Interconnection Feasibility Study Report
GIP-IR583-FEAS-R0

Generator Interconnection Request 583
50 MW Battery Energy Storage System Facility
Lunenburg County, NS

2021-09-29

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 Network Resource Interconnection Service (NRIS).

This project is listed as Interconnection Request #583 in the NSPI Interconnection Request Queue and will be referred to as IR583 throughout this report. The proposed Commercial Operation Date is 2022/11/01.

The Interconnection Customer (IC) identified a 138 kV bus at 99W-Bridgewater as the Point of Interconnection (POI). This BESS facility will be interconnected to the POI via a 750 m 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 IR583, as it is connected to the West of Halifax and is electrically remote from the portion of the transmission system most impacted by them.

There are no concerns regarding increased short circuit levels or voltage flicker. 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) 13.8kV bus is 339 MVA with all lines in service. With 230kV Line L-7008 out of service, the minimum three phase short circuit level at the 13.8kV bus falls to 309 MVA.

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

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 IR583 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 IR583 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 IR583's output levels are just below 48.5 MW. Supplementary reactive power support will be further investigated in the System Impact Study.

The 99W-Bridgewater POI for IR583 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 0.4% while discharging at the 99W-Bridgewater 138 kV bus POI. This preliminary loss factor excludes losses associated with the TPIF, ICIF transformer, and generation facility.

The power flow analysis identified four Electrically Remote transmission System contingencies inside Nova Scotia that violate thermal loading criteria or voltage criteria. One of these is pre-existing and is not the responsibility of IR583. The remaining contingencies resulted in undervoltage violations at the 23W-Clyde River; 25W-Shelburne, 30W-Souriquois; and 36W-Lockport substations. A new 12 MVar switched capacitor bank installed at the 30W-Souriquois Substation 69kV bus resolves these low voltage violations. This upgrade is classified as a Network Upgrade.

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 IR583.

The necessary Network Upgrades required for NRIS operation are:

- Installation of a 69kV capacitor bank, breaker, and switches at 30W-Souriquois
- P&C modifications at 99W-Bridgewater.

The present preliminary non-binding cost estimate for interconnecting IR583 to the 99W-Bridgewater 138 kV bus as Network Resource is $3,822,500, which does not include any To Be Determined costs associated with SIS stability analysis. $2,502,500 of this amount is the TPIF costs, with the remaining $1,320,000 as the Network Upgrade costs. These estimates include a 10% contingency. This estimate will be further refined in the SIS and Facilities (FAC) studies.

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

The necessary Network Upgrades required for ERIS operation are:

- P&C modifications at 99W-Bridgewater.

The present preliminary non-binding cost estimate for interconnecting IR583 to the 99W-Bridgewater 138 kV bus as Energy Resource is $2,722,500, which does not include any To Be Determined costs associated with SIS stability analysis. $2,502,500 of this amount is the TPIF costs, with the remaining $220,000 as the Network Upgrade costs. These estimates include a 10% contingency. This estimate will be further refined in the SIS and Facilities (FAC) studies.

The estimated time to construct the Network Upgrades and TPIF for ERIS operation is 12-18 months after the receipt of funds.

Note that the proposed transmission path from the POI to PCO requires more detailed engineering to provide a more accurate cost estimate due to the congestion at 99W-Bridgewater. 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.

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List of tables & figures

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) #583 in the NSPI Interconnection Request Queue and will be referred to as IR583 throughout this report. The proposed Commercial Operation Date is 2022/11/01.

The Interconnection Customer (IC) identified the 138 kV bus at 99W-Bridgewater as the Point of Interconnection (POI). This BESS facility will be interconnected to the POI via a 750 m long 138 kV transmission line from the Point of Change of Ownership (PCO). Figure 1 shows the approximate location of the proposed IR583 site.

