System Impact Study Report

Report GIP-IR675-SIS-R0

Generator Interconnection Request #675

112.5 MW Wind Generating Facility

Hants County, NS

September, 2023

Control Centre Operations
Nova Scotia Power Inc.

Executive summary

The System Impact Study (SIS) for IR675 will be conducted in Part 1 and Part 2. Part 1, using Power System Simulator software, will determine the impacts of IR675 on the NSPI power system with respect to steady state, stability, short circuit, power factor, voltage flicker, bulk power system status, under-frequency operation, low voltage ride through and loss factor.

Part 1 system impacts will be assessed based on NSPI system design criteria, Generator Interconnection Procedure (GIP), Transmission System Interconnection Requirements (TSIR), applicable Northeast Power Coordinating Council (NPCC) planning criteria for Bulk Power System (BPS), and applicable North American Electric Reliability Corporation (NERC) planning criteria for Bulk Electricity System (BES).

Part 2 study will use Electro Magnetic Transient software to determine IR675's impacts and control interactions when integrated with NSPI power system. It will progress in parallel with the next phase of the GIP process (facilities study). The outcomes of the Part 2 study will be captured as an addendum to the SIS Part 1 report and may trigger restudy for facilities study work completed at that time.

This report presents the results of Part 1 of the System Impact Study (SIS) for IR 675 - a proposed 112.5 MW wind turbine generating facility interconnected to the NSPI system as Network Resource Interconnection Service (NRIS). The Point of Interconnection (POI) is identified as 138 kV bus B4 at 50W-Milton substation. The proposed Commercial Operation Date is 2024/12/01.

IR 675 consists of twenty-five (25) Wind Energy Converter System (WECS) units using Vestas V150-4.5 MW with 720V terminal voltage, each rated at 4.5 MW totaling 112.5 MW. The voltage is stepped up to 34.5 kV at the collector substations with equivalent generator step-up transformers. IR 675 is then connected to the 138 kV bus at IR597 IC substation through two 34.5kV/138kV station transformers. Both IR675 and IR597 will connect to 138 kV bus B4 at 50W-Milton (POI) via a 5.2 km-long 138kV transmission line. The line termination for L-6024 at 50W-Milton has to be moved to make room for this new 138kV line termination and ROW to the new wind farm connection (IR 597 and IR 675).

The short circuit analysis shows that the maximum short circuit levels are far below 5,000 MVA for 138 kV and 3,500 MVA for 69 kV with IR675 added into the power system at POI. IR675 short circuit contribution does not require any uprating of existing breakers in the transmission system. The minimum short circuit level at the IR675 34.5 kV bus of transformer 1 with all lines in service is 264 MVA, which equates to a minimum short circuit ratio (SCR) of 4.5 with 13 generators connected. Similarly, the SCR at the 34.5kV bus of transformer 2 is 4.9 with 12 generators connected. The minimum short circuit level at the IR675 34.5 kV bus of transformer 1 with L-6025 out of service drops to 253 MVA, which equates to a minimum short circuit ratio (SCR) of 4.3 with 13 generators connected, and 4.7 with 12 generators connected. At the 138kV level, inclusive of IR 597 generation

(36MW) and IR 675 generation (112.5MW), with L-6025 out of service, the fault level at the 138kV terminals of the generator transformers is 548 MVA, which translates to a SCR of 3.7 accounting for total area generation of 148.5 MW at these two facilities.

The Vestas V150-4.5 MW models provided by the IC are applicable for a network system having a minimum SCR of 5 at the point of connection, so the IC should discuss with wind turbine manufacture to determine if any modifications for lower SCR conditions are required.

IR675 meets NS Power's leading power factor requirement, but it may not meet lagging power factor requirement therefore supplemental reactive power compensation might be required. This must be re-evaluated once detailed design information on the transformers and collector circuits are available (prior to Commercial Operation) to confirm IR675 has the required amount of supplemental reactive support.

The steady state power flow analysis shows that IR675 addition to the system will require the following customer funded Network Upgrades at POI and beyond to operate at the requested MW capability under NRIS:

- To resolve L-6531 post contingency overloads:
    - 99W-Bridgewater: Move L-6006 termination from Bus B61 to B62.
- To resolve post contingency overloads on transformers 9W-T2, 9W-T63, and 30W-T2:
    - Replace 9W-T63 with a 60/80/100 MVA, 138kV-69kV transformer
    - Replace 15/20/25MVA 30W-T2 with 30/40/50//56 MVA 9W-T63
    - Reconfigure the 9W-T63 Milton/Tusket Automated Action Scheme (AAS) to protect 9W-T2 (L-5027 trip to relieve overload) and low voltage in Tusket area
- To resolve post contingency overloads on L-6024:
    - The L-6024 rating is limited by its associated breaker and switch ratings at 9W. Replacing breaker 9W-563 and switch 9W-563A with 1200A rated equipment raises the overall line rating to 143 MVA and resolves the overload. Breaker 9W-563 is already scheduled to be replaced and is therefore the cost responsibility of NS Power.
- To resolve overloads on L-5025 and L-5026:
    - The L-5025 and L-5026 ratings are limited by the associated metering ratings at 11V-Paradise and 13V-Gulch, and by the switch ratings at 13V-Gulch and 70V-Bridgetown. Replacing the 48MVA rated switches 13V-516A, 13V-516B, 70V-503 and 70V-504 with 72 MVA rated switches, and replacing the 42 MVA rated metering at 11V and 13V with metering rated for at least 72 MVA will raise the overall summer/winter line ratings to 72 MVA and will resolve the overload.

These upgrades are funded by the customer but are refunded per the terms of the Generator Interconnection Agreement (GIA). The following Network Upgrades are the required to address pre-existing issues and are the cost responsibility of the Transmission Provider:

- To resolve the remaining post contingency issues associated with the failure of Breaker 50W-615:
  - Install an 8 MVar capacitor bank at the 30W 69kV bus
  - Expand the 30W-Souriquois substation to include a 138kV breaker at the L-6020 termination.
  - Replace breaker 9W-563 as scheduled.

No issues were identified in the stability analysis that are attributed to IR675.

The facilities associated with IR675 are not designated as NPCC BPS as IR675 does not affect the BPS status of existing facilities. However, IR675 qualifies as NERC BES as its aggregate rated output is greater than 75 MVA. It shall be designed and operated according to and meeting NERC's BES standards.

The dynamic simulation for NS being suddenly islanded from NB showed NS system frequency swing below under frequency thresholds of NS under frequency load shedding (UFLS) and this program shed 294 MW in NS. IR675 remained on-line and stable helping to stabilize NS frequency during and post contingency.

IR675 low voltage ride through (LVRT) capability was tested to cover expected system operating conditions in winter peak, summer peak and light load. The simulations showed that IR675 remained on-line with temporarily reduced power and ramped back to rated power during contingency and remained stable post contingency.

The loss factor calculation is based on a winter peak case with and without IR675 in service. The calculated loss factor is 3.4% at IR675's generator terminal (720V) and 1.1% at its POI. This means system losses on peak are marginally increased when IR675 is operating at 112.5 MW.

It is concluded that the incorporation of the proposed facility into the NS Power transmission system at the specified location has no negative impacts on the reliability of the NS Power grid, provided the recommendations provided in this report are implemented.

The following facility changes will be required to connect IR675 as NRIS to NSPI transmission system at the POI:

- Customer Funded Transmission Network Upgrades
  - Modification of protection system at 50W-Milton due to the addition of IR675.
  - L-6006 re-termination to 99W-B62.
  - Replacement of 9W-T63 with a 60/80/100 MVA, 138kV-69kV transformer.
  - Replacement of 15/20/25 MVA 30W-T2 with 30/40/50//56 MVA 9W-T63.

- Re-utilization of Milton/Tusket AAS.
- Replacement of Switch 9W-563A.
- Replacement of switches 13V-516A, 13V-516B, 70V-503 and 70V-504.
- Replacement of metering at 13V-Gulch.

- Transmission Network Upgrades funded by the Transmission Provider:
  - Replacement of Breaker 9W-563.
  - Addition of 8 MVar capacitor Bank at 30W 69kV bus.
  - Expansion of 30W to add a 138kV breaker for L-6020.

- Transmission Provider's Interconnection Facilities (TPIF) Upgrades
  - Installation of NSPI P&C Relaying Equipment.
  - Installation of NSPI supplied RTU.
  - Installation of Tele-protection and SCADA communication.

- IC Interconnection Facility
  - The ability to interface with the NS Power SCADA and communications systems to provide control, communication, metering, and other items to be specified in the forthcoming Interconnection Facilities Study.
  - NSPI to have supervisory and control of this facility, via the centralized controller such as a farm control unit. This will permit the NSPI System Operator to raise/lower the voltage setpoint, change the status of reactive power controls, change the real/reactive power remotely. NSPI will also have remote manual control of the load curtailment scheme.
  - The centralized voltage controller to control the 34.5 kV bus voltage to a settable point and will control the reactive output of each inverter unit of IR675 to achieve this common objective. Responsive *(fast-acting)* controls are required. The setpoint for this controller will be delivered via the NS Power SCADA system. The voltage controller must be tuned for robust control across a broad range of SCR.
  - Facilities to meet ±0.95 power factor requirement when delivering rated output (112.5 MW) at the 138 kV bus. IR675's power factor capability should be re-evaluated to determine the required amount of supplemental reactive support once detailed design information on its transformers and collector circuits are available.
  - Voltage flicker and harmonics characteristics as described in Section 3.3: Voltage flicker.
  - Frequency ride through capability to meet the requirements in Section 2.3.8: Underfrequency operation.
  - When not at full output, the facility shall offer over-frequency and under-frequency control with a deadband of ±0.2 Hz and a droop characteristic of 4%.
  - The ability to control active power in response to control signals from the NS Power System Operator and frequency deviations. This includes automatic curtailment to pre-set limits *(0%, 33%, 66% and no curtailment)*, over/under frequency control, and Automatic Generation Control *(AGC)* system to control tie-line fluctuations as required.

- Voltage ride through capability to meet the requirements in Section 2.3.9: Low voltage ride through.
- The facility must use equipment capable of closing a circuit breaker with minimal transient impact on system voltage and frequency *(matching voltage within ±0.05 PU and a phase angle within ±15º)*.
- To minimize the need to curtail non-dispatchable wind generation at light load, all wind farms must have the functionality to be incorporated into the Export Power Monitor SPS.
- 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.
- During the study for this SIS, section 7.6.7 of TSIR, that requires wind turbine generators to provide inertia response of 3.0 MW-s/MVA for a period of at least 10 seconds, was temporarily postponed for review by NSPI. It will be addressed in Part 2 of the System Impact Study. Vesta wind turbine generators to meet TSIR section 7.6.9 requirements that the wind generating facility shall be capable of operating at ambient temperatures as low as -30 ºC.
- The facility must meet NSPI's TSIR as published on the NSPI OASIS site.

To accommodate IR675, the total high level non-binding estimated cost in 2023 Canadian dollars for the Network Upgrades is $4,250,000 and for the new Transmission Provider's Interconnection Facilities (TPIF) is $310,000, for a total of $4,560,000, plus 10% contingency for a total of $5,016,000 excluding HST. The costs of all associated facilities required at the IC's substation and Generating Facility are in addition to this estimate. This cost excludes any additional costs or changes which may be identified by Part 2 of the System Impact Study as well as any cost associated with ICIF generating facility.

The IC will be responsible for acquiring the ROW (Right-Of-Way) for all the facilities.

The preliminary and non-binding estimate for the construction of the customer funded Network Upgrades is 24-36 months, primarily as a result of long lead time items (100 MVA transformer) and the scheduling of line outages. Timelines will be confirmed in the Facility Study. Operation at reduced capacity will be considered prior to the installation of the 100 MVA transformer at 9W and the relocation of 9W-T63 to 30W.

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1.0 Introduction

The Interconnection Customer (IC) submitted an Interconnection Request (IR) to Nova Scotia Power Inc. (NSPI) for the connection of a proposed 112.5 MW wind turbine generating facility interconnected to the NSPI system as Network Resource Interconnection Service (NRIS). The proposed Commercial Operation Date is 2024/12/01.

The IC signed a System Impact Study (SIS) Agreement for this 112.5 MW wind turbine generating facility, and this report is the result of that Agreement. This project is listed as Interconnection Request #675 in the NSPI Interconnection Request Queue and will be referred to as IR675 throughout this report.

1.1 Scope

The IC identified the 138 kV bus at 50W-Milton substation as the Point of Interconnection (POI). The proposed generation will be connected to the 138 kV bus of the IR 597 IC substation and then to the 50W-Milton POI (50W-B4) via an approximately 5.2 km long 138kV transmission line. The line termination for L-6024 at 50W-Milton will be moved to make room for this new 138kV line termination and ROW to the new wind farm connection (IR 597 and IR 675).

Figure 1: Proposed interconnection shows the approximate geographic location of the proposed IR675 site. *Figure 2: Proposed interconnection in one-line diagram* illustrates the electrical locations of IR675.

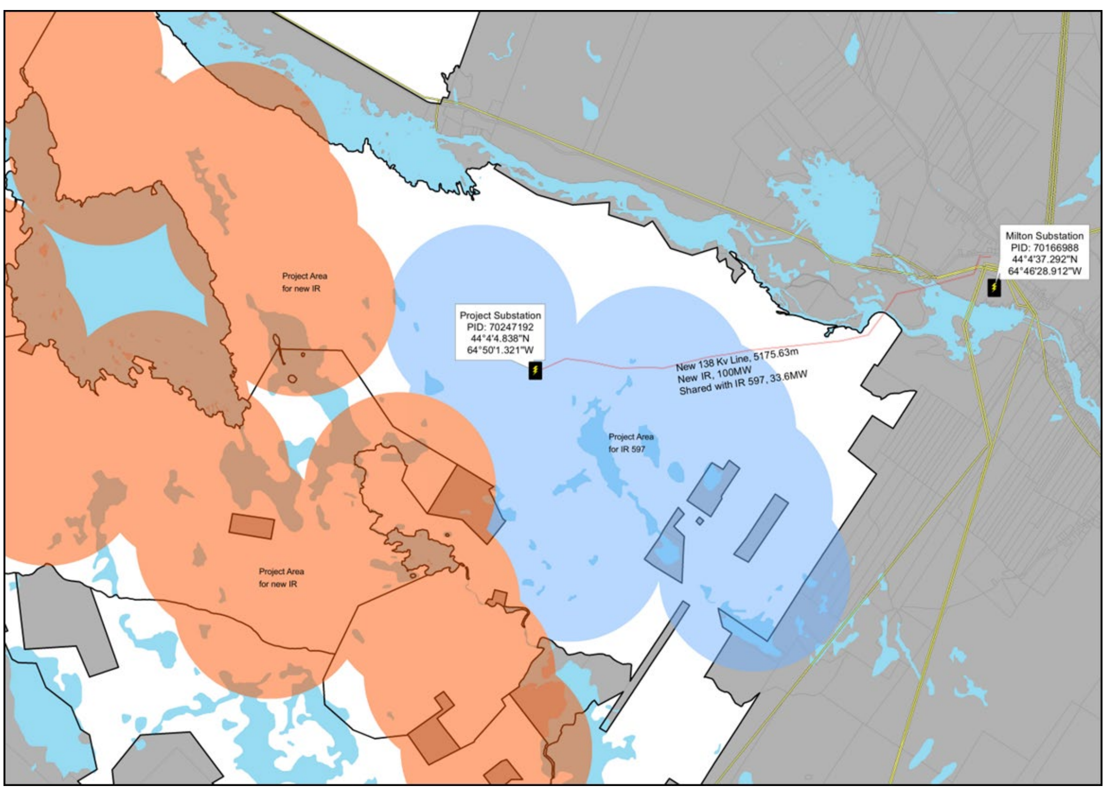


Figure 1: Proposed interconnection

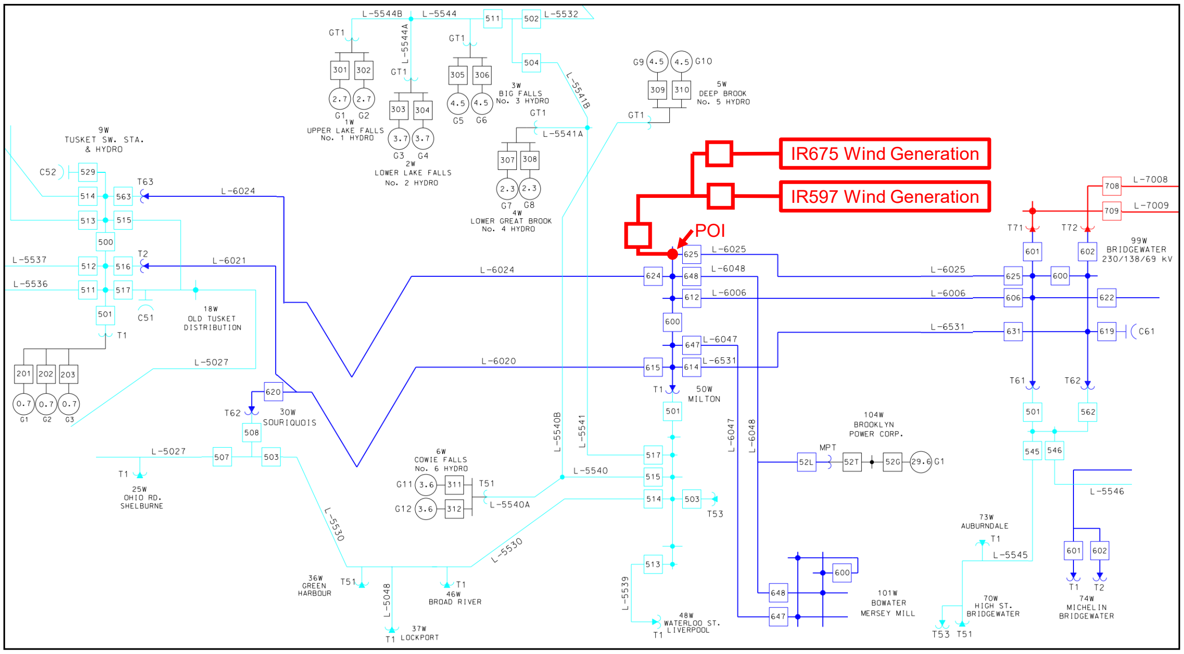


Figure 2: Proposed interconnection in one-line diagram

This report presents the results of the SIS with the objective of assessing the impact of the proposed generation facility on the NS Power Transmission System.

