System Impact Study Report
GIP-IR574-SIS-R0

Generator Interconnection Request 574
58.8 MW Wind Generating Facility
Hants County, NS

2021-01-15

Control Centre Operations
Nova Scotia Power Inc.

Executive summary

This System Impact Study (SIS) report presents the results for a 58.8 MW wind turbine generating facility interconnected to the NS Power Transmission System. Network Resource Interconnection Service (NRIS) and Energy Resource Interconnection Service (ERIS) are studied concurrently. The study performed analysis on the impact of the proposed development on the NS Power grid.

System studies, including short circuit, power factor, voltage flicker, steady state, stability, NPCC Bulk Power System (BPS), NERC Bulk Electric System (BES), under-frequency operation, low voltage ridethrough, and loss factor calculation were performed applying NSPI and NPCC planning criteria.

This wind facility will be interconnected to the 138kV line L-6051 at a Point of Interconnection (POI) approximately 2.1km from the 17V-St Croix substation and 25.0km from the 120H-Brushy Hill substation via a tap to the Interconnection Customer's (IC) wind farm substation approximately 75m away from the POI. A circuit switcher at the high side of the IC's power transformer and protection systems acceptable to NS Power are required at the IC's Interconnection Substation.

The voltage flicker P_{st} for continuous operation under this configuration is within NS Power's required limit, based on calculated data since flicker test data for the North American version of the generator was not available for this SIS.

There are no concerns regarding the increased short circuit levels. The increase in short circuit levels due the addition of IR574 are still within the capability of the associated breakers.

IR574 was not found to cause issues with the stability of the interconnected system. IR574 is neither classified as part of the Bulk Power System according to NPCC, nor the Bulk Electric System according to NERC. IR574 was found to comply with Low Voltage Ridethrough requirements and remained online through simulated under frequency islanding events.

Provided the Western Valley Transmission System is operated within historical limits, the addition of IR574 does not adversely impact the thermal capacity of the NS Power Transmission System. 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 total high-level estimate for Interconnection Costs and Network Upgrade Costs is $932,630. The IR574 Interconnection Facilities Study will provide a more detailed cost estimate. The costs of all associated facilities required for the Interconnection Customer’s Interconnection Facilities (ICIF) and Generating Facilities are in addition to this estimate.

There is no difference between the cost for NRIS and ERIS for IR574.

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1.0 Introduction

The Interconnection Customer (IC) submitted an Interconnection Request (IR) for Network Resource Interconnection Service (NRIS) to Nova Scotia Power, Inc. (NSPI) for a proposed 58.8 MW wind generating facility interconnected to the NSPI Transmission System. The IC signed a System Impact Study (SIS) Agreement for a study of the 58.8 MW wind generating facility and this report is the result of that Agreement. This IR has been designated by the NSPI System Operator as Interconnection Request #574 and will be referred to as IR574 throughout this report.

1.1 Scope

The IC indicated that the Point Of Interconnection (POI) for IR574 is L-6051, a 138kV transmission line. Two locations for the Point Of Change of Ownership (PCO) were tentatively identified, however electrically, they are nearly identical, due to their proximity (on either side of L-5060) and distance from the POI (approximately 75m). As a result, this interconnection requires a direct tap with Transfer Trip (TT) protection for the generation.

Figure 1:"IR574 approximate geographic locations illustrates the approximate geographic locations and *Figure 2: Proposed interconnection* illustrates the electrical locations.

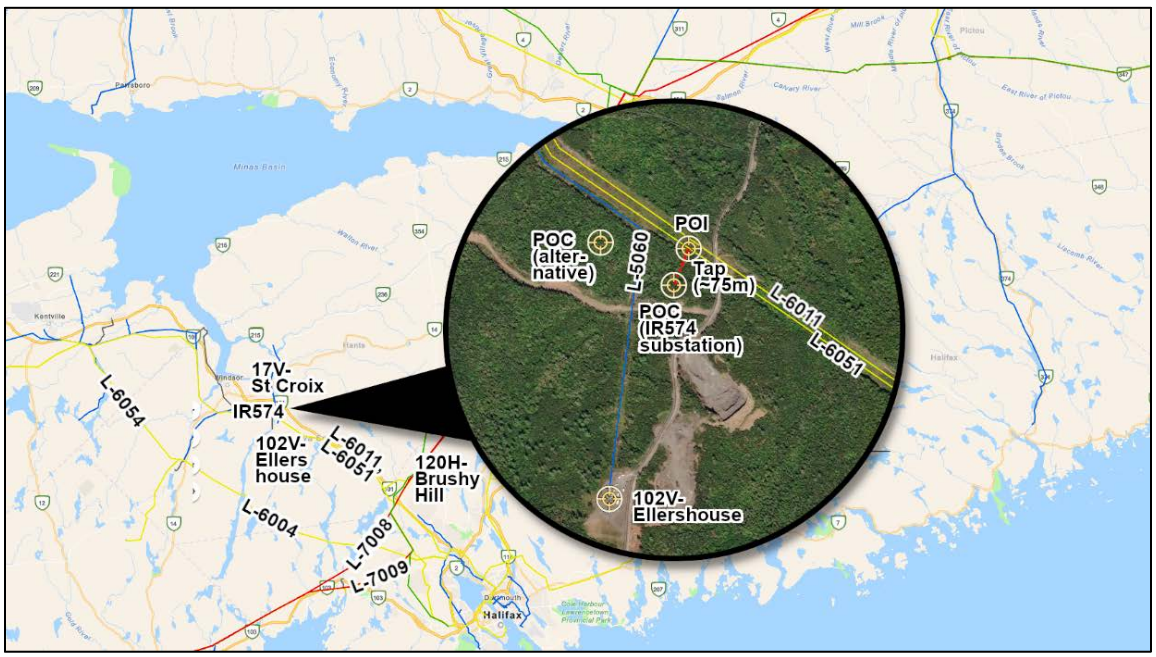


Figure 1: IR574 approximate geographic locations

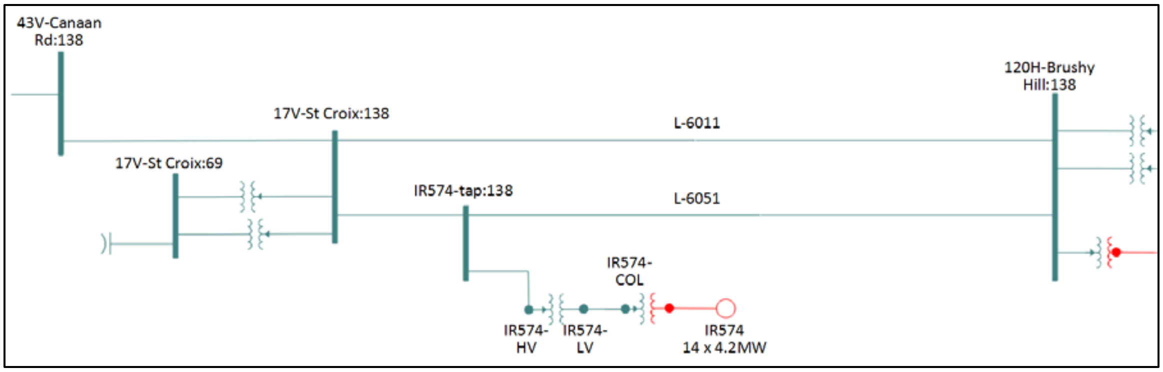


Figure 2: Proposed interconnection

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 IR574 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 ridethrough.
- 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 performed with the following assumptions:

1. Network Resource Interconnection Service (NRIS) with a 2023/06/30 commercial operation date.
2. The proposed generating facility will be equipped with 14 Goldwind GW136 wind turbine generators, each rated at 4.2MW. They were modelled as an equivalent

lumped parameter generator using the data provided by the IC. A summary of this data is included in this report (Appendix A).
3. Data for the generator step-up transformers was provided by the IC in subsequent requests and are modelled with an assumed 6.0% impedance on 4.50MVA with an X/R ratio of 12.14.
4. The ICIF transformer is 138kV (wye) to 34.5kV (wye) 45/60/75 MVA with 7.0% impedance on 45MVA with an X/R ratio of 29.5. It also has a buried delta tertiary with a ±10% off-load tap changer.
5. The POI is L-6051, approximately 2.09km from the 17V-St Croix substation and 25.00km from the 120H-Brushy Hill substation. The ICIF are approximately 75m from the tap. A direct tap with TT protection is required for the generation facility.
6. NS Power's transmission line ratings, as posted on NS Power's Intranet, including any projected line upgrades for the periods under study.
7. It is assumed that IR574 generation meets IEEE Standard 519, limiting total harmonic distortion (all frequencies), to a maximum of 5% with no individual harmonic exceeding 1%.
8. The Maritime Link can be used as an SPS target with Muskrat Falls and the Labrador Island Link in service at full rated capacity.

1.3 Project queue position

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

As of 2020/09/30, the following projects are higher queued in the Advanced Stage Interconnection Request Queue:

- IR #516: GIA executed, 2020/05/31 in-service date.
- IR #540: GIA executed, 2023/10/31 in-service date.
- IR #542: GIA executed, 2021/11/01 in-service date.
- IR #569: GIA executed, 2021/05/31 in-service date.
- IR #568: GIA executed, 2021/06/15 in-service date.
- IR #566: GIA in progress, 2020/11/30 in-service date.

If any higher-queued projects included in this SIS 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 power flow analysis, a windfarm equivalent was created for the 14 machines, their step-up transformers, and collector circuits. This was based on the 690V machine terminal voltage that was stepped up to 34.5kV for transmission along the collector circuits to the IR574 substation. The IR574 substation is modelled where voltage is stepped up to 138kV with a short line, approximately 75m in length, to the POI on L-6051.

