Interconnection Feasibility Study Report
GIP-IR730-FEAS-R1

Generator Interconnection Request 730
80 MW Wind Generating Facility
Pictou County, NS

2024-05-31

Control Centre Operations
Nova Scotia Power Inc.

Executive Summary

The Interconnection Customer (IC) submitted a Network Resource Interconnection Service (NRIS) and Energy Resource Interconnection Service (ERIS) Interconnection Request for an 80 MW wind generation facility interconnected to the NSPI transmission system, with a Commercial Operation Date of 2027-12-31. The Point of Interconnection (POI) requested by the customer is the 138kV substation 93N-Glen Dhu.

There are twenty-two (22) transmission Interconnection Requests in the Advanced Stage Transmission and Distribution Queue that must be included in the study models for IR#730.

This study assumes that the addition of generation from IR#730 will displace coal-fired generation in eastern Nova Scotia for both NRIS and ERIS.

A few post-contingency thermal loading violations occur due to IR#730 on transmission line L-6552. The following upgrades are proposed:

- Uprate of L-6552, for approximately 19.7 km, from 110 MVA (Summer) to at least 124 MVA (Summer).

No violations of voltage criteria were found for IR#730.

Data provided by the IC indicates that IR#730 will be utilizing the Enercon E-160 EP5 E3 5.56 MW type 4 wind turbines. It was assumed that the "FTQ" model was selected. Based on supplied interconnection data and assumptions, IR#730 will meet the net power factor requirement of +0.95 at the high voltage side of Interconnection Facility. However, it is noted that the proposed Enercon E-160 EP5 E3 wind turbine models do not have reactive power capability at zero active power. Due to this, the wind turbines will not meet the requirement to produce rated reactive power down to zero MW output. The adequacy of reactive power supply will be further investigated in the System Impact Study as specific details of the collector circuits become available.

NS Power notes that NERC standard PRC-029-1 is currently in development. As proposed, this standard will impose performance requirements for voltage and frequency ride through behaviour on inverter-based generating resources. It is anticipated that this standard will be applicable to the project currently under study. The Interconnection Customer is advised to consider the requirements of PRC-029-1 in their project design to ensure that their project can conform to these requirements. Conformance will be validated at the System Impact Study stage.

IR#730 was not found to adversely impact the short-circuit capabilities of existing circuit breakers. The minimum short circuit level at the Interconnection Facility 34.5kV bus is 340 MVA with all lines in service and IR#730 off-line, resulting in a Short Circuit Ratio (SCR) of 4.3. The minimum short circuit level is 236 MVA with L-6511 open, resulting in a SCR of 3.0. These conditions should be discussed with the wind turbine manufacturer to determine if the equipment can operate, or if modifications are required. NSPI system short circuit level may decline over time with changes to transmission configuration and generation mix, as noted in TSIR section 7.4.15. IR#730 must be able to accommodate these changes.

The maximum calculated voltage flicker P_{lt} of 0.162 for continuous operation is less than NS Power's required limit. This will be examined in the System Impact Study (SIS), as more detail is provided. The project design must meet NSPI requirements for low-voltage ride-through and voltage control. Harmonics must meet the Total Harmonics Distortion provisions of IEEE 519.

The preliminary value for the unit loss factor is calculated as +7.3% at the POI on 96N-Glen Dhu, net of any losses on the IC facilities up to the POI.

To connect IR#730 as NRIS, the preliminary non-binding cost estimate for interconnecting 80 MW to the 93N-Glen Dhu POI is $12,235,625. This cost estimate includes:

- A new 138 kV line terminal in the existing 93N-Glen Dhu substation.
- Protection upgrades at 93N-Glen Dhu.
- Uprate of L-6552 (19.7 km).

This cost estimate assumes the modifications to existing RAS will be approved by NPCC and includes a 25% contingency. In this estimate, $9,478,500 (plus 25% 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.

To connect IR#730 as ERIS, the preliminary non-binding cost estimate for interconnecting at the POI is $2,262,500, including a 25% contingency. This estimate includes:

- A new 138 kV line terminal in the existing 93N-Glen Dhu substation.
- Protection upgrades at 93N-Glen Dhu.

In this estimate, $1,500,000 (plus 25% 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 preliminary cost estimate does not include any supplemental devices that are potentially required to meet the NSPI power factor and/or inertia requirements. It also does not include costs to address any potential stability issues identified at the SIS stage based on dynamic analysis, and it assumes that RAS additions are approved by NPCC.

The estimated time to construct the Transmission Provider's Interconnection Facilities and any Network Upgrades is 24-36 months after receipt of funds and cleared right of way from the customer. These estimates will be further refined in the System Impact Study and the Facilities Study.

Table of Contents

1 Introduction

This Feasibility Study report (FEAS) presents the results of a Feasibility Study Agreement for the connection of "Glen Dhu 2" with an installed capacity of 83.4 MW, capped at an output of 80 MW. This wind generation facility is requesting interconnection to NSPI system, studied as Network Resource Interconnection Service (NRIS) and Energy Resource Interconnection Service (ERIS).

This project is listed as Interconnection Request #730 in the NSPI Interconnection Request Queue and will be referred to as IR#730 throughout this report. Interconnection Customer (IC) identified 93N-Glen Dhu as the Point of Interconnection (POI). This wind generation facility will be connected to the POI via a 138 kV substation expansion from the Point of Change of Ownership (PCO). Figure 1 shows the geographic location of the proposed POI (blue circle) and Figure 2 shows the electrical location (blue circle).

