Interconnection Feasibility Study Report
GIP-IR637-FEAS-R2

Generator Interconnection Request 637
35 MW Wind Generating Facility
Antigonish County, NS

2022-04-22

Control Centre Operations
Nova Scotia Power Inc.

Executive Summary

The Interconnection Customer (IC) submitted an Interconnection Request for Network Resource Interconnection Service (NRIS) and Energy Resource Interconnection Service (ERIS) for a proposed 35 MW wind generation facility interconnected to the NSPI transmission system, with a Commercial Operation Date of 2024-12-01. The Point of Interconnection (POI) requested by the customer is the 69kV line L-5527B, approximately 7.24 km from 24C-Dickie Brook Hydro 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#637. 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#637 will displace coal-fired generation in eastern Nova Scotia for both NRIS and ERIS.

L-5527B is not presently categorized NPCC Bulk Power System (BPS) or NERC Bulk Electric System (BES). IR#637 is not categorized NERC BES mainly because its POI is operated below 100 kV. Complete NPCC BPS testing will be performed in the System Impact Study (SIS) to determine if it is categorized BPS.

The assessment of the POI on the 69 kV line L-5527B indicated that several thermal loading violations would occur due to IR#637, notably on L-5524, L-5527, and 4C-T2 under system normal conditions.

To interconnect IR#637 as NRIS, the following upgrades are proposed to alleviate these overloads:

- Protection upgrade and modification at 57C and 19C.
- Transformation capacity upgrade at 4C.
- Metering upgrade at 4C-Lochaber Road and relaying upgrade at 24C-Dickie Brook.
- L-5524 & L-5527 line rebuild.

To interconnect IR#637 as ERIS, generation must be capped at 8 MW, with the following upgrades to alleviate additional overloads:

- Metering upgrade at 4C-Lochaber Road and relaying upgrade at 24C-Dickie Brook.

No violations of voltage criteria were found for IR#637.

Data provided by the IC indicates that IR#637 will be utilizing the Vestas V150- 4.5MW WECS. Based on the supplied data and assumptions, IR#637 would not be able to meet the net power factor of +0.95 to -0.95 at the Interconnection Facility 69 kV bus. The adequacy of reactive power supply will be further investigated in the System Impact Study as specific details of the facility and equipment become available. It is noted the proposed Vestas V150- 4.5MW WECS models meet the requirement to produce full Mvar capability down to zero MW output.

IR#637 was not found to adversely impact the short-circuit capabilities of existing circuit breakers. 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 69kV bus is 79 MVA with all lines in service, corresponds to a short-circuit ratio of 2.3. This falls to 2.1 with either L-6552 or L-6515 open at 4C-Lochaber Road.

The low system short circuit level may be an issue as the SCR is below the 5.0 minimum specified by the manufacturer. The impact of the low SCR will be further examined when detailed data for the machine is made available for the SIS.

The preliminary value for the unit loss factor is calculated as +15.4% at the POI at L-5527B, net of any losses on the IC facilities up to the POI.

To interconnect IR#637 as NRIS, the preliminary non-binding cost estimate for interconnecting 35 MW to the POI at L-5527B is $12,056,500 (10% contingency included). This cost estimate includes the following upgrades:

- A direct line tap with transfer trip.
- Protection upgrade and modification at 57C and 19C.
- Current transformer upgrade at 24C-Dickie Brook and relaying upgrade at 4C-Lochaber Road.
- Transformation capacity upgrade at 4C.
- L-5524 line rebuild, approximately 35.4 km.
- L-5527 line rebuild, approximately 24.4 km.

In this estimate, $10,250,000 (plus 10% contingency) represents Network Upgrade costs which are funded by the Interconnection Customer, but which are eligible for refund under the terms of the GIP. The remainder of the costs are fully funded by the Interconnection Customer.

To interconnect IR#637 as ERIS, the generation MW cap is 8 MW. The preliminary non-binding cost estimate for interconnecting 8 MW to the POI at L-5527B is $1,083,500 (10% contingency included). This cost estimate includes the following upgrades:

- A direct line tap with transfer trip.
- Protection upgrade and modification at 57C and 19C.

