Interconnection Feasibility Study Report
GIP-IR576-FEAS-R0

Generator Interconnection Request 576
110 MW Wind Generating Facility
Pictou County, NS

2021-03-04

Control Centre Operations
Nova Scotia Power Inc.

Executive Summary

The Interconnection Customer submitted an Interconnection Request to NSPI for a proposed 110 MW wind generation facility located in Clydesdale, Pictou County, to be interconnected to the NSPI 230kV transmission substation 91N-Dalhousie Mountain. The Interconnection Customer's substation is located at the Point of Interconnection at the 91N-Dalhousie Mountain three breaker ring bus substation.

There are five transmission and four distribution Interconnection Requests currently in the Advanced Stage Transmission and Distribution Queue that must be included in the study models for IR#576. In addition, there is one long-term firm transmission service reservation in the amount of 800 MW from New Brunswick to Nova Scotia (TSR-411), and one 500MW long-term firm transmission service request from Newfoundland to Nova Scotia (TSR-412) that also must be accounted for. The two transmission service requests are expected to be in service in 2025 and system studies are currently underway to determine the associated upgrades to the Nova Scotia Transmission System. These upgrades are expected to materially alter the configuration of the Transmission System in Nova Scotia. As a result, the following notice has been posted to the OASIS site at https://www.nspower.ca/oasis/generation-interconnection-procedures:

> *Effective January 19th, 2021, please be advised that the completion of advanced-stage Interconnection Studies under the Standard Generator Interconnection Procedures (GIP) may be delayed pending the outcome of the Transmission Service Request (TSR) 411 and 412 System Impact Studies, which are expected to identify significant changes to the NSPI Transmission System. The expected completion date for these studies is December 31, 2021. Feasibility Studies initiated prior to the completion of these TSR System Impact Studies will be performed based on the current system configuration.*

FEAS Results

Data provided by the IC indicates that IR#576 will not meet reactive requirements without additional reactive support. Based on the provided rated power factor of the GE 5.5 wind turbines and the provided impedances of the transformers, supplementary reactive support will not be sufficient to meet the net power factor of +0.95 to -0.95 at the Interconnection Facility 138kV bus. As specific details of the collector circuits were not available at this time, the need for supplemental reactive power support will be further investigated in the System Impact Study.

No concern regarding high short-circuit level or voltage flicker was found for this project on its own, provided that the project design meets NSPI requirements for low-voltage ride-through, reactive power range and voltage control system. Harmonics must meet the Total Harmonics Distortion provisions of IEEE 519. The minimum short circuit level at the Interconnection Facility 230kV bus with all lines in is 1674 MVA.

The 91N-Dalhousie Mountain POI for IR#576 is part of the Nova Scotia Bulk Power System. As such, protections at 91N-Dalhousie Mountain must comply with NPCC Directory 4 requirements. The 91N-Dalhousie Mountain switching substation is also classified as part of the NERC Bulk Electric System (BES), subject to the applicable NERC Reliability Criteria. As IR#576 has dispersed generation > 75MVA, each generator; the 34.5kV bus; and the 230kV-34.5kV transformer will also be classified as BES elements.

The preliminary value for the unit loss factor is calculated as 5.36% at the POI at 91N-Dalhousie Mountain

NRIS Operation

This study identified transmission contingencies inside Nova Scotia which would violate thermal loading criteria and estimated the cost of necessary upgrades to allow for full NRIS operation. For NRIS operation, the following Network Upgrades are required:

- Expand the existing three breaker ring bus switching substation at the POI to include a fourth breaker and 230kV connection complete with associated switches, control and protection systems (to existing control building).
- Uprate 30km of 230kV line L-7019 between 67N-Onslow and 91N-Dalhousie Mountain from 70°C maximum operating temperature to 100°C maximum operating temperature.
- Replace the eight 138kV, 600A gang operated switches at the 4C-Lochaber Road (Antigonish) substation with 138kV, 1200A units.
- Replace the L-6503 138kV breaker, two 600A switches and instrument transformers at 50N-Trenton.
- Replace the two 138kV, 600A switches at the 1N-Onslow end of line L-6503b with 1200A units to increase the winter line rating from 287 MVA to 335 MVA.
- Install 50MVAR fixed capacitor bank complete with breaker and switches on 138kV bus B62 at 1N-Onslow (SIS to confirm capacity and location).
- Install 50MVAR fixed capacitor bank complete with breaker and switches on 138kV bus B61 at 103H-Lakeside (SIS to confirm capacity and location).

The preliminary non-binding cost estimate for interconnecting IR#576 to the 91N-Dalhousie Mountain 230kV bus as a Network Resource, including the cost of the fixed capacitors is $12,210,000. The cost estimate includes a contingency of 10%, and this estimate will be further refined in the System Impact Study and the Facilities Study. $275,000 of this amount represents Transmission Provider's Interconnection Facilities costs, which are fully funded by the customer. The remaining items represent Network Upgrade costs, which are funded by the customer but which are eligible for refund under the terms of the GIP. The estimated time to construct the Network Upgrades and the Transmission Providers Interconnection Facilities is 24-30 months after receipt of funds.

