Interconnection Feasibility Study Report

GIP-361-FEAS-R2

System Interconnection Request #361

49.6 MW Wind Generating Facility

Cape Breton County (L-6516)

2012-02-10
Control Centre Operations
Nova Scotia Power Inc.

Executive Summary

The Interconnection Customer (IC) submitted an Interconnection Request (IR#361) for Network Resource Interconnection Service (NRIS) to NSPI for a proposed 49.6 MW wind generation facility interconnected to the NSPI transmission system, with a concurrent request for Energy Resource Interconnection Service (ERIS). The Point of Interconnection (POI) requested by the customer is on L-6516, approximately 54.5 km from 2S-Victoria Junction substation and 70.7 km from 2C-Port Hastings substation. It is assumed that the IC substation is at the POI, with no spur-line.

Because the IC requested NRIS, the system was studied with the output of IR#361 superimposed on the transmission system while operating at pre-existing transfer limits. Load flow analysis demonstrated that unacceptable overloads would occur for the contingency loss of the double-circuit tower lines L-8004 plus L-7005. The overloads would affect 321 km of 230 kV circuit (L7003, L-7004 and L-7019) and 36.5 km of 138kV line (L-6511). If upgrades associated with TSR-100 do not proceed, IR#361 would also overload an additional 50.7 km of 138kV line (L-6515). The most economic option to accommodate NRIS is to eliminate the offending contingency by re-arranging circuits at the Strait of Canso.

For the case of ERIS, it was assumed that IR#361 displaces an equivalent amount of thermal generation in Cape Breton to keep flows within limits and therefore no transmission lines needed to be uprated. Such displacement may result in out-of-merit generation dispatch.

No concern regarding short-circuit level was found for this project on its own. Available flicker coefficient data for this type of machine indicates that voltage flicker will not be a problem. The project must meet NSPI requirements for low-voltage ride-through, reactive power range and power factor control system. The data provided indicates that individual machines have a rated power factor of 0.9, and based on the supplied transformer and collector circuit data, supplementary reactive support may be needed in the form of capacitor banks at the low voltage terminals of the Interconnection Transformer. Harmonics must meet the Total Harmonics Distortion provisions of IEEE 519.

The preliminary unit loss factor is calculated to be 15.1% (system losses increased by net 7.5 MW when IR#361 is operated at 49.6 MW) at rated transfer levels.

Under the terms of NRIS, the preliminary non-binding estimated cost of facilities required to interconnect IR#361 to L-6516 is $14,551,000 including a contingency of 10%. Of this, $13,128,000 (plus contingency) is considered to be Network Upgrades and must be funded by the IC but is eligible for repayment in accordance with the terms of the GIA. Telecommunications requirements add an annual operating cost of $24,000, borne by the IC.

Under the terms of ERIS, the preliminary non-binding estimated cost of facilities required to interconnect IR#361 to L-6516 is $5,641,000 including a contingency of 10%. Of this, $4,628,000 (plus contingency) is considered to be Network Upgrades and must be funded by the IC but is eligible for repayment in accordance with the terms of the GIA. Telecommunications requirements add an annual operating cost of $24,000, borne by the IC.

These estimates will be further refined in the System Impact Study and the Facility Study.

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1 Introduction

The Interconnection Customer (IC) submitted an Interconnection Request (IR) for either Network Resource Interconnection Service (NRIS) or Energy Resource Interconnection Service (ERIS) to NSPI for a proposed 49.6 MW wind generation facility interconnected with the NSPI transmission system, with an in-service date of 2013-12-31. The Point of Interconnection (POI) requested by the customer is on line L-6516, approximately 54.5 km from 2S-Victoria Junction substation and 70.7 km from 2C-Port Hastings substation.

The Interconnection Customer signed a Feasibility Study Agreement to study the connection of their proposed generating facility to the NSPI transmission system and this report is the result of that Study Agreement. This project is listed as Interconnection Request #361 in the NSPI Interconnection Request Queue, and will be referred to as IR#361 throughout this report.

2 Scope

This Interconnection Feasibility Study (FEAS) consists of a power flow and short circuit analysis. Based on this scope, the FEAS report shall provide the following information:

1. Preliminary identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;
2. Preliminary identification of any thermal overload or voltage limits violations resulting from the interconnection;
3. Preliminary description and high level non-bonding estimated cost of facilities required to interconnect the Generating Facility to the Transmission System, and to address the identified short circuit and power flow issues.

