# Interconnection Feasibility Study Report
# GIP-IR616-FEAS-R2

## Generator Interconnection Request 616
## 130.2 MW Wind Generating Facility
## Pictou County, NS

2022-04-29

Control Centre Operations
Nova Scotia Power Inc.

# Executive Summary

The Interconnection Customer (IC) submitted an Interconnection Request (IR#616) for both Network Resource Interconnection Service (NRIS) and Energy Resource Interconnection Service (ERIS) for a 130.2 MW wind generation facility interconnected to the NSPI transmission system, with a Commercial Operation Date of 2025-01-01. The Point of Interconnection (POI) requested by the customer is the 138kV bus at 47C-Port Hawkesbury Paper (PHP) substation.

There are six transmission and six distribution Interconnection Requests in the Advanced Stage Transmission and Distribution Queue that must be included in the study models for IR#616. In addition, there is a long-term firm Transmission Service Reservation (TSR) that must be accounted for: 550 MW from New Brunswick to Nova Scotia (TSR-411). The TSR is expected to be in service in 2025 and a system study is 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 was 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#616 will displace coal-fired generation in eastern Nova Scotia for both NRIS and ERIS.

The existing 47C Port Hawkesbury Paper substation has a ring-bus configuration, the IR#616 interconnection will require an additional breaker, with associated equipment, on 47C 138kV bus. As IR#616 has dispersed generation totalling more than 75 MVA, its facility is categorized as NERC Bulk Electric System (BES), under BES inclusion I4, and subject to applicable NERC Reliability Criteria.

No violations of voltage criteria were found for IR#616.

Data provided by the IC indicates that IR#616 will be utilizing the E-138 EP3 E2 -FTQ version of the Enercon E-138 EP3 E2 4.2 MW wind turbines. Based on the provided impedances of the transformers and typical collector circuit impedances, IR#616 should be able to meet the net power factor of +0.95 to -0.95 at the Interconnection Facility 138kV bus. The adequacy of reactive power supply will be further investigated in the System Impact Study as specific details of the collector circuits become available. It is noted the proposed Enercon models do not meet the requirement to produce full Mvar capability down to zero MW output.

IR#616 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 1,125 MVA with all lines in service with an 8.6 Short Circuit Ratio (SCR). This falls to 930 MVA with L-6518 open between the POI and 2C-Port Hastings, resulting in a 7.1 SCR.

The preliminary value for the unit loss factor is calculated as +10.7% at the POI at 47C, net of any losses on the IC facilities up to the POI.

**NRIS results**

The assessment of the 47C substation 138 kV bus POI indicated thermal loading violations would occur due to IR#616, notably L-6515, L-6517, L-6518, 3C-T71 and 3C-T72. To interconnect IR#616 as NRIS, the following Network Upgrades are proposed:

- Rebuild of L-6517 and L-6518 at a cost of $8,948,000.
- 3C-T71 and 3C-T72 transformer replacements at a cost of $12,200,000.
- Reduce arming and limit values for existing Group 3, Group 5, and Group 6 RAS.

The preliminary non-binding cost estimate for interconnecting IR#616 at the requested 130.2 MW, including the Network Upgrades and Transmission Provider Interconnection Facilities (TPIF), is $37,958,800 (including 10% contingency). This cost estimate includes:

- The Network Upgrades listed above.
- One 138 kV breaker and associated equipment for line connection.
- Protection upgrades.
- A total of 15.2 km 138 kV lines and 2.6 km submarine cable from the POI to the Interconnection Customer's Interconnection Facility. U/G to O/H transitions are not included as they are dependent on shore landing conditions.

This estimate will be further refined in the System Impact Study (SIS) and the Facility Study. In this estimate, $21,398,000 (plus 10% contingency) of the amount represents Network Upgrade costs which are funded by the Interconnection Customer, but which are eligible for refund under the terms of the GIP. The remainder of the costs are fully funded by the Interconnection Customer.

If transmission upgrades were found to be necessary to address thermal overloads on L-6515, versus the alternative to the RAS arming level change, the total cost of Network Upgrades would increase by an estimated $7,500,000. These cost estimates do not include any contingency. Network upgrades are funded by the IC and are eligible for refund under the terms of the GIP.

The estimated time to construct the Transmission Providers Interconnection Facilities and the Network Upgrades are estimated to be completed 24-36 months after receipt of funds and cleared right of way from the customer.

**ERIS results**

For ERIS assessment, IR#616's output was reduced to 20 MW, however thermal loading violations would occur on L-6515. Reduction of arming and limit values for existing Group 3, Group 5, and Group 6 RAS is recommended to remediate the L-6515 overloads.

The preliminary ERIS non-binding cost estimate for interconnecting IR#616, reduced 20 MW, including the Network Upgrades and Transmission Provider Interconnection Facilities (TPIF), is $14,696,000 (including 10% contingency). This cost estimate includes:

- Reducing arming and limit values for existing Group 3, Group 5, and Group 6 RAS.
- One 138 kV breaker and associated equipment for line connection.
- Protection upgrades.
- A total of 15.2 km 138 kV lines and 2.6 km submarine cable from the POI to the Interconnection Customer’s Interconnection Facility. U/G to O/H transitions are not included as they are dependent on shore landing conditions.

This estimate will be further refined in the System Impact Study (SIS) and the Facility Study. In this estimate, $250,000 (plus 10% contingency) of the amount represents Network Upgrade costs which are funded by the Interconnection Customer, but which are eligible for refund under the terms of the GIP. The remainder of the costs are fully funded by the Interconnection Customer.

