stakeholders to ensure potential concerns are addressed where possible. Please refer to **Exhibit B, Tab 6, Schedule 5** and **Exhibit B, Tab 6, Schedule 6**, for details.

## 4.0 ENVIRONMENTAL ASSESSMENT APPROVAL

This project is subject to the Class Environmental Assessment (EA) for Minor Transmission Facilities under the *Environmental Assessment Act.* Given the low-impact nature of the project, it will be assessed under the Class EA Screening Process. The project effects will be screened against a set of criteria and notifications will be sent to all those potentially affected by it. Any issues identified will be discussed and resolved to the extent possible; subsequently a letter summarizing the results will be filed with the Ministry of the Environment. This screening is planned to be filed with the Ministry of Environment once NRWC receives approval of its Renewable Energy Approvals application.

## 5.0 COMPLIANCE WITH INDUSTRY STANDARDS AND CODES

The proposed facilities will be constructed, owned and operated by Hydro One. The design and maintenance of these facilities will be in accordance with good utility practice, as established in the Transmission System Code and in accordance with Northeast Power Coordinating Council (NPCC) and North American Electric Reliability Council (NERC) planning and operating standards.

## 6.0 LAND MATTERS

The proposed facilities upgrades will be located on the existing transmission corridor between Hamilton Beach Transformer Station and Structure number 154 located near Mountainview Road in the Town of Lincoln. Details on land requirements, existing and required land rights, and the process for acquiring the required land rights is provided in **Exhibit B, Tab 6, Schedule 7**.

## 7.0 OTHER APPROVAL REQUIREMENTS

As required, Hydro One will also address the Provincial and Federal regulatory requirements that may be required for the project as shown below:

| Provincial | Federal |
|---|---|
| • Ontario Heritage Act<br>• Species at Risk Act | • Fisheries Act |

There are also other approvals and permits that may be required as part of the construction process, including the following:

- Approval and permits for road crossings, vehicle restrictions, etc.

Hydro One also voluntarily complies with municipal noise bylaws.

# CUSTOMER LETTERS OF ENDORSEMENT FOR THE PROJECT

nrwc

Niagara Region
Wind Corporation
277 Lakeshore Road East
Suite 211
Oakville, ON L6J 6J3

905 842 4888 Phone
905 842-4885 Fax

May 23, 2013

Mr. Randy J. Church
Manager
Project Development & Oversight
Hydro One Networks Inc.
483 Bay Street
South Tower 6th Floor
Toronto, ON. M5G 2P5

**RE: Niagara Region Wind Corporation's Wind Farm**

Dear Randy,

This letter is to signify to Hydro One Networks, Niagara Region Wind Corporation's (NRWC) need for upgrades to the currently idle 115kV circuit Q5G from tower #154 to Beach Transformer Station via Beach Junction. The upgrades to the Q5G line and Beach TS will accommodate NRWC's 230MW wind generating facility and NRWC's connection to Hydro One's transmission system through NRWC's owned 115kV circuit.

Please do not hesitate to contact me if you have any questions about this project. We look forward to working with HONI on this project.

Regards,

Darren Croghan
Vice President, Project Development
Niagara Region Wind Corporation

# SYSTEM IMPACT ASSESSMENT

REPORT

Power to Ontario.
On Demand.

# System Impact Assessment Report

## CONNECTION ASSESSMENT & APPROVAL PROCESS

## Final Report

**CAA ID:** **2012-466**
**Project:** **Niagara Region Wind Farm**
**Applicant:** **Niagara Region Wind Corporation**

Market Facilitation Department
Independent Electricity System Operator

Date: July 27, 2012

| | |
|---|---|
| **Document ID** | IESO_REP_0825 |
| **Document Name** | System Impact Assessment Report |
| **Issue** | Final Report |
| **Reason for Issue** | Final Issue |
| **Effective Date** | July 27, 2012 |

# System Impact Assessment Report

## Acknowledgement

The IESO wishes to acknowledge the assistance of Hydro One in completing this assessment.

## Disclaimers

### IESO

This report has been prepared solely for the purpose of assessing whether the connection applicant's proposed connection with the IESO-controlled grid would have an adverse impact on the reliability of the integrated power system and whether the IESO should issue a notice of conditional approval or disapproval of the proposed connection under Chapter 4, section 6 of the Market Rules.

Conditional approval of the proposed connection is based on information provided to the IESO by the connection applicant and Hydro One at the time the assessment was carried out. The IESO assumes no responsibility for the accuracy or completeness of such information, including the results of studies carried out by Hydro One at the request of the IESO. Furthermore, the conditional approval is subject to further consideration due to changes to this information, or to additional information that may become available after the conditional approval has been granted.

If the connection applicant has engaged a consultant to perform connection assessment studies, the connection applicant acknowledges that the IESO will be relying on such studies in conducting its assessment and that the IESO assumes no responsibility for the accuracy or completeness of such studies including, without limitation, any changes to IESO base case models made by the consultant. The IESO reserves the right to repeat any or all connection studies performed by the consultant if necessary to meet IESO requirements.

Conditional approval of the proposed connection means that there are no significant reliability issues or concerns that would prevent connection of the proposed project to the IESO-controlled grid. However, the conditional approval does not ensure that a project will meet all connection requirements. In addition, further issues or concerns may be identified by the transmitter(s) during the detailed design phase that may require changes to equipment characteristics and/or configuration to ensure compliance with physical or equipment limitations, or with the Transmission System Code, before connection can be made.

This report has not been prepared for any other purpose and should not be used or relied upon by any person for another purpose. This report has been prepared solely for use by the connection applicant and the IESO in accordance with Chapter 4, section 6 of the Market Rules. The IESO assumes no responsibility to any third party for any use, which it makes of this report. Any liability which the IESO may have to the connection applicant in respect of this report is governed by Chapter 1, section 13 of the Market Rules. In the event that the IESO provides a draft of this report to the connection applicant, the connection applicant must be aware that the IESO may revise drafts of this report at any time in its sole discretion without notice to the connection applicant. Although the IESO will use its best efforts to advise you of any such changes, it is the responsibility of the connection applicant to ensure that the most recent version of this report is being used.

## Hydro One

The results reported in this report are based on the information available to Hydro One, at the time of the study, suitable for a System Impact Assessment of this connection proposal.

The short circuit and thermal loading levels have been computed based on the information available at the time of the study. These levels may be higher or lower if the connection information changes as a result of, but not limited to, subsequent design modifications or when more accurate test measurement data is available.

This study does not assess the short circuit or thermal loading impact of the proposed facilities on load and generation customers.

In this report, short circuit adequacy is assessed only for Hydro One circuit breakers. The short circuit results are only for the purpose of assessing the capabilities of existing Hydro One circuit breakers and identifying upgrades required to incorporate the proposed facilities. These results should not be used in the design and engineering of any new or existing facilities. The necessary data will be provided by Hydro One and discussed with any connection applicant upon request.

The ampacity ratings of Hydro One facilities are established based on assumptions used in Hydro One for power system planning studies. The actual ampacity ratings during operations may be determined in real-time and are based on actual system conditions, including ambient temperature, wind speed and project loading, and may be higher or lower than those stated in this study.

The additional facilities or upgrades which are required to incorporate the proposed facilities have been identified to the extent permitted by a System Impact Assessment under the current IESO Connection Assessment and Approval process. Additional project studies may be necessary to confirm constructability and the time required for construction. Further studies at more advanced stages of the project development may identify additional facilities that need to be provided or that require upgrading.

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# Executive Summary

## Conditional Approval for Connection

Niagara Region Wind Farm (the "project") is a new 230 MW wind power generation farm proposed by the Niagara Region Wind Corporation (the "connection applicant"), in West Lincoln and Haldimand, Ontario. The project will be connected to the 115 kV circuit Q5G, about 25km from Beach transformer station. The project has been awarded a Power Purchase Agreement under the Feed-In Tariff (FIT) program with the Ontario Power Authority. The scheduled project in-service date is February 23, 2014.

This assessment concludes that the proposed connection of the project, operating up to 230 MW, subject to the requirements specified in this report, is expected to have no material adverse impact on the reliability of the integrated power system. Therefore, the IESO recommends that a *Notification of Conditional Approval for Connection* be issued for Niagara Region Wind Farm subject to the implementation of the requirements outlined in this report.

## IESO Requirements for Connection

### Transmitter Requirements

The following requirements are applicable for the transmitter for the incorporation of the project:

(1) Hydro One is required to modify the protection at 115 kV Beach TS to incorporate the project.

Modifications to protection relays after this SIA is finalized must be submitted to IESO as soon as possible or at least six (6) months before any modifications are to be implemented. If those modifications result in adverse reliability impacts, the connection applicant and the transmitter must develop mitigation solutions.

### Connection Applicant Requirements

The connection applicant shall satisfy all applicable requirements and standards specified in the Market Rules and the Transmission System Code.

***Project Specific Requirements:***

The following *specific* requirements are applicable for the incorporation of the project. Specific requirements pertain to the level of reactive compensation needed, operation restrictions, special protection system, upgrading of equipment and any project specific items not covered in the *general* requirements.

(1) The wind farm voltage control system shall be designed as per the philosophy described in Section 6.5.

The connection applicant is required to provide a finalized copy of the functional description of the wind farm control systems for the IESO's approval before the project is allowed to connect.

***General Requirements:***

The following requirements summarize some of the general requirements that are applicable to the project, and are presented in detail in section 2 of this report.

(1) The connection applicant shall ensure that the project has the capability to operate continuously between 59.4Hz and 60.6Hz and for a limited period of time in the region above straight lines on a log-linear scale defined by the points (0.0s, 57.0Hz), (3.3s, 57.0Hz), and (300s, 59.0Hz).

The project shall respond to frequency increase by reducing the active power with an average droop based on maximum active power adjustable between 3% and 7% and set at 4%. Regulation deadband shall not be wider than ± 0.06%. The generation project shall respond to system frequency decline by temporarily boosting its active power output for some time (i.e. 10 s) by recovering energy from the rotating blades. If this technology is not available before connection, the connection applicant shall install this function in the future as soon as it becomes commercially available.

(2) The connection applicant shall ensure that the project has the capability to supply continuously all levels of active power output for 5% deviations in terminal voltage.

The project shall inject or withdraw reactive power continuously (i.e. dynamically) at the connection point up to 33% of its rated active power at all levels of active power output except where a lesser continually available capability is permitted by the IESO.

The project shall have the capability to regulate automatically voltage within ±0.5% of any set point within ±5% of rated voltage at a point whose impedance (based on rated apparent power and rated voltage) is not more than 13% from the highest voltage terminal. If the AVR target voltage is a function of reactive output, the slope $\Delta V/\Delta Q_{max}$ shall be adjustable to 0.5%. The response of the generation project for voltage changes shall be similar or better than that of a generation project with a synchronous generation unit and an excitation system that meets the requirements of Appendix 4.2 of the Market Rules.

(3) The project shall have the capability to ride through routine switching events and design criteria contingencies assuming standard fault detection, auxiliary relaying, communication, and rated breaker interrupting times unless disconnected by configuration.

(4) The connection applicant shall ensure that the 115 kV equipment is capable of continuously operating between 113 kV and 127 kV. Protective relaying must be set to ensure that transmission equipment remains in-service for voltages between 94% of the minimum continuous value and 105% of the maximum continuous value specified in Appendix 4.1of the Market Rules.

(5) The connection applicant shall ensure that the connection equipment is designed to be fully operational in all reasonably foreseeable ambient temperature conditions. The connection equipment must also be designed so that the adverse effects of its failure on the IESO-controlled grid are mitigated. This includes ensuring that all circuit breakers fail in the open position.

(6) The connection applicant shall install at the project a disturbance recording device with clock synchronization that meets the technical specifications provided by the transmitter.

(7) The connection applicant shall ensure that the new equipment at the project be designed to withstand the fault levels in the area. If any future system changes result in an increased fault level higher than the equipment's capability, the connection applicant is required to replace the equipment with higher rated equipment capable of sustaining the increased fault level, up to maximum fault level specified in Appendix 2 of the Transmission System Code.

Fault interrupting devices must be able to interrupt fault currents at the maximum continuous voltage of 127 kV.

(8) Appendix 2 of the Transmission System Code states that the maximum rated interrupting time for the 115 kV breakers must be 5 cycles or less. Thus, the connection applicant shall ensure that the installed breakers meet the required interrupting time specified in the Transmission System Code.

(9) The connection applicant shall ensure that the new protection systems at the project are designed to satisfy all the requirements of the Transmission System Code and any additional requirements identified by the transmitter.

As currently assessed by the IESO, the project is not part of the Bulk Power System (BPS) and, therefore it is not designated as essential to the power system.

The connection applicant shall have adequate provision in the design of protections and controls at the project to allow for future installation of Special Protection Scheme (SPS) equipment.

The protection systems within the project must only trip the appropriate equipment required to isolate the fault.

The autoreclosure of the high voltage breakers at the connection point must be blocked. Upon its opening for a contingency, the high voltage breaker must be closed only after the IESO approval is granted.

Any modifications made to protection relays after this SIA is finalized must be submitted to the IESO as soon as possible or at least six (6) months before any modifications are to be implemented on the existing protection systems.

(10) The connection applicant shall ensure that the telemetry requirements are satisfied as per the applicable Market Rules requirements. The finalization of telemetry quantities and telemetry testing will be conducted during the IESO Facility Registration/Market Entry process.

(11) If revenue metering equipment is being installed as part of this project, the connection applicant should be aware that revenue metering installations must comply with Chapter 6 of the IESO Market Rules. For more details the connection applicant is encouraged to seek advice from their Metering Service Provider (MSP) or from the IESO metering group.

(12) The proposed project must be compliant with applicable reliability standards set by the North American Electric Reliability Corporation (NERC) and the North East Power Coordinating Council (NPCC) that are in effect in Ontario as mapped in the following link: http://www.ieso.ca/imoweb/ircp/orcp.asp.

(13) The connection applicant will be required to be a restoration participant. Details regarding restoration participant requirements will be finalized at the Facility Registration/Market Entry Stage.

(14) The connection applicant must complete the IESO Facility Registration/Market Entry process in a timely manner before IESO final approval for connection is granted.

Models and data, including any controls that would be operational, must be provided to the IESO at least seven months before energization to the IESO-controlled grid. This includes both PSS/E and DSA software compatible mathematical models. The models and data may be shared with other reliability entities in North America as needed to fulfill the IESO's obligations under the Market Rules, NPCC and NERC rules.

The connection applicant must also provide evidence to the IESO confirming that the equipment installed meets the Market Rules requirements and matches or exceeds the performance predicted in this assessment. This evidence shall be either type tests done in a controlled environment or commissioning tests done on-site. The evidence must be supplied to the IESO within 30 days after completion of commissioning tests. If the submitted models and data differ materially from the ones used in this assessment, then further analysis of the project will need to be done by the IESO.

(15) The Market Rules governing the connection of renewable generation facilities in Ontario are currently being reviewed through the SE-91 stakeholder initiative and, therefore, new connection requirements (in addition to those outlined in the SIA), may be imposed in the future. The connection applicant is encouraged to follow developments and updates through the following link: http://www.ieso.ca/imoweb/consult/consult_se91.asp.

## Rationale for Conditional Approval for Connection

We have analyzed the impact of the project on the system reliability of the IESO-controlled grid, and based on our study results, we have identified that:

1. The proposed connection arrangement and equipment for the project are acceptable to the IESO.
2. The asymmetrical fault current at Burlington 115 kV, Allanburg 115kV, and Beck 2 230 kV switchyards before and after the incorporation of the project will exceed the interrupting capability of the existing breakers with all assumed committed generation facilities in service, including Greenfield South in the area. Hydro One is currently replacing their 115 kV breakers at both Burlington TS and Allanburg TS to improve the fault current interrupting capabilities at both stations. Hydro One has confirmed that mitigation measures are available such as opening up the bus ties to effectively address the short circuit violation at Beck 2 230 kV switchyard if necessary.
3. For now, it is not necessary for the project to participate in any existing or new Special Protection Scheme (SPS).
4. The reactive power capability of the project based on the data provided by the connection applicant is adequate.
5. The functions of the proposed wind farm control system meet the requirements in the Market Rules.
6. In the event of high flows eastward towards Toronto, there exists congestion on 230 kV circuits R14T, R17T, R19TH, R21TH, Q24HM, Q23BM, and Q25BM. The project tends to increase the congestion level on circuits R14T, R17T, R19TH, and R21TH. There may be times when the connection applicant could be required to curtail the output of the project for reliability purposes.
7. The voltage performance with the proposed project is expected to be acceptable under both pre-contingency and post-contingency operating conditions.
8. The Wind Turbine Generators (WTGs) of the project and the power system are expected to be transiently stable following recognized fault conditions.
9. The proposed WTGs are expected to remain connected to the grid for recognized system contingencies which do not remove the project by configuration.
10. Protection adjustments identified by Hydro One in the Protection Impact Assessment (PIA) to accommodate the project have no adverse impact on the reliability of IESO-controlled grid.

**– End of Section –**

# 1. Project Description

Niagara Region Wind Corporation has proposed to develop a 230 MW wind farm located in West Lincoln and Haldimand County, Ontario, to be known as Niagara Region Wind Farm (NRWF). The project has been awarded a Power Purchase Agreement under the Feed-In Tariff (FIT) program with the Ontario Power Authority. It is expected that full commercial operation will start on February 23, 2014.

**Wind Turbine**

It is proposed to use Enercon E-101 FT WTGs rated 3 MW each. The WTGs have full power converters interfacing their armature winding to the grid. The wind turbines are capable of supplying/absorbing reactive power to/from the grid, thus contributing to grid voltage support. An Enercon E101-FT WTG can operate at a power factor of 0.85 inductive to 0.85 capacitive. Each WTG is equipped with a pad mounted generator step-up (GSU) transformer rated at 3.5 MVA.

**Grouping and Collector System**

The project will be composed of 77 WTGs, totaling 230 MW. These WTGs will be arranged into 6 groups: 5 with 13 WTGs and 1 with 12 WTGs.

Each GSU transformer will be connected to one of the six 44 kV collector feeders. Each collector feeder will be connected to a 44 kV bus via a circuit breaker. There will be two 44 kV collector buses, each of which will connect 3 collector feeders. Each collector bus will be connected to a 44/115 kV main step-up transformer through a circuit breaker. At the HV side, the two transformers will be connected to one common point through a circuit breaker for each transformer.

**Transmission Facilities**

The 115kV common point of two main step-up transformers will then be connected to a decommissioned Hydro One 115kV circuit, former Q5G, via a 20 km overhead tap line with a motorized disconnect switch installed at the connection point. The connection point is approximately 25 km from Beach TS along circuit Q5G.

The single-line diagram of the proposed project is shown in Figure 1, Appendix A.

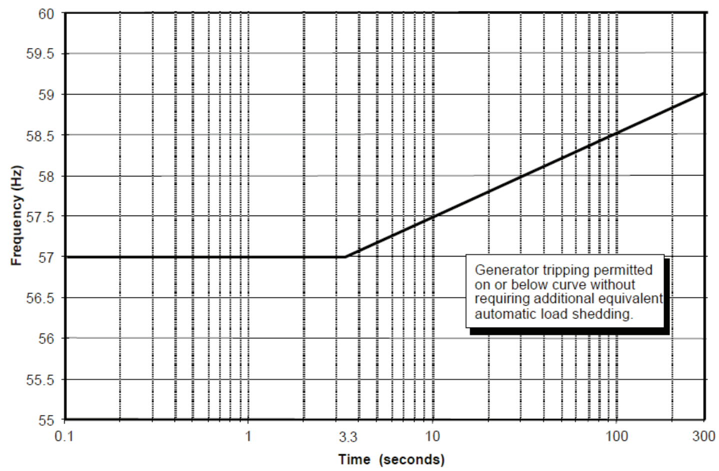
**– End of Section –**

# 2. General Requirements

The connection applicant shall satisfy all applicable requirements and standards specified in the Market Rules and the Transmission System Code. The following sections highlight some of the general requirements that are applicable to the proposed project.

## 2.1 Frequency/Speed Control

As per Appendix 4.2 of the Market Rules, the connection applicant shall ensure that the generation project has the capability to operate continuously between 59.4 Hz and 60.6 Hz and for a limited period of time in the region above straight lines on a log-linear scale defined by the points (0.0 s, 57.0 Hz), (3.3 s, 57.0 Hz), and (300 s, 59.0 Hz), as shown in the following figure.




The project shall respond to frequency increase by reducing the active power with an average droop based on maximum active power adjustable between 3% and 7% and set at 4%. Regulation deadband shall not be wider than ± 0.06%. The generation project shall respond to system frequency decline by temporarily boosting its active power output for some time (i.e. 10 s) by recovering energy from the rotating blades. This usually refers to “inertia emulation control” function within the wind farm control system. It is not required for wind facilities to provide a sustained response to system frequency decline. The connection applicant will need to indicate to the IESO whether the function of inertia emulation control is commercially available for the proposed type of wind turbine generator at the time when the wind farm comes into service. If this function is available, the connection applicant is required to implement it before the new project can be placed in-service. If this function is commercially unavailable, the connection applicant shall install this function in the future, once it is commercially available for the proposed type of wind turbine generator.

## 2.2 Reactive Power/Voltage Regulation

The generation project is directly connected to the IESO-controlled grid, and thus, the connection applicant shall ensure that the project has the capability to:

- supply continuously all levels of active power output for 5% deviations in terminal voltage. Rated active power is the smaller output at either rated ambient conditions (e.g. temperature, head, wind speed, solar radiation) or 90% of rated apparent power. To satisfy steady-state reactive power requirements, active power reductions to rated active power are permitted;

- inject or withdraw reactive power continuously (i.e. dynamically) at the connection point up to 33% of its rated active power at all levels of active power output except where a lesser continually available capability is permitted by the IESO. If necessary, shunt capacitors must be installed to offset the reactive power losses within the project in excess of the maximum allowable losses. If generators do not have dynamic reactive power capabilities, dynamic reactive compensation devices must be installed to make up the deficient reactive power;
- regulate automatically voltage within ±0.5% of any set point within ±5% of rated voltage at a point whose impedance (based on rated apparent power and rated voltage) is not more than 13% from the highest voltage terminal. If the AVR target voltage is a function of reactive output, the slope $\Delta V/\Delta Q_{max}$ shall be adjustable to 0.5%.. The response of the generation project for voltage changes shall be similar to or better than the response of a generation project with a synchronous generation unit and an excitation system that meets the requirements of Appendix 4.2 of the Market Rules.

## 2.3 Voltage Ride Though Capability

The generation project shall have the capability to ride through routine switching events and design criteria contingencies assuming standard fault detection, auxiliary relaying, communication, and rated breaker interrupting times unless disconnected by configuration.

## 2.4 Voltage

Appendix 4.1 of the Market Rules states that under normal operating conditions, the voltages in the 115 kV system in southern Ontario are maintained within the range of 113 kV to 127 kV. Thus, the IESO requires that the 115 kV equipment in southern Ontario must have a maximum continuous voltage rating of at least 127 kV.

Protective relaying must be set to ensure that transmission equipment remains in-service for voltages between 94% of the minimum continuous value and 105% of the maximum continuous value specified in Appendix 4.1of the Market Rules.

## 2.5 Connection Equipment Design

The connection applicant shall ensure that the connection equipment is designed to be fully operational in all reasonably foreseeable ambient temperature conditions. The connection equipment must also be designed so that the adverse effects of its failure on the IESO-controlled grid are mitigated. This includes ensuring that all circuit breakers fail in the open position.

## 2.6 Disturbance Recording

The connection applicant is required to install at the project a disturbance recording device with clock synchronization that meets the technical specifications provided by the transmitter. The device will be used to monitor and record the response of the project to disturbances on the 115 kV system in order to verify the dynamic response of generators. The quantities to be recorded, the sampling rate and the trigger settings will be provided by the transmitter.

## 2.7 Fault Level

The Transmission System Code requires the new equipment to be designed to sustain the fault levels in the area where the equipment is installed. Thus, the connection applicant shall ensure that the new equipment at the project is designed to sustain the fault levels in the area. If any future system enhancement results in an increased fault level higher than the equipment's capability, the connection applicant is required to replace the equipment at its own expense with higher rated equipment capable of sustaining the increased fault level, up to maximum fault level specified in the Transmission System Code. Appendix 2 of the Transmission System Code establishes the maximum fault levels for the transmission system. For the 115 kV system, the maximum 3 phase and single line to ground symmetrical fault levels are 50 kA.

Fault interrupting devices must be able to interrupt fault currents at the maximum continuous voltage of 127 kV.

## 2.8 Breaker Interrupting Time

Appendix 2 of the Transmission System Code states that the maximum rated interrupting time for the 115 kV breakers must be 5 cycles or less. Thus, the connection applicant shall ensure that the installed breakers meet the required interrupting time specified in the Transmission System Code.

## 2.9 Protection System

The connection applicant shall ensure that the protection systems are designed to satisfy all the requirements of the Transmission System Code as specified in Schedules E, F and G of Appendix 1 and any additional requirements identified by the transmitter. New protection systems must be coordinated with the existing protection systems.

Facilities that are essential to the power system must be protected by two redundant protection systems according to section 8.2.1a of the Transmission System Code. These redundant protections systems must satisfy all requirements of the Transmission System Code, and in particular, they must not use common components, common battery banks or common secondary CT or PT windings. As currently assessed by the IESO, this project is not on the current Bulk Power System list, and therefore, is not considered essential to the power system. In the future, as the electrical system evolves, this project may be placed on the BPS list.