The Scope of this FEAS includes modeling the power system in normal state (with all transmission elements in service) under anticipated load and generation dispatch conditions.

Because the IC has requested that both NRIS and ERIS be studied, the scope of each type of study is summarized.

2.1 Scope of NRIS Study

In accordance with Section 3.2.2.2 of Revised Generation Interconnection Procedures (RGIP), the FEAS for NRIS consists of short circuit/fault duty, steady state (thermal and voltage) analyses. The short circuit/fault duty analysis would identify direct Interconnection Facilities required and the Network Upgrades necessary to address short circuit issues associated with the Interconnection Facilities. The steady state studies would identify necessary upgrades to allow full output of the proposed Generating Facility. A key feature of NRIS, to differentiate it from ERIS, is quoted from the RGIP:

> *… such Generating Facility's interconnection is also studied with the Transmission Provider's Transmission System at peak load, under a variety of severely stressed conditions, to determine whether, with the Generating Facility at full output, the aggregate of generation in the local area can be delivered to the aggregate of load on the Transmission Provider's Transmission System, consistent with the Transmission Provider's reliability criteria and procedures.*

Because the NSPI power system is winter-peaking the above conditions would not necessarily demonstrate thermal loading issues, since transmission elements generally have a higher thermal rating in the winter. Therefore the studies are also conducted under summer peak load conditions and light load conditions, when transmission element ratings are reduced by higher ambient temperature.

NRIS studies superimpose the proposed Generation Facility on expected transfer conditions to determine what system upgrades, if any, are needed to increase transfer levels to accommodate the output of IR#361.

2.2 Scope of ERIS Study

In accordance with Section 3.2.1.2 of the Standard Generation Interconnection Procedures (GIP), the FEAS for ERIS consists of short circuit/fault duty, steady state (thermal and voltage) analyses. The short circuit/fault duty analysis would identify direct Interconnection Facilities required and the Network Upgrades necessary to address short circuit issues associated with the Interconnection Facilities. The steady state studies would identify necessary upgrades to allow full output of the proposed Generating Facility and would also identify the maximum allowed output, at the time the study is performed, of the interconnecting Generating Facility without requiring additional Network Upgrades.

ERIS studies can assume that the proposed facility can displace suitable out-of-merit generation as an alternative to network upgrades.

2.3 Subsequent Studies

A more detailed analysis of the technical implications of this development will be included in the System Impact Study (SIS) report. The SIS includes system stability analysis, power flow analysis such as single contingencies (including contingencies with more than one common element), off-nominal frequency operation, off-nominal voltage operation, low voltage ride through, harmonic current distortion, harmonic voltage distortion, system protection, Special Protection Systems (SPS), automatic generation control (AGC) and islanded operation. The impacts on neighbouring power systems and the requirements set by reliability authorities such as Northeast Power Coordinating Council (NPCC), North American Electric Reliability Corporation (NERC), and NSPI will be addressed at that time and will include an assessment of the status of the Interconnection Facility as a Bulk Power System element. The SIS may identify and provide a non-binding estimate of any additional interconnection facilities and/or network upgrades that were not identified in this FEAS.

An Interconnection Facilities Study follows the SIS in order to ascertain the final cost estimate to interconnect the generating facility.

