Interconnection Feasibility Study Report
GIP-IR584-FEAS-R0

Generator Interconnection Request 584
50 MW Battery Energy Storage System Facility
Spider Lake, NS

2021-11-15

Control Centre Operations
Nova Scotia Power Inc.

Executive Summary

This Feasibility Study report (FEAS) presents the results of a Feasibility Study Agreement for the connection of a 50 MW Battery Energy Storage System (BESS) facility interconnected to the NSPI system as Energy Resource Interconnection Service (ERIS).

This project is listed as Interconnection Request #584 in the NSPI Interconnection Request Queue and will be referred to as IR584 throughout this report. The proposed Commercial Operation Date is 2022/11/01.

The Interconnection Customer (IC) identified a 138 kV bus at 132H-Spider Lake as the Point of Interconnection (POI). This BESS facility will be interconnected to the POI via a 150m long 138 kV transmission line from the Point of Change of Ownership (PCO).

There are two relevant long-term firm Transmission Service Requests (TSR) that have established Queue position and are at the System Impact Study (SIS) stage, with requested in-service dates of 2025/01/01. These requests, TSR411 (800 MW from NB to NS) and TSR412 (500 MW from NFLD to NS), are expected to alter the configuration of the Transmission System in Nova Scotia As a result, the following notice has been posted to the OASIS site[1]:

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

The system upgrades resulting from these TSR studies are not expected to greatly influence the results of IR584, as it is connected in the Halifax Area and is electrically close to the load centre with minimal transmission system impact.

There are no concerns regarding increased short circuit levels. The increase in short circuit level is still within the capability of associated breakers. The minimum three phase short circuit level at the Interconnection Facility's (IF) high side bus is 373 MVA with all lines in service.

[1] OASIS Generation Interconnection Procedures; https://www.nspower.ca/oasis/generation-interconnection-procedures

Voltage flicker will not be an issue based on the data provided.

The project design must meet NSPI interconnection technical requirements, which include aspects like frequency and voltage ride-through, reactive power and voltage control, active power control, power quality, and low temperature operation. Harmonics must meet the Total Harmonic Distortion requirements in IEEE 519.

Supplementary reactive power support for IR584 is required as it is unable to meet NSPI's ±0.95 net power requirements at the IF 138 kV bus. The Hitachi BESS selected for IR584 have current-limited, bi-directional inverters capable of full four-quadrant operation at nominal voltage; however, they are only capable of >0.97 pf at 50MW output. Net power factor requirements are met when IR584's output levels are just below 48.5 MW. Supplementary reactive power support will be further investigated in the System Impact Study.

The 132H-Spider Lake POI for IR584 is not classified as NPCC BPS or NERC BES. Complete NPCC BPS status will be determined in the SIS transient testing.

The preliminary loss factor is calculated as 0.2% while discharging at the 132H-Spider Lake 138 kV bus POI. This preliminary loss factor excludes losses associated with the TPIF, ICIF transformer, and generation facility.

The power flow analysis identified no contingencies inside Nova Scotia that violate thermal loading criteria or voltage criteria while discharging at full output. Charging scenarios were evaluated during light load and summer peak conditions, and during winter off peak conditions 4 hours following the peak hour. No issues were discovered with charging of IR584.

The necessary Network Upgrades required for ERIS operation are:

- A 138 kV breaker, associated switches, and substation modifications at 132H-Spider Lake.
- P&C modifications at 132H-Spider Lake.

The present preliminary non-binding cost estimate for interconnecting IR584 to the 132H-Spider Lake 138 kV bus as Energy Resource is $2,392,500, which does not include any To Be Determined costs associated with SIS stability analysis. These estimates include a 10% contingency. This estimate will be further refined in the SIS and Facilities (FAC) studies.

Note that the proposed transmission path at 132H-Spider Lake from the POI to PCO requires more detailed engineering to provide a more accurate cost estimate. It is the customers responsibility to provide a suitable right of way for the transmission line. The right of way shall be registered in NSPI's name.

The estimated time to construct the Network Upgrades and TPIF for ERIS operation is 18-24 months after the receipt of funds.

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1.0 Introduction

This Feasibility Study report (FEAS) presents the results of a Feasibility Study Agreement for the connection of a 50 MW Battery Energy Storage System (BESS) facility interconnected to the NSPI system as Energy Resource Interconnection Service (ERIS).

This project is listed as Interconnection Request (IR) #584 in the NSPI Interconnection Request Queue and will be referred to as IR584 throughout this report. The proposed Commercial Operation Date is 2022/11/01.

The Interconnection Customer (IC) identified the 138 kV bus at 132H-Spider Lake as the Point of Interconnection (POI). This BESS facility will be interconnected to the POI via a 150m long 138 kV transmission line from the Point of Change of Ownership (PCO). Figures 1 and 2 show the approximate location of the proposed IR584 site.

