Interconnection Feasibility Study Report
GIP-IR625-FEAS-R2

Generator Interconnection Request 625
50 MW Wind Generating Facility
Pictou County, NS

2022-02-28

Control Centre Operations
Nova Scotia Power Inc.

Executive Summary

The Interconnection Customer (IC) submitted an Interconnection Request (IR#625) for Network Resource Interconnection Service (NRIS) for a proposed 50 MW wind generation facility interconnected to the NSPI transmission system, with a Commercial Operation Date of 2024-01-01. The Point of Interconnection (POI) requested by the customer is the existing 138kV substation 93N-Glendhu.

There are four transmission and three distribution Interconnection Requests currently in the Advanced Stage Transmission and Distribution Queue that must be included in the study models for IR#625. In addition, there is one long-term firm transmission service reservation in the amount of 800 MW from New Brunswick to Nova Scotia (TSR-411 that also must be accounted for. This transmission service request is expected to be in service in 2025 and system studies are currently underway to determine the associated upgrades to the Nova Scotia transmission system. These upgrades are expected to materially alter the configuration of the transmission system in Nova Scotia. As a result, the following notice has been posted to the OASIS site at https://www.nspower.ca/oasis/generation-interconnection-procedures:

> *Effective January 19th, 2021, please be advised that the completion of advanced-stage Interconnection Studies under the Standard Generator Interconnection Procedures (GIP) may be delayed pending the outcome of the Transmission Service Request (TSR) 411 System Impact Study, which is expected to identify significant changes to the NSPI transmission system. The revised expected completion date for the study is February 28, 2022. Feasibility Studies initiated prior to the completion of the TSR System Impact Study will be performed based on the current system configuration.*

This study assumes that the addition of generation from IR#625 will displace coal-fired generation in eastern Nova Scotia for NRIS.

The NRIS assessment of the POI at 93N-Glendhu indicated that thermal loading violations could occur on L-6511 due to IR#625. As an alternative to uprating L-6511, it is proposed that adjustments to the setting of a Remedial Action Scheme (RAS) be applied to alleviate these overloads. Uprating L-6511 would add $6,000,500 to the cost of Network Upgrades, so is not recommended.

No violations of voltage criteria were found for IR#625.

It is proposed that 93N-Glendhu substation be converted to a four-breaker ring bus with the addition of a new 138kV circuit breaker splitting bus 93N-B61. This circuit breaker would be considered a Network Upgrade and funded by the IC but eligible for refund under the terms of the GIP. A circuit breaker would therefore not be required on the high side of the interconnection transformer for IR#625.

Data provided by the IC indicates that IR#625 will be utilizing the E3-FTQ version of the Enercon E-160 EP5 5.56 MW wind turbines. Based on the provided impedances of the transformers and typical collector circuit impedances, IR#625 may be able to meet the net power factor of +0.95 to -0.95 at the Interconnection Facility 138kV bus without supplemental reactive power supply. As

specific details of the collector circuits become available, the adequacy of reactive power supply will be further investigated in the System Impact Study. It is noted that the proposed Enercon models do not meet the requirement to produce full Mvar capability down to zero MW output, and model E3-FTQS should be considered.

IR#625 was not found to adversely impact the short-circuit capabilities of existing circuit breakers. Although flicker coefficients were not provided for the proposed generator, voltage flicker is not expected to be a concern for this project on its own. It is assumed that the project design meets NSPI requirements for low-voltage ride-through and voltage control. Harmonics must meet the Total Harmonics Distortion provisions of IEEE 519. The minimum short circuit level at the Interconnection Facility 138kV bus is 809 MVA with all lines in service, and 393 MVA with L-6511 open between the 93N-Glendhu and 50N-Trenton, which is results in a minimum short-circuit ratio of 3.6 based on the aggregate installed capacity of 110 MW at 93N-Glendhu.

IR#625 will result in an aggregate 110 MW of disbursed generation with a common coupling point of 93N-Glendhu, therefore all generators including the existing 60 MW plant will be classified as Bulk Electric System and relevant NERC Generation Owner and Generation Operator standards will be applicable. Presently IR#625 will not be classified as Bulk Power System (BPS) under NPCC, but a final BPS determination will be performed in the System Impact Study stage.

The preliminary value for the unit loss factor is calculated as +7.7% at the POI, net of any losses on the IC facilities up to the POI.

The preliminary non-binding cost estimate for interconnecting 50 MW to the POI at 93N-Glendhu 138kV is $1,903,000. The cost estimate includes a contingency of 10%, and this estimate will be further refined in the System Impact Study and the Facility Study. In these estimates, $1,520,000 plus 10% contingency represents Network Upgrade costs which are funded by the IC but are eligible for refund under the terms of the GIP. The remainder of the costs are fully funded by the Interconnection Customer.

The estimated time to construct the Transmission Provider's Interconnection Facilities is 18-24 months, and the Network Upgrades are estimated to be completed 24-36 months after receipt of funds and cleared right of way from the IC.

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1 Introduction

The Interconnection Customer (IC) submitted an Interconnection Request for a proposed 50 MW wind generation facility interconnected to the NSPI transmission system under Network Resource Interconnection Service (NRIS), with a Commercial Operation Date of 2024-01-01. The Point of Interconnection (POI) requested by the customer is the existing 138kV substation 93N-Glendhu.

The IC signed a Feasibility Study Agreement to study the connection of their proposed generating facility to the NSPI transmission system dated 2021-09-30, and this report is the result of that Study Agreement. This project is listed as Interconnection Request 625 in the NSPI Interconnection Request Queue and will be referred to as IR#625 throughout this report.

Figure 1 shows the proposed geographic location of IR#625 in relation to the NSPI transmission system.