3 Assumptions

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

1. Network Resource Interconnection Service type per Section 3.2.2 of the RGIP. Concurrently, Energy Resource Interconnection service type as per Section 3.2.1 of the RGIP.
2. 49.6 MW wind with 31 units of GE 1.6 MW SLE Wind Turbines.
3. The generation technology used must meet the NSPI requirement for reactive power capability of 0.95 capacitive to 0.95 inductive at the HV terminals of the IC Substation Step Up transformer. The generation facility is specified for 49.6 MW at a rated power factor of 0.90 for both lagging and leading. It is also required to have high-speed Automatic Voltage Regulation to maintain constant voltage at the generator terminals during and following system disturbances as determined in the subsequent System Impact Study.
4. The Interconnection Customer indicated that the POI is on line L-6516, approximately 54.5 km from the 2S-Victoria Junction substation and 70.7 km from the 2C-Port Hastings substation.
5. Preliminary data was provided by the Interconnection Customer for the generator step-up. Modeling was conducted with a 138kV-34.5kV Interconnection Facility transformer with a maximum rating of 60 MVA and a positive sequence impedance of 8.5% on a base rating of 36 MVA (an X/R ratio of 20 was assumed). The Interconnection Customer indicated that this Interconnection Facility step-up transformer has a grounded wye – grounded wye winding configuration with a delta tertiary. The transformer has fixed taps (95% - 105% in 2½% steps).
6. The generator step-up transformer data was not provided by the IC, so typical data are assumed with a delta-grounded wye configuration, ratio of 34.5kV-0.69kV, and an impedance of 6% on 1.6 MVA.
7. The FEAS analysis is based on the assumption that IR's higher in the Generation Interconnection Queue and OATT Transmission Service Queue that have completed a System Impact Study, or that have a System Impact Study in progress will proceed, as listed in Section 4 below.
8. Although the data sheet for the proposed generator data indicates a rating for a minimum temperature of 0°C, it is assumed that the generators are provided with the "cold weather package" option permitting full rating during winter peak.

4 Projects with Higher Queue Positions

All in-service generation is included in the FEAS.

As of 2012-01-13 the following projects are higher queued in the Interconnection Request Queue and OATT Transmission Service Queue, and have the status indicated.

Interconnection Requests -Included in FEAS

- IR#8 GIA Executed
- IR#45 GIA Executed
- IR#56 GIA Executed
- IR#151 GIA Executed
- IR#219 GIA Executed
- IR#227 GIA in Progress
- IR#225 GIA in Progress
- IR#234 FAC in Progress

Interconnection Requests –Not Included in FEAS

- IR #131 SIS Milestones Met
- IR #360 SIS in progress
- IR #362 SIS in progress

OATT Transmission Service Queue– Included in FEAS
- TSR 100 SIS Complete

OATT Transmission Service Queue– **Not** Included in FEAS
- TSR 400 SIS Agreement Completed

Interconnection Requests not included in FEAS

The following IRs either have SIS Agreements complete (but have not yet met the RGIP SIS progression milestones), or have Feasibility Study agreements complete. As such, they are not included in this FEAS.

IR#67	IR#68	IR#117	IR#126	IR#128	IR#149
IR#163	IR#213	IR#222	IR#235	IR#238	IR#241
IR#242	IR#314	IR#356			

If any of the higher-queued projects included in this FEAS are subsequently withdrawn from the Queue, the results of this SIS may require updating or a re-study may be necessary. The re-study cost incurred as a result of the withdrawal of the higher-queued project shall be the responsibility of the Interconnection Customer that withdraws the higher queued project.

While TSR-100 is higher queued, it has an in-service date of 2016, whereas IR#361 has an in-service date of late 2013. Therefore the FEAS for this IR will be performed twice – for 2013 without TSR-100 in service and again for 2016 onwards with TSR-100 in-service, along with any related system changes.

An additional Transmission Service Request TSR-400 and Interconnection Requests IR#131, IR#360 and IR#362 are higher queued than IR#361 and the SIS are either in progress or about to be initiated. However, the results of these SIS are not sufficiently defined to be included in the FEAS for IR#361.

5 Objective

The objective of this FEAS is to provide a preliminary evaluation of the system impact and the high-level non-binding cost estimate of interconnecting the 49.6 MW generating facility to the NSPI transmission system at the designated location. The assessment will identify potential impacts on the loading of transmission elements, which must remain within their thermal limits. Any potential violations of voltage criteria will be identified and addressed. If the proposed new generation increases the short-circuit duty of any circuit breakers beyond their rated capacity, the circuit breakers must be upgraded. Single contingency criteria[1] are applied for the NRIS assessments.

This FEAS is based on a power flow and short circuit analysis and does not include a complete determination of facility changes/additions required to increase system transfer capabilities that may be required to the Bulk Power System to meet the design and operating criteria established by NPCC and NERC or required to maintain system stability. These requirements will be determined by the subsequent interconnection System Impact Study (SIS).

[1] The Single Contingency Criteria is defined by NPCC in its A-7 Document, and may involve more than one transmission element.

6 Short-Circuit Duty

The maximum (design) expected short-circuit level is 5000 MVA on 138kV systems. The short-circuit levels in the area before and after this development (including TSR#100) are provided below in Table 6-1.