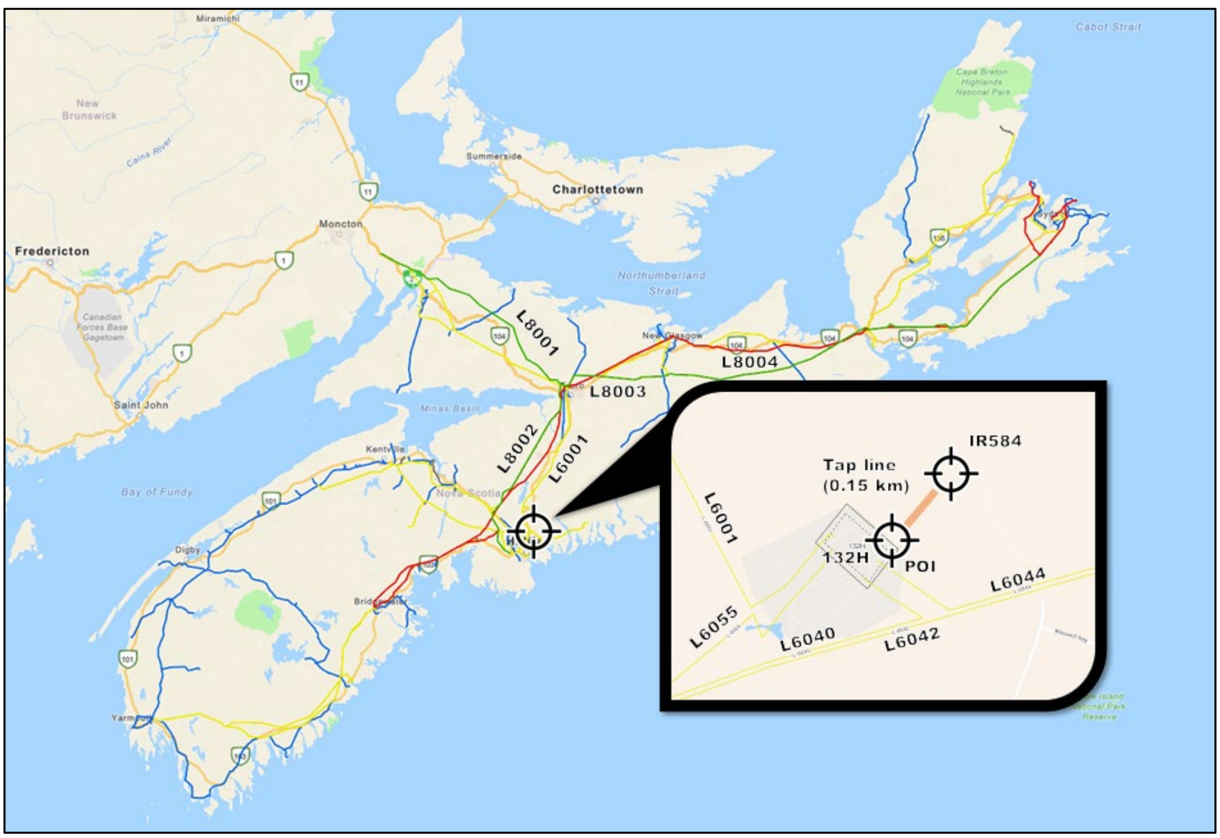

Figure 1: IR584 approximate geographic location

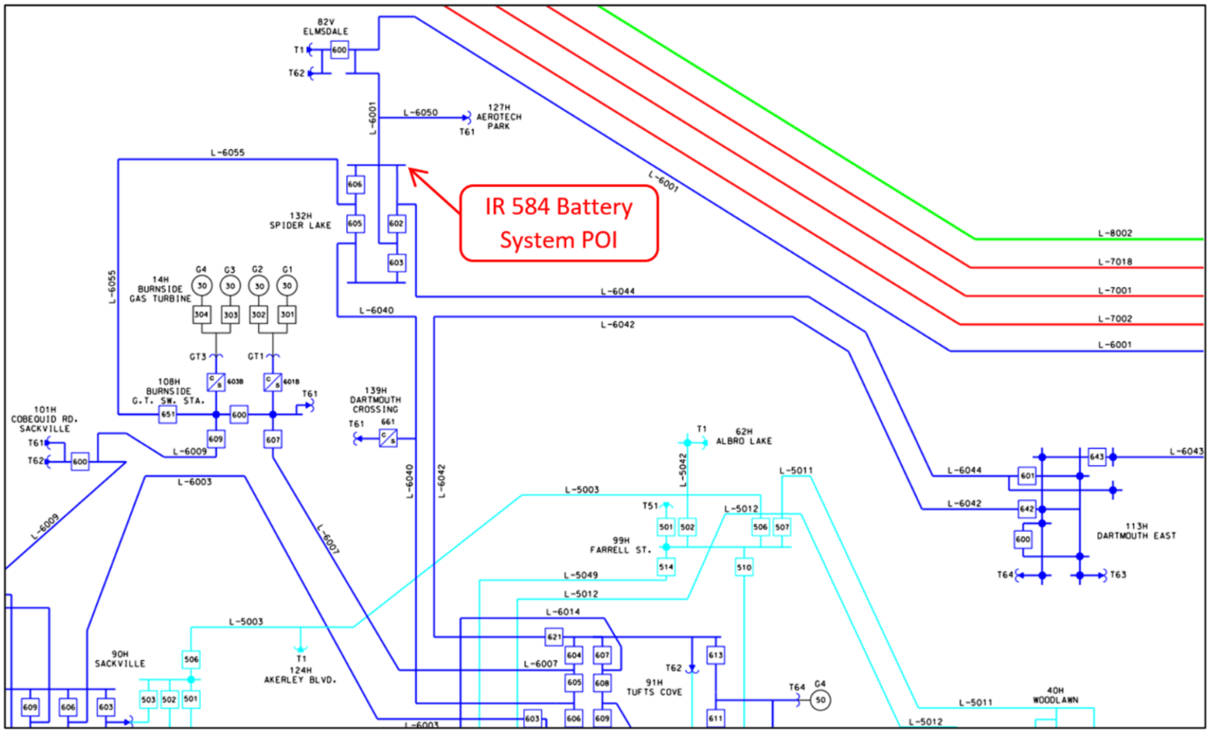

Figure 2: IR584 Point of Interconnection

2.0 Scope

This Interconnection Feasibility Study's (FEAS) objective is to provide a preliminary evaluation of system impact and a high-level non-binding cost estimate of interconnecting the new BESS facility to the NSPI Transmission System at the designated location based on single contingency criteria. This assessment will identify potential impacts on transmission element loading, which must remain with their thermal limits. Any potential voltage criteria violations will be identified and addressed. Circuit breakers must be upgraded if the proposed facility increases the short-circuit duty of any circuit breakers beyond their rated capacity.

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

- Identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection and any Network Upgrades necessary to address the short circuit issues associated with the IR.
- Identification of any thermal overload or voltage limit violations resulting from the interconnection and identify the necessary Network Upgrades to allow full output of the proposed facility.

- Description and high-level non-binding estimated cost of and time to construct the facilities required to interconnect the generating facility to the transmission system.

This FEAS does not include a complete determination of facility changes/additions required to increase the system transfer capabilities that may be required to the transmission system to meet the design and operating criteria established by NSPI, the Northeast Power Coordinating Council (NPCC), and the North American Electric Reliability Corporation (NERC). These requirements will be determined by a more detailed analysis in the subsequent interconnection System Impact Study (SIS). An Interconnection Facilities Study (FAC) follows the SIS in order to ascertain the final cost estimate to the interconnect the generating facility.

