Q. **Reference: Nalcor Energy Probabilistic Based Transmission Reliability Assessment– Island Interconnected System ("Teshmont Report") pg (i):**
"A comparison was made between Pre-HVDC and Post-HVDC systems in terms of expected unserved energy to loads due to transmission and generation outages using PSS®E software. System security, i.e. the ability of the system to transition between each pre- and post-contingency operating condition and remain stable, was not assessed in this study. That is to say, the analysis does not include transient outages, but focuses on sustained outages only."
Please explain why the assessment completed by Teshmont did not include a review of system security.

A. The assessment completed by Teshmont did not include a review of system security as this analysis has already been performed in previous studies completed by SNC Lavalin and Hydro.

These studies were reported in 2014 and the results can be seen in CA-NLH-150 Attachment 1 Application to Upgrade Transmission Line Corridor.

newfoundland labrador hydro
a nalcor energy company

Hydro Place. 500 Columbus Drive.
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 f. 709.737.1800
www.nlh.nl.ca

April 30, 2014

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

ATTENTION: Ms. Cheryl Blundon
Director of Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: An Application by Newfoundland and Labrador Hydro pursuant to Subsection 41(3) of the *Act*, for approval of the Upgrade of the Transmission Line Corridor from Bay d'Espoir to Western Avalon.

Please find enclosed the original and twelve copies of the above-noted Application, plus supporting affidavit and engineering report.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young
Senior Legal Counsel

GPY/jc

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Sheryl Nisenbaum – Praxair Canada Inc.
Thomas Johnson – Consumer Advocate
Thomas J. O'Reilly, Q.C. – Cox & Palmer
Danny Dumaresque

IN THE MATTER OF the *Electrical Power Control Act,* R.S.N.L. 1994, Chapter E-5.1 (the *EPCA*) and the *Public Utilities Act*, R.S.N.L. 1990, Chapter P-47 (the *Act*), and regulations thereunder;

AND IN THE MATTER OF an Application by Newfoundland and Labrador Hydro (Hydro) pursuant to Subsection 41(3) of the *Act*, for approval of the Upgrade of the Transmission Line Corridor from Bay d'Espoir to Western Avalon.

TO: The Board of Commissioners of Public Utilities (the Board)

THE APPLICATION OF NEWFOUNDLAND AND LABRADOR HYDRO (Hydro) STATES THAT:

1. Hydro is a corporation continued and existing under the *Hydro Corporation Act, 2007*, is a public utility within the meaning of the Act and is subject to the provisions of the *Electrical Power Control Act, 1994*.

2. Hydro is making application to the Board to request approval of the construction of a new 230 kV transmission line between the Bay d'Espoir and Western Avalon Terminal Stations. This transmission line is needed to provide ongoing reliable electrical service on the Island Interconnected System.

3. In December 2012, the Government of Newfoundland and Labrador announced sanction of the Muskrat Falls Project with an interconnection to the island portion of the

province by an HVdc transmission line as the least cost alternative to meet the long-term power and energy requirements of the Province.

4. The least cost analysis completed which resulted in the sanction of the Muskrat Falls Project identified that the requested 230 kV transmission line was required in both the isolated and HVdc interconnection scenarios.

5. Operating the electrical system when interconnected to Muskrat Falls by the HVdc interconnection will result in significant changes in the operation of generating sources and the dynamic performance on the Island Interconnected System during system disturbances.

6. Technical analyses has confirmed that, once the Labrador – Island HVdc Link is connected to the Island Interconnected System, the existing 230 kV transmission system on the island portion of the province must be enhanced to provide acceptable performance following system disturbances.

7. Hydro examined several possible alternatives to resolve this issue and narrowed the potential solutions to four options. After further study, Hydro concluded that only the construction of a new 230 kV transmission line between Bay d'Espoir and Western Avalon will ensure that the transmission planning criteria are met following completion of the HVdc interconnection.

8. The Applicant submits that the proposed transmission line project is necessary to ensure that the electrical system can continue to provide service which is safe and adequate and just and reasonable as required by Section 37 of the *Act*.

9. Hydro therefore makes application for an Order pursuant to section 41(3) of the Act approving the construction of a new 230 kV transmission line, approximately 188 km in length, between Bay d'Espoir and Western Avalon Terminal Stations at an estimated capital cost of $291.7M with an in service date of May 1, 2018 as set out in this Application and in the attached project description and justification document.

DATED at St. John's, in the Province of Newfoundland and Labrador, this 30th day of April, 2014.

Geoffrey P. Young
Counsel for the Applicant
Newfoundland and Labrador Hydro
500 Columbus Drive, P.O. Box 12400
St. John's,
Newfoundland and Labrador
A1B 4K7
Telephone: (709) 737-1277
Facsimile: (709) 737-1782

IN THE MATTER OF the *Electrical Power Control Act,* R.S.N.L. 1994, Chapter E-5.1 (the *EPCA*) and the *Public Utilities Act*, R.S.N.L. 1990, Chapter P-47 (the *Act*), and regulations thereunder;

AND IN THE MATTER OF an Application by Newfoundland and Labrador Hydro (Hydro) pursuant to Subsection 41(3) of the *Act*, for approval of the Upgrade of the Transmission Line Corridor from Bay d'Espoir to Western Avalon.

TO: The Board of Commissioners of Public Utilities (the Board)

I, Paul W. Humphries, Professional Engineer, of St. John's in the Province of Newfoundland and Labrador, make oath and say as follows:

1. I am Vice-President of Newfoundland and Labrador Hydro - System Operation and Planning, the Applicant named in the attached Application.

2. I have read and understand the foregoing Application.

3. I have personal knowledge of the facts contained therein, except where otherwise indicated, and they are true to the best of my knowledge, information and belief.

SWORN at St. John's in the Province of Newfoundland and Labrador this 30th day of April 2014 before me:)

Barrister – Newfoundland and Labrador

Paul W. Humphries

REGISTERED PROFESSIONAL ENGINEER B. THOMAS SIGNATURE 04-28-2014 PROVINCE OF NEWFOUNDLAND	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

UPGRADE TRANSMISSION LINE CORRIDOR

Bay d'Espoir to Western Avalon

April 28, 2014

newfoundland labrador hydro
a nalcor energy company

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C6 DC1020 Volume 5 – HVdc System Integration Study – Transient Stability Study, May 2008
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EXECUTIVE SUMMARY

Newfoundland and Labrador Hydro (Hydro) is requesting approval from the Public Utilities Board (the "Board") for the construction of a new 230 kV transmission line between the Bay d'Espoir and Western Avalon terminal stations to provide ongoing reliable electrical service on the Island Interconnected System. This line requirement was identified in the initial studies to determine the least cost long-term generation supply option for the Island Interconnected System. The analysis showed the line would be necessary for both the isolated island system scenario and the Labrador to island high voltage direct current (HVdc) interconnected system scenario. The isolated island system scenario would have required the new transmission line to facilitate development of renewable generation located off the Avalon Peninsula, while the Labrador-Island Link (LIL) interconnection requires the new transmission line for system stability purposes.

In December 2012, the Government of Newfoundland and Labrador announced the sanction of the Muskrat Falls Project as the least cost alternative to meet the long-term power and energy requirements of the province. The project includes development of the 824 MW hydroelectric generating station at Muskrat Falls, two 315 kV ac transmission lines between Churchill Falls and Muskrat Falls, a 900 MW, ±350 kV HVdc transmission line between Muskrat Falls in Labrador and Soldiers Pond in Newfoundland, associated converter stations at Muskrat Falls and Soldiers Pond, and a synchronous condenser plant at the Soldiers Pond station. This will result in the eventual shutdown of the Holyrood Thermal Generating Station (HTGS) as a primary producer of electric power and energy.

These system modifications will result in significant changes in the overall system loading and dynamic performance on the Island Interconnected System. The completion of the construction of the new transmission line will coincide with the completion of the Labrador-Island Link and the receipt of power to the Island Interconnected System from Labrador. It will provide the required reinforcement to maintain the stability of the system to ride through contingencies planned for within the planning criteria.

The fundamental driver for the transmission line is to ensure system stability following electrical faults on the Island Interconnected System. These faults include single line to ground faults for various causes such as lightning, single phase or three phase faults due to equipment failure or possibly human error. During these events, the system must be able to interrupt and isolate the faulted equipment without causing unnecessary customer supply interruptions through widespread system disturbances (outages).

With the changes to the Island Interconnected System with the addition of the HVdc interconnection, transmission analysis was undertaken to test the robustness of the power system for various electrical fault conditions. In addition to single phase and three phase faults, in this analysis temporary bipole faults and permanent single pole faults on the HVdc were assessed for various generation dispatch scenarios. In total, hundreds of separate load flow and stability simulations were undertaken which are outlined in the report.

Load flow and transient stability analyses confirmed that the existing 230 kV transmission system on the island portion of the province must be enhanced to provide acceptable performance following system disturbances once the Labrador – Island HVdc Link is connected to the Island Interconnected System. In particular, the analysis identified that the existing system would have stability issues during certain electrical fault conditions. These stability issues would result in widespread interruptions to customer service due to the automatic shutdown of generators and the tripping of transmission lines.

When power system stability becomes an issue along a portion of the transmission system, there are three prominent alternatives used by industry to mitigate the risk. These are: series compensation; static var compensators; or the construction of new transmission lines.

Series compensation involves the addition of a capacitor bank in series with the transmission line to effectively reduce its impedance. This reduction allows for the

"stiffening" of the transmission network and improves stability. The second common method of addressing the performance is the installation of a static var compensator (SVC). This system allows very fast system voltage compensation and thus aids stabilization of the system during faults and other disturbances.

It should be noted that the installation of series compensation or static var compensators does not materially increase the current carrying ability of the line as that is a physical constraint of the conductor impedance and ground clearance along with ambient temperature and wind speed. They do, however, increase the power transfer limits and remain stable for prescribed events, such as faults and subsequent tripping of circuits.

The other alternative to improve power system stability is to increase the number of transmission lines and/or voltage levels in a corridor. Like series compensation, the construction of parallel lines reduces the overall transmission corridor impedance and thereby "stiffens" the transmission network so that it is less susceptible to instability. As well, it increases the real power transfer limits and reduces losses.

Hydro examined possible alternatives to resolve the stability issue and narrowed down the options warranting more detailed analysis to the four solutions examined in this report. These include the following:

1. Increasing the size of the Soldiers Pond synchronous condensers;
2. Series compensation of the parallel transmission lines TL202 and TL206 between Bay d'Espoir Terminal Station (BDETS) and the Sunnyside Terminal Station (SSDTS) at compensation levels of 25% or 50%;
3. Reroute of TL202 and TL206 around SSDTS and connection to two new 230 kV transmission lines terminating at Western Avalon Terminal Station (WAVTS) with series compensation at levels of 25% or 50%; and
4. Construction of a new 230 kV transmission line between BDETS and WAVTS.

If the Muskrat Falls project and associated HVdc transmission line had not been sanctioned, need for additional west east transmission capacity was required for load or power transfer needs under normal planning criteria for a continued isolated island system. Additional hydraulic generation off the Avalon Peninsula, such as Island Pond, Round Pond and Portland Creek, as well as potential wind energy, would have required a transmission addition to serve the growing Avalon Peninsula load.

The Muskrat Falls project justification for a new transmission line is different than the justification for an isolated island scenario. The isolated island scenario would have required the line with a primary focus of getting new power sources to the east coast. For the interconnected island scenario the primary focus is stability and contingency operation for potential system events.

The detailed technical analysis considered all four potential solutions noted above and concluded that only the construction of a new 230 kV transmission line between Bay d'Espoir and Western Avalon will ensure that the transmission planning criteria are met following completion of the LIL HVdc link.

Assumptions regarding the electrical characteristics of the proposed combustion turbine for Holyrood were made in the analysis. Following the conclusion of the CT proposal and clarification of its characteristics, the requirements for further reactive support in the Avalon Peninsula area will be determined and will be planned to be in service at the time LIL is operational. However, these reactive support aspects do not alter the need for a new 230 kV transmission line between the Bay d'Espoir and Western Avalon terminal stations.

Hydro is recommending the construction of a new 230 kV transmission line, approximately 188 km in length, between Bay d'Espoir and Western Avalon terminal stations at an estimated capital cost of $291.7M with an in service date of May 1, 2018.

ABBREVIATIONS

AACSR - Aluminum Alloy Conductor Steel Reinforced

ABCB- Air Blast Circuit Breaker

ac - alternating current

ACSR – Aluminum Conductor Steel Reinforced

AIS – Air Insulated Switchgear

BDE – Bay d'Espoir

BDNWR – Bay du Nord Wilderness Reserve

CBC – Come By Chance

CEAA – Canadian Environmental Assessment Act

CT – Combustion Turbine

dc – direct current

GIS – Gas Insulated Switchgear

GT – Gas Turbine

HRD – Holyrood

HTGS – Holyrood Thermal Generating Station

HVdc – High Voltage direct current

HWD – Hardwoods

Hydro – Newfoundland and Labrador Hydro

kcmil – one thousand circular mils

km – kilometre

kV – kilovolt (1000 volts)

LCC – Line Commutated Converter

LGC – Lieutenant Governor in Council

LIL – Labrador – Island HVdc Link

LOLH – Loss of Load Hours

MVAR – Mega-volt-ampere-reactive (1,000,000 VAR)

MW – Megawatt (1,000,000 W)

NERC – North American Electric Reliability Corporation

NERC -TPL– NERC Transmission Planning

NP – Newfoundland Power

NPCC – Northeast Power Coordinating Council, Inc.

NUG – Non-Utility Generator

OPD – Oxen Pond

PEEA – Provincial Environmental Act

PHL – Piper's Hole

PLC – Power Line Carrier

PPA – Power Purchase Agreement

PSS®E – Power System Simulator Engineering

ROW – Right Of Way

SC – Synchronous Condenser

SOP – Soldiers Pond

SSD – Sunnyside

SVC – Static VAR Compensator

TL – Transmission Line

TS – Terminal Station

TW – Trapezoidal Wire

UFLS – Underfrequency Load Shedding

VAR – Volt-ampere-reactive

WAV – Western Avalon

WECC - Western Electricity Coordinating Council

WERAC – Wilderness and Ecological Reserve Action Committee

GLOSSARY

Angular stability – see power system stability

Commutation - in an HVdc system, commutation is the transfer of current between power electronic switches such as thyristors. The controlled switching of current allows for the conversion of power from ac to dc and from dc to ac.

Commutation failure - the interruption of the HVdc converter's commutation process in effect temporally stopping the transfer of power from alternating current to direct current or vice versa. For ac system faults close to the line commutated converter, the voltage depression can be significant, resulting in the interruption of the converter's commutation process, thus commutation failure.

Fault – An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection (NERC Reliability Standards, Glossary of Terms May 9, 2013).

> ***Line-to-ground fault*** - one phase conductor (wire) of a three phase transmission line becoming short circuited. Common single line to ground faults include breakage of an insulator string causing the phase conductor to fall to the ground, a tree coming in contact with the phase conductor, or a lightning strike to the conductor that results in a flashover of the insulator string.
>
> ***Three phase fault*** – all three phases of a three phase transmission line becoming short circuited. This is an onerous fault and fortunately relatively uncommon but is possible and normally planned for in so far as practical by utility planners. Causes can be structure collapse, a phase conductor falling or sagging into the remaining conductors, evolution from a single phase fault due to slow fault clearing time, switching errors and other unusual events.

Inertia constant (H) – The energy stored in the rotor when operating at rated speed expressed as kilowatt-seconds per kilovolt-ampere rating of the machine (IEEE Standard Dictionary of Electrical and Electronics Terms – IEEE Std. 100-1992)

> ***Low inertia constant*** – Kimbark (Power System Stability Volume I Elements of Stability Calculations – Edward Wilson Kimbark, ScD. – 1948) indicates that the

average value of the inertia constant for large synchronous condensers equals 1.25. By comparison, Holyrood Unit 3 operating as a synchronous condenser has an H constant of 1.29. The Hardwoods and Stephenville combustion turbines have H constants of 2.06 in synchronous condenser mode. Manitoba Hydro's 300 MVAR synchronous condensers at Dorsey Converter Station have an H constant of 2.2.

High inertia constant – with respect to a synchronous condenser a high inertia constant refers to an H constant in excess of three to four times the typical values. For this analysis, a high inertia synchronous condenser with an H constant of 7.84 is being considered.

The inertia constant is affected by the mass (weight), the diameter and the rotating speed of the mass. It is effectively a flywheel for the electrical system that helps smooth bumps in the load or generation. An analogy is similar to the difference between stopping a large truck going down a hill versus a small car, or turning a large ocean going ship versus a small craft. The larger vehicle has more inertia. In an ideal power system, it is desirable that the 'speed' of the synchronous machines, generators, turbines and synchronous condensers not slow down thus aid in the transition to a new steady state condition or state of equilibrium.

Line Commutated Converter – HVdc technology that utilizes power electronic devices known as thyristors to convert ac to dc and vice versa and relies on the line voltage of the ac system to which the converter is connected in order to effect the switching from one thyristor to another.

Post fault recovery period – the time period of the transient stability simulation following detection of the fault and tripping of the faulted element during which the system should recover from the disturbance and regain a state of equilibrium.

Power system stability – In a system of two or more synchronous machines connected through an electric network, the condition in which the difference of the angular positions of the rotors of the machines either remains constant while not subjected to a disturbance, or becomes constant following an aperiodic disturbance. (IEEE Standard Dictionary of Electrical and Electronics Terms – IEEE Std. 100-1992) An analogy would be a long steel shaft with flywheels on each end rotating at a fixed speed. Applying a brake to one wheel to stop the rotation would be stable if the far wheel stopped with no damage to the shaft. It

would be unstable if the shaft sheared off completely or when stopped had a permanent twist thus leaving the two flywheels in different relative angular positions.

Reclosing – Autoreclosing – The automatic closing of a circuit breaker in order to restore an element to service following automatic tripping of a circuit breaker. Autoreclosing does not include automatic closing of capacitor or reactor breakers. (NPCC Glossary of Terms dated January 18, 2012)

Series compensation – high voltage capacitors connected in series with transmission line phase conductors to reduce the overall impedance of the transmission path, thus making the overall transmission appear electrically shorter than it physically is in terms of conductor impedance.

Short circuit – An abnormal connection (including an arc) of relatively low impedance, whether made accidentally or intentionally, between two points of different potential. *Note:* The term fault or short circuit fault is used to describe a short circuit. (IEEE Standard Dictionary of Electrical and Electronics Terms – IEEE Std. 100-1992)

Single pole switching – The practice of tripping and reclosing one pole of a multi-pole circuit breaker without changing the state of the remaining poles, with tripping being initiated by protective relays which respond selectively to the faulted phase. *Notes*: (1) Circuit breakers used for single pole switching must inherently be capable of individual pole opening. (2) In most single pole switching schemes it is the practice to trip all poles for any fault involving more than one phase. (IEEE Standard Dictionary of Electrical and Electronics Terms – IEEE Std. 100-1992)

Single pole reclosing (see Single pole switching) - For a single line to ground fault on the 230 kV transmission system, one phase or pole of a circuit breaker on each end of the transmission line will open to isolate the fault. After a predetermined period of time, typically fractions of a second, an open circuit breaker on one end of the line is closed to test the line to determine if the fault is permanent or temporary. It is a technique used to aid power system stability by returning transmission to full service in fractions of a second or returning load without operator intervention. It slows the angular displacement spread on each side of the actual line at fault.

Successful single pole reclose - If the line to ground fault is temporary, such as a lightning strike or wind blowing a tree branch into the conductor in which the short circuit disappears, the remaining open circuit breaker will close and restore the line to normal service.

Unsuccessful single pole reclose - If the line to ground fault is permanent, such as a phase conductor lying on the ground, all phases of all circuit breakers protecting the transmission line will then open, effectively removing the transmission line from service and eliminating the fault.

Stability - The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances. (NERC Reliability Standards, Glossary of Terms May 9, 2013) See Power system stability.

Static VAR Compensator – A combination of controlled shunt reactors and switched capacitor banks used to affect the reactive power flow of the system or to regulate the system voltage. (NPCC Glossary of Terms dated January 18, 2012) Such compensator adds VARs to (capacitor) or takes VARs from (reactor) the system as required.

Steady-state stability – A condition that exists in a power system if it operates with stability when not subjected to an aperiodic disturbance. *Note:* In practical systems, a variety of relatively small aperiodic disturbances may be present without any appreciable effect upon the stability, as long as the resultant rate of change in load is relatively slow in comparison with the natural frequency of oscillation of the major parts of the system or with the rate of change in field flux of the rotating machines. (IEEE Standard Dictionary of Electrical and Electronics Terms – IEEE Std. 100-1992) A properly designed power system in a steady-state condition should settle into a new steady state condition after going through a transient state without violating the planning criteria. This is without immediate operator assistance. Following the new steady state condition, operator action is sometimes required to rebalance the system in terms or economic and possibly contractual considerations and put it in the best possible state to enable meeting another disturbance or transition. Obviously, it is generally more significant events such as transmission line or generator tripping that could result in instability and thus major disruptions of power delivery.

Synchronous condenser (rotating machine) – A synchronous machine running without mechanical load and supplying or absorbing reactive power. (IEEE Standard Dictionary of Electrical and Electronics Terms – IEEE Std. 100-1992)

Transient stability – A condition that exists in a power system if, after an aperiodic disturbance, the system regains steady-state stability. (IEEE Standard Dictionary of Electrical and Electronics Terms – IEEE Std. 100-1992)

Underfrequency Load Shedding (UFLS) – the automatic tripping of a block of load at a pre-described frequency setting or at a prescribed rate of change of frequency, with the intent of rebalancing load with available system generation following the sudden loss of a generator(s) with the intent to restore the system frequency to nominal (i.e. 60 Hz). Most systems employ UFLS but with large integrated systems with significant interconnections it rarely operates. In isolated systems such as the existing Island Interconnected System it is an essential component of the protection scheme needed to avoid widespread disruptions for loss of supply, which can be due to generation tripping or in some cases line tripping that removes significant generation from the load area such as the lines to Cat Arm, TL247. In smaller isolated systems it is not typically practical or economical to run additional generation to cover such unplanned outages.

1.0 INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) owns and operates an interconnected generation and transmission system on the island of Newfoundland. At present, the Island Interconnected System is electrically isolated from the North American grid, and as such the system must be self-sufficient in meeting the electrical needs of customers on the island portion of the province.

Previous analysis by Hydro identified that a new 230 kV transmission line between the Bay d'Espoir and Western Avalon Terminal Stations is required to reliably meet customer load growth on the Island Interconnected System. This requirement was identified for both the isolated system scenario and the Labrador – Island Link (LIL) scenario. The isolated system scenario required the new transmission line to facilitate development of generation located outside of the Avalon Peninsula, while the HVdc interconnection with Labrador scenario (interconnected island scenario) required the new transmission line for system stability purposes following interconnection. A previous report filed with an earlier application to the Board for the construction of this line reviewed both scenarios. The application and report were subsequently withdrawn. However, for convenience this report is attached as Appendix C1.

In December 2012, the Government of Newfoundland and Labrador announced sanction of the Muskrat Falls project as the best least cost alternative to meet the long- term power and energy requirements of the province. The project includes development of the 824 MW hydroelectric generating station at Muskrat Falls, two 315 kV ac transmission lines between Churchill Falls and Muskrat Falls, a 900 MW, ±350 kV HVdc transmission line between Muskrat Falls in Labrador and Soldiers Pond in Newfoundland, and a high inertia synchronous condenser plant at Soldiers Pond. It will result in the shutdown of the Holyrood Thermal Generating Station (HTGS) as a primary producer of electric power and

energy. These system modifications will result in significant changes in the overall system loading and dynamic performance on the Island Interconnected System.

This report considers the system reinforcements necessary to successfully integrate the Labrador – Island Link and the Soldiers Pond Converter Station into the Island Interconnected System. In particular, this report determines the system reinforcements between the Bay d'Espoir Generating Station and Western Avalon Terminal Station.

2.0 EXISTING SYSTEM

Hydro owns and operates 1,609 km[1] of 230 kV transmission line on its Island Interconnected Transmission System. There are eleven 230 kV lines totaling 628 km in length connecting the Bay d'Espoir Generating Station to the major load centers and generation in the eastern portion of the province. There are thirteen 230 kV lines totaling 981 km in length connecting Bay d'Espoir to major load centers and generation in the central and western portions of the province. Figure 2.1 provides a diagram of the existing Island Interconnected 230 kV transmission system.

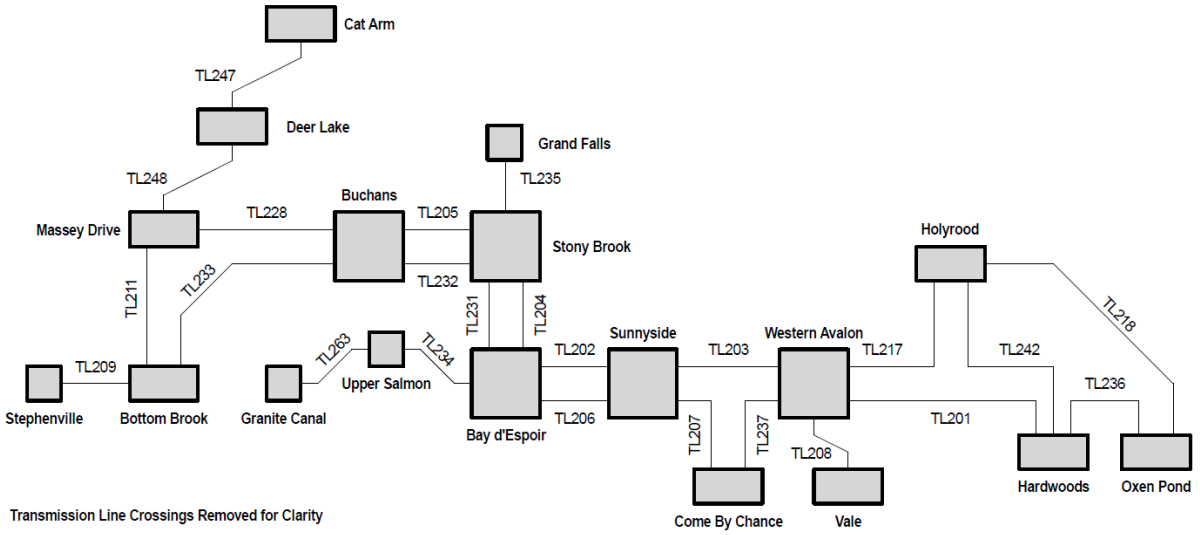


Figure 2.1 - Island Interconnected 230 kV Transmission System

The 230 kV transmission system east of Bay d'Espoir is characterized as being heavily loaded[2]. Conversely, the 230 kV transmission system west of Bay d'Espoir is characterized

[1] The removal of TL208 termination at Long Harbour and extension to the Vale Terminal Station has resulted in a net increase in total 230 kV transmission line length by 1 km up from 1608 km reported previously.

[2] Heavily loaded transmission lines result in voltage drop along the transmission path. Conversely, lightly loaded transmission lines have very little voltage drop, or even a voltage rise, along the transmission path due to line capacitance. Surge Impedance Load (SIL) can be used as a measure of transmission line loading. Transmission lines loaded above SIL experience voltage drop along the path and require voltage support in the form of reactive power injection (i.e. MVAR). A typical Hydro 230 kV transmission with a 795 kcmil, ACSR "DRAKE" conductor has an SIL of approximately 136 MW. Line flows east of Bay d'Espoir exceed 136 MW per circuit, resulting in significant voltage drop and consequently voltage support is required to maintain acceptable voltage levels at the receiving end.

as being a more lightly loaded system. In fact approximately two thirds of the system load is located east of Bay d'Espoir. Table 2.1 provides a summary of east and west loads at the time of system peak for the period ranging from 2008 – 2013.

Table 2.1: Bay d'Espoir East & West 230 kV Transmission System Peak Loads, 2008-2013

Year	Bay d'Espoir– East[1] (MW)	Bay d'Espoir – West[2] (MW)	Power East and West Total (MW)	East/West Split (%)
2008	827	416	1243	67/33
2009	878	447	1325	66/34
2010	836	378	1214	69/31
2011	802	435	1237	65/35
2012	900	441	1341	67/33
2013	990	507	1497	66/34

[1] Bay d'Espoir – East load equal to TL-202 and TL-206 flow plus Paradise River, Holyrood, Hardwoods, and wind generation at time of peak.
[2] Bay d'Espoir – West load equal to TL-204 and TL-231 flow plus Cat Arm, Hinds Lake, Stephenville, Hawke's Bay, St. Anthony Diesel Plant generation and Non-Utility Generation purchases at time of peak.
[3] Connaigre Peninsula loads not included.
Values based on the Hydro Energy Management System (EMS) hourly data and are not weather adjusted.

With a 230 kV line out from BDE East the thermal limit of the remaining line at 0 ^{o}C is 369.5 MVA or approximately 42% of the total eastern grid load. To the west the thermal limit is 469.6 MVA at 0 ^{o}C and is in excess of 100% of the western load. This is only indicated to provide a simple comparative look at the robustness of the western versus the eastern portion of the system.

The Bay d'Espoir – East 230 kV transmission system experiences significant voltage drop[3] during peak load conditions. As a result, this portion of the system requires voltage support in the form of reactive power (MVAR) injection in order to bring system voltages to within

[3] Without the addition of voltage support in the form of reactive power support on the 230 kV system east of Bay d'Espoir during peak load periods, transmission system voltages will fall well below the 95% minimum value. Without voltage support, transfers to the Avalon Peninsula would be limited and make successfully clearing typical faults less likely, thus increasing the possibility of system collapse.

normal operating voltages as per the transmission planning criteria. The HTGS, the Hardwoods Combustion Turbine (HWDCT) operating as a synchronous condenser and shunt capacitor banks at Come By Chance (CBCTS) Hardwoods (HWDTS) and Oxen Pond Terminal Stations (OPDTS) provide the MVAR injection into the 230 kV system to counteract the voltage drop associated with this limited and highly loaded transmission system.

The most recent additions to the BDE East system were four shunt capacitor banks at the CBCTS. With the closure of the pulp and paper mill in Grand Falls – Windsor, Nalcor Energy installed these four 230 kV shunt capacitor banks with a total nominal installed capacity of 150 MVAR at the Come By Chance Terminal Station to assist in voltage support on the BDE – East system to deliver the capacity available from the Exploits River hydro-electric generation to the Avalon Peninsula. This enabled the delay of start-up of the second and third units at HTGS each fall and allowed earlier shutdown of the same units in the spring. However, under this system loading scenario the first unit on in the fall and last off in the spring is now primarily dictated by transmission thermal load limits during transmission contingencies. In addition to the resource optimization, the shunt capacitors provide additional support and flexibility in outage planning and contingency operations on a day to day basis.

2.1 Impact of HVDC Interconnection

The addition of the 900 MW, ±350 kV HVdc transmission line between Labrador and Newfoundland, combined with the closure of the HTGS as a primary producer of electric capacity and energy will change the nature of the power flows on the Island Interconnected System and also alter its dynamic performance. The HVdc transmission line from Labrador will connect to the Island Interconnected System on the Avalon Peninsula at a location known as Soldiers Pond (SOP). The site is located between the major load center and the HTGS. Consequently, locating the converter station at Soldiers Pond reduces the requirement for extensive 230 kV transmission line construction on the Avalon Peninsula to connect the new 900 MW source to the load as the new station will effectively intersect existing lines.

The converter station at Soldiers Pond requires a strong connection to the existing ac transmission system to ensure proper operation. As well, multiple transmission paths are required to ensure that the power received from Labrador can be delivered to the load centers during an outage to a single transmission line. To this end, three of the existing 230 kV transmission lines will be effectively intersected by the new Soldiers Pond Terminal Station thus providing for six 230 kV transmission line connections including:

- TL201 (Western Avalon to Hardwoods) yielding two 230 kV transmission lines
    - TL201 (Western Avalon to Soldiers Pond); and
    - TL266 (Soldiers Pond to Hardwoods, a renumbered section of TL201)
- TL217 (Western Avalon to Holyrood) yielding two 230 kV transmission lines
    - TL217 (Western Avalon to Soldiers Pond); and
    - TL265 (Soldiers Pond to Holyrood, a renumbered section of TL217)
- TL242 (Holyrood to Hardwoods) yielding two 230 kV transmission lines
    - TL242 (Soldiers Pond to Hardwoods); and
    - TL268 (Soldiers Pond to Holyrood, a renumbered section of TL242).

As well, the Soldiers Pond location will also include a synchronous condenser plant to provide the necessary reactive power requirements and increased system strength through increased short circuit levels at the 230 kV ac bus to ensure proper operation of the SOP HVdc converter. The Soldiers Pond synchronous condenser plant will consist of three 175 MVAR high inertia synchronous condensers[4].

Figure 2.2 provides a diagram of the 230 kV portion of the Island Interconnected System with Soldiers Pond added.

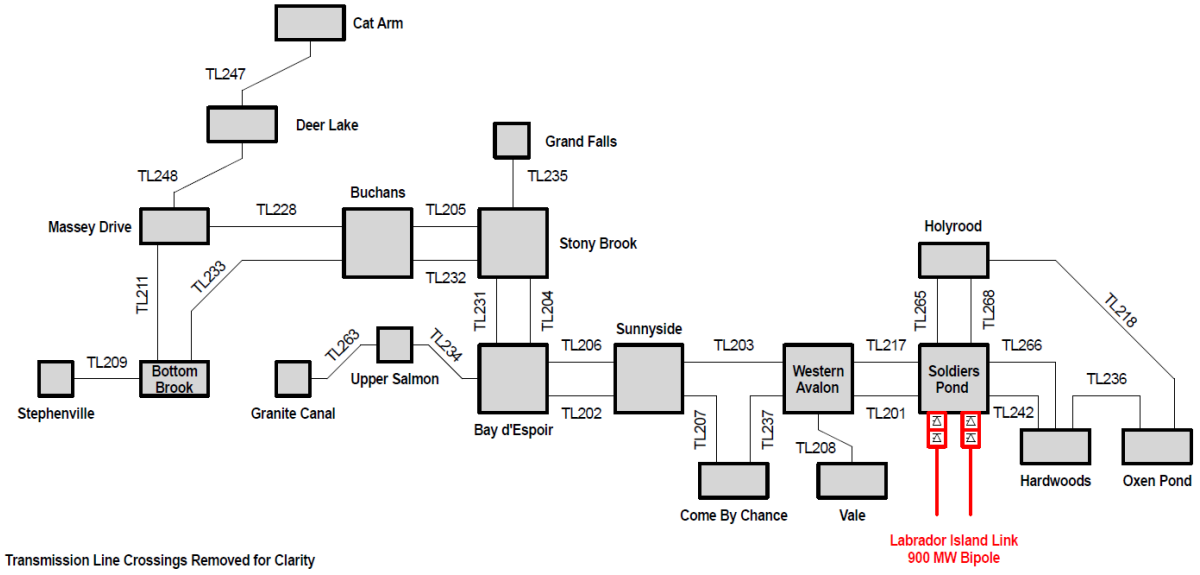


Figure 2.2 - Island Interconnected 230 kV Transmission System with HVdc Added

[4] Typically, synchronous condensers such as Holyrood Unit 3 have an inertia constant of 1.0 to 1.3 MW.s/MVA and contribute approximately 230 MW.s of inertia to the system to assist in frequency regulation. These dual purpose installations (Holyrood Unit 3) are relatively light in terms of inertia as their primary purpose is to provide power generation and voltage control. During system contingencies, such as short circuits near the Soldiers Pond converter, temporary shut-down of the converter and loss of the delivered power during the short circuit is expected. Such shut-downs are expected to last less than 200 msec. However, with the loss of up to 833 MW during the short circuit, the frequency on the island is expected to decay. In order to maintain an acceptable frequency on the island for the successful re-start of the converter station once the ac transmission system short circuit has been cleared, additional system inertia is required. The application of high inertia synchronous condensers, as planned for SOP, with an inertia constant of 7.84 MW.s/MVA provide both the required reactive power and inertia for frequency regulation and voltage support during the system contingences.

3.0 TRANSMISSION PLANNING CRITERIA

The following list is provided as summary of Hydro's Transmission Planning Criteria:

- Hydro's bulk transmission system[5] is planned to be capable of sustaining the single contingency loss of any transmission element without loss of system stability;
- In the event a transmission element is out of service, power flow in all other elements of the power system should be at or below normal rating;
- The Island Interconnected System is planned to be able to sustain a successful single pole reclose for a line to ground fault based on the premise that all system generation is available;
- Transformer additions at all major terminal stations (i.e. two or more transformers per voltage class) are planned on the basis of being able to withstand the loss of the largest unit;
- For transformer station additions at major terminal stations with a strong underlying high voltage connection, such as the Oxen Pond to Hardwoods 66 kV system, the total transformer capacity in addition to available standby generation within the loop is considered as long as the underlying system can accommodate such transfers;
- For single transformer stations there is a back-up plan in place which utilizes Hydro's and/or Newfoundland Power's mobile equipment to restore service, but this will require an outage for mobilization, connection and energization of the mobile equipment;
- For normal operations, the system is planned on the basis that all voltages be maintained between 95% and 105% of nominal voltage (i.e. 218.5 to 241.5 kV on the 230 kV network);

[5] Hydro's bulk transmission system on the Island of Newfoundland is generally considered to be the 230 kV transmission system and the underlying 138 kV transmission loops between connection points on the 230 kV system including Western Avalon to Holyrood and Deer Lake-Stony Brook-Sunnyside.

- For contingency or emergency situations, voltages between 90% and 110% of nominal voltage is an acceptable range (i.e. 207 to 253 kV on the 230 kV network); and
- For new terminal stations connected to the bulk system, Hydro's preferred bus arrangement is a breaker-and-one-half scheme. Where there are a limited number of elements, a ring bus arrangement is acceptable. The provision of conversion to a breaker and half scheme will be considered if there is known potential for additional future expansion and physical space is available.

3.1 Steady State Analysis Criteria

- With all equipment in service, power flow in all transmission elements should be at, or below, normal rating;
- With a transmission element (line, transformer, synchronous condenser, shunt or series compensation device) out of service, power flow in all other elements of the power system should be at or below normal rating;
- Transformer additions at all major terminal stations (i.e. two or more transformers per voltage class) are planned on the basis of being able to withstand the loss of the largest unit, however a brief outage to facilitate isolation and switching may be required;
- Transformer station additions at major terminal stations with a strong underlying high voltage connection, consider the total transformer capacity and available standby generation in the loop as long at the underlying system can accommodate such transfers;
- For normal operations, all voltages be maintained between 95% and 105%;
- For contingency or emergency situations, all voltages be maintained between 90% and 110%; and
- Analysis will be conducted with one high inertia synchronous condenser out of service at Soldiers Pond.

3.2 Transient Analysis Criteria

- System response shall be stable and well damped following a disturbance;
- System disturbances include:
    - Successful single pole reclosing on line to ground faults;
    - Unsuccessful single pole reclosing on line to ground faults;
    - Three phase faults with tripping of a 230 kV transmission line except a three phase fault on the Bay d'Espoir 230 kV bus;
    - Loss of the largest generator on line on the Island System with and without fault;
    - Line to ground or three phase fault with tripping of a synchronous condenser;
    - Fault and tripping of a series compensated 230 kV transmission line and if applicable with the series compensation device out of service on the in service parallel 230 kV transmission line;
    - Temporary HVdc pole fault;
    - Permanent HVdc pole fault; and
    - Temporary HVdc bipole fault.
- Post fault recovery voltages on the ac system shall be as follows:
    - Transient under voltages 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;
- Underfrequency load shedding
    - shall not occur for loss of on island generation with the HVdc link in service;
    - shall not occur for permanent loss of an HVdc pole;
    - shall not occur for a temporary bipole outage; and
    - shall be permitted, but controlled, for a permanent bipole outage.
- There shall be no commutation failures of the HVdc link during post fault recovery.

The foregoing criteria have been used throughout the technical analysis of the Lower Churchill Project, including work completed by both TransGrid Solutions and SNC-Lavalin. The criteria were also reviewed by Manitoba Hydro International as part of its independent review of the Lower Churchill Project on behalf of the Government of Newfoundland and Labrador completed in October 2012.

Two comparative tools are available to assess the appropriateness of Hydro's transmission planning criteria. These are:

1. NERC's Table 1 Transmission System Standards – Normal and Emergency Conditions found in NERC transmission planning standards TPL-001-0.1 through TPL-004-2a (refer to www.nerc.com); and
2. The NPCC Reliability Reference Directory #1 Design and Operation of the Bulk Power System dated December 1, 2009, sections 5.4 Transmission Design Criteria and 5.5 Transmission Operating Criteria (refer to www.npcc.org).

Hydro's steady state criteria are consistent with both normal and emergency conditions found in the NERC TPL standards and NPCC Directory #1 with one exception: On the Island Interconnected System, underfrequency load shedding is permitted for the loss of a generator today as the system is isolated from the North American grid and operation of sufficient spinning reserve and increased system inertia for the loss of generation contingency would be cost prohibitive for the relatively small rate base. Underfrequency load shedding is managed by both Newfoundland Power and Hydro and, where possible, participating feeders are rotated some time following interruption to ensure the same groups of customers are not repeatedly affected. In general, these outages are of short duration and occur less than ten times per year, affecting different groups of customers because the feeders selected to participate in underfrequency load shedding are changed following such events.

Hydro's transient analysis criteria generally meet the requirements set out by both NERC and NPCC with several exceptions. First, most of the existing station configurations within the Island Interconnected System have multiple transformers connected to the same high voltage bus using motor operated disconnect switches instead of circuit breakers. Consequently, a transformer fault will often result in loss of load as the high voltage bus must be tripped and the faulted transformer isolated before restoration. This longstanding practice has been considered acceptable to reduce cost where the interruption of load is considered a low probability event, and with remotely operated equipment, of short duration.

Secondly, the requirement to remain stable with no loss of load for a three phase fault on the 230 kV is problematic in some locations. Such a fault on the 230 kV bus at Bay d'Espoir is purposefully excluded. At present, loss of load with potential loss of stability will also occur for a three phase fault on the 230 kV bus at Holyrood. In assessing the HVdc interconnection at Soldiers Pond, the three phase fault at Holyrood, or Soldiers Pond for that matter, is not a significantly severe fault with respect to overall system stability. However, the three phase fault at Bay d'Espoir is particularly severe as the fault causes a temporary shutdown of the Soldiers Pond converter (commutation failure) and, at the same time, the electrical power from the Bay d'Espoir Generating Station feeds into the fault to the detriment of system stability. As the current power system is also unable to remain stable with a similar three phase fault at Holyrood, it was decided to not try to prevent this condition when completing the present analysis as the system is still susceptible to only one location where a three phase fault is of concern. Due to the generally concentrated physical location of the major generation source (BDE) within the electrical grid, this has been accepted as the cost to mitigate would be a major capital expense.

Third, NPCC requires no loss of load for permanent loss of the HVdc bipole. The criteria applied here permits controlled loss of load to maintain stability for loss of the HVdc bipole as contemplated by NERC.

As equipment is replaced, expanded or upgraded, improvements will continue to be considered to bring the system into further compliance where prudent to do. In some cases, due to space limitations or exceptional cost, other mitigation measures may be considered to reduce risk in terms of reliability exposure.

4.0 HVDC TRANSMISSION SYSTEM RATING

The Labrador – Island HVdc Link is a high voltage direct current bipolar transmission system. The system is based upon line commutated converter technology (LCC) for the ac to dc and dc to ac conversion process. The system will be capable of operating in bipolar mode and monopolar mode (i.e. one pole out of service) with ground or metallic return. The system has the following characteristics:

- Rated Voltage: ±350 kV dc
- Bipolar Operation
    - Rated Power at Rectifier (Muskrat Falls): 900 MW (450 MW per pole)
    - Rated Power at Inverter (Soldiers Pond): 830 MW[6] (415 MW per pole)
    - Rated Current: 1286 A per pole
- Ten Minute Monopolar Operation
    - Rated Power at Rectifier (Muskrat Falls): 900 MW
    - Rated Power at Inverter (Soldiers Pond): 662 MW
    - Rated Current: 2572 A
- Continuous Monopolar Operation – Earth Return
    - Rated Power at Rectifier (Muskrat Falls): 675 MW
    - Rated Power at Inverter (Soldiers Pond): 552 MW
    - Rated Current: 1929 A

For analysis purposes, the Labrador–Island HVdc Link was modeled in PSS®E software using the CDC4 dynamic model and a simple frequency controller is modeled to ensure that the link is able to adjust power delivery to the island in the event of the loss of a generator on the island (such that there is no underfrequency load shedding for the event).

[6] Actual delivered power is dependent upon overhead line resistance which varies with ambient temperature.

5.0 SYNCHRONOUS CONDENSER RATINGS

The Soldiers Pond synchronous condenser plant will include three 175 MVAR high inertia synchronous condensers. Table 5.1 provides the technical parameters for the Soldiers Pond, Holyrood Unit 3 and possible Holyrood CT synchronous condensers.

Table 5.1: Synchronous Condenser Ratings

	Soldiers Pond	Holyrood Unit 3	Proposed Holyrood CT
Machine Base, MVA	175	177.235	165.948
MVAR Rating	+175/-95	+150/-69	+127/-44
kV	15	16	13.8
H (kW.sec/kVA)	7.84	1.29	1.01
X_d (pu)	1.24	2.15	2.58
X_q (pu)	0.85	1.94	2.36
X'_d (pu)	0.27	0.26	0.20
X''_d (pu)	0.165	0.22	0.143
X''_q (pu)	0.177		0.17
X_l (pu)	0.09	0.1152	
T'_{do} (sec)	11	6.8	13.0
T''_{do} (sec)	0.08	0.06	0.05
T''_{qo} (sec)	0.29	0.06	0.05

If the proposed Holyrood combustion turbine does not include provisions for synchronous condenser operation or is sized differently than assumed, adjustments in the MVAR requirements will need to be addressed prior to LIL being in service. The future MVAR needs will be completed prior to the HVdc interconnection being placed in service.

6.0 SYSTEM PLANNING STUDIES

A system planning study was undertaken to identify the system additions and/or modifications required to ensure the successful integration of the Labrador-Island HVdc Link with the Island Interconnected System. The objective of the study was two-fold. First, the study had to identify technically viable system alternatives that will meet the transmission planning criteria. Second, the study had to complete an engineering economic analysis (i.e. cost benefit analysis) to determine the least cost technically viable alternative.

The scope of this report is to review the performance of the integrated system, identify system additions or upgrades required to ensure the compliance with the transmission planning criteria on the Island Interconnected System for the successful integration of the LIL only, and determine the least cost alternative. Any enhancements needed to ensure the technical operation of the MIL would be the responsibility of Emera, the proponent of the MIL. These have been previously identified in separate studies.

Previous studies have determined that for an isolated island scenario, a new 230 kV line was required from Bay d'Espoir to Western Avalon to facilitate generation additions that would have to be built to meet demands. A report covering this aspect is included as Appendix C1.

Previous system planning studies[7] determined that the integration of the LIL with the Island Interconnected System will require system upgrades including the addition of high inertia synchronous condensers, the uprating of transmission lines, the replacement of circuit breakers and either:

[7] DC1020 – HVdc System Integration Study, Hatch, TGS (2008), and DC1210 – HVdc System Sensitivity Analysis, Hatch, TGS (2009) considered the addition of an 800 MW HVdc transmission system between Muskrat Falls in Labrador and Soldiers Pond in Newfoundland. The analysis did not contemplate the addition of the Maritime Link. (See Appendix C)

1. the addition of a new 230 kV transmission line between Bay d'Espoir Terminal Station and Western Avalon Terminal Station; or
2. the addition of 50% series compensation[8] on TL202 and TL206.

System Planning studies completed by SNC Lavalin (SLI) during the Muskrat Falls Project Decision Gate 3 process revealed that the addition of a new 230 kV transmission line between Bay d'Espoir and Western Avalon, along with three 175 MVAR high inertia synchronous condensers at Soldiers Pond (minimum of two in service at all times), and operation of HTGS Unit 3 in synchronous condenser mode, provided acceptable system performance for contingencies on the Island Interconnected System.[9] The SLI study incorporated the Maritime Link (Newfoundland to Nova Scotia HVdc transmission link) in its scope.

The system planning study included steady state load flow and transient stability analyses performed using Version 32 of PSS®E software from Siemens PTI. The following sections summarize the results of the analysis as it relates to the Bay d'Espoir to Western Avalon 230 kV transmission line corridor.

6.1 Base Cases

Hydro developed a total of 11 base case scenarios that were meant to cover the range of expected system operating configurations following the completion of the HVdc transmission link. The base cases considered Island Interconnected System loading levels from winter peaks through spring/fall days to summer days and nights (in other words, over the extremes expected). The load on the LIL is varied between 0 MW and 830 MW delivered with the island generation adjusted to supply the load not supplied by generation

[8] 50% series compensation represents a reasonable limit for line compensation. For example, in Hydro-Québec TransÉnergie's system, series compensation ranges from 16% to 50%.

[9] SNC - Lavalin Inc. load flow, short circuit and stability studies see Appendix C9.

in Labrador. Variations in island and LIL loadings were used to assess the impact of carrying generation reserve both on the Island and in Labrador with respect to frequency response and underfrequency load shedding.

The base cases consider expected system additions or other changes that may impact the selection of the preferred alternative to address the study issue. For this study, key assumptions are that Holyrood Units 1 to 3 are decommissioned as generators, Unit 3 will be retained as a synchronous condenser and LIL is in service and the proposed combustion turbine for Holyrood is completed and is equipped with a 166 MVA generator capable of operation as a synchronous condenser. The synchronous condenser is used to assist in voltage control of the Avalon Peninsula 230 kV buses when the unit is not required to operate in generate mode. In the event that through the acquisition of the proposed CT, it is technically or financially advantageous to use a smaller generator or if synchronous condenser operation is not available on the acquired CT, the additional MVAR requirements will need to be in service for the LIL. However, it does not need to be a high inertia unit and does not affect the justification for a new line. The future additional MVAR requirements will be assessed following the decision on the proposed CT and prior to the HVdc interconnection being placed into service.

Table 6.1 summarizes each base case.

Table 6.1: Base Case Scenarios

Case	Hydro System Load MW	LIL Mode	LIL Load MW at SOP	Hydro Island Generation MW	Comments
BC1	1757	Bipole	672	1085	Maximum Future Winter Peak – Max Island Generation with reserve on LIL
BC2	1603	Bipole	830	773	Winter Peak – Max LIL import with reserve on Island Generation
BC3	1603	Bipole	518	1085	Winter Peak – Max Island Generation with reserve on LIL
BC4	1458	Monopole	200	1258	Winter – Max Island Generation with CTs running and reserve on LIL
BC5	1415	Bipole	830	585	Winter Day – Max LIL with reserve on Island Generation
BC6	1415	Bipole	330	1085	Winter Day – Max Island Generation with reserve on LIL
BC7	1261	Bipole	830	431	Spring/Fall Day – Max LIL with reserve on Island Generation
BC8	1261	Bipole	176	1085	Spring/Falls Day – Max Island Generation with reserve on LIL
BC9	700	Bipole	375	325	Summer Day – Min Island Generation with reserve on LIL
BC10	700	Monopole	154	546	Summer Day – Max LIL with reserve on Island Generation
BC11	440	Bipole	120	320	Summer Night – Min LIL and Island Generation with reserve on Island Generation

The base cases will be tested for steady state condition by load flow analysis for pre and post contingency outages which will ensure the post contingency case is acceptable. Following this, transient stability analysis will be conducted for proposed solutions to ensure the system will move from the pre contingency state to the post contingency state without system outages.

Table 6.2 provides the Hydro's Island Interconnected System generation capacities used in preparing the base case load flows. As this is an electrical study which uses electrical parameters of the various components and controls the figures below may vary somewhat from figures used in resource or adequacy planning which would be more concerned with reliable continuous power available and energy capabilities. Load flow and stability analysis serve to test the load carrying capabilities and real time response to expected events such as faults on lines, or sudden tripping of generators.

Table 6.2: Hydro System Capability

Source	Rated Capacity (MW)	Comments
Hydro		
Bay d'Espoir	604	Bay d'Espoir generation is calculated as 6 x 75 MW + 1 x 154 MW. Units 1 to 6 at Bay d'Espoir have a sustained capacity of 73 MW per unit and a peak capacity of 75 MW. (6 x 73 + 154 = 592 MW)
Cat Arm	127	2 x 63.5 MW
Upper Salmon	84	
Hinds Lake	75	
Granite Canal	40	
Paradise River	8	
Snook's, Venam's, Roddickton	0	For load flow analysis, the value of generation is netted out with load that it supplies.
Subtotal Hydro	938	
Non-Utility/PPA		
Star Lake	18	Nameplate rating
Exploits	90.8	Grand Falls + Bishop's Falls
Corner Brook Cogen	15	Nameplate rating
Rattle Brook	4	
St. Lawrence Fermeuse	11 11	The wind farms are not considered in capacity planning due to the variability of wind but are included in this analysis to assess transient response of the wind farms to system contingencies. For the purposes of this investigation, wind farms are generating at approximately 40% of rated capacity.
Subtotal NUG/PPA	146.8	
Total capacity	1084.8 (1085)	
Standby Generation		
Hardwoods CT	50	
Stephenville CT	50	
Holyrood CT (proposed)	60	
Hawke's Bay Diesel	5	
St. Anthony Diesel	9.7	
Total Standby capacity	174.7	
Spinning Reserve Requirement	154	Largest unit on system with Holyrood offline

6.2 Load Flow Analysis

The steady state load flow analysis was completed to assess whether or not transmission system elements will experience overloads and if bus voltage violations will occur with all equipment in service, and under single element outages. Once violations of the transmission planning criteria were identified, potential technical solutions were assessed to determine technical viability. A detailed description of the results of the load flow analysis and corresponding load flow plots are provided with an index in Appendix A.

During peak and spring/fall loading conditions, a loss of either TL218 or TL242 was found to result in thermal overload of TL266 between SOP and HWD. For loss of TL218, operation of the HWDCT at 50 MW was found to alleviate the overload condition. However, for the loss of TL242, operation of the HWDCT alone was not sufficient to alleviate the overload on TL266. For loss of TL242, opening TL236 between HWD and OPD in addition to operating the HWDCT at 50 MW was found to alleviate the thermal overload on TL266. The end result of opening TL236 with TL242 out of service is that both HWD and OPD stations are supplied radially leaving the island's two largest supply points exposed to load loss should a second line fail or if there were other contingency events.

Although TL242 and TL266 are parallel 230 kV transmission lines between SOP and HWD, loss of TL266 did not result in overload of TL242. The reason for there being an overload on TL266 and not on TL242 for the line out contingency is that TL266 consists of a 636 kcmil, 26/7, ACSR "GROSBEAK" conductor which has a lower thermal rating than TL242 which consists of an 804 kcmil, 23/19, AACSR/TW conductor. The overload during single line outage contingencies is driven by the load growth in the St. John's area and not the introduction of the Labrador – Island HVdc Link. This overload condition is expected in the 2020 – 2021 timeframe when the Hydro system peak load reaches 1642 MW. There are several alternatives to alleviate this condition. First, given that TL266 is an H-frame wood pole line nearing end of life, the re-build of this circuit with a larger conductor (i.e. 1192.5

kcmil, 54/19 ACSR GRACKLE) is viewed as a viable alternative. Second, construction of a new 230 kV transmission line from Soldiers Pond to the St. John's area would provide the necessary transmission capacity. A new transmission line into the region may be warranted if, as the load continues to grow, a new 230/66 kV terminal station is needed. Finally, the addition of additional fast start combustion turbine within the St. John's area could be used to alleviate thermal overloads. As this is a separate issue and one that is not materially affected by the presence or absence of the current proposal, a separate detailed analysis is required to assess the least cost technical resolution of this issue when required.

A similar situation arises for the parallel lines TL201 and TL217 between Western Avalon and Soldiers Pond where TL201 is 636 kcmil, 26/7, ACSR "GROSBEAK" and TL217 is a combination of 804 kcmil, AACSR/TW and 795 kcmil,26/7 ACSR "DRAKE". Again, the overloading can be addressed by CT power generation or increasing the Labrador-Island Link delivery. There are cases where upgrading TL201 will provide relief. Again, this is a separate issue and one that is not materially affected by the presence or absence of the current proposal. A separate detailed analysis is required to assess the least cost technical resolution of this issue when required.

For loss of one of the three 230 kV transmission lines between SSD and WAV (i.e. TL203, TL207 or TL237), load flow analysis indicated that thermal overload of the remaining in service transmission lines will occur during the peak and spring/fall loading conditions. The overloads are most severe when the island generation is at maximum output (i.e. 1085 MW) and the LIL imports at SOP are reduced. Increasing the LIL imports at SOP with a corresponding reduction in the island generation output was found to alleviate the overloads on the SSD to WAV corridor for loss of a 230 kV transmission line, particularly in the spring/fall loading condition. Alternatively, a combination of operation of the HWDCT and/or proposed HRDCT at 50 MW and 60 MW respectively, along with increases in LIL imports at SOP is also a viable operating alternative.

The loss of TL217 (WAV to SOP) during the typical spring/fall day resulted in thermal overloads of TL201. Increasing the LIL import at SOP with a corresponding reduction in island generation output alleviated the thermal overload on TL201. As noted above, the loss of TL201 does not result in thermal overload to TL217 because TL217 has a larger conductor than TL201, and therefore a higher thermal rating. At 30 ^{o}C ambient, there is an approximate 166 MW difference in the two lines.

Load flow analysis of the base cases demonstrated thermal overload and voltage collapse issues for loss of either TL202 or TL206 (BDE to SSD) in the peak, winter, and spring/fall loading conditions.

With the island generation at maximum output during the typical spring/fall day loading condition, a thermal overload of TL202 and TL206 (105% of rating) is expected prior to any transmission line contingency. To eliminate this overload condition, TL202 and TL206 could be thermally uprated or the LIL imports at SOP increased. The steady state, pre-contingency thermal overloads on TL202 and TL206 during the typical spring/fall day loading condition with maximum generation output from island generating sources are of particular concern given that the spring runoff and reservoir storage positions may require the maximization of island generation to avoid spill and thereby require reduced or minimal LIL imports at SOP. Having to limit island generation output during the spring/fall to avoid transmission line thermal overload situations is viewed as restrictive for sound and efficient reservoir operation.

System voltage collapse is evident for loss of either TL202 or TL206 particularly when the island generation is at maximum output and the LIL imports are reduced. This mode of operation maximizes the power flow from BDE to the Avalon Peninsula. Similar to the thermal overload issues in steady state during the spring/fall load condition, increasing the LIL imports at SOP will reduce the possibility of voltage collapse for loss of TL202 or TL206. To avoid voltage collapse the steady state analysis has determined that the LIL imports at

SOP must be no less than 656 MW during winter loading conditions and no less than 468 MW during spring/fall loading conditions. This is equally restrictive as it limits flexibility and optimization of all generation resources. While it may be acceptable in short-term contingency situations, it is not prudent to accept such restriction as a normal situation.

Load flow analysis of the typical summer day found that with the LIL in monopolar mode with LIL imports at 154 MW, thermal overload of TL202/206 is expected for the loss of the parallel circuit. Increasing the LIL import, operation of the HWDCT and proposed HRDCT as generators, or thermal uprating of TL202 and TL206 were found to alleviate the thermal overload issue.

Load flow analysis of the typical summer night loading conditions did not reveal any transmission planning criteria violations.

6.2.1 Thermal Overloads

The load flow analysis indicated that thermal overloads would be experienced on TL202, TL206, TL203, TL207, TL237 and TL201 during transmission line contingencies, particularly for the typical spring/fall day loading condition. This steady state analysis indicated that increasing the LIL deliveries at SOP with a corresponding decrease in island generation output provides an operational solution to alleviate the overloads in the short term. However, here are potential requirements for future thermal upgrades of the affected 230 kV transmission lines as discussed below. They will be reviewed and proposed as stand-alone proposals for consideration as deemed technically justified.

TL203 is a 45 km long, H-frame wood pole transmission line built in 1965. Further thermal uprating of this transmission line is deemed impractical given the existing structure heights, meteorological design load requirements, etc.. Therefore, to increase the rating of TL203 by any significant degree, a significant upgrade such as new heavy angle towers with mid-

span structures or reconductoring with a high temperature conductor or possibly a full rebuild of the circuit is required. For analysis purposes, TL203 is assumed to be rebuilt using the 804 AACSR/TW conductor with an 80 ^{o}C hot conductor temperature design similar to TL207, TL237, TL217 and TL236.

Analysis by Hydro's Transmission and Distribution Design Department has indicated that TL202 and TL206 could be thermally uprated from its present 50 ^{o}C hot conductor temperature design to a 75 ^{o}C hot conductor temperature design through the addition of a number of mid-span structures and excavation in the critical low ground clearance areas. The choice of a mid-span structure or excavation is done in final design stages and is affected by the cost of a structure and its installation versus the amount of material to be removed to meet standards. This is obviously a span by span decision and affected by terrain, slope and the amount of material to be removed. With this work, the thermal ratings of TL202 and TL206 will increase from 199.3 MVA, 297.7 MVA and 369.5 MVA for summer, spring/fall and winter conditions respectively to 341.8 MVA, 402.4 MVA and 453.9 MVA for summer, spring/fall and winter conditions respectively.

TL207 and TL237 are guyed V steel structured transmission lines that were upgraded as part of the Avalon Transmission Upgrade Project. These lines have an 80 ^{o}C hot conductor temperature design. Increasing the thermal rating of these lines would require a significant rebuild.

TL217 and TL201 are two parallel lines between Western Avalon and Soldiers Pond. TL217 has a thermal rating of 341.8 MVA at 30 ^{o}C ambient while TL201 is rated at 175 MVA at 30 ^{o}C ambient. Issues of overload are not apparent for the loss of TL201. In the case of a loss of TL217, some scenarios resulted in overloading on TL201. TL201 is nearing the end of its useful life and a major rebuild is likely needed in the future. This is independent of the current proposal and options to mitigate the issue will eventually be brought forward that are technically sound and least cost.

Cost for many of the upgrades or line replacements are included in the current 20-year plan. As time to complete these upgrades or replacements approaches, further study will be required to identify the final estimated cost which will be put forward for Board approval.

6.2.2 Voltage Collapse

The load flow analysis found that for system conditions in which the on island generation output is maximized and the LIL imports at SOP reduced, system voltage collapse was experienced for loss of either TL202 or TL206 between BDE and SSD. With all major island generation connected to the Avalon Peninsula via Bay d'Espoir and the 230 kV transmission lines TL202 and TL206, loss of either of these circuits will have a significant impact on the ability of the system to deliver maximum on island generation to the Avalon Peninsula. The voltage collapse was the result of increased impedance between the generation source and the load center (i.e. loss of a transmission line results in increased impedance of the transmission path) and the lack of voltage support to overcome the increased impedance. To this end, a number of system additions were considered, including:

1. Increasing the number of the Soldiers Pond synchronous condensers;
2. Series compensation of TL202 and TL206 to reduce system impedance with subsequent increase in power transfer;
3. Construction of two 45 km of 230 kV transmission line between Western Avalon and the Sunnyside area with reroute of TL202 and TL206 around Sunnyside Terminal Station and connection to the two new 230 kV transmission lines terminating at Western Avalon along with series compensation of these circuits. In essence, connecting Bay d'Espoir to Western Avalon directly; and
4. Construction of a new 230 kV transmission line between Bay d'Espoir and Western Avalon.

Other options were considered but were eliminated for various reasons. Such items included conversion to 315 kV or a new line from Bay d'Espoir to Sunnyside with and without series compensation.

6.2.2.1 Increasing the Number of Soldiers Pond Synchronous Condensers

Increasing the number of 175 MVAR synchronous condensers in service at Soldiers Pond was considered as an alternative to eliminate the voltage collapse issues experienced for the loss of TL202 or TL206 in base cases BC1, BC3, BC4, BC6 and BC8. Analysis demonstrated that a minimum of three 175 MVAR synchronous condensers (four in total) were required to eliminate the potential for voltage collapse in the steady state contingency analysis for base cases BC1 and BC3. The project sanctioned by the provincial government includes three synchronous condensers and provides for operation of the system with one out of service. With the addition of the fourth 175 MVAR synchronous condenser at SOP, thermal overload of TL202/206 was experienced for loss of TL206/202 in base cases BC1 and BC3. Operation of the HWDCT and HRDCT is effective in alleviating the post contingency overload on the healthy BDE to SSD 230 kV transmission line. Alternatively, increasing the LIL power deliveries at SOP is effective in removing the TL202/206 thermal overload.

Analysis of base cases BC6 and BC8 demonstrated that increasing the number of 175 MVAR synchronous condensers at SOP was ineffective in eliminating the steady state voltage collapse issues associated with the loss of TL202 or TL206. Instead, the addition of 115 MVAR and 230 MVAR of 230 kV shunt capacitors at Come By Chance for BC6 and BC8 respectively was found to eliminate the voltage collapse issues for loss of either TL202 or TL206.

Analysis of base case BC4 revealed that increasing the number of synchronous condensers at SOP or addition shunt capacitors at Come By Chance was not effective in eliminating the

steady state voltage collapse issues associated with the loss of TL202 or TL206.

6.2.2.2 Addition of Series Compensation on TL202 and TL206

The addition of series capacitors to a transmission line reduces the effective impedance of the transmission line thereby reducing the electrical angular displacement across the transmission line for a fixed power transfer, and resulting in improved power system stability for similar transfers. As well, series capacitors permit increased power flow across the transmission line for the same voltage drop or electrical displacement in the system without the series compensation. The application of series compensation on TL202 and TL206 is found to increase the power transfer capacity of the BDE to SSD path in steady state. As a result, it is necessary to increase the thermal rating of TL202 and TL206 in conjunction with the series compensation addition. Further, with the increase in transfer from BDE to the Avalon Peninsula it will be necessary to rebuild TL203 to alleviate thermal overloads of TL203. Figure 6.1 provides a diagram of the proposed 230 kV transmission system changes.

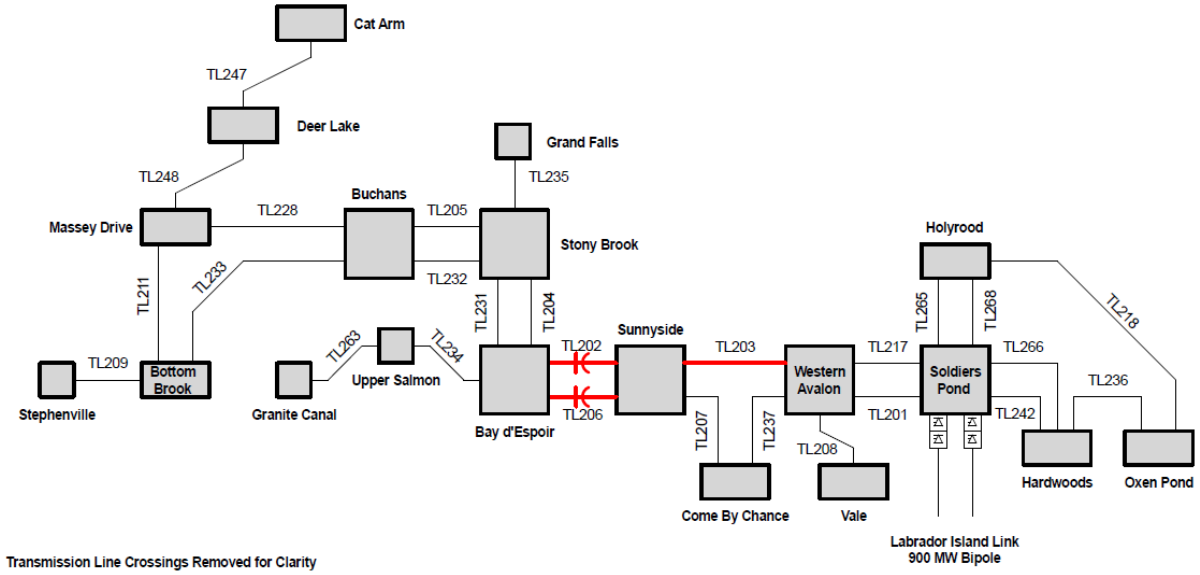


Figure 6.1 - 230 kV Transmission – TL202/TL206 Thermally Uprated and Series Compensated – TL203 Rebuilt

Assuming the thermal uprate of TL202 and TL206, the addition of 50% series compensation on TL202 and TL206 in the Sunnyside area[10] and the rebuild of TL203, the voltage collapse issues experienced for loss of TL202 or TL206 in the base cases were reassessed. The analysis demonstrated that voltage collapse can be avoided for the loss of TL202 or TL206 following thermal uprate and 50% series compensation. However, even with the thermal uprate of TL202 and TL206, the loss of one of these lines will result in a thermal overload of the remaining circuit. The thermal overload of the uprated TL202 and TL206 can be alleviated with the start of the HWDCT and/or the proposed HRDCT during the winter peak. For the typical winter day and spring/fall loading conditions it will be necessary to increase the LIL imports at SOP to alleviate the thermal overloading on TL202 and/or TL206 during line out contingencies.

The loss of TL207 or TL237 was found to result in thermal overload of the rebuilt TL203 for the winter day and spring/fall day loading conditions. The TL203 overloads can be alleviated through operation of HWDCT or increased LIL imports at SOP.

6.2.2.3 Reroute of TL202 and TL206 around Sunnyside Terminal Station

The reroute of TL202 and TL206 around the SSD with re-termination at WAV provides a more direct transmission path between Bay d'Espoir and the Avalon Peninsula load center. This modification requires the thermal up-rating of TL202 and TL206, the construction of two 45 km long 230 kV transmission lines to extend TL202 and TL206 to Western Avalon, and 25% series compensation on TL202 and TL206. The modification requires 98 km less new line construction than the 188 km long transmission line between BDE and WAV, and 45 km more new line construction than the modification with uprate of TL202 and TL206,

[10] Given that the limited space in the immediate vicinity of the Sunnyside Terminal Station, and the fact that the TL202 and TL206 corridor has a 138 kV transmission line on each side of the 230 kV transmission lines (i.e. TL212 and TL219 supplying the Burin Peninsula), it is assumed that the series compensation station would be located in the Pipers Hole area where TL212 and TL219 leave the 230 kV corridor and head down the Burin Peninsula. This location provides easy access to the two 230 kV lines to be series compensated.

rebuild of TL203 and 50% series compensation. Figure 6.2 provides a diagram of the proposed 230 kV transmission system changes.

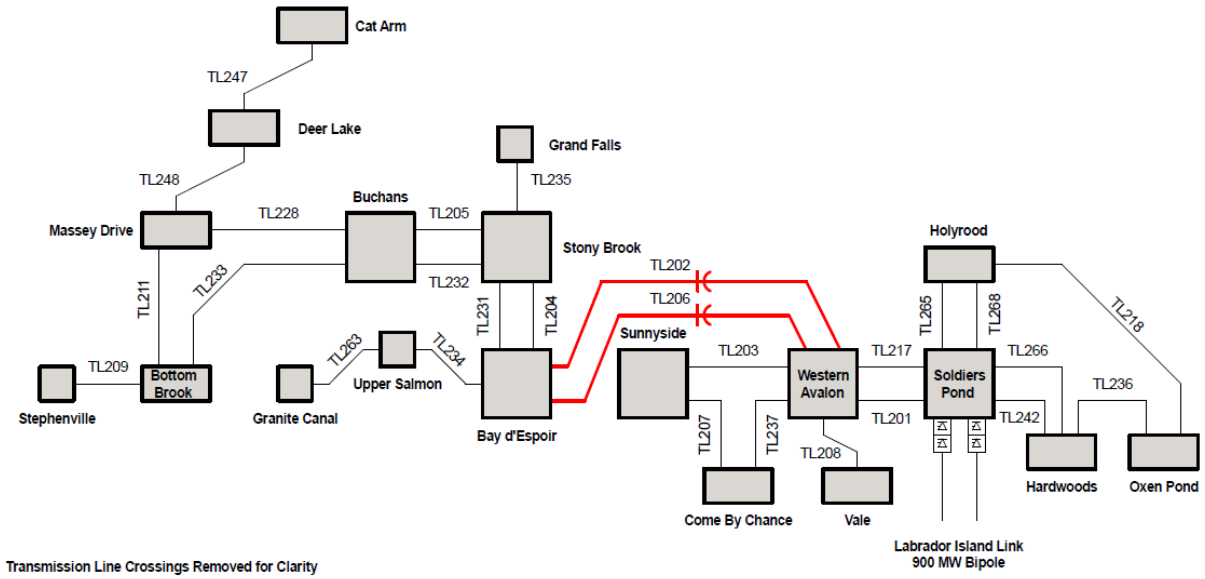


Figure 6.2 - 230 kV Transmission – TL202/TL206 Reroute around SSD – Lines Thermally Uprated and Series Compensated

The reroute of TL202 and TL206 eliminates the thermal overload issues associated with TL203 during loss of TL207 and TL237 contingencies. Load flow analysis of the reroute demonstrates that the loss of TL202 or TL206 will result in the thermal overload of the remaining 230 kV line between BDE and SSD despite the thermal uprate. In all base cases except the LIL in monopolar operation (BC4), operation of the HWDCT and HRDCT, or increasing LIL deliveries at SOP were found to be effective in alleviating the thermal overload issue during the line outage. BC4 was found to be problematic with voltage collapse occurring in the steady state analysis of the TL202/206 outage following reroute, thermal upgrade and 25% series compensation of both TL202 and TL206.

6.2.2.4 Construction of New 230 kV Transmission Line Bay d'Espoir to Western Avalon

As an alternative to the thermal uprate of TL202 and TL206 and the rebuild of TL203, construction of a new 188 km, 230 kV transmission line between Bay d'Espoir and Western Avalon provides a third 230 kV circuit to the Avalon Peninsula and eliminates the need to modify existing transmission lines in the near term. Figure 6.3 provides a diagram of the proposed 230 kV transmission system changes.

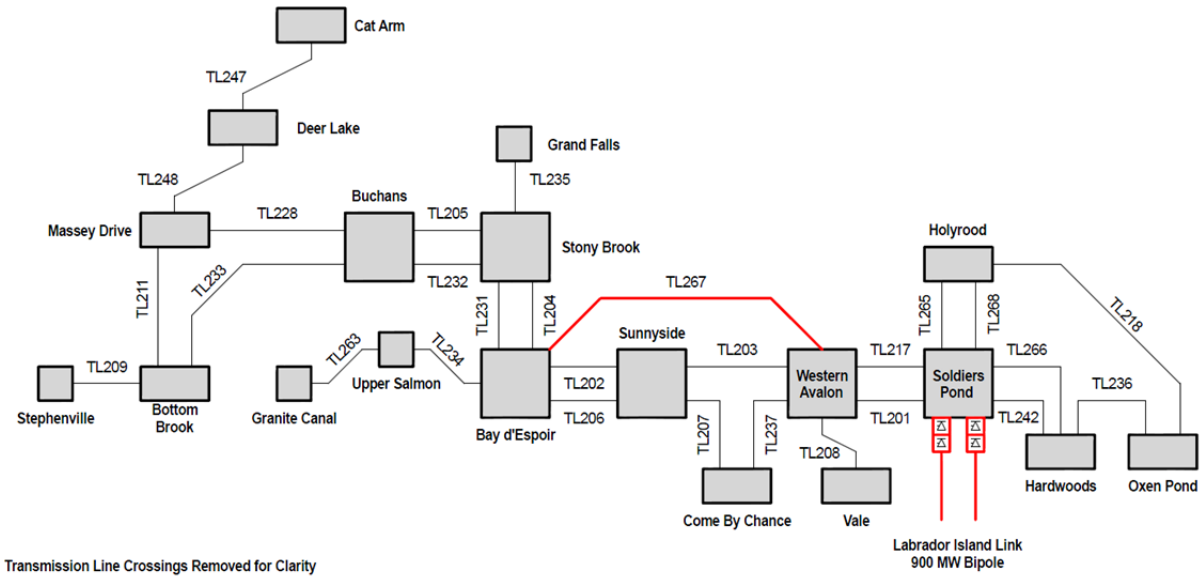


Figure 6.3 - 230 kV Transmission – New 230 kV Transmission Line Bay d'Espoir to Western Avalon

Load flow analysis of the base cases with the BDE to WAV 230 kV transmission line added demonstrates elimination of thermal overloading on TL203 for outages to TL207 or TL237. In addition, voltage collapse associated with the loss of TL202 or TL206 was also eliminated. The analysis revealed that even with the new 230 kV transmission line between BDE and WAV, under maximum island generation output during the spring/fall loading condition, loss of TL202 or TL206 will result in thermal overload of the parallel circuit. An increase in the LIL imports at SOP with a corresponding reduction in the on island generation output was found to alleviate the overload.

6.2.3 Summary of Load Flow Analysis

Table 6.3 provides a summary of the load flow analysis.

Table 6.3: Summary of Load Flow Analysis

Load Condition	Base Case(s)	Comments	Upgrades	Acceptable
Future Peak	BC1	Loss of TL207 overload of TL203	Start HWDCT + HRDCT	Yes
			Increase LIL import	Yes
			Rebuild TL203	Yes
			BDE to WAV Line	Yes
			Reroute TL202/206	Yes
		Loss of TL218 or TL242 Overloads TL266	Future Rebuild TL266	Yes
		Loss of TL202/206 Voltage collapse	Thermal uprate TL202/206, 50% series compensations and rebuild TL203 increase LIL import, or start HWDCT	Yes
			BDE to WAV Line	Yes
			4 x 175 MVAR at SOP	Yes
			Reroute TL202/206	Yes
Winter Peak	BC2, BC3, BC4	Loss of TL218 or TL242 Overloads TL266	Start HWDCT & open TL236	Reduced reliability
			Future Rebuild TL266	Yes
		Loss of TL207 overload of TL203 In monopole no standby to start	Start HWDCT + HRDCT	Yes
			Increase LIL import	Yes
			Rebuild TL203	Yes
				Yes
		Loss of TL237 overload of TL203 In monopole no standby to start	Start HWDCT	Yes
			Increase LIL import	Yes
			Rebuild TL203	Yes
			BDE to WAV Line	Yes
			Reroute TL202/206	Yes
		Loss of TL203 in monopole overload TL207 & TL237	Increase LIL import	Yes
			BDE to WAV Line	Yes
			Reroute TL202/206	Yes
		Loss of TL202/206 Voltage collapse (BC3 & BC4)	Thermal uprate TL202/206, 50% series compensations and rebuild TL203 and	Yes

Load Condition	Base Case(s)	Comments	Upgrades	Acceptable
			increase LIL import (BC3 & BC4), or start HWDCT + HRDCT (BC3)	
			BDE to WAV Line	Yes
			4 x 175 MVAR at SOP	Yes for BC3 No for BC4
			Reroute TL202/206	Yes for BC3 No for BC4
Winter Day	BC5, BC6	Loss of TL242 Overloads TL266	Start HWDCT & open TL236	Reduced reliability
			Future Rebuild TL266	Yes
		Loss of TL207 overload of TL203	Start HWDCT & HRDCT	Yes
			Increase LIL import	Yes
			Rebuild TL203	Yes
			BDE to WAV Line	Yes
			Reroute TL202/206	Yes
		Loss of TL237 overload of TL203	Start HWDCT & HRDCT	Yes
			Increase LIL import	Yes
			Rebuild TL203	Yes
			BDE to WAV Line	Yes
			Reroute TL202/206	Yes
		Loss of TL203 overloads TL207 & TL237	Start HWDCT & HRDCT	Yes
			Increase LIL imports	Yes
			BDE to WAV Line	Yes
			Reroute TL202/206	Yes
		Loss of TL202/206 Voltage collapse (BC6)	Thermal uprate TL202/206, 50% series compensations and rebuild TL203 and increase LIL import	Yes
			BDE to WAV Line	Yes
			4 x 175 MVAR at SOP	No
			Reroute TL202/206	Yes
Spring/Fall Day	B7, BC8	Steady State TL202 & TL206 Overload	Thermal uprate of TL202 & TL206	Yes
			BDE to WAV Line	Yes
		Loss of TL242 Overloads TL266	Start HWDCT & open TL236	Reduced reliability
			Future Rebuild TL266	Yes
		Loss of TL207 overloads TL202, TL206, TL203	Increase LIL imports	Yes
			Uprate TL202,TL206,TL203	Yes
			BDE to WAV Line	Yes
			Reroute TL202/206	Yes

Load Condition	Base Case(s)	Comments	Upgrades	Acceptable
		Loss of TL237 overloads TL202, TL206, TL203	Increase LIL imports	Yes
			Uprate TL202,TL206,TL203	Yes
			BDE to WAV Line	Yes
			Reroute TL202/206	Yes
		Loss of TL203 overloads TL202, TL206, TL207, TL237	Increase LIL imports	Yes
			BDE to WAV Line	Yes
			Reroute TL202/206	Yes
		Loss of TL202/206 Voltage collapse (BC8)	Thermal uprate TL202/206, 50% series compensations and rebuild TL203 increase LIL import	Yes
			BDE to WAV Line	Yes
			4 x 175 MVAR at SOP	No
			Reroute TL202/206	Yes
Summer Day	BC9	No Criteria Violations BC9	None Required	Yes
	BC10	BC10 Loss of TL202/206 Thermal overload TL206/202	Start HWDCT & HRDCT	Yes
			Increase LIL imports	Yes
			Thermal uprate TL202/206	Yes
			BDE to WAV Line	Yes
Summer Night	BC11	No Criteria Violations	None Required	Yes

6.3 Transient Stability Analysis

The North American Electric Reliability Corporation (NERC) defines stability as:

The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.[11]

For the purposes of analysis, the base cases[12] are subjected to the disturbances listed in Table 6.4. Previous system studies found these contingencies to be the most critical with respect to system stability.

[11] Glossary of Terms Used in NERC Reliability Standards, May 9, 2013.
[12] Dynamic analysis was performed on nine of the eleven base cases. Transient stability performance was not considered for Base Case 11. Limitations with the CDC4T model in PSS®E prevented dynamic analysis for Base Case 11 due to the restrictions on the minimum flow over the Labrador-Island HVdc Link.

Table 6.4: List of Contingencies for Dynamic Analysis

Contingency	Name	Description
CON1	Temporary LIL Bipole Fault	Bipole outage with full power restored after 200 ms.
CON2	Permanent Pole Fault	Pole is tripped and the healthy pole is loaded to 2.0 per unit power after 100 ms.
CON3	Three-phase fault at Soldiers Pond, followed by the tripping of a Synchronous Condenser.	Synchronous condenser is tripped after 100 ms.
CON4	Three-phase fault at Sunnyside, followed by the tripping of TL202 to Bay d'Espoir.	Line is tripped after 100 ms.
CON5	Three-phase fault at Western Avalon, followed by the tripping of a 230 kV transmission line.	Line is tripped after 100 ms.

6.3.1 Preliminary Transient Stability – No System Additions

Preliminary transient stability analysis determined that power system stability cannot be maintained for disturbances on the Island Interconnected System following the addition of the Labrador–Island HVdc Link and the synchronous condensers at Soldiers Pond. A three phase fault on TL202 or TL206 at SSD with subsequent tripping of the faulted line was found to result in angular instability, particularly when the hydro generation is operating near maximum output.

The simulation of a three phase fault on TL206 at SSD during a typical spring/fall loading condition with only 176 MW of import on the LIL at SOP was one of a number of base cases to exhibit angular instability without additional system reinforcement. Figure 6.4 provides the relative rotor angle plot for a number of generators on the Island Interconnected System. The divergence in the machine rotor angles indicates angular instability.

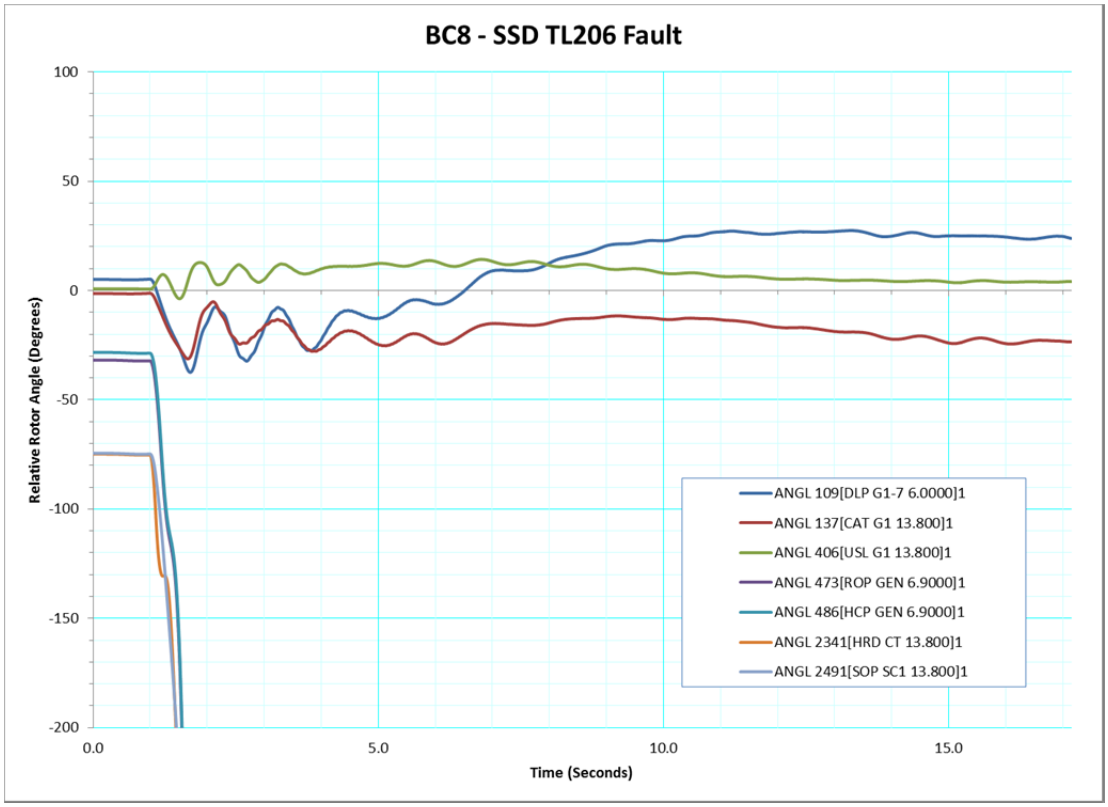


Figure 6.4 - Spring/Fall Day (BC8) SSD TL206 Fault – Relative Rotor Angle (Degrees)

Reducing the power transfer between BDE and SSD on TL202 and TL206 to 350 MW with the LIL delivering 657 MW at SOP (700 MW sending) results in a stable system following the three phase fault on TL202 at SSD. Figure 6.5 provides the plot of select generator rotor angles. The case demonstrates that in order to maintain power system stability, the power flow between Bay d'Espoir and Sunnyside must be limited to no more than 350 MW.

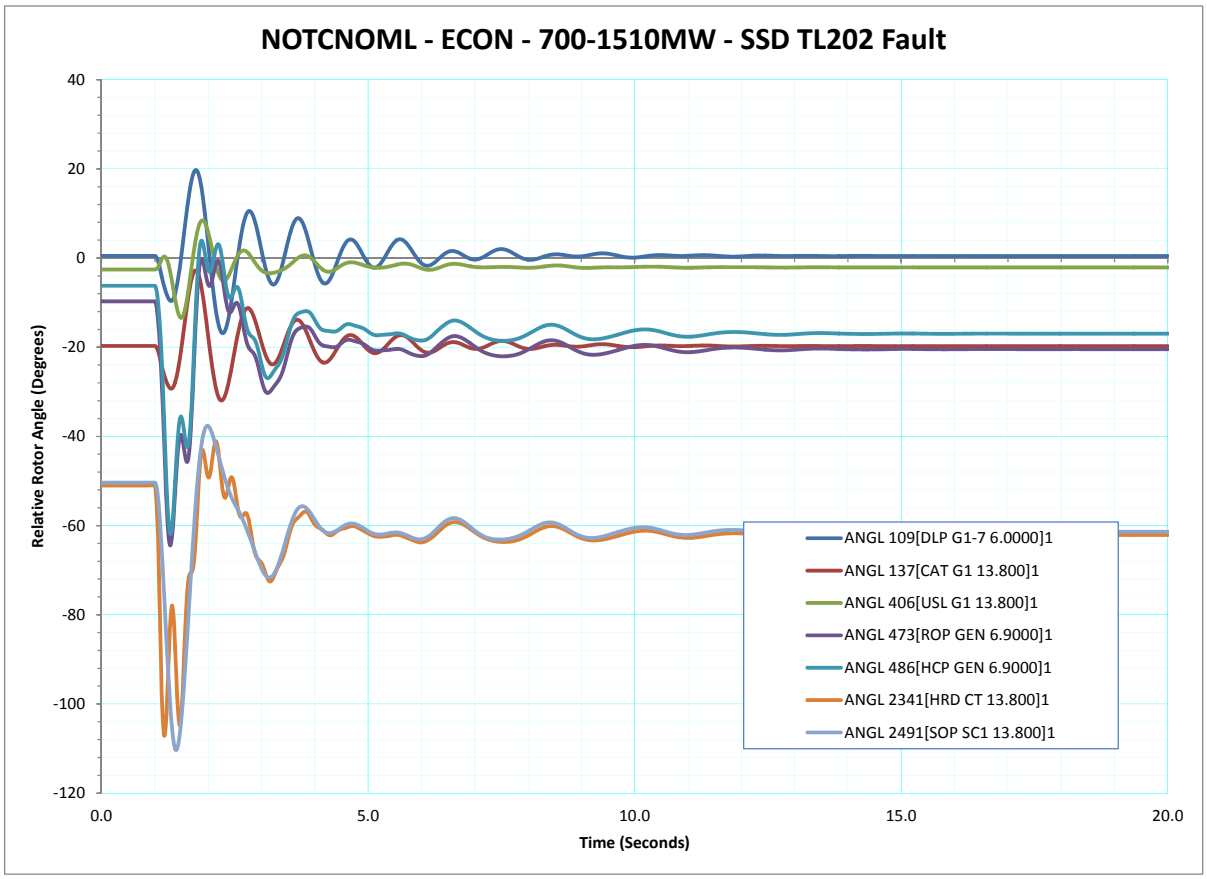


Figure 6.5 - Rotor Angles for Three Phase Fault on TL202 at SDD with LIL at 700 MW and BDE to SSD Flow at 350 MW

The preliminary transient stability analysis of the existing Island Interconnected System with the LIL and the synchronous condensers at Soldiers Pond added indicates that in order to maintain system stability and avoid violation of the transmission planning criteria, the loading on the LIL must be limited to no more than a 657 MW import at SOP and the power flow from Bay d'Espoir to Sunnyside via TL202 and TL206 must not exceed 350 MW. Given these limitations, the Island Interconnected System cannot be operated to supply the peak loads as described in the base cases. Clearly, additions and/or modifications to the existing Island Interconnected System are required to ensure the transmission planning criteria are met for all anticipated loading conditions.

6.3.2 Transient Analysis of Proposed Steady State Modifications

The load flow analysis identified a number of Island Interconnected System additions/modifications that, if implemented, would ensure the steady state transmission planning criteria are not violated including:

- 50% series compensation of TL202 and TL206;
- Reroute of TL202 and TL206 around Sunnyside Terminal Station and connection to the two new 230 kV transmission lines terminating at Western Avalon with series compensation; or
- Construction of a new 230 kV transmission line between Bay d'Espoir and Western Avalon.

Each addition was tested to assess the ability of the proposed system additions and/or modification to maintain system stability following system disturbances.

6.3.2.1 Series Compensation of TL202 and TL206

Load flow analysis demonstrated improved transfer capabilities of the Island Interconnected System if TL202 and TL206 were to be thermally uprated, TL203 were to be rebuilt and 50% series compensation was added to both TL202 and TL206. Series compensation would be added to each of TL202 and TL206 at a location west of Sunnyside Terminal Station where the 138 kV transmission line TL212 and TL219 leave the 230 kV transmission line right-of-way. For identification purposes, the series compensation location is named Piper's Hole (PHL).

While the proposed modifications demonstrated improved voltage levels and reactive power support in the Sunnyside area for steady state load flow solutions, transient stability analysis found that the application of series compensation does not permit stable operation of the system in all cases and contingencies. Simulation of a three phase fault at PHL with

subsequent tripping of the faulted 230 kV transmission line (i.e. TL202 or TL206) was found to result in instability. Simulation of this contingency revealed that the system would not maintain angular stability in the post fault recovery period. Figure 6.6 provides the relative rotor angle plot for a number of generators on the Island Interconnected System. The divergence in the machine rotor angles indicates angular instability.