Figure 1 Approximate geographic location of IR#730

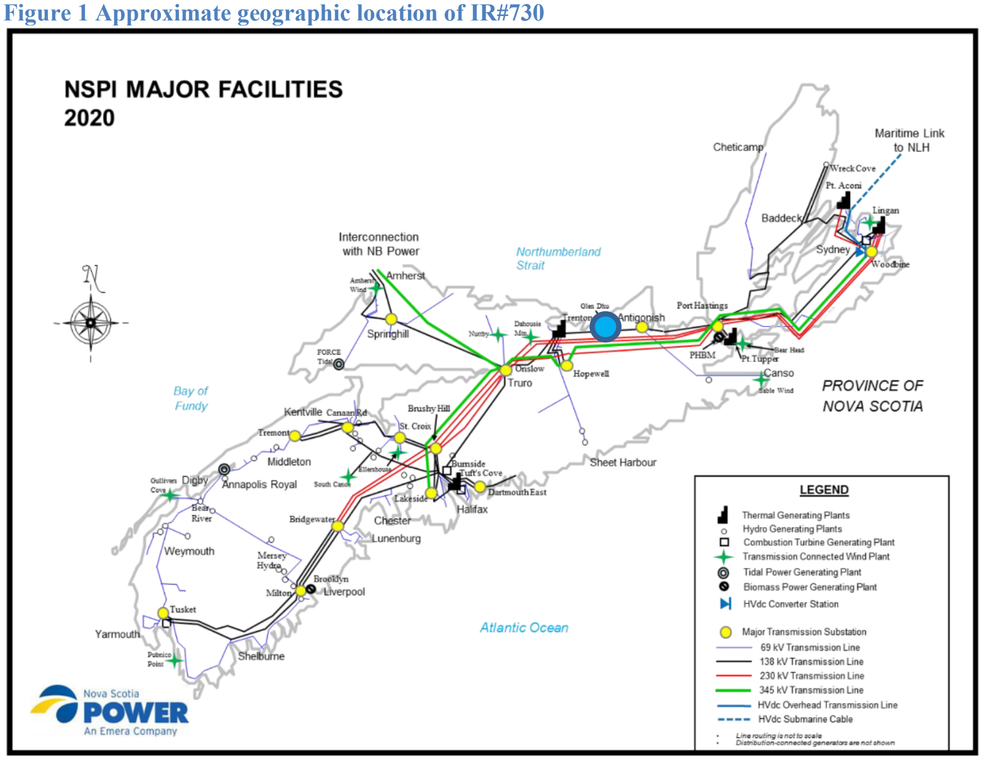
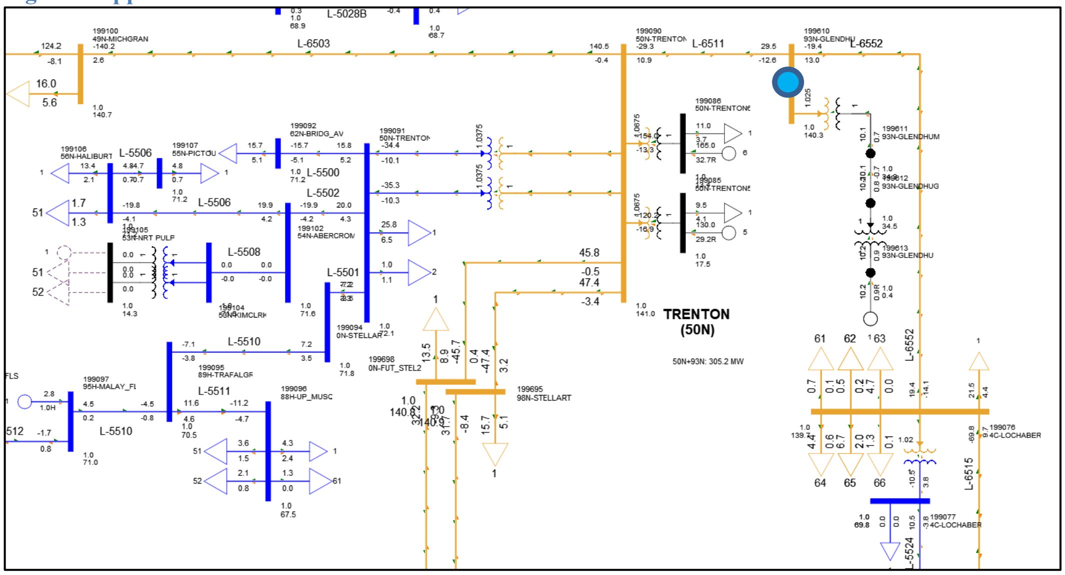


Figure 2 Approximate electrical location of IR#730



2 Scope

The objective of this 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 modeling 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 is 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 issue associated with IR#730. Expected minimum short circuit capability will also be identified for the purpose of Short Circuit Ratio analysis.

- Preliminary identification of any thermal overload or voltage 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 the transmission elements. Voltage violations occur when the post-contingency transmission bus voltage is outside the range of +/-10% of the 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#730 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 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 interconnect the generating facility.

The NRIS study identifies necessary upgrades to allow full output of the proposed generating facility. The ERIS study identifies the maximum allowed output, at the time the study is performed, of the interconnecting generating facility without requiring additional network upgrades.

3 Assumptions

This FEAS is based on the technical information provided by the IC. The POI and configuration are studied as follows:

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

2. Commercial Operation date 2027-12-31.

3. The Interconnection Customer Facility (ICIF) consists of 15 Enercon E-160 EP5 E3 wind turbine generators (WTG), each rated 5.56 MW (83.4 MW total, capped at 80 MW). It is assumed that the "FTQ" variant is used. The WTG units are connected to three collector circuits operating at a voltage of 34.5 kV.

4. 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

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

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 (SIS). 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.