Table 6-1: Short-Circuit Levels. Three-phase MVA (1)

Location	IR#361 in service	IR#361 not in service
All transmission facilities in service		
Interconnection Facility (POI)	994	943
2S-Victoria Junction 138kV	2201	2177
81S-St. Peters 138kV	1061	1033
2C-Port Hastings 138kV	2588	2568
Minimum Conditions		
Interconnection Facility (POI)	510	461

(1) Classical fault study, flat voltage profile

In determining the maximum short-circuit levels with this generating facility in service the generators have been modeled as conventional machines with reactance comparable to Class 2 (induction) wind turbine machines regardless of the type of generators proposed, which provides a worst case scenario. The SIS will refine the fault level based on the actual machine characteristics.

The maximum short-circuit level at the POI on L-6516 is presently 943 MVA. After installing IR#361 the increase will bring the short-circuit level to 994 MVA at the POI. Similarly, under summer light load conditions with certain generation units offline the minimum short-circuit level will be approximately 461 MVA at the POI. This translates into maximum equivalent system impedance at the POI of 0.22 per unit on 100 MVA base.

The interrupting capability of the 138kV circuit breakers at 2S-Victoria Junction and 2C-Port Hastings is at least 3500 MVA, which will not be exceeded by this development on its own.

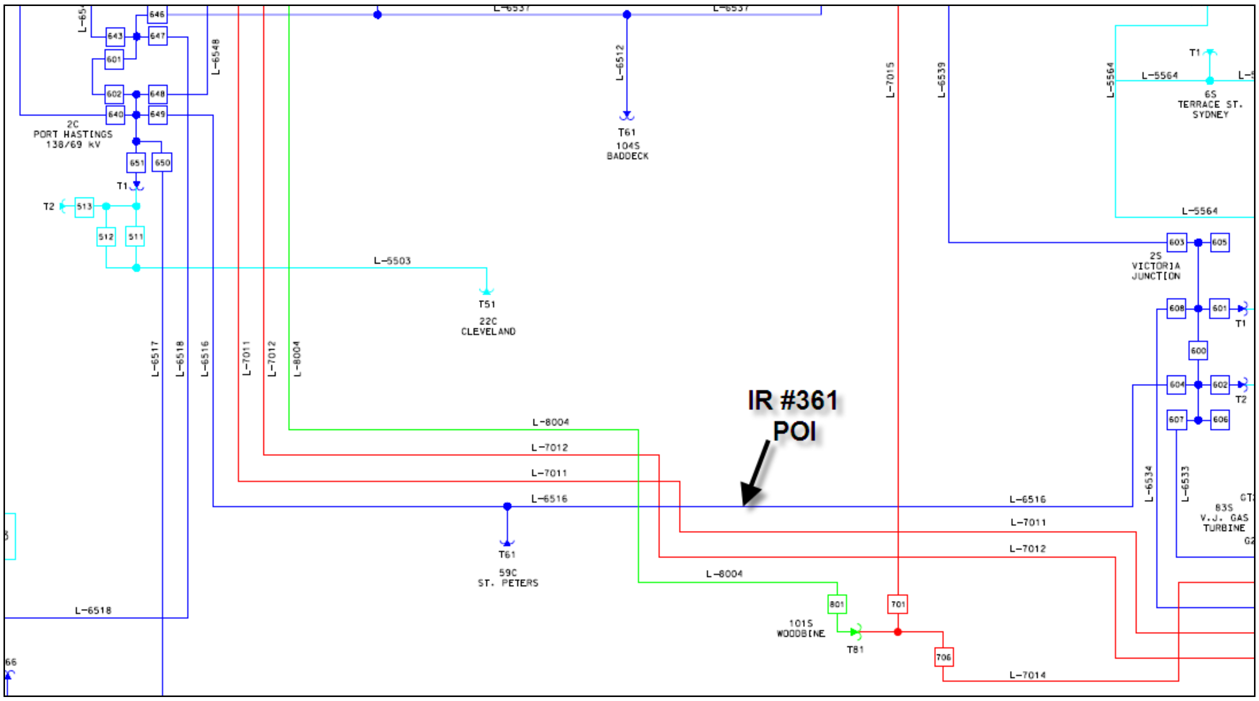
7 Voltage Flicker and Harmonics

The flicker coefficient of the GE 1.6 MW Wind Turbines is assumed to be 4.6. The calculated voltage flicker at the POI on line L-6516 using IEC Standard 61400-21 is 0.06 under normal conditions and 0.125 under line-out (minimum fault level) conditions. These are both below NSPI's required limit of 0.35 for P_{st}. Therefore voltage flicker should not be a concern for this project.