The scope of the SIS is limited to determining the impact of the IR675 generating facility on the NS Power transmission for the following:

- Short circuit analysis and its impact on circuit breaker ratings.
- Power factor requirement at the high side of the ICIF transformer.
- Voltage flicker.
- Steady state analysis to determine any thermal overload of transmission elements or voltage criteria violation.
- Stability analysis to demonstrate that the interconnected power system is stable for various single-fault contingencies.
- NPCC Bulk Power System (BPS) and NERC Bulk Electric System (BES) determination for the substation.
- Underfrequency operation.
- Low voltage ride through.
- Incremental system Loss Factor.
- Impact on any existing Special Protection Systems (SPSs).

This report provides a high-level non-binding cost estimate of requirements for the connection of the generation facility to ensure there will be no adverse effect on the reliability of the NS Power Transmission System.

1.2 Assumptions

The study is based on technical information provided by the IC. The POI and configuration are studied with the following assumptions:

1. Network Resource Interconnection Service type with an in-service date of 2024-12-01.
2. The Interconnection Facility consists of twenty-five (25) Vestas V150-4.5 MW wind energy converter units, totalling 112.5 MW. These 25 wind generation units are modelled into two groups which consist of 12 and 13 units respectively. Each group of wind generation units is modeled as one equivalent lumped parameter generators and was connected to the substation via a dedicated interconnection facility transformer. The equivalent models were developed using the data provided by the Interconnection Customer. The manufacturer's dynamics data is included in *Appendix A: Generating facility dynamic data* of this report.
3. The Vestas V150-4.5 MW wind energy converter units are the 720 V AC, 5300 kVA nameplate variant. A 1.05 PU fault current is used for short circuit analysis.
4. Individual wind turbine generator transformer (720 V/34.5 kV) was model to have an impedance of 9.9% on 5.3 MVA with an assumed X/R ratio of 12.38.
5. 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 for both equivalent collector circuits. Detailed collector circuit data must be provided by the IC prior to trial operation of the facility to confirm the validity of this assumption.
6. The two interconnection facility transformers are identical and modeled as 138 kV (wye) to 34.5 kV (wye), 40/53/66 MVA, with an impedance of 8.5% (on 40 MVA Base) and an X/R ratio of 20.
7. The IC identified the 138 kV bus B4 at the 50W-Milton substation as the POI. This project utilizes the 5.2 km interconnection transmission line from IR597 IC substation to the POI which uses the 556.5 ACSR Dove conductor rated at 100ºC with overhead ground wire.
8. NSPI's transmission line ratings are assumed as posted on NSPI's Intranet, including any projected line upgrades for the periods under study.
9. It is assumed that IR675 generation meets IEEE Standard 519 limiting total harmonic distortion (all frequencies) to a maximum of 2.5% with no individual harmonic exceeding 1.5% for 138 kV.
10. Generation in a higher queue position, except for the interconnection requests that are electrically remote from IR675, are modeled in the base cases. The included projects are listed in Section 1.3.
11. The Maritime Link can be used as an SPS target.
12. The rating of transmission facilities in the vicinity of IR#675 are shown in *Table 1: Rating of Transmission Lines* and *Table 2: Rating of Transformers*.

Table 1: Rating of Transmission Lines

Line	Conductor	Design Temp	Limiting Element	Summer Rating Normal/Emergency MVA	Winter Rating Normal/Emergency MVA
L-6006	ACSR 795 Drake	50ºC	Conductor	135.0/148.5	205.0/225.5
L-6025	ACSR 1113 Beaumont	70ºC	CT	200.0/220.0	200.0/220.0
L-6531	ACSR 556.5 Dove	50ºC	Conductor	110.0/121.0	165.0/181.5
L-6020	ACSR 336.4 Linnet	50ºC	Conductor	82.0/90.2	121.0/133.1
L-6021	ACSR 336.4 Linnet	50ºC	Switchgear	72.0/79.2	72.0/79.2
L-6024	ACSR 795 Drake	70ºC	Switchgear	72.0/79.2	72.0/79.2

Table 2: Rating of Transformers

Transformer	Normal Rating / 15 min Emergency	
	Summer MVA	Winter MVA
9W-T2	56/56	56/61.6
9W-T63	56/56	56/61.6
30W-T62	25/25	25/27.5
50W-T1	56/56	56/61.6

1.3 Project queue position

All in-service generation facilities are included in the SIS.

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 and #33. GIP Study Group #32 and #33 analysis will be limited to the 2022 Transmission System configuration plus any material Network Upgrades identified in higher queued projects.

As of 2023/04/25, the following projects are higher queued in the Advanced Stage Interconnection Request Queue:

- IR #426: GIA executed, 2018/09/01 in-service date.
- IR #516: GIA executed, 2020/05/31 in-service date.
- IR #540: GIA executed, 2023/10/31 in-service date.
- IR #542: GIA executed, 2025/06/30 in-service date.
- IR #557: SIS Complete, 2018/09/01 in-service date.
- IR #517: GIA in progress, 2019/10/01 in-service date.
- IR #569: GIA executed, 2022/02/24 in-service date.
- IR #566: GIA executed, 2022/04/30 in-service date.
- IR #574: GIA executed, 2025/09/30 in-service date.
- IR #598: GIA executed, 2024/06/30 in-service date.
- IR #604: GIA executed, 2023/03/30 in-service date.
- IR #597: FAC in progress, 2023/08/31 in-service date.

- IR #647: GIA in progress, 2023/12/31 in-service date.
- IR #653: GIA executed, 2022/10/30 in-service date.
- IR #654: GIA executed, 2022/09/20 in-service date.
- IR #656: GIA in progress, 2022/12/31 in-service date.
- IR #664: SIS in progress, 2023/12/15 in-service date.
- IR #662: SIS in progress, 2024/12/15 in-service date.
- IR #663: SIS in progress, 2024/06/15 in-service date.
- IR #670: SIS in progress, 2026/02/28 in-service date.
- IR #671: SIS in progress, 2026/02/28 in-service date.
- IR #669: SIS in progress, 2025/12/31 in-service date.
- IR #668: SIS in progress, 2025/12/01 in-service date.
- IR #618: SIS in progress, 2025/01/01 in-service date.
- IR #673: SIS in progress, 2024/12/31 in-service date.

As the section 4.2 of NSPI’s posted Generator Interconnection Procedure (GIP) allows for “Transmission Provider may study an Interconnection Request separately to the extent warranted by Good Utility Practice based upon the electrical remoteness of the proposed Generating Facility”, the following IRs are not included in this SIS due to their significant electrical remoteness with respect to the IR675:

- IR #662: SIS in progress, 2024/12/15 in-service date.
- IR #663: SIS in progress, 2024/06/15 in-service date.
- IR #670: SIS in progress, 2026/02/28 in-service date.
- IR #669: SIS in progress, 2025/12/31 in-service date.
- IR #668: SIS in progress, 2025/12/01 in-service date.
- IR #618: SIS in progress, 2025/01/01 in-service date.

The remaining of the higher-queued Interconnections will be modelled and included in IR675 study base cases. If any of these included projects are subsequently withdrawn from the Queue, it may be necessary to update this SIS or perform a re-study.

2.0 Technical model

To facilitate the load flow analysis, the proposed twenty-five (25) wind turbines are modelled into two groups with two equivalent generators representing 12 and 13 wind turbine generators respectively. The 720 V generator terminal voltage is stepped up to 34.5 kV at the collector substations with two equivalent step-up transformers. The equivalent models are then stepped up to 138 kV via two interconnection transformers.

The PSS®E model for load flow is shown in *Figure 3: PSS®E model* below. The two equivalent 720 V/34.5 kV generator transformers were modeled to have an impedance of 9.9% on 63.6 and 68.9 MVA respectively. The two identical interconnection transformers were assumed to have 8.5% impedance on the 40 MVA rating with an X/R ratio of 20. The SIS results must be updated if the actual nameplate data for these transformers materially differs from these impedance values.

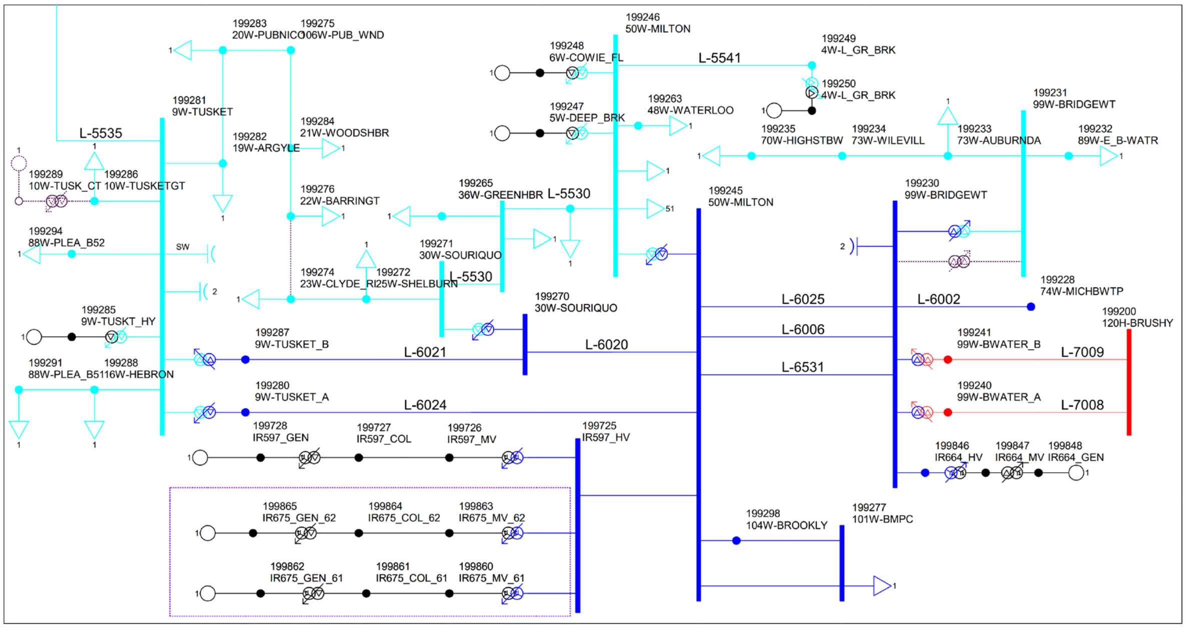


Figure 3: PSS®E model

2.1 System data

The "*2022 Load Forecast Report*", dated April 29, 2022, produced by NSPI, and submitted to Nova Scotia Utility and Review Board *(NSUARB)* was used to allocate the loads in NS. The winter peak load forecast for the near future is shown in *Table 3: Load forecast for study period*, with 2026 used for this study.

As for the summer peak and the light load forecast, their typical values are based on 67% and 35% respectively of the winter peak values.

Please note that the load forecast includes the power system losses but excludes the station service loads at power generating stations.

Table 3: Load forecast for study period

Forecast year	System peak	Interruptible contribution to peak	Firm contribution	Demand response	Growth %
2023	2,185	146	2,035	-4	0.9
2024	2,215	146	2,057	-12	1.4
2025	2,253	152	2,076	-24	1.7
2026	2,291	154	2,101	-36	1.7
2027	2,326	153	2,133	-39	1.5
2028	2,361	153	2,170	-39	1.5
2029	2,398	153	2,207	-39	1.6
2030	2,434	152	2,243	-38	1.5
2031	2,479	152	2,289	-38	1.9
2032	2,532	152	2,342	-37	2.1

2.2 Generating facility

IR675 will be equipped with twenty-five (25) Vestas V150-4.5 MW wind energy converter units, each rated at 4.5 MW totaling 112.5 MW.

The proposed generator is classified as Type 4- generator with full converter interface. Vestas V150-4.5 MW wind turbine generators are each capable of a reactive power range of +1.53 to -1.44 MVAr within 90% to 110% of 720V nominal (or +2.55 to -1.60 MVAr at 100% of 720V nominal).

The proposed generating facility will be equipped with a SCADA-based central regulator which controls the individual generator reactive power output to maintain constant voltage at the Interconnection Facility substation.

2.3 System model & methodology

Testing and analysis were conducted using the following criteria, software, and/or modelling data.

2.3.1 Short circuit

PSS®E 34.8, classical fault study, flat voltage profile at 1 PU voltage, and 3LG fault was used to assess before and after short circuit conditions. The 2026 system configuration with IR675 in service and out of service was studied, with comparison between the two.

2.3.2 Power factor

NSPI's TSIR (Transmission System Interconnection Requirements, version 1.1, dated February 25, 2021), section 7.6.2 Reactive Power and Voltage Control requires "The Asynchronous Generating Facility shall 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" and "Rated reactive power shall be available through the full range of real power output of the Generating Facility, from zero to full power". PSS®E was used to simulate high and low system voltage conditions to determine the machine capability in delivery/absorption of reactive power (VAr).

2.3.3 Voltage flicker

Voltage flicker contribution is calculated in accordance with the methodology described in CEATI Report No. T044700-5123 "Power Quality Impact Assessment of Distributed Wind Generation".

Short-term flicker severity (P_{st}) and long-term flicker severity (P_{lt}) calculations are at the WTG terminals. For multiple wind turbines at a single plant, the estimated flicker contribution is calculated as follows.

Continuous:

$$P_{st} = P_{lt} = \left(\frac{1}{S_k}\right) \sqrt[m]{\sum_{i=1}^{N_{wt}} \left[\left(c_i(\varphi_k, v_a)(S_{n,i})\right)\right]^m}$$

Switching operation:

$$P_{st\Sigma} = \left(\frac{15}{S_k}\right) \sqrt[3.2]{\sum_{i=1}^{N_{wt}} \left[(N_{10,i})\left(k_f(\varphi_k)(S_{n,i})\right)\right]^{3.2}}$$

$$P_{lt\Sigma} = \left(\frac{6.9}{S_k}\right) \sqrt[3.2]{\sum_{i=1}^{N_{wt}} \left[(N_{120,i})\left(k_f(\varphi_k)(S_{n,i})\right)\right]^{3.2}}$$

Where:

S_k = short-circuit apparent power at the high voltage side of the ICIF transformer. As calculations are for the flicker contribution for the addition of IR675 to the existing system, short-circuit values are for the existing system - with IR675 and the existing IR597 wind offline.

m = 2 in accordance with IEC 61400-21 for WTGs.

N_{wt} = number of WTGs at IR675.

$N_{10,i}$ and $N_{120,i}$ = number of switching operations of the individual wind turbine within a 10 and 120 minute period, respectively.

$c_i(\psi_k, v_a)$ = flicker coefficient of the wind turbine for the given network impedance angle, ψ_k, at the PCC, for the given annual average wind speed, v_a, at the hub-height of the wind turbine site. It is to be provided by the wind turbine supplier. NS network impedance angle is typically 80º-85º.

$k_{f,i}(\psi_k)$ = flicker step factor of the individual wind turbine.

$S_{n,i}$ = rated apparent power of the individual wind turbine.

NS Power's requirement is $P_{st} \leq 0.25$ and $P_{lt} \leq 0.35$.

2.3.4 Generation facility model

Modelling data was provided by the IC for PSS®E steady state and stability analysis in this SIS. The 25 wind turbines and collector circuits were grouped as two equivalent generators with two equivalent step-up transformers.