3.0 Assumptions

This FEAS is based on technical information provided by the IC. The POI and configuration are studied as follows:

1. ERIS will be studied per the IR584 Feasibility Study agreement and section 3.2 of the Generation Interconnection Procedures (GIP).
2. Commercial Operation date: 2022/11/01.
3. The Interconnection Facility consists of 36 x 1.5MVA Hitachi (ABB) PS1000 690VAC battery system units, capped at 50 MW total. These are grouped in blocks of 3MVA with two PS1000 units per block. Each block is connected to a collector circuit via a 3MVA padmount transformer, with a total of 6 blocks per collector circuit (18MVA). Three collector circuits connect the battery blocks to the main 30/40/50 MVA substation step-up transformer.
4. The feeder circuit impedance was assumed to be negligible, due to the short distance from the power transformer.
5. The IC identified the 138 kV bus at the 132H-Spider Lake substation as the POI. This study will use 1113 ACSR Beaumont rated at 100ºC for the 150m transmission line between 132H and the IC substation.
6. Preliminary data provided by the IC for the substation step-up transformer and padmount transformers:
   - 6.1. The substation step-up transformer was modelled as 1x (one) 138 kV (delta) – 13.8 kV (Grounded Wye) transformer rated at 30/40/50 MVA, with a positive sequence impedance of 6% at 30 MVA. An X/R ratio of 30.0 was assumed for this unit.
   - 6.2. The padmount transformers were modelled as an equivalent transformer based on 18 x 13.8 kV (delta) - 0.69 kV (ungrounded wye) 3.0 MVA transformers, with a 6% positive impedance and an estimated X/R ratio of 10.
7. The Hitachi battery racks are the 690 VAC, 1500 kVA nameplate variant. A 1.2 PU fault current is used for short circuit analysis.

