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December 13, 2018

The Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, PO Box 21040
St. John's, NL A1A 5B2

Attention: Ms. Cheryl Blundon
Director of Corporate Services and Board Secretary

Dear Ms. Blundon:

Re: The Board's Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System —Operational Studies —Stage 4 Reports

Further to Newfoundland and Labrador Hydro's correspondence of August 4, 2017, please find attached an original and twelve copies of the following reports:

- TransGrid Solutions, "Stage 4A LIL Bipole: Preliminary Assessment of High Power Operation," November 21, 2018; and
- TransGrid Solutions, "Stage 4B: Power System Stabilizer Design," November 8, 2018.

"Stage 4C: Labrador Transfer Analysis" and "Stage 4D: High Power Operational Limits" will be filed in the first quarter of 2019.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

Shirley A. Walsh
Senior Regulatory Counsel
SAW/sk

Encl.

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey
ecc: Denis Fleming – Cox & Palmer
Roberta Frampton Benefiel – Grand Riverkeeper® Lab

Dennis Brown, Q.C. – Browne Fitzgerald Morgan & Avis
Danny Dumaresque
Larry Bartlett – Teck Resources Limited

Engineering Support Services for:

RFI Studies

Newfoundland and Labrador Hydro

Attention: Mr. Rob Collett

Stage 4A LIL Bipole: Preliminary Assessment of High Power Operation

Technical Note: TN1205.62.05
Date of issue: November 21, 2018

Prepared By:
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Disclaimer

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Revisions

Project Name:	RFI Studies
Document Title:	Stage 4A LIL Bipole: Preliminary Assessment of High Power Operation
Document Type:	Technical Note
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Rev. No.	Status	Prepared By	Checked By	Date	Comments
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01	DFC	R. Ostash		June 20, 2018	Draft updated based on comments received from Hydro on May 25, 2018
02	IFC	R. Ostash		June 25, 2018	Updated based on comments received on June 25, 2018. Issued for further comments from Hydro.
03	IFC	R. Ostash		August 17, 2018	Updated based on comments received from Hydro and combined with UFLS study report.
04	IFA	R. Ostash		Sept. 13, 2018	Updated based on comments received from Hydro on August 30, 2018.
05	ABC	R. Ostash		Nov. 21, 2018	Updated based on final comments received from Hydro on November 19, 2018.

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Approved by Client	ABC	Issued for Approval	IFA
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Issued for Comments	IFC	Returned for Correction	RFC

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Appendices

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1. Executive Summary

1.1 Introduction

Three previous operational studies were performed to determine the system operating limits of the Newfoundland and Labrador Hydro (Hydro) Island Interconnected System (IIS) for the following periods in time:

1. Stage 1: "ML Only" study[1]; when the Maritime Link (ML) is in-service, but prior to the Labrador Island Link (LIL) coming in to service. The Soldiers Pond (SOP) synchronous condensers were assumed not to be in service.
2. Stage 2: "ML and SOP Syncs"[2] study; when the Maritime Link (ML) and the Soldiers Pond (SOP) synchronous condensers are in-service, but prior to the Labrador Island Link (LIL) coming in to service.
3. Stage 3: "ML, SOP Syncs and LIL Monopole"[3] study; when the Maritime Link (ML), Soldiers Pond (SOP) synchronous condensers and the LIL as a 225 MW monopole (phased approach) are in-service, but prior to the Muskrat Falls generating units coming in to service.

Stage 4 is the final stage of studies and includes the 900 MW LIL bipole, the Muskrat Falls (MFA) generators, the SOP synchronous condensers and the ML. The Holyrood thermal generators, the Stephenville Gas Turbine, and the Hardwoods Gas Turbine are no longer in-service[4]. Holyrood Unit 3 is operating as a synchronous condenser.

This report addresses technical considerations[5] identified by the Liberty Consulting Group as part of Phase 2 of the Hearing into Supply Issues and Power Outages on the Island Interconnected System. Specifically, the report addresses the technical considerations that relate to analyses being performed as part of Stage IV of the operational studies. These technical issues are summarized as follows:

- Options (e.g. operating limits) to reduce UFLS
- Re-strikes on the LIL-OHL
- ML-LIL interaction studies
- Bay d'Espoir instability issues
- ML frequency controller study

[1] TN1205.50.04, "Operational Studies: Maritime Link ONLY", TransGrid Solutions, September 8, 2017.
[2] TN1205.51.03, "Operational Studies: Maritime Link & Soldiers Pond Synchronous Condensers", TransGrid Solutions, November 10, 2017.
[3] TN1205.54.03, "Operational Studies: Maritime Link, SOP Syncs and LIL Monopole", TransGrid Solutions, May 18, 2018.
[4] The Stephenville Gas Turbine and the Hardwoods Gas Turbine are scheduled to be retired in in the early 2020's. This study considers long term operation after these units are no longer in service.
[5] Second Quarterly Monitoring Report on the Integration of Power Supply Facilities to the Island Interconnected System, The Liberty Consulting Group, Section 6e, The Liberty Consulting Group, May 23, 2018.

- IIS performance with ML in and out of service
- Soldiers Pond site for 4th high inertia synchronous condenser.

This report consists of the following sections to address these items.

1. Review of Three-Phase Faults

This section includes a technical review of impacts of three-phase faults within the eastern portion of the Interconnected Island System (IIS) from Bay d'Espoir to Soldiers Pond[6]. Faults in this area, particularly at Bay d'Espoir, are of interest since they are the most sensitive to angular instability and voltage instability.[7]

2. Loss of the Largest Unit within the IIS

This section investigates loss of the largest generator within the IIS. Frequency controller coordination and LIL operating limits are investigated to ensure that the IIS frequency stays above the 59 Hz in accordance with Transmission Planning Criteria to avoid customer load interruptions.

3. Loss of a LIL Pole

This section reviews the coordination of frequency controllers, HVdc runbacks and spinning reserves to ensure that the IIS frequency stays above the 59 Hz limit of the Transmission Planning Criteria. LIL operating limits are defined for situations when the ML frequency controller is out of service.

4. Loss of the LIL Bipole

This section determines the modifications required to the present-day UFLS scheme to ensure that the system frequency remains above the 58 Hz limit of the Transmission Planning Criteria. LIL operating limits are defined for various IIS operating conditions.

5. Review of Temporary Bipole Outages

This section reviews the impacts of a temporary LIL bipole outage. Analysis is performed to assess the maximum duration of a LIL bipole outage with a restart that can occur while meeting the 59 Hz criteria and avoiding UFLS. Analysis is also performed to determine the maximum duration of a LIL bipole outage with a restart to ensure the system frequency remains above the 58 Hz limit, as pecified in Transmission Planning Criteria. This section addresses re-strikes on the LIL-OHL.

6. Loss of the ML Bipole or Pole

This section reviews loss of the ML bipole and loss of an ML pole when operating at the 500 MW export limit and the 325 MW import[8] limit to ensure the Transmission Planning Criteria are met for overfrequency and underfrequency response.

[6] A complete review of the steady state and transient stability performance of the IIS and the Labrador Transmission System will be performed as part of upcoming analyses to be performed Stage IV operational studies.
[7] Upgrade the Transmission Line Corridor from Bay d'Espoir to Western Avalon, Hydro, April 28, 2014
[8] Limit as per Summary of Maritime Link Transfer Capability, Maine & Atlantic Technical Planning Committee, NBP/NLH/NSPI Reserve Study Working Group, April. 2017

1.2 Conclusions

The results of the analysis are summarized in the sections below.

1.2.1 Three-Phase Faults near SOP, BDE and the Avalon Peninsula

The analysis included a review of three-phase faults on the 230 kV lines between Bay d'Espoir (BDE) and SOP. It was found that instability resulting from such faults is a function of power flow in this corridor. Preliminary analysis was performed to assess transfer limits, which will be confirmed during the final Stage 4 operational studies[9]. Preliminary results related to the ability to serve Island demand are discussed below for situations when the LIL is in-service and when the LIL is out-of-service.

1) LIL in-service

The preliminary analysis indicates that flow in the BDE to Avalon Peninsula corridor can be restricted to avoid instability from the three-phase faults listed above without impacting the capacity of the transmission system to meet forecasted peak loads and ML export commitments[10] when the LIL is in-service as a bipole or as a monopole.

2) LIL out-of-service

If the LIL is out-of-service, peak Island demand cannot be served. With the LIL out of service, the maximum Island demand that can be served is around 1200 MW if the 3PF at BDE is considered. As noted below, the limitation of power flow from BDE to the Avalon Peninsula is also required to ensure system stability in the event of a loss of the LIL bipole.

In order to be capable of serving higher Island demand without a stability issue under a three-phase fault scenario on TL202, TL206 or TL267 with the LIL out of service, it is likely that either new generation would be required on the Avalon peninsula, that dynamic reactive power support would be required near Sunnyside, or that new AC transmission eastward out of BDE would be needed in order to transfer more generation from the west of the Island to the Avalon Peninsula.

1.2.2 Loss of Largest Unit with the IIS

After retirement of the Holyrood generating units, BDE Unit 7 at 154.4 MW is the largest generator on the Island. Frequency should remain above 59 Hz for loss of BDE Unit 7 to avoid UFLS.

Table 1-1 summarizes the LIL reserve requirements to ensure that loss of the largest generator meets the 59 Hz criteria to avoid UFLS.

Table 1-1. LIL reserve requirements for loss of largest generator

ML Frequency Controller	Reserve required on LIL
In-service	None
Out-of-service	54 MW to 130 MW, depending on system conditions

[9] Stage 4 studies include a review of the underfrequency load shedding schemes, HVdc runback coordination and frequency controller settings, spinning reserve requirements, and the application of power system stabilizers. Operating limits will be investigated after these other system considerations have been studied.
[10] ML export commitments of 157 MW are assumed to represent the Emera Export Block.

1.2.3 Loss of a LIL Pole

Similar to loss of the largest generator, frequency should remain above 59 Hz for loss of a LIL pole and UFLS should be avoided.

If one of the LIL poles is lost, the remaining pole has an overload rating of 2.0 pu for 10 minutes, after which the rating drops down to a 1.5 pu continuous rating. The reduction in delivered power at SOP following the transition to monopole operation depends on how much power the LIL was transferring prior to loss of the pole. In a worst case, if operating at 900 MW, this study showed that prior to converter transformer tap-changer action and due to increased DC line losses associated with the resistance of the line electrode, the remaining pole is only able to provide 633 MW at Soldiers Pond, as opposed to the 830 MW it was providing pre-contingency, resulting in the net loss of 267 MW to the IIS.

Operating restrictions to keep the IIS frequency above 59 Hz for loss of a LIL pole are summarized in Table 1-2.

Table 1-2. Operating restrictions to ensure loss of LIL pole meets 59 Hz criteria

During ML Export	At full LIL power transfer of 900 MW, loss of a LIL pole will require the ML to be runback in the range of 100 MW to 150 MW, depending on system conditions, and depending on whether or not the ML frequency controller is in- or out-of-service.
During ML Import	If the ML import is at the maximum level of 325 MW, it cannot transiently import more power from Nova Scotia via its frequency controller or via a runback, therefore it cannot not help the IIS during underfrequency events. In this case, LIL power transfer would be limited to around 400 MW to 500 MW (depending on system conditions) to avoid UFLS..

1.2.4 Loss of the LIL Bipole

Per Transmission Planning Critieria, controlled underfrequency load shedding is permitted for loss of the LIL bipole, however, the IIS frequency shall not drop below 58 Hz. Additionally, if the ML is exporting, the export will be runback to 0 MW if the LIL bipole trips.

In addition to running back ML export to 0 MW, modifications to the existing UFLS scheme are needed to maintain the IIS frequency above 58 Hz for loss of the LIL bipole. Additional blocks of load were added to the UFLS scheme, and the blocks were shifted to distribute the load shedding over a frequency range of 58.9 Hz to 58.4 Hz.

Despite the newly designed UFLS scheme, it is not possible to transfer the full 900 MW on the LIL unless there is sufficient Island generation on-line to provide adequate voltage and inertial support if the LIL bipole is lost. A preliminary operating guideline is defined in Figure 1-1, which limits LIL transfer based on a minimum requirement for Island generation. The LIL transfer limits are defined for two scenarios:

- ML is exporting firm transfer of 157 MW, and is relied upon to runback these exports to 0 MW
- ML is operating at 0 MW and only frequency controller action is available

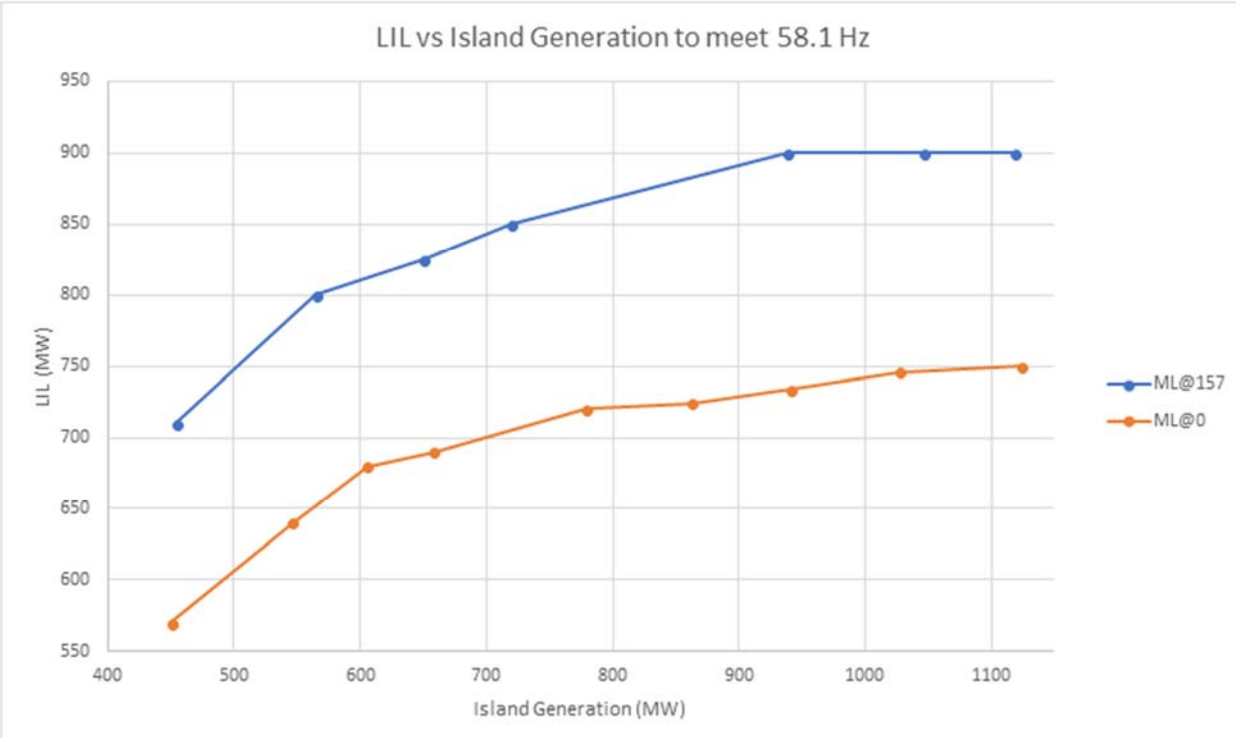

Figure 1-1. LIL Transfer limits vs. Island Generation
Blue: ML at 157 MW export
Orange: ML at 0 MW

In addition to the LIL transfer limits shown in Figure 1-1, other conclusions include:

- Instability can arise in cases when there is a high power flow from BDE to the Avalon Peninsula. Operation of the HRD GT during peak load conditions is required to prevent system instability if the LIL bipole is lost.
- The Come-By-Chance capacitor banks should be in-service when the power flow eastward from BDE towards SOP is high to help support the voltage if the LIL bipole is lost. Keeping the pre-contingency voltage near Sunnyside as high as possible (within criteria) improves the system response to the worst case contingencies, including 3PF on TL202, TL206 and TL267 that were discussed in Section 1.2.1.

1.2.5 LIL Temporary Bipole Outage

According to Transmission Planning Criteria, a temporary bipole outage should not cause the IIS frequency to drop below 59 Hz and UFLS should be avoided.

Two LIL bipole outage durations were studied under worst case system conditions[11]:

1) Maximum outage time to ensure IIS frequency stays above 59 Hz and UFLS is avoided

[11] Case HP27 was found to be the worst case for loss of LIL bipole.

2) Outage time by which all blocks of load will have been shed at 58.0 Hz.

Table 1-3 summarizes these results for the worst case system conditions.

Table 1-3. Duration of LIL Bipole Outage

Number of SOP synchronous condensers in-service	Duration to Avoid UFLS	Duration at which all blocks of load have shed
2	300 ms	680 ms
3	380 ms	780 ms

It is important to note that the LIL frequency controller must be in-service if the LIL will be automatically restarted after a bipole outage. This is to account for the runback of ML export to 0 MW and the possibility that load has shed. If the LIL frequency controller is not in-service when the LIL bipole is automatically restarted, the ML frequency controller alone cannot maintain the IIS frequency to within 62 Hz if all blocks of load are shed.

1.3 Loss of the ML Bipole or Pole

As per Tranmission Planning Criteria, the loss of an ML pole (when importing) should not result in UFLS and frequency should remain above 59 Hz. Loss of the ML bipole is allowed to result in UFLS, however the frequency should remain above 58 Hz.

If exporting, frequency should remain below 62 Hz for loss of an ML pole or bipole .

The results for loss of an ML pole or bipole are summarized in Table 1-4.

Table 1-4. Summary of results for loss of ML bipole or pole

ML Import/Export	Loss of ML Pole	Loss of ML Bipole
500 MW export	Max. frequency of 60.6 Hz (light load)	Max. frequency of 61.2 Hz (light load)
320 MW import	<u>LIL in-service:</u> min. frequency > 59 Hz <u>LIL out-of-service:</u> min. frequency 58.9 Hz, with 26 MW of loadshed	<u>LIL in-service:</u> min. frequency 58.86 Hz, with 0-76 MW of loadshed <u>LIL out-of-service:</u> min frequency 58.24 Hz, with 273-389 MW of loadshed

2. Study Models and Criteria

The Interconnected Island System (IIS) is the area of focus for this study.

2.1 Interconnected Island System

The 230 kV network of the IIS is shown in Figure 2-1.

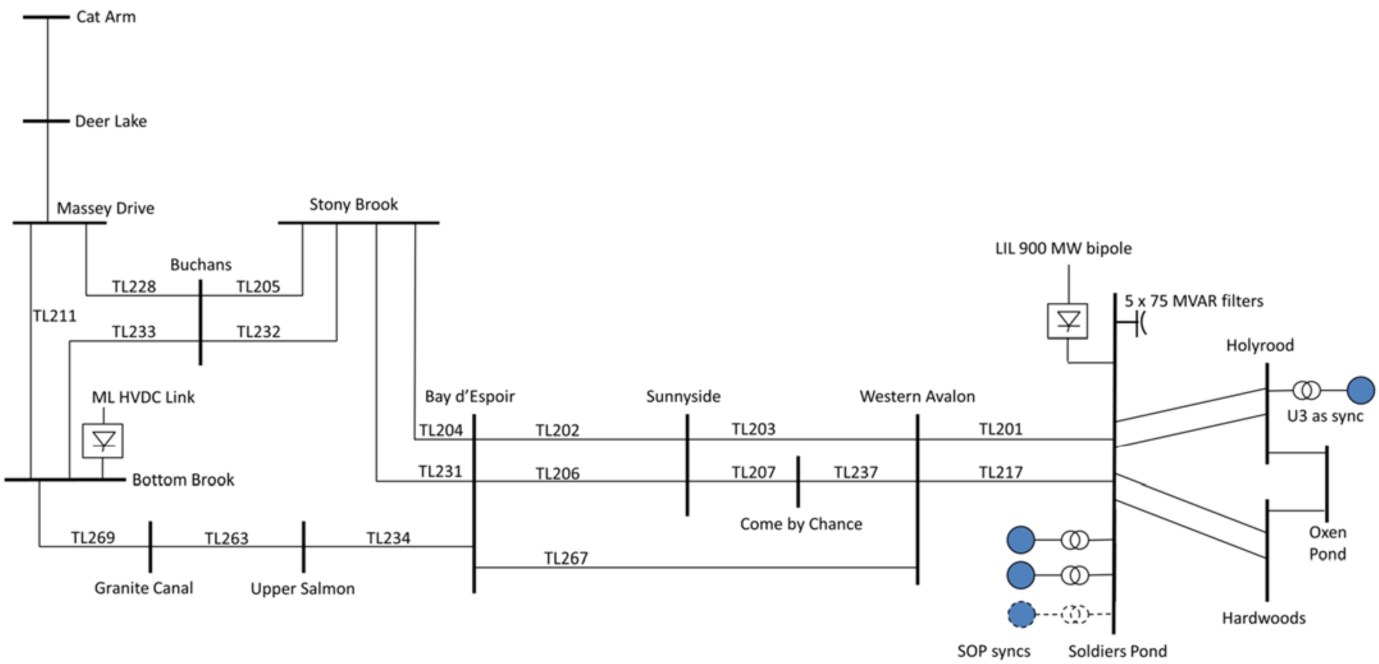

Figure 2-1. Interconnected Island System 230 kV grid

The system was setup as follows:

- The Holyrood thermal generators are no longer available
- The Hardwoods and Stephenville Gas Turbines are no longer available
- Holyrood Unit 3 is operating as a synchronous condenser
- Two of the three 175 MVA SOP synchronous condensers are in-service (assuming one is out for maintenance)

2.2 LIL

The following LIL reactive power elements were available in the models:

- MFA: 4x72 MVAR filters
- SOP: 5x75 MVAR filters

2.3 Study Criteria

The applicable Transmission Planning Criteria for this study is summarized below:

- Steady state voltage : 0.95 pu – 1.05 pu during n-0 conditions
- Steady state voltage : 0.90 pu – 1.1 pu during n-1 conditions
- Post fault recovery voltages on the ac system shall be as follows:
  - Transient undervoltages following fault clearing should not drop below 70%
  - The duration of the voltage below 80% following fault clearing should not exceed 20 cycles
- Post fault system frequencies shall not drop below 59 Hz and shall not rise above 62 Hz
- For a permanent loss of the LIL bipole, underfrequency load shedding shall be permitted, but controlled, and the system frequency shall not drop below 58 Hz

2.4 Contingencies

Table 2-1 lists the contingencies that were considered in this study.

Table 2-1. Contingencies

Line/Generator	Fault Location (230 kV)	Description
TL217	SOP WAV	3PF cleared in 100 ms
TL203	WAV SSD	3PF cleared in 100 ms
TL202	SSD BDE	3PF cleared in 100 ms
TL267	WAV BDE	3PF cleared in 100 ms
TL268	SOP	3PF cleared in 100 ms
TL242	SOP	3PF cleared in 100 ms
SOP sync	SOP	3PF cleared in 100 ms
BDE unit #7	BDE	3PF cleared in 100 ms
BDE Unit 7	BDE	3PF cleared in 100 ms
Loss of LIL pole	n/a	Permanent loss of LIL pole. Remaining LIL pole increases transfer to 2 pu (10 min overload rating) using ground return
Loss of ML pole	n/a	Permanent loss of ML pole. Remaining ML pole increases transfer power lost on faulted pole, up to its rating
Loss of LIL bipole	n/a	Permanent loss of LIL bipole
Loss of ML bipole	n/a	Permanent loss of ML bipole
Temporary loss of LIL bipole	n/a	Temporary loss of LIL bipole. Test various durations and number of restart attemps.