2.3.5 Steady state

Analysis was performed in PSS®E using Python scripts to simulate a wide range of single contingencies, with the output reports summarizing bus voltages and branch flows that exceeded established limits.

System modifications and additions up to 2026 were modelled to develop base cases to best test system reliability in accordance with NS Power and NPCC design criteria:

- Light load; high and low Western Valley generation.
- Medium load; high and low Western Valley generation.
- Peak load.

Power flow was run with the contingencies on each of the base cases listed in Section 3.4 Steady state analysis; with IR675 in and out of service to determine the impact of the proposed facility on the reliability of the NS Power grid.

2.3.6 Stability

Analysis was performed using PSS®E for the 2026 study year and system configuration. Light load, Fall, Spring, and Winter peak were studied for contingencies that provide the best measure of system reliability. Details on the contingencies studied are provided in Section 3.5 Stability analysis. The system was examined after the addition of IR675 to determine its impact.

Note all plots are performed on 100 MVA system base.

2.3.7 NPCC-BPS/NERC-BES

NS Power is required to meet reliability standards developed by the Northeast Power Coordinating Council (NPCC) and the North American Electric Reliability Corporation (NERC). Both NPCC and NERC have more stringent requirements for system elements that can have impacts beyond the local area. These elements are classified as "Bulk Power System" (BPS), for NPCC, and "Bulk Electric System" (BES), for NERC.

2.3.7.1 NPCC BPS

NPCC's Bulk Power System (BPS) substations are subject to stringent requirements like redundant and physically separated protective relay and teleprotection systems. Determination of BPS status was in accordance with NPCC criteria document A-10:

Classification of Bulk Power System Elements, dated March 27, 2020. The A-10 test requires steady state and stability testing.

The steady state test involves opening all elements connected to the bus under test in constant MVA power flow.

The stability test involves simulation of a permanent 3PH fault at the bus under test with all local protection out of service (such as station battery failure), including high speed teleportation to the remote terminals. The fault is maintained on the bus for 10 seconds to allow remote protection at surrounding substations to trip the lines to the faulted substation with the corresponding back-up protection times. The post-fault simulation is extended to 20 seconds.

A bus will be classified as part of the BPS if any of the following is observed during the steady state and/or stability tests:

- System instability that cannot be demonstrably contained with in the Area.
- Cascading that cannot be demonstrably contained within the Area.
- Net loss of source/load greater than the Area's threshold.

The NPCC A-10 Criteria document does not require rigorous testing of all buses. Section 3.4, item 2 states:

> *"...*
> *For buses operated at voltage levels between 50 kV and 200 kV, all buses adjacent to a bulk power system bus shall be tested. Testing shall continue into the 50-200 kV system until a non-bulk power system result is obtained, as detailed in Section 3.5. Once a non-bulk power system result is obtained, it is permitted to forgo testing of connected buses unless one of the following considerations shows a need to test these buses:*
> *- Slower remote clearing times.*
> *- Higher short-circuit levels.*
> *..."*

2.3.7.2 NERC BES

NERC uses Bulk Electric System (BES) classification criteria based on a "bright-line" approach rather than performance based like the NPCC BPS classification. The NERC Glossary of Terms as well as the methodology described in the NERC Bulk Electric System Definition Reference was used to determine if IR675 should be designated BES or not.

2.3.8 Underfrequency operation

Underfrequency dynamic simulation is performed to demonstrate that NS Power's automatic Underfrequency Load Shedding (UFLS) program sheds enough load to assist stabilizing system frequency, without tripping IR675's generators.

This test is accomplished by triggering a sudden loss of generation by placing a fault on L-8001 under high import conditions.

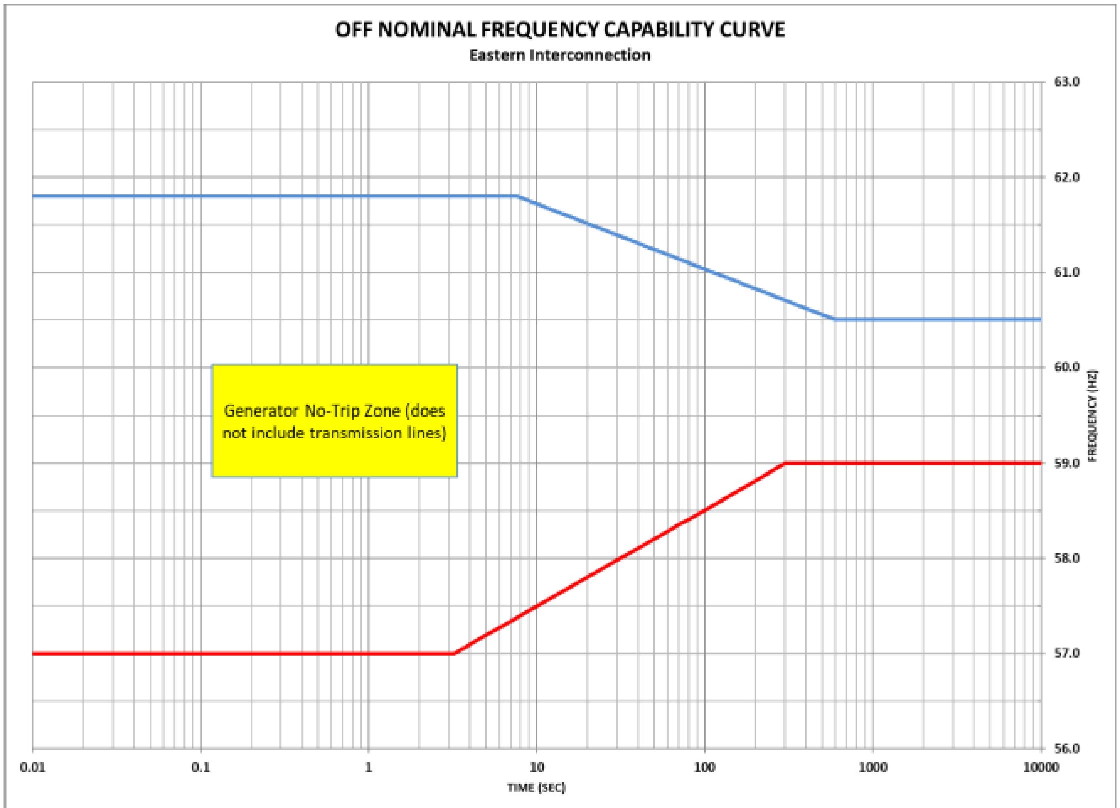
Nova Scotia is connected to the rest of the North American power grid by the following three AC transmission lines:

- L-8001 (345kV)
- L-6535 (138kV)
- L-6536 (138kV)

Under high import conditions, if L-8001, or, either of L-3025 and L-3006 in NB trips, an "Import Power Monitor" SPS will cross-trip L-6613 at 67N-Onslow to avoid thermal overloads on the 138kV transmission lines. This controlled separation will island Nova Scotia from the rest of the North American power grid. System frequency will be stabilized from the resulting generation deficiency through Under-Frequency Load Shedding (UFLS) schemes to shed load across Nova Scotia. IR675 is required to remain online and not trip under this scenario.

Other contingencies in New Brunswick and New England can also result in under-frequency islanded situation in Nova Scotia.

In addition to the test, IR675 must be capable of operating reliably for frequency variations in accordance with NERC Standards PRC-024-2 and PRC-006-NPCC-2 as shown in *Figure 4: Off-nominal frequency curve (PRC-024-2 and PRC-006-NPCC-2 combined)*. It should also have the capability of riding through a rate of change of frequency of 4Hz/s.



High Frequency Deviation		Low Frequency Deviation	
Frequency (Hz)	Time (Sec)	Frequency	Time
≥ 61.8	Instantaneous Trip	f ≥ 57.0 Hz	t ≤ 3.3 s
< 61.8 ≥ 60.5	$10^{(90.935 - 1.45713 * f)}$	f ≥ log(t) + 56.5 Hz	3.3s < t ≤ 300 s
< 60.5	Continuous Operation	f ≥ 59.0Hz	t > 300 s

Figure 4: Off-nominal frequency curve (PRC-024-2 and PRC-006-NPCC-2 combined)

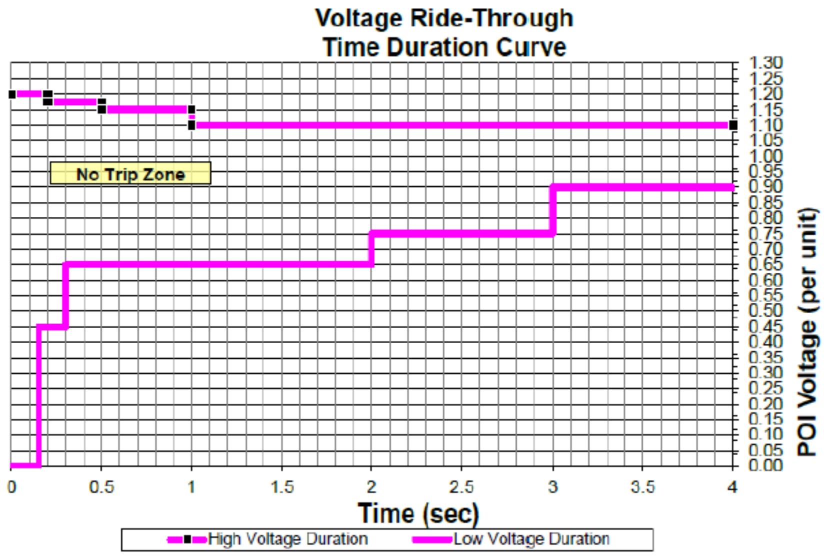
2.3.9 Voltage ride-through

IR675 must remain operational under the following voltage conditions:

- Under normal operating conditions: 0.95 PU to 1.05 PU
- Under stressed (contingency) conditions: 0.90 PU to 1.10 PU
- Under the voltage ride-through requirements in NERC Standard PRC-024-2, see *Figure 5: PRC-024-2 Attachment 2: Voltage ride-through requirements*.

This test is performed by applying a 3-phase fault to the HV and LV buses of the ICIF for 9 cycles. IR675 should not trip for faults on the Transmission System or its collector circuits.

VOLTAGE RIDE-THROUGH REQUIREMENTS



Low Voltage Ride-Through Data Points	
Bus Voltage at Point of Interconnection (pu)	Duration (sec)
< 0.45	0.15
< 0.65	0.30
< 0.75	2.00
< 0.90	3.00
High Voltage Ride-Through Data Points	
Bus Voltage at Point of Interconnection (pu)	**Duration (sec)**
≥1.200	Instantaneous trip permitted
≥1.175	0.2
≥1.150	0.5
≥ 1.100	1.00

Figure 5: PRC-024-2 Attachment 2: Voltage ride-through requirements

2.3.10 Loss factor

Loss factor was calculated by running the power flow using a standardized winter peak base case with and without IR675, while keeping 91H-Tufts Cove generation as the NS area interchange bus. The loss factor for IR675 is the differential MW displaced or increased at 91H-Tufts Cove generation calculated as a percentage of IR675's nameplate MW rating. Although the IR under study and wind generation facilities in the vicinity (existing and committed) are tested at maximum rated output, all other wind generation facilities are dispatched at an average 30% capacity factor.

This methodology reflects the load centre in and around 91H-Tufts Cove and has been accepted and used in the calculation of system losses for the Open Access Transmission Tariff (OATT). It is calculated on the hour of system peak as a means for comparing multiple projects but not used for any other purpose.

Loss factors are provided at the generator terminal bus and the POI (50W-Milton).

3.0 Technical analysis

The results of the technical analysis are reported in the following sections.

3.1 Short circuit

Short circuit analysis was performed using PSS®E 34.8, classical fault study, flat voltage profile at 1 PU voltage, and 3LG faults. The short circuit levels in the area before and after this development are provided in *Table 4: Short circuit levels, three phase, MVA*.

The transient reactance of 0.95 was used in the short circuit calculation for IR675 generator, which was obtained from IR597 SIS report.

IR675 will not impact the neighbouring breaker's interrupting capability based on this study's short circuit analysis. The interrupting capability of the 138 kV circuit breakers at 99W-Bridgewater, 30W-Souriquois and 50W-Milton are at least 3,500 MVA. The interrupting capability of the 69 kV circuit breakers at 9W-Tusket, 30W-Souriquois and 50W-Milton are at least 2,000 MVA. The NS Power design criteria for maximum system fault capability (3-phase, symmetrical) is 5,000 MVA at the 138 kV voltage level and 3,500 MVA at the 69 kV voltage level.

Table 4: Short circuit levels, three phase, MVA

Location	IR675 OFF	IR675 ON	Post % Increase
Maximum generation, all transmission facilities in service			
99W-Bridgewater, 138kV	1771	1840	3.9%
30W-Souriquois, 138kV	601	614	2.2%
30W-Souriquois, 69kV	285	288	1.0%
9W-Tusket Hydro & SW STA, 69kV	559	565	1.1%
50W-Milton 138kV (POI)	1367	1461	6.8%
50W-Milton 69kV	632	644	1.8%
IR675 & IR597 HV, 138kV	1166	1261	8.2%
IR675 34.5kV Bus1	335	390	16.4%
IR675 34.5kV Bus2	335	394	17.6%
Low Generation, all transmission facilities in service			
99W-Bridgewater, 138kV	827	917	10.9%
30W-Souriquois, 138kV	379	408	7.7%
30W-Souriquois, 69kV	223	232	4.3%
9W-Tusket Hydro & SW STA, 69kV	284	299	5.3%
50W-Milton 138kV (POI)	654	749	14.4%
50W-Milton 69kV	357	382	7.0%
IR675 & IR597 HV, 138kV	602	697	15.8%
IR675 34.5kV Bus1	264	324	22.7%
IR675 34.5kV Bus2	264	328	24.1%

Location	IR675 OFF	IR675 ON	Post % Increase
Minimum Conditions – low Generation, L-6025 out of service			
50W-Milton 138kV (POI)	592	686	15.9%
50W-Milton 69kV	339	366	8.1%
IR675 & IR597 HV, 138kV	548	644	17.4%
IR675 34.5kV Bus1	253	315	24.1%
IR675 34.5kV Bus2	253	318	25.5%

IR675's minimum fault level is expected when L-6025 is out of service and generation in the Western Valley region is off-line. Under those conditions, the SCR (Short Circuit Ratio, a measure of system strength relative to the size of the wind farm) is calculated to be 4.3 (253 MVA / 58.5 MW) at the IR675's 34.5 kV bus of transformer 1 and is calculated to be 4.7 (253 MVA / 54 MW) at the IR675's 34.5 kV bus of transformer 2. SCR is further reduced at the high side of the generator step-up transformers due to the collector circuit impedance. At the 138kV level, inclusive of IR 597 generation (36 MW) and IR 675 generation (112.5MW), with L-6025 out of service, the fault level at the 138kV terminals of the generator transformers is 548 MVA, which translates to a SCR of 3.7 accounting for total area generation of 148.5 MW at these two facilities. However, per information provided by the IC[1], the provided Vestas V150-4.5 MW models are applicable for a network system with a minimum short-circuit ratio (SCR) of 5 at the point of connection. The IC should consult the wind turbine manufacture to determine if any modifications for lower SCR conditions are required. Note that the minimum short circuit level on the 34.5kV bus will be greatly impacted by the impedance of the Interconnection Facility transformer.

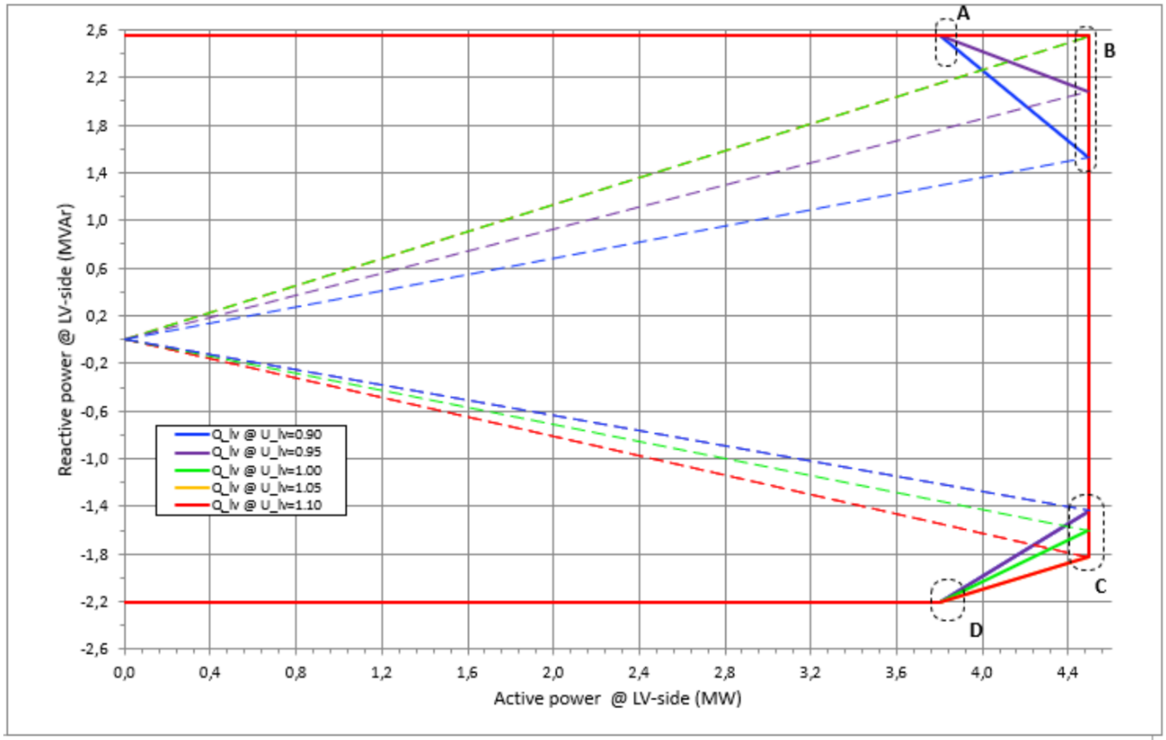
3.2 Power factor

For IR675 power factor evaluation, at all production levels up to the full rated load, the facility must be capable of operating between 0.95 PU lagging to 0.95 PU leading net power factor at the high side of the ICIF transformer. The power factor will be measured at the high side of the ICIF transformer for this requirement.