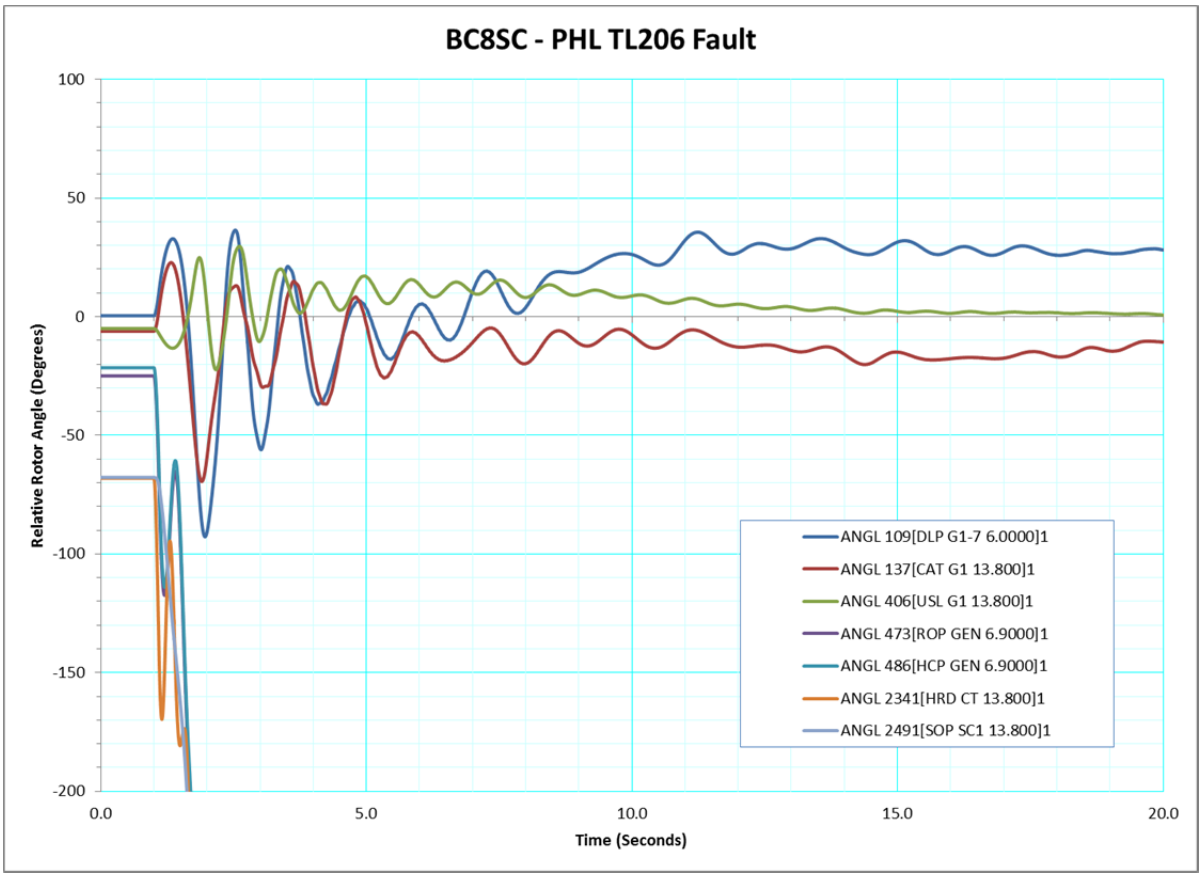


Figure 6.6 - Spring/Fall Day (BC8) – 50% Series Compensation – Three Phase Fault on TL206 at PHL – Relative Rotor Angles (Degrees

In an attempt to improve the response of the system under the 50% series compensation alternative, a 300 MVAR Static VAR Compensator (SVC) was added at SSD and the number of high inertia synchronous condensers at SOP increased to 7 x 175 MVAR (six in service). Simulation of the three phase fault at PHL with tripping of TL206 resulted in angular stability being maintained, but with system oscillations lasting approximately ten seconds following

the event. Figure 6.7 provides the rotor angle plot of the contingency for a three phase fault on TL206 at PHL during the winter peak load case.

With respect to the duration of the oscillation, NPCC Directory #1, Appendix A defines an unacceptable system dynamic response as:

> *An oscillatory response to a contingency that is not demonstrated to be clearly positively damped within 30 seconds of the initiating event.*[13]

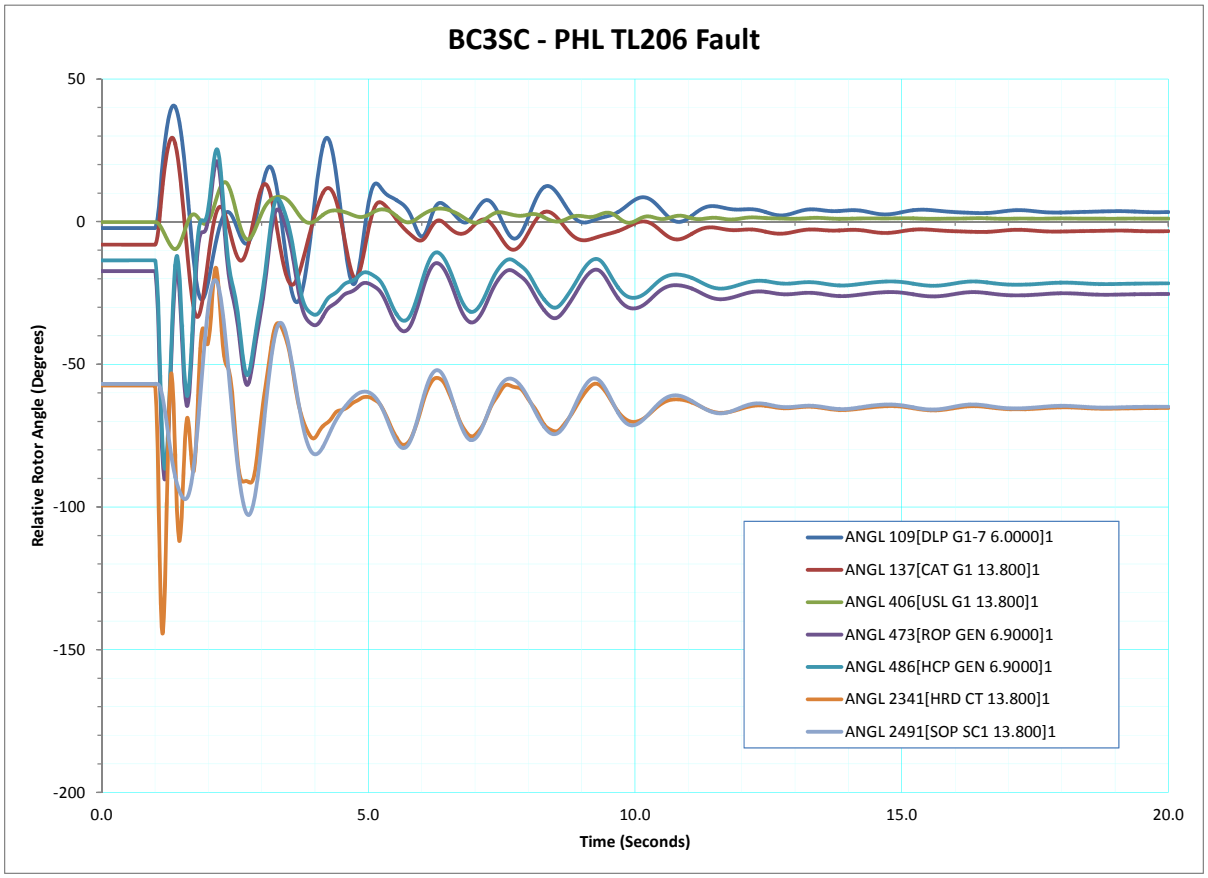


Figure 6.7 - Winter Peak (BC3) – TL202/206 50% Series Compensation - SSD 300 MVAR SVC – 7 x 175 MVAR Synchronous Condensers at SOP – Three Phase Fault TL206 at SSD – Relative Rotor Angles (Degrees)

[13] NPCC Regional and Reliability Reference Directory #1 – Design and Operation of the Bulk Power System, December 01, 2009, Appendix A page 5-6.

However, while stability is acceptable Figure 6.8 highlights severe and unacceptable over-voltages at the WAV and SSD 230 kV buses during the fault on TL206. The voltage spike is attributed to the substantial injection of reactive power by the SVC during the fault. This level of overvoltage can initiate other faults via flashover to ground or across open protective devices, such as disconnect switches particularly in adverse weather conditions, theoretical loss of life on insulated systems such as transformers and other equipment and is not acceptable from an equipment or safety perspective.

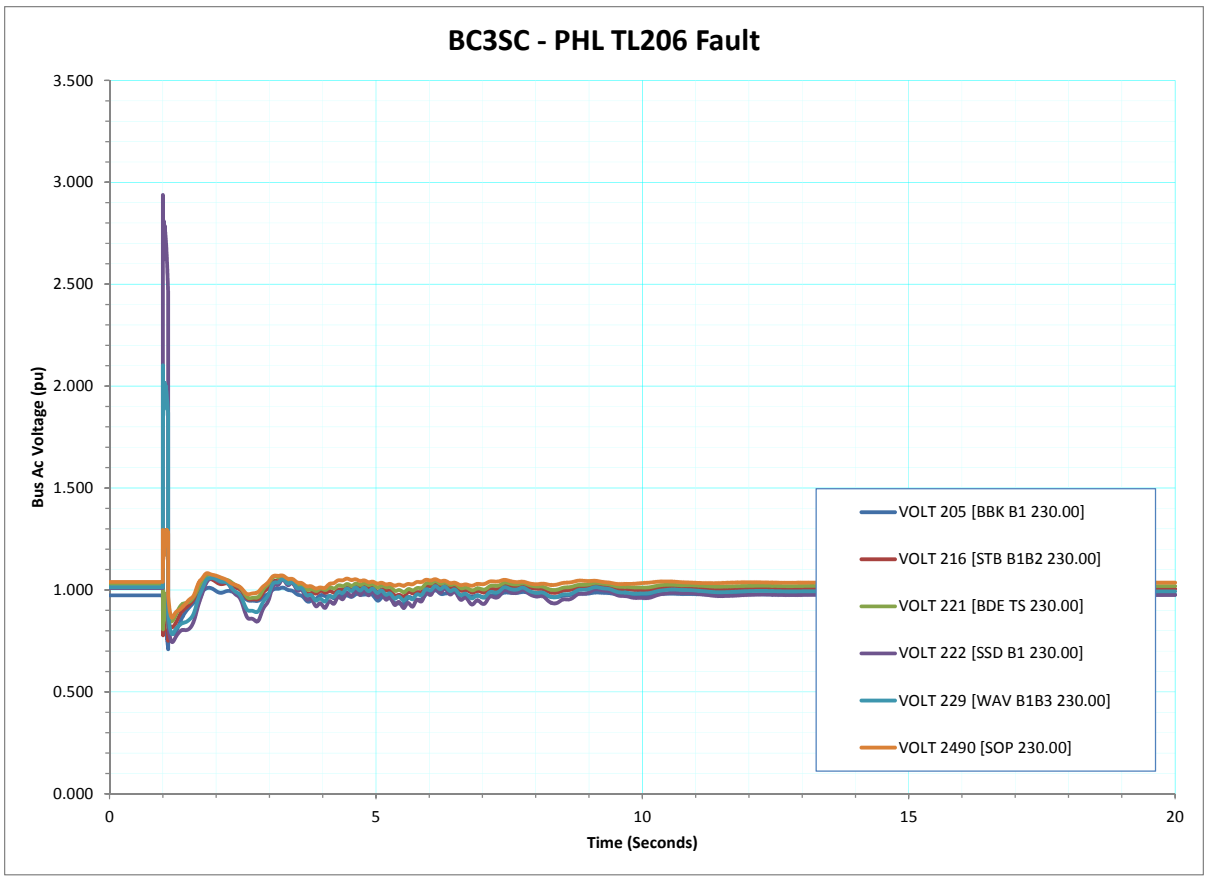


Figure 6.8 - Winter Peak (BC3) – TL202/206 50% Series Compensation at PHL, 300 MVAR SVC at SSD, 7 x 175 MVAR Synchronous Condensers at SOP – Three Phase Fault TL206 at SSD – 230 kV Bus Voltages (per unit)

Evaluation of the base cases with the LIL in monopolar mode revealed that angular stability cannot be maintained even with the addition of a 300 MVAR SVC at SSD and seven 175 MVAR synchronous condensers at SOP. Figure 6.9 provides the relative rotor angle plot.

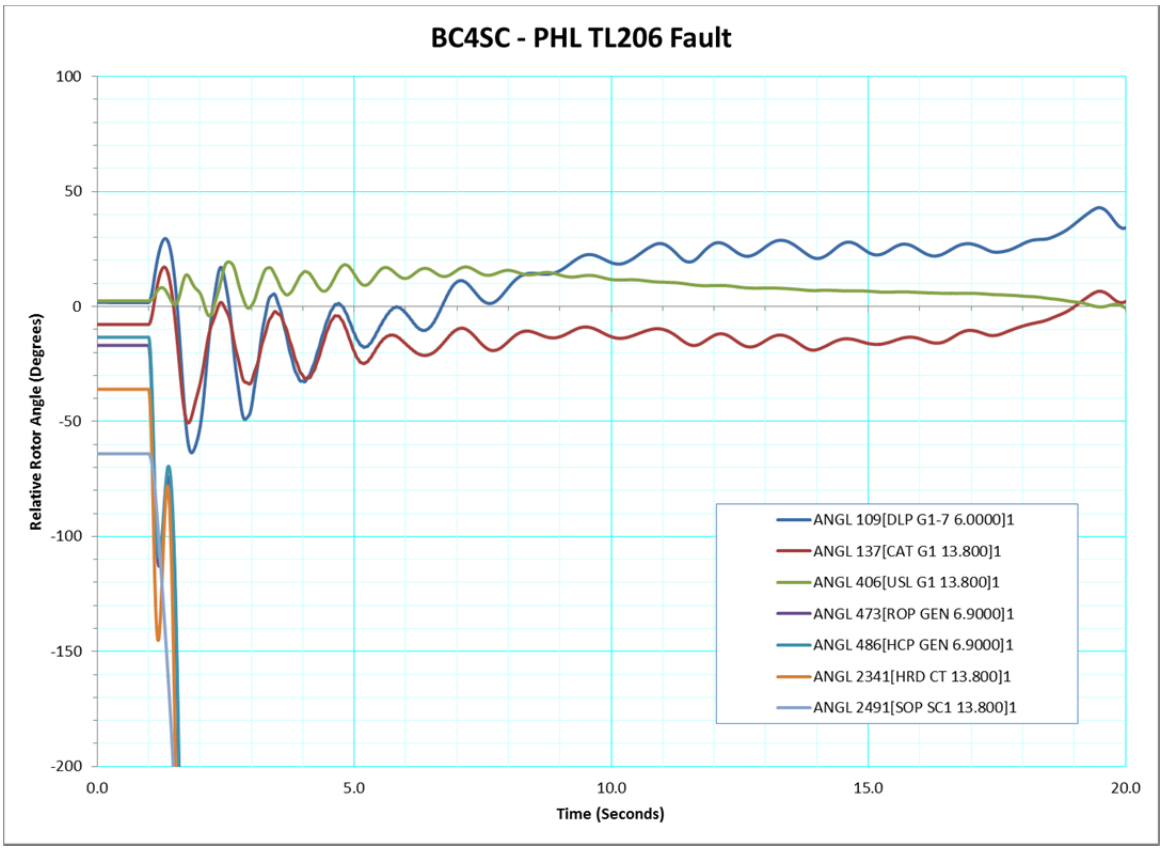


Figure 6.9 - Winter Peak LIL in Monopolar Mode (BC4) – TL202/206 50% Series Compensation - SSD 300 MVAR SVC – 7 x 175 MVAR Synchronous Condensers at SOP – Three Phase Fault TL206 at PHL – Relative Rotor Angles (Degrees)

Consequently, the application of 50% series compensation to TL202 and TL206, along with thermal uprate of TL202 and TL206 and rebuild of TL203 is not a technically viable alternative to ensure system stability is maintained following the addition of the LIL to the Island Interconnected System. Even with the additions of a SVC at SSD and additional synchronous condensers it is not technically acceptable.

6.3.2.2 Reroute of TL202 and TL206 Around Sunnyside

The load flow analysis demonstrated improved transfer capabilities if TL202 and TL206 were rerouted around Sunnyside and re-terminated at the Western Avalon Terminal Station. This alternative requires thermal up-rating of both TL202 and TL206 along with the construction

of two new 230 kV transmission lines, 45 km each, from Western Avalon towards Sunnyside to complete the re-termination of TL202 and TL206. Series compensation is added to TL202 and TL206 at Piper's Hole. In order to avoid unacceptable over voltages at the Western Avalon Terminal Station 230 kV bus during normal operation, the series compensation is limited to 25% for each transmission line.

Transient stability analysis indicated that a three phase fault on TL202 or TL206 at WAV followed by tripping of the faulted line would result in angular instability. Figure 6.10 provides the relative rotor angle plot for a number of generators on the Island Interconnected System. The divergence in the machine rotor angles indicates angular instability.

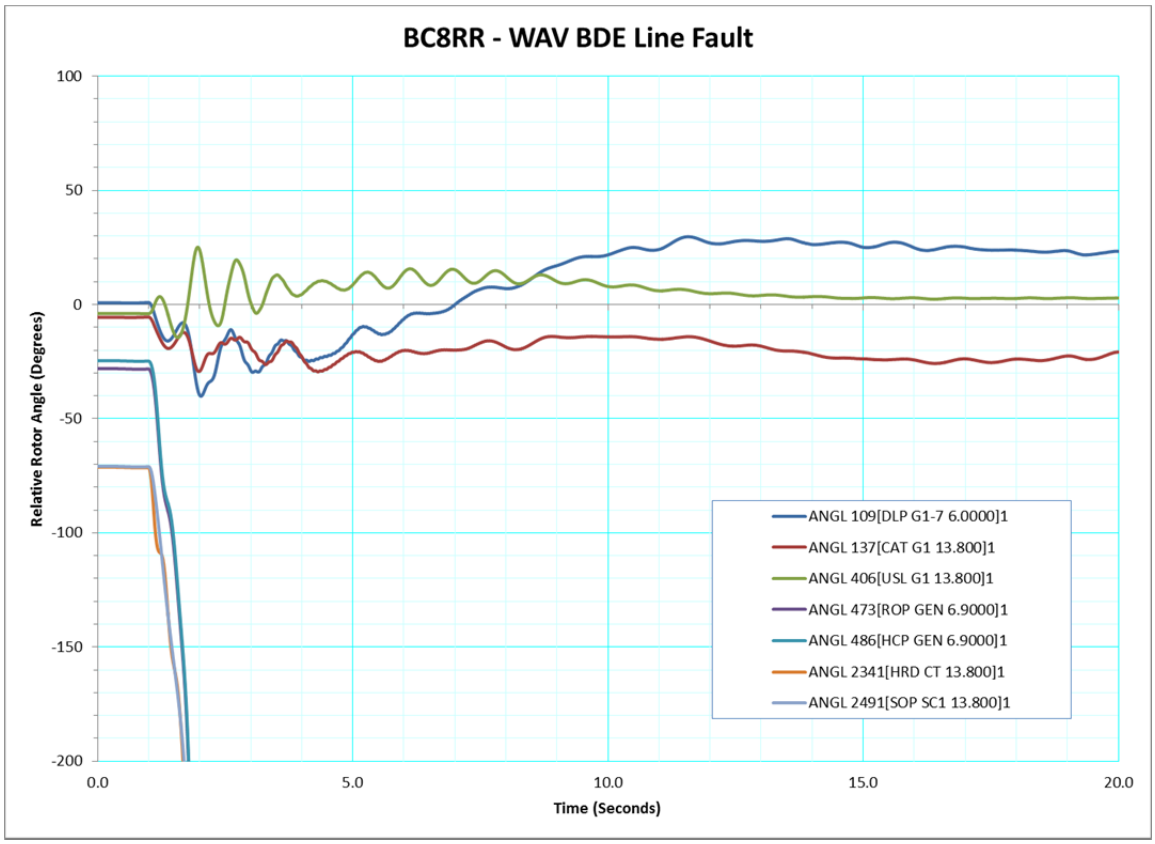


Figure 6.10 - Spring/Fall Day (BC8) – TL202/206 Reroute - Three Phase Fault TL206 at WAV – Relative Rotor Angles (Degrees)

In an attempt to improve the response of the system under the TL202/206 reroute with 25% series compensation alternative, a 300 MVAR SVC was added at WAV and the number of high inertia synchronous condensers at SOP increased to 7 x 175 MVAR (six in service). Simulation of the three phase fault at PHL with tripping of the rerouted TL206 resulted in angular stability being maintained, but with system oscillations lasting approximately 15 seconds following the event. Figure 6.11 provides the relative rotor angle plot of the contingency.

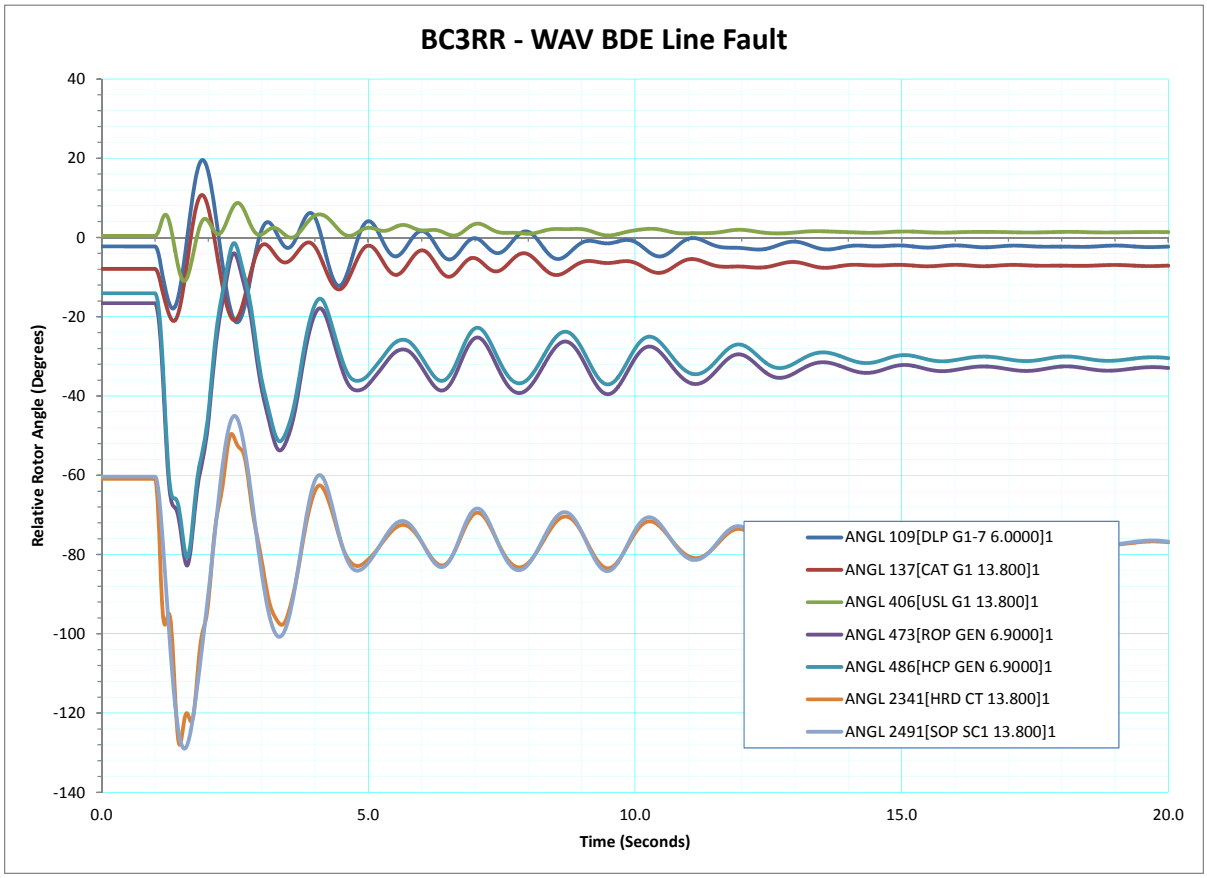


Figure 6.11 - Winter Peak (BC3) – TL202/206 Reroute - 25% Series Compensation - WAV 300 MVAR SVC – 7 x 175 MVAR Synchronous Condensers at SOP – Three Phase Fault TL206 at PHL – Relative Rotor Angles (Degrees)

Figure 6.12 demonstrates that the over-voltages experienced in the TL202/206 50% series compensation alternative are not present in the TL202/206 reroute alternative.

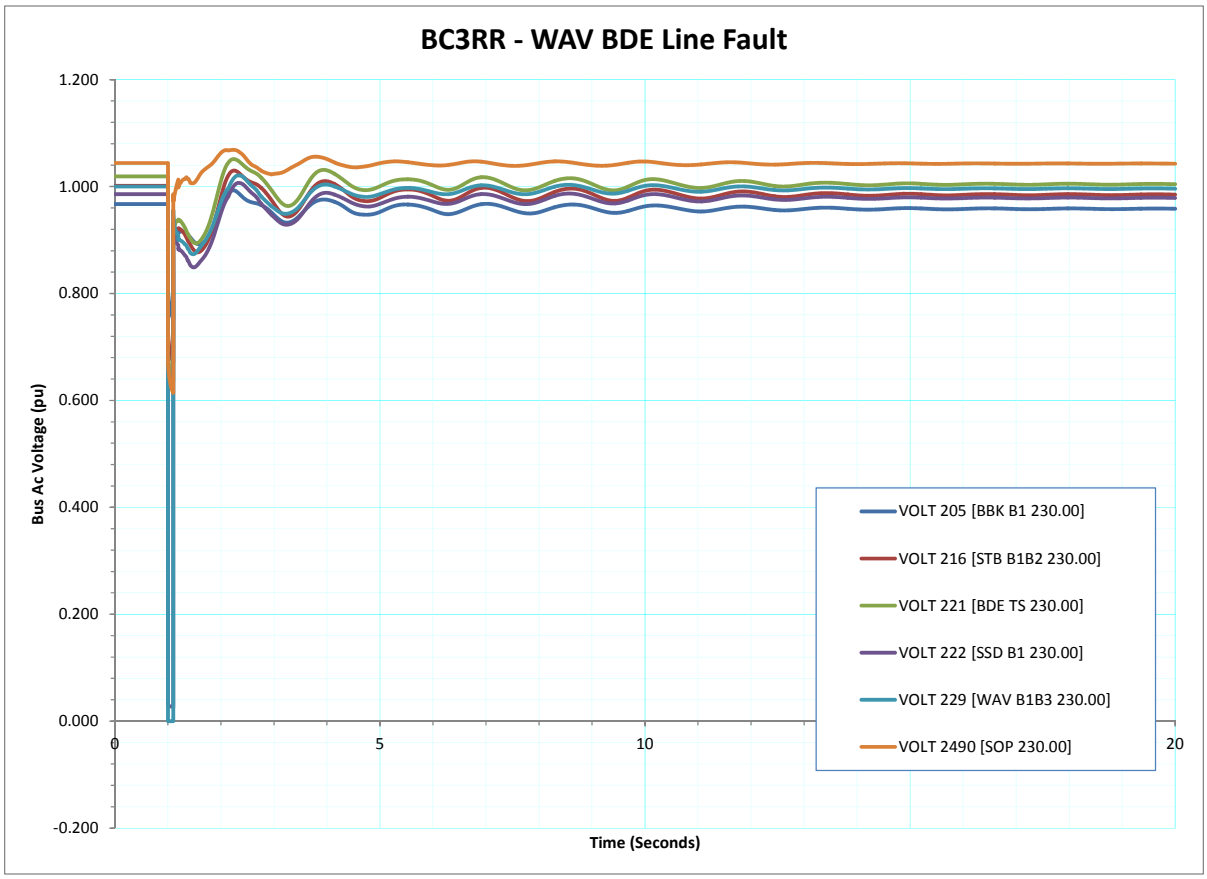


Figure 6.12 - Winter Peak (BC3) – TL202/206 Reroute 25% Series Compensation - WAV 300 MVAR SVC – 7 x 175 MVAR Synchronous Condensers at SOP – Three Phase Fault TL206 at PHL – 230 kV Bus Voltages (per unit)

However evaluation of the base cases with the LIL in monopole mode revealed that angular stability cannot be maintained even with the addition of a 300 MVAR SVC at WAV and seven 175 MVAR synchronous condensers at SOP in the TL202/206 reroute alternative. Figure 6.13 provides the rotor angle plot.

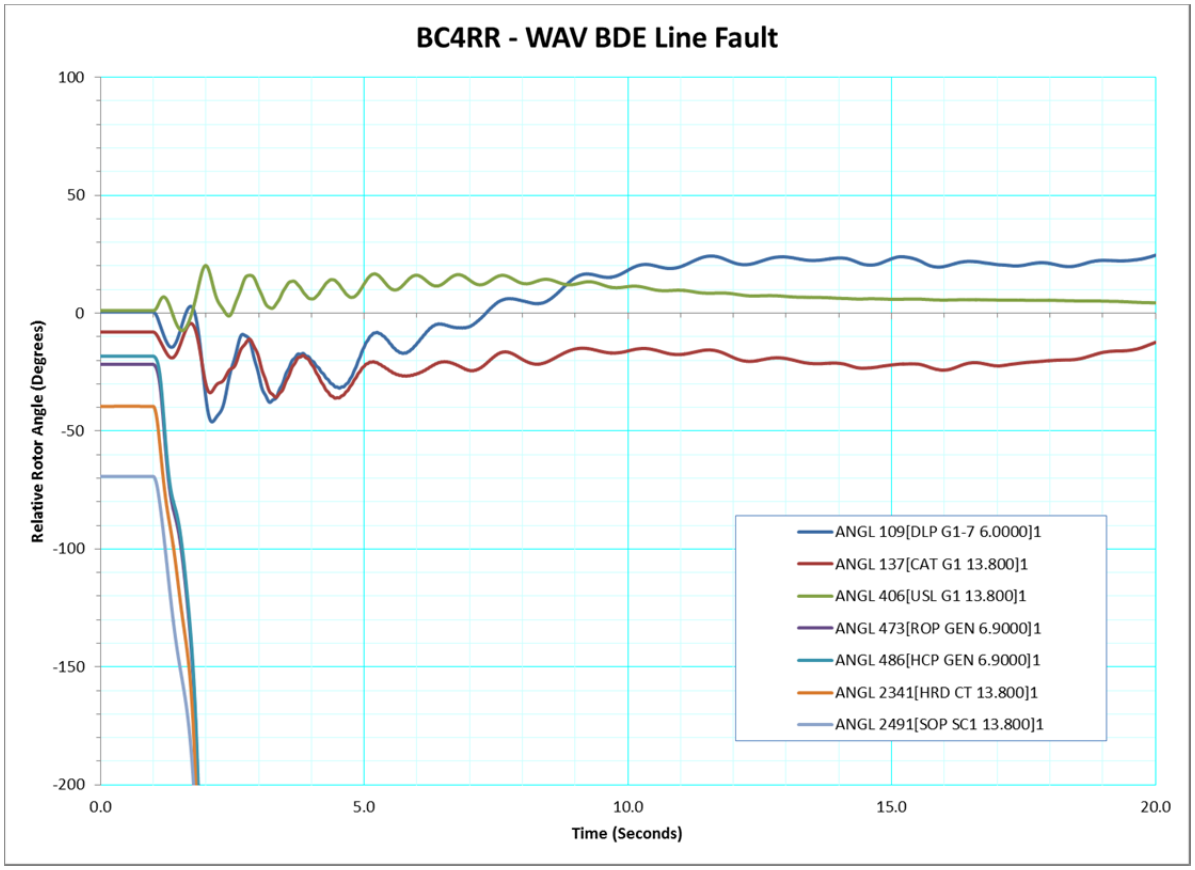


Figure 6.13 - Winter Peak LIL in Monopolar Mode (BC4) – TL202/206 Reroute 25% Series Compensation – WAV 300 MVAR SVC – 7 x 175 MVAR Synchronous Condensers at SOP – Three Phase Fault TL206 at PHL – Relative Rotor Angles (Degrees)

Consequently, the reroute of TL202 and TL206 around Sunnyside to Western Avalon with 25% series compensation is not a technically viable alternative to ensure system stability is maintained following the addition of the LIL to the Island Interconnected System.

A sensitivity analysis was completed to determine if system stability could be maintained for system contingencies if only one 230 kV transmission line (TL202) was rerouted around Sunnyside. The transient stability analysis determined that this system configuration would not provide a technically viable alternative. Analysis of base cases indicated that a three phase fault at the TL202 series compensation location (PHL) resulted in a loss of stability. With the LIL in bipolar mode, a stable response to the contingency was demonstrated with the addition of a 300 MVAR SVC at WAV and seven 175 MVAR high inertia synchronous

condensers at SOP (six in service). With these system additions the system displayed oscillations that were sustained for approximately 15 seconds. With the LIL in monopolar mode of operation, the addition of a 300 MVAR SVC at WAV and seven 175 MVAR synchronous condensers at SOP were found to be inadequate to maintain system stability for faults on the rerouted TL202.

6.3.2.3 New 230 kV Transmission Line Bay d'Espoir to Western Avalon

The load flow analysis demonstrated that the addition of a new 188 km, 230 kV transmission line between Bay d'Espoir and Western Avalon provided the necessary steady state transfer capacity between BDE and the Avalon Peninsula while eliminating the prospective thermal overloads on TL202, TL206, TL203, TL207 and TL237 and the voltage collapse issues observed for a number of the single contingency outages in steady state.

Transient stability analysis demonstrated that the addition of the 188 km long transmission line between Bay d'Espoir and Western Avalon Terminal Stations results in angular stability being maintained in the post fault recovery period for the contingencies in most base cases. For the future peak load case (BC1) and cases with more than 550 MW being transferred between Bay d'Espoir and the Avalon Peninsula (BC3) the transient stability analysis determined that with only two high inertia synchronous condensers in service at Soldiers Pond the system would not maintain angular stability for a three phase fault on TL206 at Sunnyside. Figure 6.14 provides the rotor angle plot. Further analysis of the cases determined that with all three high inertia synchronous condensers in service at Soldiers Pond angular stability is maintained for the three phase fault on TL206 at Sunnyside during peak load conditions with more than 550 MW transferred between Bay d'Espoir and Western Avalon. Figure 6.15 provides the rotor angle plot.

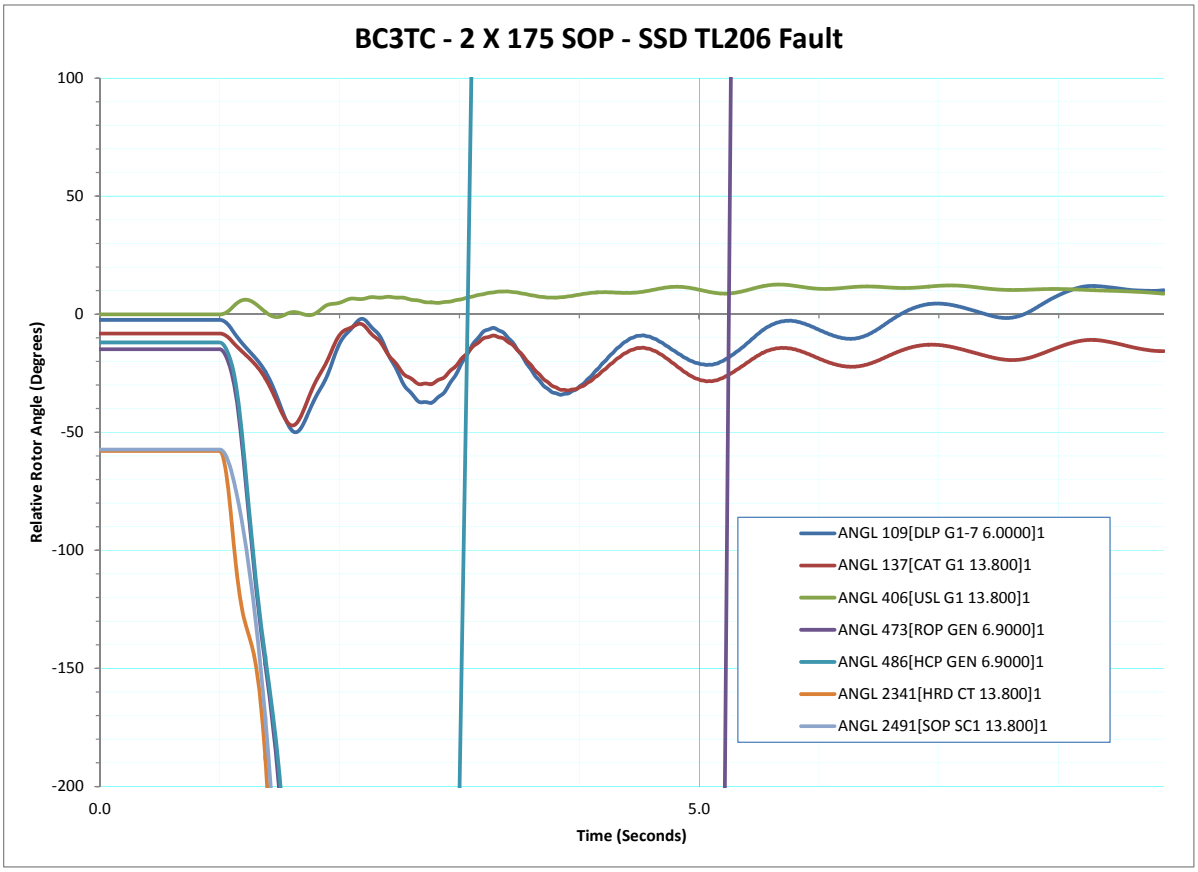


Figure 6.14 - Winter Peak LIL in Bipolar Mode (BC3) – 230 kV Line BDE to WAV – 2 x 175 MVAR Synchronous Condensers at SOP – Three Phase Fault TL206 at SSD – Relative Rotor Angles (Degrees)

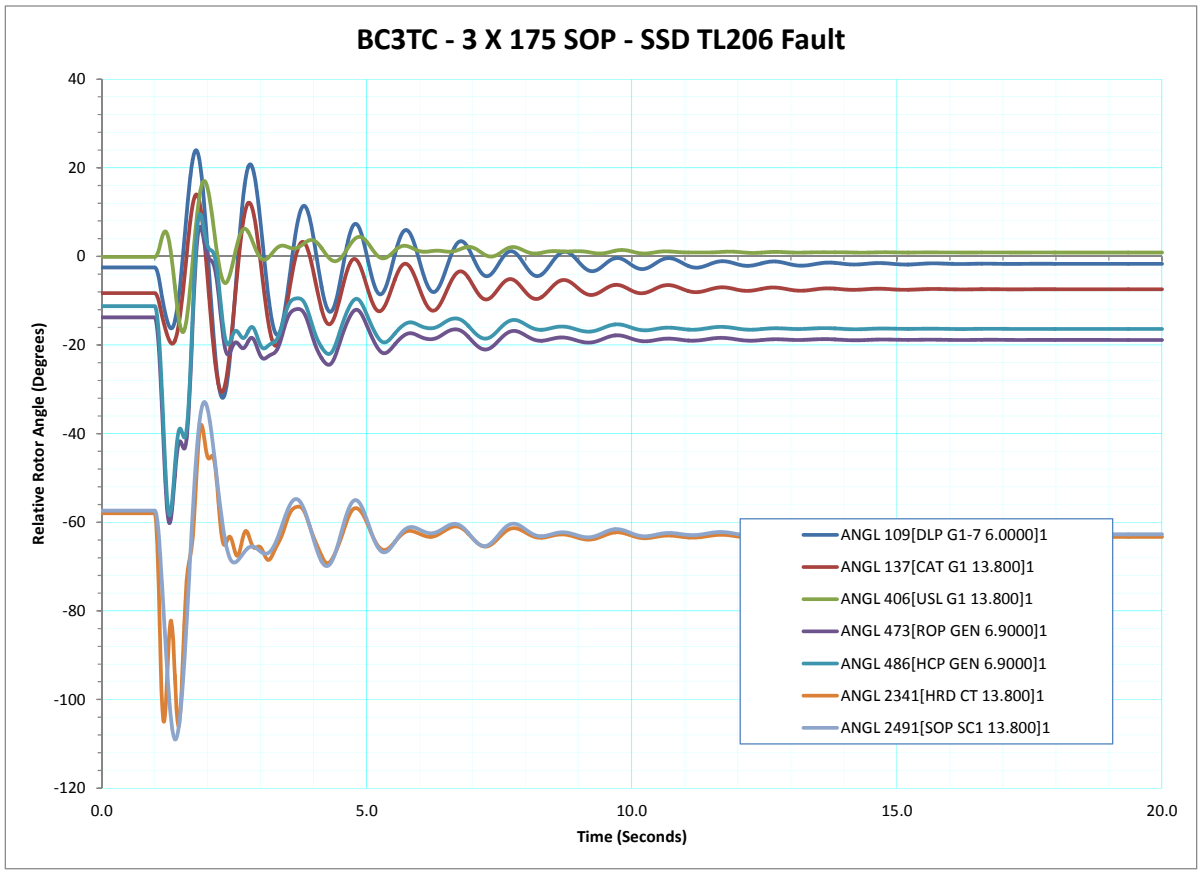


Figure 6.15 - Winter Peak LIL in Bipolar Mode (BC3) – 230 kV Line BDE to WAV – 3 x 175 MVAR Synchronous Condensers at SOP – Three Phase Fault TL206 at SSD – Relative Rotor Angles (Degrees)

Indexed transient stability plots for all base cases and associated contingencies are provided in Appendix B.

While the Maritime Link (ML) is not included in this analysis, on November 29, 2013 the Nova Scotia Utility and Review Board approved the Maritime Link Project. With the ML in service at Bottom Brook Terminal Station on the west coast of the island exporting 158 MW to Nova Scotia during peak load periods, the transient stability analysis demonstrated that the island system would remain stable for a three phase fault on TL206 at Sunnyside with only two high inertia synchronous condensers in service at Soldiers Pond. Figure 6.16 provides the rotor angle plot for the contingency with the ML in service.

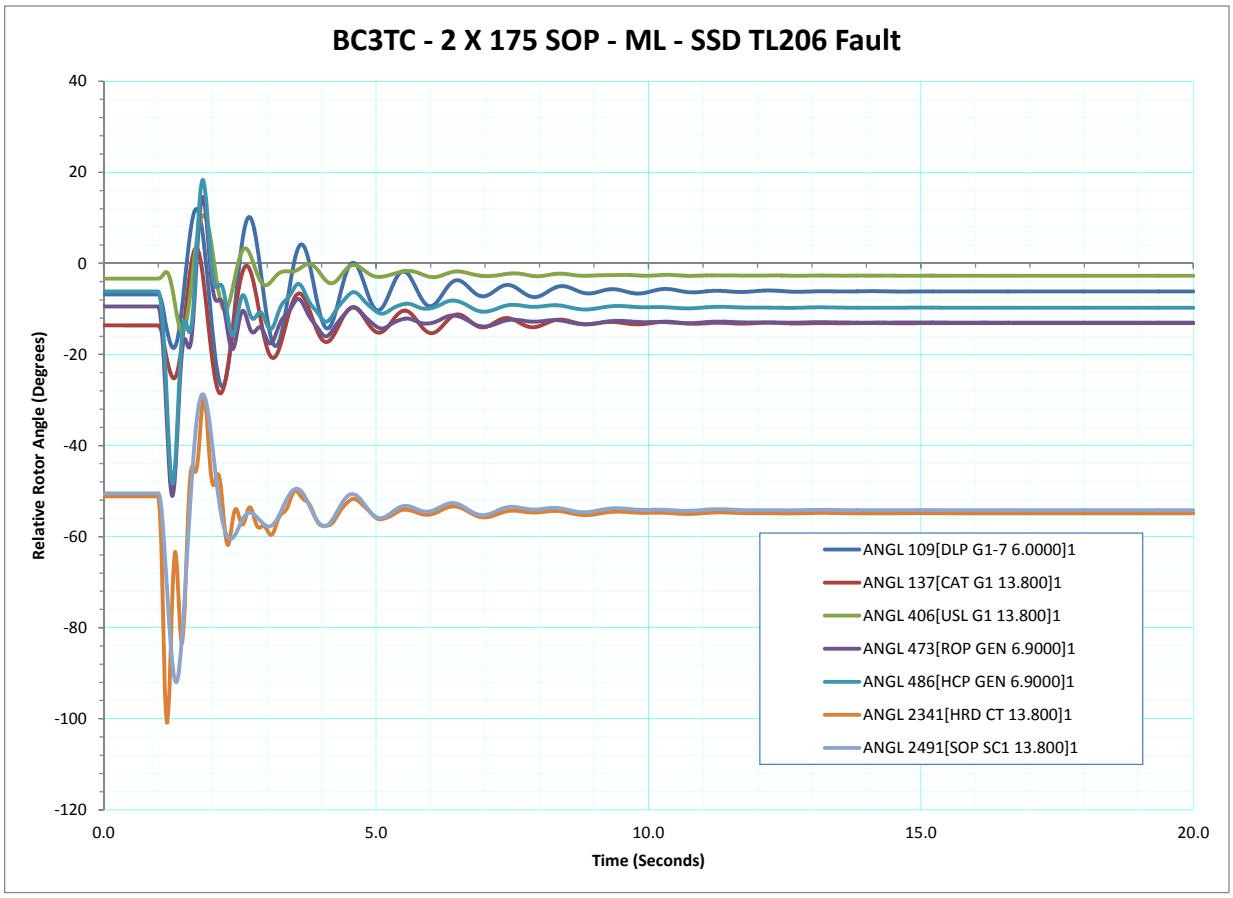


Figure 6.16 - Winter Peak LIL in Bipolar Mode (BC3) – ML In Service - 230 kV Line BDE to WAV – 2 x 175 MVAR Synchronous Condensers at SOP – Three Phase Fault TL206 at SSD – Relative Rotor Angles (Degrees)

6.3.2.4 Increasing the Soldiers Pond Synchronous Condenser Size

Increasing the size and number of the Soldiers Pond high inertia synchronous condensers was found to improve transfer capability of the system in steady state for a number of load flow transmission line contingencies. Transient stability analysis for both the 50% series compensation alternative and TL202/206 reroute alternative revealed that even with the addition of a 300 MVAR SVC in the SSD/WAV region and seven 175 MVAR synchronous condensers at SOP, system stability could not be maintained for three phase faults on 230 kV transmission lines between BDE and WAV with the LIL in monopolar mode. Consequently, increasing the number of synchronous condensers at SOP would not provide a technically viable alternative on its own.

6.3.3 230 kV Transmission Line Maintenance Considerations

At present, 230 kV transmission lines in the Bay d'Espoir to Western Avalon corridor are critical to the reliable supply of power to the Avalon Peninsula. The existing configuration has two parallel paths between BDE and WAV with intermediate stations at SSD and CBC. Removal of one line from service for maintenance leaves one connection between the hydroelectric generation and the Avalon load center. This has the potential to increase the risk of an outage, or, in other words, reduce overall reliability for the Avalon Peninsula. To reduce the risk of an outage to customers, Hydro maintains the transmission lines in the BDE to WAV corridor during the spring and fall seasons after the summer lightning season and before the potential for freezing rain and winter storms. In addition, during the spring and fall seasons, units at HTGS are available to support the Avalon load during the line maintenance if required.

Transient stability analysis of the system with the LIL added and only two 230 kV transmission lines between BDE and the Avalon Peninsula (either the TL202/206 50% series compensation alternative or the TL202/206 reroute alternative) revealed that in order to maintain system stability following the loss of TL206, the flow on TL206 at BDE must be limited to no more than 50 MW while TL202 maintenance is being performed. The remainder of the load east of BDE must be supplied by the LIL. Given a minimum hydraulic generation limit of 350 MW on the island for water flows and voltage control, maintenance on the BDE to WAV corridor would be limited to periods when the load west of BDE is equal to, or greater than, 300 MW. With the load west of BDE being approximately 33% of the total system load, a BDE west load of 300 MW equates to a system load of approximately 910 MW. Based upon the system load shape, scheduling of maintenance in the BDE to WAV corridor with system loads consistently above 910 MW for a two week maintenance window (necessary should one or more structures need to be repaired or replaced) would be confined to the peak load season from mid-November through to the end of March. Consequently, from a transmission line maintenance perspective, a transmission system

configuration that has only two 230 kV transmission lines between Bay d'Espoir and the Avalon Peninsula following the addition of the LIL is undesirable and, in fact, unacceptable as maintenance of these assets must be completed - additional major risk is assumed and major outages more likely.

Transient stability analysis with the new BDE to WAV transmission line added revealed that the power flow on the BDE east transmission lines must not exceed 350 MW with one line out of service for maintenance (i.e. TL202, TL206 or new BDE to WAV) if system stability is to be maintained for a fault on one of the two in service lines during the line maintenance. The transient stability analysis indicates that the transfer limit on the 230 kV transmission lines east of BDE under line maintenance conditions can be increased from 50 MW to 350 MW with the addition of the BDE to WAV line. This 300 MW increase eliminates the dependencies on the minimum hydraulic generation levels as the entire minimum hydraulic generation level could be delivered to the Avalon Peninsula under the maintenance condition without consideration given to the system load west of Bay d'Espoir. As a result, the addition of the new 230 kV transmission line between BDE and WAV permits maintenance on any of the transmission lines in the BDE to WAV corridor for a considerably wider maintenance window. Depending on status of other lines and generation it could be virtually any time during the year. Consequently, the addition of the proposed BDE to WAV 230 kV transmission line provides a considerable improvement in availability with respect to line maintenance scheduling.

6.3.4 Status of Synchronous Condensers

This analysis has been completed assuming the addition of a CT with synchronous condenser capabilities at Holyrood. It is recognized that the CT proposal currently before the Board does not necessarily have synchronous condenser capability and no combustion turbine addition has yet been approved by the Board. The need for additional reactive power support in the form of synchronous condenser capability has been considered throughout this analysis. While the underlying assumption in completing the analysis has

been that a Holyrood CT is added, the approval of the project identified in this report is not dependent on the Holyrood CT proposal. Following the conclusion of the combustion turbine proposal and before the HVdc interconnection is placed into service, the MVAR requirements will be refined and addressed. This will not affect the justification for the third circuit from BDE to WAV.

6.3.5 Impact of the Maritime Link

Most of the analyses completed as part of this system study has purposefully not considered the impact that the Maritime Link would have had on the Island Interconnected System additions and/or modifications. As a result, the study provides the impact directly attributed to the addition of the Labrador – Island HVdc Link.

On November 29, 2013 the Nova Scotia Utility and Review Board approved the Maritime Link Project. The Maritime Link (ML) requires the construction of a ±200 kV, 500 MW HVdc transmission link between Bottom Brook Terminal Station in western Newfoundland and Woodbine Substation in Cape Breton, NS. On the Island Interconnected System, Emera Newfoundland Limited (owner of the ML) will be constructing a new 230 kV transmission line between Granite Canal and Bottom Brook to provide sufficient transfer capacity for the ML. The addition of the ML provides Hydro with the opportunity to access power and energy from the North American market during an unforeseen outage to the LIL. Based upon existing transmission line capacity in the Maritimes, up to 300 MW can be exported from NS to NL under a LIL contingency. In order to transfer the 300 MW of power from NS to the Avalon Peninsula load center during a LIL outage, in addition to existing off Avalon Peninsula hydro resources, the new 230 kV transmission line between Bay d'Espoir and Western Avalon is required. Without this new transmission line, imports from Nova Scotia during a LIL outage will be limited.

Further, transient stability analysis of the addition of the ML with scheduled export of the Nova Scotia block (158 MW at Bottom Brook Terminal Station) reveals that only two high

inertia synchronous condensers are required to be in service at all times at Soldiers Pond under the BDE to WAV line alternative. This will not impact the need for the new line but simply add to the merits that a new line will add to the system in terms of operational flexibility and security particularly in contingency operating scenarios. Given that the ML has been sanctioned, the analysis has demonstrated that the new 230 kV transmission line between Bay d'Espoir and Western Avalon with two 175 MVAR high inertia synchronous condensers in service at Soldiers Pond (with 3 x 175 MVAR in total installed) is sufficient to ensure Island Interconnected System stability.

6.3.6 Summary of Transient Stability Analysis

Table 6.5 provides a summary of the transient stability analysis.

Table 6.5: Summary of Transient Stability Analysis

Island Upgrade Alternative	Comments	Stable Operation
Exiting System with LIL	LIL added with 3 x 175 MVAR Synchronous condensers at SOP	Unstable for SSD 3 phase faults with island generation @ 1085 MW
50% Series Compensation TL202/206	Thermal Uprate TL202/206 Rebuild of TL203 included	Unstable for 3 phase faults at PHL
	Add 300 MVAR SVC at SSD plus Total of 7 x 175 MVAR synchronous condensers at SOP	Unstable for 3 phase faults at PHL with LIL in monopolar mode
TL202/206 Reroute	Thermal Uprate TL202/206 25% series compensation	Unstable for 3 phase faults at PHL
	Add 300 MVAR SVC at SSD plus Total of 7 x 175 MVAR synchronous condensers at SOP	Unstable for 3 phase faults at PHL with LIL in monopolar mode
BDE to WAV 230 kV Line		Stable for all planned contingencies in all base cases. Future peak and load cases with more than 550 MW transfer BDE east requires 3rd SOP synchronous condenser in service, however the presence of the Maritime Link mitigates the need of the third synchronous condenser being in service.

6.4 System Study Conclusions

The load flow and transient stability analyses of the Island Interconnected System following the addition of the Labrador - Island HVdc Link indicate that the addition of a new 230 kV transmission line between Bay d'Espoir and Western Avalon Terminal Stations is required to meet the transmission planning criteria and to maintain a reliable power system capable of withstanding expected transient events. The alternatives of increasing synchronous condenser capability at SOP, increasing thermal ratings on TL202, TL206 and TL203 along with series compensation of TL202 and TL206 or re-routing of TL202 and TL206 around SSD for connection to WAV with series compensation do not meet the transmission planning criteria as they are unstable or experience unacceptable overvoltages for normally expected transient events.

As the assumptions in this review are key to the outcome, it is important to consider items that would impact the outcome. Any major changes in the future power and energy requirements may necessitate completing other projects, such as upgrading or replacing lines or the addition of series compensation. If this is the case, the future changes will be evaluated as required and the technically and economically preferred option will be put forward for consideration. A third circuit from Bay d'Espoir to Western Avalon would be a major addition to the island grid bringing benefits that positively affect the overall reliability of the grid in normal and contingency operations and allows a high level of flexibility for economic dispatch through normal and contingency operations. Furthermore, with the Maritime Link now sanctioned, it affords more flexibility and security to the system as alternate generation supply sources may be provided for normal and contingency generation planning.

The parallel circuit system currently in place was effectively completed by 1968, almost 50 years ago, and now the appropriate time has come to increase the corridor capability by adding this essential asset. The eastern part of the grid connects the existing major

renewable generation sources in the central and western areas of the province to the major growth areas in the east. This situation has been compounded by the loss of major loads in the central and western areas of the province in the paper industry. As well, in the case of the Grand Falls paper operation, additional generation has been made available. The only investment done to date to aid that increase was the capacitor bank at Come by Chance. The proposed line addition will greatly enhance energy transport to the east but, more significantly, it allows system performance to meet the criteria used for planning and ensure a more reliable operation of the system with the addition of the HVdc infeed at Soldiers Pond.

7.0 COST BENEFIT ANALYSIS

The transmission planning studies identified a single technically viable alternative to meet the transmission planning criteria following the addition of the 900 MW, ± 350 kV, Labrador – Island HVdc Link to the Island Interconnected System. The technically viable alternative requires the construction of 188 km of 230 kV transmission line between Bay d'Espoir and Western Avalon Terminal Stations, and the addition of circuit breakers and disconnect switches at each station to facilitate the termination and reliable operation of the transmission line. The total estimated cost of the Bay d'Espoir to Western Avalon transmission line addition is $291.7 million.

There are other unquantified benefits of a new line, such as the reduction of losses. A new line will reduce losses whereas the other options would actually increase losses in the transmission system in terms of higher line losses, losses associated with friction and windage on rotating equipment and other losses associated with static equipment. The actual reduction in demand losses will vary depending on the generation dispatch. For example, the difference in the case of 200 MW on LIL with the existing system and the proposed line (Figure 352 and Figure 354 respectively of Appendix A) is 26.5 MW. In cases where LIL loading is much higher, the loss reduction is less as the BDE WAV corridor is lightly

loaded and was 11.6 MW (Figure 348 and Figure 350 respectively of Appendix A). While loss reduction is a positive benefit, the primary need for the line is to allow transition to a new steady state condition following contingencies without collapsing the system. Further, a line that bypasses Sunnyside also aids reliability in that if there were major issues at Sunnyside there would be a high capacity circuit through the Isthmus of Avalon that would be unaffected by such issue.

With respect to the east west loading, while LIL will have a major impact on the typical flow of power generally, the loss of the highest rated line east from Bay d'Espoir at an ambient temperature of 0 ˚C will still leave 739 MW (versus the current 369.5 MW) of line capacity east before thermal overload concerns. This moves the thermal capacity east from 42% as noted in section 2 to 84% and implies a more robust system is needed to withstand contingencies and flexibility of generation dispatch.

Lastly, this line can be built independently of various upgrades and series compensation allowing less outages of existing assets to facilitate implementation and is a standard known technology with little if any technical issues or risk.

7.1 Conductor Selection

Conductors on existing Hydro 230 kV transmission lines on the Island Interconnected System include:

- 562.5 kcmil[14], 36/19[15], AACSR/EHS[16];
- 636 kcmil, 26/7, ACSR[17] "GROSBEAK";
- 636 kcmil, 30/19, ACSR "EGRET";
- 795 kcmil, 26/7, ACSR "DRAKE";
- 804 kcmil, 23/19, AACSR/TW[18] (795 kcmil ACSR electrical equivalent but mechanically stronger);
- 1192.5 kcmil, 54/19, ACSR "GRACKLE";
- 1376.6 kcmil, AAAC[19] (1192.5 kcmil ACSR electrical equivalent but no steel core); and
- 1431 kcmil, 54/19, ACSR "PLOVER".

The traditional conductors have been the ACSR type conductors with 795 kcmil and 1192.5 kcmil utilized on the more heavily loaded transmission lines and 636 kcmil used on the lighter loaded lines. The 562.5 kcmil conductor has been used in limited repair/redesign applications were an extra high strength (EHS) conductor is necessary to eliminate line failures associated with meteorological loading conditions beyond the original design loads (i.e. TL228 along the Buchans plateau). The 804 kcmil conductor has been utilized on the steel tower transmission lines on the Avalon Peninsula as part of the Avalon Transmission Upgrade Project and provides the necessary strength to avoid failure under the ice loads experienced on the Avalon Peninsula. The 1431 kcmil conductor found application as the

[14] kcmil is a unit of measure to describe the size of a conductor using the cross-sectional area of aluminum in the conductor. One circular mil (cmil) is the area of a circle 1 mil (0.001 inch) in diameter. The unit kcmil equals 1000 cmil. An alternate measure for kcmil is MCM with the M representing 1000 as per the Roman numeral system.

[15] 36/19 identifies the number of aluminum strands and steel strands in the conductor (i.e. #Al/#St). In this case, 36 strands of aluminum and 19 strands of steel.

[16] AACSR/EHS is an **A**luminum **A**lloy **C**onductor with **S**teel **R**einforced core. The steel core consists of **E**xtra **H**igh **S**trength steel.

[17] ACSR is an **A**luminum **C**onductor with **S**teel **R**einforced core. The core consists of steel strands.

[18] AACSR/TW is an **A**luminum **A**lloy **C**onductor with **S**teel **R**einforced core. There are two different aluminum alloys used, one in each layer. All the aluminum strands are shaped or formed as **T**rapezoidal **W**ires. The core consists of extra high strength steel strands.

[19] AAAC is an **A**ll-**A**luminum **A**lloy stranded bare **C**onductor. There is no steel core associated with this conductor. An AAAC conductor uses a different aluminum alloy (designated 6201-T81) than the ACSR conductor (designated 1350-H19). The **A**luminum **A**lloy **S**tranded **C**onductor (AASC) used the 6101-T81 aluminum alloy.

lowest cumulative present worth cost conductor (considering transmission line losses) during the construction of the third 230 kV transmission line at Holyrood.

In selecting a transmission line conductor for the proposed Bay d'Espoir to Western Avalon line, consideration must be given to a number of factors including, but not limited to:

- the impedance of the transmission line to ensure proper steady state and dynamic performance;
- the load current to be carried by the transmission line;
- existing transmission line conductors and spares inventory;
- the meteorological loading conditions along the route; and
- the economic impact of transmission line losses over the operational life of the transmission line.

From a meteorological loading condition perspective, a balance between strength and outside diameter will be required to withstand the prospective icing conditions, particularly on the Avalon Peninsula section of the route. Past practice with upgrades/repairs on the Avalon Peninsula would suggest that the 804 kcmil or 1192.5 kcmil conductors would be appropriate.

From a load current perspective, the proposed transmission line will be required to carry approximately 895 A under 30 °C ambient temperature conditions and approximately 1155 A at 0 °C ambient temperature. These load current requirements result in conductor temperatures in the 80 °C range for both the 795 kcmil and 804 kcmil conductors. Calculation of conductor temperature reveals that at 0 °C ambient temperature, a conductor current of 1155 A will result in a 636 kcmil conductor temperature of 105 °C[20].

[20] The Aluminum Association's "Aluminum Electrical Conductor Handbook" states at page 3-19: *"The usual maximum operating temperature for tensioned bare conductors is 70 °C to 85 °C, with 100 °C and over permissible only in limited emergencies".*

Further, the handbook indicates[21] that operation of an ACSR conductor at 100 °C for more than 1.5 hours is expected to result in degradation of the initial strength of the conductor. To ensure load currents do not impact upon the overall strength of the proposed conductor, application of the 636 kcmil size is not deemed to be prudent for this particular application. Consequently, based upon existing transmission line conductors and inventory, the minimum size conductor is set at 795 kcmil, 26/7, ACSR "DRAKE" or its electrical equivalent 804 kcmil, 23/19, AACSR/TW.

The technical analysis (steady state and dynamics) was completed assuming the 795 kcmil conductor size. The analysis demonstrated acceptable results, current ratings/line loading, voltage drop and angular stability with the 795 kcmil conductor.

In considering a larger conductor size, its benefit in terms of loss reduction would have to exceed the increased capital cost of installation as well as additional spares and associated cost. The traditional loss factor for these lines will change post LIL from a Hydro perspective and will actually decrease as more of the Avalon load will be supplied via LIL. This has the effect of less energy transfer from BDE thus lesser losses. In any case, the difference in the losses for Base Case 1 and Base Case 4 were reviewed and the load flow plots are included in Appendix A, Figure 348 to Figure 355. For example, the loss reduction on a lightly loaded LIL (200 MW in Figure 352 and Figure 354) dropped by 3.8 MW if a larger conductor was used. Similarly, in the case of a higher LIL load (672 MW in Figure 348 and Figure 350) the losses dropped 2.2 MW.

In terms of valuation, it was assumed that the loss factor is 50%, the value of losses (MWh) would increase at 2% per year with the starting energy value of $0.05 and $0.10 per kWh, and asset lives of 35 and 45 years were tested. This was tested for the Base Case 1 and Base Case 4 scenarios. The results indicate that the savings in energy losses for an initial energy value of $0.05 range from $8.0M to $15.0M for 35 and 45 years respectively. For an initial

[21] Figure 6.2.

energy value of $0.10 per kWh, the value ranges from $16.0M to $30.0M for 35 and 45 years respectively. If the loss factor dropped to 20%, the estimated maximum range noted ($8.0M to $30.0M) drops to $3.2M to $12.0M.

Given the incremental capital cost to build the line for the 1192.5 kcmil conductor is approximately $31M, there is no merit in Hydro considering a larger conductor over the current standard of 795 kcmil ACSR. If in the design stage a stronger conductor is required on sections of the line, then the electrically equivalent 804 kcmil AACSR/TW would likely be used, but this is a detail to be considered in the final design.

8.0 CONCLUSIONS

The load flow and transient stability analysis of the Island Interconnected Transmission System following the addition of the Labrador-Island HVdc Link, with or without the Maritime Link, determined that the addition of a new 230 kV transmission line between Bay d'Espoir and Western Avalon is required to maintain power system stability for the contingencies studied. This particular analysis primarily focused on a scenario that excluded the Maritime Link. The alternatives of increasing thermal ratings on TL202, TL206 and TL203, along with series compensation of TL202 and TL206, or re-routing of TL202 and TL206 around Sunnyside Terminal Station with re-connection at Western Avalon Terminal Station do not result in acceptable system performance for all base cases and contingencies considered. Hydro proposes to proceed with the construction of the 230 kV transmission line between Bay d'Espoir and Western Avalon with an in service date of May 01, 2018 to ensure power system stability during system disturbances on the Island Interconnected System following the Labrador-Island HVdc Infeed.

During this analysis, some thermal overloading was identified and will likely be the subject of future capital budget proposals. However, these future proposals do not affect the need for the third circuit or the associated analysis undertaken in support of the proposed transmission line addition.

9.0 PROJECT DESCRIPTION

The Upgrade Transmission Line Corridor – Bay d'Espoir to Western Avalon project will consist of a construction of a new 230 kV transmission line, 188 km in length, connecting Bay d'Espoir and Western Avalon Terminal Stations. This includes construction of a 230 kV steel tower transmission line as are the existing lines are from Bay d'Espoir, complete with overhead ground wire (OHGW) over its entire length. A minimum conductor size of 795 kcmil, 26/7, ACSR, "DRAKE" with a 75 ˚C conductor temperature rating or 804 kcmil, 54/19, AACSR/TW with an 80 ˚C conductor temperature is required to provide the necessary thermal rating for the new circuit.

The transmission line is planned to have OHGW throughout its length for lightning protection. TL206 was retro-fitted with lightning arrestors in 2001 to improve problematic lightning performance. An OHGW is more common and provides better overall protection than lightning arrestors as it shields the conductor from a lightning strike and is the normal method employed at 230 kV. The lightning arrestor simply reacts to a strike and effectively clips the voltage and energy associated with the strike. The OHGW will incorporate an optical fibre for protection and communication needs. The existing primary protection on the existing lines from BDE to SSD is by Power Line Carrier (PLC). Primary communications to Bay d'Espoir is microwave via Sandy Brook Hill near Grand Falls and future enhancements/replacement would likely use this fibre as it is much less expensive and allows much more bandwidth in terms of volume of data. The primary protection of the existing circuits from SSD to BDE will be migrated to the fibre and the existing PLC retired with parts used for spares for other lines where viable.

At Bay d'Espoir Terminal Station, three 230 kV circuit breakers, six 230 kV motor operated disconnect switches and associated control panels will be added to complete the breaker-and-one-half arrangement on the first two legs of the station layout and accommodate the new 230 kV transmission line termination on a third leg. Figure 9.1 provides a single line

diagram with the proposed additions in red. This proposal effectively converts the existing ring bus to a breaker and half scheme which adds additional reliability for some operating contingencies, such as breaker fail operations.

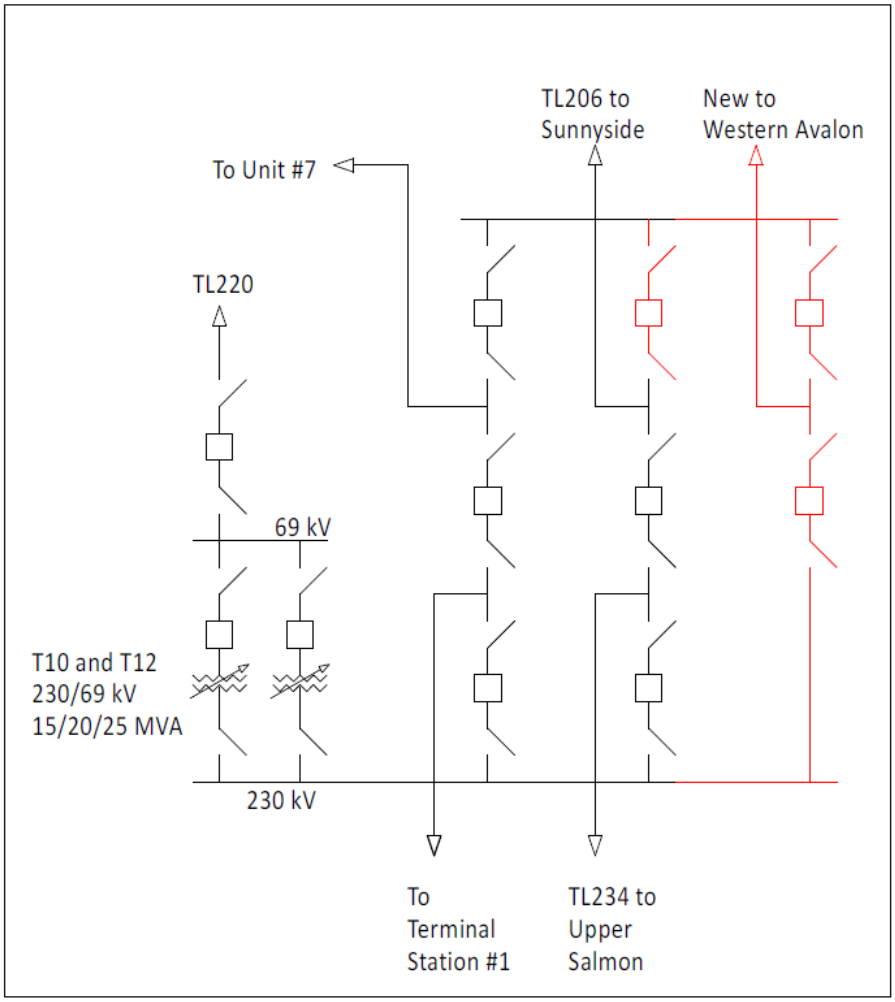


Figure 9.1 - Bay d'Espoir Terminal Station #2 Additions for New 230 kV Transmission Line

At Western Avalon Terminal Station, a new 230 kV ring bus consisting of four 230 kV circuit breakers is proposed for the southern end of the terminal station. Cost estimates were prepared to complete the new ring bus using traditional gas filled, air insulated circuit breakers and motor operated disconnect switches, and alternatively using a compact gas insulated switchgear (GIS) ring bus configuration. The rationale for the consideration of the GIS equipment is to limit the civil works for the ring bus addition. The Western Avalon

Terminal Station is situated on the side of a hill near Chapel Arm. The land to the west of the terminal station consists of an upward sloping steep embankment which has had drainage issues in the past. Excavation to the west would be extremely costly as it would require additional slope stability and drainage work along with relocation of the existing access road. The land to the east consists of a downward sloping steep embankment to Route 201 (Chapel Arm to Bellevue Road). Expansion in this direction would require extensive amounts of fill. A minimal extension to the south side of the station can be accommodated to permit installation of the compact GIS and access road realignment. The traditional gas filled, air insulated circuit breakers and motor operated disconnect switches arrangement has an estimated capital cost estimate of $15.5 million. In comparison, the GIS arrangement for the proposed ring bus has a cost estimate of $13.0 million. Given the lower capital cost, Hydro is proposing to complete the ring bus using the compact GIS design.

As part of the GIS ring bus addition, TL208 will be re-terminated in the new ring along with the new 230 kV transmission line to Bay d'Espoir. This will improve the reliability of the TL208 radial supply to Vale as it will no longer be tripped due to an outage to 230 kV bus B1 or 230/66 kV transformers T1 or T2. Figure 9.2 provides a single line diagram of the Western Avalon Terminal Station with the proposed additions shown in red. The GIS ring bus addition will contain one spare line termination for a future 230 kV transmission line. This line termination location is expected to be used to re-terminate TL201 (Western Avalon to Hardwoods) when the existing H-frame wood pole line is rebuilt/upgraded due to age. Re-terminating TL201 in the new ring bus provides a separate east – west connection through Western Avalon Terminal Station similar to the two ring bus arrangement at Stony Brook which has one 230 kV transmission line from Bay d'Espoir and one 230 kV transmission line to Buchans on each ring. The existing Air Blast Circuit Breaker (ABCB) used on TL208 will be retired but retained as a spare or used for spare parts for the remaining fleet of aging 230 kV ABCB's.

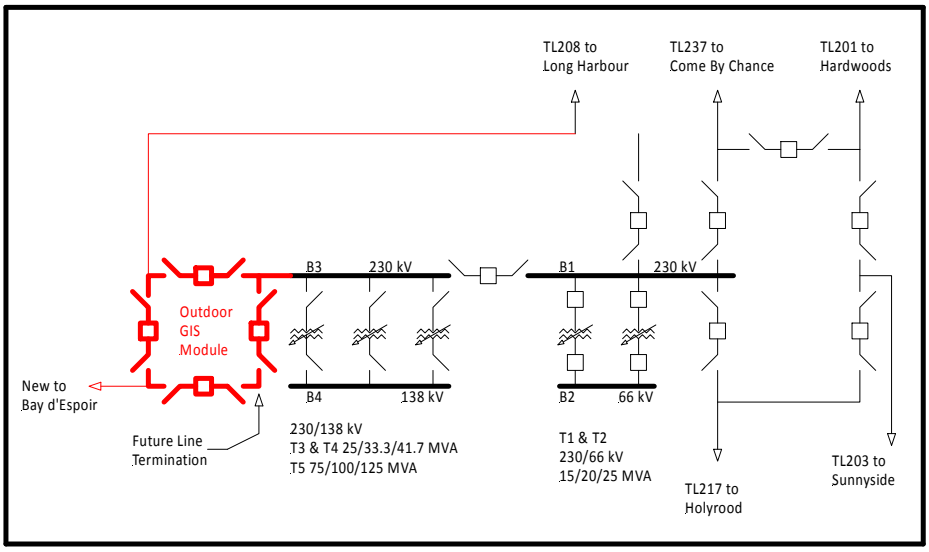


Figure 9.2 - Western Avalon Terminal Station Additions for New 230 kV Transmission Line

9.1 Environmental Aspects

It is proposed to construct the new transmission line adjacent to the existing two 230 kV transmission lines along the route between Bay d'Espoir and Western Avalon. The new right of way will pass through approximately 13 km of the Bay du Nord Wilderness Reserve (BDNWR) and be located south of the reserve boundary for approximately 22 km. It will also cross 13 scheduled salmon rivers. Linear developments that have infrastructure located within a known reserve or within 200 meters of a scheduled salmon river are considered Registerable Undertakings under the Provincial Environmental Assessment Act (PEAA). The project has no evident triggers for the Canadian Environmental Assessment Act (CEAA). The project as described will be a Registerable Undertaking under the PEAA. The BDNWR Management Plan governs existing and proposed activities within the Reserve. To receive approval to construct the proposed transmission within the BDNWR, the Management Plan must be amended and the reserve boundary revised to provide the necessary area within the reserve for the new transmission line to be constructed (if the new line cannot be constructed within the current ROW). The process to request the Management Plan be revised is laid out in the Reserve regulations. The Lieutenant

Governor in Council (LGC) has the right under the Reserve regulations to increase or decrease the existing Reserve area.

As currently stated, the BDNWR Management Plan revision request must be submitted and the approval received prior to commencing the PEAA process. Approval has already been requested to undertake these activities concurrently.

Since the establishment of the BDNWR, there has been negligible issues related to access and maintenance of the existing lines and ROWs which transverse approximately 13 kilometers of the reserve. It is anticipated that while processes will have to be undertaken to allow a third circuit to be constructed, there are no insurmountable reasons why the construction should not be approved. If the ROW needs to be expanded, the total additional area needed is less than 0.03% of the total reserve. Rerouting the line to avoid the reserve is prohibitive in terms of the additional environmental footprint as it would not utilize existing available ROW, requires new access trails and would be more costly. Further, from an operational as well as environmental perspective, logic indicates it is prudent to use the current access trails, instead of adding a totally different route with additional access trails, river fording sites and so on. From a utility perspective, while route diversity is a positive for weather related outages, this corridor has not been an issue with respect to ice storms or wind damage. It is the preferred course of action as there is no evidence to support a high probability of common mode failures. The cost of avoiding the reserve could exceed $60M.

9.2 Budget Estimate

The following capital cost estimate is higher than the original estimate presented to the Board in the 2012 Capital Budget Application report filed on September 22, 2011. That particular project was withdrawn with notice to the Board on December 14, 2011. The original budget submission of August 2011 was approximately $210M. This was increased to $268M as indicated in the five-year plan as submitted to the Board in August 2013. This

was due to increases in contingency, additional labour cost and additional electrical and civil cost driven by design progression and relative increases in IDC and escalation. The current application estimate is approximately $292M and the difference is attributed to further adjusted labour cost and design changes. The breakdown of the current estimate is indicated in Table 9.1.

Table 9.1: Project Budget Estimate

Project Cost: *($ x1,000)*	**2014**	**2015**	**2016**	**Beyond**	**Total**
Material Supply	0.0	3,000.0	19,587.0	4,673.7	27,260.7
Labour	1,916.0	4,711.0	5,625.0	8,145.0	20,397.0
Consultant	90.0	2,252.0	1,055.0	85.0	3,482.0
Contract Work	0.0	6,350.0	40,507.5	88,956.5	135,814.0
Other Direct Costs	280.0	949.7	1,222.4	1,588.4	4,040.5
Contingency	0.0	0.0	0.0	38,198.9	38,198.9
Sub Total	***2,286.0***	***17,262.7***	***67,996.9***	***141,647.5***	***229,193.1***
Escalation	78.3	974.5	5,675.6	16,515.4	23,243.8
Sub Total	***2,364.3***	***18,237.2***	***73,672.5***	***158,162.9***	***252,436.9***
Interest	48.3	727.5	3,553.1	34,892.2	39,221.1
TOTAL	**2,412.6**	**18,964.7**	**77,225.6**	**193,055.1**	**291,658.0**

9.3 Project Schedule

The project schedule is indicated in Table 9.2. The schedule is the current view of optimizing the in service date with the planned phased availability of power from Muskrat Falls and LIL. It recognizes optimization of labour resources and is intended to smooth the demands on line construction forces.

The integration of project milestones will continue and as opportunities are identified to optimize overall project schedules such opportunities will be explored and where effective exercised.

Further, with the Holyrood generating units available as generators and in the case of Unit 3 both generating and synchronous condensing capability, delivery of any available Labrador power, prior to the planned in-service of the BDE-WAV lines, over LIL will be possible. This would involve some generation at Holyrood and/or the operation of Unit 3 as a synchronous condenser and would be phased with the availability of Muskrat Falls power. As noted above, as both projects advance all opportunities for overall optimization and cost savings will be explored and exercised.

Table 9.2: Project Schedule

Item	Description	Start	End	Duration
1	Submit for PUB Approval	30 Apr 2014	30 Apr 2014	Target date
2	Crown Land Preparation and Submittal of Application	30 Apr 2014	1 Jun 2015	14 Month
3	Environmental Registration	1 Jun 2014	1 Jul 2014	Target date
4	Environmental Field Studies & Compliance with Registration Process	1 Jul 2014	1 Jan 2016	18 Months
5	Engineering & Procurement	1 Sep 2014	1 June 2016	21 Months
6	ROW Clearing Contractor Selection and Award	1 Jun 2015	1 Dec 2015	6 Months
7	ROW Clearing	1 Jan 2016	1 Jan 2017	12 Months
8	Material Procurement	1 Jan 2015	31 Dec 2016	24 months
9	Transmission Construction Contractor Selection and Award	1 Sep 2015	1 Sep 2016	12 Months
10	Transmission Line Construction	1 Sep 2016	1 Mar 2018	18 Months
11	Switchyard Extensions Construction	1 Apr 2016	31 Oct 2017	19 Months
12	Completions, Commissioning and Site Restoration	1 Mar 2018	1 May 2018	2 Months
13	In Service Date	1 May 2018	1 May 2018	Target Date
14	Project Close-out	2 May 2018	2 Aug 2018	3 Months

10.0 ADDITIONAL CAPITAL BUDGET DOCUMENTATION

The following sections provide additional capital budget documentation for further information.

10.1 Existing System

The existing Bay d'Espoir to Western Avalon transmission corridor consists of five 230 kV transmission lines including:

- TL202 – Bay d'Espoir to Western Avalon;
- TL203 – Sunnyside to Western Avalon;
- TL206 – Bay d'Espoir to Western Avalon;
- TL207 – Sunnyside to Come By Chance; and
- TL237 – Come By Chance to Western Avalon.

Table 10.1 provides the rating of each transmission line for varying ambient temperature.

Table 10.1: Bay d'Espoir to East Transmission Line Ratings

TL #		MVA Rating for an Ambient Temperature of			
	Terminals	**30 ˚C**	**25 ˚C**	**15 ˚C**	**0 ˚C**
	Bay d'Espoir to Western Avalon Lines				
TL202	BDE-SSD	199.3	236.9	297.7	369.5
TL203	SSD-WAV	261.7	278.0	307.8	347.0
TL206	BDE-SSD	199.3	236.9	297.7	369.5
TL207	SSD-CBC	355.8	375.5	411.5	459.6
TL237	CBC-WAV	355.8	375.5	411.5	459.6
TL267**	BDE-WAV	355.8	375.5	411.5	459.6

TL #		MVA Rating for an Ambient Temperature of			
	Terminals	**30 ˚C**	**25 ˚C**	**15 ˚C**	**0 ˚C**
	Western Avalon East Lines				
TL201	WAV-HDW	175.5	207.7	260.2	322.2
TL208	WAV-Vale	199.3	236.9	297.7	369.5
TL217	WAV-HRD	341.8	363.3.	402.4	453.9
TL218	HRD-OPD	199.3	236.9	297.7	369.5
TL236	HDW-OPD	355.8	375.5	411.5	459.6
TL242	HRD-HDW	355.8	375.5	411.5	459.6
TL265*	SOP-HRD	199.3	236.9	297.7	369.5
TL266*	SOP-HDW	175.5	207.7	260.2	322.2
TL268*	SOP-HRD	355.8	375.5	411.5	459.6
* Lines established by splitting existing lines at SOP					
** Proposed new line BDE - WAV					

Table 10.2 provides a summary of the major upgrade work that has been completed the along the Bay d'Espoir to Western Avalon transmission line corridor.

Table 10.2: Major Work or Upgrades

Year	Major Work/Upgrade	Comments
2003	TL203 Thermal Uprate	The thermal rating of TL203 was increased to meet system loading requirements.
2002	TL237 Rebuild	Following 1994 ice storm TL237 was rebuilt for a 3 in ice load as part of the Avalon Transmission Upgrade Project.
2002	TL207 Rebuild	Following 1994 ice storm TL207 was rebuilt for a 3 in ice load as part of the Avalon Transmission Upgrade Project.
2001	TL206 Lightning arrester additions	Poor lightning performance of TL202 and TL206 resulted in a significant number of simultaneous outages and loss of supply

Year	Major Work/Upgrade	Comments
		to Avalon Peninsula.
1993 to 1996	TL202 insulator replacements	Canadian Ohio Brass insulators replaced
1984	TL203 line upgraded with high strength 562.5 kcmil conductor	Ice storms resulted in failure of TL203 structures and outages to customers. A high strength 562.5 kcmil conductor was added to 22 km along the two-inch ice zones.

10.2 Operating Experience

As this is a new asset, there is no direct operating experience as such. However, there is significant data on transmission line performance discussed in the next section. As these are well known asset types to Hydro, there are no anticipated issues related to operating and maintenance. Practices developed over the time Hydro has been operating and maintaining such assets will be considered and implemented during the design, construction, operation and maintenance of the proposed asset.

10.2.1 Outage Statistics

As the proposed 230 kV transmission line between Bay d'Espoir and Western Avalon is a new asset, there are no available outage statistics. Given the application of an overhead ground wire along its entire length, it is anticipated that the lightning performance of the new line will be very similar to or improved over that of TL206, which is equipped with lightning arresters. Better shielding is provided by an OHGW as the lightning will less likely hit the conductor. The lightning arrestor does not shield the line from a lightning strike but mitigates the voltage and energy through the arrestor. The mechanical and structural performance of the proposed line will be very similar to that of TL202, TL206, TL207 and TL237 as it will be designed to withstand comparable meteorological loading.

Outage statistics for existing 230 kV transmission lines in the Bay d'Espoir to Western Avalon corridor are indicated in Table 10.3

Table 10.3: Transmission Line Terminal Equipment Performance Bay d'Espoir to Western Avalon Corridor

Transmission Line	Frequency (per terminal year)[1]	Unavailability (%)[2]
TL202 (2009 – 2013)[3]	0.90	0.041
TL203 (2009 – 2013)	0.20	0.016
TL206 (2009 – 2013)	0.20	0.002
TL207 (2009 – 2013)	0.10	0.003
TL237 (2009 – 2013)	0.20	0.001
Hydro 230 kV (2008 – 2012)[4]	0.79	0.030
CEA 230 kV (2008 – 2012)[5]	0.147	0.013

[1]Frequency (per terminal year) is the number of line outages per line terminal.
[2]Unavailability is amount of time the line is not available for terminal related causes.
[3] The relatively high frequency for TL202 is primarily related to several lightning strikes during 2012/2013 and tree contacts in 2009/2010.
[4] The relatively high unavailability for TL202 is primarily due to an equipment failure at Sunnyside in 2012 in excess of 21 hours and Hurricane Bill related tree contact in 2009 in excess of 15 hours.
[4, 5] The inversion between CEA and Hydro is attributed to the lack of OHGW's and automatic reclosing which together lead to more interruptions of much less duration.

10.2.2 Industry Experience

When the load or power transfer requirements of a portion of the transmission system exceed the original rating of the transmission lines, several alternatives are considered in the industry. One alternative is to investigate the potential to increase the rating of the existing transmission lines either through re-conductoring or a combination of conductor changes (replacement or re-tensioning) and structure modifications (increases in structure height and or mid span structures). The second alternative is to consider the addition of new transmission lines at the same or higher voltage to the corridor. A third alternative is to increase the voltage rating of the existing lines.

When power system stability becomes an issue along a portion of the transmission system due to changes in the system topology, generation dispatch or load patterns, the three prominent alternatives used in industry to mitigate the risk include series compensation, static var compensators or the construction of new transmission lines.

Series compensation involves the addition of a capacitor bank in series with the transmission line to effectively reduce its impedance. This reduction allows for the "stiffening" of the transmission network and improves stability. This technique is used extensively by Hydro-Québec TransÉnergie to improve system stability of their 735 kV network during transmission line contingencies. Series compensation on the 735 kV network typically ranges from 16% to 50%. It should be noted that the installation of series compensation or static var compensators does not materially increase the ampacity limit of the line as that is a physical constraint of conductor size, impedance and ground clearance of the wire conductor itself along with ambient temperature and wind speed.

The second common method of addressing the performance is the installation of a static var compensator. This system allows the very fast system voltage compensation of the system and thus better stabilizes the system during and immediately after faults and other disturbances. Like series compensation, the installation of series compensation or static var compensators do not materially increase the ampacity limit of the line.

The other alternative to improve power system stability is to increase the number of transmission lines and/or voltage levels in a corridor. Like series compensation, the construction of parallel line reduces the overall transmission corridor impedance and thereby "stiffens" the transmission network so that it improves stability limits. It has the added advantage or reducing the resistance component of the impedance and thus reducing losses.

When both transmission line ratings and power system stability issues occur along the same transmission corridor, series compensation, in and of itself, is not an effective solution on its own.

Utility industry systems vary considerably in design and this is due to loading scenarios, distances and topology. There is no standard or common single solution to provide a stable system for planned contingencies. Hydro has evaluated the technical merits of each case and concluded that the solution proposed, a new line, meets the needs of the system and thus its customers.

10.2.3 Vendor Recommendations

This project includes the purchase and installation of new terminal station equipment and the design and construction of a new 230 kV transmission line. Therefore, vendor recommendation with respect to repair or replacement is not pertinent. This work is typical of projects carried out by Hydro and well within its scope.

10.2.4 Maintenance or Support Arrangements

Normal routine maintenance work for the proposed 230 kV transmission line and associated terminal station equipment will be performed by Hydro personnel and is consistent with assets currently maintained.

10.2.5 Maintenance History

As the proposed 230 kV transmission line between Bay d'Espoir and Western Avalon is a new asset, there is no maintenance history. All lessons learned over the years pertaining to engineering, operating and maintaining such assets will be incorporated in this proposed asset to ensure equitable or better performance set.

10.2.6 Anticipated Useful Life

The proposed 230 kV transmission line has different expected service lives on the major components. The conductor and structures have an estimated life of 60 and 65 years, respectively. The insulators have an expected 30-year life.

10.3 Forecast Customer Growth

This investigation involved the analysis of load flow models representing peak load conditions for 2017. The load flows models were based on Hydro's Operating Interconnected Island Load Forecast from September, 2012. Forecasted customer loads are provided in Table 10.4. Testing of steady state conditions by load flow analysis and transient conditions by stability simulations were completed for demand levels at selected values between 440 MW and 1757 MW. The values indicated in Table 10.4 for Newfoundland Power and Hydro interconnected non-industrial loads and would typically be scaled to vary the total load with industrial loads remaining constant or minor if a very lightly loaded scenario.

Table 10.4: 2017 Peak Load Forecast

Customer	Load (MW)
Newfoundland Power[22]	1336.8
Hydro Rural Interconnected	93.8
Corner Brook Pulp & Paper[21]	
Generation Outage Power	0.0
Power on Order	23.0
Interruptible	0.0
Total HYDRO Sales	23.0
North Atlantic Refining	
Power on Order	31.3
Interruptible	0.5
Total HYDRO Sales	31.8
Teck – Duck Pond	
Power on Order	0.0
Interruptible	0.0
Total HYDRO Sales	0.0
Vale – Long Harbour	
Power on Order	77.0
Interruptible	7.0
Total HYDRO Sales	84.0
Praxair – Long Harbour	
Power on Order	6.0
Interruptible	0.0
Total HYDRO Sales	6.0
TOTAL HYDRO SALES	1545.3
Losses	47.9
Required HYDRO Generation	1593.2
Source: Market Analysis Sep 2012 Operating Load Forecast	

[22] Does not include owned generation used to supply their internal demand.

APPENDIX A – LOAD FLOW ANALYSIS

Load Flow Analysis

The steady state load flow analysis is completed to assess transmission system element overloads and bus voltage violations both with all equipment in service and under single element outages. Once violations of criteria are identified, potential technical solutions are assessed to determine technical viability. The following sections provide a summary of the results of the load flow analysis.

Winter Peak

Base Cases BC2 and BC3 consider the winter peak load conditions.

In BC2 with the LIL delivering 833 MW to SOP, loss of either TL218 or TL242 is found to result in thermal overload of TL266 from SOP to HWD (102% for loss of TL218 and 140% for loss of TL242). For loss of TL218 operation of the HWDCT at 50 MW is found to alleviate the overload condition. However, for the loss of TL242, operation of the HWDCT alone is not sufficient to alleviate the overload on TL266. In addition to operating the HWDCT at 50 MW, opening TL236 from HWD to OPD is found to alleviate the thermal overload on TL266 for the loss of TL242. The end result of opening TL236 with TL242 out of service is that both HWD and OPD stations are supplied radially. This increases the risk of outages in the event of other contingencies. It is noted that TL242 and TL266 are parallel 230 kV transmission lines between SOP and HWD. The reason for there being an overload on TL266 and not on TL242 for the line out contingency is that TL266 consists of a 636 kcmil, 26/7, ACSR "GROSBEAK" conductor which has a lower thermal rating than TL242 which consists of an 804 kcmil, 23/19, AACSR/TW conductor. The overload during single line out contingencies is driven by the load growth in the St. John's area and not the introduction of the Labrador – Island HVdc Link. This overload condition is expected in the 2020 – 2021 time frames when the Hydro system load reaches 1,642 MW at peak. There are several alternatives to alleviate this condition. First, given that TL266 is an H-frame wood pole line nearing end of life, re-build of this circuit with a larger conductor (i.e. 1,192.5 kcmil, 54/19 ACSR GRACKLE) is viewed as a viable alternative. Second, construction of a new 230 kV transmission line

from Soldiers Pond to the St. John's area would provide the necessary transmission capacity. A new transmission line into the region will likely be eventually warranted as the load continues to grow and a new 230/66 kV transformation required. Finally, the addition of a fast start combustion turbine within the St. John's area could be used to alleviate thermal overloads however environmental permitting may be challenging. A detailed analysis is required to assess the least cost alternative for this issue and is independent of the current proposal.