5. Preliminary data was provided by the IC for the IC substation interconnection facility. The transformer was rated at 60/80/100 MVA and modeled with a positive-sequence impedance of 10% on 60 MVA with an X/R ratio of 42. The IC indicated this interconnection facility transformer has a Dyn5 winding configuration with +/- 10% on-load tap changer. The impedance of each generator step-up transformer was modeled as 8% on 6.2 MVA with an X/R of 12.

6. 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.

7. 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 (SIS), or that have an SIS in progress will proceed, as listed in Section 4 below.

8. It is noted that Enercon E-160 EP5 E3 has a “Cold Climate Version” in development. It is assumed that they will be capable of operating at ambient temperature as low as -30°C and that they will be available for the construction of IR#730. Therefore, these are suitable for delivering full power under environmental conditions in Nova Scotia according to section 7.6.9 of the TSIR.

9. Planning criteria meeting NERC Standard TPL-001-5 *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 the evaluation of the impact of any facility on the Bulk Electric System.

10. The ratings of the transmission facilities in the vicinity of IR#730 are shown in Table 1 and Table 2.

Table 1: Local Transmission Element Ratings

Line	Conductor	Design Temperature (^{0}C)	Limiting Element (Summer/Winter)	Summer Rating Normal/Emergency	Winter Rating Normal/Emergency
L-6503A	1113 Beaumont	100	Switchgear	287/315 MVA	287/315 MVA
L-6503B	1113 Beaumont	85	Conductor/Switchgear	287/315 MVA	287/315 MVA
L-6507	795 Drake	75	Conductor	216/237 MVA	261/287 MVA
L-6508	795 Drake	75	Conductor	216/237 MVA	261/287 MVA
L-6511	556.5 Dove	60	Conductor	140/154 MVA	184/202 MVA
L-6515	556.5 Dove	50	Conductor/Switchgear	110/121 MVA	143/157 MVA
L-6552	556.5 Dove	50	Conductor/Switchgear	110/121 MVA	143/157 MVA
L-6613	1113 Beaumont	100	Switchgear	287/315 MVA	287/315 MVA

Table 2: Local Transformer Ratings

Transformer	Normal Rating/15 min Emergency Summer / Winter
67N-T71	224/292 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 2024/02/21, 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
- IR517: GIA in Progress
- IR574: GIA Executed
- IR598: GIA Executed
- IR597: GIA Executed
- IR647: GIA in Progress
- IR664: FAC Complete
- IR662: FAC Complete
- IR670: FAC Complete
- IR671: FAC in Progress
- IR669: FAC Complete

- IR668: FAC Complete
- IR618: FAC Complete
- IR673: FAC Complete
- IR675: FAC Complete
- IR677: SIS in Progress
- IR697: SIS in Progress
- IR739: SIS in Progress
- IR742: SIS in Progress

The power system base cases for the feasibility study include all transmission connected IRs in the GIP queue up to and including IR742 with the exception of IR686, as the IR686 SIS was not completed when IR730 was initiated.

In addition, TSR-411 is included in the queue, which reflects the study of long-term firm Transmission Service Reservation (TSR) from New Brunswick to Nova Scotia. If approved by the NSUARB, the TSR is expected to be in service in 2028 and a system study is currently underway to determine the required updates to the Nova Scotia transmission system. This has not been included in the feasibility study and the following notice is posted to the OASIS site[2]:

> *Due to ongoing development discussions and engineering studies, the Transmission System Network Upgrades identified as part of Transmission Service Request #411 will not be included in the System Impact Study (SIS) Analysis for Generator Interconnection Procedures (GIP) Study Groups #32 to #35. GIP Study Group #32 to #35 analysis will be limited to the 2024 Transmission System configuration plus any material Network Upgrades identified in higher queued projects.*

5 Short-Circuit Duty / Short Circuit Ratio

The maximum (design) expected short-circuit level is 5,000 MVA (21 kA) on 138 kV systems and 10,000 MVA (25 kA) on 230 kV systems. The transient fault current characteristics for the Enercon E-160 EP5 E3 wind turbine with "FTQ" option are given as 1.03 times rated current, or X'd = 0.97 per unit on machine base MVA.

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

[2] https://www.nspower.ca/oasis/generation-interconnection-procedures

Table 3: The Short Circuit Levels in the Area with and without IR#730.

Location	Short Circuit MVA Without IR#730	Short Circuit MVA With IR#730
Maximum generation, all transmission facilities in service		
Interconnection Facility (138 kV) (Same bus as POI at 93N-Glen Dhu)	1239	1315
Interconnection Facility (34.5 kV)	405	494
50N-Trenton (138 kV)	2894	2932
4C-Lochaber (138 kV)	1184	1225
Minimum Conditions (TC3, LG1 In -Service)		
Interconnection Facility (138 kV), all lines in-service	780	857
Interconnection Facility (138 kV), L-6511 open	388	465
Interconnection Facility (138 kV), L-6552 open	528	605
Interconnection Facility (34.5 kV), all lines in-service	340	429
Interconnection Facility (34.5 kV), L-6511 open	236	325
Interconnection Facility (34.5 kV), L-6552 open	281	370

The interrupting capability of the 138 kV circuit breakers at 93N-Glen Dhu, 50N-Trenton and 4C-Lochaber 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 the proper operation of converters and control circuits. Based on the calculated short circuit levels, a POI on 138 kV substation 93N, and an 80 MW installation consisting of 15 Enercon E-160 EP5 E3 "FTQ" units, the short circuit ratio would be 4.3 at the 34.5kV Interconnection Facility of the IR#730 substation with all lines in service and IR#730 offline. With L-6511 open the SCR drops to 3.0, and with L-6552 open the SCR drops to 3.5. These expected SCR conditions should be discussed with the wind turbine manufacturer to determine if the equipment can operate, or if modifications are required.