- Current transformer upgrade at 24C-Dickie Brook and relaying upgrade at 4C-Lochaber Road.

In this estimate, $275,000 (plus 10% contingency) represents Network Upgrade costs which are funded by the Interconnection Customer, but which are eligible for refund under the terms of the GIP. The remainder of the costs are fully funded by the Interconnection Customer.

The estimated time to construct the Transmission Providers Interconnection Facilities and any Network Upgrades is 18-24 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 Facility Study.

Table of Contents

1 Introduction

The Interconnection Customer (IC) submitted a Network Resource Interconnection Service (NRIS) and Energy Resource Interconnection Service (ERIS) Interconnection Request (IR) for a 35 MW wind generation facility interconnected to the NSPI transmission system; with a 2024-12-01 Commercial Operation Date. The Point of Interconnection (POI) requested by the customer is the 69kV line L-5527B, approximately 7.2 km from 24C-Dickie Brook Hydro substation.

This report is the result of the signed Feasibility Study Agreement to study the connection, dated 2021-10-08. This project is listed as Interconnection Request 637 in the NSPI Interconnection Request Queue and will be referred to as IR#637 throughout this report.

Figure 1 shows the proposed geographic location of IR#637's POI in relation to the NSPI transmission system.

Figure 1 IR#637 POI

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.

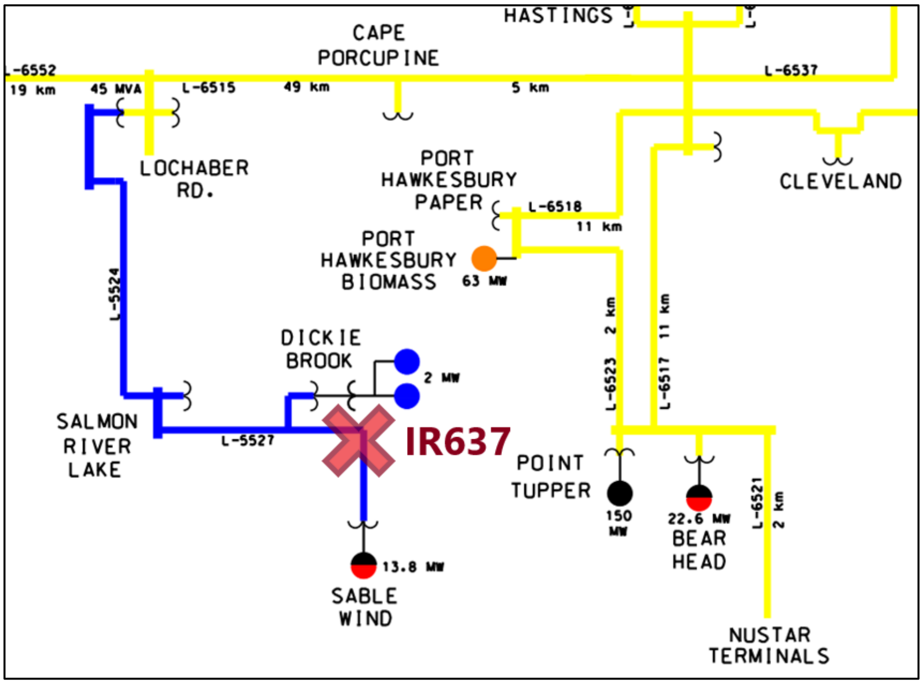


Figure 2 Point of Interconnection (not to scale)