L-7019 will require a line survey to confirm that uprating the line is possible and to refine the associated cost estimates. The required Transmission Provider's Interconnection Facilities (TPIF) will consist of bus work between the 91N-Dalhousie Mountain substation and the adjacent customer substation for IR#576.

ERIS Operation

This study also identified transmission contingencies inside Nova Scotia which would violate thermal loading criteria and estimated the cost of necessary upgrades to allow for ERIS operation. For ERIS operation, the following Network Upgrades are required:

- Expand the existing three breaker ring bus switching substation at the POI to include a fourth breaker and 230kV connection complete with associated switches, control and protection systems (to existing control building).

- Uprate 30km of 230kV line L-7019 between 67N-Onslow and 91N-Dalhousie Mountain from 70°C maximum operating temperature to 100°C maximum operating temperature, OR revise Group 3, Group 5, and Group 6 Special Protection Systems to accommodate IR#576.

The preliminary non-binding cost estimate for interconnecting IR#576 to the 91N-Dalhousie Mountain 230kV bus as an Energy Resource is $2,475,000, not including the to be determined costs associated with the SIS stability analysis or the costs associated with revising the existing Group 3, 5, and 6 SPS's. $275,000 of this amount represents TPIF costs and the remainder are Network upgrade costs. The cost estimate includes a contingency of 10%, and this estimate will be further refined in the System Impact Study and the Facility Study.

Should ERIS operation be selected by the IC, the SIS will further investigate impacts of IR#576 on the Group 3, 5 and 6 SPS's. Any revision of Type I or Type III SPS's must be thoroughly studied; presented to NPCC; and subsequently receive NPCC approval prior to implementation.

The estimated time to construct the Network upgrades and the Transmission Providers Interconnection Facilities for ERIS operation is 18-24 months after receipt of funds.

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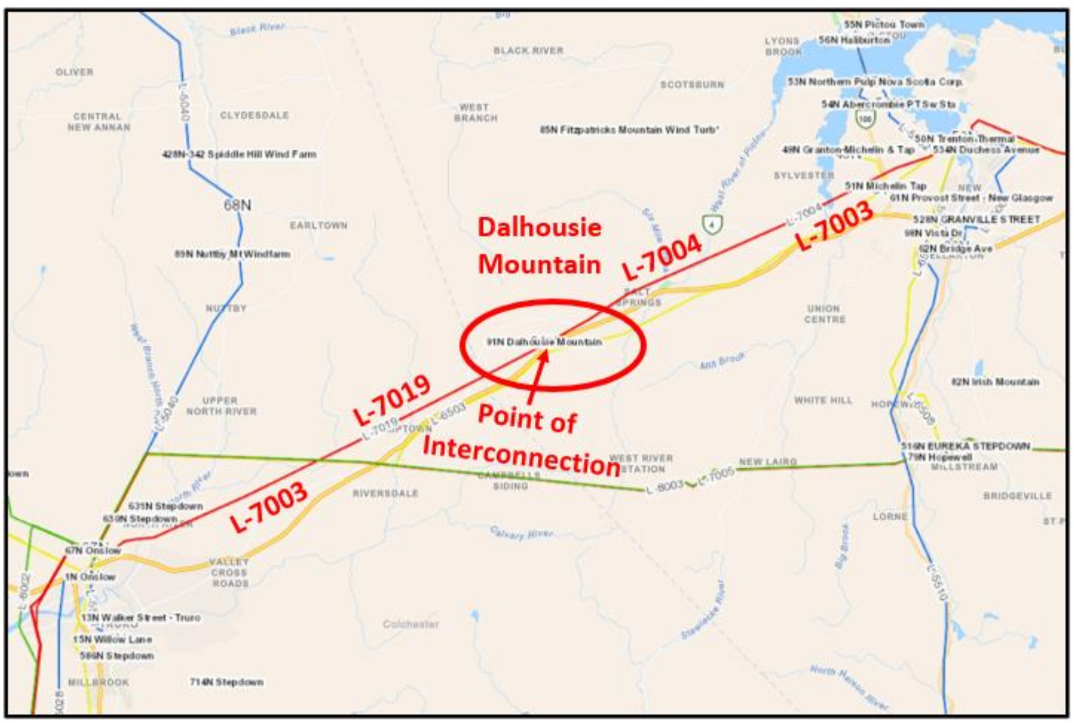
1 Introduction

The Interconnection Customer (IC) submitted an Interconnection Request to Nova Scotia Power Inc. (NSPI) for a proposed 110 MW wind generation facility interconnected to the NSPI system via the 91N-Dalhousie Mountain 230kV switching substation in Pictou County, Nova Scotia. The IC signed a Feasibility Study Agreement to study the connection of their proposed generation for both Network Resource Interconnection Service (NRIS), and Energy Resource Interconnection Service (ERIS). This report is the result of that Feasibility Study Agreement.

The project is listed as Interconnection Request (IR) 576 in the NSPI Interconnection Request Queue, and will be referred to as IR#576 throughout this report. Figure 1 shows the location of the IR#576 Dalhousie Mountain site.

