IESO_REP_0761

REPORT

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System Impact Assessment Report

CONNECTION ASSESSMENT & APPROVAL PROCESS

Final Report

CAA ID: 2011-447
Project: Grand Bend Wind Farm
Applicant: Grand Bend Wind L.P.

Market Facilitation Department
Independent Electricity System Operator

Date: December 21, 2011

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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 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.

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Executive Summary

Project Description

Grand Bend Wind L.P. (the "connection applicant") is developing a new 100MW wind power generation farm, Grand Bend Wind Farm (the "project") in Zurich, Ontario. The project will be connected to Hydro One's 230 kV circuit B23D 2.77 km south of Seaforth TS. The project has been awarded a Power Purchase Agreement under the Feed-In Tariff (FIT) program with the Ontario Power Authority. The scheduled project in-service date is October, 2013.

Findings

1. The proposed connection arrangement and equipment for the project are acceptable to the IESO. As outlined by Hydro One in the Protection Impact Assessment (PIA), an additional breaker in series with the proposed 230 kV breaker at the connection point will be installed for breaker fail scenarios.
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. The project is connecting in the Bruce Area where transmission connected generation projects participate in the Bruce Special Protection Scheme (BSPS).
4. 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.
5. The functions of the proposed wind farm control system meet the requirements in the Market Rules.
6. The voltage performance with the proposed the project is expected to be acceptable under both pre-contingency and post-contingency operating conditions
7. 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.
8. The WTGs of the project and the power system are expected to be transiently stable following recognized fault conditions.
9. The proposed wind turbine generators are expected to be able to remain connected to the grid for recognized system contingencies that do not remove the project by configuration.
10. Protection adjustments identified by Hydro One in the Protection Impact Assessment (PIA) to accommodate the project have no adverse impact on the reliability of IESO-controlled grid.
11. The relay margins on the affected circuits after the incorporation of the project 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 connection applicant to curtail its output.

IESO Requirements for Connection

Transmitter Requirements

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

(1) Hydro One is required to review the relay settings of the 230 kV circuit B23D and any other circuits affected by the project, as per solutions identified in the PIA.

Modifications 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. If those modifications result in adverse reliability impacts, the connection applicant and the transmitter must develop mitigating solutions.

(2) Hydro One must modify the existing Bruce Special Protection Scheme to incorporate the project.

Applicant Requirements

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

(1) The project is 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 7 Mvar@34.5 kV installed at the project collector bus would satisfy the reactive power requirement. The required capacitive compensation shall 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 output.

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

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

(2) Special protection system facilities must be installed at the project to accept a single pair (A & B) of 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 two 230 kV breakers at the connection point 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 project, and presented in detail in section 2 of this report.

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

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

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

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

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 project 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.

(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 230 kV equipment is capable of continuously operating between 220 kV and 250 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 project a disturbance recording device with clock synchronization that meets the technical specifications provided by the transmitter.

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

Fault interrupting devices must be able to interrupt fault currents at the maximum continuous voltage of 250 kV.

(8) Appendix 2 of the Transmission System Code states that the maximum rated interrupting time for the 230 kV breakers must be 3 cycles or less. Thus, the connection applicant shall ensure that the installed breakers meet the required interrupting time specified in the Transmission System Code.

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

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

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

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

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

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

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

(12) The 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 Marker Rules, NPCC and NERC rules.

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

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

Notification of Conditional Approval

The proposed connection of the Grand Bend Wind Farm, operating up to 100MW, 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 Grand Bend Wind Farm subject to the implementation of the requirements outlined in this report.

– End of Section –

1. Project Description

Grand Bend L.P. has proposed to develop a 100 MW wind farm located in Zurich, Ontario, known as Grand Bend Wind Farm which has been awarded a Power Purchase Agreement under the FIT program with the Ontario Power Authority. It is expected that commercial operation will start October 2013.

The wind farm will be connected to Hydro One’s 230 kV circuit B23D, 2.77 km south of Seaforth TS via a 30 km 230 kV overhead tap line. The project will consist of 40 units of GE 2.5MW wind turbines. These wind turbines will be arranged into 3 groups of 13 or 14 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 34.5/230 kV step-up transformer through a disconnect switch. A 230 kV circuit breaker and a 230 kV motorized disconnect switch will be installed between the high-voltage side of the step-up transformer and the 230 kV tap line. At the other end of the tap line, two additional 230 kV circuit breakers and a 230 kV motorized disconnect switch will connect the tap line to circuit B23D.

The proposed connection arrangement is shown in Figure 1, Appendix A.

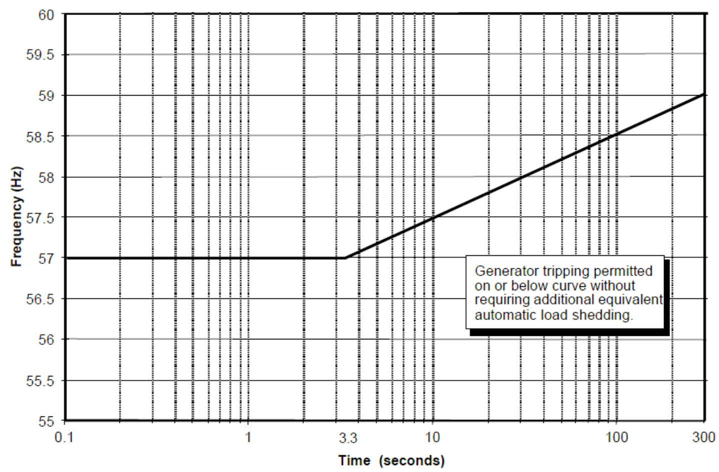
– End of Section –

2. General Requirements

The connection applicant shall satisfy all applicable requirements and standards specified in the Market Rules and the Transmission System Code. The following sections highlight some of the general requirements that are applicable to the 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 a connection point up to 33% of its rated active power at all levels of active power output except where a lesser continually available capability is permitted by the IESO. 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.

2.3 Voltage Ride Though 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 230 kV system are maintained within the range of 220 kV to 250 kV. Thus, the IESO requires that the 230 kV equipment in Ontario must have a maximum continuous voltage rating of at least 250 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 230 kV system in order to verify the dynamic response of generators. The quantities to be recorded, the sampling rate and the trigger settings will be provided by the transmitter.

2.7 Fault Level

The Transmission System Code requires the new equipment to be designed to sustain the fault levels in the area where the equipment is installed. Thus, the connection applicant shall ensure that the new equipment at the project is designed to sustain the fault levels in the area. If any future system changes result in an increased fault level higher than the equipment's capability, the connection applicant is required to replace the equipment with higher rated equipment capable of sustaining the increased fault level, up to maximum fault level specified in the Transmission System Code. Appendix 2 of the Transmission System Code establishes the maximum fault levels for the transmission system. For the 230 kV system, the maximum 3 phase symmetrical fault level is 63 kA and the maximum single line to ground symmetrical fault level is 80 kA (usually limited to 63 kA).

Fault interrupting devices must be able to interrupt fault currents at the maximum continuous voltage of 250 kV.

2.8 Breaker Interrupting Time

Appendix 2 of the Transmission System Code states that the maximum rated interrupting time for the 230 kV breakers must be 3 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, and therefore, is not considered essential to the power system. In the future, as the electrical system evolves, this project may be placed on the BPS list.

The 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 230 kV circuit B23D occurs due to events within the project, the project may be required to be disconnected from the IESO-controlled grid until the problem is resolved.

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

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

2.10 Telemetry

If applicable 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. The data shall be provided in accordance with the performance standards set forth in Appendix 4.19, subject to Section 7.6A of Chapter 4 of the Market Rules. The data is to consist of certain equipment status and operating quantities which will be identified during the IESO Facility Registration/Market Entry Process.

To provide the required data, the connection applicant must install at this project monitoring equipment that meets the requirements set forth in Appendix 2.2 of Chapter 2 of the Market rules. As part of the IESO Facility Registration/Market Entry process, the connection applicant must also 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

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

2.14 Facility Registration/Market Entry

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

Models and data, including any controls that would be operational, must be provided to the IESO. This includes both PSS/E and DSA software compatible mathematical models representing the new equipment for further IESO, NPCC and NERC analytical studies. The models and data may be shared with other reliability entities in North America as needed to fulfill the IESO's obligations under the Marker 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

As identified in the Protection Impact Assessment completed by Hydro One (Section 5 and Appendix B of this report), a second 230 kV breaker in series with the proposed breaker will be installed at the connection point.

The connection arrangement of the project will not reduce the level of reliability of the integrated power system and is, therefore, acceptable to the IESO.

3.2 GE 2.5 MW - 103 WTG

The GE 2.5MW - 103 WTG is a three bladed, variable pitch, variable speed, and full conversion wind turbine generator system. Its specifications are shown in Table 1.

Table 1: Specifications of GE2.5 MW WTG

Type	Rated Voltage	Rated MVA	Rated MW	Transformer			Q_{max} (MX)	Q_{min} (MX)
				MVA	R	X		
GE 2.5 - 103	690 V	3	2.5	2.8	0.0	6%	1.21	-1.21

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

The proposed GE 2.5MW wind turbine will be equipped with the Zero Voltage Ride-Through option (ZVRT). During a voltage drop/raise, the minimum time for a WTG to remain online is shown in Table 2.

Table 2: WTG Voltage Ride-Through Capability

Voltage Range (% of base voltage)	Minimum time for WTGs to Remain Online (sec)
V<15	0.2
15<V<30	0.7
30<V<50	1.2
50<V<90	1.9
90<V<110	No trip
110 < V < 115	1.0
V>115	0.1

The adequacy of the voltage ride-through capability for the proposed WTGs was verified by performing transient stability studies as detailed in Section 6.8 of this report.

Frequency Ride-Through Capability

The GE 2.5MW wind turbine can remain online continuously for abnormal frequency ±2.5 Hz, and stay online for 10 seconds for abnormal frequency ±5 Hz.

The Market Rules state that the generation facility 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 Main Step-Up Transformers

Table 3: Main Step-Up Transformer Data

Unit	Voltage	Rating (MVA) (ONAN/ONAF/ONAF)	Positive Sequence Impedance (pu) S_B= 75 MVA	Configuration		Zero Sequence Impedance (pu) S_B= 75 MVA	Tap
				HV	LV		
T1	230/34.5 kV	75/100/125MVA	0.00+j0.10	Yg	Delta	0.00+j0.047	ULTC@ HV: 17 steps, 226-251.5 kV

3.4 Collector System

Table 4: Equivalent Impedance of Collectors

Circuit	Unit#	MW	Positive-Sequence Impedance (pu, S_B=100MVA)			Zero-Sequence Impedance(*) (pu, S_B=100MVA)		
			R	X	B	R	X	B
C1	14	35	0.04781	0.11502	0.00089	N/A	N/A	N/A
C2	13	32.5	0.04781	0.11502	0.00089	N/A	N/A	N/A
C3	13	32.5	0.04781	0.11502	0.00089	N/A	N/A	N/A

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

3.5 Connection Equipment

3.5.1 HV Switches

Table 5: Parameters of HV Disconnect Switches

Identifier	Voltage Rating	Continuous Current Rating	Short Circuit Symmetrical Rating
89-LH1	250 kV	1200 A	50 kA
89-LH2	250 kV	1200 A	50 kA

The HV switch meets the maximum continuous voltage rating requirement of 250 kV.

3.5.2 HV Circuit Breakers

Table 6: Parameters of HV Circuit Breakers

Identifier	Voltage Rating	Interrupting Time	Continuous Current Rating	Short Circuit Symmetrical Rating
52-L1	250 kV	3 cycles (50 ms)	1200 A	50 kA
52-TL1	250 kV	3 cycles (50 ms)	1200 A	50 kA

The HV circuit breaker meets the maximum continuous voltage rating requirement of 250 kV and the required 3 cycles or less interrupting time.

The symmetrical rated short circuit breaking current of the 230 kV breakers are 50 kA. This value is below the maximum 3 phase symmetrical fault level of 63 kA established by the Transmission System Code for the 230 kV system. Fault studies shown in Section 4 of this report show that the 230kV breaker ratings of 50 kA are sufficient to withstand fault levels at the project. The connection applicant should be aware that if any future system changes result in increased fault current higher than the equipment's capability, the connection applicant would be required to replace these breakers at its own expense with higher rated breakers up to the maximum fault level of 63 kA.

3.5.3 Tap Line

Table 7: Parameters of the Tap Line

Length (km)	Positive-Sequence Impedance (pu, S_B=100MVA)			Zero-Sequence Impedance(*) (pu, S_B=100MVA)		
	R	X	B	R	X	B
30	0.00501	0.03132	0.0475	N/A	N/A	N/A

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

3.6 Wind Farm Control System

The proposed wind farm will be equipped with the GE WindCONTROL System. This control system is designed to interface with each WTG in the wind farm for regulating system voltage, system power factor and real and actual power for the entire wind farm. It also has the capability to coordinate and control fixed reactor and capacitor banks when the total reactive requirements for the farm cannot be supplied by the reactive capability of the WTGs.

Voltage Control

The WindCONTROL System has the following functions related to the voltage control:

- Voltage, VAR and Power Factor Control

The WindCONTROL System has a voltage or power factor closed loop regulator controlling voltage at the connection point or reactive power injected by the wind farm at the connection point by regulating the reactive output of the WTGs.

- Fixed Reactor and Cap Bank Control and Coordination

The WindCONTROL System is able to control and coordinate the insertion of up to 4 fixed capacitor or reactor banks. These banks may be operated automatically in conjunction with the voltage or power factor regulator.

- Line Drop Compensation / Voltage Droop Compensation

The voltage regulator and the power factor regulator can implement line drop-compensating logic to correct for voltage drops and VAR losses on the line. The voltage regulator can be configured with voltage droop compensation, which allows tightly coupled adjacent voltage regulators to share in the voltage regulation of a point that is common to all the adjacent regulators.

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 WindCONTROL 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 WindCONTROL System also has the feature of WindINERTIA which enables the GE 2.5 MW WTG to provide inertial response to help stabilize grid frequency. This feature supports the grid during under frequency events by providing a temporary increase in power production for a short duration, contributing towards frequency recovery. This is achieved by tapping into the stored kinetic energy in the rotor mass.

