Exhibit H, Tab 1, Schedule 1
Overview of Impact Assessments

OVERVIEW OF IMPACT ASSESSMENTS

Suncor received a System Impact Assessment ("**SIA**") (Addendum Report) (the "**Assessment**") on December 12, 2012 for the Cedar Point Project. The Report was issued in the form of an Addendum to the SIA issued to NextEra for the connection of its Shared Transmission Facilities on June 4, 2012. These reports conclude that the proposed connection of Cedar Point is expected to have no material adverse impacts on the reliability of the integrated power system. The IESO therefore recommended that a Notification of Conditional Approval for Connection be issued. The Notification was issued to Suncor concurrently with SIA Addendum Report.

Suncor received a final Customer Impact Assessment ("**CIA**") Report "Wind Energy Power Project, Adelaide/Bornish/Jericho Wind Energy Centres" on June 8, 2012 from Hydro One in respect of the Proposed Transmission Facilities. This report concludes that electricity from the Cedar Point generation facilities can be conveyed to the IESO-controlled grid through the proposed Transmission Facilities and the Shared Transmission Facilities without adverse impacts on area customers. The CIA Report was issued in the form of an Addendum to the previously issued Customer Impact Assessment for NextEra Shared Transmission Facilities, for which has recently been approved by the Board.

The Board noted in its decision on the Bornish Application, while discussing the SIA and the CIA performance for that project that, for both the SIA and the CIA, subsequent addenda included the impacts of the 100 MW Suncor Cedar Point Project in the combined projects.

Exhibit H, Tab 2, Schedule 1
System Impact Assessment

SYSTEM IMPACT ASSESSMENT

REPORT

Power to Ontario.
On Demand.

System Impact Assessment Report

CONNECTION ASSESSMENT & APPROVAL PROCESS

Final Report

CAA ID: **2011-445**
Project: **Cedar Point II Wind Power Project**
Applicant: **Suncor Energy Products Inc.**

Market Facilitation Department
Independent Electricity System Operator

Date: June 4th, 2012

Document ID	IESO_REP_0811
Document Name	System Impact Assessment Report
Issue	Final Report
Reason for Issue	Final Report
Effective Date	June 4th, 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 facility 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 facility 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.

Table of Contents

Executive Summary

Project Description

Suncor Energy Products Inc. (the “connection applicant”) is proposing to construct a 100 MW wind energy project named Cedar Point II Wind Power Project (the “project”) in Forest, Ontario. The project will connect to Hydro One’s 500 kV circuit B562L via a 121 kV network to which three other projects, Bornish, Adelaide and Jericho Wind Energy Centres will also be connected. As agreed with the connection applicants for all four projects, this System Impact Assessment (SIA) study was performed as a cluster with requirements being developed for the combination of the Cedar Point II, Bornish, Adelaide and Jericho wind projects (the “projects”).

The Cedar Point II Wind Power Project has been awarded a Power Purchase Agreement under the Feed-In Tariff (FIT) program with the Ontario Power Authority. The project in-service date is July 5th, 2014.

Findings

1. The proposed connection arrangement and equipment for the projects are acceptable to the IESO.
2. The asymmetrical fault current at Bruce A 230 kV switchyard before and after the incorporation of the project will exceed the interrupting capability of the existing breakers. Hydro One has planned to replace the Bruce 230 kV breakers to improve fault current interrupting capability in the long term. Before the circuit breakers are replaced, temporary operational mitigation measures have been developed by Hydro One in collaboration with the IESO.
3. Circuit S2S will be required to operate open-loop under certain conditions after the integration of the committed generation in the Bruce Area to prevent thermal overloading
4. The projects are connecting in the Bruce Area where transmission connected generation projects participate in the Bruce Special Protection Scheme (BSPS).
5. The reactive power capability of the wind turbine generators (WTGs) along with the impedance between the WTGs and the IESO controlled grid results in a reactive power deficiency at the connection point which has to be compensated with additional reactive power devices.
6. The functions of the proposed wind farm control system meet the requirements in the Market Rules except that the inertia emulation control function is unavailable. The IESO reserves the right to ask the connection applicant to install this function in the future should the function become available for the proposed type of WTG.
7. Some outage conditions and contingencies cause the voltage at the 500 kV Evergreen SS to exceed maximum permissible voltage levels of 550 kV. This will be managed by using equipment with a maximum continuous operating voltage of at least 570 kV. Alternate solutions to manage the high voltage concern may be acceptable upon the approval of the IESO.
8. The WTGs of the projects 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 projects by configuration.

10. Protection adjustments identified by Hydro One in the Protection Impact Assessment (PIA) to accommodate the projects have no adverse impact on the reliability of IESO-controlled grid.
11. The relay margins on the affected circuits after the incorporation of the projects conform to the Market Rules' requirements.
12. In the event of high flows eastward towards Toronto, there is a low probability of congestion that may require the applicant to curtail its output.

IESO Requirements for Connection

Transmitter Requirements

The following requirements are applicable to the transmitter for the incorporation of the projects:

(1) Hydro One is required to review the relay settings of the 500 kV sectionalized circuits of B562L and any other circuits affected by the projects, as per solutions identified in the PIA.

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.

(2) The transmitter shall modify the existing Bruce Special Protection Scheme (BSPS) to incorporate the new projects and the new switching station. The BSPS shall be expanded to recognize the disconnection of the circuits in the Bruce x Longwood corridor. A description of the modification to the BSPS has to be provided to the IESO in a timely manner to allow for the required approvals of the BSPS to be obtained. A Facility Description Document (FDD) describing the functionality of the expanded BSPS has to be provided to the IESO during the market entry/facility registration process.

(3) Equipment at Evergreen SS must sustain a continuous voltage up to 561 kV. Alternate solutions to manage the high voltage concern may be acceptable upon the approval of the IESO.

(4) Fault interrupting devices must be able to interrupt fault currents at the maximum continuous voltage of 561 kV.

Applicant Requirements

Specific Requirements: The following *specific* requirements are applicable for the incorporation of the projects. 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 These requirements are based on the projects' grid connection point being at the 500 kV Parkhill CTS..

(1) The projects are required to have the capability to 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.

Based on the equivalent collector impedance parameters provided by the connection applicant, a static capacitive compensation device of at least 120 Mvar@121 kV installed at the 121 kV Parkhill CTS bus would satisfy the reactive power requirement. The required capacitive compensation would need to be arranged into at least 4 approximately equal steps to allow for flexibility in adjustment of reactive power production.

The voltage profile along the projects' network greatly impacts their ability to provide full reactive support from the WTGs. The IESO recommends that projects' internal system voltages be controlled via automatic ULTC such that voltages remain within acceptable ranges, ultimately facilitating the WTGs ability to provide full reactive support.

The connection applicant has the obligation to ensure that the wind farm has the capability to meet the Market Rules' requirements at the connection point and be able to confirm this capability during the commission tests.

(2) 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.

(3) The connection applicant shall ensure that the equipments within the project have the capability to operate when the voltage at Evergreen SS is as high as 561 kV.

(4) Special protection system facilities must be installed at the projects to accept a pair (A & B) of Generation Rejection (G/R) signals from the BSPS, and disconnect the project from the system with no intentional time delay when armed for G/R following a triggering contingency. These special protection system facilities must also comply with the NPCC Reliability Reference Directory #7 for Type 1 special protection systems. In particular, if the SPS is designed to have 'A' and 'B' protection at a single location for redundancy, they must be on different non-adjacent vertical mounting assemblies or enclosures. Two independent trip coils are required on the breakers selected for G/R. The applicant must provide two dedicated communication channels, separated physically and geographically diverse, between the project and the Bruce NGS.

To disconnect the project from the system for G/R, simultaneous tripping of the 500 kV and 121 kV breakers at Parkhill CTS shall be initiated with no accompanying breaker failure response. After being tripped by the BSPS, the closing of the breakers is not permitted until approval is obtained from the IESO. Alternative solutions to disconnect the project from the system for G/R may be acceptable upon the approval of the IESO.

General Requirements: The connection applicant shall satisfy all applicable requirements and standards specified in the Market Rules and the Transmission System Code. The following requirements summarize some of the general requirements that are applicable to the proposed projects, and presented in detail in section 2 of this report.

(1) The connection applicant shall ensure that the projects have 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 projects 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 available.

(2) The connection applicant shall ensure that the projects have 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 projects for voltage changes shall be similar or better than that of a generation facility 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 500 kV equipment is capable of continuously operating between 490 kV and 561 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 4.1 of 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 projects 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 projects is designed to withstand the fault levels in the area. If any future system changes result in fault levels exceeding 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 561 kV.

(8) Appendix 2 of the Transmission System Code states that the maximum rated interrupting time for the 500 kV breakers must 2 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 projects are designed to satisfy all the requirements of the Transmission System Code and any additional requirements identified by the transmitter.

As currently assessed, the projects are not part of the Bulk Power System (BPS). However, being 500 kV connected facilities, the projects are designated as essential to the power system by the IESO and as such must meet the TSC requirements for essential elements.

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

The auto-reclosure of the high voltage breakers at Parkhill CTS 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 the projects, 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 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 projects 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.

Notification of Conditional Approval

The proposed connection of the Cedar Point II Wind Power Project, operating up to 100 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.

It is recommended that a *Notification of Conditional Approval for Connection* be issued for the Cedar Point II Wind Power Project subject to the implementation of the requirements outlined in this report.

– End of Section –

1. Project Description

Suncor Energy Products Inc. is proposing to construct a 100 MW wind energy project named Cedar Point II Wind Power Project in Forest, Ontario. The project has been awarded a Power Purchase Agreement under the FIT program with the Ontario Power Authority. The project in-service date is July 5th, 2014.

The project will consist of 45 units of Siemens 2.3 MW wind turbines, output limited to 2.221 MW each. These wind turbines will be arranged into 4 groups of 12, 11 or 10 turbines each. The collector feeder for each group of turbines will be connected to a 34.5 kV bus via a circuit breaker, which in turn will be connected to a 34.5/120 kV step-up transformer. A 120 kV circuit breaker and a 120 kV motorized disconnect switch will be installed between the high-voltage side of the step-up transformer and an 11.9 km, 120 kV tap line. At the other end of the tap line, an additional 120 kV circuit breaker and a 120 kV motorized disconnect switch will connect the tap line into a newly proposed 121/500 kV network built by Nextera Energy Canada. This 121/500 kV network will be used to inject power from three other newly proposed wind facilities (Jericho Wind Energy Centre – CAA 2011_441, Bornish Wind Energy Centre – CAA 2011_443 and Adelaide Wind Energy Centre – CAA 2011_446).

Power from all four wind farms will be transmitted to a 500/121 kV substation called Parkhill CTS through an 11.4 km line called BTS1P. Additional capacitor banks will be installed at the 121 kV bus at Parkhill CTS to provide reactive power compensation. The voltage level will subsequently be stepped up to 500 kV using a transformer. Parkhill CTS will be connected to circuit B562L, which will be sectionalized by the new Evergreen SS 500 kV ring bus at the connection point of the project. Evergreen SS will be approximately 36.5 km from Longwood TS. These shared equipment parameters that were originally assessed with the Jericho, Bornish and Adelaide System Impact Assessments have been revised by Nextera Energy Canada and their impact reassessed in this System Impact Assessment.

The single line diagram and the connection point of the project are illustrated in Figure 1 and Figure 2, Appendix A, respectively.

Sectionalizing circuits B562L and B563L at Evergreen SS and Ashfield SS (for connection of the K2 wind project) respectively resulted in four new 500 kV circuits. Figure 2 shows the names of these circuits: B562E, E562L, B563A, and A563L. The nomenclature assumed for the new circuits is for the purpose of this report and the names may differ at the time of connection.

This System Impact Assessment and its requirements are based on the projects' grid connection point being at the 500 kV Parkhill CTS. The reactive power compensation requirements specified in the System Impact Assessments completed for Jericho, Bornish and Adelaide Wind Energy Centres have also been updated.

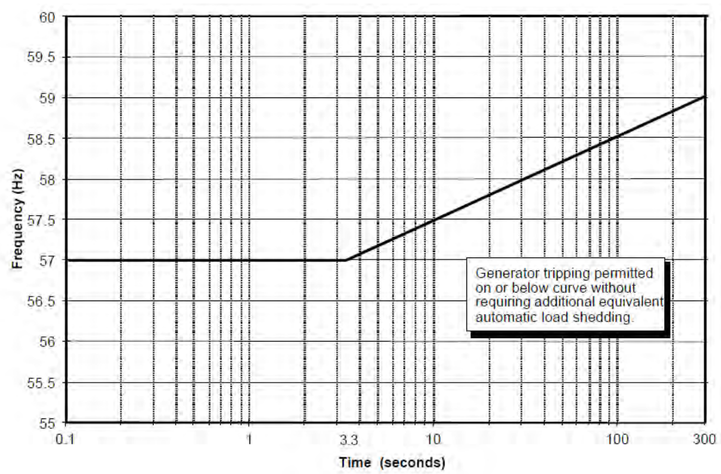
– End of Section –

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 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 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 project can be placed in-service. If this function is commercially unavailable, the IESO reserves the right to ask the connection applicant to 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 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 project for voltage changes shall be similar to or better than the response of a generation facility 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 Through Capability

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.

2.4 Voltage

Appendix 4.1 of the Market Rules states that under normal operating conditions, the voltages in the 500 kV system are maintained within the range of 490 kV and 550 kV. Thus, the IESO requires that the 500 kV equipment in Ontario must have a maximum continuous voltage rating of at least 550 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 500 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 withstand 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 changes results 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 the Transmission System Code. Appendix 2 of the Transmission System Code establishes the maximum fault levels for the transmission system. For the 500 kV system, the maximum 3 phase and single line to ground symmetrical fault levels are 80 kA (usually limited to 63 kA)..

Fault interrupting devices must be able to interrupt fault currents at their maximum continuous voltage.

2.8 Breaker Interrupting Time

Appendix 2 of the Transmission System Code states that the maximum rated interrupting time for the 500 kV breakers must be 2 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 TSC. These redundant protections systems must satisfy all requirements of the TSC, 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, however it is considered essential to the power system due to its 500 kV connection and as such must meet the TSC requirements for essential elements.

The protection systems within the project must only trip the appropriate equipment required to isolate the fault. After the project begins commercial operation, if an improper trip of the 500 kV circuits emanating from Evergreen SS 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 auto-reclosure of the high voltage breakers at Parkhill CTS 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 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

Based on the SIA application, the connection applicant meets the restoration participant criteria. Please refer to the Market Manual 7.8 to determine its applicability to the project. 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 as shown in Figure 1, Appendix A, will not reduce the level of reliability of the integrated power system and is, therefore, acceptable to the IESO.

3.2 Siemens SWT 2.3 - 113

The Siemens 2.3 MW WTG is a variable speed, full conversion wind turbine generator system. Its specifications are show in Table 1.

Table 1: Specifications of Siemens 2.3 MW WTG

Type	Rated Voltage	Rated MVA	Rated MW	Transformer			Q_{max} (Mvar)	Q_{min} (Mvar)
				MVA	R	X		
Siemens SWT-2.3-113	690 V	2.55	2.221	2.6	0	0.06	1.495	-1.610

The active power rating of the proposed wind turbines will be limited to 2.221 MW to not exceed the 100 MW facility rating. The provided Qmax and Qmin values are for full active power output at rated terminal voltage.

<u>Voltage Ride-Though Capability</u>

The Siemens 2.3 MW WTG provides voltage ride through capability. During a voltage drop/raise, the minimum time for a WTG to remain online is shown in Table 2. The proposed turbines will use this option.

Table 2: WTG Voltage Ride-Through Specifications

Voltage Range (% of base voltage)	Minimum time for WTGs to Remain Online (s)
V<15	0.85
15<V<40	1.6
40<V<70	2.6
70<V<85	11
85 < V < 90	200
110 < V < 120	1.0
V>120	0

The low voltage ride-through (LVRT) capability of the proposed WTGs was verified by performing the studies outlined in Section 6.10.

<u>Frequency Ride-Through Capability</u>

The Siemens SWT 2.3-113 wind turbine can remain online continuously for the frequency range of 57.0 Hz to 62.0 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).

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

3.3 Step-Up Transformers

Table 3: Facility Step-Up Transformer Data

Unit	Transformation	Rating (MVA) (ONAN/ONAF/OFAF)	Positive Sequence Impedance (pu) S_B = 66 MVA	Configuration		Tap
				HV-Side	LV-Side	
Cedar Point T1	120/34.5kV	66/88/110	0.0015+ j0.08	Yg	Yg	ULTC@ HV 132-108 kV, 17 steps

3.4 Collector System

Table 4: Equivalent Impedance of Collector System

Circuit	Unit#	MW	Positive-Sequence Impedance (pu, S_B=100MVA, V_B=118.05 kV)			Zero-Sequence Impedance* (pu, S_B=100MVA, V_B=118.05 kV)		
			R	X	B	R	X	B
C1	12	26.65	0.09292	0.3188406	0.034759	-	-	-
C2	10	22.21	0.15282	0.126444	0.01997	-	-	-
C3	12	26.65	0.01815	0.018736	0.011302	-	-	-
C4	11	24.43	0.05066	0.151145	0.017729	-	-	-

(*) Zero-sequence impedance has not been provided. Typical data was assumed during the SIA. The connection applicant needs to provide these data during the IESO Market Entry process.

3.5 Connection Equipment

3.5.1 HV Switches

Table 5: Specifications of HV Switches

Identifier	Voltage Rating	Continuous Current Rating	Short Circuit Symmetrical Rating
All	145 kV	1200 A	40 kA

3.5.2 HV Circuit Breakers

Table 6: Specifications of HV Circuit Breakers

Identifier	Voltage Rating	Interrupting time	Continuous Current Rating	Short Circuit Symmetrical Rating
All	145 kV	50 ms	1200 A	40 kA

3.5.3 Tap Line

Table 7: Impedance of Facility Tap Line

Circuit	Length (km)	Positive-Sequence Impedance (pu, S_B=100MVA, V_B=118.05 kV)			Zero-Sequence Impedance (pu, S_B=100MVA, V_B=118.05 kV)		
		R	X	B	R	X	B
CP1J	11.9	0.00624	0.0363	0.0064	0.0279	0.1060	0.0033

3.6 Updated Information for Shared Nextera Equipment

The following information updates the parameters for the main step up transformer and transmission lines that will be shared between the project and the previously assessed Bornish, Jericho and Adelaide Wind Energy Centres.

Table 8: Main Step-Up Transformer Data

Unit	Transformation	Rating (MVA) (ONAN/ONAF/OFAF)	Positive Sequence Impedance (pu) S_B= 256 MVA	Configuration		Tap
				HV-Side	LV-Side	
Parkhill T3	525/121	256/341/426	0.0022+ j0.10	Yg	Δ	ULTC@ LV 133.1-108.9 kV, 33 steps

Table 9: Impedance of Intermediate Transmission Lines

Circuit	Length (km)	Positive-Sequence Impedance (pu, S_B=100MVA, V_B=118.05 kV)			Zero-Sequence Impedance (pu, S_B=100MVA, V_B=118.05 kV)		
		R	X	B	R	X	B
J1BTS	14.5	0.00248	0.0316	0.0110	0.0393	0.0967	0.0061
BTS1P	11.4	0.00194	0.0249	0.0086	0.0309	0.076	0.0048

3.7 Wind Farm Control System

The proposed wind farm will be equipped with the Siemens Remote Control and Monitoring System. This control system is designed to interface with each WTG in the wind farm for regulating system voltage, and real and actual power for the entire wind farm.

The proposed wind farm will also be equipped with a separate Programmable Logic Control (PLC) to help coordinate and control fixed reactor and capacitor banks within the wind farm.

Voltage Control

- Voltage, VAR and Power Factor Control

The voltage control of the wind farm is managed by an outer and inner control loop. The HV system voltage is controlled by the outer loop managed by the Siemens Remote Control and Monitoring system. A feedback of the HV system voltage is received by the Siemens Remote Control and Monitoring system and voltage references are sent to each wind turbine controllers at the individual wind turbines. By way of the wind turbine controllers, the terminal voltages are controlled via the inner loop control.

The Siemens SWT 2.3 - 113 does not have power factor or reactive power regulation.

- Fixed Reactor and Cap Bank Control and Coordination

Reactors or capacitors installed within the wind farm will be controlled by an independent PLC. Reactive devices will be switched with the objective to minimize wind farm reactive output while ensuring that the terminal voltages of each turbine are within operational limits.

