Interconnection Feasibility Study Report
GIP-IR710-FEAS

Generator Interconnection Request 710

70 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 (IR#710) for a proposed 70 MW wind generation facility interconnected to the NSPI Transmission System, with a Commercial Operation Date of 2025-12-31. The Point of Interconnection (POI) requested by the customer is the 230kV substation 91N – Dalhousie Mountain.

There are twenty-two transmission Interconnection Requests in the Advanced Stage Transmission and Distribution Queue that must be included in the study models for IR#710. 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. This has not been included in the feasibility study as per the following (please see the following notice posted to the OASIS site at https://www.nspower.ca/oasis/generation-interconnection-procedures):

> *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.*

Although the upgrades as an outcome of TSR 411 have not been included in the feasibility study, they are only expected to strengthen the system.

This study assumes that the addition of generation from IR#710 will displace coal-fired generation in eastern Nova Scotia for both NRIS and ERIS.

Interconnection at 91N-Dalhousie Mountain will require expansion of the existing three-breaker 230kV ring bus. This substation is classified as Bulk Power System under NPCC criteria and Bulk Electric System under NERC criteria. As IR#710 has dispersed generation totalling more than 75 MVA, each generator will be classified as a NERC Bulk Electric System (BES) element. The IR#710 Interconnection Customer substation is also classified as part of the BES, subject to the applicable NERC Reliability Criteria.

The assessment of the POI at 91N-Dalhousie Mountain indicated that several thermal loading violations would occur due to IR#710, notably on L-8004, L-7019 and L-6515. To address these contingencies, it is proposed that Remedial Action Scheme (RAS) arming limits be modified.

No violations of voltage criteria were found for IR#710.

Data provided by the IC indicates that IR#710 will be utilizing Nordex N163/5.9 MW wind turbines curtailed to 5.0 MW each. The adequacy of reactive power supply will be further investigated in the System Impact Study as specific collector circuit details become available. It is noted that the proposed Nordex models do not meet the requirement to produce full MVAR capability down to zero MW output.

IR#710 was not found to adversely impact the short-circuit capabilities of existing circuit breakers. The minimum short circuit level at the Interconnection Facility 230kV bus is 1,481 MVA with all lines in service and IR#710 off-line, resulting in a 21.2 Short-Circuit Ratio. This falls to 531 MVA or an SCR of 7.6 with L-7019 open at 67N-Onslow, and 1329 MVA or 19.0 if L-7004 is open at 3C- Port Hastings.

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 preliminary value for the unit loss factor is calculated as +7.0% at the 91N POI, net of any losses on the IC facilities up to the POI.

The preliminary non-binding cost estimate for interconnecting 70.0 MW at the POI at 91N under both NRIS and ERIS is $6,500,000 including a contingency of 25%. In this estimate, $4,050,000 (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 potential incremental costs to address any stability issues identified at the SIS stage based on dynamic analysis, and it assumes that RAS modifications are approved by NPCC.
This cost estimate is the same for NRIS and ERIS due to the interdependencies between IR#710's output, the Cape Breton generation displacement, and Cape Breton Export RAS arming.

The estimated time to construct the TPIF and Network Upgrades is 24-36 months after receipt of funds from the IC. The timeframe will be further determined during the FAC study. The delivery of a 230kV circuit breaker may drive delays in the construction of Network Upgrades.

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1 Introduction

The Interconnection Customer (IC) submitted a Network Resource Interconnection Service (NRIS) and Energy Resource Interconnection Service (ERIS) Interconnection Request for a proposed 70 MW wind generation facility interconnected to the NSPI transmission system, with a Commercial Operation Date of 2025-12-31. The Point of Interconnection (POI) requested by the customer is the 230kV substation 91N (Dalhousie Mountain).

The IC signed a Feasibility Study Agreement to study the connection of their proposed generating facility to the NSPI transmission system dated 2023-07-19, and this report is the result of that Study Agreement. This project is listed as Interconnection Request 710 in the NSPI Interconnection Request Queue and will be referred to as IR#710 throughout this report.

Figure 1 shows the proposed geographic location of IR#710 in relation to the NSPI transmission system.