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

-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
- Port Dover and Nanticoke

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

(3) Recently Committed Generation Facilities

- Bluewater Wind Energy Centre
- Jericho Wind Energy Centre
- Bornish Wind Energy Centre
- Goshen Wind Energy Centre
- Cedar Point Wind Power Project Phase II
- Adelaide Wind Energy Centre
- Grand Bend Wind Farms
- Grand Valley Wind Farms (Phase 3)
- Erieau Wind
- East Lake St. Clair Wind
- Adelaide Wind Power
- Gunn's Hill Wind Farm
- Silvercreek Solar Park
- K2 wind
- Armow
- 300 MW wind at Orangeville
- 100 MW 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: build new 115 kV circuit (CAA2006-238);
- St. Catherines 115 kV circuit upgrade: circuits D9HS, D10S and Q11S (CAA2007-257);
- Tilbury West DS second connection point for DESN arrangement using K2Z and K6Z (CAA2008-332);
- Second 500kV Bruce-Milton double-circuit line (CAA2006-250);
- Woodstock Area transmission reinforcement (CAA2006-253);
  - Karn TS in service and connected to M31W & M32W at Ingersol TS
  - W7W/W12W terminated at LFarge CTS
  - Woodstock TS connected to Karn TS
- Rodney (Duart) TS DESN connected to W44LC and W45LS 230 kV circuits (CAA2007-260)

(6) System Operation Conditions

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

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

Table 8: Fault Levels at Facilities Near the Project

	Before the Project		After the Project & Committed Generation		Lowest Rating of Circuit Breakers (kA)
	3-Phase	L-G	3-Phase	L-G	
*Symmetrical (kA)**					
Bruce A 230 kV	43.0	54.4	44.6	56.2	65***
Detweiler 230 kV	22.9	19.8	23.7	20.3	40
Majestic B23D 230 kV	18.1	16.2	18.6	16.5	63
Grand Bend PCC 230 kV	-	-	8.3	8.2	50
Grand Bend 230 kV	-	-	4.7	5.3	50
Seaforth 115 kV	11.6	13.6	13.7	16.3	29.5
Detweiler 115 kV	24.2	27.1	24.7	27.5	39.3
*Asymmetrical (kA)**					
Bruce A 230 kV	57.6	78.4**	59.7	80.8**	72.6***
Detweiler 230 kV	26.8	25.3	27.8	25.9	42.1
Majestic 230 kV	21.8	18.3	22.2	18.6	66.3
Grand Bend PCC 230 kV	-	-	9.9	10.1	(unknown)****
Grand Bend 230 kV	-	-	5.5	6.5	(unknown)****
Seaforth 115 kV	12.9	16.0	15.6	19.6	34.1
Detweiler 115 kV	28.1	33.3	28.7	33.9	45.4

* 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 applicant must provide the asymmetrical rating of the 230 kV circuit breakers during the IESO Market Entry process.

Table 8 shows the interrupting capability of the 230 kV circuit breakers of the project is 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 project 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 to examine the impact of the wind farm on existing transmission system protections. Proposed changes were included in the system impact studies.

Protection Changes

The changes to the existing transmission protection systems for incorporating the project have been proposed in the PIA report (Appendix B). The protection setting changes are summarized in Table 9.

Table 9: Proposed Protection Setting Changes

Station	Zone	Existing Reach (km)	Revised Reach (km)	Comments
Seaforth TS	1	65.3	Removed	Zone 1 will be removed due the proximity of the project connection point to Seaforth TS.
	2	102.1	159.2	Set at 125% of the maximum apparent impedance seen for a fault at Detweiler TS (196% of the line impedance).
Detweiler TS	1	101.3	64.9	Zone 1 shortened to ensure no instantaneous tripping for faults on the Grand Bend tap line.
	2	101.3	101.3	Unaltered. Set at 125% of the maximum apparent impedance seen for a fault at Seaforth TS.
Bruce TS	1	88	88	Unaltered. Set at 80% of the line impedance for a fault at Seaforth TS.
	2 (inst.)	152	Removed	Instantaneous Zone 2 settings will be removed to prevent tripping for Grand Bend tap line faults.
	2 (timed)	152	152	Unaltered. Set at 125% of the maximum apparent impedance seen for a fault at Seaforth TS.

Note: Protections at Seaforth TS protecting the section of the B23D circuit from Seaforth TS to Bruce TS will not be modified.

Breaker Fail:

Due to the increased exposure to fault conditions with the connection of the project’s 30 km tap line, an additional breaker in series with the proposed breaker is required at the connection point. This will ensure that with the failure of one breaker, faults to the projects 30 km tap line can be isolated without the tripping of terminal breakers at Bruce TS, Detweiler TS and Seaforth TS. This will result in less interruption to the existing generator and load facilities connected to the B23D circuit.

Blocking Signal:

The existing Permissive Overreaching Scheme at Seaforth TS and Detweiler TS will be modified to accept a blocking signal from the project. As such, a 50 ms Zone 2 time delay will be introduced in anticipation of receiving a blocking signal.

Telecommunication Requirements:

The connection applicant will be required to install ‘A’ and ‘B’ redundant, fully separated and geographically diverse communication links between the project and terminal stations.

The PIA concluded that the incorporation of the proposed project is feasible as long as the proposed changes outlined in the PIA report are made.

-End of Section-

6. System Impact Studies

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

6.1 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);
- Buchanan TS: one 250 MVAr shunt capacitor;
- Nanticoke and Detweiler SVCs;

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

(3) Basecases: Three basecases in terms of load levels were used in the SIA studies: peak load, shoulder load, and light load. 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 project into the system;

The system demand and the primary interface flows after the incorporation of the project are listed in Table 10.

Table 10: System Demand and Primary Interface Flows for Basecases (MW)

Basecase	System Demand	NBLIP	FABC	FETT	QEW	FS	FIO
Peak Load	26880	2023	6412	6913	1146	1250	1585
Shoulder Load	20716	986	6404	6707	1055	-488	1309
Light Load	11621	663	3845	906	34	-1048	746

6.2 Bruce Special Protection Scheme (BSPS)

The Bruce Special Protection Scheme (BSPS) is a collection of special protection systems installed at the Bruce B switching station (SS) and at other stations, which perform pre-defined control actions in response to recognized contingencies by monitoring the status of 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 the Northeast Power Coordinating Council (NPCC) Reliability Reference Directory #7.

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 project to accept a single pair (A & B) of 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 two 230 kV breakers at the connection point 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.

6.3 Reactive Power Compensation

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

Dynamic reactive compensation (e.g. D-VAR or SVC) is required for a generating 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 impedance between the generator and the connection point greater than 13% based on rated apparent power, provided the WTGs have the capability to provide a reactive power range of 0.90 lagging power factor and 0.95 leading power factor at rated active power, the IESO accepts that the wind farm compensates for excessive reactive losses in the collector system of the project with static shunts (e.g. capacitors and reactors).

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

<u>Dynamic Reactive Power Capability</u>

The dynamic reactive capability of the GE 2.5 turbines is shown in Figure 2, Appendix A. The GE 2.5 - 103 turbine has an option for power factor of 0.9 inductive to 0.9 capacitive. The turbines for this project will use this option. Thus, the dynamic reactive capability of Grand Bend WF meets the MR requirements.

Table 11: WTG Dynamic Reactive Power Capability

	Rated Voltage	Rated Active Power	Reactive Power Capability	Power Factor
IESO Requirements	690 V	2.5 MW	Q_{max} = +2.5 × tan [$\cos^{-1}$ (0.9)] = +1.21 Mvar	0.9 lag
			Q_{min} = -2.5 × tan [$\cos^{-1}$ (0.95)] = -0.82 Mvar	0.95 lead
GE 2.5 – 103 Capability	690 V	2.5 MW	Q_{max} = +1.21 Mvar	0.9 lag
			Q_{min} = -1.21 Mvar	0.9 lead

<u>Static Reactive Power Capability</u>

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

Load flow studies were performed to calculate the static reactive compensation, based on the equivalent parameters provided by the *connection applicant* for the WF.

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

- typical low voltage of 236 kV at the connection point;
- maximum active power output from the equivalent WTG;
- maximum reactive power output (lagging power factor) from the equivalent WTG, unless limited by the maximum acceptable WTG terminal voltage;
- maximum acceptable WTG voltage is 1.1, as per WTG voltage capability;

- the main step-up transformer ULTC is available to adjust the LV voltage as close as possible to 1 pu voltage.

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

- typical high voltage of 242 kV at the connection point;
- minimum (zero) active power output from the equivalent WTG;
- maximum reactive power consumption (leading power factor) from the equivalent WTG, unless limited by the minimum acceptable WTG terminal voltage;
- minimum acceptable WTG voltage is 0.9, as per WTG voltage capability;
- the main step-up transformer ULTC is available to adjust the LV voltage as close as possible to 1 pu voltage.

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

Table 12: Reactive Power Performance of the Project at the Connection Point

Operation	Collector Bus Voltage (pu)	Generator Terminal Voltage (pu)	PCC Reactive Power (Mvar)	PCC Voltage (kV)
Lagging PF	1.00	1.05	+26.3 Mvar	236 kV
Leading PF	0.97	0.92	-49.5 Mvar	242 kV

Based on the equivalent parameters for the WF provided by the connection applicant, an amount of 7 Mvar @34.5 kV of static capacitive reactive compensation is required to be installed at the WF collector bus to meet the reactive power requirements at the connection point. The capacitor bank shall be implemented as a part of the wind farm control system that automatically controls the switching of capacitor banks to regulate the overall WTGs' reactive output to around zero.

<u>Static Reactive Power Switching</u>

The IESO requires the voltage change on single capacitor switching to be no more than 4% at any point on the IESO-controlled grid. A switching study was carried out to investigate the effects on system voltages when switching in the new shunt capacitor. It was assumed that the largest capacitor step size is 7 Mvar. To reflect the reasonable restrictive system conditions, the voltage change study was studies under the light load condition and assumed that circuit B22D is out of service.

Table 13: Capacitor Switching Study Results

Capacitor at LV bus	LV bus voltage	Voltage at connection point
Pre-switching	34.6 kV	236.5kV
Post-switching	35.1 kV	237.7 kV
ΔV	1.4%	0.5%

The results show that switching a single capacitor of 7 Mvar produces less than 4% voltage change at the connection point.

6.4 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.

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

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 14 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 mitigation action and is in agreements with it.

Table 14: 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 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 15 and Table 16 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 15: 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 16: 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 230 kV Area Overview

The effects of the project on the thermal loadings of the 230kV transmission system in the Bruce area were examined. The defined shoulder load basecase was used for local thermal studies as it was tested to be the most limiting for area thermal loadings. The thermal ratings for summer weather conditions of all monitored circuits are summarized in Table 17.

Table 17: Local Area Thermal Ratings

Circuit	Section		Continuous	LTE
	From	To	Amps	Amps
B22D	Bruce A TS	Majestic JCT	1060	1400
	Majestic JCT	Armow WF JCT	1060	1400
	Armow WF JCT	Wingham JCT	1060	1400
	Wingham JCT	Seaforth TS	1060	1400
	Seaforth TS	Stratford JCT	920	1210
	Stratford JCT	Detweiler TS	920	1160
B23D	Bruce A TS	Majestic JCT	1060	1400
	Majestic JCT	Wingham JCT	1060	1400
	Wingham JCT	Seaforth TS	1060	1400
	Seaforth TS	Grand Bend JCT	920	1210
	Grand Bend JCT	Stratford JCT	920	1210
	Stratford JCT	Detweiler TS	920	1160
M20D	Detweiler TS	Detweiler JCT	1370	1820
	Detweiler JCT	Kitchener #8 JCT	1370	1820
	Kitchener #8 JCT	Galt JCT	1370	1820
	Galt JCT	Middleport TS	1370	1820
M21D	Detweiler TS	Detweiler JCT	1370	1820
	Detweiler JCT	Kitchener #8 JCT	1370	1820
	Kitchener #8 JCT	Galt JCT	1370	1820
	Galt JCT	Middleport TS	1370	1820

Table 18 shows the pre-contingency flows for the monitored circuits prior to and after the connection of the project. The pre-contingency results of the circuits include current flow in ampere and loading in percentage of continuous rating.

Table 18: Pre-Contingency Thermal Analysis

CCT	Section		Cont. Rating	Grand Bend WF Out of Service		Grand Bend WF In-Service	
	From	To	Amps	Amps	Cont %	Amps	Cont %
B22D	Bruce A TS	Majestic JCT	1060	125	11	133	12
	Majestic JCT	Armow WF JCT	1060	130	12	118	11
	Armow WF JCT	Wingham JCT	1060	481	45	451	42
	Wingham JCT	Seaforth TS	1060	447	42	421	39
	Seaforth TS	Stratford JCT	920	540	58	570	62
	Stratford JCT	Detweiler TS	920	436	47	470	51
B23D	Bruce A TS	Majestic JCT	1060	349	32	280	26
	Majestic JCT	Wingham JCT	1060	439	41	368	34
	Wingham JCT	Seaforth TS	1060	414	39	338	31
	Seaforth TS	Grand Bend JCT	920	527	57	379	41
	Grand Bend JCT	Stratford JCT	920	527	57	632	68
	Stratford JCT	Detweiler TS	920	428	46	529	57
M20D	Detweiler TS	Detweiler JCT	1370	405	29	441	32
	Detweiler JCT	Kitchener #8 JCT	1370	366	26	402	29
	Kitchener #8 JCT	Galt JCT	1370	339	24	375	27
	Galt JCT	Middleport TS	1370	69	5	103	7
M21D	Detweiler TS	Detweiler JCT	1370	342	25	379	27
	Detweiler JCT	Kitchener #8 JCT	1370	302	22	338	24
	Kitchener #8 JCT	Galt JCT	1370	272	19	309	22
	Galt JCT	Middleport TS	1370	57	4	62	4

The study results show increased flow on certain sections of the B22/23D and M20/21D circuits. In particular for the B23D circuit, the project tends to reduce the thermal loading on all sections from Bruce TS to the connection point of the project, but increase flows on all sections from the connection point of the project to Detweiler TS. However, all increased flows remain well below the continuous ratings of all circuits. Thermal impact of the project on circuits D6V, D7V, D4W and D5W was negligible. As such, these circuits have not been monitored for the thermal studies.