Figure 1 Point of Interconnection (not to scale)



2 Scope

The objective of this Interconnection Feasibility Study (FEAS) is to provide a preliminary evaluation of the system impact and a high-level non-binding cost estimate of interconnecting the new generating facility to the NSPI Transmission

System at the designated location. The assessment will identify potential impacts on the loading of transmission elements, which must remain within their thermal limits. Any potential violations of voltage criteria will be identified and addressed. If the proposed new generation increases the short-circuit duty of any circuit breakers beyond their rated capacity, the circuit breakers must be upgraded. Single contingency criteria are applied.

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

- Preliminary identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection and identification of any Network Upgrades necessary to address short circuit issues associated with the IR.

- 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.

- Preliminary description and high-level non-binding estimated cost of facilities required to interconnect the Generating Facility to the Transmission System and the time to construct such facilities.

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 system transfer capabilities that may be required to the Transmission System 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 in order to ascertain the final cost estimate to interconnect the generating facility.

3 Assumptions

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

1. Network Resource Interconnection Service (NRIS) type and Energy Resource Interconnection Service (ERIS) type per Section 3.2 of the Generator Interconnection procedures (GIP).

2. Commercial Operation date 2023-12-31

3. The Interconnection Facility consists of twenty (20) 5.5 MW Cypres GE 158 Type 3 DFIG wind turbines totalling 110 MW, connected to two collector circuits via one 66/88/110 MVA generator step up transformer. Individual generator transformers are assumed to be 34.5kV – 0.69kV units rated at 6MVA and X/R ratio of 7.5.

4. The IC identified their Point of Interconnection to the NSPI Transmission System as the 230kV Substation 91N-Dalhousie Mountain, located midway between 50-Trenton and 67N-Onslow. 91N is supplied via 230kV lines L-7004 and L-7019.

5. The generation technology used must meet NSPI requirement for reactive power capability of 0.95 capacitive to 0.95 inductive at the high voltage terminals of the plant interconnection transformer. It is also required to provide 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.

6. Preliminary data was provided by the IC for the IC substation step-up transformers. Modeling for the primary interconnection point was conducted with one 138 kV - 34.5 kV transformer rated 66/88/110 MVA, with a positive sequence impedance of 8.33% at 66 MVA and an assumed X/R ratio of 34. The IC indicated that this Interconnection Facility step-up transformer has a grounded wye-delta-wye winding configuration with +/-10% fixed taps. The impedance used for each generator step-up transformer was 8.5% on 6 MVA with an assumed X/R ratio of 7.5.

7. Detailed collector circuit data was not provided, so typical data 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.

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

9. 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.

10. 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.

11. The rating of Lines L-7004 and L-7019 as follows:

Table 1: Transmission Line Ratings

NSPI Transmission Line Ratings

Last Updated: 2020-09-01

LINE	STATION	CONDUCTOR				BREAKER	SWITCH	CURRENT TRANSFORMER						TRIP MVA
		Type	Maximum Operating Temp. (Celsius)	SUMMER RATING 25 DEG (MVA)	WINTER RATING 5 DEG (MVA)	100% Name-plate	100% Name-plate	RELAYING Ratio	R.F.	MVA	FULL SCALE METERING Ratio	R.F.	MVA	
L-7004	3C Pt. Hastings EHV	ACSR 556 Dove	60	233	307	797	797	500	2	398	1000	1	462	533
	91N Dalhousie Mountain					797	797	800	2	600	800	1	368	600
L-7019	91N Dalhousie Mountain	ACSR 556 Dove	70	273	345	797	797	800	2	956	800	1	368	600
	67N Onslow EHV					797	797	500	2	398	1000	1	462	469

4 Project Queue Position

All in-service generation is included in the FEAS.

As of 2021/01/19, 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
- IR568: GIA executed
- IR566: GIA executed
- IR574: SIS in Progress

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

- TSR411: Accepted Application
- TSR412: Accepted Application

Preceding IR#576 are four transmission and three distribution Interconnection Requests with GIA's executed; one transmission and one distribution interconnection request at the SIS stage; a long-term firm transmission service reservation in the amount of 800 MW from New Brunswick to Nova Scotia (TSR-411); and a 500MW long-term firm transmission service request from Newfoundland to Nova Scotia (TSR-412). The two transmission service requests are expected to be in service in 2025 and system studies are currently underway to determine the required upgrades to the Nova Scotia Transmission System. As a result, the following notice has been posted to the OASIS site at https://www.nspower.ca/oasis/generation-interconnection-procedures:

> *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 and 412 System Impact Studies, which are expected to identify significant changes to the NSPI Transmission System. The expected completion date for these studies is December 31, 2021. Feasibility Studies initiated prior to the completion of these TSR System Impact Studies will be performed based on the current system configuration.*

5 Short Circuit Duty

The maximum (design) expected short-circuit level is 10000 MVA on 230 kV systems. The fault current characteristics for the Type 3 DFIG units are given as three times rated current for up to 5 cycles, or X'd = 0.33 per unit.

Short circuit analysis was performed using Aspen OneLiner V14.5, classical fault study, 3LG and flat voltage profile at 1 V(pu). The short-circuit levels in the area before and after this development are provided in Table 2.