If transmission upgrades were found to be necessary to address thermal overloads on L-6515, versus the alternative to the RAS arming level change, the total cost of Network Upgrades would increase by an estimated $7,500,000. These cost estimates do not include any contingency. Network upgrades are funded by the IC and are eligible for refund under the terms of the GIP.

The estimated time to construct the Transmission Providers Interconnection Facilities and the Network Upgrades are estimated to be completed 24-36 months after receipt of funds and cleared right of way from the customer.

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# 1 Introduction

The Interconnection Customer (IC) submitted an Interconnection Request (IR#616) for both Network Resource Interconnection Service (NRIS) and Energy Resource Interconnection Service (ERIS) for a proposed 130.2 MW wind generation facility interconnected to the NSPI transmission system, with a Commercial Operation Date of 2025-01-01. The Point of Interconnection (POI) requested by the customer is the 138kV bus at 47C-Port Hawkesbury Paper substation.

The IC signed a Feasibility Study Agreement to study the connection of their proposed generating facility to the NSPI transmission system dated 2021-08-18, and this report is the result of that Study Agreement. This project is listed as Interconnection Request 616 in the NSPI Interconnection Request Queue and will be referred to as IR#616 throughout this report.

Figure 1 shows the proposed geographic location of IR#616 in relation to the NSPI transmission system.

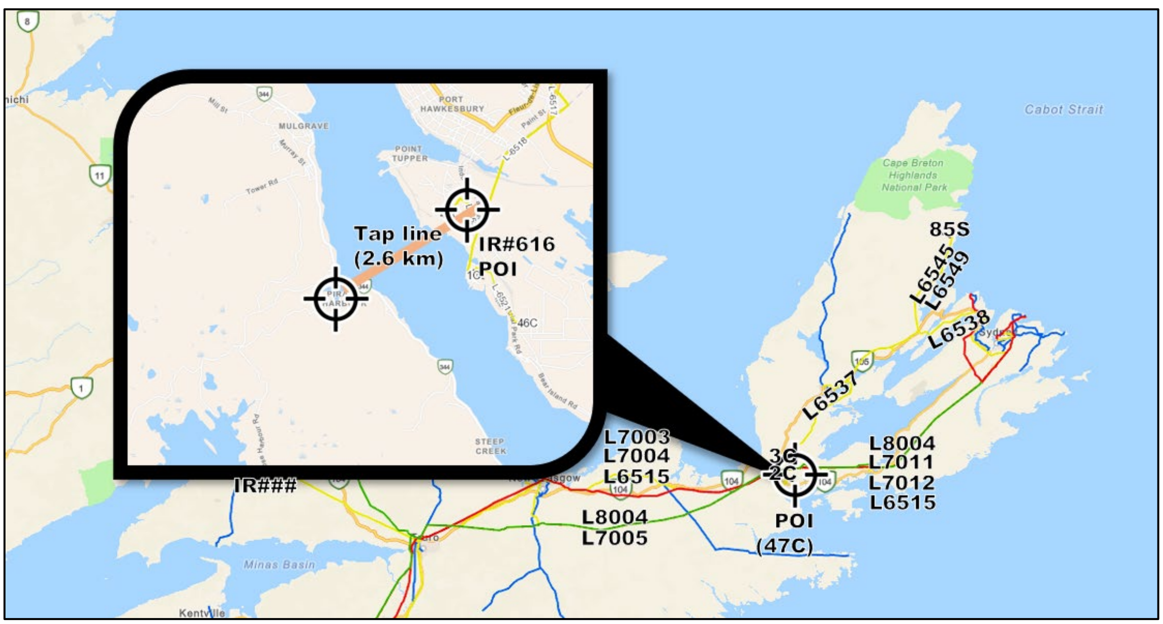


Figure 1 IR#616 Site Location

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

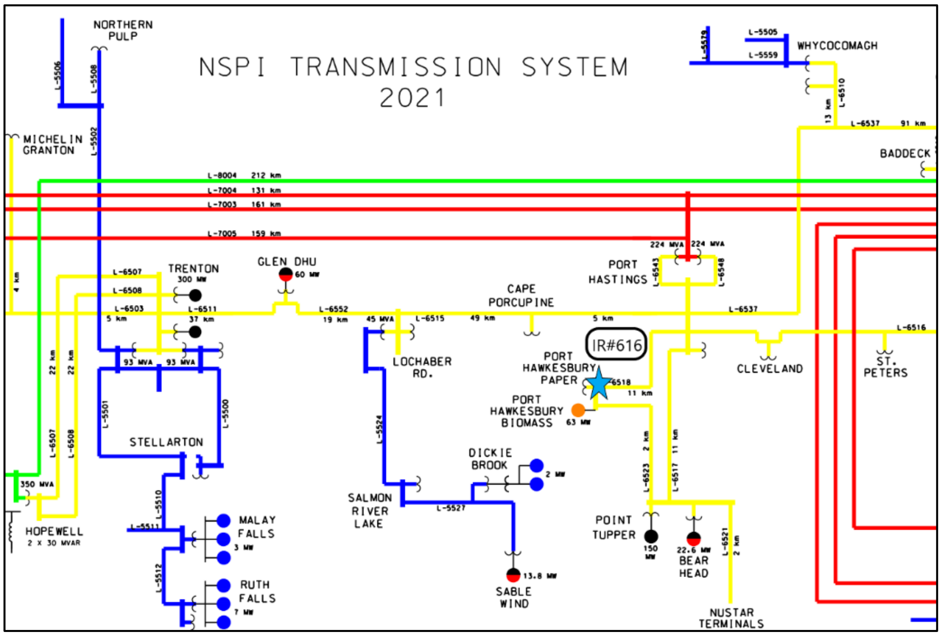


Figure 2 Point of Interconnection (not to scale)