In BC3 with the island generation at maximum output and the LIL delivering 518 MW to SOP, loss of either parallel circuit TL202 or TL206 between BDE and SSD is found to result in voltage collapse on the eastern portion of the 230 kV transmission system. To avoid voltage collapse in the steady state analysis, the LIL delivered power must be no less than 656 MW.

Loss of TL207 from SSD to CBC in BC3 is found to result in thermal overload of TL203 from SSD to WAV (118% of rating). Operation of the HWDCT at 50 MW is expected to reduce the TL203 loading to 110%. Operating the proposed 60 MW Holyrood combustion turbine (HRDCT) along with HWDCT would reduce the TL203 loading to 88% of rating. Alternatively, increasing the LIL delivered power at SOP to 598 MW reduces the TL203 loading to 100% of rating for loss of TL207.

Loss of TL237 from CBC to WAV in BC3 is also found to result in a thermal overload of TL203 (118% of rating). Operation of the HWDCT at 50 MW is found to reduce the loading on TL203 to 97% of rating. Alternatively, increasing the LIL delivered power at SOP to 564 MW reduces the TL203 loading to 100% of rating.

Similar to BC2, loss of TL242 in BC3 will result in thermal overload of TL266 (123% of rating). Operation of HWDCT at 50 MW and opening of TL236 will result in a TL266 loading of 95%.

BC4 considers a winter peak with the LIL operating in monopolar mode with the import set at 200 MW. As such, the island generation is maximized, including the combustion turbines, with one pole of the LIL out of service. As this study excludes the Maritime Link there was no consideration given to imports. In this case, the system is already under an N-1 condition prior to the steady state contingency analysis. Loss of a 230 kV transmission line on the Avalon Peninsula during this condition is expected to result in thermal overloads to other 230 kV transmission lines. Loss of TL218 results in a TL266 loading of 101% and loss of TL242 results in a TL266 loading of 129%. With all generation on line, including HWDCT, there is no generation to alleviate these overloads. The analysis also indicates that for loss of TL207, TL203 will be loaded to 184%. Similarly, loss of TL203 will result in thermal overloads of both TL207 (135%) and TL237 (121%). Increasing the delivered power at SOP will remove these overload conditions. Further, loss of TL202 or TL206 is found to result in voltage collapse during this operating condition.

Finally, BC1 considers a future winter peak load case with the island generation at maximum and the LIL delivering 672 MW at SOP. Loss of TL242 is found to result in thermal overload of TL266 (147%). Operation of the HWDCT at 50 MW and opening of TL236 is no longer effective in alleviating the overload. Consequently, thermal uprate or rebuild of TL266 or construction of a new 230 kV transmission line between SOP and St. John's will be required as the system load reaches 1,757 MW. The TL266 contingency under BC1 reveals a thermal overload on TL242 (103% of rating). Operation of the HWDCT at 50 MW reduces the TL242 loading to 95% of rating for the TL266 outage.

Winter Day

Base cases BC5 and BC6 are used to analyze the typical winter day loading condition. With the LIL providing maximum delivery to the island (830 MW) the only overload observed under transmission line contingency is TL266 for loss of TL242. Operation of the HWDCT at 50 MW and opening of TL236 (HWD to OPD) is successful in alleviating the TL266 overload.

During the winter day loading condition, if the island generation is operated at maximum output and the deliveries on the LIL are reduced to 330 MW at SOP, a number of 230 kV transmission line outages are found to result in transmission line overloads. An outage to TL203 results in overloads on TL207 (122% of rating) and TL237 (113% of rating). Operating the proposed 60 MW HRDCT is found to alleviate the overload condition. Alternatively, increasing the capacity delivered to SOP over the LIL to 384 MW delivered will also alleviate the overload conditions on TL207 and TL237.

The loss of TL237 during a winter day with island generation at maximum output will result in the overload of TL203 (147% of rating). Operation of both the HWDCT and proposed HRDCT will reduce the TL203 loading to 98% of rating. Alternatively, increasing the power delivered at SOP by the LIL will also alleviate the overload.

The loss of TL207 on a winter day will also result in a thermal overload of TL203 (159% of rating) when the island generation is at its maximum output. Operation of both the HWDCT and the proposed HRDCT is not effective in eliminating the overload on TL203 (load equals 111% of rating). The viable solution in this contingency is the increase in deliveries at SOP by the LIL to 472 MW.

Loss of either TL202 or TL206 (BDE to SSD) is found to result in system voltage collapse during the winter day load condition when the island generation is operating at maximum output and the deliveries at SOP via the LIL are reduced.

Spring/Fall Day

Base cases B7 and B8 are used to analyze the typical spring/fall day loading condition. With the LIL providing maximum power deliveries at SOP (i.e. BC7), the only thermal overload observed is TL266 for the loss of TL242. Operation of the HWDCT combined with the opening of TL236 alleviates the overload.

With the island generation at maximum output during the typical spring/fall day (i.e. BC8), a thermal overload of TL202 and TL206 (105% of rating) is expected prior to any transmission line contingency. To eliminate this overload condition TL202 and TL206 could be thermally uprated or the deliveries via the LIL at SOP can be increased by 200 MW. The steady state, pre-contingency thermal overloads on TL202 and TL206 during the typical spring/fall day loading condition with maximum generation output from island generating sources are of particular concern given that the spring runoff and reservoir storage positions may/will require the maximization of island generation to avoid spill and thereby require reduced or minimal deliveries at SOP from the LIL. Having to limit island generation output during the spring/fall to avoid transmission line thermal overload situations is viewed as restrictive to the operation and increased the risk of spilling water.

The loss of TL203 during the typical spring/fall day loading condition will result in thermal overloads to TL202 (110%), TL206 (110%), TL207 (154%) and TL237 (138%). Operation of the HWDCT and the proposed HRDCT for 50 MW and 60 MW respectively will alleviate the overloads on TL202, TL206, and TL237. However, the loading on TL207 remains at 110% of its rating. Rather than operate the combustion turbines to alleviate the thermal overloads, increasing the LIL deliveries at SOP to 322 MW with a corresponding reduction in the island generation output is found to be more effective.

The loss of TL207 during the typical spring/fall day will result in thermal overloads to TL202 (115%), TL206 (115%) and TL203 (208%). Increasing the deliveries of the LIL at SOP to 410 MW with a corresponding reduction in island generation output will alleviate the thermal overloads on the affected circuits.

The loss of TL237 during the typical spring/fall day will result in thermal overloads to TL202 (108%), TL206 (108%) and TL203 (180%). Increasing the deliveries of the LIL at SOP to 368 MW with a corresponding reduction in island generation output will alleviate the thermal overloads on the affected circuits.

The loss of TL217 (WAV to SOP) during the typical spring/fall day will result in thermal overloads to TL202 (110%), TL206 (110%), TL203 (100%) and TL201 (134%). Increasing the deliveries of the LIL at SOP to 243 MW with a corresponding reduction in island generation output will alleviate the thermal overloads on the affected circuits. Loss of TL201, the parallel circuit to TL217 does not result in thermal overload to TL217 because TL217 has a larger conductor than TL201, and therefore a higher thermal rating.

The loss of either TL202 or TL206 during the typical spring/fall day load condition will result in voltage collapse in steady state with the island generation at maximum output. Steady state analysis indicates that the LIL deliveries at SOP must be increased to a minimum of 468 MW with a corresponding decrease in the island generation output if the steady state voltage collapse is to be avoided.

Summer Day

Base cases BC9 and BC10 are used to analyze the typical summer loading condition. Steady state analysis of BC9 revealed no transmission planning criteria violations.

In BC10 the LIL is in monopolar mode with SOP deliveries set at 154 MW. Under this condition an outage to TL202 or TL206 will result in a thermal overload on the parallel circuit (136%). Steady state Analysis indicates that increasing the LIL deliveries to 230 MW is sufficient to alleviate the thermal overload condition. Alternatively, both the HWDCT and proposed HRDCT can be used in generate mode to remove the overload in this case.

Summer Night

Base case BC11 is used to analyze the typical summer night loading condition. Steady state analysis revealed no transmission planning criteria violations.

Thermal Overloads

The analysis indicated that thermal overloads would be experienced on TL202, TL206, TL203, TL207, TL237 and TL201 during transmission line contingencies, particularly for the typical spring/fall day loading condition. Steady state analysis indicated that increasing the LIL deliveries at SOP with a corresponding decrease in island generation output provides an operational solution to alleviate the overloads in the short term.

The following paragraphs give consideration to the potential for thermal upgrades of the affected 230 kV transmission lines.

TL203 is a 45 km long, H-frame wood pole transmission line built in 1965. Further thermal up-rating of this transmission line is deemed impractical given the existing structure heights, meteorological design load requirements, etc. Therefore, to increase the rating of TL203 by any significant degree, significant upgrade (i.e. new heavy angle towers and mid-span structures) or full rebuild of the circuit is required. For analysis purposes TL203 is assumed to be rebuilt using the 804 AACSR/TW conductor with an 80 ^{o}C hot conductor temperature design similar to TL207, TL237, TL217 and TL236.

Analysis by Hydro's Transmission and Distribution Design Department has indicated that TL202 and TL206 could be thermally uprated from its present 50 ^{o}C hot conductor temperature design to a 75 ^{o}C hot conductor temperature design through the addition of a number of mid-span structures and excavation in the critical low ground clearance areas. With this work the thermal ratings of TL202 and TL206 will increase from 199.3 MVA, 297.7 MVA and 369.5 MVA for summer, spring/fall and winter conditions respectively to 341.8 MVA, 402.4 MVA and 453.9 MVA for summer, spring/fall and winter conditions respectively.

TL207 and TL237 are guyed V steel structured transmission lines that were upgraded as part of the Avalon Transmission Upgrade Project. These lines have an 80 ^{o}C hot conductor temperature design. Increasing the thermal rating of these lines would require a rebuild.

With TL202/206 uprated and TL203 rebuilt, TL207 and TL237 would become the "bottleneck" with respect to thermal overload and maximum power deliveries to the Avalon Peninsula from island hydroelectric generating sources during the spring/fall period. Future enhancements to these lines, should it be necessary will be a separate undertaking and the preferred solution brought forward for approval when necessary. There are no aspects of the current proposal that has any significant material effect of that possible future requirement.

Voltage Collapse

The steady state analysis found that for system conditions in which the on island generation output is maximized and the LIL deliveries at SOP reduced, system voltage collapse was experienced for loss of either TL202 or TL206 between Bay d'Espoir and Sunnyside. With all major island generation connected to the Avalon Peninsula via Bay d'Espoir and 230 kV transmission lines TL202 and TL206, loss of either of these circuits will have a significant impact on the ability of the system to deliver maximum on island generation to the Avalon Peninsula. The voltage collapse is the result of increased impedance between the generation source and the load center (i.e. loss of a transmission line results in increased impedance of the transmission path) and the lack of voltage support to overcome the increased impedance. To this end a number of system additions were considered including:

- increasing the number of the Soldiers Pond synchronous condensers;
- addition of a nominal 150 MVAR, 230 kV switched capacitor bank at Sunnyside;
- series compensation of TL202 and TL206 to reduce system impedance with subsequent increase in power transfer;
- construction of two 45 km of 230 kV transmission line between Western Avalon and

the Sunnyside area with re-route of TL202 and TL206 around Sunnyside Terminal Station and connection to the two new 230 kV transmission lines terminating at Western Avalon. In essence, connecting Bay d'Espoir to Western Avalon directly; and

- construction of a new 230 kV transmission line between Bay d'Espoir and Western Avalon.

Increasing the Number of Soldiers Pond Synchronous Condensers

Increasing the number of 175 MVAR synchronous condensers in service at Soldiers Pond was considered as an alternative to eliminate the voltage collapse issues experienced for the loss of TL202 or TL206 in base cases BC1, BC3, BC4, BC6 and BC8. Analysis demonstrated that a minimum of three 175 MVAR synchronous condensers (four in total) were required to eliminate the potential for voltage collapse in the steady state contingency analysis for base cases BC1 and BC3. With the addition of the fourth 175 MVAR synchronous condenser at SOP, thermal overload of TL202/206 was experienced for loss of TL206/202 in base cases BC1 and BC3. Operation of the HWDCT and HRDCT is effective in alleviating the post contingency overload on the healthy BDE to SSD 230 kV transmission line. Alternatively, increasing the LIL power deliveries at SOP is effective in removing the TL202/206 thermal overload.

Analysis of base cases BC6 and BC8 demonstrated that increasing the number of 175 MVAR synchronous condensers at SOP was ineffective in eliminating the steady state voltage collapse issues associated with the loss of TL202 or TL206. Instead, the addition of 115 MVAR and 230 MVAR of 230 kV shunt capacitors at Come By Chance for BC6 and BC8 respectively was found to eliminate the voltage collapse issues for loss of either TL202 or TL206.

Analysis of base case BC4 revealed that increasing the number of synchronous condensers at SOP or addition shunt capacitors at Come By Chance was not effective in eliminating the

steady state voltage collapse issues associated with the loss of TL202 or TL206.

Addition of Series Compensation on TL202 and TL206

The addition of series capacitors to a transmission line reduces the effective impedance of the transmission line thereby reducing the electrical angle across the transmission line for a fixed power transfer, resulting in improved power system stability, or permitting increased power flow across the transmission line for the same voltage drop or electrical displacement in the system without the series compensation. The application of series compensation on TL202 and TL206 is found to increase the power transfer capacity of the BDE to SSD path in steady state. As a result, it is necessary to increase the thermal rating of TL202 and TL206 in conjunction with the series compensation addition. Further, with the increase in transfer from BDE to the Avalon Peninsula it will be necessary to rebuild TL203 to alleviate thermal overloads of TL203. Figure A1 provides a diagram of the proposed 230 kV transmission system changes.

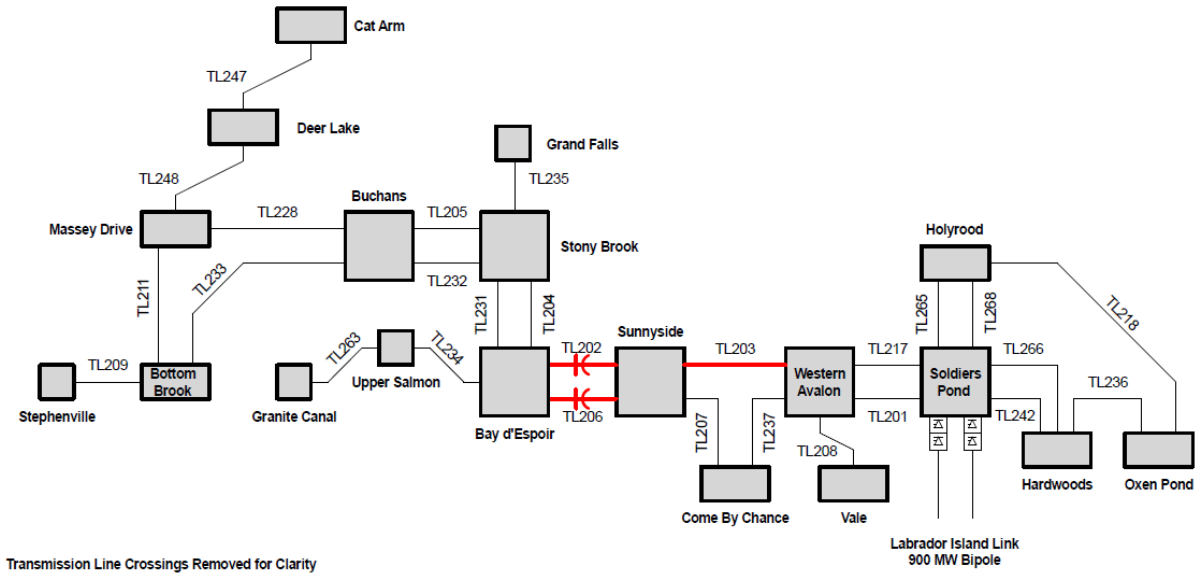


Figure A1 - 230 kV Transmission – TL202/TL206 Thermally Uprated and Series Compensated - TL203 Rebuilt

Assuming the thermal uprate of TL202 and TL206, the addition of 50% series compensation on TL202 and TL206 in the Sunnyside area[1] and the rebuild of TL203, the voltage collapse issues experienced for loss of TL202 or TL206 in base cases BC3, BC4, BC6 and BC8 were re-assessed. The analysis of BC3 demonstrates that voltage collapse can be avoided for the loss of TL202 or TL206 following thermal uprate and 50% series compensation. However, even with the thermal uprate of TL202 and TL206, the loss of one of these lines will result in a thermal overload of the remaining circuit. The thermal overload can be alleviated with the start of the HWDCT or the increase in deliveries of the LIL at SOP. Loss of TL207 or TL237 no longer result in thermal overload of TL203 once rebuilt.

The analysis of BC4 demonstrates that voltage collapse can be avoided for the loss of TL202 or TL206 following thermal uprate and 50% series compensation. However, even with the thermal uprate of TL202 and TL206, the loss of one of these lines will result in a thermal overload of the remaining circuit. The thermal overload can be alleviated with the increase in deliveries of the LIL at SOP by approximately 152 MW. This level of increase exceeds the ratings of the HWDCT and proposed HRDCT combined. The loss of TL207 results in a thermal overload of TL203 (114%) following rebuild, which can be alleviated through operation of HWDCT or increased deliveries on the LIL at SOP.

The analysis of BC6 demonstrates that voltage collapse can be avoided for the loss of TL202 or TL206 following thermal uprate and 50% series compensation. However, even with the thermal uprate of TL202 and TL206, the loss of one of these lines will result in a thermal overload of the remaining circuit. The thermal overload can be alleviated with the increase in deliveries of the LIL at SOP by approximately 134 MW. This level of increase exceeds the ratings of the HWDCT and proposed HRDCT combined. The loss of TL207 or TL237 results in

[1] Given that the limited space in the immediate vicinity of the Sunnyside Terminal Station, and the fact that the TL202 and TL206 corridor has a 138 kV transmission line on each side of the 230 kV transmission lines (i.e. TL212 and TL219 supplying the Burin Peninsula), it is assumed that the series compensation station would be located in the Pipers Hole area where TL212 and TL219 leave the 230 kV corridor and head down the Burin Peninsula. This location provides easy access to the two 230 kV lines to be series compensated.

a thermal overload of TL203 (103% or 112% respectively) following rebuild, which can be alleviated through operation of HWDCT or increased deliveries on the LIL at SOP.

The analysis of BC8 demonstrates that voltage collapse can be avoided for the loss of TL202 or TL206 following thermal uprate and 50% series compensation. However, even with the thermal uprate of TL202 and TL206, the loss of one of these lines will result in a thermal overload of the remaining circuit. The thermal overload can be alleviated with the increase in deliveries of the LIL at SOP by approximately 223 MW. This level of increase exceeds the ratings of the HWDCT and proposed HRDCT combined. The loss of TL207 or TL237 results in a thermal overload of TL203 (146% or 135% respectively) following rebuild, which can be alleviated through increased deliveries on the LIL at SOP.

Construction of New 230 kV Transmission Line Bay d'Espoir to Western Avalon

Instead of the thermal uprate of TL202 and TL206 and the rebuild of TL203, construction of a new 188 km, 230 kV transmission line between Bay d'Espoir and Western Avalon provides a third 230 kV path to the Avalon Peninsula and eliminates the need to modify existing transmission lines. Figure A2 provides a diagram of the proposed 230 kV transmission system changes.

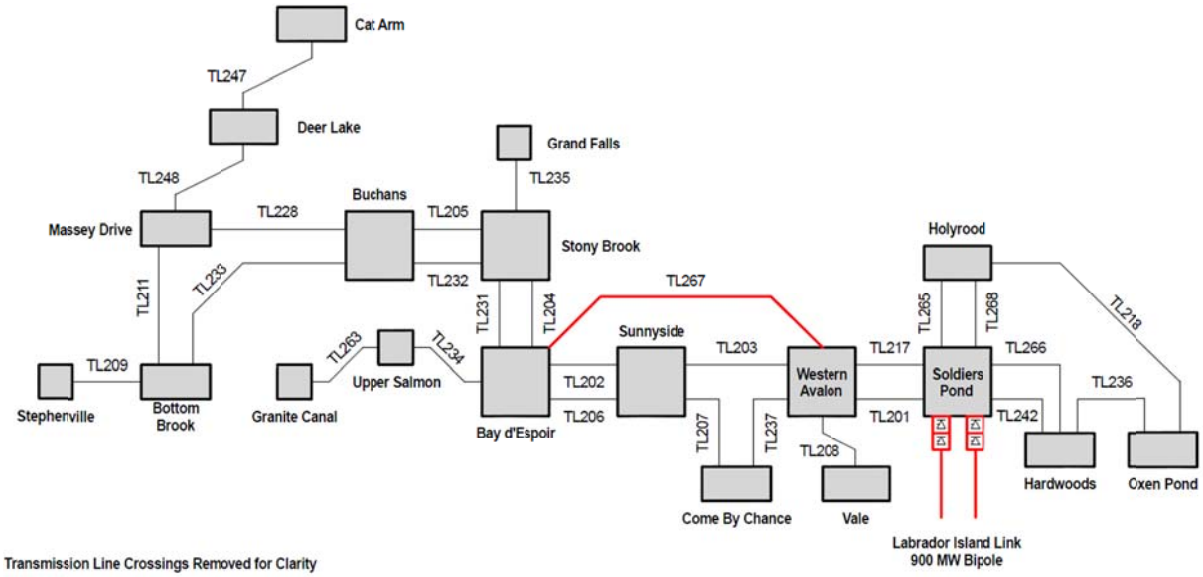


Figure A2 - 230 kV Transmission – New 230 kV Transmission Line Bay d'Espoir to Western Avalon

Analysis of the base cases with the BDE to WAV 230 kV transmission line added demonstrates elimination of thermal overloading on TL203 for outages to TL207 or TL237. In addition, voltage collapse associated with the loss of TL202 or TL206 was also eliminated.

BC8 analysis revealed that with the new 230 kV transmission line between BDE and WAV with maximum hydro generation during a spring/fall day, loss of TL202 or TL206 will result in thermal overload (117%) of the parallel circuit. An increase in the LIL deliveries at SOP with a corresponding reduction in the on island generation output was found to alleviate the overload.

Reroute of TL202 and TL206 Around Sunnyside Terminal Station

The reroute of TL202 and TL206 around the Sunnyside Terminal Station with re-termination at Western Avalon Terminal Station provides a more direct transmission path between Bay d'Espoir and the Avalon Peninsula load center. This modification requires the thermal up-rating of TL202 and TL206, the construction of two 45 km long 230 kV transmission lines to

extend TL202 and TL206 to Western Avalon, and 50% series compensation on TL202 and TL206. The modification requires 98 km less new line construction than the new transmission line between Bay d'Espoir and Western Avalon, and 45 km more new line construction than the modification with uprate of TL202 and TL206, rebuild of TL203 and 50% series compensation. Figure A3 provides a diagram of the proposed 230 kV transmission system changes.

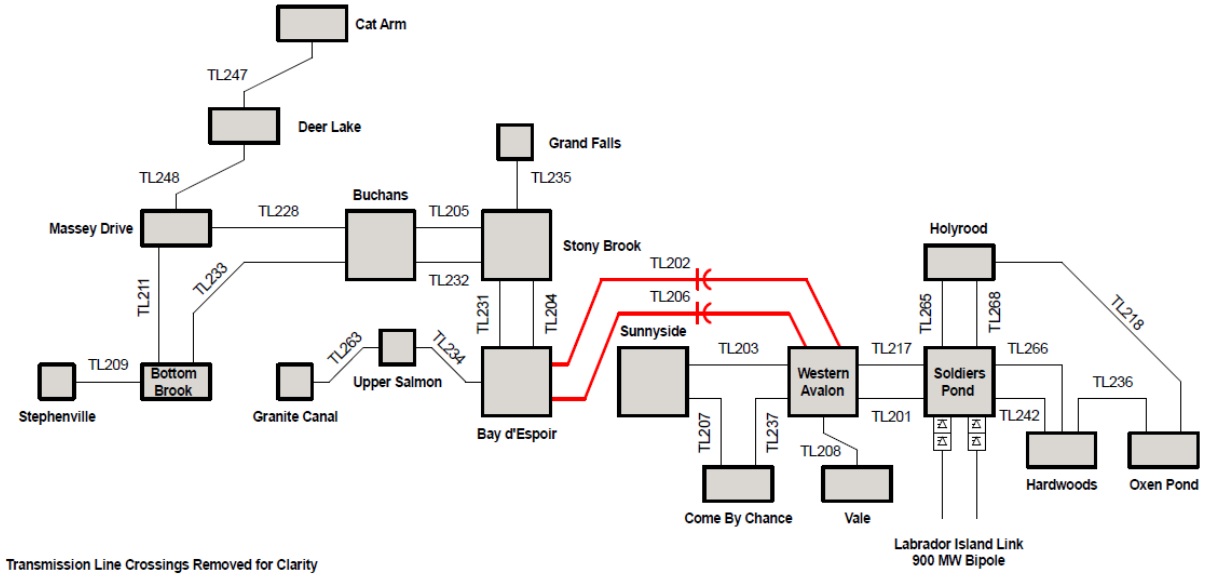


Figure A3 - 230 kV Transmission – TL202/TL206 Reroute around SSD – Lines Thermally Uprated and Series Compensated

The re-route of TL202 and TL206 eliminates the thermal overload issues associated with TL203 during loss of TL207 and TL237 contingencies. Load flow analysis of the re-route demonstrates that the loss of TL202 or TL206 will result in the thermal overload of the remaining 230 kV line between BDE and SSD despite the thermal uprate. In all base cases except BC4, operation of the HWDCT and HRDCT, or increasing LIL deliveries at SOP were found to be effective in alleviating the thermal overload issue during the line outage. BC4 was found to be problematic with voltage collapse occurring in the steady state analysis of the TL202/206 outage following re-route, thermal upgrade and 50% series compensation of both TL202 and TL206.

Summary of Load Flow Analysis

The following table provides a summary of the load flow analysis.

Table A1: Summary of Load Flow Analysis

Load Condition	Base Case(s)	Comments	Upgrades	Acceptable
Future Peak	BC1	Loss of TL207 Overload of TL203	Start HWDCT + HRDCT	Yes
			Increase LIL import	Yes
			Rebuild TL203	Yes
			BDE to WAV Line	Yes
			Re-route TL202/206	Yes
		Loss of TL218 or TL242 Overloads TL266	Future Rebuild TL266	Yes
		Loss of TL202/206 Voltage collapse	Thermal uprate TL202/206, 50% series compensations and rebuild TL203 increase LIL import, or start HWDCT	Yes
			BDE to WAV Line	Yes
			4 x 175 MVAR at SOP	Yes
			Re-route TL202/206	Yes
Winter Peak	BC2, BC3, BC4	Loss of TL218 or TL242 Overloads TL266	Start HWDCT & open TL236	Reduced reliability
			Future Rebuild TL266	Yes
		Loss of TL207 Overload of TL203 In monopole no standby to start	Start HWDCT + HRDCT	Yes
			Increase LIL import	Yes
			Rebuild TL203	Yes
				Yes
		Loss of TL237 Overload of TL203 In monopole no standby to start	Start HWDCT	Yes
			Increase LIL import	Yes
			Rebuild TL203	Yes
			BDE to WAV Line	Yes
			Re-route TL202/206	Yes
		Loss of TL203 in monopole Overload TL207 & TL237	Increase LIL import	Yes
			BDE to WAV Line	Yes
			Re-route TL202/206	Yes
		Loss of TL202/206 Voltage collapse (BC3 & BC4)	Thermal uprate TL202/206, 50% series compensations and rebuild TL203 and increase LIL import (BC3 & BC4), or start HWDCT + HRDCT (BC3)	Yes

Load Condition	Base Case(s)	Comments	Upgrades	Acceptable
			BDE to WAV Line	Yes
			4 x 175 MVAR at SOP	Yes for BC3 No for BC4
			Re-route TL202/206	Yes for BC3 No for BC4
Winter Day	BC5, BC6	Loss of TL242 Overloads TL266	Start HWDCT & open TL236	Reduced reliability
			Future Rebuild TL266	Yes
		Loss of TL207 Overload of TL203	Start HWDCT & HRDCT	Yes
			Increase LIL import	Yes
			Rebuild TL203	Yes
			BDE to WAV Line	Yes
			Re-route TL202/206	Yes
		Loss of TL237 Overload of TL203	Start HWDCT & HRDCT	Yes
			Increase LIL import	Yes
			Rebuild TL203	Yes
			BDE to WAV Line	Yes
			Re-route TL202/206	Yes
		Loss of TL203 Overloads TL207 & TL237	Start HWDCT & HRDCT	Yes
			Increase LIL imports	Yes
			BDE to WAV Line	Yes
			Re-route TL202/206	Yes
		Loss of TL202/206 Voltage collapse (BC6)	Thermal uprate TL202/206, 50% series compensations and rebuild TL203 and increase LIL import	Yes
			BDE to WAV Line	Yes
			4 x 175 MVAR at SOP	No
			Re-route TL202/206	Yes
Spring/Fall Day	B7, BC8	Steady State TL202 & TL206 Overload	Thermal uprate of TL202 & TL206	Yes
			BDE to WAV Line	Yes
		Loss of TL242 Overloads TL266	Start HWDCT & open TL236	Reduced reliability
			Future Rebuild TL266	Yes
		Loss of TL207 Overloads TL202, TL206, TL203	Increase LIL imports	Yes
			Uprate TL202,TL206,TL203	Yes
			BDE to WAV Line	Yes
			Re-route TL202/206	Yes
		Loss of TL237	Increase LIL imports	Yes
			Uprate TL202,TL206,TL203	Yes

Load Condition	Base Case(s)	Comments	Upgrades	Acceptable
		Overloads TL202, TL206, TL203	BDE to WAV Line	Yes
			Re-route TL202/206	Yes
		Loss of TL203 Overloads TL202, TL206, TL207, TL237	Increase LIL imports	Yes
			BDE to WAV Line	Yes
			Re-route TL202/206	Yes
		Loss of TL202/206 Voltage collapse (BC8)	Thermal uprate TL202/206, 50% series compensations and rebuild TL203 increase LIL import	Yes
			BDE to WAV Line	Yes
			4 x 175 MVAR at SOP	No
			Re-Route TL202/206	Yes
Summer Day	BC9	No Criteria Violations BC9	None Required	Yes
	BC10	BC10 Loss of TL202/206 Thermal overload TL206/202	Start HWDCT & HRDCT	Yes
			Increase LIL imports	Yes
			Thermal uprate TL202/206	Yes
			BDE to WAV Line	Yes
Summer Night	BC11	No Criteria Violations	None Required	Yes

Figure	Base Case	System Configuration	Contingency	Island Load	Island Generation	LIL Import (MW)	Generating Reserve
1	BC1	Existing	N-0	Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
2		Third Circuit					
3		TL202/TL206 Reroute - 50% Series Compensation/75°C Thermal Upgrade					
4		TL202/TL206 Reroute - 25% Series Compensation/75°C Thermal Upgrade					
5		TL202/TL206 - 50% Series Compensation/75°C Thermal Upgrade					
6		TL202/TL206 - 25% Series Compensation/75°C Thermal Upgrade					
7	BC2	Existing	N-0	Winter Peak (1603 MW)	773 MW	830	Island
8		Third Circuit					
9		TL202/TL206 Reroute - 50% Series Compensation/75°C Thermal Upgrade					
10		TL202/TL206 Reroute - 25% Series Compensation/75°C Thermal Upgrade					
11		TL202/TL206 - 50% Series Compensation/75°C Thermal Upgrade					
12		TL202/TL206 - 25% Series Compensation/75°C Thermal Upgrade					
13	BC3	Existing	N-0	Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
14		Third Circuit					
15		TL202/TL206 Reroute - 50% Series Compensation/75°C Thermal Upgrade					
16		TL202/TL206 Reroute - 25% Series Compensation/75°C Thermal Upgrade					
17		TL202/TL206 - 50% Series Compensation/75°C Thermal Upgrade					
18		TL202/TL206 - 25% Series Compensation/75°C Thermal Upgrade					
19	BC4	Existing	N-0	Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
20		Third Circuit					
21		TL202/TL206 Reroute - 50% Series Compensation/75°C Thermal Upgrade					
22		TL202/TL206 Reroute - 25% Series Compensation/75°C Thermal Upgrade					
23		TL202/TL206 - 50% Series Compensation/75°C Thermal Upgrade					
24		TL202/TL206 - 25% Series Compensation/75°C Thermal Upgrade					
25	BC5	Existing	N-0	Winter Day (1415 MW)	585 MW	830	Island
26		Third Circuit					
27		TL202/TL206 Reroute - 50% Series Compensation/75°C Thermal Upgrade					
28		TL202/TL206 Reroute - 25% Series Compensation/75°C Thermal Upgrade					
29		TL202/TL206 - 50% Series Compensation/75°C Thermal Upgrade					
30		TL202/TL206 - 25% Series Compensation/75°C Thermal Upgrade					
31	BC6	Existing	N-0	Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
32		Third Circuit					
33		TL202/TL206 Reroute - 50% Series Compensation/75°C Thermal Upgrade					
34		TL202/TL206 Reroute - 25% Series Compensation/75°C Thermal Upgrade					
35		TL202/TL206 - 50% Series Compensation/75°C Thermal Upgrade					

Figure	Base Case	System Configuration	Contingency	Island Load	Island Generation	LIL Import (MW)	Generating Reserve
36		TL202/TL206 - 25% Series Compensation/75°C Thermal Upgrade					
37	BC7	Existing	N-0	Spring/Fall Day (1261 MW)	431 MW	830	Island
38		Third Circuit					
39		TL202/TL206 Reroute - 50% Series Compensation/75°C Thermal Upgrade					
40		TL202/TL206 Reroute - 25% Series Compensation/75°C Thermal Upgrade					
41		TL202/TL206 - 50% Series Compensation/75°C Thermal Upgrade					
42		TL202/TL206 - 25% Series Compensation/75°C Thermal Upgrade					
43	BC8	Existing	N-0	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
44		Third Circuit					
45		TL202/TL206 Reroute - 50% Series Compensation/75°C Thermal Upgrade					
46		TL202/TL206 Reroute - 25% Series Compensation/75°C Thermal Upgrade					
47		TL202/TL206 - 50% Series Compensation/75°C Thermal Upgrade					
48		TL202/TL206 - 25% Series Compensation/75°C Thermal Upgrade					
49	BC9	Existing	N-0	Summer Day (700 MW)	Minimum (325 MW)	375	LIL
50		Third Circuit					
51		TL202/TL206 Reroute - 50% Series Compensation/75°C Thermal Upgrade					
52		TL202/TL206 Reroute - 25% Series Compensation/75°C Thermal Upgrade					
53		TL202/TL206 - 50% Series Compensation/75°C Thermal Upgrade					
54		TL202/TL206 - 25% Series Compensation/75°C Thermal Upgrade					
55	B10	Existing	N-0	Monopole Summer Day (700 MW)	Minimum (154 MW)	546	LIL
56		Third Circuit					
57		TL202/TL206 Reroute - 50% Series Compensation/75°C Thermal Upgrade					
58		TL202/TL206 Reroute - 25% Series Compensation/75°C Thermal Upgrade					
59		TL202/TL206 - 50% Series Compensation/75°C Thermal Upgrade					
60		TL202/TL206 - 25% Series Compensation/75°C Thermal Upgrade					
61	B11	Existing	N-0	Summer Night (440 MW)	Minimum (320 MW)	120	LIL
62		Third Circuit					
63		TL202/TL206 Reroute - 50% Series Compensation/75°C Thermal Upgrade					
64		TL202/TL206 Reroute - 25% Series Compensation/75°C Thermal Upgrade					
65		TL202/TL206 - 50% Series Compensation/75°C Thermal Upgrade					
66		TL202/TL206 - 25% Series Compensation/75°C Thermal Upgrade					
ALTERNATIVE 1 - USE EXISTING BULK TRANSMISSION SYSTEM							
67	BC1	TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor	TL206	Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
68		TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Future Winter Peak (1757 MW)	Maximum (1085 MW)	684	LIL

Figure	Base Case	System Configuration	Contingency	Island Load	Island Generation	LIL Import (MW)	Generating Reserve
69		TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor HWD CT Generating 50 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
70		LIL Import Increased to 774 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	774	LIL
71		HWD CT and HRD CT Generating 110 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
72		Existing	TL207	Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
73		LIL Import Increased to 699 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	699	LIL
74		HWD CT Generating 50 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
75		HRD CT Generating 60 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
76		TL266 Loaded to 113 % of Thermal Rating	TL218	Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
77		HWD CT Generating 50 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
78		TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
79		TL266 Loaded to 153 % of Thermal Rating	TL242	Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
80		HWD CT Generating 50 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
81		HWD CT Generating 50 MW + TL236 Open		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
82		TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor + HWD CT Generating 50 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
83		HYDRO System Load Reduced to 1642 MW (Year 2023 - 2012 PLF) + HWD CT Generating 50 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
84		TL266 loaded 100% of Thermal Rating - HYDRO System Load Reduced to 1349 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
85		TL242 Loaded to 106% of Thermal Rating	TL266	Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
86		HWD CT Generating 50 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
87	BC2	TL266 Loaded 103% of Rating	TL218	Winter Peak (1603 MW)	773 MW	830	Island
88		HWD CT Generating 50 MW		Winter Peak (1603 MW)	774 MW	830	Island
89		TL266 loaded 141% of Thermal Rating	TL242	Winter Peak (1603 MW)	775 MW	830	Island
90		HWD CT Generating 50 MW		Winter Peak (1603 MW)	776 MW	830	Island
91		HWD CT Generating 50 MW + TL236 Open		Winter Peak (1603 MW)	777 MW	830	Island
92		TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Winter Peak (1603 MW)	778 MW	830	Island
93	BC3	TL202 Loaded 100% of Thermal Rating - LIL Import Increased to 654 MW	TL206	Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
94		TL203 Loaded 131% of Thermal Rating	TL207	Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
95		LIL Import Increased to 598 MW		Winter Peak (1603 MW)	Maximum (1085 MW)	598	LIL
96		HWD CT and HRD CT Generating 110 MW		Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
97		TL203 Loaded 118% of Thermal Rating	TL237	Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
98		LIL Import Increased to 564 MW		Winter Peak (1603 MW)	Maximum (1085 MW)	564	LIL
99		HWD CT Generating 50 MW		Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
100	BC4	TL203 Loaded 184% of Thermal Rating	TL207	Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL

Figure	Base Case	System Configuration	Contingency	Island Load	Island Generation	LIL Import (MW)	Generating Reserve
101		TL203 Loaded 155% of Thermal Rating	TL237	Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
102		TL266 Loaded 98% of Thermal Rating	TL218	Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
103		TL266 Loaded 129 % of Thermal Rating	TL242	Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
104		TL266 Loaded 99% of Thermal Rating - TL236 Open		Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
105		TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
106	BC5	TL266 Loaded 120% of Thermal Rating	TL242	Winter Day (1415 MW)	585 MW	830	Island
107		TL266 Loaded 93% of Thermal Rating - TL236 Open		Winter Day (1415 MW)	585 MW	830	Island
108	BC6	TL237 Loaded 113% of Thermal Rating/TL207 Loaded 122% of Thermal Rating	TL203	Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
109		TL237 Loaded 88% of Thermal Rating/TL207 Loaded 100% of Thermal Rating LIL Import Increased to 384 MW		Winter Day (1415 MW)	Maximum (1085 MW)	384	LIL
110		TL237 Loaded 91% of Thermal Rating/TL207 Loaded 99% of Thermal Rating HRD CT Generating 60 MW		Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
111		TL202/TL206 Loaded 100% of Thermal Rating - LIL Import Increased to 510 MW	TL202/TL206	Winter Day (1415 MW)	Maximum (1085 MW)	510	LIL
112		TL203 Loaded 159% of Thermal Rating	TL207	Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
113		TL203 Loaded 99% of Thermal Rating – LIL Import Increased to 472 MW		Winter Day (1415 MW)	Maximum (1085 MW)	472	LIL
114		TL203 Loaded 147% of Thermal Rating	TL237	Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
115		TL203 Loaded 98% of Thermal Rating – HWD CT and HRD CT Generating 110 MW		Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
116	BC7	TL266 Loaded 128% of Thermal Rating	TL242	Spring/Fall Day (1261 MW)	431 MW	830	Island
117		TL266 Loaded 100% of Thermal Rating - TL236 Open		Spring/Fall Day (1261 MW)	431 MW	830	Island
118	BC8	Existing	N-0	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
119		TL202/TL206 Loaded 107% of Thermal Rating	TL201	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
120		TL202/TL206 Loaded 100% of Thermal Rating – LIL Import Increased to 204 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	204	LIL
121		TL202/TL206 Loaded 100% of Thermal Rating – LIL Import Increased to 466 MW	TL202/TL206	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	466	LIL
122		TL202/TL206/TL207/TL237 Loaded to 110/110/154/138% of Thermal Rating	TL203	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
123		TL207 Loaded 110% of Thermal Rating – HWD CT and HRD CT generating 110 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
124		TL203/TL202/TL206 Loaded 208/113/113% of Thermal Rating	TL207	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
125		TL203 Loaded 100% of Thermal Rating – LIL Import Increased to 408 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	408	LIL
126		TL201 Loaded 100% of Thermal Rating – LIL Import Increased to 241 MW	TL217	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	241	LIL
127		TL202/TL206/TL203 Loaded 106/106/180% of Thermal Rating	TL237	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
128		TL203 Loaded 100% of Thermal Rating – LIL Import Increased to 366 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	366	LIL
129		TL266 Loaded 119% of Thermal Rating	TL242	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
130		TL266 Loaded 93% of Thermal Rating – TL236 Open		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL

Figure	Base Case	System Configuration	Contingency	Island Load	Island Generation	LIL Import (MW)	Generating Reserve
ALTERNATIVE 2- BUILD NEW 230 kV TRANSMISSION LINE BETWEEN BDE AND WAV							
131	BC1	TL202/TL206 Loaded 74% of Thermal Rating	TL202/TL206	Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
132		No violation of Planning Criteria	TL207	Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
133	BC3	TL202/TL206 Loaded 77% of Thermal Rating Insufficient Island Generation Due to Increase in System Losses	TL202/TL206	Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
134		TL202/TL206 Out of Service – LIL Increased to 532 MW	TL202/TL206	Winter Peak (1603 MW)	Maximum (1085 MW)	532	LIL
135		No violation of Planning Criteria	TL207	Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
136		No violation of Planning Criteria	TL237	Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
137	BC4	TL202/TL206 Loaded 95% of Thermal Rating Insufficient Island Generation Due to Increase in System Losses	TL202/TL206	Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
138		No violation of Planning Criteria - LIL Increased to 218 MW		Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	218	LIL
139	BC6	No violation of Planning Criteria	TL203	Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
140		TL202/TL206 Loaded 87% of Thermal Rating Insufficient Island Generation Due to Increase in System Losses	TL202/TL206	Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
141		No violation of Planning Criteria - LIL Increased to 346 MW		Winter Day (1415 MW)	Maximum (1085 MW)	346	LIL
142		No violation of Planning Criteria	TL207	Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
143		No violation of Planning Criteria	TL237	Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
144	BC8	No violation of Planning Criteria	TL203	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
145		TL217 Loaded 117% of Thermal Rating	TL202/TL206	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
146		No violation of Planning Criteria - LIL Increased to 254 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	254	LIL
147		TL203 Loaded 112% of Thermal Rating	TL207	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
148		No violation of Planning Criteria - LIL Increased to 224 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	224	LIL
149		TL201 Loaded 126% of Thermal Rating	TL217	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
150		No violation of Planning Criteria - LIL Increased to 242 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	242	LIL
151		TL203 Loaded 103% of Thermal Rating	TL237	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
152		No violation of Planning Criteria - LIL Increased to 190 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	190	LIL
ALTERNATIVE 3 - COMPLETE 75°C THERMAL UPRATE ON TL202/TL206, SERIES COMPENSATE TL202/TL206 BY 25% AND REBUILD TL203 WITH 804 KCMIL AACSR/TW CONDUCTOR							
153	BC1	TL202/TL206 Loaded 111% of Thermal Rating Insufficient Island Generation Due to Increase in System Losses	TL202/TL206	Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
154		No violation of Planning Criteria - LIL Increased to 707 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	707	LIL
155		TL266 Loaded 150% of Thermal Rating	TL242	Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
156		TL266 Loaded 97% of Thermal Rating - TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor - HWD CT Generating 50 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
157		TL266 Loaded 97% of Thermal Rating - TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor - TL236 Open		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL

Figure	Base Case	System Configuration	Contingency	Island Load	Island Generation	LIL Import (MW)	Generating Reserve
158		TL242 Loaded 104% of Thermal Rating	TL266	Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
159		TL242 Loaded 97% of Thermal Rating - HWD CT Generating 50 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
160	BC2	TL266 Loaded 102% of Thermal Rating	TL218	Winter Peak (1603 MW)	773 MW	830	Island
161		TL266 Loaded 96% of Thermal Rating - HWD CT Generating 50 MW		Winter Peak (1603 MW)	773 MW	830	Island
162		TL266 Loaded 71% of Thermal Rating TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Winter Peak (1603 MW)	773 MW	830	Island
163		TL266 Loaded 138% of Thermal Rating	TL242	Winter Peak (1603 MW)	773 MW	830	Island
164		TL266 Loaded 99% of Thermal Rating - HWD CT Generating 50 MW and TL236 Open		Winter Peak (1603 MW)	773 MW	830	Island
165		TL266 Loaded 95% of Thermal Rating TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Winter Peak (1603 MW)	773 MW	830	Island
166	BC3	TL202/TL206 Loaded 121% of Thermal Rating Insufficient Island Generation Due to Increase in System Losses	TL202/TL206	Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
167		TL202/TL206 Loaded 90% of Thermal Rating - HWD CT and HRD CT Generating 110 MW		Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
168		TL202/TL206 Loaded 100% of Thermal Rating - LIL Increased to 590 MW		Winter Peak (1603 MW)	Maximum (1085 MW)	590	LIL
169		TL266 Loaded 134% of Thermal Rating	TL242	Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
170		TL266 Loaded 95% of Thermal Rating - HWD CT Generating 50 MW and TL236 Open		Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
171		TL266 Loaded 92% of Thermal Rating TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
172	BC4	TL202/TL206 Loaded 136% of Thermal Rating Insufficient Island Generation Due to Increase in System Losses	TL202/TL206	Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
173		TL202/TL206 Loaded 100% of Thermal Rating - LIL Increased to 352 MW		Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	352	LIL
174		TL237/TL207 Loaded 120%/133% of Thermal Rating Insufficient Island Generation Due to Increase in System Losses	TL203	Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
175		TL237/TL207 Loaded 87%/100% of Thermal Rating - LIL Increased to 297 MW		Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	297	LIL
176		TL203 Loaded 132% of Thermal Rating	TL207	Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
177		TL203 Loaded 100% of Thermal Rating - LIL Increased to 295 MW		Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	295	LIL
178		TL266 Loaded 101% of Thermal Rating	TL218	Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
179		TL266 Loaded 70% of Thermal Rating TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
180		TL266 Loaded 132% of Thermal Rating	TL242	Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
181		TL266 Loaded 100% of Thermal Rating - TL236 Open		Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL

Figure	Base Case	System Configuration	Contingency	Island Load	Island Generation	LIL Import (MW)	Generating Reserve
182		TL266 Loaded 91% of Thermal Rating TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
183	BC5	TL266 Loaded 119% of Thermal Rating	TL242	Winter Day (1415 MW)	585 MW	830	Island
184		TL266 Loaded 93% of Thermal Rating - TL236 Open		Winter Day (1415 MW)	585 MW	830	Island
185		TL266 Loaded 82% of Thermal Rating TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Winter Day (1415 MW)	585 MW	830	Island
186	BC6	TL202/TL206 Loaded 137% of Thermal Rating Insufficient Island Generation Due to Increase in System Losses	TL202/TL206	Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
187		TL266 Loaded 101% of Thermal Rating - HWD CT and HRD CT Generating 110 MW		Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
188		TL266 Loaded 100% of Thermal Rating - LIL Increased to 446 MW		Winter Day (1415 MW)	Maximum (1085 MW)	446	LIL
189		TL207 Loaded 98% of Thermal Rating – HWD CT generating 50 MW	TL203	Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
190		TL207 Loaded 100% of Thermal Rating – LIL Increased to 378 MW		Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
191		TL203 Loaded 113% of Thermal Rating	TL207	Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
192		TL203 Loaded 98% of Thermal Rating - HWD CT Generating 50 MW		Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
193		TL203 Loaded 100% of Thermal Rating - LIL Increased to 380 MW		Winter Day (1415 MW)	Maximum (1085 MW)	380	LIL
194		TL266 Loaded 112% of Thermal Rating	TL242	Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
195		TL266 Loaded 88% of Thermal Rating - TL236 Open		Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
196		TL266 Loaded 78% of Thermal Rating TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
197	BC7	TL266 Loaded 127% of Thermal Rating	TL242	Spring/Fall Day (1261 MW)	431 MW	830	Island
198		TL266 Loaded 88% of Thermal Rating - HWD CT Generating 50 MW and TL236 Open		Spring/Fall Day (1261 MW)	431 MW	830	Island
199		TL266 Loaded 100% of Thermal Rating - TL236 Open		Spring/Fall Day (1261 MW)	431 MW	830	Island
200		TL266 Loaded 88% of Thermal Rating TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Spring/Fall Day (1261 MW)	431 MW	830	Island
201	BC8	TL202/TL206 Loaded 169% of Thermal Rating Insufficient Island Generation Due to Increase in System Losses	TL202/TL206	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
202		TL202/TL206 Loaded 131% of Thermal Rating - HWD CT and HRD CT Generating 110 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
203		TL202/TL206 Loaded 100% of Thermal Rating - LIL Increased to 384 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	384	LIL
204		TL207/TL237 Loaded 157%/144% of Thermal Rating	TL203	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
205		TL207/TL237 Loaded 100%/88% of Thermal Rating - LIL Increased to 329 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	329	LIL
206		TL203 Loaded 151% of Thermal Rating	TL207	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
207		TL203 Loaded 110% of Thermal Rating - HWD CT and HRD CT Generating 110 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
208		TL203 Loaded 100% of Thermal Rating - LIL Increased to 322 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	322	LIL
209		TL201 Loaded 135% of Thermal Rating	TL217	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
210		TL201 Loaded 86% of Thermal Rating - HWD CT and HRD CT Generating 110 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
211		TL201 Loaded 100% of Thermal Rating - LIL Increased to 252 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	252	LIL

Figure	Base Case	System Configuration	Contingency	Island Load	Island Generation	LIL Import (MW)	Generating Reserve
212		TL201 Loaded 85% of Thermal Rating TL201 Rebuilt with 804 kcmil 23/19 AACSR T/W Conductor		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
213		TL203 Loaded 139% of Thermal Rating	TL237	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
214		TL203 Loaded 100% of Thermal Rating - HWD CT and HRD CT Generating 110 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
215		TL203 Loaded 100% of Thermal Rating - LIL Increased to 288 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	288	LIL
216		TL266 Loaded 118% of Thermal Rating	TL242	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
217		TL266 Loaded 92% of Thermal Rating - TL236 Open		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
218		TL266 Loaded 82% of Thermal Rating TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
ALTERNATIVE 4 - COMPLETE 75°C THERMAL UPRATE ON TL202/TL206, SERIES COMPENSATE TL202/TL206 BY 50% AND REBUILD TL203 WITH 804 KCMIL AACSR/TW CONDUCTOR							
219	BC1	TL202/TL206 Loaded 114% of Thermal Rating Insufficient Island Generation Due to Increase in System Losses	TL202/TL206	Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
220		No violation of Planning Criteria - LIL Increased to 723 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	723	LIL
221		TL202/TL206 Loaded 107% of Thermal Rating TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
222		TL202/TL206 Loaded 107% of Thermal Rating TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor LIL Increased to 695 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	695	LIL
223		No violation of Planning Criteria	TL207	Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
224		No violation of Planning Criteria	TL237	Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
225	BC3	TL202/TL206 Loaded 135% of Thermal Rating Insufficient Island Generation Due to Increase in System Losses	TL202/TL206	Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
226		TL202/TL206 Loaded 100% of Thermal Rating - LIL Increased to 607 MW		Winter Peak (1603 MW)	Maximum (1085 MW)	607	LIL
227		TL202/TL206 Loaded 107% of Thermal Rating TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor LIL Increased to 584 MW		Winter Peak (1603 MW)	Maximum (1085 MW)	584	LIL
228		No violation of Planning Criteria	TL207	Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
229		No violation of Planning Criteria	TL237	Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
230		TL266 Loaded 134% of Thermal Rating	TL242	Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
231		TL266 Loaded 95% of Thermal Rating - HWD CT Generating 50 MW and TL236 Open		Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
232		TL266 Loaded 93% of Thermal Rating TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
233	BC4	TL202/TL206 Loaded 149% of Thermal Rating	TL202/TL206	Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
234		TL202/TL206 Loaded 100% of Thermal Rating - LIL Increased to 368 MW		Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	368	LIL
235		TL237/TL207 Loaded 127%/115% of Thermal Rating	TL203	Monopole Winter Peak (1458 MW)	Maximum + CTs (1258	200	LIL

Figure	Base Case	System Configuration	Contingency	Island Load	Island Generation	LIL Import (MW)	Generating Reserve
					MW)		
236		TL207/TL237 Loaded 100%/87% of Thermal Rating - LIL Increased to 294 MW		Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	294	LIL
237		TL203 Loaded 125% of Thermal Rating	TL207	Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
238		TL203 Loaded 100% of Thermal Rating - LIL Increased to 288 MW		Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	288	LIL
239		TL266 Loaded 127% of Thermal Rating	TL242	Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
240		TL266 Loaded 95% of Thermal Rating - TL236 Open		Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
241		TL266 Loaded 88% of Thermal Rating TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
242		TL266 Loaded 98% of Thermal Rating	TL218	Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
243		TL242 Loaded 89% of Thermal Rating	TL266	Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
244	BC5	TL266 Loaded 83% of Thermal Rating TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor	TL242	Winter Day (1415 MW)	585 MW	830	Island
245		TL266 Loaded 95% of Thermal Rating - TL236 Open		Winter Day (1415 MW)	585 MW	830	Island
246		TL237/TL207 Loaded 114%/104% of Thermal Rating	TL203	Winter Day (1415 MW)	585 MW	830	Island
247		TL207/TL237 Loaded 96%/87% of Thermal Rating - HRD CT Generating 60 MW		Winter Day (1415 MW)	585 MW	830	Island
248	BC6	TL202/TL206 Loaded 100% of Thermal Rating - LIL Increased to 466 MW	TL202/TL206	Winter Day (1415 MW)	Maximum (1085 MW)	466	LIL
249		TL203 Loaded 112% of Thermal Rating	TL207	Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
250		TL203 Loaded 100% of Thermal Rating - LIL Increased to 372 MW		Winter Day (1415 MW)	Maximum (1085 MW)	372	LIL
251		TL203 Loaded 95% of Thermal Rating - HRD CT Generating 60 MW		Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
252		TL203 Loaded 98% of Thermal Rating - HWD CT Generating 50 MW		Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
253		TL203 Loaded 103% of Thermal Rating	TL237	Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
254		TL203 Loaded 100% of Thermal Rating - LIL Increased to 340 MW		Winter Day (1415 MW)	Maximum (1085 MW)	340	LIL
255		TL203 Loaded 89% of Thermal Rating - HWD CT Generating 50 MW		Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
256		TL203 Loaded 86% of Thermal Rating - HRD CT Generating 60 MW		Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
257	BC8	TL207/TL237 Loaded 151%/139% of Thermal Rating	TL203	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
258		TL207/TL237 Loaded 100%/88% of Thermal Rating - LIL Increased to 329 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	329	LIL
259		TL202/TL206 Loaded 169% of Thermal Rating	TL202/TL206	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
260		TL202/TL206 Loaded 100% of Thermal Rating - HWD CT and HRD CT Generating 110 MW LIL Increased to 290 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	290	LIL
261		TL202/TL206 Loaded 100% of Thermal Rating - LIL Increased to 399 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	399	LIL
262		TL203 Loaded 146% of Thermal Rating	TL207	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL

Figure	Base Case	System Configuration	Contingency	Island Load	Island Generation	LIL Import (MW)	Generating Reserve
263		TL201 Loaded 129% of Thermal Rating		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
264		TL201 Loaded 86% of Thermal Rating - HRD CT and HWD CT Generating 110 MW	TL217	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
265		TL201 Loaded 100% of Thermal Rating - LIL Increased to 247 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	247	LIL
266		TL203 Loaded 135% of Thermal Rating	TL237	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
ALTERNATIVE 5 - COMPLETE 75°C THERMAL UPRATE ON TL202/TL206, SERIES COMPENSATE TL202/TL206 BY 25% AND REROUTE FROM SSD TO WAV							
267	BC1	TL202/TL206 Loaded 110% of Thermal Rating Insufficient Island Generation Due to Increase in System Losses	TL202/TL206	Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
268		TL202/TL206 Loaded 94% of Thermal Rating - HWD CT Generating 50 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
269		TL202/TL206 Loaded 98% of Thermal Rating - LIL Increased to 708 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	708	LIL
270		TL266 Loaded 150% of Thermal Rating	TL242	Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
271		TL266 Loaded 95% of Thermal Rating TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor HWD CT Generating 50 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
272		TL242 Loaded 104% of Thermal Rating	TL266	Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
273		TL242 Loaded 96% of Thermal Rating - HWD CT Generating 50 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
274		TL266 Loaded 103% of Thermal Rating	TL218	Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
275		TL266 Loaded 95% of Thermal Rating - HWD CT Generating 50 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
276	BC2	TL266 Loaded 137% of Thermal Rating	TL242	Winter Peak (1603 MW)	773 MW	830	Island
277		TL266 Loaded 99% of Thermal Rating - HWD CT Generating 50 MW and TL236 Open		Winter Peak (1603 MW)	773 MW	830	Island
278		TL266 Loaded 96% of Thermal Rating TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Winter Peak (1603 MW)	773 MW	830	Island
279	BC3	TL202/TL206 Loaded 118% of Thermal Rating	TL202/TL206	Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
280		TL202/TL206 Loaded 89% of Thermal Rating - HWD CT and HRD CT Generating 110 MW	TL202/TL206	Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
281		TL202/TL206 Loaded 100% of Thermal Rating - LIL Increased to 577 MW	TL202/TL206	Winter Peak (1603 MW)	Maximum (1085 MW)	577	LIL
282		TL266 Loaded 132% of Thermal Rating	TL242	Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
283		TL266 Loaded 94% of Thermal Rating - HWD CT Generating 50 MW and TL236 Open		Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
284		TL266 Loaded 94% of Thermal Rating TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
285	BC4	TL202/TL206 Loaded 100% of Thermal Rating - LIL Increased to 347 MW	TL202/TL206	Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
286		TL266 Loaded 128% of Thermal Rating	TL242	Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
287		TL266 Loaded 97% of Thermal Rating - HWD CT Generating 50 MW		Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
288	BC5	TL266 Loaded 119% of Thermal Rating	TL242	Winter Day (1415 MW)	585 MW	830	Island
289		TL266 Loaded 109% of Thermal Rating - HWD CT Generating 50 MW		Winter Day (1415 MW)	585 MW	830	Island

Figure	Base Case	System Configuration	Contingency	Island Load	Island Generation	LIL Import (MW)	Generating Reserve
290		TL266 Loaded 93% of Thermal Rating - TL236 Open		Winter Day (1415 MW)	585 MW	830	Island
291		TL266 Loaded 82% of Thermal Rating TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Winter Day (1415 MW)	585 MW	830	Island
292	BC6	TL202/TL206 Loaded 135% of Thermal Rating	TL202/TL206	Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
293		TL202/TL206 Loaded 100% of Thermal Rating - HWD CT and HRD CT Generating 110 MW		Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
294		TL202/TL206 Loaded 100% of Thermal Rating - LIL Increased to 442 MW		Winter Day (1415 MW)	Maximum (1085 MW)	442	LIL
295		TL266 Loaded 112% of Thermal Rating	TL242	Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
296		TL266 Loaded 88% of Thermal Rating - TL236 Open		Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
297		TL266 Loaded 78% of Thermal Rating TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
298	BC7	TL266 Loaded 127% of Thermal Rating	TL242	Spring/Fall Day (1261 MW)	431 MW	830	Island
299		TL266 Loaded 127% of Thermal Rating - HWD CT Generating 50 MW		Spring/Fall Day (1261 MW)	431 MW	830	Island
300		TL266 Loaded 127% of Thermal Rating - TL236 Open		Spring/Fall Day (1261 MW)	431 MW	830	Island
301		TL266 Loaded 89% of Thermal Rating TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Spring/Fall Day (1261 MW)	431 MW	830	Island
302	BC8	TL202/TL206 Loaded 100% of Thermal Rating - LIL Increased to 365 MW	TL202/TL206	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	365	LIL
303		TL202/TL206 Loaded 124% of Thermal Rating - HWD CT and HRD CT Generating 110 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
304		TL202/TL206 Loaded 100% of Thermal Rating - HWD CT and HRD CT Generating 110 MW LIL Increased to 254 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	254	LIL
305		TL201 Loaded 124% of Thermal Rating	TL217	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
306		TL201 Loaded 98% of Thermal Rating - HRD CT Generating 60 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
307		TL201 Loaded 100% of Thermal Rating - LIL Import Increased to 232 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	232	LIL
308		TL201 Loaded 87% of Thermal Rating TL201 Rebuilt with 804 kcmil 23/19 AACSR/TW Conductor		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
309		TL266 Loaded 117% of Thermal Rating	TL242	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
310		TL266 Loaded 104% of Thermal Rating - HWD CT Generating 50 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
311		TL266 Loaded 90% of Thermal Rating - TL236 Open		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
312		TL266 Loaded 81% of Thermal Rating TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
ALTERNATIVE 6 - COMPLETE 75°C THERMAL UPRATE ON TL202/TL206, SERIES COMPENSATE TL202/TL206 BY 50% AND REROUTE FROM SSD TO WAV							
313	BC1	TL202/TL206 Loaded 112% of Thermal Rating Insufficient Island Generation Due to Increase in System Losses	TL202/TL206	Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
314		TL202/TL206 Loaded 100% of Thermal Rating - LIL Increased to 715 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	715	LIL
315		TL202/TL206 Loaded 104% of Thermal Rating TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL

Figure	Base Case	System Configuration	Contingency	Island Load	Island Generation	LIL Import (MW)	Generating Reserve
316		TL202/TL206 Loaded 104% of Thermal Rating TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor LIL Increased to 689 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	689	LIL
317		TL202/TL206 Loaded 89% of Thermal Rating TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor HRD CT Generating 60 MW		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
318	BC3	TL202/TL206 Loaded 124% of Thermal Rating Insufficient Island Generation Due to Increase in System Losses	TL202/TL206	Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
319		TL202/TL206 Loaded 91% of Thermal Rating - HWD CT and HRD CT Generating 110 MW		Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
320		TL202/TL206 Loaded 86% of Thermal Rating TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor HRD CT and HWD CT Generating 110 MW		Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
321		TL202/TL206 Loaded 100% of Thermal Rating TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor LIL Increased to 571 MW		Winter Peak (1603 MW)	Maximum (1085 MW)	571	LIL
322	BC4	TL202/TL206 Loaded 144% of Thermal Rating Insufficient Island Generation Due to Increase in System Losses	TL202/TL206	Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
323		TL202/TL206 Loaded 100% of Thermal Rating - LIL Increased to 431 MW		Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	431	LIL
324	BC6	TL202/TL206 Loaded 135% of Thermal Rating Insufficient Island Generation Due to Increase in System Losses	TL202/TL206	Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
325		TL202/TL206 Loaded 100% of Thermal Rating - LIL Increased to 454 MW		Winter Day (1415 MW)	Maximum (1085 MW)	454	LIL
326		TL202/TL206 Loaded 104% of Thermal Rating HRD CT and HWD CT Generating 110 MW		Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
327		TL202/TL206 Loaded 125% of Thermal Rating TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
328		TL202/TL206 Loaded 100% of Thermal Rating TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor LIL Increased to 428 MW		Winter Day (1415 MW)	Maximum (1085 MW)	428	LIL
329		TL202/TL206 Loaded 97% of Thermal Rating TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor HRD CT and HWD CT Generating 110 MW		Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
330	BC8	TL202/TL206 Loaded 171% of Thermal Rating Insufficient Island Generation Due to Increase in System Losses	TL202/TL206	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
331		TL202/TL206 Loaded 100% of Thermal Rating - HWD CT and HRD CT Generating 110 MW LIL Increased to 272 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	272	LIL
332		TL202/TL206 Loaded 100% of Thermal Rating - LIL Increased to 384 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	384	LIL

Figure	Base Case	System Configuration	Contingency	Island Load	Island Generation	LIL Import (MW)	Generating Reserve
333		TL202/TL206 Loaded 169% of Thermal Rating TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
334		TL202/TL206 Loaded 100% of Thermal Rating TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor HRD CT and HWD CT Generating 110 MW - LIL Increased to 287 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	287	LIL
335		TL202/TL206 Loaded 100% of Thermal Rating TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor LIL Increased to 398 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	398	LIL
ALTERNATIVE 7 - INCREASE NUMBER OF HIGH INERTIA SYNCHRONOUS CONDENSERS (HISCs) AT SOLDIERS POND (SOP)							
336	BC1	TL202/TL206 Loaded 132% of Thermal Rating - 3x175 MVAR HISCs in Service at SOP	TL202/TL206	Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
337		TL202/TL206 Loaded 98% of Thermal Rating - HWD CT and HRD CT Generating 110 MW 3x175 MVAR HISCs in Service at SOP		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
338		TL202/TL206 Loaded 100% of Thermal Rating - LIL Increased to 779 MW 3x175 MVAR HISCs in Service at SOP		Future Winter Peak (1757 MW)	Maximum (1085 MW)	779	LIL
339	BC3	TL202/TL206 Loaded 118% of Thermal Rating - 3x175 MVAR HISCs in Service at SOP	TL202/TL206	Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
340		TL202/TL206 Loaded 108% of Thermal Rating - 3x175 MVAR HISCs in Service at SOP HWD CT and HRD CT Generating 110 MW		Winter Peak (1603 MW)	Maximum (1085 MW)	518	LIL
341		TL202/TL206 Loaded 100% of Thermal Rating - LIL Increased to 653 MW 3x175 MVAR HISCs in Service at SOP		Winter Peak (1603 MW)	Maximum (1085 MW)	653	LIL
342	BC4	TL202/TL206 Loaded 156% of Thermal Rating - 3x175 MVAR HISCs in Service at SOP and 191.75 MVAR Shunt Cap Bank at CBC - LIL Increased to 240 MW	TL202/TL206	Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	240	LIL
343		TL202/TL206 Loaded 100% of Thermal Rating - 3x175 MVAR HISCs in Service at SOP and LIL Increased to 427 MW		Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	427	LIL
344	BC6	TL202/TL206 Loaded 158% of Thermal Rating - 3x175 MVAR HISCs in Service at SOP and 115.05 MVAR Shunt Cap Bank at CBC	TL202/TL206	Winter Day (1415 MW)	Maximum (1085 MW)	330	LIL
345		TL202/TL206 Loaded 100% of Thermal Rating - 3x175 MVAR HISCs in Service at SOP and LIL Increased to 510 MW		Winter Day (1415 MW)	Maximum (1085 MW)	510	LIL
346	BC8	TL202/TL206 Loaded 213% of Thermal Rating - 3x175 MVAR HISCs in Service at SOP and 230.1 MVAR Shunt Cap Bank at CBC	TL202/TL206	Spring/Fall Day (1261 MW)	Maximum (1085 MW)	176	LIL
347		TL202/TL206 Loaded 100% of Thermal Rating - 3x175 MVAR HISCs in Service at SOP and LIL Increased to 468 MW		Spring/Fall Day (1261 MW)	Maximum (1085 MW)	468	LIL
TL267 Conductor Optimization - BC1 Future Winter Peak Case							
348	BC1	TL267 Out of Service	-	Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
349		TL267 Built with 636 kcmil 26/7 ACSR GROSBEAK Conductor		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
350		TL267 Built with 795 kcmil 26/7 ACSR DRAKE Conductor		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL
351		TL267 Built with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Future Winter Peak (1757 MW)	Maximum (1085 MW)	672	LIL

Figure	Base Case	System Configuration	Contingency	Island Load	Island Generation	LIL Import (MW)	Generating Reserve
352	BC4	TL267 Out of Service	-	Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
353		TL267 Built with 636 kcmil 26/7 ACSR GROSBEAK Conductor		Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
354		TL267 Built with 795 kcmil 26/7 ACSR DRAKE Conductor		Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL
355		TL267 Built with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor		Monopole Winter Peak (1458 MW)	Maximum + CTs (1258 MW)	200	LIL

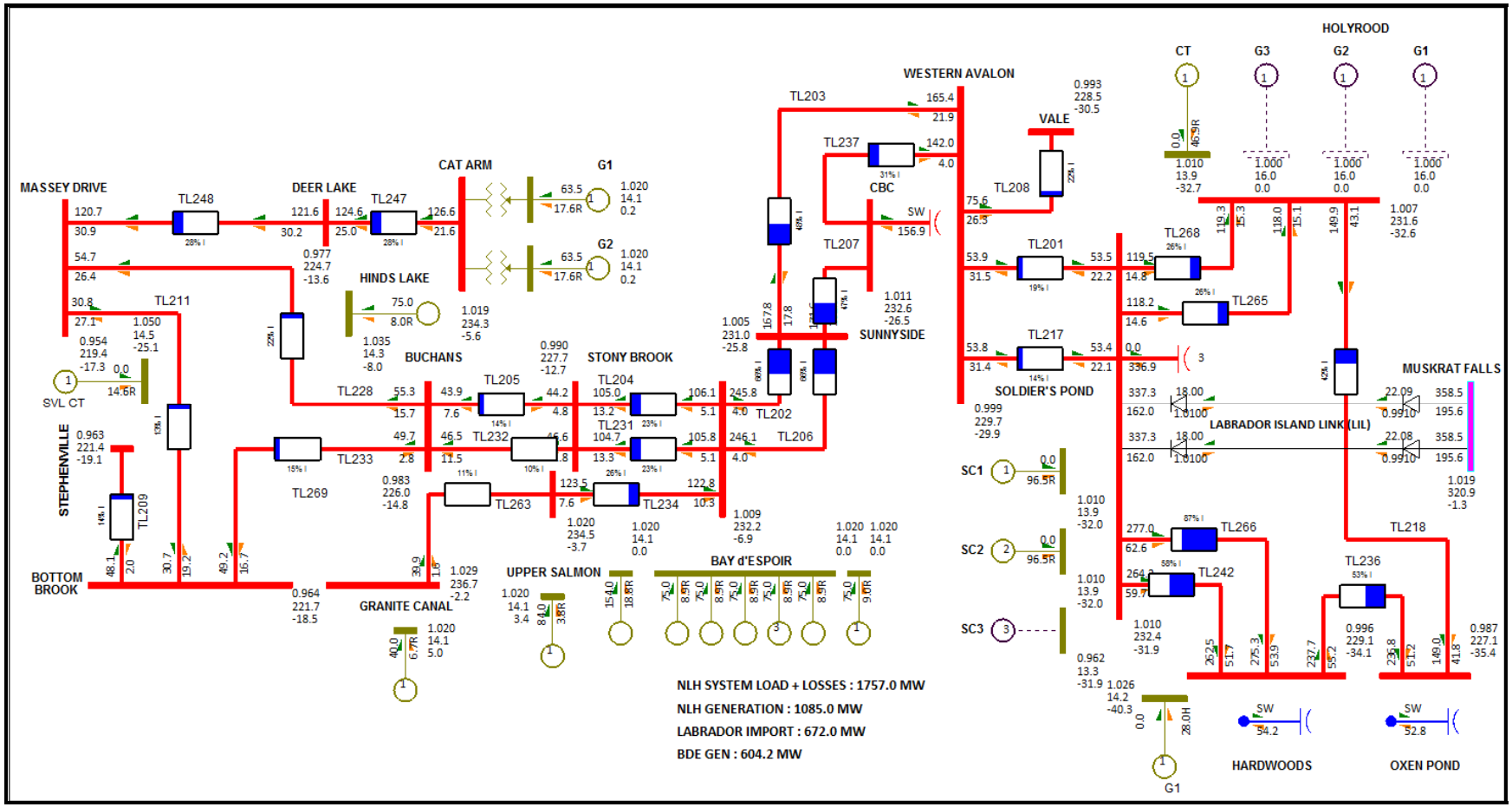


Figure 1 – Base Case 1 (BC1) Load Flow Plot – Pre-Contingency

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

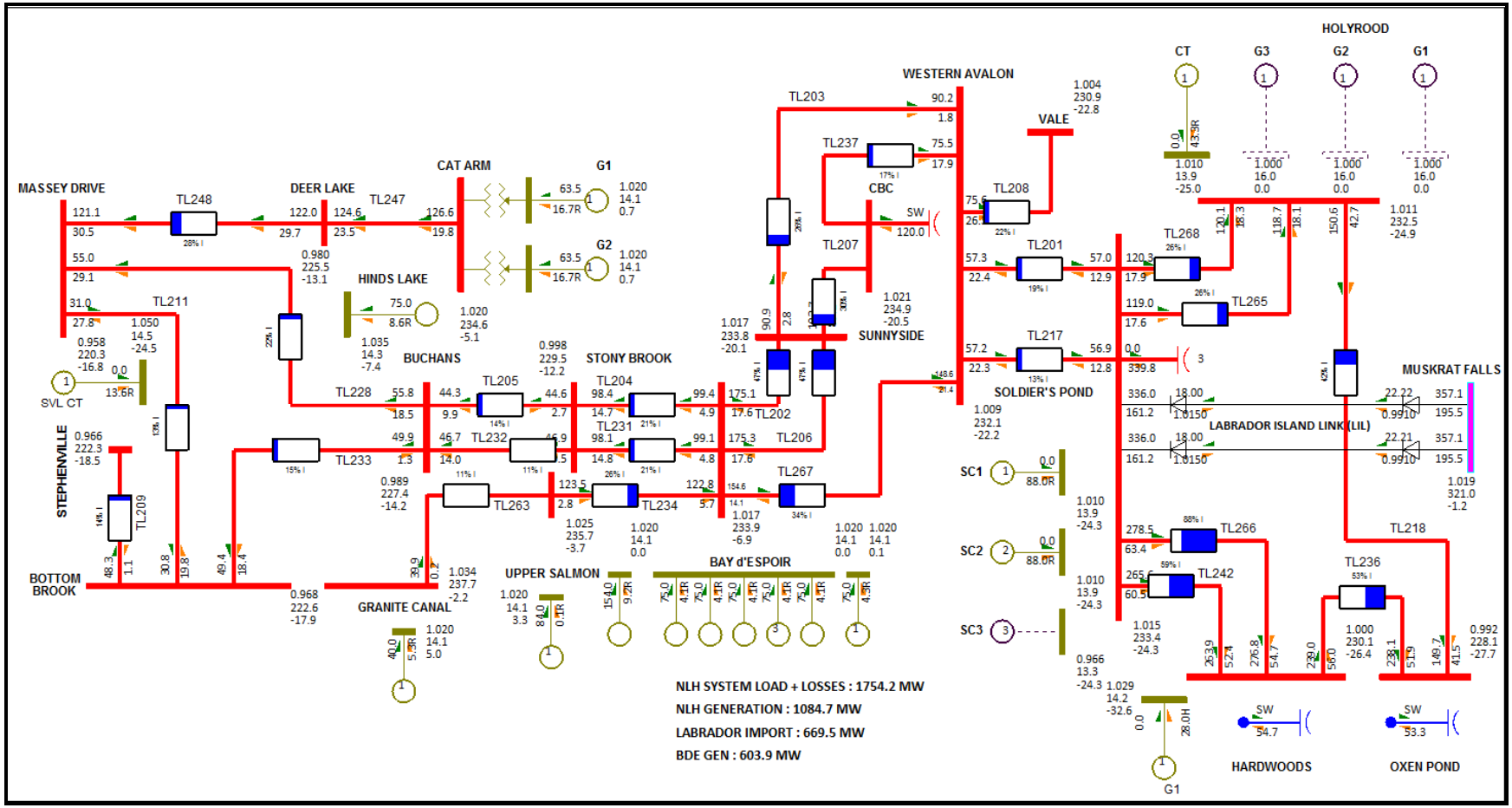


Figure 2 – Base Case 1 (BC1) Load Flow Plot – Pre-Contingency

New 230 kV Transmission Line Installed Between BDE and WAV

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

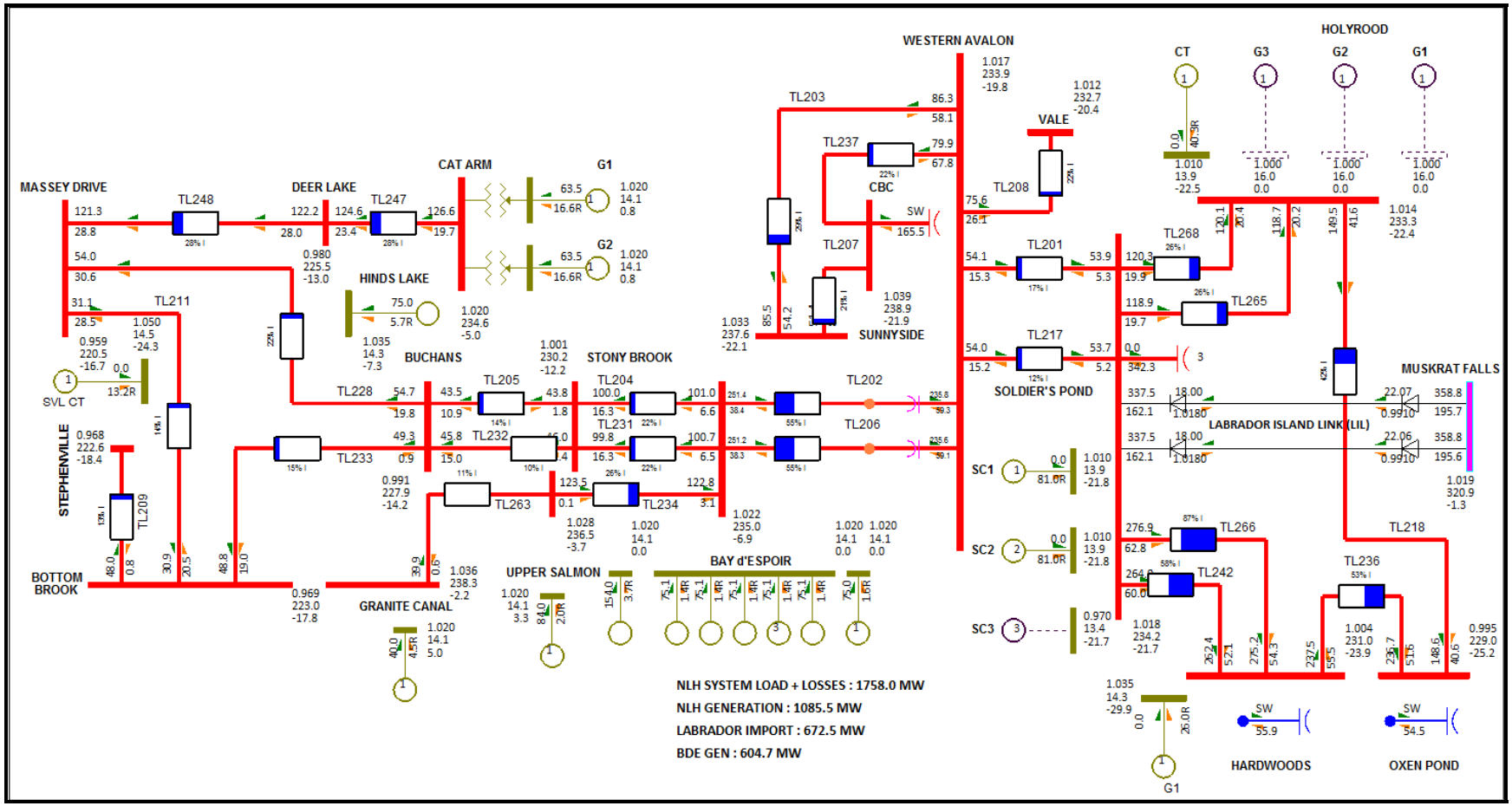


Figure 3 – Base Case 1 (BC1) Load Flow Plot – Pre-Contingency

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

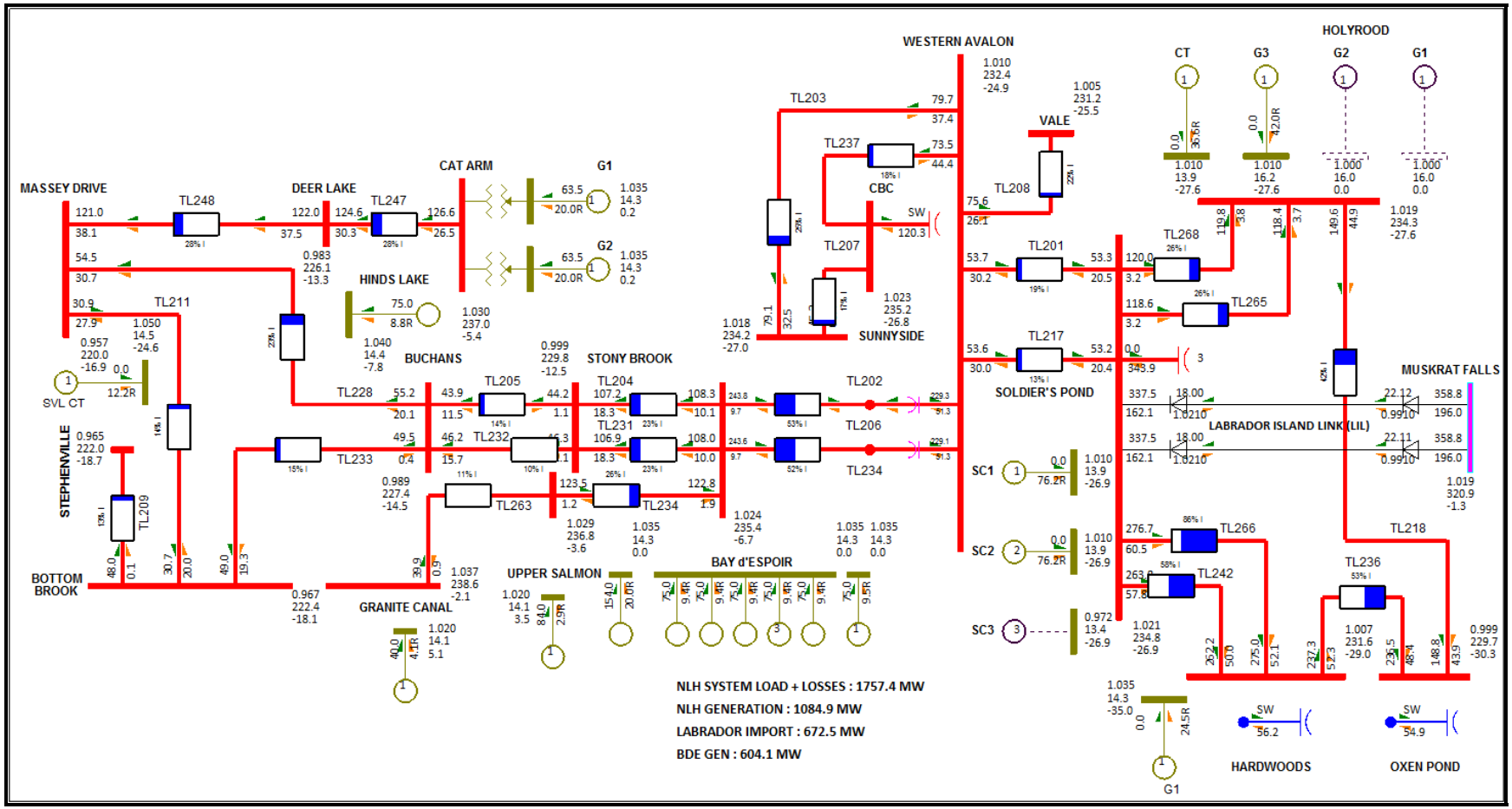


Figure 4 – Base Case 1 (BC1) Load Flow Plot – Pre-Contingency

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

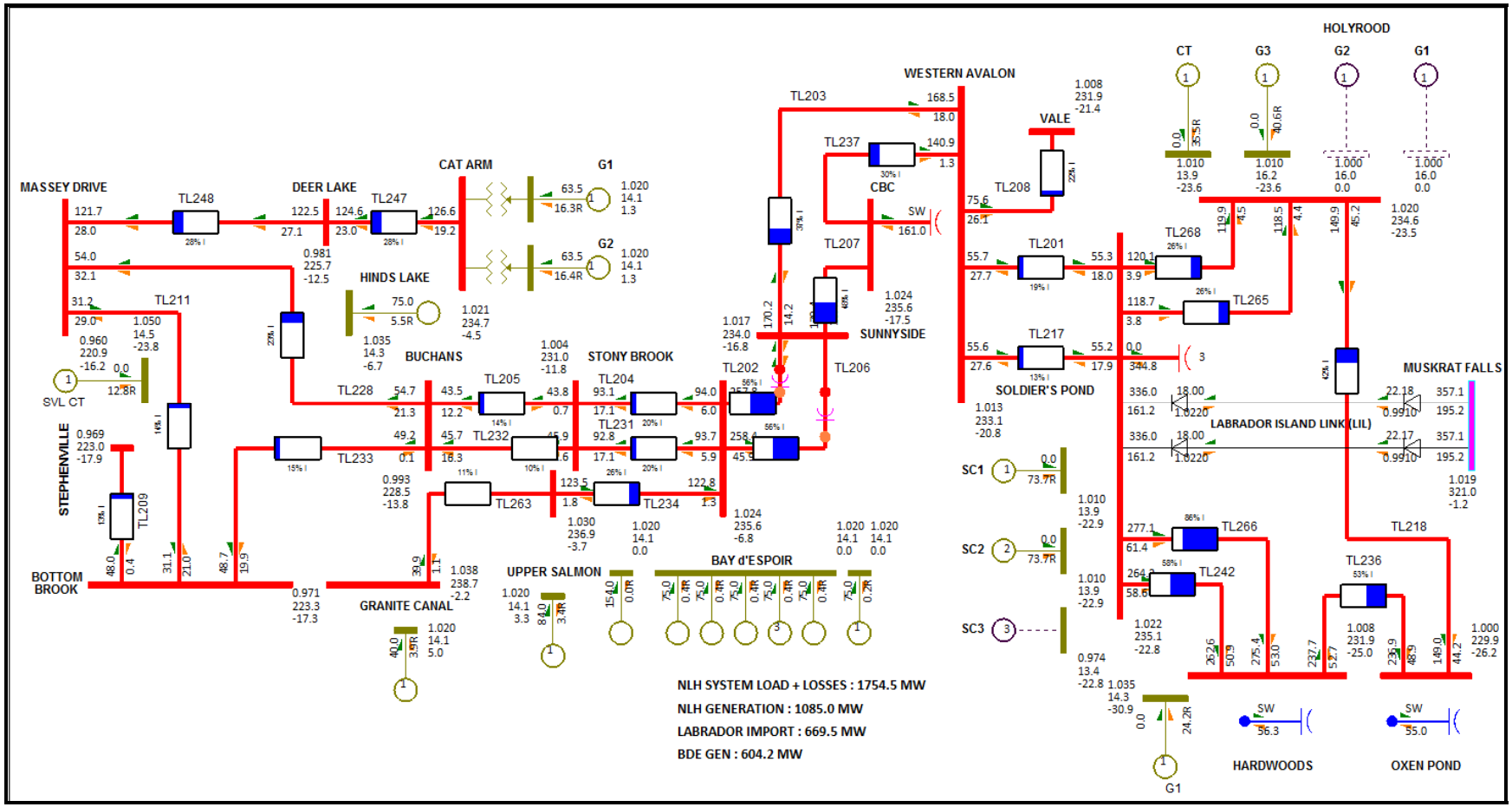


Figure 5 – Base Case 1 (BC1) Load Flow Plot – Pre-Contingency

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

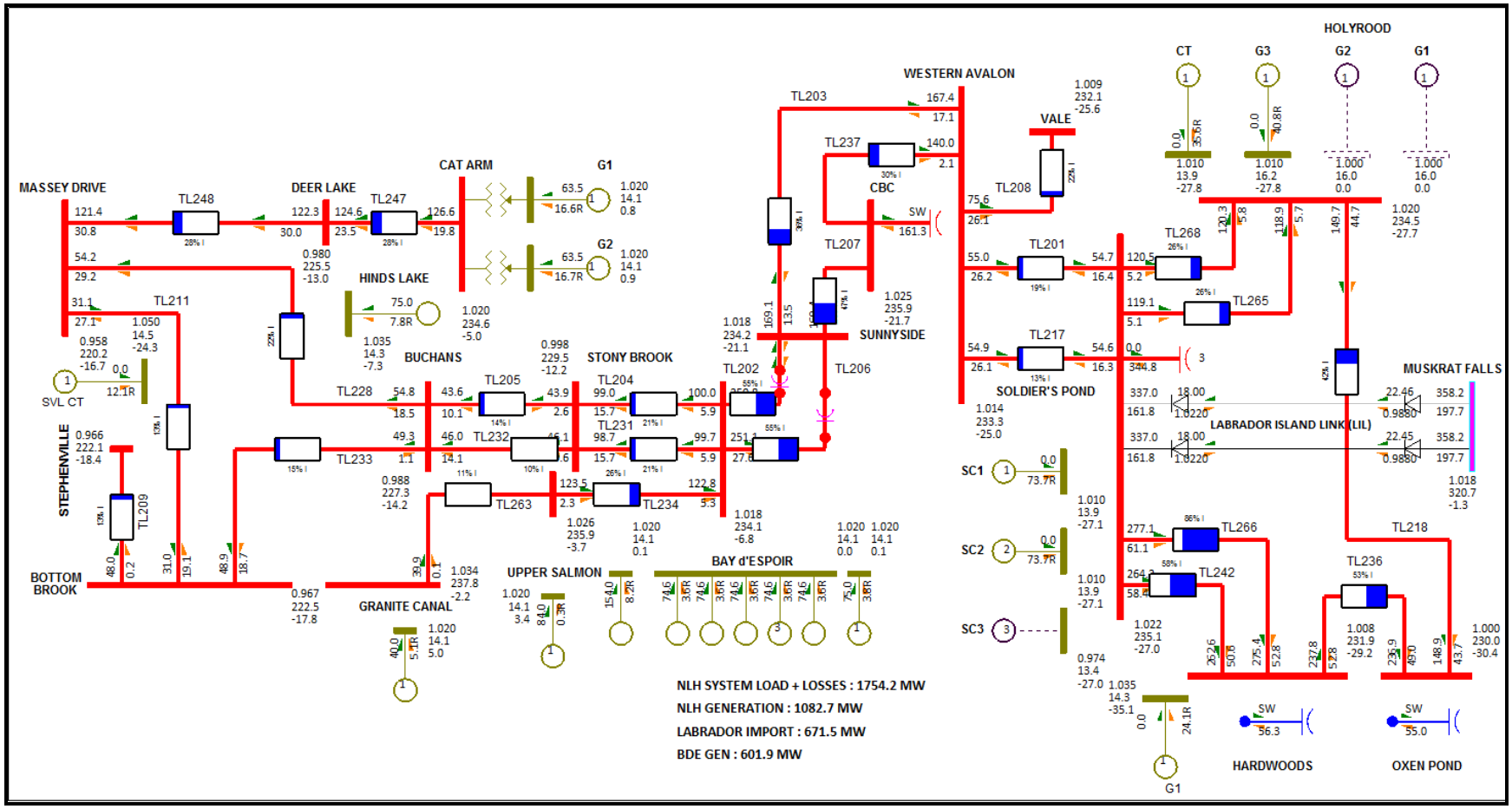


Figure 6 – Base Case 1 (BC1) Load Flow Plot – Pre-Contingency

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

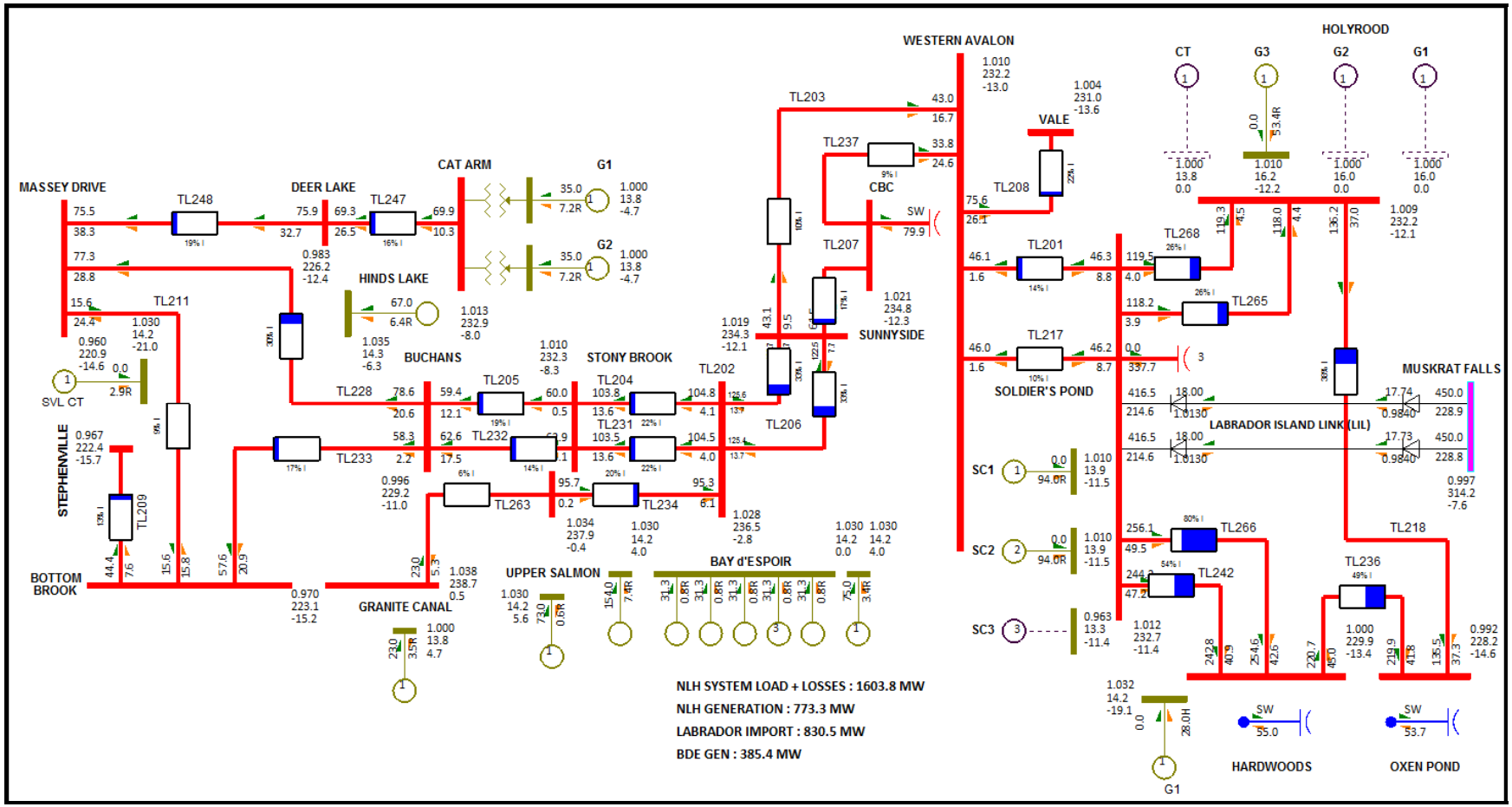


Figure 7 – Base Case 2 (BC2) Load Flow Plot – Pre-Contingency

Existing Bulk Transmission System

Winter Peak (1603 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (773 MW)