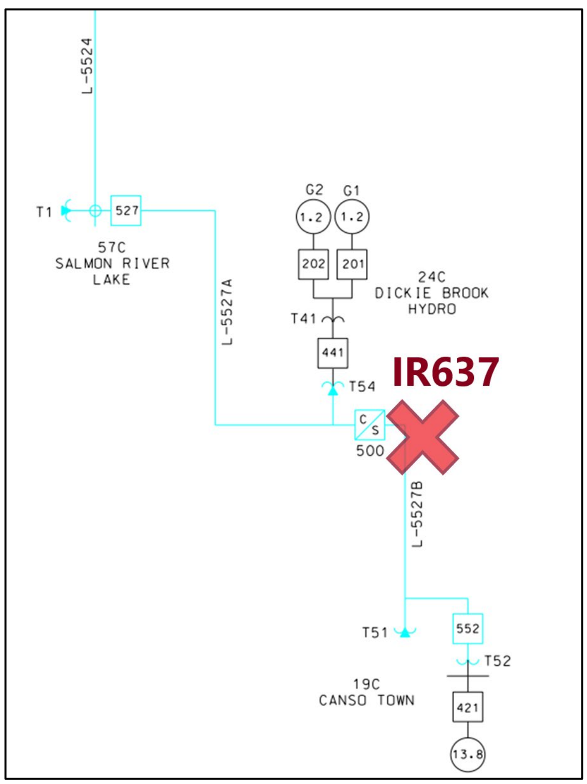


Figure 3 Circuit Configuration near POI

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 (TSIR)[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#637 on incremental system losses under standardized operating conditions is examined.

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

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

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

3 Assumptions

This FEAS is based on the technical information provided by the Interconnection Customer. The Point of Interconnection (POI) and configuration is studied as follows:

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

2. Commercial Operation date 2024-12-01.

3. The Interconnection Customer Interconnection Facility (ICIF) consists of up to 8 Wind Energy Converter System (WECS) units: Vestas V150 wind turbines, each rated at 4.5 MW AC; capped at a total of 35 MW, connected to collector circuits operating at a voltage of 34.5kV.

4. The POI on L-5527B will utilize a direct line tap with transfer trip protection based on the NS Power TSIR.

5. The ICIF is adjacent to the 69 kV transmission right-of-way (70 m) and therefore will not require a spur line from the POI to the IC 69kV/34.5kV transformer.

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. The 69kV/34.5kV station transformer was rated at 25/33/42 MVA and modeled with a positive-sequence impedance of 6.5% on 25 MVA with an X/R ratio of 25. The IC indicated this transformer has a wye-wye-delta winding configuration with +/-10% on-load tap changer in 33 taps. The impedance of each generator step-up transformer was modeled as 9.9% on 5.3 MVA with an X/R ratio of 12.38 based on the data provided by the IC.

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 facilities in the vicinity of IR#637 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-5524	ACSR 4/0 Penguin	50°C	Trip Settings	19/21 MVA	19/21 MVA
L-5527A	ACSR 2/0 Quail	50°C	CT Ratios	14/15.4 MVA	14/15.4 MVA
L-5527B	ACSR 2/0 Quail	50°C	CT Ratios	14/15.4 MVA	14/15.4 MVA
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-6537	556.5 Dove	60°C	Conductor	140/154 MVA	184/202 MVA
L-6538	Spec. Galv. Steel/ 556.5 Dove	50°C	Conductor	110/121 MVA	114/125 MVA
L-6539	555.5 Dove	100°C	Switchgear	191/210 MVA	191/210 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-7005	1113 Beaumont	70°C	CT Ratio	398/438 MVA	398/438 MVA

Table 2 Transformer Ratings

Transformer	Summer Rating Normal/Emergency	Winter Rating Normal/Emergency
4C-T2	44.8/44.8 MVA	44.8/44.8 MVA

[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#637 is in service.

4 Projects with Higher Queue Positions

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

As of 2022-03-21, 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

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 3,500 MVA (31.5 kA) on 69 kV systems. The fault current characteristic for this Vestas V150 WECS is assumed as 1.07 times rated current, or X'd = 0.9345 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#637 on L-5527B Three-phase MVA (1)

Location	Without IR#637	With IR#637
All transmission facilities in service		
POI on L-5527B (69kV)	128	163
Interconnection Facility (69kV)	128	163
57C-Salmon River Lake (69kV)	135	165
4C-Lochaber (138kV)	1,157	1,169
4C-Lochaber (69kV)	180	199
Minimum Conditions (TC3, LG1, ML In-Service)		
Interconnection Facility (69 kV), all lines in-service	79	113
Interconnection Facility (69 kV), L-6552 open at 4C	74	108
Interconnection Facility (69 kV), L-6515 open at 4C	73	107

(1) Classical fault study, flat voltage profile

The interrupting capability of the 138 kV circuit breakers is at least 2,000 MVA at 4C-Lochaber. The interrupting capability of the 69 kV circuit breakers is at least 2,000 MVA at 4C-Lochaber and 57C-Salmon River Lake. As such, the interrupting ratings 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 calculated short circuit levels and data supplied by the IC, the SCR is 2.3 at the high side of the IR#637 substation with all lines in service and IR#637 offline. This falls to 2.1 with either L-6552 or L-6515 open at 4C-Lochaber Road.