Figure 1 IR#625 Glendhu II Option B Site Location

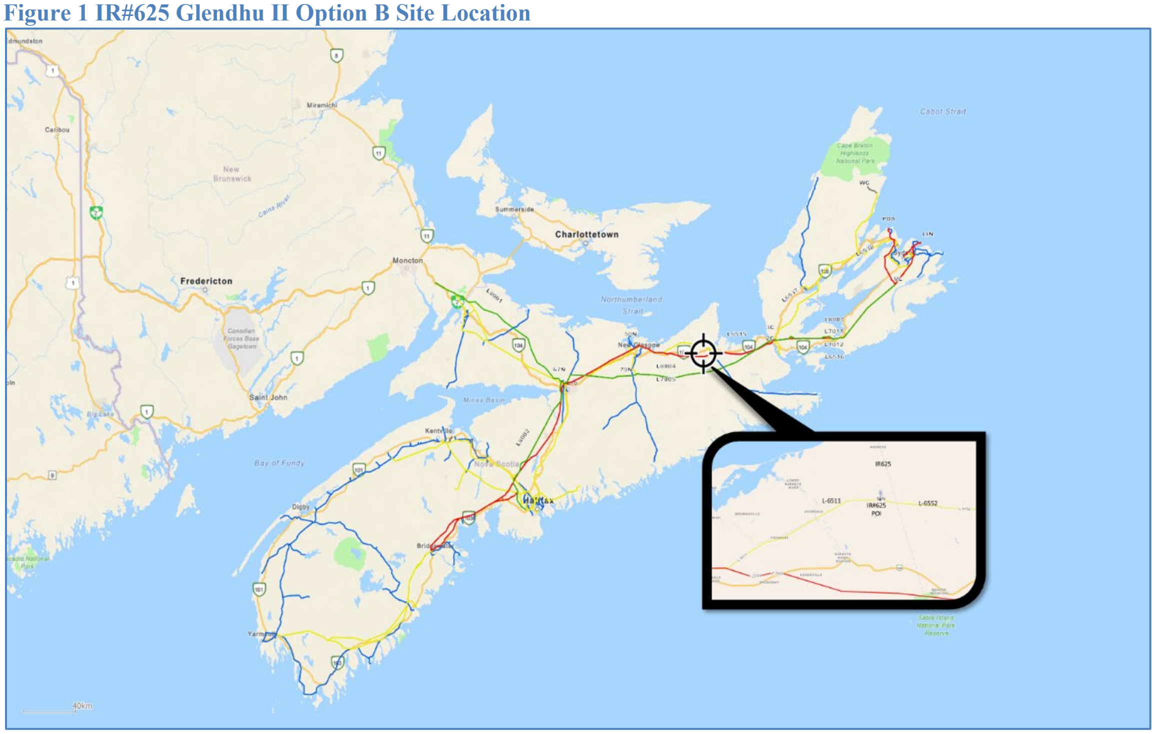


Figure 2 is a simplified one-line diagram of the transmission system configuration in central NS. Figure 3 shows the proposed circuit breaker configuration of transmission lines in the vicinity of the POI.

Figure 2 Point of Interconnection (not to scale)

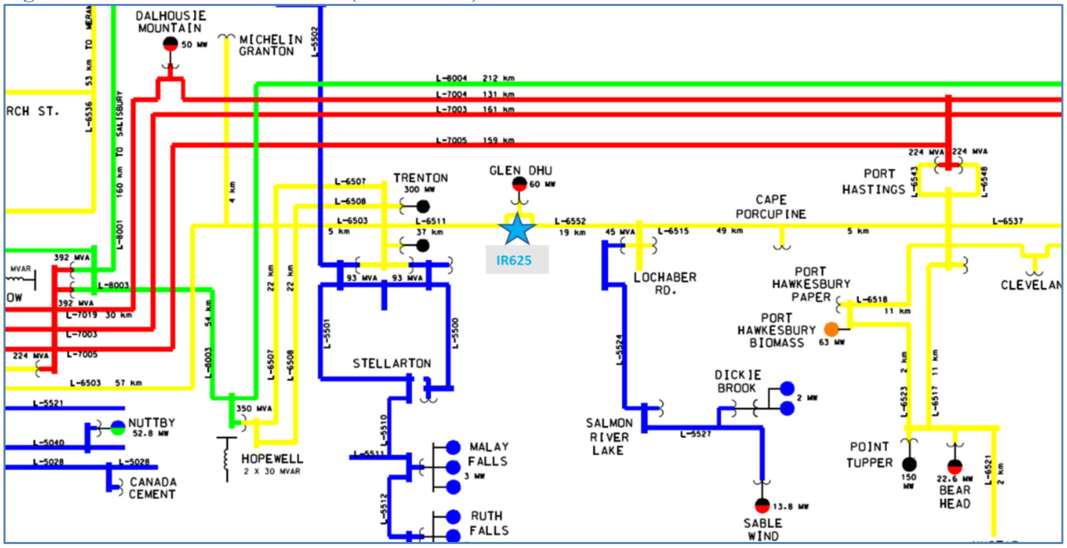
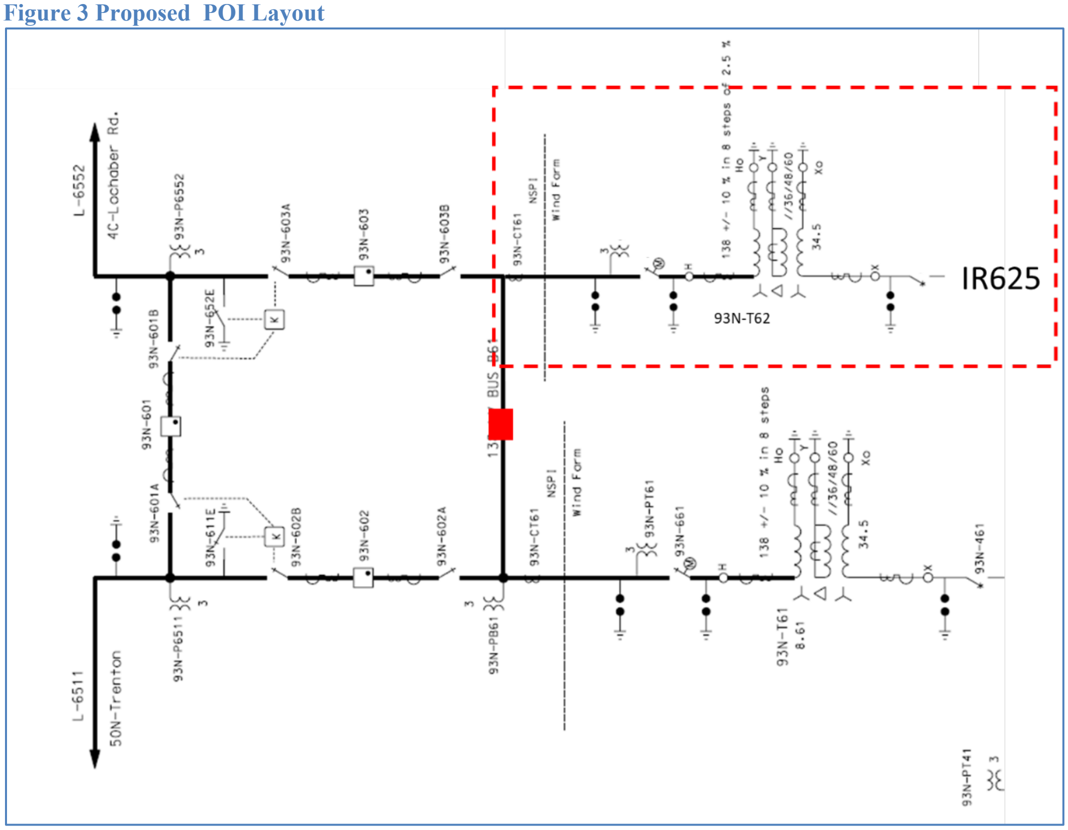