8. The BESS charge/discharge capacity under study is 50 MW.
9. Discharging occurs in light load, summer peak, and winter peak conditions.
10. Charging occurs in light load and summer peak conditions. During the winter season, charging is studied only under off-peak load conditions several hours after winter peak, which coincides with loading levels of ≤ 91% of peak load.
11. The FEAS analysis is based on the assumption that IRs higher in the Generation Interconnection Queue and OATT Transmission Service Queue that have a completed System Impact Study or that have a System Impact Study in progress will proceed, as listed in Section 4.0: Project queue position.
12. It is the IC's responsibility that the new facility will meet all requirements of NSPI's GIP and NSPI's Transmission System Interconnection Requirements.
13. Ratings of relevant transmission lines into the 132H-Spider Lake substation are:

Table 1: Transmission line ratings

NSPI Transmission Line Ratings — Last Updated: 2021-08-27

LINE	STATION	CONDUCTOR				BREAKER	SWITCH	CURRENT TRANSFORMER						TRIP MVA
		Type	Maximum Operating Temp. (Celsius)	SUMMER RATING 25 DEG (MVA)	WINTER RATING 5 DEG (MVA)	100% Name-plate	100% Name-plate	RELAYING Ratio	R.F.	MVA	FULL SCALE METERING Ratio	R.F.	MVA	
L-6001a	1N Onslow	ACSR 556.5 Dove	60	140	184	598	287	800	1.5	287	800	1	231	456
	82V Elmsdale						287				NA			
L-6001b	82V Elmsdale	ACSR 556.5 Dove	60	140	184		287				NA			
	132H Spider Lake					287	287	800	2	382	800	2	382	322
L-6040	132H Spider Lake	ACSR 556.5 Dove	70	163	201	478	478	800	2	287	800	2	287	
	91H Tufts Cove					287	287	800	2	383	800	1	231	253
L-6044	113H Dartmouth East	ACSR 795 Drake	100	268	304	478	478	800	1.3	249	800	1	231	
	132H Spider Lake					478	478	800	2	382	800	2	382	
L-6055	108H Burnside	ACSR 795 Drake	100	268	304	478	287	800	2	382	1200	2	462	382
	132H Spider Lake					478	478	800	2	382	800	2	382	382

4.0 Project Queue Position

All in-service generation is included in this FEAS. As of 2021/10/08, the following projects are higher queued in the Advanced Stage Interconnection Request Queue and are included in this study's base cases:

- IR426: GIA executed
- IR516: GIA executed
- IR540: GIA executed
- IR542: GIA executed
- IR557: SIS complete
- IR569: GIA executed
- IR568: GIA executed
- IR566: GIA executed
- IR574: FAC in progress
- IR595: SIS Complete
- IR598: SIS in Progress
- IR604: SIS in Progress
- IR603: SIS in Progress
- IR600: SIS in Progress

The following projects are included in the Transmission Service Request (TSR) Queue:

- TSR 411 (800 MW): SIS in Progress
- TSR 412 (500 MW): SIS in Progress

TSRs 411 and 412 have an expected 2025 in service date and system studies to determine required upgrades to the NS Transmission System are currently in progress. As a result, the following notice has been posted to the OASIS site[2]:

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5.0 Short Circuit

IR584 will not impact 132H-Spider Lake and neighbouring breaker's interrupting capability based on this study's short circuit analysis. Analysis was performed using PSS/e 34.8, classical fault study, flat voltage profile at 1.0 PU voltage, and 3LG faults.

[2] OASIS Generation Interconnection Procedures; https://www.nspower.ca/oasis/generation-interconnection-procedures

The maximum design interrupting capability of 138 kV circuit breakers is at least 5,000 MVA, however, the actual interrupting capability of the neighbouring 138 kV circuit breakers is at least 3,500 MVA. Short circuit levels with and without IR584 are provided in Tables 2 and 3.

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

Maximum Generation: All Generation On, All Transmission Lines In Service					
IR 584	***Measured Bus***	***Three Phase MVA***	***X/R***	***Single Phase MVA***	***X/R***
On	132H-Spider Lake 138kV Bus 199159	3117	12.0	3010	5.9
	IR 584 13.8kV Bus 199730	477	27.0	-	-
Off	132H-Spider Lake 138kV Bus 199159	3074	11.8	2983	5.9
	IR 584 13.8kV Bus 199730	427	24.6	-	-
Maximum Generation: All Generation On, L6055 Out Of Service					
On	132H-Spider Lake 138kV Bus 199159	2444	9.2	2151	5.0
	IR 584 13.8kV Bus 199730	461	23.6	-	-
Off	132H-Spider Lake 138kV Bus 199159	2401	9.1	2128	5.0
	IR 584 13.8kV Bus 199730	413	21.4	-	-

Table 3: Minimum Short circuit levels, 3-ph, in MVA

Minimum Generation: PA, ML, LG1, TR6 On, All Transmission Lines In Service					
IR 584	***Measured Bus***	***Three Phase MVA***	***X/R***	***Single Phase MVA***	***X/R***
On	132H-Spider Lake 138kV Bus 199159	1524	12.0	1781	5.9
	IR 584 13.8kV Bus 199730	421	23.8	-	-
Off	132H-Spider Lake 138kV Bus 199159	1481	11.7	1740	5.9
	IR 584 13.8kV Bus 199730	373	21.5	-	-
Minimum Generation: PA, ML, LG1, TR6 On, L6055 Out Of Service					
On	132H-Spider Lake 138kV Bus 199159	1368	10.5	1460	5.0
	IR 584 13.8kV Bus 199730	410	21.8	-	-
Off	132H-Spider Lake 138kV Bus 199159	1325	10.2	1426	5.0
	IR 584 13.8kV Bus 199730	363	19.6	-	-

Further short circuit analysis will be performed in the SIS and will also examine Short Circuit Ratio (SCR) under minimum short circuit level conditions.