The voltage control functions enable the proposed wind farm 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.

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

Frequency Control

The Siemens Remote Control and Monitoring system has a function of frequency droop control which controls the wind farm power output based upon the grid frequency. This function is similar to governor droop control for a conventional rotating generator. The function of frequency control meets the requirements of the Market Rules.

Inertia Emulation Capability

The Siemens SWT 2.3 MW wind turbines are currently unable to provide any form of Inertia Emulation capability. The IESO reserves the right to ask the connection applicant to install this function in the future, should it become commercially available for the proposed wind turbine.

-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 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	G1, G2, 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
- Port Dover and Nanticoke
- Grand Renewable Energy

- White Pines Wind Farm
- Amherst Island
- York Energy Centre
- Conestogo Wind Energy Centre 1
- Dufferin Wind Farm
- Summerhaven Wind Farm
- 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
- Lower Mattagami expansion - H22D line extension from Harmon to Kipling (CAA2006-239);
- 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
- 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 & phase shifters on neutral taps
- Maximum voltages on the buses

Table 10 summarizes the projected fault levels at facilities near the project with and without the project and other recently committed generation projects.

Table 10: Fault Levels at Facilities near the Project

Station	Before the projects		After the projects and other committed projects		Lowest Rated Circuit Breaker (kA)
	3-Phase	L-G	3-Phase	L-G	
*Symmetrical Fault (kA)**					
Bruce A 500 kV	37.13	41.72	38.09	42.66	63
Bruce A 230 kV	42.82	54.20	44.36	55.86	60***
Bruce B 500 kV	36.92	41.55	37.85	42.53	80
Longwood 500 kV	20.04	20.95	20.77	21.99	63
Longwood 230 kV	37.36	44.74	38.35	46.04	63
Evergreen 500 kV	-	-	15.71	14.03	63
Parkhill TS 121 kV	-	-	14.50	6.81	40
Bornish TS 121 kV	-	-	10.84	9.19	40
Cedar Point II 121 kV	-	-	5.58	4.47	40
Jericho WEC 121 kV	-	-	8.00	8.39	40
*Asymmetrical Fault (kA)**					
Bruce A 500 kV	54.40	63.15	55.76	64.45	74.9
Bruce A 230 kV	57.47	**78.24****	59.39	**80.43****	72.6***
Bruce B 500 kV	54.27	63.52	55.57	64.89	89.5
Longwood 500 kV	24.36	26.68	25.27	27.97	68.9
Longwood 230 kV	45.70	57.93	47.03	59.68	78
Evergreen 500 kV	-	-	19.01	18.03	63****
Parkhill TS 121 kV	-	-	18.62	6.91	40****
Bornish TS 121 kV	-	-	12.92	9.84	40****
Cedar Point II 121 kV	-	-	6.13	4.74	64
Jericho WEC 121 kV	-	-	9.37	10.49	40****

* 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 asymmetrical fault level is based on a breaker contact parting time of 44 ms.

***Three lower rated Bruce A 230 kV breakers (D1L81, K1L82 and L23T25) are scheduled to be replaced by December 2012 (see CAA ID#2010-EX511). The listed lowest rated circuit breaker value for Bruce A 230 kV assumes these breakers being replaced.

****The symmetrical rating was used as the asymmetrical rating has not been provided.

Table 10 shows the interrupting capability of the 500 kV and 121 kV circuit breakers within the newly built network are adequate for the anticipated fault levels.

The results also show that the line-to-ground asymmetrical fault current at Bruce A 230 kV before and after the incorporation of the projects and other committed projects will exceed the interrupting capability of the existing breakers. This issue has been investigated in the 2nd SIA addendum for the project of Bruce G1 and G2 restart (CAA ID 2004-163), where the IESO has identified a requirement to replace all the Bruce 230 kV breakers with higher fault current interrupting capability and assessed potential mitigation measures for this issue until these circuit breakers are replaced. Hydro One has planned to replace the Bruce 230 kV breakers.

With the exception of Bruce A 230 kV, 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

A Protection Impact Assessment (PIA) was completed by Hydro One, included in Appendix B of this report, to examine the impact of the project on existing transmission system protections. The summary of the PIA report is presented below.

Protection Changes

The changes to the existing transmission protection systems required to incorporate the project, which were included in the system impact studies, are summarized in Table 11.

In addition, with either the Evergreen-by-Longwood or Bruce-by-Evergreen circuit out of service, low infeed from the wind farm can result in delayed fault clearing. With low infeed, a fault near Evergreen SS would not be seen by the Evergreen SS protections nor by the remote stations' Zone 1 due to the fault location being within Zone 2 reach; resulting in a fault clearing time of up to 400 ms. Hydro One will implement a relay logic design to address the weak infeed scenario which will be elaborated in the planning document in preparation of the detailed design.

Table 11: Proposed Protection Changes to Circuit B562L

Station	Zone	Existing Reach (km)	Revised Reach (km)	Comments
Bruce A TS	1	149	120	Set at 80% of the line segment impedance to Evergreen SS.
	2	233	188	Set at 125% of the maximum apparent impedance seen for a fault at Evergreen SS.
Longwood TS	1	149	29	Set at 80% of the line segment impedance to Evergreen SS.
	2	233	46	Set at 125% of the maximum apparent impedance seen for a fault at Evergreen SS.
Evergreen SS to Longwood TS	1	-	29	Set at 80% of the line segment impedance to Longwood TS.
	2	-	46	Set at 125% of the maximum apparent impedance seen for a fault at Longwood TS.
Evergreen SS to Bruce A TS	1	-	120	Set at 80% of the line segment impedance to Bruce A TS.
	2	-	188	Set at 125% of the maximum apparent impedance seen for a fault at Bruce A TS.

Telecommunication Requirements

New digital and PLC (main and alternate) facilities will be installed at the Evergreen SS in order to establish necessary connections for teleprotection. The links will be established to both Bruce A TS and Longwood TS. Signal exchange is also required between Evergreen SS and the project's step-up station (Parkhill CTS). All communication links are to be redundant and fully separated with geographic diversity

The PIA concluded that it is feasible to connect the projects at the proposed location as long as the PIA proposed changes to the transmission configuration, protection hardware, protection settings, and telecommunications are made.

-End of Section-

6. System Impact Studies

The technical studies focused on identifying the impact of the projects on the reliability of the IESO-controlled grid. They include a thermal loading assessment of transmission lines, system voltage performance assessment, transient stability assessment of the proposed and major surrounding generation units, ride-through capability of the project and relay margin evaluation for transmission circuits. This chapter also investigates the performance of the proposed control systems and the reactive power capability of the project in comparison to the Market Rules' requirements.

6.1 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:

- Second 500kV Bruce-Milton double-circuit line (CAA2006-250);
- Nanticoke and Detweiler SVCs;
- Buchanan TS: one 250 Mvar shunt capacitor;

(2) **Generation Facilities:** All existing and committed major generation facilities with 2013 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:** Three basecases in terms of load level were used in this SIA studies: peak load, shoulder load, and light load. The projects were incorporated into each case. The generation dispatch philosophies for the three cases are as follows:

<u>Peak Load Basecase</u>

- All committed and existing generation in the Southwest and Bruce areas were maximized, including 8 units at Bruce;
- Gas generation, in conjunction with maximum wind generation, in the West area was dispatched to achieve a NBLIP transfer of approximately 2000MW;
- Generation in the North areas was dispatched to achieve a Flow South transfer of approximately 1250MW;
- Generation in the Greater Toronto Area included two Pickering units, four Darlington units and four Sithe Goreway units;

<u>Shoulder Load Basecase</u>

- All committed and existing generation in the Bruce area was maximized;
- Renewable and minimum level gas generation in the West was dispatched to achieve an NBLIP transfer of approximately 986MW;
- Generation in the North areas was dispatched to achieve a Flow North transfer of approximately 500MW;
- Generation in the Greater Toronto Area included two Pickering units and four Darlington units;
- Generation in the Southwest area was then dispatched to balance the load;

<u>Light Load Basecase</u>

- All dispatchable gas units out of service;
- Minimum hydraulic generation;

- Nuclear generation limited to three Pickering units, two Darlington units and five Bruce units;
- Existing Southwest, West and Bruce area wind generation in service;
- Incorporation of the projects into the system;

The system demand and the primary interface flows after the incorporation of the projects are listed in Table 12.

Table 12: System Demand and Primary Interface Flows for Basecases (MW)

Basecase	System Demand	NBLIP	FABC	FETT	QFW	FS	FIO
Peak Load	26880	2023	6412	6913	1146	1250	1585
Shoulder Load	20716	986	6412	6707	1055	-488	1309
Light Load	11621	643	3845	906	34	-1048	746

6.2 Special Protection System (SPS)

The BSPS is a collection of special protection systems installed at the Bruce B switching station (SS) and other stations which perform pre-defined control actions, including generation rejection, load rejection and reactor switching. These control actions are initiated in response to recognized contingencies by monitoring the electrical connection between nodes in southern Ontario. The primary purpose of the BSPS is to allow increased pre-contingency transfers on the existing transmission facilities emanating from the Bruce nuclear generation station (NGS).

The BSPS is classified as a “Type 1 Special Protection System”, and conforms to criteria and guidelines specified in NPCC Directory #7 for special protection system.

The IESO has identified a requirement that wind generation stations connecting near the Bruce NGS must connect to and participate in the BSPS, as detailed in the SIA report and addendum for Hydro One BSPS modifications (CAA ID 2005-EX222). The incorporation of wind generation rejection (G/R) to the BSPS is considered a new BSPS control action. This new control action will provide the IESO with increased operating flexibility during transmission outage conditions.

Special protection system facilities must be installed at the projects to accept a single pair (A & B) of G/R signals from the BSPS, and disconnect from Evergreen SS with no intentional time delay, when armed by the IESO following a triggering contingency. These special protection system facilities must also comply with the NPCC Directory #7 for special protection systems. In particular, if the SPS is designed to have ‘A’ and ‘B’ protection at a single location for redundancy, they must be on different non-adjacent vertical mounting assemblies or enclosures. Also, two independent trip coils are required on breakers that are part of the SPS. The applicant must provide two dedicated communication channels, separated physically and geographically diverse, between the projects and the Bruce NGS.

To disconnect the project from the system for G/R, simultaneous tripping of the 500 kV and 121 kV breakers at Parkhill CTS shall be initiated with no accompanying breaker failure response. After being tripped by the BSPS, the closing of the breakers is not permitted until approval is obtained from the IESO.

Alternative solutions to disconnect the project from the system for G/R may be acceptable upon the approval of the IESO.

The BSPS shall also be expanded to recognize the disconnection of the circuits in the Bruce-to-Longwood corridor. A Facility Description Document (FDD) describing the functionality of the expanded BSPS has to be provided to the IESO by Hydro One in a timely manner to allow for the required approvals of the BSPS to be obtained.

6.3 Reactive Power Compensation

The Market Rules require generators to inject or withdraw reactive power continuously (i.e. dynamically) at a connection point equal to up to 33% of the generator's 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 facility 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 an impedance between the generator and the connection point in excess of 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 compensate for excessive reactive losses in the collector system of the project with static shunts (e.g. capacitors and reactors).

The SIA proposed a solution for the project to meet the Market Rules requirements on reactive power capability. However, the applicant can deploy any other solutions which result in its compliance with the Market Rules. The applicant shall be able to confirm this capability during the commission tests.

Dynamic Reactive Power Capability

The Siemens SWT 2.3 MW WTGs can deliver IESO required dynamic reactive power at rated power and at rated terminal voltage. Thus, there is no need to install additional dynamic reactive power device.

Static Reactive Power Capability

In addition to the dynamic reactive power requirement identified above, the projects have to compensate for the reactive power losses within the projects' network 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 projects.

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

- typical voltage of 545 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 WTG voltage of 1.05 pu;
- main and intermediate level step-up transformer ULTCs are available to adjust the LV voltage as close as possible to 1 pu voltage, while ensuring the intermediate transmission and collector bus voltages within the Nextera system do not exceed 1.05 pu. No voltage limitations for the Cedar Point facility have been specified.

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

- typical voltage of 545 kV at the connection point;
- minimum (zero) active power output from the equivalent WTG;
- reactive power consumption (leading power factor) as required to meet the Market Rules requirement from the equivalent WTG.
- minimum acceptable WTG voltage is 0.9 pu, as per WTG voltage capability;
- main and intermediate level step-up transformer ULTCs are available to adjust the LV voltage as close as possible to 1 pu voltage, while ensuring the intermediate transmission and collector bus voltages within the Nextera system do not fall below 0.95 pu. No voltage limitations for the Cedar Point facility have been specified.

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 important that the project have proper internal design to ensure that the WTGs are not limited in their capability to produce active and reactive power due to terminal voltage limits or other project 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 project in an equal amount.

Based on the equivalent parameters for the wind farm provided by the connection applicant, a static capacitive reactive power compensation rated 120 Mvar at 121 kV is required to be installed at the Parkhill 121 kV bus to meet the reactive power injection requirement at the connection point. No reactor is required to meet the reactive power withdrawal requirement. A detailed summary of the results with reactive power compensation is provided in Table 13.

Table 13: Reactive Power Capability at the PCC

Operation	Intermediate Bus Voltage (kV)	Collector Bus Voltage (kV)	Max/Min Generator Terminal Voltage (pu)	PCC Reactive Power (Mvar)	PCC Voltage (kV)
Lagging PF	125.8	34.4	1.043	+134.0	545 kV
Leading PF	121	34.5	0.90	-203.3	545 kV

The required capacitive compensation will need to be arranged into at least 4 approximately equal steps to allow for flexibility in adjustment of reactive power production. It shall also be implemented as a part of wind farm control system that automatically controls the switching of capacitor banks to regulate the overall WTGs’ reactive output to around zero.

Static Reactive Power Switching

The IESO requires the voltage change on a single capacitor switching to be no more than 4 % at the any point in the IESO Controlled Grid. A switching study was carried out to investigate the effect of the new shunt capacitor banks on the voltage changes. It was assumed that the largest capacitor step size is 30 Mvar. To reflect a reasonably restrictive system condition, the voltage change study was studied under light load conditions and assumed one Bruce to Longwood circuit out of service.

Table 14: Voltage Changes Due to Static Reactive Compensation Switching

Capacitor at 121 kV bus	Parkhill 121 kV voltage	Evergreen SS voltage
Pre-switching	120.2 kV	542.0 kV
Post-switching	122.2 kV	544.1 kV
ΔV	1.7%	0.4%

Table 14 shows that switching a single capacitor of 30 Mvar results in less than 4 % voltage change at the connection point, therefore meeting the Market Rules' requirement.

6.4 Overvoltage Management at Evergreen SS

Due to the long length of Bruce-by Evergreen 500 kV circuit, voltages at Evergreen SS may exceed maximum continuous levels of 550 kV specified by Appendix 4.1 of the Market Rules under certain operating scenarios.

The voltage analysis was carried out under the following assumptions:

- Voltage of 550 kV at Bruce A TS
- Evergreen-by-Longwood circuit out of service
- Cedar Point II, Jericho, Bornish and Adelaide WTGs off line with their proposed collector systems disconnected
- Parkhill CTS and Bornish TS remaining connected to Evergreen SS

Table 15: Voltage Analysis Results at Evergreen SS

Bus	Voltage with Evergreen-by-Longwood circuit out of service
Evergreen SS 500kV	561 kV

Table 15 shows the simulation results which indicate that the voltage at Evergreen SS could be as high as 561 kV. To manage the high voltage concern at Evergreen SS, Hydro One and the connection applicant have proposed to install higher rated equipments that a maximum continuous voltage of at least 570 kV can be sustained. This solution is acceptable to the IESO.

Thus, 500kV equipment at Evergreen SS and the project must be able to sustain a maximum continuous voltage of 561 kV as per the study results. The connection applicant shall also ensure that the equipments within the project have the capability to operate when the voltage at Evergreen SS is as high as 561 kV. Fault interrupting device at Evergreen SS and the project must be able to interrupt fault currents at voltages as high as 561 kV.

Alternate solutions to manage high voltage concern may also be acceptable upon the approval of the IESO.

6.5 Wind Farm Voltage Control System

As per the Market Rules requirements, the wind farms shall operate in voltage control mode by using all voltage control methods available within the projects. The automatic voltage regulation philosophy for the projects is summarized as follows:

(1) All WTGs control the voltage at a point whose impedance (based on rated apparent power and voltage of the projects) 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.

(2) Capacitor banks are automatically switched in/out to regulate the overall WTGs' reactive generation to around zero output. The dead band for capacitor switching will be set to about ±60% size of the smallest capacitor to avoid control hunting.

(3) The main transformer ULTC is adjusted, manually or automatically, to regulate the collector bus voltage such that it is within normal range and close to about 1 pu. The IESO may require automatic control for this ULTC if manual adjustment is too slow.

In this control system, the voltage control by WTGs and the overall WTGs' reactive control by capacitor banks need to be coordinated by using different time constants.

In the event that the wind farm voltage control becomes unavailable, the IESO requires that each WTG operate 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

The *Ontario Resource and Transmission Assessment Criteria* requires 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 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 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 conductors were calculated at the sag temperature, with a 35^{o}C ambient temperature, 4 km/h wind speed and 100% continuous pre-load.

System Overview

The return of Bruce G1 and G2 combined with the addition of new Bruce and Southwest Ontario generation results in a higher flow eastward from Bruce. This naturally increases the flow along the 115 kV path of circuit S2S from Owen Sound TS to Stayner TS when circuit S2S is operated closed-loop. Table 16 shows the pre-contingency thermal results with S2S operated closed-loop under the defined shoulder load condition. It indicates the overloading of both circuit S2S from Meaford TS to Stayner TS and Stayner T1. To prevent the thermal overloading, circuit S2S will be required to operate open-loop under certain conditions after the integration of the committed generation projects in the area of Bruce and Southwest Ontario. Hydro One has investigated this mitigating action and is in agreement with it.

Table 16: Pre-Contingency Thermal Results w/ S2S Closed-Loop Under Shoulder Load Conditions

Circuit	Pre-Contingency Flow	Summer Continuous Rating	Loading (%)
S2S (Meaford-Stayner)	650 A	590 A	**110**
Stayner T1	136 MVA	125 MVA	**109**

Due to the fact that the opening of circuit S2S results in increased flows on the parallel 230 kV and 500 kV circuits emanating from Bruce, circuit S2S was assumed open-loop at Owen Sound for the rest of the SIA studies in this report.

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 6913 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 17 and Table 18 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. Additional simulation results based on the defined shoulder load basecase show post-contingency overloading on circuits E8V/E9V for the loss of the companion circuit. If flows were to reach these high levels, the generating plants in the Bruce and Southwest Ontario may be required to curtail their outputs.

Table 17: Thermal Results of Limiting Circuits in the Central Area Under Peak-Load Conditions

Circuit	Contingency	Pre-Cont. Flow (A)	Continuous Rating (A)*	Pre-Cont. Loading (%)	Post-Cont. Flow (A)	LTE Rating (A) **	Post-Cont. Loading (%)
R14T (Trafalgar-Erindale)	R17T	1059	1110	95	1577	1460	108
R17T (Trafalgar-Erindale)	R14T	1063	1110	96	1576	1460	108
R19TH (Erindale-Hanlan)	R14T+R17T	792	840	94	1131	1090	107

Table 18: Thermal Results of Limiting Transformers in the 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 500 kV Area Overview

The effects of the project on the thermal loadings of the 500kV transmission system in the Bruce area were examined. The peak-load basecase was used for thermal analysis due to the high flows out of the Bruce Area. Preliminary simulation results show the incorporation of the projects primarily increase flow on the 500 kV circuits emanating from Bruce TS and Longwood TS. This reduces the loading on 500 kV auto-transformers at Bruce A TS and Longwood TS and marginally increases the flow on 230 kV corridors from Bruce/Longwood to the GTA area. Therefore, only the 500 kV circuits were examined to assess the primary thermal impact of the projects.

Table 19: Circuit Ratings

Circuit	From	To	Continuous Rating (A)	LTE Rating (A)
B560V	Bruce A TS	Claireville TS	2820	3620
B561M	Bruce B TS	Milton TS	2820	3620
B501M	Bruce B TS	Milton TS	2820	3660
B502M	Bruce A TS	Milton TS	2820	3660
B562E	Bruce A TS	Evergreen SS	2820	3660
E562L	Evergreen SS	Longwood TS	2820	3660
B563A	Bruce B TS	Ashfield SS	2820	3660
A563L	Ashfield SS	Longwood TS	2820	3660
N582L	Nanticoke TS	Longwood TS	2820	3660

Pre-contingency thermal loadings of 500 kV circuits are shown in Table 20. It shows that there is no pre-contingency equipment overloading.