From information provided by the IC, the 138/34.5 kV transformer has a tap changer with ±10% taps and 32 equal steps. The 34.5/0.72 kV generator step-up transformers were noted to be supplied with de-energized tap changers with ±2.5% taps.

The Vestas V150-4.5 MW wind turbine generators (power factor +0.870/-0.942 at 720 V nominal) can provide +2.55/-1.6 MVAr reactive power when delivering rated power at 4.5 MW. The reactive power capability within normal voltage operation is shown in *Figure 6: Reactive power capability of the Vestas V150-4.5 MW turbine under normal voltage operation*. A total of +63.75/-40 MVAr reactive power could be provided when delivering capped power at 112.5 MW.

[1] *0067-7050_V05 - General Description 4MW Platform - 4.5MW variant.pdf*



		Coordinates								Power factor	
	Point:	A		B		C		D		B (Capacitive)	C (Inductive)
	Coordinate:	x (P)	y (Q)	x (P)	y (Q)	x (P)	y (Q)	x (P)	y (Q)		
(blue)	Reactive power [kVAr] @ LV side @ U_lv = 0.90 p.u. voltage	3,800	2,550	4,500	1,530	4,500	-1,440	3,800	-2,200	0,947	0,952
(purple)	Reactive power [kVAr] @ LV side @ U_lv = 0.95 p.u. voltage	3,800	2,550	4,500	2,080	4,500	-1,440	3,800	-2,200	0,908	0,952
(green)	Reactive power [kVAr] @ LV side @ U_lv = 1.00 p.u. voltage	3,800	2,550	4,500	2,550	4,500	-1,600	3,800	-2,200	0,870	0,942
(yellow)	Reactive power [kVAr] @ LV side @ U_lv = 1.05 p.u. voltage	3,800	2,550	4,500	2,550	4,500	-1,830	3,800	-2,200	0,870	0,926
(red)	Reactive power [kVAr] @ LV side @ U_lv = 1.10 p.u. voltage	3,800	2,550	4,500	2,550	4,500	-1,830	3,800	-2,200	0,870	0,926

Figure 6: Reactive power capability of the Vestas V150-4.5 MW turbine under normal voltage operation[1]

When IR675 generation is at rated 112.50 MW (54MW + 58.5MW) output and producing maximum 63.75 MVAr (30.60 MVAr + 33.15 MVAr) of reactive power, the real and reactive power delivered to the high side (138 kV) of the ICIF transformers is 110.00 MW (52.83 MW + 57.17 MW) and 33.08 MVAr (16.20 MVAr + 16.88 MVAr), respectively. This equates to a +0.958 lagging power factor, not meeting the existing +0.950 GIP requirement. The overall lagging power factor is calculated as +0.956 considering IR597, which does not yet meet the existing +0.950 GIP requirement. Additional reactive power compensation (at least 4 MVAr) might be needed at the high side of ICIF. The IC can consider the use of a capacitor bank on the 34.5 kV bus or consider wind turbine models which have a higher reactive power range. This should be re-evaluated to determine the required amount of supplemental reactive support once detailed design information on the transformers and collector circuits are available.

When IR675 generation is at rated 112.50 MW (54 + 58.5MW) output, while absorbing maximum 40.00 MVAr (19.2 + 20.8 MVAr) of reactive power, the real and reactive power delivered to the high side (138 kV) of the ICIF transformers is 110.07 MW (52.87 + 57.20 MW) and 69.88 MVAr (33.07 + 36.81 MVAr), respectively. This corresponds to a -0.844 power factor, meeting the -0.950 GIP requirement.

The calculated reactive power consumption of the IC's components when IR675 is at rated MW output while producing or absorbing reactive power is listed in *Table 5: MVAr consumption at rated MW output*.

Table 5: MVAr consumption at rated MW output

Component	At max MVAr production	At max MVAr absorption
ICIF transformers (138/34.5 kV) *	7.50 + 8.73 = 16.23	7.22 + 8.59 = 15.81
Collector circuit equivalent	1.41 + 1.65 = 3.06	1.37 + 1.62 = 2.99
34.5/0.75 kV generator step-up transformer equivalent (tap setting 1.00)	5.49 + 5.89 = 11.38	5.28 + 5.80 = 11.08

* *Taps setting at 1.05 for max MVAr production and 0.975 for max MVAr absorption*

NSPI's TSIR section 7.6.2 Reactive Power and Voltage Control requires "Rated reactive power shall be available through the full range of real power output of the Generating Facility, from zero to full power". Therefore, IR675 is required to produce/ absorb reactive power at all production levels from 0 MW up to its full rated output.

3.3 Voltage flicker & Harmonics

Voltage flicker is not calculated in this study as the flicker coefficient data is currently not available. IR675 is required to meet NS Power's short term and long-term voltage flicker requirements based off the measured data.

As for harmonics, NSPI requires IR675 to meet Harmonics IEEE-519 standard limiting Total Harmonic Distortion (all frequencies) to a maximum of 2.5%, with no individual harmonic exceeding 1.5% for 138 kV. The total harmonic distortion (THD) for Vestas V150-4.5 MW is currently not available. If for some reason, in the actual installation, IR675 causes issues with voltage flicker or harmonics, then IR675 will be responsible for mitigating the issues.

3.4 Steady state analysis

3.4.1 Base cases

The bases cases used for power flow analysis are listed in *Table 6: Power flow base cases*. One-line diagrams of each base case are presented in *Appendix B: Base case one-line diagrams*.

For these cases:

- Transmission connected wind generation facilities were dispatched between 19% and 100% of their rated capability.
- All interface limits were respected for base case scenarios.

Two scenarios were examined for each of the Spring Light Load, Summer Peak, and Winter Peak cases:

- Pre-IR675 cases ending with "-1": IR675 off.
- Post-IR675 cases ending with "-2": IR675 dispatched at 112.5 MW under NRIS designation.

Table 6: Power flow base cases

Case Name	NS load	IR 675	Wind generation	West wind	NS/NB	ML	CBX	ONI	Valley import	Western import	Valley export	Western Valley import
c_ll01-1	782	0	462	377	230	-300	162	148	17	-32	-7	33
c_ll01-2	774	112.5	575	489	231	-300	76	62	11	-134	-7	33
c_ll02-1	848	0	462	377	230	-300	249	234	21	65	-7	33
c_ll02-2	840	112.5	575	489	231	-300	184	170	15	-39	-7	33
c_ll03-1	798	0	648	410	231	0	0	59	7	-53	8	18
c_ll03-2	790	112.5	761	522	231	0	-92	-33	2	-155	8	18
c_ll04-1	848	0	648	410	230	0	48	107	12	43	8	18
c_ll04-2	848	112.5	761	522	231	0	-27	32	5	-60	8	18
c_ll05-1	774	0	648	410	0	0	-201	-143	7	-53	8	18
c_ll05-2	774	112.5	761	522	85	0	-201	-143	1	-155	8	18
c_ll06-1	824	0	648	410	0	0	-201	-143	12	43	8	18
c_ll06-2	824	112.5	761	522	0	0	-201	-143	5	-59	8	18
c_sh01-1	1256	0	648	410	349	-475	510	595	87	14	-22	66
c_sh01-2	1248	112.5	761	522	350	-475	445	532	80	-88	-22	65
c_sh02-1	1306	0	648	410	349	-475	509	645	91	111	-22	66
c_sh02-2	1298	112.5	761	522	349	-475	445	534	85	7	-22	65
c_sh03-1	1328	0	493	410	-300	-220	5	-55	35	-27	22	22
c_sh03-2	1319	112.5	605	522	-300	-220	-60	-121	29	-130	22	22
c_sh04-1	1378	0	493	410	-300	-300	99	39	39	69	22	22
c_sh04-2	1369	112.5	605	522	-301	-300	19	-41	33	-34	22	22
c_sp01-1	1390	0	645	407	350	-475	404	560	106	12	-26	74
c_sp01-2	1382	112.5	758	519	351	-475	316	452	100	-90	-26	74
c_sp02-1	1454	0	645	407	350	-475	456	610	110	109	-26	74
c_sp02-2	1445	112.5	758	519	350	-475	381	500	104	5	-26	74
c_sp03-1	1424	0	413	361	351	-475	764	813	106	56	-26	74
c_sp03-2	1415	112.5	526	474	350	-475	650	703	100	-47	-26	74
c_sp04-1	1483	0	413	361	350	-475	817	863	111	153	-26	74
c_sp04-2	1474	112.5	526	474	350	-475	700	752	104	48	-26	74
c_sp05-1	1409	0	256	256	0	-475	673	702	125	62	-25	74
c_sp05-2	1400	112.5	369	369	0	-475	558	592	119	-41	-25	74
c_sp06-1	1468	0	256	256	0	-475	726	753	129	159	-25	74
c_sp06-2	1459	112.5	369	369	0	-475	609	641	123	54	-25	74
c_wp01-1	2126	0	487	392	150	-320	882	1069	154	78	-15	87
c_wp01-2	2126	112.5	600	504	151	-320	764	958	148	-26	-15	87
c_wp02-1	2008	0	487	392	150	-320	667	875	135	151	-7	74
c_wp02-2	2008	112.5	600	504	150	-320	550	763	129	46	-6	73
c_wp03-1	2126	0	371	371	149	-320	869	1009	162	92	-26	99
c_wp03-2	2126	112.5	483	483	150	-320	753	899	156	-12	-26	98
c_wp04-1	2017	0	487	392	150	-320	765	969	138	176	-7	74
c_wp04-2	2008	112.5	600	504	150	-320	646	855	132	71	-6	73
c_sp07-2	1546	113	648	522	330	-369	229	522	17	-177	29	19
c_wp05-2	2349	113	761	522	150	-475	574	872	166	-39	-10	89

Note 1: All values are in MW.
Note 2: CBX (Cape Breton Export) and ONI (Onslow Import) are Interconnection Reliability defined interfaces.
Note 3: Wind refers to transmission connected wind only.

- wp01-x, wp02-x, wp03-x, wp04-x represents peak load, with high East-West transfers, where-as wp05-x represents peak load with moderate East-West transfers and high Western Valley Import levels. Generation dispatched is assumed to be typical for peak load, with high load in the Valley area.
- sh03-x represents the NS/NB import limit, presently 23% of net in-province load, to a maximum 300 MW. This case tests the performance of the Underfrequency Load Shedding *(UFLS)* system during contingencies that isolates NS from the interconnected power system *(like the loss of L8001)*.
- sp01-x, sp02-x, sp-07-x, sh01-x, and sh02-x represent off-peak load and high generation in the Western and Valley areas. This represents typical spring hydro run-off conditions. Local generation is managed to ensure transmission limits are maintained.
- ll01-x, ll02-x, ll03-x, ll04-x, sp01-x, sp02-x, sp03-x, sp04-x, sp07-x, and wp05-x represent high enough export levels from NS to NB to require arming of the Export Power Monitor SPS. ll01-x, ll02-x, ll03-x, ll04-x, and wp05-x require Group 5 arming, while sp01-x, sp02-x, sp03-x, sp04-x and sp07-x requires Group 6 arming. In either condition, the Maritime Link *(ML)* is targeted to reduce NS generation for conditions resulting from the loss of the 345kV tie line, L8001, and subsequent action to reduce flow on the 138kV line L6613, between 1N-Onslow and 74N-Springhill.
- ll05-x and ll06-x represents minimum system load under low inertia, with only two equivalent thermal units online and high wind generation.
- sp05-x and sp06-x represent the high import at Valley and Western corridors.

3.4.2 Steady state contingencies

The steady state power flow analysis includes the contingencies listed in *Table 7: Steady state contingencies*.

Table 7: Steady state contingencies

ID	Element	Type	Location	ID	Element	Type	Location
p001	2C-B61	Bus fault	2C-Hastings	p133	101S-812	Breaker fail	101S-Woodbine
p002	2C-B62	Bus fault	2C-Hastings	p134	101S-813	Breaker fail	101S-Woodbine
p003	3C-712	Breaker fail	3C-Hastings	p135	101S-814	Breaker fail	101S-Woodbine
p004	3C-715	Breaker fail	3C-Hastings	p136	101S-816	Breaker fail	101S-Woodbine
p005	L6515	Line fault	2C-Hastings	p137	88S-710	Breaker fail	88S-Lingan
p006	L6516	Line fault	2C-Hastings	p138	88S-712	Breaker fail	88S-Lingan
p007	L6517	Line fault	2C-Hastings	p139	88S-713	Breaker fail	88S-Lingan
p008	L6518	Line fault	2C-Hastings	p140	88S-720	Breaker fail	88S-Lingan
p009	L6537	Line fault	2C-Hastings	p141	88S-721	Breaker fail	88S-Lingan
p010	L6543	Line fault	2C-Hastings	p142	88S-722	Breaker fail	88S-Lingan
p011	L7004	Line fault	3C-Hastings	p143	88S-723	Breaker fail	88S-Lingan
p012	103H-B61	Bus fault	103H-Lakeside	p144	L7011	Line fault	101S-Woodbine
p013	103H-B62	Bus fault	103H-Lakeside	p145	L7014	Line fault	88S-Lingan
p014	103H-T63	Transformer fault	103H-Lakeside	p146	L7015	Line fault	101S-Woodbine
p015	104H-600	Breaker fail	104H-Kempt Rd	p147	L7021	Line fault	88S-Lingan
p016	113H-601	Breaker fail	113H-Dartmouth East	p148	L7022	Line fault	88S-Lingan
p017	120H-621	Breaker fail	120H-Brushy	p149	L8004	Line fault	101S-Woodbine
p018	120H-622	Breaker fail	120H-Brushy	p150	L6011 + L6010	Double ckt tower	Sackville
p019	120H-623	Breaker fail	120H-Brushy	p151	L6507 + L6508	Double ckt tower	Trenton