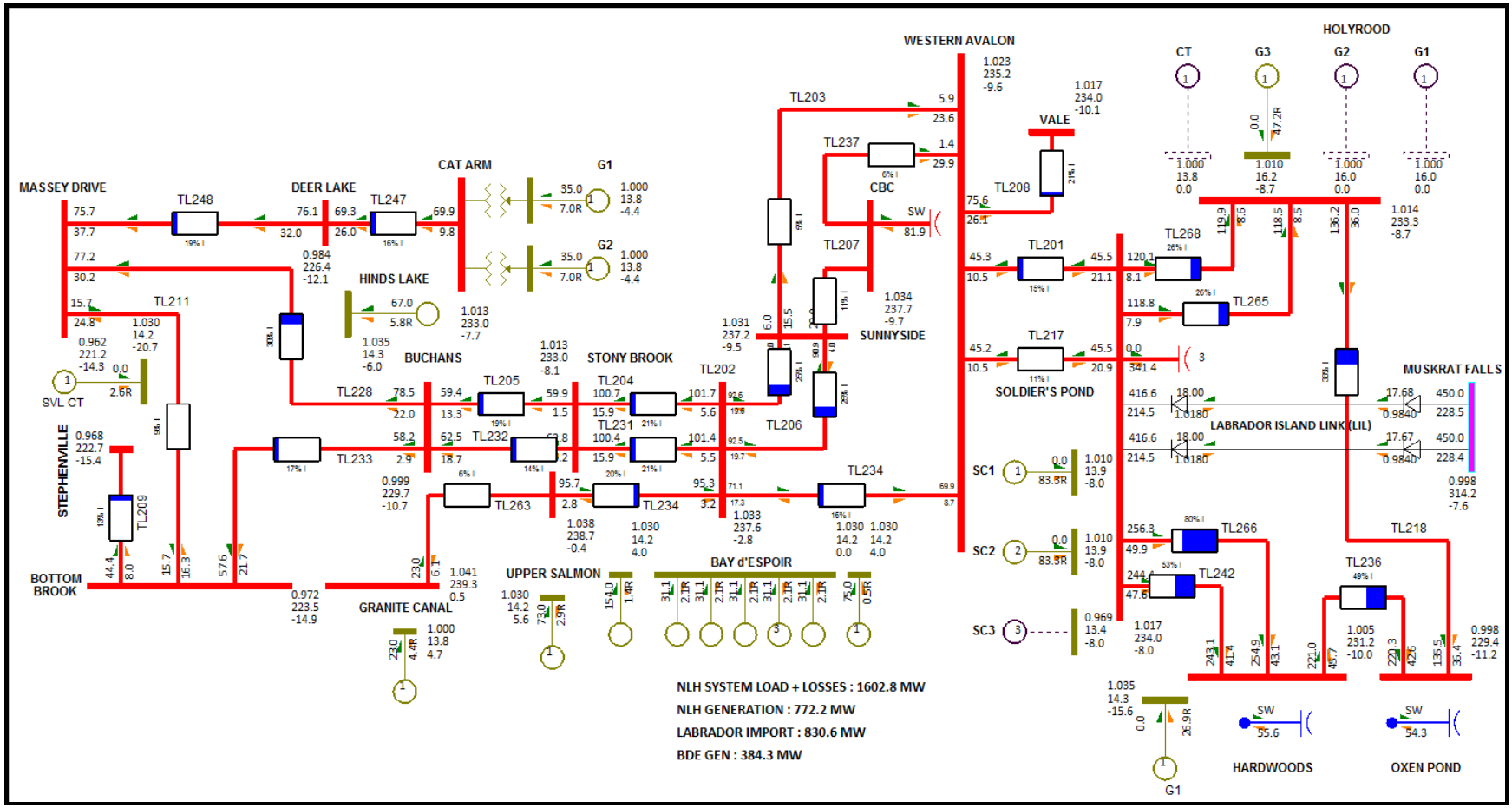


Figure 8 – Base Case 2 (BC2) Load Flow Plot – Pre-Contingency

New 230 kV Transmission Line Installed Between BDE and WAV

Winter Peak (1603 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (773 MW)

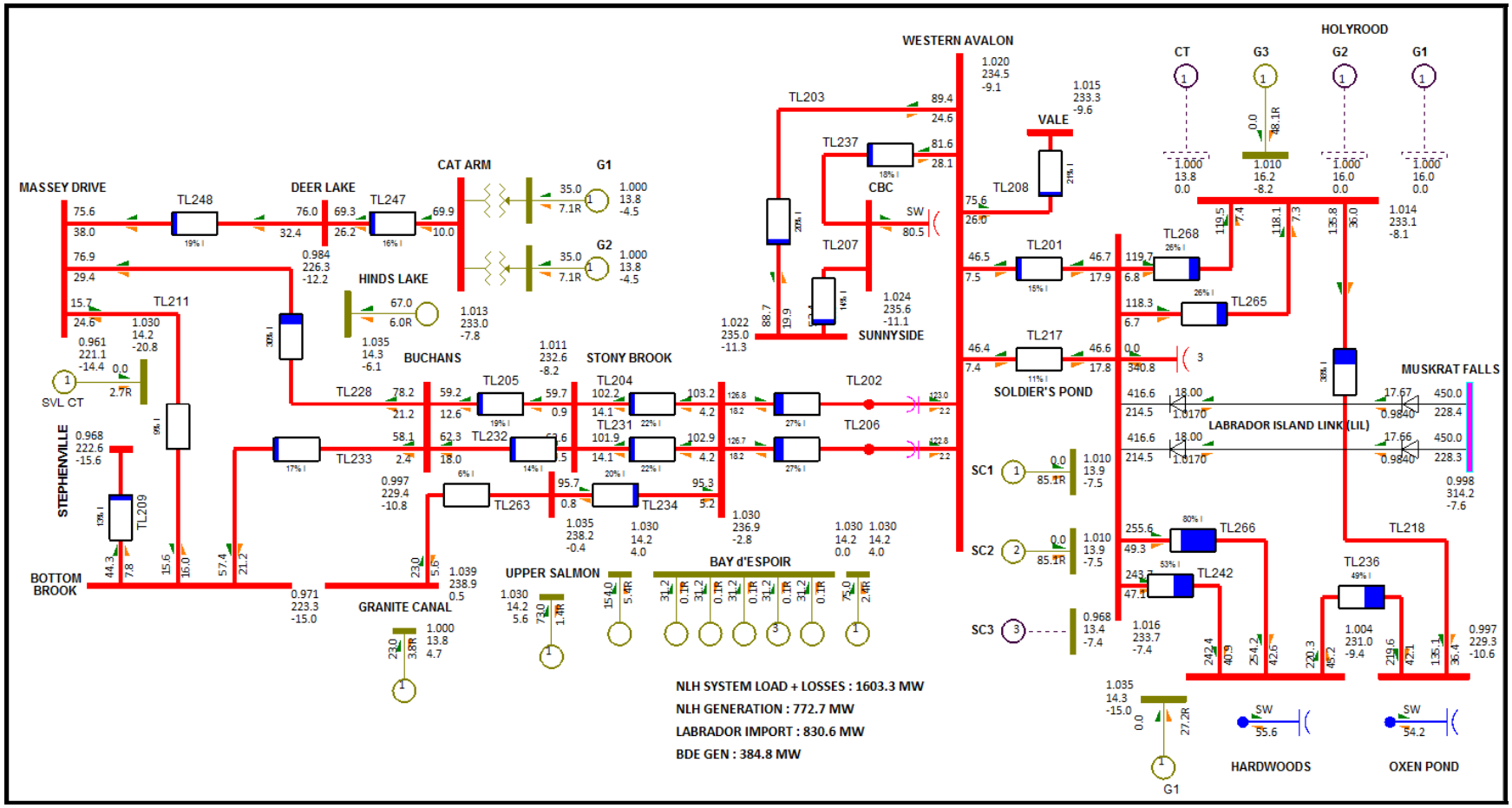


Figure 9 – Base Case 2 (BC2) Load Flow Plot – Pre-Contingency

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (773 MW)

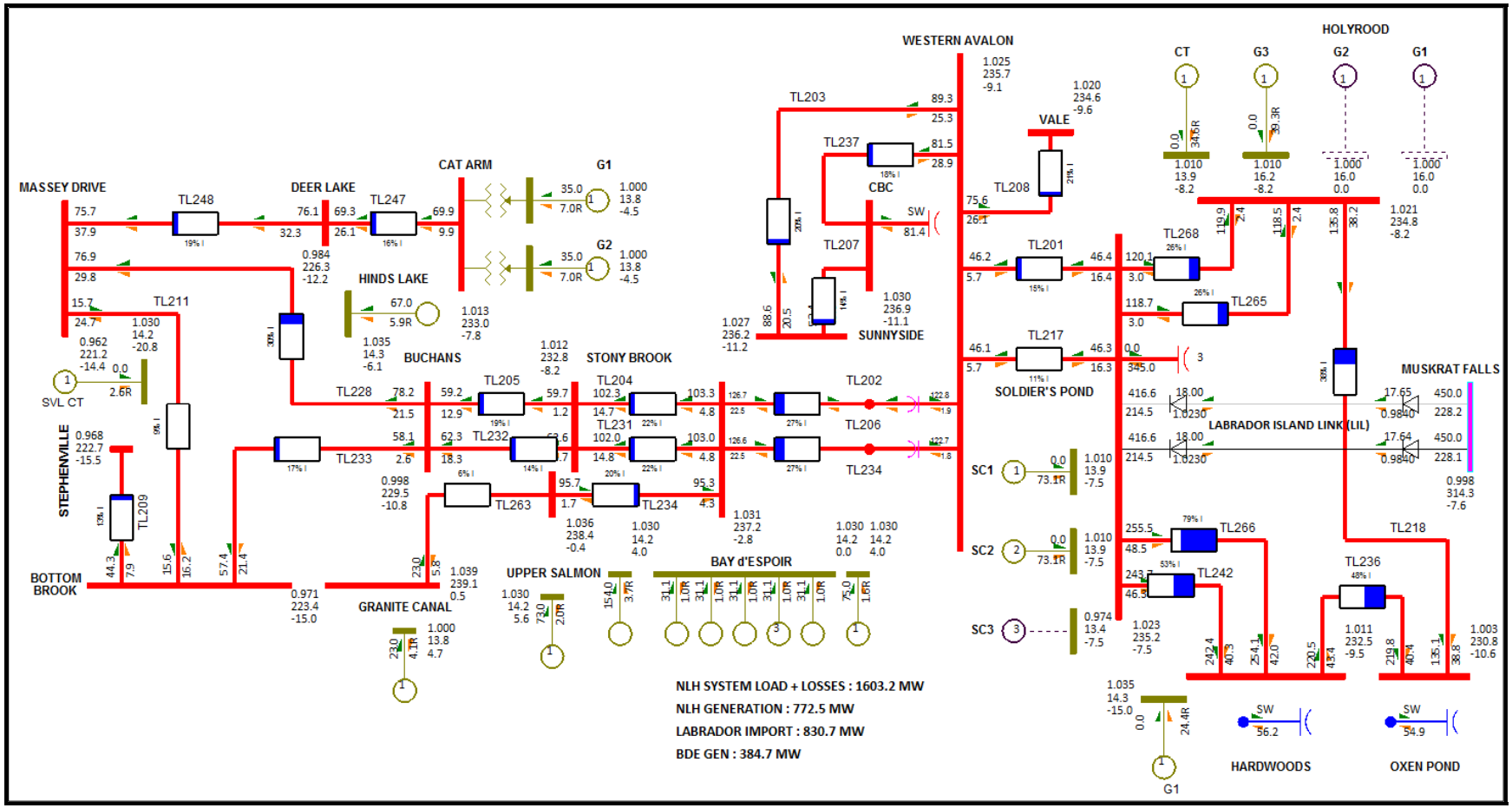


Figure 10 – Base Case 2 (BC2) Load Flow Plot – Pre-Contingency

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (773 MW)

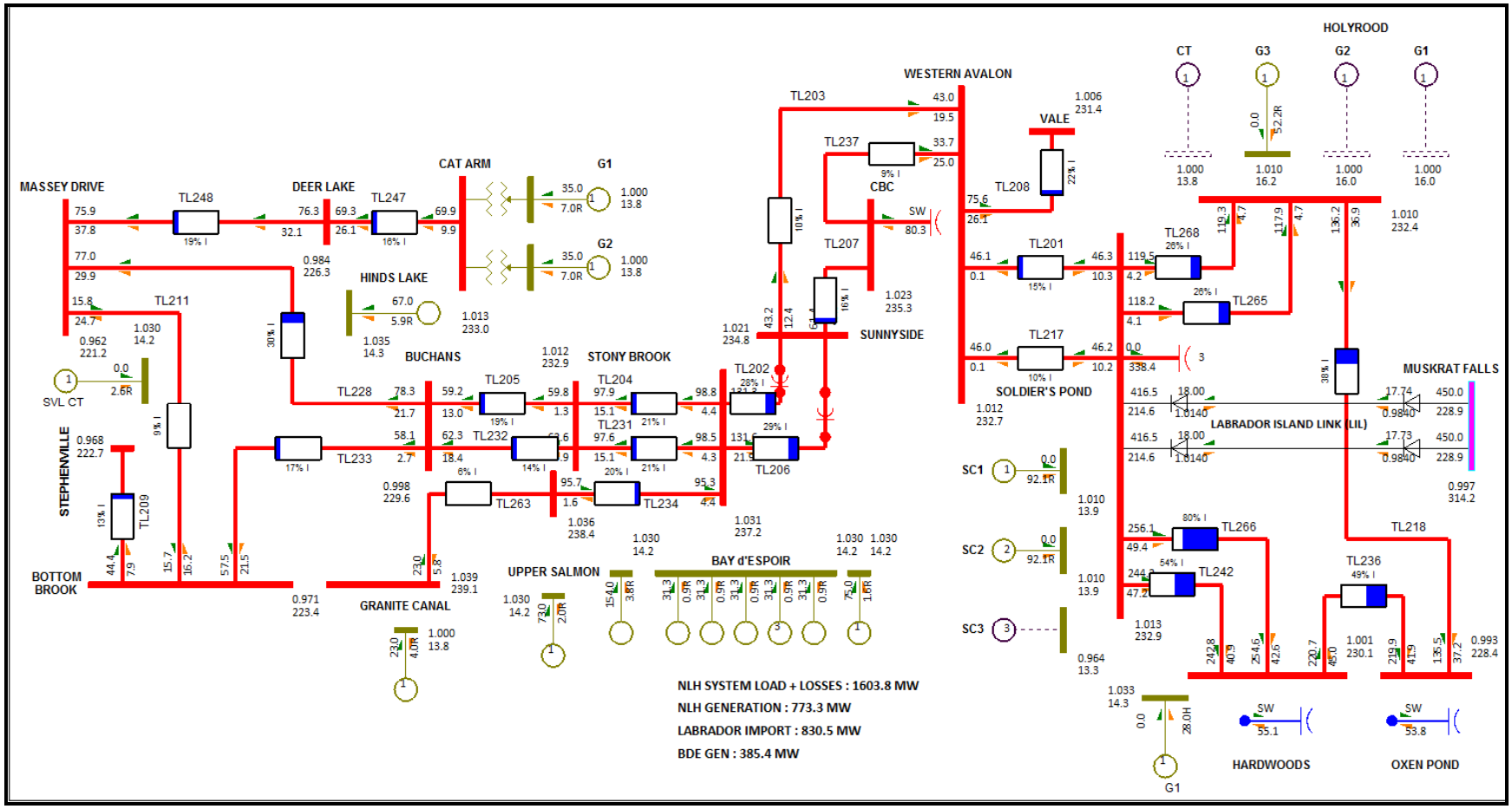


Figure 11 – Base Case 2 (BC2) Load Flow Plot – Pre-Contingency

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (773 MW)

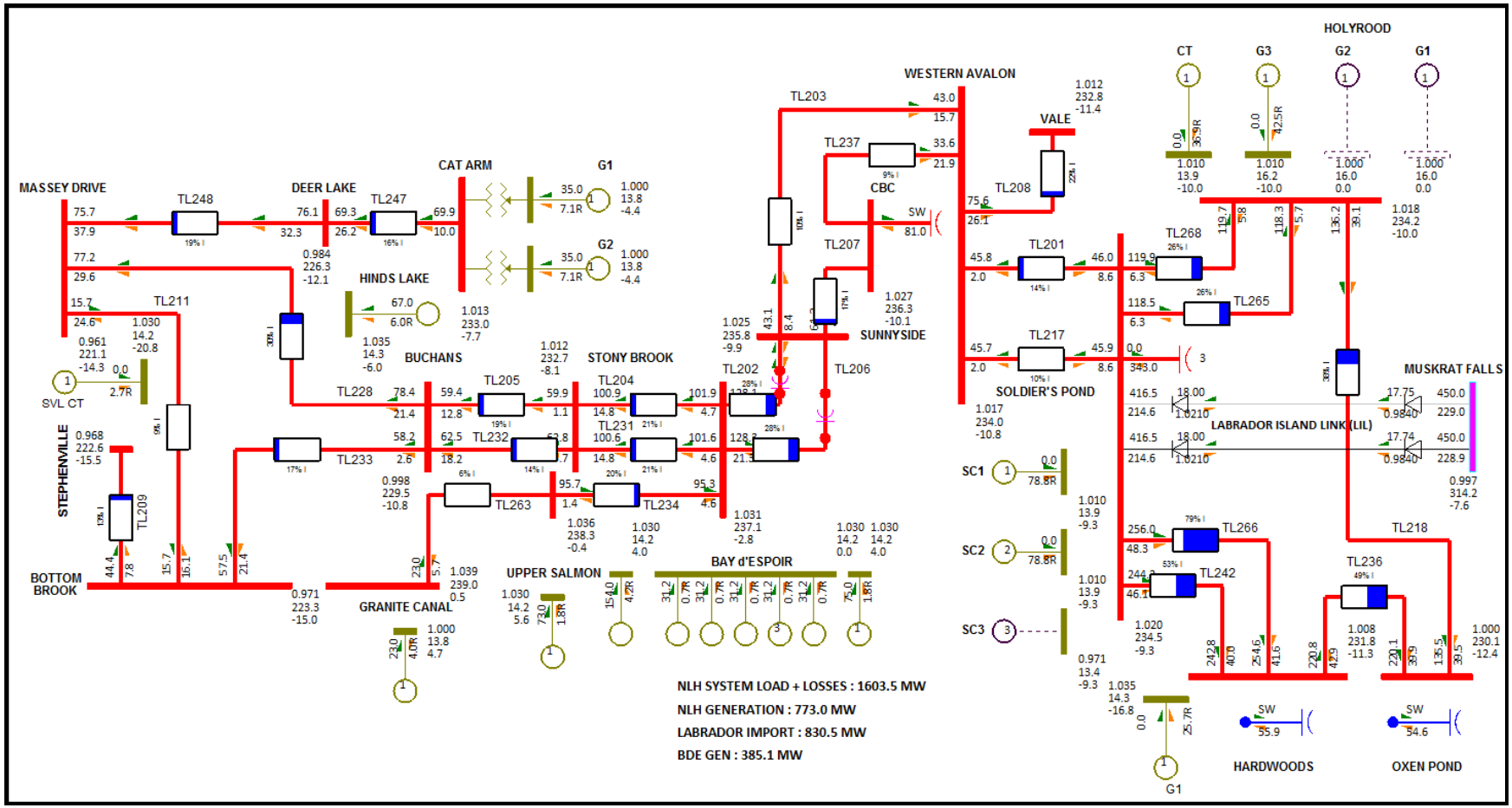


Figure 12 – Base Case 2 (BC2) Load Flow Plot – Pre-Contingency

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (773 MW)

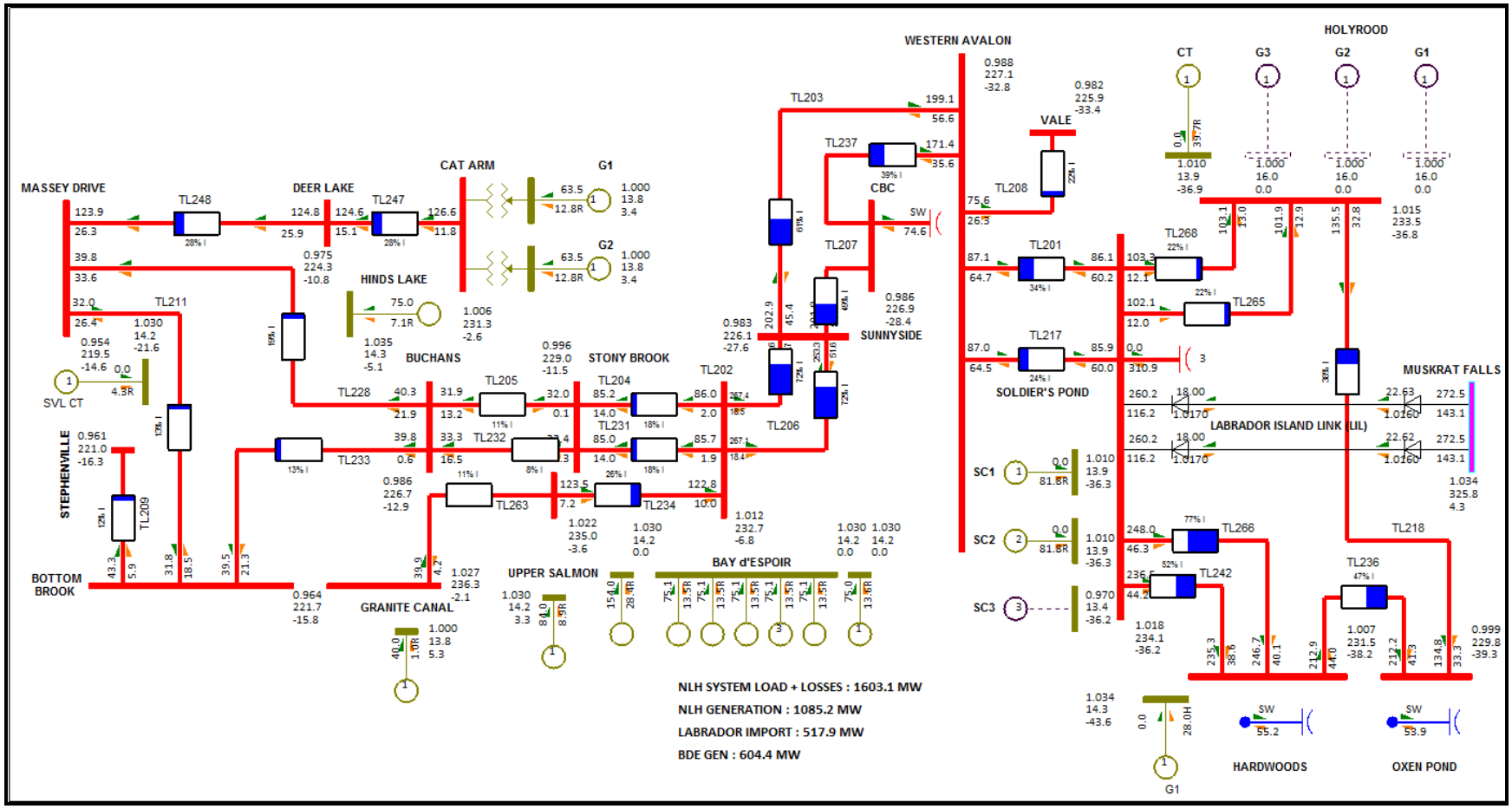


Figure 13 – Base Case 3 (BC3) Load Flow Plot – Pre-Contingency

Existing Bulk 230 kV Transmission System

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

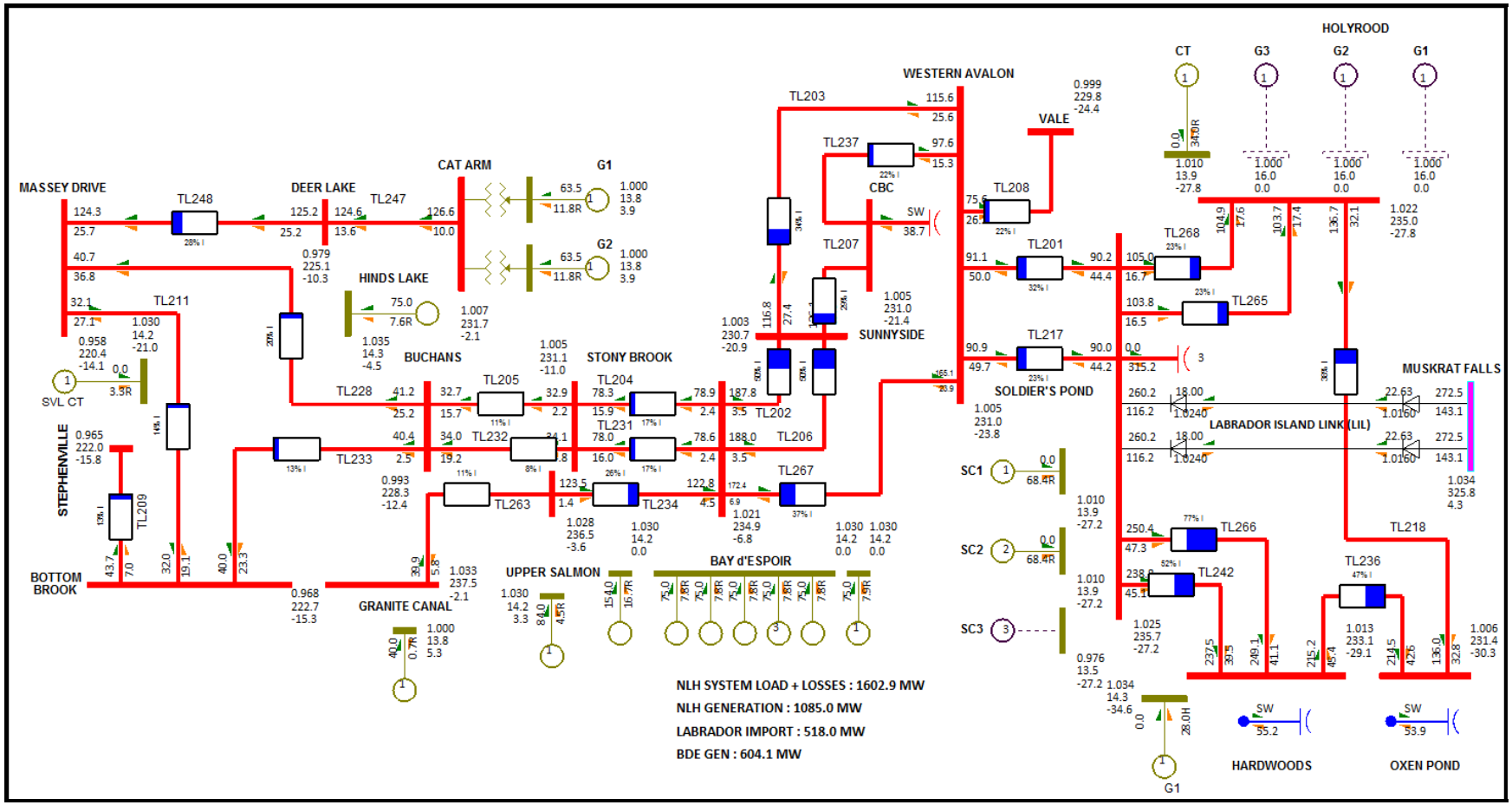


Figure 14 – Base Case 3 (BC3) Load Flow Plot – Pre-Contingency

New 230 kV Transmission Line Installed Between BDE and WAV

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

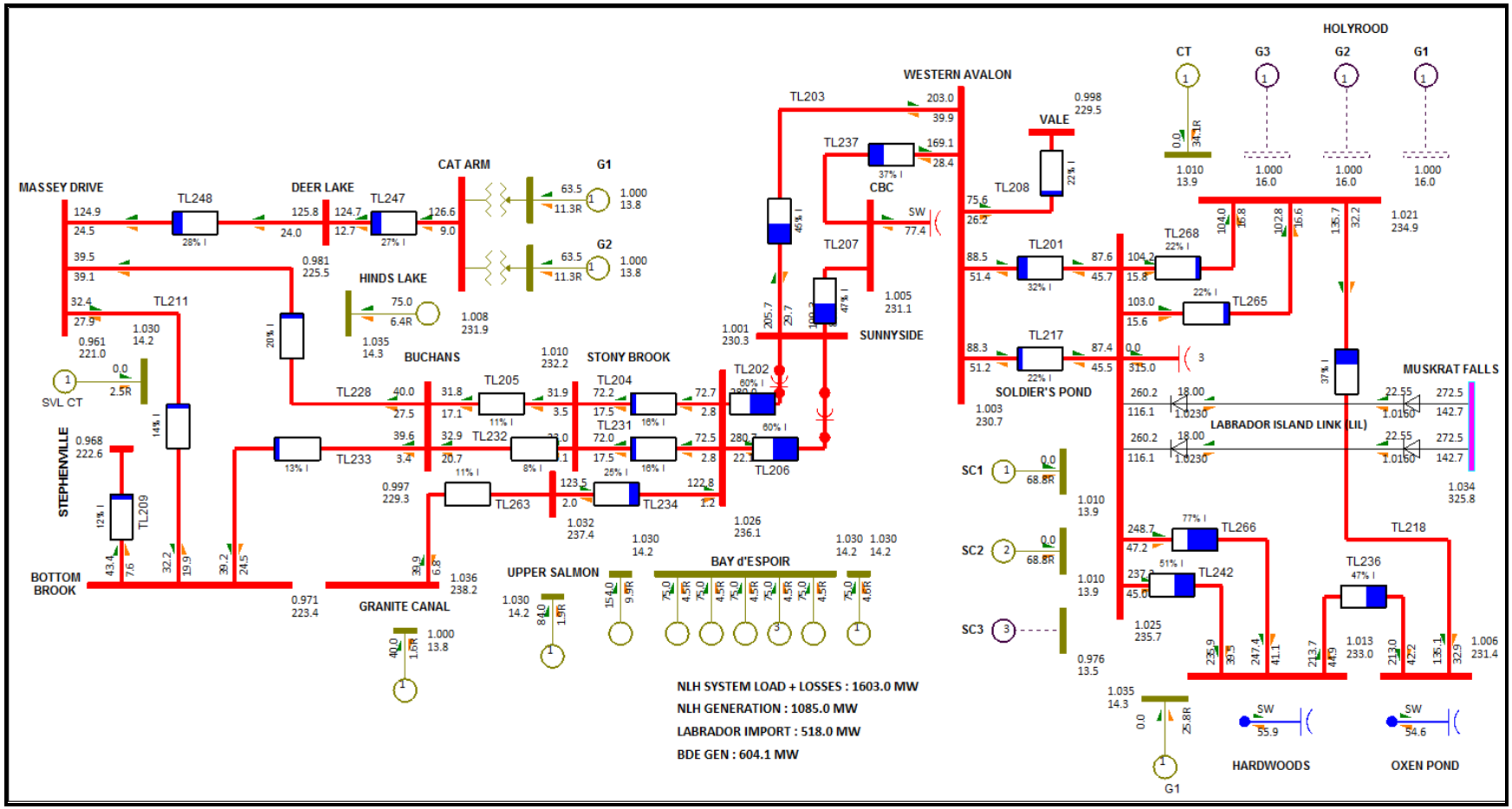


Figure 15 – Base Case 3 (BC3) Load Flow Plot – Pre-Contingency

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

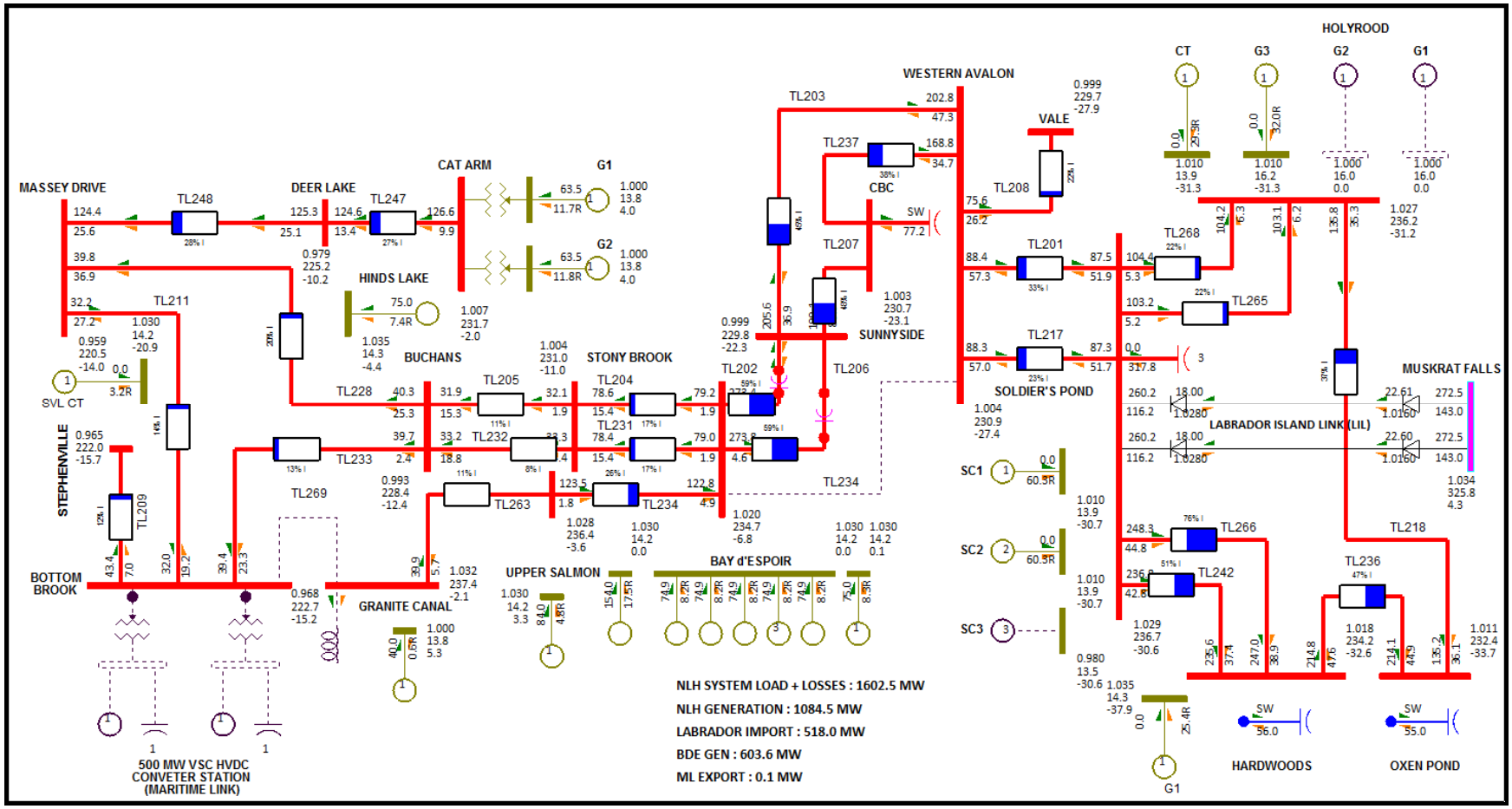


Figure 16 – Base Case 3 (BC3) Load Flow Plot – Pre-Contingency

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

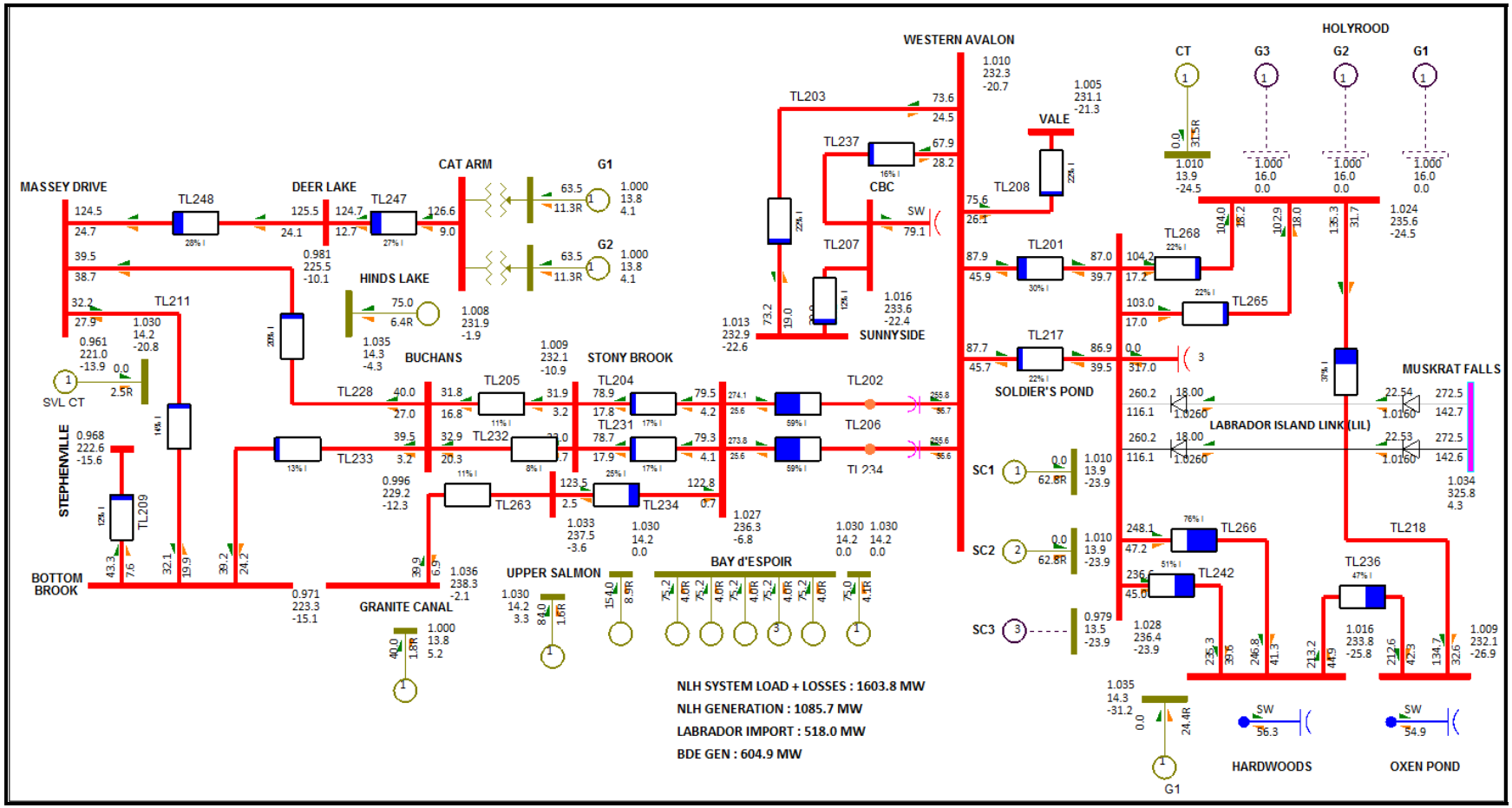


Figure 17 – Base Case 3 (BC3) Load Flow Plot – Pre-Contingency

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

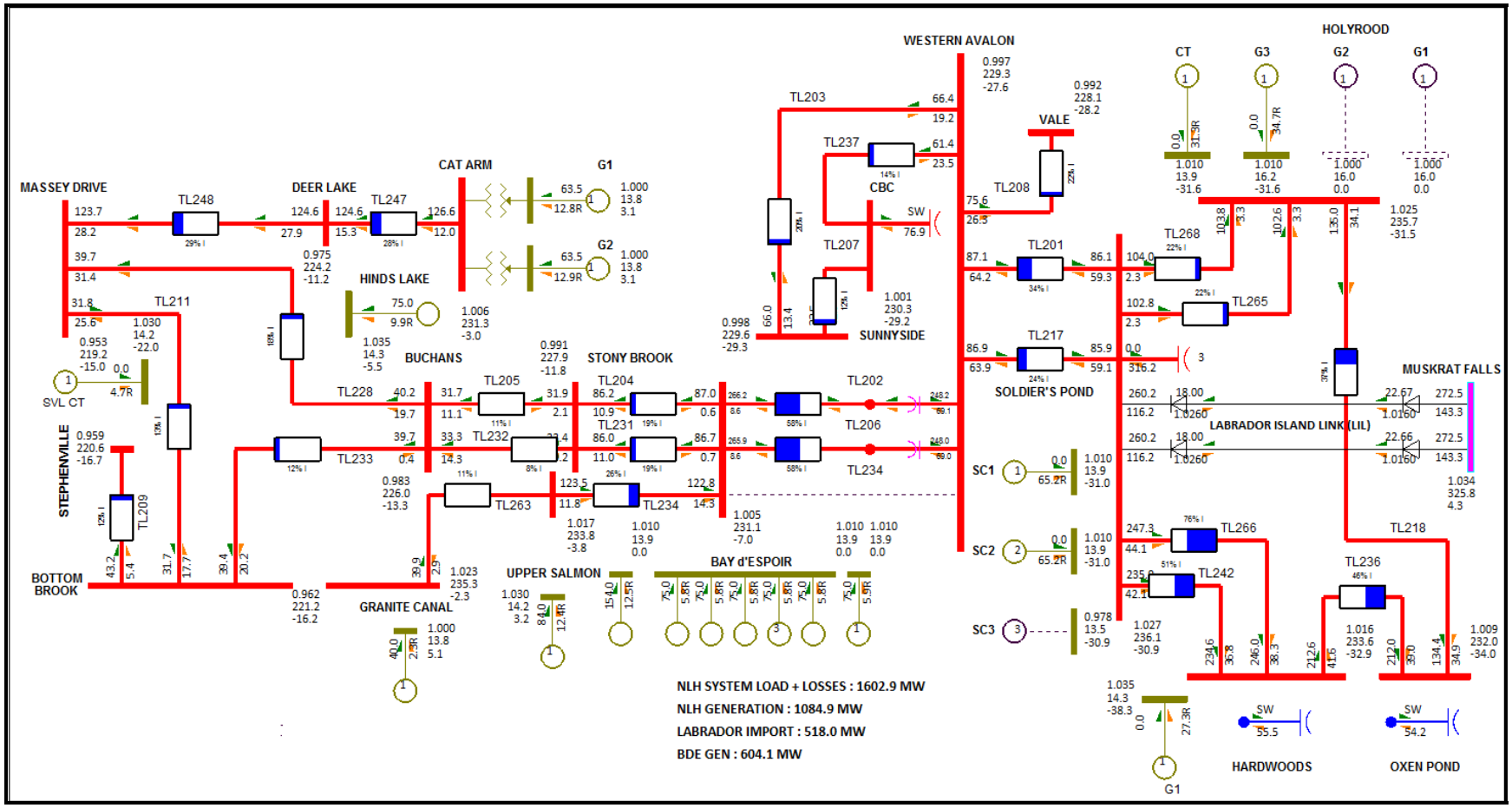


Figure 18 – Base Case 3 (BC3) Load Flow Plot – Pre-Contingency

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

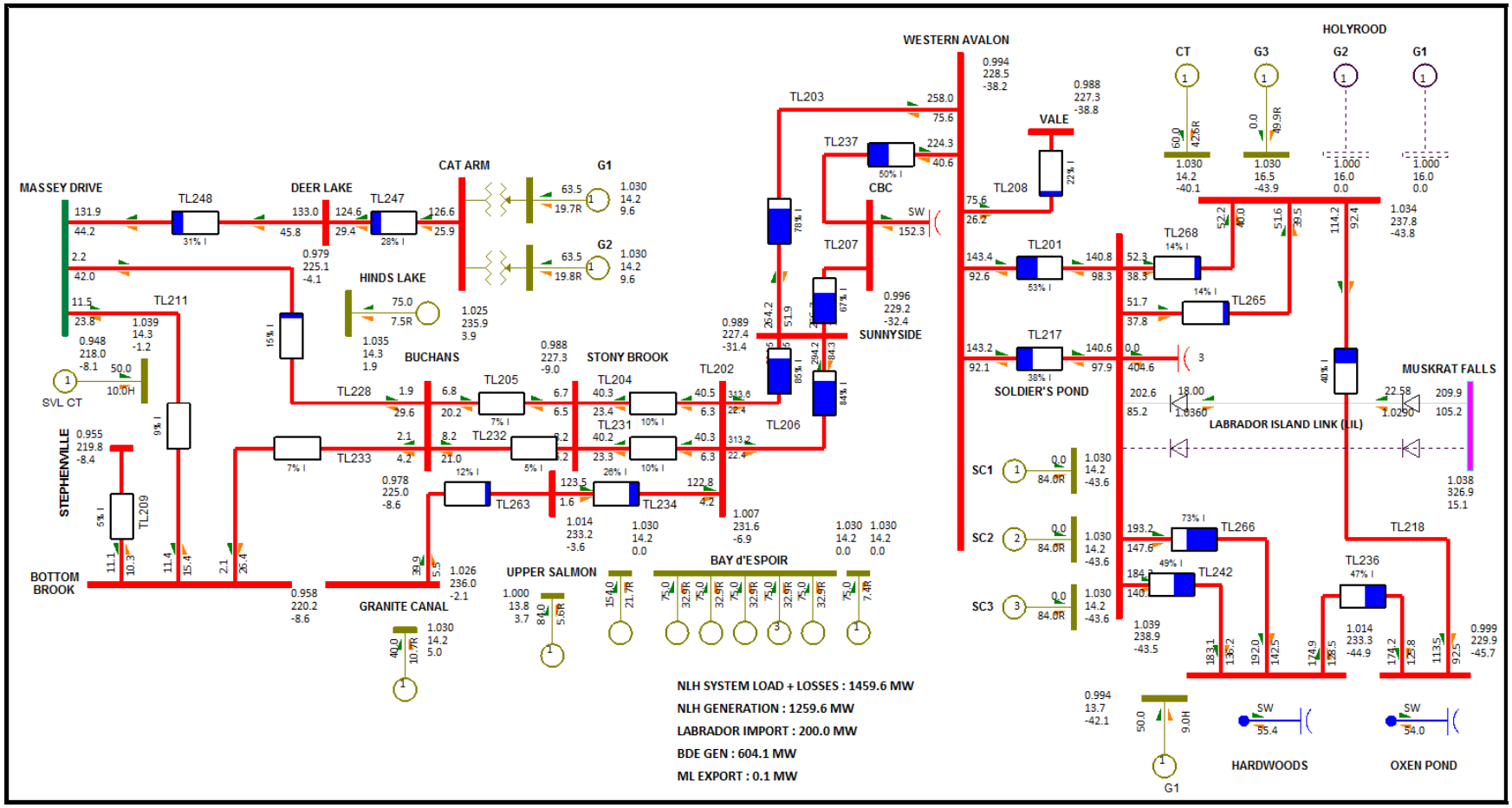


Figure 19 – Base Case 4 (BC4) Load Flow Plot – Pre-Contingency

Existing Bulk 230 kV Transmission System

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

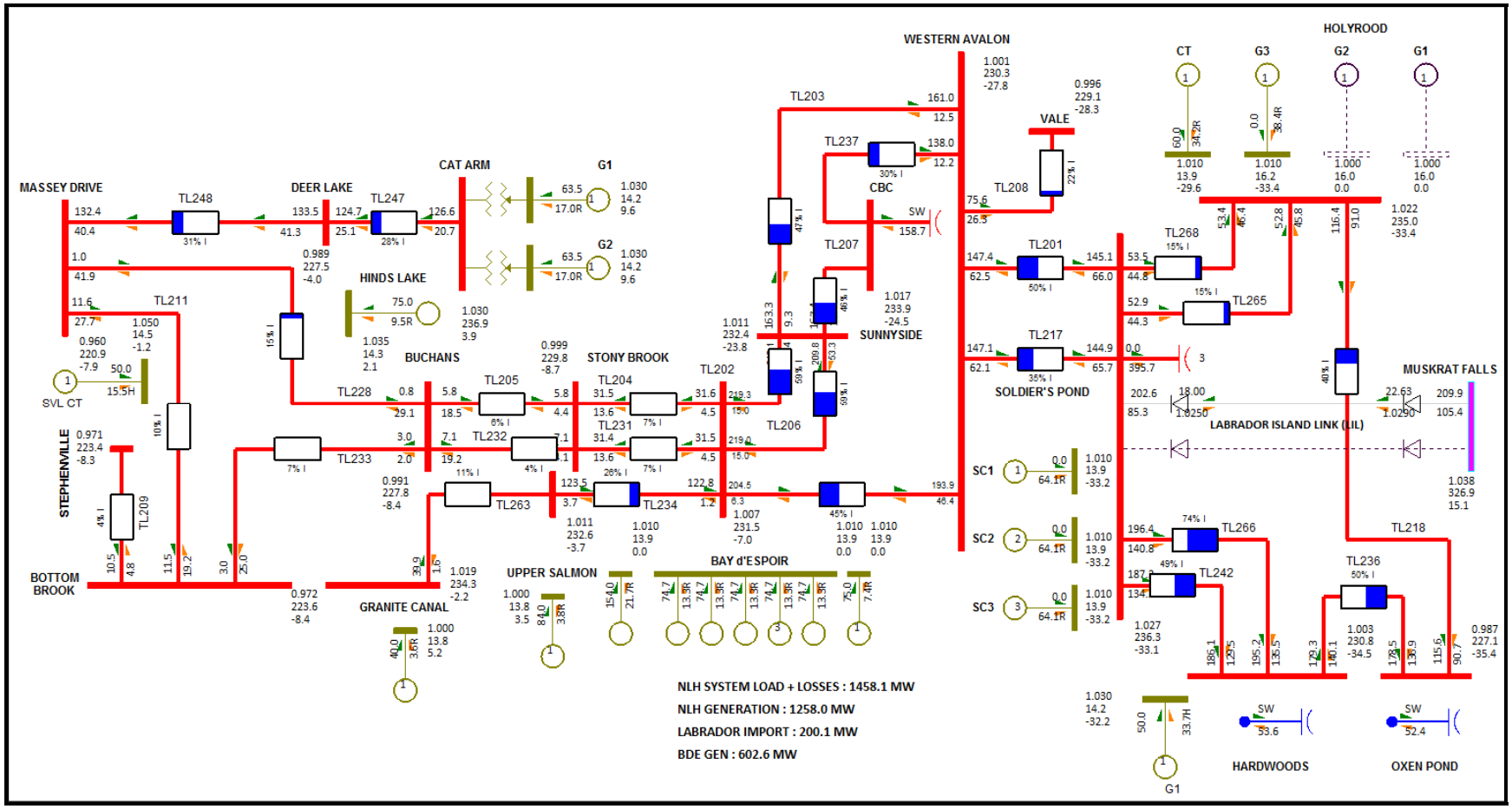


Figure 20 – Base Case 4 (BC4) Load Flow Plot – Pre-Contingency

New 230 kV Transmission Line Installed Between BDE and WAV

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

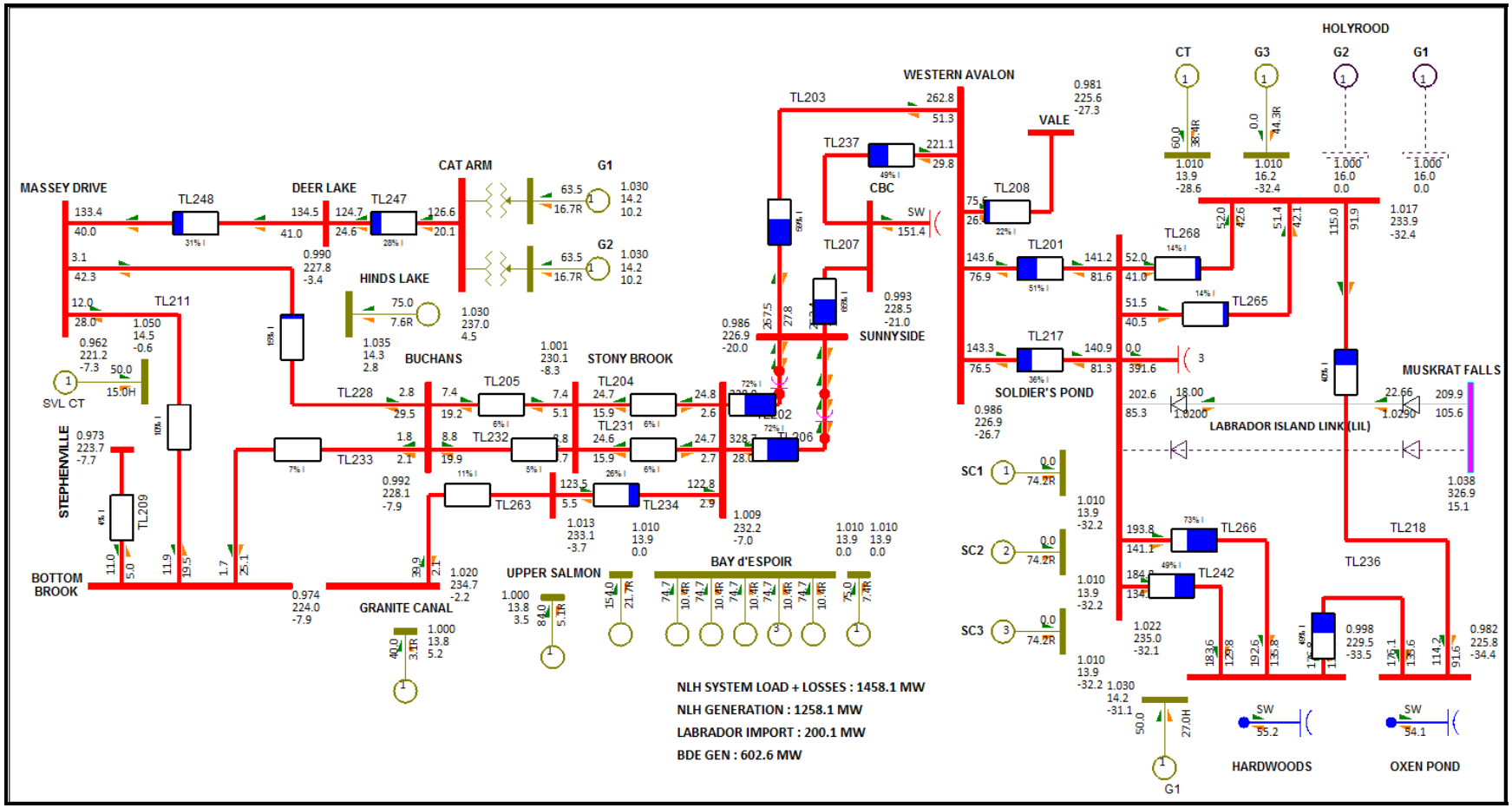


Figure 21 – Base Case 4 (BC4) Load Flow Plot – Pre-Contingency

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

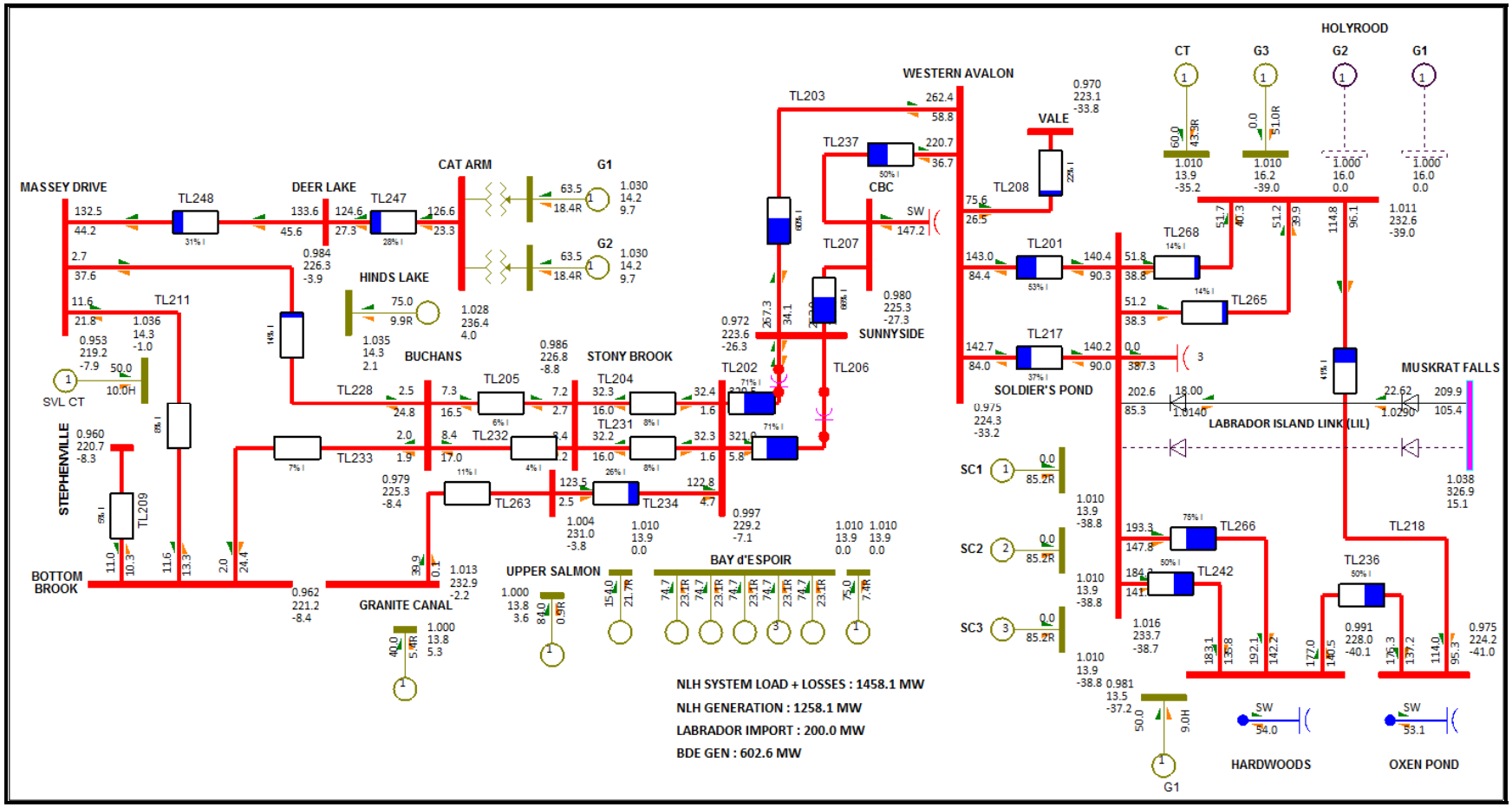


Figure 22 – Base Case 4 (BC4) Load Flow Plot – Pre-Contingency

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

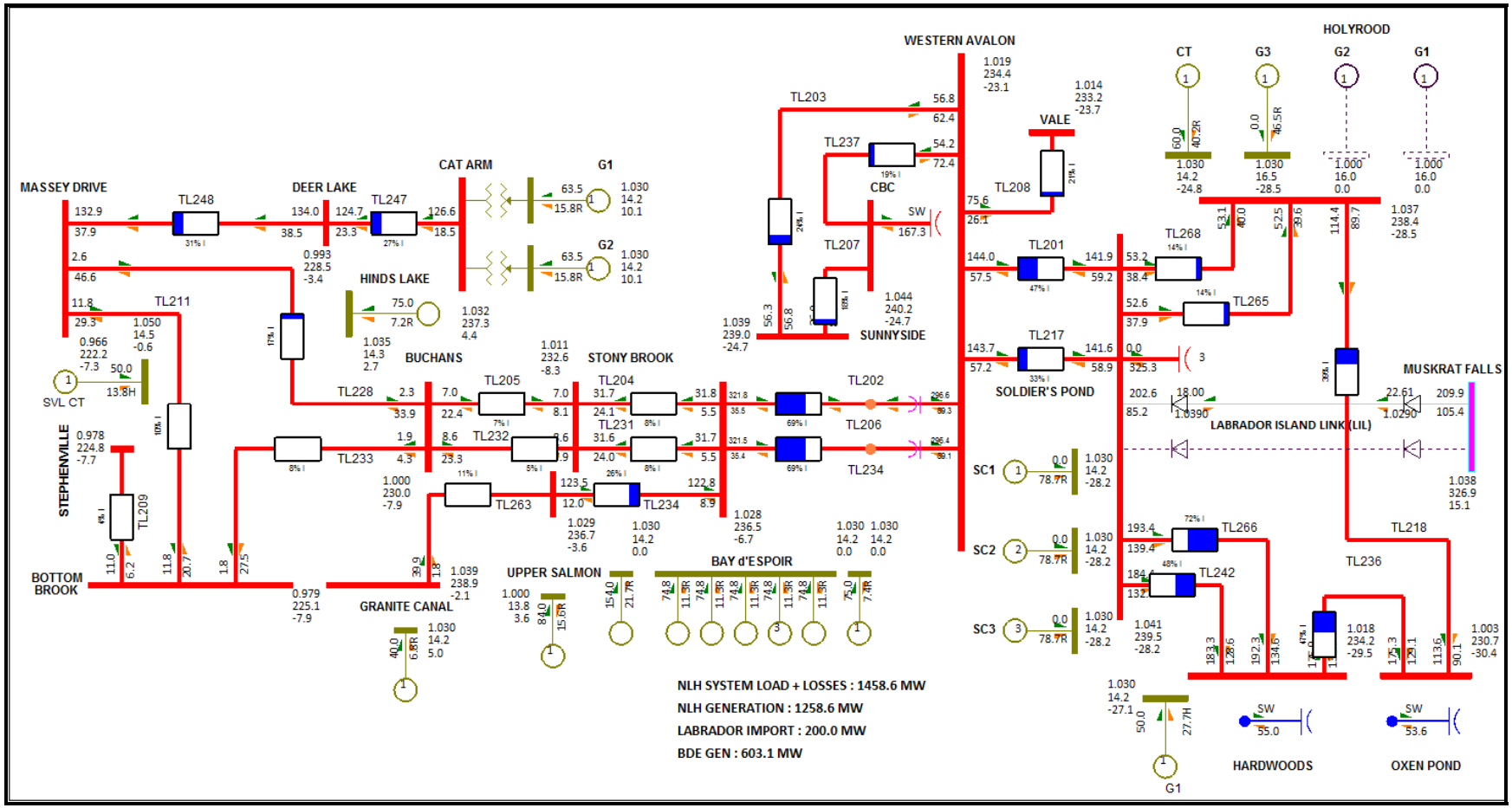


Figure 23 – Base Case 4 (BC4) Load Flow Plot – Pre-Contingency

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

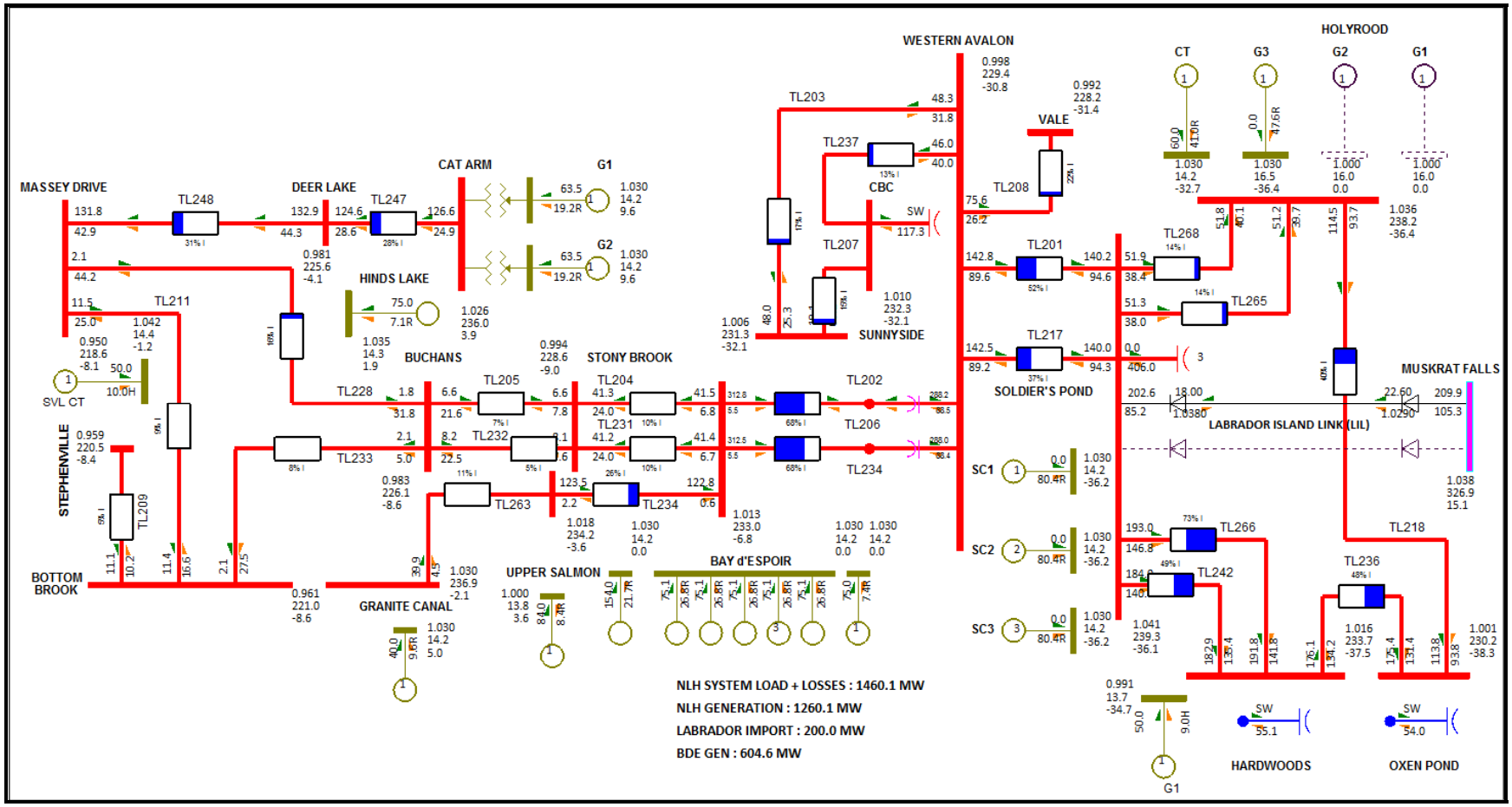


Figure 24 – Base Case 4 (BC4) Load Flow Plot – Pre-Contingency

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

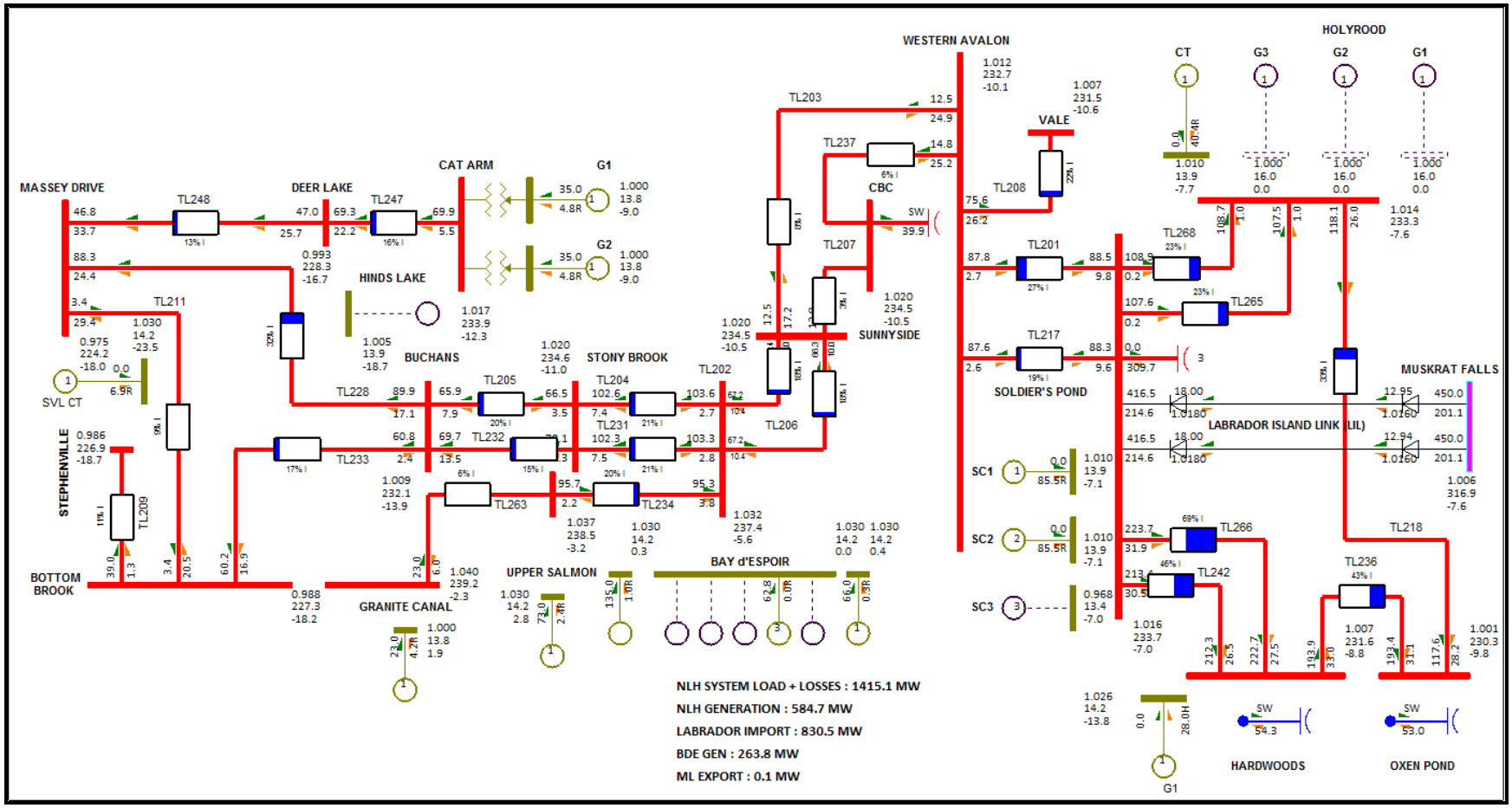


Figure 25 – Base Case 5 (BC5) Load Flow Plot – Pre-Contingency

Existing Bulk 230 kV Transmission System

Winter Day (1415 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (585 MW)

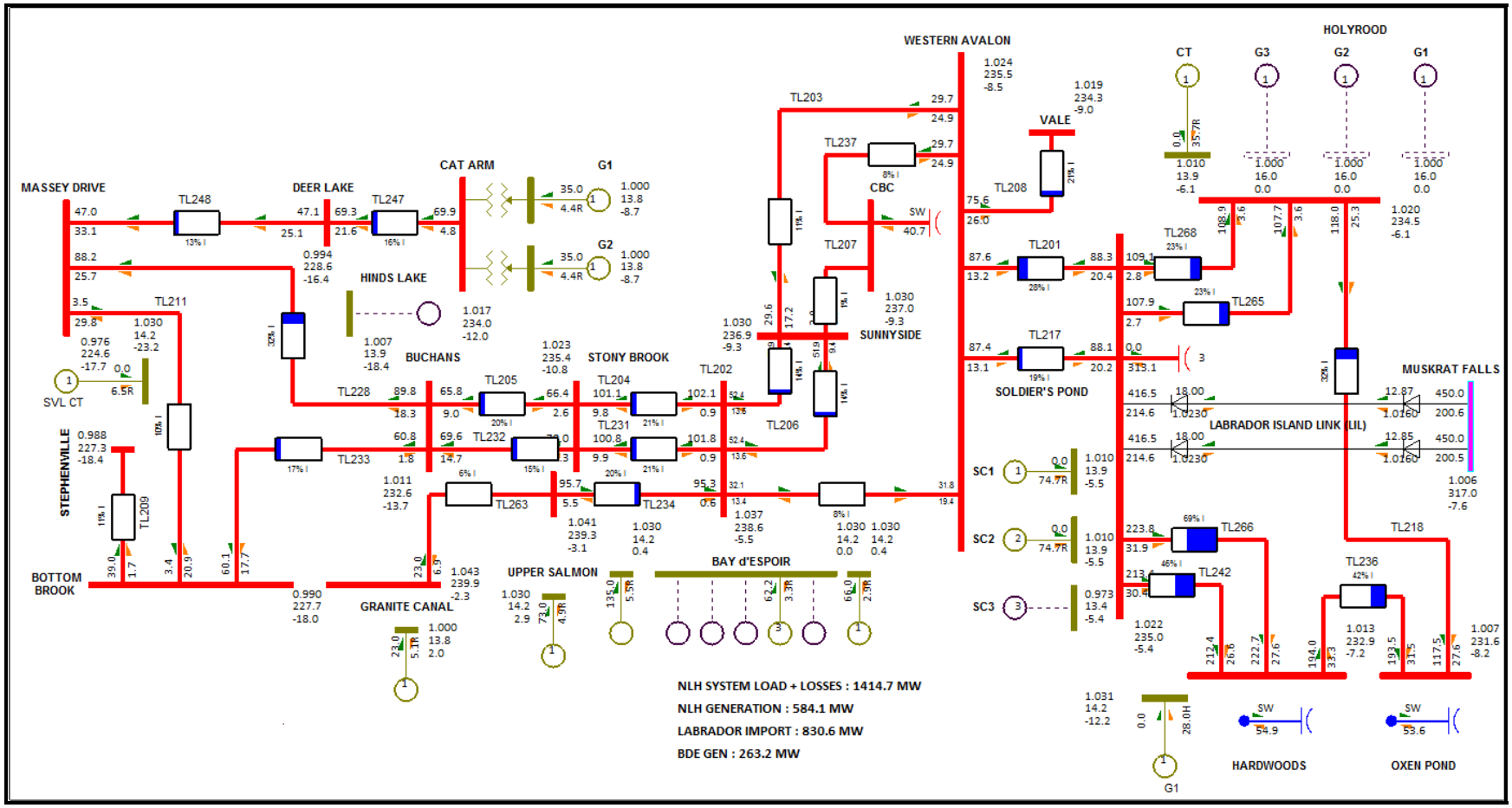


Figure 26 – Base Case 5 (BC5) Load Flow Plot – Pre-Contingency

New 230 kV Transmission Line Installed Between BDE and WAV

Winter Day (1415 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (585 MW)

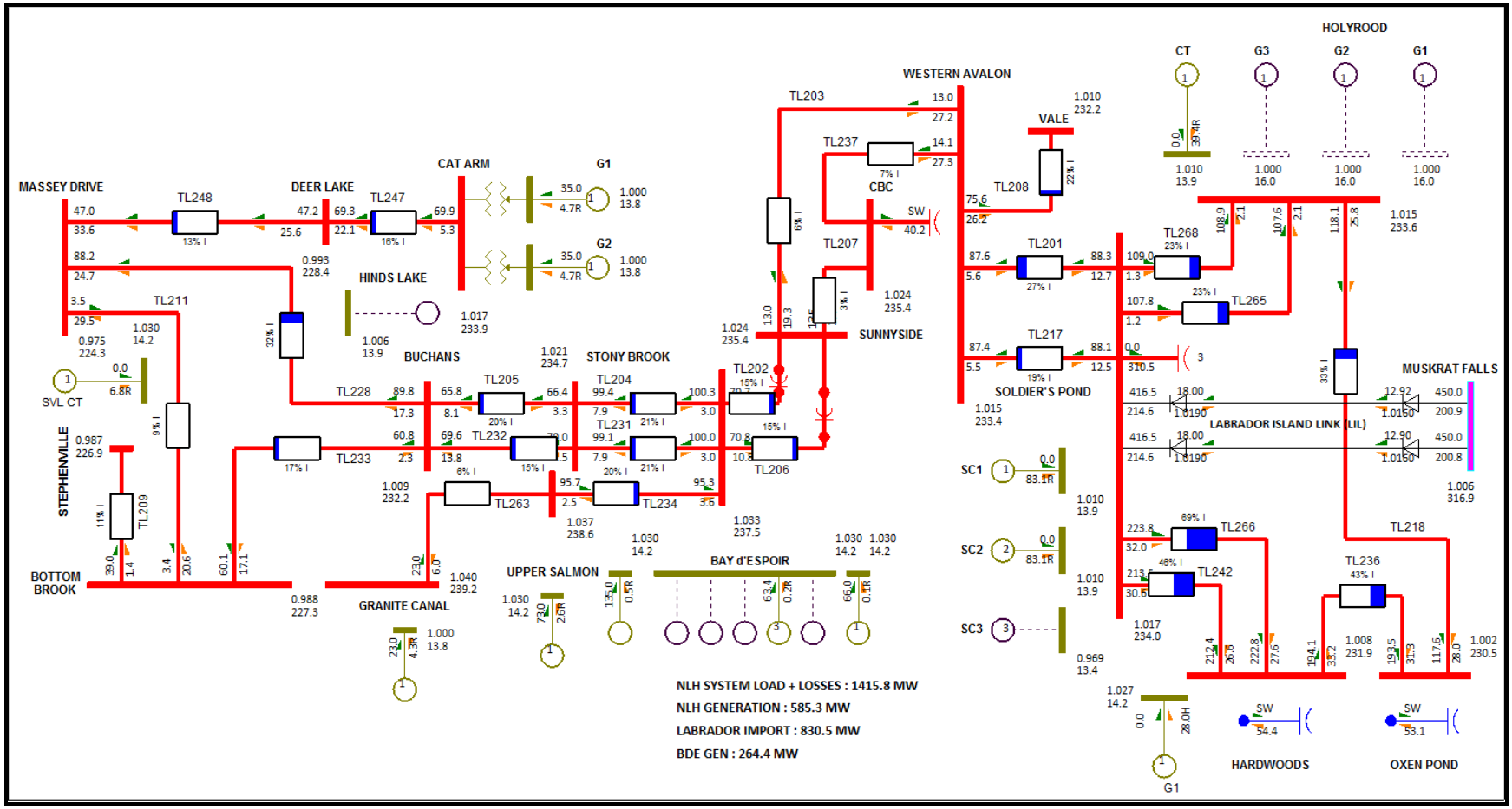


Figure 27 – Base Case 5 (BC5) Load Flow Plot – Pre-Contingency

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (585 MW)

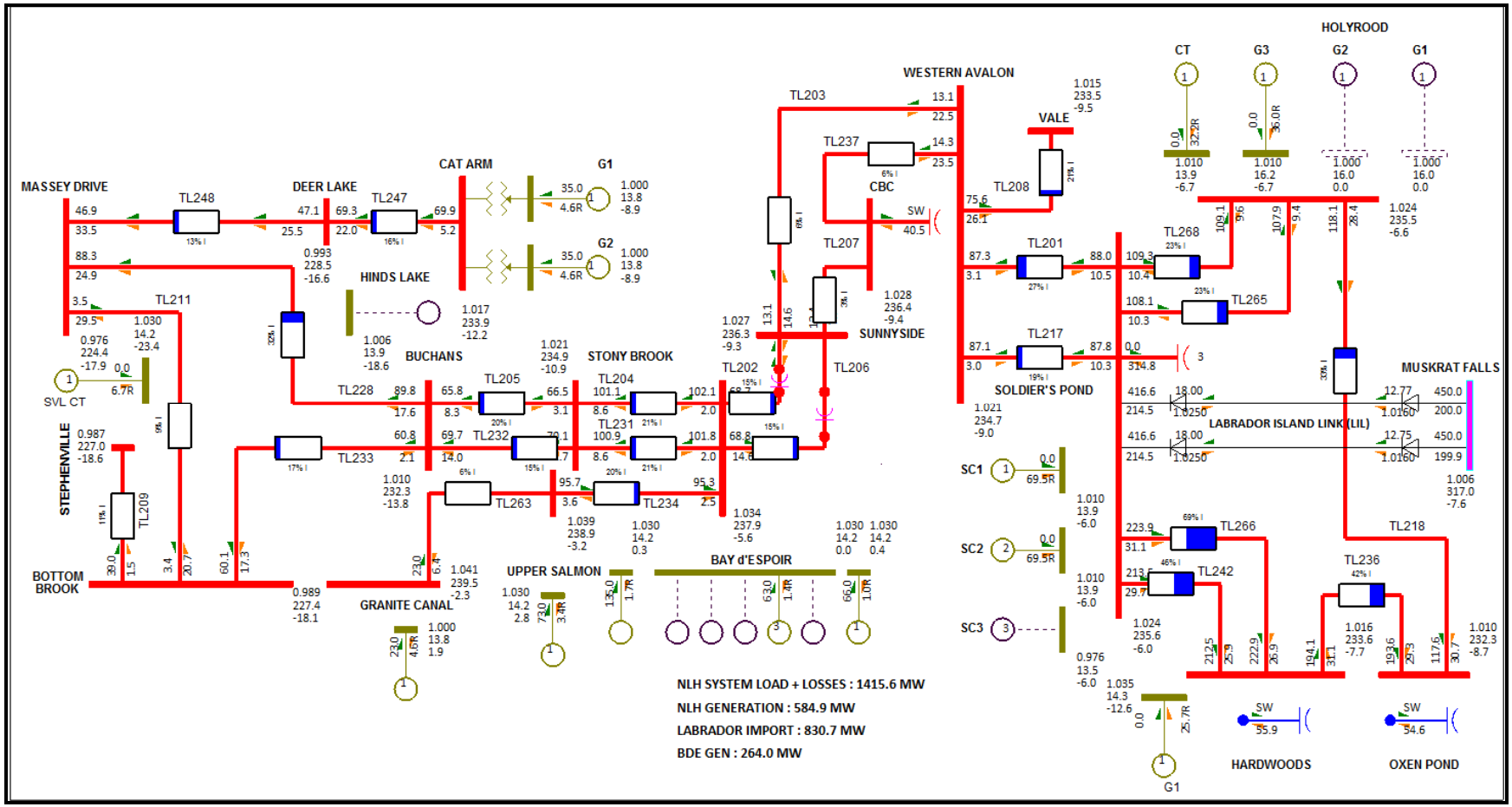


Figure 28 – Base Case 5 (BC5) Load Flow Plot – Pre-Contingency

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (585 MW)

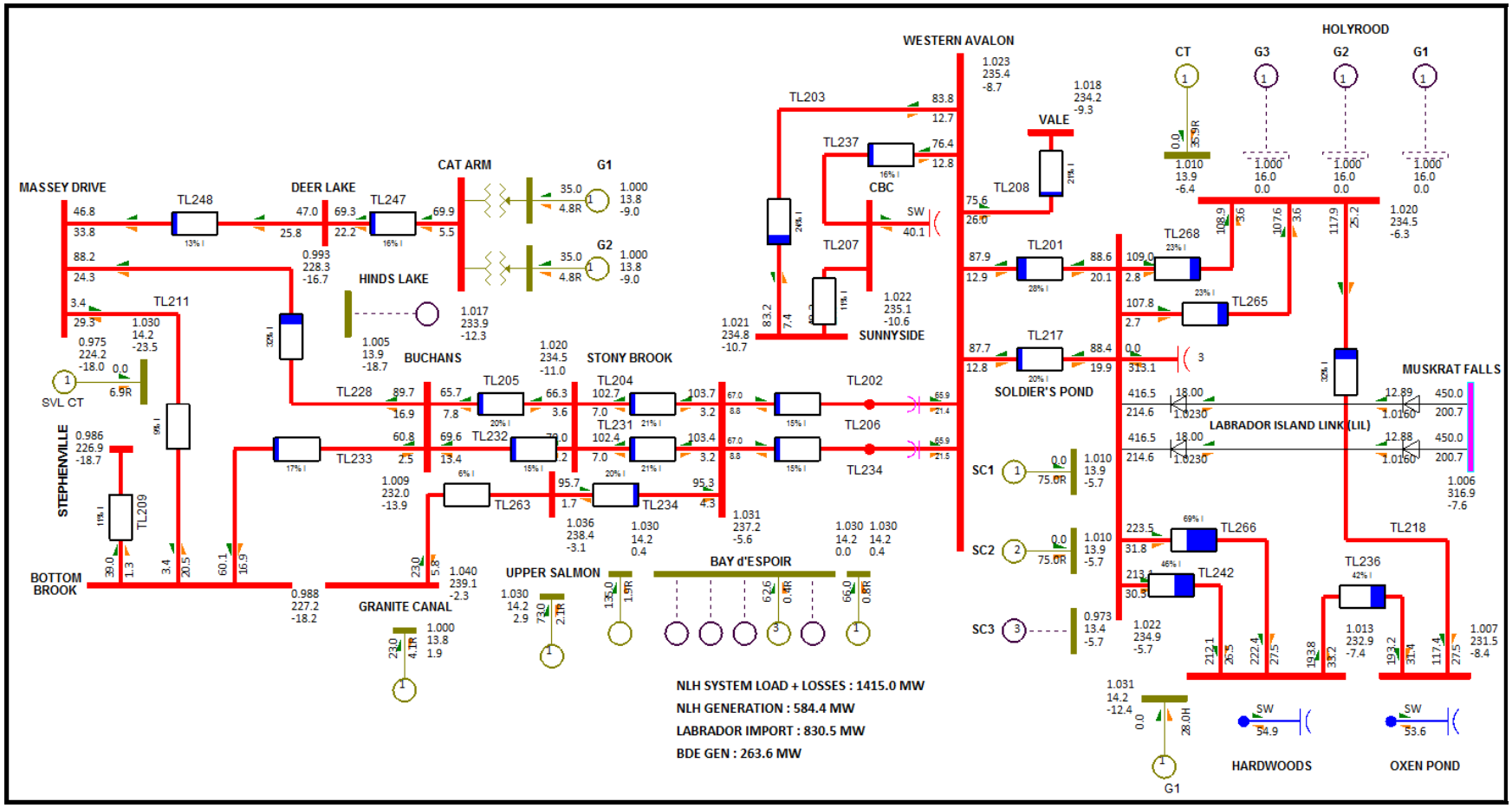


Figure 29 – Base Case 5 (BC5) Load Flow Plot – Pre-Contingency

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (585 MW)

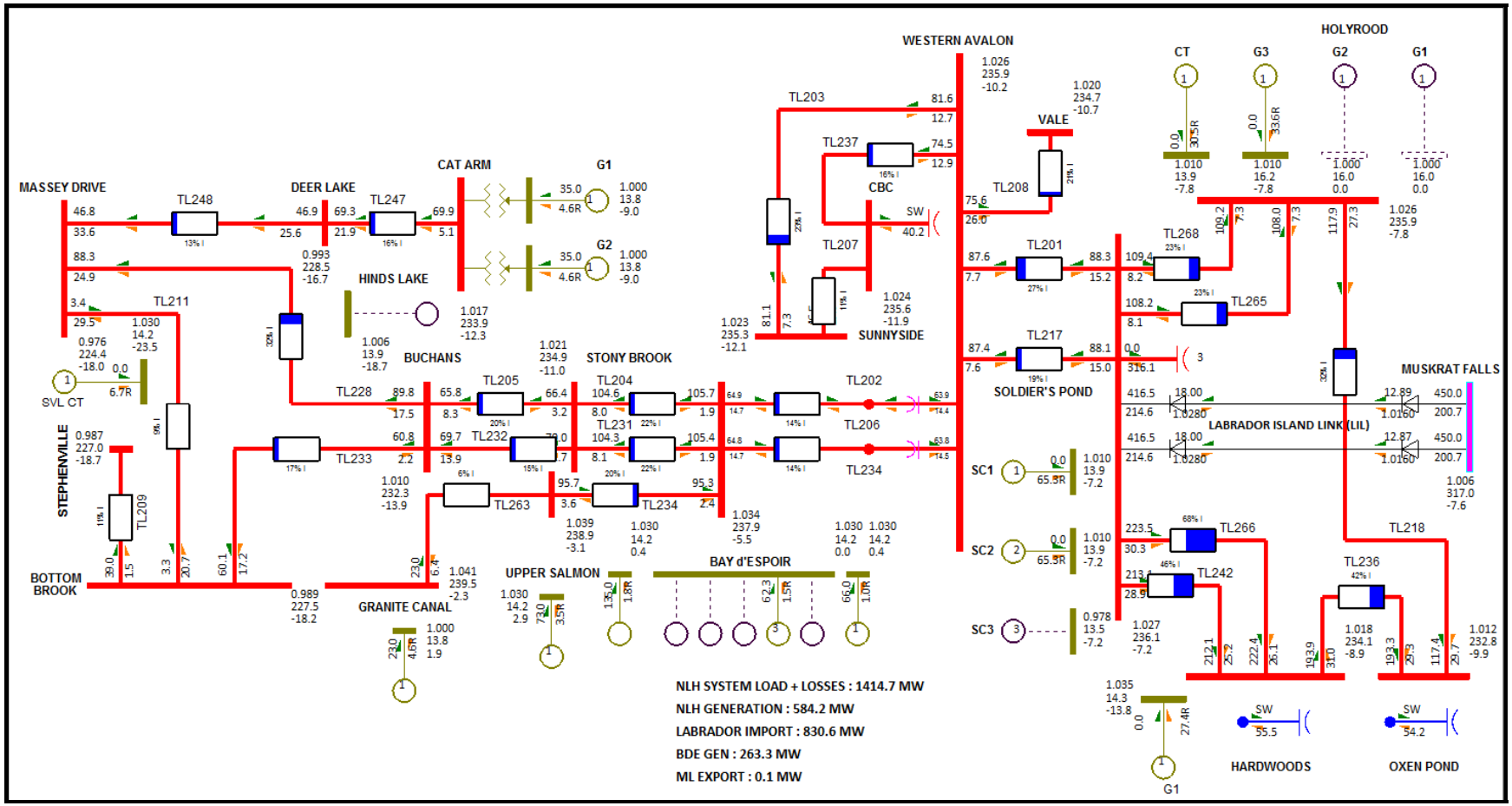


Figure 30 – Base Case 5 (BC5) Load Flow Plot – Pre-Contingency

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (585 MW)