The connection applicant is required to have adequate provision in the design of protections and controls at the project to allow for future installation of Special Protection Scheme (SPS) equipment. Should a future SPS be installed to improve the transfer capability in the area or to accommodate transmission reinforcement projects, the project will be required to participate in the SPS system and to install the necessary protection and control facilities to affect the required actions.

The protection systems within the generation project must only trip the appropriate equipment required to isolate the fault. After the project begins commercial operation, if an improper trip of the 115 kV circuit Q5G occurs due to events within the project, the project may be required to be disconnected from the IESO-controlled grid until the problem is resolved.

The autoreclosure of the high voltage breakers at the connection point must be blocked. Upon its opening for a contingency, the high voltage breaker must be closed only after the IESO approval is granted.

Any modifications made to protection relays after this SIA is finalized must be submitted to the IESO as soon as possible or at least six (6) months before any modifications are to be implemented on the existing protection systems. If those modifications result in adverse impacts, the connection applicant and the transmitter must develop mitigation solutions

## 2.10 Telemetry

According to Section 7.3 of Chapter 4 of the Market Rules, the connection applicant shall provide to the IESO the applicable telemetry data listed in Appendix 4.15 of the Market Rules on a continual basis. As per Section 7.1.6 of Chapter 4 of the Market Rules, the connection applicant shall also provide data to the IESO in accordance with Section 5 of Market Manual 1.2, for the purposes of deriving forecasts of the amount of energy that the project is capable of producing. The whole telemetry list will be finalized during the IESO Facility Registration/Market Entry process.

The data shall be provided with equipment that meets the requirements set forth in Appendix 2.2, Chapter 2 of the Market Rules and Section 5.3 of Market Manual 1.2, in accordance with the performance standards set forth in Appendix 4.19 subject to Section 7.6A of Chapter 4 of the Market Rules.

As part of the IESO Facility Registration/Market Entry process, the connection applicant must complete end to end testing of all necessary telemetry points with the IESO to ensure that standards are met and that sign conventions are understood. All found anomalies must be corrected before IESO final approval to connect any phase of the project is granted.

## 2.11 Revenue Metering

If revenue metering equipment is being installed as part of this project, the connection applicant should be aware that revenue metering installations must comply with Chapter 6 of the IESO Market Rules. For more details the connection applicant is encouraged to seek advice from their Metering Service Provider (MSP) or from the IESO metering group.

## 2.12 Reliability Standards

Prior to connecting to the IESO controlled grid, the proposed project must be compliant with the applicable reliability standards established by the North American Electric Reliability Corporation (NERC) and reliability criteria established by the Northeast Power Coordinating Council (NPCC) that are in effect in Ontario. A mapping of applicable standards, based on the proponent's/connection applicant's market role/OEB license can be found here: http://www.ieso.ca/imoweb/ircp/orcp.asp

This mapping is updated periodically after new or revised standards become effective in Ontario.

The current versions of these NERC standards and NPCC criteria can be found at the following websites:
http://www.nerc.com/page.php?cid=2|20
http://www.npcc.org/documents/regStandards/Directories.aspx

The IESO monitors and assesses market participant compliance with a selection of applicable reliability standards each year as part of the Ontario Reliability Compliance Program. To find out more about this program, write to orcp@ieso.ca or visit the following webpage: http://www.ieso.ca/imoweb/ircp/orcp.asp

Also, to obtain a better understanding of the applicable reliability compliance obligations and engage in the standards development process, we recommend that the proponent/ connection applicant join the IESO's Reliability Standards Standing Committee (RSSC) or at least subscribe to their mailing list by contacting rssc@ieso.ca. The RSSC webpage is located at:
http://www.ieso.ca/imoweb/consult/consult_rssc.asp.

## 2.13 Restoration Participant

According to the Market Manual 7.8 which states restoration participant criteria and obligations, the connection applicant will be required to be a restoration participant. Details regarding restoration participant requirements will be finalized at the Facility Registration/Market Entry Stage.

## 2.14 Facility Registration/Market Entry

The connection applicant must complete the IESO Facility Registration/Market Entry process in a timely manner before IESO final approval for connection is granted.

Models and data, including any controls that would be operational, must be provided to the IESO. This includes both PSS/E and DSA software compatible mathematical models representing the new equipment for further IESO, NPCC and NERC analytical studies. The models and data may be shared with other reliability entities in North America as needed to fulfill the IESO's obligations under the Market Rules, NPCC and NERC rules. The connection applicant may need to contact the software manufacturers directly, in order to have the models included in their packages. This information should be submitted at least seven months before energization to the IESO-controlled grid, to allow the IESO to incorporate this project into IESO work systems and to perform any additional reliability studies.

As part of the IESO Facility Registration/Market Entry process, the connection applicant must provide evidence to the IESO confirming that the equipment installed meets the Market Rules requirements and matches or exceeds the performance predicted in this assessment. This evidence shall be either type tests done in a controlled environment or commissioning tests done on-site. In either case, the testing must be done not only in accordance with widely recognized standards, but also to the satisfaction of the IESO. Until this evidence is provided and found acceptable to the IESO, the Facility Registration/Market Entry process will not be considered complete and the connection applicant must accept any restrictions the IESO may impose upon this project's participation in the IESO-administered markets or connection to the IESO-controlled grid. The evidence must be supplied to the IESO within 30 days after completion of commissioning tests. Failure to provide evidence may result in disconnection from the IESO-controlled grid.

If the submitted models and data differ materially from the ones used in this assessment, then further analysis of the project will need to be done by the IESO.

## 2.15 Other Connection Requirements

The Market Rules governing the connection of renewable generation facilities in Ontario are currently being reviewed through the SE-91 stakeholder initiative and, therefore, new connection requirements (in addition to those outlined in the SIA), may be imposed in the future. The connection applicant is encouraged to follow developments and updates through the following link: http://www.ieso.ca/imoweb/consult/consult_se91.asp

**-End of Section-**

# 3. Data Verification

## 3.1 Connection Arrangement

The connection arrangement of the project shown in Figure 1, Appendix A is not expected to reduce the level of reliability of the integrated power system and is, therefore, acceptable to the IESO.

## 3.2 Enercon E-101 FT

The Enercon E-101 FT is a three bladed, variable pitch, variable speed, and full conversion WTG system. Its specifications are shown in Table 1.

Table 1: Specifications of Enercon E-101 FT

| Type | Rated Voltage | Rated MVA | Rated MW | GSU Transformer | | | $Q_{max}$ (Mvar) | $Q_{min}$ (Mvar) | $I_d$" (pu) |
|---|---|---|---|---|---|---|---|---|---|
| | | | | MVA | R | X | | | |
| Enercon E-101 FT | 400 V | 3.5 | 3 | 3.5 | - | 6% | 1.7 | -1.7 | 1.249 |

### 3.2.1 Voltage Ride-Though Capability

The Enercon E-101 FT wind turbine provides a voltage ride-through capability. During a voltage drop/raise, the minimum time for a WTG to remain online is shown in Table 2.

Table 2: WTG voltage ride-through capability

| Voltage Range (% of base voltage) | Minimum time for WTGs to Remain Online (s) |
|---|---|
| V<80 | 5 |
| 0.9<V<120 | Continuous |
| V>120 | 0.09 |

The low voltage ride-through (LVRT) capability of the proposed WTGs was verified by performing transient stability studies as detailed in Section 6.9.

### 3.2.2 Frequency Ride-Through Capability

The frequency ride-through capability of the proposed Enercon E-101 FT WTGs meets the Market Rules' requirements.

The Enercon E-101 FT wind turbine is capable of continuous operation within the frequency band of 53 Hz to 67 Hz. Based on the model provided by the connection applicant, the WTG can operate continuously within the range of 57 Hz to 60.7 Hz.

The Market Rules state that the generation project directly connecting to the IESO-controlled grid shall operate continuously between 59.4Hz and 60.6Hz and for a limited period of time in the region above straight lines on a log-linear scale defined by the points (0.0s, 57.0Hz), (3.3s, 57.0Hz), and (300s, 59.0Hz).

## 3.3 Main Step-Up Transformers

Table 3: Main step-up transformer data

| Unit | Transformation | Rating (MVA) (ONAN/ONAF /ONAF) | Positive Sequence Impedance (pu) $S_B$= 100 MVA | Configuration | | Zero Sequence Impedance (pu) $S_B$= 100 MVA | Tap |
|---|---|---|---|---|---|---|---|
| | | | | HV | LV | | |
| TSS1 | 44/115 kV | 100/133/166 MVA | 0.0034+j0.11965 | Yg | Δ | N/A | Off-load taps 4 x 2.5 % with 115kV nominal voltage |
| TSS2 | 44/115 kV | 100/133/166 MVA | 0.0034+j0.11965 | Yg | Δ | N/A | Off-load taps 4 x 2.5 % with 115kV nominal voltage |

## 3.4 Collector System

Table 4: Equivalent impedance of collectors

| Circuit | Unit# | MW | Positive-Sequence Impedance (pu, $S_B$=100MVA) | | | Zero-Sequence Impedance (pu, $S_B$=100MVA) | | |
|---|---|---|---|---|---|---|---|---|
| | | | R | X | B | R | X | B |
| C1 | 13 | 39 | 0.081 | 0.109 | 0.043 | 0.233 | 0.059 | 0.043 |
| C2 | 13 | 39 | 0.085 | 0.105 | 0.055 | 0.253 | 0.057 | 0.056 |
| C3 | 12 | 36 | 0.045 | 0.051 | 0.034 | 0.150 | 0.028 | 0.034 |
| C4 | 13 | 39 | 0.039 | 0.044 | 0.032 | 0.123 | 0.024 | 0.032 |
| C5 | 13 | 39 | 0.027 | 0.024 | 0.029 | 0.092 | 0.014 | 0.029 |
| C6 | 13 | 38 | 0.036 | 0.039 | 0.034 | 0.117 | 0.021 | 0.034 |

## 3.5 Connection Equipment

### 3.5.1 115 kV Switches

Table 5: Specifications of 115 kV switches

| Identifier | Voltage Rating | Continuous Current Rating | Short Circuit Symmetrical Rating |
|---|---|---|---|
| 89L1-1 | 145 kV | 1200 A | 50 kA |
| 89L1-1A | 145 kV | 1200 A | 50 kA |
| 89L1-1B | 145 kV | 1200 A | 50 kA |

All switches meet the maximum continuous voltage rating requirement of 127 kV.

### 3.5.2 115 kV Circuit Breakers

Table 6: Specifications for 115 kV circuit breakers

| Identifier | Voltage Rating | Interrupting time | Continuous Current Rating | Short Circuit Symmetrical Rating |
|---|---|---|---|---|
| 52-1 | 145 kV | 50 ms | 1200 A | 50 kA |
| 52-2 | 145 kV | 50 ms | 1200 A | 50 kA |

All circuit breakers meet the maximum continuous voltage rating requirement of 127 kV. The interrupting time and short circuit symmetrical duty ratings meet the requirements of the Transmission System Code.

### 3.5.3 Tap Line

The tap line from the project to the connection point at 115 kV circuit Q5G consists of an overhead circuit about 20 km long. The parameters of the line are shown in Table 7.

Table 7: Parameters of tap line

| Circuit | Conductor | Positive-Sequence Impedance (pu, $S_B$=100MVA) | | | Zero-Sequence Impedance (pu, $S_B$=100MVA) | | |
|---|---|---|---|---|---|---|---|
| | | R | X | B | R | X | B |
| L1 | ACSR 1443kcmil 54/19 | 0.0062 | 0.0623 | 0.0106 | 0.0311 | 0.2341 | 0.00572 |

## 3.6 Wind Farm Control System

The proposed project will be equipped with the Enercon Farm Control Unit (FCU) for centralized wind farm control. The FCU registers the voltage and the current injected at a reference point and uses it to compute the actual values of the controlled variables (e.g. active or reactive power). The closed-loop controls implemented in the FCU generate the appropriate actuating signals based on the control deviation and send them to the wind energy converters. The FCU sends identical actuating signal to all wind energy converters to be controlled.

### 3.6.1 Voltage Control

The function of the voltage control discussed below meets the requirements of the Market Rules.

The Enercon FCU has the function to regulate the voltage at a remote bus to a single reference value. The controller consists of a proportional controller with time delay and a parallel integral controller.

The voltage control function enable the proposed project to operate in voltage control mode and control voltage at a point whose impedance (based on rated apparent power and voltage of the project) is not more than 13% from the connection point. Thus, it is acceptable to the IESO.

### 3.6.2 Frequency Control

The function of the Enercon E-101 FT frequency control meets the requirements of the Market Rules.

The power-frequency control system of the Enercon E-101 FT controls the wind farm power output based upon the grid frequency. This function is similar to the governor droop control for a conventional rotating generator. The active power of the WTG is ramped down once an over frequency limit has been exceeded. In case the frequency falls below the frequency limit again, active power is ramped up again with the same gradient as the previous ramp-down.

### 3.6.3 Inertia Emulation

The Enercon E-101 FT WTG will be equipped with the Inertia Emulation control feature.

The Inertia Emulation control feature enables the Enercon E-101 FT WTG to provide inertial response to help stabilize grid frequency. This feature supports the grid during under frequency events by providing a temporary increase in power production for a short duration, contributing towards frequency recovery. This is achieved by tapping into the stored kinetic energy in the rotor mass.

**-End of Section-**

# 4. Short Circuit Assessment

Fault level studies were completed by the transmitter to examine the effects of the project on fault levels at existing facilities in the surrounding area. Studies were performed to analyze the fault levels with and without the project and other recently committed generation projects in the system.

The interrupting capabilities of the 115 kV circuit breakers of the project are adequate for the anticipated fault levels.

With the exception of Burlington and Allanburg 115 kV switchyards and Beck 2 230 kV switchyard, the interrupting capability of the lowest rated circuit breakers near the project will not be exceeded after the incorporation of the project.

## 4.1 Study Assumptions

The short circuit study was carried out with the following primary system assumptions:

**(1) Generation Facilities In-Service**

**East**

| | | | |
|---|---|---|---|
| Lennox | G1-G4 | Chenaux | G1-G8 |
| Kingston Cogen | G1-G2 | Mountain Chute | G1-G2 |
| Wolf Island | 300 MW | Stewartville | G1-G5 |
| Arnprior | G1-G2 | Brockville | G1 |
| Barrett Chute | G1-G4 | Havelock | G1 |
| Chats Falls | G2-G9 | Saunders | G1-G16 |
| Cardinal Power | G1, G2 | | |

**Toronto**

| | | | |
|---|---|---|---|
| Pickering units | G1, G4-G8 | Sithe Goreway | G11-13, G15 |
| Darlington | G1-G4 | TransAlta Douglas | G1-G3 |
| Portlands GS | G1-G3 | GTAA | G1-G3 |
| Algonquin Power | G1, G2 | Brock west | G1 |
| Whitby Cogen | G1 | | |

**Niagara**

| | | | |
|---|---|---|---|
| Thorold GS | GTG1, STG2 | Beck 2 | G11-G26 |
| Beck 1 | G3-G10 | Beck 2 PGS | G1-G6 |
| Decew | G1, G2, ND1 | | |

**South West**

| | | | |
|---|---|---|---|
| Nanticoke | G5-G8 | Kingsbridge WGS | 39.6 MW |
| Halton Hills GS | G1-G3 | Amaranth WGS | 199.5 MW |

**Bruce**

| | | | |
|---|---|---|---|
| Bruce A | G1-G4 | Ripley WGS | 76 MW |
| Bruce B | G5-G8 | Underwood WGS | 198 MW |
| Bruce A Standby | SG1 | | |

**West**

| | | | |
|---|---|---|---|
| Lambton units | G3-G4 | Imperial Oil | G1 |
| Brighton Beach | G1, G1A, G1B | Kruger Port Alma WGS | 101.2 MW |
| Greenfield Energy Centre | G1-G4 | Gosfield Wind Project | 50.6 MW |
| St. Clair Energy Centre | CTG3, STG3, CTG4, STG4 | Kruger Energy Chatham WF | 101 MW |
| East Windsor Cogen | G1-G2 | Raleigh Wind Energy Centre | 78 MW |
| TransAlta Sarnia | G861, G871, G881, G891 | Talbot Wind Farm | 98.9 MW |
| Ford Windsor CTS | STG5 | Dow Chemicals | G1, G2, G5 |
| TransAlta Windsor | G1, G2 | Port Burwell WGS | 99 MW |
| West Windsor Power | G1, G2 | Fort Chicago London Cogen | 23 MVA |
| | | Great Northern Tri-Gen Cogen | 15 MVA |

**(2) Previously Committed Generation Facilities**

- Bruce G1, G2
- Big Eddy GS and Half Mile Rapids GS
- White Pines Wind Farm
- Amherst Island
- York Energy Centre
- Conestogo Wind Energy Centre 1
- Dufferin Wind Farm
- Summerhaven Wind Farm
- Port Dover and Nanticoke
- Grand Renewable Energy
- Greenfield South
- Comber East C24Z
- Comber West C23Z
- Pointe-Aux-Roches Wind
- South Kent Wind Farm

**(3) Recently Committed Generation Facilities**

- Bluewater Wind Energy Centre
- Jericho Wind Energy Centre
- Bornish Wind Energy Centre
- Goshen Wind Energy Centre
- Cedar Point Wind Power Project Phase II
- Adelaide Wind Energy Centre
- Grand Bend Wind Farms
- Grand Valley Wind Farms (Phase 3)
- Erieau Wind
- East Lake St. Clair Wind
- Adelaide Wind Power Project
- Gunn's Hill Wind Farm
- Silvercreek Solar Park
- K2 wind
- Armow
- 300 MW wind at Orangeville
- 100 MW wind at S2S

**(4) Existing and Committed Embedded Generation**

- Essa area: 264 MW
- Ottawa area: 90 MW
- East area: 580 MW
- Toronto area: 168 MW
- Niagara area: 52 MW
- Southwest area: 348 MW
- Bruce area: 26 MW
- West area: 585 MW

**(5) Transmission System Upgrades**

- Leaside - Bridgman reinforcement: Leaside TS to Birch JCT: new 115 kV circuit (CAA2006-238);
- St. Catherines 115 kV circuit upgrade: circuits D9HS, D10S and Q11S (CAA2007-257);
- Tilbury West DS second connection point for DESN arrangement using K2Z and K6Z (CAA2008-332);
- Second 500kV Bruce-Milton double-circuit line (CAA2006-250);
- Woodstock Area transmission reinforcement (CAA2006-253);
    - Karn TS in service and connected to M31W & M32W at Ingersol TS
    - W7W/W12W terminated at LFarge CTS
    - Woodstock TS connected to Karn TS
- Rodney (Duart) TS DESN connected to W44LC and W45LS 230 kV circuits (CAA2007-260)

**(6) System Operation Conditions**

- Lambton TS 230 kV operated *open*
- Claireville TS 230 kV operated *open*
- Leaside TS 230 kV operated *open*
- Leaside TS 115 kV operated *open*
- Middleport TS 230 kV bus operated *open*
- Hearn SS 115 kV bus operated *open*
- Cherrywood TS north & south 230kV buses operated ***open***
- Richview TS 230 kV bus operated ***open***
- All tie-lines in service and phase shifters on neutral taps
- Maximum voltages on the buses

## 4.2 Study Results

Table 8 summarizes the fault levels at facilities near the project with and without the project and other recently committed generation projects.

Table 8: Fault levels at facilities near the project

| Station | Before the Project | | After the Project and other committed projects | | Lowest Rated Circuit Breaker (kA) |
|---|---|---|---|---|---|
| | 3-Phase | L-G | 3-Phase | L-G | |
| *Symmetrical Fault (kA)** | | | | | |
| BEACH 115 kV | 26.564 | 32.158 | 27.645 | 33.409 | 39.3 |
| BEACH 230 kV | 37.168 | 35.607 | 37.673 | 36.047 | 41.1 |
| BURLINGTON 115 kV | 34.824 | 39.069 | 34.899 | 39.139 | 40 (existing), 50 (New)** |
| BURLINGTON 230 kV | 50.676 | 43.237 | 50.994 | 43.422 | 63 |
| MIDDLEPORT 230 kV | 45.827 | 43.377 | 45.992 | 43.482 | 60 |
| MIDDLEPORT 500 kV | 23.936 | 21.288 | 23.959 | 21.3 | 50 |
| TRAFALGAR 230 kV | 64.624 | 63.515 | 64.776 | 63.614 | 80 |
| RICHVIEW 230 kV | 58.369 | 55.402 | 58.41 | 55.426 | 69.5 |
| BECK 2 230 kV | 58.089 | 64.997 | 58.147 | 65.046 | 69.5 |
| MILTON 500 kV | 42.588 | 36.489 | 42.63 | 36.51 | 80 |
| BECK1 115 kV | 24.233 | 28.815 | 24.236 | 28.817 | 36 |
| ALLANBURG 115 kV | 35.062 | 39.42 | 35.07 | 39.427 | 40 (existing) 50 (New)** |
| MANBY EAST 230 kV | 38.847 | 37.141 | 38.865 | 37.152 | 50 |
| MANBY WEST 230 kV | 35.722 | 33.926 | 35.74 | 33.936 | 50 |
| MANBY EAST 115 kV | 26.058 | 31.041 | 26.062 | 31.044 | 39.3 |
| MANBY WEST 115 kV | 25.283 | 30.042 | 25.288 | 30.046 | 38.8 |
| NRWF HV 115 kV | 1.286 | 1.809 | 6.684 | 7.817 | 20 |
| *Asymmetrical Fault (kA)** | | | | | |
| BEACH 115 kV | 32.537 | 41.318 | 33.793 | 42.822 | 45.5 |
| BEACH 230 kV | 43.854 | 45.319 | 44.501 | 45.925 | 50 |
| BURLINGTON 115 kV | 43.453 | 50.828 | 43.568 | 50.936 | 45.5 (existing) 60 (New)** |
| BURLINGTON 230 kV | 60.877 | 55.305 | 61.263 | 55.54 | 75.6 |
| MIDDLEPORT 230 kV | 57.563 | 56.726 | 57.758 | 56.854 | 70.6 |
| MIDDLEPORT 500 kV | 30.528 | 28.472 | 30.558 | 28.489 | 62.4 |
| TRAFALGAR 230 kV | 83.688 | 87.277 | 83.874 | 87.407 | 92 |
| RICHVIEW 230 kV | 75.586 | 72.152 | 75.634 | 72.18 | 84 |
| BECK 2 230 kV | 79.91 | 92.463 | 79.983 | 92.525 | 81.5 |
| MILTON 500 kV | 55.009 | 46.045 | 55.062 | 46.069 | 95.1 |
| BECK1 115 kV | 29.399 | 36.597 | 29.401 | 36.599 | 39 |
| ALLANBURG 115 kV | 42.233 | 49.238 | 42.242 | 49.246 | 45.5 (existing) 60 (New)** |
| MANBY EAST 230 kV | 48.545 | 48.284 | 48.564 | 48.297 | 52.6 |
| MANBY WEST 230 kV | 44.064 | 44.424 | 44.083 | 44.437 | 52.6 |
| MANBY EAST 115 kV | 33.559 | 41.458 | 33.564 | 41.462 | 45.5 |
| MANBY WEST 115 kV | 32.052 | 39.801 | 32.057 | 39.806 | 45.5 |
| NRWF HV 115 kV | 1.457 | 2.13 | 9.248 | 11.037 | 20 |

* Based on a pre-fault voltage level of 550 kV for 500 kV buses, 250 kV for 230 kV buses, and 127 kV for 115 kV buses. The contact parting time is 25ms, 33ms, and 50ms for circuit breakers of 2, 3, and 5 cycles respectively.

**As per the CAA ID 2006-EX299 & 2011-EX542 the 115kV breakers at this station will be upgraded before the project comes in service.

Table 8 shows the interrupting capability of the 115 kV circuit breakers of the project are adequate for the anticipated fault levels.

The asymmetrical L-G fault current at Burlington 115 kV and Allanburg 115kV switchyards before and after the incorporation of the project will exceed the interrupting capability of the existing breakers when the station bus ties are operated in a closed position. Hydro One is currently operating the bus ties in an open position which is adequate for the anticipated short circuit levels. Hydro One is currently replacing their 115 kV breakers at both Burlington TS and Allanburg TS to improve the fault current interrupting capabilities at both stations (CAA2006-EX299 and CAA2011-EX542). There will be no short circuit violation after these circuit breakers are upgraded with the bus ties closed, and these reinforcements are expected to be completed before the connection of the project.

The short circuit results also show that the asymmetrical fault levels at Beck 2 230 kV switchyard exceeds the interrupting capability of the existing breakers before the connection of the project with all assumed committed generation facilities in service, including Greenfield South in the area. Hydro One ensures that the current fault levels at the existing facilities are within the interrupting capabilities of the existing breakers and is vigorously monitoring the fault levels with every new confirmed generation facility that connects to the Hydro One system. Hydro One has confirmed that mitigation measures are available such as opening up the bus ties to effectively address the short circuit violation at Beck 2 230 kV switchyard if necessary.

With the exception of circuit breakers at the above switchyards, the interrupting capability of the lowest rated circuit breakers near the project will not be exceeded after the incorporation of the project.

**-End of Section-**

# 5. Protection Impact Assessment

The Protection Impact Assessment (PIA) was completed by Hydro One to examine the impact of the new generator on existing transmission system protections.

The PIA concluded that it is feasible for the connection applicant to connect the project at the proposed location as long as the proposed changes to the transmission configuration, protection hardware, protection settings and telecommunications, as stated in the PIA report (Appendix B), are made.