The PSS/e model for power flow is shown in Figure 3: PSS/e model. Data for the individual 34.5/0.69 kV transformers is based on 6% impedance on 4.5MVA with a 12.14 X/R ratio. The ICIF transformer is based on 7% impedance on 45 MVA ONAN rating with a 29.5 X/R ratio.

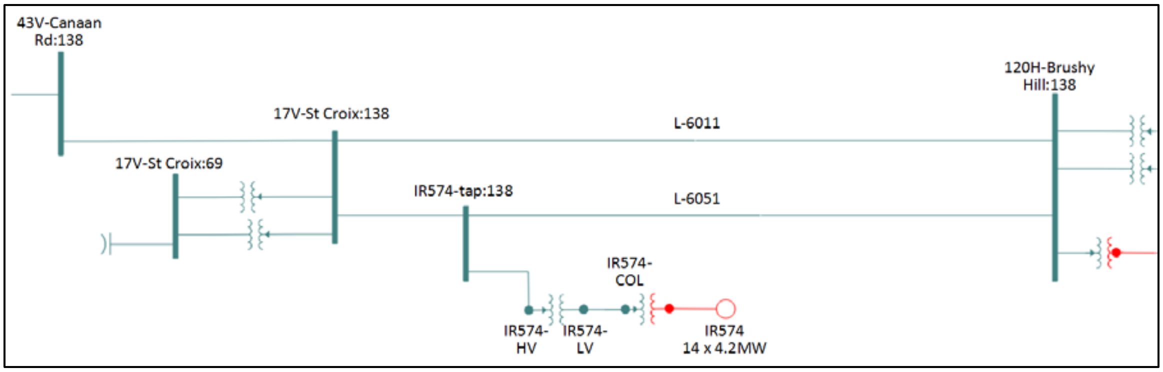


Figure 3: PSS/e model

2.1 System data

The data source used to develop the base cases for this study was the "2020 10-Year System Outlook" report, dated 2020/06/30. The winter peak demand, including Demand Side Management (DSM) effects is shown in Table 1: Load forecast for study period.

The other forecasts are derived from the winter peak load forecast using historic load patterns that resulted in the following scaling factors:

- Summer: 70%
- Light load: 39%

Table 1: Load forecast for study period

Forecast year	Base case	System peak	Non-firm	Firm
2020	Winter peak 2021	2,237	152	2,085
2020	Winter peak 2022	2,212	159	2,053
2020	Winter peak 2023	2,220	161	2,059
2020	Winter peak 2024	2,230	166	2,064
2020	Winter peak 2025	2,236	166	2,070

The primary difference between the forecast years is a slight increase in both forecasted non-firm and firm peak demand (0.1% - 0.4%). DSM, AMI-enabled peak reduction strategies, and efficiency improvements are expected offset the residential and industrial growth for the near future. There is also very little growth (almost 0%) between 2024 and 2025 in both forecast years.

Load conditions for 2022 were used in this study because the lower peak load demand is more critical to the analysis in the region around IR574. Based on its location (West of

Metro), Transmission System impacts are likely to be seen in Spring and Fall conditions, rather than winter.

Base cases for this SIS were selected to stress overall system and local conditions, with most of them at or below 1,500 MW, approximately 70% of winter peak. This is derived from Spring conditions, where Western and Valley hydro resources are dispatched at their highest values.

2.2 Generating facility

IR574 will have 14 Goldwind GW136-4.2 wind turbine generators, each rated at 4.2MW. Each unit will generate at 690V and be transformed to 34.5kV on three collector circuits, which will be further transformed to 138kV to connect to the NS Power Transmission System.

The 138/34.5 kV ICIF (Interconnection Customers Interconnection Facilities) transformer is rated 45/60/75 MVA, Y/Y with Δ tertiary, fixed +/- 10% taps (eight steps assumed), and 7.0% impedance based on 45 MVA. The results of this SIS will be reviewed if a change is made to the rating or impedance of the ICIF transformer.

The proposed generator is classified as Type 4, with fully rated AC-DC-AC inverter. It is assumed to be equipped with a SCADA-based central regulator which controls the individual generator reactive power output to maintain constant voltage at the ICIF substation. The Goldwind GW136-4.2 wind turbines are each capable of a reactive power range of +/-2,034kVAr within 90% to 110% of 690V nominal.

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 34.7, classical fault study, flat voltage profile at 1 PU voltage, and 3LG fault was used to assess before and after short circuit conditions. The 2023 system configuration with IR574 in service and out of service was studied, with comparison between the two.

2.3.2 Power factor

The Standard Generator Interconnection Procedures (GIP) requires a net power factor of ±0.95 measured at the high voltage bus of the ICIF transformer. 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 IR574 to the existing system, short-circuit values are for the existing system - before the addition of IR574.

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

N_{wt} = number of WTGs at IR574.

$N_{10,i}$ 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 provided was provided by the IC for PSS/e steady state and stability analysis in this SIS. The 14 wind turbines and three collector circuits were grouped as a single equivalent generator with an equivalent impedance line.

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 2023 were modelled to develop base cases to best test system reliability in accordance with NS Power and NPCC design criteria:

- Light load; 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 IR574 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 2023 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 before and after the addition of IR574 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, 2020/03/27. 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 enough time to allow remote zone 2 protection at 17V-St Croix and 120H-Brushy Hill (400ms) to trip the lines to the faulted bus, and 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 IR574 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 IR574's generators.

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

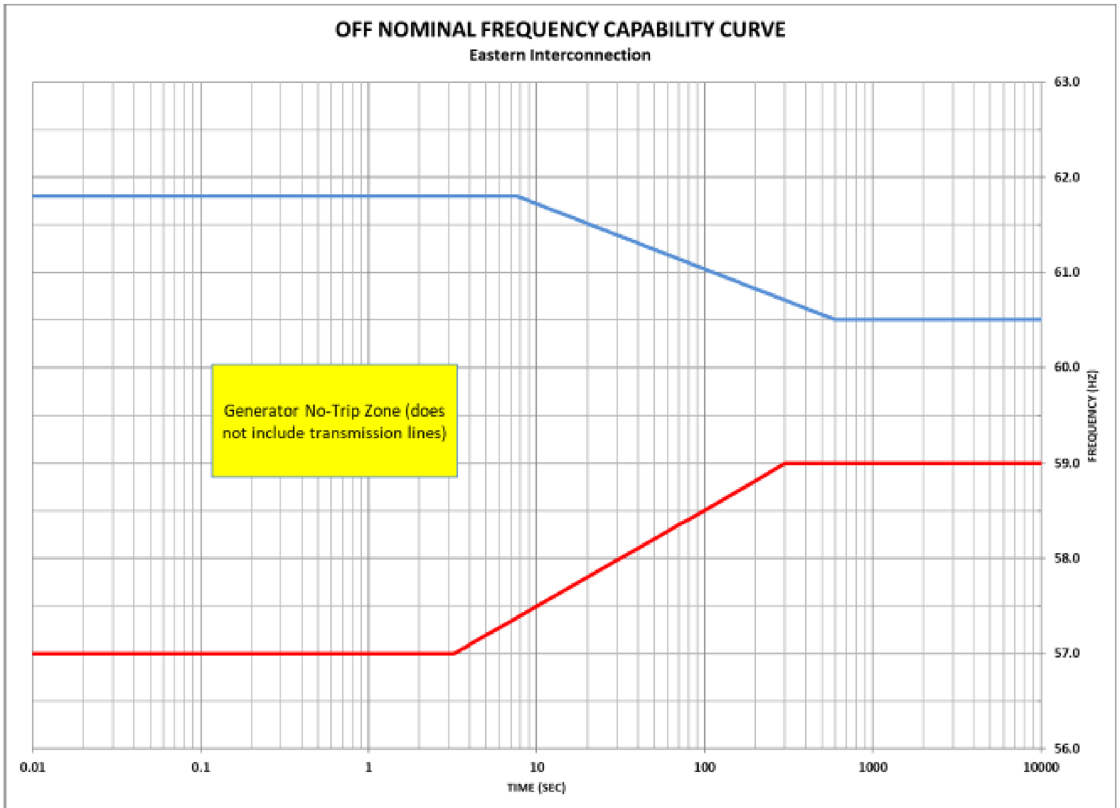
Nova Scotia is connected to the rest of the North American power grid by the following three AC transmission lines:

- 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. IR574 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, IR574 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)

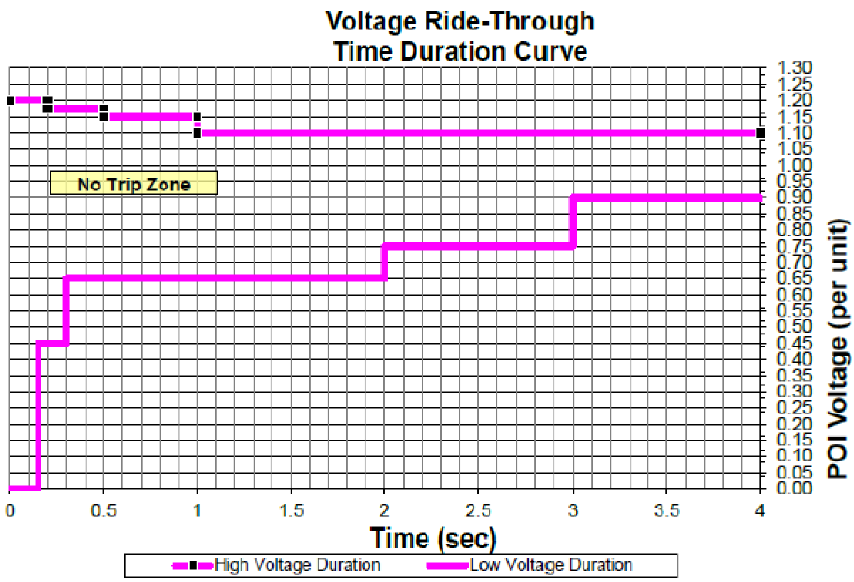
2.3.9 Voltage ridethrough

IR574 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 ridethrough requirements in NERC Standard PRC-024-2, see *Figure 5: PRC-024-2 Attachment 2: Voltage ridethrough requirements.*

This test is performed by applying a 3-phase fault to the HV and LV buses of the ICIF for 9 cycles. IR574 should not trip for faults on the Transmission System or its collector circuits.