NSPI system short circuit level may decline over time with changes to transmission configuration and generation mix. IR#730 must be able to accommodate these changes, per TSIR section 7.4.15. Windfarms in proximity to IR#730 (e.g. 93N-Glen Dhu) will also reduce the effective SCR in the area. The impact of the low SCR will be further examined when detailed data for the machine is made available for the SIS.

6 Load Flow Analysis

The load flow analysis was completed for Spring Light Load (SML), Summer Shoulder Load (SSH), Summer Peak Load (SUM) and Winter Peak Load (WIN) Scenarios with varying dispatch scenarios intended to cover a broad range of operating conditions.

Table 4 includes the list of base cases considered, along with a brief description.

Table 4: List of Base Cases

Case Name	Description
SML_01	Spring Light Load with low wind (nearby and other WTG at 17%)
SML_02	Spring Light Load with high wind (nearby and other WTG at 58% and 17%, respectively)
SSH_01	Summer Shoulder Load with low wind (nearby and other WTG at 17%)
SSH_02	Summer Shoulder Load with high wind (nearby and other WTG at 66% and 17%, respectively)
SUM_01	Summer Peak Load with low wind (nearby and other WTG at 17%)
SUM_02	Summer Peak Load with high wind (nearby and other WTG at 100% and 32%, respectively)
SUM_03	Summer Peak Load with moderate wind (nearby and other WTG at 95% and 17%, respectively). Wreck Cove dispatched at historical seasonal maximum and with Port Hawkesbury Paper at maximum load.
SUM_04	Summer Peak Load with low wind (nearby and other WTG at 17%) and with power flow between NS and NB at 320 MW, simulating delivery of reserve to NB. Wreck Cove is dispatched at historical seasonal maximum.
WIN_01	Winter Peak Load with low wind (nearby and other WTG at 17%)
WIN_02	Winter Peak Load with high wind (nearby and other WTG at 100% and 85%, respectively)
WIN_03	Winter Peak Load with high wind (nearby and other WTG at 100% and 85%, respectively) and with maximum load at Port Hawkesbury Paper.
WIN_04	Winter Peak Load with low wind (nearby and other WTG at 17%) and with power flow between NS and NB at 170 MW, simulating delivery of reserve to NB. This case represents stressed corridors with heavy flow from eastern NS to the load centre.

Those 12 base scenarios were studied with and without IR#730. This FEAS added IR#730 and displaced existing generation: thermal generation for low wind cases and other wind farms for high wind cases. Figure 3 shows the relevant corridors, generators, and loads on the NSPI transmission system. The arrow by each corridor shows the power flow direction of positive values.

Figure 3 Relevant transmission corridors, generators and loads on the NSPI transmission system.

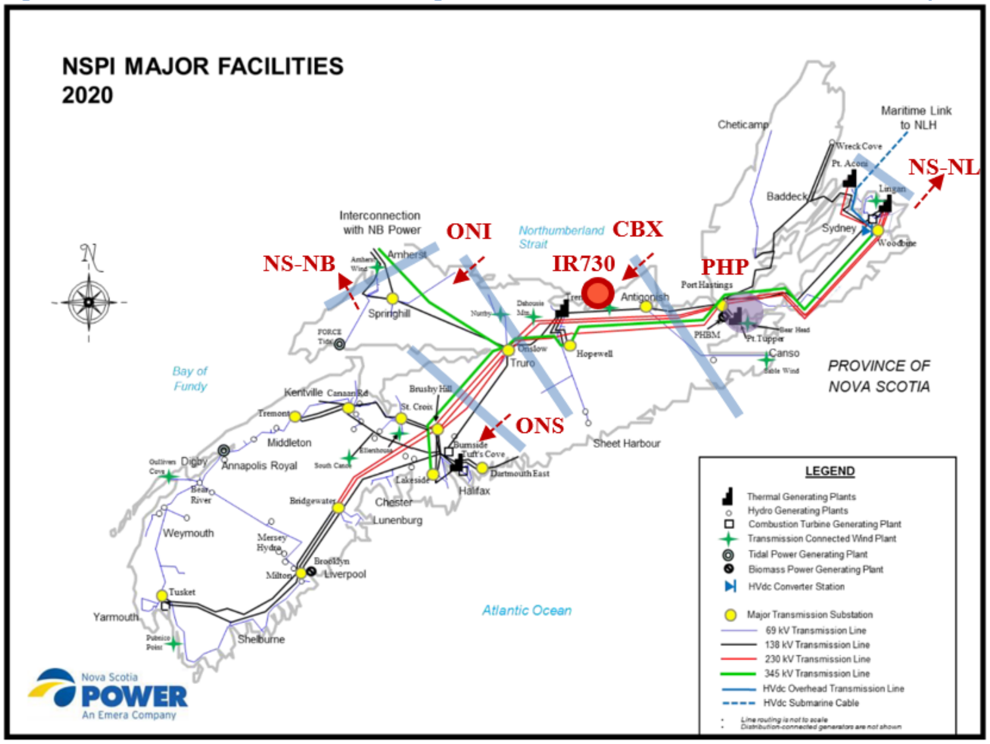


Table 5 summarizes the base cases and the dispatch scenarios to compare the effect of IR#730 on the loading of key NS corridors and generators. The case name followed by 1 (e.g., SML_01-1) stands for the case without IR#730 and the case name followed by 2 (e.g., SML_01-2) stands for the case with IR#730.