This section primarily summarizes the changes to the existing protection system of the transmission system which may impact the system performance. The changes were included in the system impact studies.

*Protection Changes*

New protection equipments will be installed for incorporating the project as per the PIA report presented in Appendix B. These include,

- Duplicate IED breaker protection will be installed for new breaker CBQ5G at Beach TS;
- New IED line protections will be installed for connection of the project. The suggested protection settings are shown in Table 9;
- Transformer T8 protection scheme will be modified to provide proper re-zoning of the protection with regards to the new single line diagram configuration and installation of the new breaker CBQ5G;
- Breaker protection schemes for H3H8 and H4H8 breakers will be modified to provide proper re-zoning of the BF and bus protection with regards to the new single line diagram configuration and installation of new breaker CBQ5G;
- H8 bus protection scheme will be modified to provide re-zoning of the BF and bus protection with regards to the new single line diagram configuration and installation of new breaker CBQ5G.

Table 9: Suggested protection settings for circuit Q5G

| Station | Zone | Setting Coverage (km) or (%) | Time Delay (ms) | Actual Coverage |
|---|---|---|---|---|
| Beach TS | 1 | 36km or 80% | Inst. | 80% of the line Q5G |
| | 2 | 56.25km or 125% | 50 | 125% of the line Q5G |

**-End of Section-**

# 6. System Impact Studies

The technical studies focused on identifying the impact of the project on the reliability of the IESO-controlled grid. It includes thermal loading assessment of transmission lines, system voltage performance assessment of local buses, transient stability assessment of the proposed and major surrounding generation units, and ride-through capability of the project. The section also investigates the performance of the proposed control system and identifies the impact of the project on existing SPS schemes. In addition, the reactive power capability of the project is assessed and compared to the Market Rules requirements.

## 6.1 Existing System

Figure 2 provides an overview of the transmission system in the vicinity of the project. Table 10 summarizes the historical bus voltages at the stations in the vicinity of the project. The voltages are based on the hourly average samples for the last two years.

Table 10: Voltages of local transmission system based on 2010-2011 historical data

| Historical Voltage | Range | Typical voltage |
|---|---|---|
| Beach 115 kV | 119-126 kV | 123 kV |
| Beach 230 kV | 235-249 kV | 243 kV |
| Burlington 115 kV | 120-127 kV | 124 kV |
| Burlington 230 kV | 238-250 kV | 245 kV |
| Middleport 230 kV | 238-250kV | 244 kV |
| Trafalgar 230 kV | 238-250 kV | 242 kV |
| Beck 2 230 kV | 235-250kV | 239 kV |

## 6.2 Study Assumptions

In this assessment, the 2014 summer base cases were used with the following assumptions:

(1) **Transmission facilities**: All existing and committed major transmission facilities with 2014 in-service dates or earlier were assumed in service. The committed facilities primarily include:

- St. Catherines 115 kV circuit upgrade: circuits D9HS, D10S and Q11S (CAA2007-257);
- Buchanan TS: one 250 MVAr shunt capacitor;
- Nanticoke and Detweiler SVCs;

(2) **Generation facilities:** All existing and committed major generation facilities with 2014 in-service dates or earlier were assumed in service. The primary committed generation facilities are outlined in the assumptions for short circuit study, Section 4.

(3) **Basecases:** Two basecases in terms of load level were used in this SIA studies: peak load and light load. The generation dispatch philosophies for the two cases are as follows:

<u>Peak load basecase</u>

- Used for thermal analysis of local 230 kV system, voltage decline and transient stability;
- All committed and existing generation in the Southwest and Bruce areas were maximized, including 8 units at Bruce;
- No Lambton and Nanticoke units;
- Generation output in Niagara area was maximized;
- Gas generation, in conjunction with maximum wind generation, in the West area was dispatched to achieve a NBLIP transfer of approximately 1278 MW which results in no pre-contingency thermal violation in Niagara area before the project is incorporated;

- Generation in the North areas was dispatched to achieve a Flow South transfer of approximately 1250 MW;
- Generation in the Greater Toronto Area included two Pickering units, four Darlington units and four Sithe Goreway units.

Light load basecase

- Used for thermal analysis of local 115 kV system, and voltage analysis;
- All dispatchable gas units out of service;
- Minimum hydraulic generation;
- Nuclear generation limited to two Pickering units, two Darlington units and five Bruce units;
- Existing Southwest, West and Bruce area wind generation in service.

The system demand and the primary interface flows after the incorporation of the proposed project are listed in Table 11.

Table 11: System demand and primary interface flows for basecases (MW)

| Base case | System Demand | NBLIP | FABC | FETT | QFW | FS | FIO |
|---|---|---|---|---|---|---|---|
| Peak Load | 26880 | 1278 | 6412 | 6653 | 1494 | 1250 | 1585 |
| Light Load | 11621 | 643 | 3845 | 906 | 34 | -1048 | 746 |

## 6.3 Area Load Forecasting

Forecasted load values for stations supplied by local circuits in the vicinity of the project are presented in Table 12. The forecasted values are for the year 2014 as this is the expected in service year of the project.

Table 12: Area Load Forecast

| Load Station | Peak Forecast Load MW | Light Forecast Load MW |
|---|---|---|
| Beach TS | 68.4 | 35.28 |
| Dofasco Kenilworth & Bay front | 221.4 | 132.3 |
| Kenilworth 115kV | 18.5 | 8.2 |
| Lake TS | 118.2 | 42.69 |
| Gage TS | 49.68 | 34.2 |
| Elgin TS | 75 | 46.8 |
| Hanlon | 33.4 | 15.5 |
| Horning TS | 56 | 19 |
| Dundas TS | 99.9 | 46.5 |
| McMaster TS | 11.8 | 6.9 |
| Mohawk TS | 82 | 29.4 |
| Palermo TS | 115.6 | 42.5 |
| Stirton TS | 49.4 | 25.7 |
| Trafalgar DESN | 83 | 27.6 |
| Meadowvale TS | 153.6 | 71.4 |
| Halton TS | 145.2 | 58.2 |
| Dunnville TS | 24 | 9.3 |
| Pleasant TS | 364.1 | 105 |
| Jim yarrow TS | 115.1 | 34.9 |
| Tomken TS | 308.4 | 103 |
| Erindale TS | 615.88 | 168.1 |
| Winona TS | 54.5 | 21.3 |
| Burlington DESN | 154 | 60.8 |
| Cedar TS | 98 | 51 |
| Hamilton Specialty bar TS | 6.5 | 0.1 |
| **Total** | **3121.56** | **1195.67** |

## 6.4 Reactive Power Compensation

Based on the equivalent parameters for the wind farm provided by the connection applicant, no additional reactive power compensation is required for the project.

The Market Rules (MR) require that generators inject or withdraw reactive power continuously (i.e. dynamically) at a connection point up to 33% of its rated active power at all levels of active power output except where a lesser continually available capability is permitted by the IESO. A generating unit with a power factor range of 0.90 lagging and 0.95 leading at rated active power connected via impedance between the generator and the connection point not greater than 13% based on rated apparent power provides the required range of dynamic reactive capability at the connection point.

Dynamic reactive compensation (e.g. D-VAR or SVC) is required for a generating project which cannot provide a reactive power range of 0.90 lagging power factor and 0.95 leading power factor at rated active power. For a wind farm with impedance between the generator and the connection point greater than 13% based on rated apparent power, provided the WTGs have the capability to provide a reactive power range of 0.90 lagging power factor and 0.95 leading power factor at rated active power, the IESO accepts that the wind farm compensates for excessive reactive losses in the collector system of the project with static shunts (e.g. capacitors and reactors). In addition, the wind farm is expected to inject or withdraw its full reactive power requirement for a 10% voltage change at the connection point, without provision for tap changer action. The response time is expected to be similar to that of a synchronous generator that meets the minimum Market Rules' requirements, outlined in Appendix 4.2 of the Market Rules, which is in the order of a few seconds.

The connection applicant shall be able to confirm this capability during the commission tests.

***Dynamic Reactive Power Capability:*** The Enercon E-101 FT generators can deliver IESO's required dynamic reactive power to the generator terminal at rated power and at rated voltage. Thus, the IESO has determined that there is no need to install any additional dynamic reactive power compensation device.

***Static Reactive Power Capability:*** In addition to the dynamic reactive power requirement identified above, the wind farm has to compensate for the reactive power losses within the project to ensure that it has the capability to inject or withdraw reactive power up to 33% of its rated active power at the connection point. As mentioned above, the IESO accepts this compensation to be made with switchable shunt admittances.

Load flow studies were performed to calculate the static reactive compensation, based on the equivalent parameters provided by the connection applicant for the wind farm. The connection point was considered to be the high voltage connection to the Hydro One line.

The reactive power capability in lagging power factor of the project was assessed under the following assumptions:

- typical low voltage of 120.4 kV at the connection point;
- maximum active power output from the equivalent WTG;
- maximum reactive power output (lagging power factor) from the equivalent WTG, unless limited by the maximum acceptable WTG terminal voltage;
- maximum acceptable WTG voltage is 1.20, as per WTG voltage capability;
- Off-load tap at the main step-up transformer set to a tap position of 120.75 kV.

The reactive power capability in leading power factor of the project was assessed under the following assumptions:

- typical high voltage of 123.5 kV at the connection point;
- minimum (zero) active power output from the equivalent WTG;
- maximum reactive power consumption (leading power factor) from the equivalent WTG, unless limited by the minimum acceptable WTG terminal voltage;

- minimum acceptable WTG voltage is 0.90, as per WTG voltage capability;
- Off-load tap at the main step-up transformer set to a tap position of 120.75 kV.

Simulation results show that no additional static reactive compensation is required for the project.

The WTGs may automatically disconnect themselves from the system during high wind conditions. This leaves only the collector system connected to the grid providing charging reactive power to the system. Simulation results show that under this situation the project will inject 26 Mvar reactive power into the system at the connection point, which may aggravate the high-voltage situation under some system condition. The project shall be capable of reducing the reactive power injection at the connection to zero at the request of the IESO. This may be obtained by disconnecting the collectors. Shall the project fail to meet the IESO's direction, the IESO reserve the right to ask the applicant to disconnect the project from the system.

The IESO's reactive power calculation used the equivalent electrical model for the WTG and collector feeders as provided by the connection applicant. It is very important that the wind farm has a proper internal design to ensure that the WTG are not limited in their capability to produce active and reactive power due to terminal voltage limits or other project's internal limitations. For example, it is expected that the transformation ratio of the WTG step up transformers will be set in such a way that it will offset the voltage profile along the collector, and all the WTG would be able to contribute to the reactive power production of the Wind farm in a shared amount.

## 6.5 Wind Farm Voltage Control System

As per the Market Rules' requirements, the wind farm shall operate in voltage control mode by using all voltage control methods available within the project. The overall automatic voltage regulation philosophy for the project is summarized as follow:

(1) All WTGs control the voltage at a point whose impedance (based on rated apparent power and voltage of the project) is not more than 13% from the connection point. Appropriate control slope is adopted for reactive power sharing among the WTGs as well as with adjacent generators. The reference voltage will be specified by the IESO during operation.

In the event that the wind farm voltage control becomes unavailable, the IESO requires that each WTG be in reactive power control and maintain its reactive power output to the value prior to the loss of signal from the wind farm voltage control. Depending on system conditions, further action such as curtailing the output of the project may be required for reliability purposes.

## 6.6 Thermal Analysis

Thermal analysis below shows that the project contributes in overloading of some of the limiting elements in the Central area. At times, the connection applicant may need to curtail the output of the project for reliability purposes.

The Ontario Resource and Transmission Assessment Criteria (ORTAC) require that all line and equipment loads be within their continuous ratings with all elements in service, and within their long-term emergency ratings with any element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings.

In the thermal analysis, the continuous ratings for the conductors were calculated at the lowest of the sag temperature or 93$^{o}$C operating temperature, with a 35$^{o}$C ambient temperature and 4 km/h wind speed. The long term emergency ratings (LTE) for the conductors were calculated at the lowest of the sag temperature or 127$^{o}$C operating temperature, with a 35$^{o}$C ambient temperature and 4 km/h wind speed. The short-term emergency ratings (STE) for the conductors were calculated at the sag temperature, with a 35$^{o}$C ambient temperature, 4 km/h wind speed and 100% continuous preload.

**System Overview:** The impact of the projects on the overall system, in conjunction with other committed projects, was examined to identify if any system congestion issues exist in Central and Southwest Ontario due to 230 kV circuit or 500 kV auto-transformer thermal constraints. The studies concluded that under exceptionally high power transfers towards Toronto, generating stations in Bruce and Southwest Ontario may be required to curtail their outputs to relieve congestion. However, the flow into Toronto at the levels examined is not expected to materialize for the next several years. Future planning assessments for the west Greater Toronto Area (GTA) are currently being undertaken by the agencies.

With the addition of new committed generation projects in Bruce and Southwest Ontario, flows east into Toronto were maximized to reach 6653 MW under the defined peak load basecase, representing a high stress case for the west of GTA equipment. Under this high flow scenario, the additional new generation projects contributed to overloading some limiting elements in the central area. Table 13 and Table 14 show the thermal results of limiting circuits and transformers in Central area under peak load conditions after the integration of new committed generation projects. It shows both pre-contingency and post-contingency overloading of the limiting elements.

Table 13: Thermal results of limiting circuits in central area under peak-load conditions

| Circuit | Contingency | Pre-Cont. Flow (A) | Continuous Rating (A) | Pre-Cont. Loading (%) | Post-Cont. Flow (A) | LTE Rating (MVA) | Post-Cont. Loading (%) |
|---|---|---|---|---|---|---|---|
| R14T (Trafalgar-Erindale) | R17T | 1111.5 | 1110 | 100.1 | 1708.6 | 1460 | 117 |
| R17T (Trafalgar-Erindale) | R14T | 1118.3 | 1110 | 100.8 | 1708.6 | 1460 | 117 |
| R19TH (Erindale-Hanlan) | R14T+R17T | 762.1 | 840 | 90.7 | 1324 | 1090 | 121.5 |

Table 14: Thermal results of limiting transformers in central area under peak-load conditions

| Transformer | Pre-Cont. Flow (MVA) | Summer Continuous Rating (MVA) | Pre-Cont. Loading (%) | LTE Rating (MVA) | Loss of Trafalgar T15 | |
|---|---|---|---|---|---|---|
| | | | | | Post-Cont. Flow(MVA) | Post-Cont. Loading (%) |
| Trafalgar T14 | 858.84 | 750 | 114.51 | 1004 | 1078.02 | 107.37 |
| Trafalgar T15 | 830.20 | 750 | 110.69 | 1132 | 0.00 | 0.00 |
| Claireville T13 | 782.34 | 750 | 104.31 | 988 | 846.71 | 85.70 |
| Claireville T14 | 796.55 | 750 | 106.21 | 995 | 861.85 | 86.62 |
| Claireville T15 | 789.09 | 750 | 105.21 | 995 | 853.96 | 85.83 |

**Local 115 kV Transmission**

The rating of the local 115 kV line Q5G provided by Hydro One is sufficient to allow the plant to deliver its full power.

After the connection of the project, the flow on the Beach 230/115 kV transformers is expected to reverse during light load conditions. As each transformer is rated 250 MVA, following the connection of the 230 MW project the loading of Beach transformers is expected to stay within the continuous rating pre-contingency and post-contingency for the loss of one transformer during light load conditions. Under the peak load conditions, the project shows the benefits of displacing the local load and reducing the loading of the Beach transformers.

**Local 230 kV Transmission**

The effects of the project on the thermal loadings of the local 230 kV transmission system were examined. The defined peak load basecase was used for this study as the local transmission system in Niagara area is stressed due to high flow eastward into the GTA. In this case, generation in the west area was dispatched to avoid pre-contingency thermal violation in Niagara area before the project is incorporated.

Table 15 shows the pre-contingency flows for the monitored circuits prior to and after the connection of the project. The pre-contingency results of the circuits include current flow in ampere and loading in percentage of continuous rating.

Table 15: Pre-Contingency Thermal Analysis

| CIRCUIT | FROM | TO | Cont Rating (A) | All Elements in service- The project O/S Loading (A) | All Elements in service- The project O/S Loading (%) Cont | All Elements in service- The project I/S Loading (A) | All Elements in service- The project I/S Loading (%) Cont |
|---|---|---|---|---|---|---|---|
| B18H | Burlington TS | Beach Road JCT | 1060 | 497.3 | 46.9% | 632.9 | 59.7% |
| B18H | Beach Road JCT | Beach TS | 1050 | 574.7 | 54.7% | 725.3 | 69.1% |
| B20H | Burlington TS | Beach Road JCT | 1050 | 491.4 | 46.8% | 626.3 | 59.6% |
| B20H | Beach Road JCT | Beach TS | 1060 | 578.1 | 54.5% | 725.9 | 68.5% |
| Q23BM | Beck #2 TS | Niagara West JCT | 1060 | 711.9 | 67.2% | 712.4 | 67.2% |
| Q23BM | Neale JCT | Middleport TS | 840 | 431.6 | 51.4% | 420.1 | 50.0% |
| Q23BM | Neale JCT | Burlington J23 | 1060 | 1054.0 | 99.4% | 1041.5 | 98.3% |
| Q25BM | Beck #2 TS | Niagara West JCT | 1060 | 716.7 | 67.6% | 717.2 | 67.7% |
| Q25BM | Neale JCT | Middleport TS | 840 | 435.1 | 51.8% | 423.5 | 50.4% |
| Q25BM | Neale JCT | Burlington TS | 1060 | 1060.4 | 100.0% | 1047.8 | 98.8% |
| M27B | Middleport TS | Horning JCT | 1060 | 637.6 | 60.2% | 633.5 | 59.8% |
| M27B | Horning JCT | Burlington TS | 1060 | 571.6 | 53.9% | 567.0 | 53.5% |
| M28B | Middleport TS | Horning JCT | 1060 | 637.4 | 60.1% | 633.3 | 59.7% |
| M28B | Horning JCT | Burlington TS | 1060 | 571.9 | 53.9% | 567.3 | 53.5% |
| Q24HM | Beck #2 TS | Hannon JCT | 1060 | 808.9 | 76.3% | 790.4 | 74.6% |
| Q24HM | Hannon JCT | Nebo JCT | 1060 | 229.5 | 21.7% | 177.3 | 16.7% |
| Q24HM | Nebo JCT | Middleport TS | 1060 | 445.9 | 42.1% | 397.6 | 37.5% |
| Q24HM | Hannon JCT | Beach TS | 1060 | 1009.2 | 95.2% | 929.9 | 87.7% |
| Q29HM | Beck #2 TS | Hannon JCT | 1060 | 836.6 | 78.9% | 816.9 | 77.1% |
| Q29HM | Hannon JCT | Nebo JCT | 1060 | 160.1 | 15.1% | 150.2 | 14.2% |
| Q29HM | Nebo JCT | Middleport TS | 1060 | 308.3 | 29.1% | 274.6 | 25.9% |
| Q29HM | Hannon JCT | Beach TS | 1060 | 890.0 | 84.0% | 817.4 | 77.1% |
| M34H | Middleport TS | Beach TS | 1060 | 440.7 | 41.6% | 387.3 | 36.5% |
| Q30M | Beck #2 TS | Allanburg Q30M JCT | 1060 | 573.5 | 54.1% | 574.3 | 54.2% |
| Q30M | Allanburg Q30M JCT | Middleport TS | 840 | 591.5 | 70.4% | 590.7 | 70.3% |
| T36B | Trafalgar TS | Lantz JCT | 1350 | 305.6 | 22.6% | 364.9 | 27.0% |
| T36B | Lantz JCT | Palermo TxB JCT | 1110 | 305.7 | 27.5% | 364.9 | 32.9% |
| T36B | Palermo TxB JCT | Burlington TS | 1110 | 393.9 | 35.5% | 460.7 | 41.5% |
| T37B | Trafalgar TS | Lantz JCT | 1350 | 492.5 | 36.5% | 521.0 | 38.6% |
| T37B | Lantz JCT | Palermo TxB JCT | 1110 | 309.5 | 27.9% | 368.1 | 33.2% |
| T37B | Palermo TxB JCT | Burlington TS | 1110 | 396.0 | 35.7% | 462.6 | 41.7% |
| T38B | Trafalgar TS | Lantz JCT | 1110 | 301.4 | 27.1% | 291.0 | 26.2% |
| T38B | Lantz JCT | Burlington TS | 1110 | 353.8 | 31.9% | 418.9 | 37.7% |
| T39B | Trafalgar TS | Lantz JCT | 1110 | 301.9 | 27.2% | 291.5 | 26.3% |
| T39B | Lantz JCT | Burlington TS | 1110 | 353.8 | 31.9% | 418.9 | 37.7% |

The study results show increased flow on certain sections of circuits T36B, T37B, T38B, T39B and B18H, and B20Hs. However, all increased flows remain well below the continuous ratings of all circuits.

Using the study scenario with the project in-service, contingency studies were performed to identify potential post-contingency thermal violations. The contingencies considered for this study were:

1. Loss of B18H+B20H
2. Loss of Q23BM+Q25BM
3. Loss of M27B+M28B
4. Loss of Q24HM+Q29HM

5. Loss of Q24HM
6. Loss of Q29HM
7. Loss of M34H
8. Loss of Q30M
9. Loss of T36B+T37B
10. Loss of M585M+V586M

Table 16 summarizes the post-contingency flows for the monitored circuits. The post-contingency results of the circuits include current flow in ampere, and loading in percentage of LTE rating.

The contingency study results show post-contingency violation of LTE ratings on sections of 230 kV circuits Q23B & Q25B for the loss of Q24HM+Q29HM and on a section of Q24HM for the loss of Q23BM & Q25BM before the connection of the project. The connection of the project tends to reduce the post-contingency flows on these circuits; thus, the project will have no adverse impact on the thermal aspect of the local 230 kV transmission system.