The maximum short-circuit level at the POI is presently 2450 MVA. The addition of the 5.5MW GE-158 units will increase the short-circuit level at the POI to 2683 MVA. Under minimum generation conditions, with only the Maritime Link, Point Aconi, Lingan 1, and Trenton 6 in service, the fault level at the POI falls to 1674 MVA with IR#576 off, and 2007 MVA with IR#576 in service.

Table 2: Short-Circuit Levels, Three-phase MVA[1]		
Location	IR576 in service	IR576 not in service
Maximum generation, all transmission facilities in service		
91N-Dalhousie Mountain_230kV (POI)	2683	2450
3C-Port Hastings	3430	3373
67N-Onslow	4566	4388
Minimum Conditions (PA1, LG1, ML & TR6 In Service)		
91N_230kV (POI); 50MW D.Mtn Off	1903	1674
91N_230kV (POI); 50MW D.Mtn On	2007	1778
91N_230kV (POI); L-7019 Off	804	572

The interrupting capability of 230kV circuit breakers at 91N, 50N, and 67N is at least 10,000 MVA. This will not be exceeded as a result of the addition of IR#576.

Wind generation installations often have a minimum Short Circuit Ratio for proper operation of converters and control circuits. Based on the calculated short circuit levels, the minimum Short Circuit Ratio based on a POI at 91N-Dalhousie Mountain and a 110 MW installation (20 units, .95pf, each 5.78 MVA) would be 14.4 at the HV terminals of the IR#576 substation with all lines in service and IR#576 off line. This falls to 4.9 with L-7019 out of service. If the existing Dalhousie Mountain generation is included in these calculations (33x1.667 MVA), then the overall short circuit ratio at minimum system generation becomes 9.8, falling to 3.3 with 230kV line L-7019 out of service. This information should be provided to GE for design specification.

6 Voltage Flicker and Harmonics

Due to the lack of flicker coefficient information on the 5.5 MW GE 158 Wind Turbines, this study assumes the same flicker data as for the GE 1.6 machines (flicker co-efficient 2.7 at average wind speed of 7.5m/s and impedance angle of 85 degrees; apparent power of each turbine 5.79 MVA). Under these conditions, Pst was calculated to be 0.0418, well below the maximum permitted level of 0.35.

Type 3 wind turbines are not expected to result in appreciable voltage flicker at minimum generation conditions. Voltage flicker will be further examined when data is made available for the SIS.

[1] Classical fault study, flat voltage profile.

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 1.0% on 230 kV.

7 Thermal Limits

The load flow analysis was completed for generation dispatches under system light load, summer peak load, and winter peak load conditions. Generation dispatch was also chosen to represent import and export scenarios that account for expected flows from the existing transmission service reservation associated with the Maritime Link. The cases and dispatch scenarios considered are shown in Table 3.

Table 3: Base Case Dispatch (MW)

Case	NL-NS	NS-NB	ONI	CBX	M at H	ONS	Wind
LL01	475	500	695	626	283	163	173
LL02	330	0	371	369	165	339	30
LL03	-100	-200	83	28	4	250	173
S01	475	0	758	741	378	667	173
S02	475	500	1270	1094	586	676	173
S03	475	-300	468	425	198	675	173
S04	-100	-300	468	420	256	675	173
S05	0	500	919	716	411	325	173
S06	475	500	1270	1140	607	675	265
W01	475	0	1127	1131	630	964	173
W02	330	330	1270	1099	585	777	222
W03	475	-100	1031	1049	569	970	265
W04	-100	-300	690	523	335	828	173
W05	0	330	1133	909	528	687	431

LL - Light Load S - Summer Peak W - Winter Peak

Transmission connected wind generation facilities were typically dispatched at approximately 40%, with some low and high wind scenarios included.

The NS generation fleet is primarily comprised of Network Resource (NR) generation. NR designation requires that the aggregate of NR generation at full capacity can be delivered to the aggregate NS load at periods of peak load under a variety of stressed system conditions. Alternatively, generation connected to the system that is eligible to deliver energy using the existing firm or non-firm capacity of the Transmission System, on an 'as available' basis, is referred to as Energy Resource (ER) generation. IR#576 was submitted with instructions to study both NRIS and ERIS operation.

The POI for IR#576 is situated on transmission lines that constitute the transmission interface known as Onslow Import (ONI). Balancing load flow and generation sources in this region can also influence the transmission interface known as Cape Breton Export (CBX). The capability of these interfaces is a function of generation at 50N-Trenton, 91N-Dalhousie Mountain, 93N-Glendhu, and COMFIT distributed generation between Truro and Cape Breton.

When IR#576 is operating at rated output, it can be assumed that other wind power generation sources in the area are also operating at full rated power. However, the Glen Dhu and Dalhousie Mountain wind farms are both classified as Energy Resource generation, and as such their output can be (fully or partially) curtailed to avoid exceeding existing ONI or CBX transfer limits. The addition of IR#576 as a NR will require Network Upgrades to increase the existing ONI and CBX interface transfer limits to enable the full capacity of IR#576 to serve native load to the south and west of Onslow.