The Interconnection Facility is expected to meet IEEE Standard 519 limiting Total Harmonic Distortion (all frequencies) to a maximum of 5%, with no individual harmonic exceeding 1%.

8 Thermal Limits

This Interconnection Facility is proposed to interconnect with L-6516 approximately 54.5 km from the 2S-Victoria Junction substation. L-6516 is constructed of 556.5 Dove ACSR with a maximum operating temperature of 50ºC, yielding a summer rating of 110 MVA and a winter rating of 165 MVA. However, the switch at the 2C-Port Hastings end of the line is limited to 143 MVA, and full-scale metering at the 2S-Victoria Junction end is currently set for 115 MVA. A small section (0.93 km) of L-6516 is constructed with a smaller conductor (339.3 ACSR) at the Beaver Narrows Crossing, but this section is not the limiting element on the line.



L-6516 is classified as a "NERC critical transmission element", and therefore generation connections to this line require a three-breaker ring bus.

NSPI defines two Interconnection Reliability Operating Limit (IROL)[2] interfaces: Onslow Import (ONI) and Cape Breton Export (CBX) which cannot be exceeded. ONI is currently 1025 MW based on system stability performance and CBX based on either system stability (900 MW) or seasonally based on thermal limits. Prior to the addition of IR#361, the CBX summer limit is 825 MW with Pt. Aconi generation on-line and 760 MW with Pt. Aconi off-line. Transfer capacity across CBX and ONI is provided by SPS rejection of one or two thermal units at Lingan following any of a number of contingencies. If Lingan units are not on-line, or if they are operated below 150 MW

[2] NERC Standard FAC-010 System Operating Limits Methodology for the Planning Horizon. (http://www.nerc.com/files/FAC-010-2.1.pdf)

each, the transfer capability across CBX can be as low as 475 MW and ONI as low as 875 MW.

8.1 NRIS Analysis

As stated in Section 2.1, NRIS facilities assume the system is pre-loaded to established transmission limits when the impact of superimposing IR#361 is examined. This means that the incremental generation displaces existing generation in the load centre.

For winter peak conditions (assuming the generators are equipped with the cold weather option), beginning with CBX and ONI at their seasonal peak values of 900 MW and 1025 MW respectively and IR#361 off-line, there were no thermal or voltage issues with any design contingency applied. Adding IR#361 increased CBX to 947 MW and ONI to 1069 MW. Load flow analysis demonstrated that there was no significant impact on reliability for winter peak conditions, primarily due to the higher thermal rating of transmission elements in winter, and local load (at peak) kept transmission flows below limits.

For summer conditions, the system was dispatched at existing limits of ONI (1025 MW) and CBX (825 MW) with Pt. Aconi generation on-line and all SPS's were assumed to be armed. All contingencies were checked to ensure that there are no pre-existing thermal or voltage issues. Then IR#361 was added on-line raising ONI and CBX to 1070 MW and 872 MW respectively. The only contingency which failed thermal loading criteria was the simultaneous loss of both circuits (the 345kV circuit L-8004 and the 230kV circuit L-7005) on the double-circuit tower across the Strait of Canso. This contingency activates the SPS which trips two Lingan units (310 MW net) and results in the following overloaded elements:

Element	Voltage	Line Length	Post Contingency Load % of Summer Rating
L-7019	230 kV	29.6 km	118%
L-7003	230 kV	160.6 km	102%
L-6511	138 kV	36.5 km	113%

In 2016, a number of system changes in NS have been recommended by TSR100. The only upgrade of interest to IR#361 is the increased thermal capacity of L-6515 from 2C-Port Hastings to 4C-Lochaber Rd.