Documentation supplied by the IC states to contact Vestas if the minimum SCR falls below 5.0. The impact of the low SCR will be further examined when detailed data for the machine is made available for the SIS.

6 Voltage Flicker and Harmonics

Flicker coefficient information was not provided for the Vestas V150 WECS. Voltage flicker will be further examined when data for the 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 5.0%, with no individual harmonic exceeding 3.0% on 69 kV.

7 Load Flow Analysis

The load flow analysis was completed for generation dispatches under system summer peak load, winter peak load, and light load conditions. These were selected to stress east-west transmission interfaces, Cape Breton Export (CBX) and Onslow Import (ONI), and the local 69 kV system to which IR#637 is interconnected to.

Generation dispatch also represents 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#637 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-determined contingencies to rapidly reduce flow by either tripping generation in Cape Breton or running-back Maritime Link HVdc import.

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

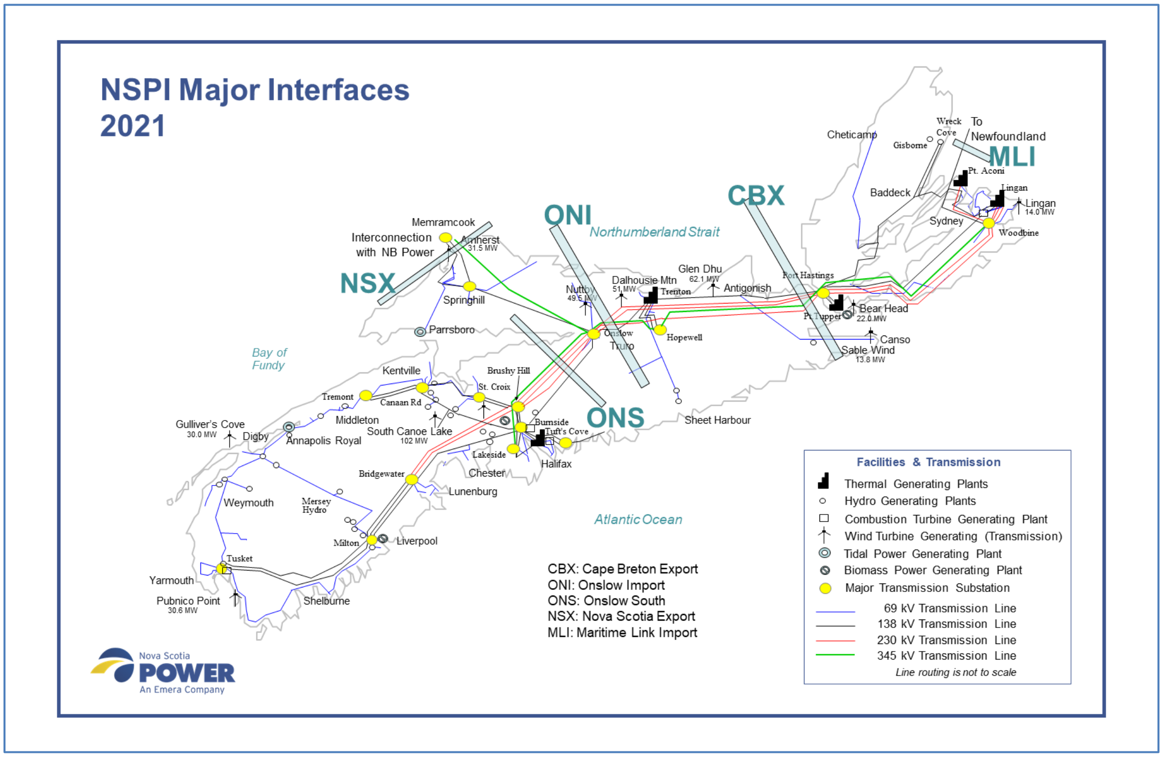


Figure 4 Major transmission interfaces

Table 4 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 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#637. 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 wind plants would be near full output when IR#637 is at rated output. The cases and dispatch scenarios considered are shown in Table 5.