2.5 PSSE Base Cases

Table 2-2 lists the base cases that were used to analyze the IIS system in this study.

Table 2-2. Base cases provided by Hydro

Number	Load Condition	Island Demand (MW)[12]	ML Import/Export (at BBK)(MW)	LIL LAB to NF Flow (at MFA)(MW)	Island Generation (MW)
HP1	Peak[13]	1824.8	157 (export)	900 (import)	1147.0
HP2	Intermediate Peak	1689.3	157 (export)	900 (import)	1012.9
HP3	Intermediate	1347.5	500 (export)	900 (import)	1012.8
HP4	Peak	1832.0	157 (export)	694 (import)	1333.6
HP5	Intermediate Peak	1717.0	157 (export)	694 (import)	1218.8
HP6	Intermediate	1374.6	500 (export)	694 (import)	1218.7
HP7	Peak	1904.6	320 (import)	294.4 (import)	1296.7
HP8	Peak	1905.2	320 (import)	337 (import)	1256.7
HP9	Intermediate	1224.4	320 (import)	0	903.6
HP10	Intermediate Peak	1756.9	104.8 (export)	~675 (import)	1302.9
HP11	Peak	1833.7	104.8 (export)	~675 (import)	1380.2
HP12	Intermediate Peak	1697.7	104.8 (export)	~675 (import)	1243.8
HP13	Peak	1812.4	158 (export)	~605 (import)	1307.3
HP14	Peak	1816.6	320 (import)	~605 (import)	833.3
HP15	Intermediate	1307.2	500 (export)	~605 (import)	1142.5
HP16	Intermediate	1272.5	158 (export)	~605 (import)	765.7
HP17	Intermediate	1278.7	320 (import)	~500 (import)	478.4
HP18	Light	779.2	500 (export)	~480 (import)	817.35
HP19	Light	742.7	158 (export)	~200 (import)	703.64
HP20	Light	767.8	320 (import)	0	447.01
HP21	Extreme Light	458.1	158 (export)	~90 (import)	526.1
HP22	Extreme Light	498.75	500 (export)	~470 (import)	546.1
HP23	Peak	1632.2	500 (export)	900 (import)	1296.8
HP24	Intermediate	1123	500 (export)	900 (import)	788.9
HP25	Light	843.6	500 (export)	900 (import)	509.4
HP26	Peak	1827.7	157 (export)	900 (import)	1150.6
HP27	Intermediate	1245.3	157 (export)	900 (import)	567.7

[12] Island Demaind includes load and losses. Variations in Island Demand for the same loading condition are attributed to incremental losses associated with variations in dispatch.
[13] Peak loading conditions are based on 2027 forecasted load.

3. Review of Three-Phase Faults

Of the three-phase ac faults (3PF) that were studied, unacceptable performance was found for 3PF located anywhere on one of the three 230 kV lines running eastward of BDE, namely TL267, TL202 and TL206. Anlysis indicates that the system response is a function of power flow in this corridor. The worst case 3PF location is at Bay d'Espoir (BDE). As noted above, a 3PF at BDE is excluded from Transmission Planning Criteria. A 3PF at Sunnyside (SSD) or Western Avalon (WAV), even if on TL267, TL202 or TL206 must meet all Transmission Planning Criteria.

Analysis was performed to assess the impacts associated with three-phase faults on the 230 kV lines in the corridor between BDE and SOP. The following scenarios were considered:

1. Assess corridor power flow limit such that a 3PF at BDE does not result in transient undervoltage conditions or instability.[14]
2. Assess corridor power flow limit with relaxed consideration of 3PF at BDE.[15]

3.1 Considering a 3PF at BDE

3.1.1 Violations

This preliminary study found four power flow cases in which system instability or transient undervoltage violations were observed for a 3PF at BDE. These cases are summarized in Table 3-1. The worst system response was observed for a 3PF at BDE on TL267.

Table 3-1. Performance Issues Resulting from a 3PF at BDE on TL267

Base Case	Flow Eastward out of BDE (MW)	Generators in-service at BDE	Generators in-service Avalon Peninsula	LIL power at MFA (MW)	ML power transfer (MW)	Island demand (MW)	Criteria Violation
HP7	840	All (1-7)	HRP 3 (sync), HRD GT	294	320 import	1905	System instability
HP8	840	All (1-7)	HRP 3 (sync), HWD (sync)	337	320 import	1905	System instability
HP9	590	1, 2, 4, 7	HRP 3 (sync), HRD GT	Out-of-service	320 import	1224	Transient undervoltage criteria
HP12	499	All (1-7)	HRP 3 (sync)	675 monopole	104.8 export	1698	Transient undervoltage criteria

[14] Such a case would be an enhancement of Transmission Planning Criteria where faults at BDE are given the same consideration as all other faults.
[15] This scenario includes cases where the 3PF at BDE is neglected, in accordance with Transmission Planning Criteria. It is also includes consideration of enhanced Transmission Planning Criteria where stability must be maintained for a 3PF at BDE, but transient undervoltage violations would be permitted.

Figure 3-1 shows the system instability observed in case HP8 for a 3PF at BDE on TL267. The second plot of machine speeds at BDE Unit 7 and Holyrood Unit 3 shows that the system west of BDE loses synchronism with the system east of BDE.

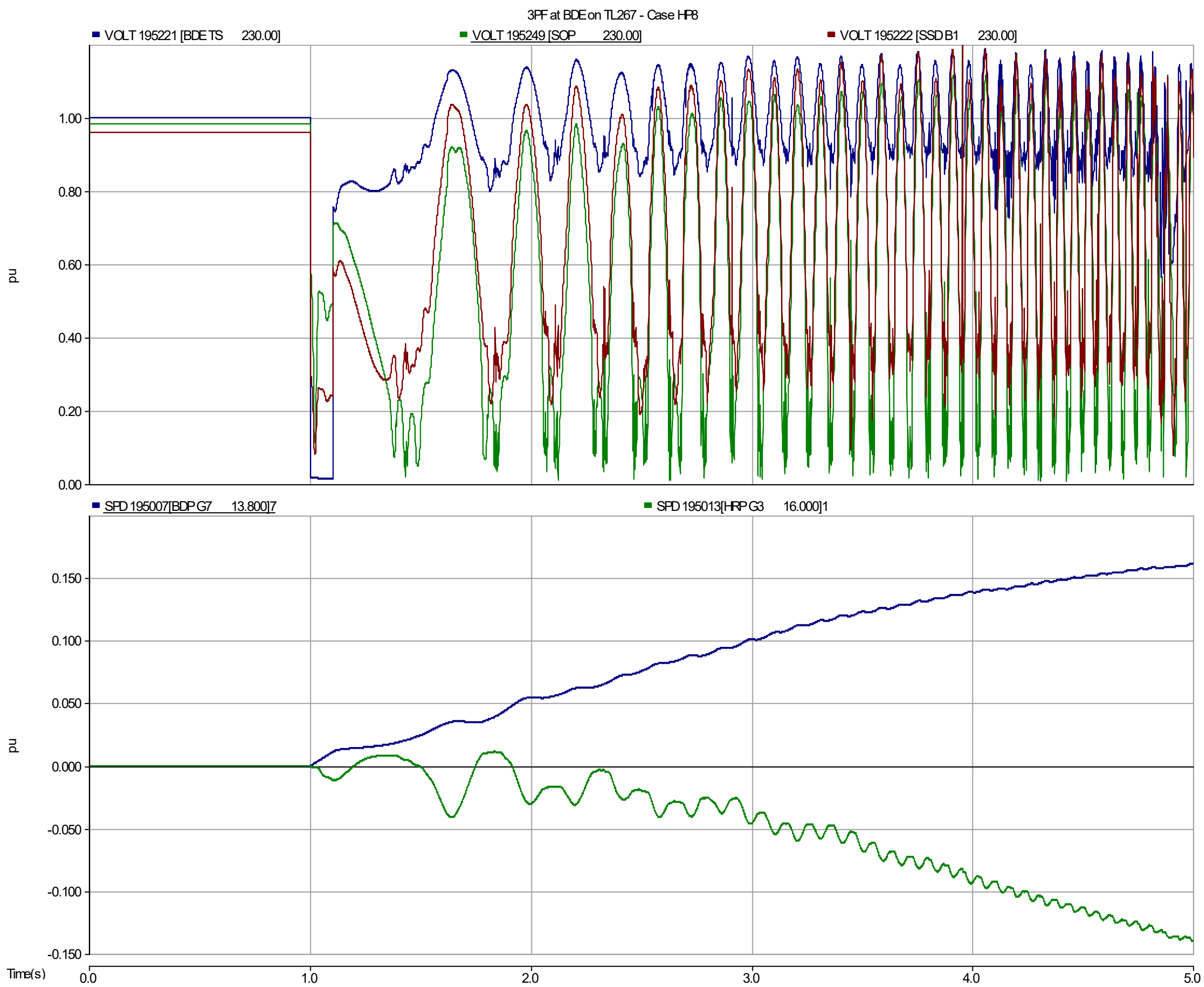

Figure 3-1. 3PF BDE on TL267, Peak load, 840 MW flow eastward out of BDE

Figure 3-2 shows an example of the transient undervoltage criteria violations observed in case HP9 for a 3PF at BDE on TL267. The system response is stable, however, the 230 kV voltage at Sunnyside is below 0.8 pu for more than 20 cycles after the fault is cleared.

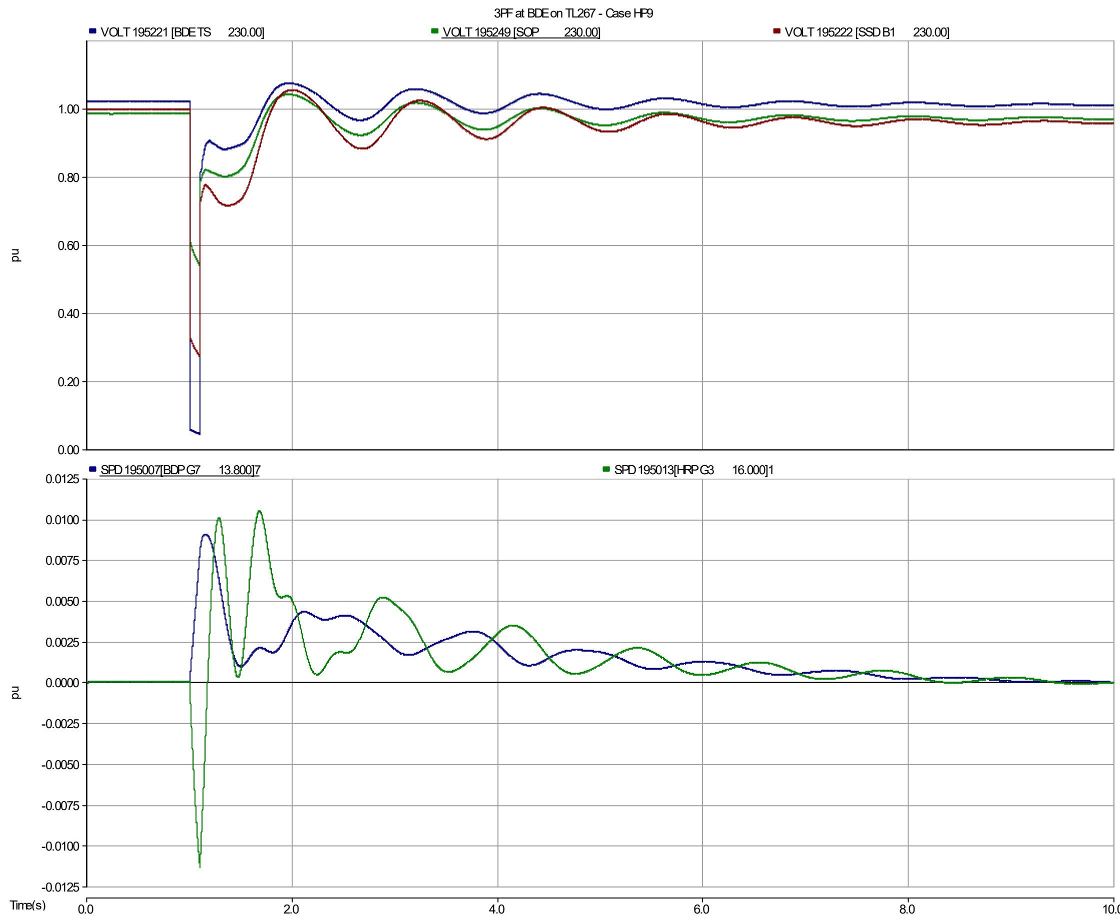

Figure 3-2. 3PF at BDE on TL267, Intermediate load, 590 MW flow eastward out of BDE

3.1.2 Mitigation

To mitigate the instability and transient low voltage issues , the flow eastward out of BDE was reduced. Table 3-2 summarizes the maximum flow eastward out of BDE to ensure acceptable system performance. Mitigation was not achievable for case HP9 when LIL was out-of-service.

Table 3-2. Mitigation for violations for a 3PF at BDE

Base Case	Limit Flow Eastward out of BDE (MW)	LIL Power Transfer (MW) after limiting BDE Flow	System response
HP7	657	474	Within criteria
HP8	617	560	Within criteria
HP9	Flow of 590 MW could not be reduced since LIL is out of service and there was no other generation to turn on on the Avalon peninsula	LIL out-of-service	Still violates transient undervoltage criteria (as shown in Figure 3-2)
HP12	458	675 monopole	Within criteria

The following sections discuss the results of Table 3-2 in more detail.

3.1.2.1 LIL Operating as a Bipole – Cases HP7, HP8

In order to meet criteria for cases HP7 and HP8, power flow in the BDE-SOP corridor was reduced by increasing LIL infeed and adjusting ML power transfer accordingly. In both cases, a reduction of power transfer eastward out of BDE to around 615-650MW[16] (from 840 MW) mitigated the system instability, and ensured the system response met criteria. For case HP7, LIL power transfer (measured at MFA) was increased from 294 MW to 474 MW. For case HP8, LIL import was increased from 337 MW to 560 MW.

In order to see if there was any appreciable improvement in allowable power transfer on the BDE to SOP 230 kV corridor, the following system additions were added to the cases (one at a time) and tested:

- A third 230 kV ac line in parallel to TL201 and TL217 between WAV and SOP
- Holyrood Unit 1 as a synchronous condenser
- Bay d'Espoir Unit 8
- Cat Arm Unit 3
- New gas turbine on the Avalon Peninsula[17] operating as a synchronous condenser

Table 3-3 summarizes the increase in power transfer eastward from BDE that can be achieved with each of these system additions. It also shows the corresponding power flow through the WAV-SOP corridor, which is limited to 322 MVA due to TL201 thermal constraints. Note that the 322 MVA thermal constraint is not the most limiting constraint, since the transient stability issues are limiting the flow to less than the 322 MVA thermal constraint.

Table 3-3. HP7 and HP8 (Peak Load)– increase in BDE power transfer with new units

System addition	Maximum eastward power flow (MW)			
	HP7 (HRD GT in-service)		HP8 (HRD GT out-of-service)	
	Out of BDE	WAV-SOP	Out of BDE	WAV-SOP
None (Base case)	656	280	617	238
HRD unit 1 sync	656	280	655	275
BDE unit 8	685	307	654	273
CAT arm 3	667	293	627	250
New GT on Avalon Peninsula (sync. cond.)	656	280	645	270
3rd ac line, in parallel with TL201 and TL217	665	301	634	266

For case HP7, which had the HRD GT in-service, there was no additional power transfer achieved by

[16] Case HP7 had the Holyrood GT in-service, which allowed for slightly higher power transfer than case HP8 where this unit was not in-service.
[17] Generator assumed to be equivalent to a 165.9 MVA, Brush BDAX 8-445ER unit.

adding a synchronous condenser on the Avalon Peninsula (HRD Unit 1 or new GT operating as a synchronous condenser). For case HP8, with the HRD GT out-of-service, there was a marginal increase in power transfer, approximately 30-40 MW, that can be achieved with a new unit on the Avalon Peninsula operating as a synchronous condenser or by using HRD Unit 1 as a synchronous condenser.

A new BDE Unit 8 off-loaded the existing BDE units and provided some additional reactive power support, which allowed a marginal increase of 30-40 MW of power transfer across the BDE to SOP corridor for both cases HP7 and HP8.

A new unit at Cat Arm had a limited impact in both cases, given its distance from the corridor of interest.

The third ac line in parallel with TL201 and TL217 had limited benefit since the bottleneck is a dynamic issue and not a thermal constraint.

It should be noted that in all cases, the dynamic performance of the system is more limiting than the thermal rating of TL201 if consideration is given to the impact of the three-phase fault at BDE. The thermal rating of TL201 (322 MVA in the winter) was flagged as the system operating limit under peak load conditions in the previous operational studies, prior to the retirement of the HRD generating units.

The final phase of Stage 4 operating studies will define an operating guideline regarding the maximum power transfer eastward out of BDE over operating conditions ranging from extreme light to peak load.

3.1.2.2 LIL out-of-service – Case HP9

Case HP9 is an intermediate load case in which the LIL is out-of-service. Since the LIL was not in-service, its power infeed could not be increased to reduce the power flow on the BDE to SOP corridor. With the HRD GT already in service, there was no additional generation available on the Avalon Peninsula that could be turned on to reduce the power flow on the BDE to SOP corridor. Therefore, the Island demand was scaled down to 1200 MW in order to meet transient undervoltage issue along the 230 kV corridor between BDE and SOP.

The following mitigation options were tested to see if they could aid in serving additional Island demand with the LIL unavailable:

- Addition of a new Holyrood gas turbine, supplying 60 MW of generation on the Avalon Peninsula
- Turning on the third SOP synchronous condenser

Table 3-4 summarizes the Island demand that can be served with the above options in place, ensuring that the transient undervoltage issue along the BDE to SOP 230 kV corridor is mitigated.

Table 3-4. Island demand that can be served with the LIL is out-of-service

Number of SOP synchronous condensers in-service	Island Demand that can be served (MW)	
	Base Case	New HRD GT (60 MW)
2	1200	1300
3	1200	1300

The additional synchronous condenser at SOP did not provide any benefit in terms of being able to serve additional Island demand. The new 60 MW HRD GT allowed for an additional 100 MW of Island demand to be served by off-loading the BDE to SOP corridor and serving load close to the source.

In order to make an appreciable improvement to the amount of load that can be served when the LIL is out-of-service under BDE 3-phase fault scenario, it is likely that either generation would be needed on the Avalon Peninsula, dynamic reactive support would be required near Sunnyside, or new ac transmission out of BDE would be required to allow more power to be transferred east to the Avalon Peninsula from the generation and ML import available on the west of the Island.

3.1.2.3 LIL operating as a Monopole at 1.5 pu – Case HP12

Case HP12 is an intermediate peak load case with the LIL operating as a monopole at 1.5 pu. Since the LIL monopolar infeed is already at maximum continuous rating, the only available mitigation was to turn on the Holyrood GT. Setting this generator to 40 MW was sufficient to mitigate the transient undervoltage violations. Figure 3-3 shows the system response after turning on the Holyrood GT at 40 MW. In this case, there is 458 MW flowing east of out BDE, and 139 MW flowing from WAV to SOP.

A peak load case (HP11) was tested with the LIL operating as a monopole at 1.5 pu. This case had the HRD GT operating at its full capacity of 123.5 MW. There were no steady state or dynamic issues observed with this case. Therefore, the peak Island demand can be met even if the LIL is operating as a monopole at 1.5 pu, as long as the HRD GT can be dispatched as needed.

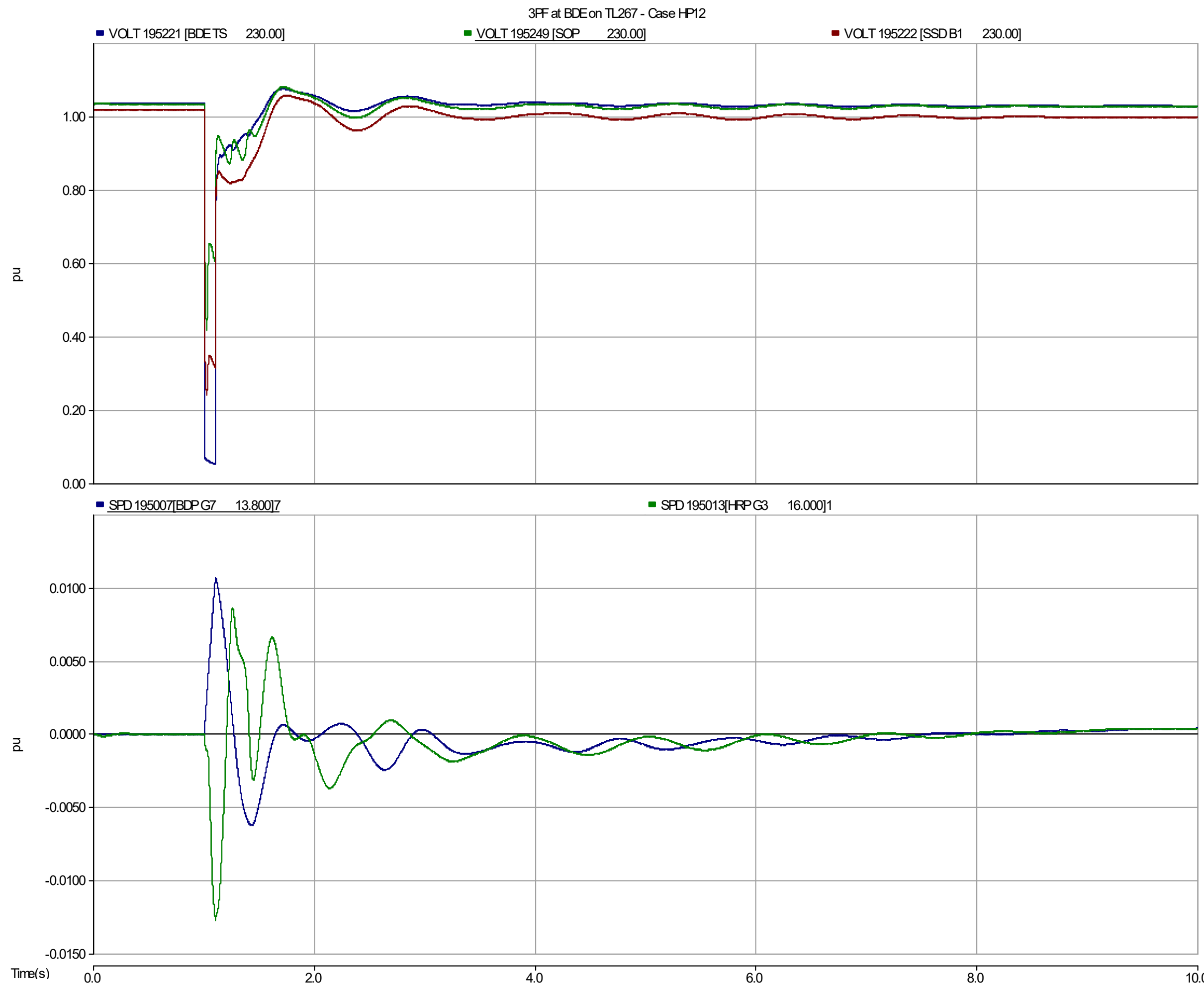

Figure 3-3. 3PF at BDE on TL267, Intermediate load, 458 MW flow eastward out of BDE

3.1.2.4 Summary of System Limits

As discussed in the previous sections, further analysis will be performed in the upcoming stages of the Stage 4 operational studies to define the operating guidelines required to limit flow between BDE and SOP in order to prevent stability issues that result due to three-phase faults on the 230 kV lines running eastward out of BDE.