In 2017, IR#225 and IR#234 are added to the system at L-6503. The transmission upgrades associated with these projects will not impact IR#361. Although the in-service date of IR#225 and IR#234 is later than IR#361, they are higher-queued in the GIP and therefore any upgrades necessary due to the addition of IR#361 become the responsibility of IR#361. Operation of IR#361 as NRIS impacts the distribution of flow across CBX such that the following overloaded elements for loss of the Strait Crossing double-circuit tower:

Element	Voltage	Line Length	Post Contingency Load % of Summer Rating
L-7004	**230 kV**	**131 km**	**106%**
L-7019	**230 kV**	**29.6 km**	**127%**
L-7003	**230 kV**	**160.6 km**	**110%**
L-6515*	**138 kV**	**50.7 km**	**113% from 2C to 100C, 109% 100C to 4C**
L-6511	**138 kV**	**35.6 km**	**141%**

*If L-6515 is uprated by TSR-100, this line item is eliminated; otherwise it would be the responsibility of IR#361

The cost of uprating these lines will depend on the number of structures and spans that need to be remedied, but an estimate of the cost ranges from $88.9M for thermal uprating to $176.4M for complete rebuild. It is therefore recommended to eliminate the offending contingency by separating L-8004 and L-7005 from the common double circuit tower. An additional crossing of the Strait of Canso has been estimated at $26M, but recent engineering studies indicate that circuits could be re-arranged at an estimated cost of $8.1M. This is considered a Network Upgrade in accordance with the RGIP.

Any impact of TSR-400 will be determined in the SIS, as results of that study are not sufficiently advanced to comment at this time.

8.2 ERIS Analysis

Section 2.2 explains that ERIS studies can assume that IR#361 can displace suitable existing (or higher-queued) generation with a potential for out-of-merit generation dispatch costs. For generation in Cape Breton, ERIS feasibility studies are assumed to displace thermal generation at Lingan, Point Aconi, or Point Tupper. It has been noted above that CBX transfer limits are reduced if Pt. Aconi generation is off-line or there are not two units at Lingan operating above 150 MW each. With this in mind, if IR#361 displaces existing thermal generation in Cape Breton, no system upgrades are required. All elements remain within their thermal limits and all voltages remain within acceptable boundaries for all contingencies studied.

9 Voltage Limits

This project, like all new generating facilities must be capable of providing both lagging and leading power factor of 0.95, measured at the HV terminals of the IC Substation Step Up Transformer, at all production levels up to the full rated load of 49.6 MW.

Data provided by the IC indicates that IR#361 may not be able to meet this requirement without additional reactive support. Based on the assumed rated power factor of the GE 1.6 MW machines (0.90), and the provided impedances of the collector circuits and transformers, capacitor banks in the range of 3-4 Mvar installed at the 34.5kV bus of the Interconnection Facility substation may be able to meet the requirements. This will be further investigated in the System Impact Study.

A centralized controller will be required which continuously adjusts individual generator reactive power output within the plant capability limits and regulates the voltage at the 34.5 kV bus voltage. The voltage controls must be responsive to voltage deviations at the terminals of the Interconnection Facility substation, be equipped with a voltage set-point control, and also have the ability to slowly adjust the set-point over several (5-10) minutes to maintain reactive power within the individual generators capabilities. The details of the specific control features, control strategy and settings will be reviewed and addressed in the SIS, as will the dynamic performance of the generator and its excitation.

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

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

10 System Security / Stability Limits (Transfer Capability)

There are a number of Special Protection Systems (SPS) and protective systems employed by NSPI to permit high transfer levels across the Nova Scotia Bulk Power System. The Type I SPS designated #119 trips either one or two thermal units at Lingan for faults on the 345kV system between 101S-Woodbine and 67N-Onslow (lines L-8004, L-8003, and bus faults or breaker failures at 79N-Hopewell and 67N-Onslow). Thermal analysis conducted in Section 8 above examined the impact of the addition of IR#361 on the steady-state post-contingency conditions assuming that this SPS has rejected the expected level of generation, however the SPS is primarily required for system stability, to prevent cascading tripping of parallel transmission on the corridor between Cape Breton and Onslow. The limits of the two interfaces designated as IROL (CBX and ONI) cannot be exceeded as required by NERC Standards TOP-004 and TOP-007, therefore the limits must be increased to provide for NRIS. Increasing the thermal capacity of lines may not increase the stability limit of interfaces, so a key objective of the System Impact Study for NRIS will be the increase of ONI and CBX interfaces to permit the addition of flow from IR#361.