Table 16: Post-Contingency Thermal Analysis

| | | | | | Loss of B18H&B20H- The project O/S | | Loss of B18H&B20H- The project I/S | | Loss of Q24HM&Q29HM- The project O/S | | | Loss of Q24HM&Q29HM- The project I/S | | | Loss of Q23BM&Q25BM- The project O/S | | | Loss of Q23BM&Q25BM- The project I/S | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | LTE Rating | STE Rating | Loading | Loading (%) | Loading | Loading (%) | Loading | Loading (%) | | Loading | Loading (%) | | Loading | Loading (%) | | Loadin g | Loading (%) | |
| CIRCUIT | FROM | TO | (A) | (A) | (A) | LTE | (A) | LTE | (A) | LTE | STE | (A) | LTE | STE | (A) | LTE | STE | (A) | LTE | STE |
| B18H | Burlington TS | Beach Road JCT | 1400 | 1900 | 0.0 | 0.0% | 0.0 | 0.0% | 436.5 | 31.2% | 23.0% | 306.7 | 21.9% | 16.1% | 908.1 | 64.9% | 47.8% | 1050.0 | 75.0% | 55.3% |
| B18H | Beach R. JCT | Beach TS | 1380 | 1880 | 0.0 | 0.0% | 0.0 | 0.0% | 266.9 | 19.3% | 14.2% | 179.5 | 13.0% | 9.5% | 1005.6 | 72.9% | 53.5% | 1154.5 | 83.7% | 61.4% |
| B20H | Burlington TS | Beach Road JCT | 1380 | 1880 | 0.0 | 0.0% | 0.0 | 0.0% | 429.9 | 31.2% | 22.9% | 300.2 | 21.8% | 16.0% | 899.5 | 65.2% | 47.8% | 1040.4 | 75.4% | 55.3% |
| B20H | Beach R. JCT | Beach TS | 1400 | 1900 | 0.0 | 0.0% | 0.0 | 0.0% | 280.4 | 20.0% | 14.8% | 201.7 | 14.4% | 10.6% | 1003.9 | 71.7% | 52.8% | 1150.6 | 82.2% | 60.6% |
| Q23BM | Beck #2 TS | Niagara W. JCT | 1170 | 1240 | 766.2 | 65.5% | 783.6 | 67.0% | 1110.5 | 94.9% | 89.6% | 1104.5 | 94.4% | 89.1% | 0.0 | 0.0% | 0.0% | 0.0 | 0.0% | 0.0% |
| Q23BM | Neale JCT | Middleport TS | 1020 | 1100 | 522.1 | 51.2% | 545.7 | 53.5% | 503.9 | 49.4% | 45.8% | 477.1 | 46.8% | 43.4% | 0.0 | 0.0% | 0.0% | 0.0 | 0.0% | 0.0% |
| Q23BM | Neale JCT | Burlington J23 | 1400 | 1900 | 1213.1 | 86.6% | 1253.5 | 89.5% | 1479.9 | 105.7% | 77.9% | 1442.9 | 103.1% | 75.9% | 0.0 | 0.0% | 0.0% | 0.0 | 0.0% | 0.0% |
| Q25BM | Beck #2 TS | Niagara W. JCT | 1240 | 1360 | 771.1 | 62.2% | 788.5 | 63.6% | 1118.6 | 90.2% | 82.3% | 1112.6 | 89.7% | 81.8% | 0.0 | 0.0% | 0.0% | 0.0 | 0.0% | 0.0% |
| Q25BM | Neale JCT | Middleport TS | 1090 | 1240 | 526.5 | 48.3% | 550.3 | 50.5% | 507.7 | 46.6% | 40.9% | 480.6 | 44.1% | 38.8% | 0.0 | 0.0% | 0.0% | 0.0 | 0.0% | 0.0% |
| Q25BM | Neale JCT | Burlington TS | 1400 | 1900 | 1220.9 | 87.2% | 1261.7 | 90.1% | 1487.6 | 106.3% | 78.3% | 1450.2 | 103.6% | 76.3% | 0.0 | 0.0% | 0.0% | 0.0 | 0.0% | 0.0% |
| M27B | Middleport TS | Horning JCT | 1300 | 1470 | 804.9 | 61.9% | 857.1 | 65.9% | 790.9 | 60.8% | 53.8% | 771.8 | 59.4% | 52.5% | 862.6 | 66.4% | 58.7% | 855.6 | 65.8% | 58.2% |
| M27B | Horning JCT | Burlington TS | 1340 | 1530 | 743.4 | 55.5% | 795.1 | 59.3% | 724.0 | 54.0% | 47.3% | 704.6 | 52.6% | 46.1% | 798.0 | 59.5% | 52.2% | 790.5 | 59.0% | 51.7% |
| M28B | Middleport TS | Horning JCT | 1300 | 1470 | 804.6 | 61.9% | 856.8 | 65.9% | 790.7 | 60.8% | 53.8% | 771.5 | 59.3% | 52.5% | 862.4 | 66.3% | 58.7% | 855.3 | 65.8% | 58.2% |
| M28B | Horning JCT | Burlington TS | 1340 | 1530 | 743.7 | 55.5% | 795.4 | 59.4% | 724.3 | 54.1% | 47.3% | 704.9 | 52.6% | 46.1% | 798.2 | 59.6% | 52.2% | 790.8 | 59.0% | 51.7% |
| Q24HM | Beck #2 TS | Hannon JCT | 1260 | 1390 | 721.6 | 57.3% | 680.6 | 54.0% | 0.0 | 0.0% | 0.0% | 0.0 | 0.0% | 0.0% | 1160.8 | 92.1% | 83.5% | 1145.0 | 90.9% | 82.4% |
| Q24HM | Hannon JCT | Nebo JCT | 1400 | 1900 | 208.2 | 14.9% | 313.7 | 22.4% | 0.0 | 0.0% | 0.0% | 0.0 | 0.0% | 0.0% | 391.5 | 28.0% | 20.6% | 333.8 | 23.8% | 17.6% |
| Q24HM | Nebo JCT | Middleport TS | 1300 | 1470 | 326.2 | 25.1% | 328.6 | 25.3% | 0.0 | 0.0% | 0.0% | 0.0 | 0.0% | 0.0% | 616.6 | 47.4% | 41.9% | 561.2 | 43.2% | 38.2% |
| Q24HM | Hannon JCT | Beach TS | 1400 | 1900 | 620.8 | 44.3% | 433.9 | 31.0% | 0.0 | 0.0% | 0.0% | 0.0 | 0.0% | 0.0% | 1489.9 | 106.4% | 78.4% | 1404.6 | 100.3% | 73.9% |
| Q29HM | Beck #2 TS | Hannon JCT | 1280 | 1420 | 744.1 | 58.1% | 700.6 | 54.7% | 0.0 | 0.0% | 0.0% | 0.0 | 0.0% | 0.0% | 1215.4 | 95.0% | 85.6% | 1197.6 | 93.6% | 84.3% |
| Q29HM | Hannon JCT | Nebo JCT | 1400 | 1650 | 315.1 | 22.5% | 421.0 | 30.1% | 0.0 | 0.0% | 0.0% | 0.0 | 0.0% | 0.0% | 184.2 | 13.2% | 11.2% | 189.5 | 13.5% | 11.5% |
| Q29HM | Nebo JCT | Middleport TS | 1300 | 1450 | 298.3 | 22.9% | 349.1 | 26.9% | 0.0 | 0.0% | 0.0% | 0.0 | 0.0% | 0.0% | 301.6 | 23.2% | 20.8% | 275.5 | 21.2% | 19.0% |
| Q29HM | Hannon JCT | Beach TS | 1400 | 1900 | 537.2 | 38.4% | 369.8 | 26.4% | 0.0 | 0.0% | 0.0% | 0.0 | 0.0% | 0.0% | 1212.8 | 86.6% | 63.8% | 1139.1 | 81.4% | 60.0% |
| M34H | Middleport TS | Beach TS | 1300 | 1470 | 256.4 | 19.7% | 234.3 | 18.0% | 838.7 | 64.5% | 57.1% | 747.4 | 57.5% | 50.8% | 502.9 | 38.7% | 34.2% | 446.7 | 34.4% | 30.4% |
| Q30M | Beck #2 TS | Allanburg JCT | 1400 | 1900 | 582.5 | 41.6% | 587.1 | 41.9% | 899.3 | 64.2% | 47.3% | 895.0 | 63.9% | 47.1% | 838.0 | 59.9% | 44.1% | 840.0 | 60.0% | 44.2% |
| Q30M | Allanburg JCT | Middleport TS | 970 | 1030 | 602.3 | 62.1% | 605.4 | 62.4% | 968.3 | 99.8% | 94.0% | 962.9 | 99.3% | 93.5% | 896.3 | 92.4% | 87.0% | 897.6 | 92.5% | 87.2% |
| T36B | Trafalgar TS | Lantz JCT | 1800 | 2170 | 245.9 | 13.7% | 287.6 | 16.0% | 253.8 | 14.1% | 11.7% | 309.9 | 17.2% | 14.3% | 213.4 | 11.9% | 9.8% | 267.9 | 14.9% | 12.3% |
| T36B | Lantz JCT | Palermo JCT | 1460 | 2080 | 245.9 | 16.8% | 287.7 | 19.7% | 253.9 | 17.4% | 12.2% | 310.0 | 21.2% | 14.9% | 213.5 | 14.6% | 10.3% | 268.0 | 18.4% | 12.9% |
| T36B | Palermo JCT | Burlington TS | 1460 | 2080 | 351.1 | 24.0% | 396.3 | 27.1% | 314.8 | 21.6% | 15.1% | 389.5 | 26.7% | 18.7% | 278.9 | 19.1% | 13.4% | 349.0 | 23.9% | 16.8% |
| T37B | Trafalgar TS | Lantz JCT | 1800 | 2170 | 535.3 | 29.7% | 547.9 | 30.4% | 436.6 | 24.3% | 20.1% | 465.7 | 25.9% | 21.5% | 457.8 | 25.4% | 21.1% | 472.2 | 26.2% | 21.8% |
| T37B | Lantz JCT | Palermo JCT | 1460 | 2080 | 249.0 | 17.1% | 290.3 | 19.9% | 259.2 | 17.8% | 12.5% | 314.3 | 21.5% | 15.1% | 218.9 | 15.0% | 10.5% | 272.3 | 18.7% | 13.1% |
| T37B | Palermo JCT | Burlington TS | 1460 | 2080 | 352.2 | 24.1% | 397.4 | 27.2% | 317.7 | 21.8% | 15.3% | 392.0 | 26.8% | 18.8% | 281.5 | 19.3% | 13.5% | 351.3 | 24.1% | 16.9% |
| T38B | Trafalgar TS | Lantz JCT | 1460 | 2080 | 260.7 | 17.9% | 245.1 | 16.8% | 362.4 | 24.8% | 17.4% | 328.4 | 22.5% | 15.8% | 354.3 | 24.3% | 17.0% | 321.9 | 22.0% | 15.5% |
| T38B | Lantz JCT | Burlington TS | 1460 | 2080 | 305.3 | 20.9% | 350.0 | 24.0% | 281.6 | 19.3% | 13.5% | 352.0 | 24.1% | 16.9% | 243.1 | 16.7% | 11.7% | 310.3 | 21.3% | 14.9% |
| T39B | Trafalgar TS | Lantz JCT | 1460 | 2080 | 261.2 | 17.9% | 245.6 | 16.8% | 362.9 | 24.9% | 17.4% | 328.9 | 22.5% | 15.8% | 354.8 | 24.3% | 17.1% | 322.4 | 22.1% | 15.5% |
| T39B | Lantz JCT | Burlington TS | 1460 | 2080 | 305.3 | 20.9% | 350.0 | 24.0% | 281.6 | 19.3% | 13.5% | 352.0 | 24.1% | 16.9% | 243.1 | 16.7% | 11.7% | 310.3 | 21.3% | 14.9% |

Table 16: Post-Contingency Thermal Analysis (Continued)

| | | | | Loss of M27B&M28B- The project O/S | | Loss of M27B&M28B- The project I/S | | Loss of M34H- The project O/S | | Loss of M34H- The project I/S | | Loss of Q24HM- The project O/S | | Loss of Q24HM- The project I/S | | Loss of Q29HM- The project O/S | | Loss of Q29HM- The project I/S | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CIRCUIT | FROM BUS | TO BUS | LTE Rating (A) | Loading (A) | Loading (%) LTE | Loading (A) | Loading (%) LTE | Loading (A) | Loading (%) LTE | Loading (A) | Loading (%) LTE | Loading (A) | Loading (%) LTE | Loading (A) | Loading (%) LTE | Loading (A) | Loading (%) LTE | Loading (A) | Loading (%) LTE |
| B18H | Burlington TS | Beach Road JCT | 1400 | 723.1 | 51.7% | 868.2 | 62.0% | 437.1 | 31.2% | 567.2 | 40.5% | 340.1 | 24.3% | 421.3 | 30.1% | 348.0 | 24.9% | 450.4 | 32.2% |
| B18H | Beach Road JCT | Beach TS | 1380 | 825.2 | 59.8% | 977.4 | 70.8% | 482.1 | 34.9% | 640.6 | 46.4% | 310.8 | 22.5% | 456.3 | 33.1% | 349.3 | 25.3% | 502.2 | 36.4% |
| B20H | Burlington TS | Beach Road JCT | 1380 | 716.1 | 51.9% | 860.3 | 62.3% | 430.9 | 31.2% | 560.5 | 40.6% | 333.3 | 24.2% | 414.9 | 30.1% | 341.5 | 24.7% | 444.1 | 32.2% |
| B20H | Beach Road JCT | Beach TS | 1400 | 823.8 | 58.8% | 973.9 | 69.6% | 489.8 | 35.0% | 644.6 | 46.0% | 326.5 | 23.3% | 465.5 | 33.2% | 362.1 | 25.9% | 509.3 | 36.4% |
| Q23BM | Beck #2 TS | Niagara West JCT | 1170 | 741.5 | 63.4% | 743.0 | 63.5% | 713.1 | 60.9% | 713.4 | 61.0% | 846.4 | 72.3% | 847.0 | 72.4% | 865.4 | 74.0% | 863.7 | 73.8% |
| Q23BM | Neale JCT | Middleport TS | 1020 | 544.2 | 53.4% | 531.3 | 52.1% | 447.4 | 43.9% | 433.7 | 42.5% | 516.9 | 50.7% | 492.4 | 48.3% | 406.1 | 39.8% | 393.0 | 38.5% |
| Q23BM | Neale JCT | Burlington J23 | 1400 | 1197.7 | 85.6% | 1184.9 | 84.6% | 1070.6 | 76.5% | 1055.7 | 75.4% | 1253.9 | 89.6% | 1226.9 | 87.6% | 1172.7 | 83.8% | 1155.9 | 82.6% |
| Q25BM | Beck #2 TS | Niagara West JCT | 1240 | 746.3 | 60.2% | 747.8 | 60.3% | 717.9 | 57.9% | 718.2 | 57.9% | 852.3 | 68.7% | 853.0 | 68.8% | 871.5 | 70.3% | 869.9 | 70.2% |
| Q25BM | Neale JCT | Middleport TS | 1090 | 549.2 | 50.4% | 536.1 | 49.2% | 451.2 | 41.4% | 437.4 | 40.1% | 521.4 | 47.8% | 496.6 | 45.6% | 408.9 | 37.5% | 395.7 | 36.3% |
| Q25BM | Neale JCT | Burlington TS | 1400 | 1205.4 | 86.1% | 1192.4 | 85.2% | 1077.1 | 76.9% | 1062.1 | 75.9% | 1261.3 | 90.1% | 1233.9 | 88.1% | 1179.1 | 84.2% | 1162.2 | 83.0% |
| M27B | Middleport TS | Horning JCT | 1300 | 0.0 | 0.0% | 0.0 | 0.0% | 710.8 | 54.7% | 697.0 | 53.6% | 670.4 | 51.6% | 663.6 | 51.0% | 713.9 | 54.9% | 700.1 | 53.9% |
| M27B | Horning JCT | Burlington TS | 1340 | 0.0 | 0.0% | 0.0 | 0.0% | 643.8 | 48.0% | 629.6 | 47.0% | 604.2 | 45.1% | 597.2 | 44.6% | 646.6 | 48.3% | 632.4 | 47.2% |
| M28B | Middleport TS | Horning JCT | 1300 | 0.0 | 0.0% | 0.0 | 0.0% | 710.5 | 54.7% | 696.7 | 53.6% | 670.1 | 51.5% | 663.3 | 51.0% | 713.6 | 54.9% | 699.8 | 53.8% |
| M28B | Horning JCT | Burlington TS | 1340 | 0.0 | 0.0% | 0.0 | 0.0% | 644.1 | 48.1% | 629.9 | 47.0% | 604.5 | 45.1% | 597.4 | 44.6% | 646.9 | 48.3% | 632.7 | 47.2% |
| Q24HM | Beck #2 TS | Hannon JCT | 1260 | 825.4 | 65.5% | 808.0 | 64.1% | 824.5 | 65.4% | 803.7 | 63.8% | 0.0 | 0.0% | 0.0 | 0.0% | 1029.2 | 81.7% | 1005.5 | 79.8% |
| Q24HM | Hannon JCT | Nebo JCT | 1400 | 262.1 | 18.7% | 208.0 | 14.9% | 285.3 | 20.4% | 225.4 | 16.1% | 0.0 | 0.0% | 0.0 | 0.0% | 182.9 | 13.1% | 115.1 | 8.2% |
| Q24HM | Nebo JCT | Middleport TS | 1300 | 471.6 | 36.3% | 421.5 | 32.4% | 499.9 | 38.5% | 444.1 | 34.2% | 0.0 | 0.0% | 0.0 | 0.0% | 584.1 | 44.9% | 525.8 | 40.4% |
| Q24HM | Hannon JCT | Beach TS | 1400 | 1057.6 | 75.5% | 978.5 | 69.9% | 1078.3 | 77.0% | 989.2 | 70.7% | 0.0 | 0.0% | 0.0 | 0.0% | 1201.7 | 85.8% | 1107.2 | 79.1% |
| Q29HM | Beck #2 TS | Hannon JCT | 1280 | 824.1 | 64.4% | 805.8 | 63.0% | 845.3 | 66.0% | 824.3 | 64.4% | 1065.8 | 83.3% | 1040.0 | 81.2% | 0.0 | 0.0% | 0.0 | 0.0% |
| Q29HM | Hannon JCT | Nebo JCT | 1400 | 356.4 | 25.5% | 311.0 | 22.2% | 250.1 | 17.9% | 212.3 | 15.2% | 45.7 | 3.3% | 47.0 | 3.4% | 0.0 | 0.0% | 0.0 | 0.0% |
| Q29HM | Nebo JCT | Middleport TS | 1300 | 533.5 | 41.0% | 486.5 | 37.4% | 414.5 | 31.9% | 364.3 | 28.0% | 469.7 | 36.1% | 423.7 | 32.6% | 0.0 | 0.0% | 0.0 | 0.0% |
| Q29HM | Hannon JCT | Beach TS | 1400 | 1124.0 | 80.3% | 1050.4 | 75.0% | 1007.1 | 71.9% | 918.7 | 65.6% | 1091.9 | 78.0% | 1001.8 | 71.6% | 0.0 | 0.0% | 0.0 | 0.0% |
| M34H | Middleport TS | Beach TS | 1300 | 682.6 | 52.5% | 625.4 | 48.1% | 0.0 | 0.0% | 0.0 | 0.0% | 587.4 | 45.2% | 520.4 | 40.0% | 609.8 | 46.9% | 539.1 | 41.5% |
| Q30M | Beck #2 TS | Allanburg JCT | 1400 | 506.3 | 36.2% | 508.3 | 36.3% | 555.1 | 39.6% | 558.3 | 39.9% | 699.0 | 49.9% | 697.4 | 49.8% | 687.1 | 49.1% | 688.1 | 49.2% |
| Q30M | Allanburg JCT | Middleport TS | 970 | 519.0 | 53.5% | 520.0 | 53.6% | 572.3 | 59.0% | 574.7 | 59.2% | 732.0 | 75.5% | 729.6 | 75.2% | 723.7 | 74.6% | 724.1 | 74.6% |
| T36B | Trafalgar TS | Lantz JCT | 1800 | 243.8 | 13.5% | 298.0 | 16.6% | 297.2 | 16.5% | 356.0 | 19.8% | 278.4 | 15.5% | 334.7 | 18.6% | 283.6 | 15.8% | 340.8 | 18.9% |
| T36B | Lantz JCT | Palermo JCT | 1460 | 243.9 | 16.7% | 298.1 | 20.4% | 297.3 | 20.4% | 356.1 | 24.4% | 278.5 | 19.1% | 334.8 | 22.9% | 283.7 | 19.4% | 340.9 | 23.4% |
| T36B | Palermo JCT | Burlington TS | 1460 | 312.3 | 21.4% | 380.1 | 26.0% | 379.4 | 26.0% | 447.9 | 30.7% | 347.0 | 23.8% | 417.3 | 28.6% | 356.6 | 24.4% | 426.3 | 29.2% |
| T37B | Trafalgar TS | Lantz JCT | 1800 | 453.9 | 25.2% | 473.6 | 26.3% | 476.1 | 26.5% | 506.3 | 28.1% | 445.7 | 24.8% | 475.2 | 26.4% | 454.5 | 25.3% | 484.1 | 26.9% |
| T37B | Lantz JCT | Palermo JCT | 1460 | 249.0 | 17.1% | 302.2 | 20.7% | 301.4 | 20.6% | 359.5 | 24.6% | 283.4 | 19.4% | 338.8 | 23.2% | 288.4 | 19.8% | 344.7 | 23.6% |
| T37B | Palermo JCT | Burlington TS | 1460 | 314.9 | 21.6% | 382.5 | 26.2% | 381.7 | 26.1% | 450.0 | 30.8% | 349.8 | 24.0% | 419.7 | 28.7% | 359.2 | 24.6% | 428.6 | 29.4% |
| T38B | Trafalgar TS | Lantz JCT | 1460 | 346.2 | 23.7% | 319.6 | 21.9% | 316.8 | 21.7% | 301.1 | 20.6% | 347.9 | 23.8% | 323.7 | 22.2% | 338.4 | 23.2% | 316.9 | 21.7% |
| T38B | Lantz JCT | Burlington TS | 1460 | 276.7 | 19.0% | 341.6 | 23.4% | 340.9 | 23.4% | 407.3 | 27.9% | 312.2 | 21.4% | 379.2 | 26.0% | 320.6 | 22.0% | 387.4 | 26.5% |
| T39B | Trafalgar TS | Lantz JCT | 1460 | 346.7 | 23.7% | 320.1 | 21.9% | 317.3 | 21.7% | 301.6 | 20.7% | 348.4 | 23.9% | 324.2 | 22.2% | 338.9 | 23.2% | 317.4 | 21.7% |
| T39B | Lantz JCT | Burlington TS | 1460 | 276.7 | 19.0% | 341.6 | 23.4% | 340.9 | 23.4% | 407.3 | 27.9% | 312.2 | 21.4% | 379.2 | 26.0% | 320.6 | 22.0% | 387.4 | 26.5% |

Table 16: Post-Contingency Thermal Analysis (Continued)

| | | | | **Loss of Q30M-The project O/S** | | **Loss of Q30M-The project I/S** | | **Loss of M585M&V586M-The project O/S** | | **Loss of M585M&V586M-The project I/S** | | **Loss of T36B&T37B-The project O/S** | | **Loss of T36B&T37B-The project I/S** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CIRCUIT | FROM BUS | TO BUS | LTE Rating (A) | Loading (A) | **Loading (%)** LTE | Loading (A) | **Loading (%)** LTE | Loading (A) | **Loading (%)** LTE | Loading (A) | **Loading (%)** LTE | Loading (A) | **Loading (%)** LTE | Loading (A) | **Loading (%)** LTE |
| B18H | Burlington TS | Beach Road JCT | 1400 | 509.8 | 36.4% | 645.8 | 46.1% | 563.7 | 40.3% | 720.9 | 51.5% | 434.0 | 31.0% | 562.1 | 40.1% |
| B18H | Beach Road JCT | Beach TS | 1380 | 588.1 | 42.6% | 738.6 | 53.5% | 661.2 | 47.9% | 828.0 | 60.0% | 513.2 | 37.2% | 657.2 | 47.6% |
| B20H | Burlington TS | Beach Road JCT | 1380 | 503.8 | 36.5% | 639.2 | 46.3% | 557.8 | 40.4% | 714.1 | 51.7% | 428.5 | 31.0% | 556.1 | 40.3% |
| B20H | Beach Road JCT | Beach TS | 1400 | 591.3 | 42.2% | 739.1 | 52.8% | 661.3 | 47.2% | 825.7 | 59.0% | 516.7 | 36.9% | 658.0 | 47.0% |
| Q23BM | Beck #2 TS | Niagara West JCT | 1170 | 813.7 | 69.6% | 814.4 | 69.6% | 705.8 | 60.3% | 706.6 | 60.4% | 701.6 | 60.0% | 702.5 | 60.0% |
| Q23BM | Neale JCT | Middleport TS | 1020 | 395.8 | 38.8% | 384.6 | 37.7% | 553.4 | 54.3% | 556.8 | 54.6% | 389.0 | 38.1% | 369.5 | 36.2% |
| Q23BM | Neale JCT | Burlington J23 | 1400 | 1111.1 | 79.4% | 1098.4 | 78.5% | 1155.7 | 82.5% | 1158.4 | 82.7% | 995.0 | 71.1% | 973.6 | 69.5% |
| Q25BM | Beck #2 TS | Niagara West JCT | 1240 | 819.5 | 66.1% | 820.1 | 66.1% | 710.4 | 57.3% | 711.2 | 57.4% | 706.5 | 57.0% | 707.3 | 57.0% |
| Q25BM | Neale JCT | Middleport TS | 1090 | 398.7 | 36.6% | 387.4 | 35.5% | 558.9 | 51.3% | 562.3 | 51.6% | 392.1 | 36.0% | 372.5 | 34.2% |
| Q25BM | Neale JCT | Burlington TS | 1400 | 1117.3 | 79.8% | 1104.4 | 78.9% | 1163.0 | 83.1% | 1165.7 | 83.3% | 1000.7 | 71.5% | 979.0 | 69.9% |
| M27B | Middleport TS | Horning JCT | 1300 | 573.1 | 44.1% | 569.0 | 43.8% | 758.2 | 58.3% | 768.5 | 59.1% | 590.7 | 45.4% | 578.5 | 44.5% |
| M27B | Horning JCT | Burlington TS | 1340 | 505.7 | 37.7% | 501.1 | 37.4% | 690.6 | 51.5% | 700.5 | 52.3% | 522.7 | 39.0% | 510.1 | 38.1% |
| M28B | Middleport TS | Horning JCT | 1300 | 572.8 | 44.1% | 568.7 | 43.7% | 757.9 | 58.3% | 768.2 | 59.1% | 590.4 | 45.4% | 578.2 | 44.5% |
| M28B | Horning JCT | Burlington TS | 1340 | 506.0 | 37.8% | 501.4 | 37.4% | 690.9 | 51.6% | 700.8 | 52.3% | 523.0 | 39.0% | 510.4 | 38.1% |
| Q24HM | Beck #2 TS | Hannon JCT | 1260 | 922.5 | 73.2% | 904.1 | 71.8% | 801.1 | 63.6% | 782.9 | 62.1% | 799.1 | 63.4% | 780.8 | 62.0% |
| Q24HM | Hannon JCT | Nebo JCT | 1400 | 205.0 | 14.6% | 156.5 | 11.2% | 308.1 | 22.0% | 265.5 | 19.0% | 204.1 | 14.6% | 150.9 | 10.8% |
| Q24HM | Nebo JCT | Middleport TS | 1300 | 425.4 | 32.7% | 378.8 | 29.1% | 524.7 | 40.4% | 485.0 | 37.3% | 424.2 | 32.6% | 372.4 | 28.6% |
| Q24HM | Hannon JCT | Beach TS | 1400 | 1090.4 | 77.9% | 1010.8 | 72.2% | 1068.2 | 76.3% | 998.6 | 71.3% | 969.6 | 69.3% | 884.2 | 63.2% |
| Q29HM | Beck #2 TS | Hannon JCT | 1280 | 962.4 | 75.2% | 942.8 | 73.7% | 827.3 | 64.6% | 808.0 | 63.1% | 825.8 | 64.5% | 806.1 | 63.0% |
| Q29HM | Hannon JCT | Nebo JCT | 1400 | 185.8 | 13.3% | 207.7 | 14.8% | 229.5 | 16.4% | 209.6 | 15.0% | 156.5 | 11.2% | 155.3 | 11.1% |
| Q29HM | Nebo JCT | Middleport TS | 1300 | 273.6 | 21.0% | 258.5 | 19.9% | 387.9 | 29.8% | 357.9 | 27.5% | 294.6 | 22.7% | 260.3 | 20.0% |
| Q29HM | Hannon JCT | Beach TS | 1400 | 905.3 | 64.7% | 832.6 | 59.5% | 957.9 | 68.4% | 894.5 | 63.9% | 856.4 | 61.2% | 778.5 | 55.6% |
| M34H | Middleport TS | Beach TS | 1300 | 384.9 | 29.6% | 335.0 | 25.8% | 520.1 | 40.0% | 475.4 | 36.6% | 418.0 | 32.2% | 360.4 | 27.7% |
| Q30M | Beck #2 TS | Allanburg JCT | 1400 | 0.0 | 0.0% | 0.0 | 0.0% | 548.6 | 39.2% | 547.4 | 39.1% | 575.3 | 41.1% | 577.0 | 41.2% |
| Q30M | Allanburg JCT | Middleport TS | 970 | 0.0 | 0.0% | 0.0 | 0.0% | 568.6 | 58.6% | 566.2 | 58.4% | 588.3 | 60.7% | 589.2 | 60.7% |
| T36B | Trafalgar TS | Lantz JCT | 1800 | 305.3 | 17.0% | 364.6 | 20.3% | 434.2 | 24.1% | 520.8 | 28.9% | 0.0 | 0.0% | 0.0 | 0.0% |
| T36B | Lantz JCT | Palermo JCT | 1460 | 305.4 | 20.9% | 364.7 | 25.0% | 434.2 | 29.7% | 520.9 | 35.7% | 0.0 | 0.0% | 0.0 | 0.0% |
| T36B | Palermo JCT | Burlington TS | 1460 | 394.6 | 27.0% | 461.1 | 31.6% | 550.2 | 37.7% | 639.0 | 43.8% | 0.0 | 0.0% | 0.0 | 0.0% |
| T37B | Trafalgar TS | Lantz JCT | 1800 | 495.4 | 27.5% | 523.5 | 29.1% | 615.1 | 34.2% | 667.2 | 37.1% | 0.0 | 0.0% | 0.0 | 0.0% |
| T37B | Lantz JCT | Palermo JCT | 1460 | 309.1 | 21.2% | 367.9 | 25.2% | 436.0 | 29.9% | 522.4 | 35.8% | 0.0 | 0.0% | 0.0 | 0.0% |
| T37B | Palermo JCT | Burlington TS | 1460 | 396.6 | 27.2% | 463.0 | 31.7% | 551.2 | 37.8% | 640.0 | 43.8% | 0.0 | 0.0% | 0.0 | 0.0% |
| T38B | Trafalgar TS | Lantz JCT | 1460 | 298.4 | 20.4% | 288.5 | 19.8% | 248.1 | 17.0% | 288.4 | 19.8% | 312.2 | 21.4% | 369.9 | 25.3% |
| T38B | Lantz JCT | Burlington TS | 1460 | 354.2 | 24.3% | 419.1 | 28.7% | 502.6 | 34.4% | 590.9 | 40.5% | 567.2 | 38.9% | 676.6 | 46.3% |
| T39B | Trafalgar TS | Lantz JCT | 1460 | 298.9 | 20.5% | 289.0 | 19.8% | 248.5 | 17.0% | 288.7 | 19.8% | 312.5 | 21.4% | 370.1 | 25.4% |
| T39B | Lantz JCT | Burlington TS | 1460 | 354.2 | 24.3% | 419.1 | 28.7% | 502.6 | 34.4% | 590.9 | 40.5% | 567.2 | 38.9% | 676.6 | 46.3% |

## 6.7 Voltage Analysis

Based on the voltage analysis below, voltage performance of the system is expected to be adequate with the proposed project in service.