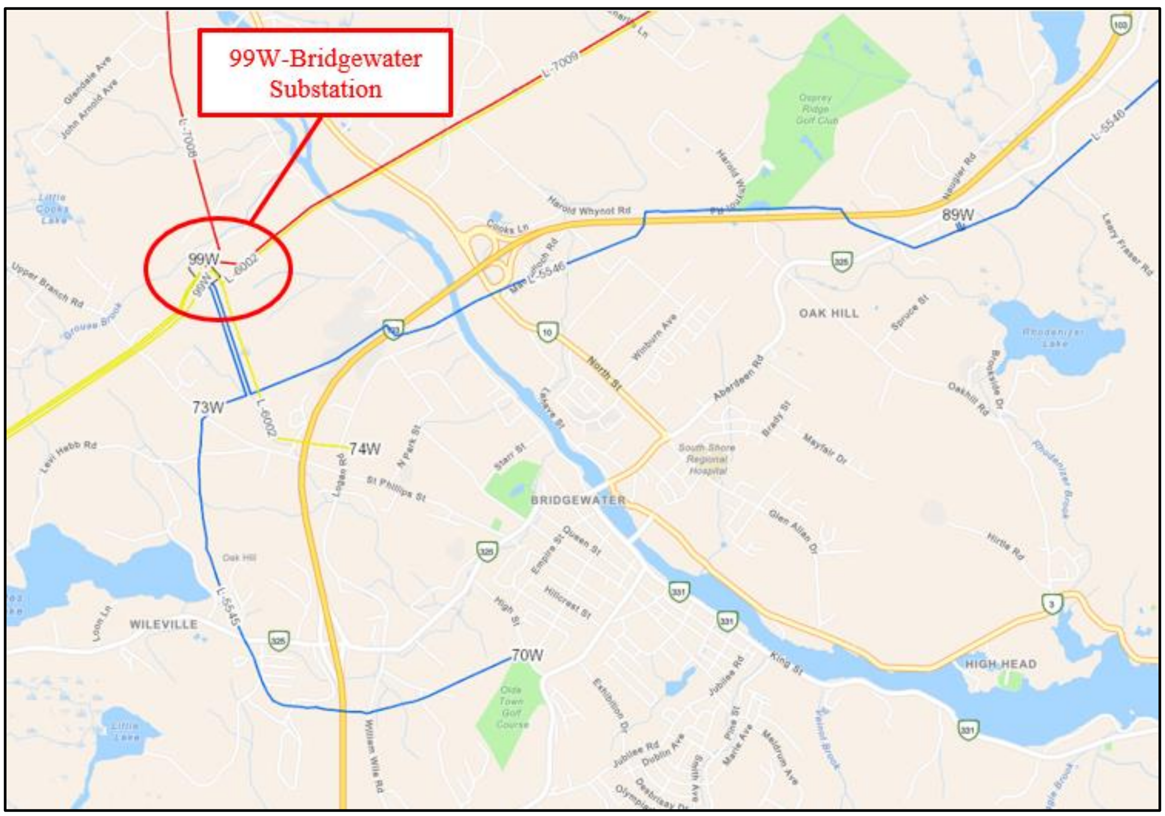

Figure 1: IR583 approximate geographic location

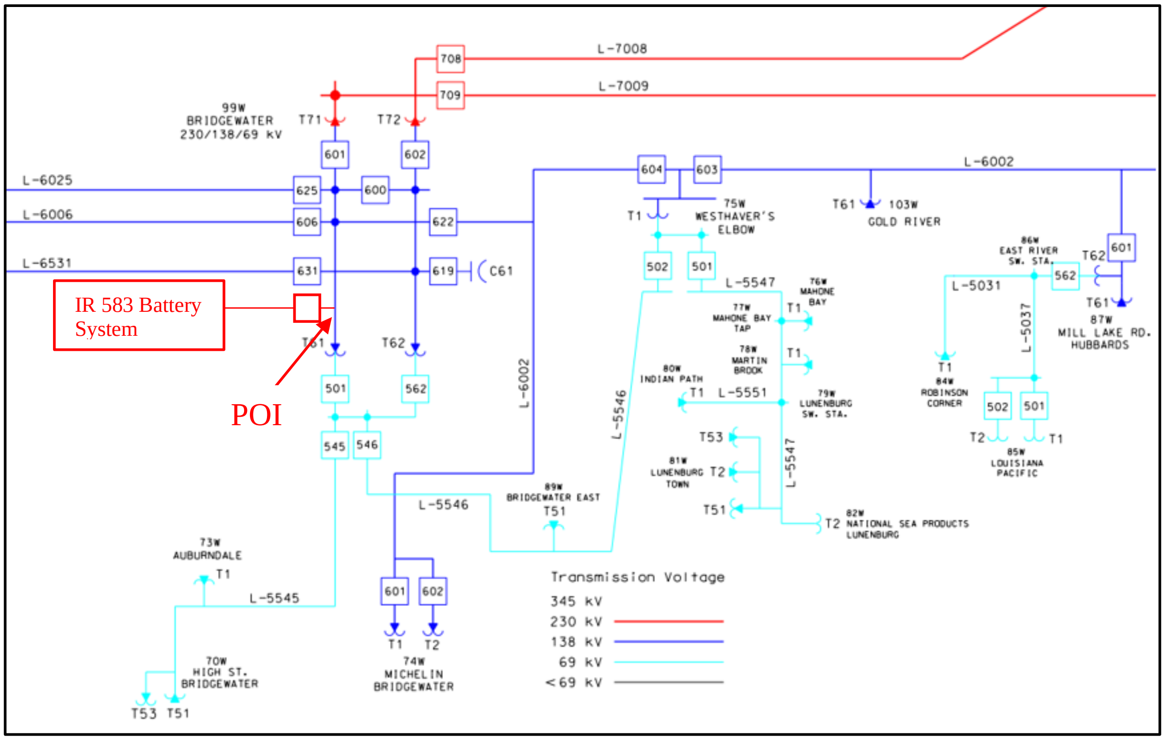

Figure 2: IR583 Point of Interconnection

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. Both NRIS and ERIS will be studied per the IR583 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 99W-Bridgewater substation as the POI. This study will use 1113 ACSR Beaumont rated at 100ºC for the 750m transmission line between 99W 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 rate 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 only occurs 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 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 Bridgewater Substation are as follows:

Table 1: Transmission line ratings

NSPI Transmission Line Ratings

Last Updated: 2021-08-27

LINE	STATION	CONDUCTOR Type	Maximum Operating Temp. (Celsius)	SUMMER RATING 25 DEG (MVA)	WINTER RATING 5 DEG (MVA)	BREAKER 100% Name-plate	SWITCH 100% Name-plate	CURRENT TRANSFORMER RELAYING Ratio	RELAYING R.F.	RELAYING MVA	FULL SCALE METERING Ratio	METERING R.F.	METERING MVA	TRIP MVA
L-6002a	90H Sackville	ACSR 556.5 Dove	100	215	242	287	287	600	2	287	600	1	173	421