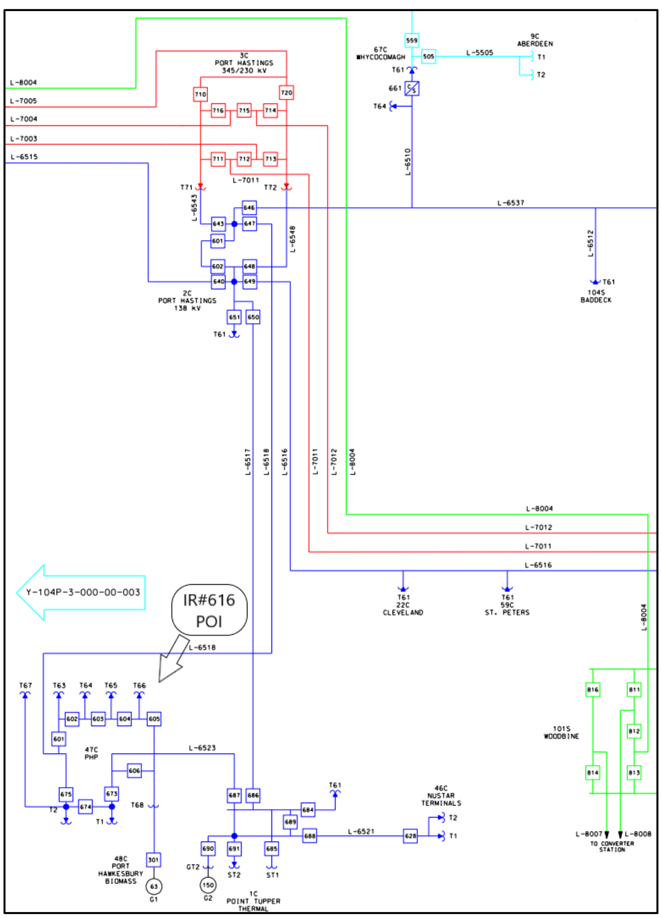


Figure 3 Circuit Configuration near POI

# 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 because of the interconnection, and any network upgrades necessary to address the short circuit issues associated with the IR. 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] (TSIR).

- 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#616 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

[1] NS Power Transmission System Interconnection Requirements (TSIR)

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 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 Point of Interconnection (POI) and configuration is studied as follows:

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

2. Commercial Operation date 2025-01-01.

3. The Interconnection Customer Interconnection Facility (ICIF) consists of up to 31 Wind Energy Converter System (WECS) units; Enercon E-138 EP3 E2 4.2 MW wind turbines with FTQ option, 630V, Type 4 (full converter), capped at a total of 130.2 MW, connected to two main collector circuits operating at a voltage of 34.5kV. One collector circuit connected to 13 WECS units and the other one connected to 18 units.

4. The POI is on 138 kV ring bus at 47C Port Hawkesbury Paper substation and will therefore require an additional 138 kV breaker.

5. The ICIF is located approximately 10 km from the POI and will require the construction of a 2.6 km submarine cable to the IC substation at Pirate Bay and continues with two overhead transmission lines (7.48 km and 7.73km) to the IC 138kV/34.5kV transformers located at Long Lake and English Lake respectively. The IC will be responsible for providing the Right-of-Way permitting for the submarine cable and overhead lines. Detailed cable or overhead line data was not provided, so typical data was assumed. For the cable, R+jX = 0.0003+j0.00195 p.u. on system base 100 MVA was used; for the overhead lines, typical data was assumed based on 556.5 Dove conductor and 60°C.

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 two 138kV/34.5kV station transformers both rated at 71.5/79.6 MVA and were modeled with a positive-sequence impedance of 14% on 100 MVA with an X/R ratio of 32.

    a. The substation step-up transformer at Long Lake connected to the collector circuit with 13 WECS units.
    b. The transformer at English Lake connected to the collector circuit with 18 WECS units.
    c. The IC indicated these interconnection facility transformers have a grounded wye-delta winding configuration with +/-10% on-load tap changer in 32 steps. The impedance of each generator step-up transformer was not provided by the IC and is assumed as 9.9% on 5.15 MVA with an X/R ratio of 12.14.

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 assumes 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.

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 rating of transmission lines in the vicinity of IR#616 are shown in Table 1 and Table 2.

**Table 1 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-6516 | 556.5 Dove | 50°C | Conductor | 110/121 MVA | 143/157 MVA |
| L-6517 | 556.5 Dove | 100°C | Conductor | 215/237 MVA | 242/266 MVA |
| L-6518 | 556.5 Dove | 100°C | Conductor | 215/237 MVA | 242/266 MVA |
| L-6523 | 795 Drake | 100°C | Conductor | 268/295 MVA | 287/316 MVA |

| Table 1 Local Transmission Element Ratings | | | | | |
|---|---|---|---|---|---|
| Line | Conductor | Design Temp | Limiting Element | Summer Rating Normal/Emergency | Winter Rating Normal/Emergency |
| L-6537 | 556.5 Dove | 60°C | Conductor | 140/154 MVA | 184/202 MVA |
| L-7003 | 556.5 Dove | 70°C[2] | 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 |

| Table 2 Transformer Ratings | |
|---|---|
| Transformer | Normal Rating / 15 min Emergency Summer/Winter |
| 3C-T71 | 225/236 MVA |
| 3C-T72 | 225/236 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 2021-03-21, the following 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
- IR557: SIS complete
- IR569: GIA executed
- IR566: GIA executed
- IR574: GIA executed
- IR598: GIA executed
- IR604: GIA executed
- IR603: GIA executed
- IR600: GIA executed

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

- TSR411: SIS in progress
- TSR412: Withdrawn

[2] L-7003 is currently being uprated from a design temperature of 60°C to 70°C. This study assumed that the upgrade is complete before IR#616 is in service.