The ORTAC states that with all facilities in service pre-contingency, the following criteria shall be satisfied:

- The pre-contingency voltage on 230 kV buses must not be less than 220 kV and voltages on 115kV buses cannot be less than 113 kV;
- The post-contingency voltage on 230 kV buses must not be less than 207 kV and voltages on 115V buses cannot be less than 108 kV; and
- The voltage drop following a contingency must not exceed 10% pre-ULTC and 10% post-ULTC.

The voltage performance of the IESO-controlled grid was evaluated by examining if pre- and post-contingency voltages and post-contingency voltage declines remain within criteria at various facilities.

Contingency of the loss of the project was simulated under the peak and light load conditions. The studies were performed with the project absorbing its full reactive power capability for the light load case and injecting its full reactive power capability for the peak load case. These two cases represent the worst cases in terms of the voltage change following the loss of the wind farm. The study results are presented in Table 17 which indicates that all voltage criteria are met and there are no voltage concerns with the incorporation of the project.

Table 17: Voltage assessment results

| Base Case | Bus Name | Pre-Contingency | Loss of NRWF | | | |
|---|---|---|---|---|---|---|
| | | | Pre-ULTC | | Post-ULTC | |
| | | Voltage (kV) | Voltage (kV) | Change (%) | Voltage (kV) | Change (%) |
| Peak Load | NRWF TAP 115 kV | 123.0 | 120.3 | -2.2% | 121.0 | -1.7% |
| | BEACH TS 115 kV | 120.7 | 120.3 | -0.3% | 120.9 | 0.2% |
| | BEACH TS 230 kV | 238.5 | 237.5 | -0.4% | 238.7 | 0.1% |
| | BURLINGTON 230 kV | 240.4 | 239.5 | -0.4% | 240.7 | 0.1% |
| | BECK 2 TS 230 kV | 240.5 | 240.3 | -0.1% | 240.5 | 0.0% |
| Light Load | NRWF TAP 115 kV | 116.1 | 126.1 | 8.7% | 126.0 | 8.6% |
| | BEACH TS 115 kV | 123.1 | 126.1 | 2.4% | 125.9 | 2.3% |
| | BEACH TS 230 kV | 244.6 | 246.7 | 0.9% | 246.5 | 0.8% |
| | BURLINGTON 230 kV | 246.4 | 247.9 | 0.6% | 247.7 | 0.5% |
| | BECK 2 TS 230 kV | 241.9 | 242.3 | 0.2% | 242.2 | 0.1% |

## 6.8 Transient Stability Performance

Transient stability analysis below shows that the project will not cause any transient instability or un-damped oscillations.

Transient stability simulations were completed to determine if the power system will be transiently stable with the incorporation of the project for recognized fault conditions. In particular, rotor angles of generators at Beck 2, Thorold, Decew Falls, Bruce GS, Sithe Goreway GS, and Halton Hills GS were monitored.

Transient stability analyses were performed considering recognized faults in Southwest area. Two scenarios were considered as follows:

Scenario 1: Peak load condition with Halton Hills GS out of service (the defined peak load basecase);
Scenario 2: Peak load condition with Halton Hills GS in service (changes are made to the defined peak load basecase to displace the Pickering generation by Halton Hills GS);

Table 18 and Table 19 show the contingencies that were simulated for the two scenarios with the project in service. The protection changes proposed in the PIA were part of the assumptions for this analysis.

Table 18: Simulated contingencies for transient stability with Halton Hills GS out of service

| ID | Contingency | Location | Fault Type | Fault Clearing Time (ms) | | SPS action(s) (ms) | | Re-closure Time (s) |
|---|---|---|---|---|---|---|---|---|
| | | | | Local | Remote | LRSS* | G/R | |
| SC1 | B560V+B561M | Willow Creek Junction | LLG | 66 | 91 | 124 | - | 10 |
| SC2 | M585M+V586M | Middleport TS | 3ph* | 75 | 100 | - | - | 10 |
| SC3 | B18H+B20H | Beach TS | 3ph* | 83 | 108 | - | - | 5 |
| SC4 | LV side of main step-up transformer | Adelaide WPP | 3 ph | Un-cleared | | - | - | - |

* 3-phase fault was simulated instead of LG or LLG fault as required by the ORTAC, as the system is stable under the fault which is more conservative.

Table 19: Simulated contingency for transient stability with Halton Hills GS in service

| ID | Contingency | Location | Fault Type | Fault Clearing Time (ms) | | SPS action(s) (ms) | | Re-closure Time (s) |
|---|---|---|---|---|---|---|---|---|
| | | | | Local | Remote | LRSS* | G/R | |
| SC5 | R14T+R17T | Trafalgar TS | 3ph* | 83 | 108 | - | - | 5 |

* 3-phase fault was simulated instead of LG or LLG fault as required by the ORTAC, as the system is stable under the fault which is more conservative.

Figure 3 to Figure 12, Appendix A show the transient responses of the rotor angles and bus voltages. The transient responses show that the generators remain synchronized to the power system and the oscillations are sufficiently damped following all simulated contingencies. It can be concluded that, with the project on-line, none of the simulated contingencies caused transient instability or un-damped oscillations.

It can be also concluded that the protection adjustments proposed in the PIA report have no material adverse impact on the IESO-controlled grid in terms of transient stability.

## 6.9 Voltage Ride-Through Capability

As presented below, the proposed WTGs are able to remain connected to the grid for recognized system contingencies that do not remove the project by configuration.

The IESO requires that the wind turbine generators and associated equipment with the project be able to withstand transient voltages and remain connected to the IESO-controlled grid following a recognized contingency unless the generators are removed from service by configuration. This requirement is commonly referred to as the voltage ride-through (VRT) capability.

The Enercon E-101 FT to be installed will be equipped with the LVRT capability. The LVRT capability of wind turbines is shown in Table 2.

The LVRT capability of the WTGs was assessed based on the terminal voltages of the WTGs under simulated contingency in Table 20.

Table 20: Simulated contingencies for LVRT

| ID | Contingency | Location | Fault Type | Fault Clearing Time (ms) | | Re-closure Time (s) |
|---|---|---|---|---|---|---|
| | | | | Local | Remote | |
| SC6 | HL3 | Beach TS | 3 ph | 83 | - | - |
| SC7 | B18H+B20H | Beach TS | 3ph* | 83 | 108 | 5 |

* 3-phase fault was simulated instead of LG or LLG fault as required by the ORTAC, as the system is stable under the fault which is more conservative.

Figure 13, Appendix A shows the terminal voltage response of the Enercon E-101 FT WTGs under simulated contingency. It shows that the terminal voltages of the WTGs remain below 0.3 pu for about 100 ms, and recover to 0.9 pu in less than 200 ms after the fault inception. As compared with the LVRT capability of the Enercon E-101 FT, the proposed WTGs are able to remain connected to the grid for recognized system contingencies that do not remove the project by configuration.

However, when the project is incorporated into the IESO-controlled grid, if actual operation shows that the WTGs trip for contingencies for which they are not removed by configuration, the IESO will require the voltage ride-through capability be enhanced by the applicant to prevent such tripping.

The voltage ride-through capability must also be demonstrated during commissioning by monitoring several variables under a set of IESO specified field tests and the results should be verifiable using the PSS/E model.

**-End of Section-**

# Appendix A: Figures

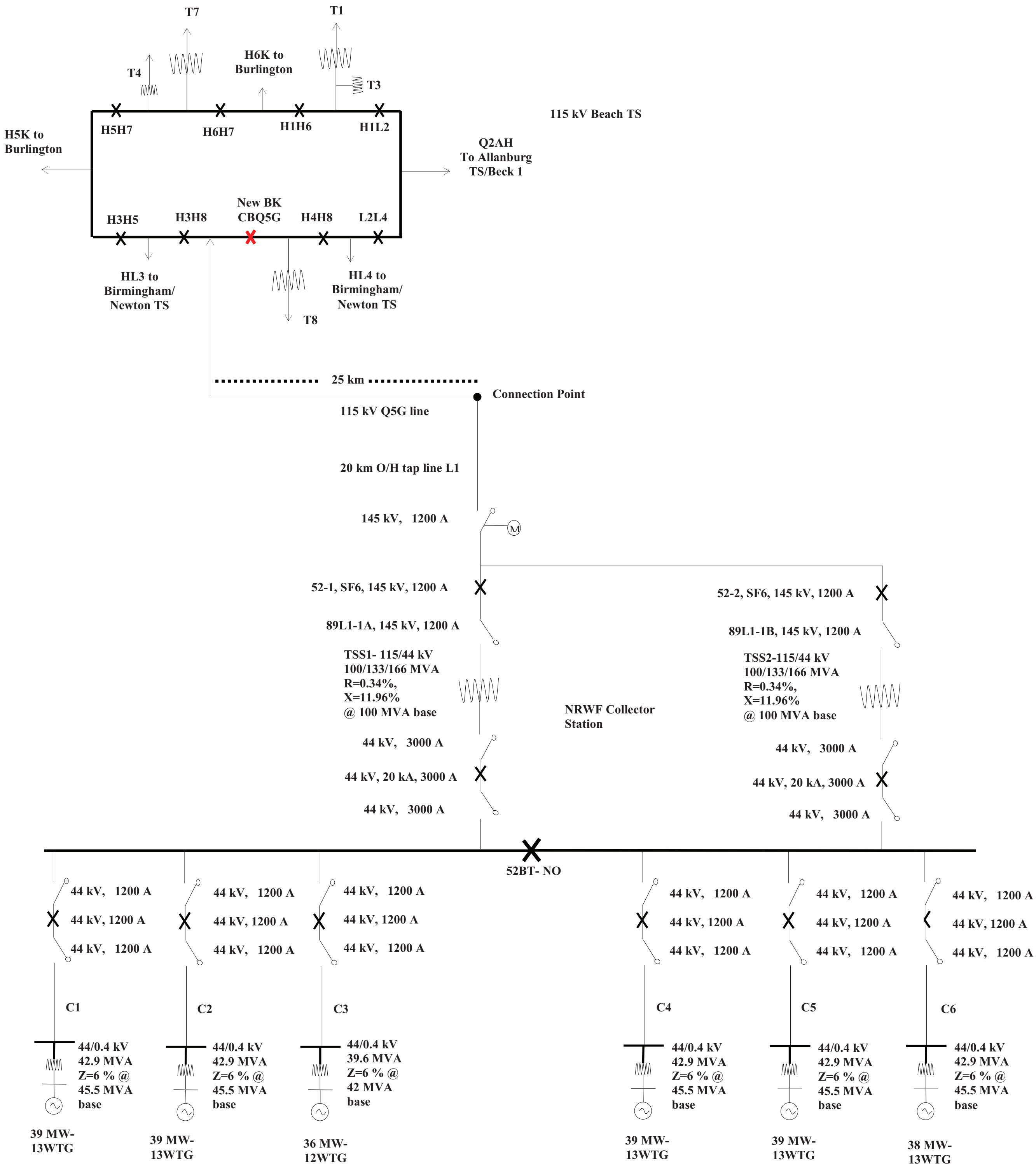



Figure 1: Single-line diagram of Niagara Region Wind Farm (NRWF)

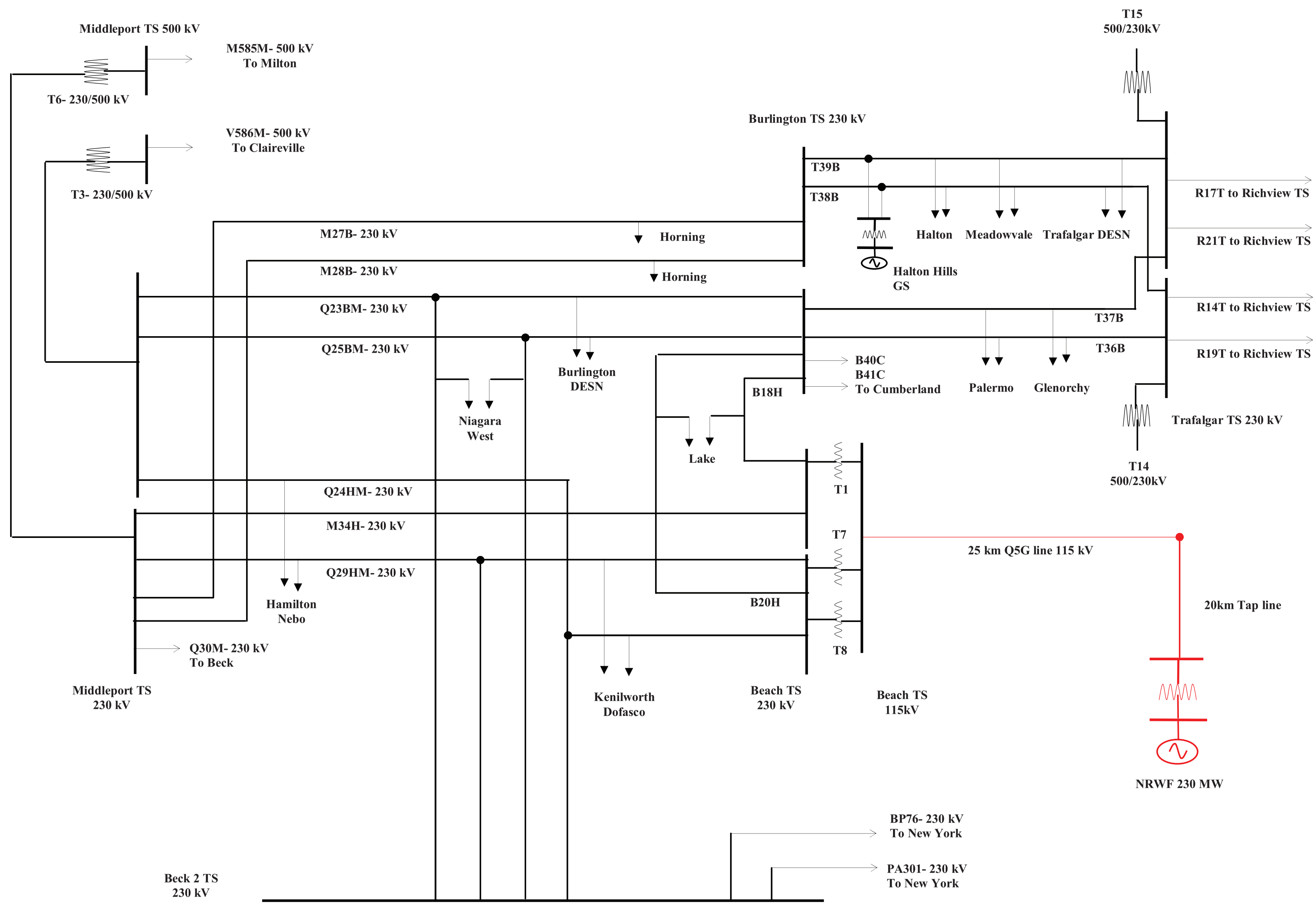



Figure 2: Transmission system in the vicinity of the project

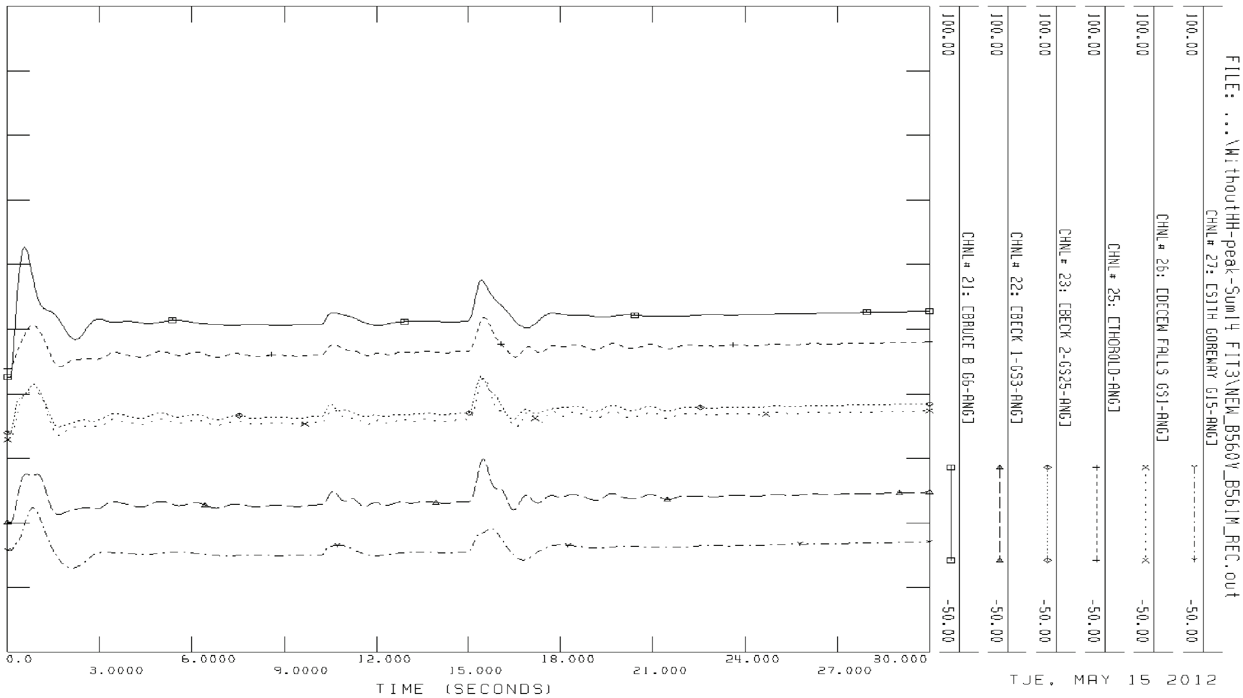



Figure 3: Major generator angle response following a LLG fault on circuit B560V+B561M at Willow Creek Junction with Halton Hills GS out of service

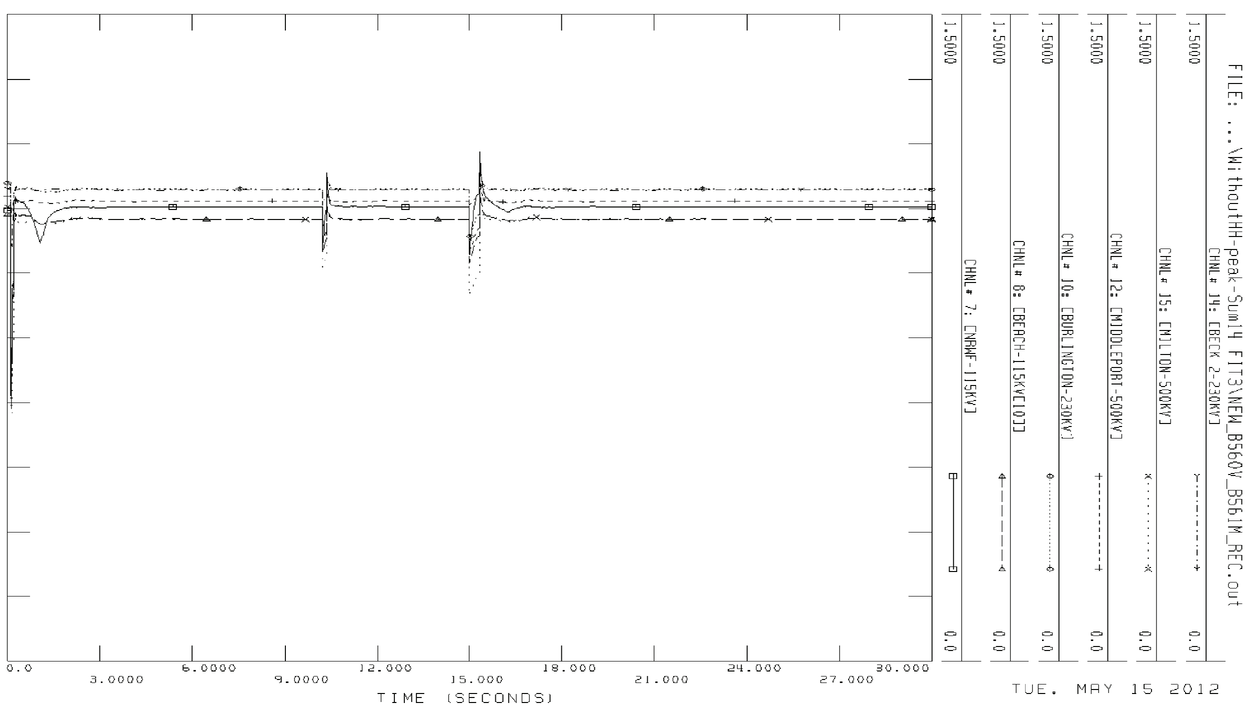



Figure 4: Voltage response following a LLG fault on circuit B560V+B561M at Willow Creek Junction with Halton Hills GS out of service

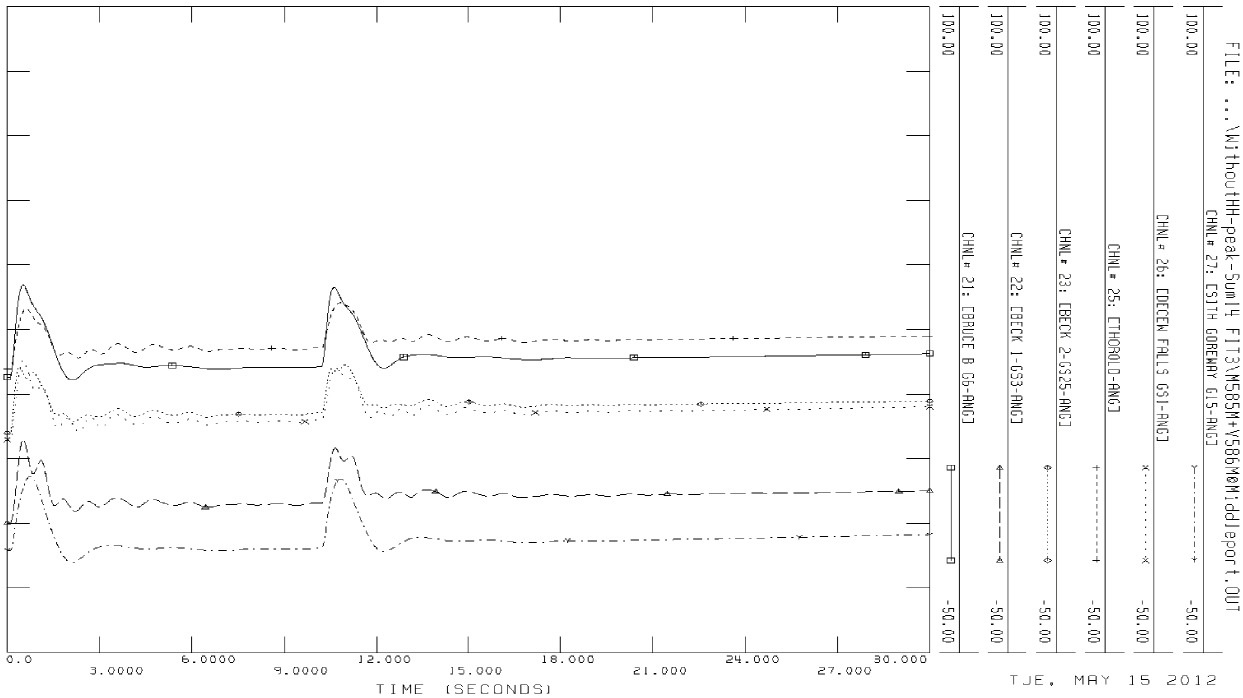



Figure 5: Major generator angle response following a 3ph fault on circuit M585M+V586M at Middleport TS with Halton Hills GS out of service