Table 20: Pre-Contingency Thermal Assessment Results – Circuits

Circuit	Circuit Loading Pre-Contingency (A)	Summer Continuous Rating (A)	Percent of Continuous Rating (%)
B560V	1514	2820	53.69
B561M	1533	2820	54.36
B501M	1527	2820	54.15
B502M	1513	2820	53.65
B562E	134	2820	4.75
E562L	453	2820	16.06
B563A	60	2820	2.13
A563L	279	2820	9.89
N582L	1348	2820	47.80

The following contingencies were simulated for the circuit thermal analysis:

(1) **Simultaneous loss of 500 kV circuits B560V and B561M:** 500 kV circuits B560V and B561M are main arteries out of the Bruce Area. The loss of these circuits results in higher transfers on the remaining circuits emanating from Bruce area.

(2) **Simultaneous loss of 500 kV circuits E562L and A563L:** This loss results in the projects and K2 generating radially onto the Bruce 500 kV system, resulting in a higher flow emanating from Bruce TS.

Post-contingency circuit loading results are summarized in Table 21. The results show that there is no post-contingency thermal concern on the 500 kV circuits and that the project does not introduce any thermal constraints.

Table 21: Post-Contingency Thermal Assessment Results – Circuits

Circuit	Circuit Loading Pre-Contingency (A)	Summer Continuous Rating (A)	Percent of Continuous Rating (%)	Long Term Emergency Rating (A)	Loss of B560V+B561M		Loss of E562L+A563L	
					Circuit Loading Post (A)	% of LTE	Circuit Loading Post (A)	% of LTE
B560V	1514	2820	53.69	3620	0	0.00	1659	45.83
B561M	1533	2820	54.36	3620	0	0.00	1693	46.77
B501M	1527	2820	54.15	3660	2528	69.07	1685	46.04
B502M	1513	2820	53.65	3660	2510	68.58	1672	45.68
B562E	134	2820	4.75	3660	479	13.09	385	10.52
E562L	453	2820	16.06	3660	829	22.65	0	0.00
B563A	60	2820	2.13	3660	393	10.74	280	7.65
A563L	279	2820	9.89	3660	675	18.44	0	0.00
N582L	1348	2820	47.80	3660	1859	50.79	938	25.63

6.7 Voltage Analysis

The *Ontario Resource and Transmission Assessment Criteria (ORTAC)* states that with all facilities in service pre-contingency, the following criteria shall be satisfied:

- The pre-contingency voltages on 500 kV buses must not exceed 550 kV or be less than 490 kV and voltages on 230 kV buses cannot exceed 250 kV be less than 220 kV;
- The post-contingency voltages on 500 kV buses must not exceed 550 kV or be less than 470 kV and voltages on 230 kV buses cannot exceed 250 kV be less than 207 kV;
- 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 changes remain within criteria at various facilities.

The following two contingencies were simulated:

(1) **Simultaneous loss of 500 kV circuits B560V and B561M:** 500 kV circuits B560V and B561M are main arteries of the FETT interface which feeds the load centre in the GTA. This contingency is the most severe contingency for the voltage profile. The contingency was simulated assuming automatic switching of the Bruce and Longwood reactors post-contingency. The defined peak load case was used.

(2) **Loss of the Parkhill 500/121 kV Transformer:** Using the defined light load case, the loss of the main 500/121 kV Parkhill transformer was assessed. The study was conducted assuming Cedar Point II Wind Project and Bornish, Adelaide, Jericho Wind Energy Centres were in-service and absorbing reactive power close to their maximum capability pre-contingency. As generating stations help control voltages pre-contingency, the simultaneous loss by configuration of these wind farms may result in significant voltage changes post-contingency.

The study results summarized in Table 22 and Table 23 indicate that voltages at Evergreen SS can rise above 550 kV for the loss of the entire 500/121 kV network. This concern can be mitigated by installing higher rated equipments as outlined in section 6.4.

Table 22: Voltage Analysis for Peak Load Case

Monitored Busses		Pre-Cont Voltage kV	Loss of B560V + B561M			
Bus Name	Base kV		Pre-ULTC		Post-ULTC	
			kV	%	kV	%
Longwood TS	500	545.6	540.3	-1	543.6	-0.4
Bruce A TS	500	548.3	547.5	-0.1	547.9	-0.1
Bruce B SS	500	549	549	0	549	0
Evergreen SS	500	546.8	542.2	-0.8	544.8	-0.4
Milton SS	500	528.9	501.8	-5.1	510.4	-3.5
Claireville TS	500	526.7	503.6	-4.4	512.7	-2.7
Bruce A TS	230	247.3	246.8	-0.2	247.4	0
Longwood TS	230	245	244.9	0	246.6	0.7

Table 23: Voltage Analysis for Light Load Case

Monitored Busses		Pre-Cont Voltage kV	Loss of the projects' network with maximum var withdrawal			
Bus Name	Base kV		Pre-ULTC		Post-ULTC	
			kV	%	kV	%
Longwood TS	500	543.4	549.6	1.1	549.6	1.1
Bruce A TS	500	547.6	547.7	0	547.7	0
Bruce B SS	500	548.5	548.5	0	548.5	0
Evergreen SS	500	542.7	551.3	1.6	551.3	1.6
Bruce A TS	230	247.4	247.6	0.1	247.6	0.1
Longwood TS	230	245.3	247.6	0.9	247.6	0.9

6.8 Steady State Voltage Stability

The *Ontario Resource and Transmission Assessment Criteria (ORTAC)* states that the maximum acceptable pre-contingency power transfer must be 10% lower than the voltage instability point of the pre-contingency P-V curve, and 5% lower than the voltage instability point of the post-contingency P-V curve.

The voltage performance of the IESO-controlled grid was evaluated by examining if the FABC transfer after the incorporation of the project meets the above requirement based on pre- and post-contingency and post-contingency P-V curves under peak load conditions. The contingency of simultaneous loss of B560V+561M was selected for studying the post-contingency steady-state voltage stability as it is the worst-case contingency in terms of system voltage stability. For this recognized contingency, two post-contingency scenarios, either tripping the reactors at Bruce and Longwood or no tripping of these reactors are investigated. Only the voltage responses at Claireville 500kV were recorded as it is the most critical point in the system in terms of system voltage stability performance.

Figure 3, Appendix A shows the steady-state voltage responses at Claireville 500kV as the FABC transfer increases under the pre-contingency scenario and two post-contingency scenarios. It indicates that the maximum FABC transfer under the pre-contingency scenario, post-contingency reactor tripping scenario, and post-contingency no reactor tripping scenario are 8748 MW, 7256 MW, and 6766 MW, respectively. The pre-contingency FABC transfer is 6412 MW. Thus, the pre-contingency FABC transfer is 10% lower than the voltage instability point of the pre-contingency P-V curve, and 5% lower than the voltage instability point of the post-contingency P-V curve, under either reactor tripping or no reactor tripping scenario. It can be concluded that the steady-state voltage stability of the system after the incorporation of the project conforms to the Market Rules' requirement.

6.9 Transient Stability Performance

Transient stability simulations were performed to determine if the power system can be transiently stable for recognized fault conditions. In particular, rotor angles of generators at Bruce GS, Darlington GS, Pickering GS and Greenfield GS were monitored. Simulations were performed under both the peak and shoulder load conditions, however only results for the peak load condition are provided as the flows out of the Bruce Area were higher representing the more critical case for transient stability performance.

Transient stability analyses were performed considering recognized faults in Southwest Ontario. Four contingencies were simulated as shown in Table 24.

The simultaneous loss of B560V and B561M was simulated since it is the worst contingency in terms of the transient stability of Bruce generating units and GTA voltage stability.

The simultaneous loss of B563A and B562E was simulated since it results in having the projects and K2 wind farm radially connected to Longwood TS, to evaluate the transient stability performance of the West area.

The simultaneous loss of A563L and E562L was simulated since it results in having the projects and K2 wind farm radially connected to Bruce TS, to evaluate the transient stability performance of Bruce generating units.

Finally, an un-cleared 3-phase fault at the Parkhill 121 kV bus was simulated to ensure that the failure of the projects' internal protections does not adversely impact the stability of the IESO controlled grid.

Table 24: Simulated Contingencies for Transient Stability Analysis

Contingency	Location	Fault Type	Fault Clearing Time (ms)		B/L RSS* (ms)	Reclosure Time	Reclosure Location
			Local	Remote			
B560V+B561M	Bruce	LLG	66	91	124	10s for B560V 15s for B561M	Claireville Milton
B563A + B562E	Bruce	LLG	66	91	-	10s	Ashfield Evergreen
A563L + E562L	Longwood	LLG	75	100	-	10s	Longwood
LV side of main step-up transformer	Parkhill 121 kV	3 phase	Un-cleared		-	-	-

*B/L RSS denotes the Bruce and Longwood Reactor Switching Schemes

Figure 4 to Figure 7, Appendix A show the transient responses of 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 none of the simulated contingencies causes transient instability or un-damped oscillations.

It can be also concluded that the protection changes proposed in the PIA report do not have materially adverse impact on the transient stability of the IESO-controlled grid.

6.10 Voltage Ride-Through Capability

The IESO requires that the wind turbine generators and associated equipment within the projects 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 Siemens SWT WTGs to be installed have VRT capability. The VRT capability of the wind turbines is shown in Table 2.

The VRT capability of the WTGs was assessed based on the terminal voltages of the WTGs under simulated contingencies in Table 25. These contingencies result in the lowest transient voltages at the projects.

Table 25: Simulated Contingencies for VRT Analysis

Contingency	Location	Fault Type	Fault Clearing Time (ms)	
			Local	Remote
E562L	Evergreen SS	3 phase	66	100
Bruce T27 w/ EL560 BKF	Bruce A 500 kV	3 phase	194 (500 kV) 98 (230 & 27.6 kV)	269 (Claireville)
Longwood T7 w/ KL582 BKF	Longwood 500 kV	3 phase	203 (500 kV) 90 (230 kV) 98 (27.6 kV)	278 (Nanticoke)

Note: 3 phase faults with breaker fail have been simulated in place of line to ground (LG) faults with breaker fail, as this represents a more conservative and more severe fault than recognized by the IESO. If voltage ride through is adequate for a three phase fault, then voltage ride through for a LG fault will also be adequate

Figure 8¸ Appendix A shows the terminal voltage response of the Siemens SWT WTGs. It shows that the terminal voltages of the WTGs dip, in the worst case, to approximately 0.3 pu and remain below 0.6 pu for about 300 ms, and recover thereafter. As compared with the VRT capability of the Siemens SWT model, 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 out of zone faults, 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 either providing manufacturer test results or monitoring several variables under a set of IESO specified field tests and the results should be verifiable using the PSS/E model.

6.11 Relay Margin

The Market Manual 7.4 Appendix B.3.2 requires that, following fault clearance or the loss of an element without a fault, the margin on all instantaneous and timed distance relays that affect the integrity of the IESO-controlled grid, including generator loss of excitation and out-of-step relaying at major generating stations, must be at least 20 and 10 percent, respectively.

Relay margin analysis was performed to determine if circuits B562E or E562L will trip for out of zone faults due to the incorporation of the projects. The shoulder load basecase was used as it had the highest transfers on the Bruce-by-Longwood circuits. Simulations were performed with the projects in-service and out of service, however, only results for the in-service case are provided as varying the project status had minimal impact. The contingencies listed in Table 26 were simulated with the results shown in Figure 9 to Figure 20, Appendix A.

Table 26: Simulated Contingencies for Relay Margin Analysis

Contingency	Location	Fault Type	Fault Clearing Time (ms)		B/L RSS* (ms)	Reclosure Time	Reclosure Location
			Local	Remote			
B560V+B561M	Bruce	LLG	66	91	124	10s for B560V 15s for B561M	Claireville Milton
A563L	Longwood	3 phase	75	100	-	10s	Longwood
B563A	Bruce	3 phase	66	91	-	10s	Ashfield

*B/L RSS denotes the Bruce and Longwood Reactor Switching Schemes

The relay margin plots shown in Appendix A show that the impedance trajectories at both ends of circuits B562E and E562L do not penetrate the relay characteristics and have a margin of greater than 20%, thereby meeting the Market Manual requirement.

It can be also concluded that the protection adjustments proposed in the PIA report have no material adverse impact on the IESO-controlled grid with respect to relay margins.