Table 5: Base Case Dispatch (MW) IR#637 On-Line								
Case	MLI	NS-NB	CBX	ONI	ONS	LIN	TRE	RAS (1)
LL01	170	225	295	461	192	63	135	-
SP01	475	333	900	1017	581	300	160	79NG5, 67NG5
SP02	475	0	773	897	795	90	160	79NG5
SP03	475	330	827	824	431	63	0	79NG6
SP04	475	0	697	828	734	234	160	79NG5
SP05	475	0	696	816	711	252	160	-
SP06	475	0	802	777	675	192	0	79NG6
SP07	-100	-225	-128	42	202	77	165	-
WP01	320	150	944	1191	861	428	324	67NG6
WP02	320	150	918	1131	798	364	324	67NG6
WP03	320	0	754	976	796	365	324	-
WP04	320	150	937	1017	712	343	165	67NG5, 79NG5
WP05	320	150	876	1127	801	428	324	67NG6
WP06	-100	-100	292	572	560	373	324	-
S - Summer Peak W - Winter Peak LIN – Lingan Gen TRE – Trenton Gen (1) Based on present RAS arming levels								

For both NRIS and ERIS analysis, IR#637 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, 138 kV and 69 kV voltage levels for the above system conditions with IR#637 interconnected to the POI at L-5527B. 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	

Table 6 Contingency List			
Transmission Line	**Transformer / Bus**	**Circuit Breaker Failure**	**Double Circuit Tower**
L-7003, L-7004, L-7005, L-7019	3C-T71	3C: 710, 712, 713, 715, 716	L-7003+L-7004*
L-6503, L-6613	1N: B61, B62	1N: 600, 613	
L-8001*, L-8002, L-8003*	67N: T71, T81	67N: 701, 702, 7-3, 705, 711, 712, 713, 811*, 812, 813, 814*, 815*	L-7003+L7004
L-6507, L-6508,	79N: T81*	79N: 601*, 606*, 803*, 810*	
	91N: B71	91N: 701, 702, 703	
L-6511, L-6507, L-6508, L-5500, L-5501, L-5502	50N:T12, T8, GT5, GT6	50N: 614, 607, 604, 513, 508, 500	
L-6552	4C: T63, T2	4C: 621, 620, 622, 623	

*Indicates contingency was studied with/without RAS action

Results

With the connection of IR#637, the study shows up to 243% overload on L-5524, 338% on L-5527 and 115% overload on 4C-T2 transformer under system normal conditions during summer, as well as under various contingency conditions. The highest overloads are only listed for system normal conditions in Table 7. Other conditions were found to also violate thermal loading criteria, but to a lesser degree.

No contingencies resulted in a violation of thermal or voltage limit criteria once the system normal conditions were remediated.

Table 7 Contingencies Resulting in Highest Line Overload				
Facility ID	**Facility / Line Segment**	**Highest Overload (% of Normal Rating)**	**Case**	**Condition**
4C-T2	Lochaber Road Transformer	Summer: 115%	LL01	System Normal
L-5524	4C-Lochaber Rd/ 57C-Salmon Lake	Summer: 243%	LL01	System Normal
L-5527B	24C-Dickie Brook/IR#637 POI	Summer: 334%	LL01	System Normal
L-5527A	57C-Salmon Lake/ 24C- Dickie Brook	Summer: 338%	LL01	System Normal

To interconnect IR#637 as NRIS, the overloads of transformer 4C-T2, L-5527, and L-5524 under system normal conditions must be alleviated. The following upgrades to alleviate these overloads are proposed:

- Current transformer upgrade at 24C-Dickie Brook and relaying upgrade at 4C-Lochaber Road.
- Transformation capacity upgrade at 4C.
- L-5524 line rebuild, approximately 35.4 km.
- L-5527 line rebuild, approximately 24.4 km.

Both L-5524 and L-5527 require a line rebuild due to the heavier conductor required to accommodate IR#637's injection into the NSPI transmission system. The present structures would not be capable of supporting the new conductor.