3.2 Relaxed Consideration of a 3PF at BDE

3.2.1.1 LIL Operating as a Bipole – Cases HP7, HP8

Increased flow in this corridor would be possible if 3PF at BDE is neglected, in accordance with Transmission Planning Criteria. Increased flow would also be possible if enhanced Transmission Planning Criteria were considered where stability must be maintained for a 3PF at BDE, but transient undervoltage violations are permitted. Cases HP7 and HP8 were revisited on this basis and the results are summarized in Table 3-5.

Table 3-5. BDE to SOP Corridor Limits - with and without considering 3PF at BDE

Consider a 3PF at BDE?	Maximum eastward power flow (MW)			
	HP7 (HRD GT in-service)		HP8 (HRD GT out-of-service)	
	Out of BDE	WAV-SOP	Out of BDE	WAV-SOP
Yes	656	280	617	238
No (3PF BDE is stable but violates criteria)	709	328	690	310
No (3PF BDE is unstable)	725	344	710	331

3.2.1.2 LIL out-of-service – Case HP9

Analysis was also performed to assess increased power flow limits in this corridor when the LIL is not in service. Case HP9 was investigated on this basis.

As discussed in Section 3.1.2.2, if a 3PF at BDE is considered to meet all Transmission Planning Criteria, the maximum load that can be served with the LIL out of service is 1200 MW.

If the 3PF location at BDE is ignored in terms of meeting transient voltage criteria, but still required to provide a stable system response, the maximum IIS load that can be served only increases to approximately 1260 MW. However, at this level of Island demand, the 3PF at BDE on TL267 is on the verge of instability as shown in Figure 3-4.

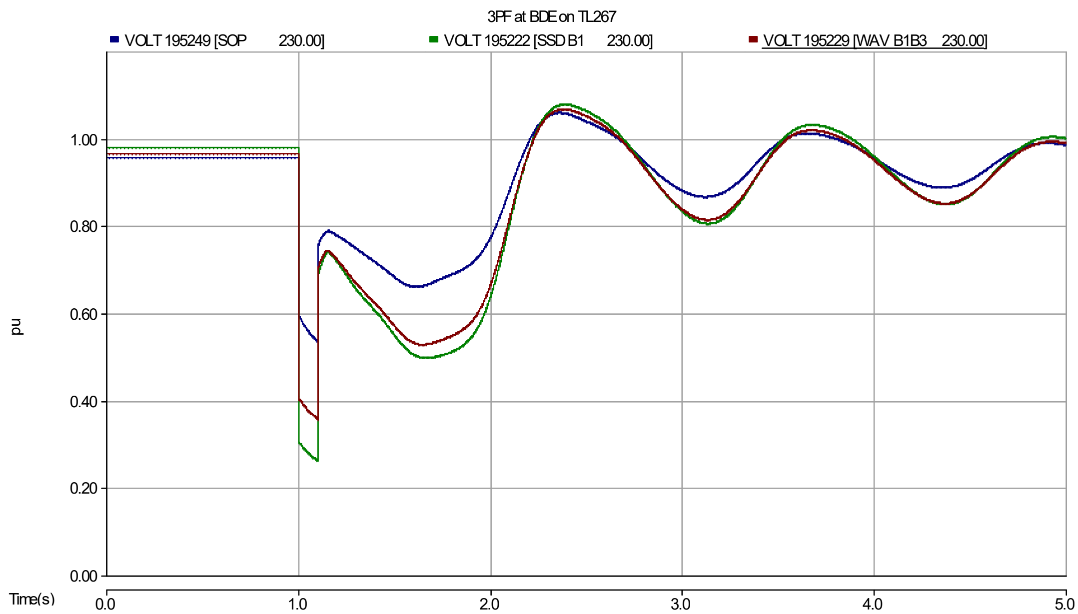

Figure 3-4. 3PF at BDE on TL267, Island demand 1225 MW, LIL out of service

If the 3PF at BDE is neglected, as per Transmission Planning Criteria, the next worst-case contingency would be a 3PF at WAV, followed by a trip of TL267. A maximum Island Demand of 1290 MW can be supported in this case.

A summary of preliminary transfer limits is provided in Table 3-6. As discussed above, limits for all transmission system corridors will be confirmed as part of the final phase of the Stage IV studies.

Table 3-6. BDE to SOP Corridor Limits with the LIL Out of Service - with and without considering 3PF at BDE

Consider a 3PF at BDE?	Maximum eastward power flow (MW)		Island Demand that can be met (MW)
	HP9		
	Out of BDE	WAV-SOP	
Yes	580	310	1200
No (3PF BDE is stable but violates criteria)	617	334	1260
No (3PF BDE is unstable)	645	352	1290

4. Loss of Largest Generator in IIS

After retirement of the Holyrood generating units, BDE Unit 7 at 154.4 MW is the largest generator on the IIS. For loss of largest generator, frequency should remain above 59 Hz, and UFLS should be avoided.

4.1 LIL in-service

Loss of BDE Unit 7 was tested for various Island demand levels ranging from peak load to light load with the LIL transferring rated power of 900 MW. These tests were performed with the ML frequency controller in-service, and with the ML frequency controller out-of-service.

The purpose was to determine if any reserve is needed on the LIL to keep the frequency on the IIS above 59 Hz if BDE Unit 7 trips. Table 4-1 summarizes the results.

Table 4-1. Loss of BDE Unit 7, with and without ML frequency controller in-service

Case	Load Condition	Island Generation (MW)	Island Demand (MW)	LIL (MW) @ MFA	ML Export (MW)	ML Frequency Controller In-service	ML Frequency Controller Out-of-service	
						IIS Freq (Hz)	IIS Freq (Hz)	LIL (MW) to meet 59 Hz
HP23	Peak	1296.8	1632.2	900	500	59.22	58.77	846
HP24	Intermed.	788.9	1123	900	500	59.08	58.60	810
HP25	Light	509.4	843.6	900	500	59.10	58.62	770
HP26	Peak	1150.6	1827.7	900	157	59.16	58.75	830
HP27	Intermed.	567.7	1245.3	900	157	59.18	58.62	832

With the ML frequency controller in-service, the Island frequency remained above 59 Hz for loss of BDE Unit 7. Therefore, no reserve is required on the LIL if the ML frequency controller is in-service.

With the ML frequency controller out-of-service, the frequency dropped below 59 Hz for loss of BDE unit 7, to the levels shown in Table 4-1. In order to keep the frequency above 59 Hz, the LIL will need to carry reserve varying from 54 MW to 130 MW as shown in Table 4-1, depending on Island demand and generation levels.

4.2 LIL out-of-service

If the LIL is out-of-service, the frequency remains above 59 Hz for loss of the largest generator, as long as the ML frequency controller is in-service.

If the ML frequency controller is out-of-service, however, loss of the largest generator will cause frequency to drop below 59 Hz and the UFLS scheme will be initiated as summarized in Table 4-2.

Table 4-2. Loss of Largest Generator with LIL out-of-service

Case	Load Condition	Island Generation (MW)	Island Demand (MW)	LIL	ML Export (MW)	ML Frequency Controller In-service	ML Frequency Controller Out-of-service	
						IIS Freq (Hz)	IIS Freq (Hz)	Load Shed* (MW)
HP9	Intermed.	903.6	1224.4	OUT	320	59.21	58.78	90.6
HP20[18]	Light	447.0	767.8	OUT	320	59.31	58.83	25.5

*Using revised UFLS discussed in Section 7

The final Stage IV study will include an assessment to determine maximum unit loading to avoid instability and UFLS if frequency controllers are not in service.

[18] Loss of BDE Unit 1 at 60 MW. BDE Unit 7 is not in-service in this case.

5. Loss of a LIL Pole

The Transmission Planning Criteria for loss of a LIL pole states that this event should not cause the IIS frequency to drop below 59 Hz, and it should not result in UFLS.

If one of the LIL poles is lost, the remaining pole is rated to transmit 2.0 pu for 10 minutes, after which the continuous monopole rating drops down to 1.5 pu. The purpose of the 10-minute 2.0 pu overload rating is to allow operators time to quickly turn on generation to make up for the loss of infeed from the LIL pole that was lost. However, there are two issues that restrict the LIL monopole from actually providing the full overload rating during the transient stability timeframe (seconds):

1. When operating as a monopole, immediately after the other LIL pole has tripped, the monopole will be operating in ground return. The LIL has a long electrode, which adds a significant amount of resistance to the link when operating in ground return. This increased resistance results in increased losses on the LIL DC line.

2. Within a transient stability timeframe (i.e. seconds), the remaining LIL pole is not necessarily able to transmit the full 2.0 pu due to the rectifier firing angle hitting its minimum limit, which keeps the DC current from getting up to the full 2.0 pu until the tap-changers on the converter transformers can operate to release the firing angle from its limit. Therefore, within this initial time period after the LIL pole is lost, there is still loss of infeed to the IIS despite the 2.0 pu 10-minute overload rating. The amount of infeed that is lost depends on how much power the LIL was transferring before the pole was lost. In a worst case, if operating at 900 MW, this study showed that without tap-changer action on the converter transformers and with hitting minimum alpha, and also due to increased DC line losses associated with the resistance of the line electrode, the remaining pole is only able to provide 633 MW to SOP, as opposed to the 830 MW it was providing pre-contingency, resulting in the net initial loss of 267 MW.

5.1 During ML Export

In order to keep the IIS frequency above 59 Hz, loss of a LIL pole will require a runback on the ML. The ML will receive a signal to runback its exports to 0 MW if the LIL experiences a loss of pole. Loss of a LIL pole was simulated for the study base cases. Table 5-1 summarizes the results for loss of a LIL pole when operating at 900 MW, for the scenarios with the ML frequency controller in-service and out-of-service.

Table 5-1. Minimum Frequency following Loss of LIL Pole with ML runback to 0 MW

Case	Load Condition	LIL (MW) @ MFA	ML (MW)	Minimum Frequency Dip (Hz)	
				ML frequency controller in-service	ML frequency controller out-of-service
HP23	Peak	900	500 (export)	59.76*	58.76
HP24	Intermediate	900	500 (export)	59.79*	59.79
HP25	Light	900	500 (export)	59.80*	59.80
HP26	Peak	900	157 (export)	59.11	58.94
HP27	Intermediate	900	157 (export)	59.14	58.84

If the ML frequency controller is in-service, the frequency remained above 59 Hz.

If the ML frequency controller is out of service, the cases with 157 MW of ML export (cases HP26, HP27) experience a frequency slightly less than 59 Hz, down to around 58.8 Hz.

Please note that the cases marked with (*) in Table 5-1 require the LIL frequency controller to be in-service to prevent a large overfrequency (>62 Hz) from occurring after the 500 MW ML export is run-back to 0 MW. Alternatively, a more sophisticated ML runback detailing a specific amount of power to be runback would be required.

5.2 During ML Import

If the ML import is at the maximum level of 320 MW, it cannot transiently import more power from Nova Scotia via its frequency controller and it cannot be runback, therefore it cannot help the IIS during underfrequency events. In this case, LIL power transfer would have to be limited as per Table 5-2 in order to keep the IIS frequency above 59 Hz in case a LIL pole is lost.

Table 5-2. LIL Transfer Limits: Loss of LIL pole during ML 320 MW import

Case	Load Condition	LIL (MW) @ MFA	ML (MW)	IIS Minimum Frequency (Hz)	Maximum LIL Transfer to meet 59 Hz (MW)
HP7	Peak	294.4	320 (import)	59.66	-
HP8	Peak	337	320 (import)	59.44	-
HP14	Peak	704	320 (import)	58.76	488
HP17	Intermediate	500	320 (import)	58.80	395

The final Stage IV study will include an assessment to determine maximum LIL loading to ensure compliance with Transmission Planning Criteria.

6. Loss of an ML Pole

6.1 During ML Export

If the ML is exporting and a pole is lost, the IIS will experience an overfrequency. This overfrequency should not rise above 62 Hz.

The worst case occurs when the ML is at maximum export of 500 MW. If an ML pole is lost, there will be an excess of 250 MW in the IIS. All base cases with the ML exporting 500 MW were used to simulate loss of an ML pole. These results are summarized in Table 6-1.

For this analysis, a runback of the LIL was not considered. Rather the LIL frequency controller was found to adequately limit overfrequency conditions. The highest overfrequencies were found to occur during light and extreme light load conditions, in which an overfrequency of 60.6 Hz occurred when an ML pole was lost.

Table 6-1. ML 500 MW export cases – loss of ML pole

Case	Load Condition	LIL (MW) @ MFA	ML (MW)	Frequency (Hz)
HP3	Intermediate	900	500 (export)	60.50
HP6	Intermediate	694	500 (export)	60.49
HP15	Intermediate	704	500 (export)	60.49
HP22	Extreme Light	470	500 (export)	60.56
HP23	Peak	900	500 (export)	60.49
HP24	Intermediate	900	500 (export)	60.54
HP25	Light	900	500 (export)	60.60

6.2 During ML Import

If the ML is importing and a pole is lost, the IIS will experience an underfrequency. This underfrequency should not drop below 59 Hz and UFLS should not occur.

The worst case occurs when the ML is at maximum import of 320 MW. If an ML pole is lost, the healthy pole will automatically increase its power from importing 160 MW to 250 MW (rating of the pole), resulting in a net loss of approximately 70 MW to the IIS. All base cases with the ML importing 320 MW were used to simulate loss of an ML pole. Table 6-2 summarizes these results.

- With the LIL and its frequency controller in-service, the IIS frequency remained above 59 Hz and the Transmission Planning Criteria is met.
- With the LIL out-of-service, however, loss of an ML pole resulted in the IIS frequency dropping just below 59 Hz. For the intermediate load case, the frequency drops to 58.96 Hz, however, this is not low enough to result in load shedding. For the light load case, the frequency drops to 58.86 Hz, and load is shed.

Table 6-2. ML 320 MW import cases – Loss of ML pole

Case	Load Condition	LIL (MW) @ MFA	ML (MW)	Frequency (Hz)	Load Shed (MW)
LIL (and frequeny controller) in-service					
HP7	Peak	294.4 (import)	320 (import)	59.69	-
HP8	Peak	337 (import)	320 (import)	59.67	-
HP14	Peak	704	320 (import)	59.67	-
HP17	Intermediate	500	320 (import)	59.60	-
LIL (and frequeny controller) out-of-service					
HP9	Intermediate	Out-of-service	320 (import)	58.96	0
HP20	Light	Out-of-service	320 (import)	58.86	26

The final Stage IV study will include an assessment to determine maximum ML loading to ensure compliance with Transmission Planning Criteria.

7. Loss of the LIL Bipole

7.1 Permanent Loss of the LIL Bipole

A permanent loss of the LIL bipole (i.e. without successful restart) is the contingency that defines the requirements of the UFLS scheme for the IIS. If the LIL bipole is lost, the ML (if exporting) will be runback to 0 MW[19]. Additionally, the UFLS scheme will operate to ensure that the system remains stable and that the IIS frequency remains above 58 Hz, as per Transmission Planning Criteria.

There are two stability issues that were found to occur when the LIL bipole is lost:

1. Fast decline in IIS frequency
2. Voltage collapse around the mid-point of the BDE-SOP 230 kV corridor (around Sunnyside)

Modifications to the existing UFLS scheme were required to keep the IIS frequency above the 58 Hz criteria. The modified scheme consists of load shed blocks over a frequency range of 58.9 Hz to 58.4 Hz. Details of the new UFLS scheme are provided in Appendix 1.

Loss of the LIL bipole was simulated for each of the study base cases using the newly defined UFLS scheme. The results are summarized in Table 7-1, including the amount of load that is shed for each case. For all cases in Table 7-1, the minimum IIS frequency was found to remain at or above 58.1 Hz, providing a 0.1 Hz margin to the 58 Hz Transmission Planning Criteria, with the exception of cases HP8, HP14, HP26 and HP27, which are discussed in further detail in Sections 7.1.1 and 7.1.2.

Table 7-1. Scenarios studied for permanent loss of LIL bipole, and corresponsding UFLS

Study Case	Load Condition	Island Demand (MW)	ML (at BBK) (MW)	LIL (at MFA) (MW)	Island Generation (MW)	Load Shed (MW)
HP1	Peak	1824.8	157 (export)	900	1147	782
HP2	Intermediate Peak	1689.3	157 (export)	900	1012.9	718
HP3	Intermediate	1347.5	500 (export)	900	1012.8	268
HP4	Peak	1832	157 (export)	694	1333.6	628
HP5	Intermediate Peak	1717	157 (export)	694	1218.8	723
HP6	Intermediate	1374.6	500 (export)	694	1218.7	55
HP7	Peak	1861.7	320 (import)	474	1084.9	780
HP8*	Peak	1849.5	320 (import)	560	994.1	782
HP10	Intermediate Peak	1756.9	104.8 (export)	675 (MP)	1302.9	576
HP11	Peak	1833.7	104.8 (export)	675 (MP)	1380.2	601

[19] If the ML is not exporting, the ML response would be limited to frequency controller action.

Study Case	Load Condition	Island Demand (MW)	ML (at BBK) (MW)	LIL (at MFA) (MW)	Island Generation (MW)	Load Shed (MW)
HP12	Intermediate Peak	1697.7	104.8 (export)	675 (MP)	1243.8	716
HP13	Peak	1812.4	158 (export)	704	1307.3	653
HP14*	Peak	1830.4	320 (import)	488	1040.6	779
HP15	Intermediate	1307.2	500 (export)	704	1142.5	51
HP16	Intermediate	1272.5	158 (export)	704	765.7	539
HP17	Intermediate	1285.1	320 (import)	395	582	440
HP18	Light	779.2	500 (export)	480	817.35	0
HP19	Light	742.7	158 (export)	200	703.64	0
HP21	Extreme Light	458.1	158 (export)	90	526.1	0
HP22	Extreme Light	498.75	500 (export)	470	546.1	0
HP23	Peak	1632.2	500 (export)	900	1296.8	338
HP24	Intermediate	1123	500 (export)	900	788.9	240
HP25	Light	843.6	500 (export)	900	509.4	199
HP26*	Peak	1827.7	157 (export)	900	1150.6	782
HP27**	Intermediate	1245.3	157 (export)	900	567	512

*Unstable unless HRD GT put in-service

**Stable but frequency < 58 Hz unless LIL reduced to 820 MW and Island generation increased to 633 MW

7.1.1 Minimum Island Generation

Based on further investigation of Case HP27, it became evident that it would not be possible to transfer the full 900 MW on the LIL if there was not sufficient Island generation on-line to support the IIS frequency and voltage if the LIL bipole is lost. In the original Case HP27, the LIL is transferring 900 MW with only 567 MW of Island generation on-line. A series of simulations were performed from peak load to extreme light load conditions to determine the maximum LIL transfer that could be lost for a given amount of Island generation. This was performed by starting out at peak load, then scaling down Island demand/generation and finding out at what LIL transfer limit the IIS frequency would drop to 58 Hz if the LIL bipole was lost. Based on these series of simulations, a preliminary operating guideline was developed to define LIL transfer limits based on Island generation. In this operating guideline, the maximum LIL power transfer is tied to a minimum requirement for Island generation, as shown in Figure 7-1. The LIL transfer limits are defined for two scenarios; one, where the ML is exporting firm transfer of 157 MW (and can be relied upon to runback these exports to 0 MW), and two, where the ML is operating at 0 MW (and cannot be relied upon for runback).

Please note that the LIL transfer limits shown in Figure 7-1 are valid when the ML frequency controller is in-service. Further restrictions on LIL transfer would likely be necessary if the ML or the ML frequency controller is out-of-service. A similar graph with the ML frequency controller out-of-service will be developed during the final phase of Stage 4 operating studies.

In order for Case HP27 to result in a minimum frequency of 58.1 Hz if the LIL bipole is lost, the LIL transfer had to be reduced from 900 MW to 820 MW, and consequently the Island generation had to be increased from 567 MW to 633 MW. This new operating point lines up well with the blue curve in Figure 7-1.

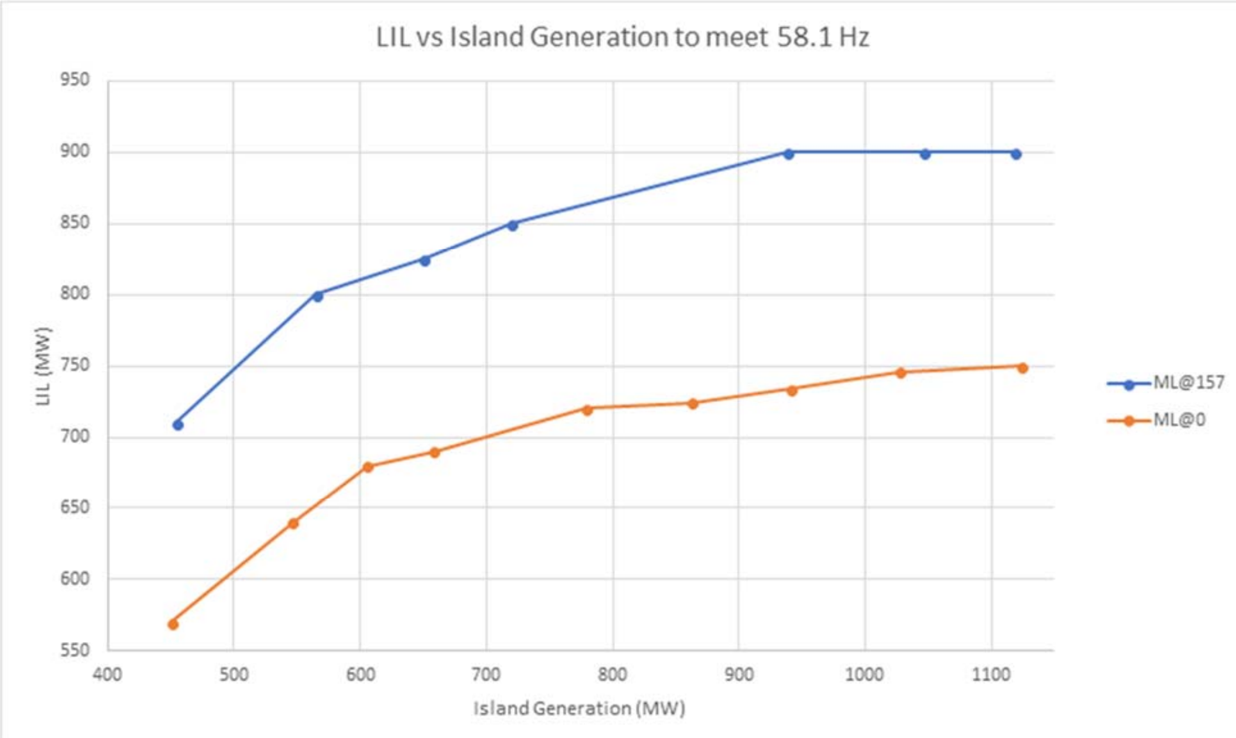

Figure 7-1. LIL Transfer limits vs. Island Generation
Blue: ML @ 157 MW export
Orange: ML @ 0 MW

7.1.2 Peak Load – Need for HRD GT to be in-service

Peak load cases HP8, HP14 and HP26 are unstable even with the newly designed UFLS scheme. This is due to voltage collapse near Sunnyside Terminal Station. Case HP26 has sufficient Island generation to transfer the full 900 MW LIL rating, according to Figure 7-1, and cases HP14 and HP8 have significantly reduced LIL power transer, but yet still they are unstable.