ID	Element	Type	Location	ID	Element	Type	Location
p020	120H-624	Breaker fail	120H-Brushy	p152	L6534 + L7021	Double ckt tower	Lingan / VJ
p021	120H-625	Breaker fail	120H-Brushy	p153	L7003 + L7004	Double ckt tower	Canso Causeway
p022	120H-626	Breaker fail	120H-Brushy	p154	L7008 + L7009	Double ckt tower	Bridgewater
p023	120H-627	Breaker fail	120H-Brushy	p155	L7009 + L8002	Double ckt tower	Sackville
p024	120H-628	Breaker fail	120H-Brushy	p156	101V-601	Breaker fail	101V-MacDonald Pond
p025	120H-629	Breaker fail	120H-Brushy	p157	13V-B51	Bus fault	13V-Gulch
p026	120H-710	Breaker fail	120H-Brushy	p158	15V-B51	Bus fault	15V-Sissiboo
p027	120H-711	Breaker fail	120H-Brushy	p159	17V-B1	Bus fault	17V-St Croix
p028	120H-712	Breaker fail	120H-Brushy	p160	17V-B2	Bus fault	17V-St Croix
p029	120H-713	Breaker fail	120H-Brushy	p161	1V-442	Breaker fail	1V-Avon 1
p030	120H-714	Breaker fail	120H-Brushy	p162	20V-B51	Bus fault	20V-Five Points
p031	120H-715	Breaker fail	120H-Brushy	p163	3V-551	Breaker fail	3V-Hell's Gate
p032	120H-716	Breaker fail	120H-Brushy	p164	43V-B51	Bus fault	43V-Canaan Rd
p033	120H-720	Breaker fail	120H-Brushy	p165	43V-B61	Bus fault	43V-Canaan Rd
p034	132H-602	Breaker fail	132H-Spider Lake	p166	43V-B62	Bus fault	43V-Canaan Rd
p035	132H-603	Breaker fail	132H-Spider Lake	p167	43V-T61	Transformer fault	43V-Canaan Rd
p036	132H-605	Breaker fail	132H-Spider Lake	p168	43V-T62	Transformer fault	43V-Canaan Rd
p037	132H-606	Breaker fail	132H-Spider Lake	p169	51V-601	Breaker fail	51V-Tremont
p038	1H-603	Breaker fail	1H-Water St	p170	51V-B51	Bus fault	51V-Tremont
p039	90H-601	Breaker fail	90H-Sackville	p171	51V-T61	Transformer fault	51V-Tremont
p040	90H-602	Breaker fail	90H-Sackville	p172	51V-T62	Transformer fault	51V-Tremont
p041	90H-603	Breaker fail	90H-Sackville	p173	6V-GT1	Transformer fault	6V-Hollow Bridge
p042	90H-605	Breaker fail	90H-Sackville	p174	82V-600	Breaker fail	82V-Elmsdale
p043	90H-606	Breaker fail	90H-Sackville	p175	92V-B51	Bus fault	92V-Michelin Waterville
p044	90H-608	Breaker fail	90H-Sackville	p176	L4045	Line fault	17V-St Croix
p045	90H-609	Breaker fail	90H-Sackville	p177	L4046	Line fault	17V-St Croix
p046	90H-611	Breaker fail	90H-Sackville	p178	L4047	Line fault	17V-St Croix
p047	90H-612	Breaker fail	90H-Sackville	p179	L4048W	Line fault	39V-Fundy Gypsum
p048	90H-613	Breaker fail	91H-Tufts Cove	p180	L4049	Line fault	3V-Hell's Gate
p049	90H-621	Breaker fail	91H-Tufts Cove	p181	L5014	Line fault	17V-St Croix
p050	91H-603	Breaker fail	91H-Tufts Cove	p182	L5015	Line fault	17V-St Croix
p051	91H-604	Breaker fail	91H-Tufts Cove	p183	L5016	Line fault	17V-St Croix
p052	91H-605	Breaker fail	91H-Tufts Cove	p184	L5021	Line fault	43V-Canaan Rd
p053	91H-606	Breaker fail	91H-Tufts Cove	p185	L5022	Line fault	43V-Canaan Rd
p054	91H-607	Breaker fail	91H-Tufts Cove	p186	L5025	Line fault	11V-Paradise
p055	91H-608	Breaker fail	91H-Tufts Cove	p187	L5026	Line fault	11V-Paradise
p056	91H-609	Breaker fail	91H-Tufts Cove	p188	L5033	Line fault	43V-Canaan Rd
p057	91H-611	Breaker fail	91H-Tufts Cove	p189	L5035	Line fault	3V-Hell's Gate
p058	L6044	Line fault	132H-Spider Lake	p190	L5050	Line fault	15V-Sissiboo
p059	L6002E	Line fault	90H-Sackville	p191	L5053	Line fault	92V-Michelin Waterville
p060	L6003	Line fault	90H-Sackville	p192	L5060	Line fault	17V-St Croix
p061	L6004	Line fault	90H-Sackville	p193	L5531	Line fault	13V-Gulch
p062	L6005	Line fault	120H-Brushy	p194	L5532	Line fault	13V-Gulch
p063	L6007	Line fault	91H-Tufts Cove	p195	L5533	Line fault	13V-Gulch
p064	L6008	Line fault	103H-Lakeside	p196	L5535	Line fault	15V-Sissiboo
p065	L6009	Line fault	90H-Sackville	p197	L5538	Line fault	15V-Sissiboo
p066	L6010	Line fault	120H-Brushy	p198	L6001N	Line fault	82V-Elmsdale
p067	L6011	Line fault	120H-Brushy	p199	L6001S	Line fault	82V-Elmsdale
p068	L6014	Line fault	91H-Tufts Cove	p200	L6012	Line fault	43V-Canaan Rd
p069	L6016	Line fault	120H-Brushy	p201	L6013	Line fault	43V-Canaan Rd

ID	Element	Type	Location	ID	Element	Type	Location
p070	L6033	Line fault	103H-Lakeside	p202	L6015	Line fault	43V-Canaan Rd
p071	L6035	Line fault	1H-Water St	p203	L6051	Line fault	17V-St Croix
p072	L6038	Line fault	103H-Lakeside	p206	L6052	Line fault	43V-Canaan Rd
p073	L6040	Line fault	91H-Tufts Cove	p207	L6054	Line fault	43V-Canaan Rd
p074	L6042	Line fault	91H-Tufts Cove	p209	30W-B51	Bus fault	30W-Souriquois
p075	L6043	Line fault	113H-Dartmouth East	p210	30W-B61	Bus fault	30W-Souriquois
p076	L6044	Line fault	113H-Dartmouth East	p211	3W-B53	Bus fault	3W-Big Falls
p077	L6051	Line fault	120H-Brushy	p212	50W-B2	Bus fault	50W-Milton
p078	L6055	Line fault	132H-Spider Lake	p213	50W-B3	Bus fault	50W-Milton
p079	L7018	Line fault	120H-Brushy	p214	50W-B4	Bus fault	50W-Milton
p080	90H-T1	Transformer fault	90H-Sackville	p215	50W-T53	Transformer fault	50W-Milton
p081	1N-B61	Bus fault	1N-Onslow	p216	99W-B51	Bus fault	99W-Bridgewater
p082	1N-B62	Bus fault	1N-Onslow	p217	99W-B61	Bus fault	99W-Bridgewater
p083	50N-604	Breaker fail	50N-Trenton	p218	99W-B62	Bus fault	99W-Bridgewater
p084	67N-701	Breaker fail	67N-Onslow	p219	99W-B71	Bus fault	99W-Bridgewater
p085	67N-702	Breaker fail	67N-Onslow	p220	99W-B72	Bus fault	99W-Bridgewater
p086	67N-703	Breaker fail	67N-Onslow	p221	99W-T61	Transformer fault	99W-Bridgewater
p087	67N-704	Breaker fail	67N-Onslow	p222	99W-T62	Transformer fault	99W-Bridgewater
p088	67N-705	Breaker fail	67N-Onslow	p223	99W-T71	Transformer fault	99W-Bridgewater
p089	67N-706	Breaker fail	67N-Onslow	p224	99W-T72	Transformer fault	99W-Bridgewater
p090	67N-710	Breaker fail	67N-Onslow	p225	9W-B52	Bus fault	9W-Tusket
p091	67N-711	Breaker fail	67N-Onslow	p226	9W-B53	Bus fault	9W-Tusket
p092	67N-712	Breaker fail	67N-Onslow	p227	L5530	Line fault	50W-Milton
p093	67N-713	Breaker fail	67N-Onslow	p228	L5540	Line fault	50W-Milton
p094	67N-811	Breaker fail	67N-Onslow	p229	L5541	Line fault	3W-Big Falls
p095	67N-812	Breaker fail	67N-Onslow	p230	L5545	Line fault	99W-Bridgewater
p096	67N-813	Breaker fail	67N-Onslow	p231	L5546	Line fault	99W-Bridgewater
p097	67N-814	Breaker fail	67N-Onslow	p232	L6006	Line fault	99W-Bridgewater
p098	74N-600	Breaker fail	74N-Springhill	p233	L6020	Line fault	50W-Milton
p099	79N-B61	Bus fault	79N-Hopewell	p234	L6024	Line fault	50W-Milton
p100	79N-B81	Bus fault	79N-Hopewell	p235	L6025	Line fault	99W-Bridgewater
p101	L5029	Line fault	74N-Springhill	p236	L6048	Line fault	50W-Milton
p102	L5058	Line fault	74N-Springhill	p237	L6531	Line fault	99W-Bridgewater
p103	L6001	Line fault	1N-Onslow	p238	L7008	Line fault	99W-Bridgewater
p104	L6057	Line fault	50N-Trenton	p239	L7009	Line fault	99W-Bridgewater
p105	L6503	Line fault	50N-Trenton	p240	17V-611	Breaker fail	17V- St. Croix
p106	L6507	Line fault	79N-Hopewell	P241	17V-512	Breaker fail	17V- St. Croix
p107	L6508	Line fault	50N-Trenton	P242	17V-563	Breaker fail	17V- St. Croix
p108	L6511	Line fault	50N-Trenton	P243	17V-T63	Transformer fault	17V- St. Croix
p109	L6514	Line fault	74N-Springhill	P244	1V-B51	Bus fault	1V-Avon 1
p110	L6527	Line fault	1N-Onslow	P245	43V-503	Breaker fail	43V-Canaan Rd
p111	L6536	Line fault	74N-Springhill	P246	43V-562	Breaker fail	43V-Canaan Rd
p112	L6613	Line fault	74N-Springhill	P247	51V-500	Breaker fail	51V-Tremont
p113	L7001	Line fault	67N-Onslow	P248	51V-521	Breaker fail	51V-Tremont
p114	L7002	Line fault	67N-Onslow	P249	51V-562	Breaker fail	51V-Tremont
p115	L7003	Line fault	67N-Onslow	P250	51V-602	Breaker fail	51V-Tremont
p116	L7005	Line fault	67N-Onslow	P251	51V-603	Breaker fail	51V-Tremont
p117	L7019	Line fault	67N-Onslow	P252	51V-B52	Bus fault	51V-Tremont
p118	L8001	Line fault	67N-Onslow	P253	82V-B61	Bus fault	82V-Elmsdale
p119	L8002	Line fault	67N-Onslow	P254	101V-602	Breaker fail	101V-MacDonald Pond

ID	Element	Type	Location	ID	Element	Type	Location
p120	L8003	Line fault	67N-Onslow	P255	101V-603	Breaker fail	101V-MacDonald Pond
p121	L8003	Line fault	79N-Hopewell	P256	50W-501	Breaker fail	50W-Milton
p122	L8004	Line fault	79N-Hopewell	P257	50W-514	Breaker fail	50W-Milton
p123	101S-701	Breaker fail	101S-Woodbine	P258	50W-517	Breaker fail	50W-Milton
p124	101S-702	Breaker fail	101S-Woodbine	P259	50W-600	Breaker fail	50W-Milton
p125	101S-703	Breaker fail	101S-Woodbine	P260	50W-615	Breaker fail	50W-Milton
p126	101S-704	Breaker fail	101S-Woodbine	P261	99W-501	Breaker fail	99W-Bridgewater
p127	101S-705	Breaker fail	101S-Woodbine	P262	99W-600	Breaker fail	99W-Bridgewater
p128	101S-706	Breaker fail	101S-Woodbine	P263	99W-601	Breaker fail	99W-Bridgewater
p129	101S-711	Breaker fail	101S-Woodbine	P264	99W-602	Breaker fail	99W-Bridgewater
p130	101S-712	Breaker fail	101S-Woodbine	P265	9W-500	Breaker fail	9W-Tusket
p131	101S-713	Breaker fail	101S-Woodbine				
p132	101S-811	Breaker fail	101S-Woodbine				

3.4.3 Steady state evaluation

The steady state power flow analysis was conducted without IR675 in service and with IR675 in service. The differential line flows are shown in *Appendix C: Differential line flows*. The one-line diagrams display the difference in flow on each transmission line with and without IR675. Notable differences on the lines between 120H-Brushy Hill, 99W-Bridgewater and 50W-Milton are expected as these substations are along the corridor towards the system IR675 is placed in. The flow on Western Import corridor from Metro area is reduced by up to 105.3 MW as IR675 comes online. The flow on Valley Import corridor from Metro area is reduced by up to 6.7 MW.

IR675 has some impact on constrained transmission system in the Milton and Tusket area, although the flow from Milton to Tusket area (on L-6020, L-6024 and L-5530) changes no more than 3.6 MW as IR675 comes online under system normal (N-0) conditions. The flow change on L-5532 and L-5535 is no more than 6.5 MW.

Results of the steady state analysis are presented in *Appendix D: Steady-state analysis results*. The power flow analysis identified a number of electrically remote transmission system contingencies inside Nova Scotia that violate thermal loading criteria or voltage criteria. A few pre-existing overloads and under-voltage issues were identified:

- Contingencies p213 (loss of 50W-B3), p233 (loss of L-6020) and p256 (50W-501 breaker fail) overload transformer 9W-T63 in sp03-2, sp04-2, sp05, sp06, wp01, wp02, wp03, wp04 and wp05 cases. When the Milton/Tusket load rejection AAS is armed, it will trip 9W-515 (L-5027) to reduce loading of 9W-T63. As a last resort, the overcurrent protection of 9W-T63 will result in the transfer trip for L-5532 and L-5535 overloads, which causes the South Shore's separation from the system. With the addition of IR-675, the Milton/Tusket load rejection AAS is no longer sufficient to offload 9W-T63 below its overload rating during some summer and winter dispatch scenarios.

- Contingencies p213 (loss of 50W-B3) and p256 (50W-501 breaker fail) overload line L-6024 (up to 173%) in wp01 and wp03 cases besides transformer 9W-T63 overload. These issues could activate the overcurrent protection of 9W-T63 and mitigate the L-6024 overload.
- Contingencies p212 (loss of 50W-B2), p213 (loss of 50W-B3), p256 (50W-501 breaker fail) and p258 (50W-517 breaker fail) overload Souriquois transformer 30W-T2 (up to 109%) in the wp05 case.
- Contingency p214 (loss of 50W-B4) and Contingency p234 (loss of L-6024) also causes overload on transformer 9W-T2 and low voltage (down to 0.75 p.u) in Tusket area in wp01, wp03 and wp05 cases.
- Contingency p233 (loss of L-6020) also causes low voltage (down to 0.87pu) at 23W-Clyde River, 25W-Shelburne, 30W-Souriquois, 36W-Green Harbor substations in wp03 and wp05 cases.
- Contingency p260 (50W-615 breaker fail) is identified as one of the worst contingencies in the study area cause the following issues:
    - transformer 9W-T63 overload and low voltage (down to 0.72pu) at 23W-Clyde River, 25W-Shelburne, 30W-Souriquois, 36W-Green Harbor, 37W-Lockport, 46W-Broad River, 50W-Milton, 91W-Middlefield in wp01 and wp03 cases, which triggers L5027 cross-trip. No thermal issues after L-5027 trip.
    - low voltage (down to 0.58pu) at 23W-Clyde River, 25W-Shelburne, 30W-Souriquois, 36W-Green Harbor, 37W-Lockport, 46W-Broad River, 50W-Milton, 91W-Middlefield substations in ll01, ll02, ll03, ll04, ll05, ll06 and wp02 cases.
    - overload of transformer 9W-T63 and line L-5532, as well as low voltage (down to 0.72pu) at 23W-Clyde River, 25W-Shelburne, 30W-Souriquois, 36W-Green Harbor, 37W-Lockport, 46W-Broad River, 50W-Milton, 91W-Middlefield Distribution substations in sh01, sh02, sp01, sp02, sp03, sp04, sp05, sp06 and wp04 cases, which could trigger the rejection of Tusket area load by the tripping of 9W-515 (L-5027), and/or L-5532 trip due to the overload. No other thermal or voltage issues after the RAS or AAS activation.

- Contingencies p166 (loss of 43V-B62), p168 (loss of 43V-T62) and p246 (43V-562 breaker fail) can overload L-6004 (up to 113%) in ll01, ll02, ll03, ll04, sh01, sh02, sh03, sh04, sp01, sp02, sp03 and sp04 cases. The issue is electrically remote from IR 675 and is not impacted by IR675. The overload is a result of loss of 138kV connection to 43V (L-6054), resulting in all wind generation from IR673, South Canoe, and IR671 flowing to the 138kV 90H-Sackville bus, which overloads the section of L-6004 between IR671 and 90H.
- Contingency p217 (99W-B61 bus fault) can overload L-5025 and L-5026 meter ratings at the 11V and 13V substations, and can overload L-5026 switch ratings at the 13V and 70V substations.
- Contingencies p186 (loss of L5025) and p187 (loss of L5026) could overload L-5541 (up to 112%) in sp07-2 case.

- Contingency p166 (loss of 43V-B62), p167 (loss of 43V-T62) or p168 (loss of 43V-T61) could overload the remaining 138/69 kV transformer at 43V in wp05-2 case.

Although the issues identified above are pre-existing, IR675 will exacerbate the following violations:

- **9W-T63 Overload Conditions (Loss of 50W-B3; 50W-615; 50W-501; L-6020):** With the addition of IR-675, the Milton/Tusket load rejection AAS is no longer sufficient to offload 9W-T63 below its overload rating during some summer and winter dispatch scenarios. As a result, transformer 9W-T63 must be replaced with a larger unit (60/80/100 MVA). The existing 30/40/50//56 MVA 9W-T63 can then be moved to replace the 15/20/25 MVA Souriquois 30W-T2 transformer to resolve subsequent overloads on that unit. The Milton/Tusket AAS can then be repurposed to protect transformer 9W-T2 against overloads following the loss of line L-6024 between 50W-Milton and 9W-Tusket or Milton Bus 50W-B4. These modifications represent Network Upgrades that are the cost responsibility of the Interconnection Customer.