Table 5: Load Flow Data for Base Cases in MW

Case	NS Load	NS-NB	NS-NL	CBX	ONI	ONS	PHP	TR5+ TR6	Wind	IR#730
SML_01-1	727	151	-170	39	68	-94	176	0	236	-
SML_01-2	727	150	-170	12	119	-42	176	0	316	80
SML_02-1	759	152	-170	-22	198	106	209	0	516	-
SML_02-2	759	152	-170	-24	219	106	209	0	516	80
SSH_01-1	1161	151	-330	291	369	163	146	100	236	-
SSH_01-2	1161	149	-330	289	423	219	146	78	316	80
SSH_02-1	1157	151	-330	256	542	423	146	78	571	-
SSH_02-2	1157	151	-330	254	563	423	146	78	571	80
SUM_01-1	1545	150	-330	558	659	411	145	160	236	-
SUM_01-2	1545	151	-330	480	660	411	145	160	316	80
SUM_02-1	1604	145	-330	282	689	589	207	78	909	-
SUM_02-2	1604	150	-330	281	763	659	207	78	919	80
SUM_03-1	1604	147	-330	420	799	689	207	78	768	-
SUM_03-2	1604	150	-330	418	821	688	207	78	768	80
SUM_04-1	1541	323	-475	852	939	516	145	160	236	-
SUM_04-2	1541	326	-475	774	941	516	145	160	316	80
WIN_01-1	2354	0	-170	886	1040	855	15	295	236	-

Case	NS Load	NS-NB	NS-NL	CBX	ONI	ONS	PHP	TR5+ TR6	Wind	IR#730
WIN_01-2	2354	-1	-170	859	1039	855	15	243	316	80
WIN_02-1	2349	-4	-170	446	851	815	15	156	1286	-
WIN_02-2	2349	0	-170	445	925	885	15	156	1293	80
WIN_03-1	2545	3	-170	395	741	708	220	78	1286	-
WIN_03-2	2545	3	-170	317	741	708	220	78	1366	80
WIN_04-1	2354	168	-330	1043	1206	852	15	315	236	-
WIN_04-2	2354	166	-330	1036	1205	852	15	243	316	80

(1) For inter-area flows, +ve indicates export and -ve indicates import.
(2) The Wind column accounts only for transmission-connected wind facilities.

As shown in Table 5 the loading of corridors west to the POI (i.e., Onslow Import - ONI) has generally increased with the addition of IR#730 and loading of corridors east to the POI (i.e., Cape Breton Export - CBX) has decreased. This is due to the displacement of generation in the east of the province based on the merit order, though in some cases the IR#730 generation displaces 50N-Trenton generation, leaving ONI and CBX largely unaffected. Inter-provincial power flows between NS-NB are varied in these base cases, but only export conditions are considered in order to assess the impact of IR#730 integration with stressed CBX/ONI corridors.

Single contingencies were applied at the 345 kV, 230 kV and 138 kV voltage levels for the above system conditions with and without IR#730. Automated analysis searched for violations of emergency thermal ratings and emergency voltage limit for each contingency. Contingencies studied are listed in Table 6. Contingencies marked with * denote applicable in service SPS may be armed.

Table 6: Contingency List

Contingencies Studied				
88S_L7014	3C_712*	1N_B62	91H_511	DCT_L6010_L6005
88S_L7021	3C_713	1N_600	91H_516	DCT_L6005_L6016
88S_L7022	3C_714	1N_601	91H_521	DCT_L7008_L7009
88S_710	3C_715*	1N_613	91H_523	DCT_L7003_L7004*
88S_711	3C_716	120H_L7008	91H_G3	DCT_L7024_L7004*
88S_713	2C_L6515	120H_L7009	91H_G4	DCT_L6507_L6508
88S_714	2C_L6516	120H_L6005	91H_G5	DCT_L7021_L6534
88S_715	2C_L6517	120H_L6010	91H_G6	DCT_L6033_L6035
88S_720	2C_L6518	120H_L6011	14H_GT1	85S_L6545
88S_721	2C_L6537	120H_L6051	14H_GT3	5S_L6538
88S_722	2C_B61	120H_L6016	83S_GT1	3S_L6539
88S_723*	2C_B62	120H_T71	83S_GT2	5S_L6537
88S_T71	79N_L8003*	120H_T72	85S_GT1	5S_L6516
88S_T72	79N_L6507	120H_SVC	85S_GT2	5S_606
88S_G2	79N_L6508	120H_710	132H_602	5S_607
88S_G3	79N_T81*	120H_711	132H_603	2S_513
88S_G4	67N_L8001*	120H_712	132H_605	89S_G1

Contingencies Studied				
101S_ML_POLE1	67N_L8002	120H_713	132H_606	1C_G2
101S_ML_POLE2	67N_L7019	120H_714	91N_701	48C_G1
101S_ML_BIPOLE	67N_L7001	120H_715	91N_702	50N_G5
101S_T81	67N_L7002	120H_716	91N_703	50N_G6
101S_T82	67N_L7018	120H_720	91N_B71	104W_G1
101S_L7011*	67N_T81	120H_621	125C_L7025	110W_T62
101S_L7012*	67N_T82	120H_622	125C_701	104H_600
101S_L7015	67N_T71	120H_623	125C_B71	SALISBURY_L3004
101S_L8004*	67N_811*	120H_624	127C_L7003	SALISBURY_L3013
101S_701	67N_812	120H_626	127C_701	SALISBURY_SA3_2*
101S_702	67N_813	120H_627	127C_B71	SALISBURY_L3006*
101S_703	67N_814*	120H_628	102N_L7005	MEMRAMCOOK_L1159
101S_704	67N_701	120H_629	102N_701	MEMRAMCOOK_L1160
101S_705	67N_702	103H_L6008	102N_B71	MEMRAMCOOK_ME3_1*
101S_706	67N_703	103H_L6033	100N_L6555	4C_B63
101S_711	67N_704	103H_L6038	100N_601	4C_B64
101S_712	67N_705	103H_T81	100N_B61	4C_620
101S_713	67N_706	103H_T61	101V_L6054	4C_621
101S_811	67N_710	103H_T63	101V_L6004	4C_622
101S_812*	67N_711*	103H_B61	101V_601	4C_623
101S_813*	67N_712	103H_B62	99W_BESS	93N_L6511
101S_814	67N_713	103H_881	43V_BESS	93N_L6552
101S_816	1N_L6613	103H_600	132H_BESS	93N_B61
3C_L7024	1N_L6503	103H_608	99W_708	93N_601
3C_L7004	1N_L6001	103H_681	99W_709	50N_B61
3C_L7027*	1N_T1	91H_L5049	99W_T71	50N_B62
3C_T71	1N_T4	91H_L5012	99W_T72	50N_604
3C_T72	1N_T65	91H_L5041	DCT_L5039_L6033	50N_B55
3C_710*	1N_C61	91H_T62	DCT_L7009_L8002	50N_B57
3C_711	1N_B61	91H_T11	DCT_L6011_L6010	50N_500