One commonality between these three cases is that the HRD GT is not on-line. In all of the other peak load cases in Table 7-1, the HRD GT is dispatched.

These cases were investigated in further detail as described below.

7.1.2.1 Case HP26 – During 900 MW LIL, 157 MW ML Export

Case HP26, although it has sufficient Island generation to transfer the full 900 MW on the LIL according Figure 7-1, is not stable. Referring to Table 7-1, case HP26 is the same as case HP1, except case HP1 has the HRD GT dispatched. It was found that if the HRD GT is turned on in case HP26, while keeping the same spinning reserve (i.e. turning off other generators that were on while keeping a spinning reserve of 70 MW), the IIS response is stable and the frequency remains above the 58 Hz criteria. The voltage in the Sunnyside area dips to around 0.6 pu, but the system recovers as shown in Figure 7-2. It is important to note that three CBC capacitor banks are in-service in this case to help support the voltage in this area.

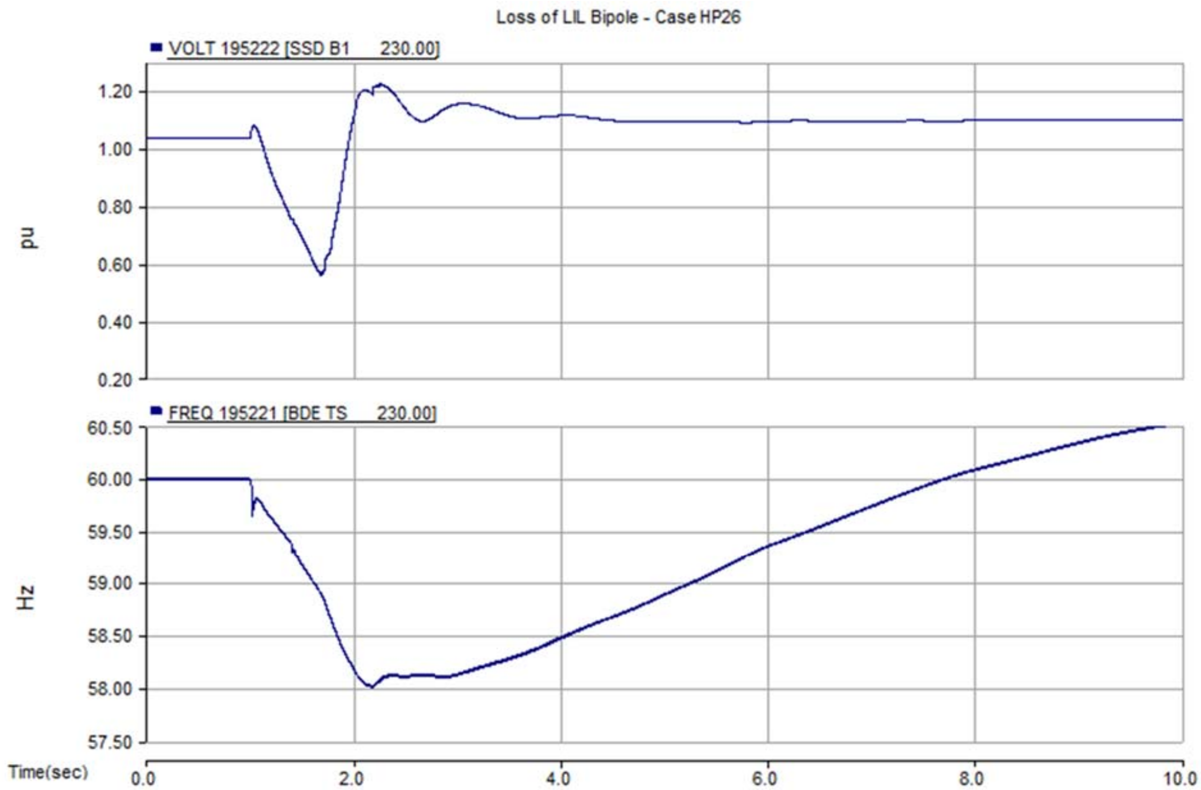

Figure 7-2. Loss of LIL Bipole (Case HP26 with HRD GT on)

Consequently, it may be necessary to have an additional operating guideline stating that, in addition to the LIL transfer limits shown in Figure 7-1, the HRD GT and three CBC capacitor banks must be in service during peak load conditions when LIL power transfer is high.

7.1.2.2 Case HP8, Case HP14 – During 320 MW ML Import

Cases HP8 and HP14 are both cases where the ML is importing 320 MW, and therefore the ML frequency controller is not able to provide assistance when the LIL bipole is lost.

Case HP8 is one of the cases used to test high power flow eastward from BDE towards SOP.

Case HP14 is similar to case HP8. The original case HP14 as provided by Hydro had the LIL transferring 704 MW. However, loss of a LIL pole (discussed in Section 5.2) determined that the maximum LIL transfer in this case could only be 488 MW in order to satisfy the 59 Hz criteria for loss of a LIL pole. This case would therefore also require redispatch. However, when the LIL transfer is reduced to 488 MW, the power flow eastward from BDE towards SOP also becomes high, similar to case HP8.

When simulating loss of the LIL bipole at these operating points, case HP7 (HRD GT in-service) is stable and meets criteria. However, case HP8 and case HP14 (HRD GT out-of-service) are not stable. In these cases, the LIL power transfer must be further increased to further restrict power flow in this corridor. Case HP8 becomes stable with LIL power transfer of 600 MW (instead of 560 MW), which corresponds to a BDE to SOP power flow of approximately 650 MW.

However, increasing LIL power beyond 488 MW will result in the 59 Hz criteria being violated if a LIL pole is lost.

Therefore, instead of reducing power flow on the BDE to SOP corridor by increasing LIL transfer, cases HP8 and HP14 also become stable if the HRD GT is turned on, which also results in reduced power flow on this corridor.

Please also note that during times of high power flow between BDE and SOP, adding pre-contingency voltage support in the Sunnyside area is necessary. It is recommended to keep the voltage in this area as high as possible (without violating steady state voltage criteria) by turning on the capacitor banks at Come-By-Chance.

The details of the operating guideline to limit power flow between BDE and SOP will be finalized during the final phase of the Stage 4 operational studies, taking into consideration all contingencies in the system including three-phase AC faults and loss of the LIL bipole. This preliminary study indicates a power flow limit in the range of 650 MW in this corridor (as measured eastward out of BDE) in order to maintain system stability following the loss of the LIL bipole.

It appears that during peak load conditions, the HRD GT should be placed online.Requirements for gas turbine operation will be defined during the final Stage 4 operational studies.

7.2 LIL Temporary Bipole Outage

An analysis of temporary LIL bipole outages of varying durations prior to successful restart was performed in order to find the maximum restart time that would ensure the IIS frequency remains above 59 Hz (in accordance with Transmission Planning Criteria to prevent an underfrequency load shed event). A further assessment was also performed to observe how much this outage time could be increased prior to all of the blocks of UFLS required for the permanent loss of the LIL bipole (assuming the new UFLS scheme required for the permanent loss of the LIL bipole is in place).

In a typical HVDC link, the time for the first restart attempt is usually in the range of 100 ms to 200 ms. Subsequent restart attempts typically add 50 ms to 100 ms for each additional restart attempt. For example, if an HVDC link has four restart attempts, an example for possible timing for restart attempts might be as follows:

- First attempt: 150 ms
- Second attempt: 200 ms
- Third attempt: 300 ms
- Fourth attempt: 400 ms

If it took all four restart attempts before successfully restarting the HVDC link, this could mean a total temporary outage time of more than 1 second. A temporary LIL bipole outage of 1 second is also simulated in this study.

7.2.1 To Meet 59 Hz and Avoid UFLS

The 900 MW LIL transfer cases from Table 7-1 were used to simulate the temporary LIL bipole outage with successful restart. Case HP27 was found to be the most limiting case to meet the 59 Hz criteria. As discussed in Section 7.1.1, this case was characterized by having insufficient Island generation for the full import of 900 MW over the LIL, and as such the LIL power transfer was reduced to 820 MW and the Island generation was increased to 633 MW. Even at 820 MW of LIL transfer, this case was the worst in terms of frequency dip compared to the other LIL 900 MW cases when simulated a temporary LIL bipole outage.

Assuming that the ML (if exporting) will runback to 0 MW during the LIL temporary bipole outage, the 59 Hz criteria can be met as long as the LIL is successfully restarted within:

- 300 ms if two SOP synchronous condensers in-service
- 380 ms if three SOP synchronous condensers in-service

Figure 7-3 shows the IIS response to a temporary LIL bipole outage with two SOP synchronous condensers in-service for case HP27. A successful restart after 300 ms is shown. It is noted that this case includes a runback of 157 MW and frequency controller operation.

If there is no ML export to runback and/or if the ML frequency controller is not in-service, a LIL operating restriction would be required to meet the 59 Hz criteria. The final phase of the Stage IV studies will determine limits to LIL import if the ML frequency controller is not in-service or if there is no export on the ML.

The generator additions tested earlier in this report were also tested to see if they had any impact on the allowable LIL bipole temporary outage duration. These units included:

- Holyrood Unit 1 as a synchronous condenser
- Bay d’Espoir Unit 8
- Cat Arm Unit 3
- New gas turbine on the Avalon Peninsula[20] operating as a synchronous condenser

The addition of these units did not have an appreciable impact on the frequency response of the system.

[20] Generator assumed to be equivalent to Brush BDAX 8-445ER

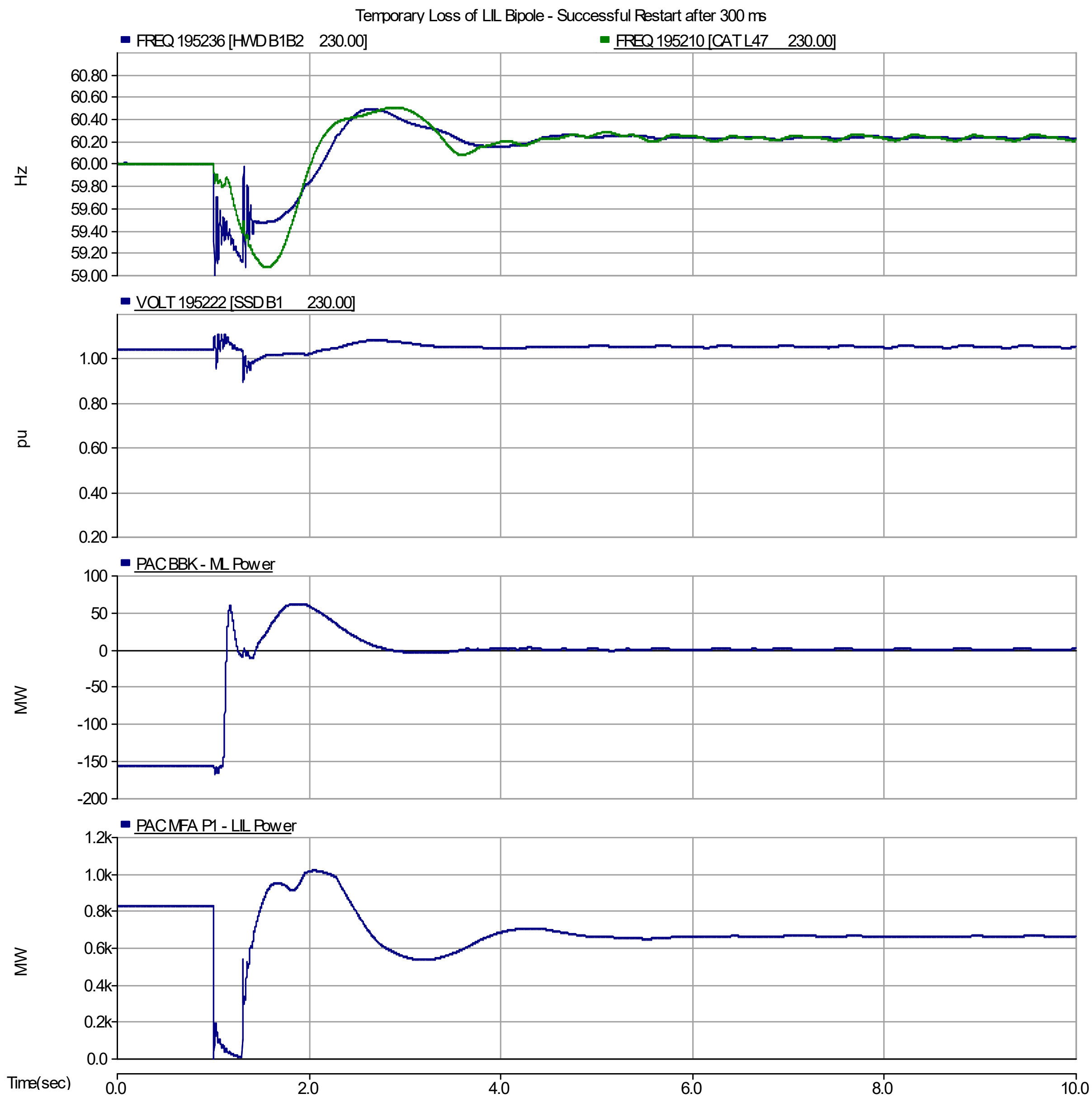

Figure 7-3. Temporary Loss of LIL Bipole (Case HP27), restart in 300 ms, 59 Hz (no UFLS)

7.2.2 Outage Duration before all Blocks of Load are Shed

It is planned that the LIL will have multiple restart attempts. If the total outage time of the LIL bipole increases beyond the durations stated in Seciton 7.2.1, then blocks of UFLS will begin to activate once the frequency falls to 58.9 Hz.

Analysis was performed to determine the total LIL bipole outage duration by which the majority of the blocks of load will have been shed. For case HP27, the majority of the blocks of the newly designed UFLS scheme were shed within:

- 680 ms if two SOP synchronous condensers in-service
- 780 ms if three SOP synchronous condensers are in-service

The example of restart timings described in Section 7.2 shows that multiple restart attempts could result in a temporary LIL bipole outage of around 1 second. This scenario was simulated to show the system response to a temporary LIL bipole outage of 1 second. Note that in PSSE, multiple restart attempts are not actually simulated, but rather it is simulated as a single total outage duration of 1 second.

The system response to a temporary LIL bipole outage that is successfully restarted after 1 second is shown in Figure 7-4. Note that upon successfully restarting, the LIL frequency controller reduces the LIL power transfer power to near minimum power due to the load that was shed on the Island and due to the runback of 157 MW of ML export during the temporary outage of the LIL bipole.

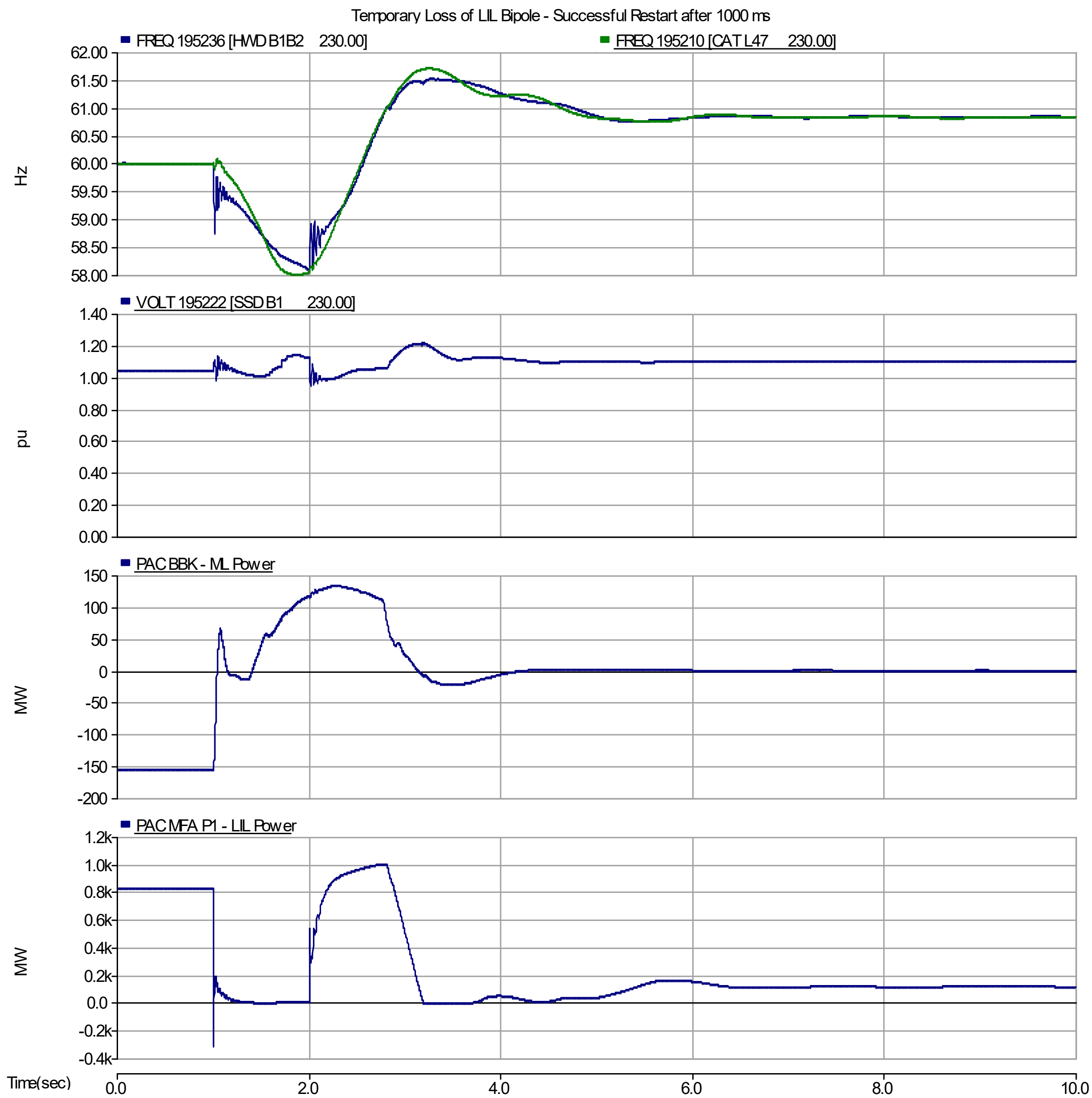

Figure 7-4. Temporary Loss of LIL Bipole (Case HP27), restart in 1 second

If the LIL frequency controller is not in-service, the system frequency continues to rise beyond 62 Hz upon successful restart of the LIL bipole as shown in Figure 7-5. Therefore, if restart attempts are going to be made on LIL bipole outages, it is essential that the LIL frequency controller be in-service, otherwise if all blocks of load have been shed and the LIL returns to full power, the system frequency will rise far beyond 62 Hz.

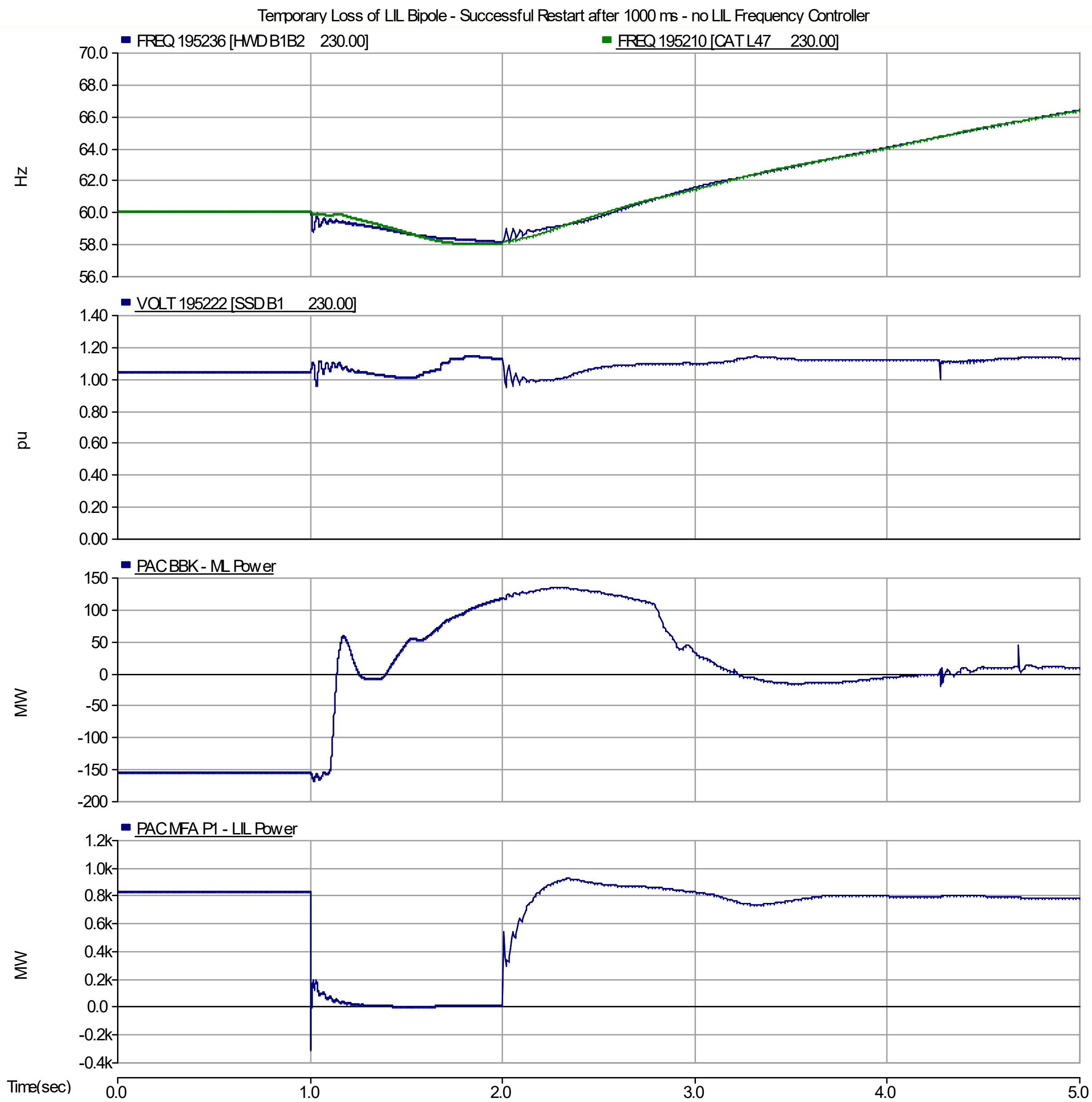

Figure 7-5. Temporary Loss of LIL Bipole (Case HP27), restart in 1 second, no LIL frequency controller

8. Loss of the ML Bipole

8.1 During ML Export

If the ML is exporting and the ML bipole is lost, the IIS will experience an overfrequency. Transmission Planning criteria states that this overfrequency should not rise above 62 Hz.

The worst case occurs when the ML is at maximum export of 500 MW. If the ML bipole is lost, there will be an excess of 500 MW in the IIS. All base cases with the ML exporting 500 MW were used to simulate loss of the ML bipole. These results are summarized in Table 8-1.

Without running back power on the LIL, the worst case system conditions occur during light and extreme light loading, which experienced an overfrequency of 61.2 Hz when the ML bipole was lost.