Figure 1 IR#710 Site Location

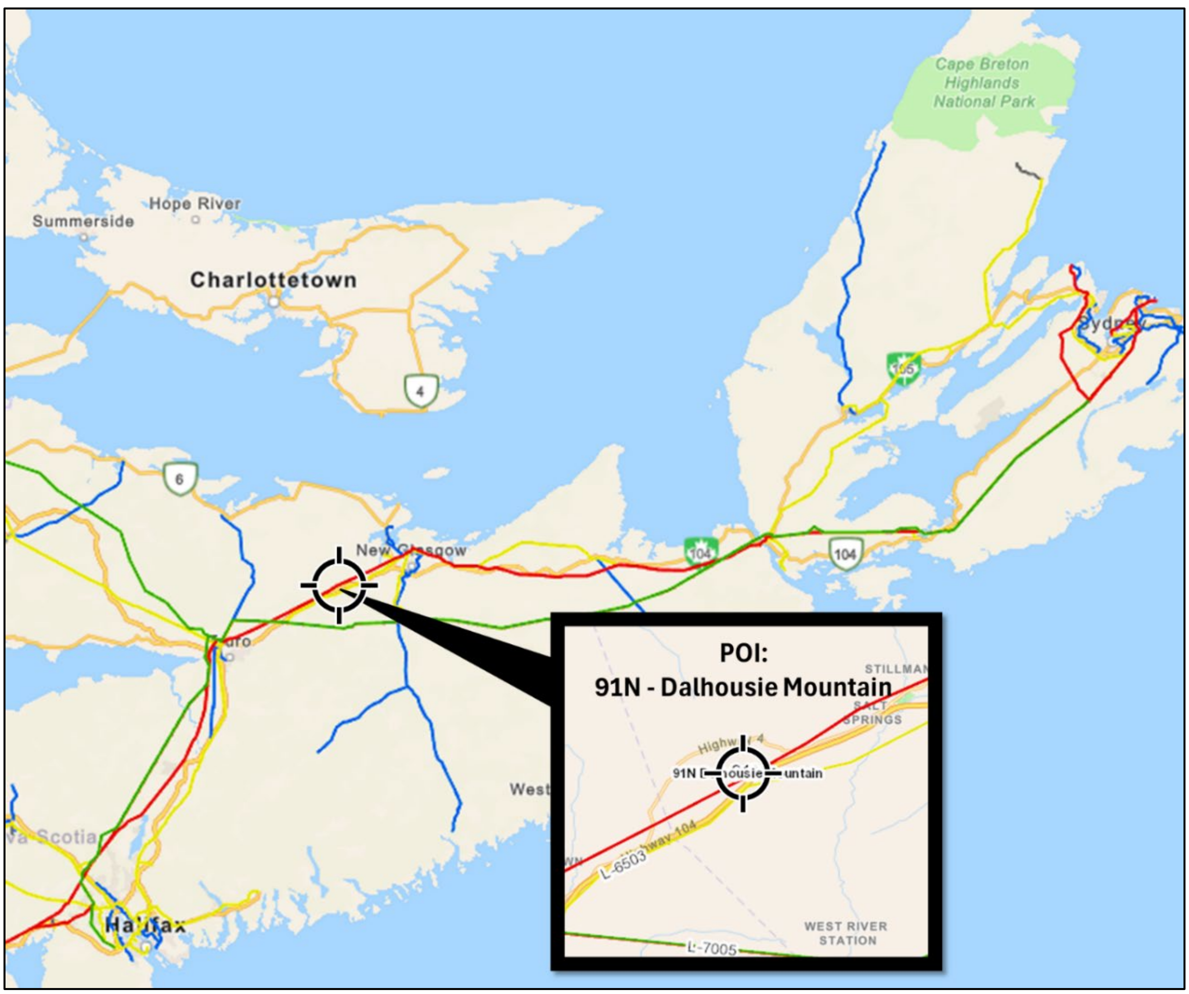
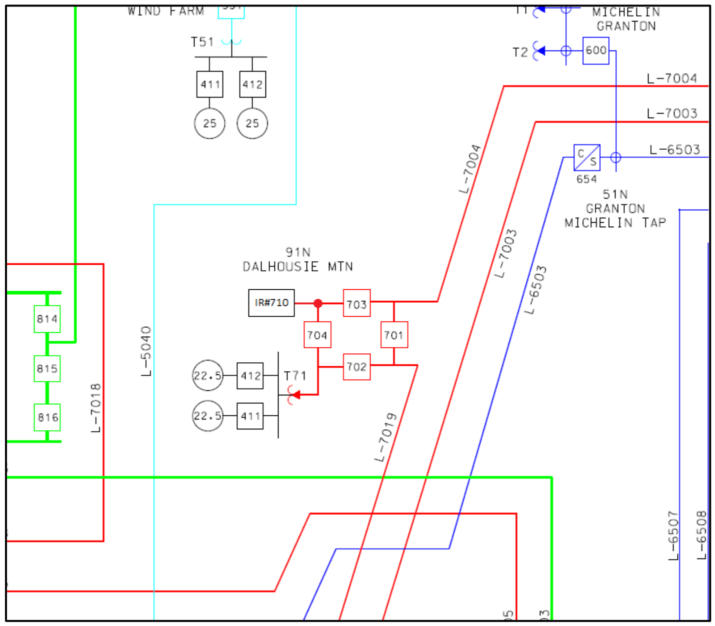