FIGURE 2
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 ridethrough 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 IR574, while keeping 91H-Tufts Cove generation as the NS area interchange bus. The loss factor for IR574 is the differential MW displaced or increased at 91H-Tufts Cove generation calculated as a percentage of IR574's nameplate MW rating. Although the IR under study is tested at maximum rated output, all other (existing or committed) 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.

Because of the uncertainty the collector circuit design and transformer equipment specification, loss factors are provided at the high side of the ICIF transformer and the POI (L-6051).

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 34.7, 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 2: Short circuit levels, 3-ph, MVA.*

The machine was modelled as instructed in the IC-supplied model user guide[1] with site-specific data provided by the IC.

IR574 does not cause circuit breaker ratings to be exceeded at either end of L-6051 (17V-St Croix / 120H-Brushy Hill). The NS Power design criteria for maximum system fault capability (3-phase, symmetrical) at the following voltage levels is:

- 5,000MVA at 138kV.
- 3,500MVA at 69kV.

[1] *Wind Turbine PSS/e Dynamic Models User Guide* (Version 4.8.4). Goldwind Science & Technology Co. Ltd.

Table 2: Short circuit levels, 3-ph, MVA

Location	IR574 not in service	IR574 in service	Post % increase
2023, max generation, all transmission facilities in service			
17V-St Croix:138kV	1,915	1,943	1%
17V-St Croix:69kV	894	898	1%
120H-Brushy:138kV	3,706	3,732	1%
IR574 POI, L6051:138kV	1,885	1,916	2%
IR574 IF, 138kV	1,878	1,909	2%
IR574 IF, 34.5kV	479	512	7%
2023, min fault level, all transmission facilities in service			
17V-St Croix:138kV	1,315	1,344	2%
17V-St Croix:69kV	669	676	1%
120H-Brushy:138kV	2,179	2,209	1%
IR574 POI, L6051:138kV	1,308	1,339	2%
IR574 IF, 138kV	1,305	1,336	2%
IR574 IF, 34.5kV	431	464	8%
2023, min fault level, L-6051 open @ 17V-St Croix			
17V-St Croix:138kV	986	991	1%
17V-St Croix:69kV	581	583	0%
120H-Brushy:138kV	2,178	2,208	1%
IR574 POI, L6051:138kV	907	938	3%
IR574 IF, 138kV	906	937	3%
IR574 IF, 34.5kV	376	409	9%
2023, min fault level, L-6051 open @ 120H-Brushy Hill			
17V-St Croix:138kV	986	1,016	3%
17V-St Croix:69kV	581	591	2%
120H-Brushy:138kV	2,178	2,206	1%
IR574 POI, L6051:138kV	936	967	3%
IR574 IF, 138kV	934	965	3%
IR574 IF, 34.5kV	381	414	9%

IR574's minimum fault levels occur in the two following scenarios:

- The line section between the POI and 17V-St Croix is out of service (*the lowest of the two*).
- The line section between the POI and 120H-Brushy Hill is out of service (*slightly higher of the two*).

When the line section between the POI and 17V-St Croix is out of service, the SCR[2] is calculated as 6.39 (376 MVA / 58.8 MW) at IR574's 34.5kV bus. The SCR will be less than 6.39 at the high side of generator step-up transformer due to the collector circuit impedance.

[2] Short Circuit Ratio: a measure of system strength relative to the windfarm size.

Note that the minimum short circuit level on the 34.5kV bus can be greatly impacted by the impedance of the ICIF transformer and collector circuit impedance.

3.2 Power factor

At all production levels up to the full rate load, the facility must be capable of operating between 0.95 PU lagging to 0.95 PU leading net power factor at the POI. The power factor will be measured at the high side of the ICIF transformer for this requirement due to the IC substation's proximity to the POI.

Information provided by the IC, the 138/34.5 kV transformer has an off-load tap changer with ±10% taps; however, each tap step is assumed to be a typical value of 2.5% since the number of steps were not specified. The 34.5/0.6 kV generator step-up transformers were assumed to be supplied without taps since no tap settings were specified.

The Goldwind GW136 turbines (power factor ±0.90) can provide ±2.034 MVAr reactive power when delivering rated power at 4.2 MW. IR574 is composed of 14 wind turbines and the total VAr output from these generators will be ±28.476 MVAr. The reactive power capability within normal voltage operation is shown in *Figure 5: Reactive power capability of the Goldwind GW136 turbine under normal voltage operation*.

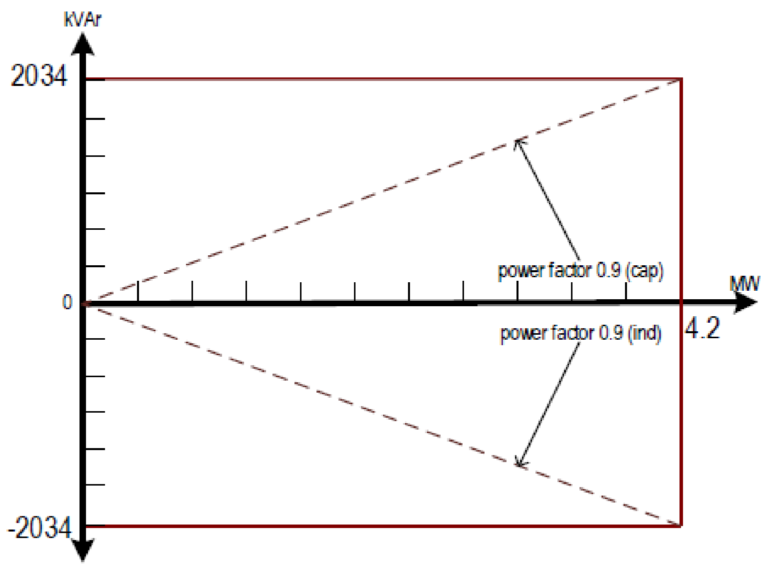


Figure 6: Reactive power capability of the Goldwind GW136 turbine under normal voltage operation[3]

[3] *Goldwind 4.2MW WTGs Grid Connection Performance* (Edition A-V12). No GW-08FW.0562. Goldwind Science & Technology Co. Ltd.

When IR574 generation is at rated 58.8 MW output and producing maximum 28.476 MVAr of reactive power, the real and reactive power delivered to the high side (138kV) of the ICIF transformer is 57.81 MW and 18.42 MVAr, respectively. This equates to a +0.953 power factor, almost meeting the existing +0.950 GIP requirement.

When IR574 generation is at rated 58.8 MW output, while absorbing maximum 28.476 MVAr of reactive power, the real and reactive power at the high side (138kV) of the IF transformer is 57.27 MW and 44.06 MVAr, respectively. This corresponds to a -0.793 power factor, meeting the -0.950 GIP requirement.

The calculated reactive power consumption the IC's components when IR574 is at max MW output while producing or absorbing reactive power is listed in Table 3: MVAr consumption at rated MW output.

Table 3: MVAr consumption at rated MW output

Component	At max MVAr production	At max MVAr absorption
ICIF transformer*	5.42	8.38
Collector circuit equivalent	1.33	2.06
34.5/0.6 kV generator step-up transformer equivalent *(tap setting 1.0)*	3.31	6.13

** Taps set a 1.000 for max MVAr production and 1.025 for max MVAr absorption*

IR574 meets NS Power's lagging power factor requirement but is on the threshold of meeting the leading power factor requirement. This should be re-evaluated to determine the required amount of supplemental reactive support, if any, once detailed design information on the transformers and collector circuits are available.

3.3 Voltage flicker

NS Power's voltage flicker requirements are:

- $P_{st} \leq 0.25$
- $P_{lt} \leq 0.35$

The voltage flicker calculations use IEC Standard 61300-21 based on test data provided by the IC for the Goldwind 4.2 MW machines at 50Hz. A 0.79 flicker coefficient was selected from the test data measured for an 85º system angle and 8.5m/s wind speed. The voltage flicker P_{st} and P_{lt} levels are calculated at the POI for various system conditions listed in Table 4: Calculated voltage flicker.

Table 4: Calculated voltage flicker

System conditions	Continuous (Pst = Plt)
Maximum generation	
All transmission facilities in service	0.007
Minimum generation	
All transmission facilities in service	0.010
L-6051 open @ 17V-St Croix	0.015
L-6051 open @ 120H-Brushy Hill	0.014

IR574 meets NS Power's required short term and long-term voltage flicker requirements based off the supplied calculated data.

The generator is also expected to meet IEEE Standard 519 limiting Total Harmonic Distortion (all frequencies) to a maximum of 5%, with no individual harmonic exceeding 1%. It is the generating facility's responsibility to ensure that this requirement is met as this SIS cannot make this assessment.

3.4 Steady state analysis

3.4.1 Base cases

The bases cases used for power flow analysis are listed in *Table 5: Power flow base cases*. One-line diagrams of each base case, in sets of three, are presented in *Appendix B: Base case one-line diagrams*.