The local 69 kV network in the area has been operated at its capacity. To interconnect IR#637 as ERIS, the generation MW must be capped at 8 MW with the following proposed:

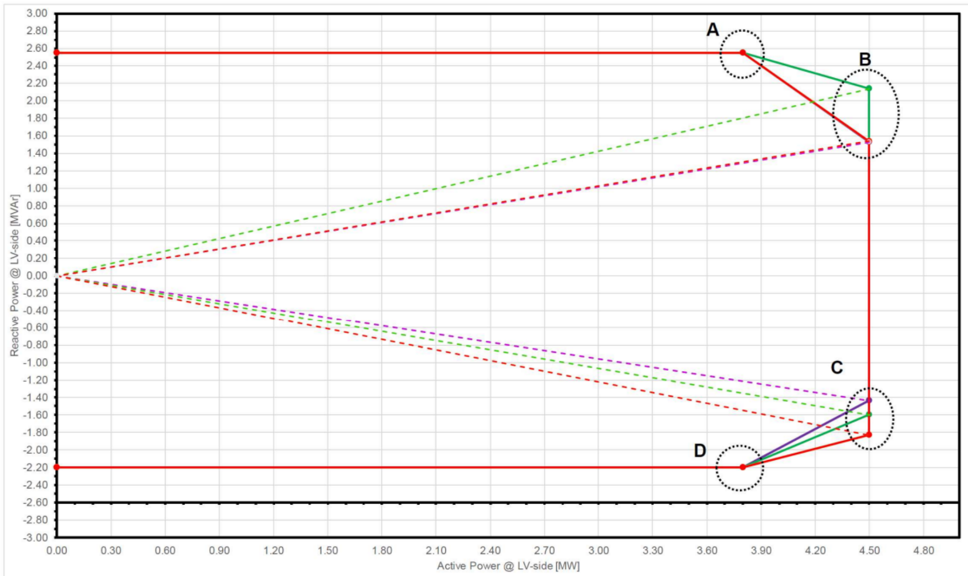
- Current transformer upgrade at 24C-Dickie Brook and relaying upgrade at 4C-Lochaber Road.
- Transformation capacity upgrade at 4C.

8 Reactive Power and Voltage Control

In accordance with Section 7.6.2 of the TSIR, IR#637 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 the IC indicates that the Vestas V150 4.5 MW WECS have a rated power factor of 0.83 lagging and 0.87 leading (+2.55~ -2.20 Mvar per WECS) at the machine terminal voltage of 1.0 p.u. or above, from 0% to 84% of rated power. The reactive power capability is reduced to a 0.90 lagging and 0.94 leading (+2.14~-1.6 Mvar per WECS) power factor from 84% to 100% power.

The TSIR (Section 7.6.2) requires rated reactive power be available through the full range of real power output of the Generating Facility, from zero to full power. The Vestas V150 4.5 MW WECS should be able to meet this requirement.



	Coordinates								Power factor	
Point	A		B		C		D			
Coordinate	X(P)	Y(Q)	X(P)	Y(Q)	X(P)	Y(Q)	X(P)	Y(Q)	B(Capacitive)	C(Inductive)
Reactive power [kVAr] @ LV @ U_lv = 0.90 p.u. voltages	3.80	2.55	4.50	1.53	4.50	-1.44	3.80	-2.20	0.95	0.95
Reactive power [kVAr] @ LV @ U_lv = 0.95 p.u. voltages	3.80	2.55	4.50	1.53	4.50	-1.44	3.80	-2.20	0.95	0.95
Reactive power [kVAr] @ LV @ U_lv = 1.00 p.u. voltages	3.80	2.55	4.50	2.14	4.50	-1.60	3.80	-2.20	0.90	0.94
Reactive power [kVAr] @ LV @ U_lv = 1.05 p.u. voltages	3.80	2.55	4.50	1.54	4.50	-1.83	3.80	-2.20	0.95	0.93
Reactive power [kVAr] @ LV @ U_lv = 1.10 p.u. voltages	3.80	2.55	4.50	1.54	4.50	-1.83	3.80	-2.20	0.95	0.93

Figure 5 Vestas V150 4.5 MW reactive capability for power optimized mode

The analysis shown in Figure 6 indicates that IR#637 may not be able to meet the full-load reactive power requirement without additional reactive support. The model shows that with 8 Vestas V150 units operating at a total 35 MW and 17.1 Mvar (maximum), the delivered power to the high side of the ICIF transformers is 34.5 MW and 9.5 Mvar, or a power factor of 0.964 with the WECS terminal voltage at 1.03 p.u.