-End of Section-

Appendix A: Figures

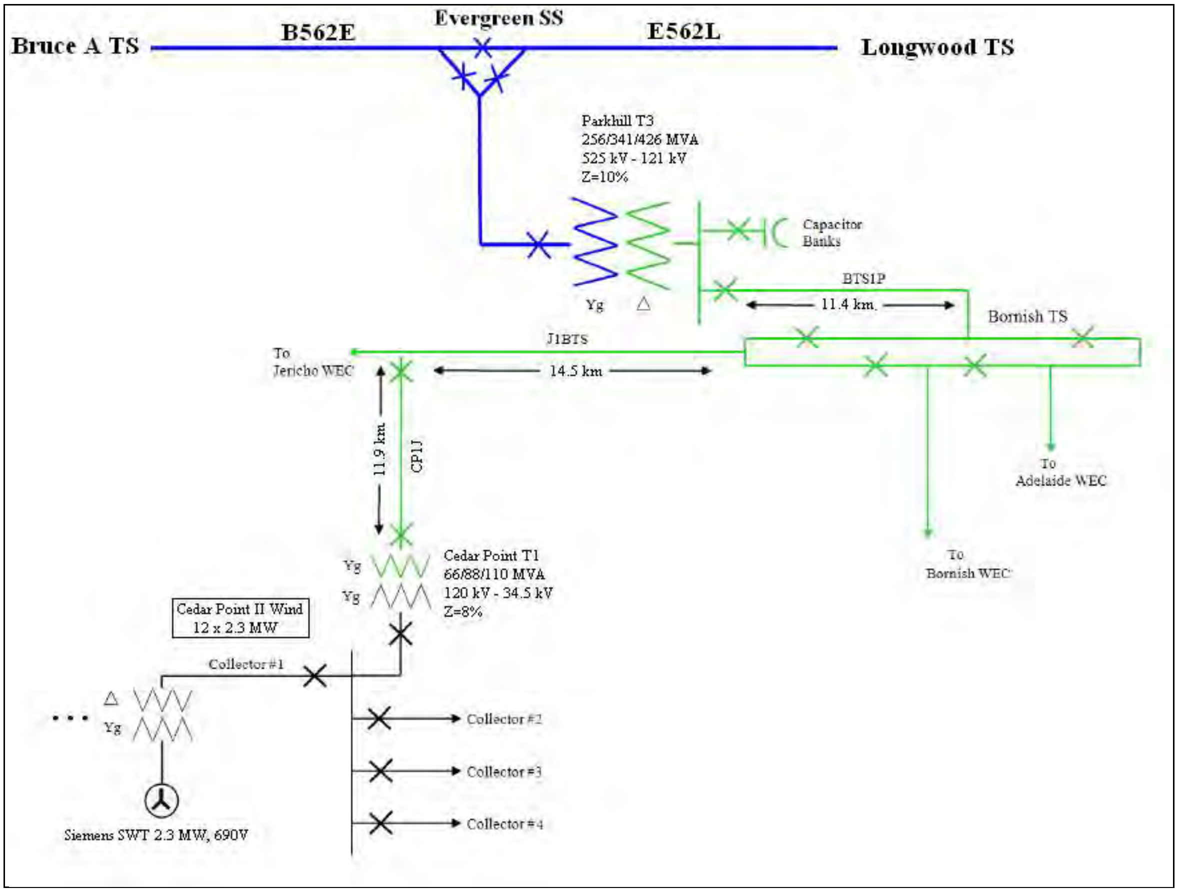


Figure 1: Cedar Point II Wind Power Project Single Line Diagram

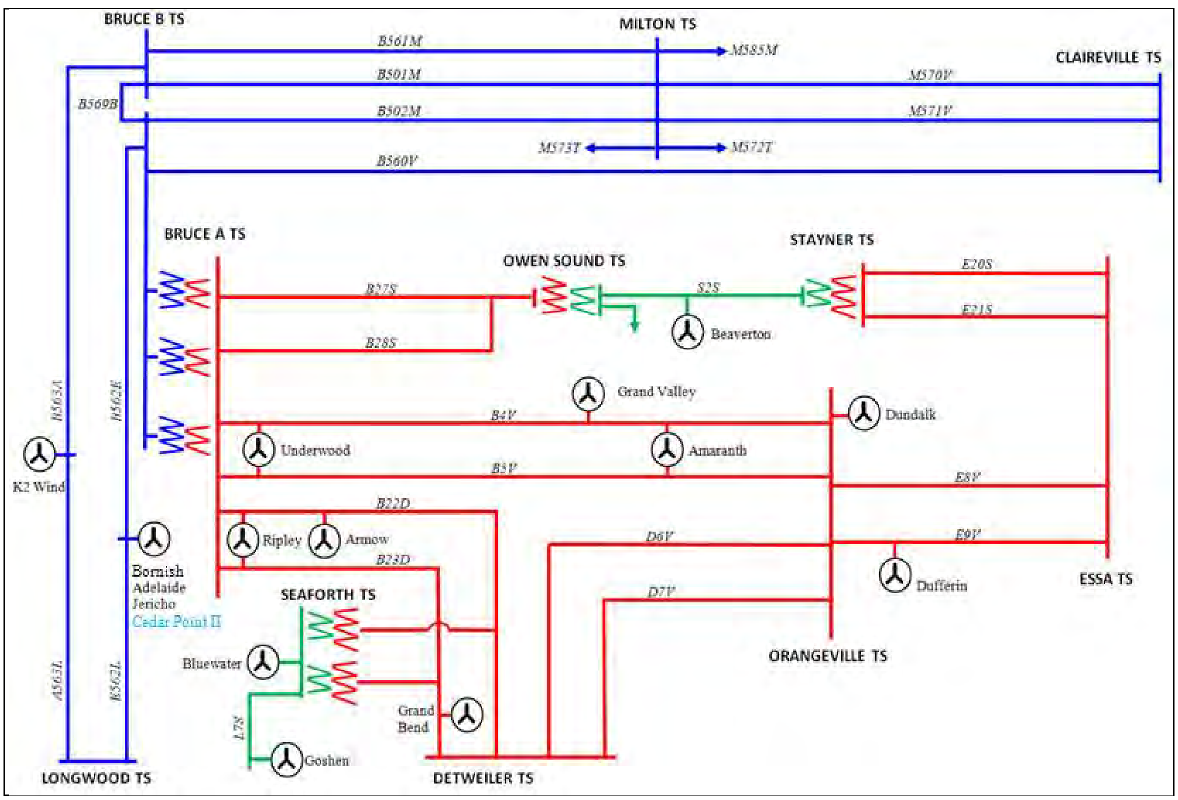


Figure 2: Location of Cedar Point II Wind Project

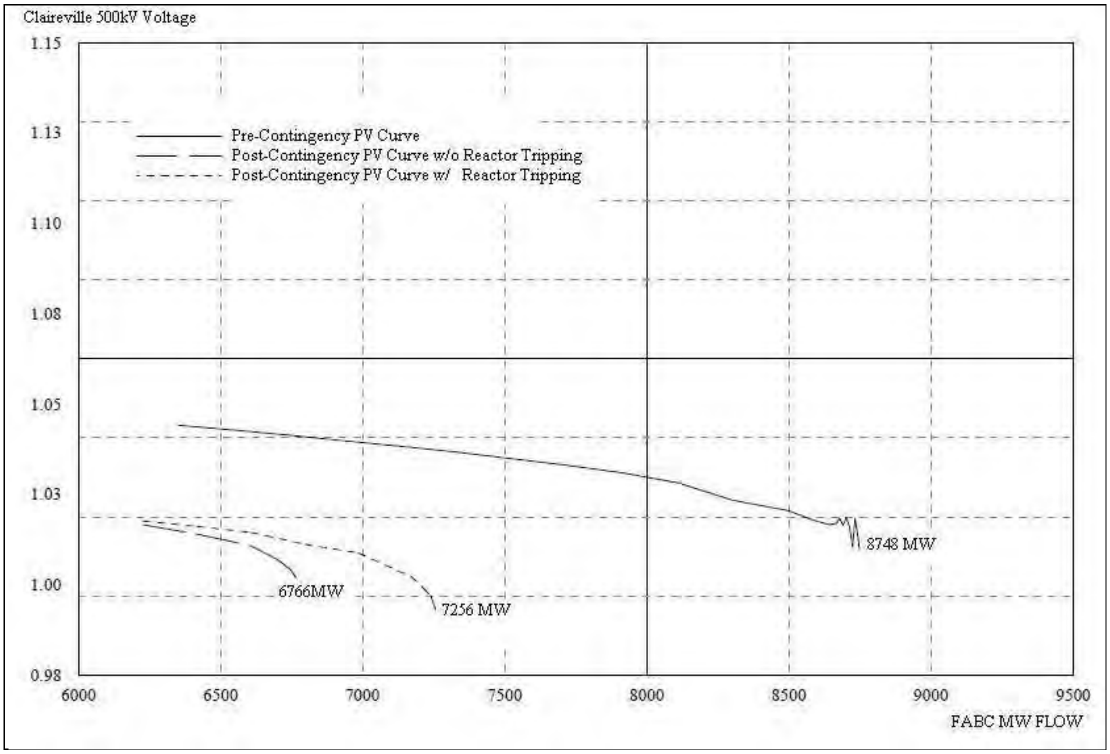


Figure 3: Voltage performance at Claireville 500kV vs. FABC transfer

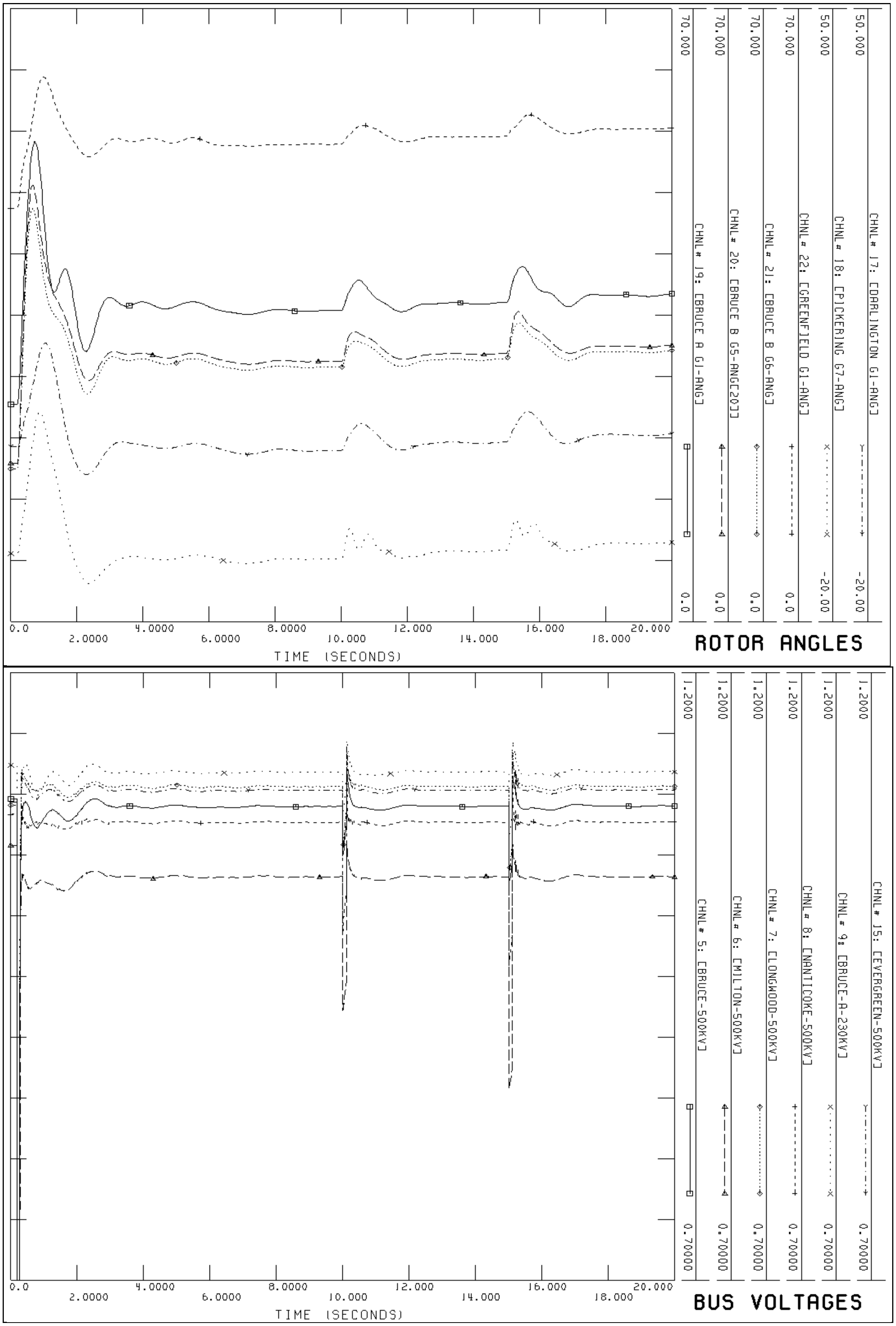


Figure 4: B560V & B561M – LLG fault @ Willow Creek Junction with reclosure

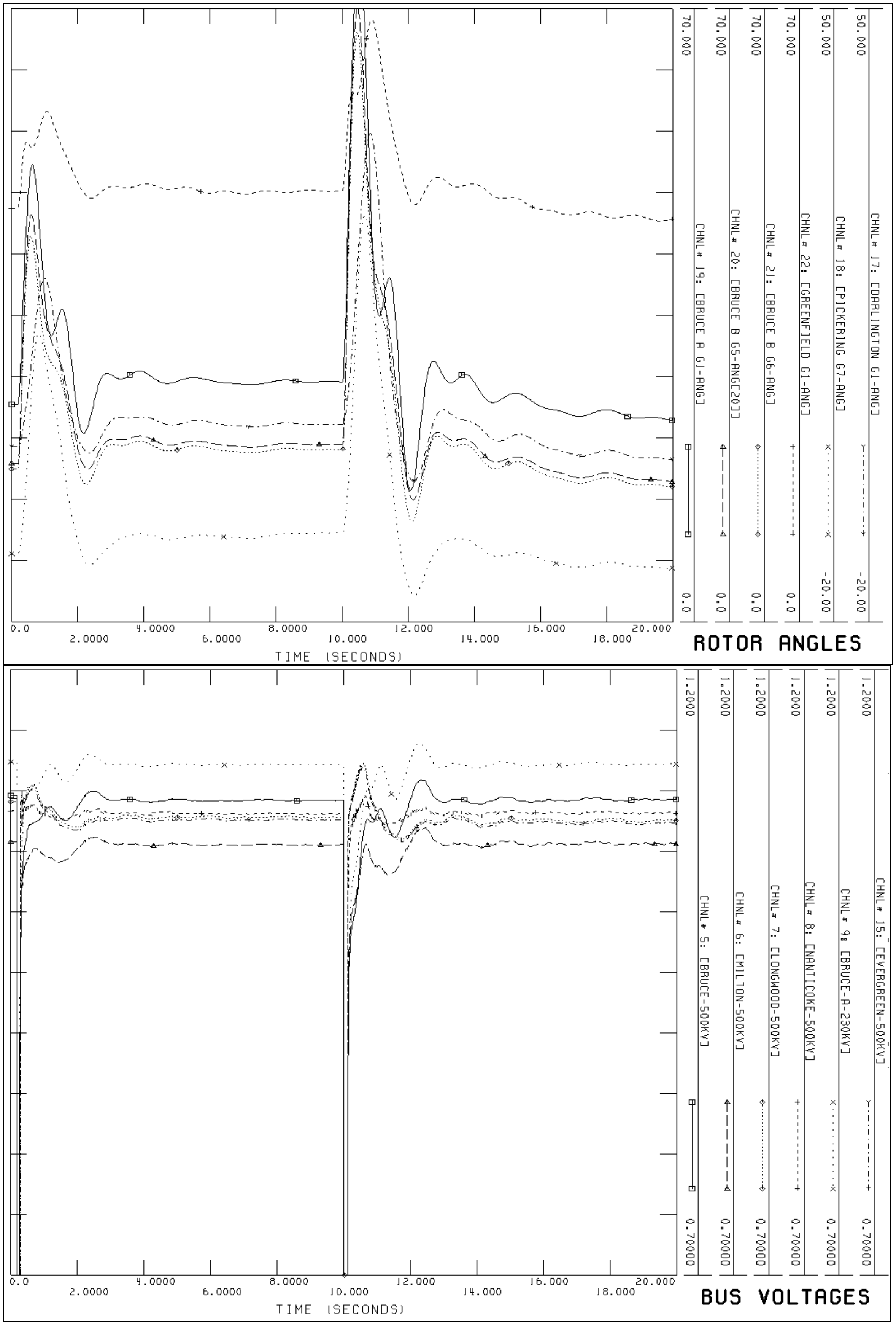
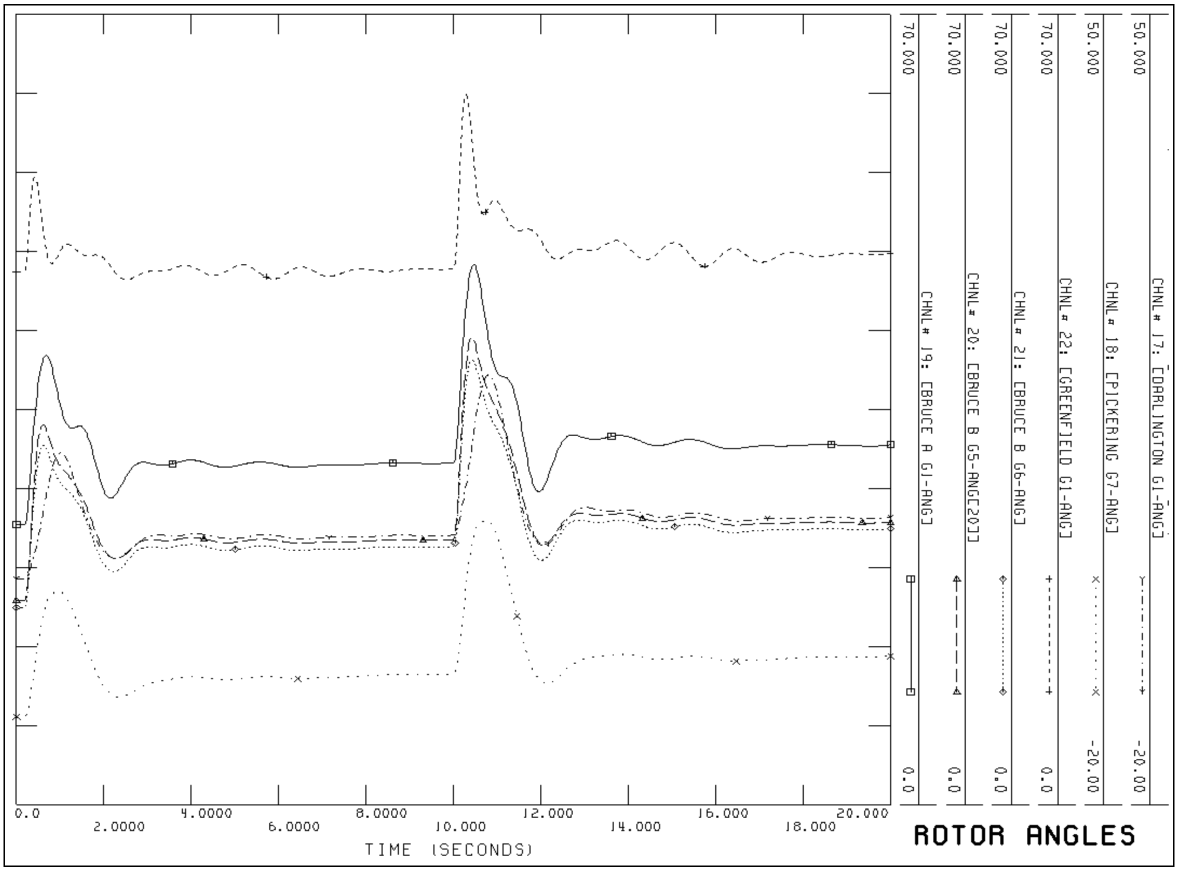