TSR-411 is a long-term firm point-to-point transmission service reservation in the amount of 550 MW from New Brunswick to Nova Scotia; The TSR is expected to be in service in 2025 and a system study is 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:

> *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.*

# 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 system. The fault current characteristic for this Enercon E-138 EP3 E2 4.2 MW wind turbines Type 4 fully converted units is given as 1.045 times rated current, or X'd = 0.957 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#616 (Type 4) at 47C Three-phase MVA (1)**

| Location | Without IR#616 | With IR#616 |
|---|---|---|
| All transmission facilities in service | | |
| POI at 47C (138 kV) | 2,273 | 2,401 |
| Interconnection Substation (138kV) | 2,273 | 2,400 |
| 3C-Port Hastings (230kV) | 3,282 | 3,346 |
| 2C-Port Hastings (138kV) | 2,813 | 2,920 |
| 1C-Point Tupper (138kV) | 2,296 | 2,411 |
| Minimum Conditions (TC3, LG1, ML In-Service) | | |
| Interconnection Facility (138kV kV), all lines in-service | 1,125 | 1,252 |
| Interconnection Facility (138kV), L-6518 open at 2C | 930 | 1,058 |
| Interconnection Facility (138kV), L-6523 open at 1C | 989 | 1,117 |

(1) Classical fault study, flat voltage profile

The interrupting capability of the 230 kV circuit breakers at 3C-Port Hastings is at least 10,000 MVA. The interrupting capability of the 138 kV circuit breakers at 47C-Port Hawkesbury Paper, 2C-Port Hastings and 1C- Point Tupper is at least 3,500 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. Based on the supplied and assumed data, the SCR would be 8.6 at the IR#616's substation's HV terminals under minimal generation conditions and IR#616 offline. The SCR falls to 7.1 with L-6518 open at 2C-Port Hastings.

# 6 Voltage Flicker and Harmonics

Flicker coefficient information was not provided for the Enercon E-138 EP3 E2 4.2 MW Wind Turbines, however, 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 4.2 MW Enercon E-138 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 2.5%, with no individual harmonic exceeding 1.5% on 138 kV.

# 7 Load Flow Analysis

The load flow analysis was completed for generation dispatches under light load, summer peak, and winter peak conditions to stress local transmission around the Strait area as well as the East-West corridor 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#616 are shown in Figure 4. The nominal interface thermal limits are summarized in Table 4. NSPI relies on Remedial Action Schemes (RAS[3]) approved by NPCC to maintain interface limits. These RAS are armed by system conditions and flow across the respective interfaces and react to pre-

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

determined contingencies to rapidly reduce flow by either tripping generation in Cape Breton or running-back Maritime Link HVdc import.

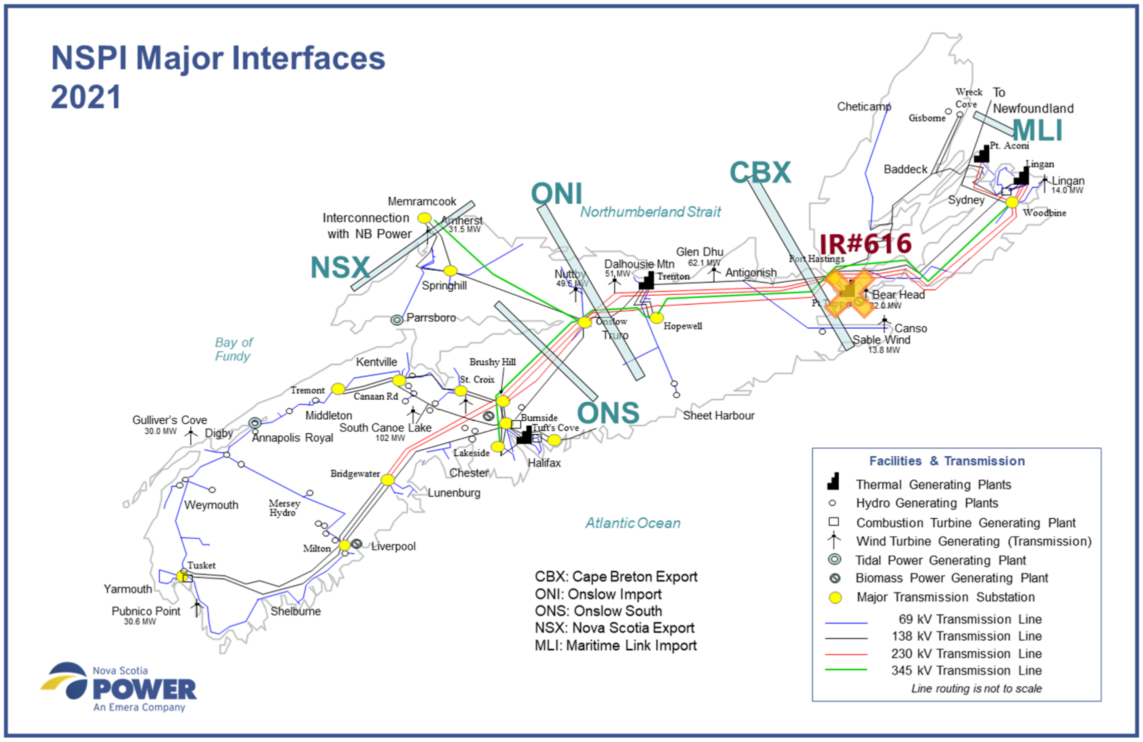


**Figure 4 Major transmission interfaces**

| 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) 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 38% 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#616. 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#616 is at rated output. The cases and dispatch scenarios considered are shown in Table 5.