Figure 3 Proposed POI Layout



2 Scope

The objective of this Interconnection Feasibility Study (FEAS) is to provide a preliminary evaluation of system impacts from interconnecting the proposed generation facility to the NSPI transmission system at the requested location. The assessment will identify potential impacts on transmission element loading, which must remain within their thermal limits. Any potential violations of voltage criteria will be identified and addressed. If the proposed generation increases the short-circuit duty of any existing circuit breakers beyond their rated capacity, the circuit breakers must be upgraded. Single contingency criteria are applied.

The scope of the FEAS includes the modelling of the power system in normal state (with all transmission elements in service) under anticipated load and generation dispatch conditions. A power flow and short circuit analysis will be performed to provide the following information:

- Preliminary identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection, and any network upgrades necessary to address the short circuit issues associated with IR#625. Expected minimum short circuit capability will also be identified for the purposes of Short Circuit Ratio analysis.

- Preliminary identification of any thermal overload or voltage limit violations resulting from the interconnection and identification of the necessary network upgrades to allow full output of the proposed facility. Thermal limits are applied to the seasonal (summer/winter) emergency ratings of transmission elements. Voltage violations occur when the post-contingency transmission bus voltage is outside the range of +/-10% of nominal voltage.

- Preliminary analysis of the ability of the proposed Interconnection Facility to meet the reactive power, power quality and cold-weather capability requirements of the NSPI *Transmission System Interconnection Requirements*[1].

- Preliminary description and high-level non-binding estimated cost and time to construct the facilities required to interconnect the generating facility to the transmission system.

- For comparative purposes, the impact of IR#625 on incremental system losses under standardized operating conditions is examined.

This FEAS is based on a power flow and short circuit analysis and does not include a complete determination of facility changes/additions required to increase the system transfer capabilities that may be required to meet the design and operating criteria established by NSPI, the Northeast Power Coordinating Council (NPCC), and the North

[1] transmission-system-interconnection-requirements (nspower.ca)

American Electric Reliability Corporation (NERC). These requirements will be determined by a more detailed analysis in the subsequent interconnection System Impact Study (SIS). An Interconnection Facilities Study (FAC) follows the SIS to ascertain the final cost estimate to the interconnect the generating facility.

3 Assumptions

This FEAS is based on the technical information provided by the Interconnection Customer. The configuration is studied as follows:

1. NRIS per section 3.2 of the Generator Interconnection procedures (GIP).

2. Commercial Operation date 2024-01-01.

3. The Interconnection Customer Interconnection Facility (ICIF) consists of 9 Wind Energy Converter System (WECS) units; Enercon E-160 EP5 E3-FTQ 5.56 MW, 690V, Type 4 (full converter), capped at a total of 50 MW, connected to two feeder circuits operating at a voltage of 34.5kV.

4. The POI at 93N-Glendhu is not considered Bulk Power System facilities (NPCC BPS) nor is it currently considered Bulk Electric System (NERC BES). However, the addition of 50 MW of disbursed generation associated with IR#625 will result in the aggregate generation at the POI exceeding 75 MVA, and therefore NERC BES standards will apply to the generation associated with IR#625 and the existing Glendhu plant.

5. The addition of a new breaker splitting 93N-B61 will create a four-breaker ring bus and will eliminate the need for a circuit breaker on the high side of the ICIF transformer. The new breaker will be classified as a Network Upgrade.

6. The generation technology used must meet NSPI requirements for reactive power capability of at least 0.95 capacitive to 0.95 inductive at the HV terminals of the IC substation step up transformer. It is also required to have high-speed Automatic Voltage Regulation to maintain constant voltage at the designated voltage control point during and following system disturbances as determined in the subsequent System Impact Study. The designated voltage control point will either be the low voltage terminals of the wind farm transformer, or if the high voltage terminals are used, equipped with droop compensation controls. It is assumed that the generating units are not de-rated in their MW capability when delivering the required reactive power to the system.

7. Preliminary data was provided by the IC for the IC substation interconnection facility transformer, consisting of one 138kV/34.5kV 36/48/60 MVA station transformer. The station transformer was modeled with a positive-sequence impedance of 10.0% on 36 MVA with an assumed X/R ratio of 42. The IC indicated that this interconnection

facility transformer has a grounded wye-delta-wye winding configuration with +/-10% on-load tap changer in (assumed) 32 steps. The impedance of each generator step-up transformer was not provided by the IC and is assumed as 9.9% on 6.5 MVA with an X/R ratio of 11.

8. Detailed collector circuit data was not provided, so typical data (R+jX = 0.01+j0.04 p.u. on system base 100 MVA) was assumed with the understanding that the net real and reactive power output of the plant will be impacted by losses through transformers and collector circuits.

9. The FEAS analysis is based on the assumption that IR's higher in the Generation Interconnection Queue and OATT Transmission Service Queue that have completed a System Impact Study, or that have a System Impact Study in progress will proceed, as listed in Section 4 below.

10. It is assumed that the wind turbines are equipped with a "cold weather option" suitable for delivering full power under expected Nova Scotia winter environmental conditions and are therefore capable of operating at full rating during winter peak.

11. Planning criteria meeting NERC Standard TPL-001-4 *Transmission System Planning Performance Requirements* and NPCC Directory 1 *Design and Operation of the Bulk Power System* as approved for use in Nova Scotia by the Utility and Review Board, are used in evaluation of the impact of any facility on the Bulk Electric System.