Using the study scenario with Grand Bend WF in-service, contingency studies were performed to identify potential post-contingency thermal violations. Table 19 summarizes the post-contingency flows for the monitored circuits. The post-contingency results of the circuits include current flow in ampere, and loading in percentage of LTE rating.

Table 19: Post-Contingency Thermal Analysis

CCT	Section		LTE	Loss of B22D		Loss of M20D		Loss of D4W + D5W		Loss of B4V + B5V		Loss of D6V + D7V		Loss of B560V + B561M	
	From	To	Amps	Amps	LTE %	Amps	LTE %	Amps	LTE %	Amps	LTE %	Amps	LTE %	Amps	LTE %
B22D	Bruce A TS	Majestic JCT	1400	-	-	137	9	184	13	144	10	112	8	185	13
	Majestic JCT	Armow WF JCT	1400	-	-	112	8	186	13	177	12	103	7	234	16
	Armow WF JCT	Wingham JCT	1400	-	-	434	31	495	35	542	38	458	32	603	43
	Wingham JCT	Seaforth TS	1400	-	-	405	28	465	33	512	36	429	30	574	41
	Seaforth TS	Stratford JCT	1210	-	-	557	46	606	50	655	54	593	49	715	59
	Stratford JCT	Detweiler TS	1160	-	-	457	39	505	43	555	47	493	42	615	53
B23D	Bruce A TS	Majestic JCT	1400	241	17	263	18	332	23	370	26	285	20	432	30
	Majestic JCT	Wingham JCT	1400	383	27	352	25	415	29	458	32	374	26	520	37
	Wingham JCT	Seaforth TS	1400	319	22	322	23	385	27	428	30	344	24	490	35
	Seaforth TS	Grand Bend JCT	1210	497	41	364	30	423	35	467	38	395	32	526	43
	Grand Bend JCT	Stratford JCT	1210	751	62	618	51	668	55	717	59	655	54	776	64
	Stratford JCT	Detweiler TS	1160	561	48	516	44	556	47	613	52	557	48	672	57
M20D	Detweiler TS	Detweiler JCT	1820	354	19	-	-	329	18	282	15	481	26	659	36
	Detweiler JCT	Kitchener #8 JCT	1820	315	17	-	-	295	16	243	13	443	24	620	34
	Kitchener #8 JCT	Galt JCT	1820	289	15	-	-	278	15	217	11	415	22	591	32
	Galt JCT	Middleport TS	1820	38	2	-	-	276	15	94	5	196	10	356	19
M21D	Detweiler TS	Detweiler JCT	1820	288	15	667	36	255	14	207	11	430	23	601	33
	Detweiler JCT	Kitchener #8 JCT	1820	248	13	590	32	224	12	167	9	392	21	562	30
	Kitchener #8 JCT	Galt JCT	1820	218	11	528	29	211	11	137	7	363	19	531	29
	Galt JCT	Middleport TS	1820	97	5	172	9	336	18	178	9	68	3	220	12

The contingency study results show no post-contingency thermal overloads on the monitored circuits in the local area. Therefore, there are no local area pre-contingency or post-contingency thermal overload issues after the incorporation of the proposed project.

6.5 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 cannot be less than 490 kV, voltages on 230 kV buses cannot be less than 220 kV and voltages on 115kV buses cannot be less than 113 kV;
- The post-contingency voltages on 500 kV buses cannot be less than 470 kV, voltages on 230 kV buses cannot be less than 207 kV and voltages on 115 kV buses cannot be less than 108 kV; and
- The pre-contingency and post-contingency voltages on 500 kV, 230 kV and 115 kV buses must be less than 550 kV, 250 kV and 127 kV respectively: and
- The voltage change following a contingency cannot 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.

Three contingencies were simulated under the defined light load case: (1) loss of Grand Bend WF; (2) loss of 230 kV circuit B23D; and (3) loss of 230 kV double circuits B23D and B22D. These studies were conducted assuming all wind facilities connected to circuits B22D, B23D and Seaforth 115kV system were in-service and absorbing reactive power close to their maximum capability pre-contingency, which result in the largest voltage change on the system due to the loss of these facilities by configuration.

One contingency was studied under the peak load case: (1) loss of B561M + B560V.

The study results summarized in Table 20 and Table 21 indicate that all voltage criteria are met and there are no voltage concerns after the incorporation of the project.

Table 20: Voltage Analysis for Light Load Case

Monitored Bus	Pre-Cont Voltage (kV)	***Loss of Grand Bend WF***				***Loss of B23D***				***Loss of B22D + B23D***			
		Pre-ULTC		Post-ULTC		Pre-ULTC		Post-ULTC		Pre-ULTC		Post-ULTC	
		kV	%	kV	%	kV	%	kV	%	kV	%	kV	%
Bruce A 230kV	245.5	246.2	0.3	246.2	0.3	245.7	0.1	245.7	0.1	248.9	1.4	248.9	1.4
Majestic B22D 230kV	243.7	244.5	0.3	244.4	0.3	243	0.3	242.9	0.3	-	-	-	-
Armow B22D 230kV	243.4	244.2	0.3	244.2	0.3	242.6	0.3	242.5	0.4	-	-	-	-
Wingham B22D 230kV	240.1	241.7	0.7	241.7	0.7	237.7	1	237.6	1	-	-	-	-
Seaforth B22D 230kV	237.5	239.7	0.9	239.7	0.9	234.2	1.4	234.1	1.4	-	-	-	-
Stratford B22D 230kV	239.8	241.8	0.8	241.8	0.8	237.5	1	237.5	1	-	-	-	-
Majestic B23D 230kV	244.3	245.4	0.5	245.4	0.5	-	-	-	-	-	-	-	-
Wingham B23D 230kV	239.2	242.3	1.3	242.3	1.3	-	-	-	-	-	-	-	-
Seaforth B23D 230kV	234.7	239.7	2.1	239.7	2.1	-	-	-	-	-	-	-	-
Grand Bend JCT 230kV	234.5	239.8	2.3	239.8	2.3	-	-	-	-	-	-	-	-
Grand Bend WF 230kV	231	-	-	-	-	-	-	-	-	-	-	-	-
Stratford B23D 230kV	237.6	240.9	1.4	240.9	1.4	-	-	-	-	-	-	-	-
Detweiler 230kV	242	243.6	0.6	243.6	0.6	242.7	0.3	242.7	0.3	246.8	2	246.8	2
Seaforth 115 kV	121.5	123.2	1.4	123.2	1.4	118.9	2.1	118.9	2.2	-	-	-	-

Table 21: Voltage Analysis for Peak Load Case

Monitored Bus	Pre-Cont Voltage (kV)	***Loss of B560V + B561M***			
		Pre-ULTC		Post-ULTC	
		kV	%	kV	%
Bruce A 500 kV	548.3	544.6	0.7	545.6	0.5
Bruce B 500 kV	549.0	545.1	0.7	546.1	0.5
Claireville 500 kV	526.9	507.6	3.7	513.5	2.5
Milton 500 kV	529.1	505.5	4.5	511.1	3.4
Nanticoke 500 kV	542.4	524.1	3.4	528.9	2.5
Bruce A 230 kV	247.0	249.8	1.0	249.9	1.2
Claireville 230 kV	248.1	239.3	3.6	242.7	2.2
Detweiler 230 kV	245.1	244.2	0.4	244.2	0.4

6.6 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.

Figures 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.

6.7 Transient Stability Performance

Transient stability simulations were completed to determine if the power system will be transiently stable with the incorporation of the proposed WF for recognized fault conditions in the Bruce area. In particular, rotor angles of generators at Bruce GS were monitored. Peak load conditions were used under the study assumptions provided in Section 6.1 of this report. All simulated contingencies are shown in Table 22.

Table 22: Simulated Contingencies for Transient Stability

ID	Contingency	Location	Fault Type	Fault Clearing Time (ms)		Reclosure Time (sec)
				Local	Remote	
SC1	B22D	Bruce	3 phase	83	108 (Detweiler & Seaforth)	Not Simulated***
SC2	B22D	Detweiler	3 phase	83	108 (Detweiler & Seaforth)	10s @ Detw.
SC3	D4W + D5W	Detweiler	3 phase**	83	108	Not Simulated***
SC4	B4V + B5V	Bruce	3 phase**	83	108 (Orangeville & Hanover)	Not Simulated***
SC5*	B560V + B561M	Bruce	L-L-G	66	91	Not Simulated***
SC6	B23D	Seaforth	3 phase	133	133 Detweiler 108 Bruce	Not Simulated***
SC7	Grand Bend WF	LV Collector Bus	3 phase	Uncleared		-

* Longwood Reactor Switching simulated at 124 ms

** 3 phase faults on these double circuit lines have been simulated in place of line to line to ground (LLG) faults, as this represents a more conservative and more severe fault than recognized by the IESO. If transient responses are stable and well damped for the three phase fault, then the responses for the LLG fault will also be stable and well damped.

*** Effects of reclosure are negligible and have been omitted for the specified simulation.

Figures 4 - 10, Appendix A show the transient response plots of the rotor angles and bus voltages. The transient responses show that the generators remain synchronized to the power system and the oscillations are sufficiently damped following all simulated contingencies. It can be concluded that with the proposed project in-service, none of the simulated contingencies caused transient instability or un-damped oscillations.

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

6.8 Voltage Ride-Through Capability

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

The proposed GE 2.5 MW WTGs are equipped with the ZVRT capability. The ZVRT settings of the GE 2.5 WM WTG were outlined in Table 2 of Section 3.2.

The VRT capability of the WTGs was assessed based on the terminal voltages of the WTGs under the simulated contingencies in Table 22 and the additional breaker fail contingencies in Table 23.

Table 23: Additional Simulated Contingencies for Voltage Ride Through

ID	Contingency	Location	Fault Type	Fault Clearing Time (ms)	
				Local	Remote
SC8	Detweiler T2 w/ HT2 BFK	Detweiler 230 kV	3 phase	281	131
SC9	Bruce T28 w/ K2L4 BKF	Bruce 230 kV	3 phase	211	81

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 11, Appendix A shows the terminal voltages of the WTGs at collector C1 under simulated contingencies of Table 23. Only contingencies in Table 23 have been shown as they are the most severe for voltage ride through. It shows that the terminal voltages of the WTGs remain below 0.75 pu for about 200 ms, and recover to within 0.9 – 1.1 pu in less than 400 ms after the fault inception. As compared with the VRT capability of the GE 2.5 WTG, the proposed WTGs are able to remain connected to the grid for recognized system contingencies that do not remove the project by configuration.

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

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

6.9 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 circuit B23D will trip for out of zone faults due to the addition of the project, as well as to verify the feasibility of the proposed changes to protection reaches outlined in the PIA report. The contingencies in Table 22 were simulated with the results of impedance trajectories at Seaforth TS (looking toward Detweiler TS) for SC1, SC2, SC4, and SC5 shown in Figures 12-15, Appendix A.

The relay margin plots show that the trajectory on circuit B23D does not penetrate the relay characteristic with a margin of greater than 20%, thereby meeting the Market Manual requirement and verifying that circuit B23D will not trip for out of zone faults.

It can be concluded that the increasing of the zone 2 reach at Seaforth TS as proposed in the PIA report will have no material adverse impact on the IESO-controlled grid in terms of relay margin criteria.