For NRIS analysis, this FEAS added IR#576 to each base case and displaced generation south of Onslow, increasing Onslow South (ONS) and Onslow Import (ONI) transfers. For ERIS analysis, this FEAS displaced generation east of Onslow in each base case, which had no impact on ONI, or ONS transfer levels, but which did impact CBX transfer levels. Single contingencies were applied at the 345 kV, 230 kV, and 138 kV voltage levels for the above system conditions with IR#576 interconnected to the 230kV bus at the 91N-Dalhousie Mountain switching substation.

When IR#576 was added to the base cases above for NRIS and ERIS analysis, it was noted that operating both the existing 49.5MW Dalhousie Mountain wind farm and IR#576 at full output under summer line rating conditions caused pre-contingency overloads on L-7019 under some dispatch scenarios (cases S02 and S06). Upgrading L-7019 to a higher conductor temperature rating resolved this issue.

NRIS Results (Case designation N)

In order for the system to withstand normal criteria contingencies without the risk of voltage collapse, adequate dynamic reactive power reserve must be maintained in the Metro area to regulate voltage through and following each contingency. The dynamic reactive reserve (DRR) required to survive contingencies is dependent primarily on the ONS power flow and pre-contingency system voltages. Under existing system conditions, the available dynamic reactive reserves enable ONS transfers up to 975MW. The limiting factor to the ONS transfer level is not the thermal ratings of the transmission lines running between Onslow and Halifax, but rather the potential for voltage collapse in Metro.

In the winter case W01, with high levels of ONS transfers (i.e., near the existing limit of 975MW), the addition of IR#576 as NR resulted in ONS flow well above the existing transfer limit. As such, contingencies associated with the loss of the 345kV line L-8002 between 67N-Onslow and 103H-Lakeside resulted in Metro voltage collapse (i.e., Failure of breakers 67N-812 & 67N-813, resulting in loss of L-8002 and a 345kV-230kV transformer at 67N; and loss of a double circuit tower taking out lines L-7009 & L-8002). Additional reactive supply in the form of two 50 MVAR fixed capacitor banks[2] were required in the Metro/Truro areas to rectify this situation. The SIS will include dynamic analysis to further evaluate the VAR requirements needed to support full NRIS generation at IR#576.

The load flow results for the majority of the cases with IR#576 operating at full output as a Network Resource show all system elements either operating within 110% of their posted seasonal equipment ratings or operating within documented maximum equipment ratings if greater than 110% of the posted seasonal ratings.

Load flow cases S02, S05, S06, W02, W03, and W05 represent the system with generation dispatched at or near the ONI and/or CBX corridor limits, with IR#576 generation then added to displace generation south of Onslow. In these cases, the addition of IR#576 generation resulted in the overloads of the following lines and equipment:

1. 230kV Line L-7003 (112%): S01-N, S02-N, S06-N
2. 230kV line L-7019 (135%): S02-N, S05-N, S06-N, W02-N, W05-N
3. 138kV L-6515 Switches (104%): W03-N
4. 138kV L-6503 Switchgear (102%): W02-N, W05

The existing ratings for each of these lines is shown in Table 4. Overall line ratings are the lesser of the thermal conductor ratings and the breaker, switch, and current transformer ratings.

[2] NS Power considers the maximum size of a single capacitor bank in the Metro area to be 50 Mvar for all possible operating conditions. Capacitor banks larger than 50 Mvar change the system voltage significantly causing adverse impact on voltage sensitive customer equipment.

Table 4: Transmission Line Ratings

NSPI Transmission Line Ratings

Last Updated: 2020-09-01

LINE	STATION	CONDUCTOR				BREAKER	SWITCH	CURRENT TRANSFORMER						TRIP MVA
		Type	Maximum Operating Temp. (Celsius)	SUMMER RATING 25 DEG (MVA)	WINTER RATING 5 DEG (MVA)	100% Name-plate	100% Name-plate	RELAYING Ratio	RELAYING R.F.	RELAYING MVA	FULL SCALE METERING Ratio	FULL SCALE METERING R.F.	FULL SCALE METERING MVA	
L-6503a	50N Trenton	ACSR 1113 Beaumont	100	320	363	287	287	1000	2	287	1000	1	554	589
	49N/51N Michelin Granton						404				NA			
L-6503b	51N Michelin Granton	ACSR 1113 Beaumont	85	287	335		404				NA			
	1N Onslow					478	287	1200	2.5	717	1200	1	665	449
L-6515	2C Pt. Hastings	ACSR 556.5 Dove	50	110	165	287	287	600	2	287	600	1	173	560
	4C Lochaber Rd.					191	143	600	2	287	600	1	173	752
L-7003	3C Pt. Hastings EHV	ACSR 556 Dove	60	233	307	797	797	500	2	398	1000	1	462	533
	67N Onslow EHV					797	797	500	2	398	1000	1	462	468
L-7019	91N Dalhousie Mountain	ACSR 556 Dove	70	273	345	797	797	800	2	956	800	1	368	600
	67N Onslow EHV					797	797	500	2	398	1000	1	462	469

In order to maintain the existing corridor flows and accommodate the IR#576 NRIS generation, the system will require the following Network Upgrades:

1. **Uprate 230kV line L-7003 to 70°C from 60°C.** This work is currently being undertaken by NSPI (CI# 44987). This project was initiated to increase the ground clearance and replacement of insulators and deteriorated assets to raise the maximum conductor temperature from 60°C to 70°C and will provide sufficient line capacity to accommodate IR#576.