- **9W-T2 Overload Conditions (Loss of L-6024):**
  By replacing 9W-T63 with a larger unit and transferring the Milton/Tusket AAS to 9W-T2, overloads on 9W-T2 and the low voltages in the Tusket area are resolved. Activation of the AAS will trip radial load supplied via 9W (69kV line L-5027), reducing the area load and improving area voltage. Re-purposing the AAS for 9W-T2 is a Network Upgrade that is the cost responsibility of the Interconnection Customer.

- **L-6024 Overload Conditions (Loss of 50W-B5; 50W-501):**
  L-6024 is limited by the rating of its breaker and switch at the 9W-Tusket substation. Replacing Breaker 9W-563 and switches 9W-563A with units rated for 143 MVA will resolve this overload. It should also be noted that Breaker 9W-563 is scheduled to be replaced and is therefore the cost responsibility of NS Power. Replacement of Switch 9W-563A is a Network Upgrade that is the cost responsibility of the Interconnection Customer.

- **Under-voltage Conditions in Souriquois (Loss of L-6020):**
  The under-voltage issues in the Souriquois area can be resolved by the installation of an 8 MVar switched capacitor bank at the 30W-Souriquois 69kV bus. This is an existing condition and is the cost responsibility of the Transmission Provider.

- **50W-615 Breaker Fail:**
  As previously noted, with the addition of IR675, the Milton/Tusket load rejection AAS is no longer sufficient to offload 9W-T63 below its overload rating during some summer and winter dispatch scenarios. As a result, transformer 9W-T63 must be replaced with a 60/80/100 MVA unit which will resolve the T63 overload issue.

The low voltage issues in the Souriquois area can be resolved by the installation of an 8 MVar capacitor bank at the 30W 69kV bus as noted above.

The L-5532 overload issues are pre-existing and occur when a Breaker 50W-615 failure causes protection to trip 50W-B3; L6021; and 30W-T61. This can be resolved by the expansion of the 30W-Souriquois substation to include a 138kV breaker at the L-6020 termination. A 50W-615 failure would then trip 50W-B3, L-6020, and the new 30W breaker, leaving the 138-69kV Souriquois transformer still supplied by L-6021; the new 9W-T63 transformer; and L-6024. This Network Upgrade would be the cost responsibility of the Transmission Provider.

It's noted that contingency 50W-501, 50W-B4 or L-6024 can still result in the undervoltage issues (below 0.8 p.u.) in Tusket area after thermal upgrade of 9W-T63 and 30W-T2. These are pre-existing conditions and not the responsibility of the IC. The re-purposed AAS might be used to cross trip L-5027 and voltage on the remaining Tusket area buses would be within the limit. Low voltage during these contingencies could also be resolved with new capacitor banks at 22W-Barrington and 9W-Tusket, which is the cost responsibility of the Transmission Provider.

New thermal issues are identified which are attributed to IR675:

- Contingencies p221 (loss of 99W-T61), p261 (99W-501 breaker fail) and p263 (99W-601 breaker fail) can overload L-6531 (up to 171%) in ll03-2, ll04-2, ll05-2, ll06-2, sh03-2, sh04-2 and sp07-2 cases. This can be resolved by moving the termination of line L-6006 at 99W-Bridgewater from 138kV bus B61 to B62 as shown below in *Figure 7: Re-termination of L-6006 from Bus B61 to B62 at 99W-Bridgewater*.

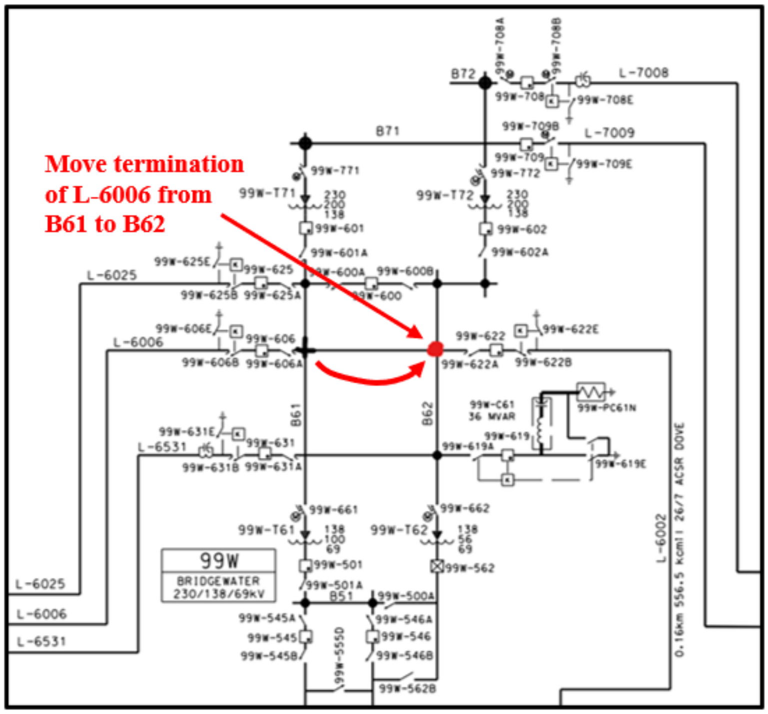


Figure 7: Re-termination of L-6006 from Bus B61 to B62 at 99W-Bridgewater

The re-termination of L-6006 and the associated protection modifications at 99W are Network Upgrades that are the cost responsibility of the Interconnection Customer.

The above contingencies also result in exceeding L-5025 and L-5026 meter ratings at the 11V and 13V substations, and can overload L-5026 switches at the 13V and 70V substations. These issues can be resolved by upgrading the 42 MVA metering at 11V and 13V to 73MVA, and replacing the 48 MVA switches at 13V and 70V with 73 MVA switches.

3.5 Stability analysis

System design criteria requires the system to be stable and well damped in all modes of oscillations.

3.5.1 Stability base cases

Selected steady-state cases were studied for contingencies that provide the best measure of system reliability. The parameters of these base cases are listed below in *Table 8: Stability base cases*.

Table 8: Stability base cases

Case Name	NS load	IR 675	Wind generation	West wind	NS/NB	ML	CBX	ONI	Valley import	Western import	Valley export	Western Valley import
c_ll01-2	774	112.5	575	489	231	-300	76	62	11	-134	-7	33

Case Name	NS load	IR 675	Wind generation	West wind	NS/NB	ML	CBX	ONI	Valley import	Western import	Valley export	Western Valley import
c_ll02-2	840	112.5	575	489	231	-300	184	170	15	-39	-7	33
c_ll03-2	790	112.5	761	522	231	0	-92	-33	2	-155	8	18
c_ll04-2	848	112.5	761	522	231	0	-27	32	5	-60	8	18
c_ll05-2	774	112.5	761	522	85	0	-201	-143	1	-155	8	18
c_ll06-2	824	112.5	761	522	0	0	-201	-143	5	-59	8	18
c_sh01-2	1248	112.5	761	522	350	-475	445	532	80	-88	-22	65
c_sh02-2	1298	112.5	761	522	349	-475	445	534	85	7	-22	65
c_sh03-2	1319	112.5	605	522	-300	-220	-60	-121	29	-130	22	22
c_sh04-2	1369	112.5	605	522	-301	-300	19	-41	33	-34	22	22
c_sp01-2	1382	112.5	758	519	351	-475	316	452	100	-90	-26	74
c_sp02-2	1445	112.5	758	519	350	-475	381	500	104	5	-26	74
c_sp03-2	1415	112.5	526	474	350	-475	650	703	100	-47	-26	74
c_sp04-2	1474	112.5	526	474	350	-475	700	752	104	48	-26	74
c_sp05-2	1400	112.5	369	369	0	-475	558	592	119	-41	-25	74
c_sp06-2	1459	112.5	369	369	0	-475	609	641	123	54	-25	74
c_wp01-2	2126	112.5	600	504	151	-320	764	958	148	-26	-15	87
c_wp02-2	2008	112.5	600	504	150	-320	550	763	129	46	-6	73
c_wp03-2	2126	112.5	483	483	150	-320	753	899	156	-12	-26	98
c_wp04-2	2008	112.5	600	504	150	-320	646	855	132	71	-6	73

3.5.2 Stability contingencies

The contingencies tested for this study are listed in *Table 9: Stability contingency list*.

Table 9: Stability contingency list

90H-605_LG	120H L6051_3PH	67N-813_ LG	17V-B63_3PH	99W-601_LG
90H-606_LG	120H L7008_3PH	67N-814_ LG*	17V L5016_3PH	99W-602_LG
90H-608_LG	120H L7018_3PH	67N L7001_3PH	43V-503_LG	99W-606_LG*
90H-609_LG	132H-602_LG	67N L7003_3PH*	43V-562_LG	99W-625_LG*
90H L6003_3PH	132H-603_LG	67N L7005_3PH*	43V-612_ LG	99W-631_LG*
90H L6004_3PH	132H-606_LG	67N L7018_3PH	43V-B61_3PH	99W-B61_3PH*
90H L6008_3PH	132H-605_LG	67N L7019_3PH*	43V-B62_3PH	99W-B62_3PH*
90H L6009_3PH	132H L6044_3PH	67N L8001_3PH*	43V L6012_3PH	99W L6002_3PH
91H L6007_3PH	132H L6055_3PH	67N L8002_3PH	51V-521_LG*	99W L6006_3PH
91H L6014_3PH	1N-600_LG	67N L8003_3PH*	51V-562_LG	99W L6025_3PH
91H L6040_3PH	1N-601_ LG	74N-600_ LG	51V-B51_3PH*	99W L6531_3PH
103H-600_LG	1N-613_ LG	74N L6514_3PH	51V L5025_3PH*	99W L7008_3PH*
103H-608_ LG	1N-B61_3PH	74N L6536_3PH	9W-500_LG	99W L7009_3PH*
103H-881_LG	1N-B62_3PH	74N L6613_3PH	9W-B52_3PH	DCT L6005_L6010_LLG
103H-681_LG	1N L6001_3PH	410N L3006_3PH	9W-B53_3PH	DCT L6010_L6011_LLG
103H L6008_3PH	1N L6503_3PH	410N L8001_3025_3PH*	9W L5535_3PH	DCT L6005_L6016_LLG
103H L6016_3PH	1N L6613_3PH	11V-B51_3PH*	9W L6021_3PH	DCT L6033_L6035_LLG
103H L6033_3PH	67N-701_LG	11V L5025_3PH*	9W L6021_LG	DCT L6507_L6508_50N_LLG

103H L8002_3PH	67N-702_ LG	11V L5026_3PH*	9W L6024_3PH	DCT L6507_L6508_79N_LLG
108H L6055_3PH	67N-703_ LG	13V-B51_3PH	50W-501_LG*	DCT L6534_L7021_LLG
113H-600_3PH	67N-704_ LG	13V L5026_3PH	50W-514_LG	DCT L7003_L7004_LLG *
120H-622_3PH	67N-705_ LG *	13V L5531_3PH	50W-517_LG	DCT L7008_L7009_LLG
120H-628_3PH	67N-706_ LG	13V L5532_3PH	50W-600_LG*	DCT L7009_L8002_LLG
120H-710_3PH	67N-710_ LG	15V-B51_3PH	50W-615_LG*	DCT L7009_L8002_A_LLG
120H-715_3PH	67N-711_ LG	15V L5535_3PH	50W-B2_3PH	
120H L6005_3PH	67N-712_ LG	17V-512_LG	50W-B3_3PH	* Indicates RAS/AAS
120H L6010_3PH	67N-713_ LG	17V-563_LG	50W-B4_3PH	
120H L6011_3PH	67N-811_ LG *	17V-611_LG	99W-501_LG	
120H L6016_3PH	67N-811_T82_ LG *	17V-612_LG	99W-600_LG	

3.5.3 Stability evaluation

PSS®E plotted output files for each contingency with IR675 in service are presented in *Appendix H: Stability analysis results*. All contingencies were found to be stable and well-damped.

3.6 NPCC-BPS/NERC-BES

NSPI is a member of NPCC and adheres to NPCC's requirements, including the requirements for BPS. The methodology for determining if a substation is BPS is defined in NPCC's criteria document A-10 titled "Classification of Bulk Power System Elements". To determine if IR675 will be BPS, the latest A-10 document, dated March 27, 2020, is used for the determination.

Both steady state and stability BPS testing was performed using the Spring Light Load, Summer Peak, Winter Peak cases shown in *Table 8: Stability base cases*. The steady state test was conducted by dispatching the new facility at request MW output, then disconnecting it. Post-contingency results reveal no voltage violations or thermal overloads outside the local area.

The stability test was performed by placing a 3-phase fault at the 50W-Milton 138 kV bus for 10 seconds, assuming all local protection out of service. *Appendix E: NPCC-BPS determination results* demonstrates IR675 does not have adverse impact outside the local area, confirming the transmission facilities associated with IR675 are not classified as NPCC BPS.

Note NPCC's A-10 Classification of Bulk Power System Elements requires NS Power to perform a periodic comprehensive re-assessment at least once every five years[2]. It is possible for this site's BPS status to change, depending on future system configuration changes, requiring the IC to adapt to NPCC reliability requirements accordingly[3].

Based on NERC BES criteria, IR675 is considered part of the BES with the aggregated plant nameplate rating greater than 75MVA.

3.7 Underfrequency operation

IR675's low frequency ride-through performance was tested by simulating a fault on L-8001 under high import conditions. The case selected for dynamic simulation was based on 2026 Shoulder, with 300 MW import into Nova Scotia (sh03-2).

IR675 remains stable and online as required. Simulation indicates that NS Power's Stage 3 UFLS activates to stabilize system frequency by shedding 294 MW load. The simulation results are shown in figures *Figure 8: Underfrequency performance (frequency at 120H-Brushy Hill:138kV), Figure 9: Underfrequency performance (frequency at NS_410N, Mass, Cherrywood, Orrington, and 120H-Brushy Hill)*, *Figure 10: Underfrequency performance (IR675 machine-1 output)* and *Figure 11: Underfrequency performance (IR675 machine-2 output)*. Note values are plotted on 100 MVA system base, so IR675 at 1.125 PU power represents maximum output of the generators rather than 112.5% output.

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[2] Regional Reliability Reference Criteria A-10, *Classification of Bulk Power System Elements*, 2020/03/27, https://www.npcc.org/content/docs/public/program-areas/standards-and-criteria/regional-criteria/criteria/a-10-20200508.pdf

[3] NPCC Reliability Reference Directory # 4, *Bulk Power System Protection Criteria*, 2020/01/30, https://www.npcc.org/content/docs/public/program-areas/standards-and-criteria/regional-criteria/directories/directory-4-tfsp-rev-20200130.pdf.