Table 8-1. Overfrequency due to loss of ML bipole at 500 MW export

Case	Load Condition	LIL (MW) @ MFA	ML (MW)	Frequency (Hz)
HP3	Intermediate	900	500 (export)	60.87
HP6	Intermediate	694	500 (export)	60.86
HP15	Intermediate	704	500 (export)	60.86
HP18	Light	480	500 (export)	61.20
HP22	Extreme Light	470	500 (export)	61.20
HP23	Peak	900	500 (export)	60.86
HP24	Intermediate	900	500 (export)	60.92
HP25	Light	900	500 (export)	60.87

8.2 During ML Import

If the ML bipole is lost while importing, the IIS will experience an underfrequency. Transmission Planning criteria states that frequency should remain above 58 Hz, however controlled UFLS is permitted.

The worst case underfrequency occurs when the ML is at maximum import of 320 MW. If the ML bipole is lost, there will be a deficiency of 320 MW in the IIS. All base cases with the ML importing 320 MW were used to simulate loss of the ML bipole. These results are summarized in Table 8-2. In all cases, the frequency remained well above 58 Hz.

Table 8-2. Underfrequency due to loss of ML bipole at 320 MW import

Case	Load Condition	LIL (MW) @ MFA	ML (MW)	Frequency (Hz)	Load shed (MW)
HP7	Peak	294.4	320 (import)	59.35	-
HP8	Peak	337	320 (import)	59.32	-
HP9	Intermediate	Out-of-service	320 (import)	58.48	381
HP14	Peak	704	320 (import)	58.86	76
HP17	Intermediate	500	320 (import)	59.33	-
HP20	Light	Out-of-service	320 (import)	58.24	273

In the cases with the LIL in-service, only the peak load case (HP14) with the LIL operating at 704 MW experienced an UFLS event of 76 MW when the ML bipole was lost. In the rest of the cases with the LIL in-service, the IIS frequency remained above 59 Hz.

In the cases where the LIL is out-of-service (HP2, HP20), its frequency controller is not available to support the IIS frequency when the ML bipole is lost. In these cases, the frequency still remained well above the 58 Hz criteria, however UFLS in the amount of 273 MW occurred in the light load case and 381 MW occurred in the intermediate load case using the revised UFLS scheme discussed in Section 7.

9. Conclusions

9.1 Conclusions

The results of the analysis are summarized in the sections below.

9.1.1 Three-Phase Faults near SOP, BDE and the Avalon Peninsula

The analysis included a review of three-phase faults on the 230 kV lines between Bay d'Espoir (BDE), SOP, and the Avalon Peninsula. Anlysis indicates that the system response is a function of power flow on 230 kV lines at BDE, namely TL202, TL206 and TL267. While the BDE three-phase fault is excluded from Transmission Planning Criteria, three-phase faults at Sunnyside (SSD) and Western Avalon (WAV) must meet criteria. A prelimary investigation of operating limits was performed and these limits will be confirmed during the final Stage 4 operational studies.

1) LIL in-service

The preliminary analysis indicates that flow in the BDE to Avalon Peninsula corridor can be restricted to avoid instability from a three-phase fault without impacting the capacity of the transmission system to meet forecasted peak loads when the LIL is in-service as a bipole or as a monopole.

2) LIL out-of-service

If the LIL is out-of-service, peak Island demand cannot be served. Flow in the BDE to Avalon Peninsula corridor is restricted to avoid customer impact for a 3PF on TL202, TL206 or TL267. With the LIL out of service, the maximum Island demand that can be served is around 1200 MW if the 3PF at BDE is considered. Increased transfer limits are possible if consideration of the BDE 3PF location is relaxed.

In order to be capable of serving higher Island demand without a stability issue under a three-phase fault scenario on TL202, TL206 or TL267 with the LIL out of service, it is likely that either new generation would be required on the Avalon peninsula, that dynamic reactive power support would be required near Sunnyside, or that new AC transmission eastward out of BDE would be needed in order to transfer more generation from the west of the Island to the Avalon Peninsula.

9.1.2 Loss of Largest Unit with the IIS

After retirement of the Holyrood generating units, BDE Unit 7 at 154.4 MW is the largest generator on the Island. Frequency should remain above 59 Hz for loss of BDE Unit 7 and UFLS should be avoided.

Table 9-1 summarizes the LIL reserve requirements to ensure that loss of the largest generator meets the 59 Hz criteria and avoids UFLS.

Table 9-1. LIL reserve requirements for loss of largest generator

ML Frequency Controller	Reserve required on LIL
In-service	None
Out-of-service	54 MW to 130 MW, depending on system conditions

9.1.3 Loss of a LIL Pole

Similar to loss of the largest generator, frequency should remain above 59 Hz for loss of a LIL pole and UFLS should be avoided.

If one of the LIL poles is lost, the remaining pole has an overload rating of 2.0 pu for 10 minutes, after which the rating drops down to 1.5 pu continuous. The amount of LIL infeed that is lost at SOP depends on how much power the LIL was transferring prior to loss of the pole. In a worst case, if operating at 900 MW, this study showed that prior to converter transformer tap-changer action, and due to increased DC line losses associated with the resistance of the line electrode, the remaining pole is only able to provide 633 MW at Soldiers Pond, as opposed to the 830 MW it was providing pre-contingency, resulting in the net loss of 267 MW to the IIS.

Operating restrictions to keep the IIS frequency above 59.1 Hz for loss of a LIL pole are summarized in Table 9-2.

Table 9-2. Operating restrictions to ensure loss of LIL pole meets 59 Hz criteria

ML Export	At full LIL power transfer of 900 MW, loss of a LIL pole will require ML runback in the range of 100 MW to 150 MW, depending on system conditions, and depending on whether or not the ML frequency controller is in- or out-of-service.
ML Import	If the ML import is at the maximum level of 320 MW, it cannot transiently import more power from Nova Scotia via its frequency controller or via a runback, therefore it cannot not help the IIS during underfrequency events. In this case, LIL power transfer should be limited to around 400 MW to 500 MW depending on system conditions.

9.1.4 Loss of the LIL Bipole

Controlled underfrequency load shedding is permitted for loss of the LIL bipole, however, the IIS frequency shall not drop below 58 Hz. Additionally, if the ML is exporting, the export will be runback to 0 MW if the LIL bipole trips.

In addition to running back ML export to 0 MW, modifications to the existing UFLS scheme are needed to maintain the IIS frequency above 58 Hz for loss of the LIL bipole. Additional blocks of load were added to the UFLS scheme, and the blocks were shifted to distribute the load shedding over a frequency range of 58.9 Hz to 58.4 Hz.

Despite the newly designed UFLS scheme, it is not possible to transfer the full 900 MW on the LIL unless there is sufficient Island generation on-line to provide adequate voltage and inertial support if the LIL bipole is lost. A preliminary operating guideline is defined in Figure 9-1, which limits LIL transfer based on a minimum requirement for Island generation. The LIL transfer limits are defined for two scenarios:

- ML is exporting firm transfer of 157 MW, and is relied upon to runback these exports to 0 MW
- ML is operating at 0 MW, and cannot be relied upon for runback

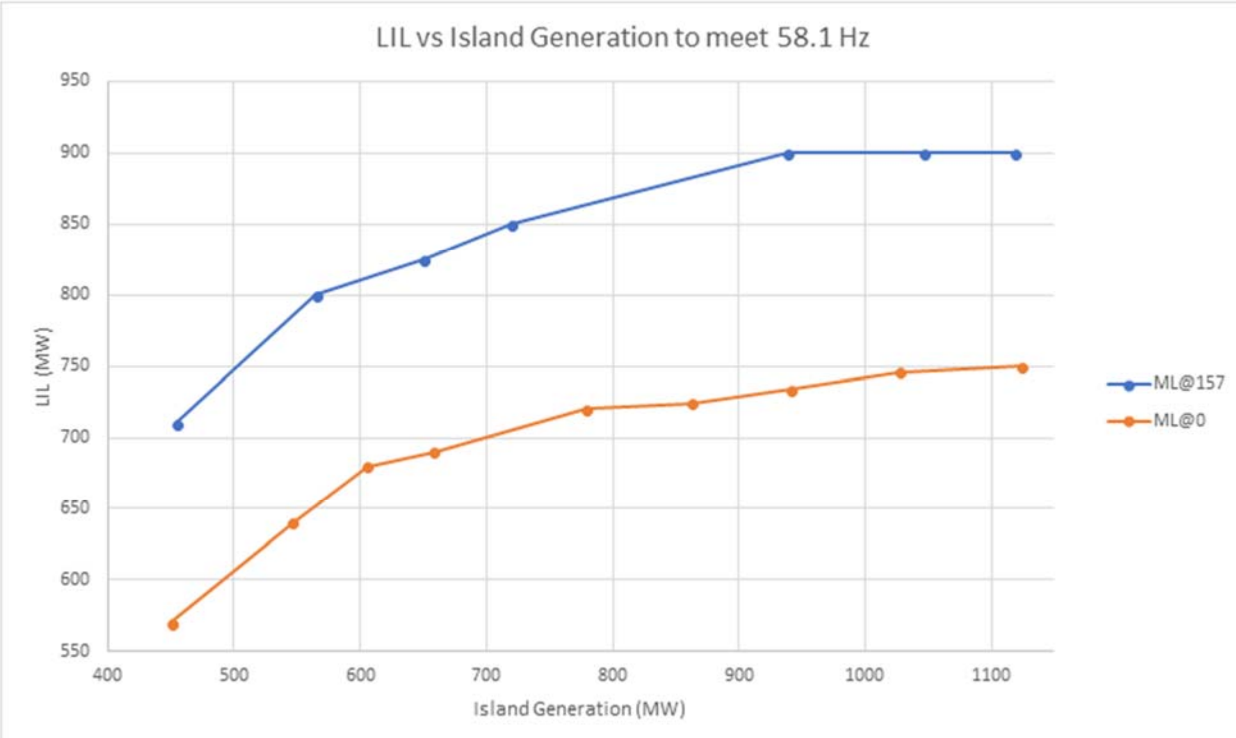

Figure 9-1. LIL Transfer limits vs. Island Generation
Blue: ML @ 157 MW export
Orange: ML @ 0 MW

In addition to the LIL transfer limits shown in Figure 9-1, other conclusions include:

- Instability can arise in cases when there is a high power flow from BDE to the Avalon Peninsula. Operation of the HRD GT during peak load conditions is required to prevent system instability if the LIL bipole is lost.
- The Come-By-Chance capacitor banks should be in-service when the power flow eastward from BDE towards SOP is high to help support the voltage if the LIL bipole is lost. Keeping the pre-contingency voltage near Sunnyside as high as possible (within criteria) improves the system response to the worst case contingencies, including 3PF on TL202, TL206 and TL267 that were discussed in Section 1.2.1.

9.1.5 LIL Temporary Bipole Outage

According to Transmission Planning Criteria, a temporary bipole outage should not cause the IIS frequency to drop below 59 Hz and UFLS should be avoided.

Two LIL bipole outage durations were studied under worst case system conditions[21]:

1. Maximum outage time to ensure IIS frequency stays above 59 Hz and UFLS is avoided
2. Outage time by which all blocks of load will have been shed

[21] Case HP27 was found to be the worst case for loss of LIL bipole.

Table 9-3 summarizes these results for the worst case system conditions.

Table 9-3. Duration of LIL Bipole Outage

Number of SOP synchronous condensers in-service	Duration to Avoid UFLS	Duration at which all blocks of load have shed
2	300 ms	680 ms
3	380 ms	780 ms

It is important to note that the LIL frequency controller must be in-service if the LIL will be automatically restarted after a bipole outage. This is to account for the runback of ML export and the possibility that load has shed. If the LIL frequency controller is not in-service when the LIL bipole is automatically restarted, the IIS frequency can go significantly beyond 62 Hz if all blocks of load have shed.

9.1.6 Loss of the ML Bipole or Pole

If importing, loss of an ML pole should not result in UFLS and frequency should remain above 59 Hz. Loss of the ML bipole is allowed to result in UFLS, however the frequency should remain above 58 Hz.

If exporting, frequency should remain below 62 Hz for loss of an ML pole or bipole .

The results for loss of an ML pole or bipole are summarized in Table 9-4.

Table 9-4. Summary of results for loss of ML bipole or pole

ML Import/Export	Loss of ML Pole	Loss of ML Bipole
500 MW export	Max. frequency of 60.6 Hz (light load)	Max. frequency of 61.2 Hz (light load)
320 MW import	LIL in-service: min. frequency > 59 Hz LIL out-of-service: min frequrency 58.9 Hz, with 26 MW of loadshed	LIL in-service: min. frequency 58.86 Hz, with 0-76 MW of loadshed LIL out-of-service: min frequrency 58.24 Hz, with 273-389 MW of loadshed

9.2 Summary of Technical Issues

As described above, the following technical issues were identified by the Liberty Consulting Group as part of Phase 2 of the Hearing into Supply Issues and Power Outages on the Island Interconnected System. Conclusions with respect to these items are summarized as follows:

- Options (e.g. operating limits) to reduce UFLS
    - Analysis has been performed to confirm that Transmission Planning Criteria are met. A modified UFLS scheme has been developed and it has been confirmed that load shed is avoided and frequencies do not drop below 59 Hz for events including the loss of

generating units, the permanent loss of an HVdc pole, and for the temporary loss of a bipole. Preliminary operating limits have been identified to ensure that UFLS is avoided in operating conditions when HVdc links or frequency controllers are not in service. These limits will be fully developed as part of the final phase of the operating studies.

- Re-strikes on the LIL-OHL
  - As summarized in Section 7.2, an analysis was performed to assess temporary LIL bipole outages . It was found that UFLS is avoided if the LIL is restarted within 300 ms. This limitation assumes that the ML frequency controller is in place and 157 MW of ML export is being curtailed. Operating limits for the LIL will be developed to ensure that UFLS does not occur if the ML frequency controller is not in service or if export is reduced.
  - The LIL frequency controller must be in-service if the LIL will be automatically restarted after a bipole outage. This is to account for the runback of ML export and the possibility that load has shed before the LIL is successfully restarted. If the LIL frequency controller is not in-service when the LIL bipole is automatically restarted, the IIS frequency can go significantly beyond 62 Hz if all blocks of load have shed.
- ML-LIL interaction studies
  - The coordinated runbacks of the ML for loss of a LIL pole or the LIL bipole were studied, as described above. It has been confirmed that UFLS is avoided under normal operation. Preliminary operating limits have been identified to ensure that UFLS is avoided in operating conditions when HVdc links or frequency controllers are not in service. These limits will be fully developed as part of the final phase of the operating studies.
- Bay d'Espoir instability issues
  - Analysis was performed to assess the impact of a 3PF at BDE. It was found that instability and transient undervoltage conditions for this event are a function of the eastward flow from BDE to the Avalon Peninsula. With the LIL in service, instability resulting from the 3PF at BDE can be avoided by limiting the flow in this corridor. Analysis was also performed to identify maximum limits that may be transferred in this corridor in the event of a LIL bipole outage.
- ML frequency controller study
  - The analyses described above include the operation of the ML frequency controller in its current configuration. This is defined by a 0.5 Hz deadband and a capacity limit of +/- 100 MW. These settings were the basis for the analysis presented in this report and were found be acceptable for high power operation.
- IIS performance with ML in and out of service
  - As described above, preliminary analysis has been performed to assess operating limits to the LIL the event of an outage to the ML. Reserve requirements for the LIL have also been identified to ensure that the loss of the largest generator on the Island does not result in UFLS in the event of an ML outage.

- Soldiers Pond site for 4th high inertia synchronous condenser
    - On the basis of the above, a fourth high inertia synchronous condenser at Soldiers Pond is not required in the near term. Study results indicate that instability resulting from the 3PF at BDE can be avoided by applying operational limits on the power flow from BDE to the Avalon Peninsula without impacting the ability to meet peak loads. It has also been found that the system can withstand a temporary bipole outage of up to 300 ms before the occurrence of UFLS. Further, it has been confimed that stable system operation can be achieved for a permanent bipole fault with a revised UFLS scheme. Based on the findings of this report, effective system reinforcements would involve the addition of generation on the Avalon Peninsula rather than a high inertia synchronous condenser. Such additions would help to offload power flow from BDE to the Avalon Peninsula in the event that LIL capacity is limited. This input will be considered as part of Hydro's ongoing Generation Planning review, which is expected to be completed in late 2018.

9.3 Next Steps

The following studies are the next phases of the Stage 4 LIL bipole studies being performed:

1. Stage 4b - PSS tuning study for all generators in the IIS
   This study is nearing completion, and will determine parameters for the power system stabilizers (PSS) for all of the generators in the IIS in order to improve the system's damping.

2. Stage 4c - Labrador Power Transfer study
   This study is currently underway and will include an operational review and will define the maximum power transfer limits between Muskrat Falls and Churchill Falls on the two 315 kV ac lines.

3. Stage 4d – Full operational studies
   Once the boundaries of the study cases have been determined by earlier Stage 4 studies (4a through 4c), the final set of base cases can be created and the full steady state and dynamic analysis will be performed on the system to ensure the performance of the Labrador and IIS systems are within criteria, and to define any operating guidelines and/or further HVDC run-backs.

Appendix 1

Revised UFLS Scheme

TGS™

TransGrid Solutions

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/**********************************************************************
/       NLH Underfrequency Load Shedding
/       Burgeo load shed at 58.8 Hz
/     St. Albans load shed at 58.6 Hz
/       TL226 loads shed at 58.2 Hz
/       TL220 loads shed at 58.1 Hz
/
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/**********************************************************************
/       NP Underfrequency Load Shedding
/**********************************************************************
/ 59.0 Hz 15 sec time delay block - KEN1,GLV - 54.9 + 8.9
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  195135,'LDSHBL',1,59.0,15.0167,1.000,0.0,0.0,0.0,0.0,0.0,0.0,0.1/

/ 58.8 Hz block - BLK,GRH - 39.5 + 15.2
  196546,'LDSHBL',1,58.9,0.05,1.0,0.0,0.0,0.0,0.0,0.0,0.0,0.1/
  196221,'LDSHBL',1,58.9,0.05,1.0,0.0,0.0,0.0,0.0,0.0,0.0,0.1/

/ 58.6 Hz block - MDR,KBR1 - 90.2 + 39.7 (*MATCHES DFDT BLOCK)
  195624,'LDSHBL',1,58.7,0.05,0.696,0.0,0.0,0.0,0.0,0.0,0.0,0.1/
  196570,'LDSHBL',1,58.7,0.05,0.600,0.0,0.0,0.0,0.0,0.0,0.0,0.1/

/ 58.4 Hz block - CLV,SJM1 - 57.9 + 49.7 (*SAME AS DFDT BLOCK)
  195144,'LDSHBL',1,58.6,0.05,0.885,0.0,0.0,0.0,0.0,0.0,0.0,0.1/
  196568,'LDSHBL',1,58.6,0.05,1.0,0.0,0.0,0.0,0.0,0.0,0.0,0.1/

/ 58.2 Hz block - GFS,RRD - 0.6 + 40.6 (*SAME AS DFDT BLOCK)
  195126,'LDSHBL',1,58.6,0.05,1.0,0.0,0.0,0.0,0.0,0.0,0.0,0.1/
  196572,'LDSHBL',1,58.6,0.05,1.0,0.0,0.0,0.0,0.0,0.0,0.0,0.1/

/ 58.1 Hz block - GAN, VIR1, HWD1 - 23.4 + 70.1 + 53.3
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/ 58.0 Hz block - COB, BRB, BCV, GOU, KEL, SLA - 28.6 + 24.5 + 27.7 + 27.2 + 23.6 + 56.7
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/
/ Additional Load Shedding - 11.1 + 38.4 + 23.5 + 17.3 + 49.1 + 63.7 + 7.0 + 10.9 + 12.4 + 6.9 + 12.5
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Engineering Support Services for:

RFI Studies

Newfoundland and Labrador Hydro

Attention: Mr. Rob Collett

Stage 4B: Power System Stabilizer Design

Technical Note: TN1205.65.01
Date of issue: November 8, 2018

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Appendices

1. Executive Summary

Stage 4 is the final stage of operational studies that are being performed to determine the system operating limits of the Newfoundland and Labrador Hydro (Hydro) Island Interconnected System (IIS) for the point in time when the 900 MW LIL bipole, the Muskrat Falls (MFA) generators, the Soldiers Pond (SOP) synchronous condensers and the Maritime Link (ML) are in-service. The Holyrood thermal generators, the Stephenville Gas Turbine, and the Hardwoods Gas Turbine are no longer in-service, and Holyrood Unit 3 is operating as a synchronous condenser.

Stage 4A[1] performed a preliminary assessment of the IIS at high power operation of the LIL bipole.

Stage 4B, this study, performs a small signal stability assessment of the IIS. This report investigates the small signal stability of the IIS and the need for tuning of power system stabilizers. The following generating stations were evaluated to determine the need for stabilizer tuning:

i. Bay d'Espoir (BDE) units 1 to 7
ii. Cat Arm (CAT) units 1 and 2
iii. Upper Salmon (USL)
iv. Granite Canal (GCL)
v. Holyrood (HRD) Unit 3 synchronous condenser
vi. Holyrood (HRD) GT
vii. Hardwoods (HWD) synchronous condenser
viii. Soldiers Pond (SOP) synchronous condensers

The Muskrat Falls generator power system stabilizers are also evaluated in this report.

1.1 Conclusions

1.1.1 Interconnected Island System Generators

The need for power system stabilizers (PSSes) was evaluated over various loading conditions and for critical contingencies in the IIS. As a result of the small signal stability assessment, PSSes were proposed for the following generating stations to improve the electromechanical oscillation damping in the system:

(1) Cat Arm units 1 and 2

(2) Upper Salmon

(3) Granite Canal

(4) Bay d'Espoir units 1-7 (for inter-area oscillation damping)

[1] TN1205.62.04, “Stage 4A LIL Bipole: Preliminary Assessment of High Power Operation”, TransGrid Solutions, September 13, 2018.

The performance of the proposed PSSes were evaluated in PSSE for system intact and critical contingencies. It was observed that the PSSes provide better damping compared to the cases without PSSes. Furthermore, under light load conditions, PSSes can help to avoid instabilities in the system.

It should be noted that small signal stability assessment is a linear analysis technique and, therefore, the non-linear behaviors, such as the impact of frequency controllers that have dead-bands, are not considered in the analysis. If the system is well damped, the small signal stability analysis results typically match well with the actual system behavior as simulated in PSSE. However, if the damping of certain oscillations is low, other non-linear controllers may have a significant impact (positive or negative) on these oscillations. After the PSSes were added to the generators listed earlier, the small signal stability analysis showed very good damping of the electromechanical oscillations in the IIS. Therefore, such impact of the other non-linear controllers are not expected.

It should also be noted that the validity of the powerflow scenarios under contingency conditions (N-1 and N-2) needs to be further evaluated in the final Stage 4 operational studies considering the steady state and dynamic performance. Therefore, some of the operating points considered in this small signal stability analysis may not be practical.

In summary, the PSS parameters provided in this report should be considered as preliminary values for use and evaluation in the final Stage 4 operational study, and it is recommended to further evaluate the performance of the PSSes during the final Stage 4 operational study.

1.1.2 Muskrat Falls Generators

During the Stage 4c operational study, which investigates power transfer capability between Muskrat Falls and Churchill Falls, it was observed that the original power system stabilizer models of the Muskrat Falls generators are not effective under certain operating conditions when one of the two 315 kV lines between Churchill Falls and Muskrat Falls experiences a three-phase fault. Therefore, the Muskrat Falls PSSes were re-tuned to obtain acceptable damping under those operating conditions.