Figure 2 shows the circuit breaker configuration of transmission lines in the vicinity of the POI.

Figure 2 Circuit Configuration near POI



2 Scope

This Interconnection Feasibility Study (FEAS) objective 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].

- 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#710 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 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 2025-12-31.

3. The Interconnection Customer Interconnection Facility (ICIF) consists of 14 Wind Energy Converter System (WECS) units; Nordex N163, 5.9 MW wind turbines curtailed to 5.0 MW, 750 V, Type 3 (double fed asynchronous generator), capped at a total of 70.0 MW.

4. The WECS are distributed among the Dalhousie Mountain site.

5. The POI at 91N-Dalhousie Mountain is considered Bulk Power System facilities and will therefore require a ring bus configuration in accordance with Table 8 of the NSPI *Transmission System Interconnection Requirements.* 91-N, as it exists today, is a three breaker ring bus with space for the addition of a fourth breaker.

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

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, the facility must be 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 provided by the IC for the IC Interconnection Facility has one 230kV/34.5kV station transformer rated at 45/60/75 MVA. The transformer is connected to two collector circuits each comprised of 7 WECS units. The transformer was modeled with a positive-sequence impedance of 16.67% on 100 MVA with an X/R ratio of 20. The IC indicated that the interconnection facility transformer has a grounded wye-grounded wye winding configuration with a grounded-delta tertiary winding. The tertiary winding voltage was not supplied. IC provided data states that the interconnection transformer will be equipped with +/-10% fixed taps which is assumed to be in 9 steps of 2.5% increments. The positive-sequence impedance of each generator step-up transformer provided by the IC is 9% on 6.35 MVA.

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 required that the wind turbines are equipped with a “cold weather option” suitable for delivering full power under expected Nova Scotia winter environmental conditions as provided in the *Transmission System Interconnection Requirements*.

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#710 are shown in Table 1.

Table 1: Local Transmission Element Ratings					
Line	Conductor				Limiting Element
	Type	Design Temp	Summer Rating Normal/Emergency	Winter Rating Normal/Emergency	
L-6503	1113 Beaumont	85°C	287/315 MVA	287/315 MVA	Switchgear
L-6511	556.5 Dove	60°C	140/154 MVA	184/202 MVA	Conductor
L-6552	556.5 Dove	50°C	110/121 MVA	143/157 MVA	Conductor
L-6515	556.5 Dove	50°C	110/121 MVA	143/157 MVA	Conductor
L-7003	556.5 Dove	70°C[2]	273/303 MVA	345/379 MVA	Conductor
L-7004	556.5 Dove	60°C	233/246 MVA	307/338 MVA	Conductor
L-7019	555.5 Dove	70°C	273/303 MVA	345/379 MVA	Conductor
L-7005	1113 Beaumont	70°C	398/438 MVA	398/438 MVA	CT Ratio
L-8001	2x 795 Drake	49°C	670/737 MVA	1021/1123 MVA	CT Ratio
L-8002	2x 795 Drake	49°C	670/737 MVA	1021/1123 MVA	CT Ratio
L-8003	2x 1113 Beaumont	120°C	1372/1509 MVA	1832/2015 MVA	CT Ratio
L-8004	Type 41 SDC	50°C	520/572 MVA	880/968 MVA	Conductor

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 2024/05/22, the following twenty-two Transmission 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

[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#710 is in service.