6.0 Voltage Flicker & Harmonics

The IC supplied manufacturer test data with P_{st} and P_{lt} values meeting NS Power's voltage flicker requirements. A summary is listed in Table 4: Flicker requirements.

Table 4: Flicker requirements

	P_{st}	P_{lt}
NS Power's requirements	≤ 0.25	≤ 0.35
Manufacturer-supplied data	0.08	0.09

The battery system must meet IEEE Standard 519-2014 limiting voltage Total Harmonic Distortion *(all frequencies)* to no higher than 1.5% with no individual harmonic exceeding 1.5% on 138 kV.

7.0 Thermal Limits

Power flow analysis was performed for generation dispatches under system light load, summer peak load, and winter peak load conditions. Dispatch was selected to represent import and export scenarios with New Brunswick for various flows associated with the existing Maritime Link transmission service reservation. These include exports to NB of up to 330 MW between March 1st and November 30th, and exports of 150MW to NB for the period from December 1st to February 28th. These represent flows under normal system conditions. In the event of a contingency in New Brunswick, NSPI must provide an additional 171MW of supply.

IR584 is located to the north of Halifax, connected via 138 kV to the Secondary Transmission System. IR584 is most notably impacted by the Onslow South (ONS) corridor which defines the interface flows into the load centre in Halifax via Truro. The ONS corridor includes line L8002, L7001, L7002, L7018, and L6001.

7.1 Base Cases:

The base cases used in this study are shown in Table 5: Base Case Dispatch. For these cases:

- Transmission connected wind generation facilities were dispatched between 19% and 100% of their rated capability.
- Spring Light Load and Summer Peak cases tested charging at the same system load levels as discharging.
- For Winter Peak cases, charging was performed at off-peak hours of peak load dispatch (91% of peak, based on measured load 4 hours after system peak).
- All interface limits were respected for base case scenarios.

Three scenarios were examined for each of the Spring Light Load (SLL), Summer Peak (SUM), and Winter Peak (WIN) cases:

- IR584 off (i.e., SUM_00).
- IR584 discharging at 50 MW with ERIS designation (i.e., SUM_00-E).
- IR584 charging at 50 MW (i.e., SUM_00-L).

Table 5: Base Case Dispatch

Case Name	NS Load	Wind³	NS-NB	NS-NL	CBX²	ONI²	Onslow South	Mainland at Hastings	Hastings From
SLL_00	870	367	331	-330	245	347	19	82	222
SLL_01	854	245	0	-165	7	104	86	-9	83
SUM_00	1,443	490	332	-475	708	762	392	346	384
SUM_01	1,443	330	-99	-330	457	484	521	230	272
SUM_02	1,443	330	332	-475	929	1020	625	488	454
WIN_00	2,211	490	154	-320	651	886	624	375	263
WIN_01	2,211	110	0	-320	875	1010	842	503	411
WIN_02	2,206	490	332	-320	986	1164	724	549	443

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

7.2 Load Flow Contingencies:

Load Flow contingencies associated with the Primary & Secondary Transmission System and the Electrically Remote Transmission System share the following post contingency requirements:

- All system elements must be within 110% of their thermally limited ratings (assuming system operator action can resolve the overload in < 10 minutes)
- Steady state bus voltage must remain within 90% - 110% of nominal voltage following correction by automatic tap changers.
- Any Pre/Post contingency voltage change at buses must be < 10% prior to tap changer action

The Primary Transmission System contingencies must also include breaker failure, which can impact multiple system elements.

7.3 Load Flow Results:

The results for the Primary & Secondary Transmission System contingencies were acceptable with no criteria violations in any of the dispatch cases considered. The contingency list for the Primary & Secondary Transmission System is provided in Appendix A for reference.

In summary, the steady state contingencies evaluated in this study demonstrate that IR584 does not require Network Upgrades beyond the POI to operate at its full source capacity of 50 MW under ERIS. No network upgrades are required to supply IR584 during charging operations assuming that charging in periods of winter peak is delayed at least 4 hours after the peak load occurs.

8.0 Voltage Control

NS Power requires ±0.95 net power factor requirement at the HV terminals of the ICIF substation in addition to producing/absorbing reactive power at all production levels up to its full rated output. The PQ curve for the PS1000 unit is shown in figure 3. However, despite the -750kVar to 600kVar reactive range indicated in Figure 3, the IC has confirmed that the units will have full -1500kVar to 1500kVar capability at 0 MW real power.