12. The ratings of transmission lines in the vicinity of IR#625 are shown in Table 2.

Table 2 Local Transmission Element Ratings

Line	Conductor	Design Temp	Limiting Element	Summer Rating Normal/Emergency	Winter Rating Normal/Emergency
L-6503	1113 Beaumont	85°C	Switchgear	287/315 MVA	287/315 MVA
L-6511	556.5 Dove	60°C	Conductor	140/154 MVA	184/202 MVA
L-6552	556.5 Dove	50°C	Conductor	110/121 MVA	143/157 MVA
L-6515	556.5 Dove	50°C	Conductor	110/121 MVA	143/157 MVA
L-7003	556.5 Dove	70°C	Conductor	273/303 MVA	345/379 MVA
L-7004	556.5 Dove	60°C	Conductor	233/246 MVA	307/338 MVA
L-7019	555.5 Dove	70°C	Conductor	273/303 MVA	345/379 MVA
L-7005	1113 Beaumont	70°C	CT Ratio	398/438 MVA	398/438 MVA

4 Projects with Higher Queue Positions

All in-service generation is included in the FEAS, except for Lingan Unit 2, which is assumed to be retired.

As of 2022-01-10, the following Transmission Interconnection projects are higher queued in the Advanced Stage Interconnection Request Queue and are committed to the study base cases:

- IR426: GIA executed
- IR516: GIA executed
- IR540: GIA executed
- IR542: GIA executed
- IR574: GIA in progress
- IR598: FAC in progress

The following projects have been submitted to the Transmission Service Request (TSR) Queue:

- TSR411: SIS in progress
- TSR412: SIS in progress

Preceding IR#625 are six transmission and three distribution Interconnection Requests with GIA's executed. A long-term firm point-to-point transmission service reservation in the amount of 800 MW from New Brunswick to Nova Scotia (TSR-411). This transmission service request is expected to be in service in 2025 and system studies are currently underway to determine the required upgrades to the Nova Scotia transmission system. As a result, the following notice has been posted to the OASIS site at https://www.nspower.ca/oasis/generation-interconnection-procedures:

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5 Short-Circuit Duty / Short Circuit Ratio

The maximum expected (design) short-circuit level is 5,000 MVA (21 kA) on 138kV systems and 10,000 MVA (25 kA) on 230kV systems. The fault current characteristic for the Enercon Type 4 fully converted units is given as 1.08 times rated current, or X'd = 0.926 per unit on machine base MVA.

Short circuit analysis was performed using PSS®E for a classical fault study, 3LG and flat voltage profile at 1.0 p.u. V. The short-circuit levels in the area before and after this development are provided below in Table 3.

Table 3: Short-Circuit Levels. IR#625 (Type 4) at 93N Three-phase MVA (1)		
Location	Without IR#625	With IR#625
All transmission facilities in service		
POI 93N-B61 (138kV)	1272	1319
4C-Lochaber Rd (138kV)	1187	1212
50N-Trenton (138kV)	2854	2877
Minimum Conditions (TC3, LG1, ML In-Service)		
Interconnection Facility (138kV), all lines in-service	809	857
Interconnection Facility (138kV), L-6511 open at 50N-Trenton	393	441
Interconnection Facility (138kV), L-6552 open at 4C-Lochaber	543	591

(1) Classical fault study, flat voltage profile

The interrupting capability of the 138kV circuit breakers at 93N-Glendhu, 50N-Trenton and 4C-Lochaber Rd. is at least 5,000 MVA. As such, the interrupting rating at these substations will not be exceeded by this development on its own.

Inverter-based generation installations often have a minimum Short Circuit Ratio (SCR) for proper operation of converters and control circuits. Consideration of the SCR at 93N-Glendhu POI must include the existing 60 MW wind farm in conjunction with the additional 50 MW from IR#625, therefore the short circuit ratio would be 7.4 at the HV terminals of the IR#625 substation with all lines in service and IR#625 off line. This falls to 4.9 with L-6552 open at 4C-Lochaber Rd, and 3.6 if L-6511 is open at 50N-Trenton. As this value falls below 5.0, special consideration should be made in control design.

6 Voltage Flicker and Harmonics

Flicker coefficient information was not provided for the Enercon E-160 – EP5 E3-FTQ / 5.560 MW Wind Turbines, however, it is known that Type 4 wind turbines typically have a flicker coefficient of 2.0 - 2.4 at angle of 85°, which is about half that of Type 3 machines. Type 4 wind turbines are not expected to result in appreciable voltage flicker at minimum generation conditions. Voltage flicker will be further examined when data for the 5.56 MW Enercon E-160 machine is made available for the SIS.

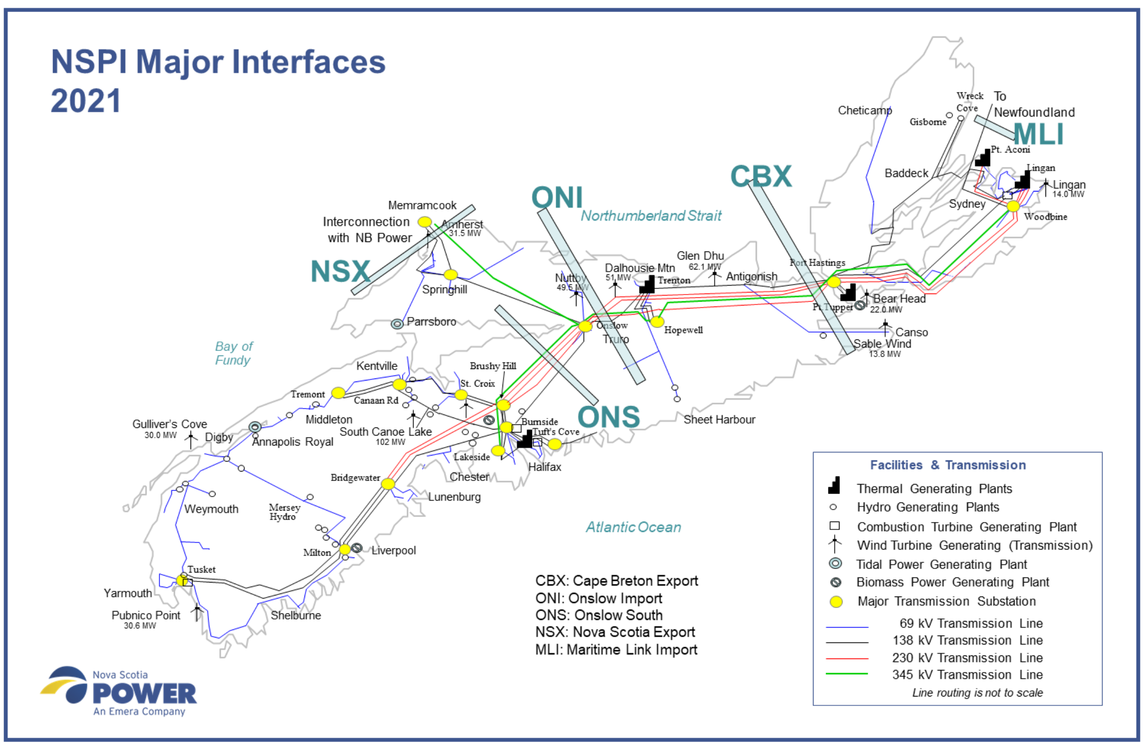
The generator is expected to meet IEEE Standard 519-2014 limiting voltage Total Harmonic Distortion (all frequencies) to a maximum of 1.5%, with no individual harmonic exceeding 1.5% on 138kV.