The power system base cases for the feasibility study includes 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 IR710 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 (at https://www.nspower.ca/oasis/generation-interconnection-procedures):

> *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 2022 Transmission System configuration plus any material Network Upgrades identified in higher queued projects.*

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 the Nordex N163, 5.9 MW Type 3 (double fed asynchronous generator) units was not provided by the IC, but for the 5.7MW unit it is given as 0.319 on machine base MVA. This corresponds to 3.135 times rated current during a symmetrical fault.

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 2.

Table 2: Short-Circuit Levels IR#710 (Type 3) on L-7003 Three-phase MVA (1)

Location	Without IR#710	With IR#710
All transmission facilities in service		
POI at 91N (230kV)	2,410	2,569
Interconnection Facility (34.5kV)	545	751
3C-Port Hastings (230kV)	3,542	3,582
2C-Port Hastings (138kV)	2,976	2,994
67N-Onslow (230kV)	4,402	4,525
1N-Onslow (138kV)	2,448	2,470
Minimum Conditions (TC3, LG1, PA1 in service)		
Interconnection Facility (230kV), all lines in-service	1,469	1,629
Interconnection Facility (230kV), L-7019 open at 67N	521	680
Interconnection Facility (230kV), L-7004 open at 3C	1,318	1,477

(1) Classical fault study, flat voltage profile

The interrupting capability of the 230 kV circuit breakers at 3C-Port Hastings and 67N-Onslow is at least 10,000 MVA. The interrupting capability of the 138 kV circuit breakers at 2C-Port Hastings is at least 3,500 MVA. As such, the interrupting rating at these substations will not be exceeded by this development.

Inverter-based generation installations often have a minimum Short Circuit Ratio (SCR) for proper operation of converters and control circuits. Based on the assumed data and calculated short circuit levels, the SCR is 20.0 at the 230kV bus of IR#710 ICIF with all lines in service and IR#710 offline. This falls to 7.4 with L-7019 open at 67N-Onslow, and 18.8 if L-7004 is open at 3C- Port Hastings.

When accounting for the 49.5 MW Dalhousie Mountain Wind Farm installation at the 91N-Dalhousie Mountain substation, the minimum weighted SCR at the 230kV bus is 12.3 with all lines in service. With L-7019 out of service the weighted SCR is 4.4, and with L-7004 out of service the weighted SCR is 11.0. It is recommended that the IC confirm the turbine's capabilities when operating at low SCR.

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.

6 Voltage Flicker and Harmonics

Specific flicker coefficient information was not provided for the Nordex N163 5.9MW wind turbines, however, the coefficient is listed as being no higher than 4 across the entire active power range, and as such is not expected to present any issues at minimum output. Voltage flicker will be further examined when data for the 5.9 MW Nordex N163 machine is made available for the SIS.