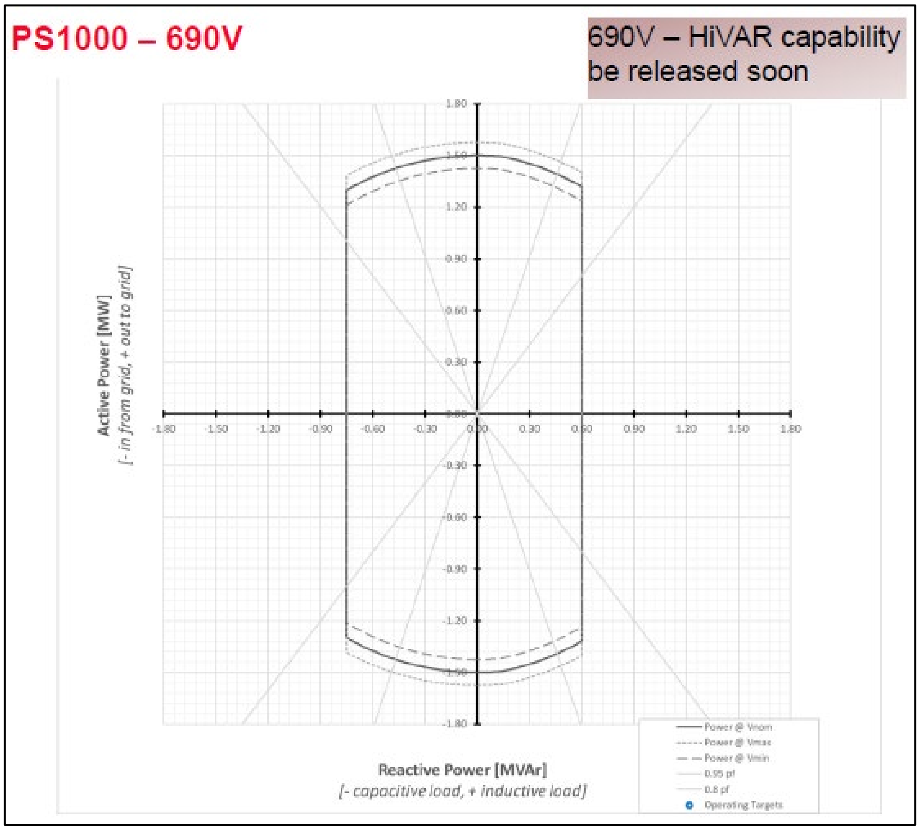

Figure 3: PS1000 capability curve[3]

IR584 has a total of 36 x 1.5 MVA PS1000's that use current-limited, bi-directional inverters, capable of full four-quadrant operation at nominal voltage, for a total of 54MVA. The site capacity for IR584 was given as 50 MW in the interconnection request and real power will be capped at that value.

IR584 is capable of reaching > 0.97 power factor at the HV terminals of the facility step up transformer at full output and nominal voltage. As a result, supplementary reactive support will be required at the low voltage terminals of the Interconnection Transformer to meet NS Power's requirements.

[3] PS1000 Interconnection Data; Supplied by the IC.

Net power factor requirements for supplying VARs are met when the batteries are operating just below 48.5 MW *(23.7 MVAR supplied from the source with 15.9 MVAR calculated at the high side of the ICIF transformer)*. The following table shows the power factor for BESS output levels of 48.5MW to 50MW. Supplementary reactive power support will be further investigated in the System Impact Study.

Table 6: Power Factor at IR584 Transformer HV Terminals

Machine terminals		High side of ICIF transformer (supplying VARs)			High side of ICIF transformer (absorbing VARs)			Net power factor requirements met?
MW	MVAR	MW	MVAR	pf	MW	MVAR	pf	
50	20.4	49.5	12.4	0.970	49.4	-31.6	0.842	no
49.5	21.6	49	13.7	0.963	48.9	-32.9	0.830	no
49	22.7	48.5	14.8	0.956	48.4	-34.2	0.817	no
48.5	23.7	48.1	15.9	0.949	47.7	-35.1	0.805	yes

A centralized controller will be required, which continuously adjusts the individual battery reactive power output within the plant capability limits and regulates the voltage at the low voltage terminal of the ICIF transformer. The voltage controls must be responsive to voltage deviations, be equipped with a voltage setpoint control, and have facilities that will slowly adjust the setpoint over several (5-10) minutes to maintain reactive power within the individual batteries' capabilities. Details of the specific control features, control strategy, and settings will be reviewed and addressed in the SIS.

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

This facility must have voltage ride-through capability as detailed in NERC Standard PRC-024-2 Attachment 2, included as the figure below. The SIS will examine the battery/plant capabilities and controls in detail to specify options, controls, and additional facilities that are required to achieve low voltage ride-through.