	87W Hubbards						143				NA			243
L-6002b	87W Hubbards	ACSR 556.5 Dove	50	110	165		143				NA			
	99W Bridge Water					299	143	600	1.5	215	800	1	231	358
L-6006	99W Bridgewater	ACSR 795 Drake	50	135	205	478	478	800	2	382	800	1	231	973
	50W Milton					287	287	800	2	382	800	1	231	973
L-6025	99W Bridgewater	ACSR 1113 Beaumo nt	70	242	301	287	287	800	1	200	800	1	231	972
	50W Milton					287	287	800	1	200	800	1	231	972
L-6531	99W Bridgewater	ACSR 556.5 Dove	50	110	165	299	202	800	1.5	287	800	1	231	973
	50W Milton					287	301	800	2	382	800	1	231	943

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			FULL SCALE METERING			
								Ratio	R.F.	MVA	Ratio	R.F.	MVA	
L-7008	120H Brushy Hill	ACSR 1113 Beaumont	70	404	502	797	797	800	2	478	1200	1	554	1235
	99W Bridgewater EHV					797	797	500	2	398	1000	1	462	1235
L-7009	120H Brushy Hill	ACSR 795 Drake	50	223	340	797	797	800	2	637	1200	1	577	901
	99W Bridgewater EHV					996	797	500	2	398	1200	1	577	751

14. Contingencies applied in and North/East of Halifax comply with NSPI's Primary & Secondary Transmission System design criteria. Contingencies applied to the west of Halifax comply with the Electrically Remote Transmission System design criteria.