6.1 NRIS Results

With the interconnection of IR#730 as NRIS a few contingencies resulted in thermal overload on L-6552. Table 7 shows the highest thermal overloads found, but other conditions were found that also violated thermal loading criteria, but to a lesser degree. No contingencies resulted in a violation of voltage limit criteria.

Table 7: Contingencies Resulting in Highest Line Overload

Line	Line Segment	Overload (% of Emergency Rating)	Case	Contingency
L-6552	93N-Glen Dhu/4C-Lochaber	112.3%	SUM_02-2	L-6511

For the contingencies resulting in the thermal overloads of L-6552, the only mitigation option identified is thermal uprating of L-6552 (from 110 MVA summer rating to 124 MVA summer rating), approximately 19.7 km, at a cost of $7,978,500.

6.2 ERIS Results

With the interconnection of IR#730 as ERIS, the facility can generate up to 64.8 MW before exceeding thermal loading constraints on L-6552 for the L-6511 contingency. This thermal loading constraint is limited to summer ratings and is based on maximum simultaneous wind generation at the 93N-Glen Dhu facility (noted that the 93N-Glen Dhu wind farm is connected as ERIS). The maximum combined output from IR#730 and 93N-Glen Dhu will be 124.8 MW under summer ratings.

7 Voltage Flicker and Harmonics

The voltage flicker calculations use IEC Standard 61400-21 based on estimated data provided for Enercon E-160 EP5 E3 “FTQ” wind turbines (2.5 flicker coefficient c(ψk, va) at 85° system angle). The voltage flicker P_{st} and P_{lt} levels are calculated at the Interconnection Facility for various system conditions and are shown in Table 8.

Table 8: The Voltage Flicker Pst and Plt Levels

System Condition	Flicker at 138 kV Bus P_{st}=P_{lt} Continuous
Maximum Generation	
All Transmission in Service	0.051
Minimum Conditions (TC3, LG1 in-service)	
All Transmission in Service	0.081
L-6511 open	0.162
L-6552 open	0.119

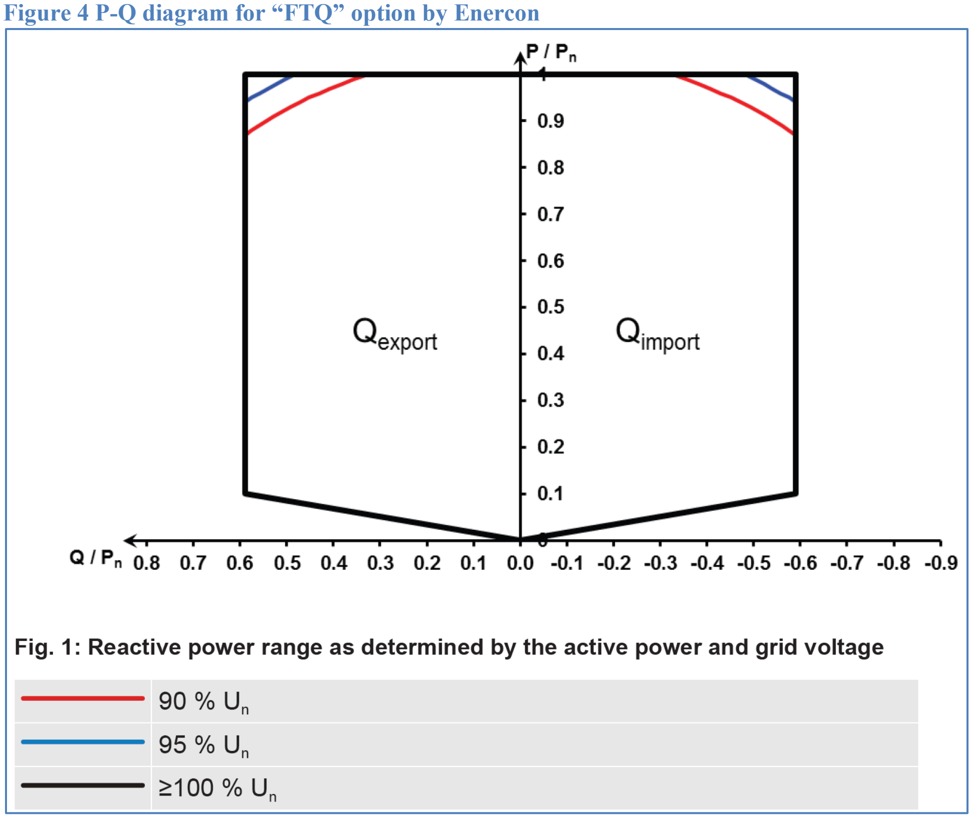
NS Power’s required limits are 0.35 for P_{st} and 0.25 for P_{lt}. It is likely that IR#730 will be able to meet the flicker requirement. This will be further evaluated in the SIS.

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.