2. **Uprate 230kV line L-7019 to 100°C from 60°C.** Uprate 30km of 230kV line L-7019 between 67N-Onslow and 91N-Dalhousie Mountain to raise the maximum conductor temperature from 60°C to 100°C to increase the line

rating from 273MVA summer / 345MVA winter to 358MVA summer / 403MVA winter.

3. **Replace 4C 138kV Switches:** Replace the eight 138kV, 600A gang operated switches at the 4C-Lochaber Road substation with 138kV, 1200A units. The line ratings for both L-6515 and L-6552 are currently restricted to 143MVA by the switch ratings at 4C. Replacing these switches will raise the winter rating of L-6515 and L-6552 from 143MVA to their full 50℃ conductor rating of 165 MVA.

4. **Replace 50N-Trenton Breaker and Switches:** Replace the 138kV breaker, switch and instrument transformers at the 50N-Trenton end of line L-6503a to increase the line rating from 287MVA summer/287MVA winter to 320MVA summer/363MVA winter.

5. **Replace 1N-Onslow Switches:** Replace the two 138kV, 600A switches at the 1N-Onslow end of line L-6503b with 1200A units to increase the winter line rating from 287 MVA to 335 MVA.

6. **Install Two 50MVAR Capacitor Banks:** Install one 50MVAR fixed capacitor bank complete with breaker and switches on the 138kV bus B62 at 1N-Onslow, and one 50MVAR fixed capacitor bank complete with breaker and switches on the 138kV bus B61 at 103H-Lakeside.

ERIS Results (Case designation E)

The load flow results for the majority of the cases with IR#576 operating at full output as an Energy Resource show all system elements either operating within 110% of their posted seasonal equipment ratings or operating within documented maximum equipment ratings if greater than 110% of the posted seasonal ratings.

Load flow cases S02 and W02 represent the system with generation dispatched at or near the ONI and/or CBX corridor limits, with IR#576 generation then added to displace generation east of Onslow in Cape Breton Island. In these cases, the addition of IR#576 generation resulted in the overloads of the following lines and equipment:

1. 230kV Line L-7003 (112%): S02-E
2. 230kV line L-7019 (140%): S02-E, W02-E
3. 138kV line L-6515 (105%): W02-E

As previously noted, NSPI has a project in progress to address line L-7003 overloads. The overloads associated with items 2 and 3 were determined to be caused by impacts of IR#576 on NSPI's existing Special Protection Systems.

The following issues were identified regarding ERIS operation of IR#576 in relation to the operation of the existing Transmission System SPS's:

1. Loss of the 79N-Hopewell substation (including loss of 345kV lines L-8003 and L-8004) when Dalhousie Mountain and IR#576 are in full operation results in a 40% overload of L-7019 based on summer ratings and case S02-E. This is resolved if L-7019 is uprated from 60°C conductor rating to 100°C conductor rating. However, the overload occurs because IR#576 as an Energy Resource offsets generation in Cape Breton, which impacts Group 5 (Type I) and Group 6 (Type I) SPS arming levels associated with the CBX transfer levels.

   Group 5 and 6 SPS's are designed to reduce power flow between 2C-Port Hastings and 67N-Onslow, via HVdc runback or generation rejection on CB island for specific contingencies at 79N-Hopewell and/or 67N-Onslow.

   The reduced CBX flows resulting from offsetting CB generation with IR#576 change what would normally be Group 6 (Type I) SPS arming to Group 5 (Type 1) SPS arming only. As a result, on loss of the 79N-Hopewell substation, the SPS action is limited to reducing CB generation by 165MW (G5) instead of 330MW (G6), causing the substantial overload of L-7019. To avoid this situation, the existing Group 5 and Group 6 arming levels and control logic associated with CBX would have to be revised to account for IR#576. The SIS will further investigate impacts of IR#576 on the Group 5 and 6 SPS's. Any revision of a Type I SPS must be thoroughly studied; presented to NPCC; and subsequently receive NPCC approval before implementation.

   Case S02-E also demonstrates that the Group 3 (Type III) SPS will require revision to accommodate IR #576. At present, the Group 3 SPS only arms if a 345kV element is out of service (excepting for double circuit tower loss of L-7003 & L-7004). This SPS is designed to reduce power flow on the 3C-Port Hastings to 67N-Onslow 230kV corridor for faults or operation of L-7003, L-7004, L-7019, or L-7005, and either activates HVdc power runback or rejects targeted generation on Cape Breton to stabilize the power system. The SIS will further investigate the impacts of IR#576 on the Group 3 SPS. Any revision of a Type III SPS must be thoroughly studied; presented to NPCC; and subsequently receive NPCC approval before implementation.