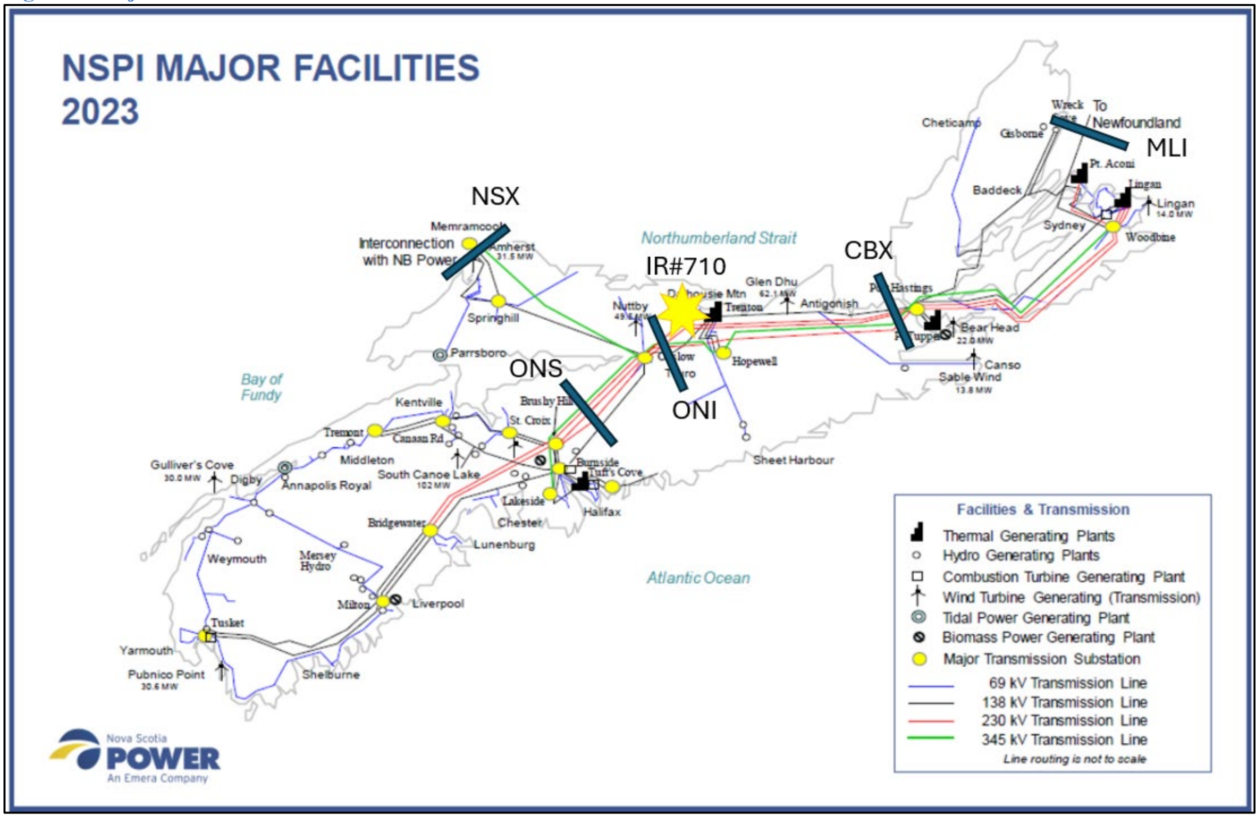
The generator is expected to meet IEEE Standard 519-2014 limiting voltage Total Harmonic Distortion (all frequencies) to a maximum of 1.5%, with no individual harmonic exceeding 1.5% on 230 kV.

7 Load Flow Analysis

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

The major transmission interfaces/corridors relating to the IR#710 are shown in Figure 3. The nominal interface thermal limits are summarized in Table 3. 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-determined contingencies to rapidly reduce flow by either tripping generation in Cape Breton or running-back Maritime Link HVdc import.

Figure 3 Major Transmission Interfaces



Note: IR#710 does not directly contribute to the CBX corridor measurement as the CBX corridor is measured from 3C-Port Hastings.

Table 3: Transmission Interface Limits						
Interface	MLI (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) MLI is limited by simultaneous New Brunswick Import
(2) NS Export to NB (NSX) is dependant on RAS operating parameters
(3) NS import from NB (NSI) is dependant on conditions in NB and PEI
(4) Dependant on generation at Trenton and Point Tupper
(5) Dependant on reactive power reserve in Metro

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

Transmission connected wind generation facilities were typically dispatched at approximately 30%, except in the vicinity of IR#710. There is high correlation 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#710 is at rated output. The cases and dispatch scenarios considered are shown in Table 4.

Table 4: Base Case Dispatch (MW) for IR#710

Case	MLI	NSX	NSI	CBX	ONI	ONS	LIN	TRE	Wind	RAS (1)
SL00	170	150	-	40	69	-93	0	0	235	NSX1
SL01	170	150	-	-33	249	87	0	0	498	NSX1
SL02	330	330	-	151	430	87	0	0	498	NSX1
SL03	0	1	-	-149	133	121	63	0	498	-
SP00	330	150	-	509	616	383	75	160	235	NSX1
SP01	330	150	-	364	749	514	0 (2)	87	600	NSX1
SP02	330	0	0	155	608	525	0 (2)	150	600	-
SP03	475	300	-	642	1075	689	185	149	600	NSX1, ONIG5
SP04	475	300	-	903	1100	715	434	94	401	NSX1, ONIG5, CBXG5
SP05	-100	-	95	2	444	456	0 (2)	137	600	-
WP00	170	0	0	738	930	764	300	324	250	-
WP01	170	0	0	668	930	764	300	324	320	-
WP02	330	300	-	725	1200	732	322	324	550	NSX1, ONIG6
WP03	330	150	-	1093	1237	920	484	260	321	NSX1, ONIG6, CBXG5
WP04	-100	-	95	115	609	537	126	324	700	-

SP – Summer Peak SL – Summer light load WP - Winter Peak LIN – Lingan Gen TRE – Trenton Gen

1. **Based on present RAS arming levels**
2. **IR710 displacing Lingan**

For both NRIS and ERIS analysis, this FEAS added IR#710 and primarily 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#710 interconnected to the POI at 91N-Dalhousie Mountain. Automated analysis searched for violations of emergency thermal ratings and emergency voltage limits for each contingency. Contingencies studied are listed in Table 5.