| Table 5: Base Case Dispatch (MW) IR#616 On-Line | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Case | MLI | NS-NB | CBX | ONI | ONS | LIN | TRE | Wind | RAS (1) |
| SP01 | 475 | 330 | 966 | 992 | 549 | 215 | 159 | 220 | 79NG6 |
| SP02 | 475 | 330 | 843 | 876 | 434 | 237 | 159 | 220 | 79NG5 |
| SP03 | 475 | 330 | 843 | 875 | 434 | 257 | 159 | 220 | 79NG5 |
| SP04 | 320 | 0 | 723 | 761 | 652 | 63 | 159 | 220 | - |
| SP05 | 475 | 150 | 797 | 684 | 489 | 63 | 0 | 456 | 79NG5 |
| SP06 | 475 | 330 | 782 | 818 | 441 | 193 | 160 | 456 | 79NG5 |
| LL01 | 475 | 330 | 573 | 538 | 159 | 0 | 0 | 227 | - |
| WP01 | 320 | 150 | 999 | 1121 | 791 | 351 | 324 | 220 | 67NG5 |
| WP02 | 320 | 150 | 992 | 1018 | 727 | 345 | 165 | 379 | 79NG5<br>67NG5 |
| WP03 | 320 | 150 | 844 | 1071 | 781 | 343 | 324 | 409 | 67NG5 |
| WP04 | 320 | 150 | 845 | 1072 | 781 | 356 | 324 | 409 | 67NG5 |
| **S - Summer Peak  W - Winter Peak  LIN – Lingan Gen  TRE – Trenton Gen**<br>**(1) Based on present RAS arming levels** | | | | | | | | | |

For both NRIS and ERIS analysis, this FEAS added IR#616 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 345 kV, 230 kV, and 138 kV voltage levels for the above system conditions with IR#616 interconnected to the POI at 47C. 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 | |

| Table 6 Contingency List | | | |
|---|---|---|---|
| **Transmission Line** | **Transformer / Bus** | **Circuit Breaker Failure** | **Double Circuit Tower** |
| L-8001*, L-8002 | 67N: T71, T81 | 67N: 701, 702, 7-3, 705, 711, 712, 713, 811*, 812, 813, 814*, 815* | L-7003+L7004 Trenton area |
| L-6507, L-6508, L-8003* | 79N: T81* | 79N: 601*, 606*, 803*, 810* | |
| L-6537, L-6538*, L-6539, L-6516 | 91N: B71 | 91N: 701, 702, 703<br>5S: 606, 607 | |
| L-6517, L-6518, L-6523 | 47C-T68, T67 | | |

*Indicates contingency was studied with/without RAS action

**Results**
Several 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 an RAS, or the addition of a new RAS, 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/Transformer** | **Line segment** | **Highest overload (% of Emergency Rating)** | **Case** | **Contingency** |
| L-6517 | 2C-Hastings/1C-Tupper | Summer: 123% | SP01 | L-6518, 2C_B61 |
| L-6518 | 2C-Hastings/47C-PHP | Summer: 123% | SP01 | L-6517, 2C_B62 |
| 3C-T71 | 3C/2C-Hastings | Winter: 140% | WP01 | 2C_B62, 3C-714, 3C-T72 |
| 3C-T72 | 3C/2C-Hastings | Winter: 115% | WP01 | 3C-711, 3C-T71 |
| L-6515 | 2C-Hastings / 4C-Lochaber | Summer: 105% | SP05 | 101S-813, L-8004 |
| L-6515 | 2C-Hastings / 4C-Lochaber Rd | Summer: 105% | SP05 | L-7003 L-7004 Double Circuit Tower |

## <u>NRIS analysis</u>

For the contingencies resulting in the thermal overloads on L-6517 (11.4 km) and L-6518 (10.9 km), it’s recommended to rebuild L-6517 and L-6518 for 22.4 km at a cost of $8,948,000. The rebuild is required over uprating as the lines are presently rated at a 100℃ max operating temperature.

For the contingencies resulting in the thermal overloads on 3C-T71 and 3C-T72, transformers replacement of 3C-T71 and 3C-T72 is proposed at a cost of $12,200,000.

For the contingencies resulting in the thermal overloads on L-6515, the options examined include:

1. Thermal uprating of L-6515 at a cost of $7,500,000, or
2. Reduce arming values for existing Group 3, Group 5, and Group 6 RAS, estimated at $50,000 if no functional changes are required.

To interconnect IR#616 as NRIS, it's recommended that:

- Rebuild of L-6517 and L-6518 at a cost of $8,948,000.
- Transformer replacement of 3C-T71 and 3C-T72 at a cost of $12,200,000.
- Reduce arming and limit values for existing Group 3, Group 5, and Group 6 RAS.