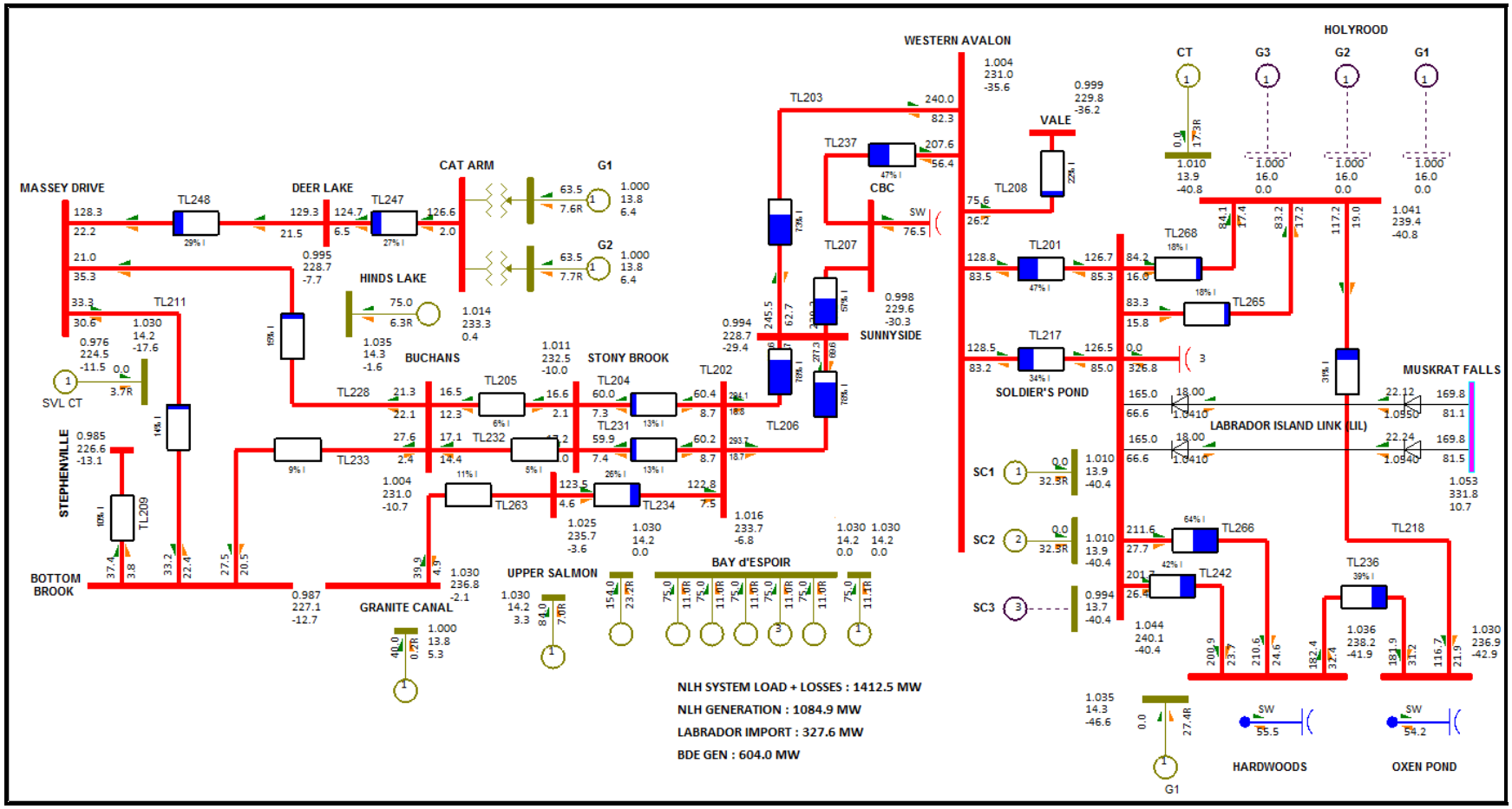


Figure 31 – Base Case 6 (BC6) Load Flow Plot – Pre-Contingency

Existing Bulk 230 kV Transmission System

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

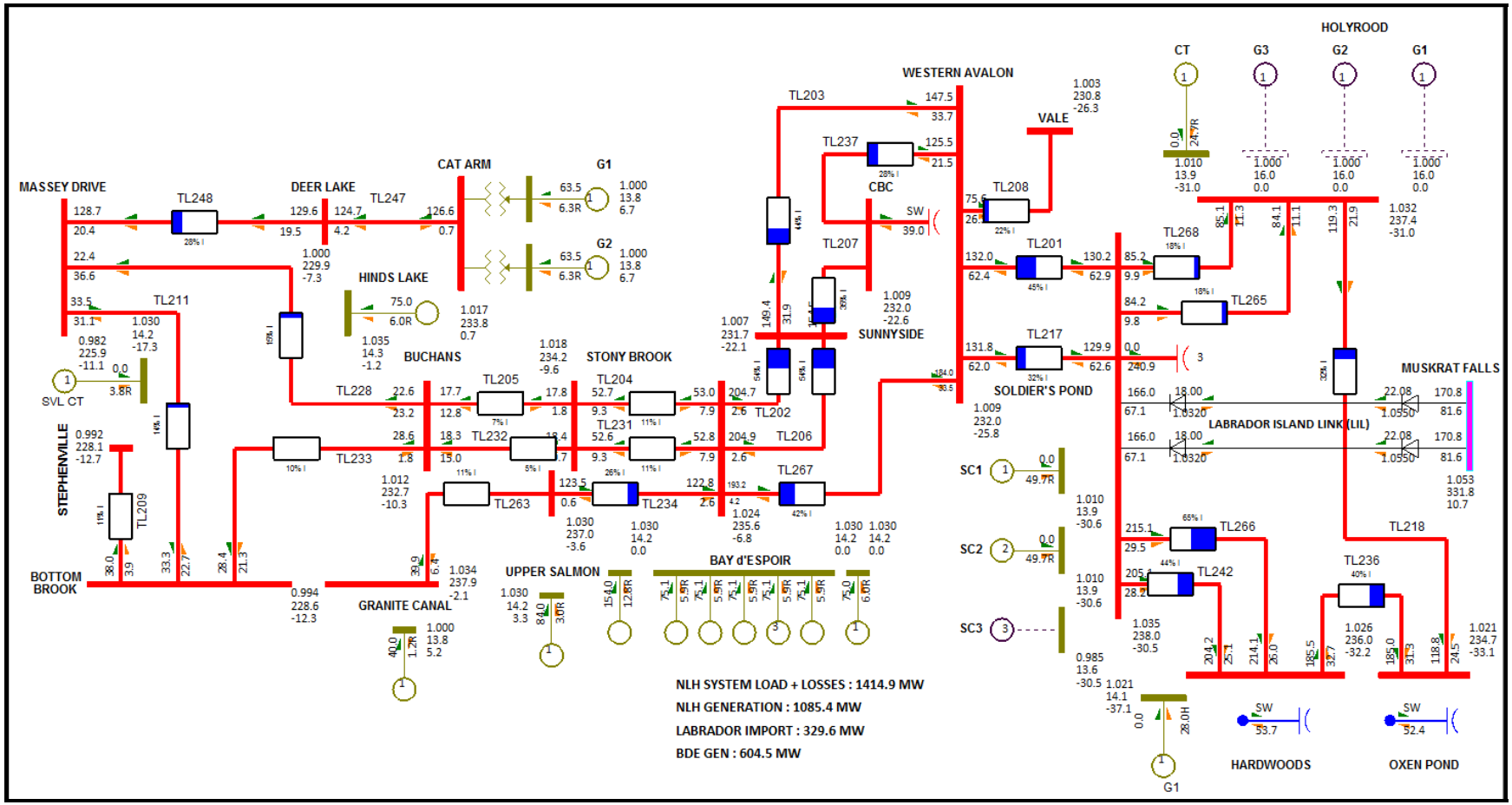


Figure 32 – Base Case 6 (BC6) Load Flow Plot – Pre-Contingency

New 230 kV Transmission Line Installed Between BDE and WAV

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

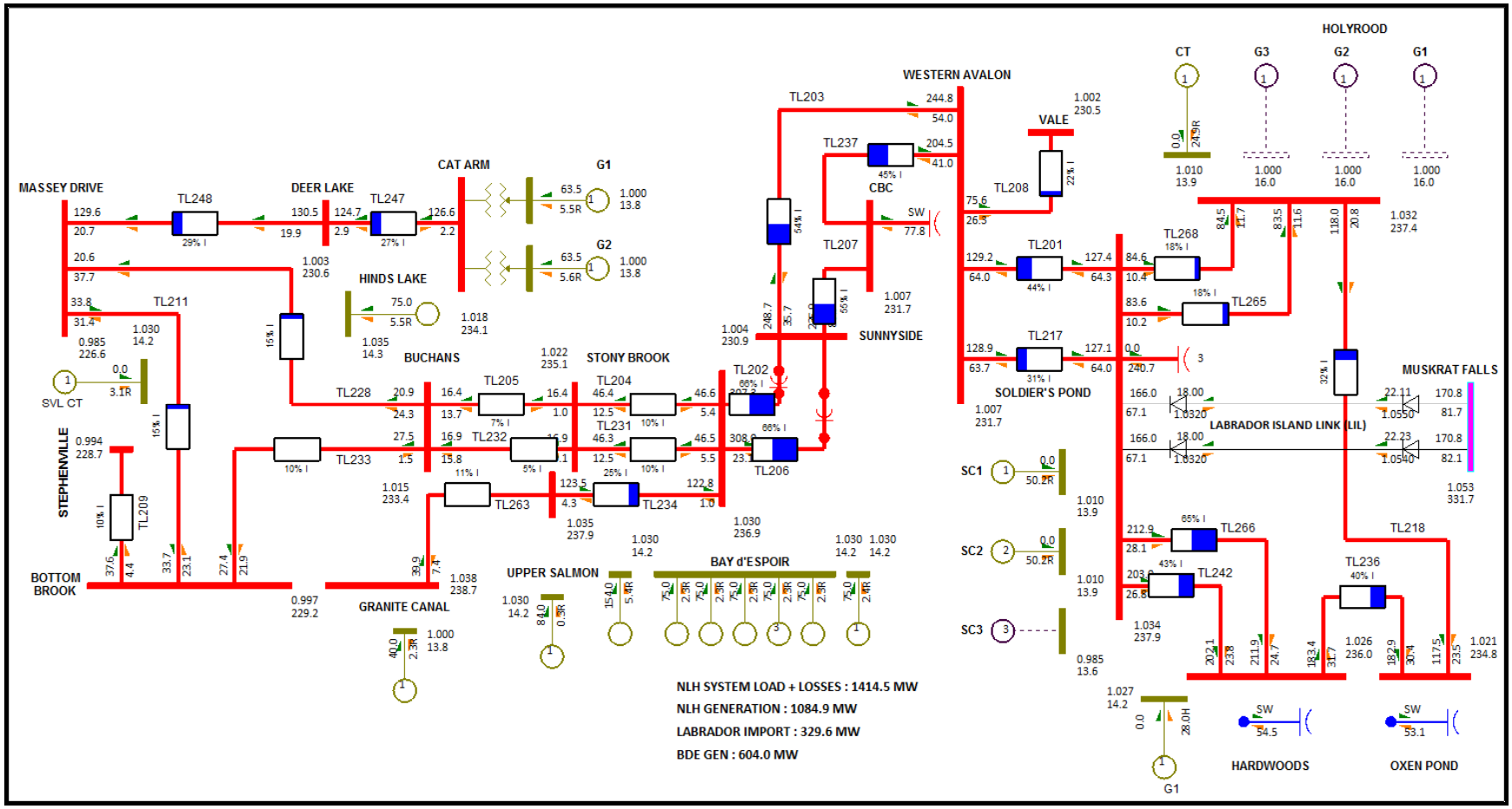


Figure 33 – Base Case 6 (BC6) Load Flow Plot – Pre-Contingency

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

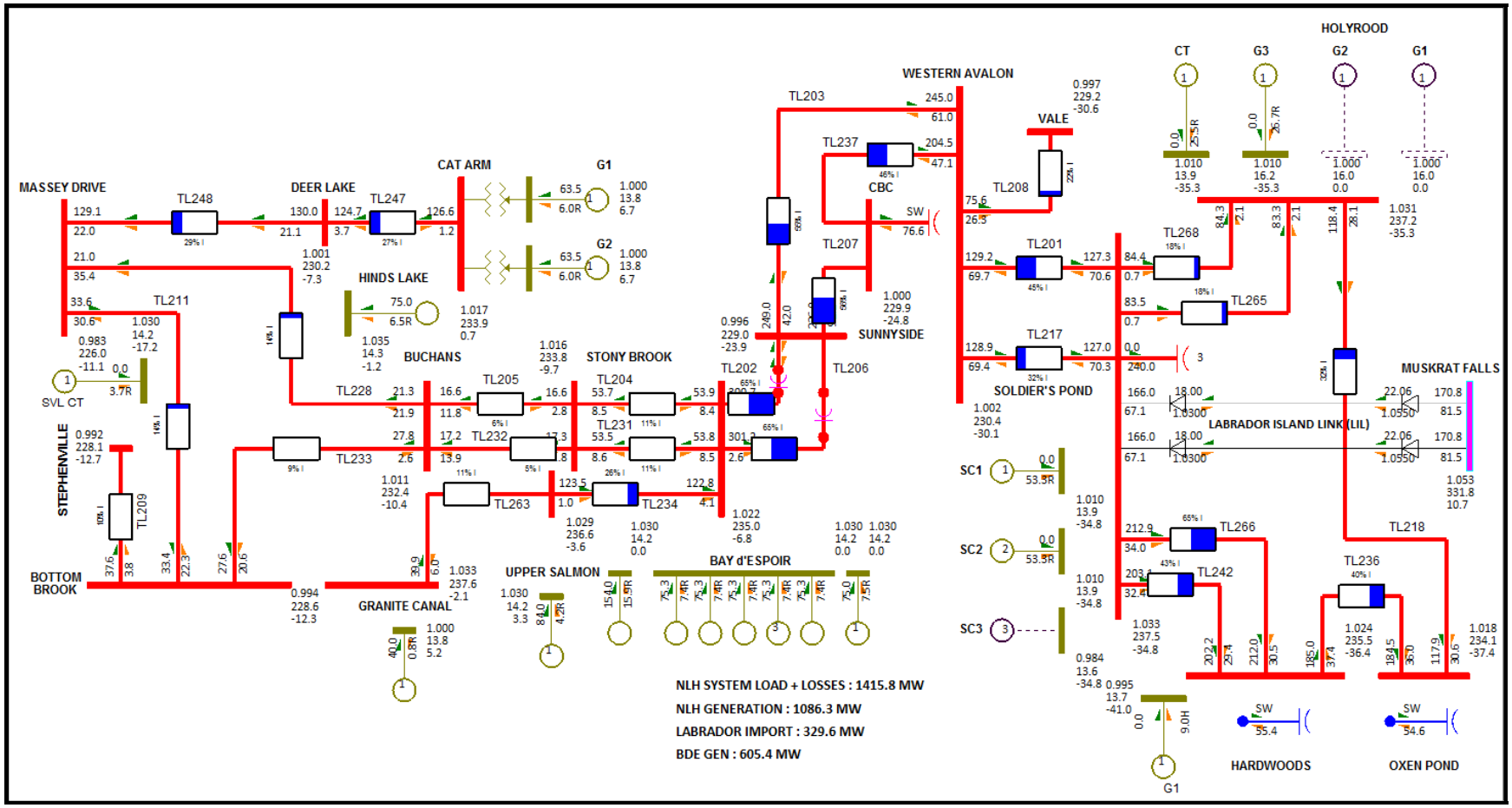


Figure 34 – Base Case 6 (BC6) Load Flow Plot – Pre-Contingency

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

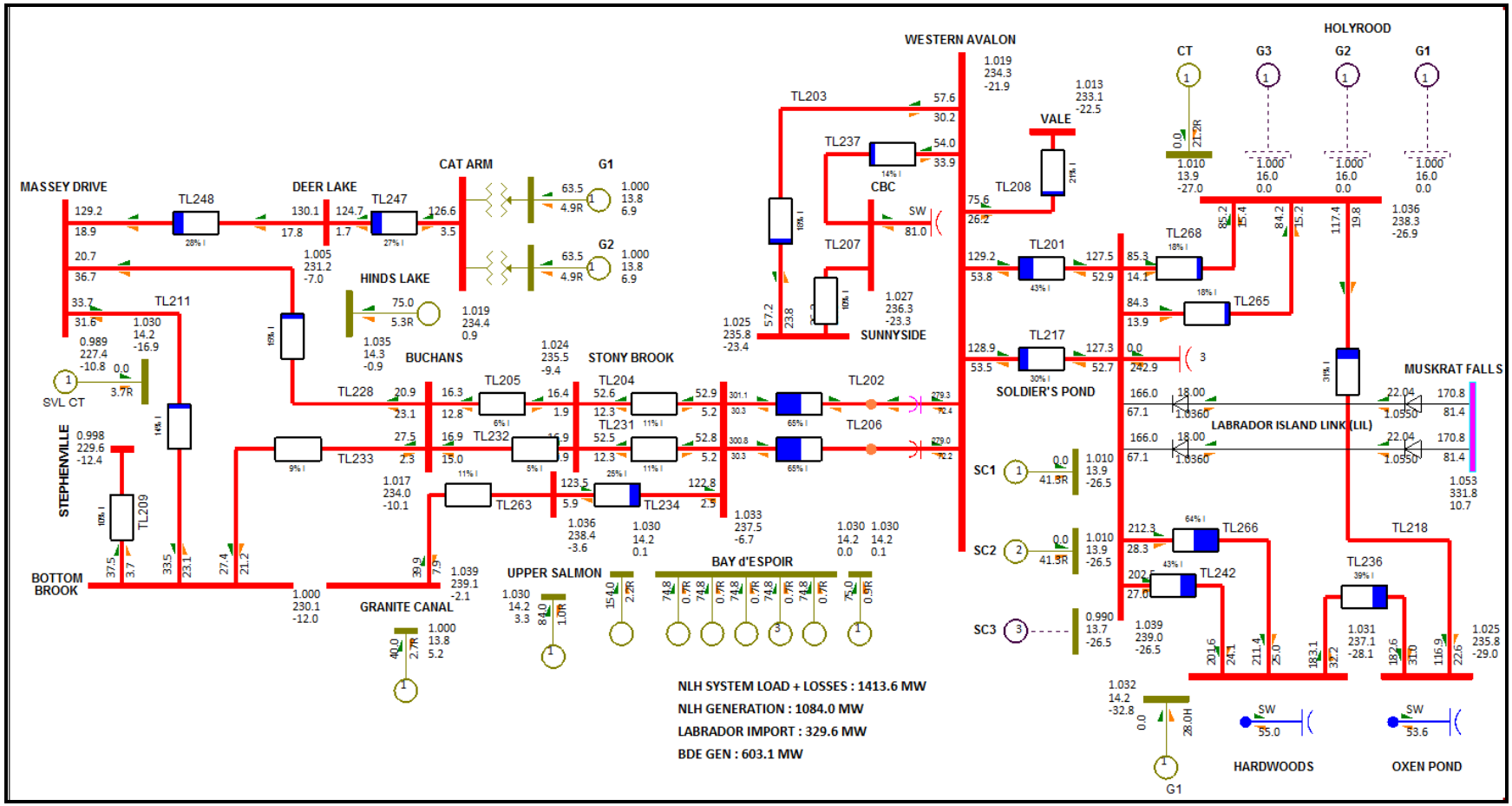


Figure 35 – Base Case 6 (BC6) Load Flow Plot – Pre-Contingency

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

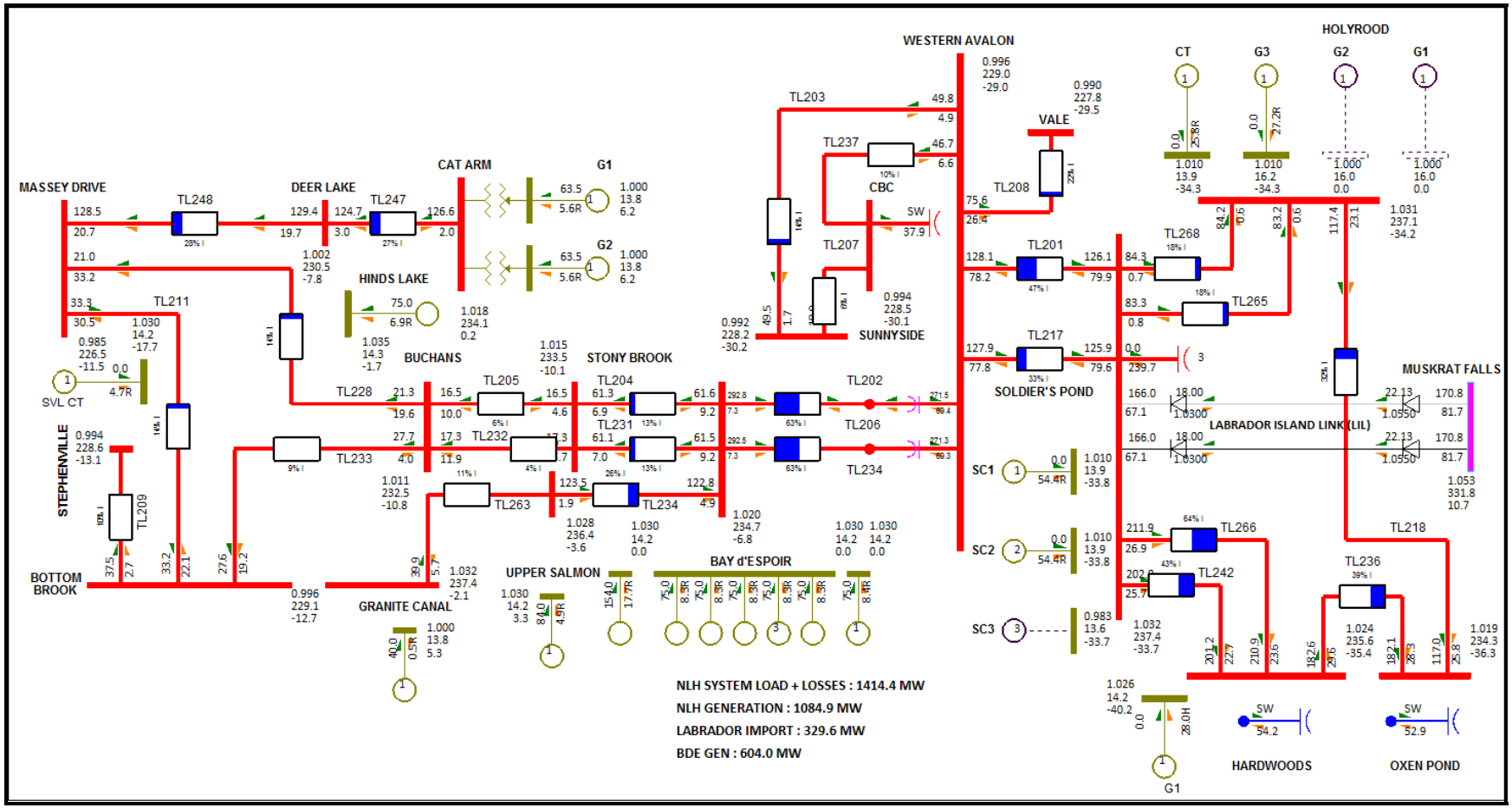


Figure 36 – Base Case 6 (BC6) Load Flow Plot – Pre-Contingency

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

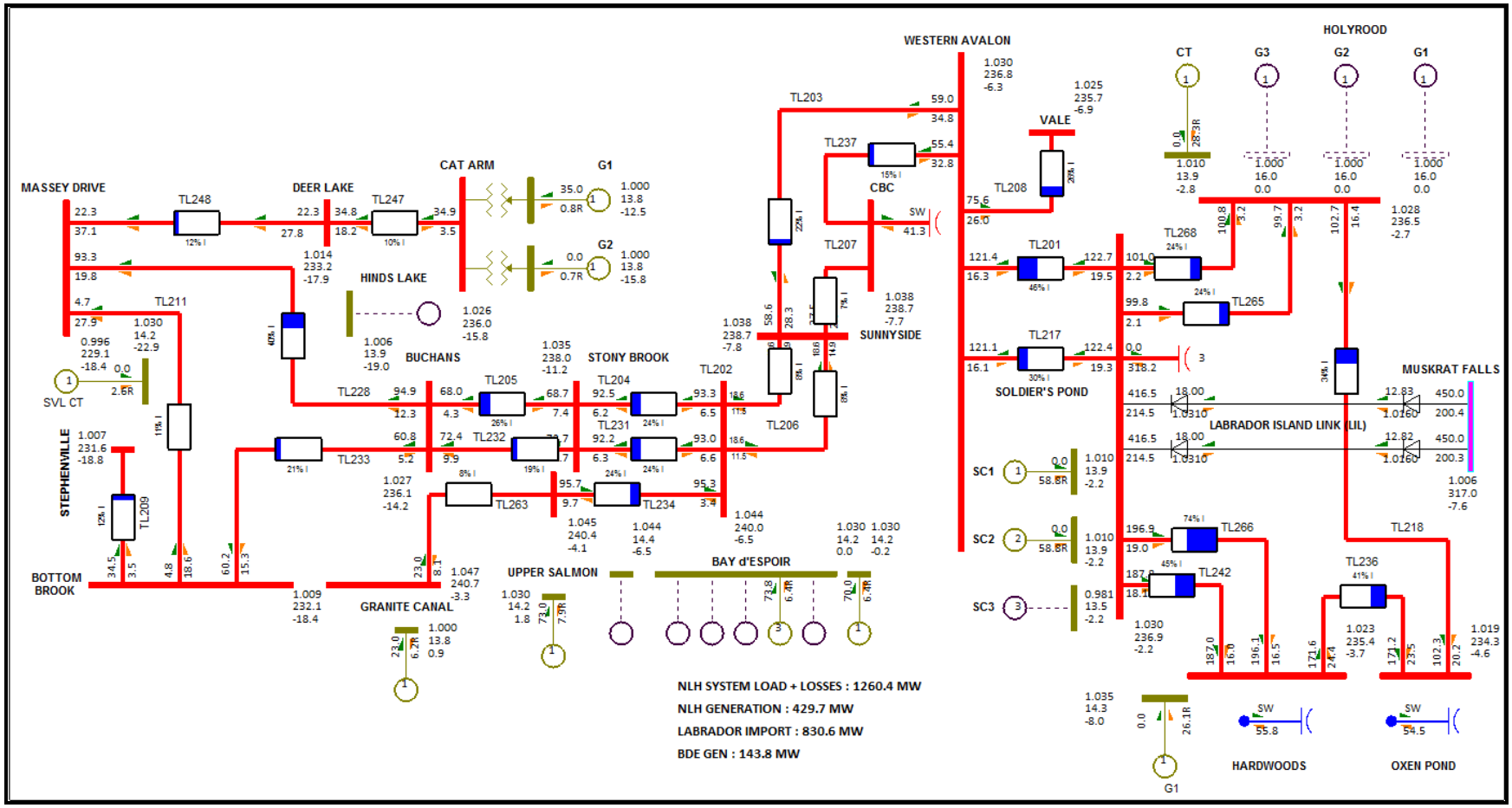


Figure 37 – Base Case 7 (BC7) Load Flow Plot – Pre-Contingency

Existing Bulk 230 kV Transmission System

Spring/Fall Day (1261 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (431 MW)

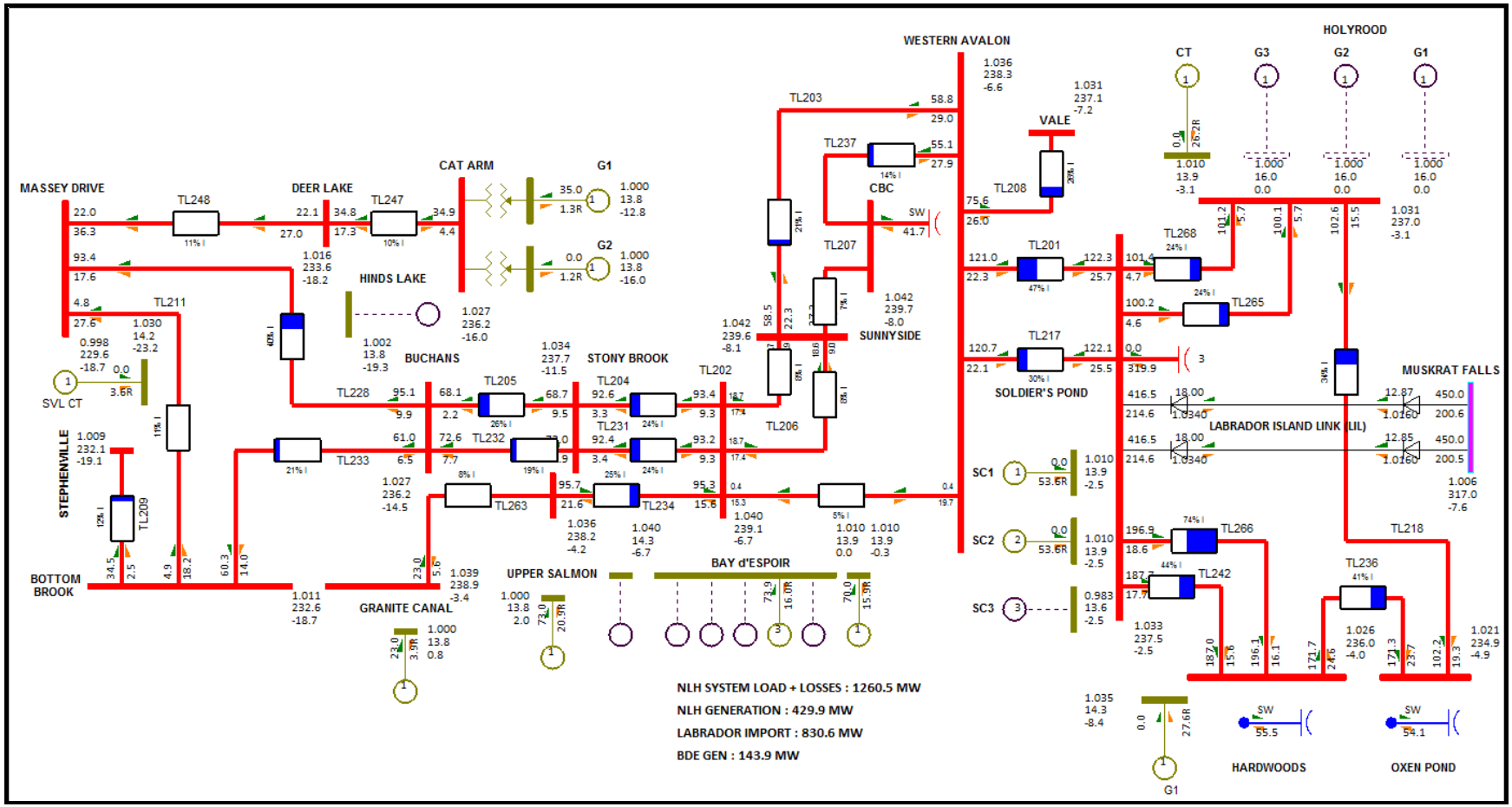


Figure 38 – Base Case 7 (BC7) Load Flow Plot – Pre-Contingency

New 230 kV Transmission Line Installed Between BDE and WAV

Spring/Fall Day (1261 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (431 MW)

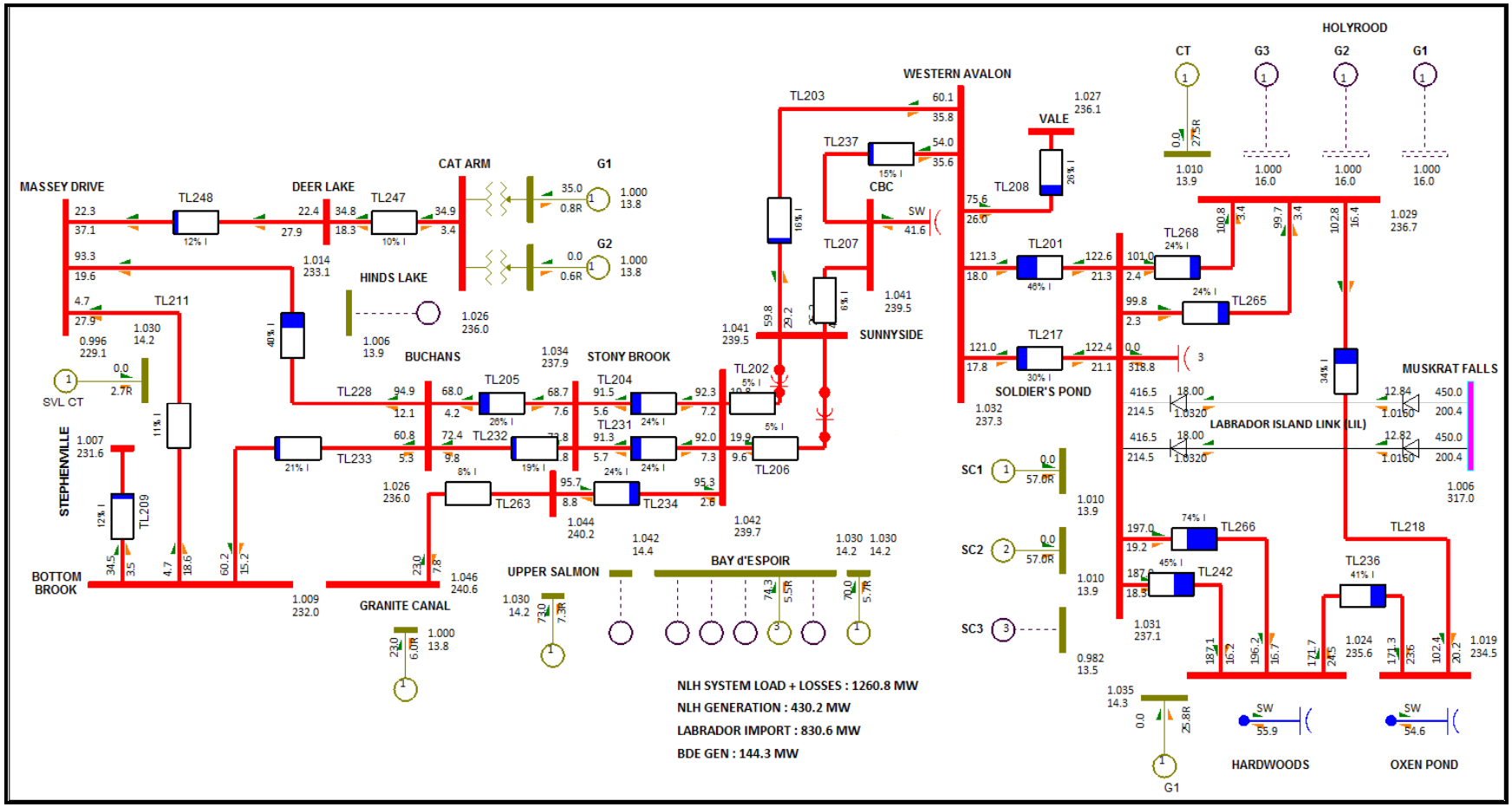


Figure 39 – Base Case 7 (BC7) Load Flow Plot – Pre-Contingency

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (431 MW)

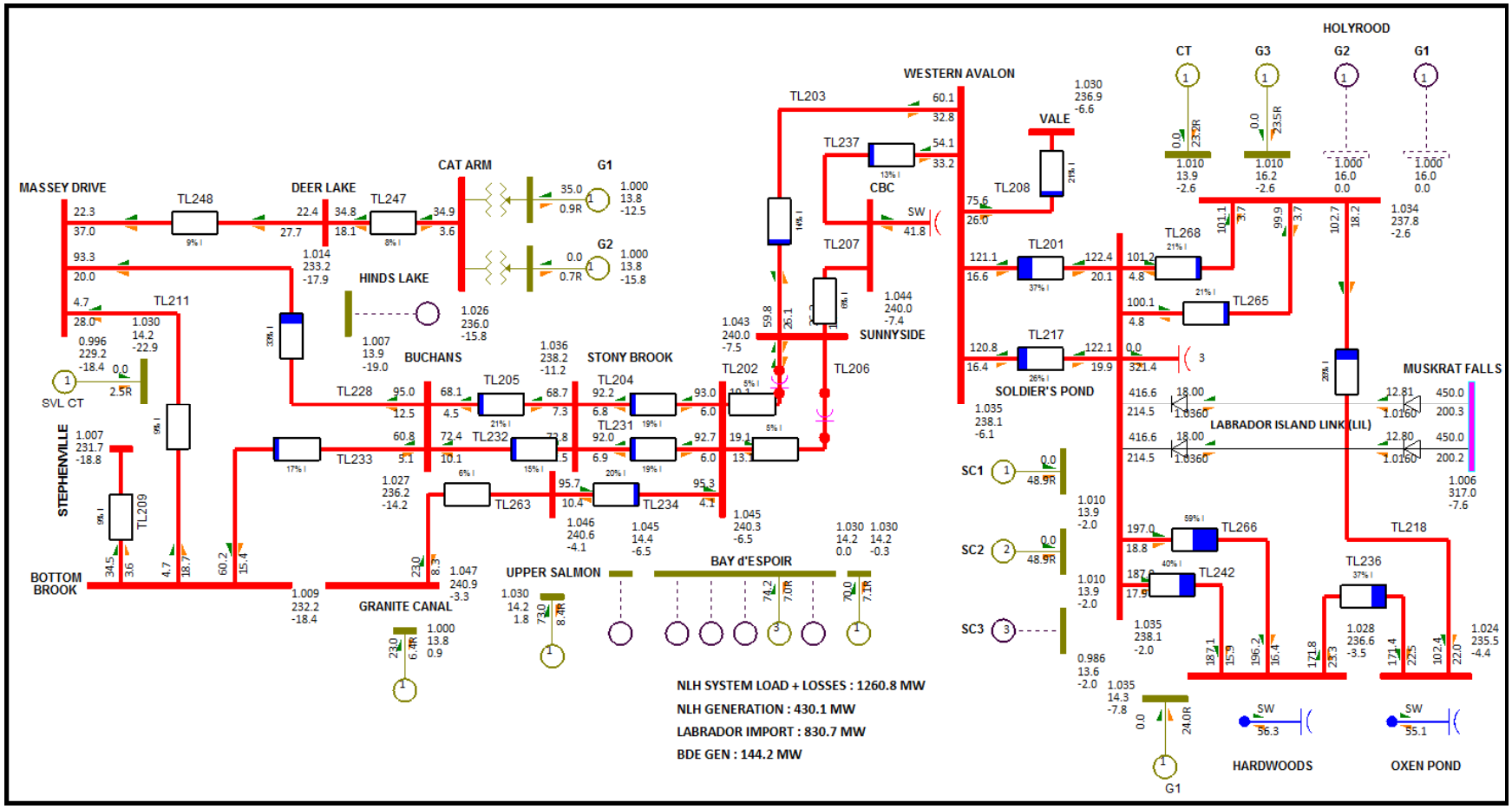


Figure 40 – Base Case 7 (BC7) Load Flow Plot – Pre-Contingency

TL202/TL206 with 25% Series Compensation and 25°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (431 MW)

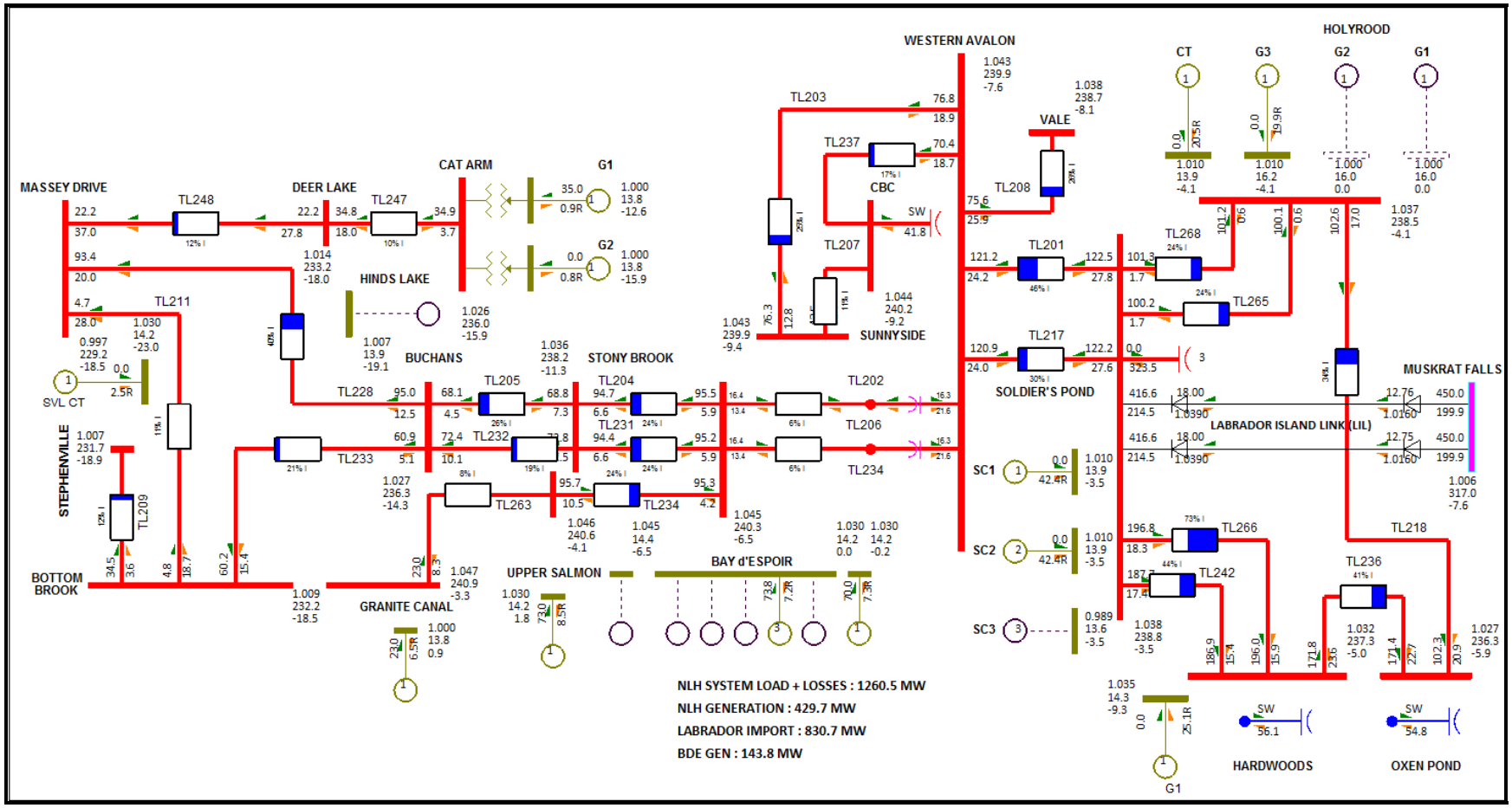


Figure 41 – Base Case 7 (BC7) Load Flow Plot – Pre-Contingency

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (431 MW)

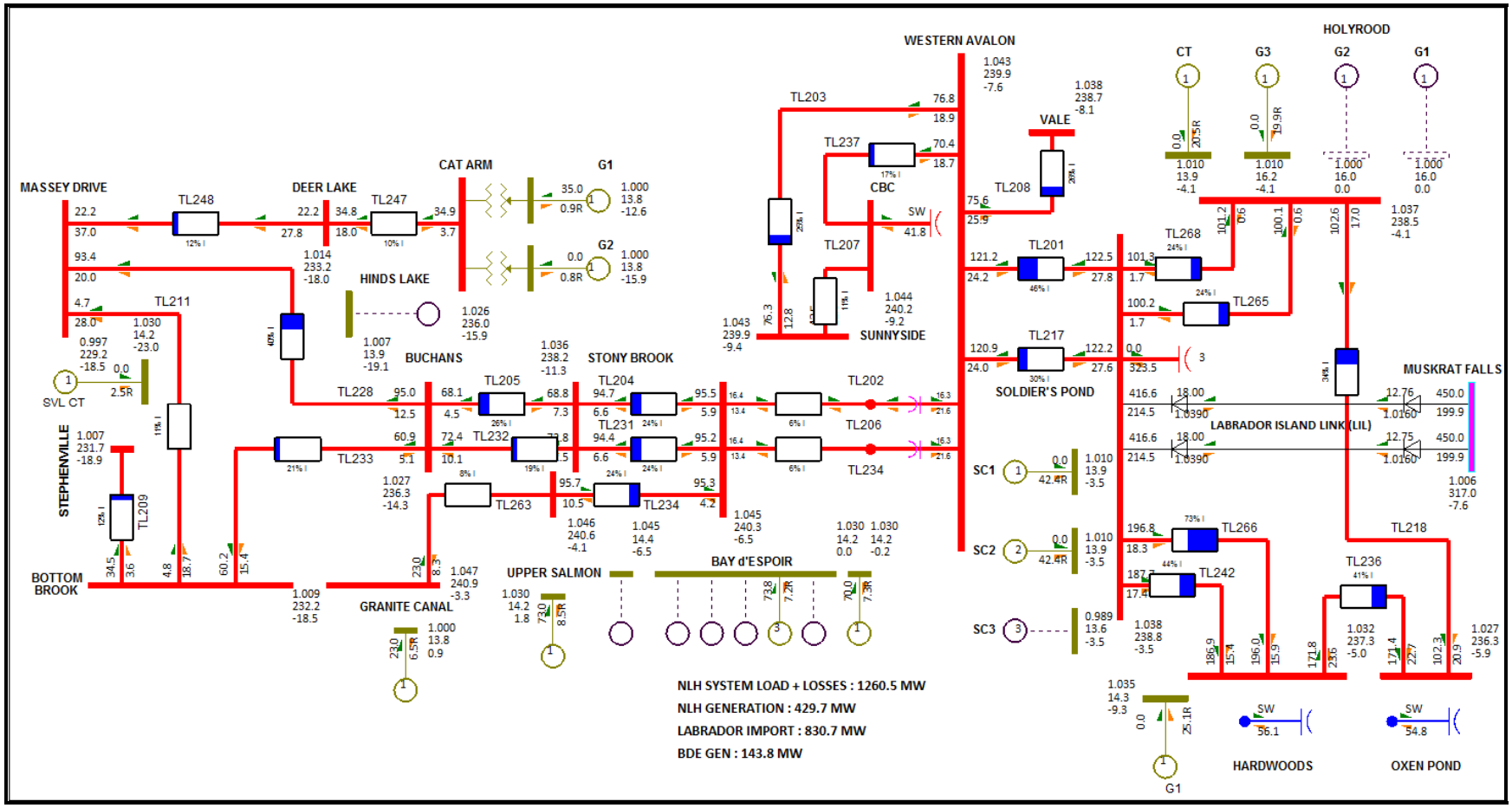


Figure 42 – Base Case 7 (BC7) Load Flow Plot – Pre-Contingency

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (431 MW)

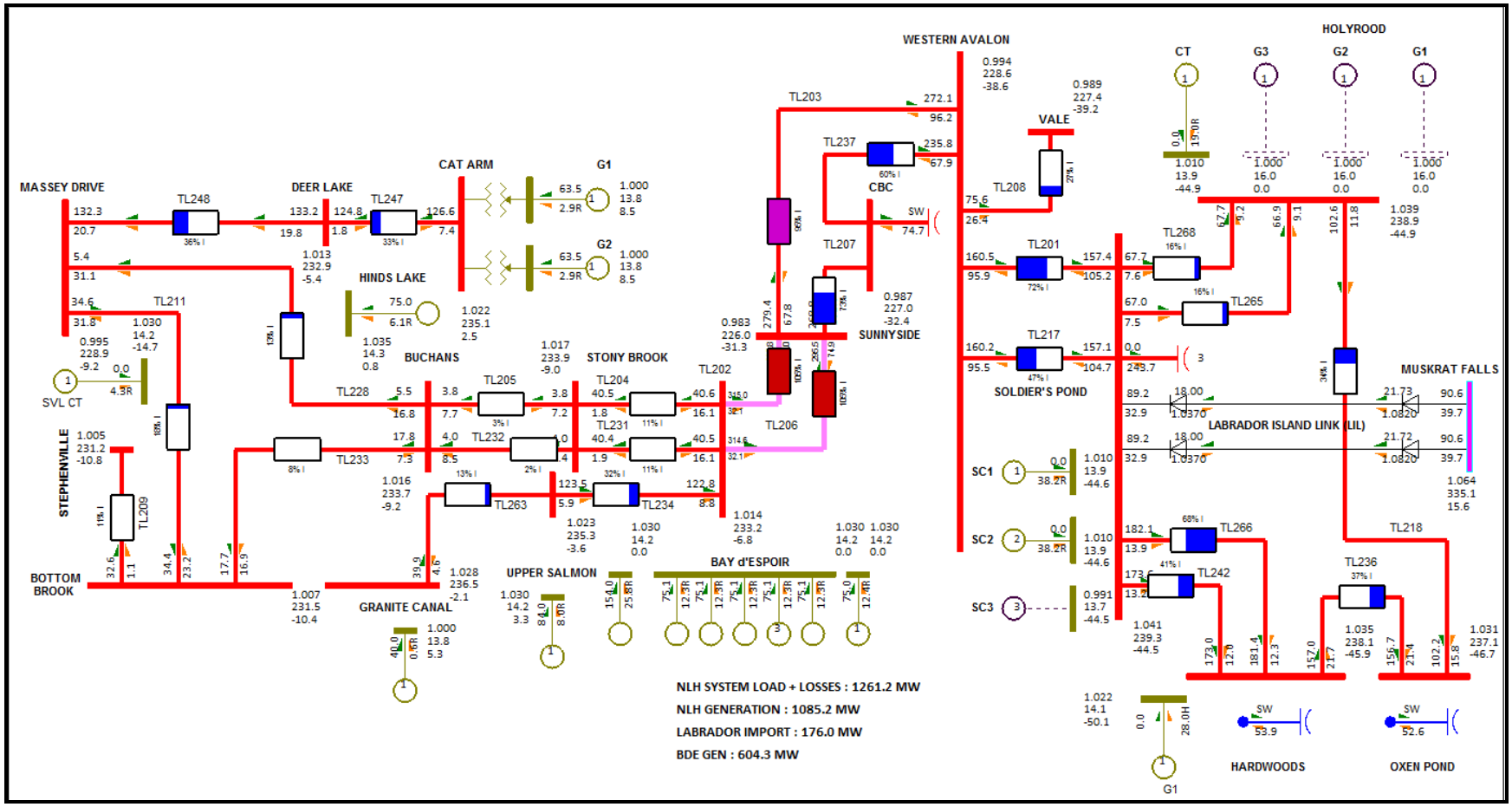


Figure 43 – Base Case 8 (BC8) Load Flow Plot – Pre-Contingency

Existing Bulk 230 kV Transmission System

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

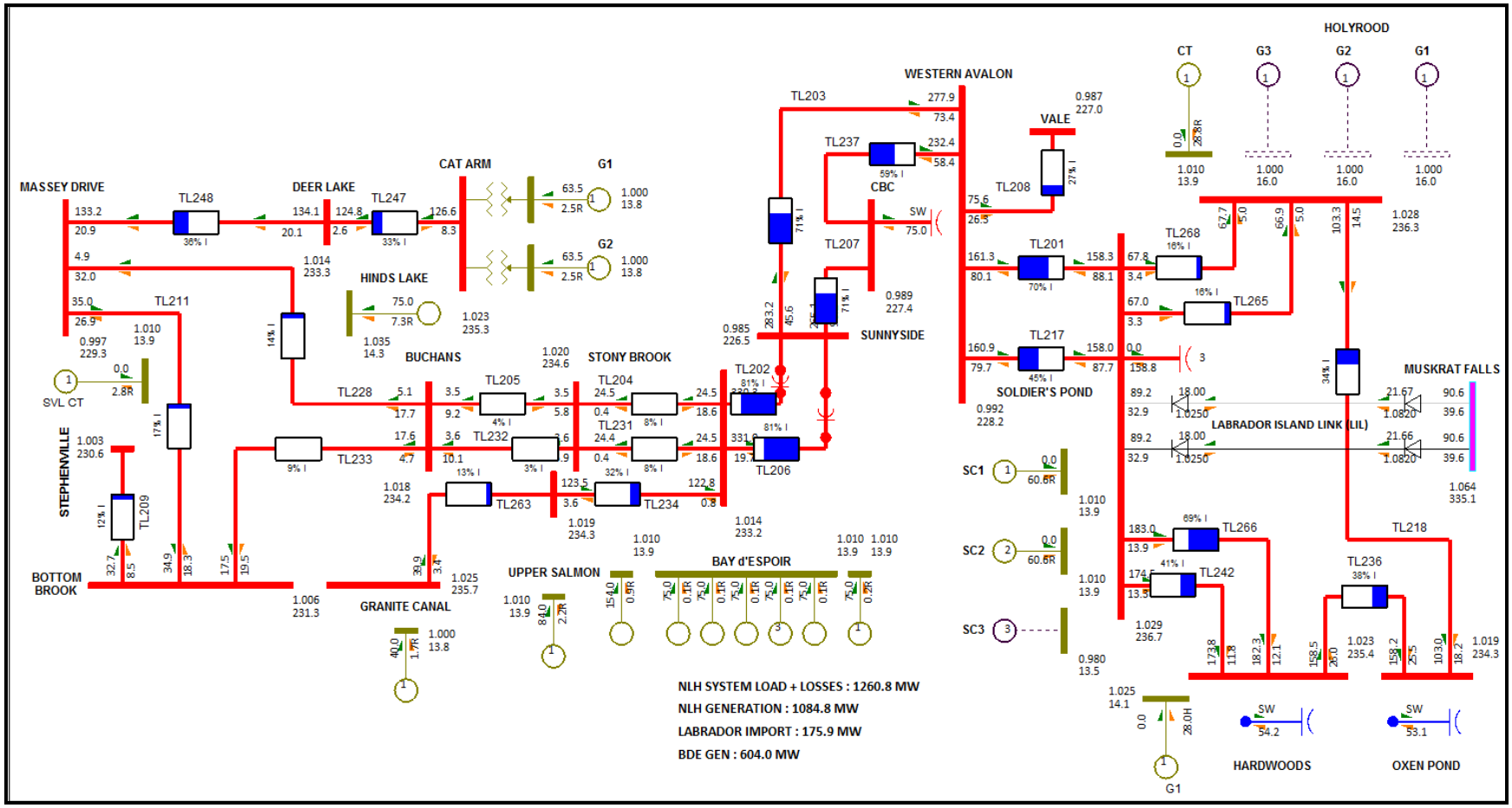


Figure 44 – Base Case 8 (BC8) Load Flow Plot – Pre-Contingency

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

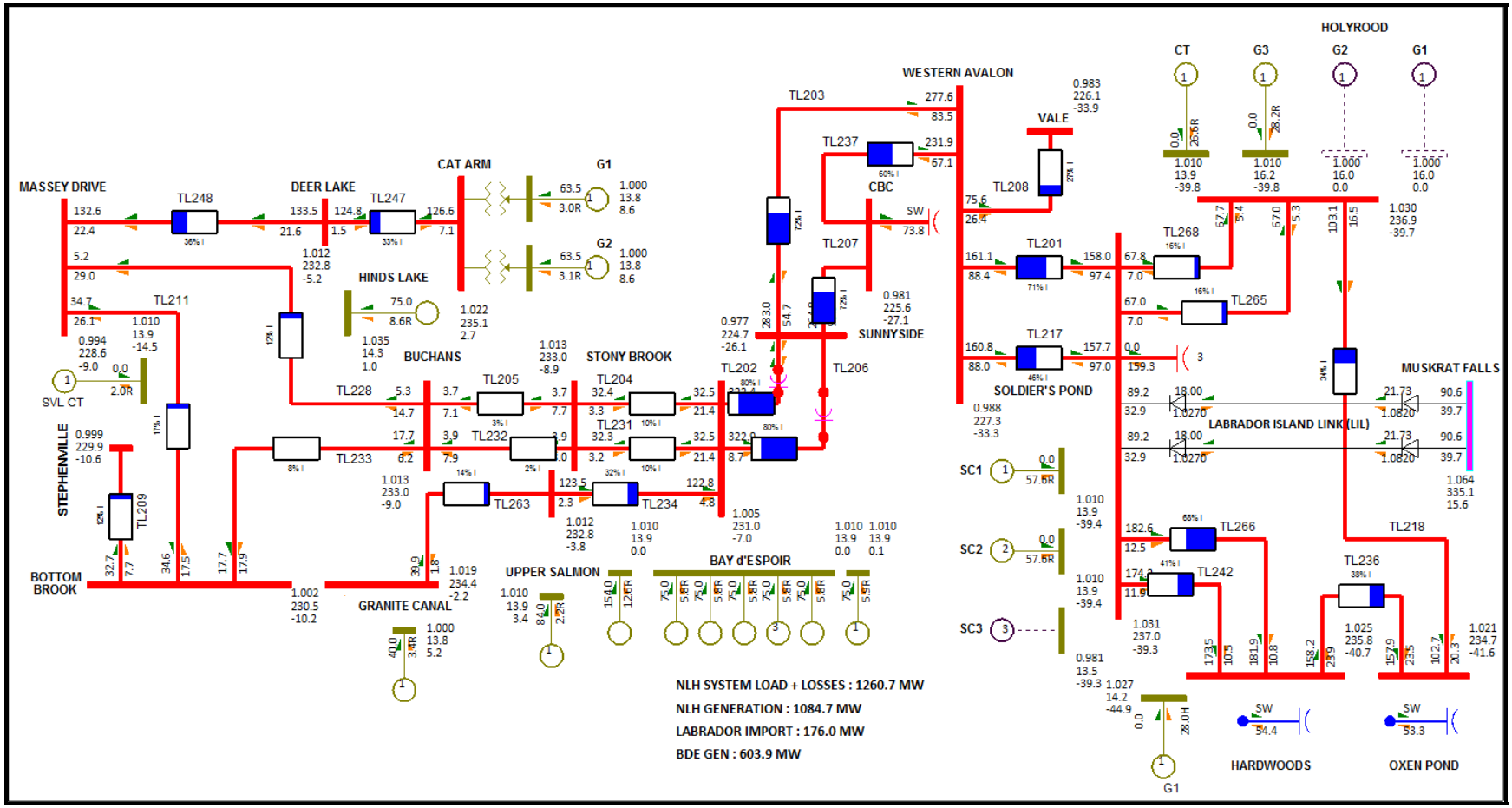


Figure 45 – Base Case 8 (BC8) Load Flow Plot – Pre-Contingency

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

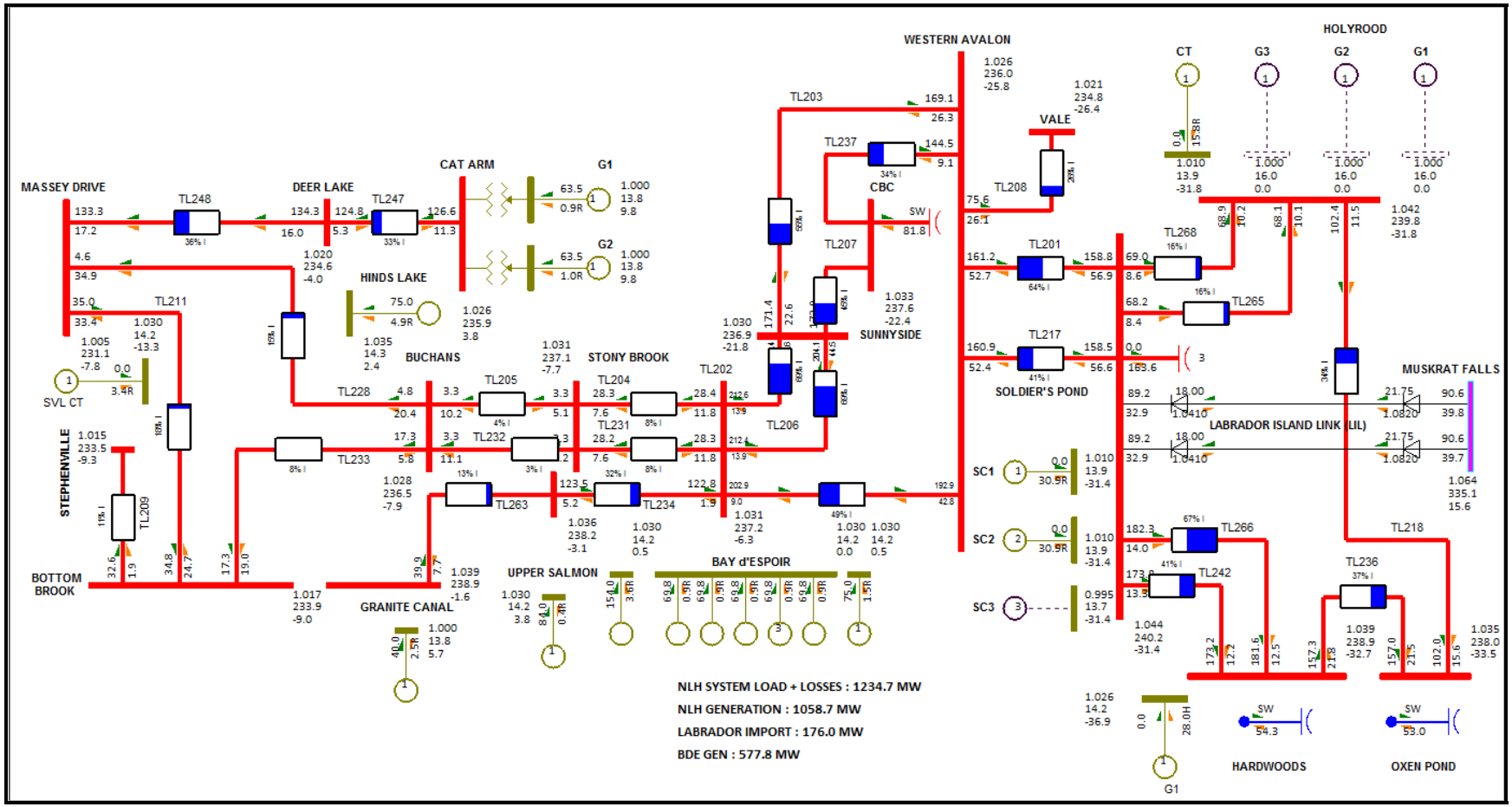


Figure 46 – Base Case 8 (BC8) Load Flow Plot – Pre-Contingency

New 230 kV Transmission Line Installed Between BDE and WAV

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

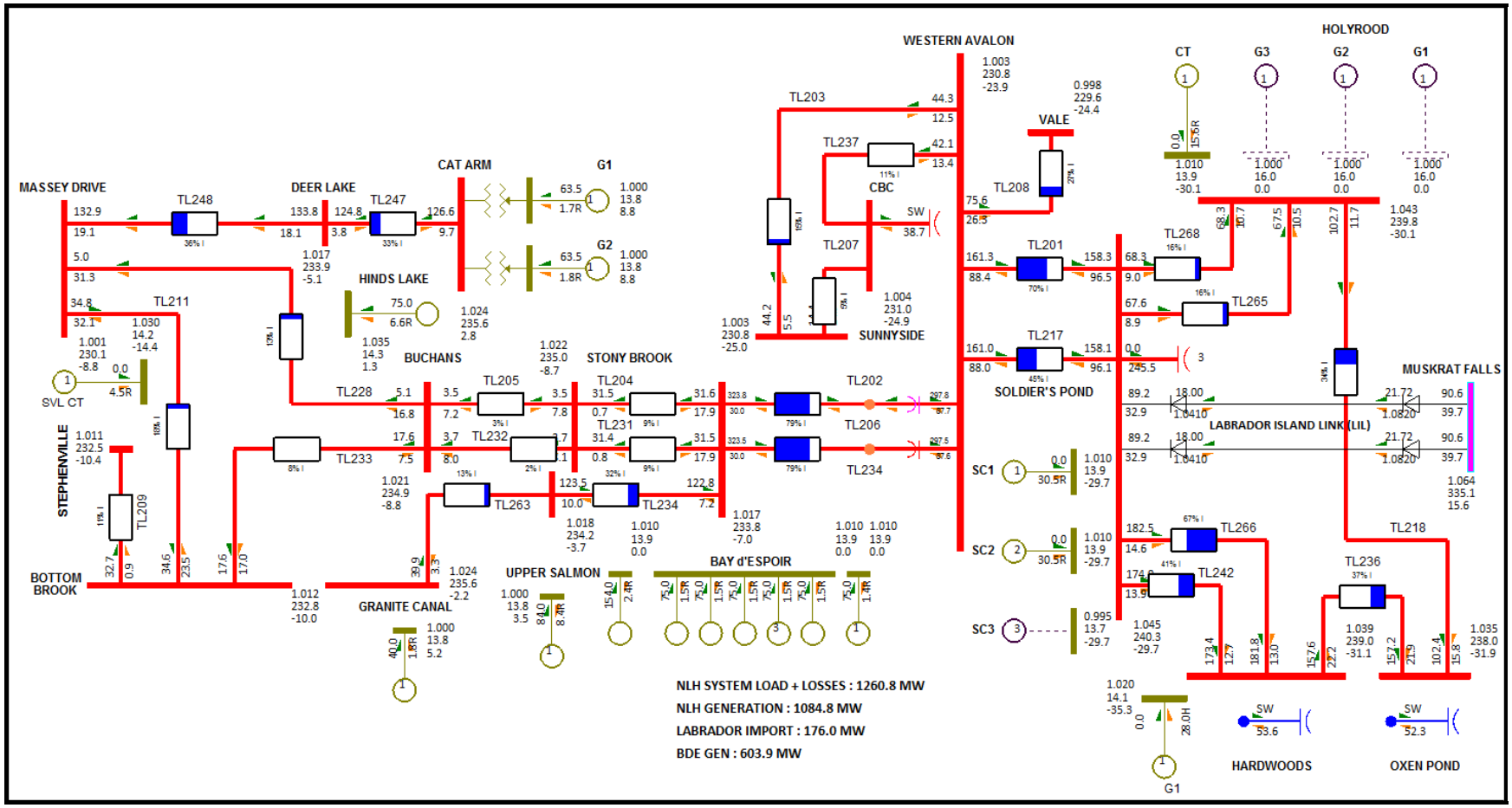


Figure 47 – Base Case 8 (BC8) Load Flow Plot – Pre-Contingency

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

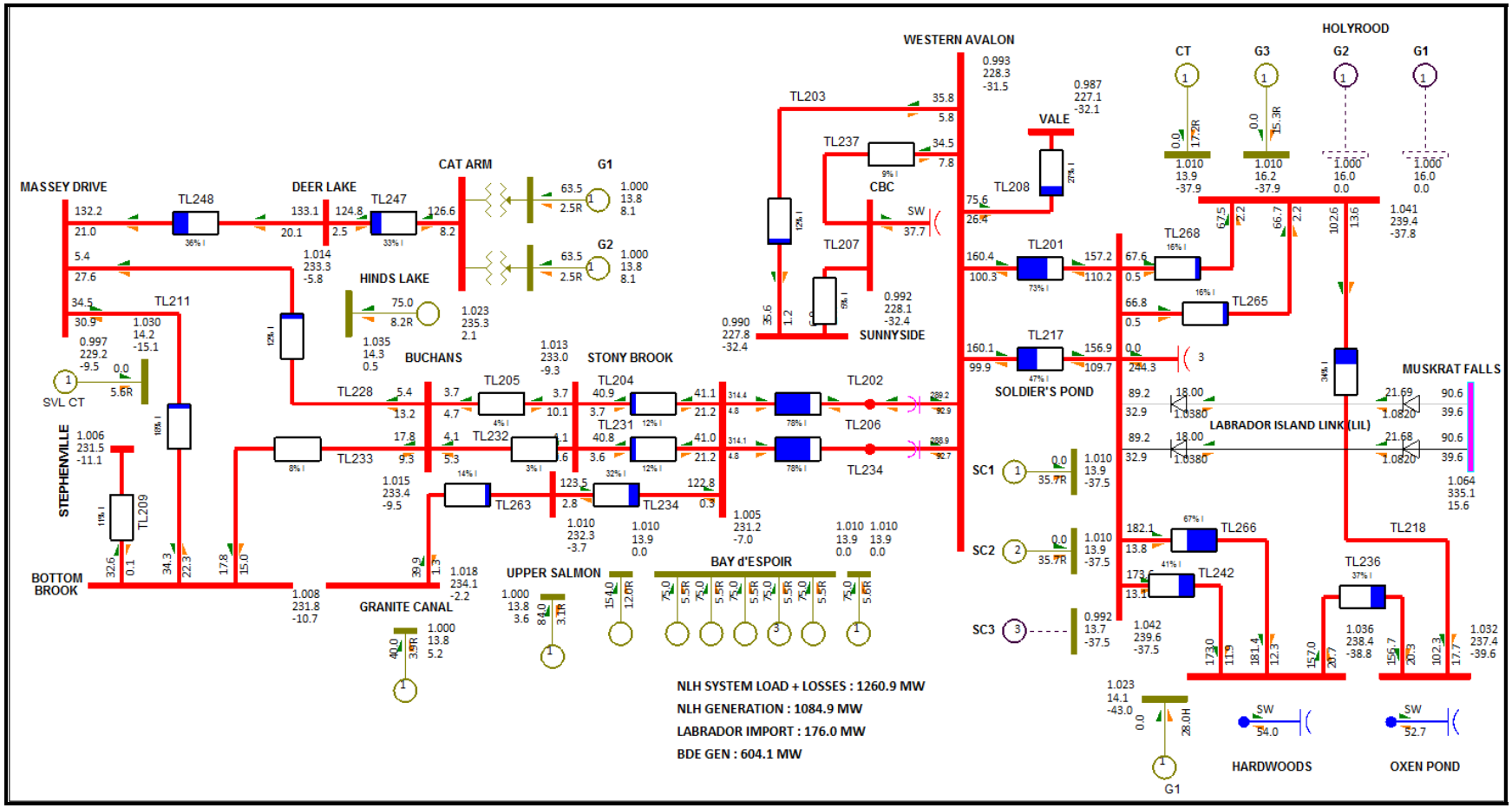


Figure 48 – Base Case 8 (BC8) Load Flow Plot – Pre-Contingency

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

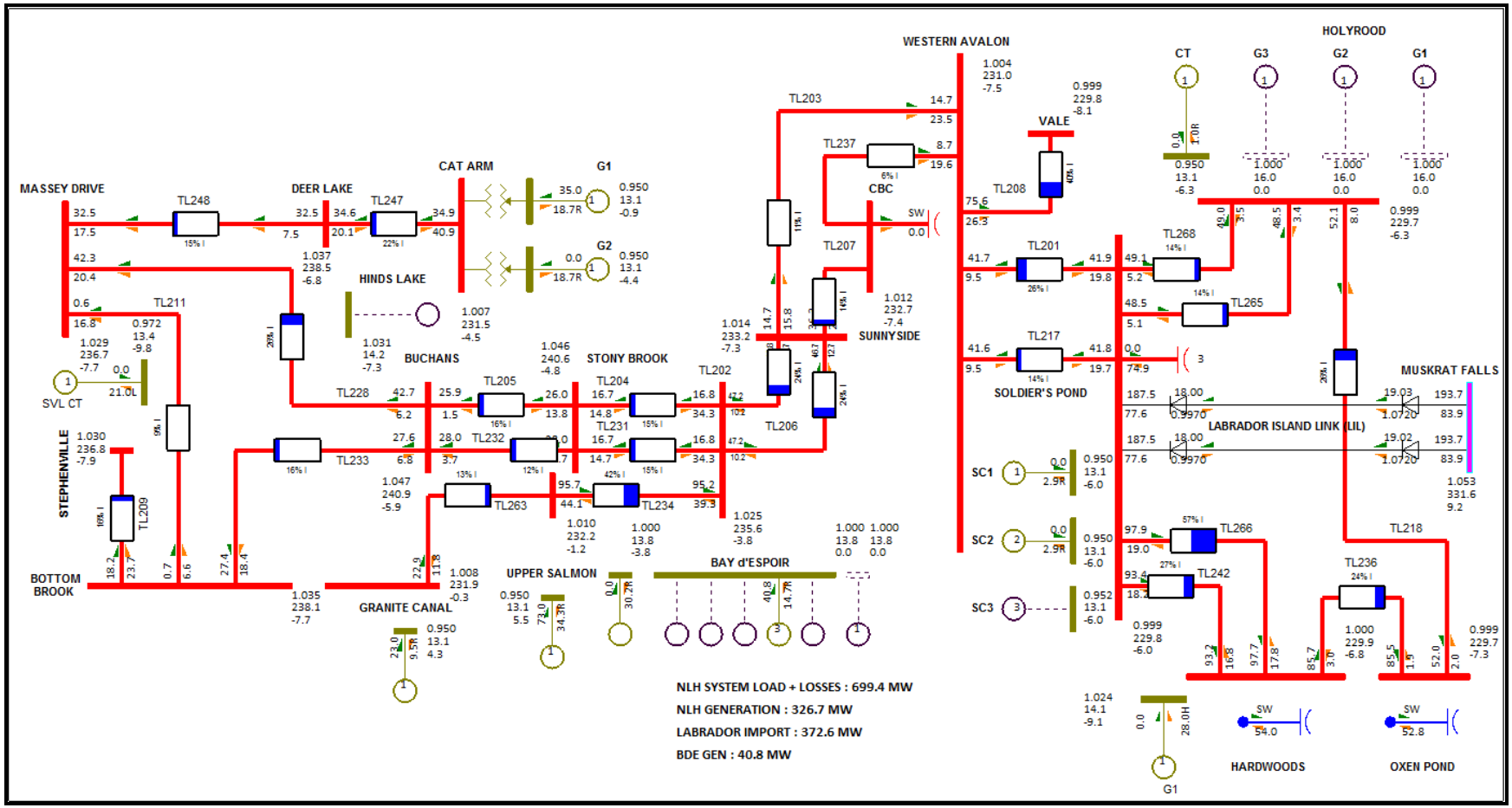


Figure 49 – Base Case 9 (BC9) Load Flow Plot – Pre-Contingency

Existing Bulk 230 kV Transmission System

Summer Day (700 MW) – Minimum Island Generation (325 MW) with Reserve on LIL (375 MW)

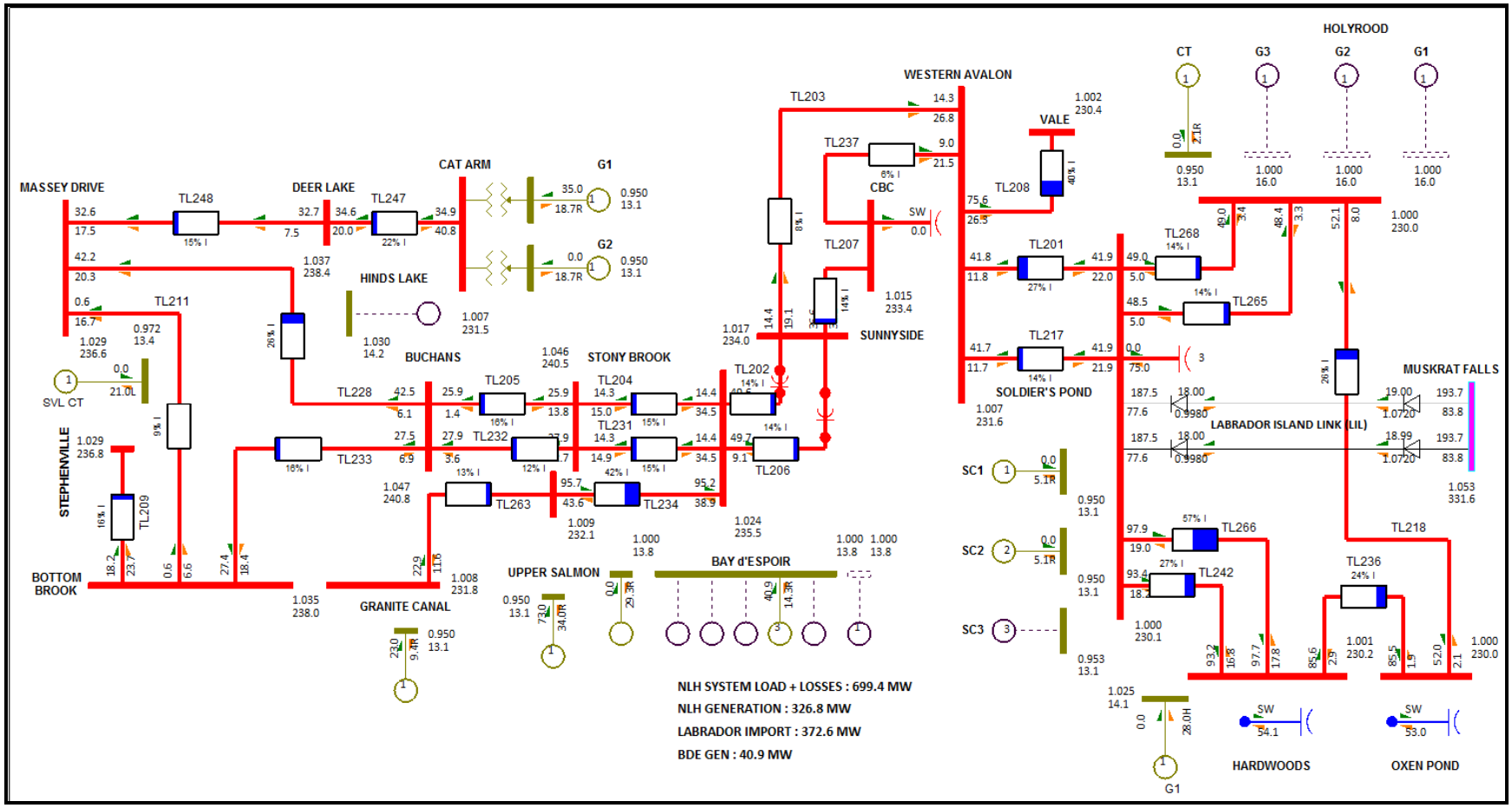


Figure 50 – Base Case 9 (BC9) Load Flow Plot – Pre-Contingency

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Summer Day (700 MW) – Minimum Island Generation (325 MW) with Reserve on LIL (375 MW)

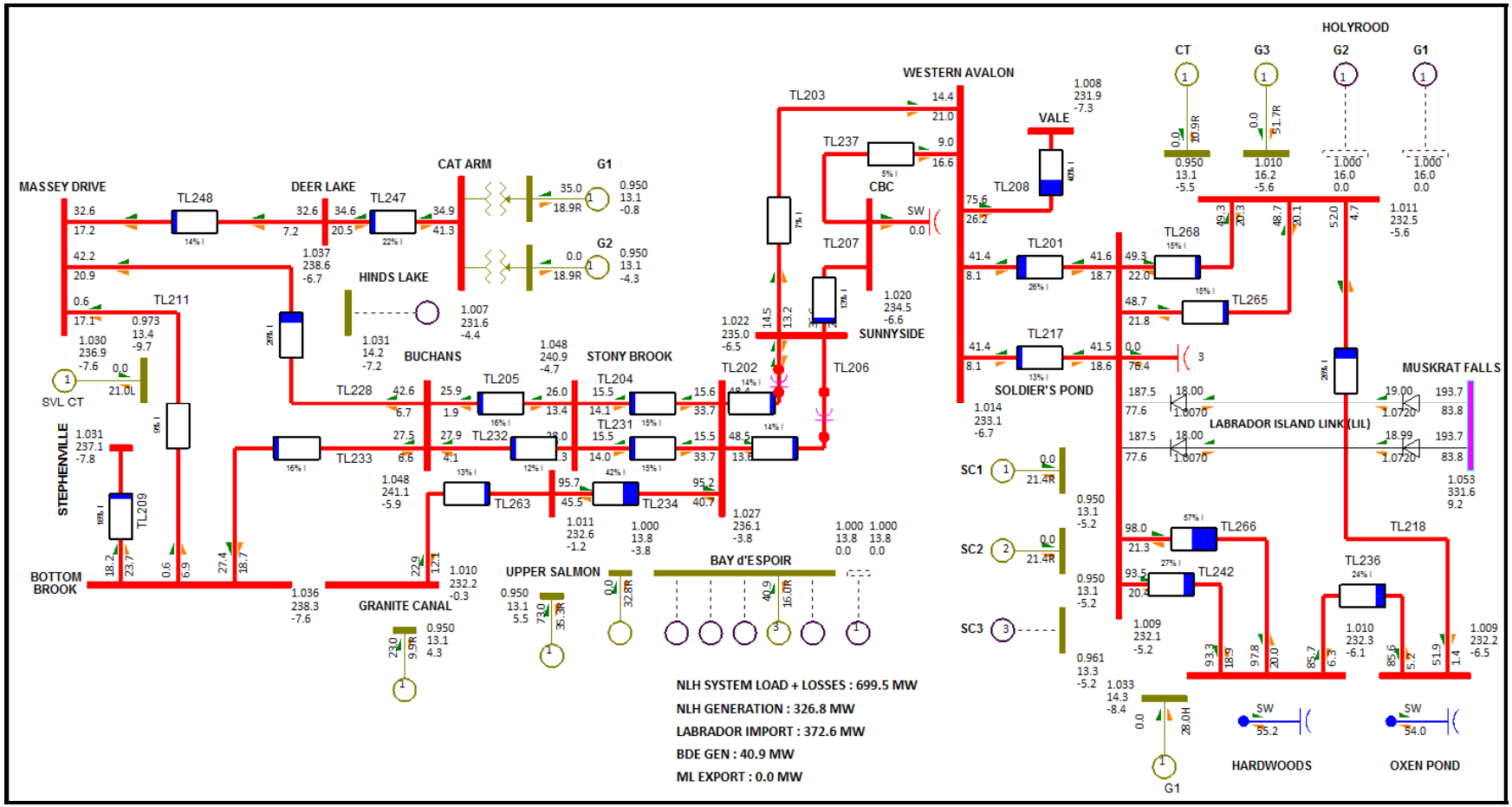


Figure 51 – Base Case 9 (BC9) Load Flow Plot – Pre-Contingency

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Summer Day (700 MW) – Minimum Island Generation (325 MW) with Reserve on LIL (375 MW)

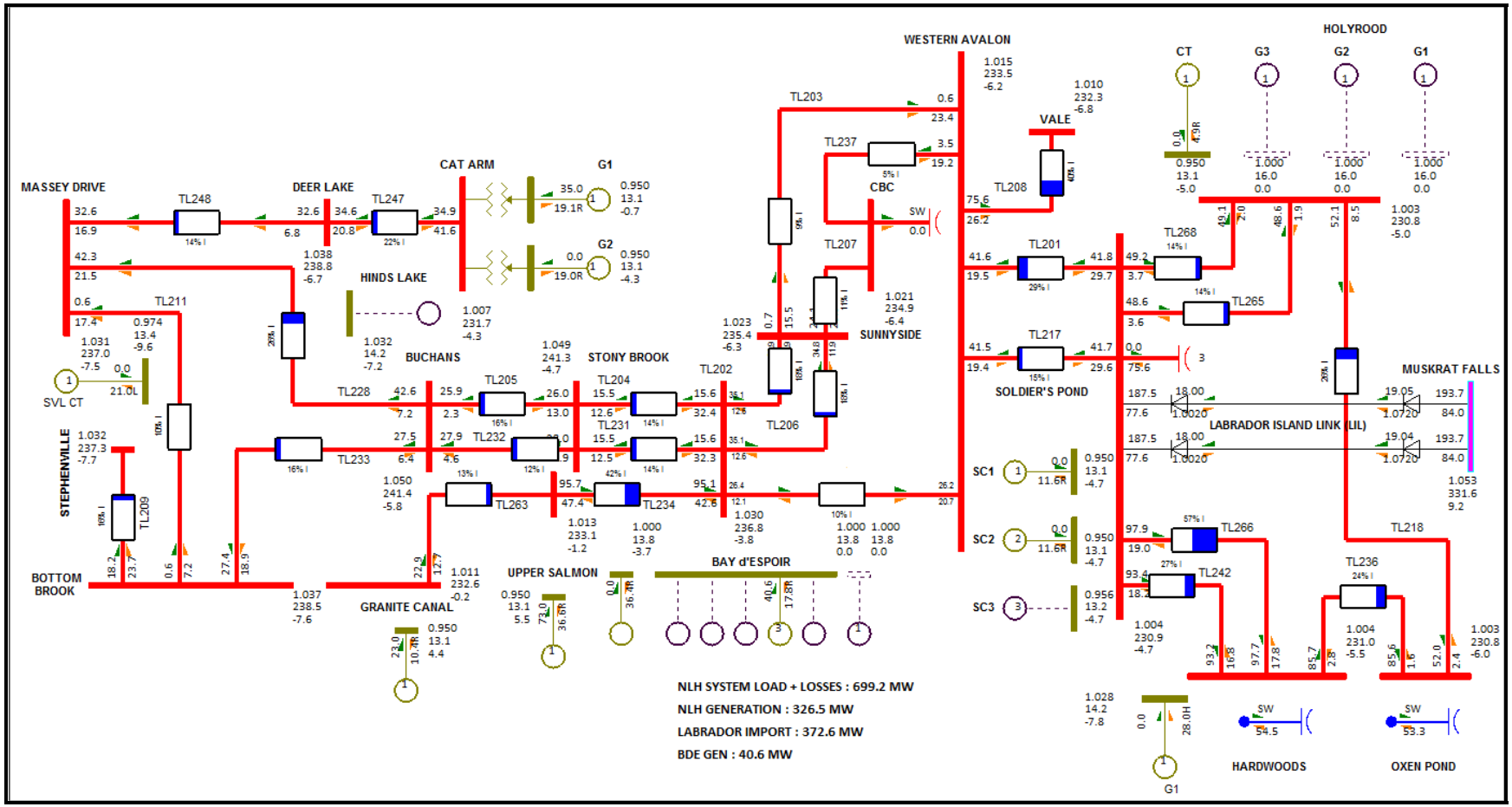


Figure 52 – Base Case 9 (BC9) Load Flow Plot – Pre-Contingency

New 230 kV Transmission Line Installed Between BDE and WAV

Summer Day (700 MW) – Minimum Island Generation (325 MW) with Reserve on LIL (375 MW)

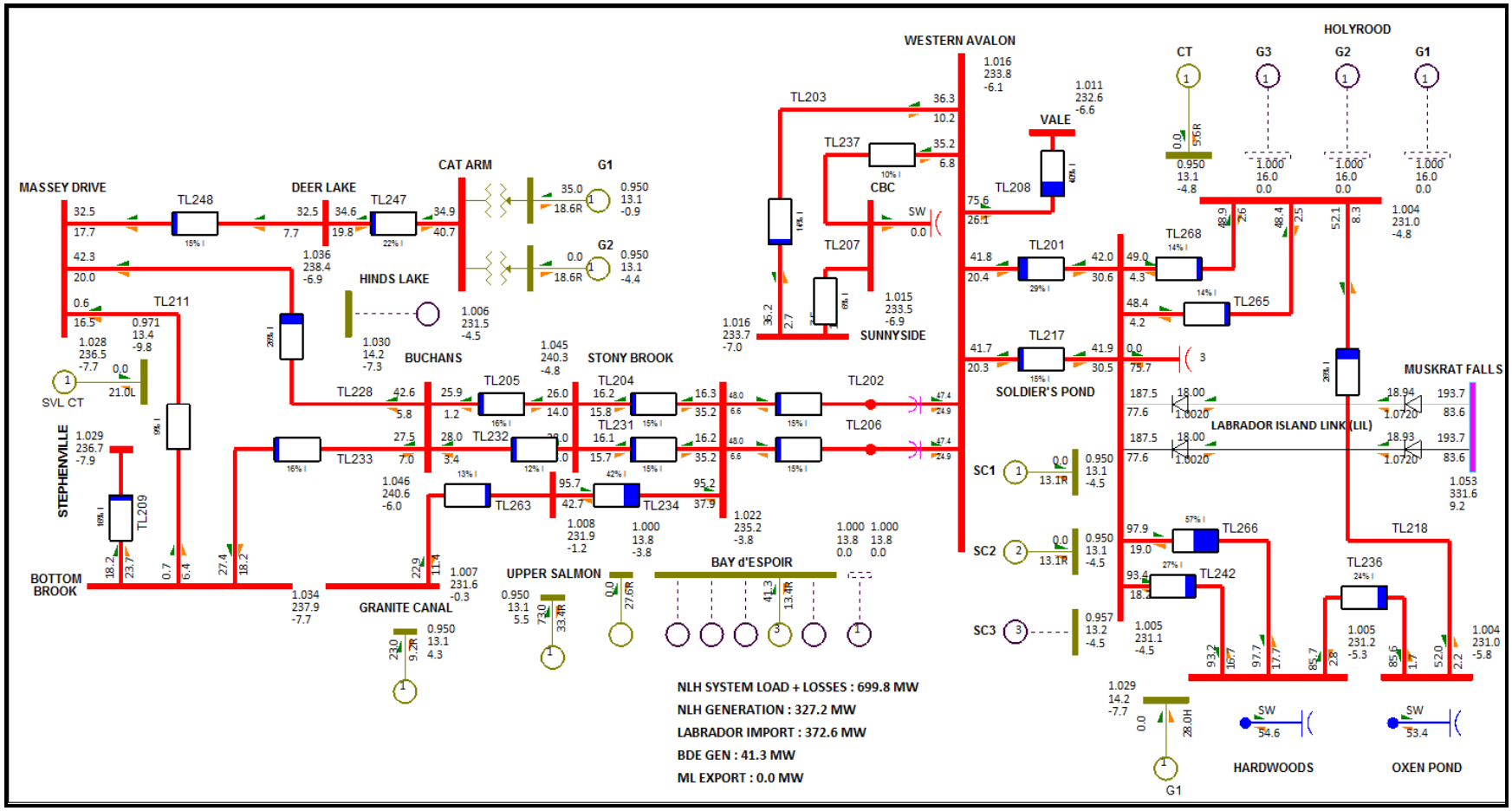


Figure 53 – Base Case 9 (BC9) Load Flow Plot – Pre-Contingency

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Summer Day (700 MW) – Minimum Island Generation (325 MW) with Reserve on LIL (375 MW)