-End of Section-

Appendix A: Figures

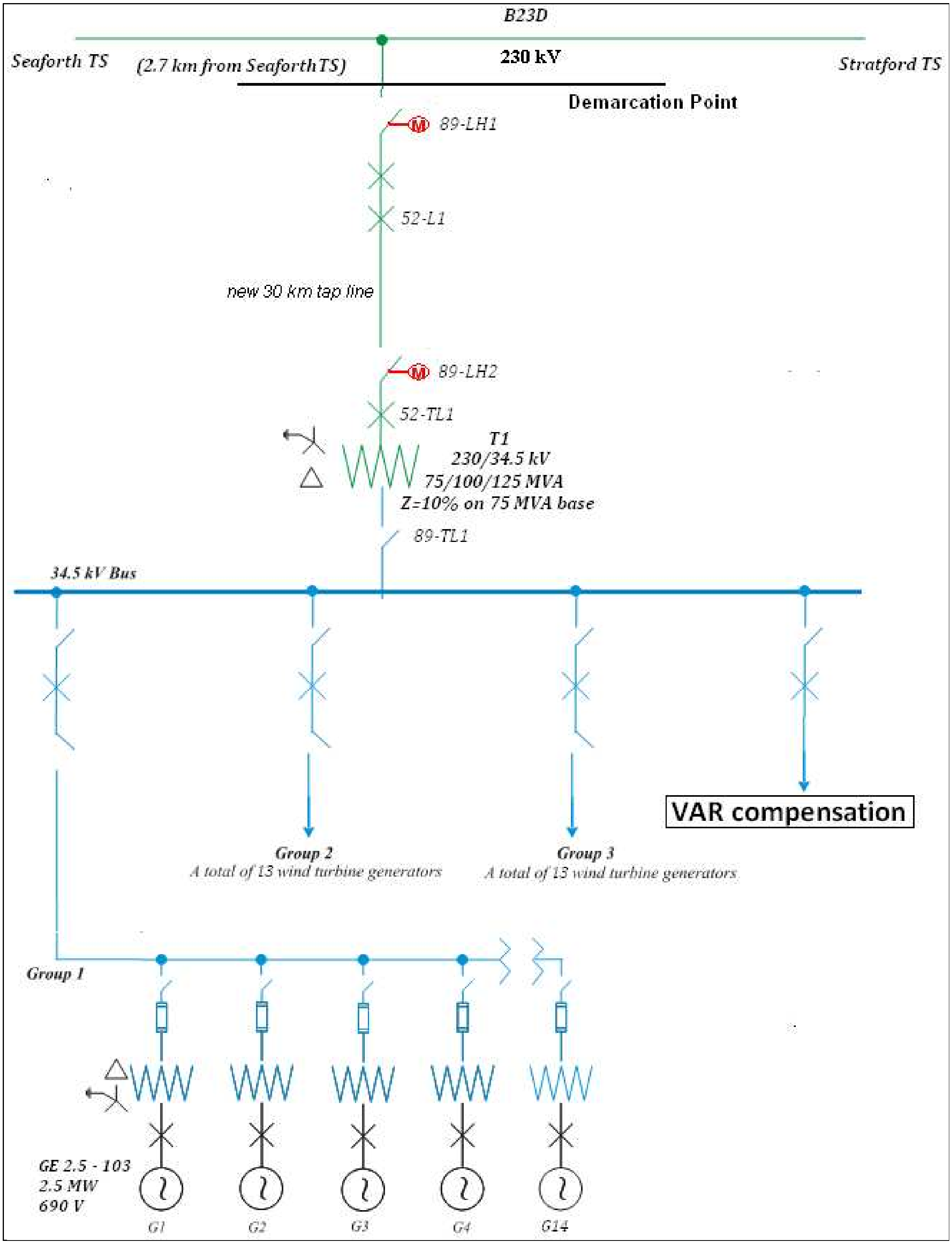


Figure 1: Proposed Connection Arrangement

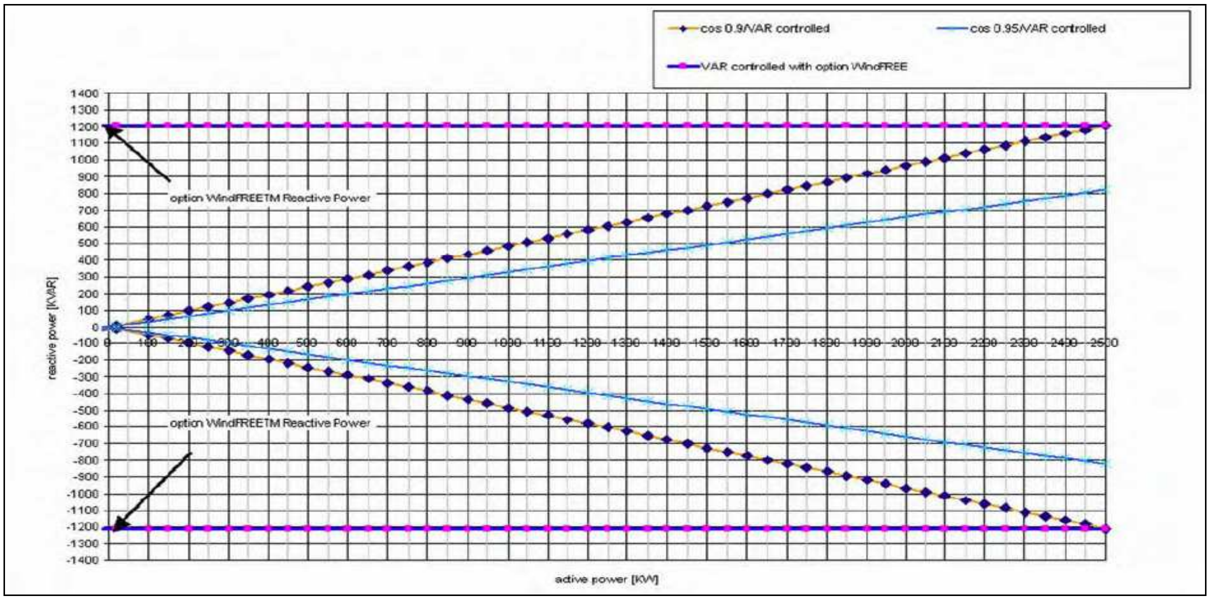


Figure 2: GE 2.5 MW WTG Dynamic Reactive Power Capability Curve

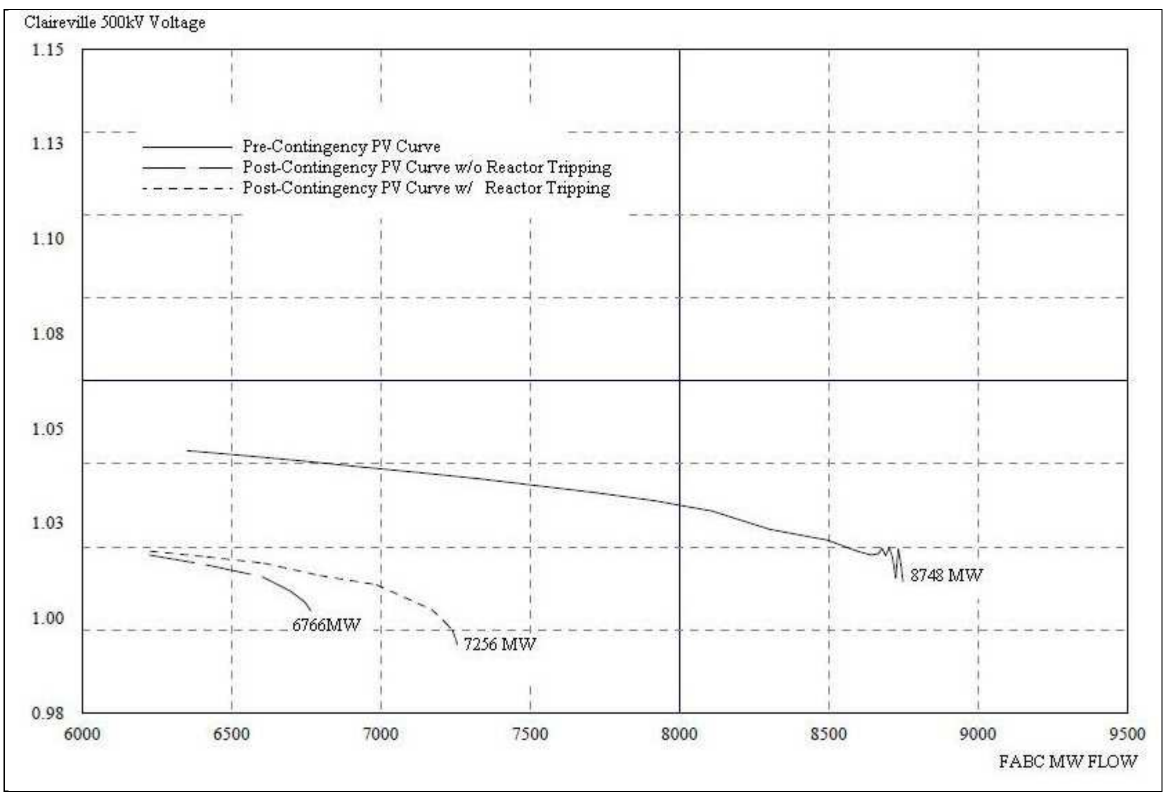
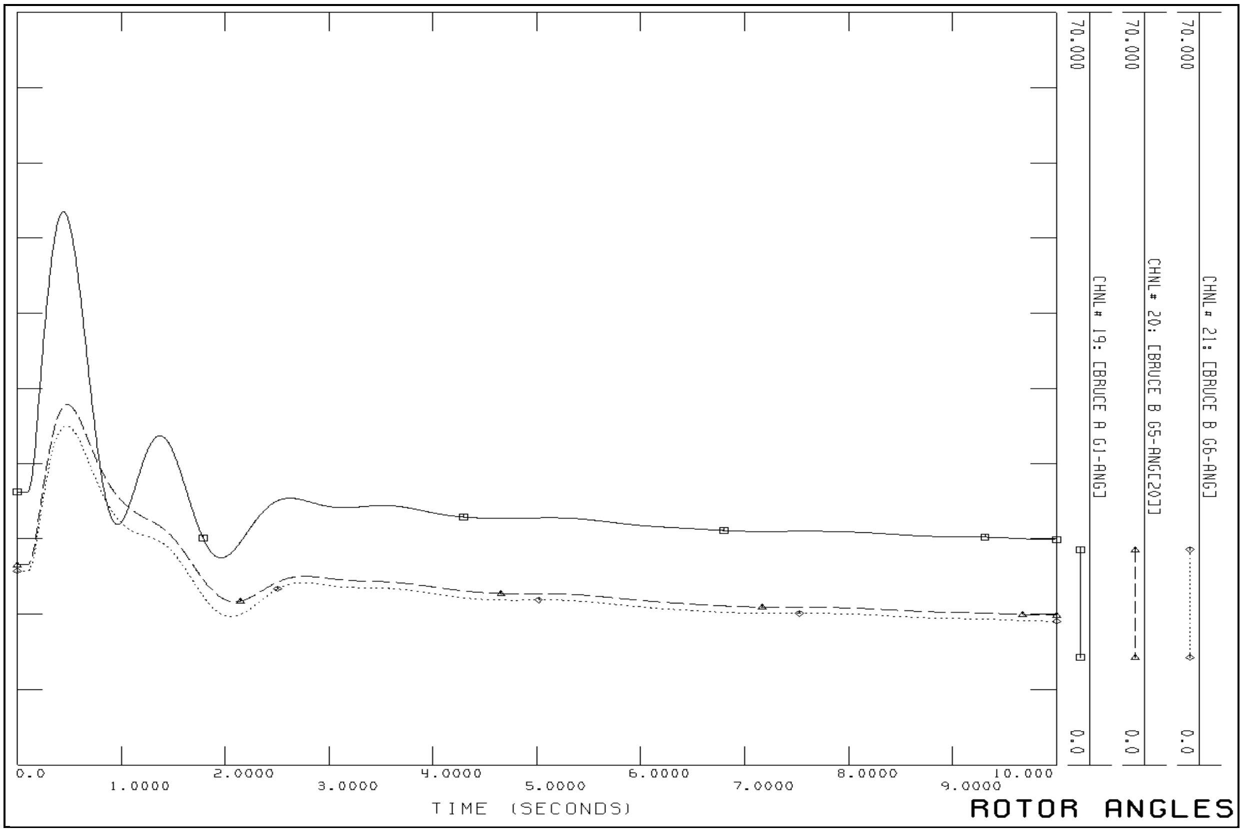


Figure 3: Voltage Responses at Claireville 500kV vs. FABC Transfer under Defined Scenarios



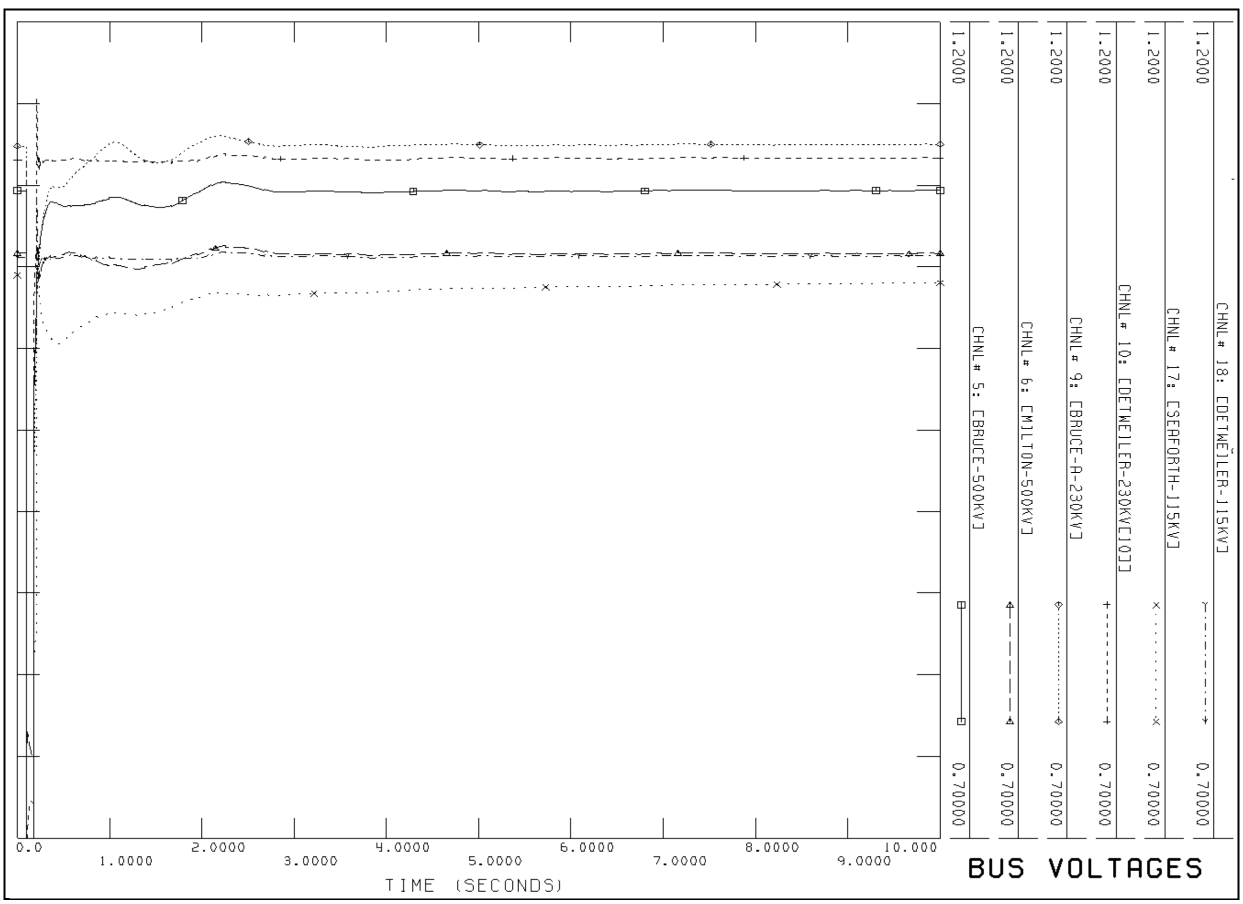
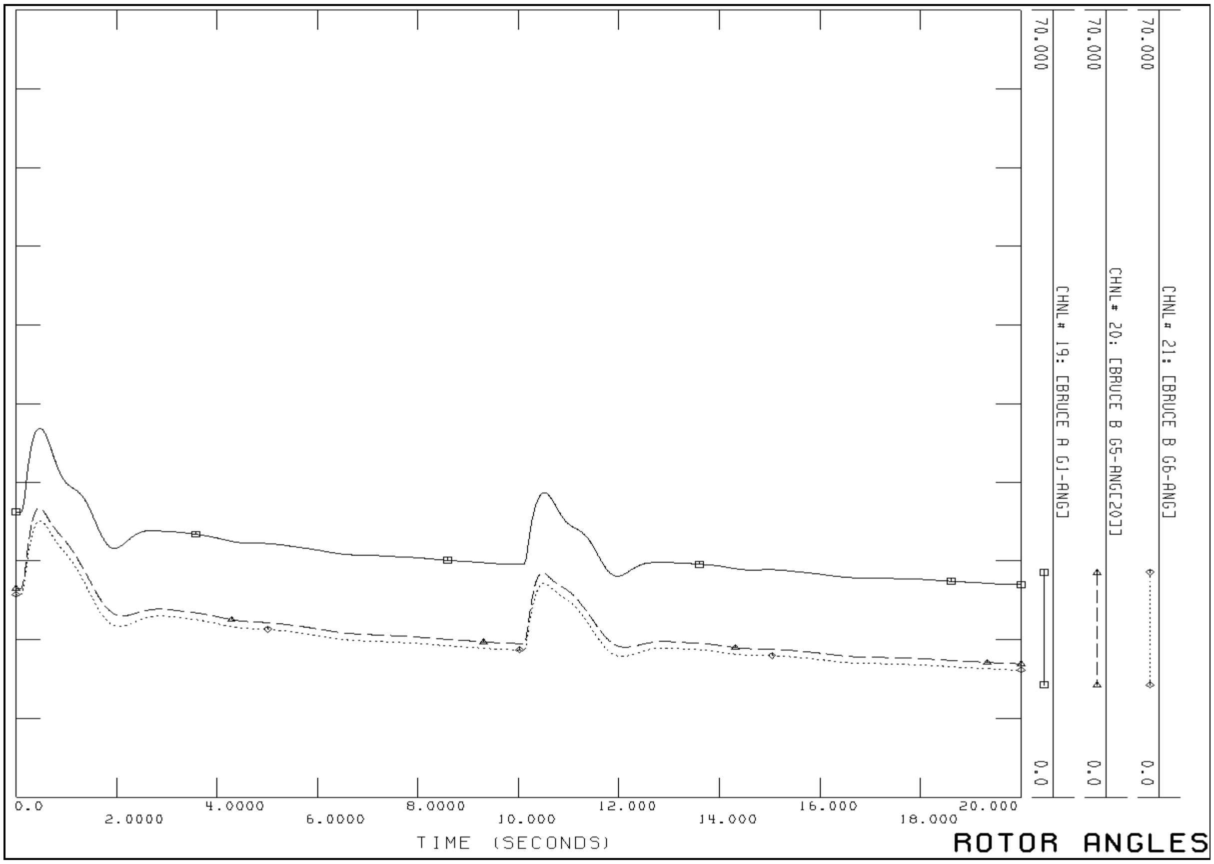