Figure 5: B562E & B563A – LLG fault @ Bruce with reclosure



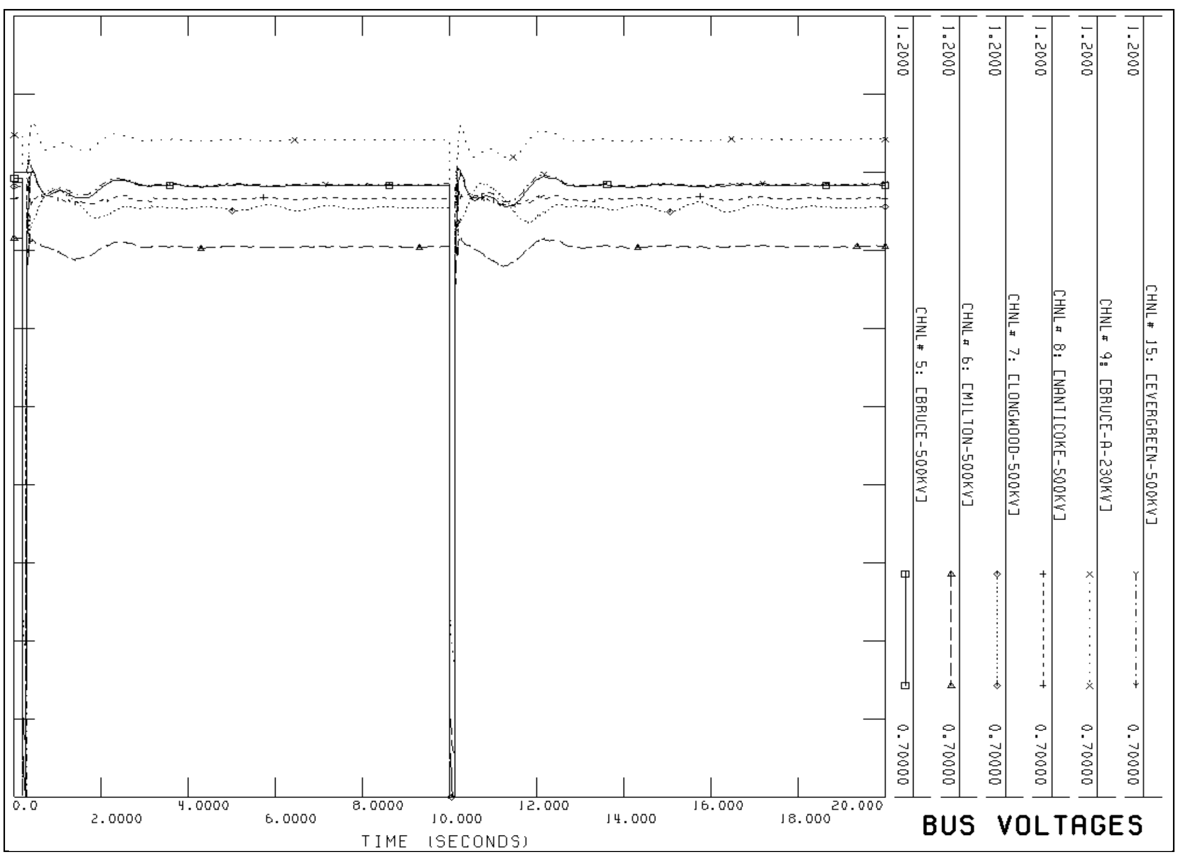


Figure 6: A563L & E562L – LLG fault @ Longwood with reclosure

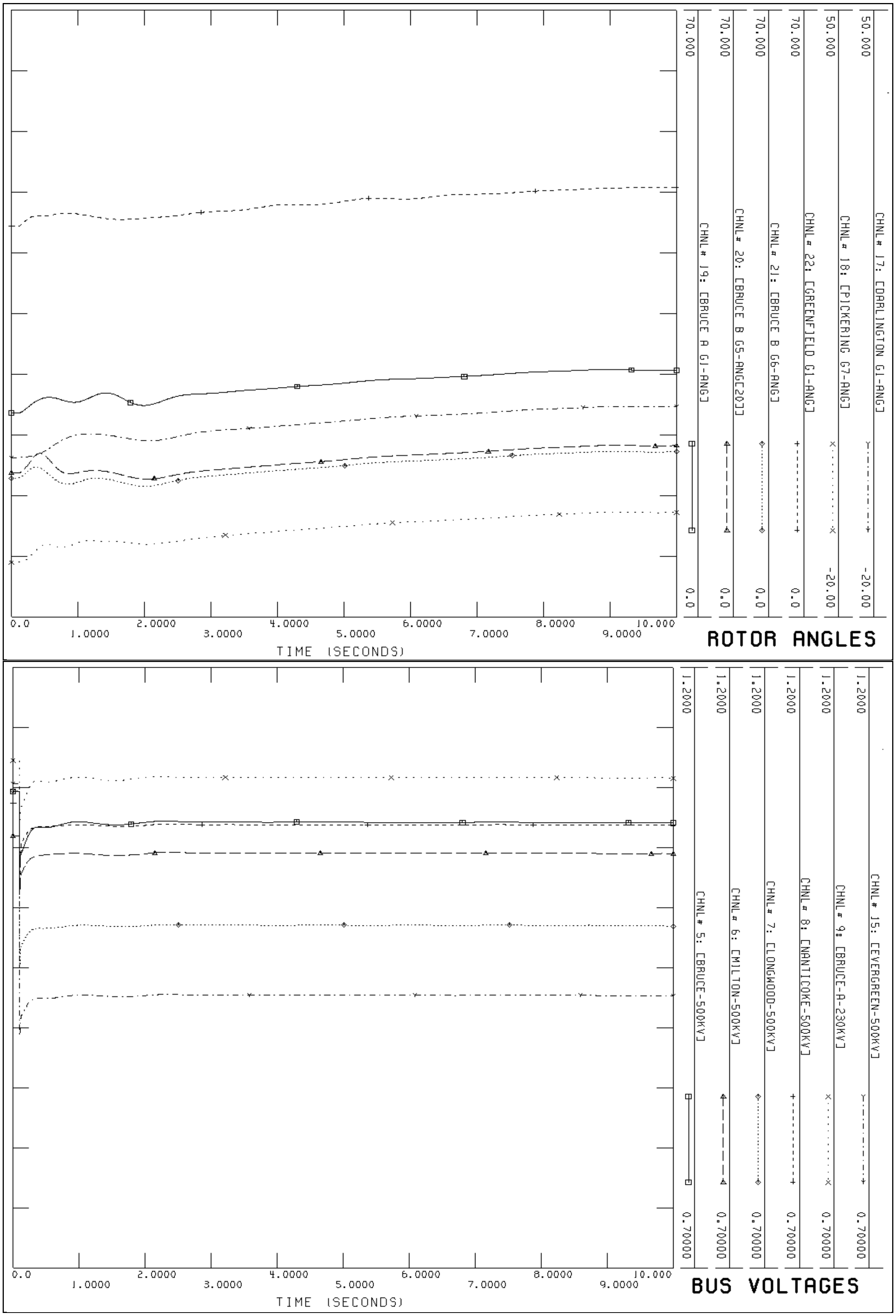


Figure 7: Parkhill 121 kV - Un-cleared 3 phase fault

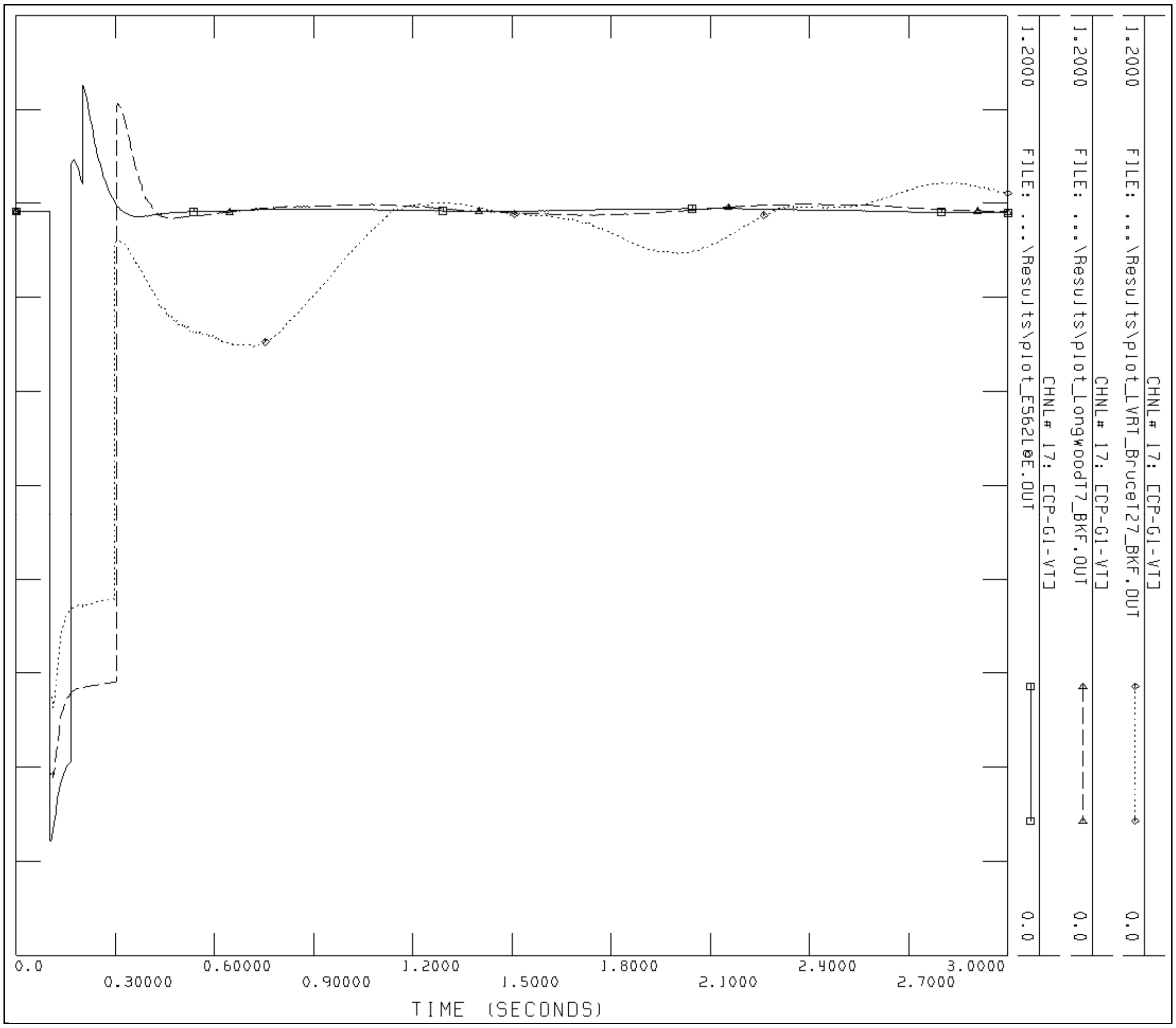


Figure 8: WTG terminal voltages of feeder C1 for studied contingencies

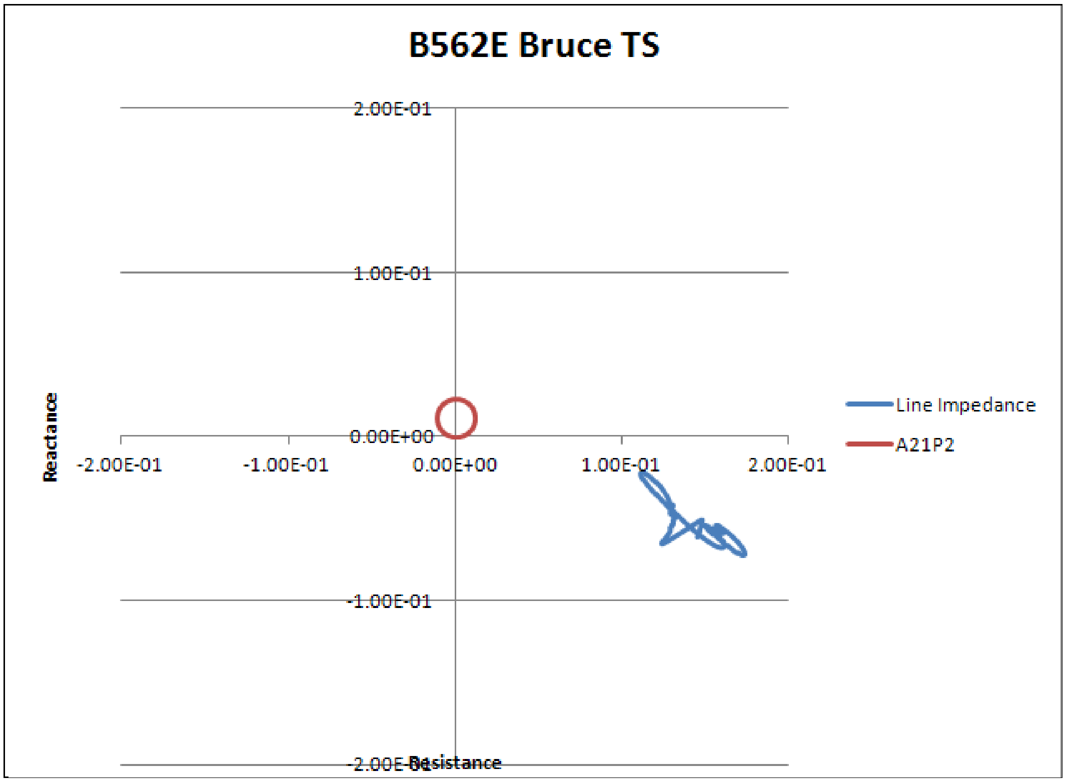


Figure 9: B562E @ Bruce trajectory for a LLG fault on B560V and B561M at Willow Creek Junction

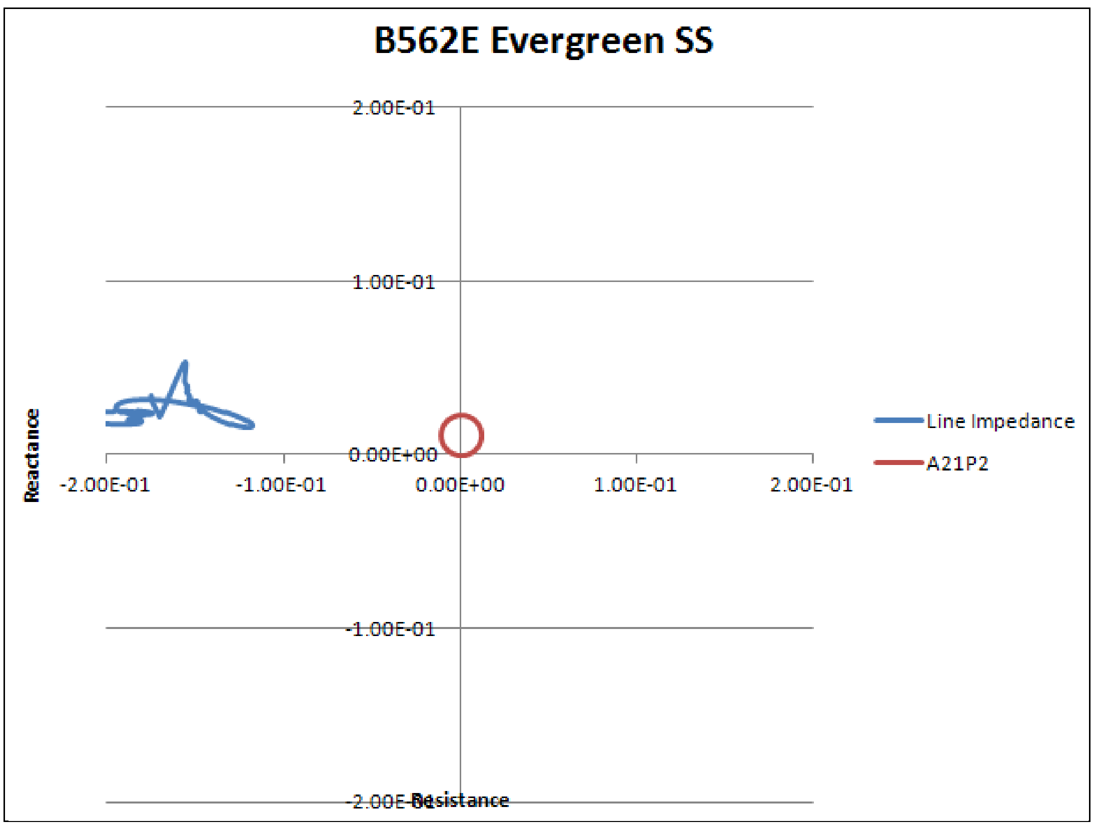


Figure 10: B562E @ Evergreen trajectory for a LLG fault on B560V and B561M at Willow Creek Junction

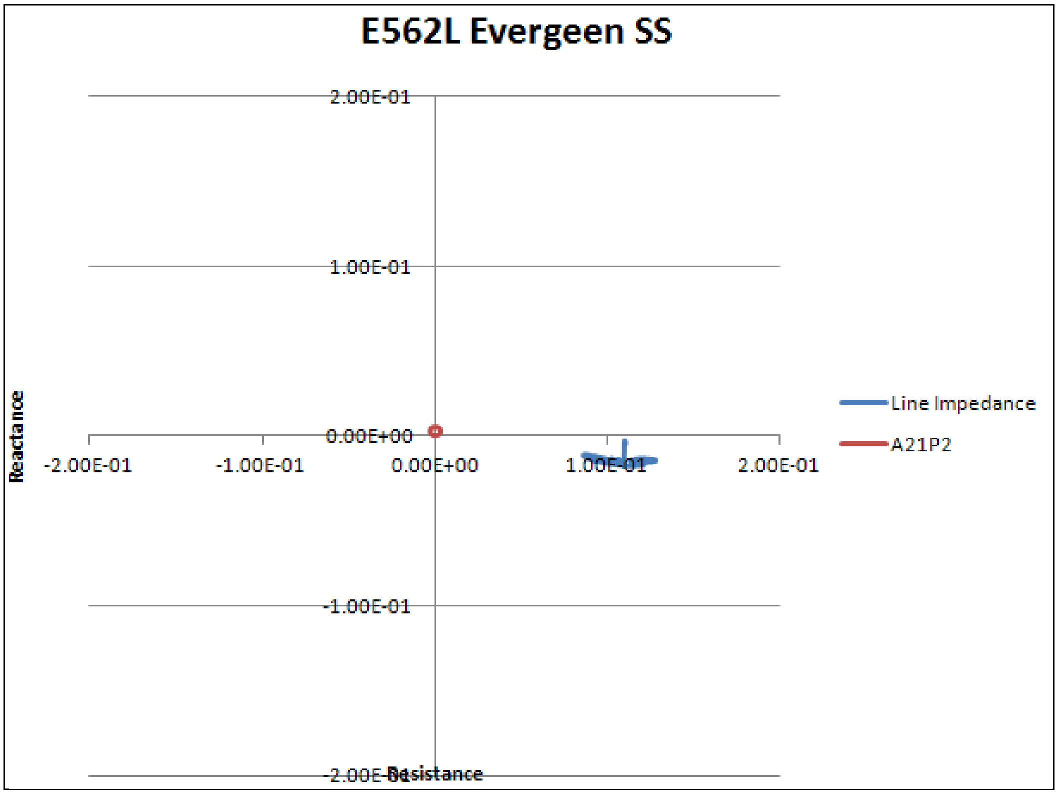


Figure 11: E562L @ Evergreen trajectory for a LLG fault on B560V and B561M at Willow Creek Junction

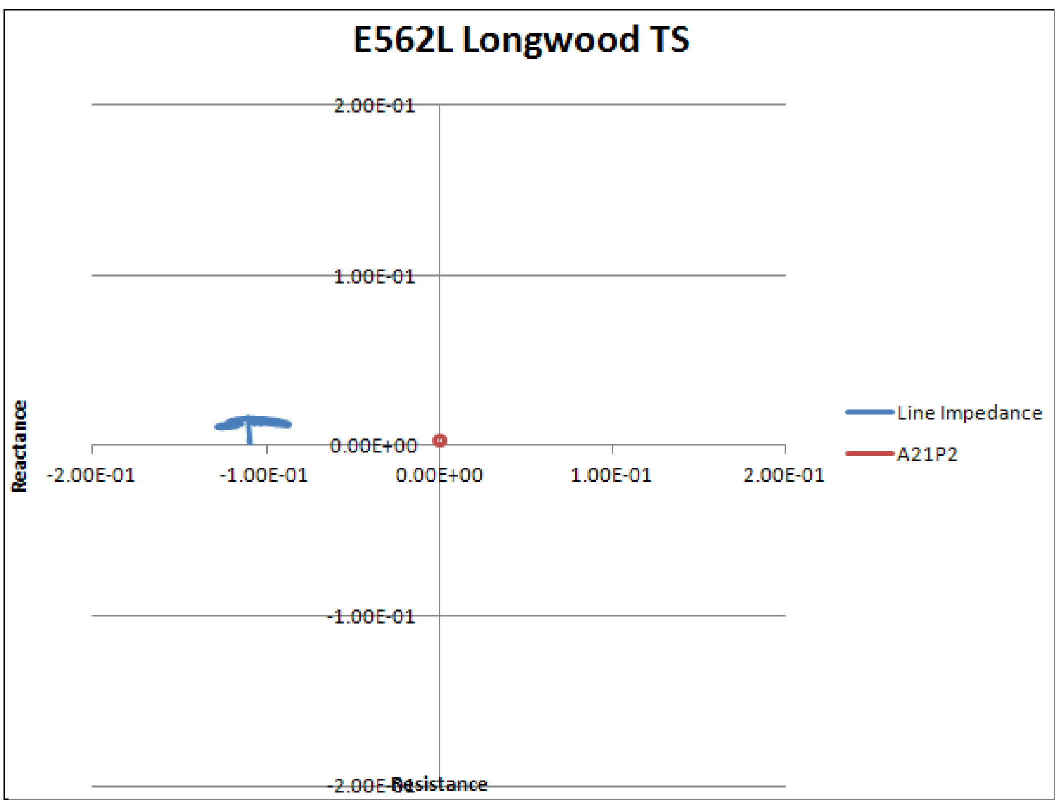


Figure 12: E562L @ Longwood trajectory for a LLG fault on B560V and B561M at Willow Creek Junction