This generating facility will also increase loading on the Onslow South corridor (Truro to Halifax) by replacing generation located south and west of Truro. This may require increased reactive support requirements in the Halifax area or invoke facility additions that can reduce the reactive support requirements. This will be evaluated in the SIS.

The SIS will determine if any facility changes are required to permit the proposed higher transmission loadings while maintaining compliance with NERC/NPCC standards and in keeping with good utility practice.

11 Expected Facilities Required for Interconnection

The following facility changes are required to interconnect IR#361 to the 138 kV transmission line L-6516:

Additions/Changes to POI on L-6516:

1. Establish a new 138kV substation at the POI, with a three-breaker ring bus.
2. Turn L-6516 into the new substation.
3. Control and communications between the Generating Facility and NSPI SCADA system. It is expected that the existing fibre optic link on L-8004 can be turned into the Interconnection Substation.
4. Protection upgrades at 2S-Victoria Junction and 2C-Port Hastings substations.

Network Upgrades Associated with NRIS:

1. Modification of the 345kV Double Circuit Towers (DCT) at Strait of Canso. Move L-6515 to DCT with L-8004, move L-7005 to new structures.

Requirements for the Generating Facility

1. 138 kV Interconnection Substation. An RTU to interface with NSPI's SCADA, with telemetry and controls as required by NSPI.
2. Facilities to provide 0.95 leading and lagging power factor when delivering rated output (49.6 MW) at the HV terminals of the IC Substation Step Up Transformer when the voltage at that point is operating between 95 and 105 % of nominal. Preliminary analysis indicates that 3-4 Mvar of capacitors may be required at the low voltage terminals of the Interconnection Facility transformer to meet this requirement.
3. A centralized controller will be required which continuously adjusts individual generator reactive power output within the plant capability limits and regulates the voltage at the 34.5 kV bus voltage. The voltage controls must be responsive to voltage deviations at the terminals of the Interconnection Facility substation, be equipped with a voltage set-point control, and also have the ability to slowly adjust the set-point over several (5-10) minutes to maintain reactive power within the individual generators capabilities. The controls will include a curtailment scheme which will limit or reduce total output from the facility, upon receipt of a telemetered signal from NSPI's SCADA system. The controller will also limit the load ramp rate of the facility to within limits set by NSPI and/or telemetered from NSPI's SCADA system.
4. NSPI to have control and monitoring of voltage control and reactive output of this facility, via the centralized controller. This will permit the NSPI Operator to raise or lower the voltage set-point remotely.

5. Low voltage ride-through capability as per Appendix G to the Standard Generator Interconnection and Operating Agreement (GIA).
6. Real-time monitoring of the interconnection facilities via NSPI SCADA.
7. Facilities for NSPI to execute high speed rejection of generation (transfer trip) if determined in SIS.
8. The Interconnection Facility is expected to meet IEEE Standard 519 limiting Total Harmonic Distortion (all frequencies) to a maximum of 5%, with no individual harmonic exceeding 1%.

12 NSPI Interconnection Facilities and Network Upgrades Cost Estimate

Estimates for NSPI Interconnections Facilities and Network Upgrades for interconnecting 49.6 MW wind generation facility with NRIS are included in Table 12-1, and ERIS in Table 12-2.

Table 12-1: Cost Estimates for NRIS		
	Determined Cost Items	**Estimate**
NSPI Interconnection Facilities		
i	Protection, control and communications, plus annual operating cost of leased telecom facilities $24,000	$500,000
Network Upgrades		
ii	Three 138kV circuit breakers in a ring-bus arrangement, with substation development	$4,628,000
iii	Rearrange Strait Crossing circuits	$8,100,000
Totals		
iv	Subtotal	$13,228,000
v	Contingency	$1,323,000
vi	Total of Determined Cost Items	$14,551,000
	To be Determined Costs	
vii	System additions to address potential stability limits	TBD (SIS)

Table 12-2: Cost Estimates for ERIS		
	Determined Cost Items	**Estimate**
NSPI Interconnection Facilities		
i	Protection, control and communications plus annual operating cost of leased telecom facilities $24,000	$500,000
Network Upgrades		
ii	Three 138kV circuit breakers in a ring-bus arrangement	$4,628,000
Totals		
iii	Subtotal	$5,128,000
iv	Contingency (10%)	$513,000
v	Total of Determined Cost Items	$5,641,000
	To be Determined Costs	
vi	System additions to address potential stability limits	TBD (SIS)

The preliminary non-binding cost estimate for interconnecting IR#361 on L-6516 would be $14.551M for NRIS and $5.641M for ERIS. In both cases, an annual operating cost of

$24,000 will be borne by the IC. The IC is required to fund the Network Upgrade (items ii and iii for NRIS, item ii for ERIS) costs, and would be eligible for repayment in accordance with the terms of the GIA.