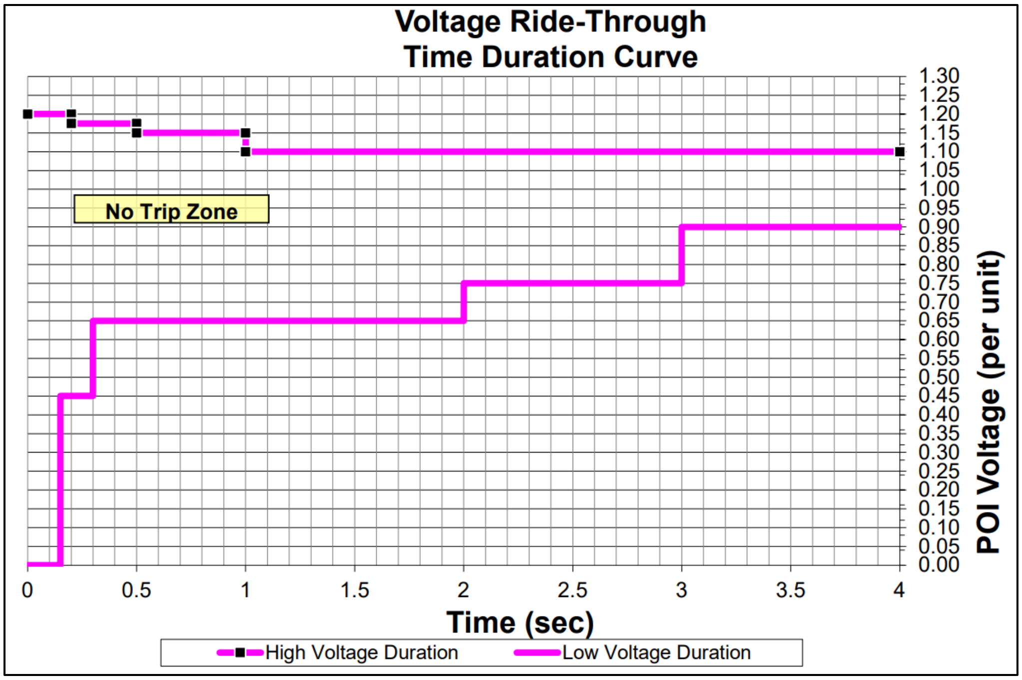

Figure 4: NERC PRC-024-2 Attachment 2

9.0 System Security

Transmission System Elements may be required to meet NPCC[4] Bulk Power System (BPS) and NERC[5] Bulk Electric System (BES) requirements.

NPCC BPS criteria is performance based, and currently the 138 kV bus at 132H-Spider Lake is not designated NPCC BPS. The SIS will complete NPCC BPS determination for IR584 and determine if the BPS status of any existing NSPI substations is impacted.

NERC BES criteria uses a bright line approach for expected facilities required for interconnection. IR584 does not meet any of the five BES inclusion criteria and will not be designated NERC BES.

The following table summarizes the BPS/BES status of neighbouring system elements.

Table 7: BPS & BES classification of neighbouring elements

Neighbouring element classification	NPCC BPS	NERC BES
132H 138 kV Bus	no	no
L6001	yes	yes
L6040	no	no
L6044	no	no
L6055	no	no

[4] Northeastern Power Coordination Council.
[5] North American Electric Reliability Corporation.

10.0 Expected Facilities Required for Interconnection

The following facilities are required to interconnect IR584 to the NSPI system via the 138 kV bus at 132H-Spider Lake as ERIS:

1) **Network Upgrades:**
   a) A 138 kV breaker, associated switches, and substation modifications at 132H-Spider Lake.
   b) P&C modifications at 132H-Spider Lake.

2) **Transmission Provider's Interconnection Facilities (TPIF):**
   a) A 138 kV transmission line built to NSPI standards from 132H-Spider Lake 138 kV bus to the IR584 substation.
   b) Control and communications between the ICIF and the NSPI SCADA and protection system.

3) **Interconnection Customer's Interconnection Facilities (ICIF):**
   a) Facilities to provide ±0.95 power factor when delivering rated output (50 MW) at the 138 kV bus when voltage is operating between ±5% of nominal. Rated reactive power shall be available through the full range of real power output, from zero to full power.
   b) Centralized controls for voltage setpoint control for the low side of the ICIF transformer. Fast acting control is required and will include a curtailment scheme, which will limit/reduce total load/output from the facility, upon receipt of a telemetered signal from NSPI's SCADA system.
   c) NSPI to have supervisory and control of this facility, via the centralized controller. 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.
   d) 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 active power controls shall also have the capability to react to continuous control signals from the NSPI SCADA system's Automatic Generation Control (AGC) system to control tie-line fluctuations as required.
   e) Real-time telemetry will include MW, MVAR, bus voltages, curtailment state, and state of charge.
   f) Voltage ride-through capability as detailed in Figure 2 of NERC Standard PRC-024-2 Attachment 2. As well as operation within NSPI's continuous nominal voltage range *(0.95 to 1.05 VPU)* and during stressed *(contingency)* conditions *(0.90 to 1.10 VPU)*.

g) Frequency ride-through capability in accordance with NERC Standard PRC-024 and NPCC Standard PRC-006-NPCC-2. The facility shall have the capability of riding through a rate of change of frequency of 4 Hz/s as well as continuous operation in the 59.5 Hz to 60.5 Hz frequency range.

h) Facilities for NSPI to execute high speed rejection of generation and load (transfer trip), if determined in the SIS. The plant may be incorporated in SPS runback or load reject schemes.

i) 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°)*.

j) Operation at ambient temperatures as low as -30ºC.