4.0 Project queue position

All in-service generation is included in this FEAS. As of 2021/09/08, 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
- TSR 413 (9 MW): Accepted application

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]:

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

5.0 Short circuit

IR583 will not impact 99W-Bridgewater and neighbouring breaker's interrupting capability based on this study's short circuit analysis. Analysis was performed using Aspen OneLiner V14.5, classical fault study with flat voltage profile at 1.0 PU voltage.

The interrupting capability of the neighbouring 138 kV circuit breakers is at least 3,500 MVA. Short circuit levels with and without IR583 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 583	**Supply Configuration**	**Three Phase MVA**	**X/R**	**Single Phase MVA**	**X/R**
On	99W-Bridgewater 138kV Bus 199230	1789	7.8	2280	8.5
	IR 583 13.8kV Bus 199237	450	39.4	526	56.3
OFF	99W-Bridgewater 138kV Bus 199230	1734	7.5	2159	8.0
	IR 583 13.8kV Bus 199237	387	33.9	416	41.8
Maximum Generation: All Generation On, L-7008 Out of Service					
On	99W-Bridgewater 138kV Bus 199230	1347	6.5	1798	7.4
	IR 583 13.8kV Bus 199237	423	26.6	507	41.1
OFF	99W-Bridgewater 138kV Bus 199230	1292	6.2	1668	6.7
	IR 583 13.8kV Bus 199237	360	22.6	394	28.9

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

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

Minimum Generation: PA, ML, LG1, & TR6 On, All Transmission Lines In Service					
IR 583	**Supply Configuration**	**Three Phase MVA**	**X/R**	**Single Phase MVA**	**X/R**
On	99W-Bridgewater 138kV Bus 199230	1088	3.9	1505	4.4
	IR 583 13.8kV Bus 199237	401	13.7	493	22
OFF	99W-Bridgewater 138kV Bus 199230	1034	3.7	1368	3.9
	IR 583 13.8kV Bus 199237	339	11.6	376	14.5
Minimum Generation: PA, ML, LG1, & TR6 On, L-7008 Out of Service					
On	99W-Bridgewater 138kV Bus 199230	830	3.7	1195	4.2
	IR 583 13.8kV Bus 199237	368	10.8	469	17.7
OFF	99W-Bridgewater 138kV Bus 199230	776	3.4	1053	3.6
	IR 583 13.8kV Bus 199237	309	9.0	349	11.3

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 April 1st and November 30th, and exports of 150MW to NB for the period from December 1st to March 31st. These represent flows under normal system conditions. In the event of a contingency in New Brunswick, NSPI must provide an additional 171MW of supply.

IR583 is located to the West of Halifax near the boundary between the Primary & Secondary Transmission System and the Electrically Remote Transmission System, where Electrically Remote is defined as those parts of the system having a three phase fault level less than 1500MVA. IR583 is not materially impacted by changes to the interface flows on the Primary NSPI transmission system to the North/East of the load centre in Halifax. The Primary system includes transmission from Lingan through Port Hawkesbury to Truro; from Truro to Halifax; and from Truro to Memramcook in New Brunswick.

7.1 Base Cases:

The base cases used in this study are shown in Table 5: Base Case Dispatch, and Table 6: Western Interfaces: 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.
- Historic flow levels were considered when dispatching Western generation

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

- IR583 off (i.e., SUM_00).
- IR583 discharging at 50 MW with NRIS designation (i.e., SUM_00N).
- IR583 discharging at 50 MW with ERIS designation (i.e., SUM_00E).
- IR583 charging at 50 MW (i.e., SUM_00L).

Table 5: Base Case Dispatch

Case name	NS load	Wind	NS/NB	ML	CBX	ONI	ONS	M @ H	H from
SLL_00	852	367	330	-330	245	348	19	71	223
SLL_01	842	193	0	-165	58	165	139	-24	200
SUM_00	1,448	490	330	-475	709	804	436	347	385
SUM_01	1,427	330	-100	-330	413	491	527	185	291
WIN_00	2,203	490	150	--320	646	881	624	367	292
WIN_01	2,235	111	0	-320	994	1,111	941	567	486
WIN_02	2,232	454	330	-320	1,022	1,168	729	571	472

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.

Cases were dispatched to include a variety of transfer levels in the West. The interface flows are shown in Table 6 for each of four scenarios noted above. The transmission lines associated with each interface are also identified for reference.