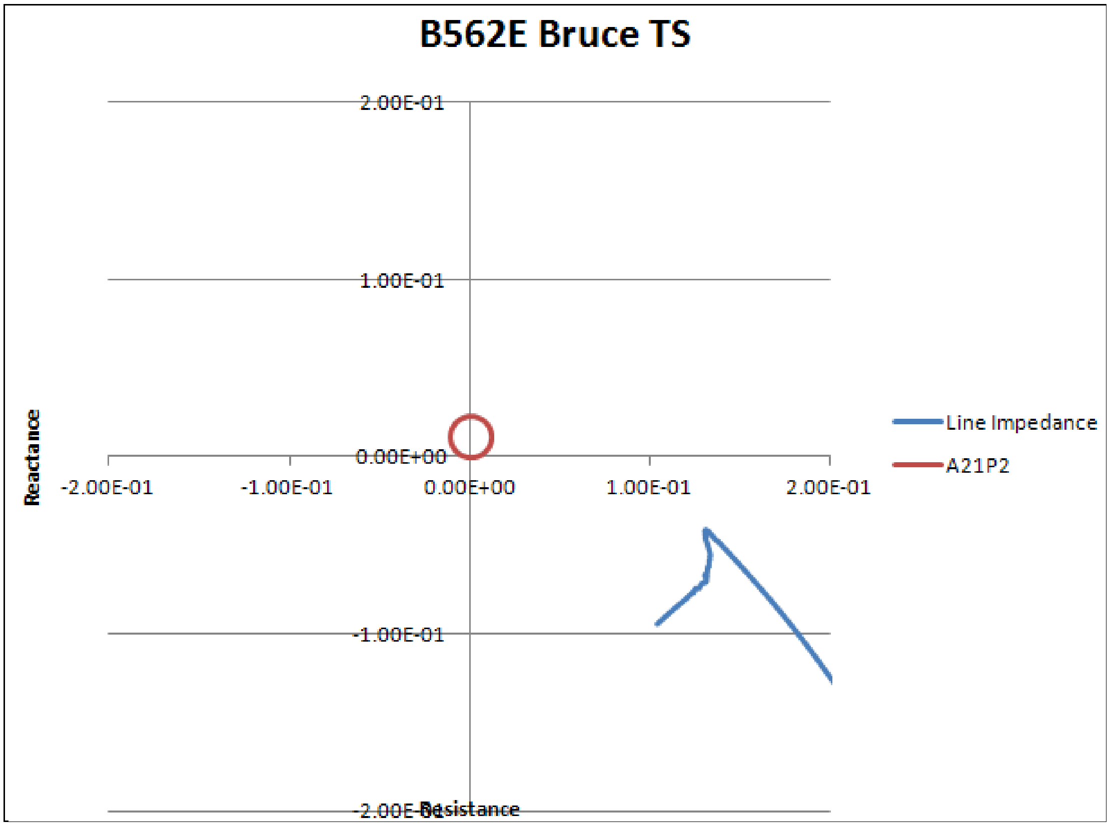


Figure 13: B562E @ Bruce trajectory for a 3 phase fault on B563A at Bruce

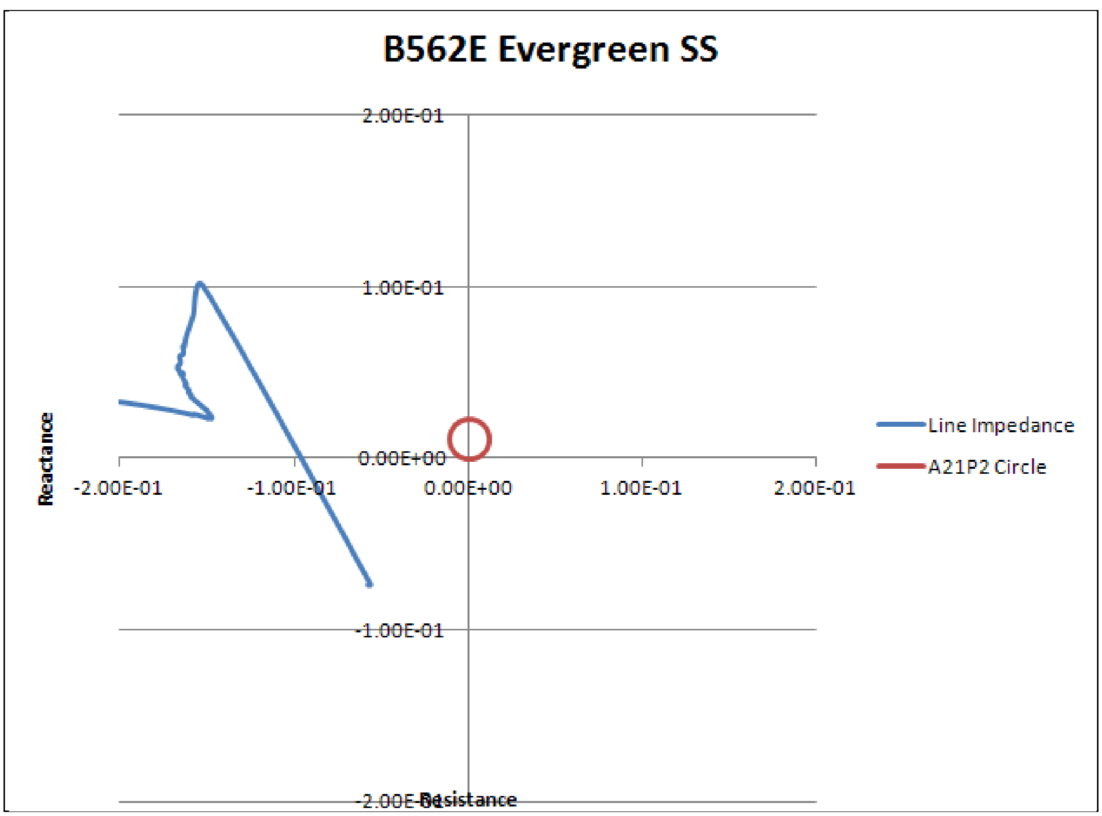


Figure 14: B562E @ Evergreen trajectory for a 3 phase fault on B563A at Bruce

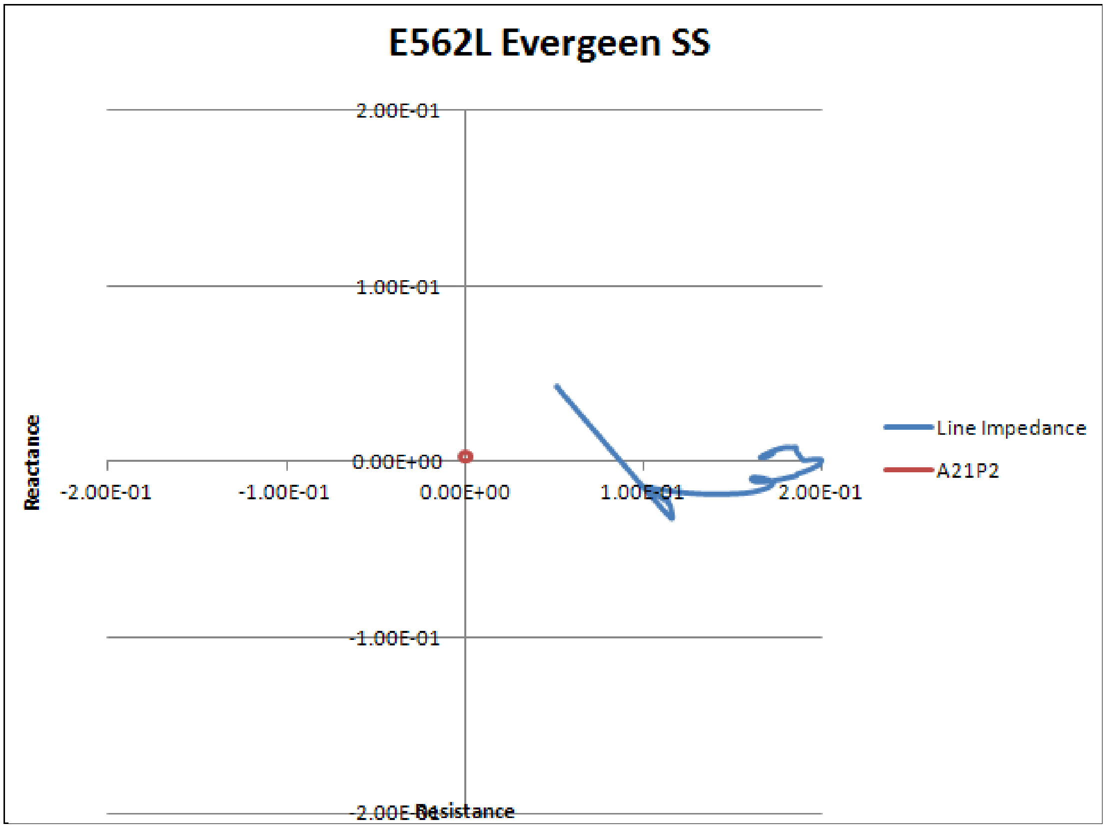


Figure 15: E562L @ Evergreen trajectory for a 3 phase fault on B563A at Bruce

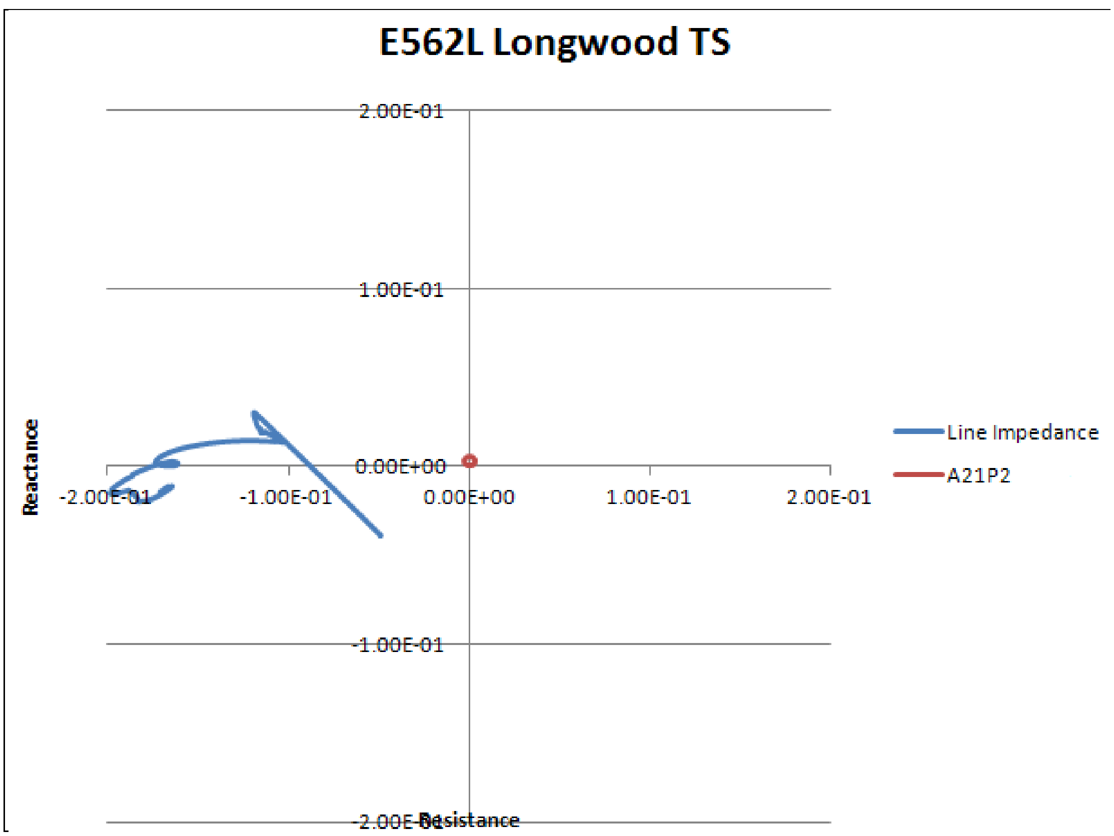


Figure 16: E562L @ Longwood trajectory for a 3 phase fault on B563A at Bruce

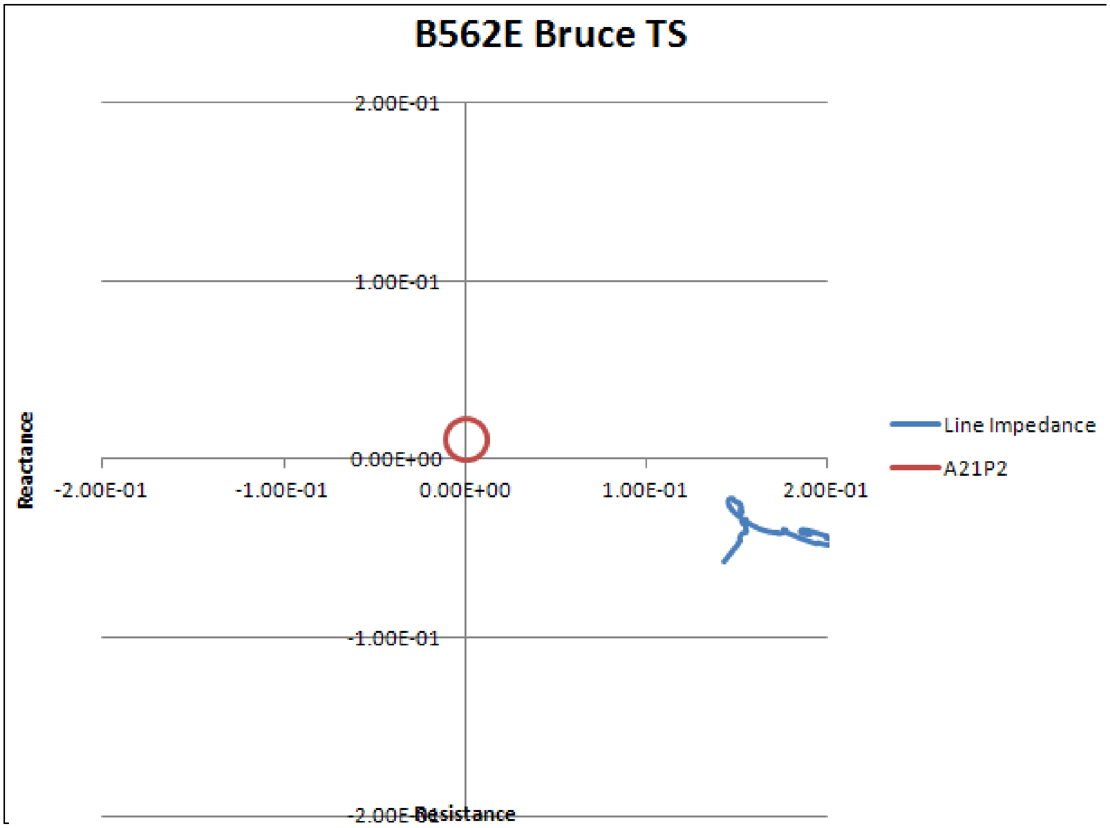


Figure 17: B562E @ Bruce trajectory for a 3 phase fault on A563L at Longwood

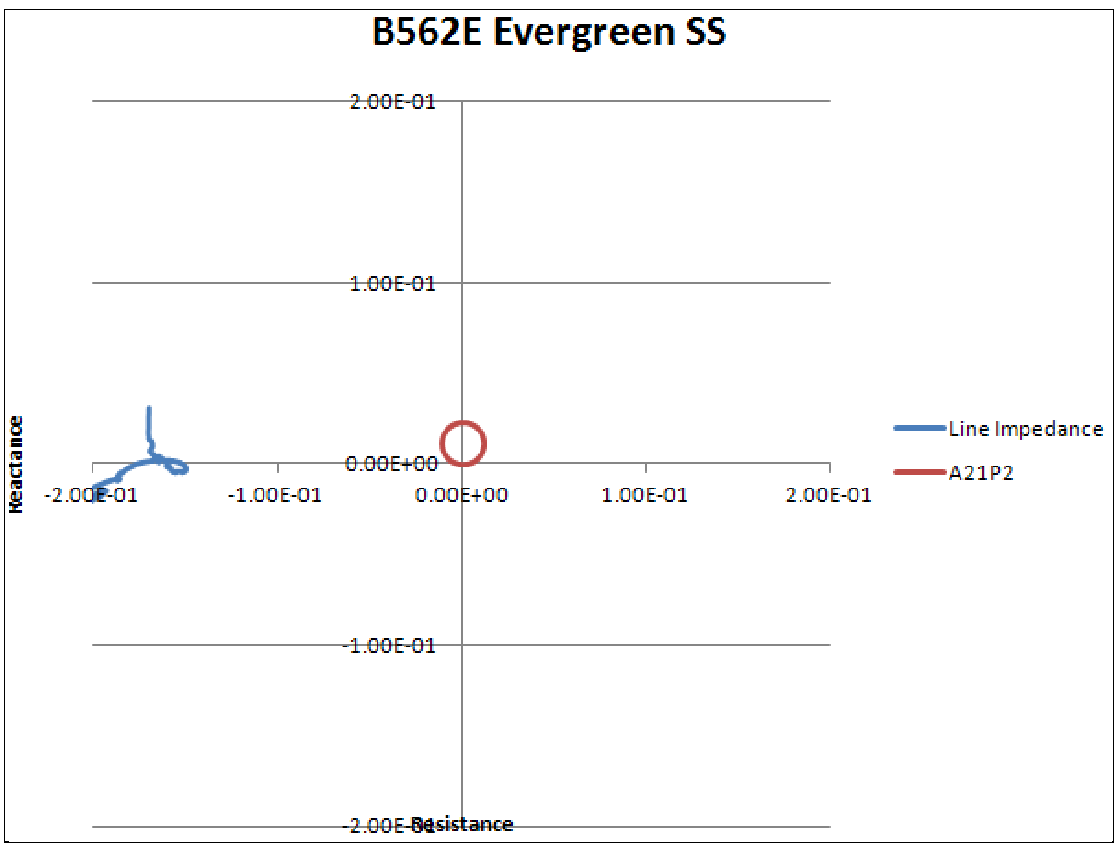


Figure 18: B562E @ Evergreen trajectory for a 3 phase fault on A563L at Longwood

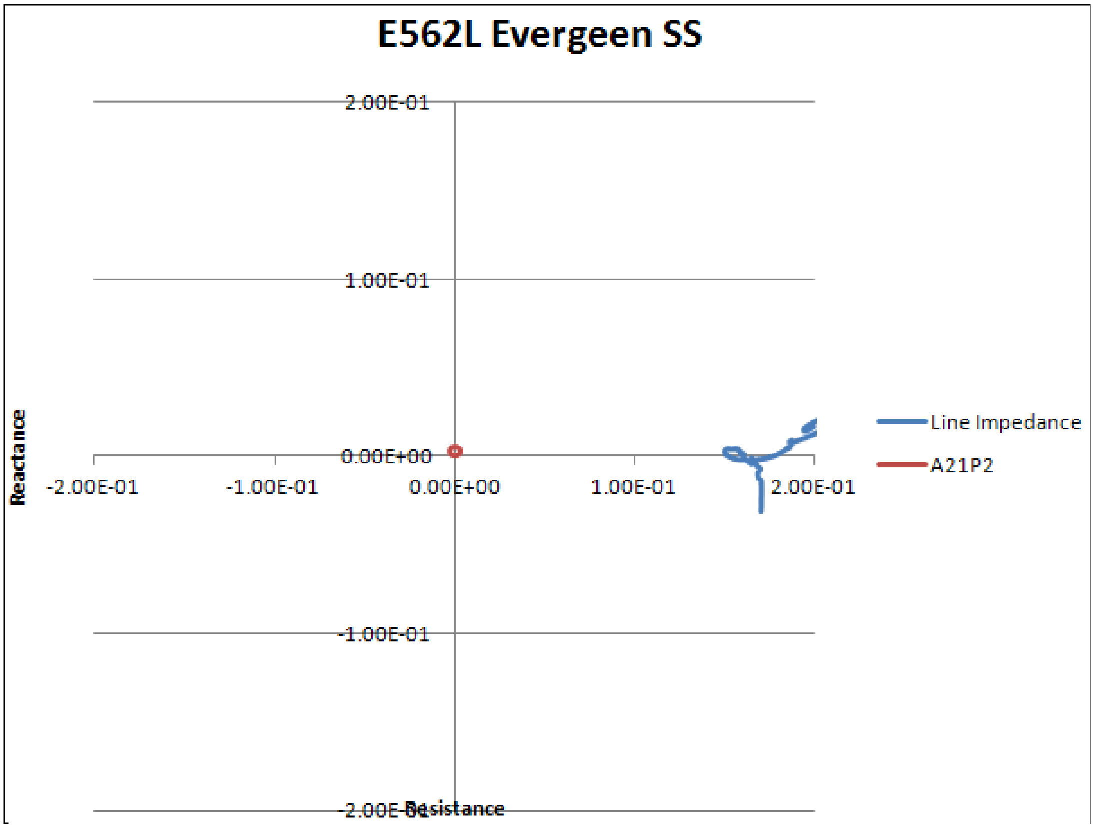


Figure 19: E562L @ Evergreen trajectory for a 3 phase fault on A563L at Longwood

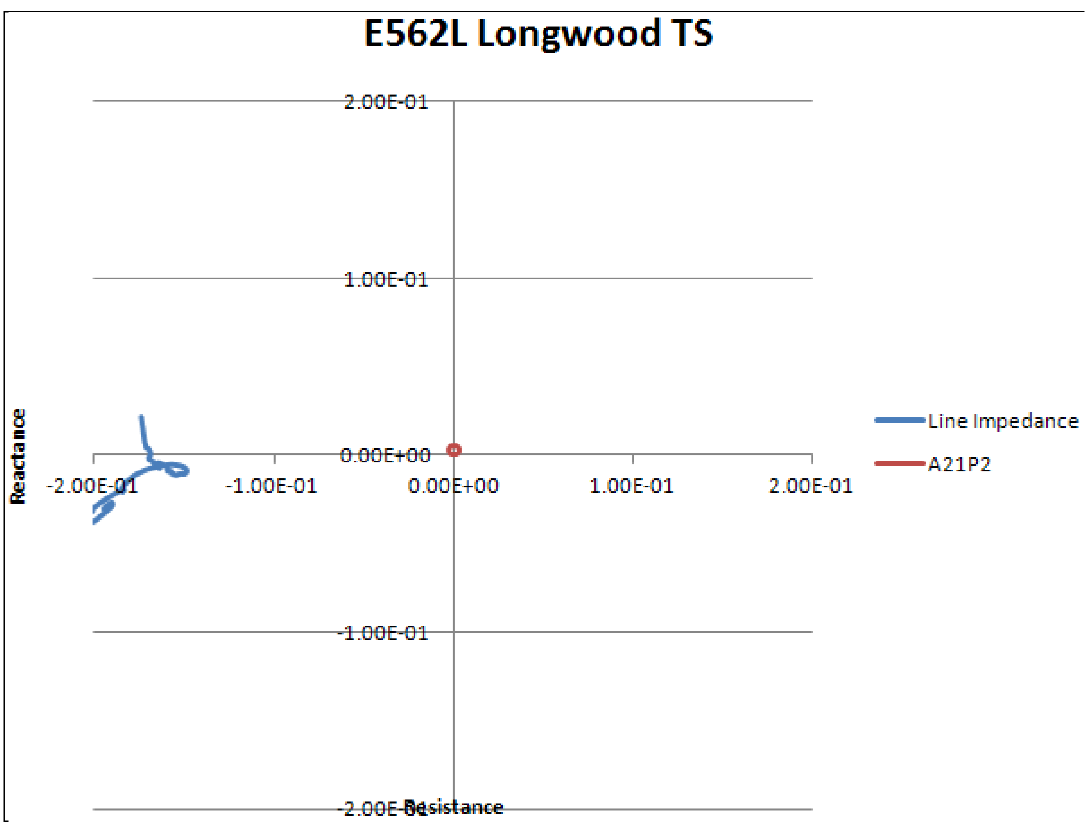


Figure 20: E562L @ Longwood trajectory for a 3 phase fault on A563L at Longwood

Appendix B: PIA Report

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

PROTECTION IMPACT ASSESSMENT

NEXTERA/SUNCOR CEDAR POINT II WIND FARM PROJECTS

283.5 MW / 100 MW WIND GENERATORS
GENERATION CONNECTION

Date: February 10, 2012
P&C Planning Group Project #: PCT-291-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	September 6, 2011	First draft
R1	October 27, 2011	Change in requirements for multiple setting groups and the name of the switching station to Evergreen SS.
R2	November 7, 2011	New approach for low WF infeed.
R3	February 10, 2012	Removed scenario that excluded Cedar Point II

EXECUTIVE SUMMARY

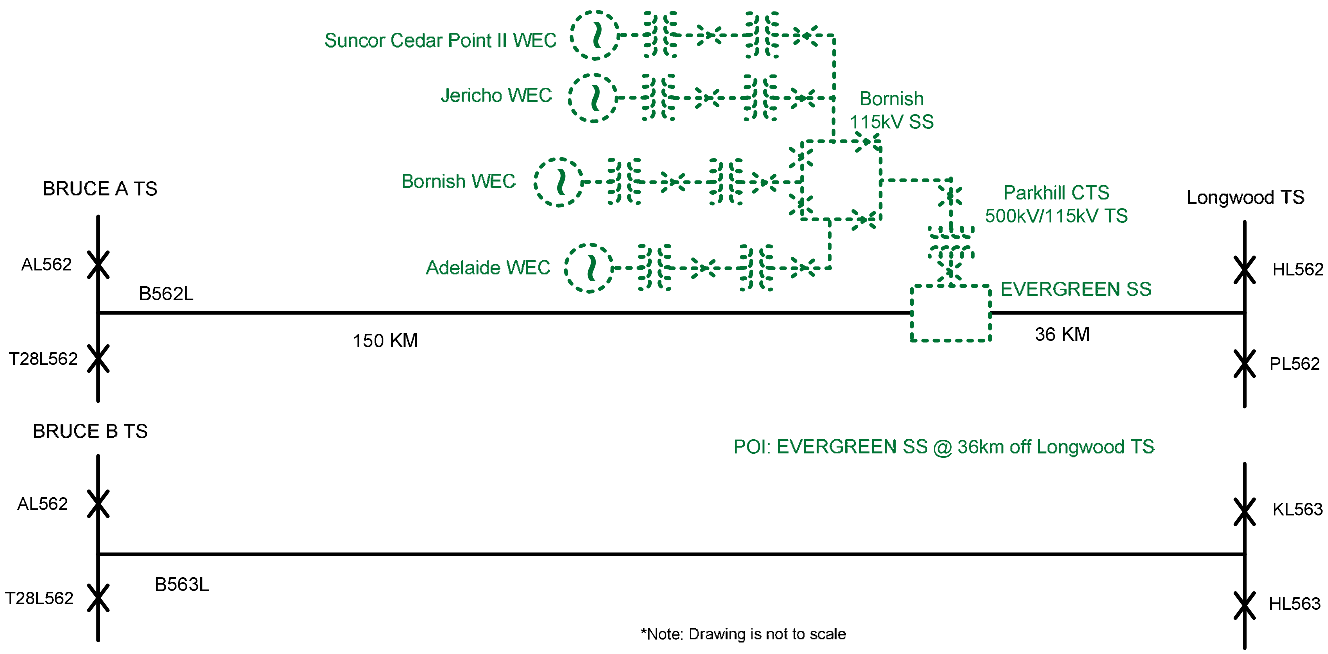


Figure 1: NextEra/SUNCOR WF Connection to HONI Transmission System

It is feasible for both NextEra and Suncor to connect their proposed generation projects (NextEra 283.5MW and Suncor 100 MW) at the location shown in Figure 1. A sectionalizing ring bus will be constructed on line B562L. Line segment between Bruce TS and Evergreen SS will be approximately 150km. Line segment between Evergreen SS and Longwood TS will be approximately 36.5 km. It is recommended to protect both the new 150km and the 36.5 km line segments by using a line distance scheme.