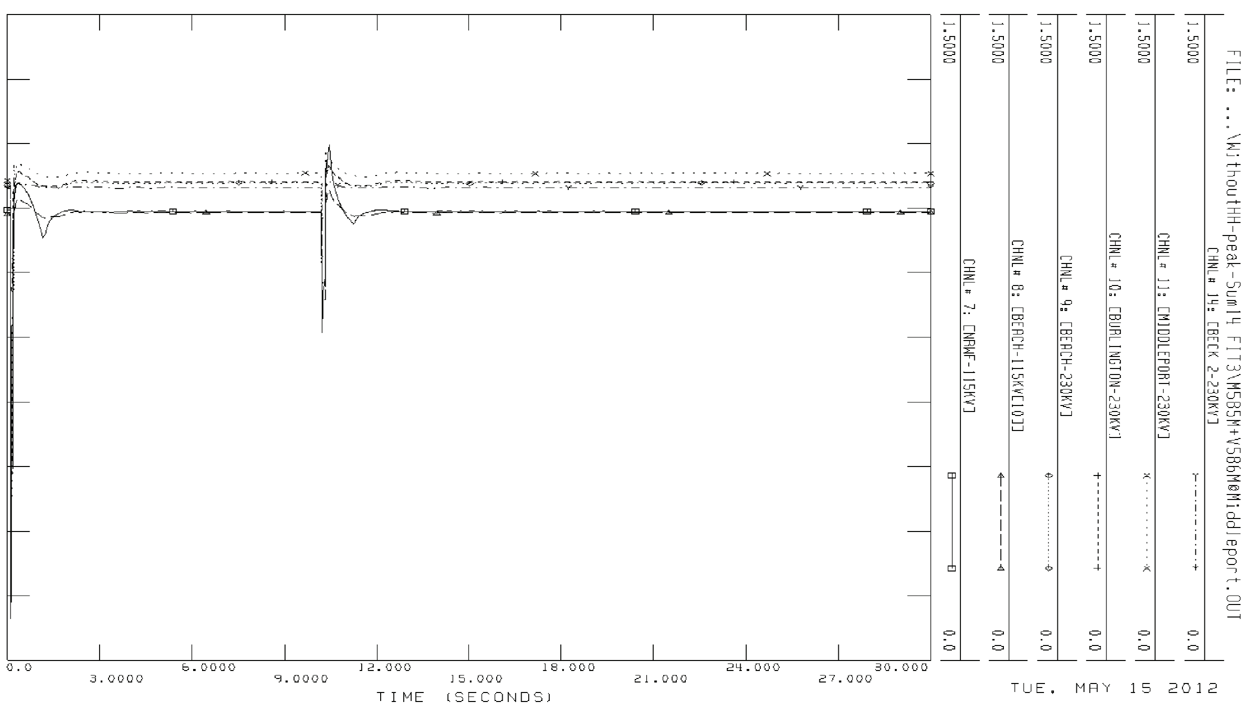



Figure 6: Voltage response following a 3ph fault on circuit M585M+V586M at Middleport TS with Halton Hills GS out of service

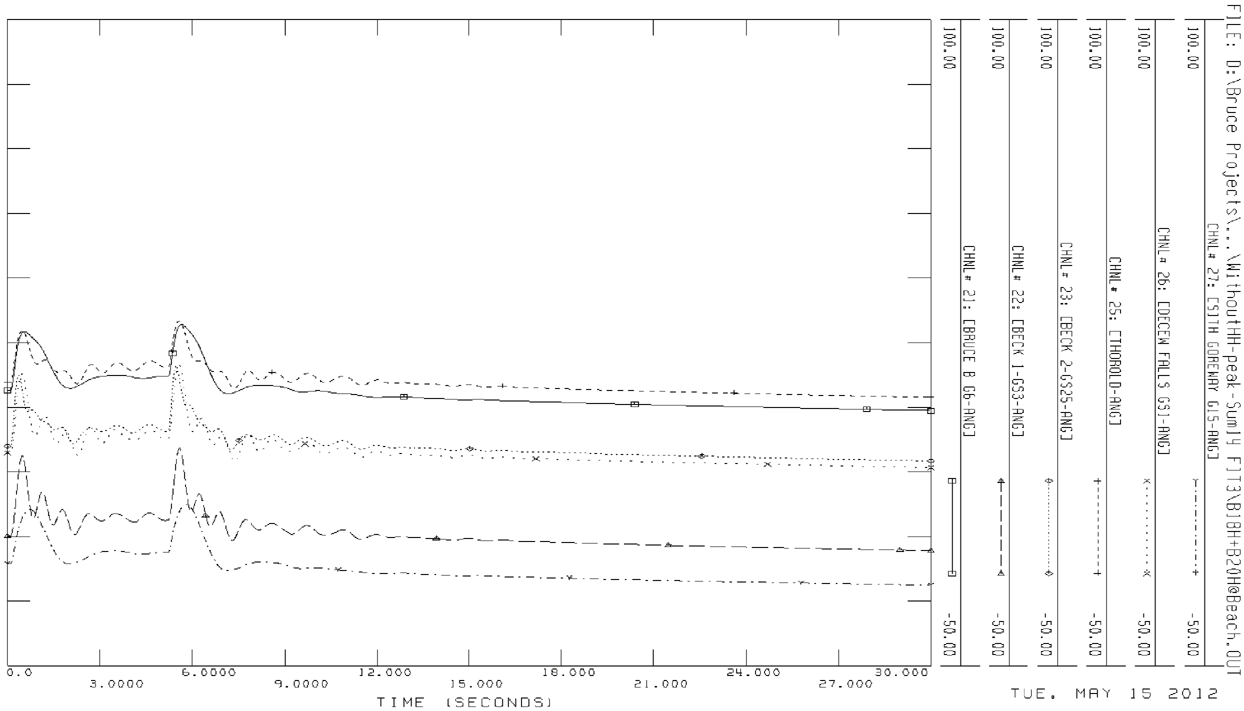



Figure 7: Major generator angle response following a 3ph fault on circuit B18H+B20H at Beach TS with Halton Hills GS out of service

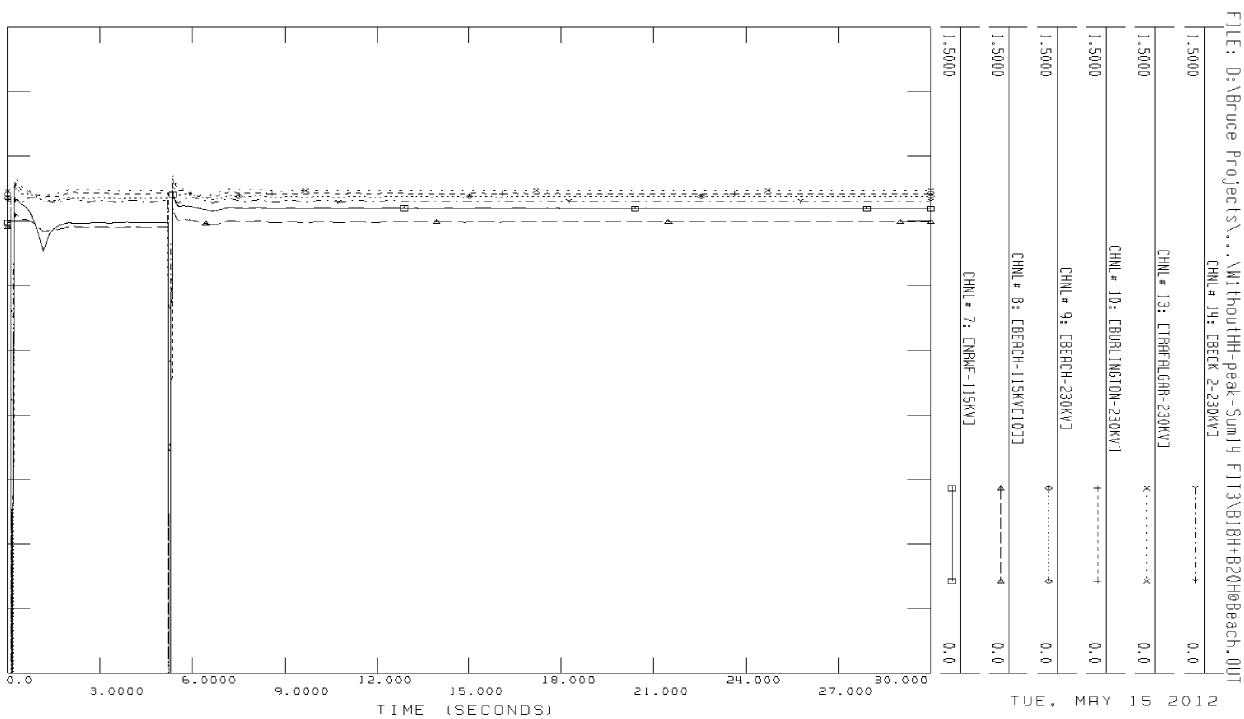



Figure 8: Voltage response following a 3ph fault on circuit B18H+B20H at Beach TS with Halton Hills GS out of service

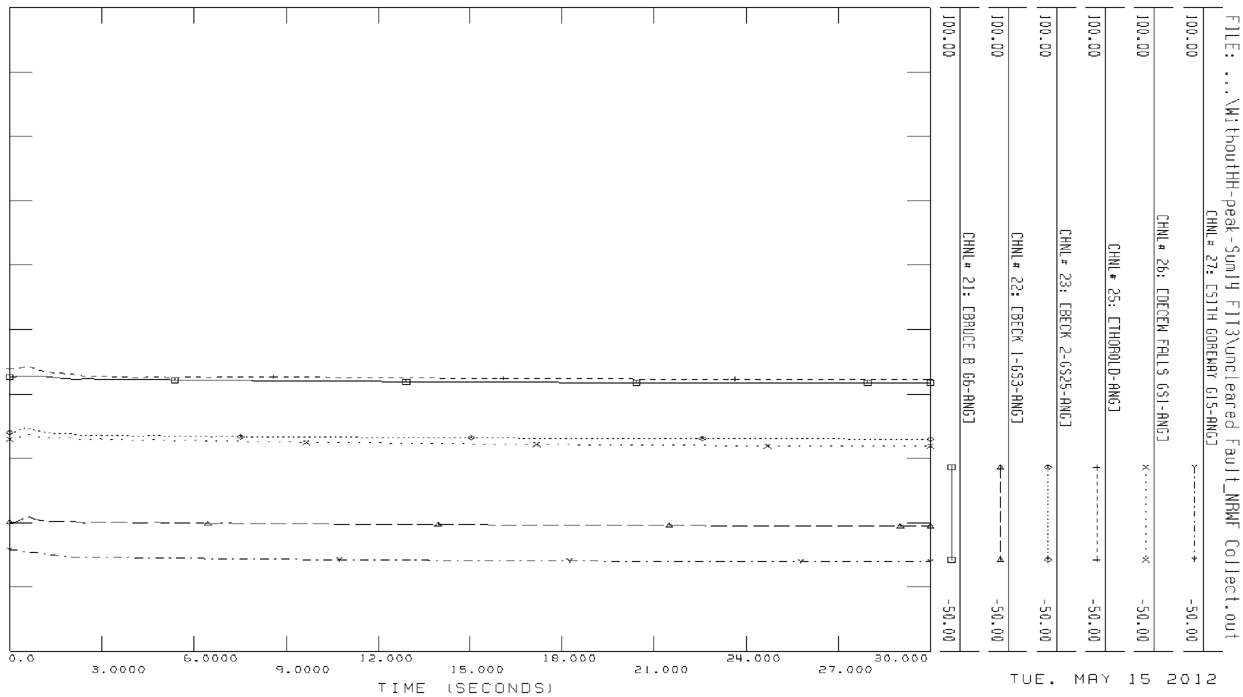



Figure 9: Major generator angle response following an un-cleared 3ph fault inside the NRWF with Halton Hills GS out of service

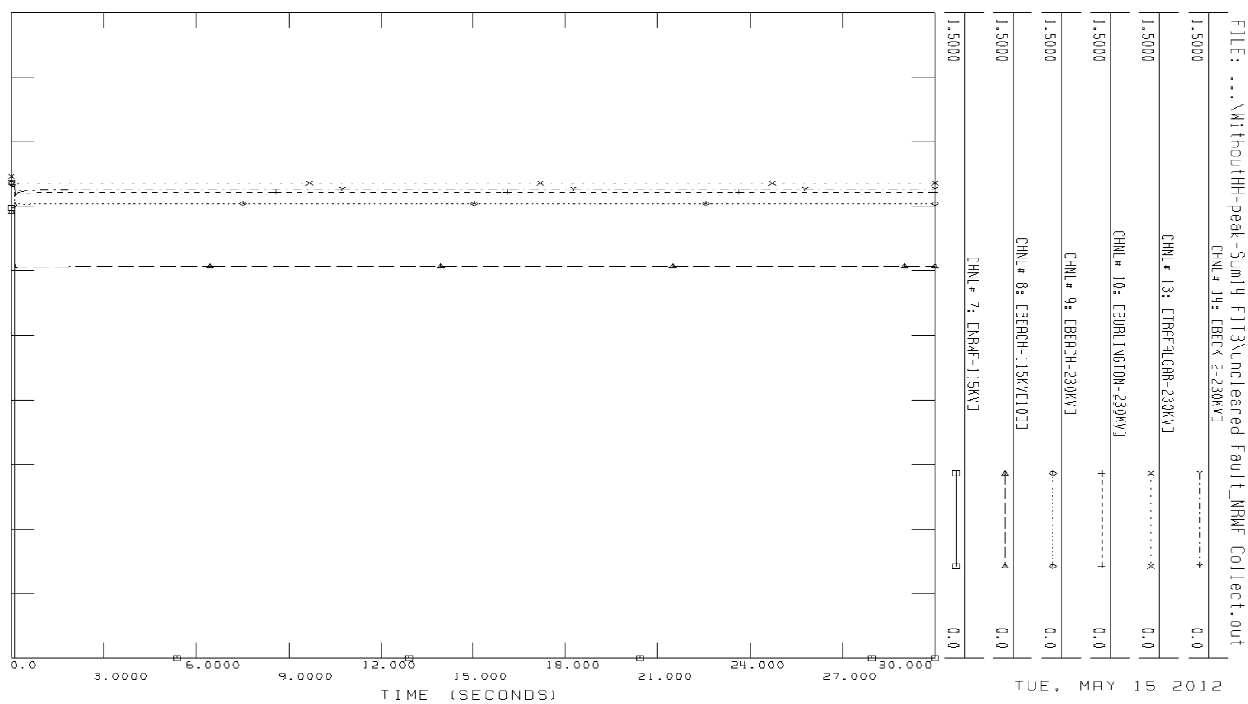



Figure 10: Voltage response following an un-cleared 3ph fault inside the NRWF with Halton Hills GS out of service

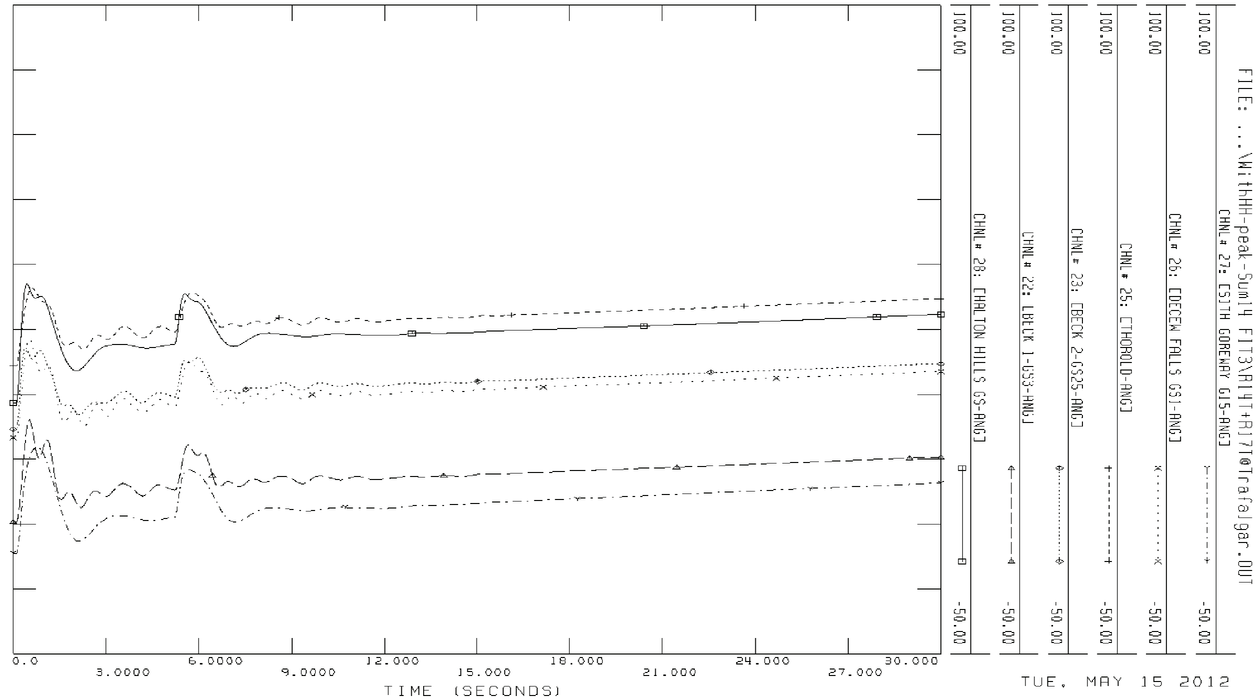



Figure 11: Major generator angle response following a 3ph fault on circuit R14T+R17T at Trafalgar TS with Halton Hills GS in-service

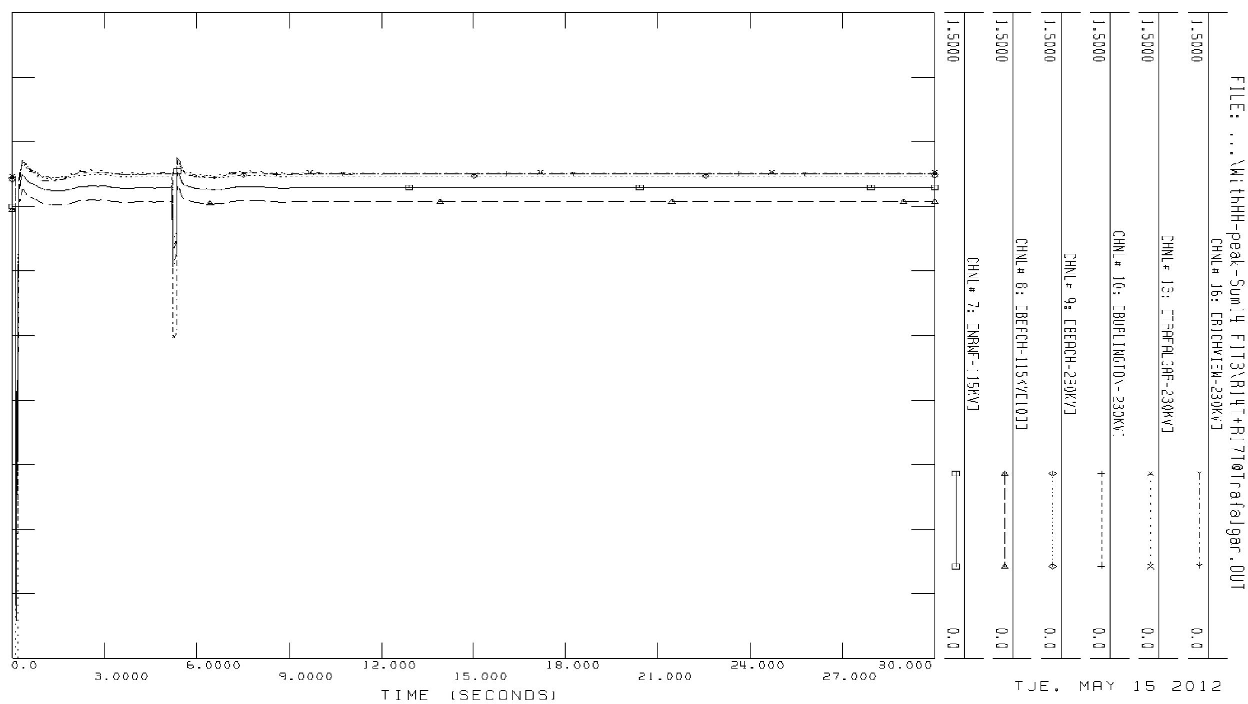



Figure 12: Voltage response following a 3ph fault on circuit R14T+R17T at Trafalgar TS with Halton Hills GS in-service

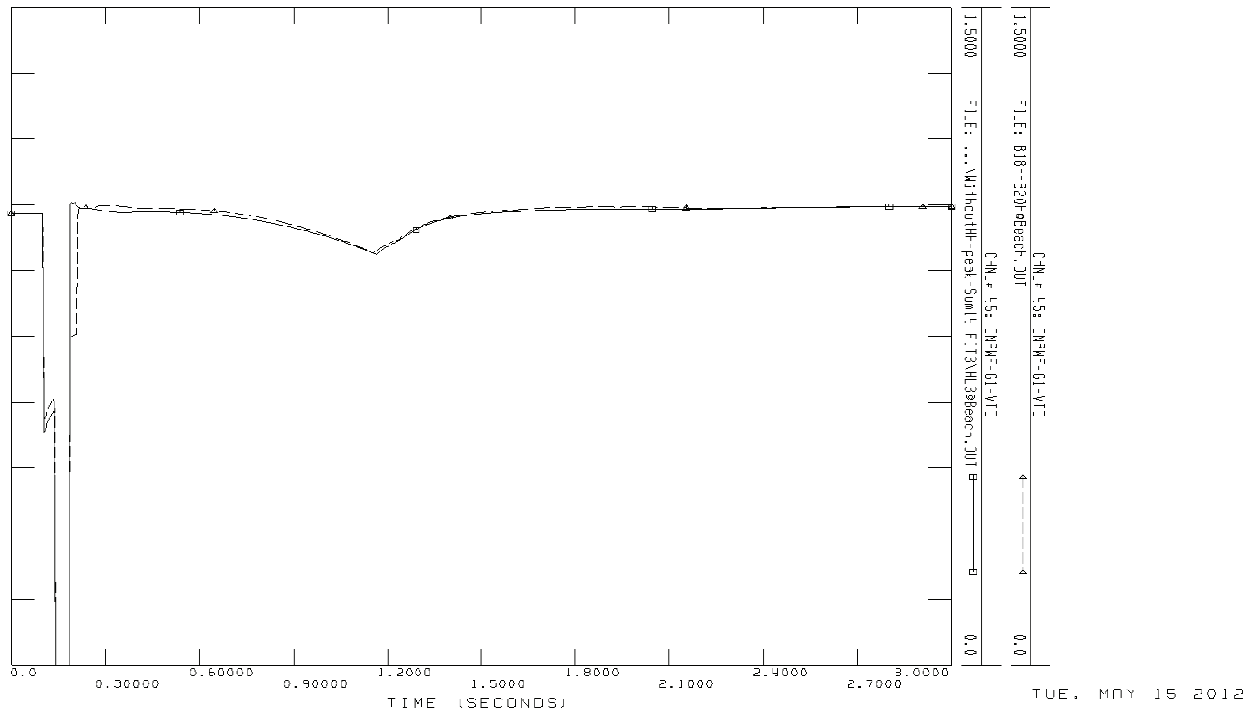



Figure 13: WTG terminal voltage responses for studied contingencies

# Appendix B: PIA Report

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

# PROTECTION IMPACT ASSESSMENT

# NIAGARA REGION 230MW WIND FARM GENERATION CONNECTION

# AR 2128

Date: June 7, 2012
P&C Planning Group Project #: PCT-357-PIA

Prepared By:

Hydro One Networks Inc.

## Disclaimer

This Protection Impact Assessment has been prepared solely for the IESO for the purpose of assisting the IESO in preparing the System Impact Assessment for the proposed connection of the proposed generation facility to the IESO–controlled grid. This report has not been prepared for any other purpose and should not be used or relied upon by any person, including the connection applicant, for any other purpose.