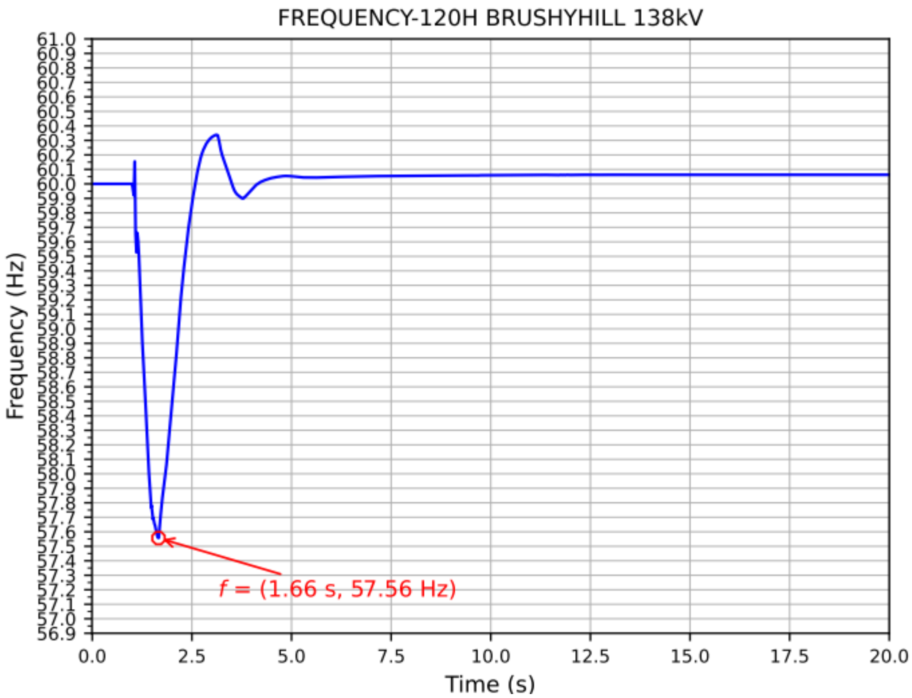

Figure 8: Underfrequency performance (frequency at 120H-Brushy Hill:138kV)

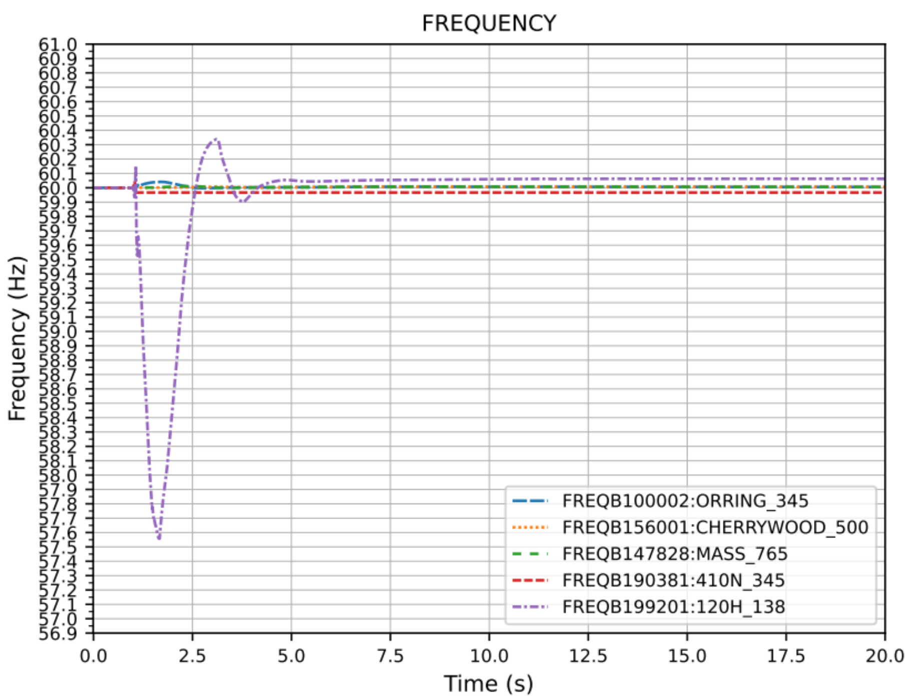

Figure 9: Underfrequency performance (frequency at NS_410N, Mass, Cherrywood, Orrington, and 120H-Brushy Hill)

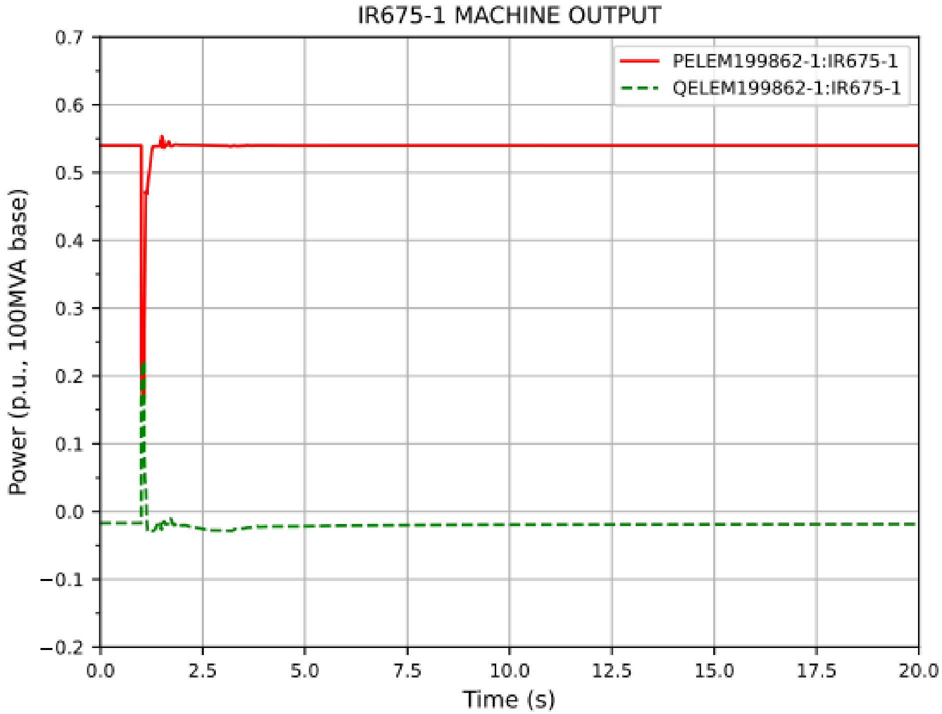

Figure 10: Underfrequency performance (IR675 machine-1 output)

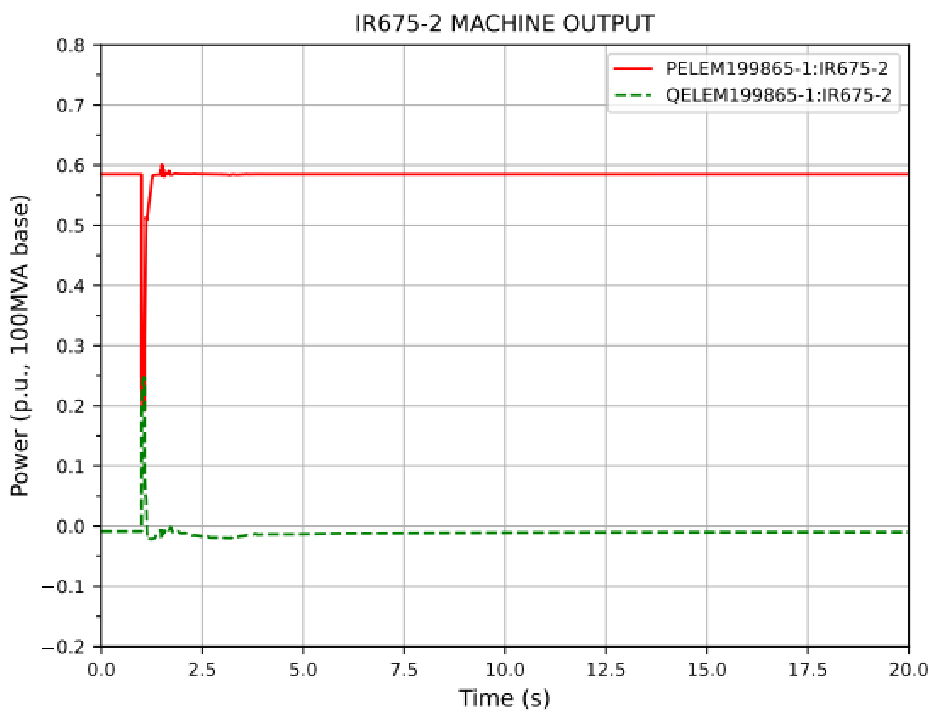

Figure 11: Underfrequency performance (IR675 machine-2 output)

3.8 Voltage ride-through

IR675 low voltage ride through (LVRT) capability was tested under expected system operating conditions in winter peak, summer peak and light load. A 3-phase fault for 9 cycles was applied to 138kV and 34.5kV buses of IR675 ICIF under all stability base cases.

The stability plot in *Figure 12: IR675 LVRT performance (HV fault, 9 cycles)*, *Figure 13: IR675 LVRT performance (MV bus-1 fault, 9* cycles) and *Figure 14: IR675 LVRT performance (MV bus-2 fault, 9 cycles)* demonstrate IR675 rides through the fault and stays online using wp05 case, as required. Results for all studied cases are shown in *Appendix G: Low voltage ride through*. Note values are plotted on 100 MVA system base, so IR675 at 1.125 PU power represents request capped MW output of the generator rather than 112.5% output.

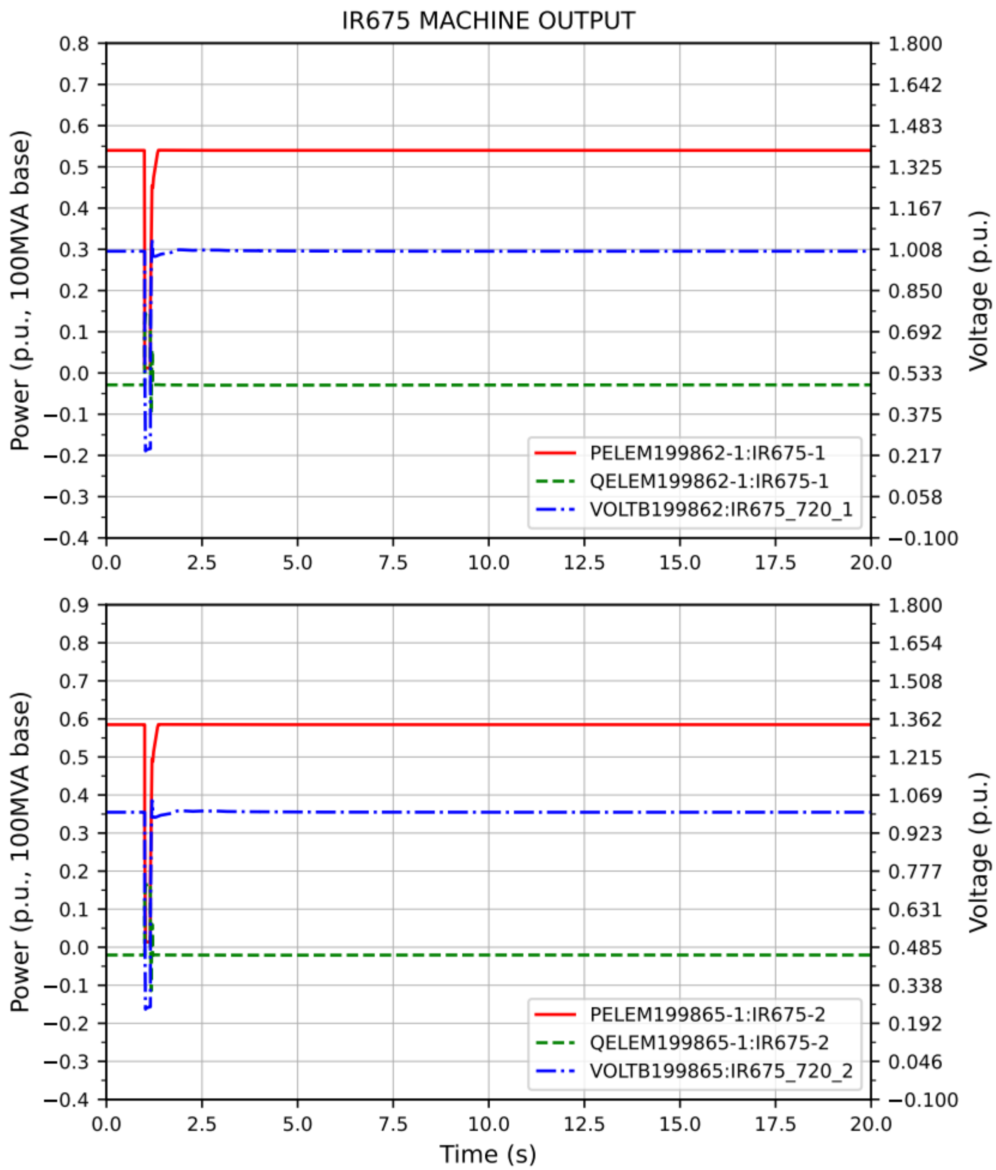

Figure 12: IR675 LVRT performance (HV fault, 9 cycles)

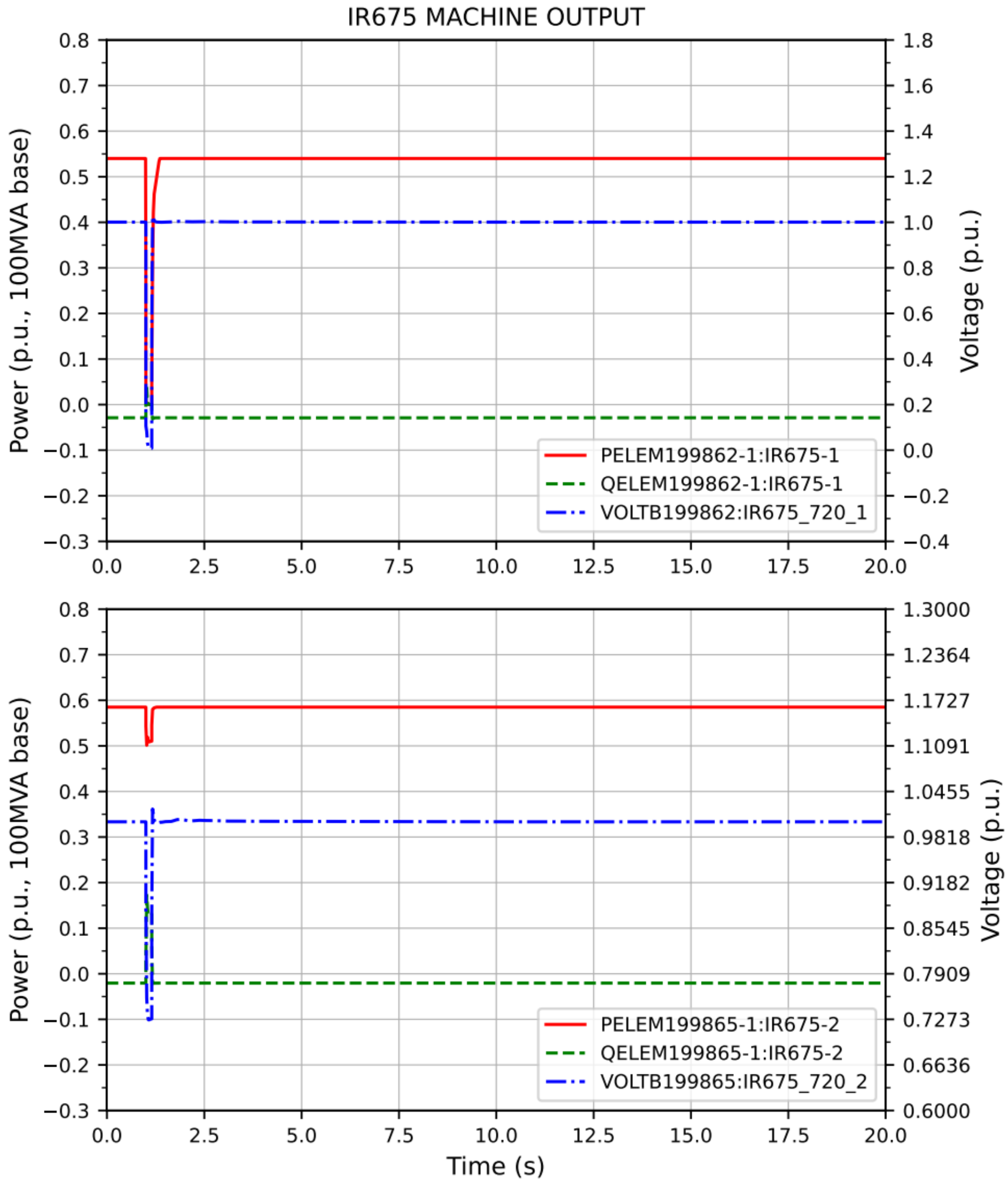

Figure 13: IR675 LVRT performance (MV bus-1 fault, 9 cycles)