PROTECTION HARDWARE

The present relays at Bruce TS and Longwood TS shall be upgraded to standard line distance relays meeting NPCC D4 separation requirements. One of the relays ('B' group) at Bruce TS may be retained if feasible. This will trigger upgrading the 4 breaker (2 in each Bruce TS and Longwood TS) failure protections. New standard line protection relays will also have to be installed at Evergreen SS.

PROTECTION SETTINGS

Permissive Overreaching Schemes shall be implemented in both new line segments (previously part of B562L). New settings will be required for both Bruce TS and Longwood TS as the new three-breaker ring bus sectionalizes the line.

For the case where one of the line segments is open and the infeed from the wind farm is low, if a fault occurs close to Evergreen SS it will not be seen by Evergreen SS due to low infeed nor by the terminal station Zone 1 due to the fault location being within only Zone 2 reach, resulting in potentially long fault clearing time (up to 400ms). This scenario will require implementation of a relay logic design for the weak infeed solution which will be elaborated in the planning document in preparation of the detailed design.

New settings will also be required for relays at Evergreen SS. Essentially, the protection over B562L will have to be modified to protect two new line segments.

TELECOMMUNICATIONS

The telecommunication media between Bruce A TS and Longwood TS are digital Microwave (Main) and PLC (alternate) in both ‘A’ and ‘B’ groups. New digital MW and PLC (main and alternate) facilities shall be installed at Evergreen SS in order to establish necessary connections for teleprotection. The links shall be established to both Bruce A TS and Longwood TS.

In addition, the proponent is responsible for establishing the communication links (‘A’ & ‘B’ redundant and fully separated with geographic path diversity) to Evergreen SS. The proponent is also responsible for establishing the communication links to IESO and HONI control centers for SCADA.

CUSTOMERS RESPONSIBILITIES

The customers shall be responsible to reliably disconnect their equipment for a fault within their system in case of a single contingency in their equipment. New protection hardware shall be installed at Evergreen SS as described above. Teleprotection shall comply with the described above. Teleprotection signals such as transfer trip shall be transmitted to both terminal stations from Evergreen SS as well as Breaker Fail shall be initiated upon receiving TT signals from any of the terminal stations. Adequate signal exchange shall be established between Evergreen SS and customer’s step-up station Parkhill CTS.

Exhibit H, Tab 3, Schedule 1
Customer Impact Assessment

CUSTOMER IMPACT ASSESSMENT

Hydro One Networks Inc.
483 Bay Street
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- ADDENDUM -
CUSTOMER IMPACT ASSESSMENT

CEDAR POINT II WIND POWER PROJECT
ADELAIDE / BORNISH / JERICHO WIND ENERGY CENTRES

100 MW Wind Turbine Generation Connection
283.5 MW Wind Turbine Generation Connection

- FINAL -

Revision: 0

Date: June 8, 2012

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

Prepared by:

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Approved by:

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

Disclaimer

This Customer Impact Assessment was prepared based on information available about the connection of the proposed Suncor Energy Products Inc. –Cedar Point II Wind Power Project. 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. Subsequent changes to the required modifications or the implementation plan may affect the impacts of the proposed connection identified in Customer Impact Assessment. The results of this Customer Impact Assessment are also subject to change to accommodate the requirements of the IESO and other regulatory or municipal authority requirements.

Hydro One 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. Any liability that Hydro One may have to Suncor Energy Products Inc. in respect of the Customer Impact Assessment is governed by the Agreement between:

1. Suncor Energy Products Inc. and Hydro One dated February 14, 2012.

ADDENDUM: CUSTOMER IMPACT ASSESSMENT
CEDAR POINT II WIND POWER PROJECT &
ADELAIDE/BORNISH/JERICHO WIND ENERGY CENTRES
383.5 MW WIND TURBINE GENERATION CONNECTION

1.0 INTRODUCTION

Suncor Energy is to develop a 100 MW wind energy generation facility. The wind energy facility, known in this document as Cedar Point Wind Project (CPWP), will be constructed in the Township of Adelaide-Metcalfe in Middlesex County. CPWP will connect into the NEXTera ENERGY 283.5 MW wind energy generation facility, known in this document as NEXTera Wind Energy Centre (NWEC). NWEC consists of the three wind energy projects: Adelaide WEC (60 MW), Bornish WEC (73.5 MW) and Jericho WEC (150 MW). The total 383.5 MW of Suncor and NEXTera generation will connect to Hydro One's transmission system through one new step-up transformer via a new 500 kV switching station that will sectionalize Hydro One's 500 kV circuit, B652L, approximately 36.5 km from Longwood TS. The switching station will be located in Middlesex County, in the Municipality of North Middlesex. The switching station will be called Evergreen SS and will be Hydro One owned and operated. Evergreen SS interconnection station will be located just west and adjacent to Hydro One's B562/563L Right-Of-Way (ROW).

In accordance with section 6 of the Ontario Energy Board's Transmission System Code, Hydro One Networks Inc (Hydro One) is to carry out a Customer Impact Assessment (CIA) study to assess the impact of the proposed generator connection on existing customers in the affected area.

This study does not evaluate the overall impact of the Cedar Point Wind Project on the bulk electricity system. The impact of the new generator on the bulk electricity system is the subject of the System Impact Assessment (SIA) issued by the Independent Electricity System Operator (IESO).

The study does not evaluate the impact of the Cedar Point Wind Project on the network Protection and Control facilities. Protection and Control aspects are reviewed during the Protection Impact Assessment, which is part of the SIA. Protection and Control aspects are again reviewed, in detail, during the preparation of the connection cost estimate and will be reflected in the Connection and Cost Recovery Agreement.

1.2 Addendum: Proposed Connection: Cedar Point II Wind Power Project

1.2.1 The Wind Farm

The proposed 100 MW wind farm consists of 45 Siemens 2.3 MW Series Wind Turbine Generators (WTG). The maximum output of the WTG will be curtailed to a total generation output capability of 100 MW. Appendix A, Figures 1 & 2 shows an overview of the proposed connection arrangement.

Cedar Point II WPP consists of 4 groups of 10-12 x 2.3 MW Siemens wind turbine units totaling 100 MW. Each group of wind turbines is placed on a 34.5 kV feeder and is protected by a circuit breaker before connecting to a 34.5 kV bus at a substation located in the Municipality of Adelaide-Metcalfe. This substation will be called Cedar Point Customer Generation Station (CGS). At Cedar Point CGS, the power will be transformed to 121 kV via one 120/34.5 kV, 66/88/110 MVA transformer.

An 11.9 km, 121 kV customer-owned transmission line named CP1J will connect Cedar Point CGS to Cedar Point Customer Switching Station (CSS) which will be located next to NEXTera's Jericho CGS. At this point, Suncor's Cedar Point II WPP will join with the Jericho WEC. The combined wind farm outputs will then be transported 14.5 km on a 121 kV customer transmission line named J1BTS to NEXTera's Bornish CSS.

At Bornish CSS four wind generating facilities converge: Suncor's Cedar Point II WPP (100 MW) and NEXTera's Adelaide WEC (60 MW), Bornish WEC (73.5 MW) and Jericho WEC (150 MW). Bornish CSS will be a 121 kV switching station owned and operated by the generator customers. The station will consist of a four breaker ring and will be located in the Municipality of North Middlesex.

An 11.4 km, 121 kV customer-owned transmission line will then connect Bornish CSS to the generator's 500 kV transformer station located close to Hydro One's ROW. This transformer station will be called Parkhill CTS (Customer Transformer Station). At this station, the power will be transformed to 500 kV via one 525/121 kV 256/341/426 MVA transformer. The 500 kV bus at Parkhill CTS will connect to the new Hydro One 500 kV switching station known as Evergreen SS. Please see Appendix A, Figure 2.

The wind farm's dynamic Var compensation is provided via their Siemens 2.3 Series Wind Turbine Generators (WTG). The WTG are designed to supply or absorb reactive power to or from the transmission grid to regulate and stabilize the voltage. In addition, it was determined in the System Impact Assessment that this project, in conjunction with the three NEXTera WEC's, will also require static Var compensation of 120 MVAr that can be provided via shunt capacitor banks located at the Parkhill CTS 121 kV bus.

1.2.2 Addendum: Connection to Hydro One's 500 kV Transmission System

The combined CPWP and NWEC will connect their generated power via 500 kV Hydro One owned interconnection station called Evergreen SS. The Parkhill CTS 525/121 kV power transformer will connect directly via 1-500 kV breaker and 1 motorized disconnect switch onto a 500 kV 3-breaker ring bus at Evergreen SS, Appendix A, Figure 3. This ring bus will split Hydro One's existing 500 kV circuit B562L from Bruce A TS to Longwood TS into 2 sections: Bruce A TS x Evergreen SS and Evergreen SS x Longwood TS. This sectionalizing will occur approximately 36.5 km from Longwood TS, near tower number 563 of existing B562L. Both Evergreen SS and Parkhill CTS will be adjacent or as close as possible to Hydro One's existing ROW to limit the additional exposure to Hydro One's 500 kV system. In addition, it was determined in the System Impact Assessment that Evergreen SS will experience overvoltage during certain system configurations.

To manage the overvoltage concerns at Evergreen SS, Hydro One is proposing to construct Evergreen SS with equipment capable of withstanding the overvoltage. This additional capability will forego the previous requirement of a shunt reactor.

1.3 Customers in the Study Area

The primary focus of this study was on customers supplied from stations directly connected to existing circuit B562L and in the local electrical area. Affected customers are show in Table 1.

Table 1: Transmission Customers connected in the study area

Station	Customer
Bruce A TS	Bruce Power L.P.
Bruce B SS	Bruce Power L.P.
Bruce Heavy Water Plant B TS	Bruce Power L.P.
Douglas Point TS	Hydro One Networks Inc. (Distribution) Westario Power Inc.
Longwood TS	Hydro One Networks Inc. (Distribution) Middlesex Power Distribution Corp.

1.4 Operating Conditions

Normal operating conditions are such that CPWP will solely generate onto NEXTera's 121 kV circuit J1BTS. When NEXTera's 500 kV transformer breaker at Parkhill CTS that connects to the 500 kV ring bus at Evergreen SS is taken out of service, CPWP will not generate onto Hydro One's systems, transmission nor distribution.

2.0 ADDENDUM - SHORT CIRCUIT RESULTS

Short-circuit studies were carried out to assess the fault contribution when the CPWP is connected to the NWEC subsystem and a total of 383.5 MW is generating into Evergreen SS.

The study results are summarized in Tables 3 and 4 below showing both symmetric and asymmetric fault currents in kA, respectively. The anticipated fault levels after the incorporation of all committed and proposed generation in the Bruce area are shown in Table 5.

Table 3: CPWP & NWEC impact on symmetrical fault levels

Station	without CPWP & NWEC* (kA)		with CPWP & NWEC (kA)		% Difference	
	3-Phase	L-G	3-Phase	L-G	3-Phase	L-G
Bruce B SS 500 kV	36.92	41.55	37.13	41.74	0.57	0.46
Bruce A TS 500 kV	37.13	41.72	37.35	41.93	0.59	0.50
Bruce A TS 230 kV	42.82	54.20	42.90	54.3	0.19	0.18
BHWP B TS 13.8 kV A	19.77	1.98	19.77	1.98	0.00	0.00
BHWP B TS 13.8 kV B	19.75	1.98	19.75	1.98	0.00	0.00
Douglas Point TS 44 kV	14.37	6.89	14.37	6.89	0.00	0.00
Longwood TS 500 kV	20.05	20.95	20.50	21.75	2.24	3.82
Longwood TS 230 kV	37.36	44.74	37.86	45.53	1.34	1.77
Longwood TS 27.6 kV	15.41	10.79	15.43	10.79	0.13	0.00

* Includes existing and committed generation projects up to the award of FIT3 and Samsung Phase 2 & 3 contracts

Table 4: CPWP & NWEC impact on asymmetrical fault levels

Station	without CPWP & NWEC* (kA)		with CPWP & NWEC (kA)		% Difference	
	3-Phase	L-G	3-Phase	L-G	3-Phase	L-G
Bruce B SS 500 kV	54.27	63.52	54.56	63.79	0.53	0.43
Bruce A TS 500 kV	54.40	63.15	54.71	63.44	0.57	0.46
Bruce A TS 230 kV	57.47	78.24	57.57	78.37	0.17	0.17
BHWP B TS 13.8 kV A	23.04	1.98	23.04	1.98	0.00	0.00
BHWP B TS 13.8 kV B	22.33	1.98	22.33	1.98	0.00	0.00
Douglas Point TS 44 kV	16.34	8.82	16.34	8.83	0.00	0.11
Longwood TS 500 kV	24.36	26.68	24.95	27.67	2.42	3.71
Longwood TS 230 kV	45.70	57.93	46.44	59.03	1.62	1.90
Longwood TS 27.6 kV	21.54	15.67	21.57	15.68	0.14	0.06

*Includes existing and committed generation projects up to the award of FIT3 and Samsung Phase 2 & 3 contracts

Table 5: Anticipated Fault Levels Resulting from FIT3 and Samsung Phase 2 & 3 contracts

Station	Symmetrical Fault Level (kA)		Asymmetrical Fault Level (kA)	
	3-Phase	L-G	3-Phase	L-G
Bruce B SS 500 kV	37.85	42.53	55.57	64.89
Bruce A TS 500 kV	38.09	42.66	55.76	64.45
Bruce A TS 230 kV	44.36	55.86	59.39	**80.43**
BHWP B TS 13.8 kV A	19.79	1.98	23.06	1.98
BHWP B TS 13.8 kV B	19.77	1.98	22.35	1.98
Douglas Point TS 44 kV	14.92	6.97	17.00	8.95
Longwood TS 500 kV	20.77	21.99	25.27	27.97
Longwood TS 230 kV	38.35	46.04	47.03	59.68
Longwood TS 27.6 kV	15.44	10.80	21.59	15.69

*Includes existing, committed and proposed generation projects in the Bruce Transmission Area as per applications received by December 2011

Observations made from the short-circuit study results in Tables 3 & 4 above may be summarized as follows:

- Table 3 shows that fault levels are below the maximum symmetrical three-phase and single line-to-ground fault values set out in Appendix 2 of the *Transmission System Code* (TSC).

- Table 3 shows that although there is a 3.82 % increase in the symmetrical short-circuit level at Longwood TS 500 kV bus, the fault levels are well below the allowable 500 kV fault limits and are acceptable to Hydro One.

- Table 4 shows that although there is a 3.71 % increase in the asymmetrical short-circuit level at Longwood TS 500 kV bus, the fault level is within Hydro One's asymmetrical breaker ratings** and are acceptable to Hydro One.

It can be observed from Table 5 that the anticipated fault levels at the stations shown are below the maximum symmetrical three-phase and single line-to-ground fault values set out in Appendix 2 of the TSC. In addition, with the exception of Bruce A TS 230 kV bus**, the anticipated fault levels are within Hydro One's breaker ratings.

**Note: The asymmetrical fault current at Bruce A 230 kV before and after the incorporation of the projects will exceed the interrupting capability of the existing breakers. To address this issue in the long term, Hydro One has planned to replace the Bruce 230 kV breakers to improve fault current interrupting capability. Before the circuit breakers are replaced, temporary operational mitigation measures have been developed by Hydro One in collaboration with the IESO. The CPWP has no impact on this issue.

<u>Conclusion</u>
The short-circuit level increases at Bruce A TS, Bruce B SS, BHWP B TS, Douglas Point TS and Longwood TS are acceptable to Hydro One and are below Hydro One's 5 % TSC margin limit.

3.0 ADDENDUM - VOLTAGE ANALYSIS

Load flow studies were carried out to analyze the impact of CPWP in conjunction with NWEC on the voltage performance of Hydro One customers in the affected area.

Local voltage impact was assessed using load flow contingency analysis. The incorporation of CPWP and NWEC at full output was used to assess voltage change during peak summer loading conditions.

The following contingencies were used to assess the voltage impact:

a) A single contingency loss of Parkhill CTS with all generation at full output, 383.5 MW
b) A single contingency loss of Bruce A TS x Evergreen SS 500 kV circuit
c) A single contingency loss of Evergreen SS x Longwood TS 500 kV circuit
d) A double contingency loss of Evergreen SS x Longwood TS circuit and Parkhill CTS (due to Breaker Failure B/F at Evergreen SS)
e) A double contingency loss of Evergreen SS x Longwood TS circuit and Parkhill CTS (due to Breaker Failure B/F at Evergreen SS), with Ashfield SS x Longwood TS 500 kV circuit out of service pre-contingency
f) A double contingency loss of Bruce A TS x Evergreen SS circuit and Parkhill CTS (due to Breaker Failure B/F at Evergreen SS), with Bruce B SS x Ashfield SS 500 kV circuit out of service pre-contingency

Basic Assumptions:

- New 500 kV switching station Ashfield SS will sectionalize companion circuit B563L approximately 61.5 km from Bruce B SS to incorporate another wind energy project known as K2 Wind.
- *No 500 kV shunt reactor installed at Evergreen SS (contrary to the original CIA assessment for this connection point)*
- A 120 MVAr at 121 kV shunt capacitor will be installed at Parkhill CTS for the combined generators reactive power capability as per IESO System Impact Assessment requirements.
- ULTC – Under Load Tap Changer
- For the period of time labeled “After ULTC”, the switching of reactive devices such as reactors and capacitors is implemented.

Results are shown in Appendix B, Tables 1 – 5 and the impact to existing customers is summarized below:

- Table B1: For the loss of Parkhill CTS (the proposed generators) the maximum voltage change is 0.18% at Longwood TS 500 kV bus before ULTC operation and is 0.16% at Longwood TS 500 kV bus after ULTC operation.

- Table B2: For the loss the 500 kV circuit between Bruce A TS and Evergreen SS the maximum voltage change is -0.67% at Longwood TS 500 kV bus before ULTC operation and is -0.67% at Longwood TS 500 kV bus after ULTC operation.

- Table B3: For the loss of the 500 kV circuit between Evergreen SS and Longwood TS, the maximum voltage change is -0.42% at Longwood TS 500 kV bus before ULTC operation and is -0.41% at Longwood TS 500 kV bus after ULTC operation.

- Table B4: For the loss of the 500 kV circuit between Evergreen SS and Longwood TS with a breaker failure at Evergreen SS which disconnects Parkhill CTS (the generators), the maximum voltage change is -0.88% at Longwood TS 27.6 kV bus before ULTC operation and is -0.91% at Longwood TS 27.6 kV bus after ULTC operation

- Table B5: Given the 500 kV circuit from Ashfield SS to Longwood TS is out of service, for the loss of the 500 kV circuit between Evergreen SS and Longwood TS with a breaker failure at Evergreen SS which disconnects Parkhill CTS, the maximum voltage change is -1.98% at Longwood TS 500 kV bus before ULTC operation and is -2.01% at Longwood TS 500 kV bus after ULTC operation.