Table 5: Power flow base cases

Case name	NS load	IR574	Wind	W hydro	NS/NB	ML	CBX	ONI
WP01-1	2,202	-	430	91	150	-320	796	998
WP01-2	2,202	59	489	91	150	-320	796	998
FL01-1	1,500	-	430	63	-300	-170	249	315
FL01-2	1,500	59	489	63	-300	-170	249	315
FL02-1	1,500	-	397	13	350	-466	1,012	1,052
FL02-2	1,500	59	456	13	350	-466	1,012	1,052
LL01-1	860	-	430	6	225	-330	179	308
LL01-2	860	59	489	6	225	-330	179	308
SP01-1	1,350	-	430	148	350	-466	675	761
SP01-2	1,350	59	489	148	350	-466	675	761

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 represents peak load, with high East-West transfers. Generation dispatched is assumed to be typical for peak load, with high load in the Valley area.
- FL01-x represents the NS/NB import limit, presently 27% of net in-province load, to a maximum 300 MW. This case has four large thermal units online, running at minimum load (plus two small biomass units). It represents probable minimum inertia on the NS system and 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 represents off-peak load and maximum generation in the Valley area. This represents typical spring hydro run-off conditions. Local generation is managed to ensure transmission limits are maintained. In these cases, it is assumed local hydro generation is backed off when the 81V-Annapolis Royal Tidal Plant is online (diurnal tidal cycle). *Section 3.5.3: Sensitivity analysis* has additional discussion about the tidal plant's usage due to its recent outage.
- Cases FL02-x, LL01-x, and SP01-x represent high enough export levels from NS to NB to require arming of the Export Power Monitor SPS. LL01-x requires Group 5 arming, while FL02-x and SP01-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.

3.4.2 Steady state contingencies

The steady state power flow analysis includes the contingencies listed in *Table 6: Steady state contingencies*.

Table 6: Steady state contingencies

ID	Element	Type	Location	ID	Element	Type	Location
p001	2C-B61	Bus fault	2C-Hastings	p121	L8003	Line fault	79N-Hopewell
p002	2C-B62	Bus fault	2C-Hastings	p122	L8004	Line fault	79N-Hopewell
p003	3C-712	Breaker fail	3C-Hastings	p123	101S-701	Breaker fail	101S-Woodbine
p004	3C-715	Breaker fail	3C-Hastings	p124	101S-702	Breaker fail	101S-Woodbine
p005	L6515	Line fault	2C-Hastings	p125	101S-703	Breaker fail	101S-Woodbine
p006	L6516	Line fault	2C-Hastings	p126	101S-704	Breaker fail	101S-Woodbine
p007	L6517	Line fault	2C-Hastings	p127	101S-705	Breaker fail	101S-Woodbine
p008	L6518	Line fault	2C-Hastings	p128	101S-706	Breaker fail	101S-Woodbine
p009	L6537	Line fault	2C-Hastings	p129	101S-711	Breaker fail	101S-Woodbine
p010	L6543	Line fault	2C-Hastings	p130	101S-712	Breaker fail	101S-Woodbine
p011	L7004	Line fault	3C-Hastings	p131	101S-713	Breaker fail	101S-Woodbine
p012	103H-B61	Bus fault	103H-Lakeside	p132	101S-811	Breaker fail	101S-Woodbine
p013	103H-B62	Bus fault	103H-Lakeside	p133	101S-812	Breaker fail	101S-Woodbine
p014	103H-T63	Transformer fault	103H-Lakeside	p134	101S-813	Breaker fail	101S-Woodbine
p015	104H-600	Breaker fail	104H-Kempt Rd	p135	101S-814	Breaker fail	101S-Woodbine
p016	113H-601	Breaker fail	113H-Dartmouth East	p136	101S-816	Breaker fail	101S-Woodbine
p017	120H-621	Breaker fail	120H-Brushy	p137	88S-710	Breaker fail	88S-Lingan
p018	120H-622	Breaker fail	120H-Brushy	p138	88S-712	Breaker fail	88S-Lingan
p019	120H-623	Breaker fail	120H-Brushy	p139	88S-713	Breaker fail	88S-Lingan
p020	120H-624	Breaker fail	120H-Brushy	p140	88S-720	Breaker fail	88S-Lingan
p021	120H-625	Breaker fail	120H-Brushy	p141	88S-721	Breaker fail	88S-Lingan
p022	120H-626	Breaker fail	120H-Brushy	p142	88S-722	Breaker fail	88S-Lingan
p023	120H-627	Breaker fail	120H-Brushy	p143	88S-723	Breaker fail	88S-Lingan
p024	120H-628	Breaker fail	120H-Brushy	p144	L7011	Line fault	101S-Woodbine
p025	120H-629	Breaker fail	120H-Brushy	p145	L7014	Line fault	88S-Lingan
p026	120H-710	Breaker fail	120H-Brushy	p146	L7015	Line fault	101S-Woodbine

ID	Element	Type	Location	ID	Element	Type	Location
p027	120H-711	Breaker fail	120H-Brushy	p147	L7021	Line fault	88S-Lingan
p028	120H-712	Breaker fail	120H-Brushy	p148	L7022	Line fault	88S-Lingan
p029	120H-713	Breaker fail	120H-Brushy	p149	L8004	Line fault	101S-Woodbine
p030	120H-714	Breaker fail	120H-Brushy	p150	L6011 + L6010	Double ckt tower	Sackville
p031	120H-715	Breaker fail	120H-Brushy	p151	L6507 + L6508	Double ckt tower	Trenton
p032	120H-716	Breaker fail	120H-Brushy	p152	L6534 + L7021	Double ckt tower	Lingan / VJ
p033	120H-720	Breaker fail	120H-Brushy	p153	L7003 + L7004	Double ckt tower	Canso Causeway
p034	132H-602	Breaker fail	132H-Spider Lake	p154	L7008 + L7009	Double ckt tower	Bridgewater
p035	132H-603	Breaker fail	132H-Spider Lake	p155	L7009 + L8002	Double ckt tower	Sackville
p036	132H-605	Breaker fail	132H-Spider Lake	p156	101V-601	Breaker fail	101V-MacDonald Pond
p037	132H-606	Breaker fail	132H-Spider Lake	p157	13V-B51	Bus fault	13V-Gulch
p038	1H-603	Breaker fail	1H-Water St	p158	15V-B51	Bus fault	15V-Sissiboo
p039	90H-601	Breaker fail	90H-Sackville	p159	17V-B1	Bus fault	17V-St Croix
p040	90H-602	Breaker fail	90H-Sackville	p160	17V-B2	Bus fault	17V-St Croix
p041	90H-603	Breaker fail	90H-Sackville	p161	1V-442	Breaker fail	1V-Avon 1
p042	90H-605	Breaker fail	90H-Sackville	p162	20V-B51	Bus fault	20V-Five Points
p043	90H-606	Breaker fail	90H-Sackville	p163	3V-551	Breaker fail	3V-Hell's Gate
p044	90H-608	Breaker fail	90H-Sackville	p164	43V-B51	Bus fault	43V-Canaan Rd
p045	90H-609	Breaker fail	90H-Sackville	p165	43V-B61	Bus fault	43V-Canaan Rd
p046	90H-611	Breaker fail	90H-Sackville	p166	43V-B62	Bus fault	43V-Canaan Rd
p047	90H-612	Breaker fail	90H-Sackville	p167	43V-T61	Transformer fault	43V-Canaan Rd
p048	90H-613	Breaker fail	91H-Tufts Cove	p168	43V-T62	Transformer fault	43V-Canaan Rd
p049	90H-621	Breaker fail	91H-Tufts Cove	p169	51V-601	Breaker fail	51V-Tremont
p050	91H-603	Breaker fail	91H-Tufts Cove	p170	51V-B51	Bus fault	51V-Tremont
p051	91H-604	Breaker fail	91H-Tufts Cove	p171	51V-T61	Transformer fault	51V-Tremont
p052	91H-605	Breaker fail	91H-Tufts Cove	p172	51V-T62	Transformer fault	51V-Tremont
p053	91H-606	Breaker fail	91H-Tufts Cove	p173	6V-GT1	Transformer fault	6V-Hollow Bridge
p054	91H-607	Breaker fail	91H-Tufts Cove	p174	82V-600	Breaker fail	82V-Elmsdale
p055	91H-608	Breaker fail	91H-Tufts Cove	p175	92V-B51	Bus fault	92V-Michelin Waterville
p056	91H-609	Breaker fail	91H-Tufts Cove	p176	L4045	Line fault	17V-St Croix
p057	91H-611	Breaker fail	91H-Tufts Cove	p177	L4046	Line fault	17V-St Croix
p058	L0644	Line fault	132H-Spider Lake	p178	L4047	Line fault	17V-St Croix
p059	L6002E	Line fault	90H-Sackville	p179	L4048W	Line fault	39V-Fundy Gypsum
p060	L6003	Line fault	90H-Sackville	p180	L4049	Line fault	3V-Hell's Gate
p061	L6004	Line fault	90H-Sackville	p181	L5014	Line fault	17V-St Croix
p062	L6005	Line fault	120H-Brushy	p182	L5015	Line fault	17V-St Croix
p063	L6007	Line fault	91H-Tufts Cove	p183	L5016	Line fault	17V-St Croix
p064	L6008	Line fault	103H-Lakeside	p184	L5021	Line fault	43V-Canaan Rd
p065	L6009	Line fault	90H-Sackville	p185	L5022	Line fault	43V-Canaan Rd
p066	L6010	Line fault	120H-Brushy	p186	L5025	Line fault	11V-Paradise
p067	L6011	Line fault	120H-Brushy	p187	L5026	Line fault	11V-Paradise
p068	L6014	Line fault	91H-Tufts Cove	p188	L5033	Line fault	43V-Canaan Rd
p069	L6016	Line fault	120H-Brushy	p189	L5035	Line fault	3V-Hell's Gate
p070	L6033	Line fault	103H-Lakeside	p190	L5050	Line fault	15V-Sissiboo