Table 6: Western Interfaces: Base Case Dispatch

Case	Net Load (MW)	IR585 (MW)	Western Valley Import (MW)	Valley Import (MW)	Valley Export (MW)	West Valley Export (MW)	West Import (MW)	Milton / Tusket AAS (MW)
SLL_00	853	0	-17	-1	45	13	-20	-17
SLL_00E	851	50	-12	2.5	38	8	-27	-10
SLL_00N	853	50	-16	-3	45	11	-69	-15
SLL_00L	903	-50	-18	1	45	14	31	-17
SLL_01	842	0	11	40	7	1	22	5
SLL_01E	844	50	29	50	-15	-5	-4	25
SLL_01N	843	50	12	39	7	0	-28	6
SLL_01L	893	-50	10	43	7	2	72	4
SUM_00	1448	0	32	73	-4	-1	73	25
SUM_00E	1446	50	35	80	-10	-1	63	55
SUM_00N	1419	50	32	70	-4	-2	24	26
SUM_00L	1498	-50	31	75	-4	0	124	23
SUM_01	1427	0	25	74	4	2	68	29
SUM_01E	1429	50	27	78	0	2	63	52
SUM_01N	1428	50	26	74	4	2	68	30
SUM_01L	1478	-50	27	77	4	3	119	27
WIN_00	2203	0	49	119	-4	3	123	57
WIN_00E	2205	50	61	125	-19	-4	108	67
WIN_00N	2202	50	50	116	-4	2	73	58
WIN_00L	2053	-50	35	100	3	5	155	45
WIN_01	2203	0	89	164	-51	-14	140	67
WIN_01E	2205	50	89	174	-51	-15	120	67
WIN_01N	2202	50	90	161	-51	-15	91	69
WIN_01L	2053	-50	77	145	-43	-12	171	55
WIN_02	2203	0	39	105	10	7	112	52
WIN_02E	2205	50	56	111	-10	-3	92	64
WIN_02N	2202	50	40	102	10	6	62	53
WIN_02L	2053	-50	38	108	10	8	165	52
		Line Flows	L5022; L5532; L5535; L6013; L6015	L6011; L6051; L6054	L5025; L5532; L5535	L5535	L7008; L7009; L5532; L5535	L6020; L6024; L5530

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.

The results for the Electrically Remote Transmission System contingencies were acceptable for the Spring Light Load and the Summer dispatch scenarios with no criteria violations in any of the dispatch cases considered.

Results for the Electrically Remote Transmission System contingencies were acceptable for the Winter dispatch scenarios with no criteria violations in the dispatch cases with the following exceptions:

Table 7: Western Contingencies

Western Contingencies	Load Flow Case					
	WIN_00E	WIN_00L	WIN_01	WIN_01N	WIN_01E	WIN_01L
51V, 51V-B51	ok	ok	O/L U/V	O/L U/V	O/L U/V	O/L U/V
9W, 9W-T2	LV	ok	ok	ok	LV	ok
30W, 30W-T62	LV	ok	ok	ok	LV	ok
50W, L-6020	LV	ok	ok	ok	LV	ok

The contingency leading to an overload of L-5535 >110% and low voltages < 0.9pu in the Valley (51V-B51) is an existing issue and is not the responsibility of IR583 (51V-B51).

Contingencies 9W-T2, 30W-T62; and L-6020 are similar and all result in the loss of lines L-6020 & L-6021 and transformers 9W-T2 & 30W-T62. This removes one of the two 138kV supplies between 50W-Milton and 9W-Tusket, while also tripping the 138kV-69kV supply at 30W-Souriquois. These contingencies result in low voltages < 0.9 pu at the 23W-Clyde River; 25W-Shelburne, 30W-Souriquois; and 36W-Lockport substations, but do not result in criteria violations in any of the base cases that do not contain IR583. A new 12 MVar switched capacitor bank installed on the 30W-Souriquois Substation 69kV bus resolves these low voltage violations.

The contingency list for the Electrically Remote Transmission System is shown in Appendix B for reference.

In summary, the steady state contingencies evaluated in this study demonstrate that IR583 requires Network Upgrades beyond the POI to operate at its full source capacity of 50 MW under NRIS and ERIS. No network upgrades are required to supply IR583 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.