- Table B6: Given the 500 kV circuit from Bruce B SS to Ashfield SS is out of service, for the loss of the 500 kV circuit between Bruce A TS and Evergreen SS with a breaker failure at Evergreen SS which disconnects Parkhill CTS, the maximum voltage change is -0.53% at Longwood TS 27.6 kV bus before ULTC operation and is -0.56% at Longwood TS 27.6 kV bus after ULTC operation.

Conclusion
Load flow studies thus confirmed that the incorporation of 383.5 MW of wind generation between Bruce A TS and Longwood TS will not result in substantial change in the voltage profile of customers supplied from these stations and in the local electrical area. Following the worst contingency, the voltage changes are well within the voltage decline guideline for customer buses of less than 10% and 5% voltage change before- and after- transformer tap-changer operation.

4.0 ADDENDUM - CONCLUSIONS AND RECOMMENDATIONS

This Addendum: Customer Impact Assessment (CIA) presents results of short-circuit and voltage performance study analyses. The report has confirmed that CPWP can be incorporated into the NWEC without adverse impact on existing customers supplied from Bruce A TS and Longwood TS and in the local electrical area provided that the required facilities are installed. In addition to the facilities required by the IESO by issue of the original SIA's and their subsequent Addendums (http://www.ieso.ca/imoweb/pubs/caa/CAA_2011-446_Final_Report.pdf; http://www.ieso.ca/imoweb/pubs/caa/CAA_2011-443_Final_Report.pdf; http://www.ieso.ca/imoweb/pubs/caa/CAA_2011-441_Final_Report.pdf; http://www.ieso.ca/imoweb/pubs/caa/CAA_2011-445_Final_Report.pdf) and required by the original CIA, CPWP and NWEC are required to install the following facilities as part of their connection:

- Connection facilities at Parkhill CTS must have the capability to operate continuously at a maximum operating voltage of at least 570 kV.
- Fully duplicated protection and telecommunication systems must be installed as outlined in the Transmission System Code.
- SCADA facilities to allow transmission of generation facility components: i.e. status, measurement quantities & alarms, as outlined in the IESO's SIA and Hydro One's planning specification for the connection of CPWP.

Facilities to permit the above work must be provided.

All customers are required to check to ensure that the equipment and grounding system at their stations/facilities meet the expected increase in fault level.

Appendix A: Diagrams

Figure 1: Suncor Cedar Point II WPP, Overall Project
(Drawing from generator)

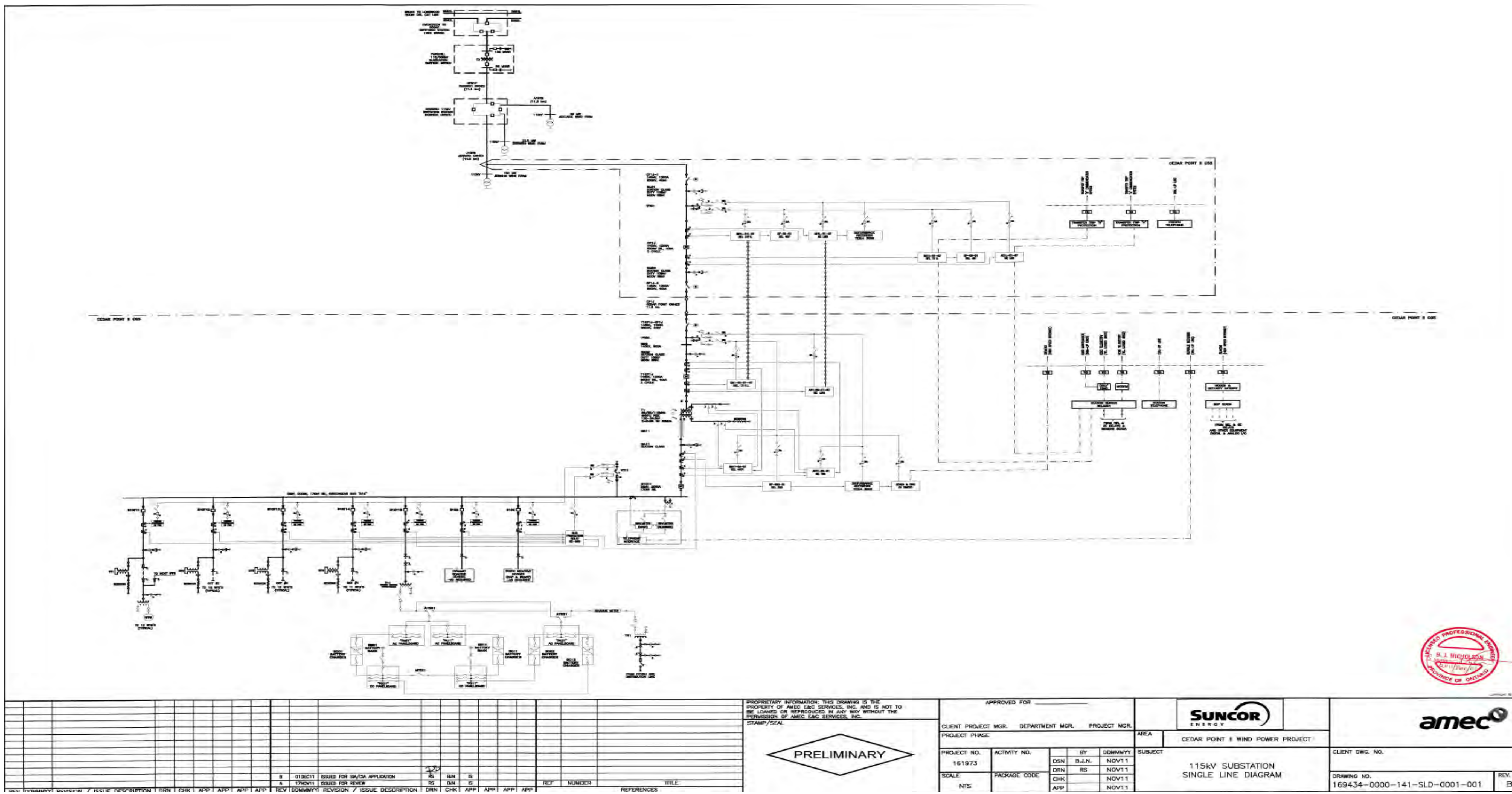
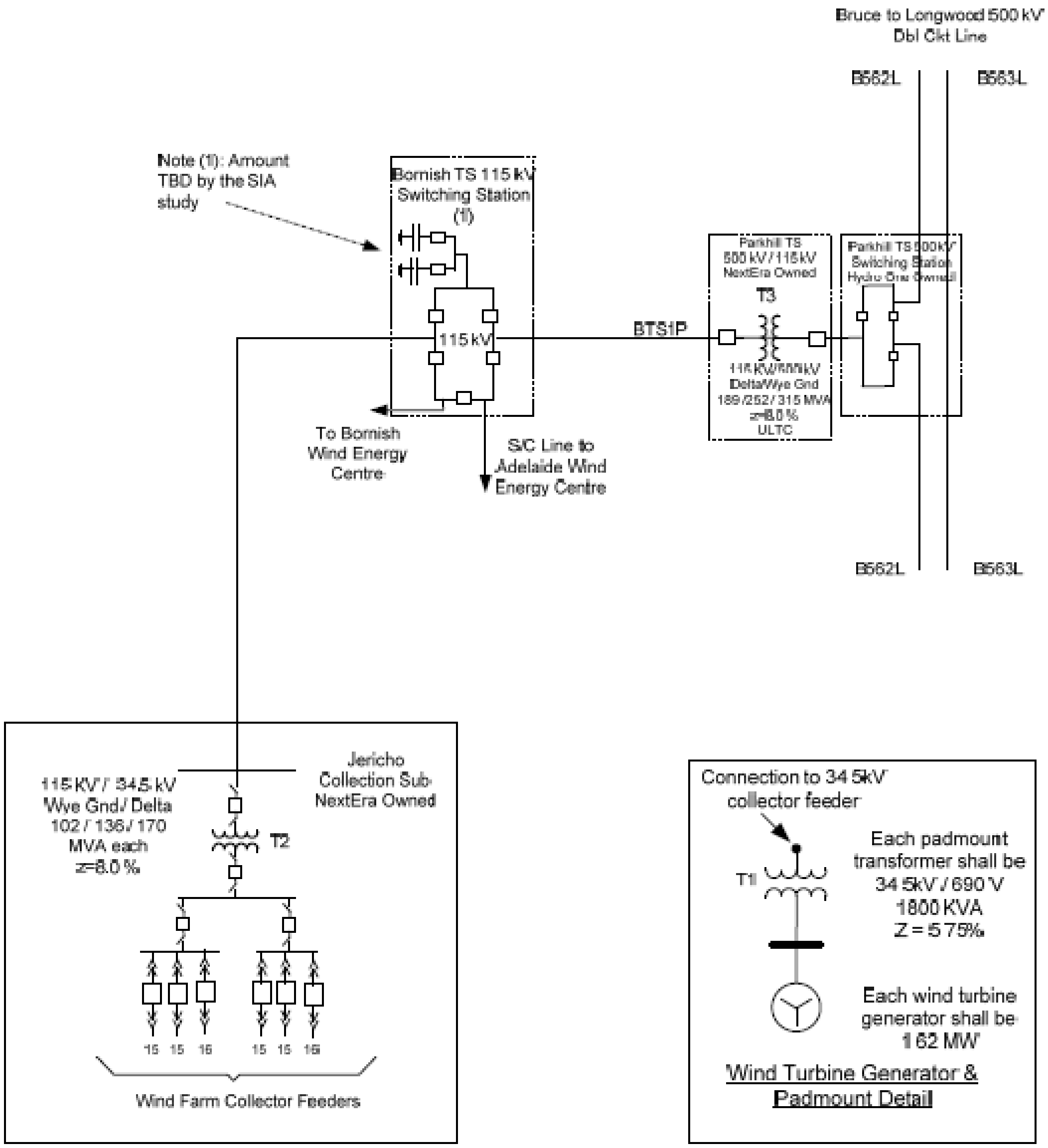


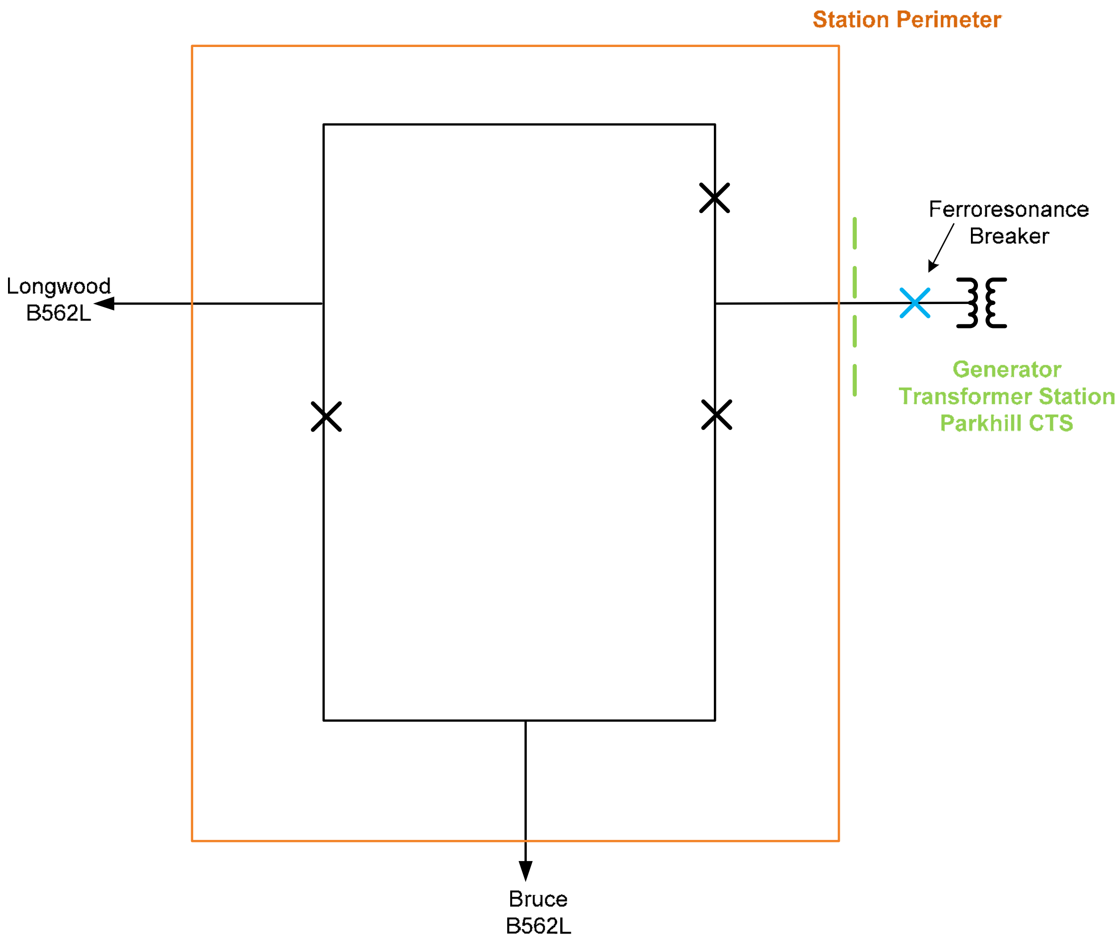
Figure 2: NEXTera Jericho Wind Energy Centre
(Drawing from generator)

Parkhill TS 500 kV Switching Station renamed to Evergreen SS.
Parkhill TS 115 kV/500kV station renamed to Parkhill CTS



Jericho WEC

Figure 3: Evergreen Switching Station



APPENDIX B: VOLTAGE PERFORMANCE RESULTS

Table 1: Loss of Parkhill CTS

Bus	Initial Voltage (kV)	Before ULTC (kV)	% Change	After ULTC (kV)	% Change
Bruce A TS 500 kV	548.19	548.76	0.10	548.73	0.10
Bruce A TS 230 kV	247.12	247.26	0.06	247.25	0.06
Bruce B SS 500 kV	548.92	549.44	0.09	549.41	0.09
BHWP B TS 13.8 kV A bus	14.52	14.52	0.06	14.52	0.06
BHWP B TS 13.8 kV B bus	14.53	14.54	0.06	14.54	0.06
Douglas Point TS 44 kV	46.13	46.16	0.06	46.15	0.06
Evergreen SS 500 kV	547.17	549.61	0.45	549.50	0.43
Longwood TS 500 kV	545.66	546.64	0.18	546.51	0.16
Longwood TS 230 kV	244.82	244.63	-0.08	244.55	-0.11
Longwood TS 27.6 kV	29.04	29.01	-0.08	29.00	-0.12

Table 2: Loss of Bruce A TS x Evergreen SS

Bus	Initial Voltage (kV)	Before ULTC (kV)	% Change	After ULTC (kV)	% Change
Bruce A TS 500 kV	548.19	547.07	-0.20	547.07	-0.20
Bruce A TS 230 kV	247.12	246.84	-0.11	246.84	-0.11
Bruce B SS 500 kV	548.92	547.98	-0.17	547.98	-0.17
BHWP B TS 13.8 kV A bus	14.52	14.50	-0.11	14.50	-0.11
BHWP B TS 13.8 kV B bus	14.53	14.51	-0.11	14.51	-0.11
Evergreen SS 500 kV	547.17	541.12	-1.11	541.11	-1.11
Douglas Point TS 44 kV	46.13	46.07	-0.12	46.07	-0.12
Longwood TS 500 kV	545.66	542.02	-0.67	542.02	-0.67
Longwood TS 230 kV	244.82	243.47	-0.55	243.47	-0.55
Longwood TS 27.6 kV	29.04	28.87	-0.57	28.87	-0.58

Table 3: Loss of Evergreen SS x Longwood TS

Bus	Initial Voltage (kV)	Before ULTC (kV)	% Change	After ULTC (kV)	% Change
Bruce A TS 500 kV	548.19	547.69	-0.09	547.69	-0.09
Bruce A TS 230 kV	247.12	246.98	-0.06	246.98	-0.06
Bruce B SS 500 kV	548.92	548.45	-0.09	548.45	-0.09
BHWP B TS 13.8 kV A bus	14.52	14.51	-0.06	14.51	-0.06
BHWP B TS 13.8 kV B bus	14.53	14.52	-0.06	14.52	-0.06
Douglas Point TS 44 kV	46.13	46.10	-0.06	46.10	-0.06
Evergreen SS 500 kV	547.17	549.21	0.37	549.21	0.37
Longwood TS 500 kV	545.66	543.39	-0.42	543.40	-0.41
Longwood TS 230 kV	244.82	243.97	-0.35	243.98	-0.35
Longwood TS 27.6 kV	29.04	28.93	-0.36	28.93	-0.36

Table 4: Loss of Evergreen SS x Longwood TS & Parkhill CTS

Bus	Initial Voltage (kV)	Before ULTC (kV)	% Change	After ULTC (kV)	% Change
Bruce A TS 500 kV	548.19	549.31	0.21	549.29	0.20
Bruce A TS 230 kV	247.12	247.39	0.11	247.39	0.11
Bruce B SS 500 kV	548.92	549.85	0.17	549.83	0.17
BHWP B TS 13.8 kV A bus	14.52	14.53	0.11	14.53	0.11
BHWP B TS 13.8 kV B bus	14.53	14.55	0.11	14.55	0.11
Douglas Point TS 44 kV	46.13	46.18	0.11	46.18	0.11
Evergreen SS 500 kV	547.17	**559.78***	2.30	**559.75***	2.30
Longwood TS 500 kV	545.66	541.60	-0.74	541.45	-0.77
Longwood TS 230 kV	244.82	242.75	-0.85	242.67	-0.88
Longwood TS 27.6 kV	29.04	28.78	-0.88	28.77	-0.91

*****Overvoltage at Evergreen SS will be managed by installing equipment capable of handling it.

Table 5: Loss of Evergreen SS x Longwood TS & Parkhill CTS while Ashfield SS x Longwood TS Out-of-Service

Bus	Initial Voltage (kV)	Before ULTC (kV)	% Change	After ULTC (kV)	% Change
Bruce A TS 500 kV	546.97	548.00	0.19	547.99	0.19
Bruce A TS 230 kV	246.81	247.05	0.10	247.04	0.10
Bruce B SS 500 kV	547.82	548.57	0.14	548.56	0.14
BHWP B TS 13.8 kV A bus	14.50	14.51	0.10	14.51	0.10
BHWP B TS 13.8 kV B bus	14.51	14.53	0.10	14.53	0.10
Douglas Point TS 44 kV	46.07	46.11	0.10	46.11	0.10
Evergreen SS 500 kV	539.60	**558.44***	3.49	**558.43***	3.49
Longwood TS 500 kV	536.13	525.52	-1.98	525.37	-2.01
Longwood TS 230 kV	245.05	240.44	-1.88	240.37	-1.91
Longwood TS 27.6 kV	29.06	28.50	-1.95	28.49	-1.98

*****Overvoltage at Evergreen SS will be managed by installing equipment capable of handling it.

Table 6: Loss of Bruce A TS x Evergreen SS & Parkhill CTS while Bruce B SS x Ashfield SS Out-of-Service

Bus	Initial Voltage (kV)	Before ULTC (kV)	% Change	After ULTC (kV)	% Change
Bruce A TS 500 kV	547.55	546.28	-0.23	546.26	-0.24
Bruce A TS 230 kV	246.96	246.64	-0.13	246.64	-0.13
Bruce B SS 500 kV	548.19	547.07	-0.20	547.05	-0.21
BHWP B TS 13.8 kV A bus	14.51	14.49	-0.13	14.49	-0.13
BHWP B TS 13.8 kV B bus	14.52	14.50	-0.13	14.50	-0.13
Douglas Point TS 44 kV	46.10	46.04	-0.13	46.04	-0.13
Evergreen SS 500 kV	546.82	544.24	-0.47	544.08	-0.50
Longwood TS 500 kV	545.35	543.59	-0.32	543.44	-0.35
Longwood TS 230 kV	244.70	243.46	-0.51	243.37	-0.54
Longwood TS 27.6 kV	29.02	28.87	-0.53	28.86	-0.56