ID	Element	Type	Location	ID	Element	Type	Location
p071	L6035	Line fault	1H-Water St	p191	L5053	Line fault	92V-Michelin Waterville
p072	L6038	Line fault	103H-Lakeside	p192	L5060	Line fault	17V-St Croix
p073	L6040	Line fault	91H-Tufts Cove	p193	L5531	Line fault	13V-Gulch
p074	L6042	Line fault	91H-Tufts Cove	p194	L5532	Line fault	13V-Gulch
p075	L6043	Line fault	113H-Dartmouth East	p195	L5533	Line fault	13V-Gulch
p076	L6044	Line fault	113H-Dartmouth East	p196	L5535	Line fault	15V-Sissiboo
p077	L6051	Line fault	120H-Brushy	p197	L5538	Line fault	15V-Sissiboo
p078	L6055	Line fault	132H-Spider Lake	p198	L6001N	Line fault	82V-Elmsdale
p079	L7018	Line fault	120H-Brushy	p199	L6001S	Line fault	82V-Elmsdale
p080	T1	Transformer fault	90H-Sackville	p200	L6012	Line fault	43V-Canaan Rd
p081	1N-B61	Bus fault	1N-Onslow	p201	L6013	Line fault	43V-Canaan Rd
p082	1N-B62	Bus fault	1N-Onslow	p202	L6015	Line fault	43V-Canaan Rd
p083	50N-604	Breaker fail	50N-Trenton	p203	L6051	Line fault	17V-St Croix
p084	67N-701	Breaker fail	67N-Onslow	p204	L6051E	Line fault	IR574-POI
p085	67N-702	Breaker fail	67N-Onslow	p205	L6051W	Line fault	IR574-POI
p086	67N-703	Breaker fail	67N-Onslow	p206	L6052	Line fault	43V-Canaan Rd
p087	67N-704	Breaker fail	67N-Onslow	p207	L6054	Line fault	43V-Canaan Rd
p088	67N-705	Breaker fail	67N-Onslow	p208	POI_tap	Line fault	IR574-POI
p089	67N-706	Breaker fail	67N-Onslow	p209	30W-B51	Bus fault	30W-Souriquois
p090	67N-710	Breaker fail	67N-Onslow	p210	30W-B61	Bus fault	30W-Souriquois
p091	67N-711	Breaker fail	67N-Onslow	p211	3W-B53	Bus fault	3W-Big Falls
p092	67N-712	Breaker fail	67N-Onslow	p212	50W-B2	Bus fault	50W-Milton
p093	67N-713	Breaker fail	67N-Onslow	p213	50W-B3	Bus fault	50W-Milton
p094	67N-811	Breaker fail	67N-Onslow	p214	50W-B4	Bus fault	50W-Milton
p095	67N-812	Breaker fail	67N-Onslow	p215	50W-T53	Transformer fault	50W-Milton
p096	67N-813	Breaker fail	67N-Onslow	p216	99W-B51	Bus fault	99W-Bridgewater
p097	67N-814	Breaker fail	67N-Onslow	p217	99W-B61	Bus fault	99W-Bridgewater
p098	74N-600	Breaker fail	74N-Springhill	p218	99W-B62	Bus fault	99W-Bridgewater
p099	79N-B61	Bus fault	79N-Hopewell	p219	99W-B71	Bus fault	99W-Bridgewater
p100	79N-B81	Bus fault	79N-Hopewell	p220	99W-B72	Bus fault	99W-Bridgewater
p101	L5029	Line fault	74N-Springhill	p221	99W-T61	Transformer fault	99W-Bridgewater
p102	L5058	Line fault	74N-Springhill	p222	99W-T62	Transformer fault	99W-Bridgewater
p103	L6001	Line fault	1N-Onslow	p223	99W-T71	Transformer fault	99W-Bridgewater
p104	L6057	Line fault	50N-Trenton	p224	99W-T72	Transformer fault	99W-Bridgewater
p105	L6503	Line fault	50N-Trenton	p225	9W-B52	Bus fault	9W-Tusket
p106	L6507	Line fault	79N-Hopewell	p226	9W-B53	Bus fault	9W-Tusket
p107	L6508	Line fault	50N-Trenton	p227	L5530	Line fault	50W-Milton
p108	L6511	Line fault	50N-Trenton	p228	L5540	Line fault	50W-Milton
p109	L6514	Line fault	74N-Springhill	p229	L5541	Line fault	3W-Big Falls
p110	L6527	Line fault	1N-Onslow	p230	L5545	Line fault	99W-Bridgewater
p111	L6536	Line fault	74N-Springhill	p231	L5546	Line fault	99W-Bridgewater
p112	L6613	Line fault	74N-Springhill	p232	L6006	Line fault	99W-Bridgewater
p113	L7001	Line fault	67N-Onslow	p233	L6020	Line fault	50W-Milton
p114	L7002	Line fault	67N-Onslow	p234	L6024	Line fault	50W-Milton
p115	L7003	Line fault	67N-Onslow	p235	L6025	Line fault	99W-Bridgewater
p116	L7005	Line fault	67N-Onslow	p236	L6048	Line fault	50W-Milton
p117	L7019	Line fault	67N-Onslow	p237	L6531	Line fault	99W-Bridgewater
p118	L8001	Line fault	67N-Onslow	p238	L7008	Line fault	99W-Bridgewater
p119	L8002	Line fault	67N-Onslow	p239	L7009	Line fault	99W-Bridgewater

ID	Element	Type	Location	ID	Element	Type	Location
p120	L8003	Line fault	67N-Onslow				

3.4.3 Steady state evaluation

The steady state contingencies evaluated in this study demonstrate IR574 does not require Network Upgrades beyond the POI to operate at full load under NRIS. Therefore, there is no difference between ERIS and NRIS.

Integrating new generation facilities in the Valley area presents potential overloading on local 69kV transmission lines, even under normal system conditions *(no contingencies)* during light load coincident with high local generation. Under this condition, the 69kV transmission lines in the Western Valley region can become heavily loaded as flows head towards Metro area.

IR574 has little impact on constrained transmission in the Western Valley region due to its location on the far Eastern end of the Valley region. This is also demonstrated with 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 IR574.

Notable differences on the lines between 90H-Sackville, 120H-Brushy Hill, 17V-St Croix, and 43V-Canaan Rd are expected as these substations are endpoints around the corridor IR574 is placed in. Flows on the Western transmission corridor from Metro change no more than 0.3 MW as IR574 comes online and goes to full load. The circuits likely to limit Western Valley generation (L5532 and L5535) change no more than 0.3 MW.

Results of the steady state analysis are presented in *Appendix D: Steady-state analysis results*. Notes are provided to explain observed issues, which are also summarized below, in *Table 7: Steady state issues*. Observed in the SP01-x base cases, these contingencies occur in the Western Valley region. Corridors in this region are already heavily loaded, pre-contingency, as power is exported under low load and high local generation; These are existing issues, unrelated to IR574, and are being addressed separately.

Table 7: Steady state issues

ID	Contingency	Post-contingency overload	Overload magnitude
p185	DCT, L7008 + L7009	L5026 (81V-Annapolis/11V-Paradise)	122%.
p219	L5025	L5541 (50W-Milton/4W-Lower Great Brook), L5535 (9W-Tusket/15V-Sissiboo)	121%, 118%
p223	L5535	L5541 (50W-Milton/4W-Lower Great Brook)	115%
p246	50W-B2	L5535 (9W-Tusket/15V-Sissiboo)	122%
p260	9W-B53	L5541 (50W-Milton/4W-Lower Great Brook)	114%
p263	L5541	L5535 (9W-Tusket/15V-Sissiboo)	125%

3.5 Stability analysis

System design criteria requires the system to be stable and well damped in all modes of oscillations. The peak values of any mode of oscillation must decay to a value that is 60% less than the original amplitude over any 10 second period.

3.5.1 Stability base cases

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

Table 8: Stability base cases

Case name	NS load	IR574	Wind	W hydro	NS/NB	ML	CBX	ONI
WP01-1	2,202	-	430	91	150	-320	796	998
WP01-2	2,202	59	489	91	150	-320	796	998
FL01-1	1,500	-	430	63	-300	-170	249	315
FL01-2	1,500	59	489	63	-300	-170	249	315
FL02-1	1,500	-	397	13	350	-466	1,012	1,052
FL02-2	1,500	59	456	13	350	-466	1,012	1,052
LL01-1	860	-	430	6	225	-330	179	308
LL01-2	860	59	489	6	225	-330	179	308
SP01-1	1,350	-	430	148	350	-466	675	761
SP01-2	1,350	59	489	148	350	-466	675	761

3.5.2 Stability contingencies

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

Table 9: Stability contingency list

ID	Contingency	Fault	Trips	Note
d001	50W, L6021	3ph line fault @ 50W	50W/9W	Open-ended
d002	9W, L6021	3ph line fault @ 9W	50W/9W	
d003	11V, 11V-B51, SPS	3ph bus fault @ 11V	L5025:11V/10V/51V L5026:11V/70V/13V 11V-G1	98V AAS
d004	13V, 13V-B51	3ph bus fault @ 13V	L5531:13V/15V L5533:13V/77V L5532:13V/14V/3W L5026:13V/74V/11V 13V-G1	
d005	15V, 15V-B51	3ph bus fault @ 15V	L5538:15V/16V L5531:15V/13V L5050:15V/91V L5535:15V/34W/9W 15V-G1/2	