Table 5: Contingency List			
Transmission Line	**Transformer/ Bus/Generator**	**Circuit Breaker Failure**	**Double Circuit Tower**
L-7014, L-7021, L-7022	88S: T71, T72	88S: 710, 711, 713, 721, 722, 723*	L-5039 + L-6033, L-6011 + L-6010, L-6010 + L-6005, L-6005 + L-6016 L-6033 + L-6035, L-6033 + L-6035 L-6534 + L-7021, L-7003 + L-7004*, L-7024 + L-7004*, L-7008 + L-7009, L-7009 + L-8002
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-7004, L-7024, L-7027*	3C: T71, T72	3C: 710*, 711, 712*, 713*, 714, 715*, 716	
L-7001, L-7002, L-7018, L-7019, L-8001*, L-8002	67N: T71, T81, T82	67N: 701, 702, 703, 704, 705, 706, 711*, 712, 713, 811*, 813, 814*	
L-6001, L-6503, L-6613	1N: B61, B62, C61, T1, T4, T65	1N: 600, 601, 613	
L-6507, L-6508, L-8003*	79N: T81*		
Line segments either side of POI	91N: B71, B72	91N: 701, 702, 703, 704	
L-6005, L-6010, L-6011, L-6016, L-6051, L-7008, L-7009	120H: SVC, T71, T72	120H: 621, 622, 623, 624, 626, 627, 628, 629, 710, 711, 712, 713, 714, 715, 716, 720	
L-6008, L-6033, L-6038	103H: B61, B62, T61, T63, T81	103H: 600, 608, 691	
L-5012, L-5041, L-5049	91H: G3, G4, G5, G6, T62, T11	91H: 511, 516, 521, 523	
L-7025	125C: B71	125C: 701	
L-7003	127C: B71	127C: 701	
L-7005	102N: B71	102N: 701	
L-7555	100N: B71	100N: 701	
	99W: T71, T72	99W: 708, 709	
L-6545, L-6054	110W: T62 89S: G1 104W: G1 1C: G2 48C: G1 50N: G5, G6	2S: 513 104H: 600 132H: 602, 603, 605, 606 101V: 601	
99W: BESS, 43V: BESS, 132H: BESS			

*Indicates contingency was studied with and 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 a RAS is subject to the approval of NPCC.

No contingencies resulted in a violation of voltage limit criteria. Table 6 shows a summary of overload conditions found.

Table 6: Load Flow Contingencies Resulting in Line Overloads

Case	Line	Line segment	Overload % of Normal Rating	Contingency	Resolution
SP03	L-6515	2C-Hastings / 4C-Lochaber Rd	119%	101S-813	Reduce CBX G5 arming level
			119%	L-8004	Reduce CBX G5 arming level
	L-7019	91N-Dalhousie / 67N-Onslow	119%	101S-813	Reduce CBX G5 arming level
			119%	L-8004	Reduce CBX G5 arming level
			123%	79N-T81	Reduce CBX G5 arming level
SP04	L-6515	2C-Hastings / 4C-Lochaber Rd	132%	101S-813	Reduce CBX G6 arming level
			132%	L-8004	Reduce CBX G6 arming level
			118%	L-7003/L-7004 Double Circuit Tower	Reduce DCT G3 arming level
	L-7019	91N-Dalhousie / 67N-Onslow	123%	101S-813	Reduce CBX G6 arming level
			123%	L-8004	Reduce CBX G6 arming level
			125%	79N-T81	Reduce CBX G6 arming level
			112%	3C-715	Reduce 3C-712/715 BBU arming level
			130%	67N-811	Reduce ONI G6 arming level
			114%	L-8003	Reduce ONI G6 arming level
	L-8004	79N-Hopewell / 101S-Woodbine	120%	L-7003/L-7004 Double Circuit Tower	Reduce DCT G3 arming level

L-7003 has two locations where it shares a common tower with L-7004 (Canso Causeway and Trenton Bypass). NERC and NPCC considers simultaneous loss of two circuits on a multi-circuit tower to be a normal (single) contingency for which voltage, stability, and thermal loading criteria must be met. There is currently a RAS (Group 3) which will operate for loss of these two circuits if the faults are at either location. When this RAS is armed the contingency must not result in overload conditions. Based on the load flow contingency simulation, the modification of the Group 3 RAS arming limits resolves the overload.