Figure 4: B22D - 3 Phase Fault @ Bruce



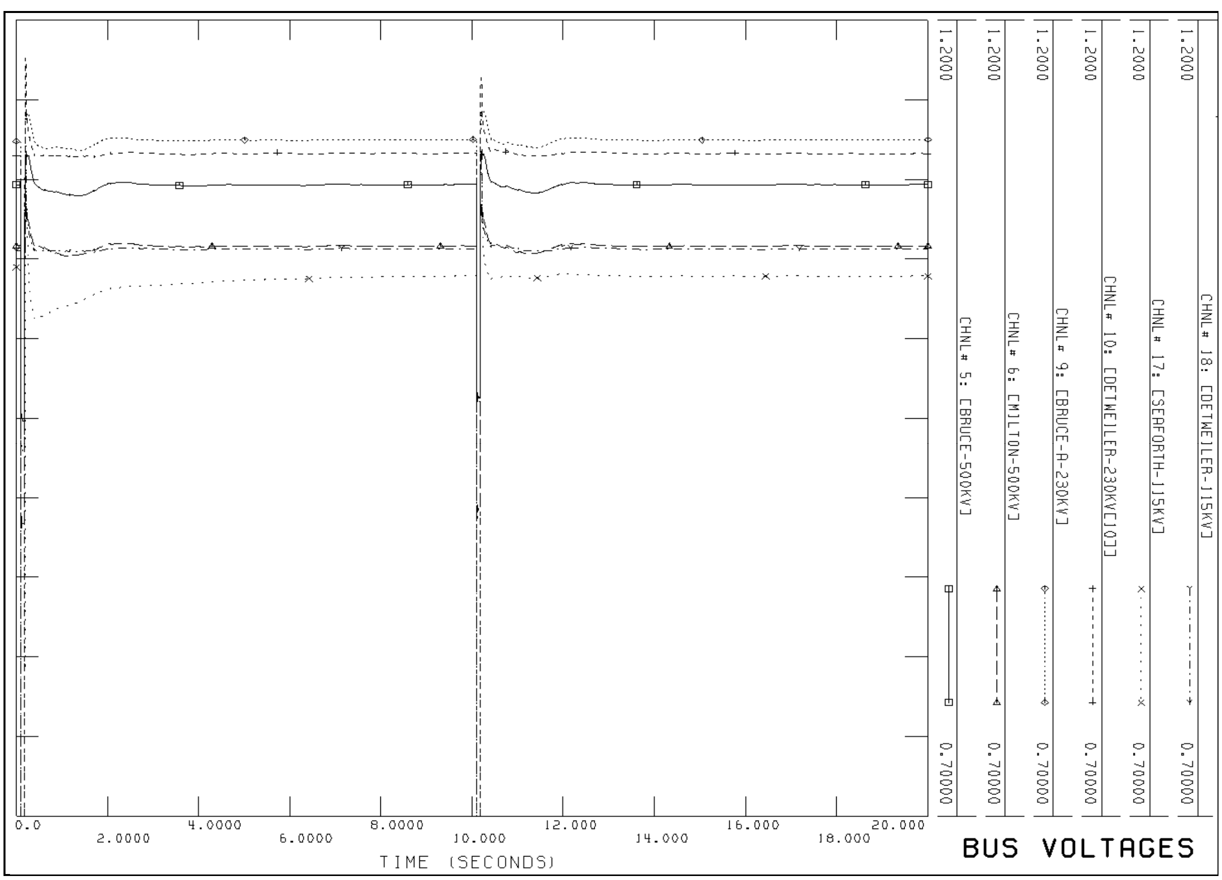


Figure 5: B22D - 3 Phase Fault @ Detweiler

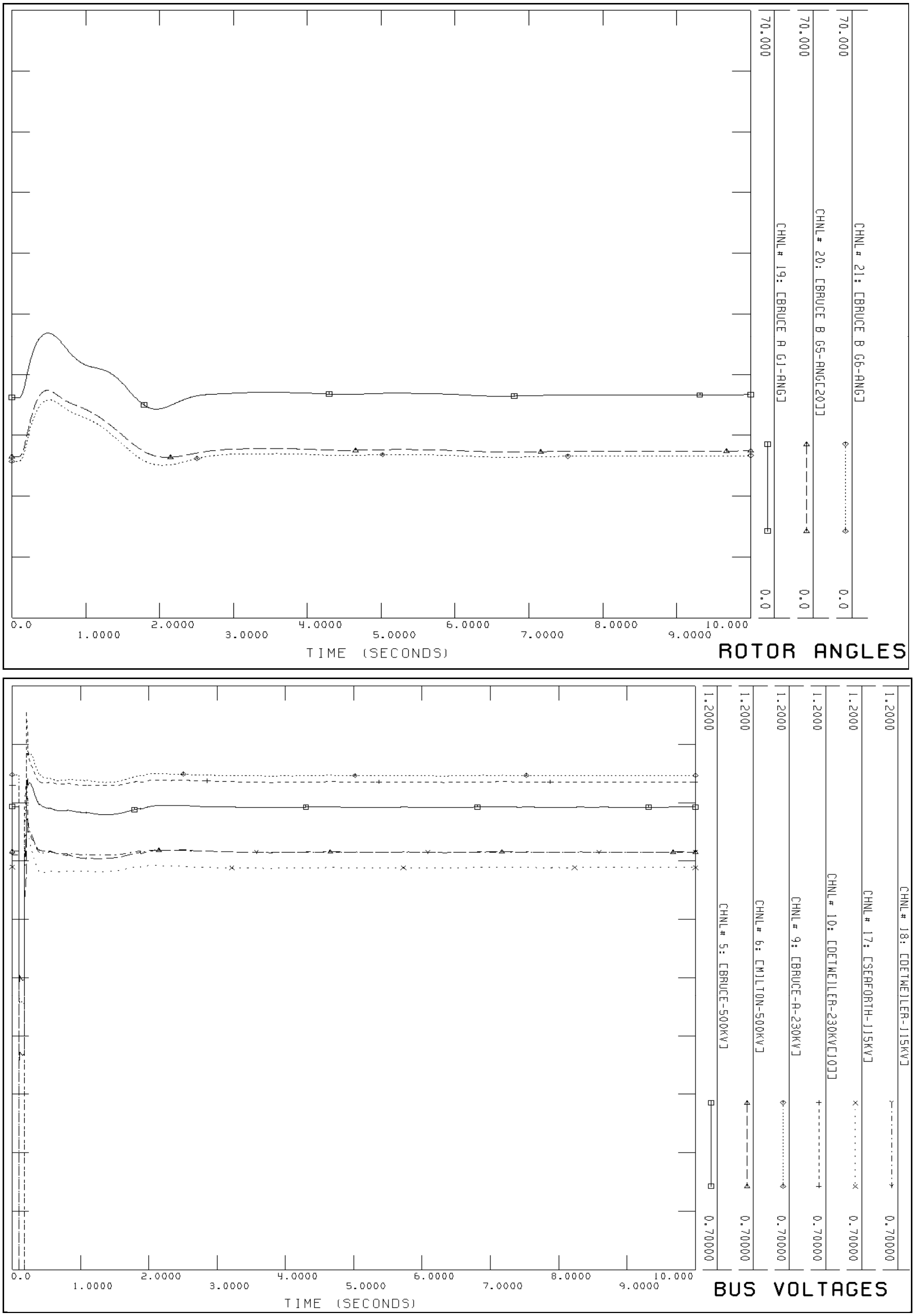


Figure 6: D4W & D5W – 3 Phase Fault @ Detweiler

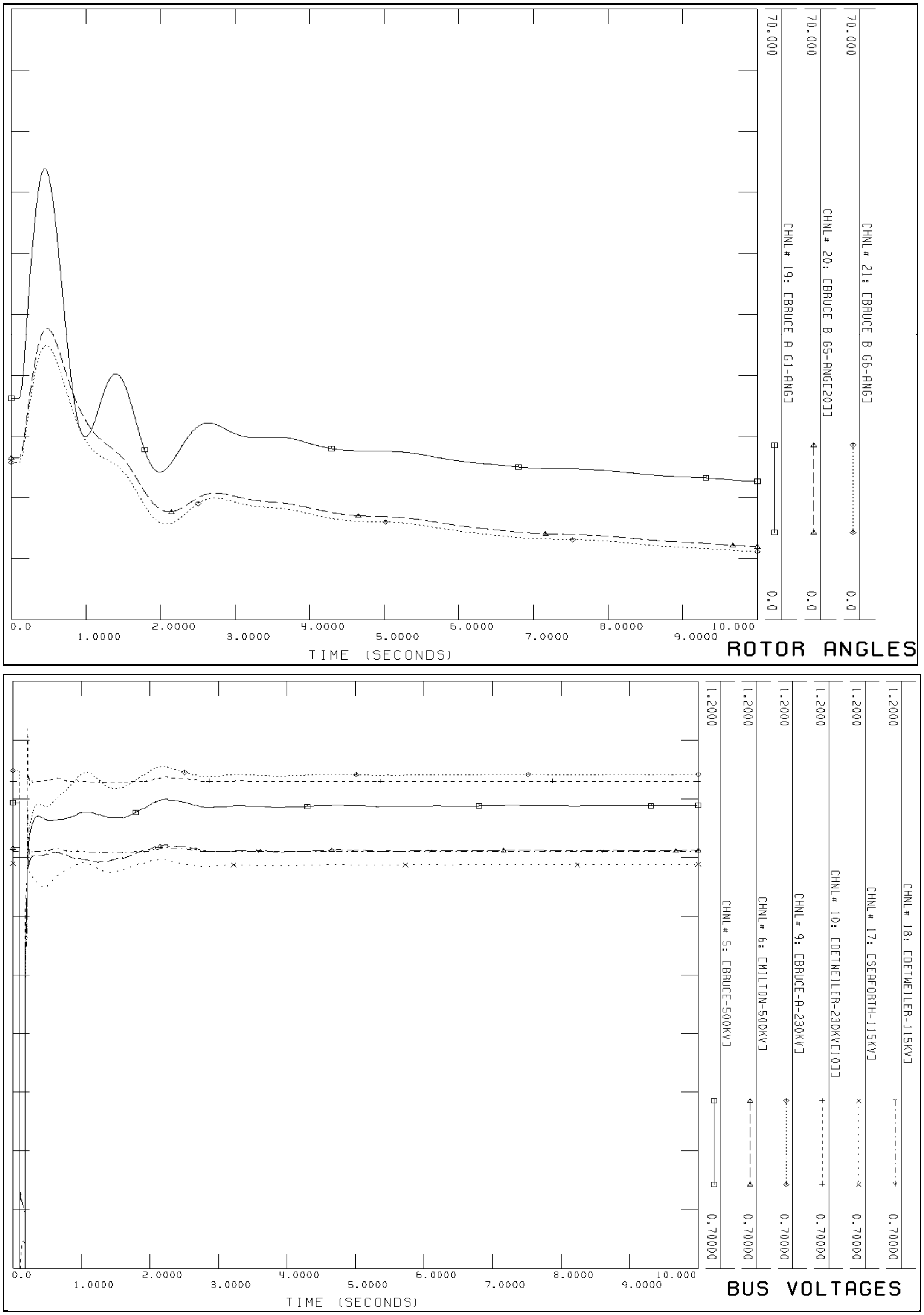
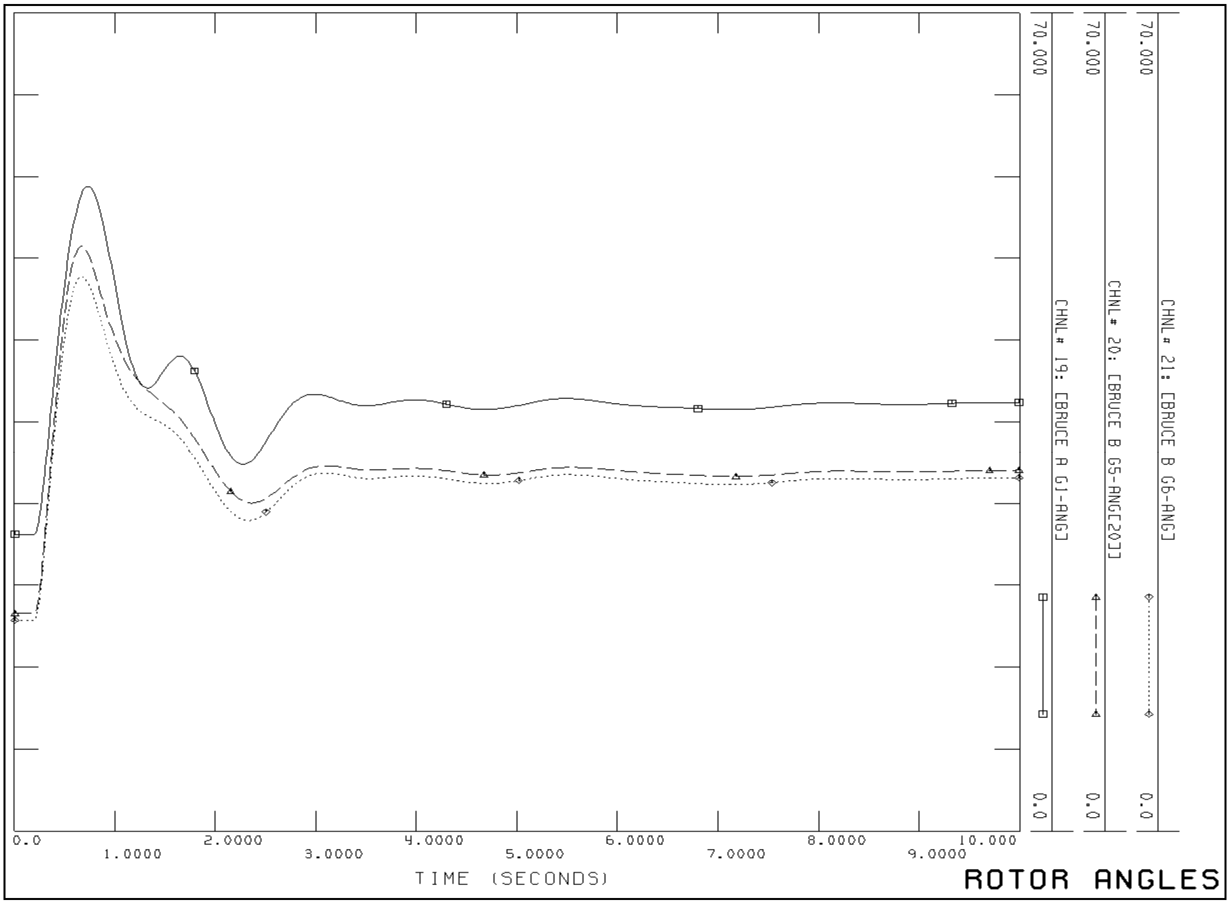