7 Load Flow Analysis

The load flow analysis was completed for generation dispatches under system summer peak load and winter peak load conditions which are expected to stress the east-west corridor across the transmission interfaces Cape Breton Export (CBX) and Onslow Import (ONI). Generation dispatch was also chosen to represent import and export scenarios that consider expected flows from the existing transmission service reservation associated with the Maritime Link, and scenarios where Maritime Link imports displace NS thermal generation.

The major transmission interfaces/corridors relating to the IR#625 are shown in Figure 4. The nominal interface limits are summarized in Table 4. NSPI relies on Remedial Action Schemes (RAS[2]) approved by NPCC to maintain interface limits. These RAS are armed by system conditions and flow across the respective interfaces and react to pre-determined contingencies to rapidly reduce flow by either tripping generation in Cape Breton or running-back Maritime Link HVdc import.

Figure 4 Major Transmission Interfaces



[2] Also referred to as Special Protection Scheme (SPS),

Table 4 Transmission Interface Limits						
Interface	NLI (1)	NSX (2)	NSI (3)	CBX (4)	ONI	ONS (5)
Summer	475	500	Up to 300	875-1075	1075-1275	600-850
Winter	475	500	Up to 300	950-1150	1275	600-975

(1) Newfoundland and Labrador Import (NLI) is limited by simultaneous New Brunswick Import
(2) NS Export to NB (NSX) is dependant on Maritime Link runback RAS
(3) NS import from NB (NSI) is dependant on conditions in NB and PEI, capped at 28% of NS load.
(4) Dependant on generation at Trenton and Point Tupper
(5) Dependant on reactive power reserve in Metro

Transmission connected wind generation facilities were typically dispatched at approximately 40%, except in the vicinity of IR#625. There is high co-relation between wind plants in the Central Region between Port Hastings and Onslow, so it is reasonable to expect that these other wind plants would be near full output when IR#625 is at rated output. The cases and dispatch scenarios considered are shown in Table 5.

Table 5: Base Case Dispatch (MW) with IR#625 on-line									
Case	MLI	NS-NB	CBX	ONI	ONS	LIN	TRE	Wind	RAS (3)
SP01	475	338	932	1,018	610	255	78	295	79NG6 67NG5
SP02	475	0	792	888	782	270	120	217	79NG5
SP03	475	335	829	859	472	60 (1)	0	424	79NG6
SP04	475	0	700	891	820	220	165	300	-
SP05	475	200	1027	1163	857	359	156 (2)	213	79NG6 67NG6
SP06	475	170	832	853	579	160	0	252	79NG6
SP07	-100	-245	106	300	463	80	160	318	-
WP01	320	169	908	1,180	870	446	324	283	67NG6
WP02	475	150	1097	1,210	920	430	165	268	79NG6 67NG6
WP03	320	150	794	1,063	792	427	324	290	67NG6
WP04	475	0	1,093	1,109	930	426	115	175	79NG5 67NG6
WP07	-100	-150	211	524	553	184	324	480	-

SP - Summer Peak **WP - Winter Peak** **LIN – Lingan Gen** **TRE – Trenton Gen**

(1) IR625 displaces 30 MW of Lingan plus 30 MW of Point Aconi
(2) Two Trenton units at minimum load
(3) Based on present RAS arming levels

For NRIS analysis, this FEAS added IR#625 and displaced coal-fired generation in Cape Breton, reducing Cape Breton Export (CBX) transfers while maintaining Onslow Import (ONI) transfers. Single contingencies were applied at the 345kV, 230kV, and 138kV voltage levels for the above system conditions with IR#625 interconnected to the POI at 93N-Glendhu. Automated analysis searched for violations of emergency thermal ratings and emergency voltage limits for each contingency. Contingencies studied are listed in Table 6.

Table 6 Contingency List

Transmission Line	Transformer / Bus	Circuit Breaker Failure	Double Circuit Tower
L-7014, L-7021, L-7022	88S: T71, T72	88S: 710, 711, 713, 690, 721, 722, 723*	L-6534 + L-7021
L-7011, L-7012, L-7015, L-8004*	101S: T81, T82	101S: 701, 702, 703, 704, 705, 706, 711, 712, 713, 811, 812*, 813*, 814, 816	
L-6515, L-6516, L-6537*	2C: B61*, B62	4C: 620, 621, 622, 623	
L-7003, L-7004, L-7005	3C-T71	3C: 710, 712, 713, 715, 716	L-7003+L-7004* Canso Causeway
L-6503, L-6613	1N: B61, B62	1N: 600, 613	
L-8001*, L-8002	67N: T71, T81	67N: 701, 702, 703, 705, 711, 712, 713, 811*, 812, 813, 814*, 815*	L-7003+L-7004 Trenton area
L-6507, L-6508, L-8003*	79N: T81*	79N: 601*, 606*, 803*, 810*	
L-6511, L-6552	91N: B71	91N: 701, 702, 703	

*Indicates contingency was studied with/without RAS action

Results

Two contingencies resulted in thermal overloads based on the current function and settings of RAS. In most cases, the overloads can be resolved by lowering the arming levels of these RAS without modification of the RAS design. This will increase the probability of a RAS operating and causing a run-back of the Maritime Link, or tripping of a thermal unit at Lingan or Point Aconi. Re-design of a RAS, or the addition of a new RAS, shall be subject to the approval of NPCC.

No contingencies resulted in a violation of voltage limit criteria. Table 7 shows the highest thermal overloads found, but other conditions were found which also violated thermal loading criteria, but to a lesser degree.