2. Introduction

Stage 4 is the final stage of operational studies that are being performed to determine the system operating limits of the Newfoundland and Labrador Hydro (Hydro) Island Interconnected System (IIS) for the point in time when the 900 MW LIL bipole, the Muskrat Falls (MFA) generators, the Soldiers Pond (SOP) synchronous condensers and the Maritime Link (ML) are in-service. The Holyrood thermal generators, the Stephenville Gas Turbine, and the Hardwoods Gas Turbine are no longer in-service, and Holyrood Unit 3 is operating as a synchronous condenser.

NLH requested to investigate the small signal stability of the IIS and the need for tuning of power system stabilizers. The following generating stations need to be evaluated to determine the need for stabilizer tuning:

i. Bay d'Espoir (BDE) units 1 to 7
ii. Cat Arm (CAT) units 1 and 2
iii. Upper Salmon (USL)
iv. Granite Canal (GCL)
v. Holyrood (HRD) Unit 3 synchronous condenser
vi. Holyrood (HRD) GT
vii. Hardwoods (HWD) synchronous condenser
viii. Soldiers Pond (SOP) synchronous condensers

The Muskrat Falls generator PSSes are also evaluated in this report.

3. Study Methodology

The electromechanical oscillations of the IIS were identified through a small signal stability assessment using TGS's small signal stability program: "TGSSR".

3.1 Small Signal Stability Tool: TGSSR

TGSSR uses dynamic phasor based small signal stability analysis (frequency domain) in order to perform an in-depth analysis of the small signal stability issues in power systems including electromechanical oscillations and sub-synchronous oscillations. This method provides insight into the oscillation phenomena and enables the systematic design of devices and controllers to eliminate the problems. TGSSR is capable of analyzing oscillation phenomena such as:

- Electromechanical oscillations (local and inter-area oscillations)
- Generator-turbine – Series capacitor sub synchronous resonance (SSR)
- Generator-turbine – HVdc torsional interactions (SSTI)
- Wind turbine – Series capacitor sub-synchronous resonances/interactions (SSCI)
- HVdc control interactions and DC resonance issues
- Multi-in-feed HVdc interactions
- All other sub-synchronous frequency interactions in power systems (Interactions of FACTS devices, Network resonances, etc.)
- Power system stabilizer (PSS) and sub-synchronous damping controller tuning
- Optimization of the locations of damping controllers

The main difference between TGSSR and conventional small signal stability analysis programs is the inclusion of the ac network dynamics and the generator stator dynamics. In addition to the generic dynamic models provided in PSSE, TGS has developed detailed models of HVDC, VSC, FACTS devices and wind power plants. These models have been validated against detailed EMT models. A large number of articles related to TGSSR have been published by TGS personnel [1] [2] [3] [4] [5] [6] [7] [8] and more than ten projects have been recently completed using TGSSR.

The inputs to TGSSR are the power flow and dynamic data of the power system. The analysis is performed as follows:

- The initial dynamic network model is created by combining the dynamic phasor based linearized models of the transmission lines, series capacitors, shunt capacitors/reactors and dynamic loads [5].
- The linearized models of the dynamic devices such as generators, HVDC, VSC, FACTS devices and wind power plants are obtained and then combined with the dynamic network model.

TGSSR uses Eigen value analysis techniques (small signal stability assessment) to analyze the oscillations in the entire power system.

3.2 Small Signal Stability Analysis using TGSSR

The Eigen value analysis technique is performed as follows:

- TGSSR creates the linearized models of all the dynamic devices around the steady state operating point specified by the power flow cases. Further, TGSSR combines the dynamic phasor model of the ac network to create the state space small signal stability model. More information on modeling can be found in [9]. The state space model is then analyzed using eigenvalue analysis to determine the oscillatory modes and their damping.
    - A real eigenvalue corresponds to an aperiodic (non-oscillatory) mode. If the eigenvalue is negative the mode is a decaying mode and if it is positive, the mode is unstable (aperiodic instability).
    - A complex conjugate pair of eigenvalues corresponds to an oscillatory mode. If the eigenvalue pair is, $\lambda = \sigma \pm j\omega$, the frequency of oscillation is given by,

    $$f = \omega / (2\pi)$$

    The damping ratio is given by,

    $$\zeta = -\sigma / |\lambda|$$

  If the real part of the eigenvalues is negative (i.e. damping ratio is positive), the mode is stable. The magnitude of the damping ratio determines the rate of decay of the amplitude of the oscillation. Usually, the damping ratio is given as a percentage value. In this study, only the electromechanical oscillatory modes (<3Hz) of the are considered. The rule of thumb is that damping of 5% is sufficient for the electromechanical modes.

- The oscillation mode characteristics are analyzed using the properties of the eigenvectors.
    - The participation factors are obtained by multiplying the relevant elements of the right eigenvector and the left eigenvector. The elements of a participation factor vector are dimensionless and the sum of the elements is unity. Therefore, the participation factor (elements) can be used as an index to compare the relative participation of the state variables for a particular mode of oscillation. Since the participation factors of an oscillatory mode are complex numbers, the magnitudes of the participation factors are used for the comparisons. Note that the participation factors give an indication of the contribution of the devices in an oscillation, however precise analysis of the contribution is not possible. Simply, the devices with higher participation factors have a higher contribution to the oscillation. In TGSSR the participation factors are scaled such that the highest participating state variable has a participation factor of 1.

    - The right eigenvector of a particular mode provides the mode shape, which shows the relative phasors of the state variables when that mode is excited. Since the units and the scaling of the state variables may differ, the magnitudes of the elements cannot be compared against each other. Therefore, only the phase angles (mode shapes) are used to determine the relative phases of the state variables for a particular mode of oscillation. For example, the angles of mode shapes can be used to determine whether two state variables oscillate together or against each other in a particular oscillatory mode.

The process is carried out for critical operating conditions such as min-max generation under system intact and contingency conditions. More information on eigenvalue analysis can be found in [10].

4. Study Models and Criteria

4.1 Power Flow Cases

The power flow cases listed in Table 4-1 were used for the study.

Table 4-1. Powerflow Cases used for Small Signal Stability Assessment

Number	Load Condition	Island Generation (MW)	Island Demand (MW)	Load Scaled?	HRD GT Status?	LIL (MW) @ MFA	ML (MW)
HP13	Peak	1307.3	1812.4	NO	ON (60MW)	~605 (import)	158 (export)
HP14	Peak	833.3	1816.6	NO	OFF	~704 (import)	320 (import)
HP15	Intermediate	1142.5	1307.2	YES	OFF	~605 (import)	500 (export)
HP16	Intermediate	765.7	1272.5	YES	OFF	~605 (import)	158 (export)
HP17	Intermediate	478.4	1278.7	YES	OFF	~500 (import)	320 (import)
HP18	Light	817.35	779.2	YES	OFF	~480 (import)	500 (export)
HP19	Light	703.64	742.7	YES	OFF	~200 (import)	158 (export)
HP20	Light	447.01	767.8	YES	OFF	0	320 (import)
HP21	Extreme Light	526.1	458.1	YES	OFF	~90 (import)	158 (export)
HP22	Extreme Light	546.1	498.75	YES	OFF	~470 (import)	500 (export)

4.2 Contingencies

Initially, the studies considered system intact, all N-1, and critical N-2 contingencies. It was found that the N-2 contingencies cover all of the critical cases in terms of small signal stability. Therefore, the full small signal stability assessment was carried out for system intact conditions and the for the critical N-2 contingencies listed in Table 4-2.

Table 4-2. Contingencies

Case	Contingency
BaseCase	System Intact
ContCase1	TL203-TL237
ContCase2	TL203-TL217
ContCase3	TL203-TL202
ContCase4	TL203-TL267
ContCase5	TL268-TL265
ContCase6	TL268-TL218
ContCase7	TL268-TL266
ContCase8	TL266-TL236
ContCase9	TL218-TL266

Case	Contingency
ContCase10	TL202-TL267
ContCase11	TL202-TL217
ContCase12	TL231-TL204
ContCase13	TL231-TL234
ContCase14	TL232-TL205
ContCase15	TL211-TL233
ContCase16	TL211-TL269
ContCase17	TL233-TL269
ContCase18	TL233-TL228
ContCase19	TL269-TL228
ContCase20	TL263-TL233
ContCase21	TL263-TL211
ContCase22	TL234-TL233
ContCase23	TL234-TL211

4.3 Criteria

The rule of thumb is that damping of 5% is sufficient for the local area electromechanical modes (0.8 to 3.0 Hz) and 3% damping is sufficient for inter-area modes (< 0.8 Hz). However, when designing the damping controllers, at least 10% damping for the local area oscillations associated with the relevant generators was considered. For the inter-area oscillations at least 5% damping was considered.

5. PSS Design

The small signal stability of the IIS was first evaluated without PSSes. Then, if low damping was found, PSS parameters were determined based on the electromechanical modes found to be associated with each generator.

The analysis was performed using the following steps:

- Step 1: Initial small signal stability assessment – to identify critical local area oscillations
- Step 2: Design of PSSes for critical local area oscillations
- Step 3: Second small signal assessment with PSSes designed to damp out critical local area oscillations – to identify critical inter-area oscillations
- Step 4: Design of PSSes for critical inter-area oscillations
- Step 2: Final small signal assessment with all PSSes

5.1 Step 1 - Initial Small Signal Stability Assessment

The peak power flow case HP13 was initially used to evaluate the small signal stability of the system. As the first step, the local area electromechanical oscillations associated with the IIS generators were identified.

5.1.1 Local Oscillations - Bay d'Espoir Generators

The local area electromechanical oscillations associated with the Bay d'Espoir generators, along with the lowest possible damping observed under contingency conditions, are given in Table 5-1. The generator local oscillations are well damped and there is no need to add a PSS to damp out these oscillations. The PSSes for these generators are considered later in the study for damping out inter-area oscillations.

Table 5-1: Local Oscillations Associated with Bay d'Espoir Generators

Lowest damping in Case HP13		
Freq (Hz)	**Damping (%)**	**Contingency**
1.25	13.38	TL202-TL267
1.54	12.42	TL202-TL267
1.48	20.09	TL202-TL267
1.42	19.58	TL202-TL267
1.43	19.60	TL202-TL267
1.43	19.45	TL202-TL267
1.63	11.77	TL202-TL267

5.1.2 Local Oscillations - Cat Arm Generators

There are two electromechanical oscillation modes associated with the Cat Arm generators as shown in Table 5-2. Both of these modes show greater than 5% damping. There is one oscillatory mode at 1.19 Hz with approximately 6% damping. Although damping of 6% is typically considered to be acceptable since it is greater than 5 %, there is a benefit to improving this damping because when local oscillations are well damped, the possibility of inter-area oscillations occurring is low. Therefore, it was decided to add PSSes improve the damping of this mode to greater than 10%.

Table 5-2: Local Oscillations Associated with Cat Arm Generators

Lowest damping in Case HP13		
Freq (Hz)	**Damping (%)**	**Contingency**
1.19	5.95	TL234-TL233
1.50	12.02	TL211-TL269

5.1.3 Local Oscillations - Upper Salmon Generator

There is one local oscillatory mode at 1.12 Hz associated with the Upper Salmon generator, with damping of 3.99% following an N-2 outage of TL234-TL211 Therefore, it was decided to add a PSS to improve the damping of this oscillation.

5.1.4 Local Oscillations - Granite Canal Generator

The Granite Canal generator contributes to an oscillation at 1.34 Hz, with the lowest damping being approximately 4.66% following an N-2 outage of TL263-TL211. Therefore, it was decided to add a PSS to improve the damping of this oscillation.

5.1.5 Local Oscillations - Holyrood Unit 3 and GT

There are two oscillatory modes associated with Holyrood Unit 3 and the Holyrood GT as shown in Table 5-3. Both of these modes are well damped and there is no need to add PSSes for these units.

Table 5-3: Local Oscillations Associated with Holyrood Unit 3 and GT

Lowest damping in Case HP13		
Freq (Hz)	**Damping (%)**	**Contingency**
2.73	13.26	TL202-TL267
2.08	11.87	TL268-TL265

5.1.6 Local Oscillations - Solders Pond Synchronous Condensers

There is one location oscillation at 1.33 Hz associated with the Solders Pond synchronous condensers, however the damping is greater than 30% and therefore, PSSes are not required.

5.2 Step 2 - PSS Design for Local-Area Oscillation Modes

In Step 1 (Section 4.1), poorly damped local-area oscillations were identified in the following generators:

- Cat Arm unit 1 and 2
- Upper Salmon unit
- Granite Canal unit

In this step, the PSSes were designed for these generators to damp out the identified local-area oscillation modes. The designing process is described in the following sub-sections.

5.2.1 Integral-of-accelerating Power Based Stabilizer (PSS2A/PSS2B)

It is common practise to use the integral-of-accelerating power (ΔPω) based stabilizers to damp out electromechanical oscillations of generators. The conceptual design is summarized below.

From the swing equations:

$$\Delta\omega = \frac{1}{2H}\int(\Delta P_m - \Delta P_e)dt \qquad (1)$$

The integral of the mechanical power can be obtained from the above equation as follows:

$$\int \Delta P_m dt = 2H\,\Delta\omega + \int \Delta P_e dt \qquad (2)$$

Based on equation (2), the integral of mechanical power can be recreated from the measurements of the generator speed and electrical power output. Therefore, the integral of the accelerating power can be obtained as follows:

$$\int \frac{\Delta P_a dt}{2H} \to \frac{-\Delta P_e}{2HS} + \left[\frac{\Delta P_e}{2HS} + \Delta\omega\right] \qquad (3)$$

This is the basis for the stabilizer models PSS2A and PSS2B. The control block diagram of PSS2A is shown in Figure 5-1. Note that the PSS2B stabilizer is very similar and the only difference is that PSS2B has an additional lead-lag block (3 instead of 2).

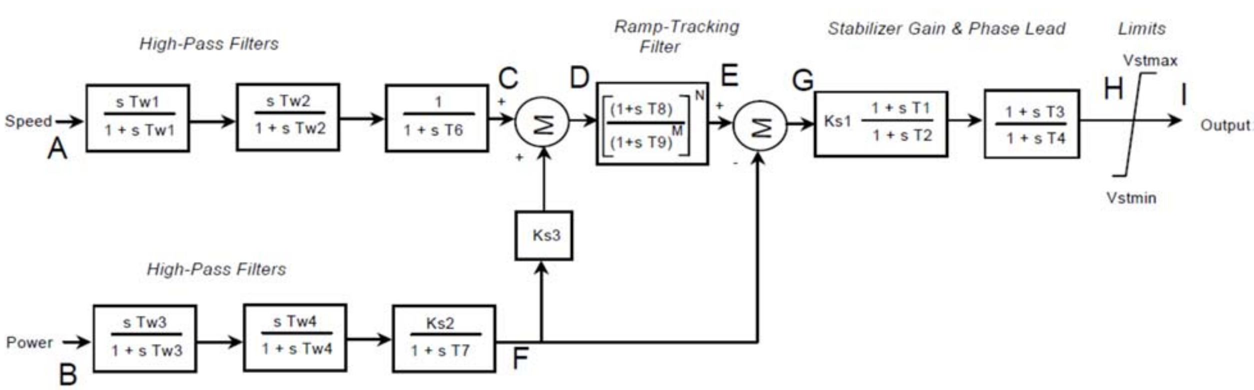

Figure 5-1: PSS2A Block Diagram

The generator speed is considered as the first input. The washout time constant (Tw1) is selected to block the steady state (DC) changes. Typically, Tw1 is in the range of 5 to 20 seconds when considering electromechanical oscillations. The second washout time constant (Tw2) is also set to the same value (i.e. two washout stages) to match the delays associated with the second input path. T6 can be used to model the measuring delays.

The second input is the power output in per unit (pu). The integral of electrical power can be created as follows:

$$\int \frac{\Delta P_e dt}{2H} \rightarrow \frac{\Delta P_e}{2HS} = \left(\frac{STw3}{1+STw3}\right)^2 \frac{1}{2HS} P_e = \left(\frac{STw3}{1+STw3}\right)\left(\frac{Ks2}{1+ST7}\right) P_e \qquad (4)$$

Where

- Tw3 = T7 = Tw1
- Ks2 = Tw1/(2H)
- Ks3 = 1

The second washout block is ignored (i.e. Tw4=0).

By doing this, at point “D” a signal similar to the integral of the mechanical power is created.

In order to minimize the PSS output deviations for rapid mechanical power ramping, a ramp tracking filter is added as shown in Figure 5-1. The most common filter coefficients are as follows:

- N=1
- M=5
- T9 = 0.1
- T8 = M*T9

At point “E”, a filtered signal proportional to the integral of mechanical power is obtained and the integral of electrical power signal is then subtracted to obtain a signal proportional to the integral of accelerating power at point “G”. The required phase compensation and the gain is determined using small signal stability assessment techniques to determine the lead-lag time constants and the gain, Ks1. In this project, PSS2B stabilizers with 3 lead-lag blocks were used.

5.2.2 Cat Arm PSSes

There is a 1.19 Hz oscillation associated with the two units at Cat Arm. The participation factors and the mode shapes of the generator rotor angles are shown in Figure 5-2. The Cat Arm generators are the main contributors. Mode shapes show that the Cat Arm generators are oscillating against the rest of the system in this mode. The main contributors from the rest of the system are the Upper Salmon, Granite Canal and Deer Lake units.

The PSSes were tuned at the Cat Arm units to improve the damping of these oscillations. For this mode, a washout time constant of 5s was considered. The PSS2B parameters were selected as follows:

- Washout time constants: Tw1 = Tw2 =Tw3 = T7 = 5 s
- As described in the above section, Tw4=0
- Generator inertia (from PSSE data), H = 4.02 s

Therefore,

- Ks2 = Tw3/(2H) = 0.6219
- Ks3 = 1
- N=1 M=5
- T9 = 0.1 s
- T8 = M*T9 = 0.5 s

The eigen sensitivities ("residues") were used to determine the required phase compensation. It was found that a phase lead of about 55 deg is required to compensate the total phase lag. Therefore, two lead-lag blocks, each providing approximately 27.5 deg phase lead, were used. In order to get the required phase lead at 1.19 Hz:

- T1 = T3 = 0.2202 s
- T2 = T4 = 0.0808 s
- The third lead-lag block was bypassed (i.e. T5 = T6 = 0)

The frequency characteristics of the overall transfer function of the PSS are shown in Figure 5-3. The required gain of the PSS was adjusted by trial and error. Using a gain of 5 (i.e. Ks1=5), the damping of the oscillation can be increased to 10.7%.

The PSS parameters are given in Appendix-1.

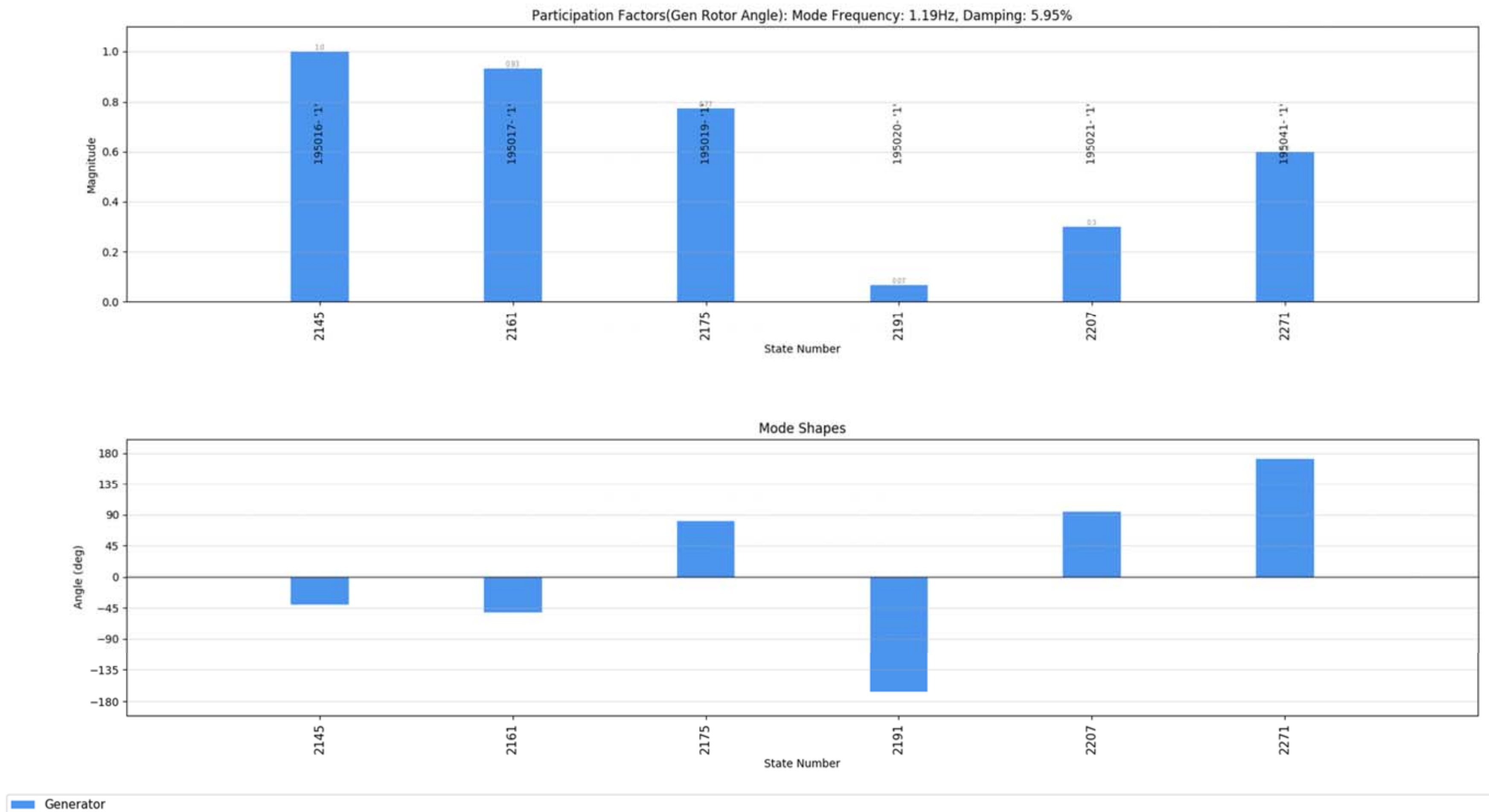

Figure 5-2: Participation Factors and Mode Shapes - 1.19 Hz Mode at Cat Arm

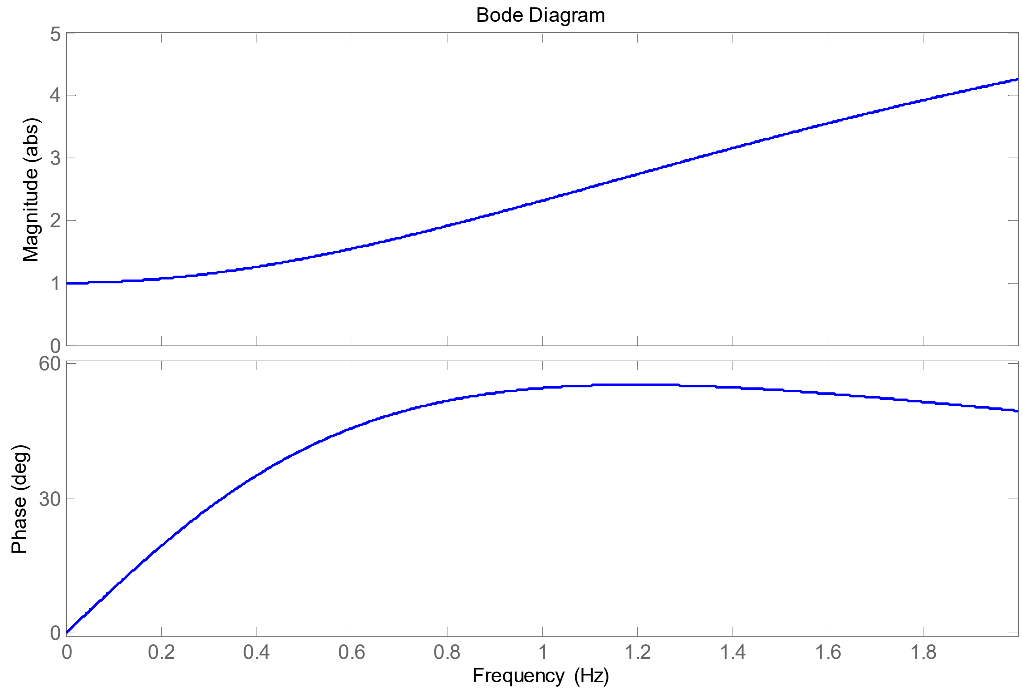

Figure 5-3: Frequency Response of Cat Arm PSSes

5.2.3 Upper Salmon PSS

There is a 1.12 Hz oscillation associated with the Upper Salmon generator. The participation factors and the mode shapes of the generator rotor angles are shown in Figure 5-4 for this mode. The Upper Salmon generator is the main contributor and there is some contribution of Granite Canal generator. Mode shapes show that these two generators are oscillating against the rest of the system in this mode.