Figure 7: B4V & B5V – 3 Phase Fault @ Bruce



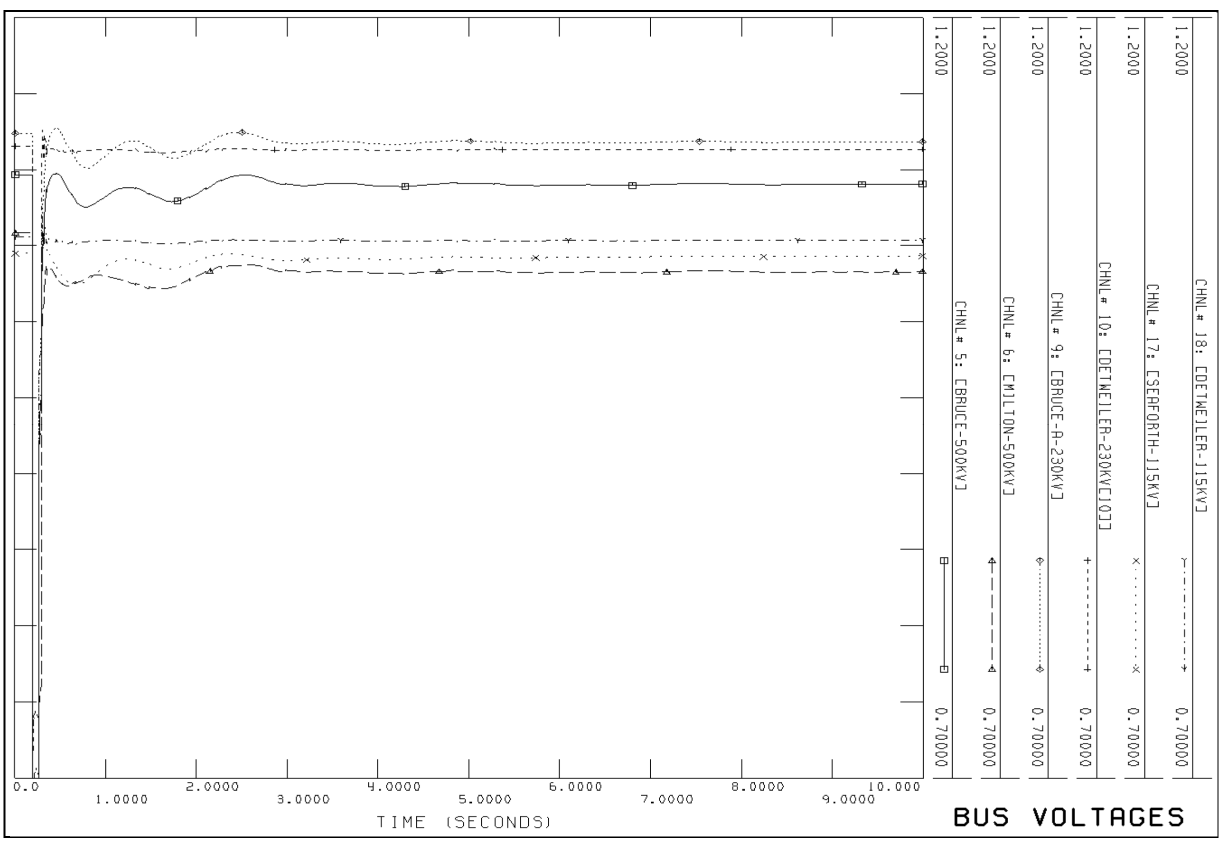
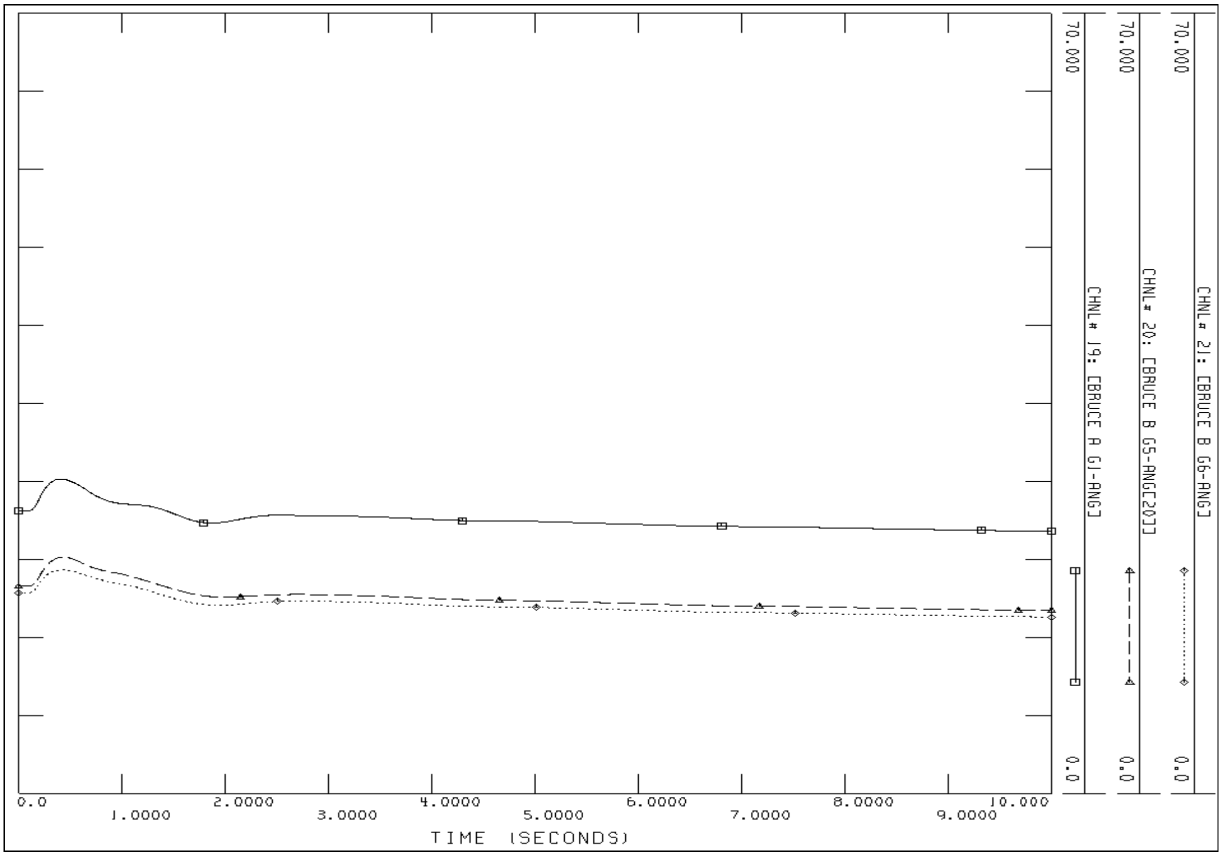