This Protection Impact Assessment was prepared based on information provided to the IESO and Hydro One by the connection applicant in the application to request a connection assessment at the time the assessment was carried out. It is intended to highlight significant impacts, if any, to affected transmission protections early in the project development process. The results of this Protection Impact Assessment are also subject to change to accommodate the requirements of the IESO and other regulatory or legal requirements. In addition, further issues or concerns may be identified by Hydro One during the detailed design phase that may require changes to equipment characteristics and/or configuration to ensure compliance with the Transmission System Code legal requirements, and any applicable reliability standards, or to accommodate any changes to the IESO-controlled grid that may have occurred in the meantime.

Hydro One shall not be liable to any third party, including the connection applicant, which uses the results of the Protection Impact Assessment under any circumstances, whether any of the said liability, loss or damages arises in contract, tort or otherwise.

Revision History

| Revision | Date | Change |
|---|---|---|
| R0 | April 25, 2012 | First draft |
| R1 | June 7, 2012 | Change the bus configuration of 115kV Beach TS |
| | | |

**PROTECTION IMPACT ASSESSMENT**
**NIAGARA REGION WIND GENERATION CONNECTION**
**230MW WIND FARM GENERATION**

# 1.0 INTRODUCTION

## 1.1 Protection Impact Assessment

This PIA study is prepared for the IESO to assess the potential impact of the proposed connection on the existing transmission protection. The primary focus of this study is on protecting Hydro One system equipment while meeting IESO System Reliability Criteria.

## 1.2 Description of Proposed Connection to the Grid

The proposed project is to develop new wind generation facilities in Niagara region by Niagara Region Wind Corporation. The total capacity of wind farm generation is 230MW. The wind generation consists of two 115KV/44kV step-up transformers with capacity 100/133/166MVA. The HV side of each transformer is equipped with circuit breaker. The facilities will be connected to the Hydro One's transmission system at tower #154 of Hydro One's 115kV circuit Q5G. The circuit length of the customer owned 115kV overhead is 20km to the tower #154. The distance between the tower #154 and Beach TS is 25km. The existing 115kV Beach TS operation diagram and the simplified single line connection diagram of the 230MW wind generation to Hydro One Q5G are shown in Figure 1a and 1b respectively.

Since Beach TS 115kV switchyard is not on the BPS list, detailed design requirement will be described in planning specification.

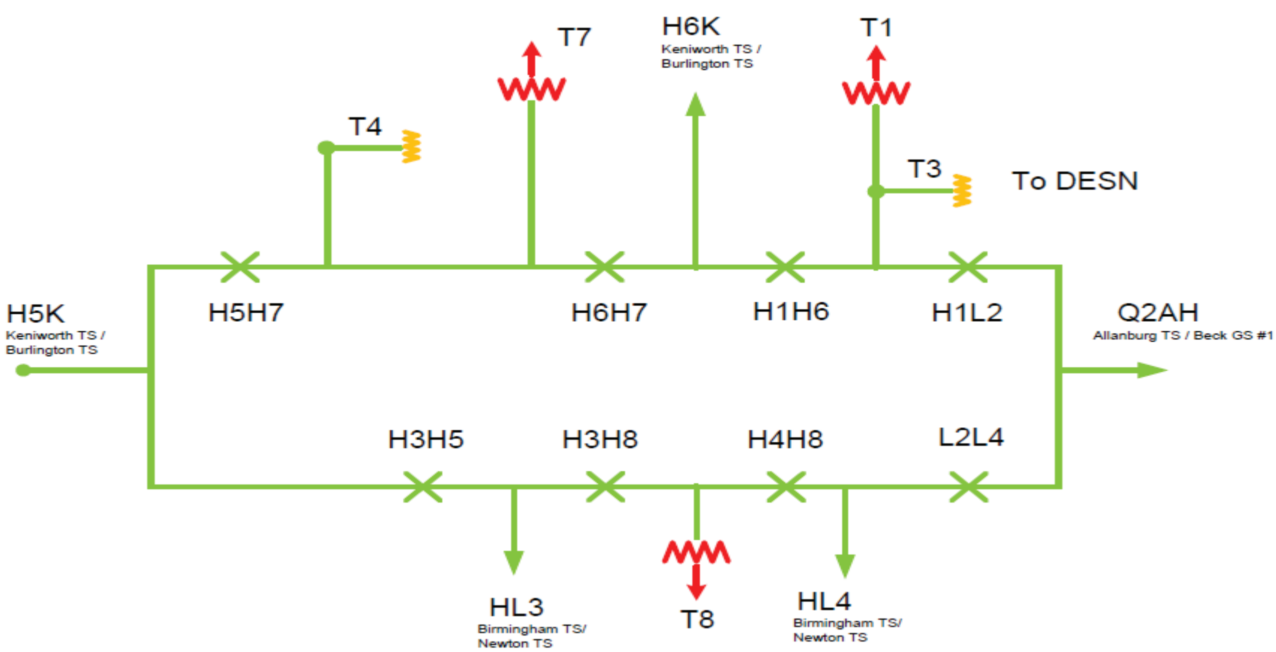



Figure 1a: The Existing 115kV Beach TS Operation Diagram

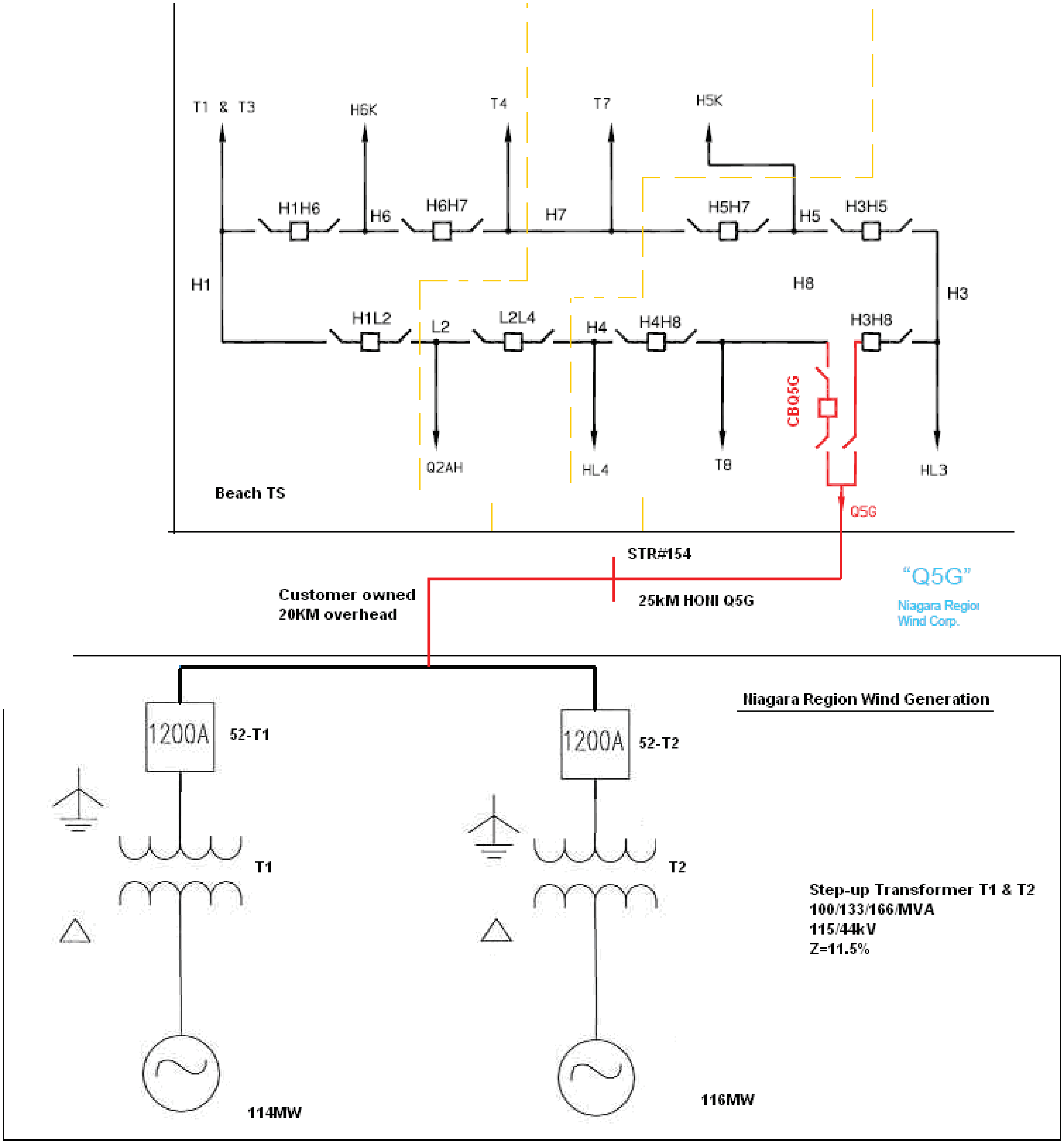



Figure 1b: The Proposed 230MW Wind Farm Generation Connection

## 1.3 Assumptions

The study presented in this document was based on the data provided by the proponent in the SIA application form.

# 2.0 PROTECTION

## 2.1 General

The bus at 115kV Beach TS will be re-configured to accommodate the 230MW Niagara region wind generation. The change of the 115kV bus and the adjustment of the element connection will result in the modification of protection scheme.

In addition, new protections and other equipment are required to address the new wind generation connection.

TT will be sent from 115kV Beach TS to WF if the zone 1 protection at Beach TS operates, but not vice versa.

## 2.2 Specific Protection Requirements

In case of a failure of any circuit breaker at the HV side of the transformer of the new generation station, the suitable telecommunication must be used to send a transfer trip to open breakers H3H8 and CBQ5G (temporary breaker designation) at Beach TS. Similarly, failure of CBQ5G or H3H8 of Beach TS will send a transfer trip to open breakers 52-T1 and 52-T2 at Wind farm station.

The operation of the line protection of Q5G at Beach TS shall send transfer trip to the Wind farm generation to open 52-T1 and 52-T2.

### 2.2.1 115kV Beach TS

#### 2.2.1.1 New Installations

**1) Q5G Line Protection**

New IED 'A' and 'B' line protections shall be installed. A modified DCB scheme should be used for the line protections to ensure their dependability. In this scheme, the line protection at the Wind Farm shall send blocking signal to Beach TS if a fault occurs in backward. However, no blocking signal will be sent to the Wind Farm from Beach TS.

Duplicate transfer trip sending is required to open the circuit breakers 52-T1 and 52-T2 when a fault occurs on the Q5G or failure of CBQ5G or H3H8. Both Z1 and the fast zone 2 need to send transfer trip.

Duplicate transfer trip receiving is required to open the circuit breakers CBQ5G and H3H8 upon failure of breaker 52-T1 or 52-T2.

GEO signals from both 52-T1 and 52-T2 at the wind generation station are required to be incorporated into Q5G line protection.

**2) New Breaker CBQ5G Protection**

Duplicate IED breaker protection shall be installed for new breaker CBQ5G.

#### 2.2.1.2 Modifications

**1) T8 Transformer Protection**

Modification of the T8 protection scheme is required to provide proper re-zoning of the protection with regards to the new single line diagram configuration and installation of the new breaker CBQ5G.

**2) Breakers H3H8 and H4H8 Protection**

Modification of the breaker protection schemes for both breakers is required to provide proper re-zoning of the BF and bus protection with regards to the new single line diagram configuration and installation of new breaker CBQ5G.

**3) H8 Bus protection**

Modification of the H8 bus protection scheme is required to provide proper re-zoning of the BF and bus protection with regards to the new single line diagram configuration and installation of new breaker CBQ5G.

### 2.2.2 Wind Farm Generation

#### 2.2.2.1 'A and B' Line Protections

'A' and 'B' line protection must be installed. A modified DCB scheme shall be applied with the line protections to send blocking signal to HONI's protection for the faults in transformer zones. The fast zone 2 function must be disabled to avoid trip for an external fault. The independent zone 2 must be set with 400ms delay as a blocking signal will not be sent from Beach TS.

#### 2.2.2.2 52-T1 and 52-T2 Breaker Protections

Both breakers should be equipped with breaker fail protections. A transfer trip must be sent to Beach TS to disconnect the wind generation from Hydro One's grid if 52-T1 or 52-T2 breaker fails.

#### 2.2.2.3 GEO

GEO signal shall be sent to Beach TS when both 52-T1 and 52-T2 are successfully opened.

## 2.3 <u>Tele-Protection</u>

Telecom links shall comply with the reliability requirements listed in TSC.

The proponent is responsible to establish dual telecommunication links to transmit protection signals between Beach TS and the wind farm generation. Leased S4T4 circuits or better performing media are acceptable.

## 2.4 Protection Settings Fault Clearing

Table 1 is the suggested protection settings.

Table 1 Suggested Protection Settings

| Station | Zone | Setting Coverage (km) or (%) | Time Delay (s) | Actual Coverage |
|---|---|---|---|---|
| Beach TS | 1 | 36km or 80% | Inst. | 80% of the line Q5G |
| | 2 | 56.25km or 125% | 50ms | 125% of the line Q5G |

Since Q5G is a simple two-ended circuit without tapped infeed, the coverage of the zone 1 distance protection at each terminal shall be same. Therefore, the overlap percentage of two zone 1 elements is 60% of the whole line length or 27km.

The maximum clearing time for an internal fault beyond the zone 1 is 50ms+BFT(200ms)+TT (20ms)+CBT (100ms). The total time is around 370ms.

# 3.0 SCADA/RTU

# 4.0 POWER SYSTEM MONITORING

# 5.0 REVENUE METERING

# 6.0 CYBER SECURITY

NERC's standards CIP-002 thru CIP-009 may apply.

# 7.0 STATION REQUIREMENTS

# 8.0 UPDATE DATABASES AND DOCUMENTATION

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

# CUSTOMER IMPACT ASSESSMENT

## Proposed 230 MW
## Niagara Region Wind Farm

**FIT-FLKZ509**

Revision: **Final**

Date: **August 3rd, 2012**

Issued by: **Transmission System Department**
**Transmission Projects Division**
**Hydro One Networks Inc.**

Prepared by:

Gene Ng

Gene Ng, P.Eng
Network Management Engineer
Transmission System Development
Hydro One Networks Inc.

Approved by:

John Sabiston, P.Eng
Transmission Planning Manager
Transmission System Development
Hydro One Networks Inc.

## Disclaimer

This Customer Impact Assessment was prepared based on preliminary information available about the connection of the proposed Niagara Region Wind Farm generation facilities, near the town of Beamsville, Ontario. It is intended to highlight significant impacts, if any, to affected transmission customers early in the project development process and thus allow an opportunity for these parties to bring forward any concerns that they may have including those needed for the review of the connection and for any possible application for leave to construct. Subsequent changes to the required modifications or the implementation plan may affect the impacts of the proposed connection identified in this Customer Impact Assessment. The results of this Customer Impact Assessment and the estimate of the outage requirements are also subject to change to accommodate the requirements of the IESO and other regulatory or municipal authority requirements.

Hydro One Networks shall not be liable to any third party which uses the results of the Customer Impact Assessment under any circumstances whatsoever, for any indirect or consequential damages, loss of profit or revenues, business interruption losses, loss of contract or loss of goodwill, special damages, punitive or exemplary damages, whether any of the said liability, loss or damages, arises in contract, tort or otherwise.

This Final Customer Impact Assessment incorporates all comments received during the customer review period which ended on August 3rd 2012.

# CUSTOMER IMPACT ASSESSMENT

## PROPOSED 230 MW
## NIAGARA REGION WIND FARM

## 1.0 INTRODUCTION

### 1.1 Scope of the Study

This Customer Impact Assessment (CIA) study assesses the potential impacts of the proposed Niagara Region Wind Farm on the load customers and generators in the local vicinity. This study is intended to supplement the System Impact Assessment "CAA ID 2012-466" issued by the IESO.

This study covers the impact of the generation addition of the Niagara Region Wind Farm on the Hydro One Networks Inc. (Hydro One) system in the area. The primary focus of this study is to identify the impact on the transmission customer connected facilities and operating constraints based on facility voltage performance. The study also assists to determine if any transmission system upgrade will be required to integrate the proposed interconnection during possible system conditions.

**This study does not evaluate the overall impact of the Niagara Region Wind Farm on the bulk system. The impact of the new generator on the bulk system is the subject of the System Impact Assessment (SIA) which is issued by the Independent Electricity System Operator (IESO).**

**This study does not evaluate the impact of the Niagara Region Wind Farm on the existing network Protection and Control facilities. Protection and Control aspects are reviewed under the Protection Impact Assessment, which is part of the SIA.**

### 1.2 Background

Niagara Region Wind Corporation is proposing to develop a wind farm near the town of Beamsville located in Southern Ontario. The new development will provide a total installed capacity of 230MW. This customer impact assessment (CIA) will address the connection to the Hydro One grid via the 115kV circuit "Q5G".

The Niagara Region Wind Farm is comprised of 77 Enercon inverter based wind turbines connected to six (6) collector circuits. Of the six collector wind farm circuits, 5 circuits will produce a maximum of 39MW (13 turbines) and one circuit will produce a maximum of 36MW (12 wind turbines). Each turbine can produce a maximum of at 3MW each. The maximum installed capacity for all six collector circuits will be 231MW. These circuits will be stepped up via a new 115-44kV substation.

The Niagara Region Wind Farm substation will be connected though a privately owned 115kV circuit approximately 20 km in length into the idle Hydro One 115kV circuit "Q5G". The line tap is approximately 25km from Beach Jct. Beach Jct will be connected into Beach TS.

An overview geographical diagram is provided in Figure 1. A single line diagram of the connection is provided in Figure 2.

The facility has a commercial contractual in-service date of Feb 25 2014.

## METHODOLOGY & CRITERIA

### 1.3 Voltage Performance - Planning Criteria

To establish the impact of incorporating the proposed Niagara Region Wind Farm facilities, the following post-fault voltage decline criteria would have to be observed:

- At the Bulk Electricity System level (115kV and up): The loss of a single transmission circuit should not result in a voltage decline greater than 10% for pre- and post- transformer tap-changer action
- The maximum and minimum phase-to-phase voltages given in the IESO's Transmission Assessment Criteria and Canadian Standard Association document CAN-3-C235-83 were considered. In Northern Ontario, the maximum continuous voltage for the 230 and 115kV systems can be as high as 260kV and 132kV respectively. [from IESO document IESO_REQ_0041 Issue 2.0]
- With all planned facilities in service pre-contingency, system voltage changes in the period immediately following a contingency shall not result in a voltage decline greater than 10% for pre-transformer tap-changer action (including station loads less than 50kV) and 10% post transformer tap-changer action (5% for station loads less than 50kV). In addition, the steady state voltage at station loads less than 50kV are to remain within 6% of the nominal voltage.

The voltage performance on Hydro One customers supplied by Q5G and in the area has to meet the above standard subsequent to the addition of the Niagara Region Wind Farm Project.

### 1.4 Customers Connected

The focus of this study is on customers supplied by stations connected to Beach TS. The affected customers are shown below.

| Station | Customer |
|---|---|
| Lake TS | Horizon Utilities Corporation<br>Hydro One Networks Inc |
| Dofasco Kenilworth CTS | Dofasco Inc. (Kenilworth) |
| Dofasco Bay Front CTS | Dofasco Inc. (Bay Front) |
| Kenilworth TS | Horizon Utilities Corporation |
| Stirton TS | Horizon Utilities Corporation |
| Speciality Bar CTS | Hamilton Speciality Bar Inc. |
| Birmingham TS | Horizon Utilities Corporation |
| Beach TS | Horizon Utilities Corporation |

## 2.0 POWER SYSTEM ANALYSIS

Power System Analysis is an integral part of the transmission planning process. It is used by Hydro One to evaluate the capability of the existing network to deliver power and energy from generating stations to provide a reliable supply to customers. Two relevant aspects of Power System Analysis were used for this assessment, namely:

a. Short-circuit Studies: A Short Circuit Analysis program was used to determine the impact on customers. Due to the unavailability of some of the data, typical values were used when necessary.

b. Load Flow Studies: An AC load flow program was used to set up a base case with the Niagara Region Wind Farm generating facility.

## SHORT- CIRCUIT STUDIES

Short-circuit studies were carried out to assess the fault contribution when the Niagara Region Wind Farm generators are placed in-service. The impact of the new facility on the fault levels in the Hydro One customers supplied in the Beach TS area was analyzed.

The study results are summarized in Table 1 below showing both symmetric and asymmetric fault currents in kA. Table 1 shows the fault levels based on the following assumptions:

- All existing generating facilities in-service in the area. The study assumptions are identical to Section 4.1 of the IESO System Impact Assessment Report for this project, which include committed generation.
- The maximum pre-fault voltage considered for the voltage levels is shown on the table below for fault levels at critical buses near the new generation.

| Fault Location | Bus Voltage (kV) | Present | | | | With Niagara Region Wind Farm | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | 3 Phase Fault (kA) | | L-G Fault (kA) | | 3 Phase Fault (kA) | | L-G Fault (kA) | |
| | | Sym | Asym | Sym | Asym | Sym | Asym | Sym | Asym |
| Beach 230 | 250 | 37.777 | 44.52 | 35.98 | 45.752 | 38.281 | 45.162 | 36.42 | 46.356 |
| Beach 115 | 127 | 26.711 | 32.72 | 32.3 | 41.509 | 27.792 | 33.977 | 33.553 | 43.012 |
| Beach B Bus | 14.2 | 18.488 | 22.92 | 8.842 | 11.045 | 18.549 | 22.994 | 8.851 | 11.056 |
| Beach Y Bus | 14.2 | 18.536 | 22.97 | 8.849 | 11.054 | 18.598 | 23.047 | 8.859 | 11.065 |
| Beach Q Bus | 14.2 | 17.683 | 22.62 | 7.479 | 10.538 | 17.691 | 22.638 | 7.48 | 10.54 |
| Beach J Bus | 14.2 | 17.388 | 22.33 | 7.444 | 10.494 | 17.396 | 22.342 | 7.445 | 10.496 |
| Burlington BY Bus | 29 | 13.42 | 18.33 | 10.19 | 14.416 | 13.423 | 18.335 | 10.192 | 14.418 |
| Burlington JQ Bus | 29 | 13.403 | 18.29 | 10.19 | 14.413 | 13.406 | 18.296 | 10.188 | 14.415 |
| Cumberland B Bus | 29 | 13.107 | 16.98 | 11.92 | 16.212 | 13.109 | 16.989 | 11.925 | 16.215 |
| Cumberland Q Bus | 29 | 13.029 | 16.88 | 11.88 | 16.144 | 13.032 | 16.887 | 11.877 | 16.147 |
| Dofasco Bay Front | 14.2 | 18.345 | 24.67 | 0.234 | 0.234 | 18.354 | 24.69 | 0.234 | 0.234 |
| Dofasco Bay Front H35D | 250 | 34.634 | 40.09 | 32.39 | 38.45 | 35.057 | 40.603 | 32.737 | 38.865 |
| Dofasco Bay Front H36D | 250 | 34.236 | 39.56 | 31.94 | 37.737 | 34.649 | 40.063 | 32.285 | 38.137 |
| Kennilworth Q24HM | 250 | 36.413 | 42.36 | 34.22 | 40.946 | 36.881 | 42.944 | 34.612 | 41.421 |
| Kennilworth Q29HM | 250 | 36.413 | 42.36 | 34.22 | 40.95 | 36.881 | 42.944 | 34.612 | 41.425 |
| Kenilworth A1 Bus | 127 | 25.108 | 29.66 | 28.98 | 32.383 | 26.057 | 30.69 | 29.982 | 33.38 |
| Kenilworth A3 Bus | 127 | 24.808 | 29.17 | 28.65 | 32.227 | 25.733 | 30.167 | 29.617 | 33.198 |
| Kenilworth EJ Bus | 14.2 | 18.531 | 23.14 | 14.77 | 19.407 | 18.595 | 23.219 | 14.797 | 19.442 |
| Lake B18H | 250 | 24.93 | 28.41 | 20.74 | 23.29 | 25.122 | 28.64 | 20.869 | 23.424 |
| Lake B20H | 250 | 24.923 | 28.41 | 20.74 | 23.287 | 25.116 | 28.631 | 20.868 | 23.421 |
| Lake BY Bus | 29 | 16.607 | 21.49 | 11.11 | 12.365 | 16.62 | 21.513 | 11.117 | 12.37 |
| Lake J Bus | 14.2 | 17.856 | 22.52 | 7.553 | 10.615 | 17.863 | 22.536 | 7.554 | 10.617 |
| Lake Q Bus | 14.2 | 17.856 | 22.52 | 7.551 | 10.612 | 17.863 | 22.536 | 7.552 | 10.614 |
| Specialty Bar B Bus | 14.2 | 7.448 | 9.092 | 0.579 | 0.579 | 7.46 | 9.106 | 0.579 | 0.579 |
| Specialty Bar Y Bus | 14.2 | 7.448 | 9.092 | 0.579 | 0.579 | 7.46 | 9.106 | 0.579 | 0.579 |
| Specialty Bar HL3 | 127 | 16.145 | 17.73 | 14.06 | 14.776 | 16.534 | 18.122 | 14.289 | 14.999 |
| Specialty Bar HL4 | 127 | 16.148 | 17.73 | 14.06 | 14.776 | 16.536 | 18.125 | 14.288 | 14.998 |
| Stirton HL3 | 127 | 14.822 | 16.08 | 12.41 | 12.947 | 15.148 | 16.411 | 12.588 | 13.12 |
| Stirton HL4 | 127 | 14.824 | 16.09 | 12.41 | 12.947 | 15.15 | 16.413 | 12.587 | 13.119 |
| Stirton BY Bus | 14.2 | 15.62 | 19.67 | 7.049 | 9.769 | 15.673 | 19.732 | 7.056 | 9.779 |
| Stirton QZ Bus | 14.2 | 15.679 | 19.63 | 7.055 | 9.758 | 15.732 | 19.698 | 7.062 | 9.768 |
| Winona LV | 29 | 11.767 | 13.73 | 9.375 | 12.126 | 11.826 | 13.794 | 9.4 | 12.157 |
| Winona Junction | 127 | 11.431 | 12.23 | 8.6 | 8.95 | 11.624 | 12.417 | 8.686 | 9.032 |

**Table 1 – Short Circuit Levels of Buses at Neighbouring Stations/Junctions with Niagara Region Wind Farm**

Table 1 shows the fault levels after the incorporation of the new Niagara Region Wind Farm meets the maximum symmetrical three-phase and single line-to-ground faults (kA) of 115 kV stations as set out in Appendix 2 of the *Transmission System Code* (**TSC**) [2] and reproduced below. It also meets the requirements of Hydro One equipment in the stations identified.

| Nominal Voltage (kV) | Max. 3-Phase Fault (kA) | Max. SLG Fault (kA) |
|---|---|---|
| 230 | 63 | 80(1) |
| 115 | 50 | 50 |
| 27.6 (4-wire) | 17(2) | 12(2) |
| 13.8 | 21(2) | 10(2) |

Notes :

(1) – Usually limited to 63 kA

(2) – Effective September 1, 2010, Hydro One requires a 5 % margin on the acceptable TSC limits at voltage levels of <50kV to account for other sources of fault current on the distribution system such as unmodelled synchronous motors and data inaccuracies.