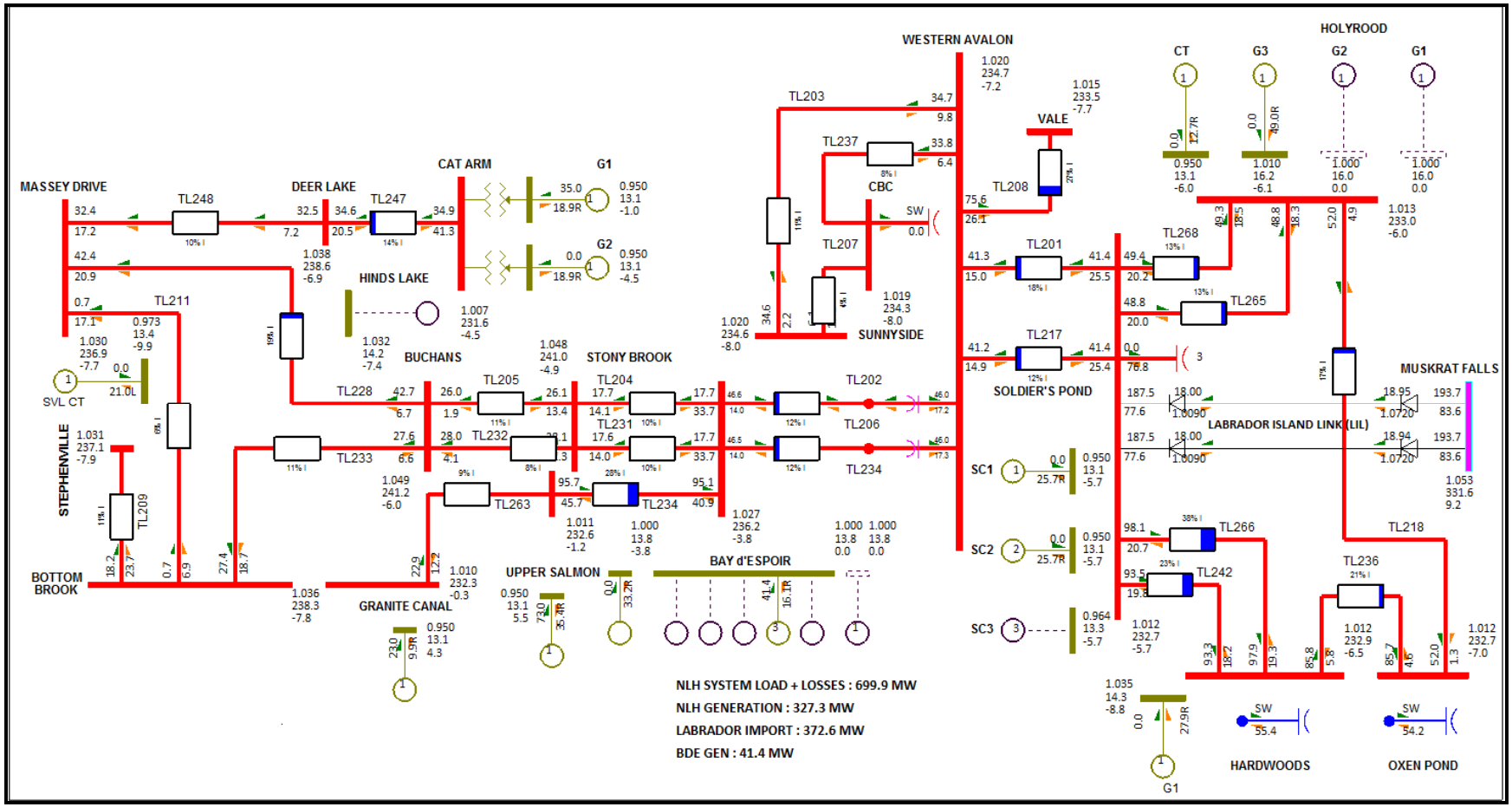


Figure 54 – Base Case 9 (BC9) Load Flow Plot – Pre-Contingency

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Summer Day (700 MW) – Minimum Island Generation (325 MW) with Reserve on LIL (375 MW)

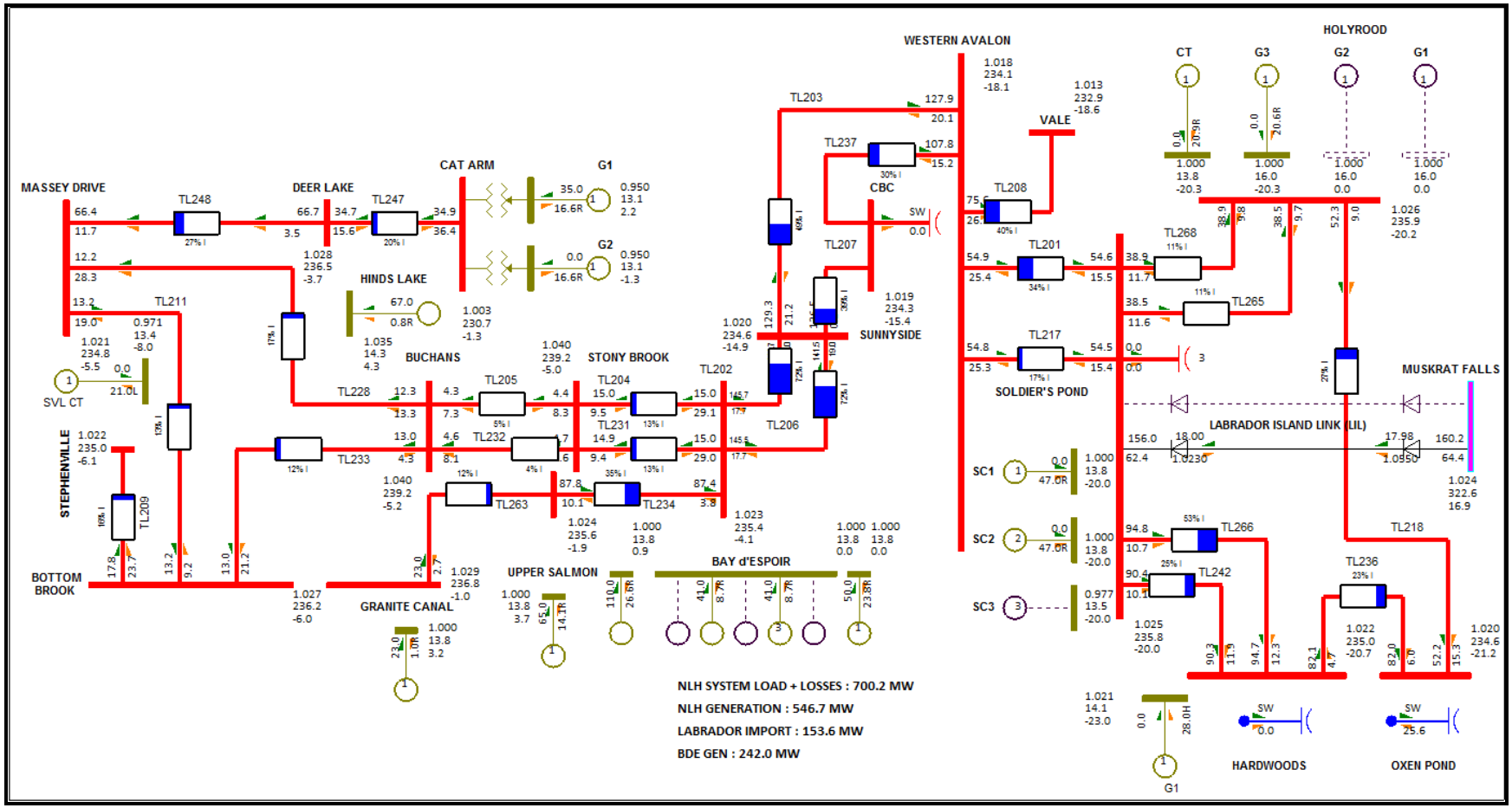


Figure 55 – Base Case 10 (BC10) Load Flow Plot – Pre-Contingency

Existing Bulk 230 kV Transmission System

Monopole Summer Day (700 MW) – Minimum Island Generation (154 MW) with Reserve on LIL (546 MW)

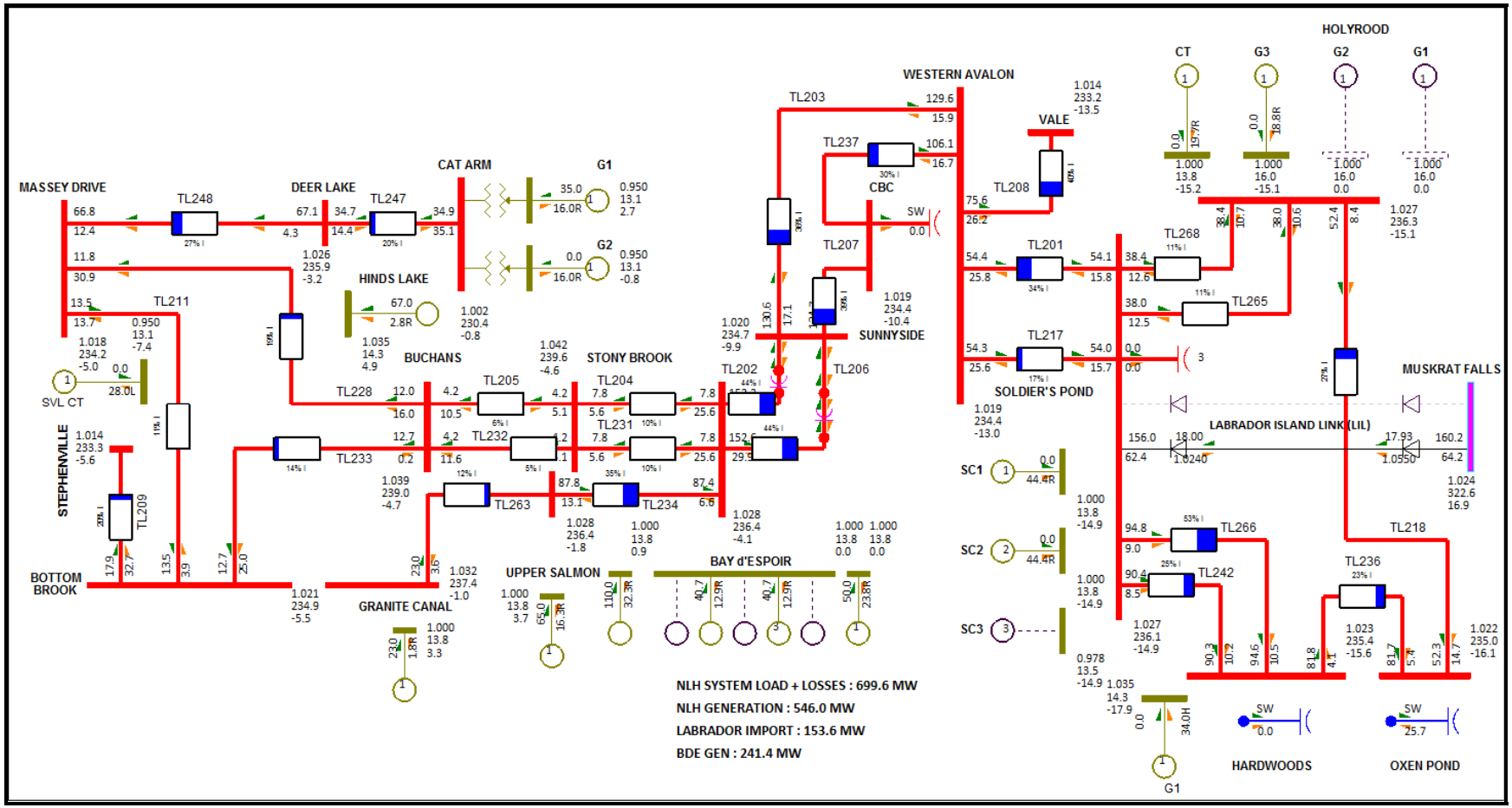


Figure 56 – Base Case 10 (BC10) Load Flow Plot – Pre-Contingency

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Monopole Summer Day (700 MW) – Minimum Island Generation (154 MW) with Reserve on LIL (546 MW)

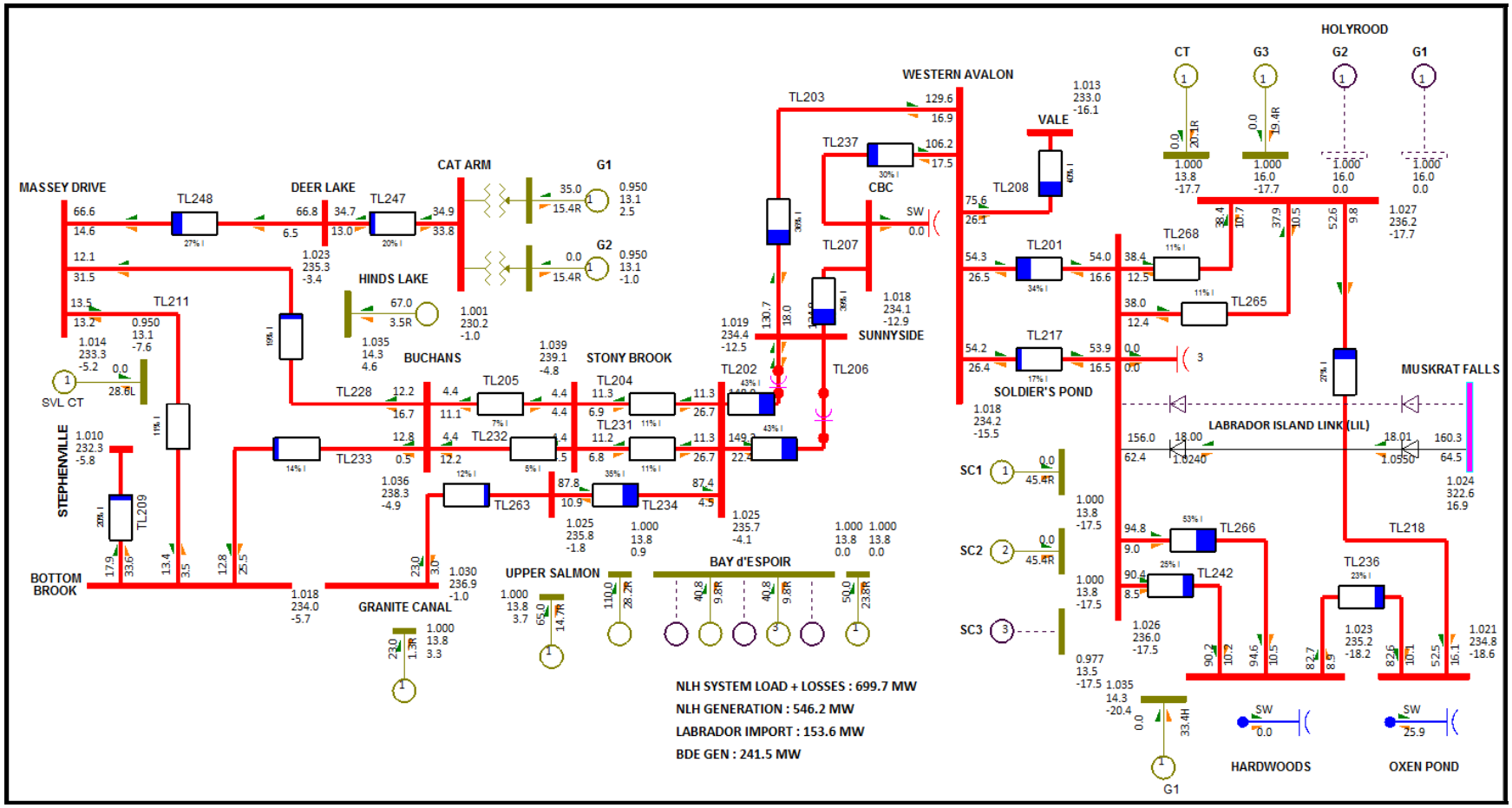


Figure 57 – Base Case 10 (BC10) Load Flow Plot – Pre-Contingency

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Monopole Summer Day (700 MW) – Minimum Island Generation (154 MW) with Reserve on LIL (546 MW)

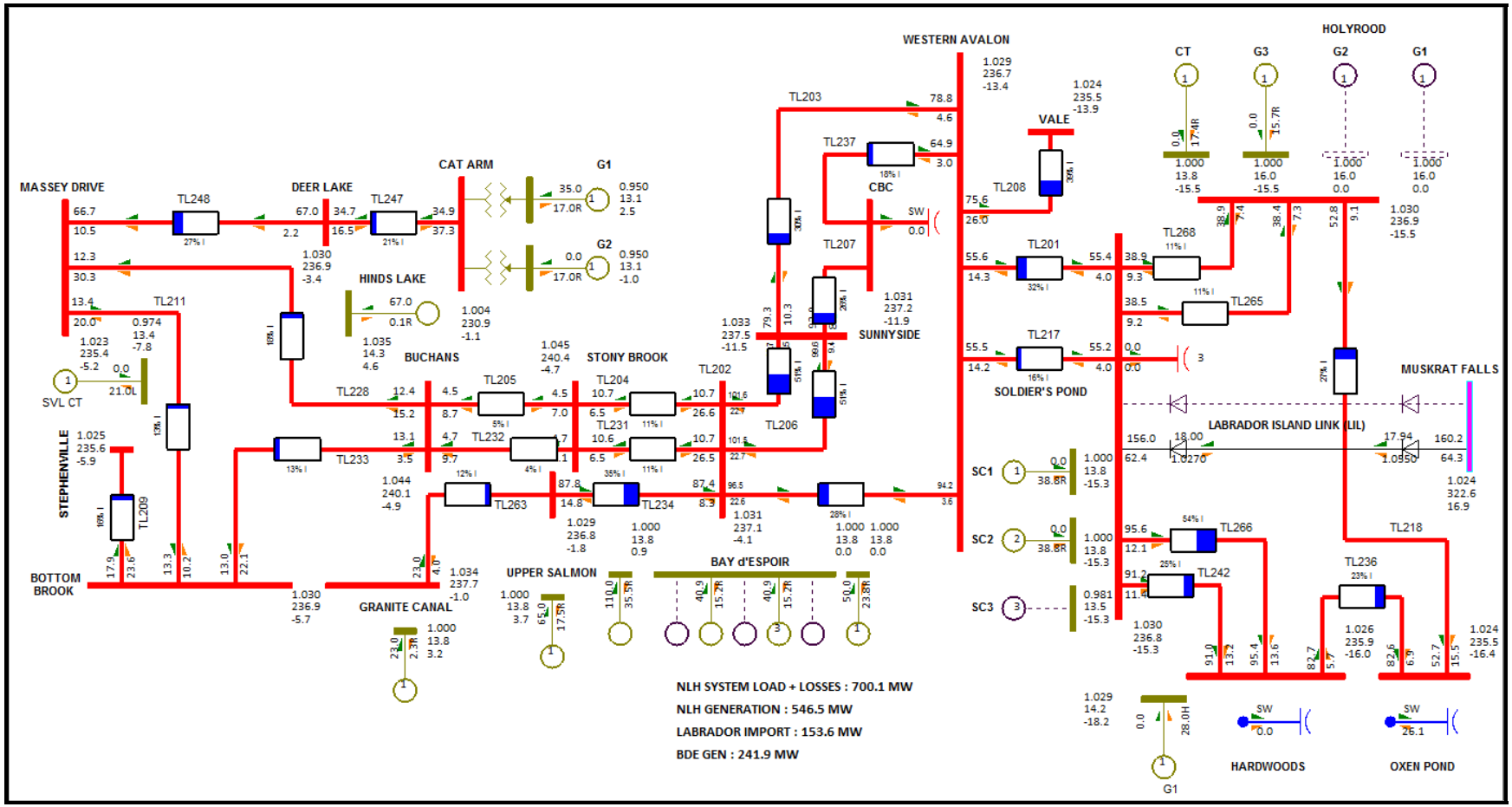


Figure 58 – Base Case 10 (BC10) Load Flow Plot – Pre-Contingency

New 230 kV Transmission Line Installed Between BDE and WAV

Monopole Summer Day (700 MW) – Minimum Island Generation (154 MW) with Reserve on LIL (546 MW)

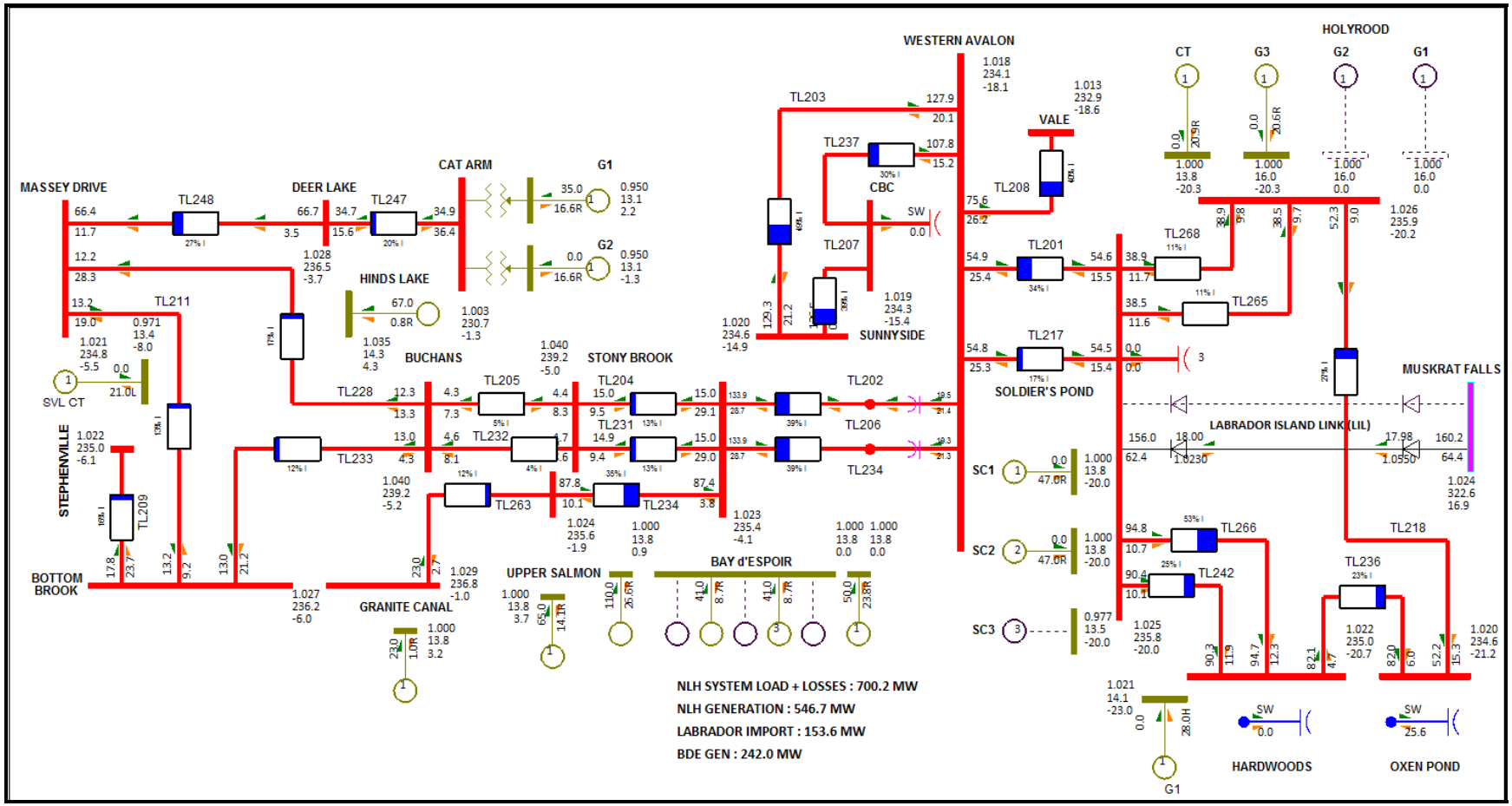


Figure 59 – Base Case 10 (BC10) Load Flow Plot – Pre-Contingency

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Monopole Summer Day (700 MW) – Minimum Island Generation (154 MW) with Reserve on LIL (546 MW)

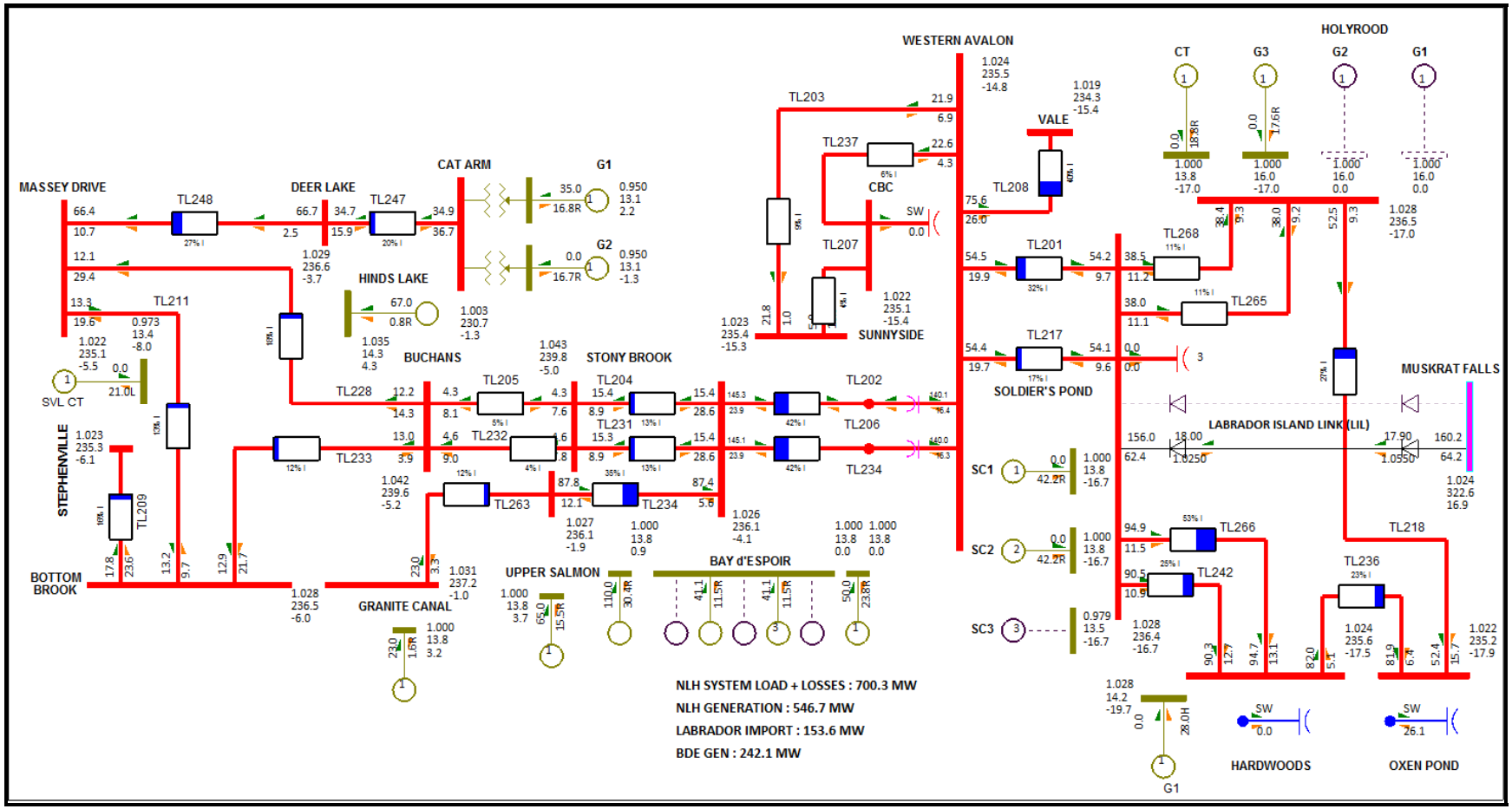


Figure 60 – Base Case 10 (BC10) Load Flow Plot – Pre-Contingency

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Monopole Summer Day (700 MW) – Minimum Island Generation (154 MW) with Reserve on LIL (546 MW)

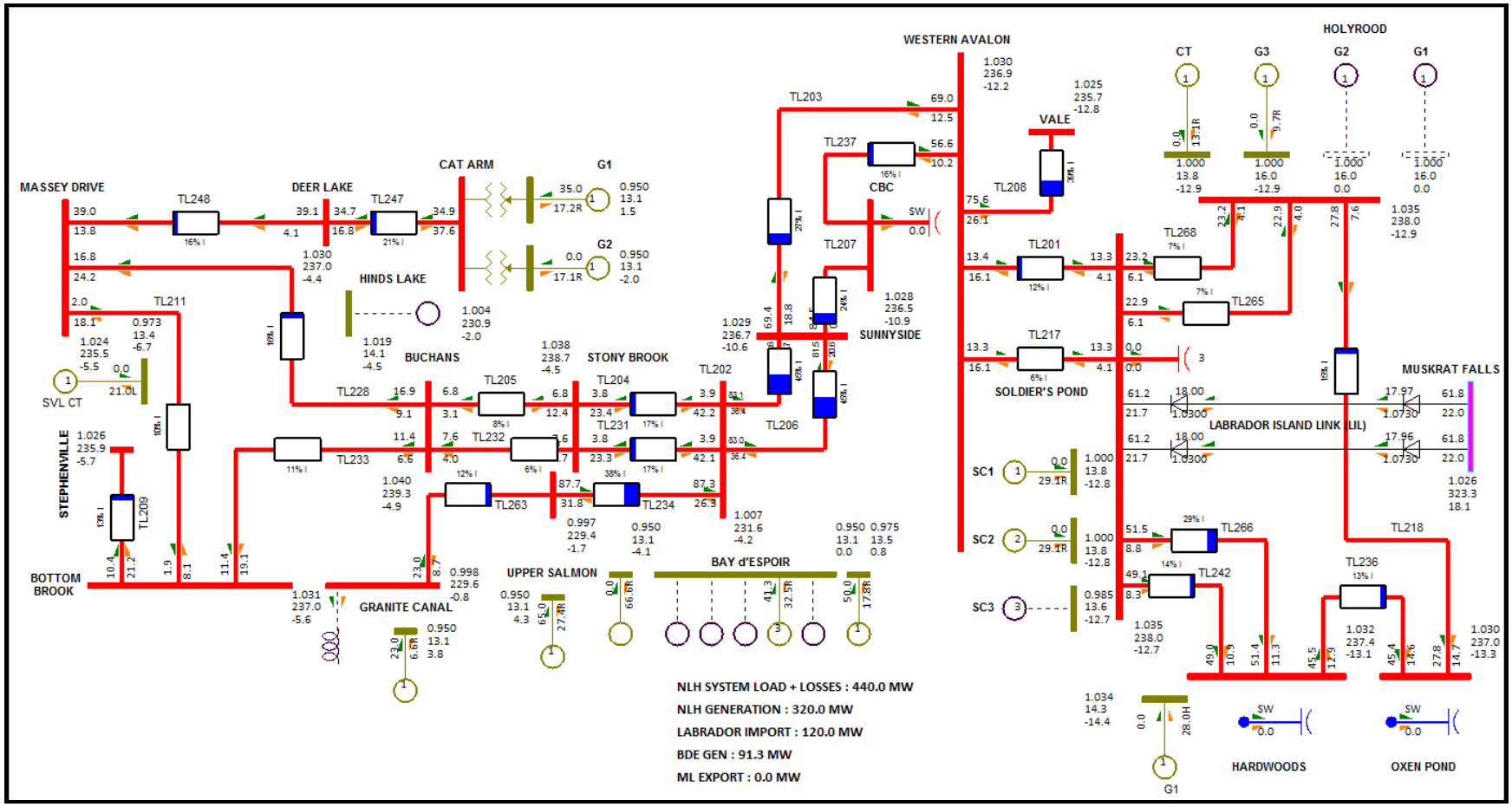


Figure 61 – Base Case 11 (BC11) Load Flow Plot – Pre-Contingency

Existing Bulk 230 kV Transmission System

Summer Night (440 MW) – Minimum Island Generation (320 MW) and Minimum LIL Import (120 MW) with Reserve on LIL

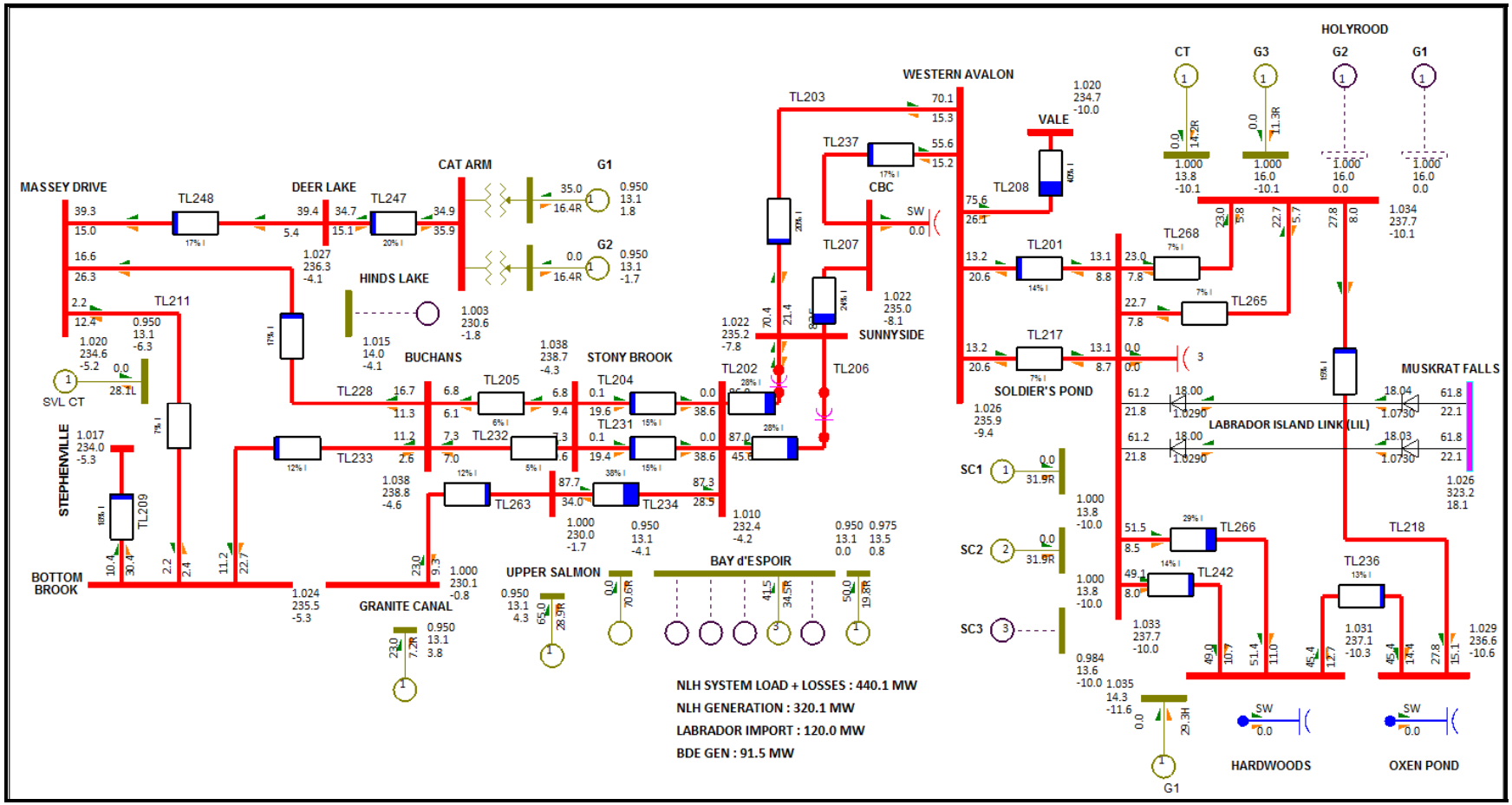


Figure 62 – Base Case 11 (BC11) Load Flow Plot – Pre-Contingency

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Summer Night (440 MW) – Minimum Island Generation (320 MW) and Minimum LIL Import (120 MW) with Reserve on LIL

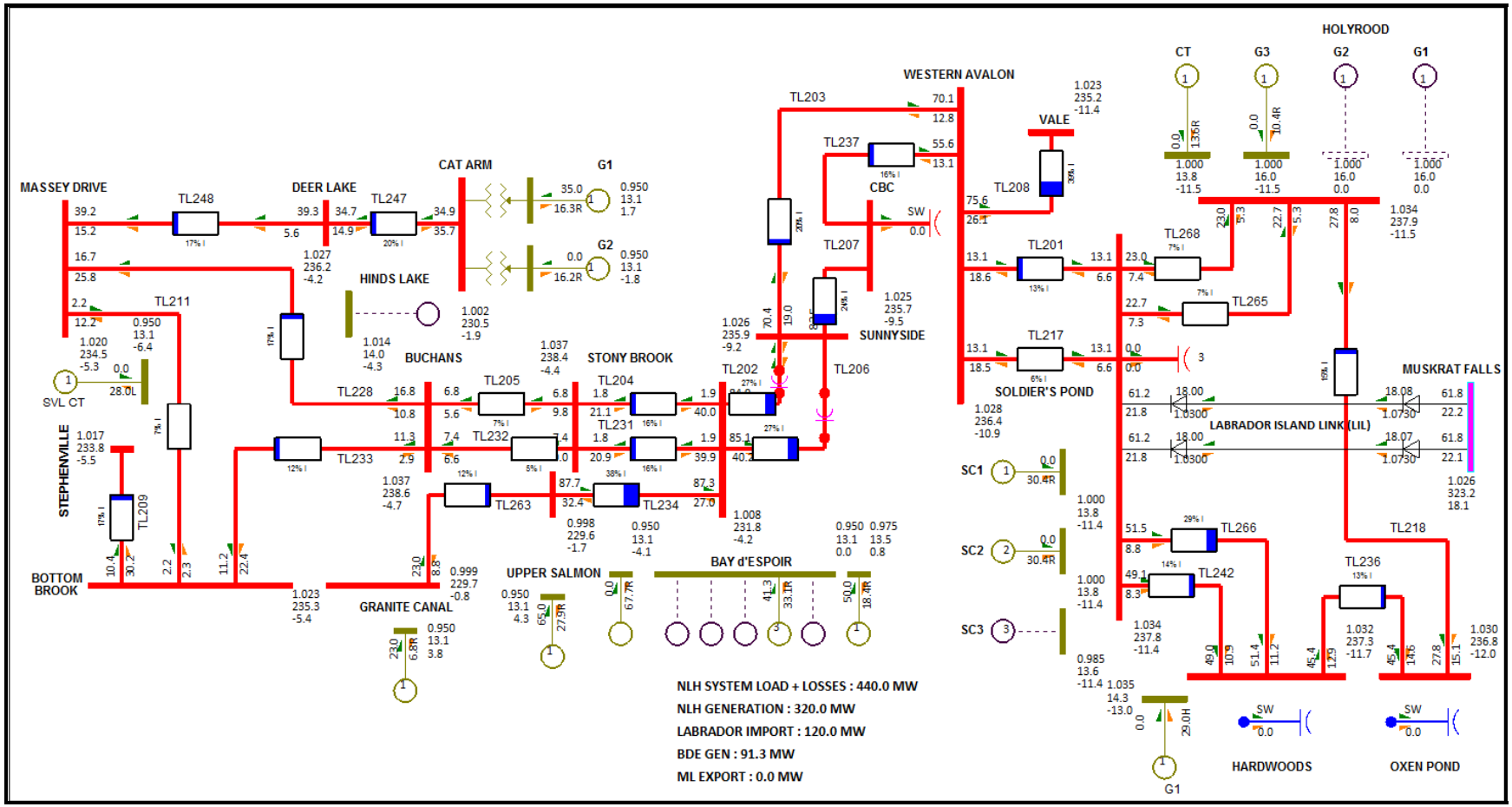


Figure 63 – Base Case 11 (BC11) Load Flow Plot – Pre-Contingency

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Summer Night (440 MW) – Minimum Island Generation (320 MW) and Minimum LIL Import (120 MW) with Reserve on LIL

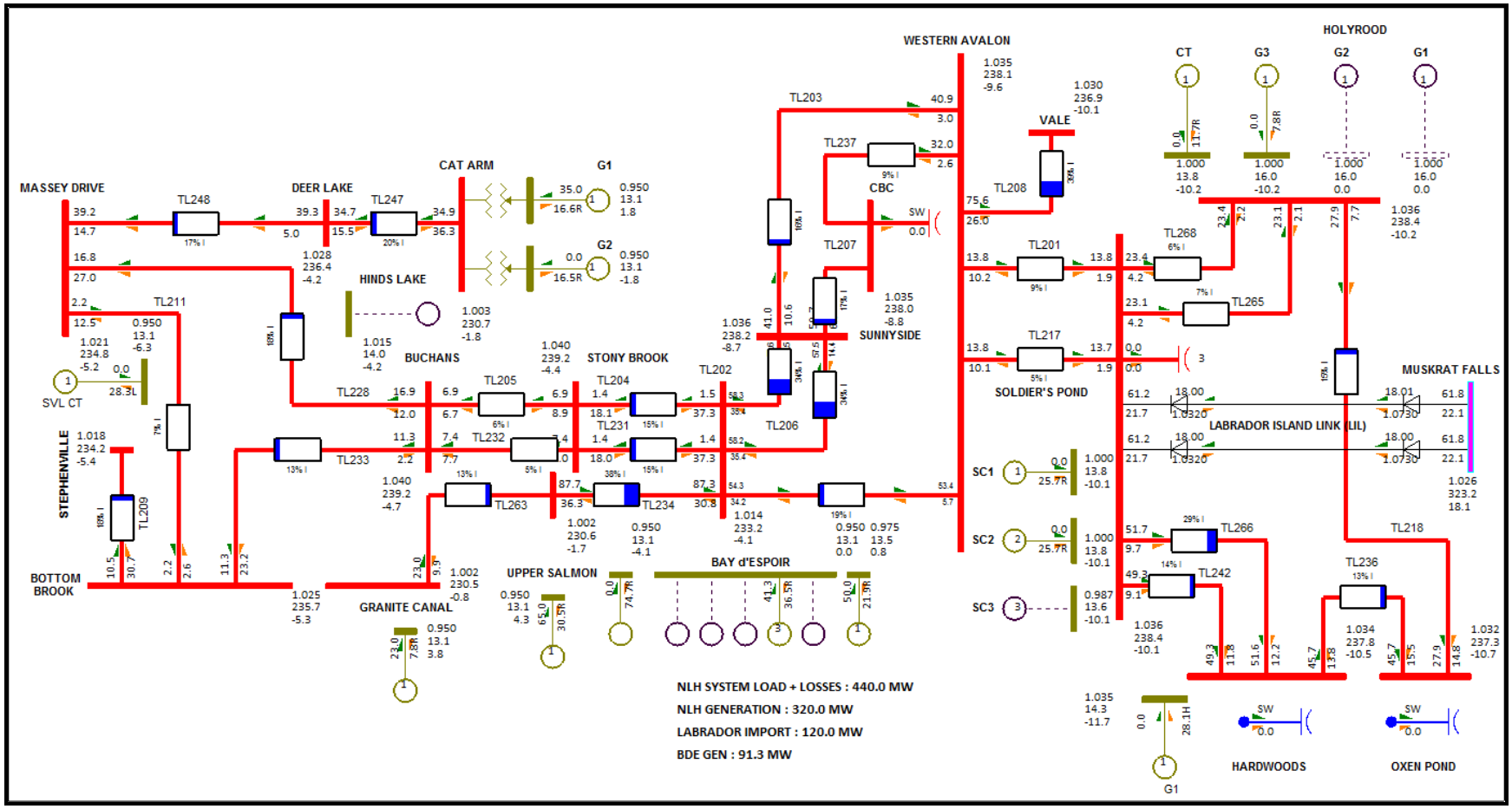


Figure 64 – Base Case 11 (BC11) Load Flow Plot – Pre-Contingency

New 230 kV Transmission Line Installed Between BDE and WAV

Summer Night (440 MW) – Minimum Island Generation (320 MW) and Minimum LIL Import (120 MW) with Reserve on LIL

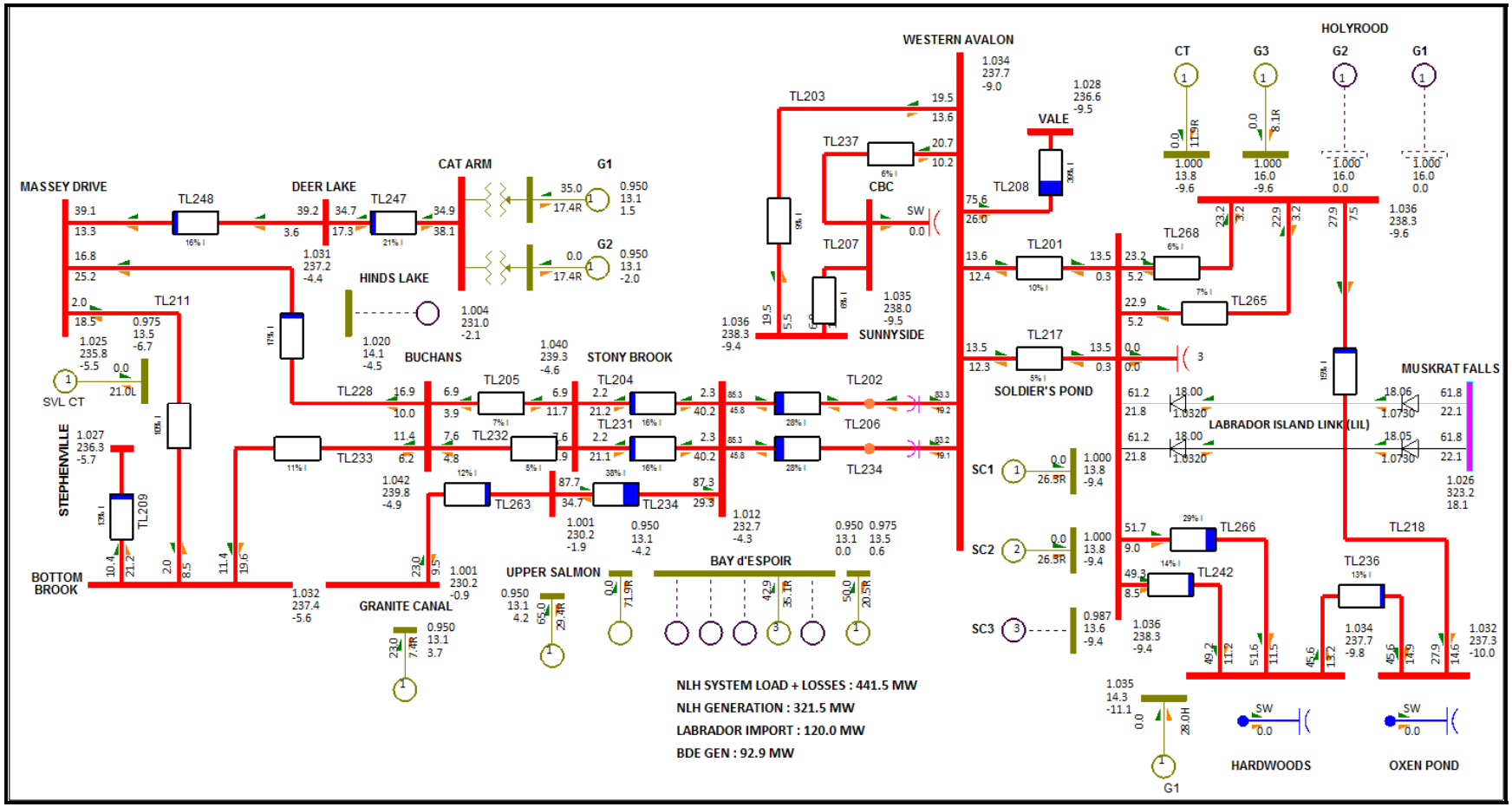


Figure 65 – Base Case 11 (BC11) Load Flow Plot – Pre-Contingency

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Summer Night (440 MW) – Minimum Island Generation (320 MW) and Minimum LIL Import (120 MW) with Reserve on LIL

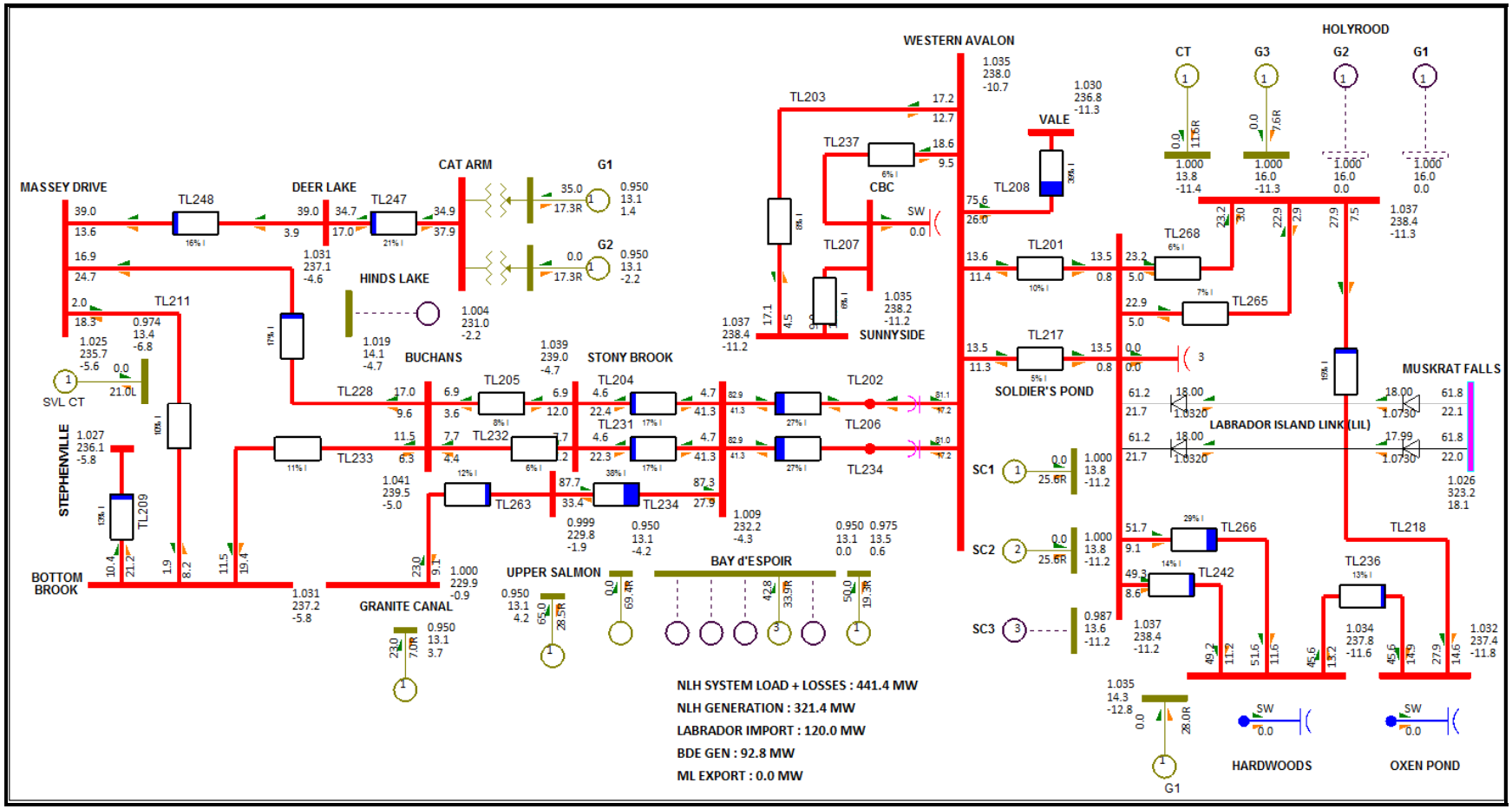


Figure 66 – Base Case 11 (BC11) Load Flow Plot – Pre-Contingency

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Summer Night (440 MW) – Minimum Island Generation (320 MW) and Minimum LIL Import (120 MW) with Reserve on LIL

Alternative 1

Use Existing Bulk Transmission System

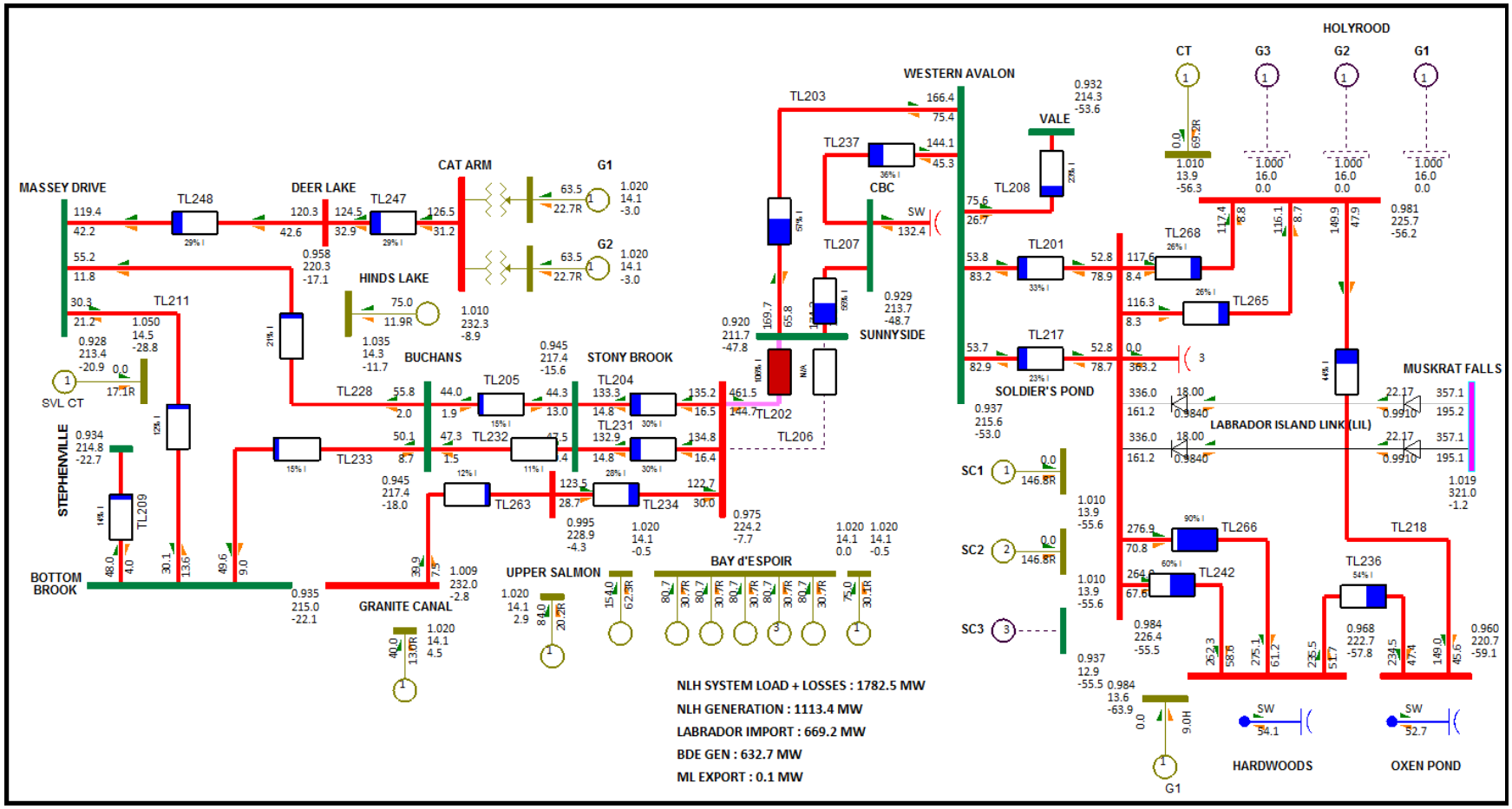


Figure 67 – Base Case 1 (BC1) Load Flow Plot – TL206 Out of Service

TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

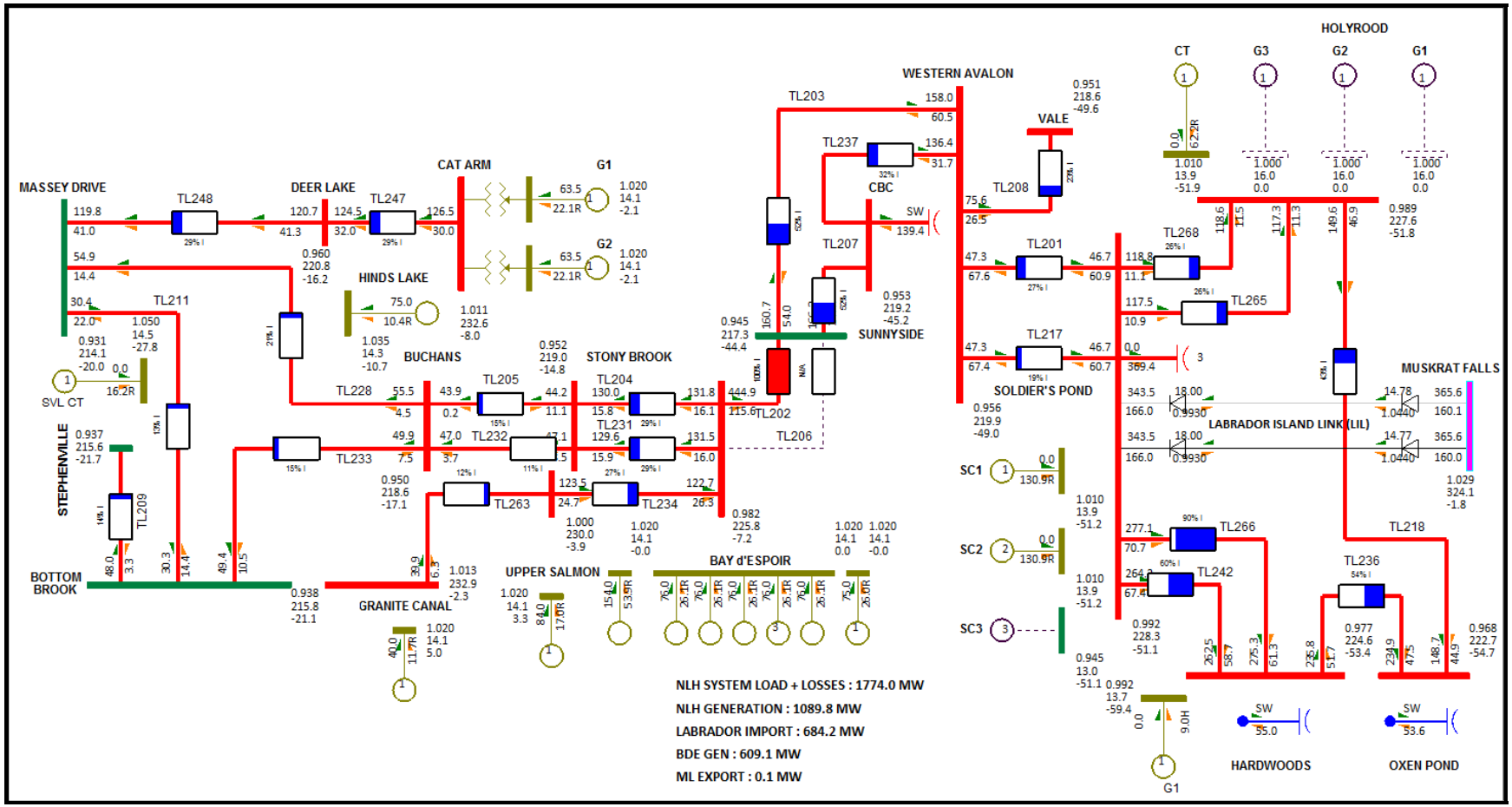


Figure 68 – Base Case 1 (BC1) Load Flow Plot – TL206 Out of Service

TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor – LIL Import Increased to 684 MW

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

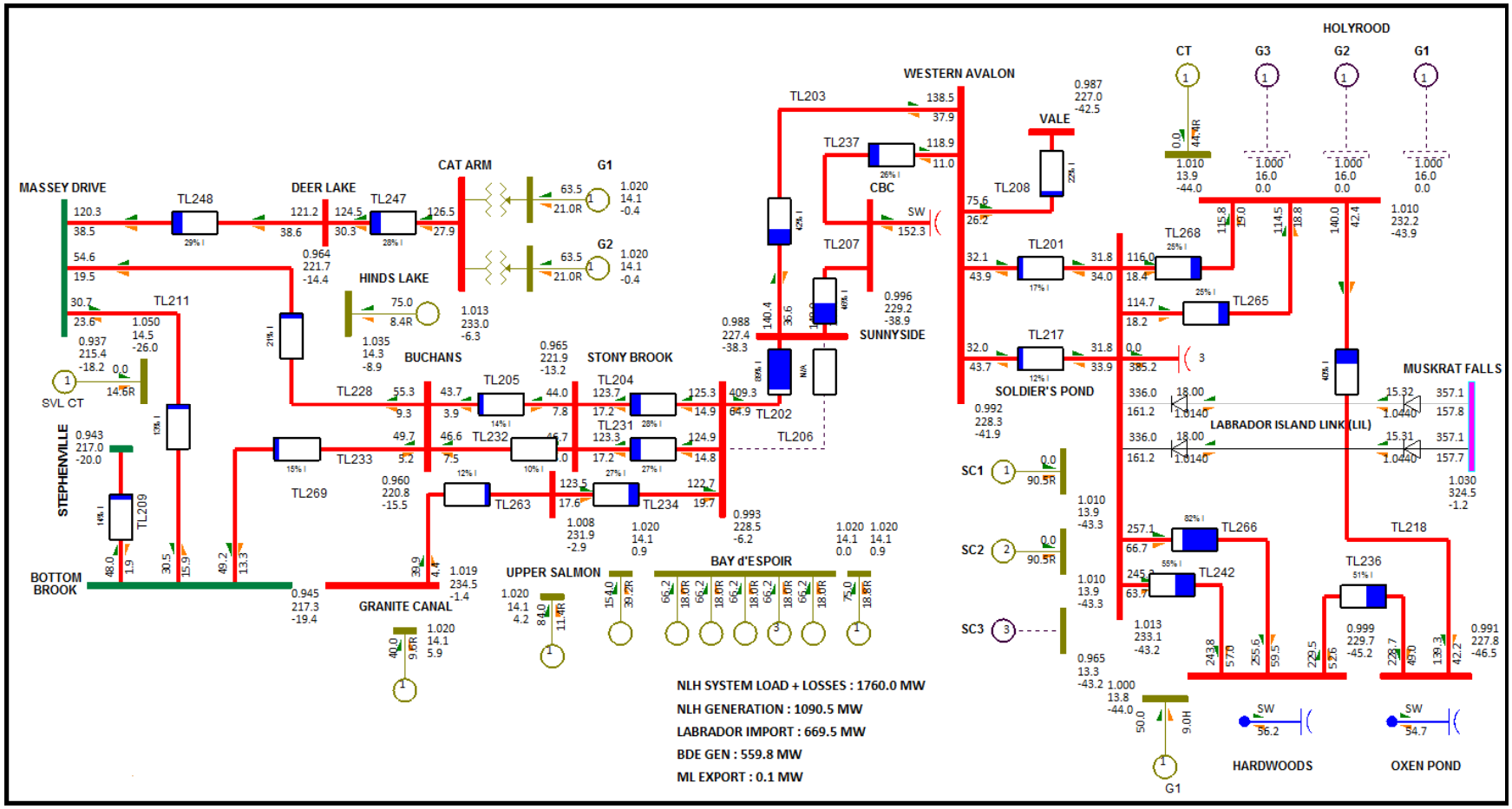


Figure 69 – Base Case 1 (BC1) Load Flow Plot – TL206 Out of Service

TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor – HWD CT Generating 50 MW

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

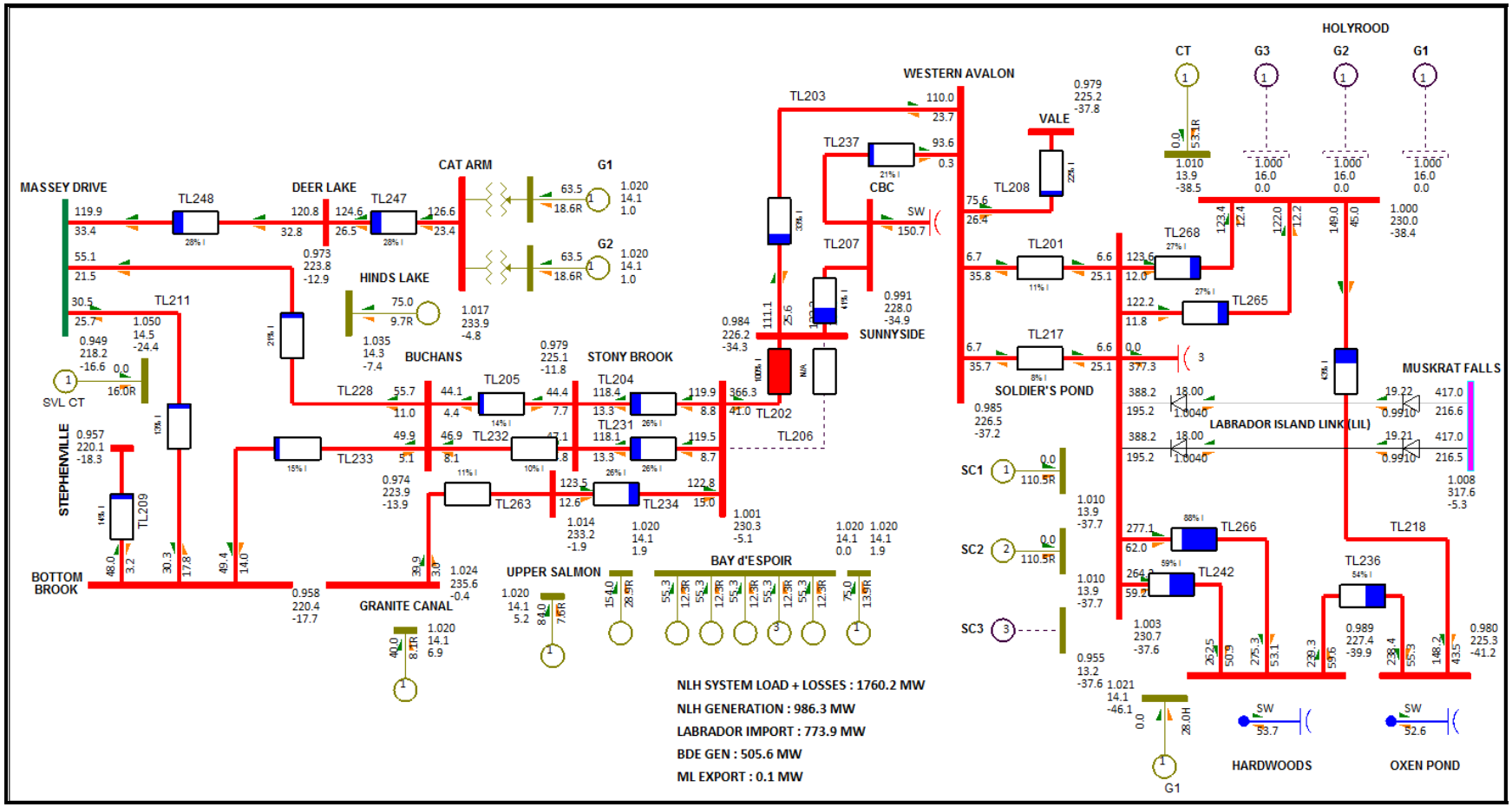


Figure 70 – Base Case 1 (BC1) Load Flow Plot – TL206 Out of Service

LIL Import Increased to 774 MW

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

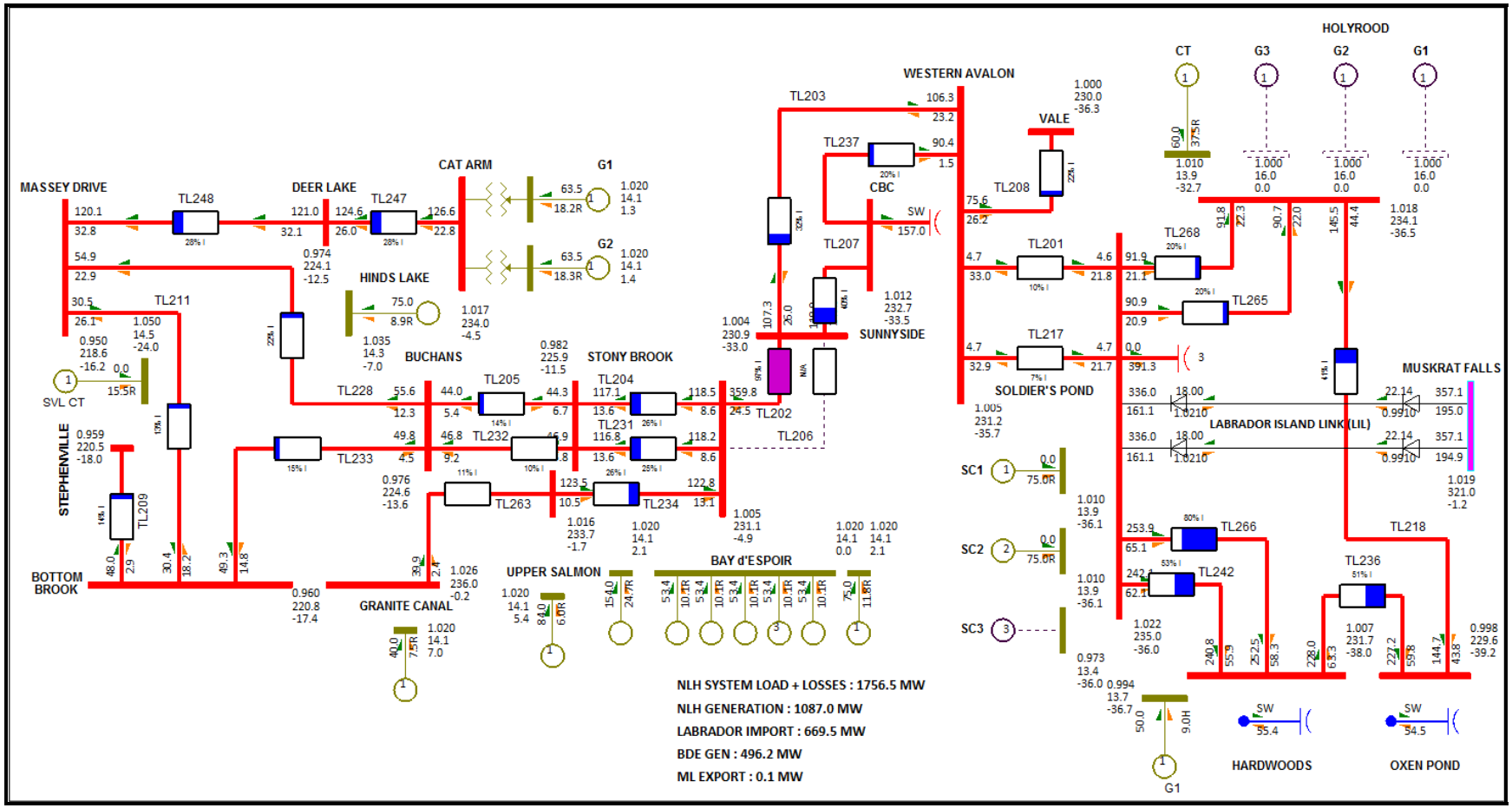


Figure 71 – Base Case 1 (BC1) Load Flow Plot – TL206 Out of Service

HWD CT and HRD CT Online Generating 110 MW

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

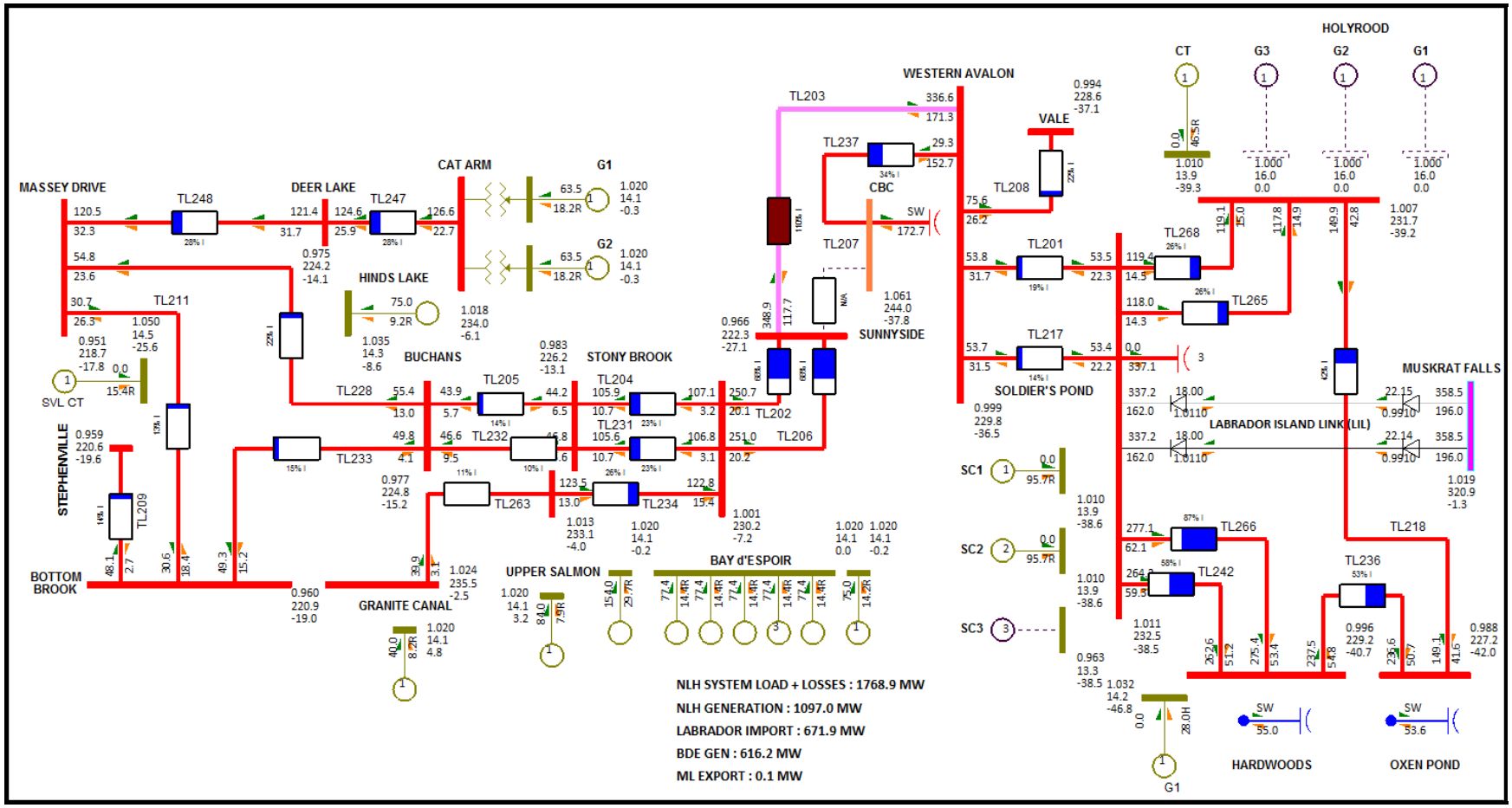


Figure 72 – Base Case 1 (BC1) Load Flow Plot – TL207 Out of Service

TL203 Loaded to 110% of Thermal Rating

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

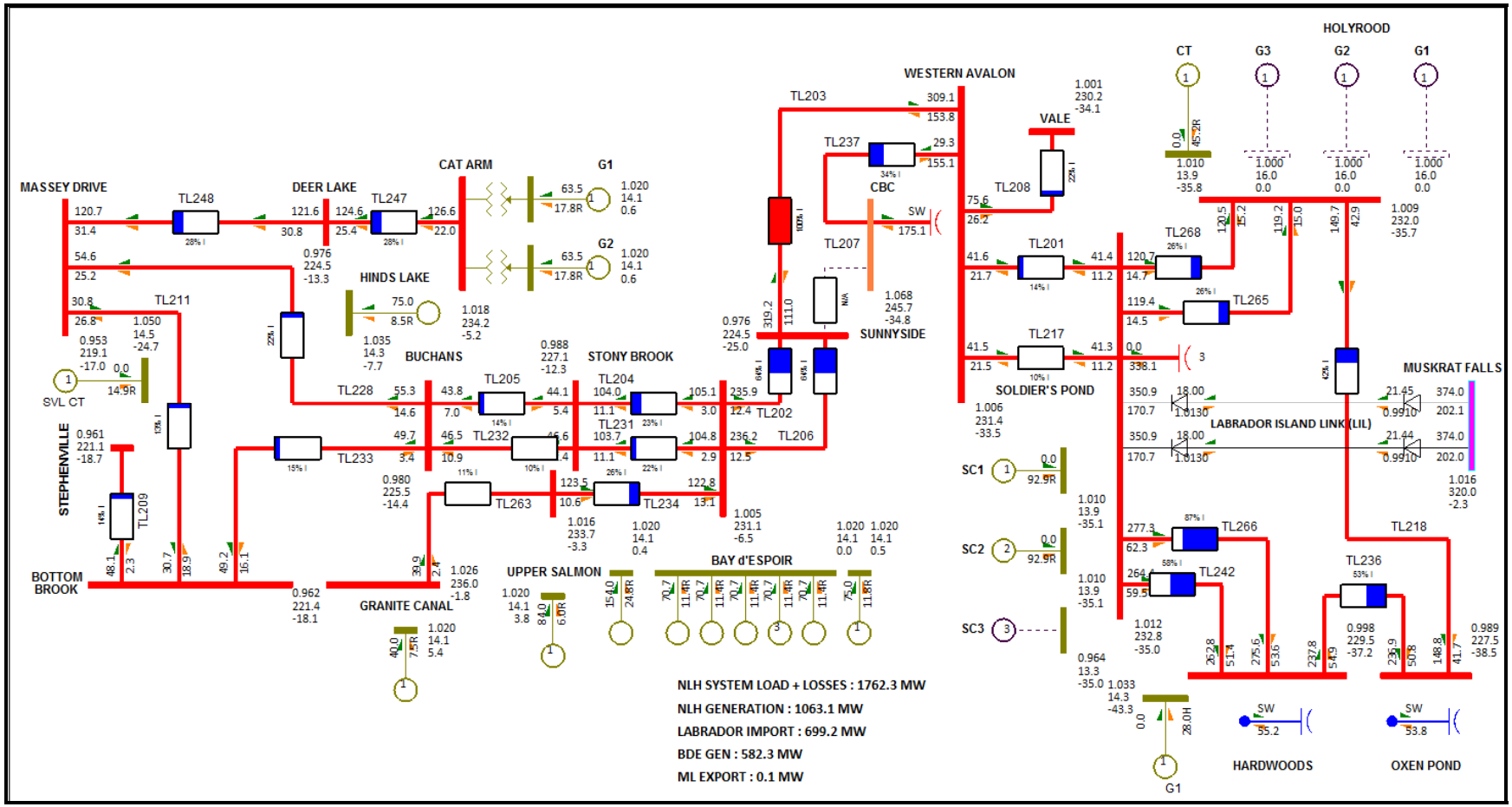


Figure 73 – Base Case 1 (BC1) Load Flow Plot – TL207 Out of Service

TL203 Loaded to Thermal Rating – LIL Import Increased to 699 MW

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

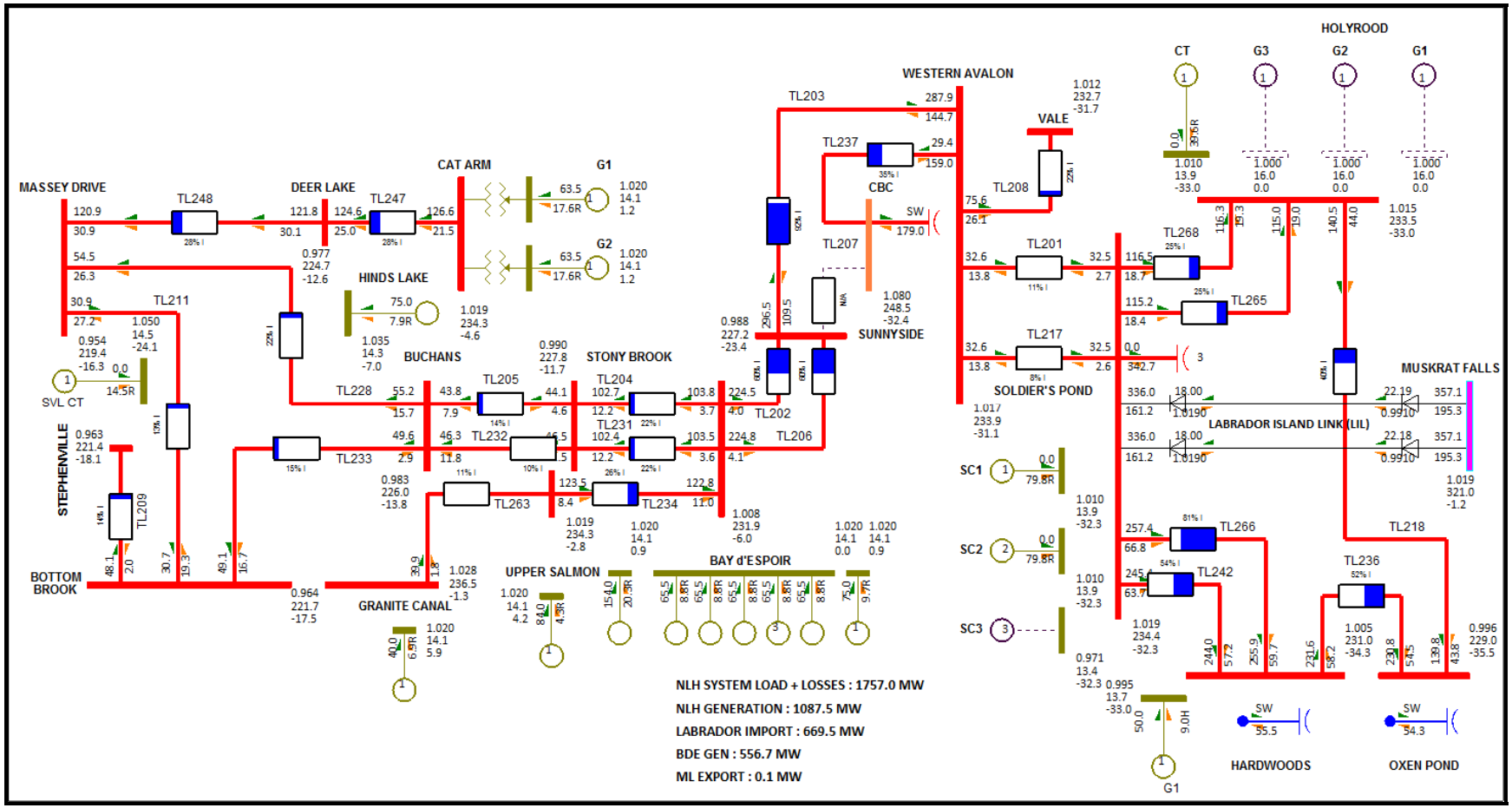


Figure 74 – Base Case 1 (BC1) Load Flow Plot – TL207 Out of Service

TL203 Loaded 92% of Thermal Rating – HWD CT Generating 50 MW

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

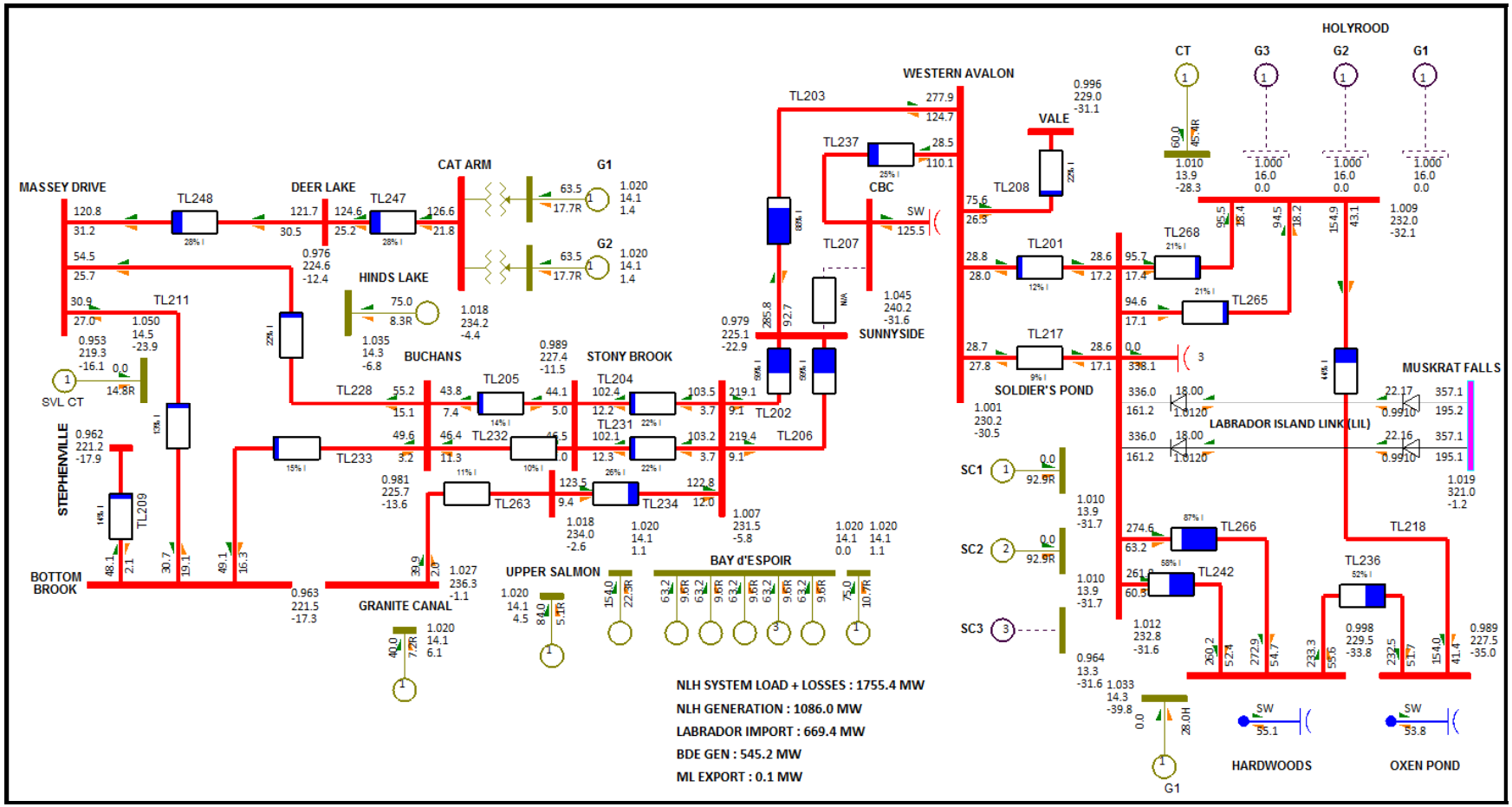


Figure 75 – Base Case 1 (BC1) Load Flow Plot – TL207 Out of Service

TL203 Loaded 88% of Thermal Rating – HRD CT Generating 60 MW

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

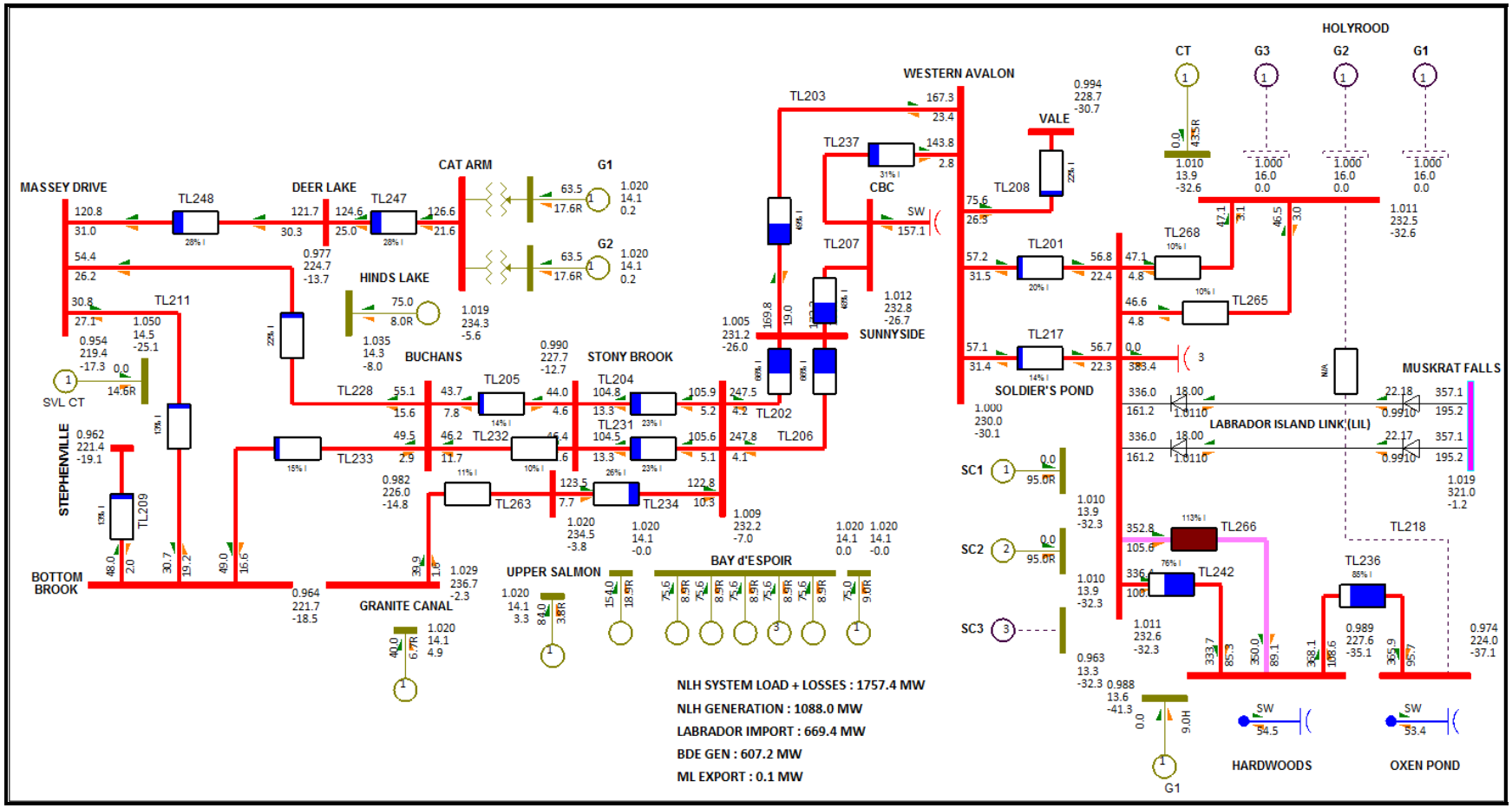


Figure 76 – Base Case 1 (BC1) Load Flow Plot – TL218 Out of Service

TL266 Loaded to 113% of Thermal Rating

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

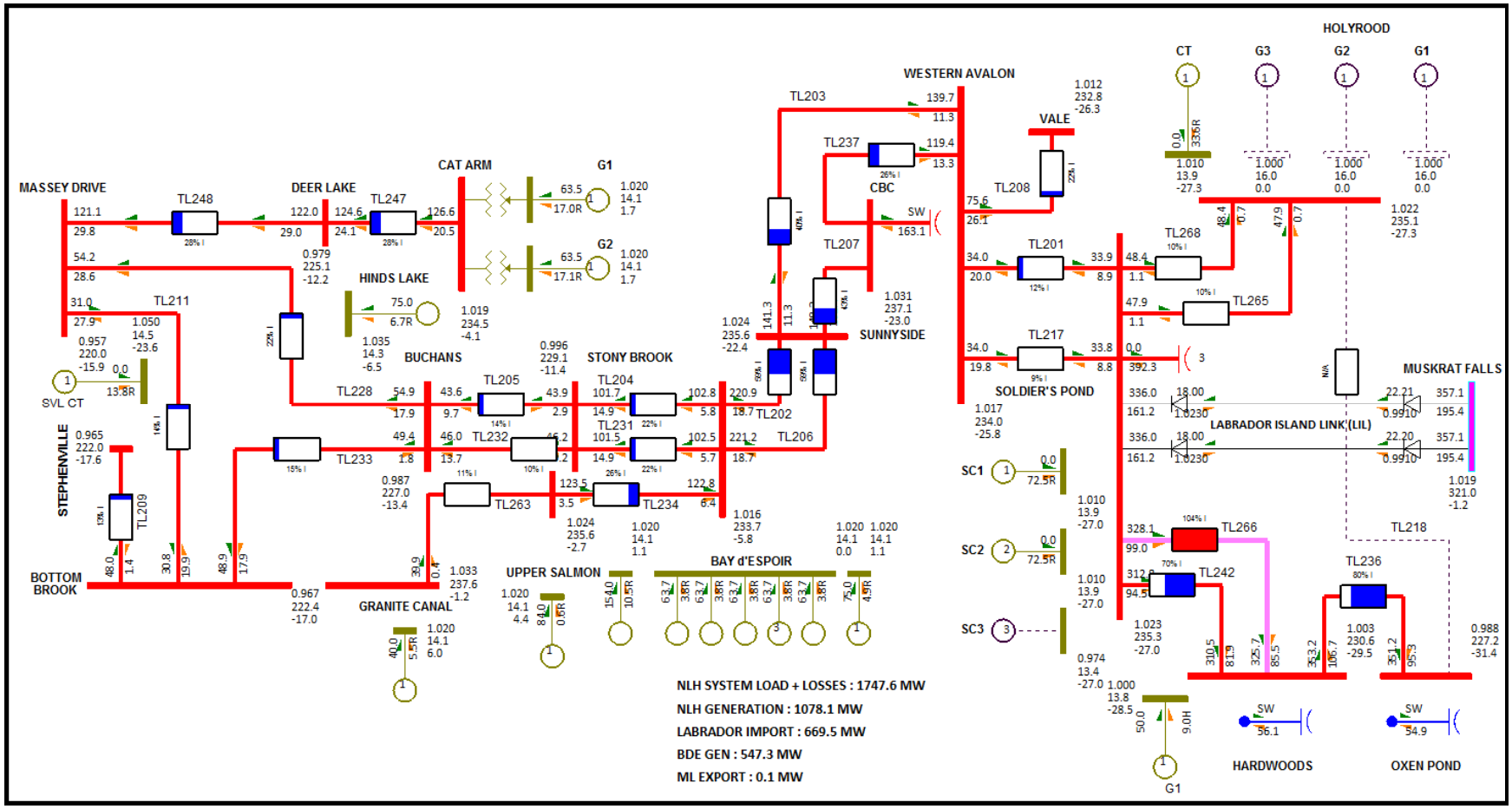


Figure 77 – Base Case 1 (BC1) Load Flow Plot – TL218 Out of Service

TL266 Loaded 104% of Thermal Rating – HWD CT Generating 50 MW

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

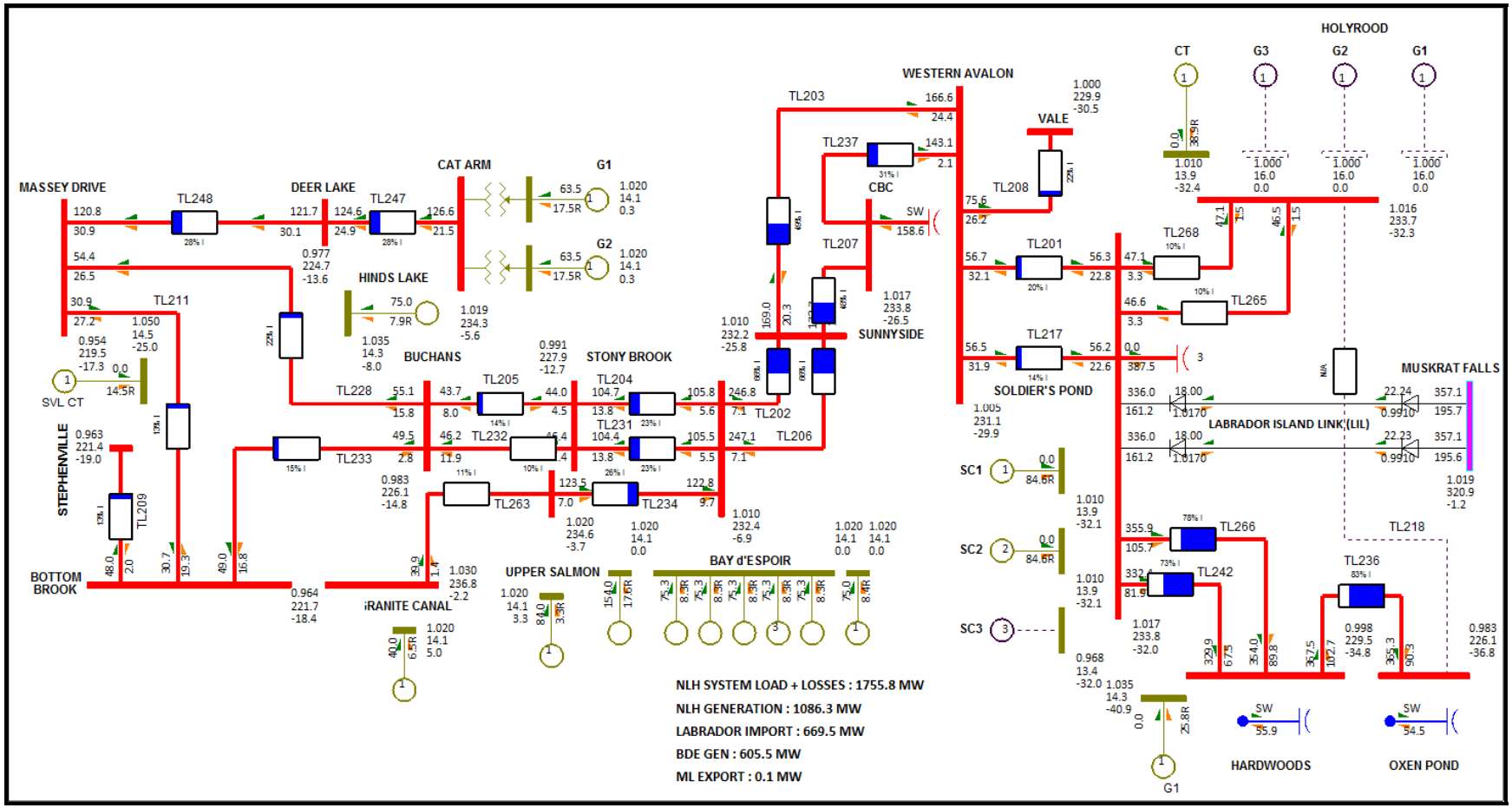


Figure 78 – Base Case 1 (BC1) Load Flow Plot – TL218 Out of Service

TL266 Loaded 78% of Thermal Rating – TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