This configuration would be able to meet the leading power factor requirement of -0.95 at the high side of both ICIF transformers at while the Vestas V150s are operating at a total of 34.5 MW and -4.6 Mvar at a terminal voltage of 0.99 p.u.

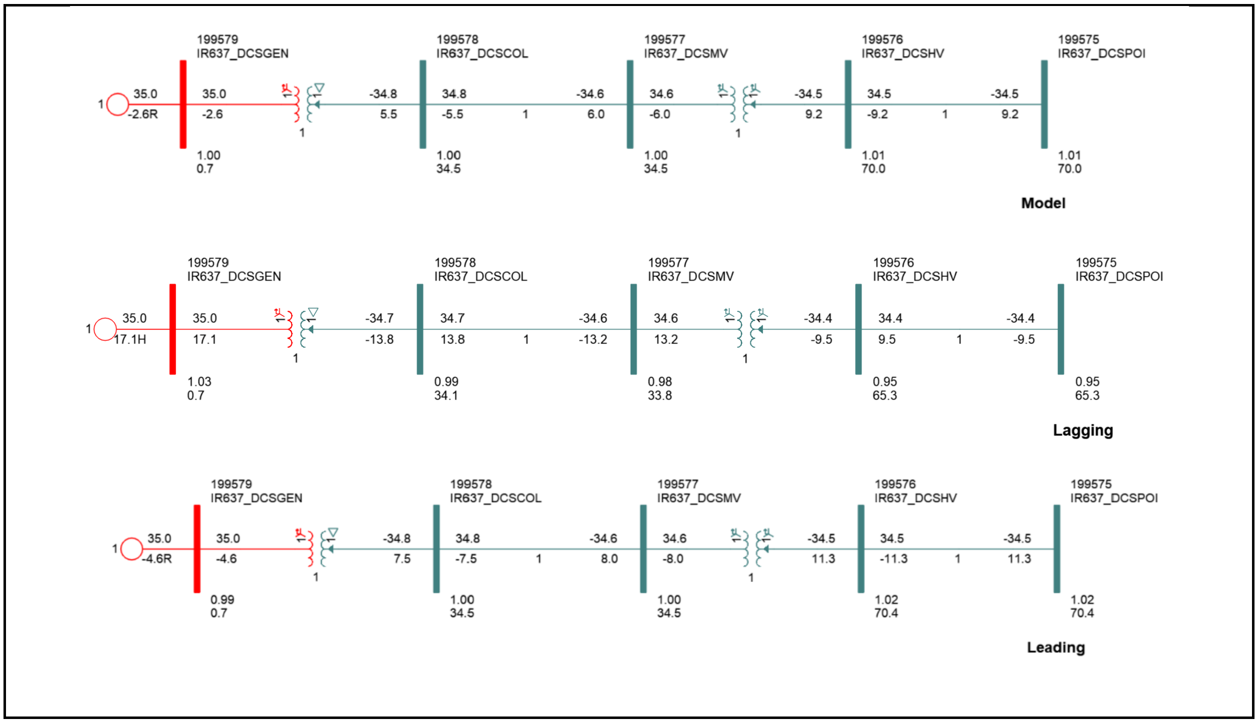


Figure 6 Power Factor analysis

Reactive capability will be confirmed in the SIS when more detailed data is supplied; analysis in this report is based on preliminary transformer data and assumed collector circuit models.

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, 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

L-5527B is not presently categorized NPCC Bulk Power System (BPS) or NERC Bulk Electric System (BES). IR#637 is not categorized NERC BES mainly because its POI is operated below 100 kV. Complete NPCC BPS testing will be performed in the System Impact Study (SIS) to determine if it is categorized BPS.