Based on the Eigen sensitivities, it was required to have approximately 80 deg (leading) phase compensation in the PSS. It was possible to achieve a damping of 12.3% using a gain of 10. The PSS parameters are tabulated in Appendix-1.

5.2.4 Granite Canal PSS

There is a 1.34 Hz oscillation associated with the Granite Canal generator. The participation factors showed that this mode is local to the generator.

Based on the Eigen sensitivities, it was required to have approximately 50 deg (leading) phase compensation in the PSS. It was possible to achieve a damping of 11.3% using a gain of 3. The PSS parameters are tabulated in Appendix-1.

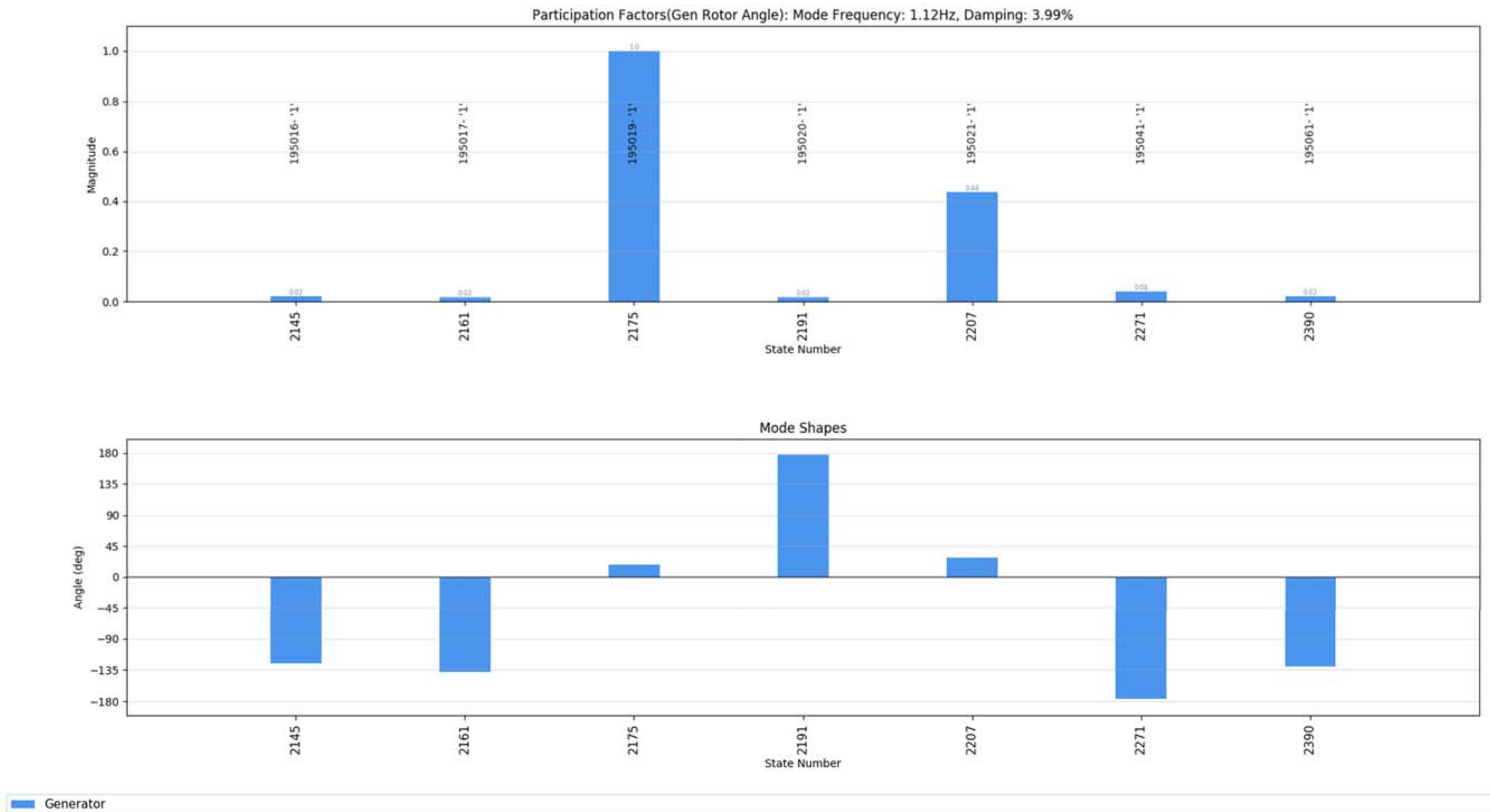

Figure 5-4: Participation Factors and Mode Shapes - 1.12 Hz Mode at Upper Salmon

5.3 Step 3 – Small Signal Stability Assessment with PSSes tuned for Local-Area Oscillations

After adding the PSSes at the Cat Arm, Upper Salmon and Granite Canal units, the small signal stability of the IIS was re-evaluated for all of the power flow cases listed in Table 4-1 considering the contingencies in Table 4-2. Nearly all of the electromechanical oscillations were found to be well damped, however there is one critical inter-area oscillation mode that was found. The frequency, damping and the contribution of the generators in this mode depends on the operating scenario. The frequency of this mode varies in the range of 0.75 Hz to 1.0 Hz. In case HP18, when there is a N-2 outage of TL231-TL234, the damping is approximately 2%. In case HP21, when there is an N-2 outage of TL203-TL237, the oscillation becomes unstable (damping is -7.3%). The participation factors and the mode shapes of the generator rotor angles for this mode are shown in Figure 5-5. The Deer Lake, Cat Arm and Bay d'Espoir generators contribute to the oscillation. There are some contributions of the Soldiers Pond synchronous condensers as well.

It was decided to tune the PSSes in the Bay d'Espoir generators to damp out this oscillation. Further investigation of case HP21 during an N-2 outage of TL203-TL237 revealed that this case is transiently unstable and tuning of the PSSes cannot solve this issue. The final Stage 4 operational studies will investigate this issue since it is likely that a system operating limit will be required during a prior outage of either TL203 or TL237 in case the other line is lost. Therefore, the PSSes were tuned based on the next critical operating condition observed in case HP18 during an N-2 outage of TL231-TL234. In this case, it was required to have a phase compensation of 45 Deg (leading). The gains of the PSSes were set to 17. All PSS parameters are tabulated in Appendix-1.

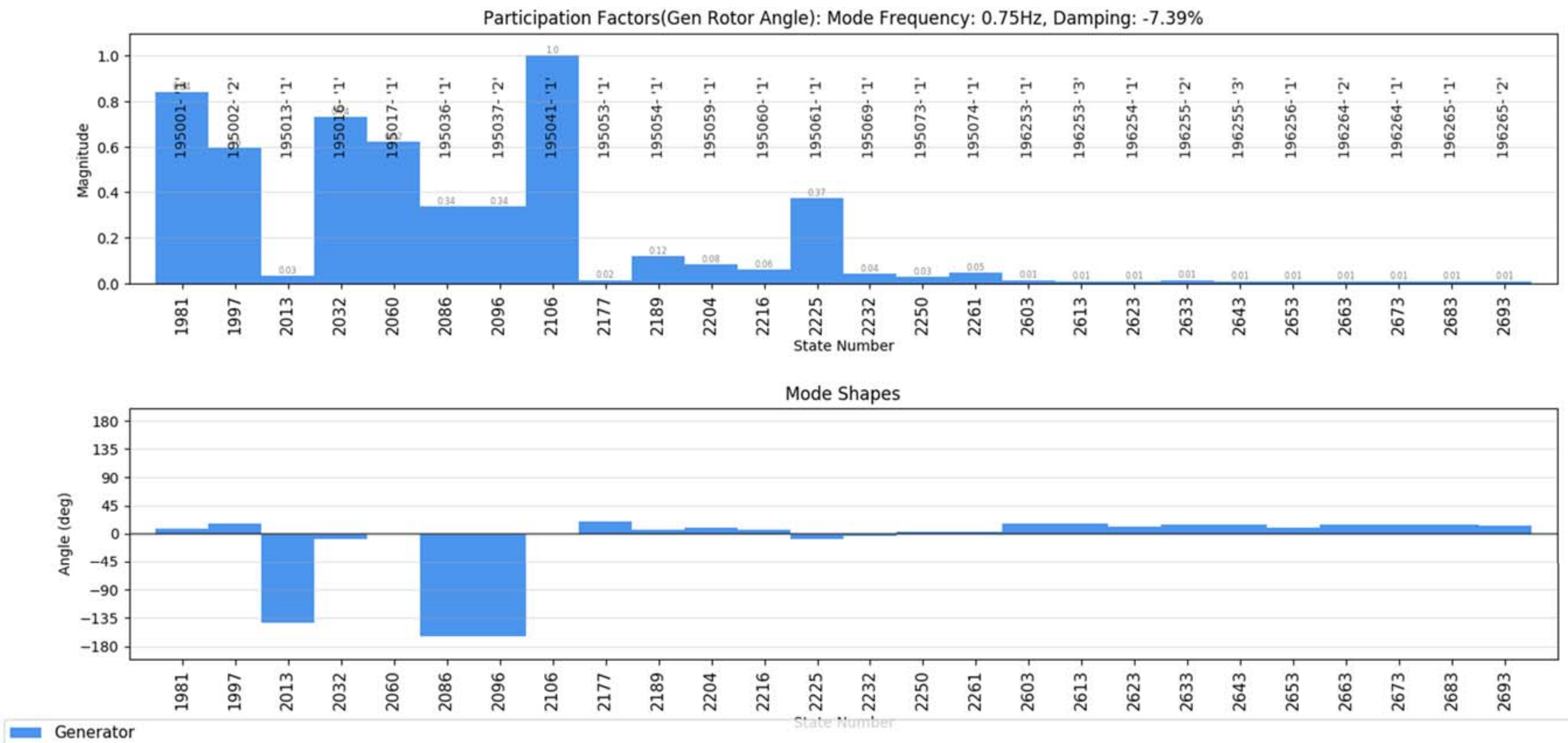

Figure 5-5: Participation Factors and Mode Shapes for 0.75 Hz Inter-area Oscillations

5.4 Step 4 – Final Small Signal Stability Assessment with PSSes

A final small signal stability assessment of the IIS was performed with the PSSes added to the Cat Arm, Upper Salmon, Granite Canal, and Bay d'Espoir units.

5.4.1 Inter-area oscillations

There are several contingencies in case HP20 (light load conditions) where the damping of the inter-area oscillation is less than 5% damping as shown in Table 5-4. The cases with the PSSes show significant improvement compared to the cases without the PSSes. However, it was found that most of these contingencies result in transient instability if simulated in PSSE. Therefore, it is likely that the final Stage 4 operational study will define system operating limits for prior outages involving these lines. Once the final Stage 4 operational study is complete, it is recommended to re-evaluate the small signal stability of these cases when system operating limits are in place for prior outages. For all other cases, more than 6% damping for the inter-area oscillation was achieved.

Table 5-4: Inter-area oscillation mode in HP20 powerflow scenario

Powerflow	Contingency	With PSSes		Without PSSes	
		Freq (Hz)	Damping (%)	Freq (Hz)	Damping (%)
HP20	TL231-TL204	0.90	1.67	0.87	-1.77
HP20	TL232-TL205	0.91	2.33	0.88	-1.59
HP20	TL203-TL237	0.80	3.02	0.75	-8.48
HP20	TL233-TL228	0.95	3.44	0.91	-0.59
HP20	TL231-TL234	0.94	3.61	0.91	0.18
HP20	TL233-TL269	0.96	4.62	0.93	0.86
HP20	TL203-TL267	0.92	4.81	0.88	-0.70

5.4.2 Local area oscillations

All of the local area oscillations associated with the IIS showed more than 7% damping.

6. Performance Verification

The PSSes were added to the generator models in PSSE, and the performance of the PSSes were evaluated in PSSE considering the critical contingencies identified during the Eigen value analysis. As mentioned in Section 4.4.1, it was found that there are some transient instability issues in case HP20, and these cases were not considered during the performance verification.

The generator performances for N-2 outages of TL234-TL211, TL234-TL233 and TL263-TL211 in case HP13 are shown in Figure 6-1, Figure 6-2 and Figure 6-3, respectively. All of the generators show better performance with the PSSes. The oscillations damp out within approximately 5 seconds after the disturbance.

The inter-area oscillation was mainly observed under light load conditions. Figure 6-4 shows the generator performance for the N-2 outage of TL231-TL234 in case HP18. Before adding the PSSes, the 0.85Hz oscillation grew and the system became unstable. The PSSes were effective in damping the oscillation and the system stability was restored. Note that the small signal stability assessment showed approximately 1.95% damping without the PSSes. When the damping is low like this, the other non-linear controllers, such as frequency controllers, may also contribute to the oscillation. This may be the reason that the system response was observed to be unstable without PSSes in PSSE dynamic simulations as compared to just poorly damped in the small signal stability assessment. When the PSSes are added, the damping is improved to approximately 6% for this contingency.

A select number of PSS performance verification tests were performed in this study. The performance of the PSSes will be further evaluated during the final Stage 4 operational study.

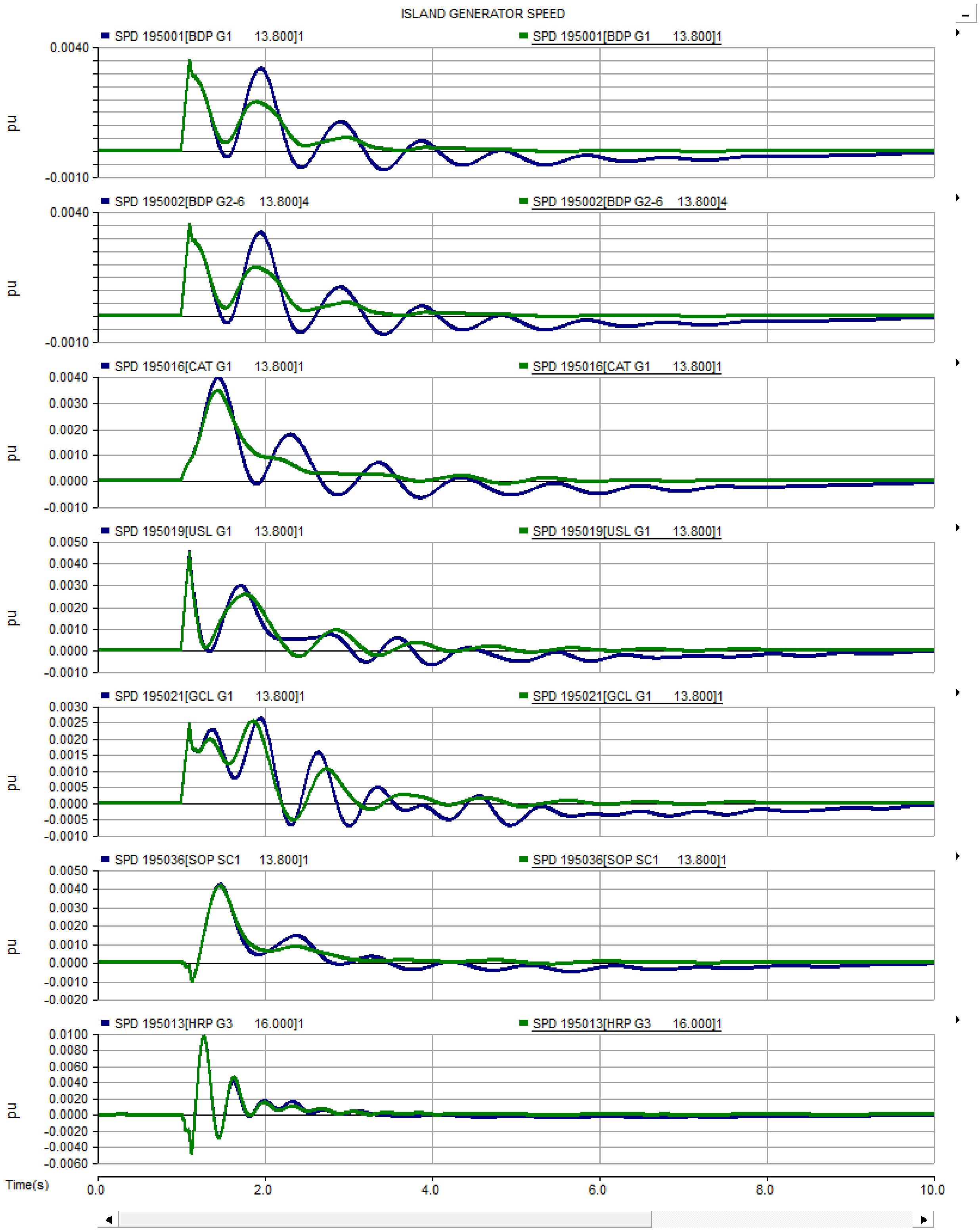

Figure 6-1. Performance of Island Generators for N-2 outage of TL234-TL211in HP13 (Blue: Without PSSes, Green: With PSSes)

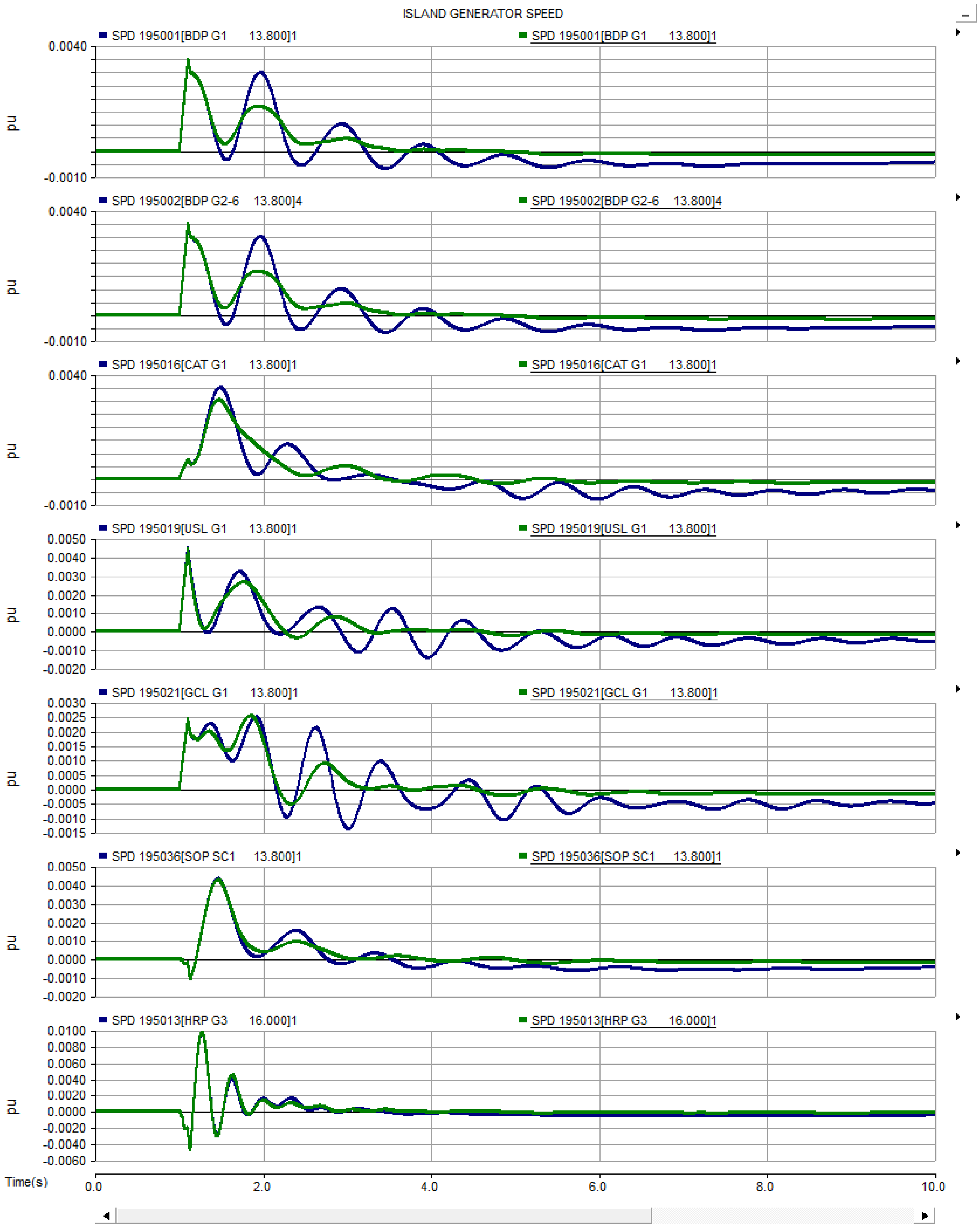

Figure 6-2. Performance of Island Generators for N-2 outage of TL234-TL233 in HP13 (Blue: Without PSSes, Green: With PSSes)