Similarly, additional RAS arming limit modifications will resolve the rest of the issues identified in Table 6. Each modification is estimated to cost $50,000 to study and implement if no functional changes are required.

Due to the interdependency between IR#710, Cape Breton generation displacement, and Cape Breton Export RAS arming, the upgrades for NRIS and ERIS are the same.

8 Reactive Power and Voltage Control

In accordance with the *Transmission System Interconnection Requirements* Section 7.6.2, IR#710 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 4) provided by Nordex indicates that the Nordex N163/5.9 MW WECS have a rated power factor of 0.86 lagging and leading (+/- 3.0 MVAR per WECS) at the machine terminal voltage range of 0.87-1.06 p.u., from 0.5% to 100% of the capped power rating (5.0 MW). 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.

Because this analysis is based on preliminary transformer data and assumed collector circuit models, reactive capability and facility compliance with the *Transmission System Interconnection Requirements* 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 also have the ability to slowly adjust the set-point over several (5-10) minutes to maintain reactive power within the individual generator's 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.

While the IC provided transformer data states that it will have a fixed tap-changer, it is highly recommended that the interconnection transformer be equipped with an on-load tap-changer. Control of the mid-level voltage on the facility collector system will be crucial to reliable operation of the facility in a variety of system conditions. Settings for the on-load tap-changer must be coordinated with plant voltage controller for long-term reactive power and voltage management at the POI.

Figure 4: N163/5.9 MW WECS Reactive Capability

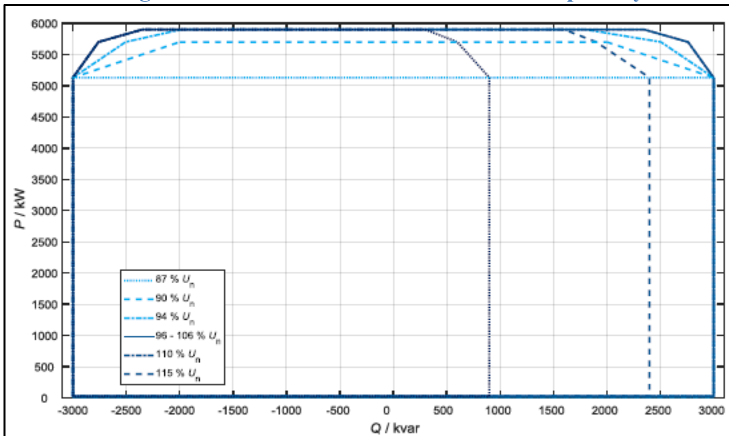


Figure 2: Q-P-diagram N149/5.X Mode 0.a/0.ab and N163/5.X Mode 0.a (5900 kW)

Table 2: Maximum possible reactive power N149/5.X Mode 0.a/0.ab and N163/5.X Mode 0.a (5900 kW) in relation to active power and voltage at the reference point.

Active power *P* / kW		**25**	**5130**	**5700**	**5900**
Maximum reactive power range	87 % U_n -Q...+Q / kvar	-3000	-3000	-	-
		3000	3000	-	-
	90 % U_n -Q...+Q / kvar	-3000	-3000	-2000	-
		3000	3000	2000	-
	94 % U_n -Q...+Q / kvar	-3000	-3000	-2507	-1985
		3000	3000	2507	1800
	96...106 % U_n -Q...+Q / kvar	-3000	-3000	-2761	-2350
		3000	3000	2761	2350
	110 % U_n -Q...+Q / kvar	-3000	-3000	-2761	-2350
		2400	2400	1900	1600
	115 % U_n -Q...+Q / kvar	-3000	-3000	-2761	-2350
		900	900	600	300

9 System Security / Bulk Power Analysis

The 230kV buses at the 91N-Dalhousie Mountain substation as well as lines L-7004 and L-7019 are part of the Nova Scotia Bulk Power System (BPS). As such, all protection systems associated with the expansion of the existing three-breaker ring bus at the POI must comply with NPCC Directory 4 *System Protection Criteria*.