### 2.1 Impact at Stations Mitigated for Fault Level

The results of the fault levels studies shown on these tables above show that the Niagara Region Wind Farm does not have a measureable (>= 0.01kA) impact at the fault level at any of the stations (Windsor Walker #1 TS, Kingsville TS, Caledonia TS & Martindale TS) where mitigation measures are necessary to limit fault levels to acceptable values.

## LOAD FLOW STUDIES

Load flow studies were carried out to analyze the impact of the new facilities on the voltage performance of Hydro One customers in the affected area. The load flow model used for the load flow analysis performed by Hydro One was based on information supplied by the IESO.

### 2.2 Base Case and Study Assumptions

The 2012 Summer Peak load conditions within operating limits in the area were used in the load flow analysis. The Niagara Region Wind Farm generation was modeled into the base case prior to performing contingency studies.

The Niagara Region Wind Farm supplied 230MW with the worst case scenario of 0.9 PF to the surrounding area.

### 2.3 Contingency Analysis

The following single transmission element contingencies were considered for this local impact assessment with Niagara Region Wind Farm operating at maximum output.

1) Loss of a Beach TS 230/115kV autotransformer;
2) Loss of H5K; and
3) Loss of HL3

In addition, the impact on the local area with the loss of Niagara Region Wind Farm was assessed.

The studies indicated that under this contingency the voltage change on the HV customer connections are well within the acceptable range of the voltage performance criteria mentioned in Section 1.3. The results are tabulated in Table 2.

| | | Loss of NRWF | | Loss of Beach Auto | | Loss of H5K | | Loss of HL3 | |
|---|---|---|---|---|---|---|---|---|---|
| **BUS NAME** | **BASE V** | **Pre ULTC** | **Post ULTC** | **Pre ULTC** | **Post ULTC** | **Pre ULTC** | **Post ULTC** | **Pre ULTC** | **Post ULTC** |
| NRWF HV | 122.29 | ***OOS*** | | 122.01 | 122.01 | 122.25 | 122.24 | 122.25 | 122.24 |
| NRWF Tap | 122.26 | ***OOS*** | | 121.97 | 121.97 | 122.21 | 122.21 | 122.21 | 122.21 |
| Beach 115kV | 122.98 | 123.66 | 123.55 | 122.50 | 122.50 | 122.90 | 122.89 | 122.90 | 122.89 |
| Winona Jct | 122.37 | 123.06 | 122.95 | 121.89 | 121.89 | 122.29 | 122.28 | 122.29 | 122.29 |
| Kenilworth A1 | 122.96 | 123.65 | 123.53 | 122.49 | 122.48 | 121.34 | 121.29 | 122.88 | 122.88 |
| Kenilworth A3 | 122.96 | 123.64 | 123.53 | 122.48 | 122.48 | 122.86 | 122.84 | 122.88 | 122.87 |
| Gage TS K1G | 122.98 | 123.66 | 123.55 | 122.50 | 122.50 | 122.87 | 122.85 | 122.90 | 122.90 |
| Gage TS K2G | 122.98 | 123.66 | 123.55 | 122.50 | 122.50 | 121.37 | 121.31 | 122.90 | 122.90 |
| Birmingham HL3 | 122.54 | 123.23 | 123.11 | 122.07 | 122.06 | 122.46 | 122.45 | 116.28 | 116.40 |
| Birmingham HL4 | 123.19 | 123.88 | 123.76 | 122.71 | 122.71 | 123.11 | 123.10 | 122.64 | 122.63 |
| Speciality Bar HL3 | 122.41 | 123.09 | 122.98 | 121.93 | 121.93 | 122.33 | 122.32 | 116.22 | 116.36 |
| Speciality Bar HL4 | 123.26 | 123.95 | 123.84 | 122.78 | 122.78 | 123.18 | 123.17 | 122.62 | 122.60 |
| Stirton TS HL3 | 122.40 | 123.08 | 122.97 | 121.92 | 121.91 | 122.32 | 122.30 | 116.24 | 116.37 |
| Stirton TS HL4 | 123.24 | 123.93 | 123.81 | 122.76 | 122.75 | 123.16 | 123.14 | 122.55 | 122.54 |
| Beach 230kV | 242.70 | 242.68 | 242.47 | 242.72 | 242.72 | 242.64 | 242.63 | 242.64 | 242.63 |
| Beach B Bus | 13.96 | 14.04 | 14.03 | 14.04 | 14.04 | 13.95 | 13.95 | 13.95 | 13.95 |
| Beach Y Bus | 14.08 | 14.17 | 14.15 | 14.38 | 14.38 | 14.08 | 14.07 | 14.08 | 14.07 |
| Trafalgar 230kV | 245.22 | 245.09 | 245.04 | 245.23 | 245.23 | 245.20 | 245.19 | 245.19 | 245.19 |
| Lake TS B18H | 242.45 | 242.43 | 242.22 | 242.48 | 242.48 | 242.40 | 242.39 | 242.40 | 242.39 |
| Lake TS B20H | 242.45 | 242.43 | 242.22 | 242.48 | 242.47 | 242.39 | 242.38 | 242.39 | 242.39 |
| Dofasco Ken Q24HM | 242.70 | 242.68 | 242.47 | 242.72 | 242.72 | 242.64 | 242.63 | 242.64 | 242.63 |
| Dofasco Ken Q29HM | 242.70 | 242.68 | 242.47 | 242.72 | 242.72 | 242.64 | 242.63 | 242.64 | 242.63 |
| Dofasco Bay H35D | 242.73 | 242.72 | 242.50 | 242.76 | 242.76 | 242.67 | 242.66 | 242.67 | 242.67 |
| Dofasco Bay H36D | 242.74 | 242.73 | 242.51 | 242.77 | 242.76 | 242.68 | 242.67 | 242.68 | 242.67 |
| Beach TS Q12 | 14.61 | 14.60 | 14.59 | 14.61 | 14.61 | 14.60 | 14.60 | 14.60 | 14.60 |
| Beach TS J12 | 14.55 | 14.55 | 14.53 | 14.55 | 14.55 | 14.54 | 14.54 | 14.54 | 14.54 |

**Table 2: Voltage Levels in the Surrounding Area**

## 3.0 CUSTOMER RELIABILITY

The proposed Niagara Region Wind Farm will add another position in the existing 115kV ring bus at Hamilton Beach TS. A new high voltage breaker will be added to the ring bus. Faults along the the HV and LV station bus of the project will be cleared by the ring bus breakers and have minimum impact on the customers supplied by the 115kV Hamilton Beach TS.

### 3.1 <u>Preliminary Outage Impact Assessment</u>

Exact outage schedule will be made available during the detailed engineering phases of the project development and established in consultation with load customers in the area. The outage duration will be minimized and risk managed with proper outage planning and co-ordination.

## CONCLUSIONS AND RECOMMENDATIONS

The Customer Impact Assessment (CIA) Report presents the results of short circuit, and voltage performance study analyses.

The overall findings of this CIA provided that the above recommendations are implemented are:

- The results of the short circuit analysis showed that some area's stations encountered small increases in fault level at the connection points. The largest increase observed was at Beach TS with an increase of 4%. The Kenilworth TS HV bus connection will also increase by 3.8% (~1kA).
- These increases were within the capability of the existing Hydro One facilities. However, the customers connected in the area should review the fault levels at their connection points to confirm their equipment is capable of withstanding the increased fault and voltage levels.
- When in operation, the Niagara Region Wind Farm will assist in supporting the voltages seen by the connected customers under system disturbances and will not adversely impact the local voltage performance in the local area

The study has confirmed that the proposed 230 MW Generation at the Niagara Region Wind Farm can be incorporated without any adverse impact on Hydro One customers.

**References**

[1] Independent Electricity System Operator (IESO), ***System Impact Assessment Report (Draft)- Niagara Region Wind Farm*****,** CAA ID-2012-466, June 20, 2012.

[2] Independent Electricity System Operator (IESO), ***IESO Transmission Assessment Criteria*****,** Issue 2.0.

[3] Ontario Energy Board, **Transmission System Code**, June 10, 2010


**Figure 1: Geographical Location of Niagara Region Wind Farm**

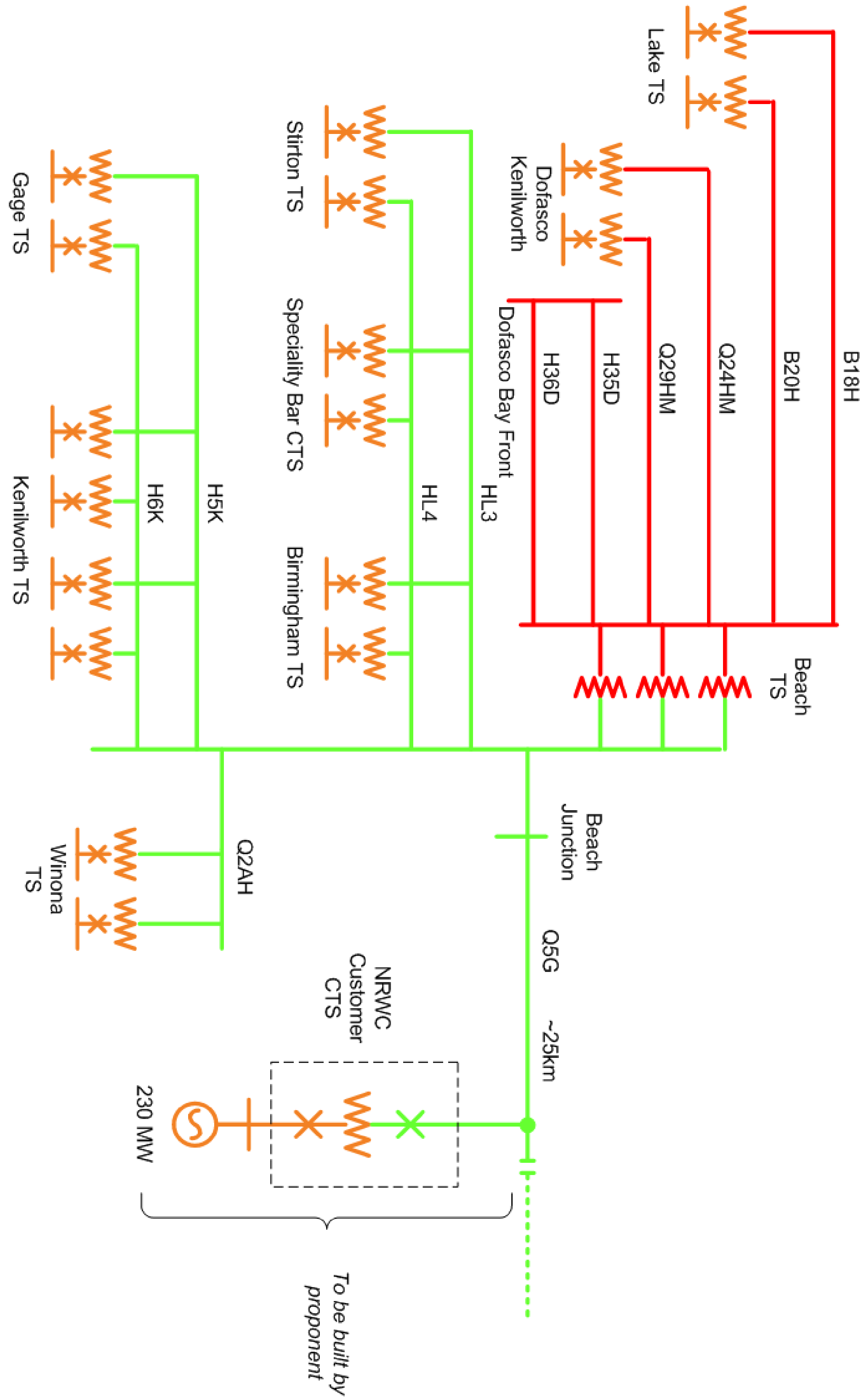



**Figure 2: Single Line Diagram for the Niagara Region Wind Farm**

# FIRST NATIONS & MÉTIS COMMUNITIES

## 1.0 INTRODUCTION

Hydro One recognizes the importance of early engagement with First Nations and Métis communities regarding the Niagara Region Wind Generation Connection Project ("**the Project**"). The following sets out Hydro One's process for engaging with First Nations communities who may have an interest in, or may be potentially affected by, the Project.

## 2.0 IDENTIFICATION OF FIRST NATIONS & MÉTIS COMMUNITIES

On December 10, 2012 Hydro One sent a letter including a Project Study Area Map to the Ontario Ministry of Energy requesting the Crown provide Hydro One a list of Aboriginal communities that have or may have Aboriginal or treaty rights that could be adversely impacted by the project and with respect to which the Crown delegates procedural aspects of its constitutional duty to consult. By letters to Hydro One dated February 8, 2013 and February 11, 2013 the Ontario Ministry of Energy stated they are of the view that the project will not result in any appreciable adverse impacts on the rights of any Aboriginal communities so as to trigger the duty to consult. Copies of these letters have been attached as **Exhibit B, Tab 6, Schedule 5 Attachments 1 and 2.**

## 3.0 PUBLIC ENGAGEMENT PROCESS FOR FIRST NATIONS & MÉTIS COMMUNITIES

Where the Crown has determined that the duty to consult does not arise, Hydro One provides relevant Project information to neighbouring First Nations and Métis communities by way of its public engagement process. First Nation and Métis communities in the vicinity of the Project are informed in a timely manner and Hydro One responds to and considers issues, concerns or questions raised in a clear and transparent manner throughout the regulatory review processes (e.g., the Environmental Assessment (“**EA**”) and OEB processes). Engagement activities with First Nations and Métis communities include:

- Providing Project-related information to neighbouring First Nations and Métis communities including, project notification letters which describe the need for and nature of the project, and ensuring that all publicly available information is also made available to First Nations and Métis communities;

- Offering to meet with neighbouring First Nations and Métis communities to provide Project-related information, identify issues, and respond to questions about the Project, and wherever possible, address concerns, in relation to the Project;

- Providing information, when requested, on the OEB’s regulatory process, the EA process or any other decision-making processes applicable to the Project;

- Consideration to all issues and concerns raised by the First Nations and Métis communities as to how the Project may affect them;

- Recording all forms of engagement with the First Nations and Métis communities, maintaining a record of the concerns and issues raised by the First Nations and Métis communities regarding the Project and Hydro One’s responses thereto, and communicating the same with the Ministry of Energy.

## 4.0 ENGAGEMENT TO DATE WITH FIRST NATIONS COMMUNITIES

Although the Crown advised they are of the view that the project will not result in any appreciable adverse impacts on the rights of any Aboriginal communities so as to trigger the duty to consult, Hydro One will undertake the following engagement activities in parallel with the initiation of the EA process:

- Hydro One will send letters notifying First Nations and Métis communities who may have an interest in, the Project, and offer to meet to discuss the Project.
- Hydro One will follow-up with the Project notification letters by telephone.

## 5.0 SUMMARY

Hydro One is prepared to notify neighbouring First Nations communities relating to the Project. Once notification commences, Hydro One will work to resolve any issues or concerns in the event that anything should arise.

**Ministry of Energy**

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**First Nation and Métis Policy and Partnerships Office**

February 8, 2013

Murray Maracle
Senior Manager, First Nation and Métis Relations
Hydro One Networks Inc.
483 Bay Street, South Tower, 5th Floor
Toronto, ON M5G 2P5

**Re: Upgrade of 115 kV Transmission Line (Circuit Q5G in Grimsby Area, for Generation Connection**

Dear Mr. Maracle:

Thank you for your letter of December 10, 2012 to inform me about the planned upgrade on circuit Q5G.

I understand that the planned upgrades include replacing the existing conductor, insulators and associated hardware, as well as 12 to 15 transmission towers, in order to connect a planned wind electricity generation project in the area.

You have advised us that the project will result in no appreciable environmental impacts. You have also advised us that all required field studies, including additional archaeological work, will be conducted as part of the Renewable Energy Approval process for the associated wind generation project. Based on the information that Hydro One has provided, the Ministry of Energy is of the view that the project will not result in any appreciable adverse impact on the rights of any Aboriginal communities so as to trigger the duty to consult.

I recommend that Hydro One Networks Inc. maintain a record of any interactions it may have with First Nation or Métis communities about the project. In the event that the environmental impact proves more significant, there is an archaeological find, or a community provides Hydro One Networks Inc. with information indicating a potential adverse impact of the project on its Aboriginal or Treaty rights, I request that you notify me.

Please do not hesitate to contact me if you have any further questions or wish to discuss this matter in more detail.

Sincerely,

for Amy Gibson
Manager
First Nation and Métis Policy and Partnerships Office

c: Agatha Garcia-Wright, Director
Environmental Approvals Branch, Ministry of the Environment

Ashley Johnson, Advisor
Consultation Unit, Ministry of Aboriginal Affairs

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**First Nation and Métis Policy and Partnerships Office**

February 13, 2013

Murray Maracle
Senior Manager, First Nation and Métis Relations
Hydro One Networks Inc.
483 Bay Street, South Tower, 5th Floor
Toronto, ON M5G 2P5

**Re: Upgrade of 115 kV Transmission Line (Circuit Q5G in Grimsby Area, for Generation Connection**

Dear Mr. Maracle:

This letter is the Ministry of Energy's response to your December 10, 2012 inquiry and replaces any previous communications regarding consultation on this project.

I understand that the planned upgrades include replacing the existing conductor, insulators and associated hardware, as well as 12 to 15 transmission towers, in order to connect a planned wind electricity generation project in the area.

You have advised us that the project will result in no appreciable environmental impacts, and that all required field studies, including required additional archaeological work, will be conducted at the sites of the tower replacements. Based on the information that Hydro One has provided, the Ministry of Energy is of the view that the project will not result in any appreciable adverse impact on the rights of any Aboriginal communities so as to trigger the duty to consult.

I recommend that Hydro One Networks Inc. maintain a record of any interactions it may have with First Nation or Métis communities about the project. In the event that the environmental impact proves more significant, there is an archaeological find, or a community provides Hydro One Networks Inc. with information indicating a potential adverse impact of the project on its Aboriginal or Treaty rights, I request that you notify me.

Please do not hesitate to contact me if you have any further questions or wish to discuss this matter in more detail.

Sincerely,

Amy Gibson

Amy Gibson
Manager
First Nation and Métis Policy and Partnerships Office

c: Agatha Garcia-Wright, Director
Environmental Approvals Branch, Ministry of the Environment

Ashley Johnson, Advisor
Consultation Unit, Ministry of Aboriginal Affairs

# STAKEHOLDER AND COMMUNITY CONSULTATION

## 1.0 INTRODUCTION

This exhibit outlines Hydro One's consultation and communication process, and input received to date regarding the Project. Hydro One is committed to working to address community and stakeholder issues to ensure any concerns regarding the proposed transmission upgrades are addressed, and that municipal staff, elected officials, the general public, as well as relevant government ministries are kept informed of the project status.

The proposed 115 kV upgrades are located in the City of Hamilton, the Town of Grimsby and the Town of Lincoln, adjacent to Lake Ontario and the Queen Elizabeth Way.

Hydro One is working with the Niagara Region Wind Corporation (**"NRWC"**) and understands that its public consultation process for this project has included information about the required Hydro One's transmission upgrades. As such, Hydro One's consultation approach will focus on notifying key stakeholders in the vicinity of the transmission line who may have an interest in the proposed transmission line upgrade, and providing them with a dedicated project contact.

The initial steps in Hydro One's consultation process involved identifying key issues and potentially affected communities and stakeholders and ensuring coordination of consultation activities and building on activities already undertaken by Niagara Region Wind Corporation.

## 2.0 OBJECTIVES AND CONSULTATION PROCESS

The intent of the consultation process is to inform the community and stakeholders about the project, identify any issues, and develop plans that address those issues where appropriate. Hydro One's project is limited to upgrading the currently idle 115 kV, 25 Hz infrastructure to operate at 115 kV with increased capacity and at 60 Hz, and install or modify towers within an already existing right-of-way to accommodate the NRWC project. Hydro One's generation connection project is expected to have little or no environmental impact since no vegetation removal or right-of-way widening is required and construction crews are expected to be able to mostly use existing access roads; however, some temporary access rights may be required.

In addition, NRWC's consultation process has provided the local community with an awareness of the need for Hydro One's infrastructure upgrade. The general public has had an opportunity to participate in NRWC's consultation program.

## 3.0 NOTIFICATION OF ELECTED OFFICIALS AND STAFF

In an effort to ensure local municipal officials are aware of Hydro One's role and plans, it will provide written notice to the Mayor and Council members in the City of Hamilton, Town of Grimsby, Town of Lincoln and Regional Chair and Regional Council in the Regional Municipality of Niagara of the Environmental Assessment process. Hydro One will continue to keep elected officials informed as the project progresses.

## 4.0 PUBLIC NOTIFICATION

Hydro One will also provide written notice to all homes and businesses within the project area of the section 92 application that includes project details as part of the notice of the Environmental Assessment (EA) process, once the proponent has completed its

Renewable Energy Approvals process. The notice to announce the EA component will include project details, the need and timelines. A project information page will be created on the Hydro One Networks' website www.HydroOne.com/projects to further facilitate public access to information about the project and communication with Hydro One staff. This site provides information about the project and timelines, as well as details on the environmental screening process. The site will be kept up to date as new information becomes available.

# LAND MATTERS

## 1.0 DESCRIPTION OF LAND REQUIRED

The Niagara Region proposed transmission upgrade will involve replacing the existing idle 25Hz 115 kV conductor (wire) with a new 115kV higher-capacity overhead conductor between Hamilton Beach Transformer Station (TS) and Structure Number #154 located near Mountainview Road in the Town of Lincoln. The total length of the upgrade is approximately 25 kilometres (km). Part of the upgrade will also include underground conductor between Hamilton Beach Junction and Hamilton Beach Transformer Station (TS). The existing corridor from Hamilton Beach TS to Structure #154 is a combination of:

- provincially owned property segments held under title to the Ministry of Public Infrastructure and Renewal, and managed by the Infrastructure Ontario;
- provincially owned property segments held under title to her Majesty the Queen, In Right of the Province of Ontario, Represented by Minister of Highways;
- easement rights on private properties;
- municipal roads; and
- one railway crossing.

The proposed transmission line facilities will be largely accommodated by existing land rights which Hydro One has secured along the existing corridor. These rights consist of the existing statutory easement rights Hydro One enjoys on all of the provincially-owned corridor lands, as well as its existing permanent easement rights on private property lands.

## 2.0 DESCRIPTION OF LAND RIGHTS

The existing transmission line corridor crosses an estimated 111 privately-owned properties where Hydro One Networks Inc. has easements from Hamilton Beach TS to Structure #154 in the Town of Lincoln. Additionally, there are an estimated 28 properties where Hydro One Networks Inc. has easements on lands owned by local and provincial agencies. The properties along the corridor include industrial, commercial, residential, one aggregate operation, and agricultural areas. The proposed upgrade will also cross one railway right-of-way located next to Hamilton Beach TS which is owned by CN Rail. There is also an estimated 38 road allowances crossed.

Hydro One has certain permanent easement rights along the length of the existing corridor that allow for the construction and use of the lands for the project. Any temporary off-corridor requirements including construction staging areas and access will be communicated with affected private property owners.

## 3.0 LAND ACQUISITION PROCESS

Hydro One will be using its existing land rights for the entire project, from Hamilton Beach TS to Structure #154.

Most of the work will be carried out within the existing right-of-way, and construction activities will be intermittent over the construction period. Any temporary off-corridor requirements will be negotiated with private land owners.

The detailed construction work plan for this project is currently being developed by Hydro One. Properties that will be impacted by construction work activities will be provided at a later stage.

Landowners have been informed of this project as part of the stakeholder and community consultation process described in **Exhibit B, Tab 6, Schedule 6**. Landowners will also be notified of the proposed transmission upgrade as part of the Board's Section 92 notice requirements and as part of the Class Environmental Assessment approval process.