**ERIS analysis**

Reducing IR#616's output to 20 MW relieved the overloads associated with the Strait area 138 kV transmission lines (L-6517 and L6518) and 3C-Hastings transformers (3C-T71 and 3C-T72). However, L-6515 thermal overloads are still present for the contingencies associated with the CBX corridor.

For the contingencies resulting in the thermal overloads on L-6515, the options examined include:

3. Thermal uprating of L-6515 at a cost of $7,500,000, or
4. Reduce arming values for existing Group 3, Group 5, and Group 6 RAS, estimated at $50,000 if no functional changes are required.

To interconnect IR#616 as ERIS, it's recommended to reduce arming and limit values for existing Group 3, Group 5, and Group 6 RAS.

# 8 Reactive Power and Voltage Control

In accordance with the *Transmission System Interconnection Requirements* Section 7.6.2, IR#616 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(s). 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 (Figure 5) provided by Enercon indicates that the Enercon E-138 EP3 E2 -FTQ 4.2 MW WECS have a rated power factor of 0.85 lagging and leading (+/- 2.65 Mvar per WECS) at the 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.

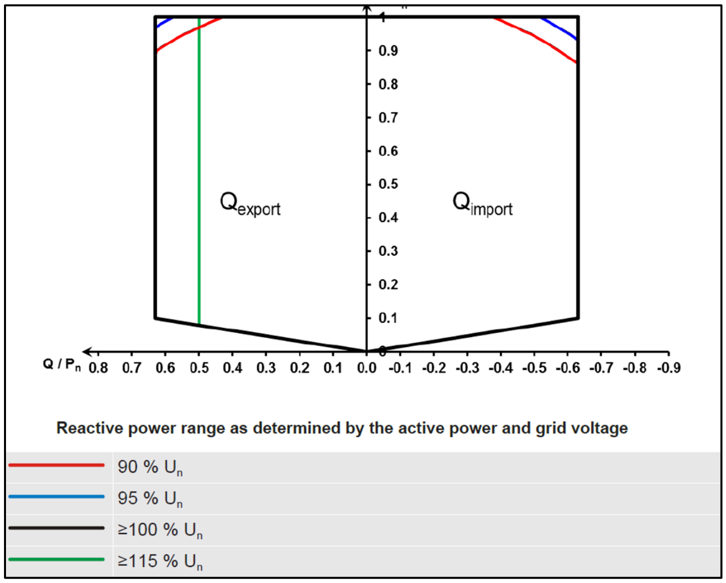


Figure 5 Model E-FTQ WECS reactive capability

Analysis shown in Figure 6 indicates that IR#616 may be able to meet the full-load reactive power requirement without additional reactive support. The model shows that with 31 WECS units (E2-FTQ version) operating at a total 130.2 MW and 82.2 Mvar, the delivered power to the high side of the ICIF transformers at:

- Long Lake is 53.6 MW and 20.6 Mvar, or a power factor of 0.933 with WECS terminal voltage at 1.08 p.u.
- English Lake is 74.0 MW and 22.8 Mvar, or a power factor of 0.956 with WECS terminal voltage at 1.09 p.u.

The overall delivered power to the 47C POI is 127.2 MW and 43.0 Mvar, or a power factor of 0.947.

This configuration would be able to meet the leading power factor requirement of -0.95 at the high side of both ICIF transformers at Long Lake and English Lake while the WECS are operating at a total of 130.2 MW and -10.5 Mvar both at a terminal voltage of 0.99 p.u.