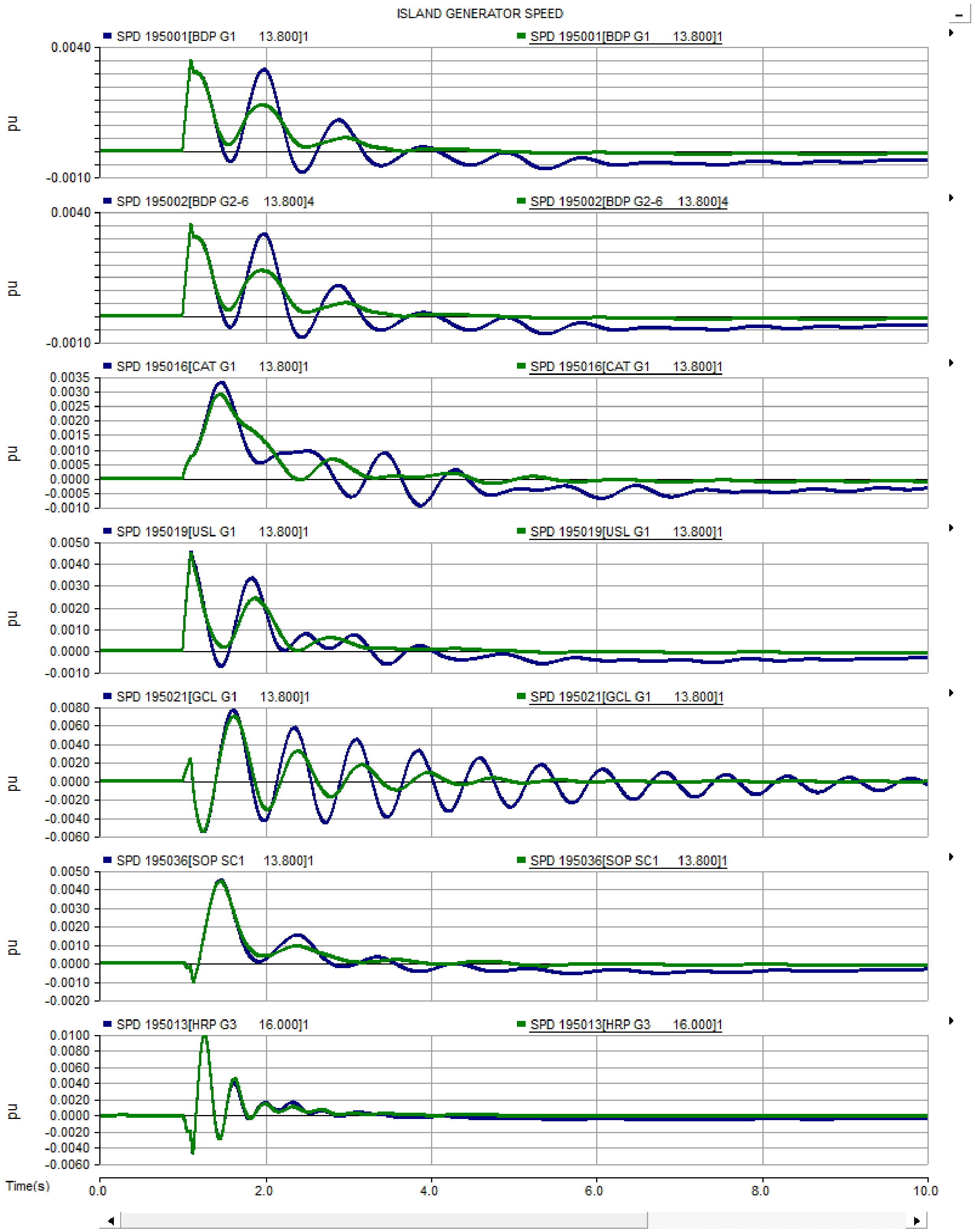

Figure 6-3. Performance of Island Generators for N-2 outage of TL263-TL211 in HP13 (Blue: Without PSSes, Green: With PSSes)

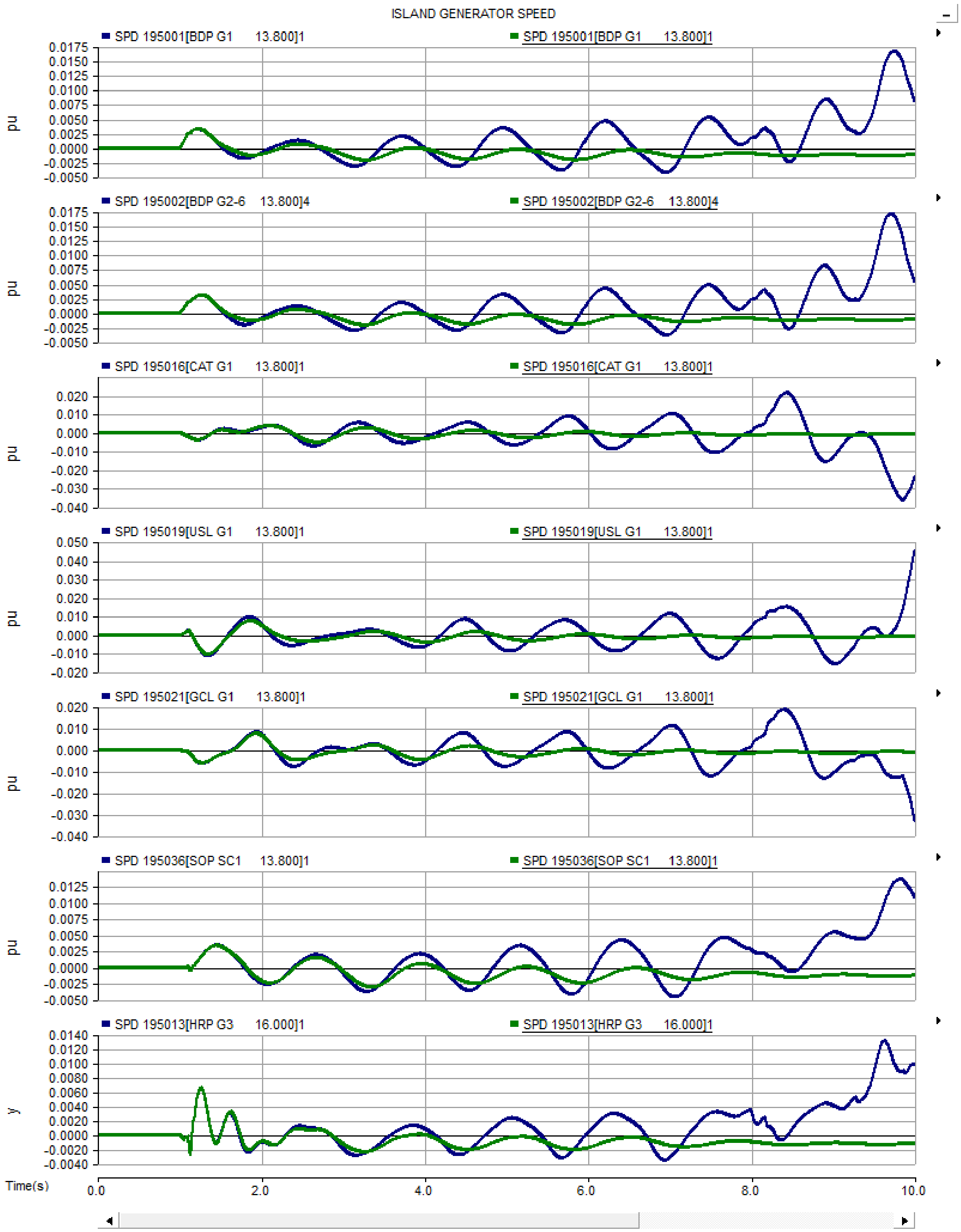

Figure 6-4. Performance of Island Generators for N-2 outage of TL231-TL234 in HP18 (Blue: Without PSSes, Green: With PSSes)

7. Performance of Muskrat Fall Generators

During the Stage 4c[2] operational study, which was performed to evaluate power transfer limits between Churchill Falls and Muskrat Falls, it was observed that the Muskrat Falls generators produce low damped oscillations under certain system conditions[3] when there is a three-phase fault one of the 315 kV circuits between Churchill Falls and Muskrat Falls and when the line is tripped to clear the fault. The Muskrat Falls generator speeds are shown in Figure 7-1.

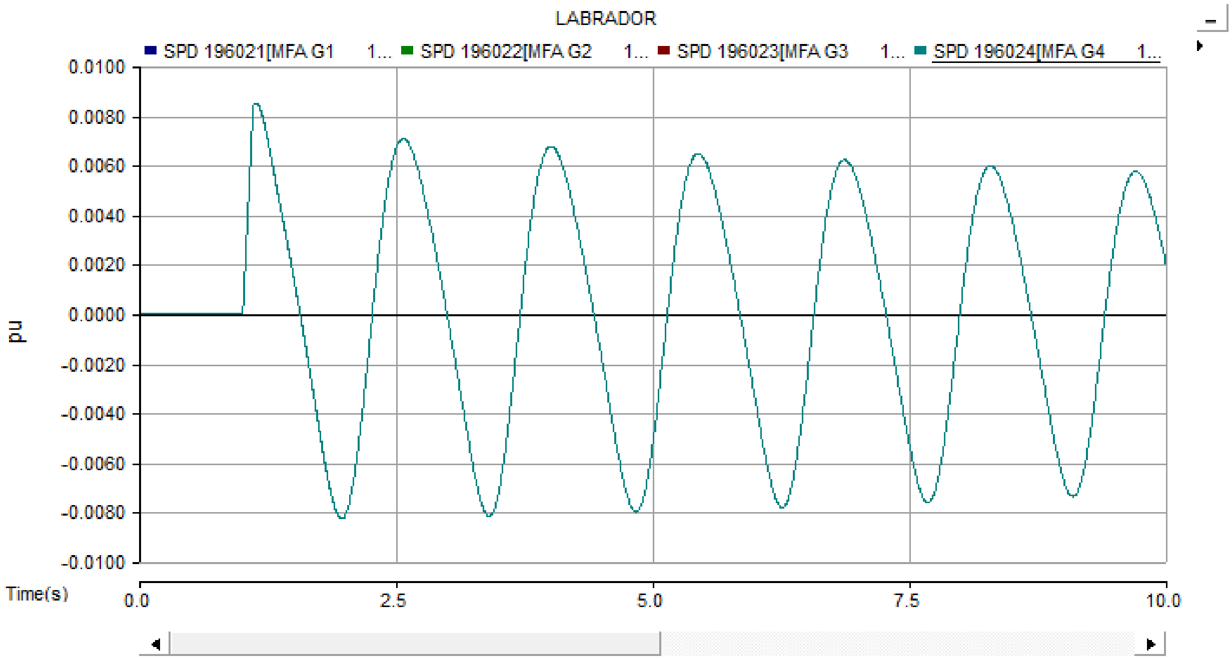

Figure 7-1: Muskrat Falls Generator Oscillations when one 315 kV circuit between Chirchill Falls and Muskrat Falls is tripped (oscillation frequency ~ 0.71 Hz)

It seems that the preliminary stabilizer models used for the Muskrat Falls generators in the PSSE simulations are not effective for this operating condition. Therefore, a small signal stability assessment was performed for the Muskrat Falls generators as well. The analysis revealed that the oscillations have approximately 5% damping with the existing PSSes (IEEEST model). Note that the PSSE simulations show much lower damping and the non-linear controllers associated with the HVDC may be part of the reason for the difference. If the existing stabilizers are removed, the oscillations become unstable (about -3% damping).

[2] TN1205.66.00, "Stage 4C LIL Bipole: Labrador Transfer Analysis", TransGrid Solutions
[3] Specifically, cases LAB5 and LAB9 from the Stage 4c study.

With today's modern generators, it is common practice to use the integral of accelerating power type stabilizers as discussed in Section 4.2.1. Therefore, PSS2B models were considered for the Muskrat Falls generators as well. By properly tuning the PSSes, the damping under aforementioned contingency increased to approximately15%. The full list of PSS parameters is given in Appendix-1. The dynamic responses with the original and new PSS models are shown in Figure 7-2. With the new PSS models, the oscillations damp out within approximately 10 seconds after the disturbance.

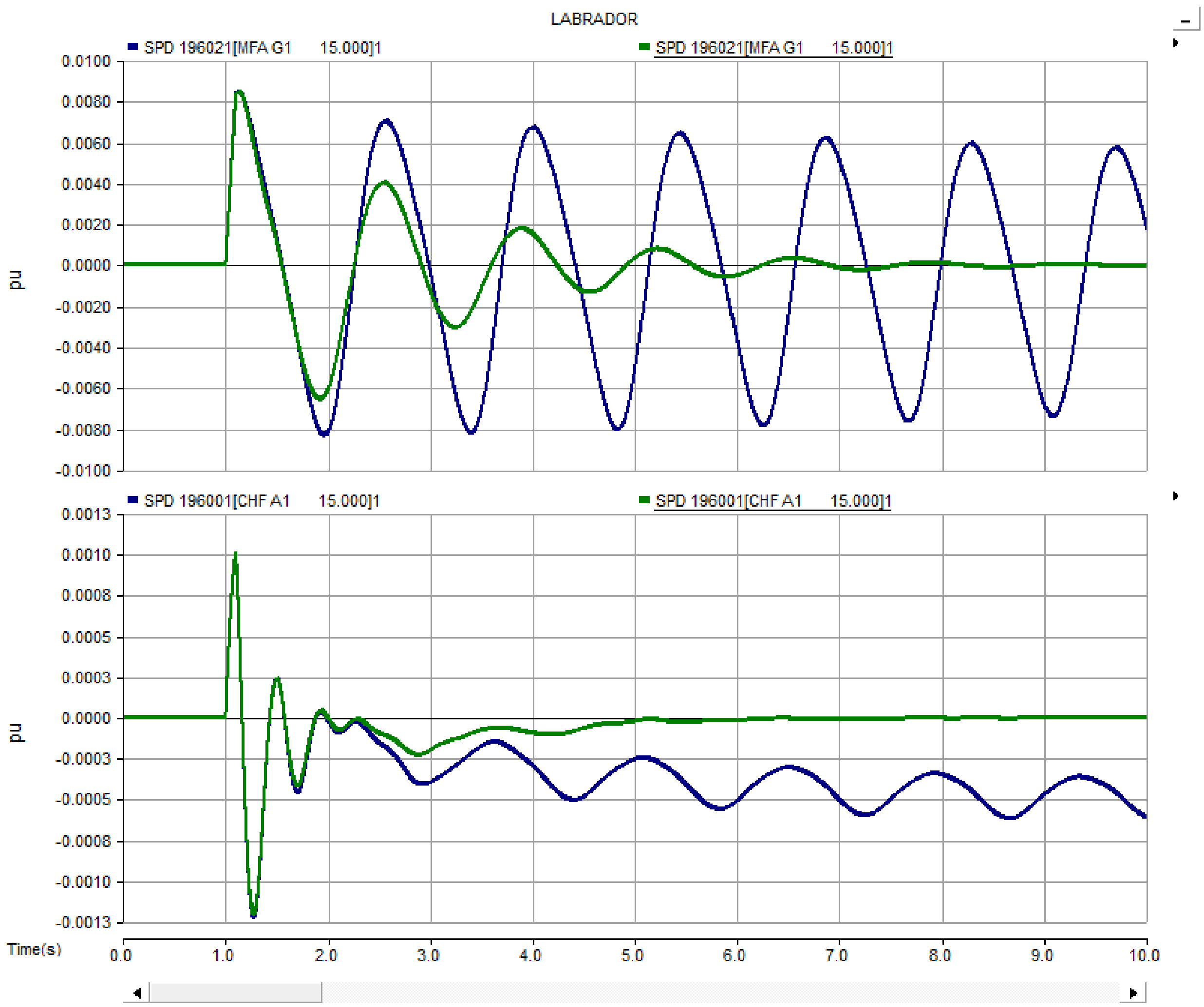

Figure 7-2: Performance of Labrador Island Generators for outage of one 315 kV circuit between Churchill Falls and Muskrat Falls in case LAB5 (Blue: With Original PSSes at MFA, Green: With New PSSes at MFA)

8. Conclusions

8.1 IIS Generators

The need for PSSes was evaluated considering various loading conditions (cases HP13 to HP23) and critical contingencies in the IIS. Based on the small signal stability assessment, PSSes were proposed to be used at the following generating stations to improve the electromechanical oscillation damping in the system:

(5) Cat Arm units 1 and 2

(6) Upper Salmon

(7) Granite Canal

(8) Bay d'Espoir units 1-7 (for inter-area oscillation damping)

The performance of the PSSes were evaluated in PSSE considering the system intact and critical N-2 contingencies. It was observed that the PSSes provide better damping compared to the cases without PSSes. Furthermore, under light load conditions, PSSes can help to avoid the instabilities in the system.

It should be noted that small signal stability assessment is a linear analysis technique and, therefore, the non-linear behaviors, such as the impact of frequency controllers that have dead-bands, are not considered in small signal stability analysis. If the system is well damped, the small signal stability analysis results match well with the actual system behavior seen in PSSE. However, if the damping of certain oscillations is low, other non-linear controllers may have a significant impact (positive or negative) on these oscillations. After the PSSes were added to the IIS, the small signal stability analysis showed very good damping of the electromechanical oscillations in the IIS. Therefore, such impacts of the other non-linear controllers are not expected.

It should also be noted that the validity of the powerflow scenarios under contingency conditions (N-1 and N-2) needs to be further evaluated in the final Stage 4 operational study considering the steady state and dynamic performance of the IIS. Therefore, some of the operating points considered in this small signal stability analysis may not be practical.

In summary, the PSS parameters provided in this report should be considered as preliminary values for use and evaluation in the final Stage 4 operational study and it is recommended to further evaluate the performance of the PSSes during that study.

8.2 Muskrat Falls Generators

During the Stage 4c operational study, which investigates power transfer capability between Muskrat Falls and Churchill Falls, it was observed that the original power system stabilizer models of the Muskrat Falls generators are not effective under certain operating conditions when there is a three-phase fault on one of the two 315 kV lines between Churchill Falls and Muskrat Falls. Therefore, the Muskrat Falls PSSes were re-tuned to obtain acceptable damping under those operating conditions.

9. References

[1] C. Karawita, D. H. R. Suriyaarachchi and U. D. Annakkage, "A Case Study on the Vulnerability of VSC HVDC Systems for Sub-synchronous Interactions with Generator-Turbine Units," in *CIGRE SCB4 Colloquium 2011* , 2011.

[2] C. Karawita, D. H. R. Suriyaarachchi and U. Annakkage, "A Case Study on the Vulnerability of VSC HVDC Systems for Sub-synchronous Interactions with Generator-Turbine Units," in *CIGRE SCB4 Colloquium 2011, Brisbane, Australia*, October 2011.

[3] C. Karawita and U. Annakkage, "A Hybrid Network Model for Small Signal Stability Analysis of Power Systems," *Power Systems, IEEE Transactions on,* vol. 25, no. 1, pp. 443-451, Feb 2010.

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[5] C. Karawita and U. Annakkage, "Multi-Infeed HVDC Interaction Studies Using Small-Signal Stability Assessment," *Power Delivery, IEEE Transactions on,* vol. 24, no. 2, pp. 910-918, April 2009.

[6] C. Karawita and U. D. Annakkage, "HVDC-Generator-Turbine Torsional Interaction Studies Using A Linearized Model With Dynamic Network Representation," in *International Conference on Power Systems Transients*, Kyoto, Japan, 2009.

[7] D. Suriyaarachchi, U. Annakkage, C. Karawita and D. Jacobson, "A Procedure to Study Sub-Synchronous Interactions in Wind Integrated Power Systems," *Power Systems, IEEE Transactions on,* vol. 28, no. 1, pp. 377-384, Feb 2013.

[8] D. Suriyaarachchi, U. Annakkage, C. Karawita, D. Kell, R. Mendis and R. Chopra, "Application of an SVC to damp sub-synchronous interaction between wind farms and series compensated transmission lines," in *Power and Energy Society General Meeting, 2012 IEEE*, 2012.

[9] C. Karawita, "HVDC interaction studies using small signal stability assessment," 2009.

[10] P. Kundur, N. Balu and M. Lauby, Power system stability and control, McGraw-Hill, 1994.

Appendix-1

PSS Parameters (Preliminary Values)

TGS™
TransGrid Solutions

Island Generators:

Parameters	Bay d'Espoir							Cat Arm		Upper Salmon	Granite Canal
	195001 - 1	195002 - 2	195002 - 3	195002 - 4	195002 - 5	195002 - 6	195007 - 7	195016 - 1	195017 - 1	195019 - 1	195021 - 1
TW1 Washout Time constant - Signal 1	5	5	5	5	5	5	5	10	10	10	10
TW2 Washout Time Constant - Signal 1	5	5	5	5	5	5	5	10	10	10	10
T6 Lag Time Constant - Signal 1	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
TW3 Washout Time Constant - Signal 2	5	5	5	5	5	5	5	10	10	10	10
TW4 Washout Time Constant - Signal 2	0	0	0	0	0	0	0	0	0	0	0
T7 Lag Time Constant - Signal 2	5	5	5	5	5	5	5	10	10	10	10
KS2 Gain - Signal 2	0.4771	0.5136	0.4771	0.4771	0.4771	0.4771	0.6438	1.2438	1.2438	1.4286	1.25
KS3 Gain - Signal 2	1	1	1	1	1	1	1	1	1	1	1
T8 Ramp Tracking Filter Lead Time Constant	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
T9 Ramp Tracking Filter Lag Time Constant	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
KS1 Stabilizer Gain	17	17	17	17	17	17	17	5	5	10	3
T1 Lead Time Constant - Phase Comp. Block 1	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.2202	0.2202	0.3028	0.3237
T2 Lag Time Constant - Phase Comp. Block 1	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0877	0.0808	0.0808	0.0663	0.0433
T3 Lead Time Constant - Phase Comp. Block 2	0	0	0	0	0	0	0	0.2202	0.2202	0.3028	0
T4 Lag Time Constant - Phase Comp. Block 2	0	0	0	0	0	0	0	0.0808	0.0808	0.0663	0
T10 Lead Time Constant - Phase Comp. Block 3	0	0	0	0	0	0	0	0	0	0	0
T11 Lag Time Constant - Phase Comp. Block 3	0	0	0	0	0	0	0	0	0	0	0
VS11MAX Stabilizer Input Maximum. Input 1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
VS11MIN Stabilizer Input Minimum. Input 1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
VS12MAX Stabilizer Input Maximum. Input 2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
VS12MIN Stabilizer Input Minimum. Input 2	0	0	0	0	0	0	0	0	0	0	0
VSTMAX Stabilizer Output Maximum	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
VSTMIN Stabilizer Output Minimum	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1

Muskrat Falls Generators:

Parameter	Muskert Falls			
	196021- 1	196022 - 2	196023- 3	196024 - 4
TW1 Washout Time constant - Signal 1	10	10	10	10
TW2 Washout Time Constant - Signal 1	10	10	10	10
T6 Lag Time Constant - Signal 1	0.05	0.05	0.05	0.05
TW3 Washout Time Constant - Signal 2	10	10	10	10
TW4 Washout Time Constant - Signal 2	0	0	0	0
T7 Lag Time Constant - Signal 2	10	10	10	10
KS2 Gain - Signal 2	1.2195	1.2195	1.2195	1.2195
KS3 Gain - Signal 2	1	1	1	1
T8 Ramp Tracking Filter Lead Time Constant	0.5	0.5	0.5	0.5
T9 Ramp Tracking Filter Lag Time Constant	0.1	0.1	0.1	0.1
KS1 Stabilizer Gain	15	15	15	15
T1 Lead Time Constant - Phase Comp. Block 1	0.299	0.299	0.299	0.299
T2 Lag Time Constant - Phase Comp. Block 1	0.0814	0.0814	0.0814	0.0814
T3 Lead Time Constant - Phase Comp. Block 2	0	0	0	0
T4 Lag Time Constant - Phase Comp. Block 2	0	0	0	0
T10 Lead Time Constant - Phase Comp. Block 3	0	0	0	0
T11 Lag Time Constant - Phase Comp. Block 3	0	0	0	0
VS11MAX Stabilizer Input Maximum. Input 1	0.1	0.1	0.1	0.1
VS11MIN Stabilizer Input Minimum. Input 1	-0.1	-0.1	-0.1	-0.1
VS12MAX Stabilizer Input Maximum. Input 2	1.1	1.1	1.1	1.1
VS12MIN Stabilizer Input Minimum. Input 2	0	0	0	0
VSTMAX Stabilizer Output Maximum	0.1	0.1	0.1	0.1
VSTMIN Stabilizer Output Minimum	-0.1	-0.1	-0.1	-0.1