IR#637's interconnection configuration will utilize a direct line tap with transfer trip protection as prescribed in the TSIR.

10 Expected Facilities Required for Interconnection

The following facility changes will be required to connect IR#637 to the NSPI transmission system at a POI on L-5527B:

1a. Required Network Upgrades under NRIS:

- Modification of NSPI protection systems at 57C-Salmon River Lake and 19C-Canso Town.
- Current transformer upgrade at 24C-Dickie Brook and relaying upgrade at 4C-Lochaber Road.
- Transformation capacity upgrade at 4C-Lochaber Road substation.
- Rebuild L-5524, approximately 36.5 km.
- Rebuild L-5527 between IR#637 POI and 57C-Salmon River Lake, approximately 24.4 km.

1b. Required Network Upgrades under ERIS (capped at 8 MW):

- Modification of NSPI protection systems at 57C-Salmon River Lake and 19C-Canso Town.
- Current transformer upgrade at 24C-Dickie Brook and relaying upgrade at 4C-Lochaber Road.

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

- Construct a direct line tap with transfer trip protection to the generation facilities.

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

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

The NSPI Transmission System Interconnection Requirements (TSIR) has a detailed description of ICIF requirements, including:

- 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.
- 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 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

NRIS Cost Estimate

Estimates for NSPI Interconnections Facilities and Network Upgrades for interconnecting 35 MW wind energy at the 69 kV POI on L-5527B are included in Table 8 for NRIS.

Table 8 Cost Estimate NRIS @ POI L-5527B		
Item	**Network Upgrades**	**Estimate**
1	P&C modifications at 57C-Salmon River Lake and 19C-Canso Town	$200,000
2	Metering upgrade at 4C-Lochaber Road and Relaying upgrade at 24C-Dickie Brook	$75,000
3	Rebuild L-5527 between 57C and IR#637 POI (approximately 24.4 km)	$3,050,000
4	Rebuild L-5524 (approximately 36.5 km)	$4,425,000
5	Transformation capacity upgrade at 4C-Lochaber Road	$2,500,000
	Sub-total for Network Upgrades	$10,250,000
Item	**TPIF Upgrades**	**Estimate**
1	A direct line tap with transfer trip scheme to generation facility	$400,000
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	$710,000
	Total Upgrades	**Estimate**
	Network Upgrades + TPIF Upgrades	$10,960,000
	Contingency (10%)	$1,096,000
	Total (Incl. 10% contingency and Excl. HST)	$12,056,000

These 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 any Network Upgrades is 18-24 months after receipt of funds and cleared right of way from the customer.

ERIS Cost Estimate

Estimates for NSPI Interconnections Facilities and Network Upgrades for interconnecting IR#637 capped at 8 MW for ERIS at the 69 kV POI on L-5527B are included in Table 9.

Table 9 Cost Estimate ERIS @ POI L-5527B (capped at 8 MW)		
Item	**Network Upgrades**	**Estimate**
1	P&C modifications at 57C-Salmon River Lake and 19C-Canso Town	$200,000
2	Metering upgrade at 4C-Lochaber Road and Relaying upgrade at 24C-Dickie Brook	$75,000
	Sub-total for Network Upgrades	$275,000
Item	**TPIF Upgrades**	**Estimate**
1	A direct line tap with transfer trip scheme to generation facility	$400,000
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	$710,000
	Total Upgrades	**Estimate**
	Network Upgrades + TPIF Upgrades	$985,000
	Contingency (10%)	$98,500
	Total (Incl. 10% contingency and Excl. HST)	$1,083,500

These 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 any Network Upgrades is 18-24 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#637 in service, losses in the winter peak case total 86.2 MW. With IR#637 in service at the POI of L-5527B, displacing generation at 91H, and not including losses associated with the IR#637 Generation Facilities or TPIF Interconnection Facilities, system losses total 91.5 MW, an increase of 5.3 MW. The power delivered to the POI is 34.5 MW, therefore the loss factor is calculated as 5.3/34.5 = +15.4%.

13 Issues to be addressed in SIS

The following provides a preliminary scope of work for the subsequent SIS for IR#637. 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#637 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.

Nova Scotia Power
Transmission System Operations
2022-04-22

[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*