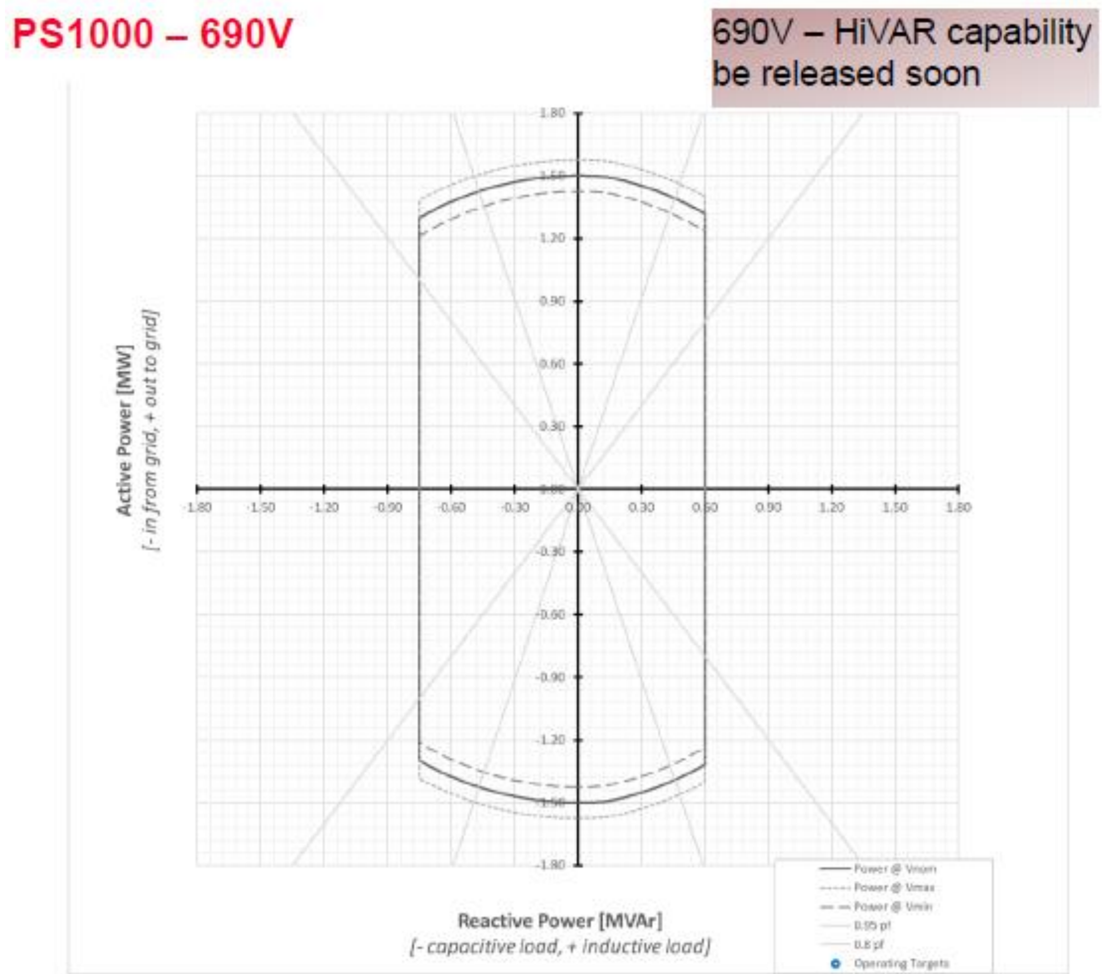

Figure 3: PS1000 capability curve[3]

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

IR583's 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 IR583 was given as 50 MW in the interconnection request and real power will be capped at that value.

IR583 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.

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 machine with 15.9 MVAR calculated at the high side of the ICIF transformer)*. Table 8 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 8: Power Factor at IR583 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 Figure 2 of NERC Standard PRC-024-2 Attachment 2. 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.

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 99W-Bridgewater is not designated NPCC BPS. The SIS will complete NPCC BPS determination for IR583 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. IR583 does not meet any of the five BES inclusion criteria and will not be designated NERC BES.