8 Reactive Power and Voltage Control

In accordance with the *Transmission System Interconnection Requirements* Section 7.6.2, IR#730 must be capable of delivering reactive power for a net power factor of at least +/- 0.95 of rated capacity (i.e. +/-26.3 MVAr for an 80 MW plant) to the high side of the plant interconnection transformer(s). Reactive power can be provided by continually acting auxiliary devices such as STATCOM, synchronous condenser, etc. supplied by the Interconnection Customer. The provided P-Q diagram for the "FTQ" option is shown in Figure 4.

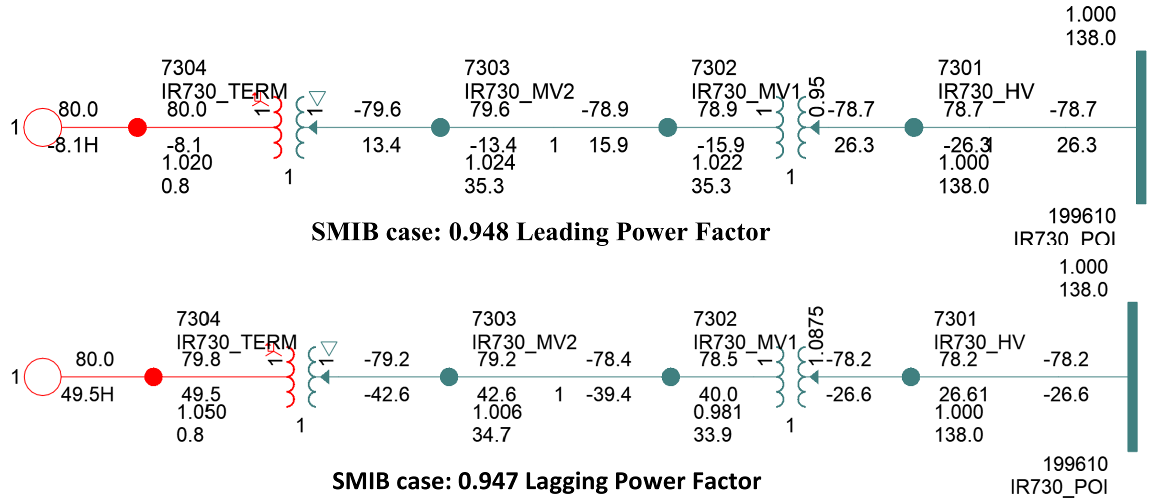
Figure 4 P-Q diagram for "FTQ" option by Enercon



When the active power is zero, the reactive power is zero. Due to this, IR#730 will not be able to meet the TSIR requirement for rated reactive power availability through the full range of active power output of the Generating Facility from zero to full power.

The power factor analysis is conducted using a SMIB (Single Machine Infinite Bus) case for IR#730. The leading and lagging power factor analysis for IR#730 results in power factor values less than 0.95. This verifies the ability of the configuration to meet the leading and lagging power factor requirement at full power output, for the "FTQ" option of Enercon E-160 EP5 E3 WTG. Note that the power factor requirement cannot be met with "FT" option. The analysis shown in Figure 5 verifies the reactive power capability of the system.

Figure 5 Reactive Power Analysis results



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

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 generator 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, and 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 the plant voltage controller for long-term reactive power and voltage management at the POI.

9 Bulk Electric / Bulk Power Analysis

Presently, the 138 kV bus 93N-Glen Dhu is not part of the Nova Scotia Bulk Power System (BPS). This will be further evaluated in the SIS phase. Note that if IR#730 is categorized as BPS, the existing 93N-Glen Dhu windfarm's BPS status will change as well.

Since IR#730 has dispersed generation totaling more than 75 MVA, Inclusion I4 of the NERC Bulk Electric System (BES) Definition would apply, and each generator would be classified as a BES element. The 34.5 kV bus and the 138 kV bus would also be considered BES.

Note that the existing 93N-Glen Dhu site is not presently designated BES. However, the connection of IR730 to the 138 kV bus means that a single point of failure removes 93N-Glen Dhu + IR730's generation (60 MW + 80 MW = 140 MW). As a result, 93N-Glen Dhu's generators and GSU will also be designated as BES elements. Its collector bus and substation step-up transformer will not be affected.

10 Expected Facilities Required for Interconnection

The following facility changes will be required to connect IR#730 to the NSPI transmission system at a POI on 93N-Glen Dhu:

10.1 Network Upgrades under NRIS

- Install a new 138 kV line terminal in the existing 93N-Glen Dhu substation with control and protection. Modifications to existing Remote Terminal Unit (RTU) to interface with NSPI's SCADA, with telemetry and controls as required by NSPI.
- Uprate of L-6552 from 110 MVA (Summer) to 124 MVA (Summer).

10.2 Transmission Provider's Interconnection Facilities (TPIF):

- Supervisory, control, and communications between the wind farm and NSPI SCADA system (to be specified).

10.3 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 shows that Enercon E-160 EP5 E3 FTQ would meet the 0.95 lagging power factor requirement at full load but will 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. Note that the IR#730 FCU must be coordinated with the existing 93N FCU. 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 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.
- Automatic Generation Control to assist with tie-line regulation.
- Compliance with section 7.6.7 of TSIR, "WECS Generating Facilities shall support short-duration frequency deviations by providing inertia response equivalent to a Synchronous Generator with an inertia factor (H) of at least 3.0 MW-s/MVA for a period of at least 10 seconds." This item will be assessed in the SIS, which may identity additional resources such as synchronous condenser, Flexible AC Transmission System (FACTS) devices, etc.
- Operation at an ambient temperature of -30°C, section 7.6.9 of the TSIR.
- The proposed facility shall comply with TSIR requirement 7.4.15 and shall be able to accommodate changes to the SCR as the system evolves.
- NS Power notes that NERC standard PRC-029-1 is currently in development. As proposed, this standard will impose performance requirements for voltage and frequency ride through behaviour on inverter-based generating resources. It is anticipated that this standard will be applicable to the project currently under study. The Interconnection Customer is advised to consider the requirements of PRC-029-1 in their project design to ensure that their project can conform to these requirements. Conformance will be validated at the System Impact Study stage.
- The facility must meet NSPI's TSIR as published on the NSPI OASIS site.