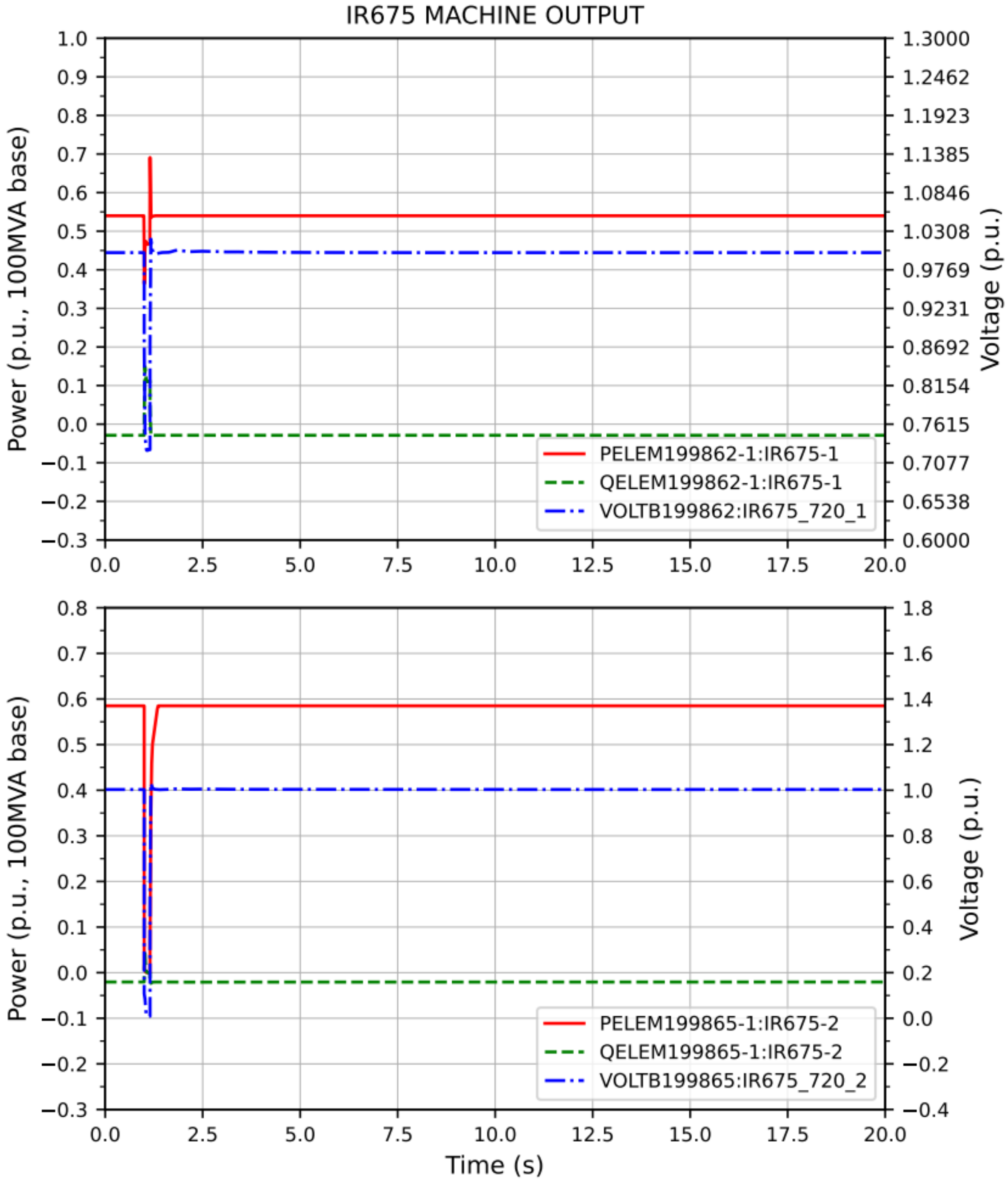

Figure 14: IR675 LVRT performance (MV bus-2 fault, 9 cycles)

3.9 Loss factor

The loss factor for IR675 is calculated as 3.4% at IR675's generator terminal (720V) and 1.1% at its POI (50W-Milton, 138kV bus). This means system losses on peak are marginally increased when IR675 is operating at 112.5 MW.

This preliminary loss factor analysis is calculated on the hour of system peak as a means for comparing multiple projects but is not used for any other purpose.

Table 10: 2026 Loss factor

Loss Factor measured at IR675 Terminal (720 V)	
Description	**MW**
IR675 On	112.50
TC2 and TC3 with IR675 On	119.40
TC2 and TC3 with IR675 Off	228.03
Loss Factor Measured at IR675 Voltage Terminal	3.4%

Loss Factor Measured at POI (50W-Milton, 138kV)	
Description	**MW**
IR675 On	112.50
Power measured at POI with IR675 On	145.32
Power measured at POI with IR675 Off	35.43
TC2 and TC3 with IR675 On	119.40
TC2 and TC3 with IR675 Off	228.03
Loss Factor Measured at POI	1.1%

4.0 Requirements & cost estimate

The following facility changes will be required to connect IR675 as NRIS to NSPI transmission system at the POI:

- Transmission Network Upgrades funded by the Interconnection Customer:
  - Modification of protection system at 50W-Milton due to the addition of IR675.
  - L-6006 re-termination to 99W-B62.
  - Replacement of 9W-T63 with a 60/80/100 MVA, 138kV-69kV transformer.
  - Relocate 9W-T63 to 30W-Souriquois to replace 30W-T2.
  - Re-utilization of Milton/Tusket AAS for 9W-T2.
  - Replacement of switch 9W-563A.
  - Replacement of switches 13V-516A, 13V-516B, 70V-503 and 70V-504.
  - Replacement of metering at 11V-Paradise and 13V-Gulch.

- Transmission Network Upgrades funded by the Transmission Provider:
  - Replacement of Breaker 9W-563.
  - Addition of 8 MVar capacitor Bank at 30W 69kV bus.
  - Expansion of 30W to add 138kV breaker for L-6020.

- Transmission Provider's Interconnection Facilities (TPIF) Upgrades
  - Installation of NSPI P&C Relaying Equipment.
  - Installation of NSPI supplied RTU.
  - Installation of Tele-protection and SCADA communication.

- IC Interconnection Facility
  - Facilities for NSPI to execute high speed rejection of generation (transfer trip) with a circuit breaker at IC substation 138 kV side. The plant may be incorporated into RAS run-back schemes at some point in time in the future.
  - The ability to interface with the NS Power SCADA and communications systems to provide control, communication, metering, and other items to be specified in the forthcoming Interconnection Facilities Study.
  - NSPI to have supervisory and control of this facility, via the centralized controller such as a farm control unit. This will permit the NSPI System Operator to raise/lower the voltage setpoint, change the status of reactive power controls, change the real/reactive power remotely. NSPI will also have remote manual control of the load curtailment scheme.
  - The centralized voltage controller to control the 34.5 kV bus voltage to a settable point and will control the reactive output of each inverter unit of IR675 to achieve this common objective. Responsive *(fast-acting)* controls are required. The setpoint for this controller will be delivered via the NS Power SCADA system. The voltage controller must be tuned for robust control across a broad range of SCR.
  - Facilities to meet ±0.95 power factor requirement when delivering rated output (112.5 MW) at the 138 kV bus. IR675's power factor capability must be re-evaluated to confirm it has the required amount of supplemental reactive support once detailed design information on its transformers and collector circuits are available.
  - Voltage flicker and harmonics characteristics as described in Section 3.3: Voltage flicker.
  - Frequency ride through capability to meet the requirements in Section 2.3.8: Underfrequency operation.
  - When not at full output, the facility shall offer over-frequency and under-frequency control with a deadband of ±0.2 Hz and a droop characteristic of 4%.
  - The ability to control active power in response to control signals from the NS Power System Operator and frequency deviations. This includes automatic curtailment to pre-set limits *(0%, 33%, 66% and no curtailment)*, over/under frequency control, and Automatic Generation Control *(AGC)* system to control tie-line fluctuations as required.
  - Voltage ride through capability to meet the requirements in Section 2.3.9: Low voltage ride through.
  - The facility must use equipment capable of closing a circuit breaker with minimal transient impact on system voltage and frequency *(matching voltage within ±0.05 PU and a phase angle within ±15°)*.
  - To minimize the need to curtail non-dispatchable wind generation at light load, all wind farms must have the functionality to be incorporated into the Export Power Monitor SPS.
  - 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.
  - During the study for this SIS, section 7.6.7 of TSIR, that requires wind turbine generators to provide inertia response of 3.0 MW-s/MVA for a period of at least 10 seconds, was temporarily postponed for review by NSPI. It will be addressed in Part 2 of the System Impact Study.

- o Vesta wind turbine generators to meet TSIR section 7.6.9 requirements that the wind generating facility shall be capable of operating at ambient temperatures as low as -30 ºC.
- o The facility must meet NSPI's TSIR as published on the NSPI OASIS site.

The cost estimate as shown in *Table 11: System upgrades cost estimate* is high level non-binding in 2023 Canadian dollars. It includes 10% contingency but excludes applicable taxes. This cost estimate includes the additions/modifications to the NS Power system only, and the cost of the IC's substation, interconnection facilities and generating facility are not included. It does not include additional costs which may be identified in Part 2 of the System Impact Study. The Interconnection Facilities Study will provide a more detailed cost estimate.

Table 11: System upgrades cost estimate

	Determined Cost Items	Estimate
Transmission Providers Interconnection Facilities		
I	Telecommunications (protection & SCADA)	$150,000
II	Protection and control upgrades	$160,000
Network Upgrades (Interconnection Customer Cost Responsibility) for NRIS		
III	Capital Contribution for 5.2km spur line associated with IR 597 (50% of line cost unless waived by IR 597)	Installed by IR 597
IV	Re-termination of L-6006 to 99W-B62	$100,000
V	Replacement of Transformer 9W-T63 with 60/80/100 MVA unit	$3,000,000
VI	Replacement of Switch 9W-563A	$50,000
VII	Replacement of 30W-T2 with relocated 9W-T63	$500,000
VII	Milton/Tusket AAS Reconfiguration	$100,000
VIII	L-5026 Switch and metering upgrades at 11V, 13V, and 70V	$ 500,000
Network Upgrades (Transmission Providers Cost Responsibility)		
IX	Replacement of Breaker 9W-563	-
X	Addition of 8 MVar capacitor Bank at 30W 69kV bus	-
XI	Expansion of 30W to add 138kV breaker for L-6020.	-

Determined costs	
Subtotal	$4,560,000
Contingency (10%)	$456,000
Total of determined cost items	$5,016,000

5.0 Conclusion & recommendations

5.1 Summary of technical analysis

The System Impact Study (SIS) for IR675 will be conducted in Part 1 and Part 2. Part 1, using Power System Simulator software, will determine the impacts of IR675 on the NSPI power system with respect to steady state, stability, short circuit, power factor, voltage flicker, bulk power system status, under-frequency operation, low voltage ride through and loss factor.

Part 1 system impacts will be assessed based on NSPI system design criteria, Generator Interconnection Procedure (GIP), Transmission System Interconnection Requirements (TSIR), applicable Northeast Power Coordinating Council (NPCC) planning criteria for Bulk Power System (BPS), and applicable North American Electric Reliability Corporation (NERC) planning criteria for Bulk Electricity System (BES).

Part 2 study will use Electro Magnetic Transient software to determine IR675's impacts and control interactions when integrated with NSPI power system. It will progress in parallel with the next phase of the GIP process (facilities study). The outcomes of the Part 2 study will be captured as an addendum to the SIS Part 1 report and may trigger restudy for facilities study work completed at that time.

This report presents the results of Part 1 of the System Impact Study (SIS) for IR 675 - a proposed 112.5 MW wind turbine generating facility interconnected to the NSPI system as Network Resource Interconnection Service (NRIS). The Point of Interconnection (POI) is identified as 138 kV bus B4 at 50W-Milton substation. The proposed Commercial Operation Date is 2024/12/01.

IR 675 consists of twenty-five (25) Wind Energy Converter System (WECS) units using Vestas V150-4.5 MW with 720V terminal voltage, each rated at 4.5 MW totaling 112.5 MW. The voltage is stepped up to 34.5 kV at the collector substations with equivalent generator step-up transformers. IR 675 is then connected to the 138 kV bus at IR597 IC substation through two 34.5kV/138kV station transformers. Both IR675 and IR597 will connect to 138 kV bus B4 at 50W-Milton (POI) via a 5.2 km-long 138kV transmission line. The line termination for L-6024 at 50W-Milton has to be moved to make room for this new 138kV line termination and ROW to the new wind farm connection (IR 597 and IR 675).

The short circuit analysis shows that the maximum short circuit levels are far below 5,000 MVA for 138 kV and 3,500 MVA for 69 kV with IR675 added into the power system at POI. IR675 short circuit contribution does not require any uprating of existing breakers in the transmission system. The minimum short circuit level at the IR675 34.5 kV bus of transformer 1 with all lines in service is 264 MVA, which equates to a minimum short circuit ratio (SCR) of 4.5 with 13 generators connected. Similarly, the SCR at the 34.5kV bus of transformer 2 is 4.9 with 12 generators connected. The minimum short circuit level at the IR675 34.5 kV bus of transformer 1 with L-6025 out of service drops to 253 MVA, which equates to a minimum short circuit ratio (SCR) of 4.3 with 13 generators connected, and 4.7 with 12 generators connected. At the 138kV level, inclusive of IR 597 generation (36MW) and IR 675 generation (112.5MW), with L-6025 out of service, the fault level at the 138kV terminals of the generator transformers is 548 MVA, which translates to a SCR of 3.7 accounting for total area generation of 148.5 MW at these two facilities.

The Vestas V150-4.5 MW models provided by the IC are applicable for a network system having a minimum SCR of 5 at the point of connection, so the IC should discuss with wind turbine manufacture to determine if any modifications for lower SCR conditions are required.

IR675 meets NS Power's leading power factor requirement, but it may not meet lagging power factor requirement therefore supplemental reactive power compensation might be required. This must be re-evaluated once detailed design information on the transformers and collector circuits are available (prior to Commercial Operation) to confirm IR675 has the required amount of supplemental reactive support.

The steady state power flow analysis shows that IR675 addition to the system will require the following customer funded Network Upgrades at POI and beyond to operate at the requested MW capability under NRIS:

- To resolve L-6531 post contingency overloads:
    - 99W-Bridgewater: Move L-6006 termination from Bus B61 to B62.
- To resolve post contingency overloads on transformers 9W-T2, 9W-T63, and 30W-T2:
    - Replace 9W-T63 with a 60/80/100 MVA, 138kV-69kV transformer
    - Replace 15/20/25MVA 30W-T2 with 30/40/50//56 MVA 9W-T63
    - Reconfigure the 9W-T63 Milton/Tusket Automated Action Scheme (AAS) to protect 9W-T2 (L-5027 trip to relieve overload)
- To resolve post contingency overloads on L-6024:
    - The L-6024 rating is limited by its associated breaker and switch ratings at 9W. Replacing breaker 9W-563 and switch 9W-563A with 1200A rated equipment raises the overall line rating to 143 MVA and resolves the overload. Breaker 9W-563 is already scheduled to be replaced and is therefore the cost responsibility of NS Power.
- To resolve overloads on L-5025 and L-5026:
    - The L-5025 and L-5026 ratings are limited by the associated metering ratings at 11V-Paradise and 13V-Gulch, and by the switch ratings at 13V-Gulch and 70V-Bridgetown. Replacing the 48MVA rated switches 13V-516A, 13V-516B, 70V-503 and 70V-504 with 72 MVA rated switches, and replacing the 42 MVA rated metering at 11V and 13V with metering rated for at least 72 MVA will raise the overall summer/winter line ratings to 72 MVA and will resolve the overload.

These upgrades are funded by the customer but are refunded per the terms of the Generator Interconnection Agreement (GIA). The following Network Upgrades are the required to address pre-existing issues and are the cost responsibility of the Transmission Provider:

- To resolve the remaining post contingency issues associated with the failure of Breaker 50W-615:
    - Install an 8 MVar capacitor bank at the 30W 69kV bus
    - Expand the 30W-Souriquois substation to include a 138kV breaker at the L-6020 termination.
    - Replace breaker 9W-563 as scheduled.

No issues were identified in the stability analysis that are attributed to IR675.

The facilities associated with IR675 are not designated as NPCC BPS as IR675 does not affect the BPS status of existing facilities. However, IR675 qualifies as NERC BES as its aggregate rated output is greater than 75 MVA. It shall be designed and operated according to and meeting NERC's BES standards.

The dynamic simulation for NS being suddenly islanded from NB showed NS system frequency swing below under frequency thresholds of NS under frequency load shedding (UFLS) and this program shed 294 MW in NS. IR675 remained on-line and stable helping to stabilize NS frequency during and post contingency.

IR675 low voltage ride through (LVRT) capability was tested to cover expected system operating conditions in winter peak, summer peak and light load. The simulations showed that IR675 remained on-line with temporarily reduced power and ramped back to rated power during contingency and remained stable post contingency.

The loss factor calculation is based on a winter peak case with and without IR675 in service. The calculated loss factor is 3.4% at IR675's generator terminal (720V) and 1.1% at its POI. This means system losses on peak are marginally increased when IR675 is operating at 112.5 MW.

It is concluded that the incorporation of the proposed facility into the NS Power transmission system at the specified location has no negative impacts on the reliability of the NS Power grid, provided the recommendations provided in this report are implemented.

5.2 Summary of expected facilities

To accommodate IR675, the total high level non-binding estimated cost in 2023 Canadian dollars for the Network Upgrades is $4,250,000 and for the new Transmission Provider's Interconnection Facilities (TPIF) is $310,000, for a total of $4,560,000, plus 10% contingency for a total of $5,016,000 excluding HST. The costs of all associated facilities required at the IC's substation and Generating Facility are in addition to this estimate. This cost excludes any additional costs or changes which may be identified by Part 2 of the System Impact Study as well as any cost associated with ICIF generating facility.

The IC will be responsible for acquiring the ROW (Right-Of-Way) for all the facilities.

The preliminary and non-binding estimate for the construction of the customer funded Network Upgrades is 24-36 months, primarily as a result of long lead time items (100 MVA transformer) and the scheduling of line outages. Timelines will be confirmed in the Facility Study. Operation at reduced capacity will be considered prior to the installation of the 100 MVA transformer at 9W and the relocation of 9W-T63 to 30W.