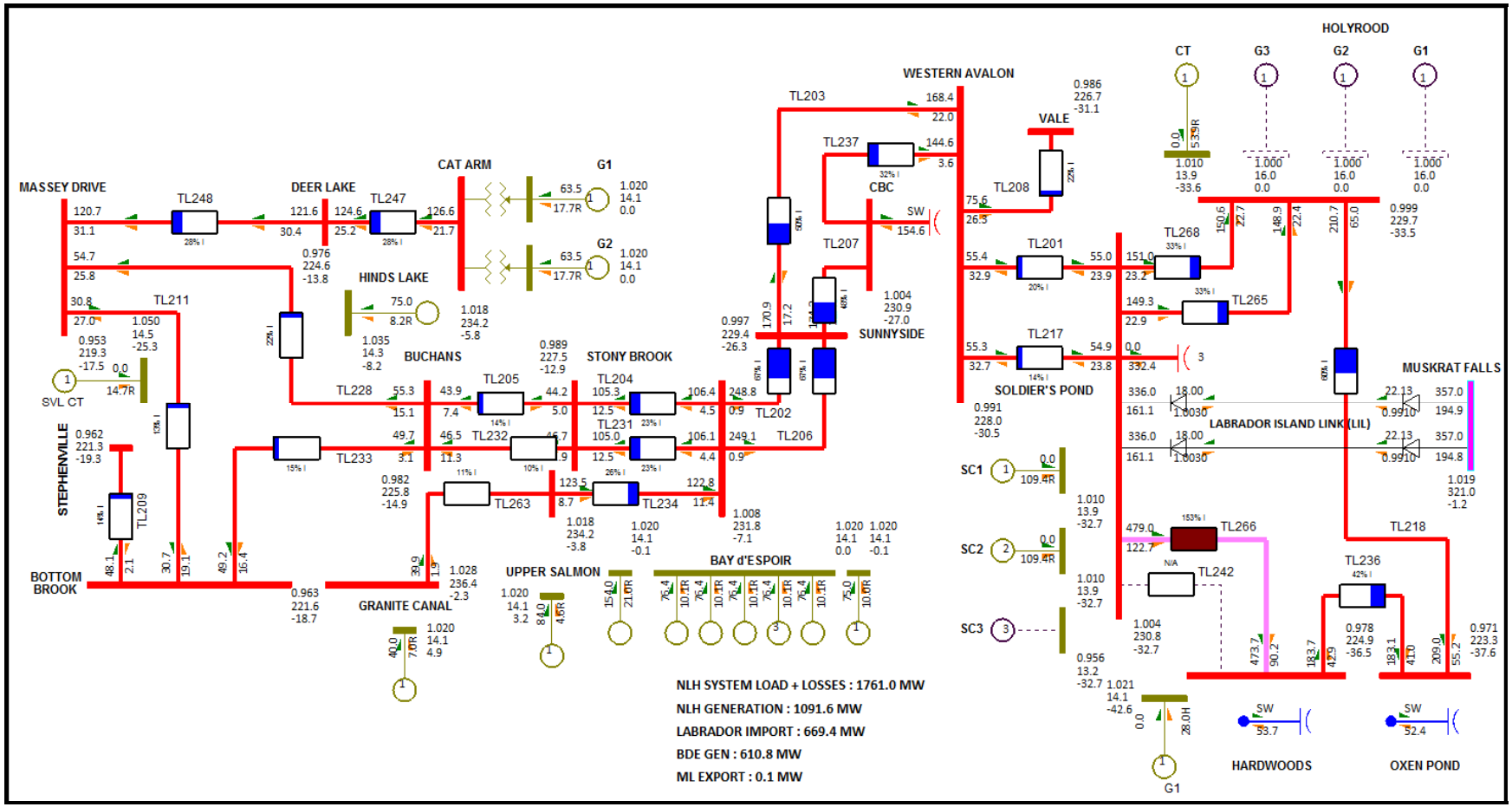


Figure 79 – Base Case 1 (BC1) Load Flow Plot – TL242 Out of Service

TL266 Loaded 153% of Thermal Rating

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

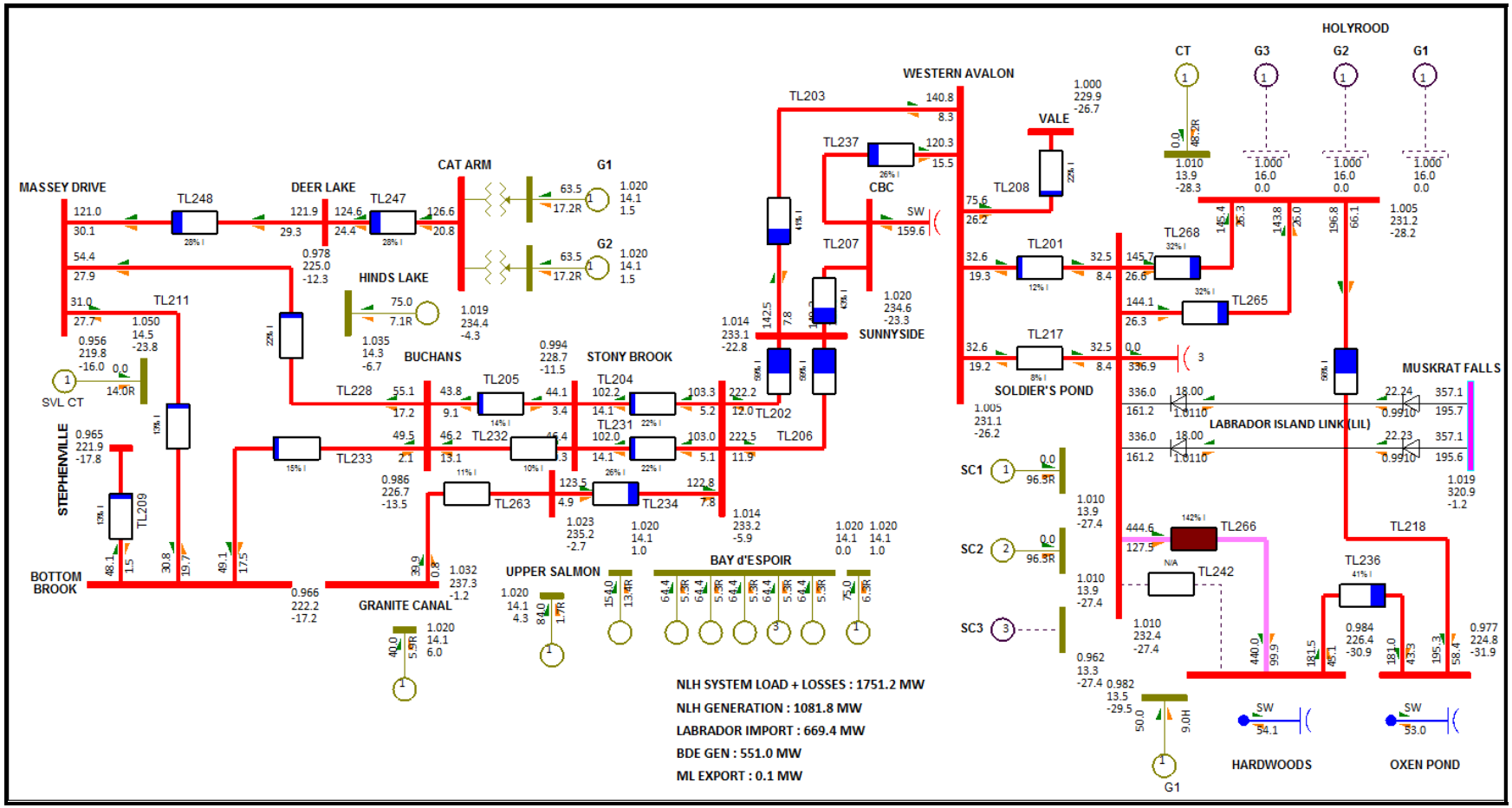


Figure 80 – Base Case 1 (BC1) Load Flow Plot – TL242 Out of Service

TL266 Loaded 142% of Thermal Rating – HWD CT Generating 50 MW

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

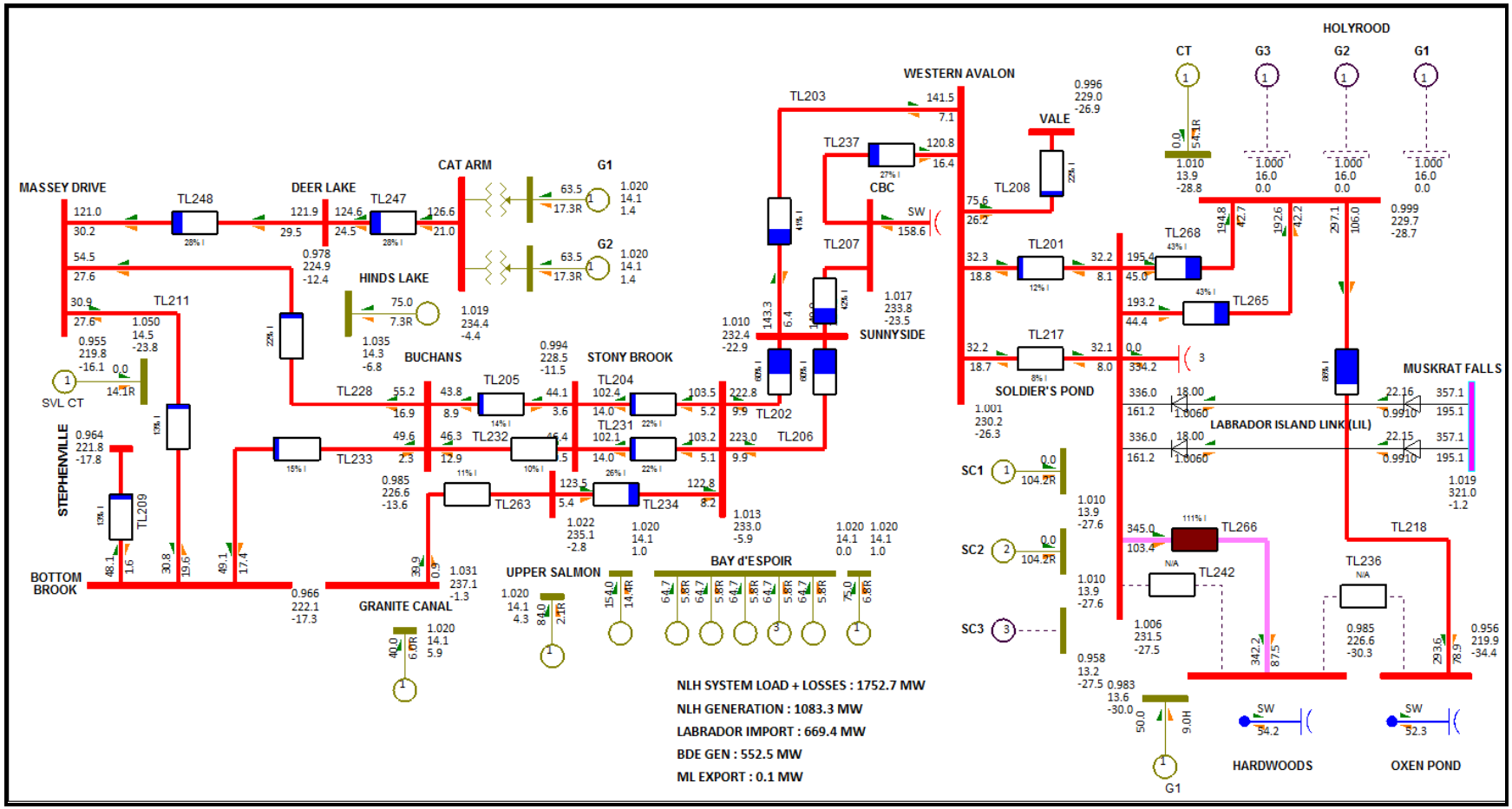


Figure 81 – Base Case 1 (BC1) Load Flow Plot – TL242 Out of Service

TL266 Loaded 111% of Thermal Rating – HWD CT Generating 50 MW + TL236 Open

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

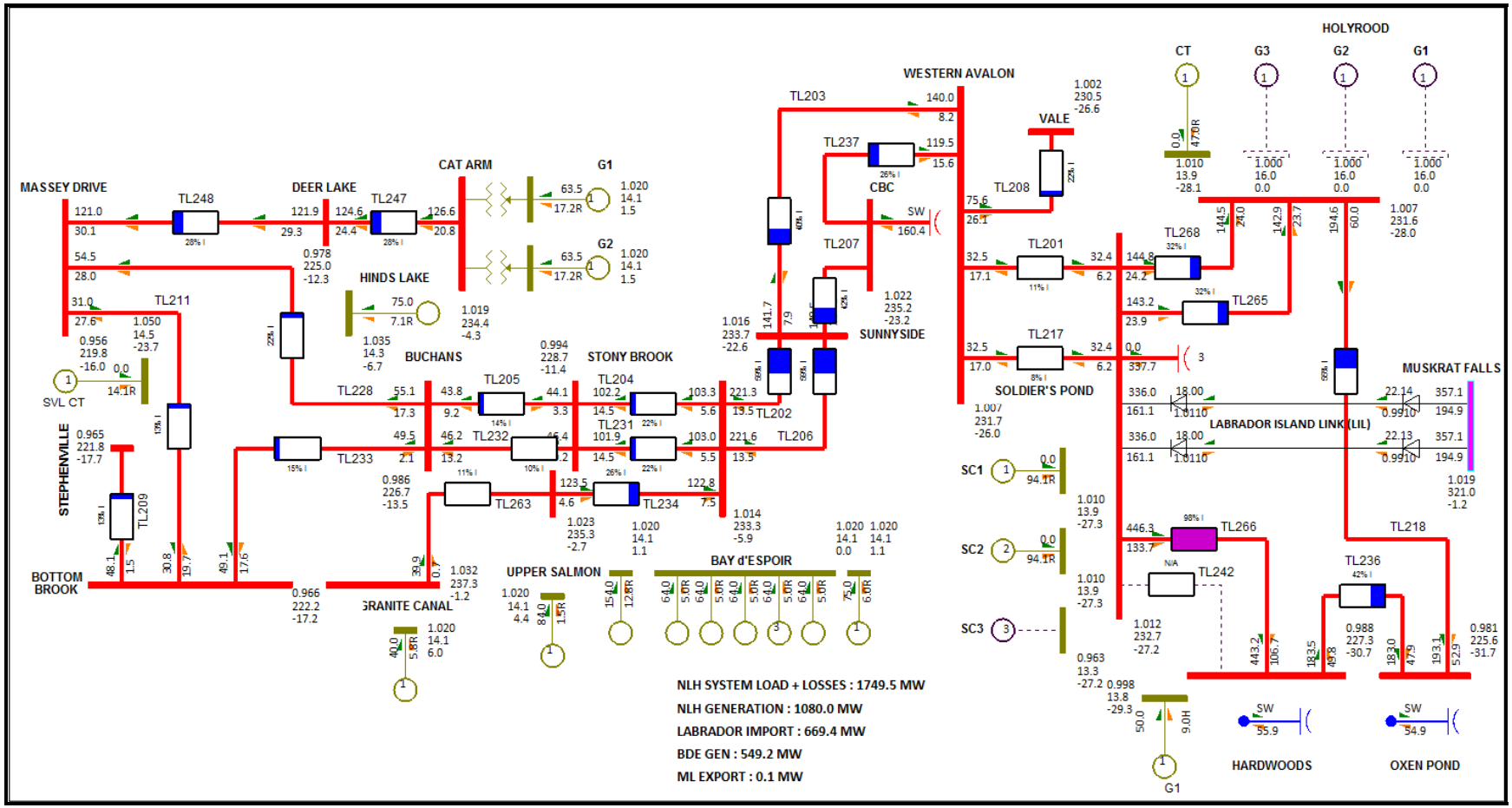


Figure 82 – Base Case 1 (BC1) Load Flow Plot – TL242 Out of Service

TL266 Loaded 98% of Thermal Rating – TL266 Rebuilt with 1192.5 54/19 ACSR GRACKLE Conductor

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

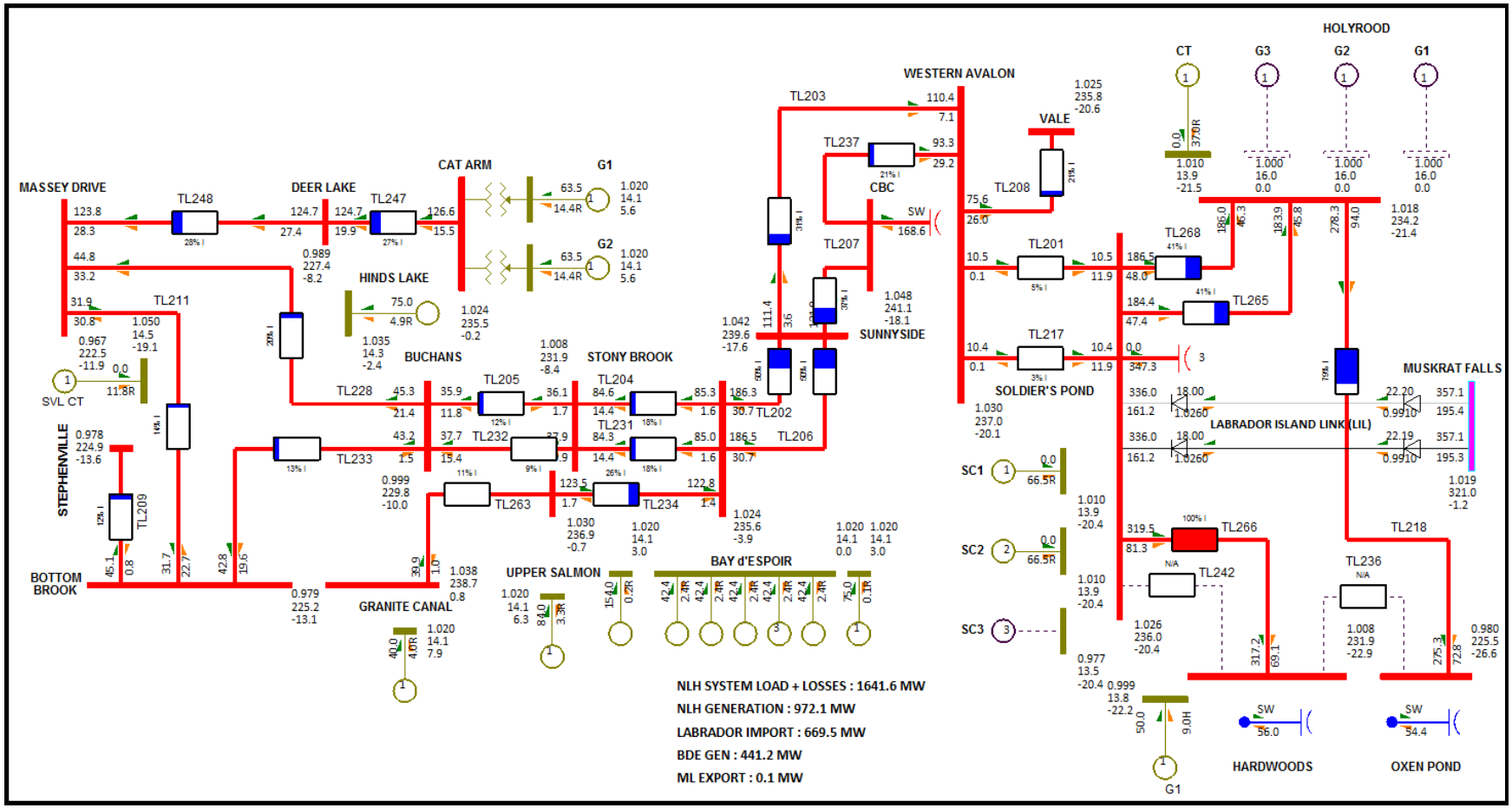


Figure 83 – Base Case 1 (BC1) Load Flow Plot – TL242 Out of Service

TL266 Loaded 100% of Thermal Rating – NLH System Load Reduced to 1642 MW (2023 – 2012 PLF)

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

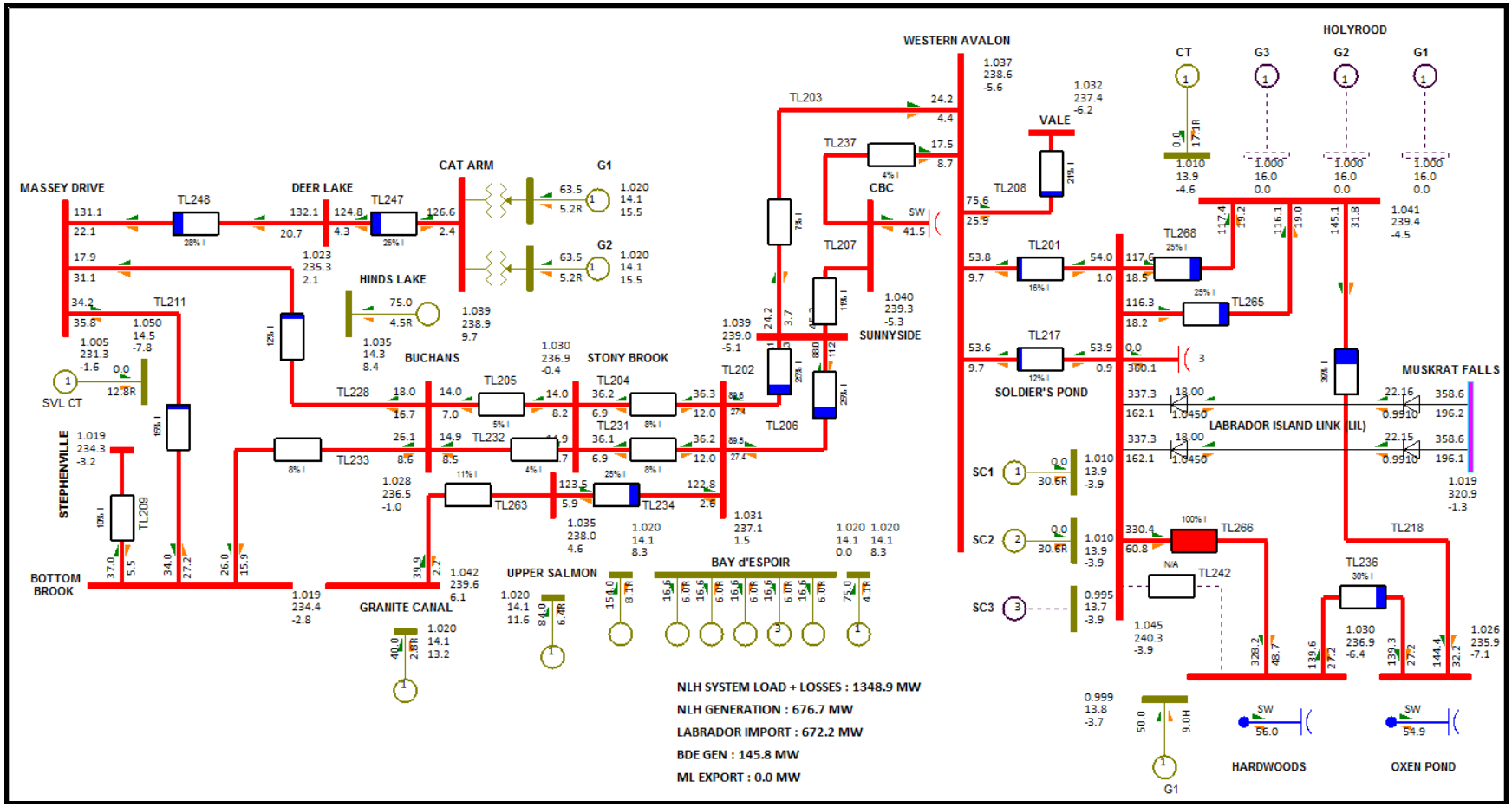


Figure 84 – Base Case 1 (BC1) Load Flow Plot – TL242 Out of Service

TL266 Loaded 100% of Thermal Rating – NLH System Load Reduced to 1349 MW

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

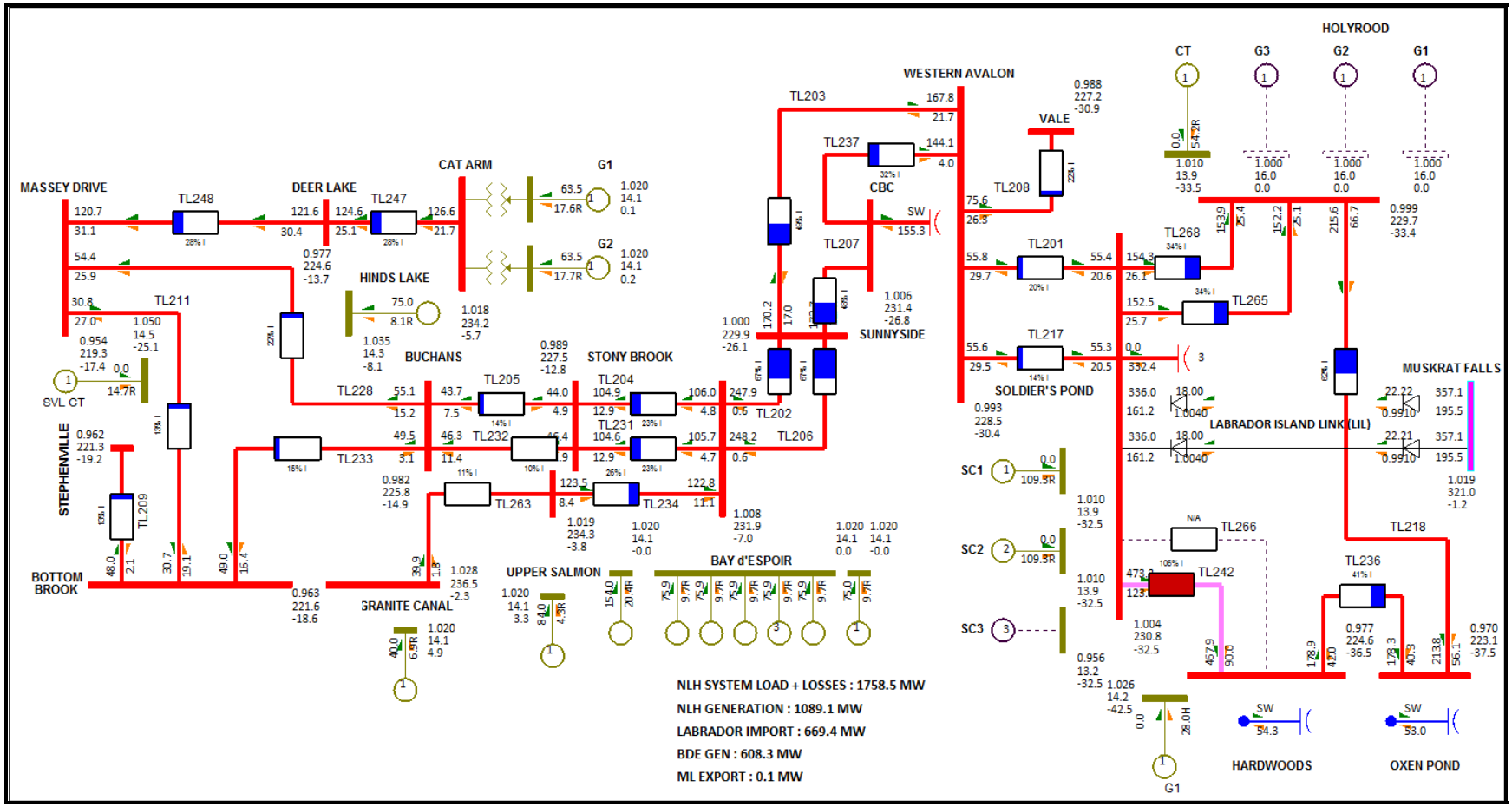


Figure 85 – Base Case 1 (BC1) Load Flow Plot – TL266 Out of Service

TL242 Loaded 106% of Thermal Rating

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

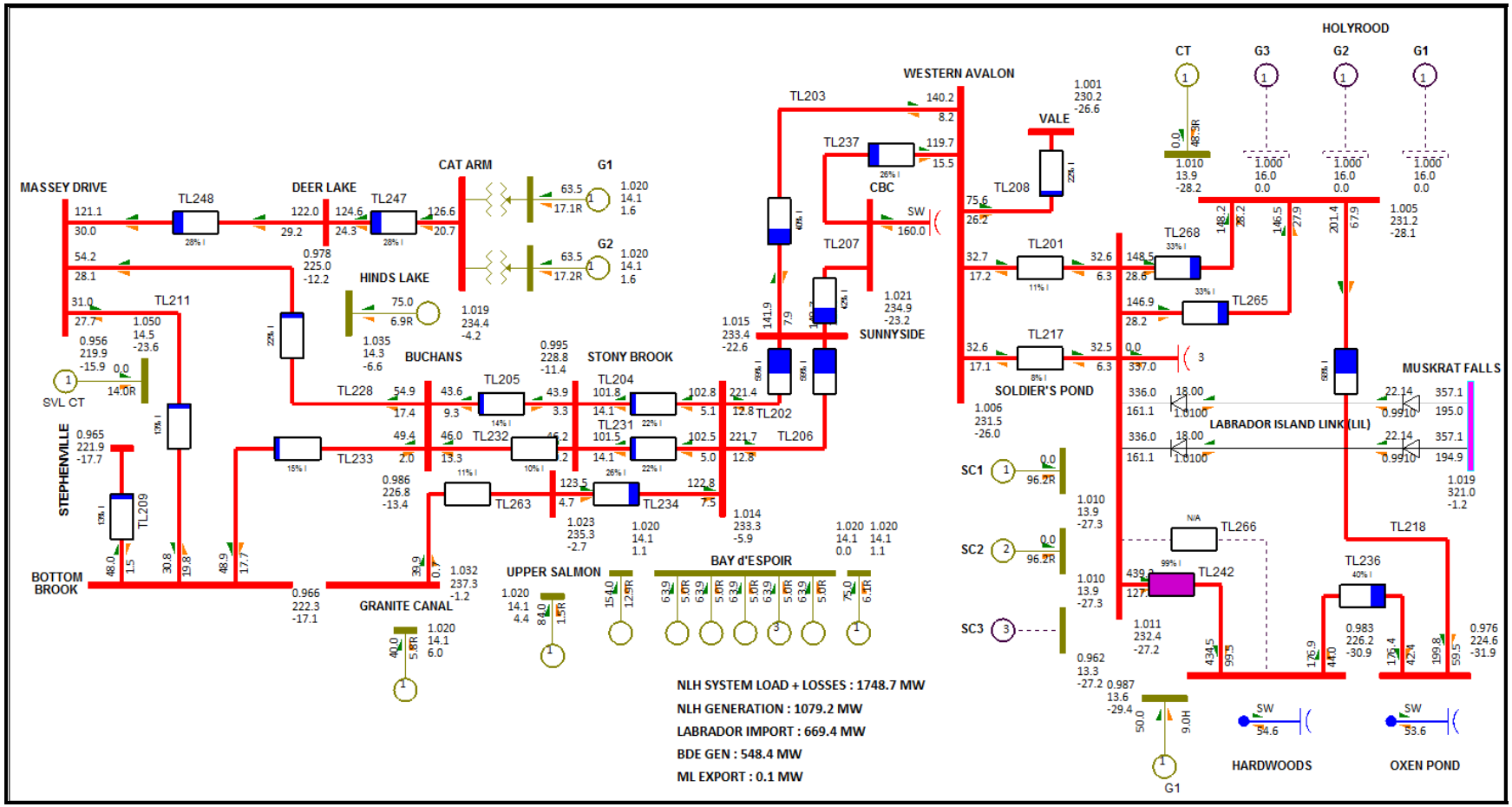


Figure 86 – Base Case 1 (BC1) Load Flow Plot – TL266 Out of Service

TL242 Loaded 99% of Thermal Rating – HWD CT Generating 50 MW

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

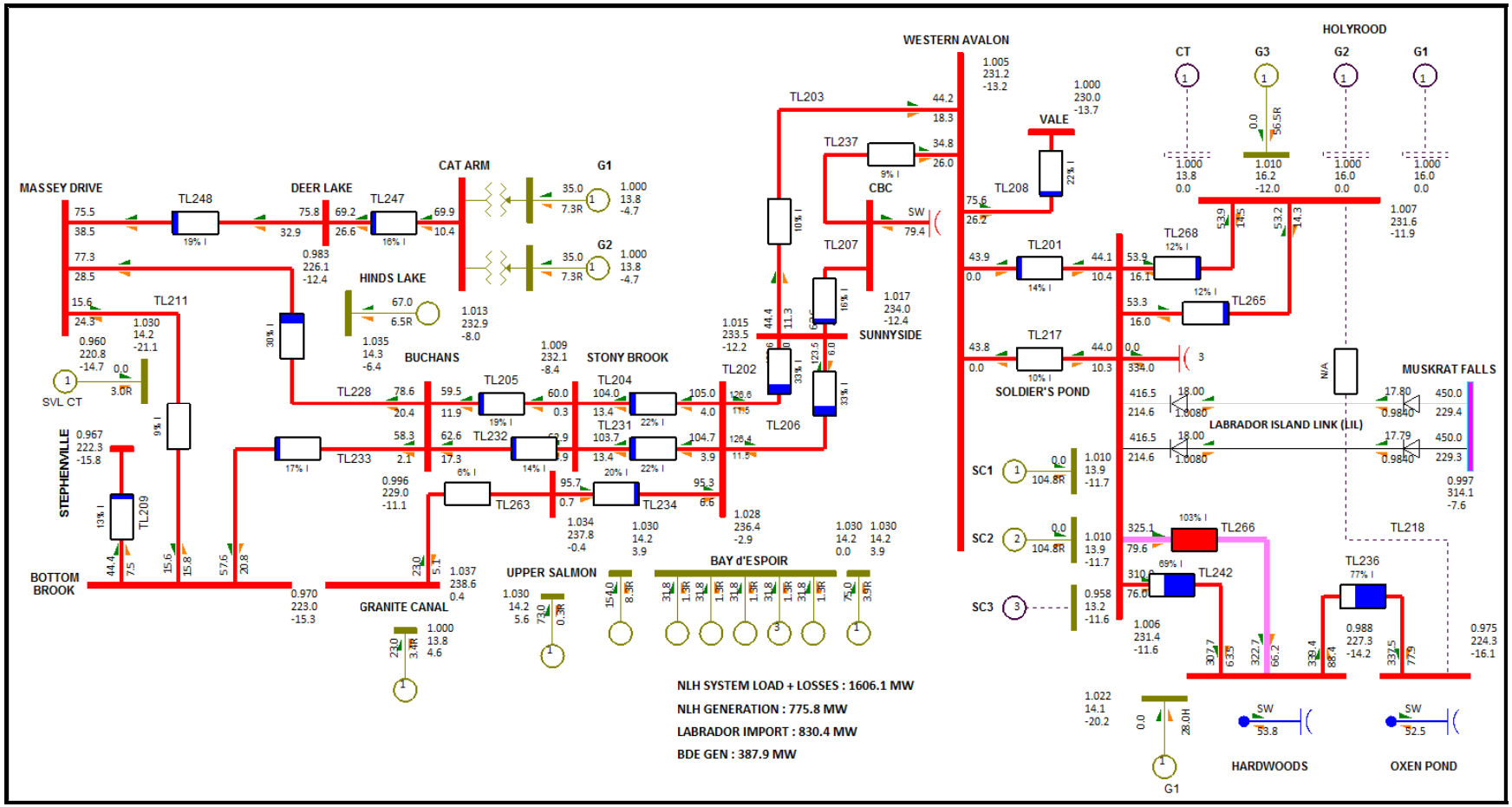


Figure 87 – Base Case 2 (BC2) Load Flow Plot – TL218 Out of Service

TL266 Loaded 103% of Thermal Rating

Existing Bulk 230 kV Transmission System

Winter Peak (1603 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (773 MW)

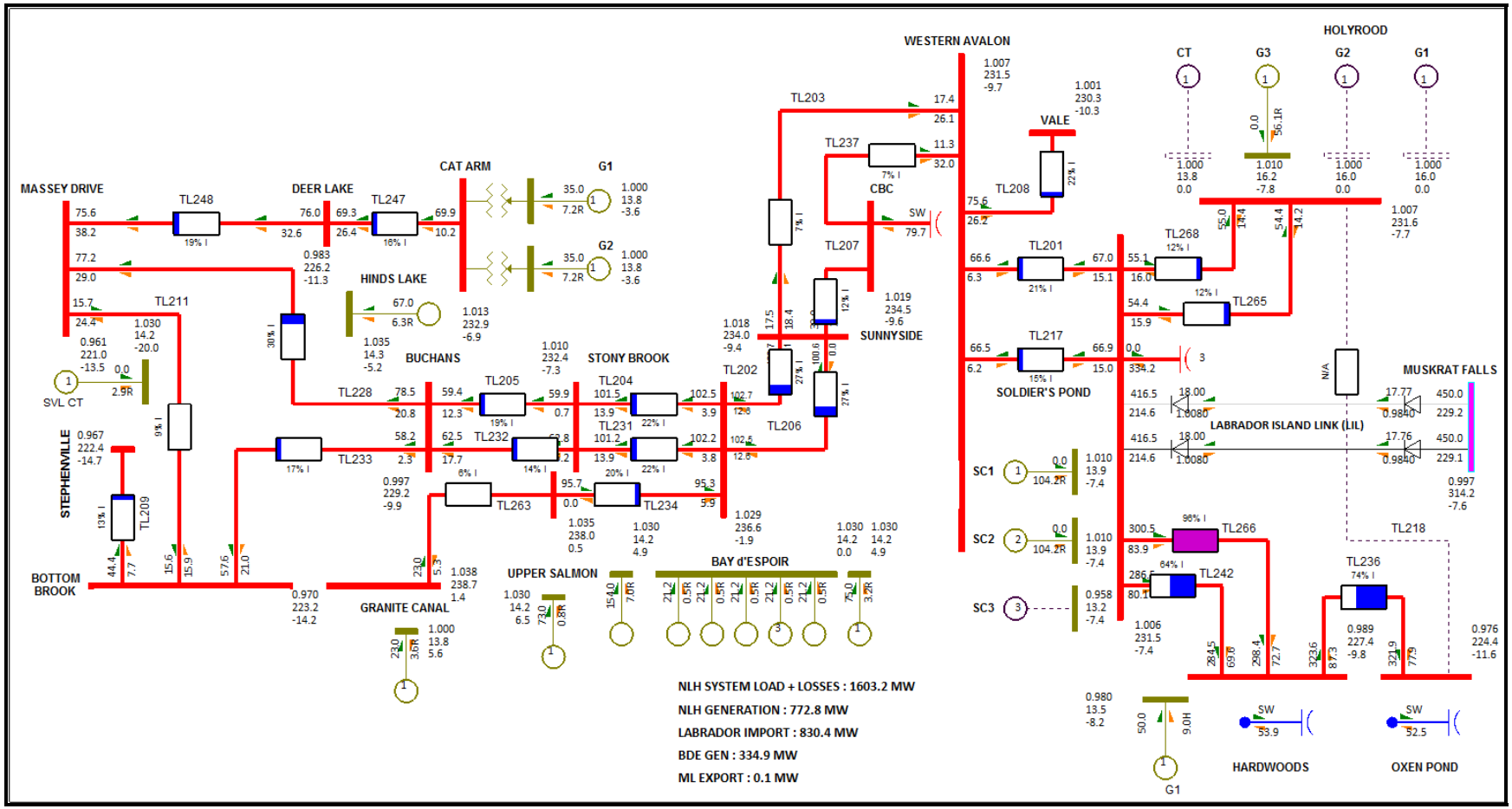


Figure 88 – Base Case 2 (BC2) Load Flow Plot – TL218 Out of Service

TL266 Loaded 96% of Thermal Rating – HWD CT Generating 50 MW

Existing Bulk 230 kV Transmission System

Winter Peak (1603 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (773 MW)

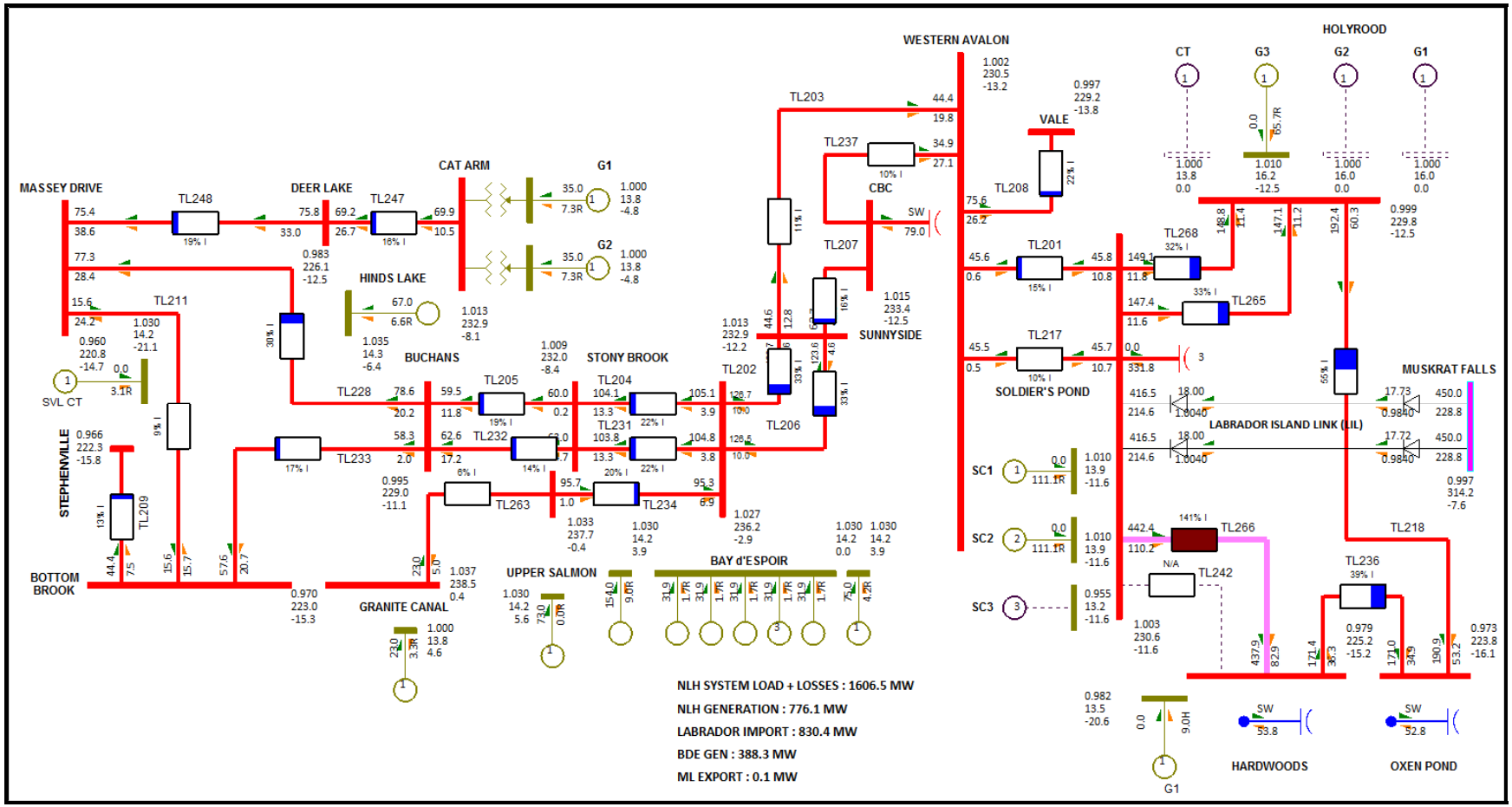


Figure 89 – Base Case 2 (BC2) Load Flow Plot – TL242 Out of Service

TL266 Loaded 141% of Thermal Rating

Existing Bulk 230 kV Transmission System

Winter Peak (1603 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (773 MW)

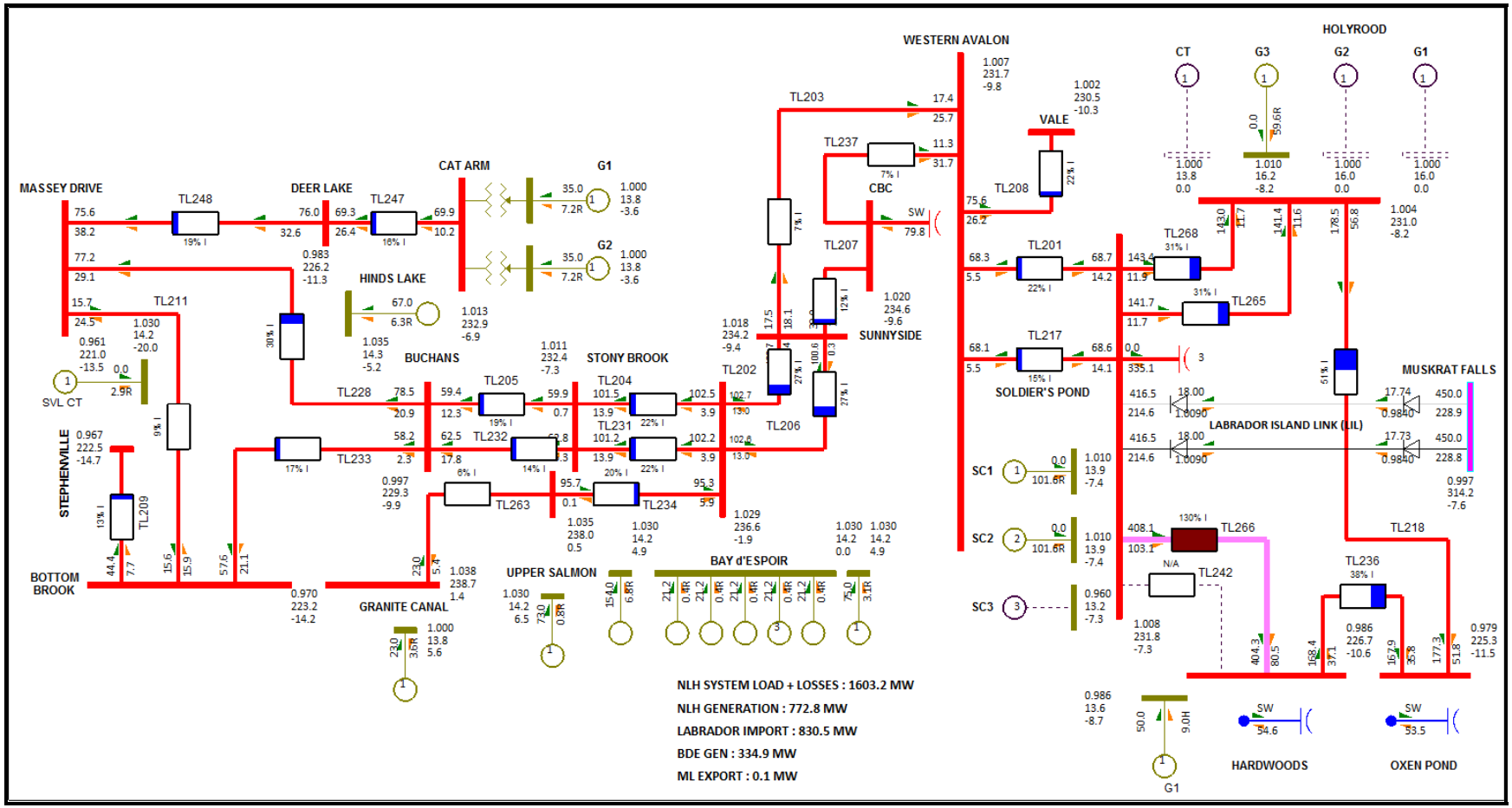


Figure 90 – Base Case 2 (BC2) Load Flow Plot – TL242 Out of Service

TL266 Loaded 130% of Thermal Rating – HWD CT Generating 50 MW

Existing Bulk 230 kV Transmission System

Winter Peak (1603 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (773 MW)

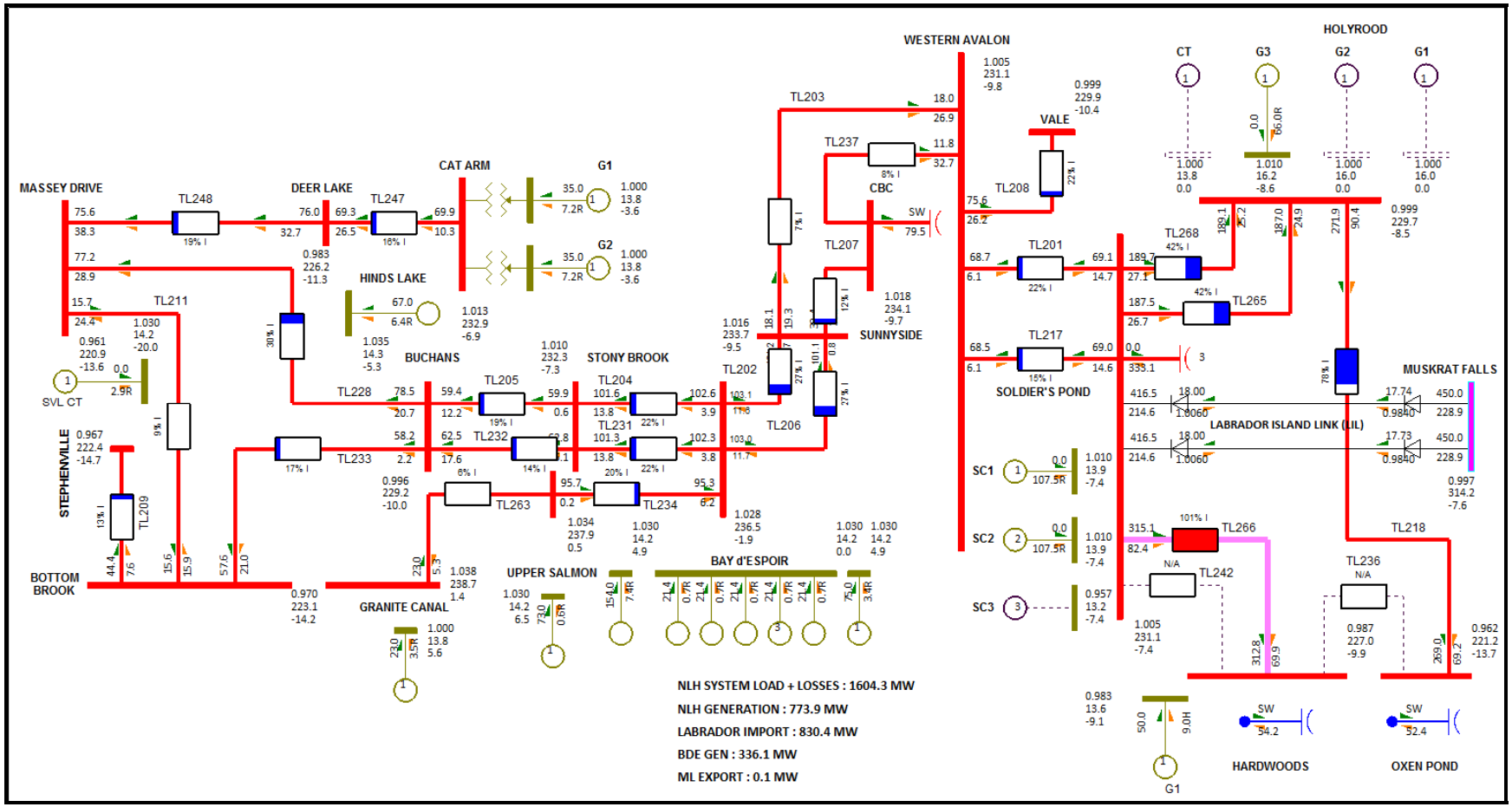


Figure 91 – Base Case 2 (BC2) Load Flow Plot – TL242 Out of Service

TL266 Loaded 101% of Thermal Rating – HWD CT Generating 50 MW + Open TL236

Existing Bulk 230 kV Transmission System

Winter Peak (1603 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (773 MW)

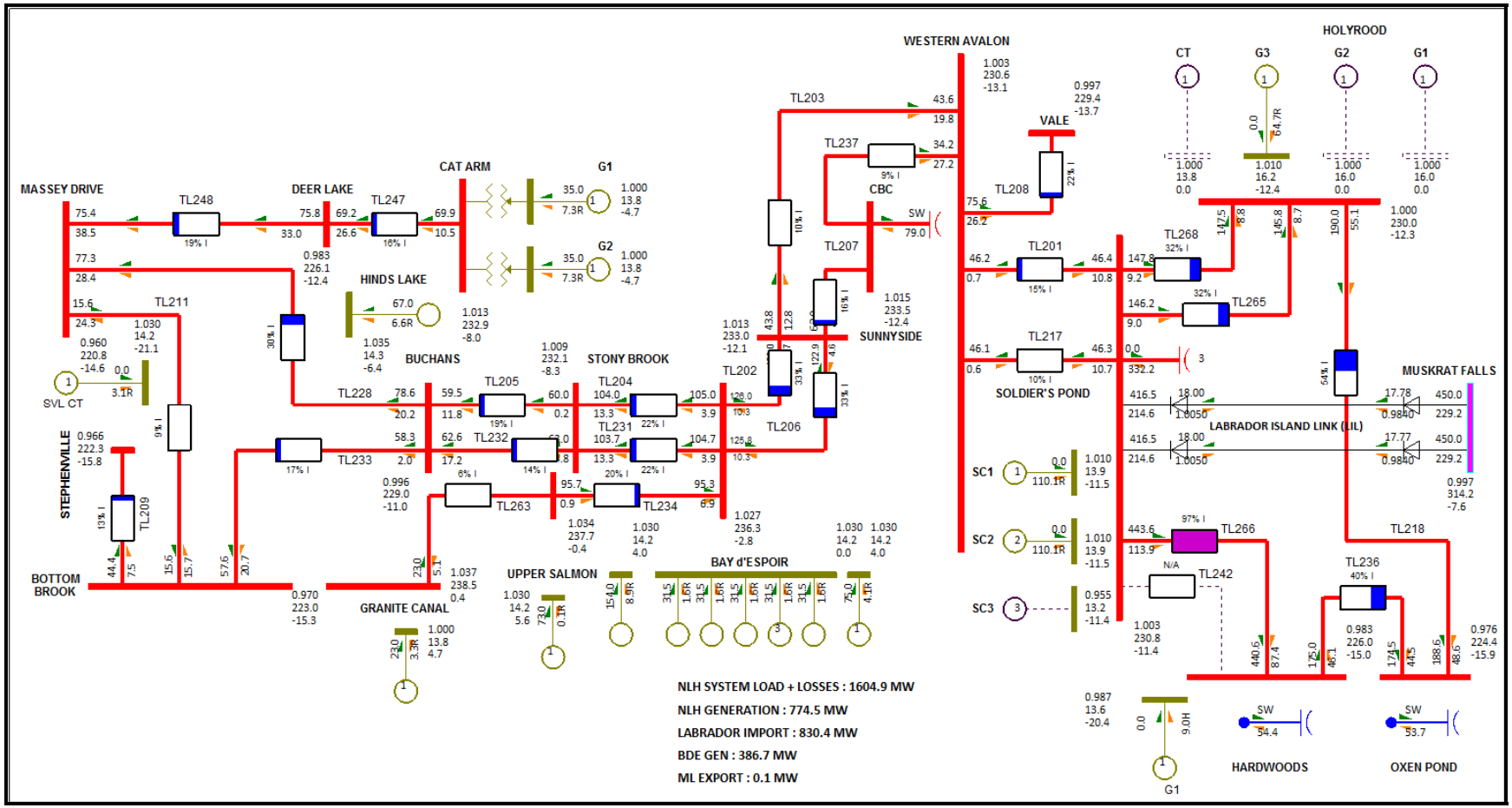


Figure 92 – Base Case 2 (BC2) Load Flow Plot – TL242 Out of Service

TL266 Loaded 97% of Thermal Rating – TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

Existing Bulk 230 kV Transmission System

Winter Peak (1603 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (773 MW)

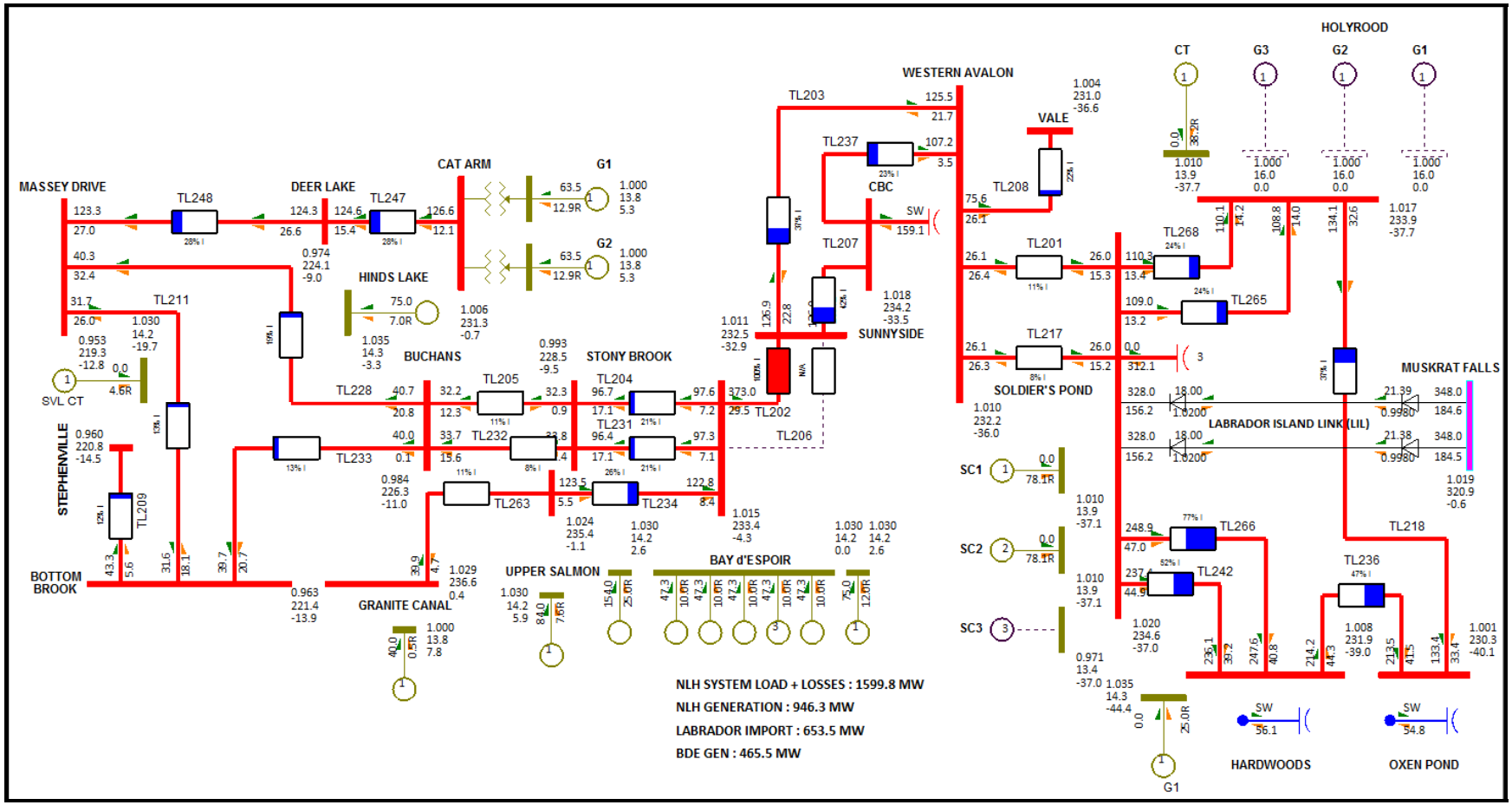


Figure 93 – Base Case 3 (BC3) Load Flow Plot – TL206 Out of Service

TL266 Loaded 100% of Thermal Rating – LIL Import Increased to 654 MW

Existing Bulk 230 kV Transmission System

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

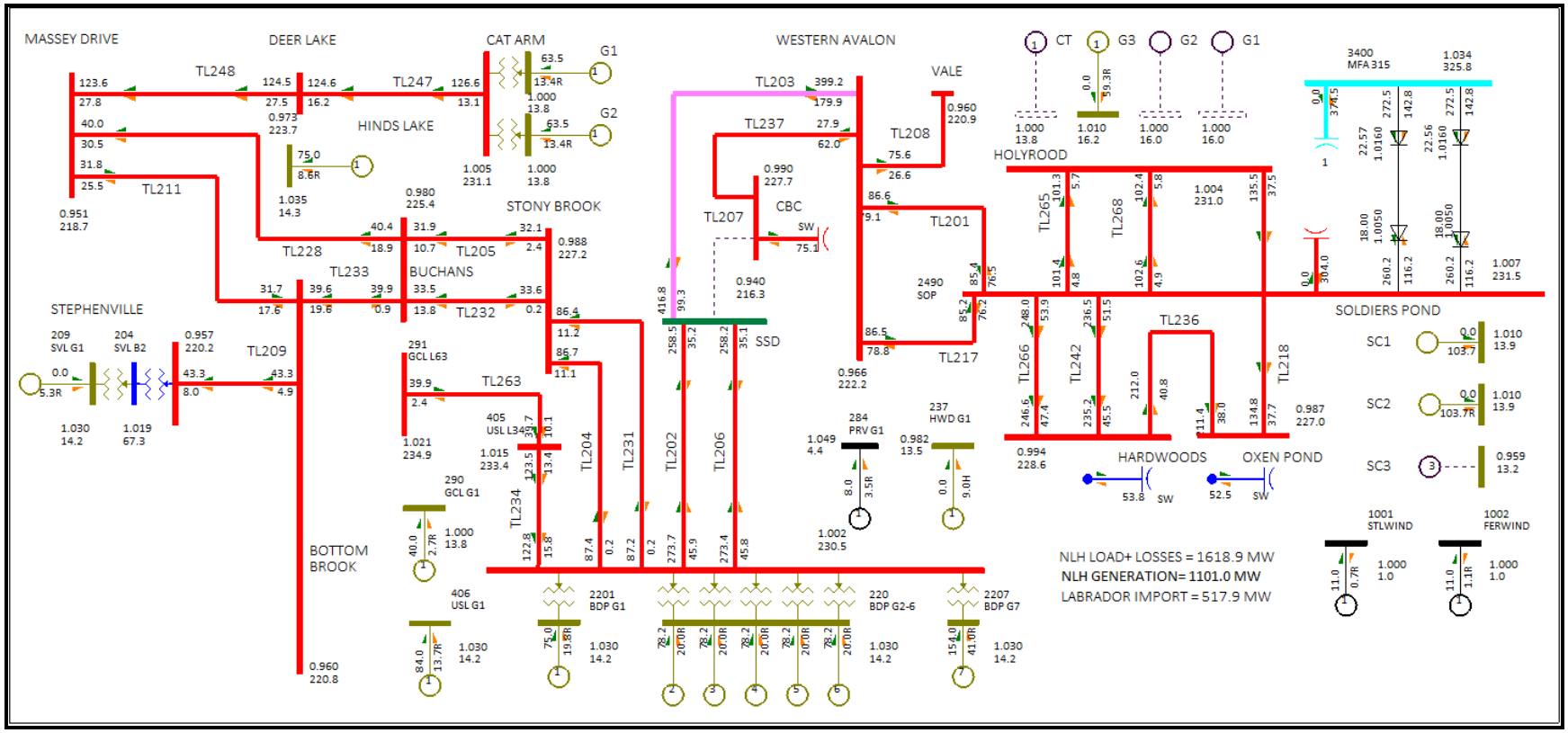


Figure 94 – Base Case 3 (BC3) Load Flow Plot – TL207 Out of Service

TL203 Loaded 131% of Thermal Rating

Existing Bulk 230 kV Transmission System

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

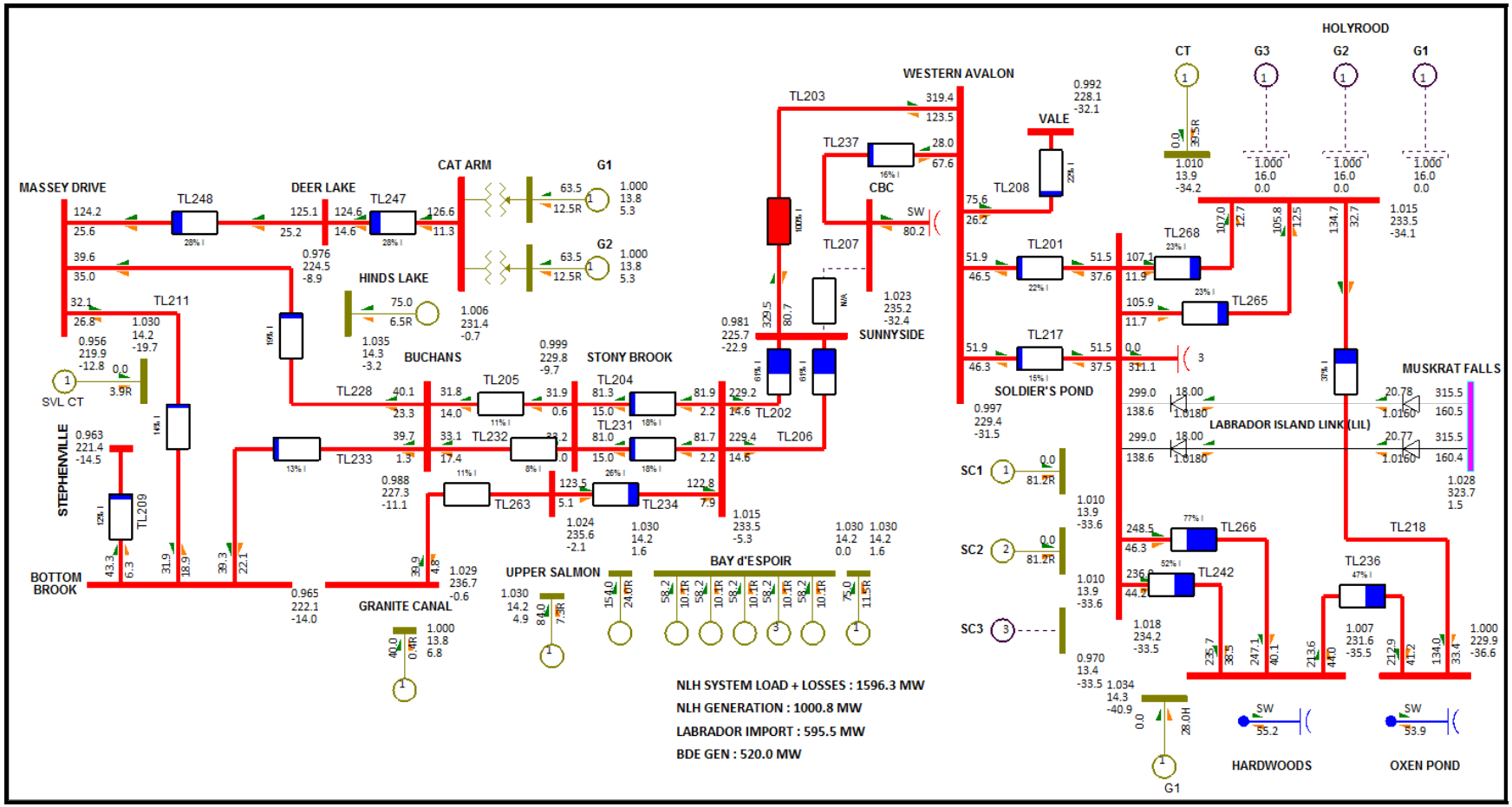


Figure 95 – Base Case 3 (BC3) Load Flow Plot – TL207 Out of Service

TL203 Loaded 100% of Thermal Rating – LIL Import Increased to 598 MW

Existing Bulk 230 kV Transmission System

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

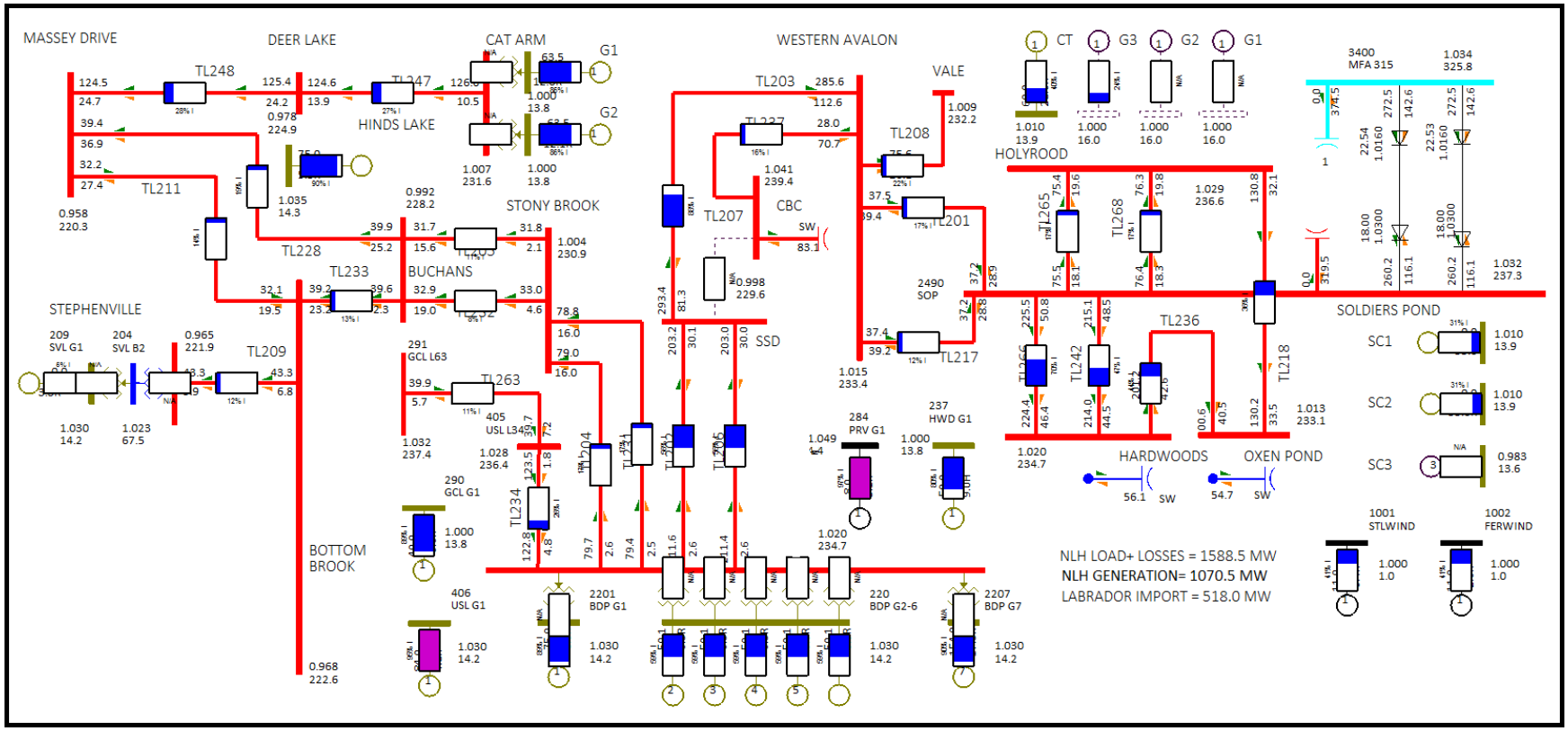


Figure 96 – Base Case 3 (BC3) Load Flow Plot – TL207 Out of Service

TL203 Loaded 88% of Thermal Rating – HWD CT and HRD CT Generating a Total of 110 MW