Figure 8: B560V & B561M – 3 Phase Fault @ Bruce



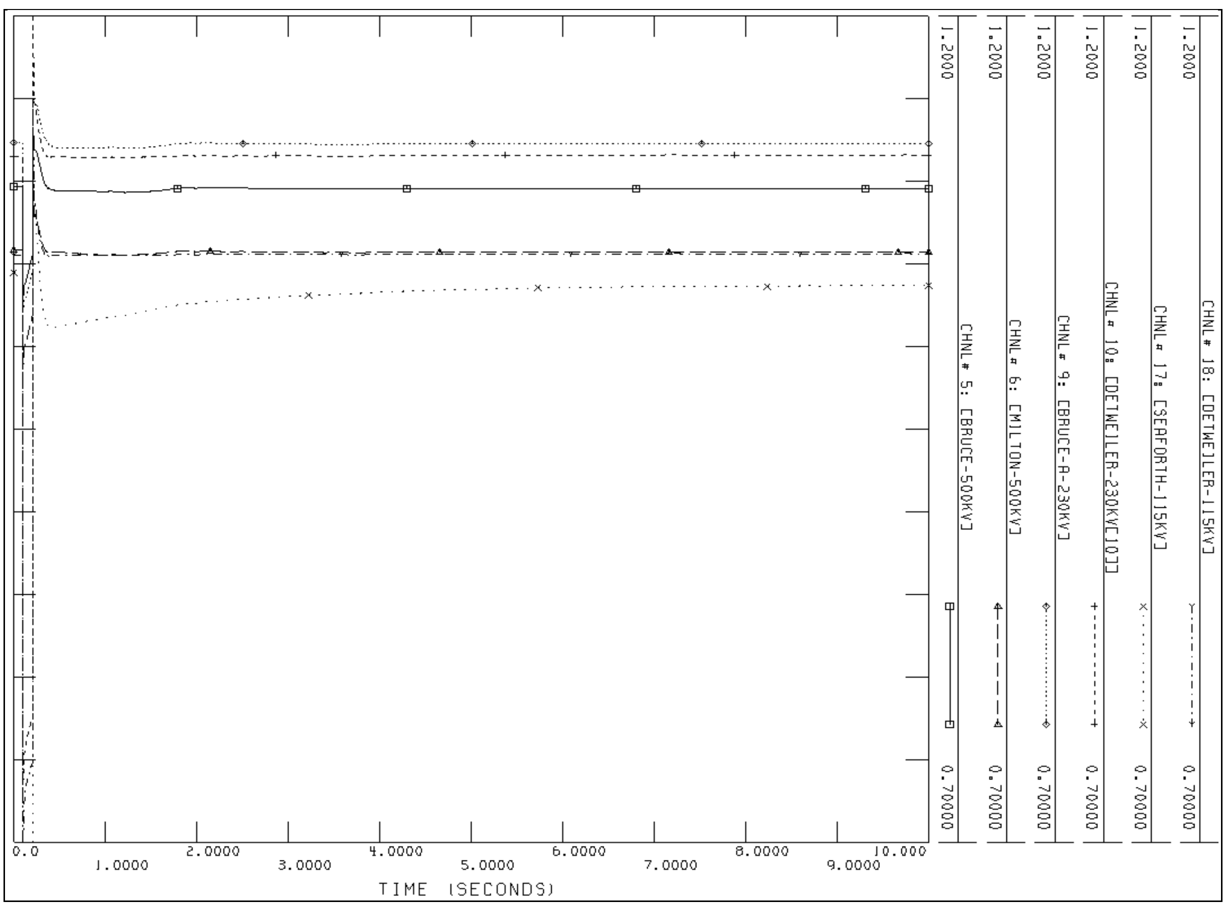


Figure 9: B23D – 3 Phase Fault @ Seaforth

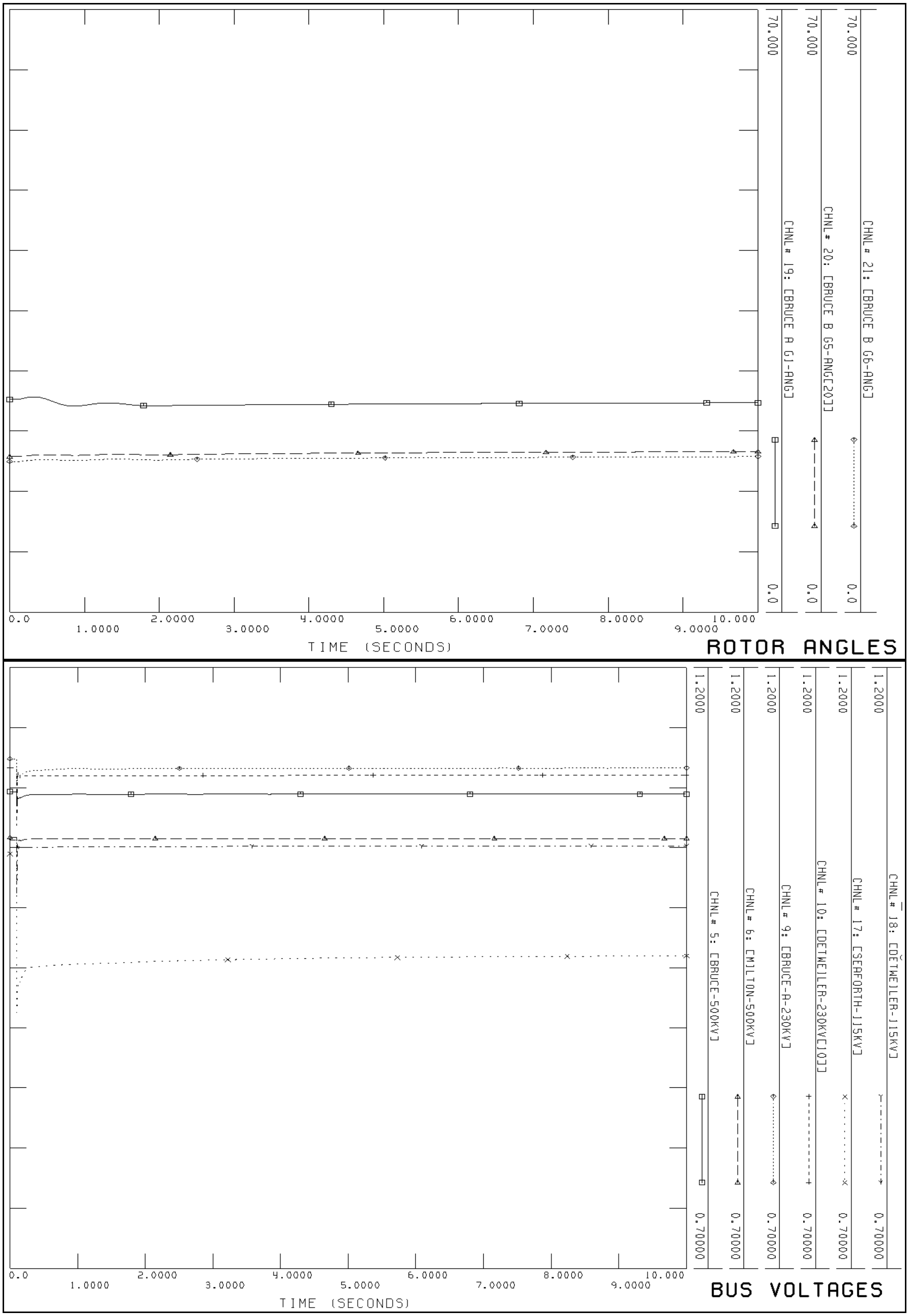


Figure 10: Uncleared 3 Phase Fault @ Grand Bend 34.5 kV Collector Bus

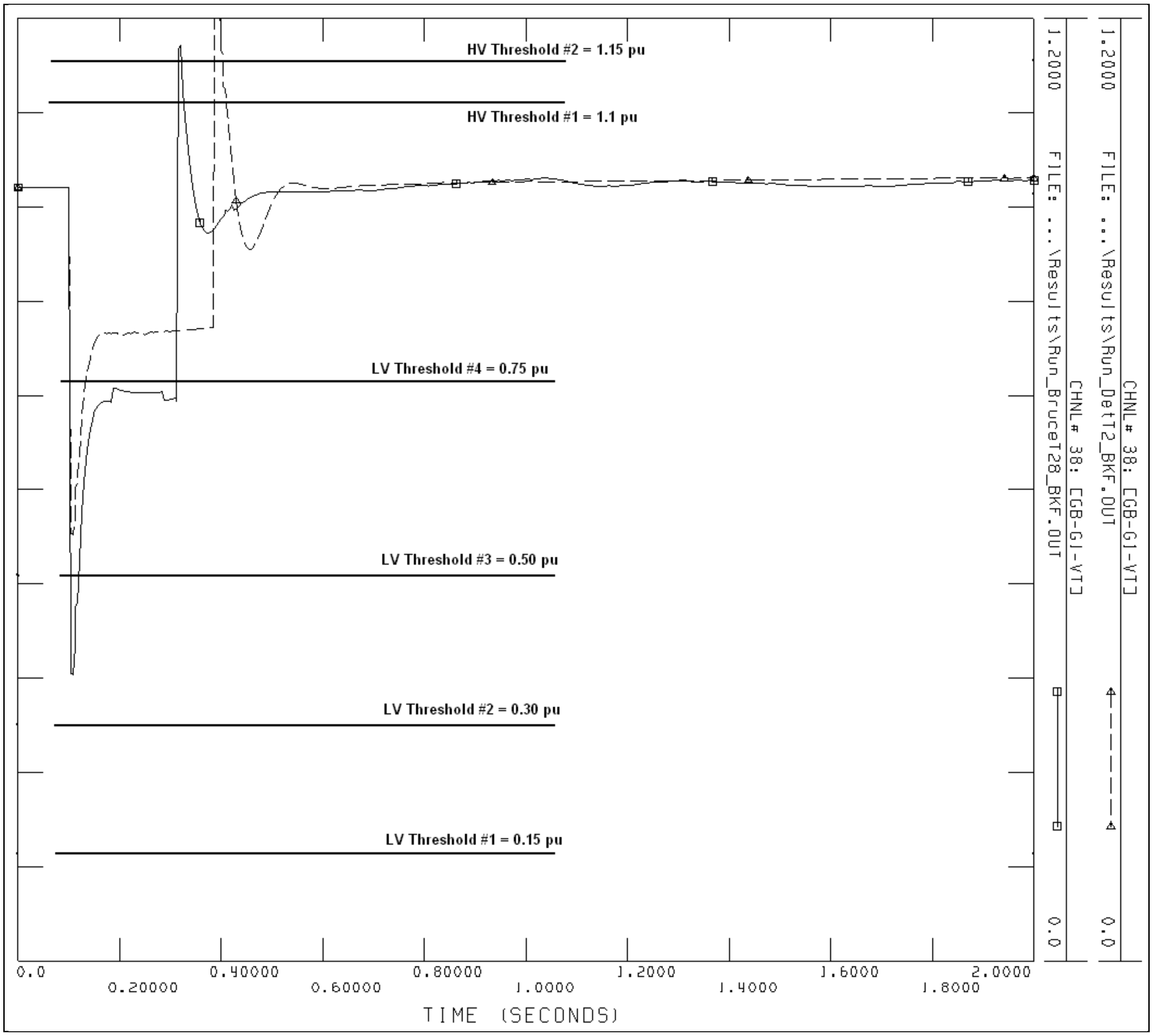


Figure 11: WTG Terminal Voltages of Feeder C1 for Studied Contingencies

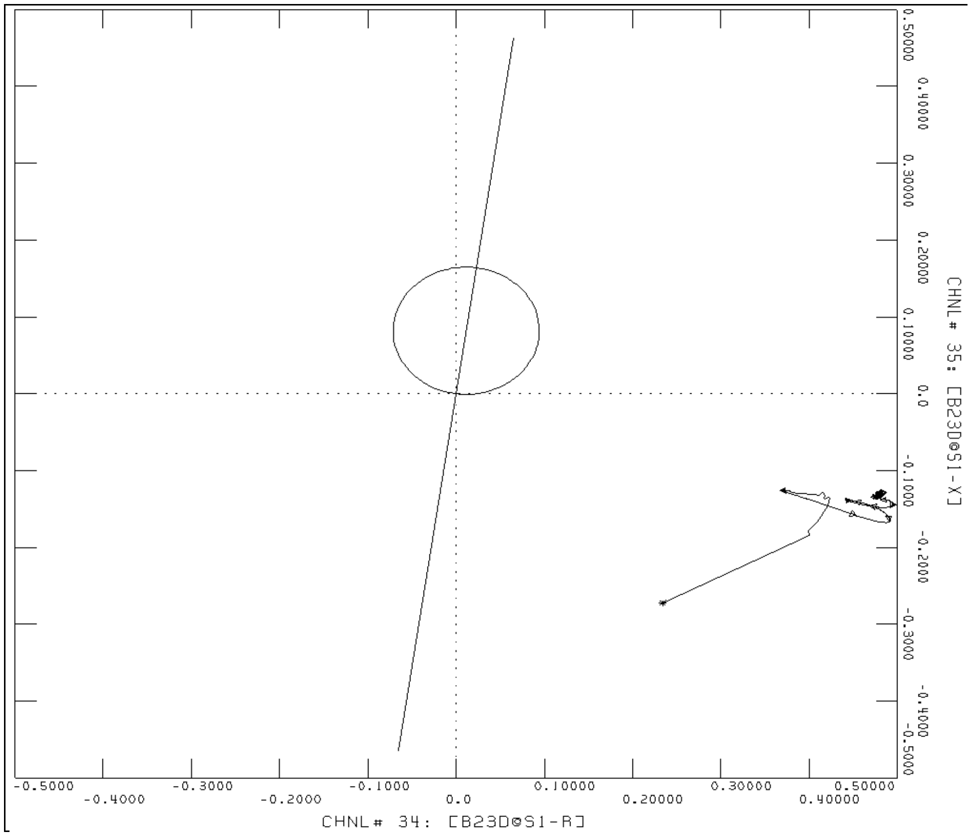


Figure 12: B23D @ Seaforth Impedance Trajectory for 3 phase fault on B22D at Bruce

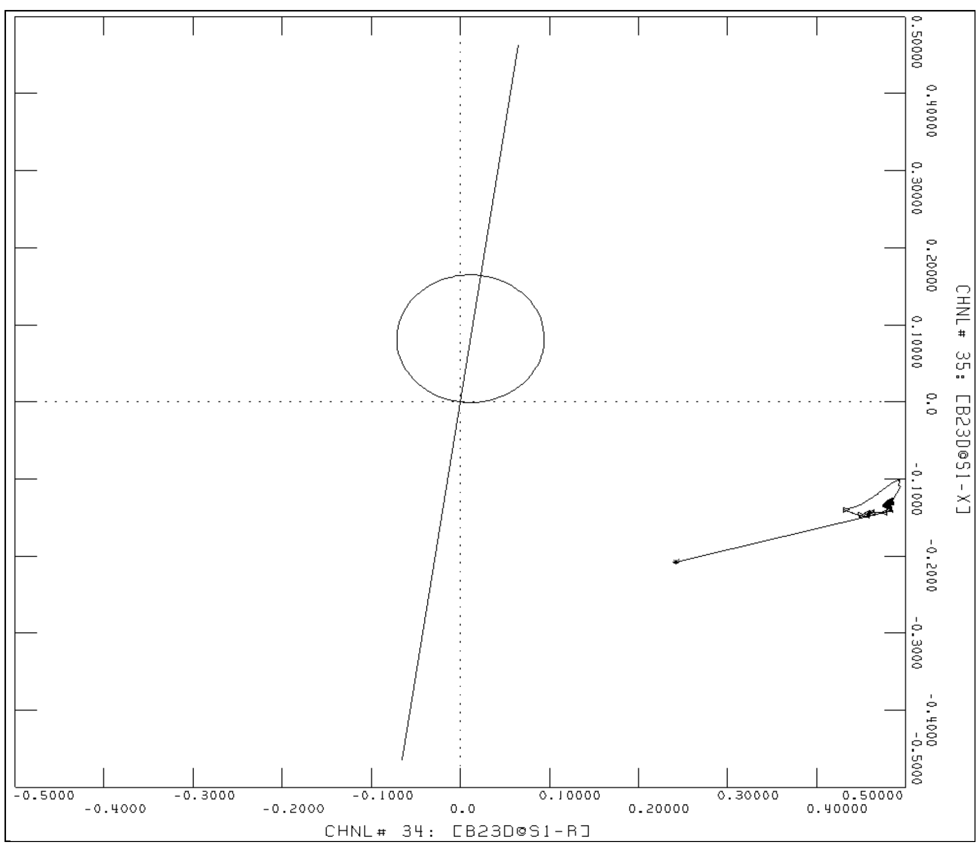


Figure 13: B23D @ Seaforth Impedance Trajectory for 3 phase fault on B22D at Detweiler