8 Voltage Control

In accordance with the Transmission System Interconnection Requirements Section 7.6.2, IR#576 must be capable of delivering reactive power at a net power factor of at least +/- 0.95 of rated capacity to the high side of the plant interconnection transformer. Reactive power can be provided by the Asynchronous Generator or by continually acting auxiliary devices such as STATCOM, DSTATCOM or synchronous condenser, supplied by the Interconnection Customer. Rated reactive power shall be available through the full range of real power output of the Generating Facility, from zero to full power. This translates into a reactive capability of 36.2 Mvar leading and lagging.

Based on the data provided by the IC for +/- 0.95 power factor for the wind turbines, the transformer impedances, and the assumed collector impedances, the load flow analysis shows that IR#576 is not able to meet the power factor requirement for absorbing and delivering vars at the 230 kV side of the GSU transformer. When the wind turbines deliver their maximum vars, the power factor at the 230 kV side of the GSU is +0.99. As such, supplementary reactive support will be needed. This will be further investigated in the System Impact Study.

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 generators capabilities. The details of the specific control features, control strategy and settings will be reviewed and addressed in the SIS, as will the dynamic performance of the generator and its excitation. Line drop compensation, voltage droop, control of separate switched capacitor banks must be provided.

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

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

GE offers an optional WindFree Reactive Power mode feature which provides reactive power and voltage control down to zero real power operation (low wind). It is recommended that the IC obtain an optional quote for this feature, as it may help to support system voltage and stability during high power transfer levels. The need for this feature will be further examined in the SIS.

9 System Security

The 230kV bus at the 91N-Dalhousie Mountain Switching Substation is already part of the Nova Scotia Bulk Power System (BPS). As such, all protection systems associated with the new 230kV breaker supplying IR#576 substation comply with NPCC Directory 4 *System Protection Criteria*.

The 91N-Dalhousie Mountain switching substation is also currently classified as part of the NERC Bulk Electric System (BES), subject to the applicable NERC Reliability Criteria. As IR#576 has dispersed generation totalling more than 75MVA, Inclusion I4 of the NERC BES Definition would apply and each generator would be classified as a BES element. The collector systems would not receive a BES classification, as only those parts of the IR#576 facility where the aggregation of dispersed generation resources > 75MVA would be designated as BES. The IR#576 66/88/110MVA site transformer and common 34.5kV bus would also be classified as BES elements.

The addition of 110MW of wind generation at Clydesdale will not change the non-BES status of the existing 91N-Dalhousie Mountain wind farm infrastructure or generation.

10 Expected Facilities Required for Interconnection

The following facility changes will be required to connect IR#576 to the NSPI Transmission System at 91N-Dalhousie Mountain:

10.1 NRIS:

a. Required Network Upgrades

1. Expand the existing three breaker ring bus switching substation at the POI to include a fourth breaker and 230kV connection consisting of:

    - One 230kV circuit breaker and associated switches,
    - Control and protection systems (to existing control building),
    - Tie into existing control and communications system

2. Uprate 30km of 230kV line L-7019 between 67N-Onslow and 91N-Dalhousie Mountain from 70°C maximum operating temperature to 100°C maximum operating temperature.

3. Replace the eight 138kV, 600A gang operated switches at the 4C-Antigonish substation with 138kV, 1200A units.

4. Replace the L-6503 138kV breaker, two 600A switches and associated instrument transformers at 50N-Trenton.

5. Replace the two 138kV, 600A switches at the 1N-Onslow end of line L-6503b with 1200A units to increase the winter line rating from 287 MVA to 335 MVA.

6. Install one 50MVAR fixed capacitor bank complete with breaker and switches on 138kV bus B62 at 1N-Onslow

7. Install one 50MVAR fixed capacitor bank complete with breaker and switches on 138kV bus B61 at 103H-Lakeside.

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

1. Construct tubular bus structure from 230kV Ring bus switching station to adjacent IR#576 substation.

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

1. Facilities to provide 0.95 leading and lagging power factor when delivering rated output (110 MW) all at the 138kV bus when the voltage at that point is operating between 95 and 105 % of nominal.

2. 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.

3. NSPI to 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 and change the status of any reactive power controls, remotely. NSPI will also have remote manual control of the load curtailment scheme.

4. Low voltage ride-through capability per Section 7.4.1 of the Nova Scotia Power Transmission System Interconnection Requirements (TSIR) document. The TSIR is posted on the NS Power OASIS site at https://www.nspower.ca/oasis/standards-codes.

5. 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.

6. Facilities for NSPI to execute high speed rejection of generation (transfer trip) if determined in SIS. The plant may be incorporated into SPS run-back schemes.

7. Synthesized inertial response controls as offered by GE.

8. Automatic Generation Control to assist with tie-line regulation.

9. Operation at ambient temperature of -30°C.

10.2 ERIS:

a. ERIS: Required Network Upgrades

1. For ERIS generation, the additional breaker for the ring bus switching station described in Section 10.1.a.1 is required.

2. Revision of Group 3, Group 5, and Group 6 Special Protection Systems, OR upgrade of L-7019 to 100°C and conductor temperature rating.