Table 9 9 summarizes the BPS/BES status of neighbouring system elements.

Table 9: BPS & BES classification of neighbouring elements

Neighbouring element classification	NPCC BPS	NERC BES
99W 230kV Bus	no	no
99W-138kV Bus	no	no
L7008	yes	yes
L7009	yes	yes
L6006	no	no
L6025	no	no
L6531	no	no

10.0 Expected facilities required for interconnection

The following facilities are required to interconnect IR583 to the NSPI system via the 138 kV bus at 99W-Bridgewater as NRIS:

1) **Network Upgrades:**
   a) P&C modifications at 99W-Bridgewater.
   b) 69kV, 12MVar switched capacitor bank, breaker, and switches at 30W-Souriquois
2) **Transmission Provider's Interconnection Facilities (TPIF):**
   a) A 138 kV breaker, associated switches, and substation modifications at 99W-Bridgewater.
   b) A 138 kV transmission line built to NSPI standards from 99W-Bridgewater 138 kV bus to the IR583 substation.

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

c) 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.

The following facilities are required to interconnect IR583 to the NSPI system via the 138 kV bus at 99W-Bridgewater as ERIS:

1) Network Upgrades:

a) P&C modifications at 99W-Bridgewater.

The TPIF and ICIF are the same as indicated for NRIS.

11.0 NSPI Interconnection Facilities and Network Upgrades cost estimate

The present high level, non-binding, cost estimate, excluding HST, for IR583's Network Resource Interconnection Service is shown in Table 10: NRIS Cost Estimate. This estimate assumes there is adequate space for new equipment and modifications. This does not include any TBD costs addressing any stability issues identified at the SIS stage based on dynamic analysis.

Table 10: NRIS cost estimate

	Determined Cost Items	Estimate
NSPI Interconnection Facilities		
i	138kV breaker, switches, terminal, at 99W-Bridgewater	$1,500,000
ii	New spur line from 99W to IR-583 substation (750m)	$375,000
iii	Protection, control	$250,000
iv	Communications	$150,000
	Subtotal	$2,275,000
Network Upgrades for NRIS (increased export capability)		
v	Protection modifications	$200,000
vi	12 MVAR, 69kV Switched Capacitor Bank & Breaker at 30W	$1,000,000
	Subtotal	$1,200,000
	Total	$3,475,000
Totals		
vii	Contingency (10%)	$347,500
viii	Total of Determined Cost Items	$3,822,500
	To be Determined Costs	
ix	System additions to address potential stability limits (ONS)	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.
- The 99W-Bridgewater substation is congested and issues with implementation may be discovered. No major issues were found in this preliminary review, however detailed design could potentially find issues resulting in increased scope.
- Issues with implementation may also be discovered at the 30W-Souriquois substation.

The present high level, non-binding, cost estimate, excluding HST, for IR583's Energy Resource Interconnection Service is shown in Table 11: ERIS Cost Estimate.

Table 11: ERIS cost estimate

	Determined Cost Items	Estimate
NSPI Interconnection Facilities		
i	138kV breaker, switches, terminal, at 99W-Bridgewater	$1,500,000
ii	New spur line from 99W to IR-583 substation (750m)	$375,000
iii	Protection, control	$250,000
iv	Communications	$150,000
	Subtotal	$2,275,000
Network Upgrades for NRIS (increased export capability)		
v	Protection modifications	$200,000
	Subtotal	$200,000
	Total	$2,475,000
Totals		
vii	Contingency (10%)	$247,500
viii	Total of Determined Cost Items	$2,722,500
	To be Determined Costs	
ix	System additions to address potential stability limits (ONS)	TBD (SIS)

The estimated time to construct the Network Upgrades and Transmission Provider's Interconnection Facilities is 12-18 months after receipt of funds.

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 IR583 in service and discharging, the loss factor is calculated as 0.4% at the POI as shown in Table 12. This preliminary loss factor excludes losses associated with the TPIF, ICIF transformer, and generation facility.

Table 12: IR583 loss factor while discharging

Parameter	Generation (MW)
IR583 @ POI	50.00
TC3 w/ IR583	95.2
TC3 w/o IR583	145.0
Delta	0.2
2022 loss factor	0.4%

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 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
2021/09/21

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

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