11 NSPI Interconnection Facilities and Network Upgrades Cost Estimate

NRIS Cost Estimate:
Estimates for NSPI Interconnections Facilities and Network Upgrades for interconnecting 80 MW wind energy at the 138 kV POI on 93N-Glen Dhu are included in Table 9.

Table 9: Cost Estimate NRIS @ POI 93N-Glen Dhu

Item	Network Upgrades	Estimate
1	Install a new 138 kV line terminal in the existing 93N-Glen Dhu substation with control and protection. Modifications to Remote Terminal Unit (RTU) to interface with NSPI's SCADA, with telemetry and controls as required by NSPI	$1,500,000
2	Uprate of L-6552 (19.7 km)	$7,978,500
	Sub-total for Network Upgrades	$9,478,500
Item	**TPIF Upgrades**	**Estimate**
2	NSPI P&C relaying equipment*	$100,000
3	NSPI supplied RTU	$60,000
4	Tele-protection and SCADA communications*	$150,000
	Sub-total for TPIF Upgrades	$310,000
	Total Upgrades	**Estimate**
	Network Upgrades + TPIF Upgrades	$9,788,500
	Contingency (25%)	$2,447,125
	Total (Incl. 25% contingency and Excl. HST)	$12,235,625

*Note: Some of this equipment is already existing at the 93N-Glen Dhu substation, but will require modifications.

The preliminary non-binding cost estimate for interconnecting 80 MW at the POI at 93N-Glen Dhu under NRIS is $12,235,625 including a contingency of 25%. In this estimate, $9,478,500 (plus 25% 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.

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

ERIS Cost Estimate

Estimates for NSPI Interconnections Facilities and Network Upgrades for interconnecting IR#730 as ERIS at the 138 kV POI on 93N-Glen Dhu are included in Table 10.

Table 10: Cost Estimate ERIS @ POI 93N-Glen Dhu

Item	Network Upgrades	Estimate
1	Install a new 138 kV line terminal in the existing 93N-Glen Dhu substation with control and protection. Modifications to Remote Terminal Unit (RTU) to interface with NSPI's SCADA, with telemetry and controls as required by NSPI	$1,500,000
	Sub-total for Network Upgrades	$1,500,000
Item	**TPIF Upgrades**	**Estimate**
2	NSPI P&C relaying equipment*	$100,000
3	NSPI supplied RTU	$60,000
4	Tele-protection and SCADA communications*	$150,000
	Sub-total for TPIF Upgrades	$310,000
	Total Upgrades	**Estimate**
	Network Upgrades + TPIF Upgrades	$1,810,000
	Contingency (25%)	$452,500
	Total (Incl. 25% contingency and Excl. HST)	$2,262,500

*Note: Some of this equipment is already existing at the 93N-Glen Dhu substation, but will require modifications.

The preliminary non-binding cost estimate for interconnecting at the POI at 93N-Glen Dhu under ERIS is $2,262,500 including a contingency of 25%. In this estimate, $1,500,000 (plus 25% 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.

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

12 Loss Factor

The loss factor is calculated by running the winter – peak load flow case (WIN_01) with and without the new facility in service, while keeping 91H-Tufts Cove as the NS Area Interchange bus. This methodology reflects the load center in and around 91H-Tufts Cove. A negative loss factor reflects a reduction in system losses.

The data and calculation are detailed in Table 11 and Equation (01), respectively.

Table 11: Data for Loss Factor Calculation

Parameter/Measurement	Value (MW)
Power at POI of IR#730	78.66
Power generation at TC with IR#730	75.46
Power generation at TC without IR#730	148.4
Loss Factor	**7.30 %**

$$Loss\ Factor = \frac{(IR730_{POI} + TC_{withIR730}) - TC_{withoutIR730}}{IR730_{POI}} \qquad (01)$$

13 Preliminary scope of subsequent SIS

The following provides a preliminary scope of work for the subsequent SIS for IR#730.

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, transient stability, ride through capability, 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 response, frequency response, control interactions with other IBR facilities, 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 notice on OASIS provides additional clarification on the SIS model requirements:

NSPI-TPR-015-2: PSSE and PSCAD Model Requirements and NSPI-TPR-014-1: Model Quality Testing will undergo revision as the grid evolves and performance criteria changes. The most up to date version will be provided as they become available.

To be eligible for inclusion in the Interconnection System Impact Study stage, and thereby advance the Interconnection Request's initial Queue Position, the Interconnection Customer must meet the progression milestone requirements of Section 7.2 of the GIP at least ten (10) Business Days prior to the Interconnection System Impact Study commencement date. For clarity, item 7.2 (i) – provision of a detailed stability model for the generator(s) shall mean:

- ***Provision of PSSE and PSCAD models in compliance with documents NSPI-TPR-015-2: PSSE and PSCAD Model Requirements, and***
- ***Provision of test data demonstrating model testing in compliance with NERC, NPCC and NSPI criteria. NSPI-TPR-014-1: Model Quality Testing lists the minimum requirements that will be performed by NSPI. Additional testing may be performed to assess compliance with all applicable criteria. Any test not meeting the minimum NSPI requirements will be documented in the MQT report to the IC.***

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 TSIR.
- 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-001-5.1.
- NSPI System Design Criteria, report number NSPI-TPR-003-6.

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 NPCC[3] and NERC[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.

[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-001-5.1