11.0 NSPI Interconnection Facilities and Network Upgrades Cost Estimate

The present high level, non-binding, cost estimate, excluding HST, for IR584's Energy Resource Interconnection Service is shown in the following table. This estimate assumes there is adequate space for new equipment and modifications. This does not include any yet to be determined costs relating to any stability issues identified at the SIS stage based on dynamic analysis.

Table 8: Cost estimate

Determined Cost Items		Estimate
NSPI Interconnection Facilities		
i.	New spur line from 132H to IR 584 substation (150m)	$ 75,000
ii.	Protection, control	$ 250,000
iii.	Communications	$ 150,000
	Subtotal	$ 475,000
Network Upgrades		
iv.	138kV breaker, switches, terminal at 132H-Spider Lake	$ 1,500,000
v.	Protection modifications	$ 200,000
	Subtotal	$ 1,700,000
Totals		
vi.	Contingency (10%)	$ 217,500
vii.	Total of Determined Cost Items	$ 2,392,500
To Be Determined Cost Items		
viii.	System additions to address potential stability limits	TBD (SIS)

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

Note that the proposed transmission corridor requires more detailed design work that is not in scope for this FEAS. Below are a few highlighted issues that could significantly impact the estimate for this project:

- The requirement for easements and structure relocations.
- Issues with implementation may be discovered at the 132H-Spider Lake substation. No major issues were found in this preliminary review, however, detailed design could potentially find issues resulting in increased scope.

12.0 Loss Factor

Loss factor is calculated by running the winter peak load flow case with and without the new facility in service, while keeping 91H-Tufts Cove as the NS Area Interchange bus. This methodology reflects the load centre in and around 91H-Tufts Cove. A negative loss factor reflects a reduction in system losses.

With IR584 in service and discharging, the loss factor is calculated as 0.2% at the POI. This preliminary loss factor excludes losses associated with the TPIF, ICIF transformer, and generation facility.

Table 9: Loss factor while discharging

Parameter	Generation (MW)
IR584 at POI	50.0
TC3 w/ IR584	98.3
TC3 w/o IR584	148.4
Delta	0.1
2022 loss factor	0.2%

13.0 Preliminary Scope of Subsequent SIS

The SIS will be conducted in accordance with the GIP with the assumption that all appropriate higher-queued projects will proceed, and the facilities associated with those projects are installed. It will provide a more comprehensive assessment, based on NSPI, NPCC, and NERC criteria, of the technical issues and requirements to interconnect the proposed facility as requested.

The assessment will consider, but not be limited, to the following:

- Contingency analysis for both steady state and system stability.
- Ride-through and operation following a contingency (n-1 operation).
- The minimum transmission and substation additions/upgrades that are necessary to permit operation of this generating facility, under all dispatch conditions, catering to, at a minimum, the first contingencies listed below.
- Options and ancillary equipment that the customer must install to control flicker, voltage and ensure that the required ride-through capability.
- Identify guidelines and restrictions applicable following a first contingency (curtailments, etc.).
- Loss Factor.

- Determination of BPS designation.
- Changes to SPS schemes required for operation of this generating facility
- Under-frequency load shedding.
- Facilities that the customer must install to meet the requirements of the GIP.

Parameters for a generic model must be supplied for transient analysis in PSS/e.

The SIS will determine the facilities required to operate this facility at full capacity, withstand the contingencies as defined by NPCC/NERC and identify any restrictions that must be placed on the system following a first contingency loss. The SIS will be conducted with the assumption that all projects higher queued will proceed and the facilities associated with those projects are installed.

Any changes to SPS schemes required for operation of this generating facility, in addition to existing generation and facilities that can proceed before this project, will be determined by the SIS as well as any required additional transmission facilities. The determination will be based on NERC[6] and NPCC[7] criteria as well as NSPI guidelines and good utility practice. The SIS will also determine the contingencies for which this facility must be curtailed.

A thorough assessment will be provided to ensure that the facilities will meet applicable NSPI, NPCC and NERC transmission design criteria.

Nova Scotia Power
Transmission System Operations
2021/10/29

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[6] NPCC Directory #1: *Design and Operation of the Bulk Power System*

[7] NERC Reliability Standard TPL-001-4: *Transmission Operations*

Appendix A:

Primary & Secondary Transmission System Contingency List