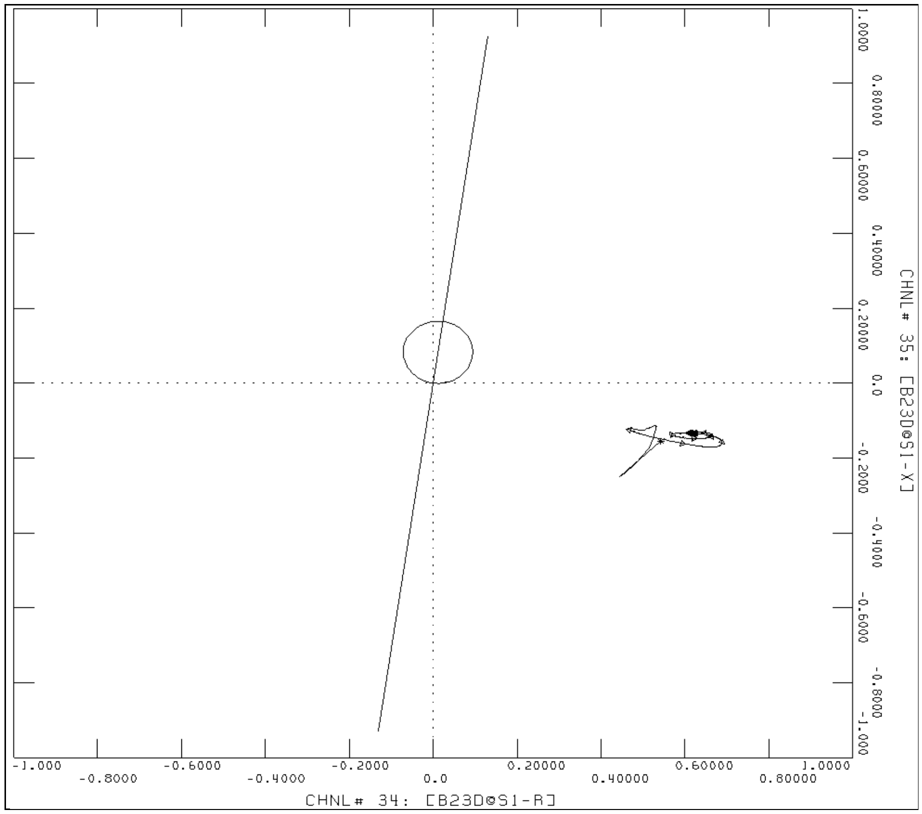


Figure 14: B23D @ Seaforth Impedance Trajectory for LLG fault on B4V and B5V at Bruce

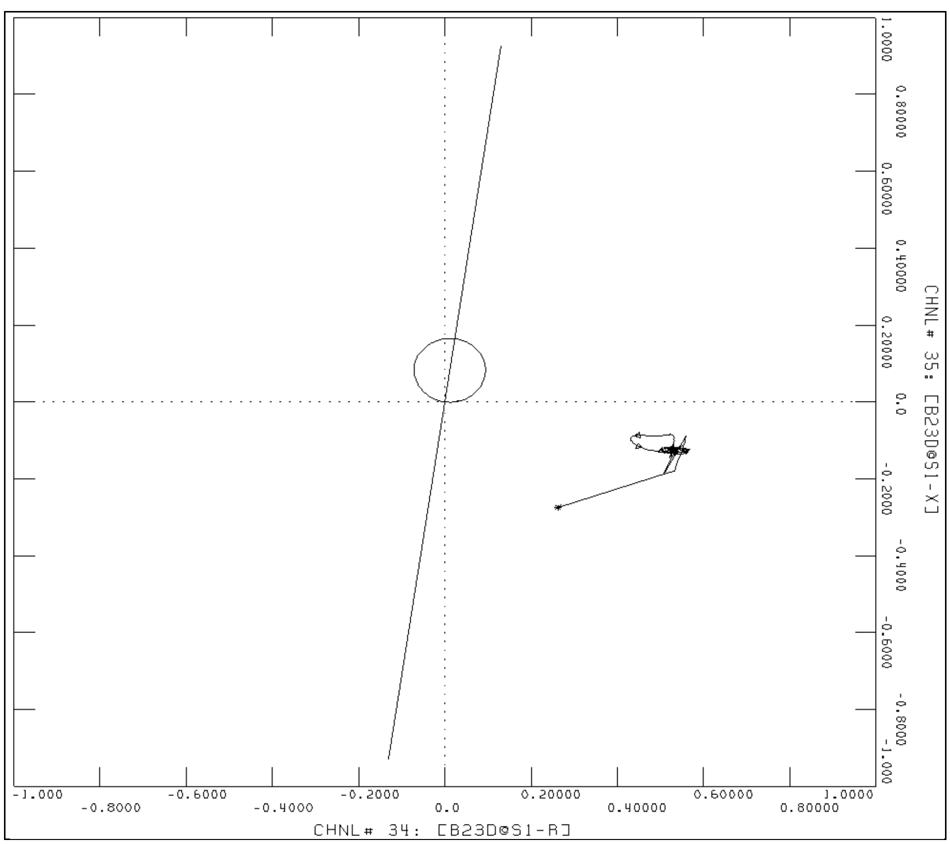


Figure 15: B23D @ Seaforth Impedance Trajectory for LLG fault on B560V and B561M at Willow Creek JCT

Appendix B: PIA Report

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

PROTECTION IMPACT ASSESSMENT

GRAND BEND WIND FARM PROJECT

100 MW WIND FARM GENERATION CONNECTION

Date: October 24, 2011
P&C Planning Group Project #: PCT-295-PIA

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	September13, 2011	
R1	September 28,2011	Modified Sec. 1.0 (Executive Summary)
R2	October 12, 2011	Modified Zone 1 reach for Detweiler TS & Outlined protection changes for Bruce.
R3	October 24, 2011	Revised Tele-protection requirements.

PROTECTION IMPACT ASSESSMENT
GRAND BEND WF PROJECT
100 MW WIND GENERATION CONNECTION

1.0 EXECUTIVE SUMMARY

The impact of the proposed 100 MVA, 60 HZ wind generating station on the existing transmission protections has been studied and the connection of the generation is deemed feasible at the proposed location with the necessary changes highlighted in the subsequent sections.

The generating station will be connected to HONI's 230 KV circuit, B23D (LH19), between Seaforth TS and Detweiler TS approximately 3.5 km south of Seaforth TS via a 30 km long overhead line as shown in Figure 1 below. The connection presents many challenges and requires a vigilant analysis of the Hydro One circuit reliability and protection complexities arising there of.

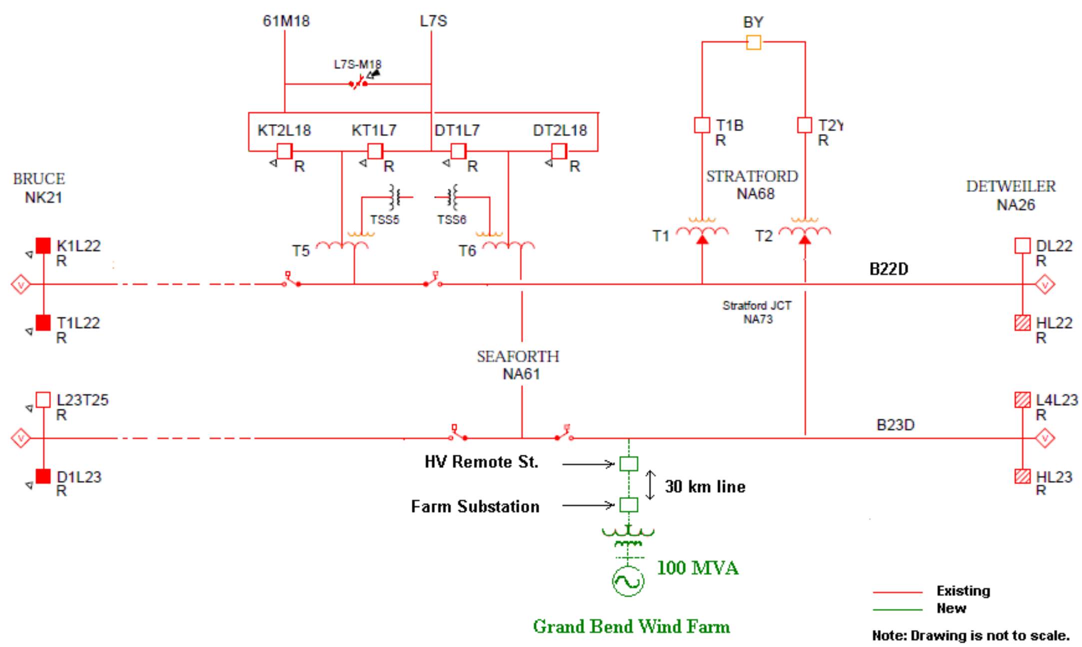


Figure 1: Grand Bend WF Connection to HONI Transmission System

The proposed arrangement would require a breaker failure protection to be installed at the proponents HV remote station. The increased frequency of faults due to an additional 30 km of 230 KV line makes the region more susceptible to instabilities; an un-cleared fault (breaker failure) on this line would trip the HONI terminal stations (Bruce and Detweiler TS) resulting in a widespread tripping of the present and future customers on that line as shown in Figure 2 below – consequently degrading the reliability of the HONI circuit. The reliability is further impacted due to the procedural complexities involved and the time required for the manual restoration of the HONI circuit after a breaker failure.

The proximity of the point of connection to the Seaforth TS (3.5 km) presents a protection challenge adding to the overall impact on the reliability of the HONI circuit, this is due to the fact that existing Zone1 protection at the Seaforth TS will need to be eliminated as the reach can not be contracted enough to exclude the proponent's connection and the new line.

It is therefore critical to devise an arrangement that will, to extent possible, mitigate the impact on the reliability of the HONI circuit. For this reason, it is required to have two breakers in series at the proponent's HV Remote Station to eliminate the need of a breaker failure protection – avoiding the widespread tripping as well as the difficulties involved in restoration of the line after a breaker failure.

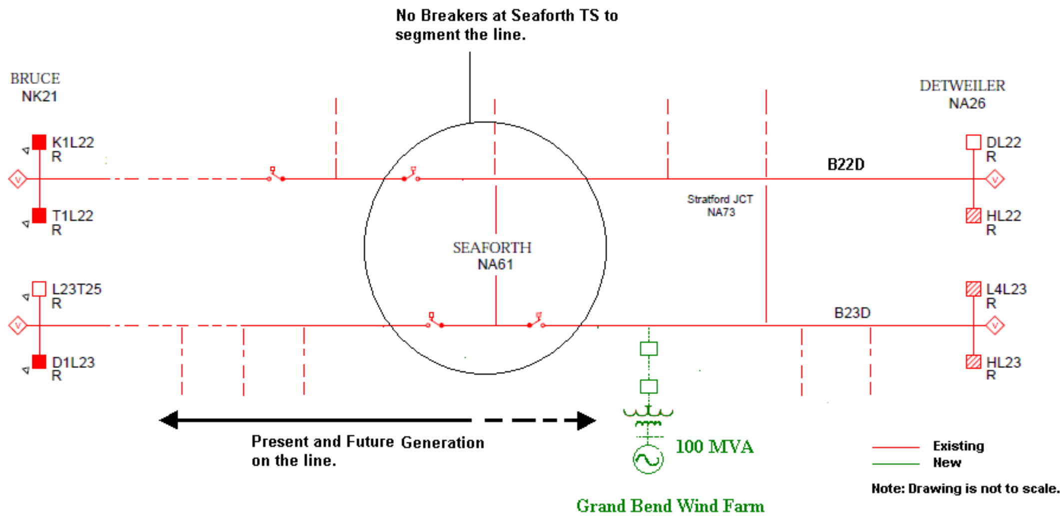


Figure 2: Breaker positions on the line B23D (LH15 & LH19)

2.0 PROTECTION HARDWARE

The necessary protection hardware requirements are highlighted below.

2.1 Seaforth TS

The existing protections on the line B23D (LH19) consist of electro-mechanical relays in the 'A' and microprocessor based relays in the 'B' group protections. New 'A' protection shall be installed with the standard IEDs meeting NPCC requirements in order to facilitate addition of the teleprotections for Grand Bend WF.

2.2 Detweiler TS

The existing protections on the line B23D (LH19) consist of microprocessor-based relays in the 'A' and 'B' group protections. No major changes are anticipated in the protection hardware.

2.3 Bruce TS

The existing protections on the line B23D (LH15) consist of electro-mechanical relays in the 'A' and microprocessor based relays in the 'B' group protections. No major changes are anticipated in the protection hardware.

2.4 Grand Bend Wind Farm HV Remote Station

Two breakers in series shall be installed at this station to eliminate the need of a breaker failure protection.

'A' and 'B' Trip/Close modules, alarms, status and reclose devices shall be installed for the new 230kV breakers meeting NPCC requirements. 'A' and 'B' line protections for the 230 kV line (Grand Bend HV Remote Station to Grand Bend HV Substation) shall be installed with the standard IEDs meeting NPCC requirements. It is recommended to employ the differential line protection scheme for this line.

Communication paths shall be established between the Grand Bend HV Remote Station to Seaforth TS and the Detweiler TS. The line protection will send a blocking signal to both Seaforth TS and the Detweiler TS incase of a fault on the line to avoid tripping of the terminal stations by the Zone 2 protections.

2.5 Grand Bend HV Substation

It is customer's responsibility to protect this station in coordination with what is specified in Section 2.4.

3.0 PROTECTION SETTINGS

The necessary protection setting requirements are highlighted below.

3.1 Seaforth TS

Zone 1 shall be eliminated from the Seaforth TS; the existing Permissive Overreaching Scheme between Seaforth TS and Detweiler TS shall be modified to accept a blocking signal from the Grand Bend HV Remote Station for faults on their line. The Zone 2 settings shall be changed to cover the maximum apparent impedance of the line due to the increased generation close to this station.

3.2 Detweiler TS

The Zone 1 reach shall be contracted to cover 80% of the line to Seaforth and Zone 2 shall be delayed and protection logic shall be modified to accept a blocking signal from the Grand Bend HV Remote Station.

3.3 Bruce TS

The Zone 2 instantaneous tripping shall be eliminated from the current protection and the existing permissive scheme shall be revised to enable the Zone 2 to trip instantaneously with the permissive signal.

4.0 TELE-PROTECTION

The customer must have communications ('A' & 'B' redundant, fully separated and geographically diversified) between the Grand Bend HV Remote Station and the terminal stations. Customer has an option of sending a GEO signal or alternatively HONI will need to apply sync-check monitored autoreclosing.

5.0 SCADA/RTU

N/A

6.0 POWER SYSTEM MONITORING

Not in scope of the PIA. To be addressed in future.

7.0 REVENUE METERING

Not in scope of the PIA.

8.0 CYBER SECURITY

CIP-002 through CIP-009 need to be reviewed as applicable.

9.0 STATION REQUIREMENTS

N/A

10.0 UPDATE DATABASES AND DOCUMENTATION

Not in scope of the PIA. To be addressed in future.