ID	Contingency	Fault	Trips	Note
d006	50W, 50W-B2	3ph bus fault @ 50W	L5549:50W/48W L5530:50W/46W/30W L5540A:50W/6W L5540B:50W/5W L5541:50W/4W/3W 50W-T1	
d007	50W, 50W-B4	3ph bus fault @ 50W	L6024:50W/9W L6006:50W/99W L6048:50W/104W/101W L6025:50W/99W	
d008	51V, 51V-B51, SPS	3ph bus fault @ 51V	L5025:51V/10V/11V 51V-T61 51V-T51	98V AAS
d009	79N, 79N-T81, SPS	Transformer fault @ 79N	L8003:79N/67N L8004:79N/101S L6508:79N/50N L6507:79N/50N	G5/G6 SPS
d010	9W, 9W-B53	3ph bus fault @ 9W	L6024:9W/50W L5534:9W/16W L5535:9W/92W 9W-T63	
d011	410N, L3006, SPS	3ph line fault @ 410N	410N/4592-Salisbury	Export SPS: G5/G6 Import SPS
d012	11V, L5025, SPS	3ph line fault @ 11V	11V/10V/51V	98V AAS
d013	51V, L5025, SPS	3ph line fault @ 51V	51V/10V/11V	98V AAS
d014	11V, L5026, SPS	3ph line fault @ 11V	11V/70V/13V	98V AAS
d015	13V, L5026, SPS	3ph line fault @ 13V	13V/70V/11V	98V AAS
d016	13V, L5531	3ph line fault @ 13V	13V/15V	
d017	13V, L5532	3ph line fault @ 13V	13V/14V/3W	
d018	15V, L5535	3ph line fault @ 15V	15V/34W/92W/9W	
d019	9W, L5535	3ph line fault @ 9W	9W/92W/34W/15V	
d020	43V, L6054	3ph line fault @ 43V	43V/101V	
d021	90H, L6004	3ph line fault @ 90H	90H/101V	
d022	43V, L6012	3ph line fault @ 43V	43V/17V	
d023	43V, L6015	3ph line fault @ 43V	43V/51V	
d024	9W, L6024	3ph line fault @ 9W	9W/50W	
d025	74N, L6613	3ph line fault @ 74N	74N/81N/1N	
d026	30N, L6514	3ph line fault @ 30N	30N/74N	
d027	92N, L6535	3ph line fault @ 92N	92N/410N	
d028	74N, L6536	3ph line fault @ 74N	74N/22N/410N	
d029	92N, L6551	3ph line fault @ 92N	92N/30N	
d030	3C, L7005	3ph line fault @ 3C	3C/67N	
d031	67N, L7005	3ph line fault @ 67N	67N/3C	
d032	120H, L7008	3ph line fault @ 120H	120H/99W	
d033	67N, L8001, SPS	3ph line fault @ 67N	67N/410N	Export SPS: G5/G6 Import SPS
d034	103H, L8002	3ph line fault @ 103H	103H/67N	
d035	67N, L8002	3ph line fault @ 67N	67N/103H	
d036	67N, L8003, SPS	3ph line fault @ 67N	67N/79N	G5/G6 SPS

ID	Contingency	Fault	Trips	Note
d037	79N, L8003, SPS	3ph line fault @ 79N	79N/67N	G5/G6 SPS
d038	101S, L8004, SPS	3ph line fault @ 101S	101S/79N	G5/G6 SPS
d039	79N, L8004, SPS	3ph line fault @ 79N	79N/101S	G5/G6 SPS
d040	88S, 88S-721	3ph breaker fail @ 88S	LG3 LG4	
d041	1N, 1N-613	3ph breaker fail @ 1N	L6613:1N/81N/74N L6503:1N/49N/51N 1N-T65	
d042	120H, 120H-715	3ph breaker fail @ 120H	L7001:120H/67N L7008:120H/99W	
d043	67N, 67N-712	3ph breaker fail @ 67N	L7018:67N/120H L7005:67N/3C	
d044	67N, 67N-814, SPS	3ph breaker fail @ 67N	L8001:67N/410N 67N-T81	Export SPS: G5/G6 Import SPS
d045	67N, 67N-813	3ph breaker fail @ 67N	L8002:67N/103H 67N-T81	
d046	67N, 67N-811, SPS	3ph breaker fail @ 67N	L8003:67N/79N 67N-T82	G5/G6 SPS
d047	103H, 103H-881	3ph breaker fail @ 103H	L8002:103H/67N 103H-T81	
d048	103H, 103H-600	3ph breaker fail @ 103H	L6008:103H/90H L6016:103H/137H/120H L6038:103H/129H L5039:103H/34H/20H	
d049	1N, 1N-600	3ph breaker fail @ 1N	L6527:1N/67N L6613:1N/81N/74N L6503:1N/49N/51N/50N L6001:1N/82V/132H 1N-T65 1N-T1 1N-T4	Isolates 1N-Onslow
d050	DCT, L7003+7004	DCT near 50N	3C/67N 3C/91N	
d051	DCT, L7005+8004, SPS	DCT @ Canso Crossing	3C/67N 79N/101S	G5/G6 SPS
d052	DCT, L7009+8002	DCT near 120H	120H/99W 67N/103H	
d053	17V, 17V-613	3ph breaker fail @ 17V	L6012:17V/43V L6051:17V/POI/120H 17V-T2	
d054	17V, 17V-B63	3ph bus fault @ 17V	L6011:17V/120H 17V-T63	
d055	20V, L5016	3ph line fault @ 20V	20V/79V/17V	
d056	17V, L5016	3ph line fault @ 17V	17V/79V/20V	
d057	POI, L6051	3ph line fault @ POI	17V/POI/120H	
d058	43V, 43V-B61	3ph bus fault @ 43V	L6012:43V/17V L6013:43V/51V 43V-T61	

ID	Contingency	Fault	Trips	Note
d059	43V, 43V-B62	3ph bus fault @ 43V	L6015:43V/51V L6051:43V/99V L6054:43V/101V 43V-T62	
d060	101S, 101S-812, SPS	3ph breaker fail @ 101S	L8004:101S/79N MLP2	G5/G6 SPS
d061	30W, L6021	3ph line fault @ 30W	50W/30W/9W	

3.5.3 Sensitivity analysis

This section compares system response with the 81V-Annapolis Tidal Plant at full output vs situations where its output is displaced by generation at 12V-Lequille and 13V-Gulch.

Base cases SP01-x demonstrated high hydro generation in the Western Valley area for a system load level representing spring run-off hydro conditions at a system load level 70% of winter peak. Historically, the 81V-Annapolis Tidal Plant has been observed to come up at full load (twice per day), during which hydro generation in the area is reduced within local transmission limits while accounting for expected wind generation in the area.

At the time of this study, the 81V-Annapolis Royal Tidal Plant has been offline since early 2019 due to plant issues. While it has not been included in 2020's 10-Year System Outlook, its generation agreement remains active and a return to service is possible within the study period.

Comparison of a 3-phase fault on the 69kV bus at 51V-Tremont, with and without 81V-Annapolis was performed to ensure the results of the stability analysis in Section 3.5 Stability analysis are valid with the 81V-Annapolis Tidal Plant displacing generation at 12V-Lequille and 13V-Gulch.

The results shown in *Appendix E: Sensitivity analysis* for this sensitivity test demonstrate no significant difference between the results. shows a comparison between 11V-Paradise's output with and without 81V-Annapolis Tidal Plant running.

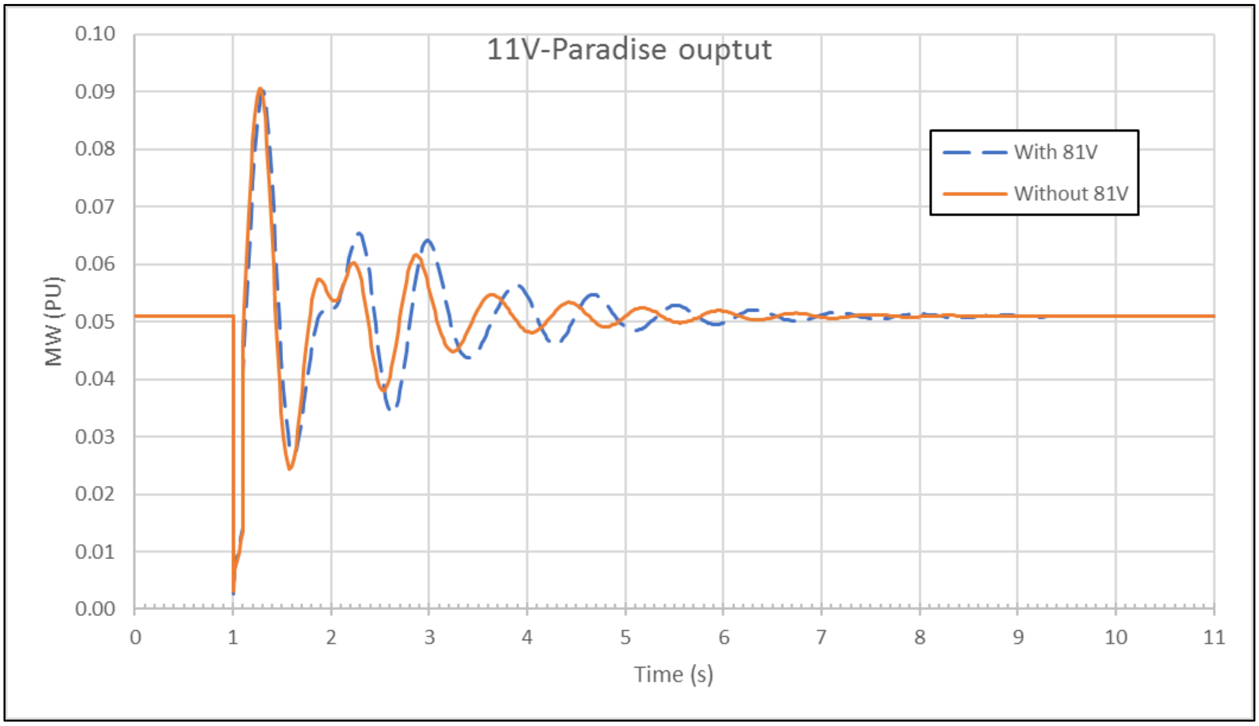


Figure 7: Annapolis Tidal Plant sensitivity

3.5.4 Stability evaluation

PSS/e plotted output files for each contingency with IR574 out of service and in service are presented in Appendices I through R. All contingencies were found to be stable and well-damped.