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

1. The TPIF for ERIS generation is the same as for the NRIS generation in Section 10.1.b.

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

1. The ICIF for ERIS generation is the same as for the NRIS generation in Section 10.1.c.

11 NSPI Interconnection Facilities Cost Estimate

11.1 NRIS

The high-level cost estimate (non-binding), excluding HST taxes, for the interconnection of IR#576 as a Network Resource is shown in Table 5. This does not include TBD costs to address any stability issues identified at the SIS stage based on dynamic analysis.

Table 5: NRIS Cost Estimate

	NRIS Cost Estimates	
	Network Upgrades	**Estimate**
i	230kV breaker addition at 91N	$1,750,000
ii	*L-6503 Breaker /switch replacement at 50N*	$1,200,000
iii	*L-6503 Switch Replacement (2) at 1N*	$100,000
iv	*Replace 8 Switches at 4C (L-6515 & L-6552)*	$400,000
v	*Uprate 30km of L-7019 from 70C to 100C*	$3,750,000
vi	*50 Mvar Fixed Capacitor Bank c/w breaker & switch*	$1,700,000
vii	*50 Mvar Fixed Capacitor Bank c/w breaker & switch*	$1,700,000
viii	Communications / P & C Systems	$250,000
	Sub-total	**$10,850,000**
	TPIF	**Estimate**
ix	Tubular Bus extension to IR#576 substation	$250,000
	Sub-total	**$250,000**
	Contingency (10%)	$1,110,000
	Total of Determined Cost Items	**$12,210,000**
	To be Determined Costs	
x	System additions to increase east-west transfer capability	TBD (SIS)
xi	Impacts to Group 3,5, and 6 SPS's	TBD (SIS)

The estimated time to construct the Network Upgrades and Transmission Providers Interconnection Facilities is 24-30 months after receipt of funds.

11.2 ERIS

The high-level cost estimate (non-binding), excluding HST taxes, for the interconnection of IR#576 as an Energy Resource is shown in Table 6. This does not include TBD costs to address any stability issues identified at the SIS stage based on dynamic analysis, or costs associated with revising the existing Group 3, Group 5, and Group 6 Special Protection Systems.

Table 6: ERIS Cost Estimate

	ERIS Cost Estimates	
	Network Upgrades	**Estimate**
i	230kV breaker addition at 91N	$1,750,000
ii	Communications / P & C Systems	$250,000
	Sub-total	**$2,000,000**
	TPIF	**Estimate**
iii	Tubular Bus extension to IR#576 substation	$250,000
	Sub-total	**$250,000**
	Contingency (10%)	$225,000
	Total of Determined Cost Items	**$2,475,000**
	To be Determined Costs	
x	System additions to increase east-west transfer capability	TBD (SIS)
xi	Impacts to Group 3,5, and 6 SPS's	TBD (SIS)

The estimated time to construct the Network Upgrades and Transmission Providers Interconnection Facilities is 18-24 months after receipt of funds.

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 91H.

Without IR#576 in service, losses in the winter peak case total 86.2 MW. With IR#576 in service displacing generation at 91H, and not including losses associated with the IR#576 Generation Facilities or TPIF Interconnection Facilities, system losses total 92.1 MW, an increase of 5.9 MW. As such, the loss factor for IR#576 is as follows: 5.9 MW / 110 MW x 100% = +5.36%.

13 Issues to be addressed in SIS

The following provides a preliminary scope of work for the subsequent SIS for IR#576. 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 and 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 to 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 will proceed and the facilities associated with those projects are installed.

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

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

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

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

- L-8001/3025
- L-3006
- Memramcook 345/138 kV transformer
- L-6613
- L-6514
- L-6535/L-1159
- L-6513/L-1160
- L-8001 & 67N-T81 (common circuit breaker)
- L-8002 & 67N-T81 (common circuit breaker)
- L-3006 & L-3025 & Memramcook 345/138 kV Tx (common breaker)
- L-3006 & L3017 (common breaker)
- 1N-B61 (bus fault)
- L-1108/1190 Common 138 kV structure
- Loss of 180 MW of load under peak load conditions
- Loss of largest generation source in NS
- Loss of Maritime Link

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

- 3 phase fault L-8001/3025 at 67N-Onslow, NS Import SPS operation (islanding)
- 3 phase fault L-8001/3025 at 67N-Onslow, NS Export SPS operation
- 3 phase fault L-3006 at Memramcook, NB SPS/UVLS operation (islanding)
- 3 phase fault L-3006 at Memramcook, NB Export SPS
- 3 phase fault L-3006 at Salisbury, NB SPS/UVLS operation (islanding)
- 3 phase fault L-8003 at 67N-Onslow
- 3 phase fault L-8002 at 67N-Onslow
- SLG L-3017, drops L-3017&L-3006 (common CB), NB SPS/UVLS operation,
- SLG Memramcook T3, drops L-3006 (common CB), NB SPS/UVLS operation
- SLG L-8003 at Onslow, drops 67N-T82, 345kV SPS Operation
- 3 phase fault at 79N-Hopewell, drops L-8003, 8004, bus, SPS operation
- 3 phase fault 1N-Onslow 138 kV bus B61

Any changes to SPS 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[3] and NPCC[4] criteria as well as NSPI guidelines and good utility practice. The SIS will also determine the contingencies for which this facility must be curtailed.

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