13 Issues to be addressed in SIS

The following provides a preliminary scope of work for the subsequent SIS for IR#361. The SIS will include a more comprehensive assessment of the technical issues and requirements to interconnect generation as requested. It will include contingency analysis, system stability and ride through and operation following a contingency (N-1 operation). The SIS must determine the facilities required to operate this facility at full capacity, withstand any contingencies (as defined by the criteria appropriate to the location) and identify any restrictions that must be placed on the system following a first contingency loss. The SIS will confirm the options and ancillary equipment that the customer must install to control flicker, voltage and ensure that the facility has the required ride-through capability. The SIS will be conducted in accordance with the GIP with the assumption that all appropriate higher-queued projects will proceed and the facilities associated with those projects are installed.

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

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

i. Facilities that the customer must install to meet the requirements of the GIP.
ii. The minimum transmission additions/upgrades that are necessary to permit operation of this Generating Facility, under all dispatch conditions, catering to the first contingencies listed.
iii. Guidelines and restrictions applicable to first contingency operation (curtailments etc).
iv. System loss impacts.
v. Under-frequency load shedding impacts.
vi. Bulk Power status in accordance with NPCC A-10 criteria.

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

- L-8001/3025
- L-3006 – with and without NBPT SPS operation
- Memramcook 345/138 kV transformer
- L-8004
- L-8003

- L-7005
- L-7012
- L-7014
- L-6537 (with SPS as required)
- L-8002 & L-8003 (common circuit breaker)
- L-8003 & L-8004 (common circuit breaker)
- L-8001 & 67N-T81 (common circuit breaker)
- L-8002 & 67N-T81 (common circuit breaker)
- L-8004 & L-7005 (common circuit tower)
- L-7003 & L-7004 (common circuit tower)
- 2C-B61 or 2C-B62 bus sections
- 1N-B61 bus
- 2S-B61 and 2S-B62 bus sections

To complete this assessment the dynamics of the following first contingencies, as a minimum, will be assessed (all faults are considered permanent, i.e. automatic reclosing fails to restore the circuit):

- 3 phase fault L-8001/3025 at 67N-Onslow, NS Import SPS operation (islanding)
- 3 phase fault L-8003 at 67N-Onslow and 79N-Hopewell
- 3 phase fault L-8002 at 67N-Onslow
- 3 phase fault L-8004 at 101S-Woodbine
- Single Phase to Ground fault (spg) separate phases of L-8004 and L-7005
- Spg L-8003 at 67N-Onslow, drops L-8003 and L-8002
- 3 phase fault at 79N-Hopewell, drops L-8003, L-8004, bus.
- 3 phase fault 2C-B62, drops L-6516, L-6515, L-6517
- 3 phase fault 2S-Victoria Junction 69 kV bus (repeated for each bus section)

Any changes to SPS schemes required for operation of this generating facility, in addition to existing generation and facilities that can proceed before this project, will be determined by the SIS as well as any required additional transmission facilities. The determination will be based on NERC[3] and NPCC[4] criteria as well as NSPI guidelines and good utility practice. Any new SPS, or any significant change to an existing SPS, must be approved by NPCC. The SIS will also determine the contingencies for which this facility must be curtailed.

The SIS will calculate the unit loss factor, which is a measure of the percentage of the net output of IR#361 which is lost through the transmission system while displacing generation in the load centre. Preliminary value is calculated to be 15.1% (system losses increased by net 7.5 MW when IR#361 is operated at 49.6 MW).

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2012-02-10

[3] NPCC criteria are set forth in Reliability Reference Directory #1 *Design and Operation of the Bulk Power System*
[4] NERC transmission criteria are set forth in *NERC Reliability Standards TPL-001, TPL-002, TPL-003*