3.6 NPCC-BPS/NERC-BES

Both steady state and stability BPS testing was performed in accordance with the A-10 methodology described in *Section 2.3.7: NPCC-BPS/NERC-BES*.

The steady state test was conducted by dispatching the new facility at full 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 high voltage terminals at the POI, with all local protection out of service. *Appendix F: NPCC-BPS determination results* demonstrates IR574 does not have adverse impact outside the local area, confirming the transmission facilities associated with IR574 are not classified as NPCC BPS.

Based on NERC BES criteria, IR574 is not considered part of the BES because:

- The ICIF transformer's secondary terminal is <100kV.
- The gross plant/facility aggregate nameplate rating is <75MVA.
- The POI, off L-6051, is not on a Black Start path.
- It is a radial system that emanates from a single point of connection of ≥100kV and only includes generation resources <75MVA.

3.7 Underfrequency operation

IR574's low frequency ridethrough performance was tested by simulating a fault on L-8001 under high import conditions. The case selected for dynamic simulation was based on 2023 Fall Peak, with 300 MW import into Nova Scotia (FL01-2).

IR574 remains stable and online as required. Simulation indicates that NS Power's Stage 4 UFLS activates to stabilize system frequency. The simulation results are shown in figures *Figure 7: Underfrequency performance (frequency at 120H-Brushy Hill:138kV)* and *Figure 8: Underfrequency performance (IR574 machine output)*. Note values are plotted on 100 MVA system base, so IR574 at 0.588 PU power represents full output of the generator rather than 58.8% output.

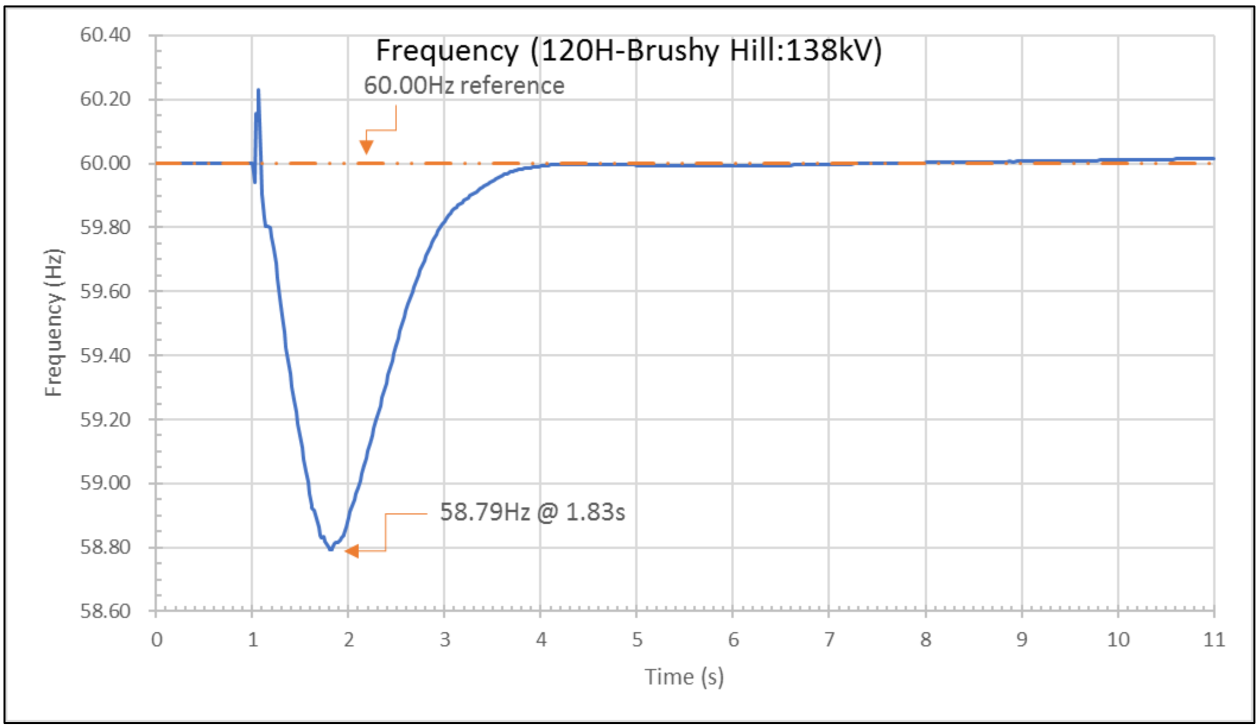


Figure 8: Underfrequency performance (frequency at 120H-Brushy Hill:138kV)

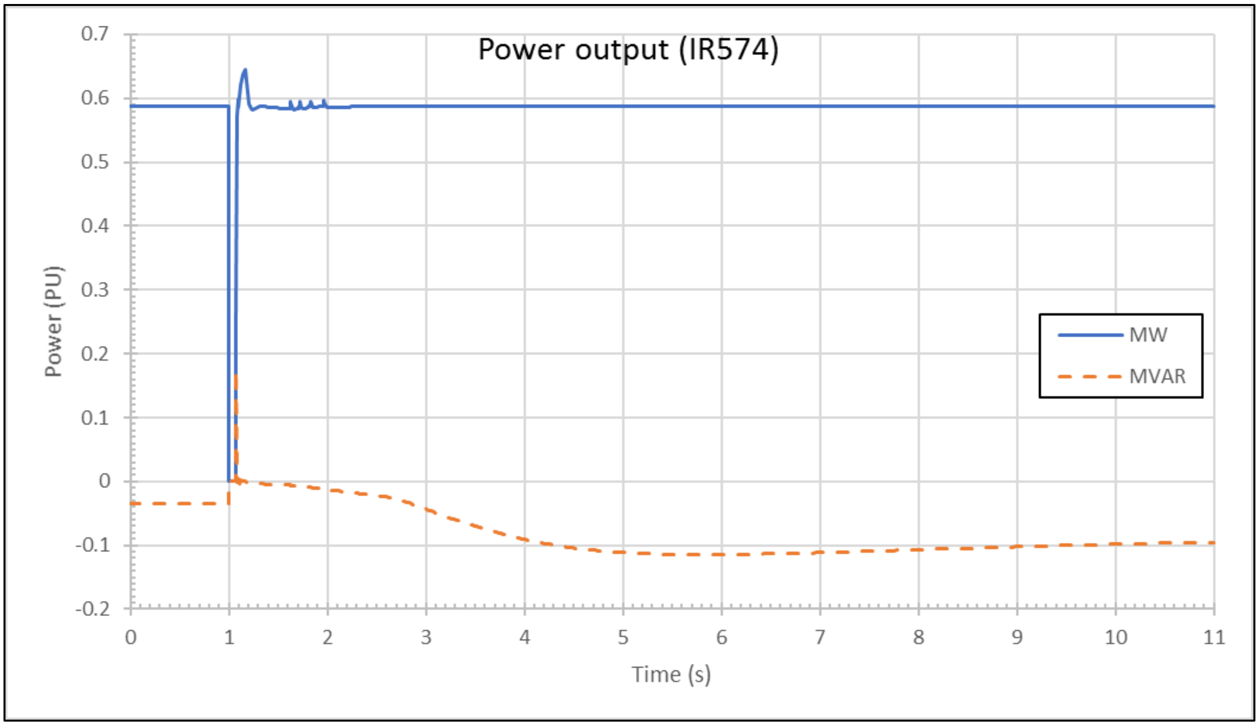


Figure 9: Underfrequency performance (IR574 machine output)

3.8 Voltage ridethrough

A 3-phase fault for 9 cycles, simulating a Transmission System fault, was applied to IR574's 138kV and 34.5kV buses to test the windfarm's Low Voltage Ridethrough (LVRT) capability.

The stability plot in Figure 9: "*IR574 LVRT performance (HV fault, 9 cycles)*" and Figure 10: "*IR574 LVRT performance (LV fault, 9 cycles)*" demonstrate IR574 rides through the fault and stays online in both cases, as required. Results are shown in *Appendix H: Low voltage ridethrough*. Note values are plotted on 100 MVA system base, so IR574 at 0.588 PU power represents full output of the generator rather than 58.8% output.