Since the 91N-Dalhousie Mountain substation is currently classified as part of the NERC Bulk Electric System (BES), it is subject to the applicable NERC Reliability Criteria. As IR#710 has dispersed generation totalling more than 75 MVA, Inclusion I4 of the NERC BES Definition applies; each generator and systems designed for delivering that aggregate capacity to the POI classified are categorized as BES elements.

10 Expected Facilities Required for Interconnection

The following facility changes will be required to connect IR#710 to the NSPI transmission system at a POI at 91N-Dalhousie Mountain under NRIS and ERIS:

a. **Required Network Upgrades**
   - Modification of NSPI protection systems at 91N-Dalhousie, 67N-Onslow and 3C-Port Hastings.
   - Expand the existing 91N substation with additional breaker capacity with control and protection, a Remote Terminal Unit (RTU) updates for NSPI's SCADA system, with telemetry and controls as required by NSPI.
   - Changes to existing NSPI RAS (Group 3, Group 5, Group 4 BBU, and Group 6)

b. **Required Transmission Provider's Interconnection Facilities (TPIF):**
   - Supervisory, control, and communications between the wind farm and NSPI SCADA system (to be specified).
   - Short section of radial 230kV line or bus between the POI and the ICIF.

c. **Required Interconnection Customer's Interconnection Facilities (ICIF)**
   - Facilities to provide 0.95 leading and lagging power factor when delivering rated output at the HV terminals of the IC Substation Step Up Transformer when the voltage at that point is operating between 95 and 105 % of nominal. This study assumed that Nordex model N163 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).
   - 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.
   - 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.

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.

11 NSPI Interconnection Facilities and Network Upgrades Cost Estimate

Estimates for NSPI Interconnections Facilities and Network Upgrades for interconnecting 70.0 MW wind energy at the 230kV POI at 91N-Dalhousie Mountain are included in Table 7.

Table 7: Cost Estimate NRIS & ERIS @ POI 91N		
Item	**Network Upgrades**	**Estimate**
1	Addition of fourth breaker at existing 230 kV substation complete with P&C at NSPI POI substation, including P&C modifications	$2,500,000
2	Modifications to four RAS settings (Group 3, Group 5, Group 4 BBU, and Group 6)	$800,000
3	Remote P&C Modifications	$750,000
	Sub-total for Network Upgrades	$4,050,000
Item	**TPIF Upgrades**	**Estimate**
4	NSPI P&C relaying equipment	$300,000
5	NSPI supplied RTU	$100,000
6	Tele-protection and SCADA communications	$750,000
	Sub-total for TPIF Upgrades	$1,150,000
	Total Upgrades	**Estimate**
	Network Upgrades + TPIF Upgrades	$5,200,000
	Contingency (25%)	$1,300,000
	Total (Incl. 25% contingency and Excl. HST)	$6,500,000

The preliminary non-binding cost estimate for interconnecting 70.0 MW at the POI at 91N under both NRIS and ERIS is $6,500,000 including a contingency of 25%. In this estimate, $4,050,000 (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 potential incremental costs to address any stability issues identified at the SIS stage based on dynamic analysis, and it assumes that RAS modifications are approved by NPCC.

The estimated time to construct the TPIF and Network Upgrades is 24-36 months after receipt of funds from the IC. The timeframe will be further determined during the FAC study. The delivery of a 230kV circuit breaker may drive delays in the construction of Network Upgrades.

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#710 in service, losses in the winter peak case total 76.1 MW. With IR#710 in service at the POI of 91N, displacing generation at 91H, and not including losses associated with the IR#710 Generation Facilities or TPIF Interconnection Facilities, system losses total 81.0 MW, an increase of 4.9 MW. The power delivered to the POI is 70.0 MW, therefore the loss factor is calculated as 4.9/70.0 = +7.0%.

13 Issues to be addressed in SIS

The following provides a preliminary scope of work for the subsequent SIS for IR#710.

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:

> *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[4] and NERC[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.

Nova Scotia Power
Control Centre Operations
2024-05-31

[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-001-5.1