Table 7 Contingencies Resulting in Highest Line Overload

Line	Line segment	Highest load (% of Emergency Rating)	Case	Contingency
L-6511	50N-Trenton / 93N-Glendhu	Summer: 108.5%	SP03-2	L-7003/L-7004 Dbl Circuit Tower
L-6552	93N-Glendhu / 4C-Lochaber Rd	Summer: 100%	SP07-2	Bus Fault, bkr failure 79N-Hopewell

NRIS Analysis

Case SP07-2 where high negative CBX (Cape Breton Import) with one unit at Trenton at full load in summer and both Glendhu I and II at full-load, L-6552 would reach full load for loss of the bus at 79N-Hopewell, which is acceptable loading and does not need Network Upgrades.

The case of high CBX flow with no generation at Trenton in summer, simultaneous loss of L-7003 and L-7004 (double-circuit towers at Canso Causeway or Trenton Bypass), L-6511 would reach 108.5% of its seasonal emergency rating. Two alternatives to this situation were considered:

1. Uprate L-6511 from 60°C to 70°C, 36.5 km, at an estimated cost of $6,022,000 including 10% contingency.
2. Adjust the arming level of Group 3 RAS (double-circuit L-7003/L7004 contingency) at an estimated cost of $20,000.

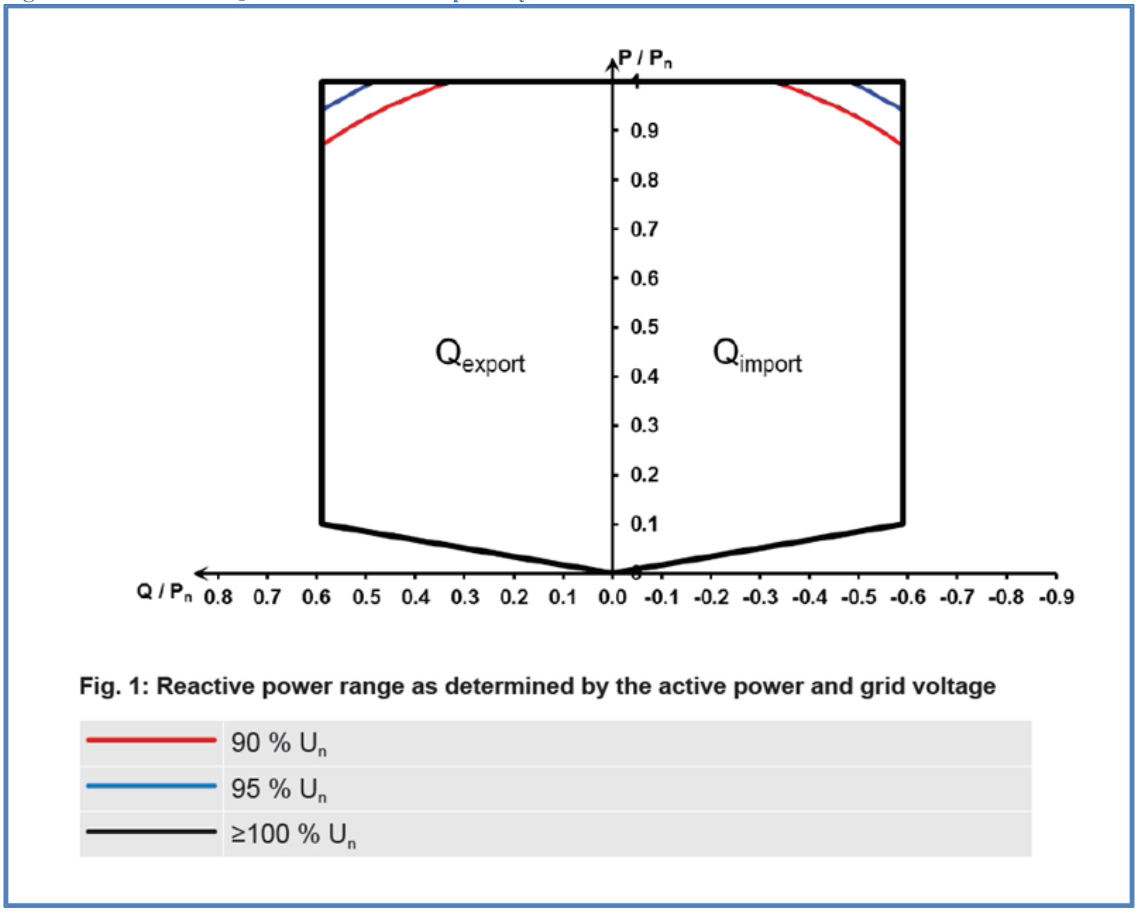
The recommended option is (2) modification of the arming level of existing RAS.

8 Reactive Power and Voltage Control

In accordance with the *Transmission System Interconnection Requirements* Section 7.6.2, IR#625 must be capable of delivering reactive power at a net power factor of at least +/- 0.95 of rated capacity to the high side of the plant interconnection transformer. Reactive power can be provided by the asynchronous generator or by continually acting auxiliary devices such as STATCOM, DSTATCOM or synchronous condenser, supplied by the Interconnection Customer.

The information provided by Enercon (Figure 6) indicates that the Enercon E-160 EP5 E3-FTQ 5.56 MW WECS have a rated power factor of 0.85 lagging and leading (+/- 3.5 Mvar per WECS, total of +/- 31 Mvar) at a machine terminal voltage of 1.0 p.u. or above, from 10% to 100% of rated power. However, the NSPI Transmission System Interconnection Requirements (Section 7.6.2) requires that rated reactive power shall be available through the full range of real power output of the Generating Facility, from zero to full power. Enercon model E3-FTQS would be meet this requirement.