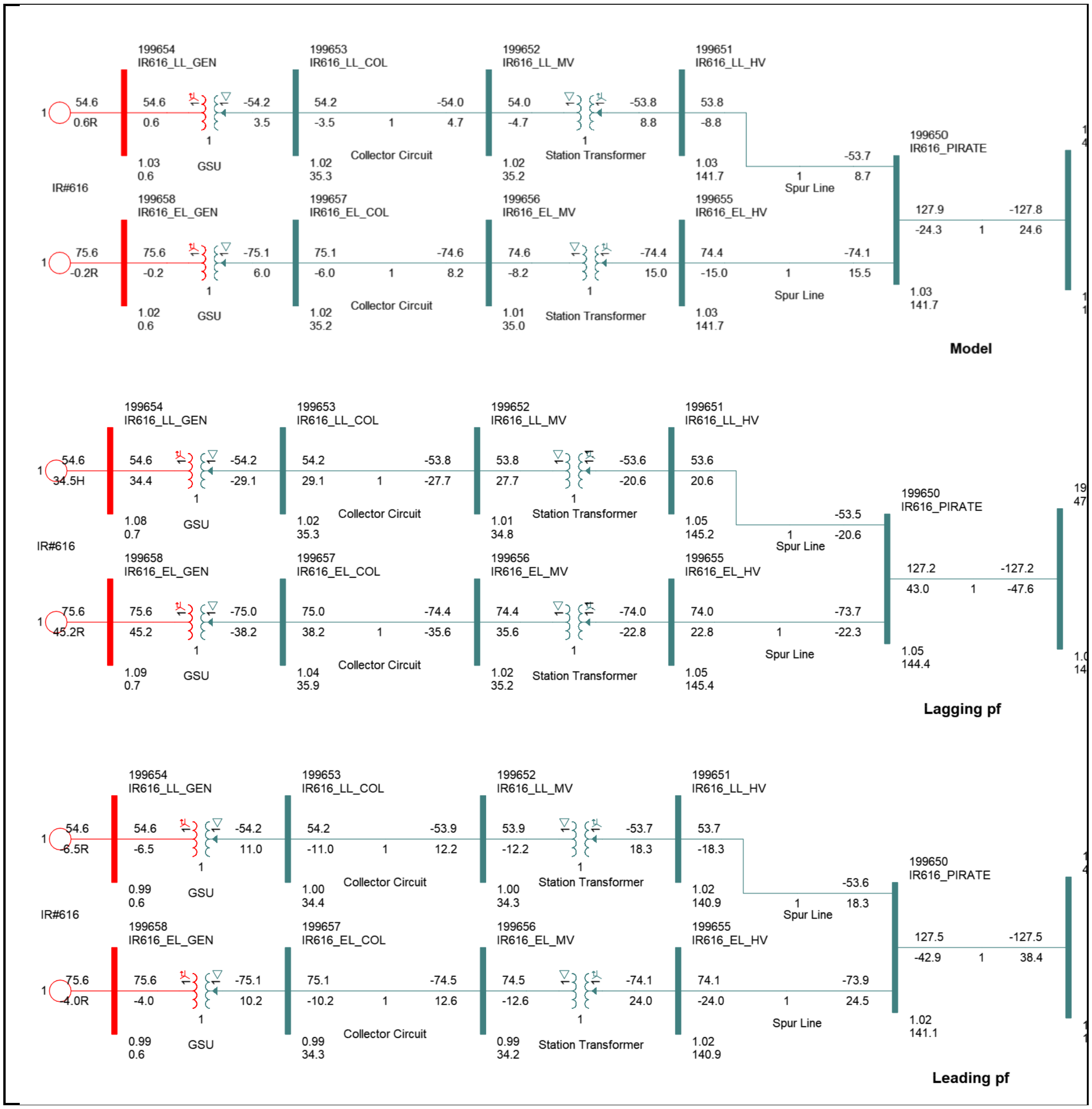


Figure 6 Power Factor analysis

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 34.5 kV 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 can 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.

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

47C-Port Hawkesbury Paper substation presently is not categorized NPCC Bulk Power System (BPS) or NERC Bulk Electric System (BES). Final BPS determination will be performed in the SIS.

IR#616 will be categorized as BES due to NERC BES Inclusion I4, due to its facility containing dispersed generation aggregating to > 75 MVA. As a result, each generator would be classified as a BES element. Other BES elements include the 138kV IC lines, the IR#616 138kV bus, the 34.5kV bus, and 138kV – 34.5 kV transformers.

Table 8 contains a summary of neighbouring elements' BPS/BES status. Note that the exceptions granted for 47C-Port Hawkesbury Paper and L-6523 may be re-evaluated in the SIS stage as grounds for their previous exception did not account for IR#616's injection.

**Table 8: Neighbouring elements BPS/BES status**

| Substation/element | BPS | BES |
|---|---|---|
| 47C-Port Hawkesbury Paper substation | No | No *(BES exception granted)* |
| L-6517 | Yes | Yes |
| L-6518 | Yes | Yes |
| L-6523 | No | No *(BES exception granted)* |

# 10 Expected Facilities Required for Interconnection

The following facility changes will be required to connect IR#616 to the NSPI transmission system at a POI at 47C under NRIS:

1. **Required Network Upgrades**

**a. NRIS Network Upgrades (full output, 130.2 MW)**

- Modification of NSPI protection systems at 47C-Port Hawkesbury Paper substation.
- Changes to arming/limit values for existing NSPI RAS (Group 3, Group 5, and Group 6).
- Rebuild of L-6517 and L-6518 for 22.4 km.
- 3C-T71 and 3C-T72 transformers replacements at 3C-Port Hastings.

**b. ERIS Network Upgrades (if capped at 20 MW)**

- Modification of NSPI protection systems at 47C-Port Hawkesbury Paper substation.
- Changes to arming/limit values for existing NSPI RAS (Group 3, Group 5, and Group 6).

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

- Install a new 138 kV breaker and associated equipment at the 47C POI with protection and control.
- Construct a total of 15.2 km transmission lines and 2.6 km submarine cable between the POI at 47C and the Interconnection Customer's Interconnection Facility. These lines and cable would be built to 138kV standards. U/G to O/H transitions are not included as they are dependent on shore landing conditions.
- Add control and communications between the wind farm and NSPI SCADA system (to be specified).

**3. 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 assumed that Enercon model E3-FTQ would meet this requirement, however the data provided did not meet the requirement that rated reactive power be delivered from zero to full rated real power.
- Centralized controls. These will provide centralized voltage set-point controls and are known as Farm Control Units (FCU). The FCU will control the 34.5 kV 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.
- Synthesized inertial response 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

**<u>Network Resource Interconnection Service (NRIS) estimate</u>**

The preliminary non-binding cost estimate for interconnecting IR#616 under NRIS at 130.2 MW is $37,958,800, with 10% contingency included. In this estimate, $21,398,000 (plus 10% contingency) of the amount represents Network Upgrade costs which are funded by the Interconnection Customer, but which are eligible for refund under the terms of the GIP. This does not include TBD costs to address any stability issues identified at the SIS stage based on dynamic analysis, and it assumes that RAS changes are approved by NPCC.

If transmission upgrades were found to be necessary to address thermal overloads on L-6515, as an alternative to the RAS arming level change, the total cost of Network Upgrades would increase by an estimated $7,500,000. These cost estimates do not include any contingency. Network upgrades are funded by the IC and are eligible for refund under the terms of the GIP.