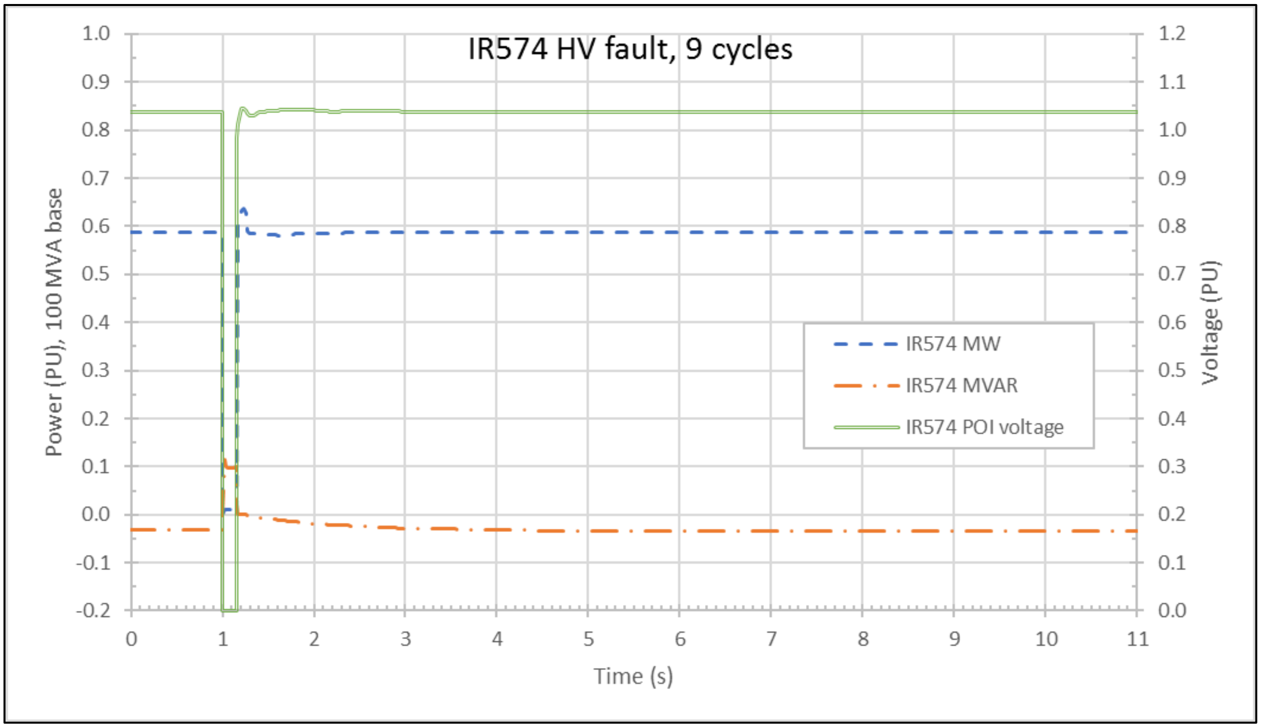


Figure 10: IR574 LVRT performance (HV fault, 9 cycles)

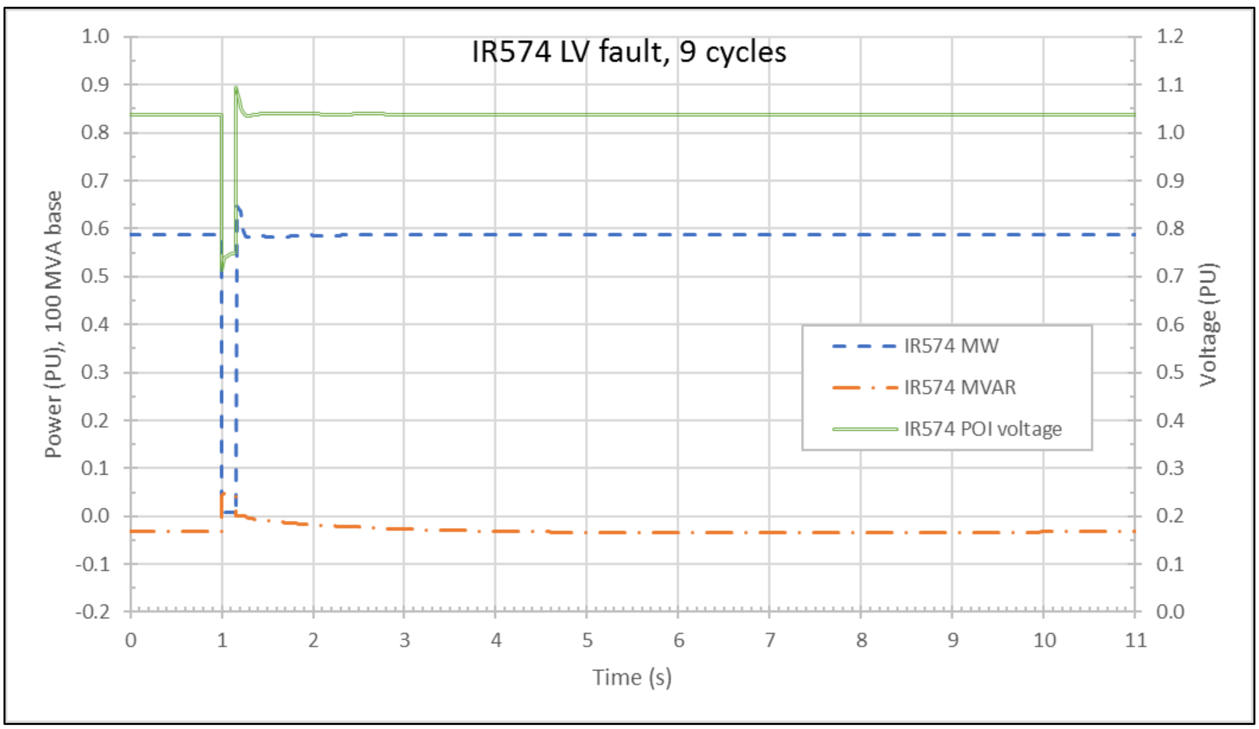


Figure 11: IR574 LVRT performance (LV fault, 9 cycles)

3.9 Loss factor

The loss factor for IR574 is calculated as 0.68% at IR574's 34.5kV ICIF bus. This means system losses on peak are marginally increased when IR574 is operating at full capacity. This is slightly higher than the 0.56% for a 75MW 17V-St Croix source calculated in the 2020 OATT Information Package; due to modelling IR574's ICIF substation transformer and short tap from the 17V-St Croix substation.

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. Losses associated with IR574's collector circuits and generator step-up transformers are ignored.

Table 10: Loss factor

2023 loss factor	Placed @ IF distribution bus (34.5kV)	Placed @ IF POI (138kV)
IR574 output	58.80	58.80
TC3 w/ IR574	62.35	62.15
TC3 w/o IR574	120.75	120.75
Delta	(0.40)	(0.30)
2023 loss factor	0.68%	0.34%

4.0 Requirements & cost estimate

The cost estimate includes the additions/modifications to the NS Power system only. The cost of the IC's substation and Generating Facility are not included. All costs of the associated facilities required at the IC's substation and Generating Facility are in addition to the estimate provided in Table 11: System upgrades cost estimate.

The following facility changes are required to interconnect IR574 to the NS Power system via L-6051:

- Modifications to tap the 138kV line, L-6051, from the POI to the IC's substation, approximately 75m away with 138kV ACSR 795 Drake with a maximum 100 °C operating temperature.
- Protection and SCADA communications upgrades at 17V-St Croix, 120H-Brushy Hill, and equipment at the ICIF. This quote also includes a radio link from the ICIF substation to the 17V-St Croix substation as well as associated communications equipment up to and including a demarcation enclosure to be installed at the ICIF substation.

In addition, IR574 must be equipped with the following:

- 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.
- A centralized voltage controller to maintain constant voltage at the 34.5kV IC substation bus. 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.

- A circuit-switcher at the high-side of the IC transformer capable of interfacing and implementing the NS Power Transfer Trip signal in the event of a nearby disturbance.
- Sufficient reactive power support to maintain a net power factor at the 138kV IC bus. IR574's power factor capability should be re-evaluated to determine if the required amount of reactive power is met once detailed design information on its transformers and collector circuits are available. Based on the preliminary information submitted, IR574 is on the threshold of meeting the lagging power factor requirement.
- Voltage flicker and harmonics characteristics as described in Section 3.3: Voltage flicker.
- Frequency ridethrough capability to meet the requirements in Section 2.3.8: Underfrequency operation.
- 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).
- Voltage ridethrough capability to meet the requirements in Section 2.3.9: Low voltage ridethrough.
- 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.

Table 11: System upgrades cost estimate

Item	TPIF	Estimate
I	Modifications to tap L-6051, with ACSR 795 Drake to ICIF substation approx. 75m away.	$ 438,149
II	Telecommunications (protection & SCADA)	$ 66,697
III	Protection and control upgrades	$ 343,000

Determined costs	
Subtotal	$ 847,846
Contingency (10%)	$ 84,785
Total of determined cost items	$ 932,630

These System Upgrade costs are the same for NRIS and ERIS. The Interconnection Facilities Study will provide a more detailed cost estimate.

5.0 Conclusion & recommendations

5.1 Summary of technical analysis

Technical analysis, including short circuit, power factor, voltage flicker, steady state, stability, and protection and control analysis was performed. Both NS Power and NPCC planning criteria were applied.

IR574 is on the threshold of meeting the lagging power factor requirement based on the preliminary information supplied. This should be re-evaluated once the transformer impedances and collector circuit design are finalized.

The facilities associated with IR574 are not designated as NPCC BPS as IR574 does not affect the BPS status of existing facilities. IR574 also does not qualify as NERC BES based on project size and interconnection voltage.

Provided the Western Valley Transmission System is operated within historical limits, the addition of IR574 does not adversely impact the thermal capacity of the NS Power Transmission System. No issues were identified in the steady state or stability analysis that are attributed to IR574.

It is concluded that the incorporation of the proposed facility into the NS Power transmission 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

In order to accommodate the full output of IR574, a tap is required at the POI, plus approximately 75m of new 138kV transmission line between the POI and IC substation.

The total high level estimated cost for Interconnection Costs and Network Upgrades is $932,630. The Interconnection Facilities Study will provide a more detailed cost estimate. The costs of all associated facilities required at the IC's substation and Generating Facility are in addition to this estimate.