Figure 6: Model E-FTQ WECS Reactive Capability



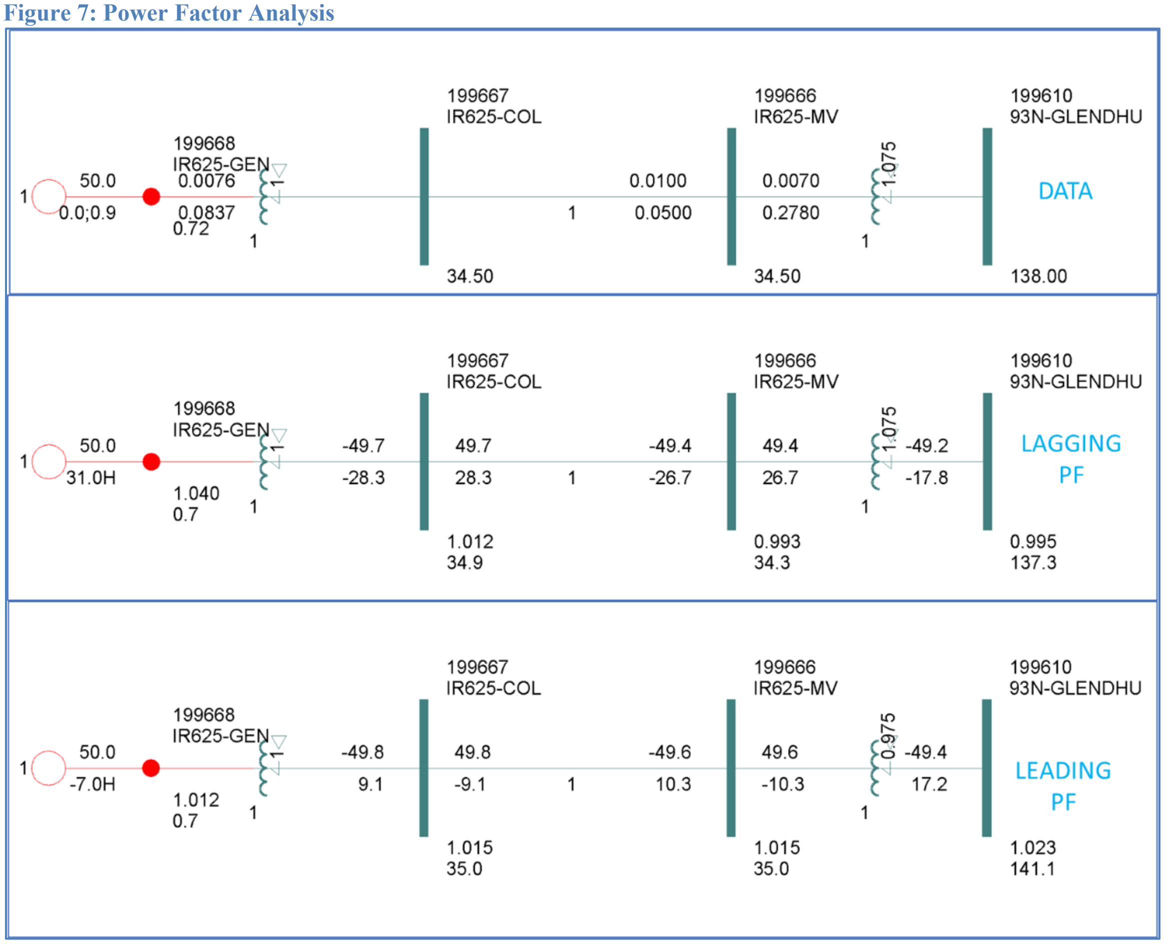
Analysis shown in Figure 7 indicates that IR#625 may be able to meet the full-load reactive power requirement without additional reactive support. The model shows that with 9 WECS units (E3-FTQ version) operating at a total 50 MW and 31 Mvar at terminal voltage of 1.04 p.u., the delivered power to the high side of the ICIF transformer is 49.2 MW and 17.8 Mvar, or a power factor of 0.947.

This configuration would be able to meet the leading power factor requirement of -0.95 while the WECS are operating at 50 MW and -7.0 Mvar at a terminal voltage of 1.01 p.u.

Because this analysis is based on preliminary transformer data and assumed collector circuit models, reactive capability will be confirmed in the SIS.

A centralized controller will be required which continuously adjusts individual generator reactive power output within the plant capability limits and regulates the voltage at the 34.5kV bus voltage. The voltage controls must be responsive to voltage deviations at the terminals of the Interconnection Facility substation; be equipped with a voltage set-point control; and also have the ability to slowly adjust the set-point over several (5-10) minutes to maintain reactive power within the individual generators capabilities. The details of the specific control features, control strategy and settings will be reviewed and addressed in the SIS, as will the dynamic performance of the generator and its excitation. Line drop compensation, voltage droop, control of separate switched capacitor banks must be provided.

Figure 7: Power Factor Analysis



The NSPI System Operator must have manual and remote control of the voltage set-point and the reactive set-point of this facility to coordinate reactive power dispatch requirements.

This facility must also have low voltage ride-through capability as per Appendix G of the Standard Generator Interconnection and Operating Agreement (GIA). The SIS will state specific options, controls and additional facilities that are required to achieve this.

Settings for the ICIF on-load tap-changer must be coordinated with plant voltage controller for long-term reactive power and voltage management at the POI.

9 System Security / Bulk Power Analysis

The addition of IR#625 to the 93N-Glendhu substation along with the existing 60 MW of disbursed generation at that location will be greater than 75 MVA, and therefore Inclusion I4 of the NERC BES Definition will apply. All generators (110 MW) at 93N-Glendhu would be classified as BES elements and NERC reliability standards relevant to Generation Owners and Generation Operators will therefore be applicable.

Presently, IR#625 is not classified as Bulk Power System (BPS) under NPCC, however the final BPS determination will be determined in the SIS stage.

10 Expected Facilities Required for Interconnection

The following facility changes will be required to connect IR#625 to the NSPI transmission system at a POI at 93N-Glendhu under NRIS:

a. Required Network Upgrades

- Addition of a 138kV circuit breaker into bus 93N-B61 to make a four-breaker ring.
- Adjustment to the setpoint of existing NSPI RAS (Group 3).
- Modifications to remote protection and control at 4C-Lochaber Rd and 50N-Trenton

b. Required Transmission Provider's Interconnection Facilities (TPIF):

- Add Remote Terminal Unit (RTU) to interface with NSPI's SCADA, with telemetry and controls as required by NSPI. Modification of the existing RTU at 93N may be possible
- Add control and communications between the wind farm and NSPI SCADA system (to be specified).

c. Required Interconnection Customer's Interconnection Facilities (ICIF)

- Facilities to provide 0.95 leading and lagging power factor when delivering rated output at the HV terminals of the IC Substation Step Up Transformer when the voltage at that point is operating between 95% and 105% of nominal. This study found that Enercon model E3-FTQ may meet this requirement. The data provided did not meet the requirement that rated reactive power be delivered from zero to full rated real power, therefore model E3-FTQS may be required.