The NSPI Interconnections Facilities and Network Upgrades estimate for interconnecting IR#616 as NRIS is summarized in Table 9.

| Table 9 NRIS Cost Estimate @ 47C POI | | |
|---|---|---|
| **Item** | **Network Upgrades** | **Estimate** |
| 1 | P&C modifications at 47C-PHP | $200,000 |
| 2 | Modifications to RAS settings Group 3, Group 5, Group 6 | $50,000 |
| 3 | Rebuild of L-6517 and L-6518 for 22.4 km | $8,948,000 |
| 4 | 3C-T71 and 3C-T72 transformer replacements | $12,200,000 |
| | Sub-total for Network Upgrades | $21,398,000 |
| **Item** | **TPIF Upgrades** | **Estimate** |
| 1 | Build 2.6 km 138kV submarine cable from TPIF to ICIF, with IC responsible to provide right-of-way and permitting | $5,200,000 |
| 2 | Build 15.2 km 138kV lines from ICIF to IC transformers, with IC responsible to provide right-of-way, U/G to O/H transitions not included | $7,600,000 |
| 3 | NSPI P&C relaying equipment | $100,000 |
| 4 | NSPI supplied RTU | $60,000 |
| 5 | Tele-protection and SCADA communications | $150,000 |
| | Sub-total for TPIF Upgrades | $13,110,000 |
| | **Total Upgrades** | **Estimate** |
| | Network Upgrades + TPIF Upgrades | $34,508,000 |
| | Contingency (10%) | $3,450,800 |
| | Total (Incl. 10% contingency and Excl. HST) | $37,958,800 |

The estimated time to construct the Transmission Providers Interconnection Facilities and the Network Upgrades are estimated to be completed 24-36 months after receipt of funds and cleared right of way from the customer.

**Energy Resource Interconnection Service (ERIS), capped at 20 MW**

The preliminary non-binding cost estimate for interconnecting IR#616 under ERIS, capped at 20 MW, is $14,696,000, with 10% contingency included. In this estimate, $250,000 (plus 10% contingency) of the amount represents Network Upgrade costs which are funded by the Interconnection Customer, but which are eligible for refund under the terms of the GIP. This does not include TBD costs to address any stability issues identified at the SIS stage based on dynamic analysis, and it assumes that RAS changes are approved by NPCC.

If transmission upgrades were found to be necessary to address thermal overloads on L-6515, as an alternative to the RAS arming level change, the total cost of Network Upgrades would increase by an estimated $7,500,000. These cost estimates do not include any contingency. Network upgrades are funded by the IC and are eligible for refund under the terms of the GIP.

The NSPI Interconnections Facilities and Network Upgrades estimate for interconnecting IR#616 as NRIS is summarized in Table 10.

| Table 10 ERIS Cost Estimate, capped at 20 MW, @ 47C POI | | |
|---|---|---|
| **Item** | **Network Upgrades** | **Estimate** |
| 1 | P&C modifications at 47C-PHP | $200,000 |
| 2 | Modifications to RAS settings Group 3, Group 5, Group 6 | $50,000 |
| | Sub-total for Network Upgrades | $250,000 |
| **Item** | **TPIF Upgrades** | **Estimate** |
| 1 | Build 2.6 km 138kV submarine cable from TPIF to ICIF, with IC responsible to provide right-of-way and permitting | $5,200,000 |
| 2 | Build 15.2 km 138kV lines from ICIF to IC transformers, with IC responsible to provide right-of-way, U/G to O/H transitions not included | $7,600,000 |
| 3 | NSPI P&C relaying equipment | $100,000 |
| 4 | NSPI supplied RTU | $60,000 |
| 5 | Tele-protection and SCADA communications | $150,000 |
| | Sub-total for TPIF Upgrades | $13,110,000 |
| | **Total Upgrades** | **Estimate** |
| | Network Upgrades + TPIF Upgrades | $13,360,000 |
| | Contingency (10%) | $1,336,000 |
| | Total (Incl. 10% contingency and Excl. HST) | $14,696,000 |

The estimated time to construct the Transmission Providers Interconnection Facilities and the Network Upgrades are estimated to be completed 24-36 months after receipt of funds and cleared right of way from the customer.

## 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#616 in service, losses in the winter peak case total 86.2 MW. With IR#616 in service at the POI of 47C, displacing generation at 91H, and not including losses associated with the IR#616 Generation Facilities or TPIF Interconnection Facilities, system losses total 99.9 MW, an increase of 13.7 MW. The model shows power delivered to the POI is 127.8 MW, therefore the loss factor is calculated as 13.7/127.8 = +10.7%.

## 13 Issues to be addressed in SIS

The following provides a preliminary scope of work for the subsequent SIS for IR#616. 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 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:

- Facilities that the customer must install to meet the requirements of the GIP and the *Transmission System Interconnection Requirements*.
- 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.
- Guidelines and restrictions applicable to first contingency operation (curtailments etc.).
- Under-frequency load shedding impacts.

The SIS will assess system contingencies such that the system performance will meet the following criteria:

- Table 1 "Planning Design Criteria" of NPCC Directory 1.
- Table 1 "Steady State & Stability Performance Planning Events" of NERC TPL-001-4.
- NSPI System Design Criteria, report number NSPI-TPR-003-4.

Additionally, electromagnetic transient study may be required to account for IR#616 control system to coordinate with other facilities in the transmission system and to ensure fault ride through.

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 SIS as well as any required additional transmission facilities. The determination will be based on NERC[4] and NPCC[5] 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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[4] NPCC criteria are set forth in its Reliability Reference Directory #1 *Design and Operation of the Bulk Power System*
[5] NERC transmission criteria are set forth in *NERC Reliability Standard TPL-001-4*