- Centralized controls. These will provide centralized voltage set-point controls and are known as Farm Control Units (FCU). The FCU will control the 34.5kV bus voltage and the reactive output of the machines. Responsive (fast-acting) controls are required. The controls will also include a curtailment scheme which will limit or reduce total output from the facility, upon receipt of a telemetered signal from NSPI's SCADA system.
- NSPI will have control and monitoring of reactive output of this facility, via the centralized controller. This will permit the NSPI Operator to raise or lower the voltage set-point remotely.
- Low voltage ride-through capability per Section 7.4.1 of the Nova Scotia Power Transmission System Interconnection Requirements (TSIR).
- Real-time monitoring (including an RTU) of the interconnection facilities. Local wind speed and direction, MW and Mvar, as well as bus voltages are required.
- Facilities for NSPI to execute high speed rejection of generation (transfer trip) if determined in SIS. The plant may be incorporated into RAS run-back schemes.
- Fast Frequency Response (synthesized inertial) controls within the WECS.
- Automatic Generation Control to assist with tie-line regulation.
- Operation at ambient temperature of -30°C.

11 NSPI Interconnection Facilities and Network Upgrades Cost Estimate

Estimates for NSPI Interconnections Facilities and Network Upgrades for interconnecting 50 MW of wind energy at the 138kV POI at 93N-Glendhu are included in Tables 7 and 8.

Table 7 Cost Estimate NRIS @ POI 93N-Glendhu		
Item	**Network Upgrades**	**Estimate**
1	138kV Circuit Breaker in Bus 91N-B61	$1,000,000
2	Remote P&C Modifications	$500,000
3	Adjustment to RAS settings Group 3	$20,000
	Sub-total for Network Upgrades	$1,520,000
Item	**TPIF Upgrades**	**Estimate**
1	NSPI supplied RTU	$60,000
2	Tele-protection and SCADA communications	$150,000
	Sub-total for TPIF Upgrades	$210,000

	Total Upgrades	Estimate
	Network Upgrades + TPIF Upgrades	$1,730,000
	Contingency (10%)	$173,000
	Total (Incl. 10% contingency and Excl. HST)	$1,903,000

The preliminary non-binding cost estimate for interconnecting 50 MW at the POI at 93N-Glendhu under NRIS is $1,947,000 including a contingency of 10%. In this estimate, $1,560,000 (plus 10% contingency) represents Network Upgrade costs which are funded by the Interconnection Customer, but which are eligible for refund under the terms of the GIP.

These estimates do not include TBD (to be determined) costs to address any stability issues identified at the SIS stage based on dynamic analysis.

The estimated time to construct the Transmission Provider's Interconnection Facilities is 18-24 months after receipt of funds. The estimated time to construct the Network Upgrades is expected to take 24-36 months after receipt of funds from the IC.

12 Loss Factor

Loss factor is calculated by running the winter peak load flow case with and without the new facility in service while keeping 91H-Tufts Cove as the Nova Scotia Area Interchange bus. This methodology reflects the load centre in and around Metro.

Without IR#625 in service, losses in the winter peak case total 86.2 MW. With IR#625 in service at the 93N substation, displacing generation at 91H, and not including losses associated with the IR#625 Generation Facilities or TPIF Interconnection Facilities, system losses total 89.99 MW, an increase of 3.79 MW. The model shows power delivered to the POI is 49.4 MW, therefore the loss factor is calculated as 3.79/49.4 = +7.7%.

13 Issues to be addressed in SIS

The following provides a preliminary scope of work for the subsequent SIS for IR#625. The SIS will include a more comprehensive assessment of the technical issues and requirements to interconnect generation as requested. It will include contingency analysis, system stability, ride through, and operation following a contingency (N-1 operation). The SIS must determine the facilities required to operate this facility at full capacity, withstand any contingencies (as defined by the criteria appropriate to the location) and identify any restrictions that must be placed on the system following a first contingency loss. The SIS will confirm the options and ancillary equipment that the customer must install to control flicker, voltage, frequency response, active power and ensure that the facility has the required ride-through capability. The SIS will be conducted in accordance with the GIP with the assumption that all appropriate higher-queued projects proceed, and the facilities associated with those projects are installed.

The following outline provides the minimum scope that must be complete in order to assess the impacts. It is recognized the actual scope may deviate, to achieve the primary objectives.

The assessment will consider but not be limited to the following.

i. Facilities that the customer must install to meet the requirements of the GIP and the *Transmission System Interconnection Requirements*.
ii. The minimum transmission additions/upgrades that are necessary to permit operation of this Generating Facility, under all dispatch conditions, catering to the first contingencies listed.
iii. Guidelines and restrictions applicable to first contingency operation (curtailments etc.).
iv. Under-frequency load shedding impacts.

To complete this assessment the following first contingencies, as a minimum, will be assessed:

- L-6511
- L-6552
- L-8001
- L-8004
- L-8003
- Transformer 79N-T81
- L-7003
- L-7019 with 91N generation
- L-8004 & 79N-T81 (common circuit breaker)
- L-8004 & 101S-T81 (common circuit breaker)
- 1N-B61 (bus fault)
- L-7004 & 3C-T71 (common circuit breaker)
- L-7004 & L-7012 (common circuit breaker)
- L-7005
- Loss L-7003 & L-7004 (double circuit tower) at Canso Causeway and Trenton Bypass
- Loss of largest generation source in NS
- Loss of Maritime Link

To complete this assessment the dynamics of the following first contingencies, as a minimum, will be assessed:

- 3 phase fault L-8004 at 101S-Woodbine, CBX and ONI, RAS armed
- 3 phase fault L-8003 at 67N-Onslow, ONI RAS armed
- 3 phase fault L-8001 with high NS import from NB (islanding)
- 3 phase fault L-8002 at 67N-Onslow
- Simultaneous SLG on L-7003 and L-7004 double circuit tower at 3C-Port Hastings
- SLG L-8003 at Onslow, drops 67N-T82, 345kV RAS Operation
- 3 phase fault at 79N-Hopewell, drops L-8003, 8004, bus, RAS operation
- 3 phase fault 1N-Onslow 138kV bus B61

Any changes to RAS schemes required for operation of this generating facility, in addition to existing generation and facilities that can proceed before this project, will be determined by the RAS as well as any required additional transmission facilities. The determination will be based on NERC[3] and NPCC[4] criteria as well as NSPI guidelines and good utility practice. The SIS will also determine the contingencies for which this facility must be curtailed.

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[3] NPCC criteria are set forth in its Reliability Reference Directory #1 *Design and Operation of the Bulk Power System*
[4] NERC transmission criteria are set forth in *NERC Reliability Standard TPL-001-4*