Existing Bulk 230 kV Transmission System

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

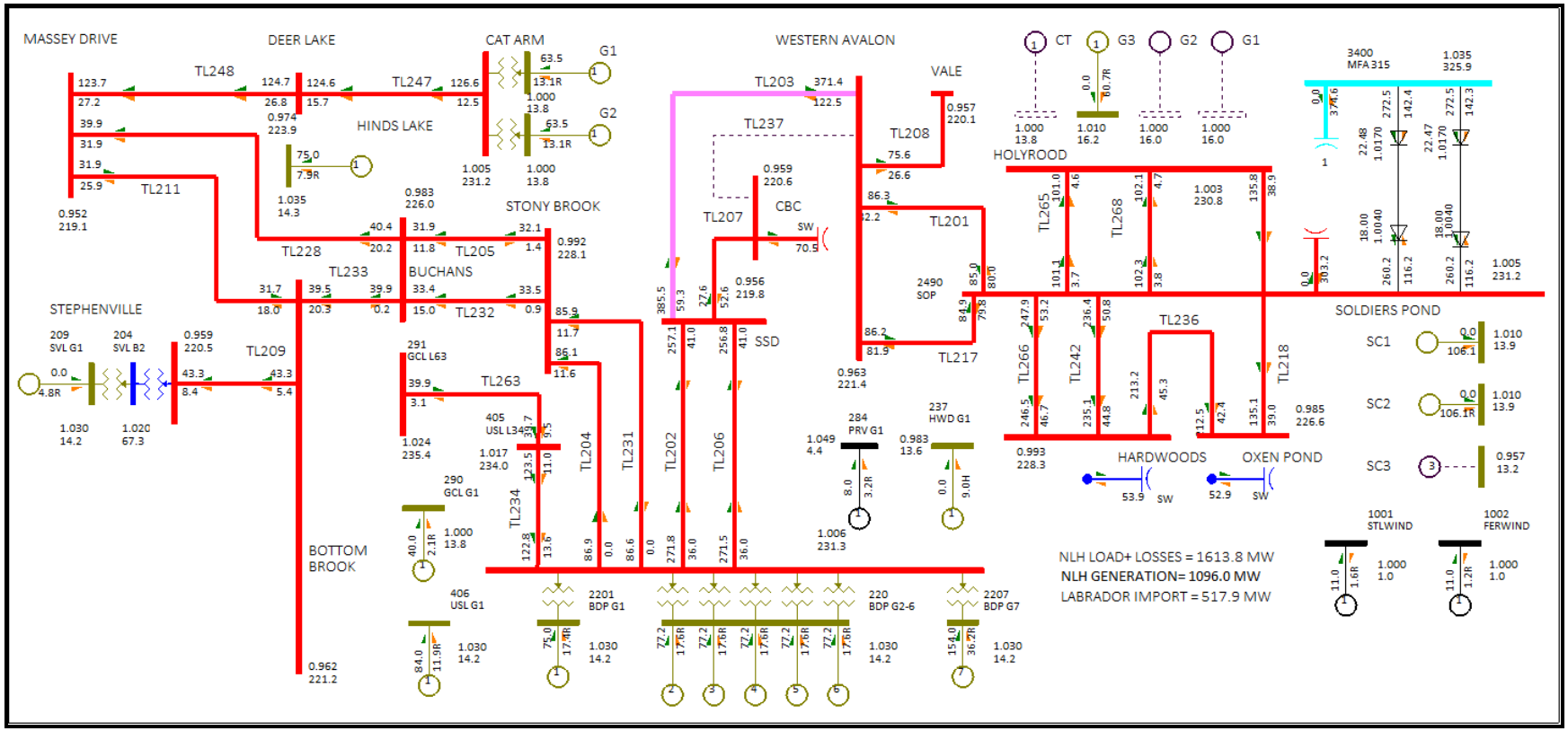


Figure 97 – Base Case 3 (BC3) Load Flow Plot – TL237 Out of Service

TL203 Loaded 118% of Thermal Rating

Existing Bulk 230 kV Transmission System

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

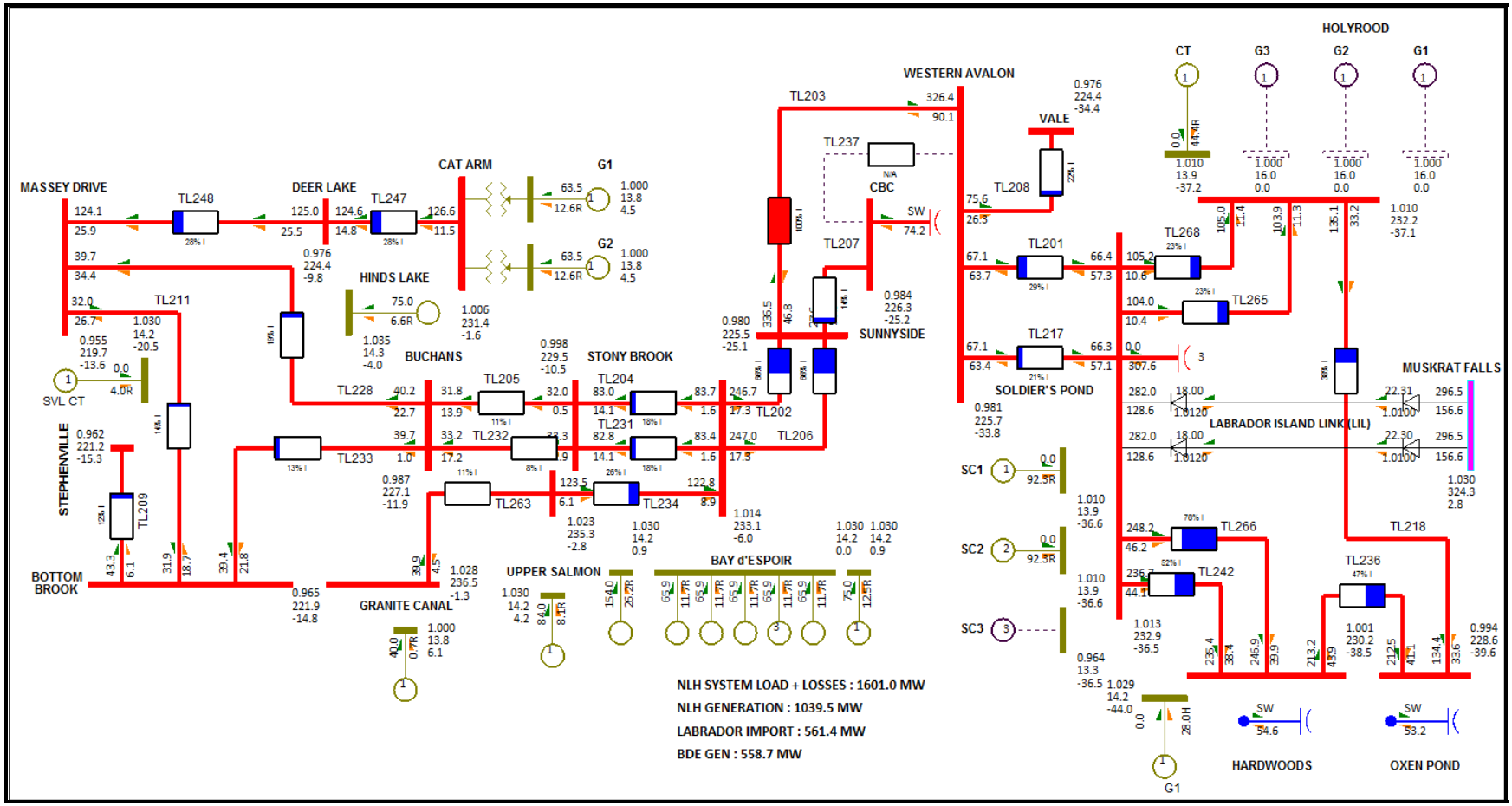


Figure 98 – Base Case 3 (BC3) Load Flow Plot – TL237 Out of Service

TL203 Loaded 100% of Thermal Rating

Existing Bulk 230 kV Transmission System

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

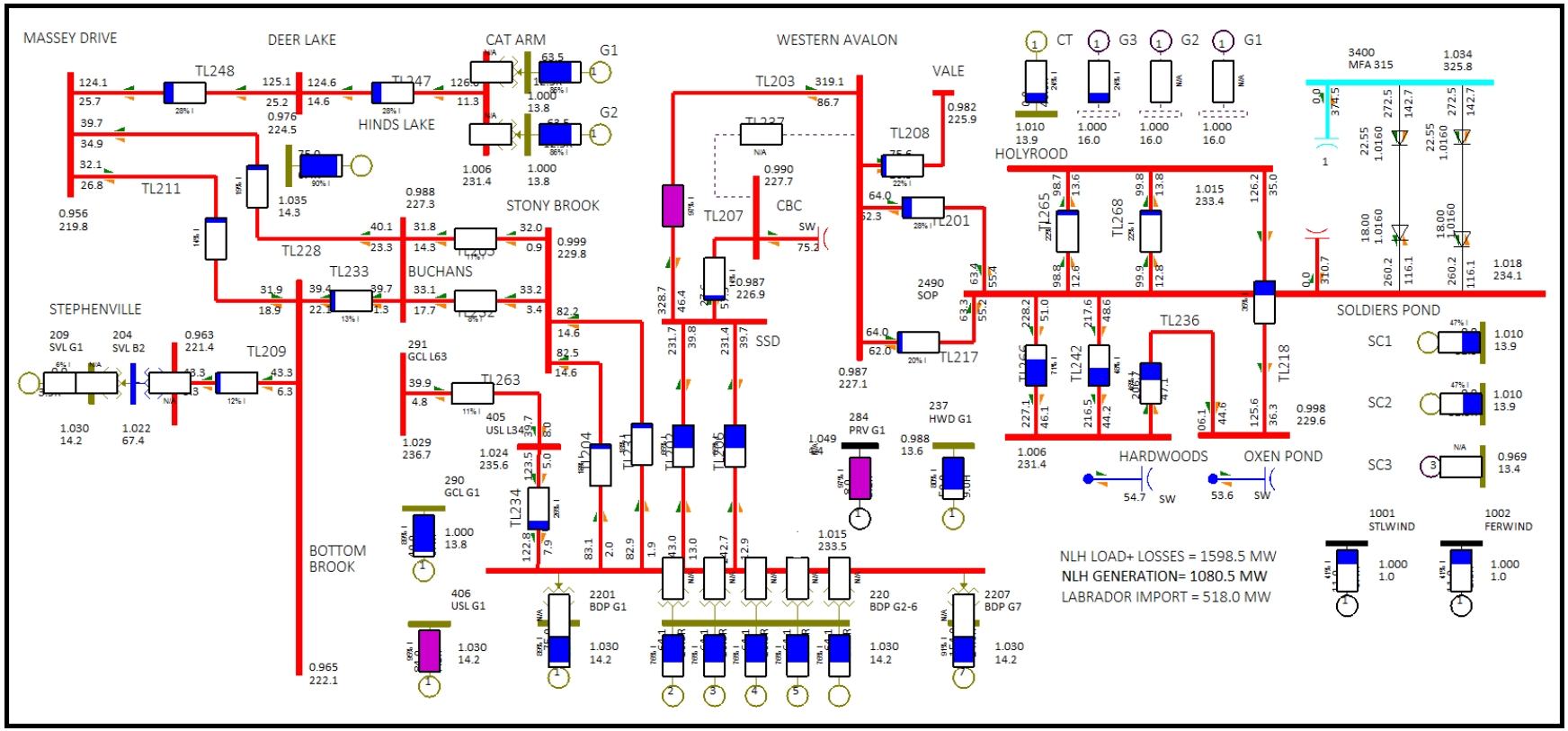


Figure 99 – Base Case 3 (BC3) Load Flow Plot – TL237 Out of Service

TL203 Loaded 97% of Thermal Rating – HWD CT Generating 50 MW

Existing Bulk 230 kV Transmission System

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

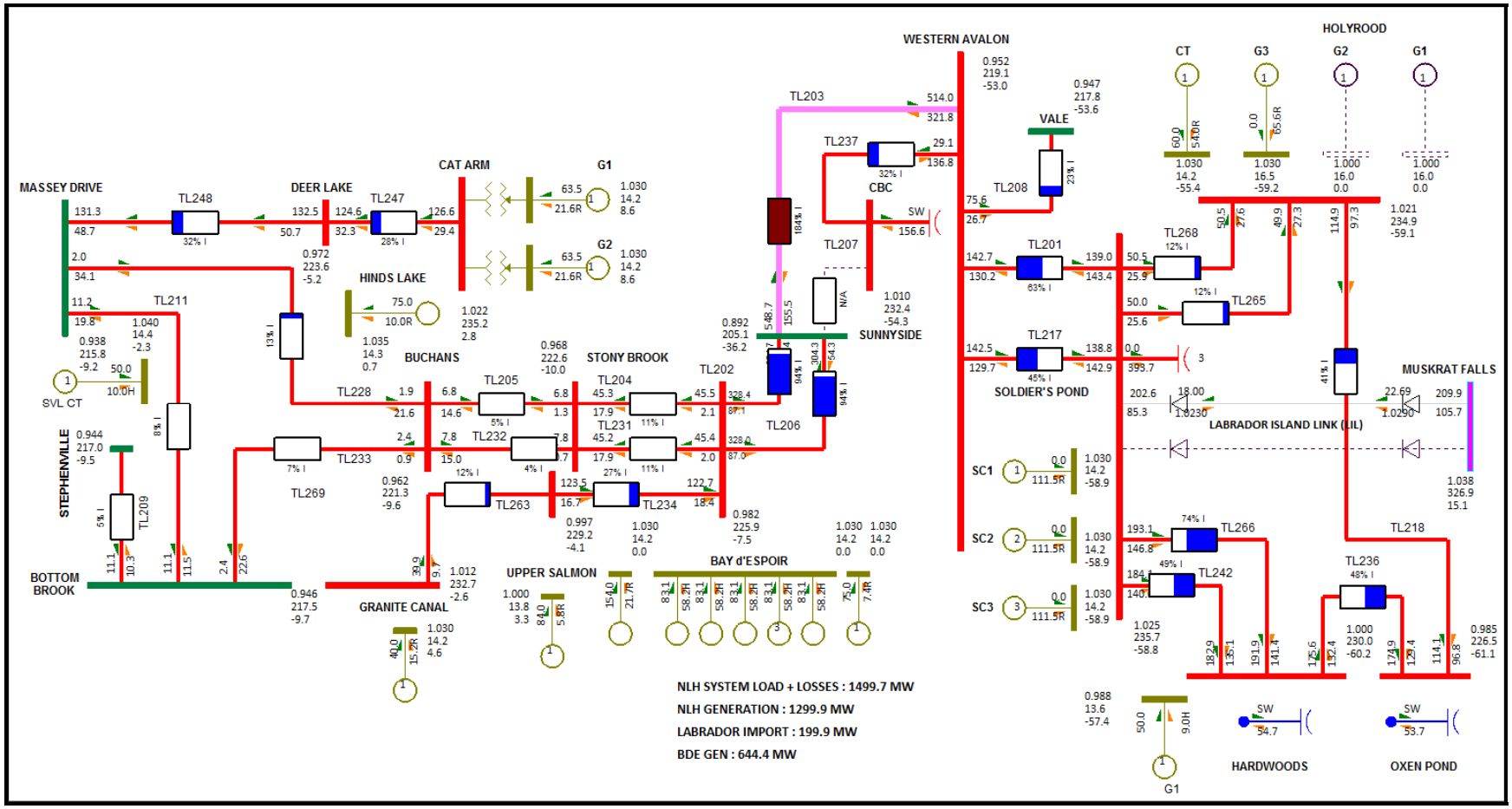


Figure 100 – Base Case 4 (BC4) Load Flow Plot – TL207 Out of Service

TL203 Loaded 184% of Thermal Rating

Existing Bulk 230 kV Transmission System

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

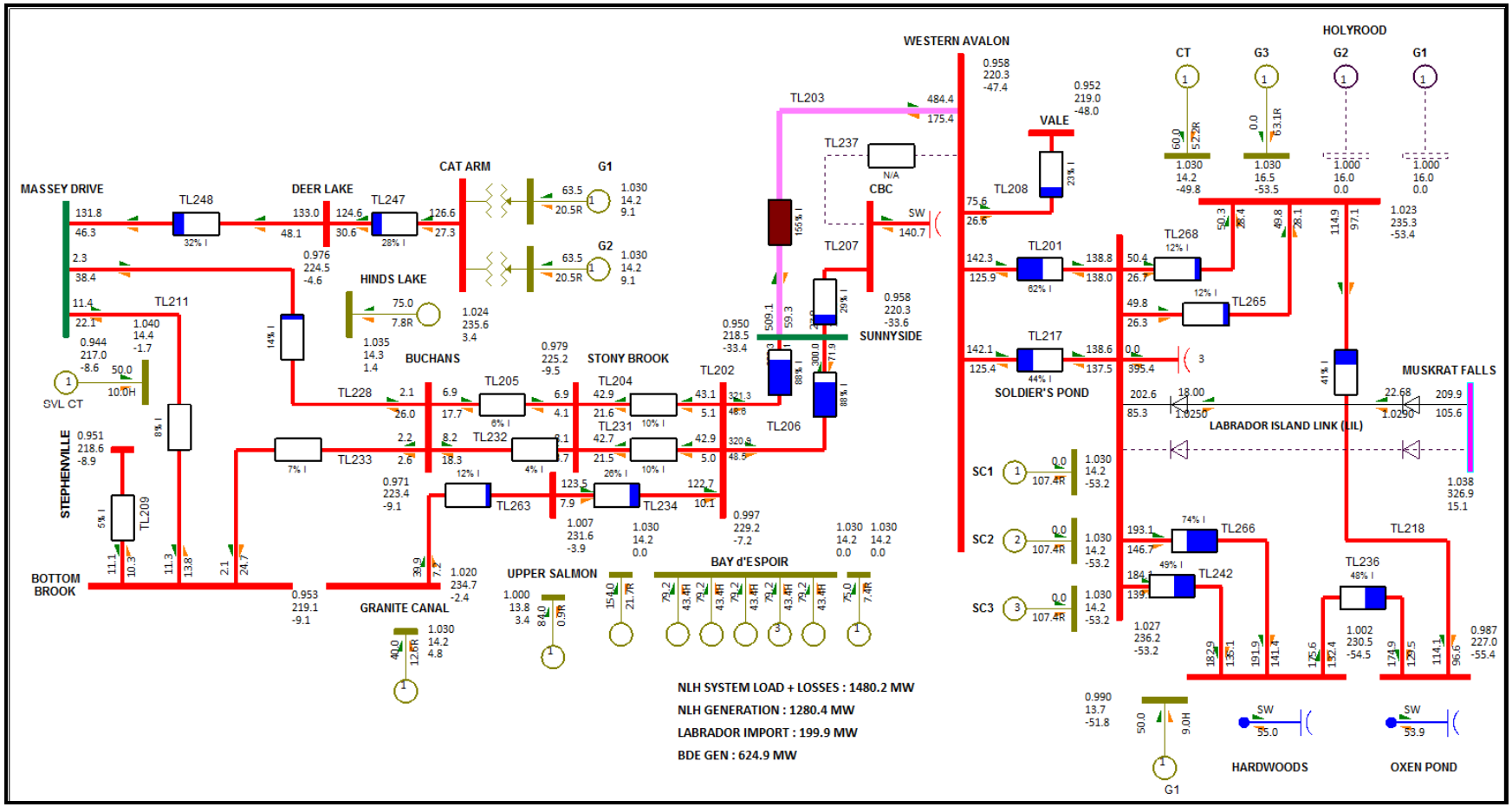


Figure 101 – Base Case 4 (BC4) Load Flow Plot – TL237 Out of Service

TL203 Loaded 155% of Thermal Rating

Existing Bulk 230 kV Transmission System

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

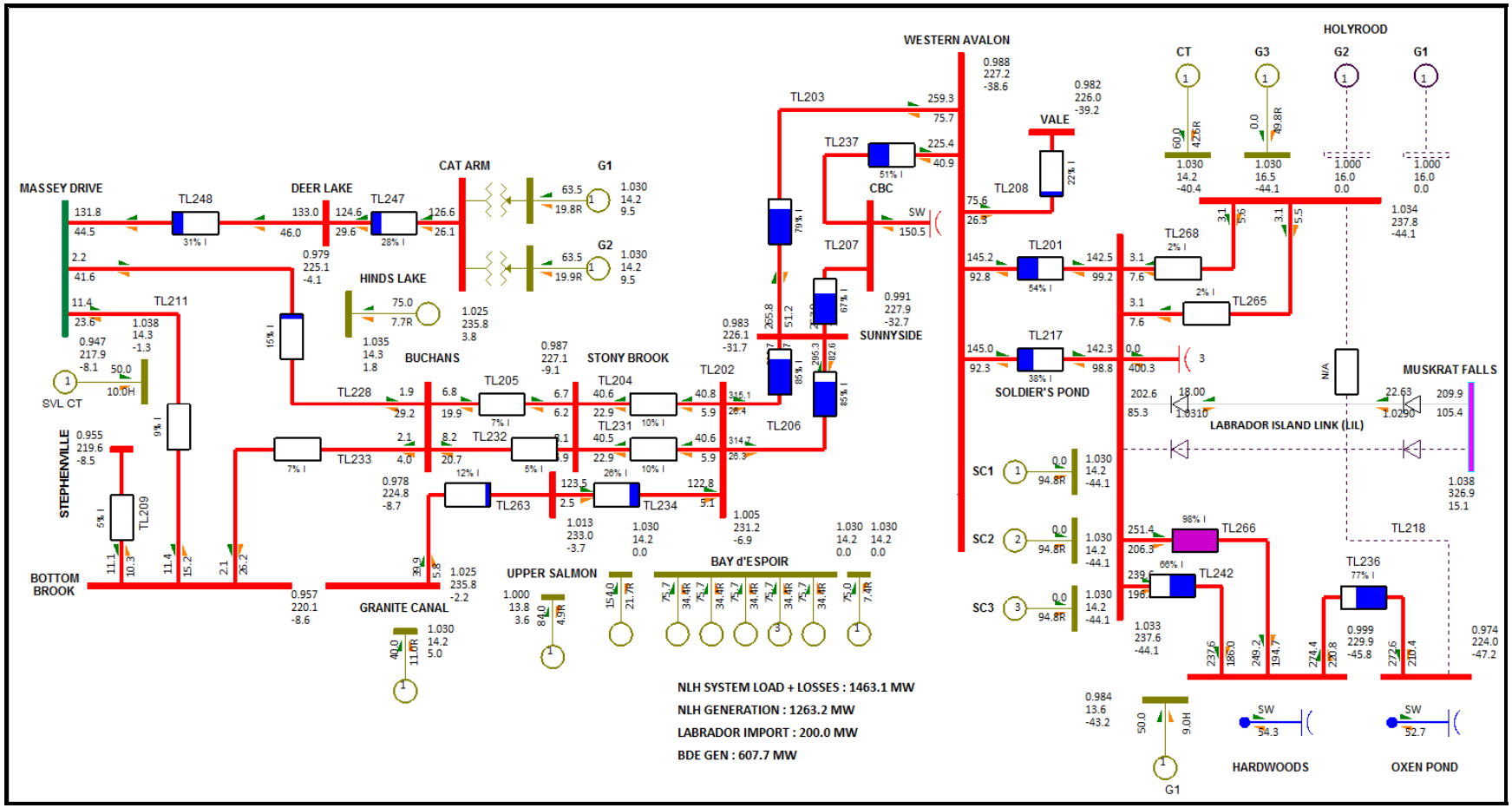


Figure 102 – Base Case 4 (BC4) Load Flow Plot – TL218 Out of Service

TL266 Loaded 98% of Thermal Rating

Existing Bulk 230 kV Transmission System

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

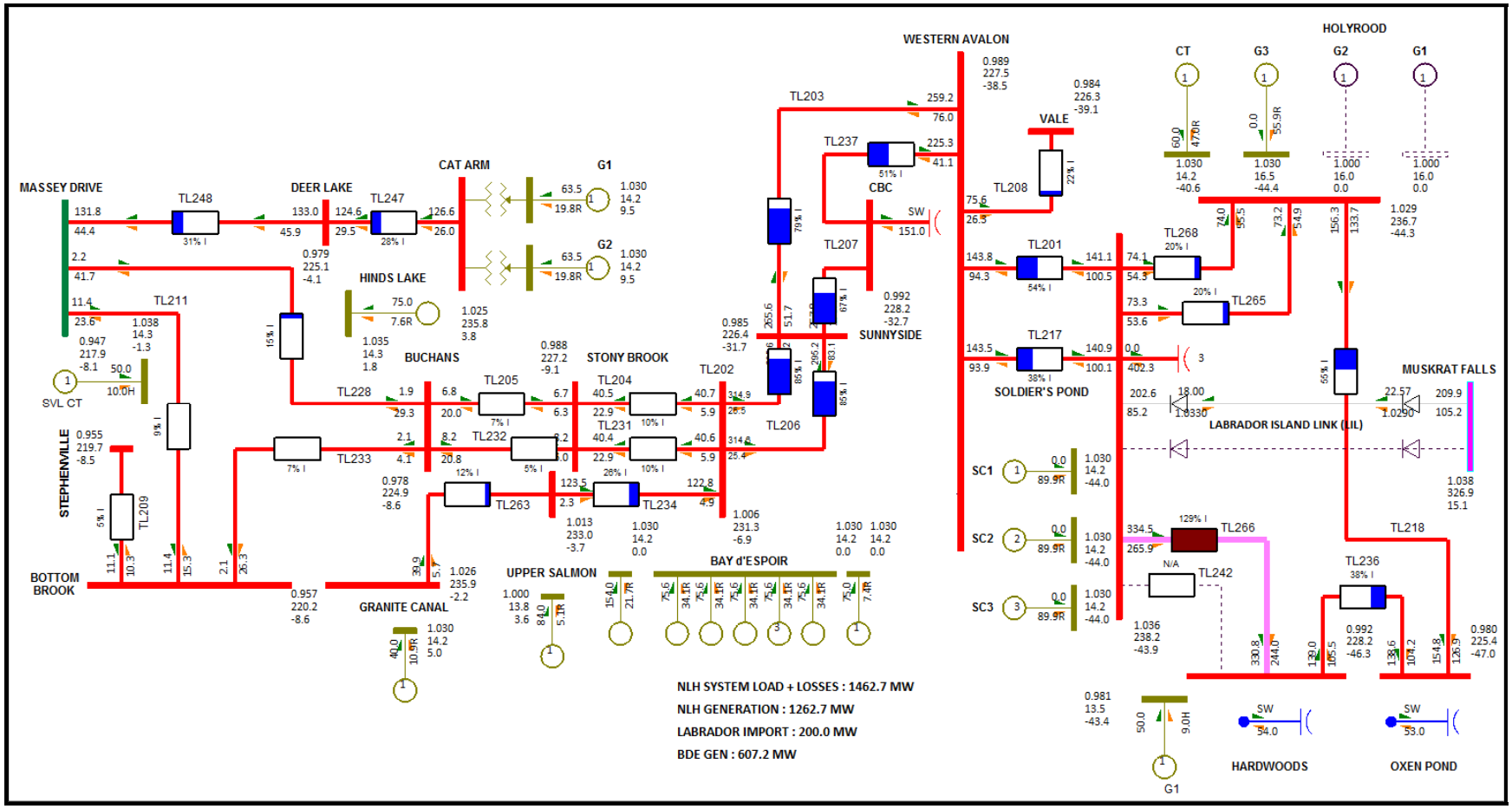


Figure 103 – Base Case 4 (BC4) Load Flow Plot – TL242 Out of Service

TL266 Loaded 129% of Thermal Rating

Existing Bulk 230 kV Transmission System

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

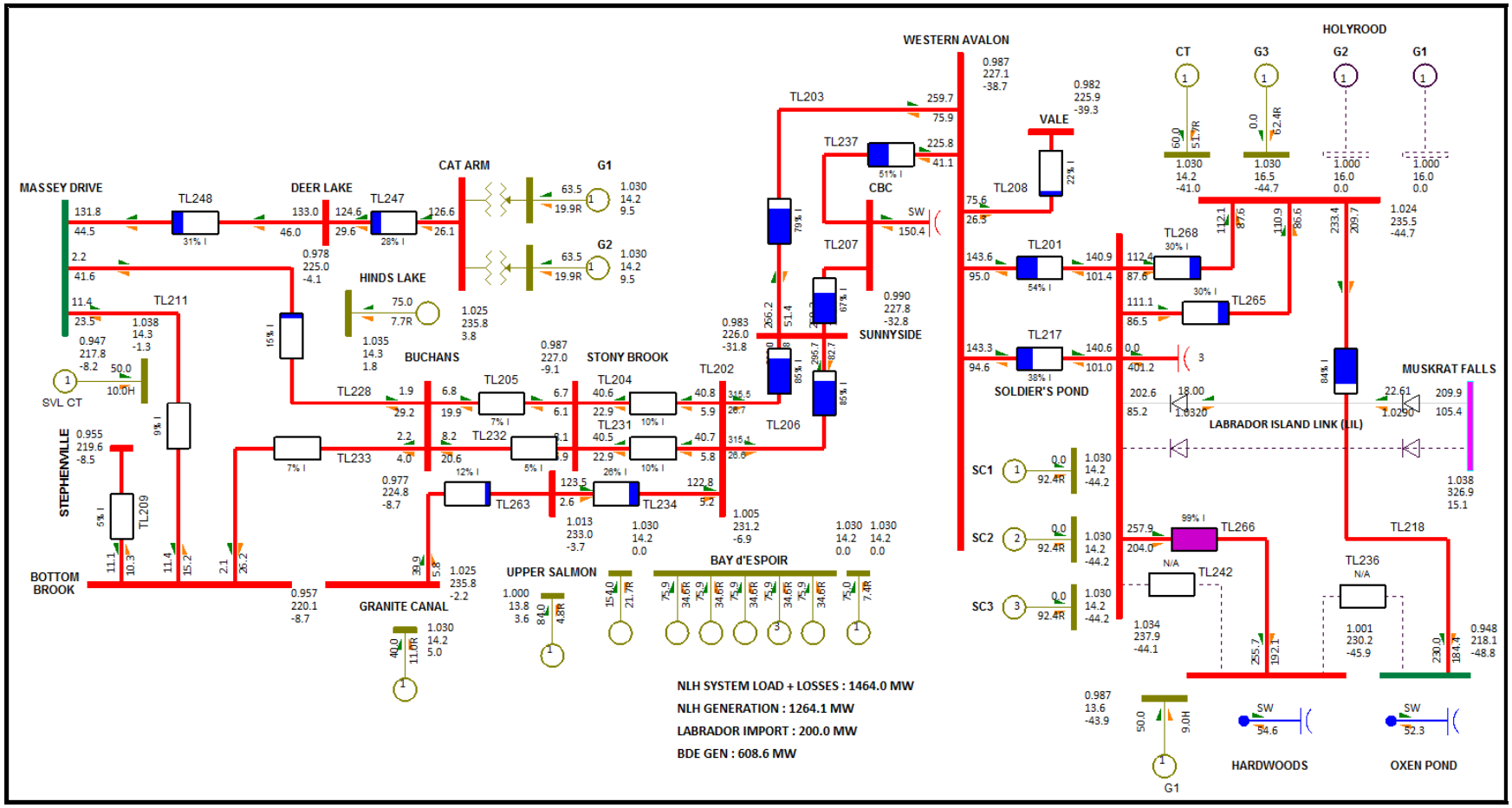


Figure 104 – Base Case 4 (BC4) Load Flow Plot – TL242 Out of Service – TL236 Open

TL266 Loaded 99% of Thermal Rating

Existing Bulk 230 kV Transmission System

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

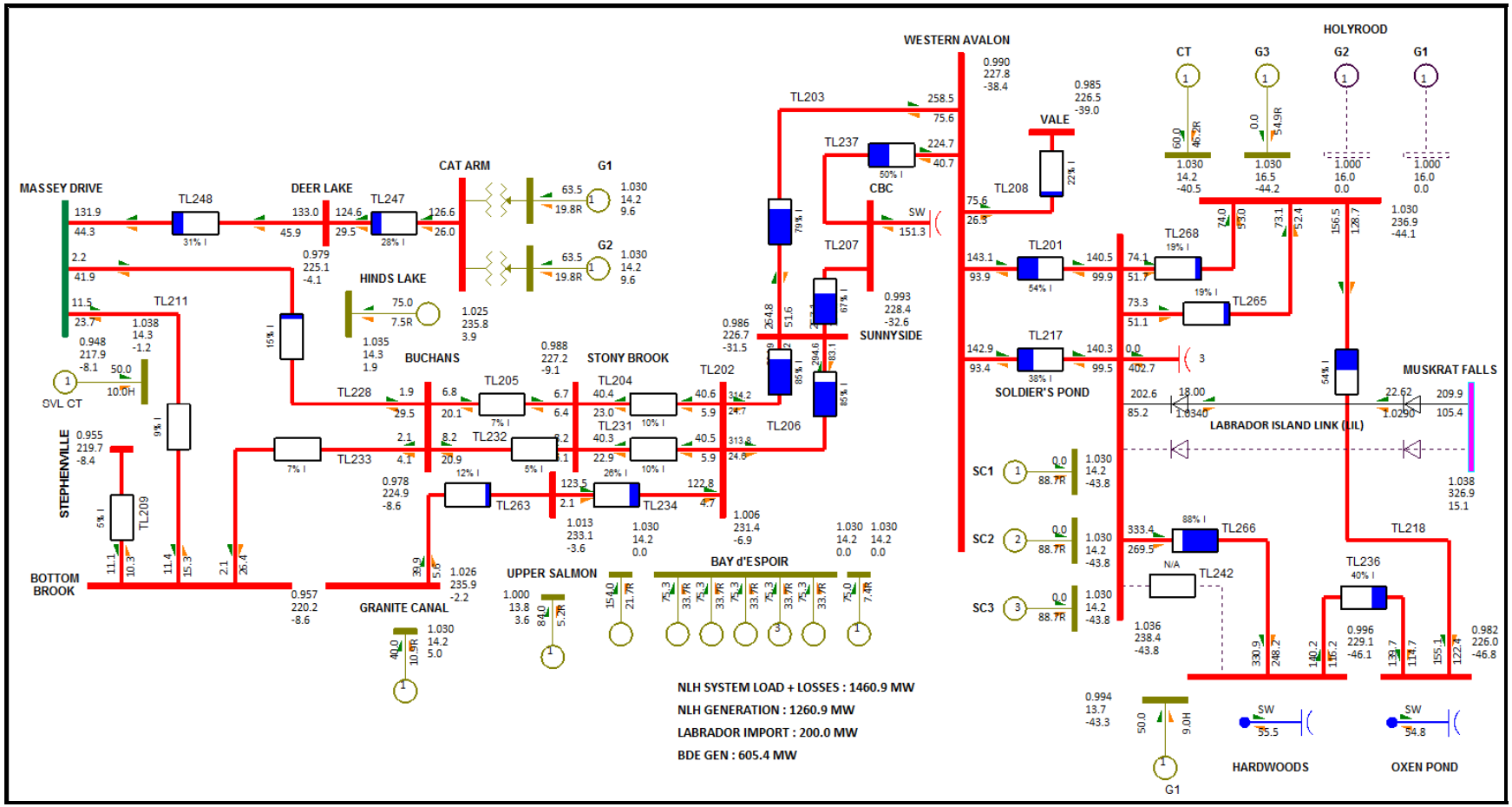


Figure 105 – Base Case 4 (BC4) Load Flow Plot – TL242 Out of Service

TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

Existing Bulk 230 kV Transmission System

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

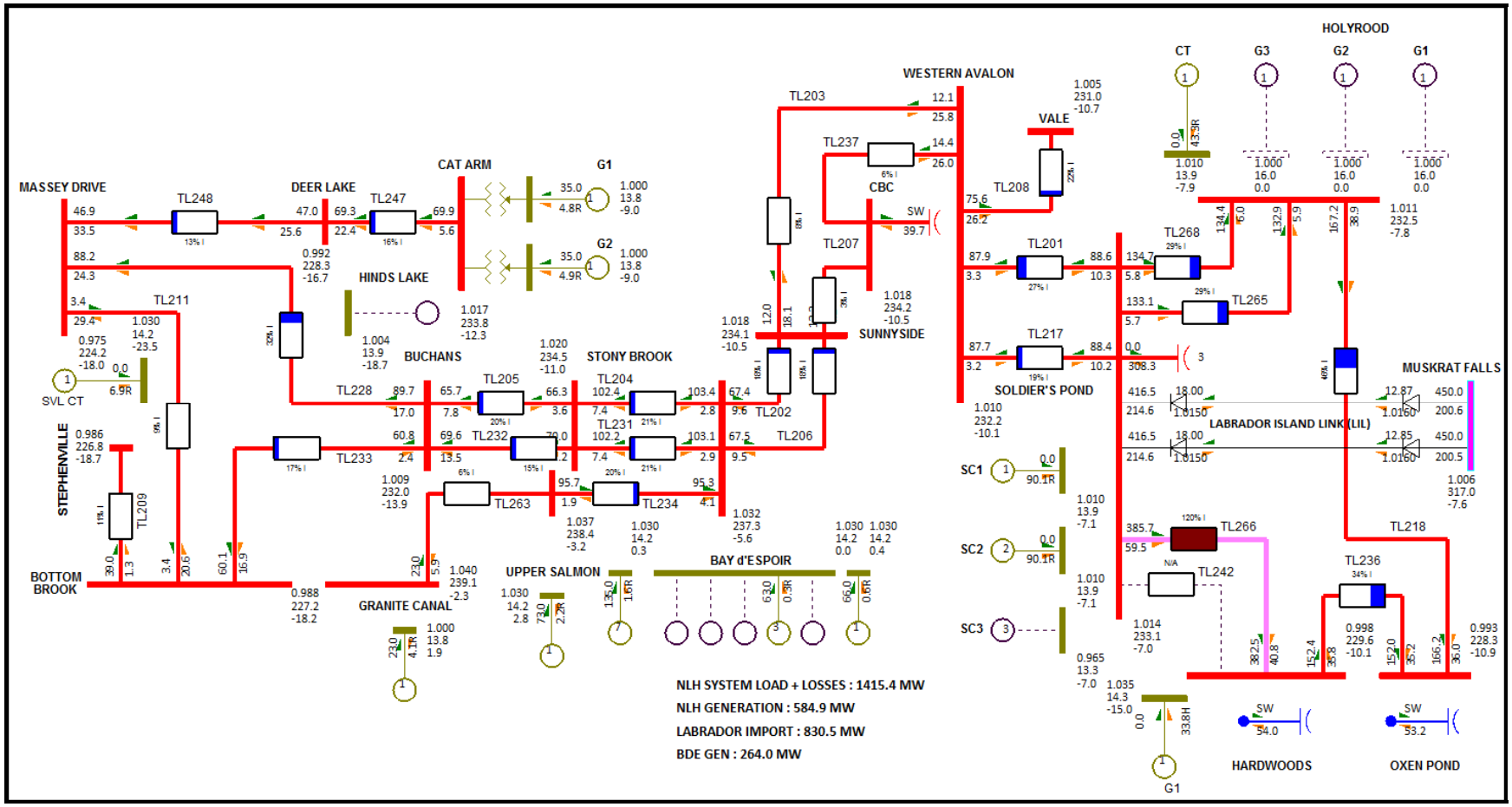


Figure 106 – Base Case 5 (BC5) Load Flow Plot – TL242 Out of Service

TL266 Loaded 120% of Thermal Rating

Existing Bulk 230 kV Transmission System

Winter Day (1415 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (585 MW)

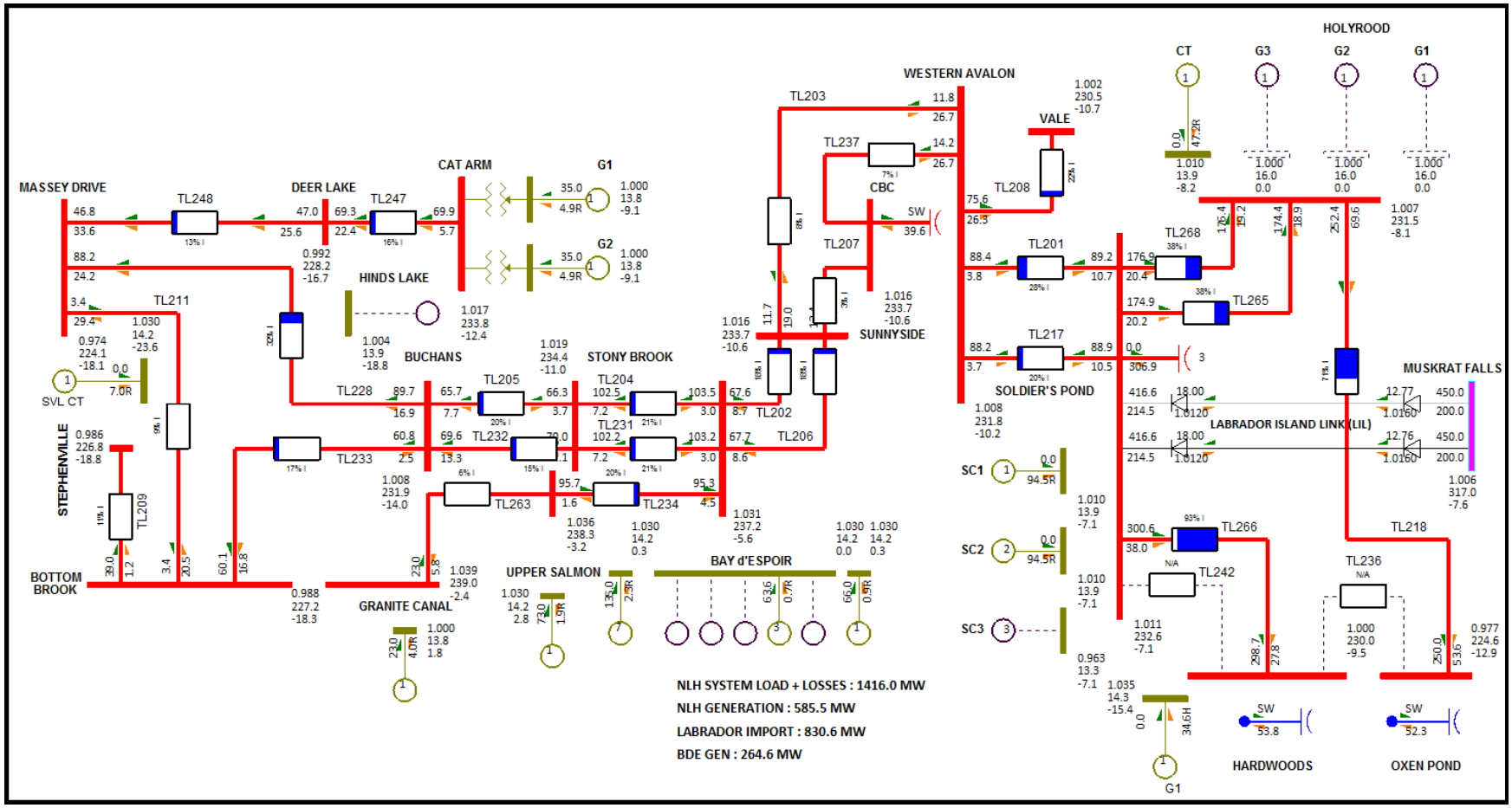


Figure 107 – Base Case 5 (BC5) Load Flow Plot – TL242 Out of Service

TL266 Loaded 93% of Thermal Rating – TL236 Open

Existing Bulk 230 kV Transmission System

Winter Day (1415 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (585 MW)

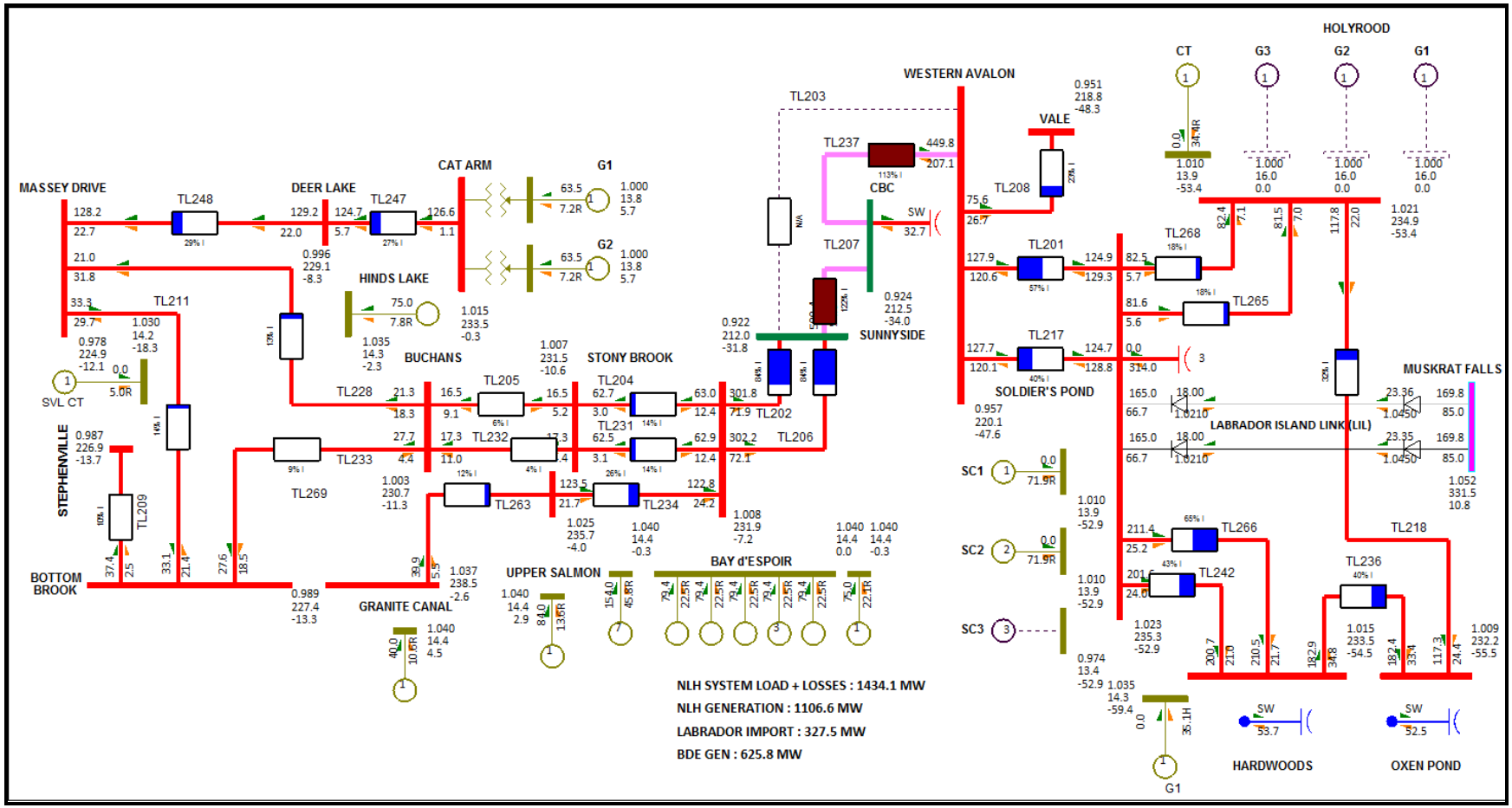


Figure 108 – Base Case 6 (BC6) Load Flow Plot – TL203 Out of Service

TL237 Loaded 113% of Thermal Rating- TL207 Loaded 122% of Thermal Rating

Existing Bulk 230 kV Transmission System

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

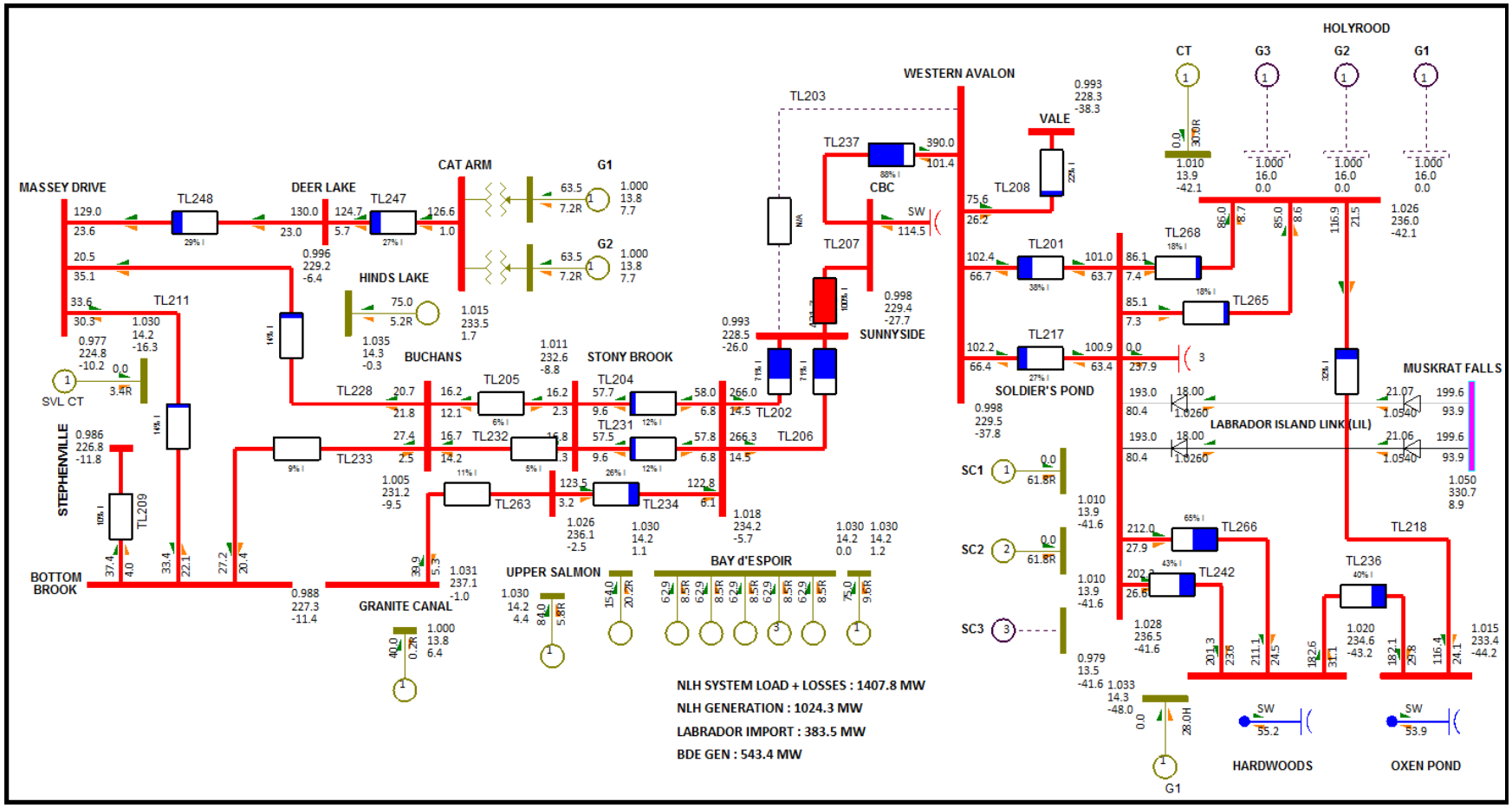


Figure 109 – Base Case 6 (BC6) Load Flow Plot – TL203 Out of Service

TL237 Loaded 88% of Thermal Rating- TL207 Loaded 100% of Thermal Rating – LIL Import Increased to 384 MW

Existing Bulk 230 kV Transmission System

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

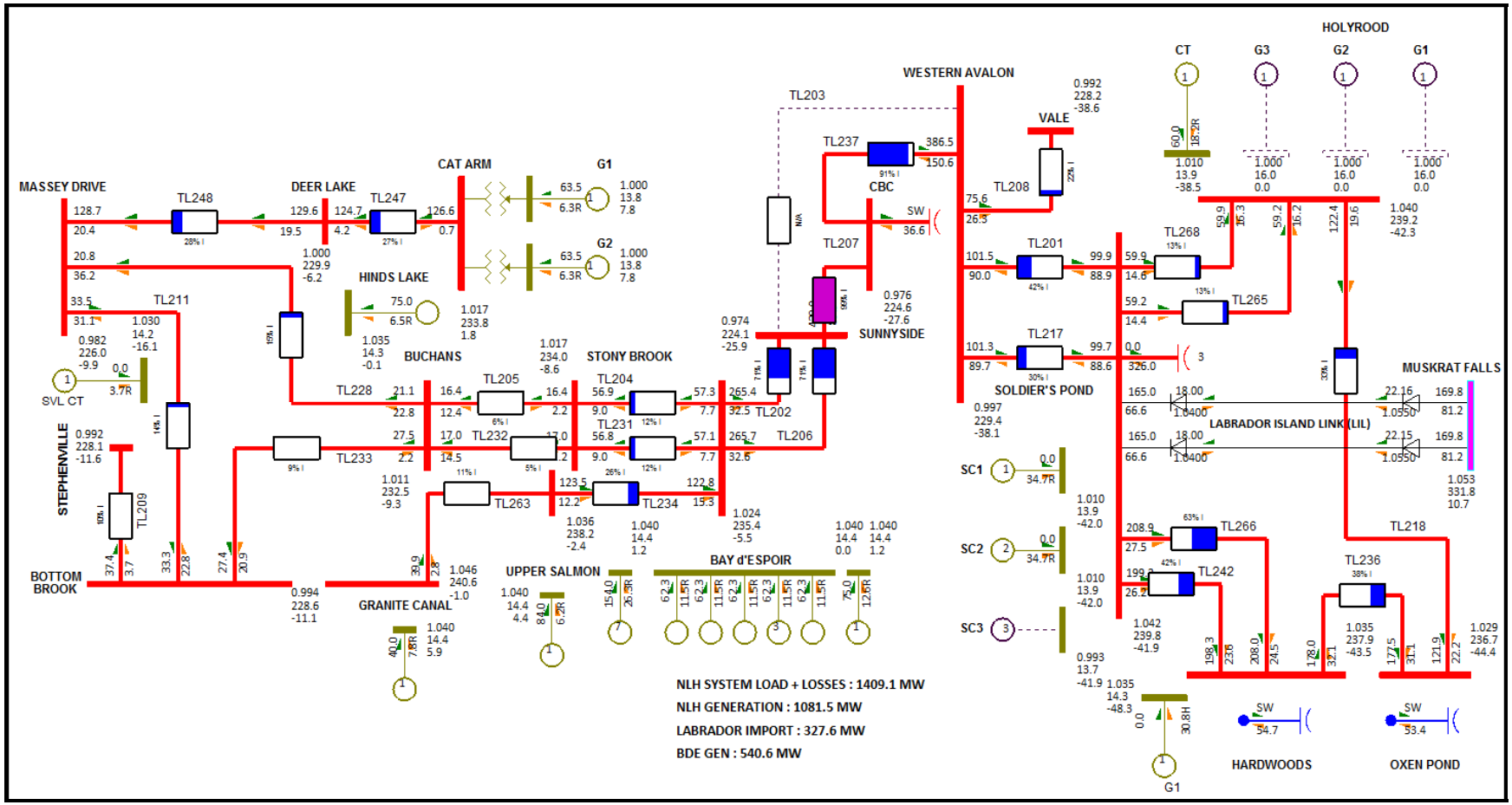


Figure 110 – Base Case 6 (BC6) Load Flow Plot – TL203 Out of Service

TL237 Loaded 91% of Thermal Rating- TL207 Loaded 99% of Thermal Rating – HRD CT Generating 60 MW

Existing Bulk 230 kV Transmission System

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

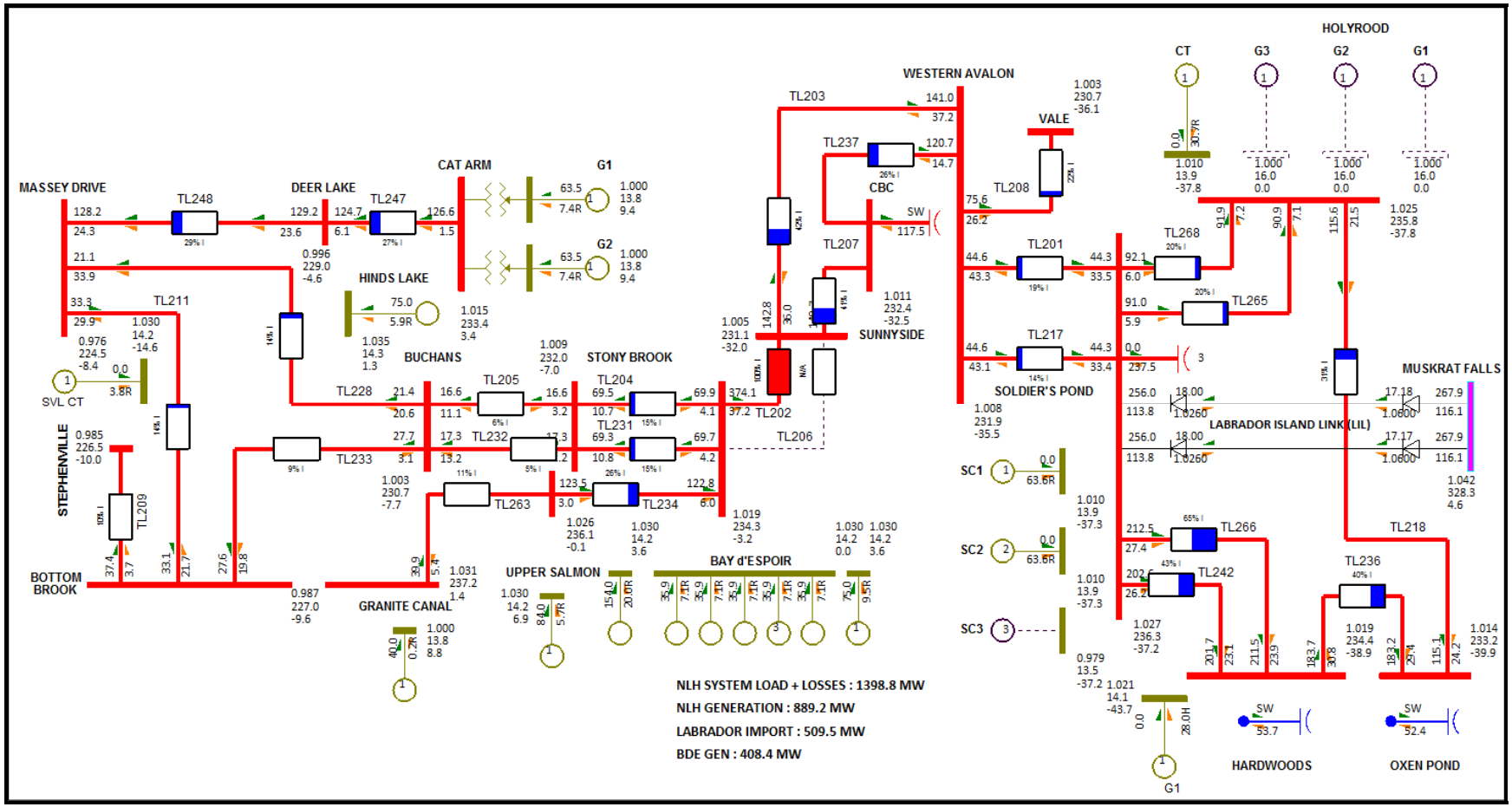


Figure 111 – Base Case 6 (BC6) Load Flow Plot – TL206 Out of Service

TL202 Loaded 100% of Thermal Rating – LIL Import Increased to 510 MW

Existing Bulk 230 kV Transmission System

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

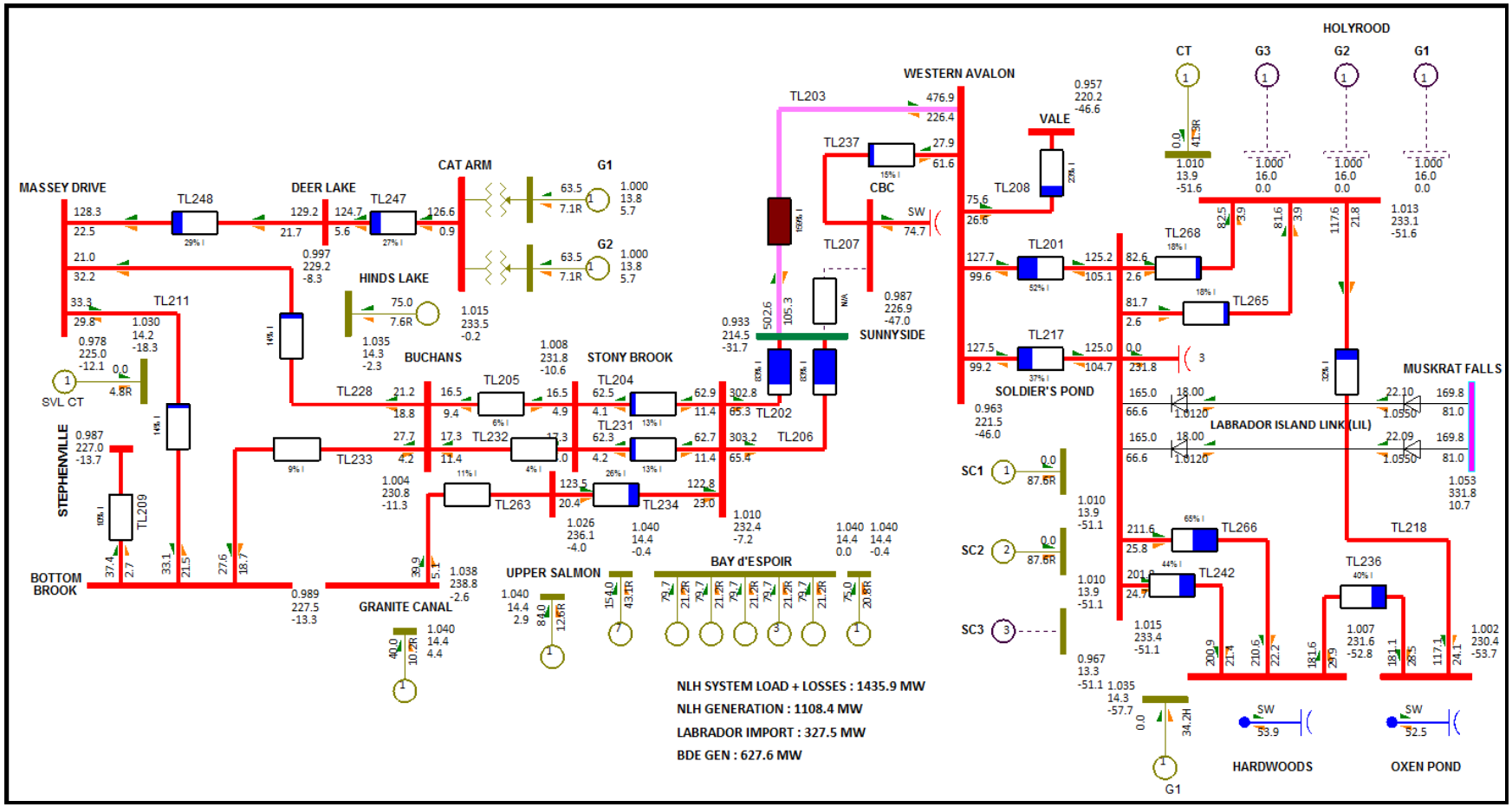


Figure 112 – Base Case 6 (BC6) Load Flow Plot – TL207 Out of Service

TL203 Loaded 159% of Thermal Rating

Existing Bulk 230 kV Transmission System

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

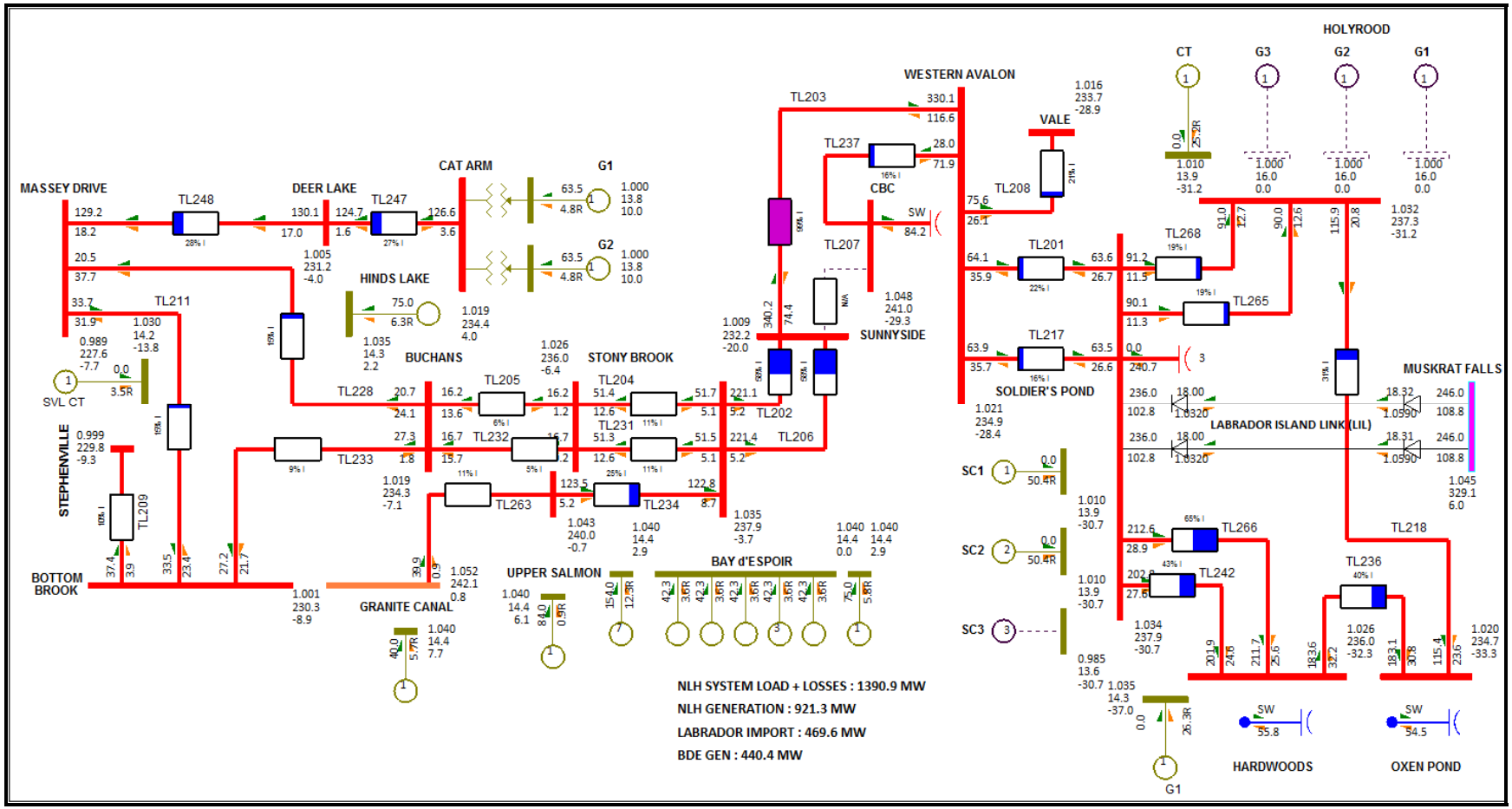


Figure 113 – Base Case 6 (BC6) Load Flow Plot – TL207 Out of Service

TL203 Loaded 99% of Thermal Rating – LIL Import Increased to 472 MW

Existing Bulk 230 kV Transmission System

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

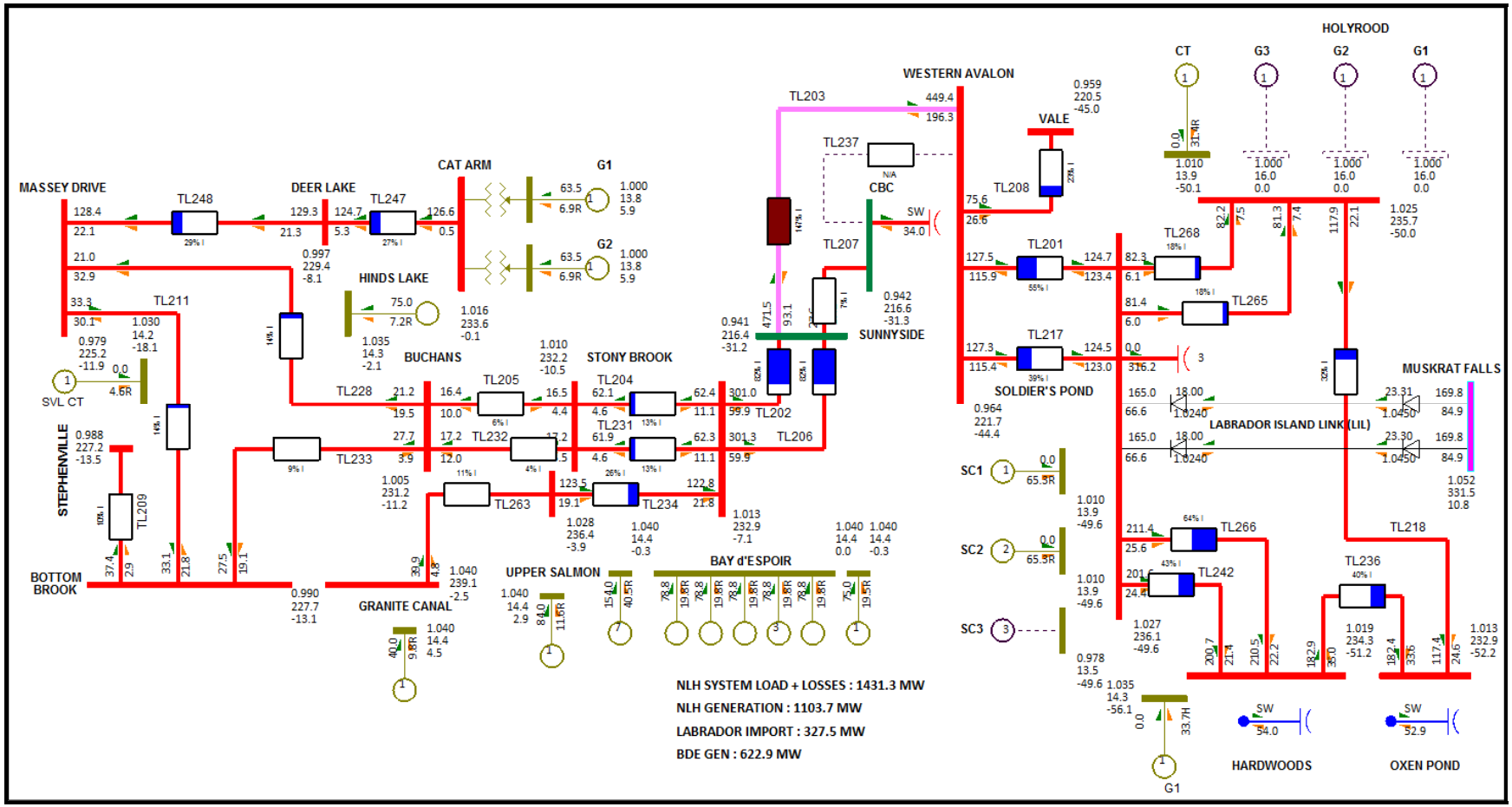


Figure 114 – Base Case 6 (BC6) Load Flow Plot – TL237 Out of Service

TL203 Loaded 147% of Thermal Rating

Existing Bulk 230 kV Transmission System

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

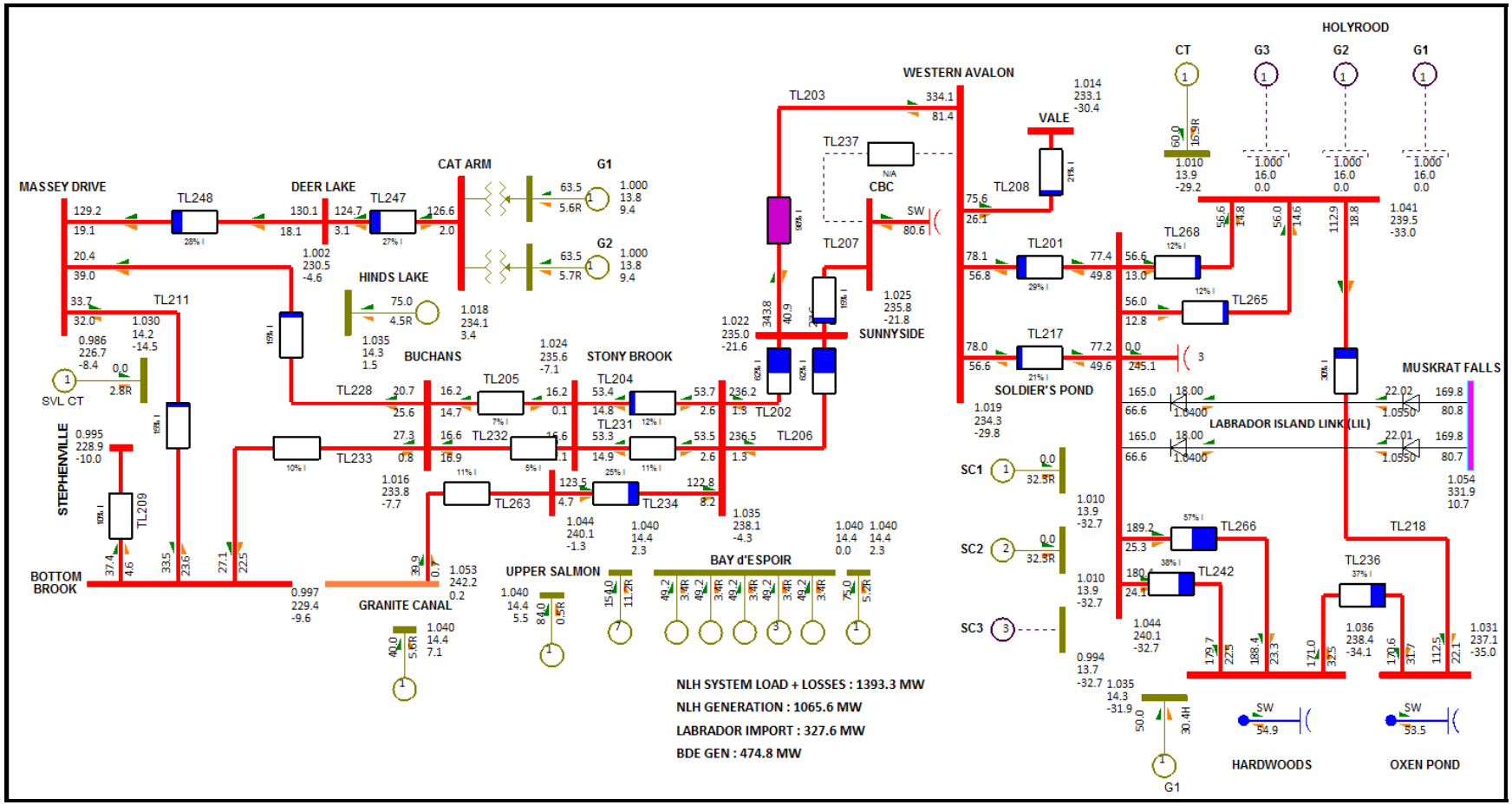


Figure 115 – Base Case 6 (BC6) Load Flow Plot – TL237 Out of Service

TL203 Loaded 98% of Thermal Rating – HWD CT and HRD CT Generating 110 MW

Existing Bulk 230 kV Transmission System

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

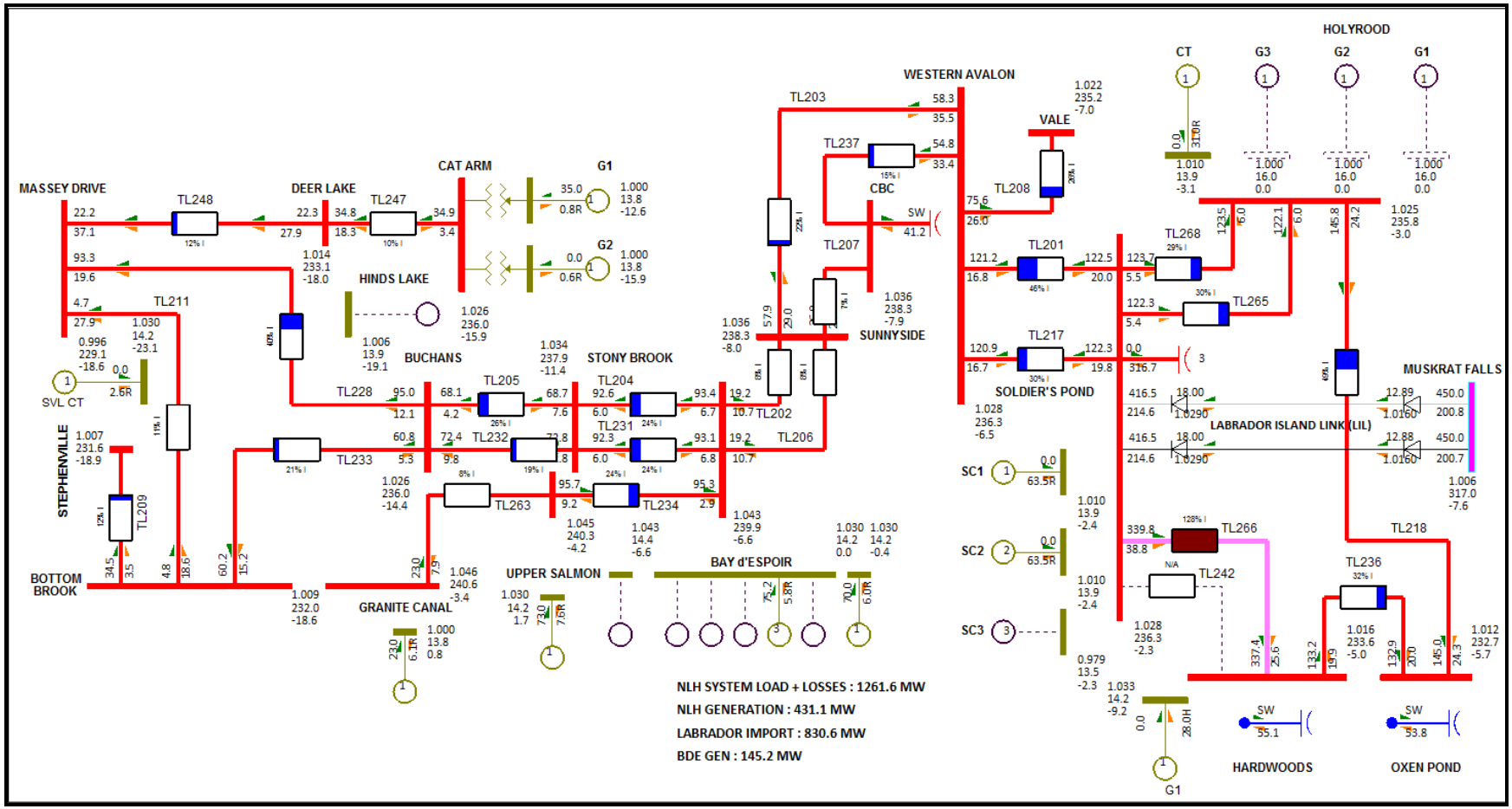


Figure 116 – Base Case 7 (BC7) Load Flow Plot – TL242 Out of Service

TL266 Loaded 128% of Thermal Rating

Existing Bulk 230 kV Transmission System

Spring/Fall Day (1261 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (431 MW)

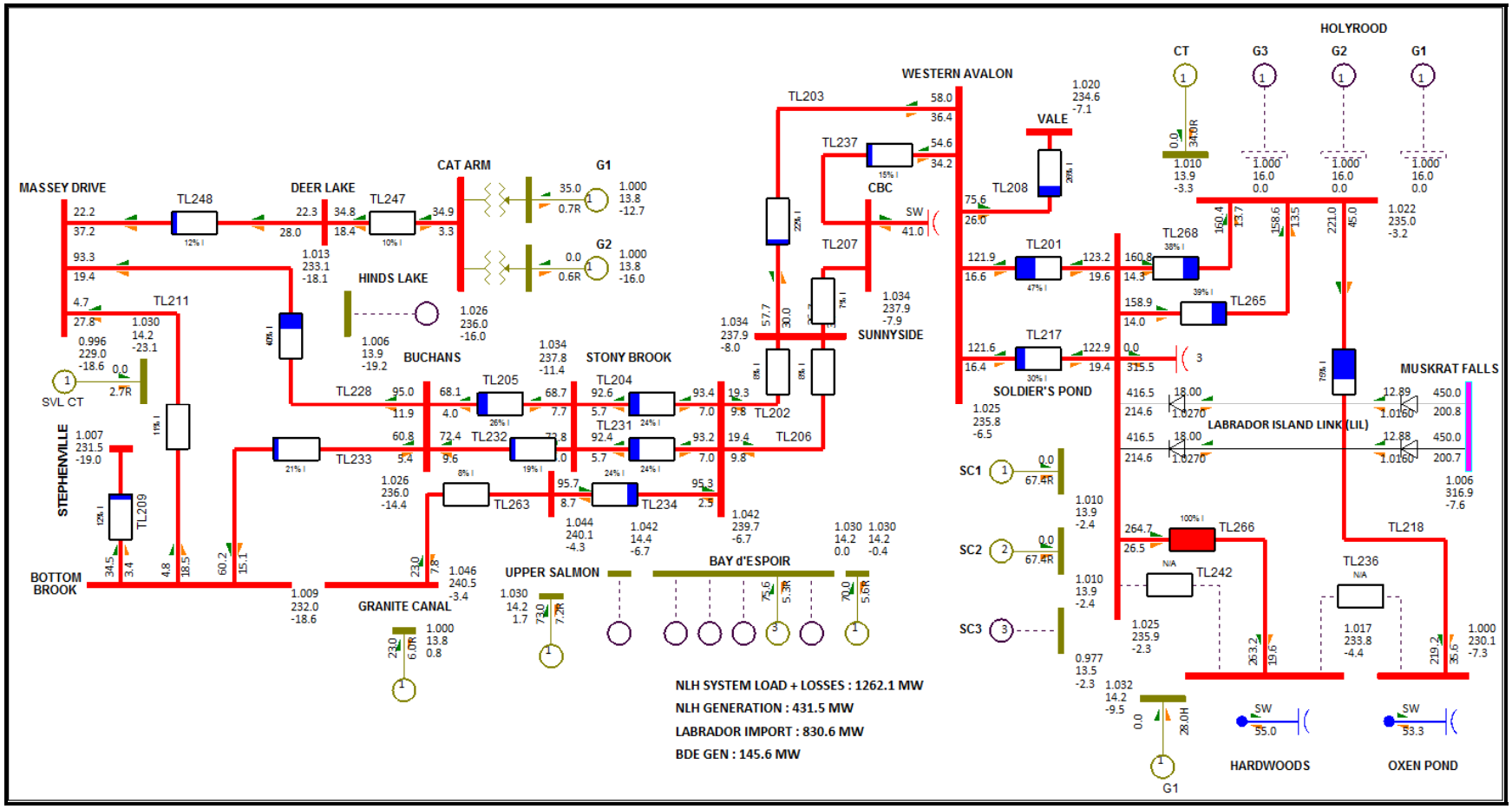


Figure 117 – Base Case 7 (BC7) Load Flow Plot – TL242 Out of Service

TL266 Loaded 100% of Thermal Rating – TL236 Open

Existing Bulk 230 kV Transmission System

Spring/Fall Day (1261 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (431 MW)

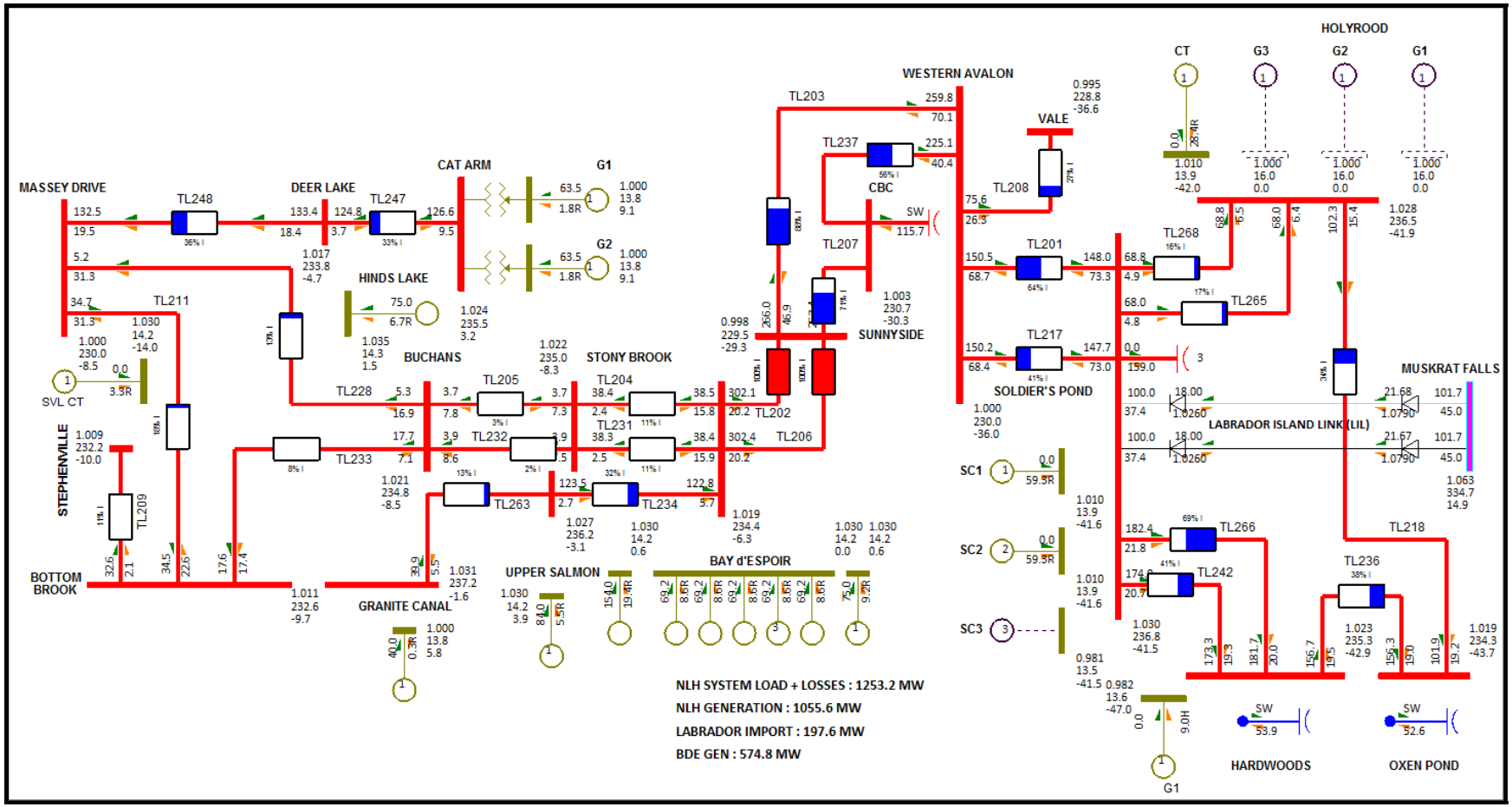


Figure 118 – Base Case 8 (BC8) Load Flow Plot – N-0

TL202/TL206 Loaded 100% of Thermal Rating – LIL Import Increased to 198 MW

Existing Bulk 230 kV Transmission System

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

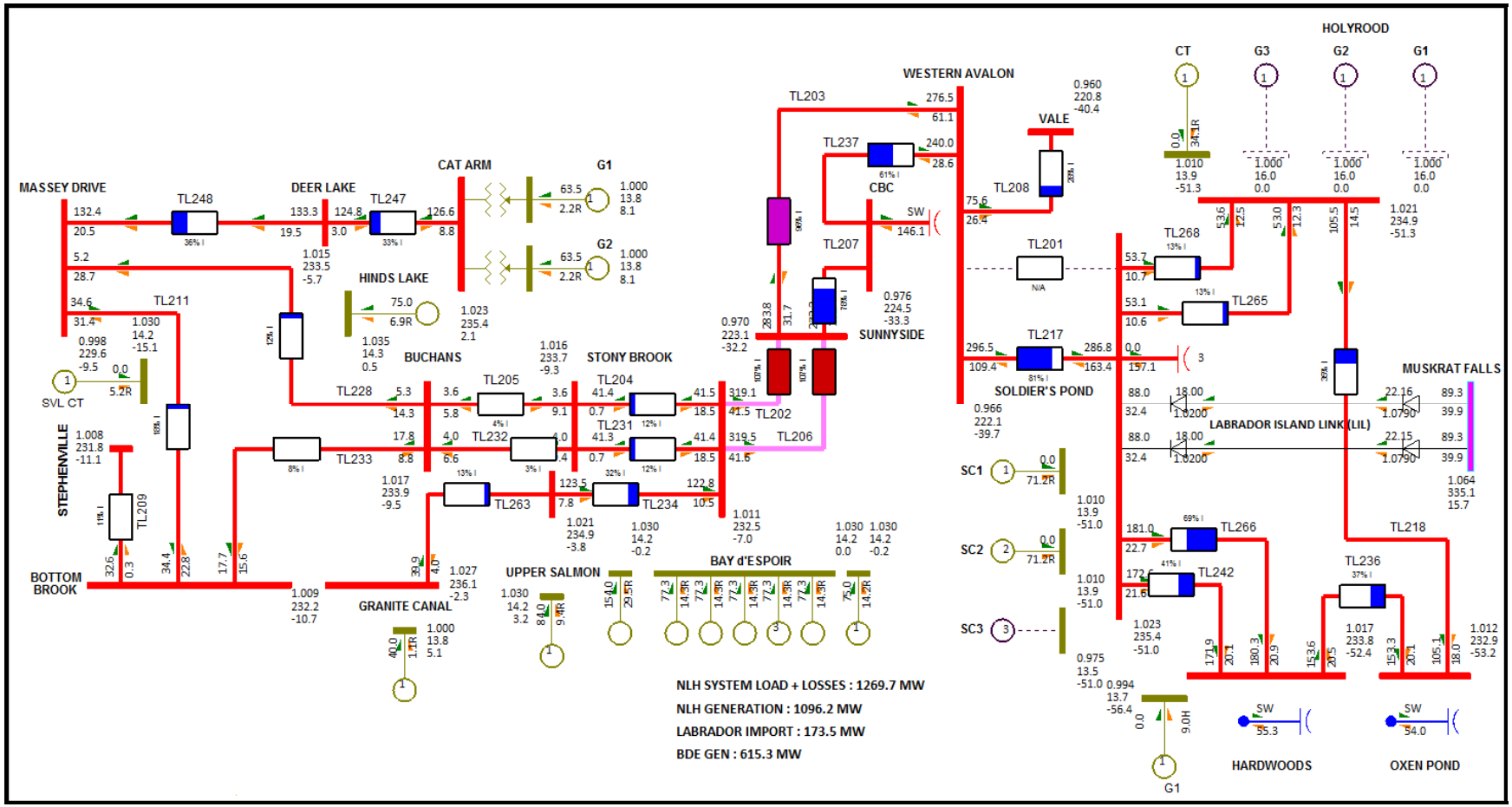


Figure 119 – Base Case 8 (BC8) Load Flow Plot – TL201 Out of Service

TL202/TL206 Loaded 107% of Thermal Rating

Existing Bulk 230 kV Transmission System

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

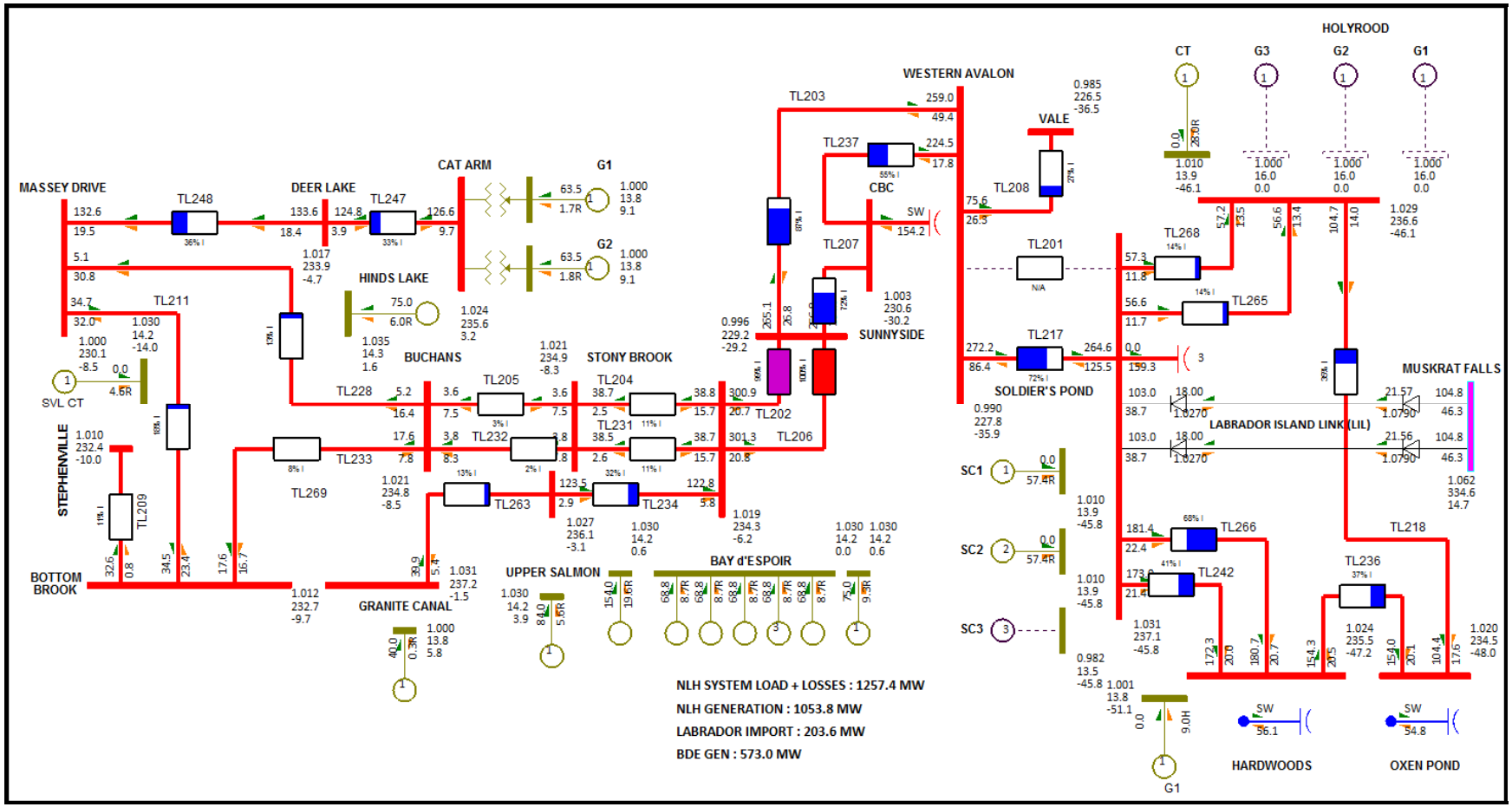


Figure 120 – Base Case 8 (BC8) Load Flow Plot – TL201 Out of Service

TL202/TL206 Loaded 100% of Thermal Rating – LIL Import Increased to 204 MW

Existing Bulk 230 kV Transmission System

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

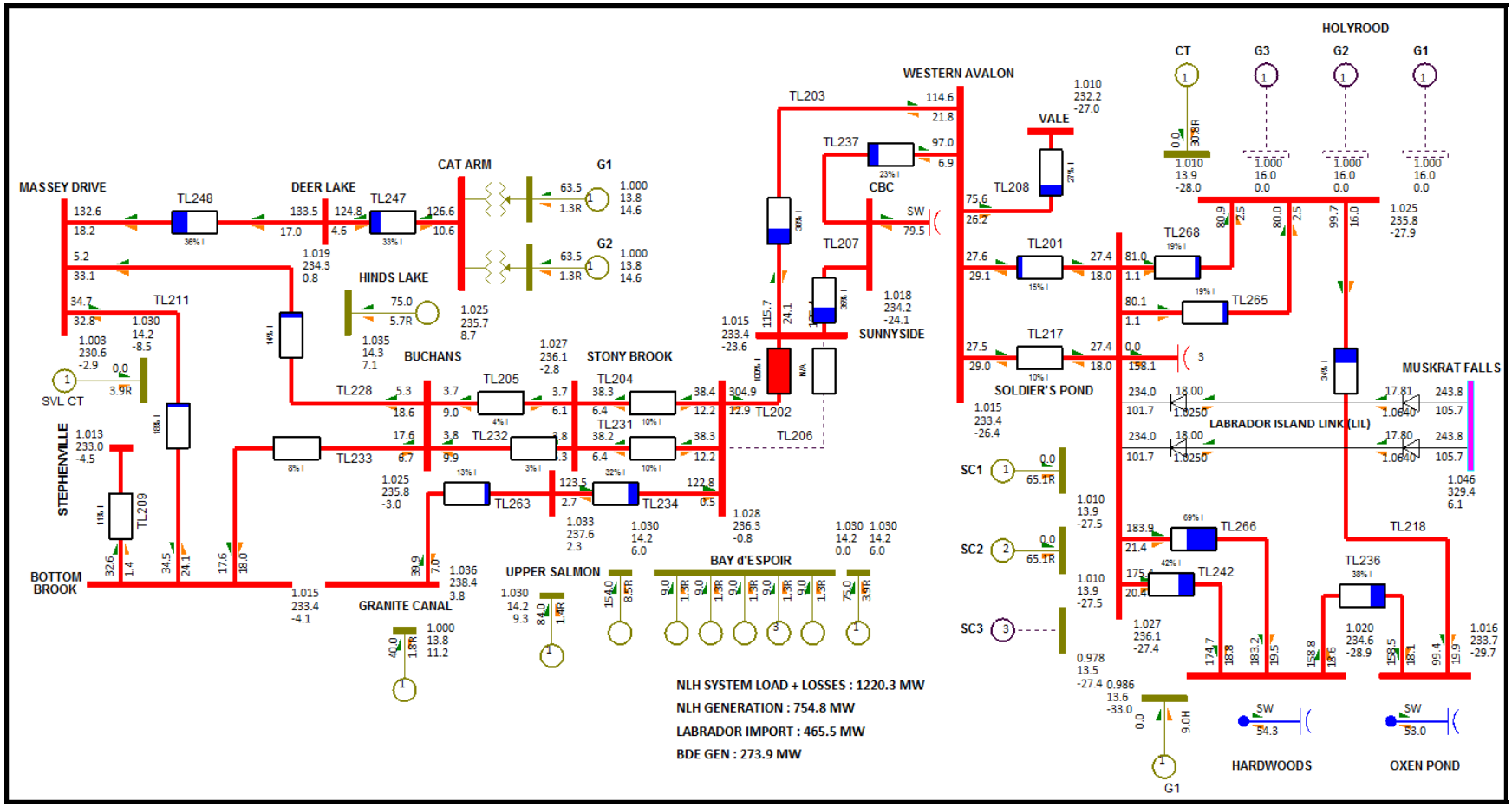


Figure 121 – Base Case 8 (BC8) Load Flow Plot – TL202/TL206 Out of Service

TL202/TL206 Loaded 100% of Thermal Rating – LIL Import Increased to 466 MW

Existing Bulk 230 kV Transmission System

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

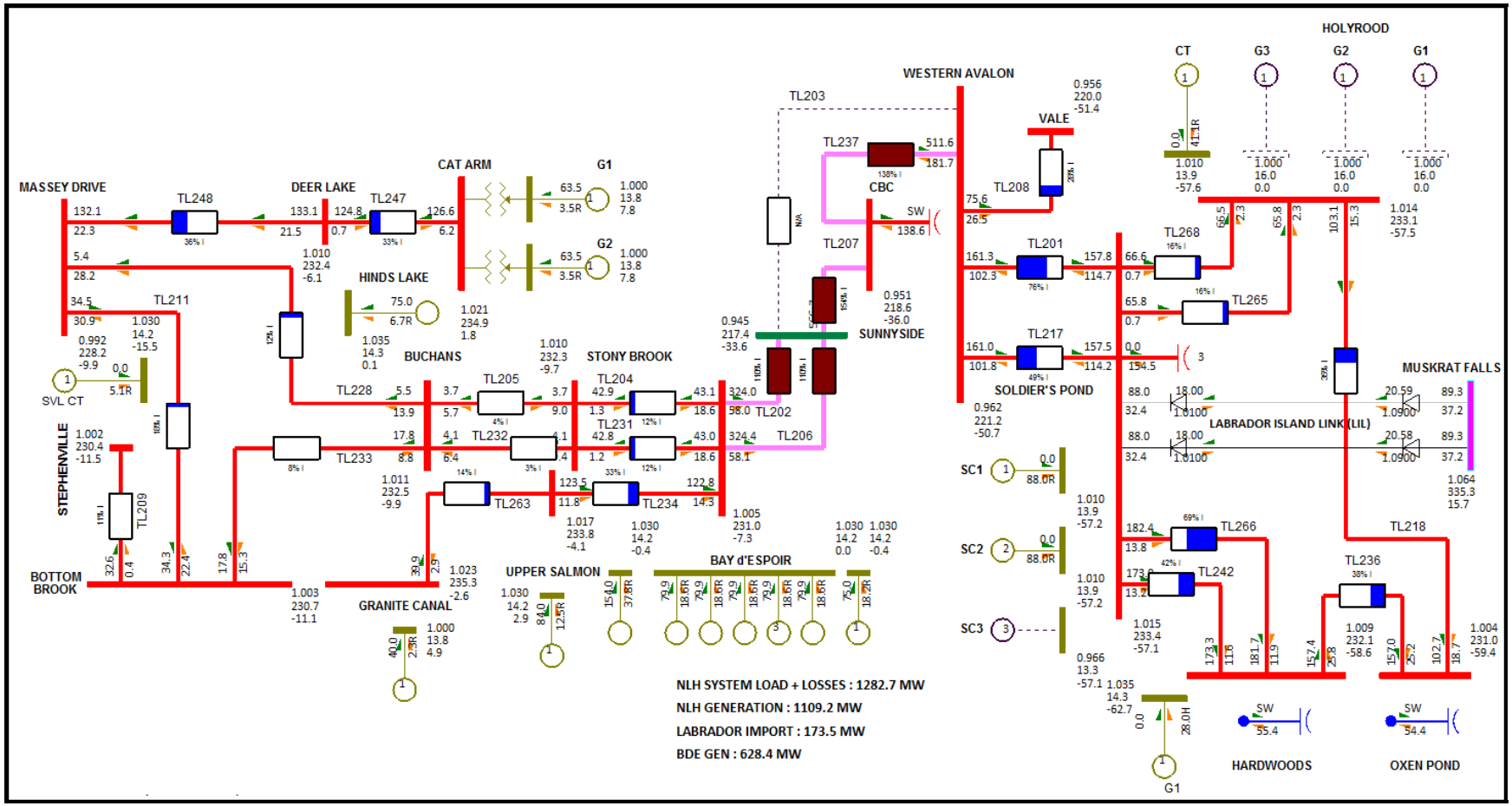


Figure 122 – Base Case 8 (BC8) Load Flow Plot – TL203 Out of Service

TL202/TL206/TL207/TL237 Loaded to 110/110/154/138% of Thermal Rating

Existing Bulk 230 kV Transmission System

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

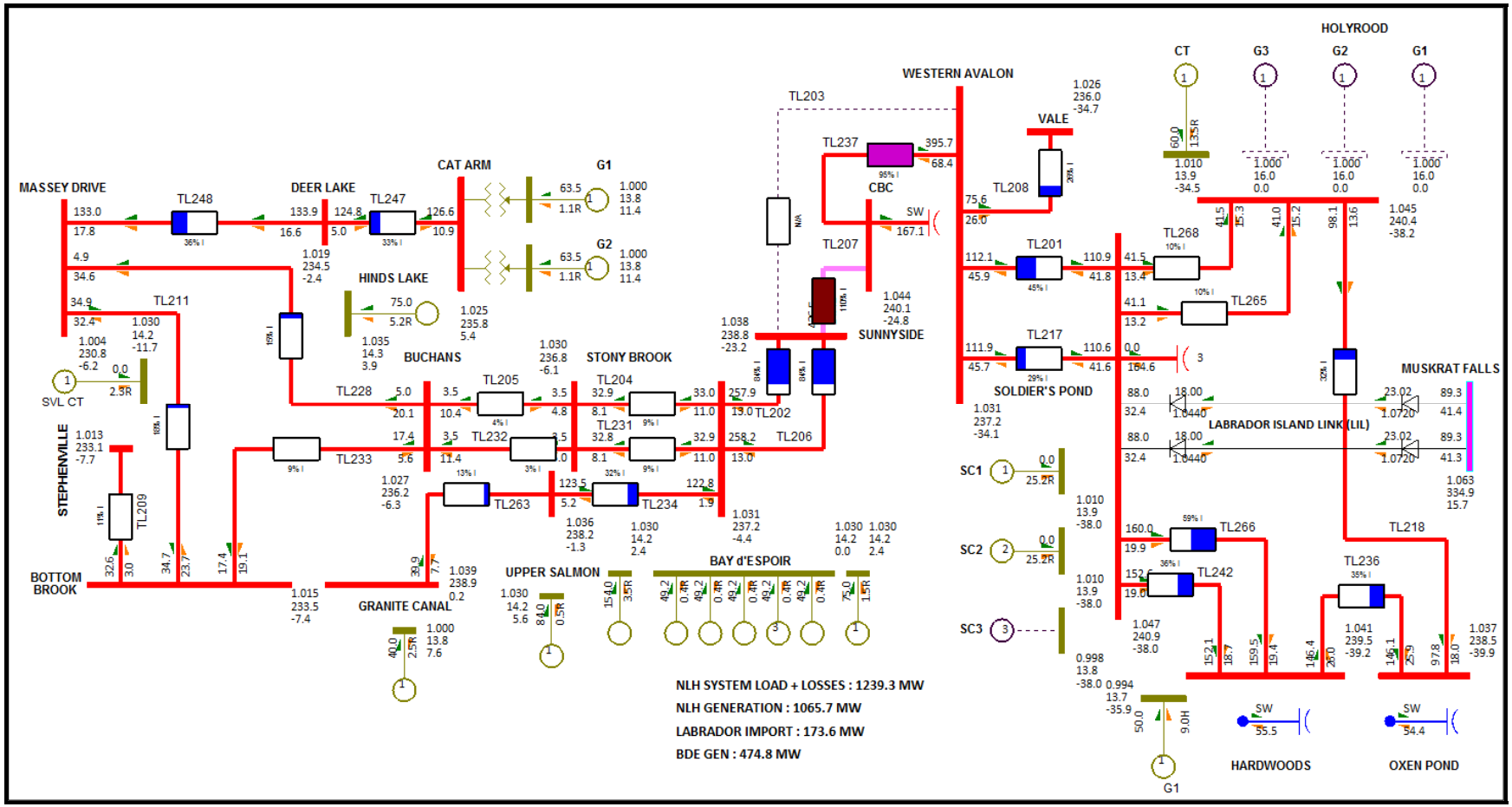


Figure 123 – Base Case 8 (BC8) Load Flow Plot – TL203 Out of Service

TL207 Loaded 110% of Thermal Rating – HWD CT and HRD CT generating 110 MW

Existing Bulk 230 kV Transmission System

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

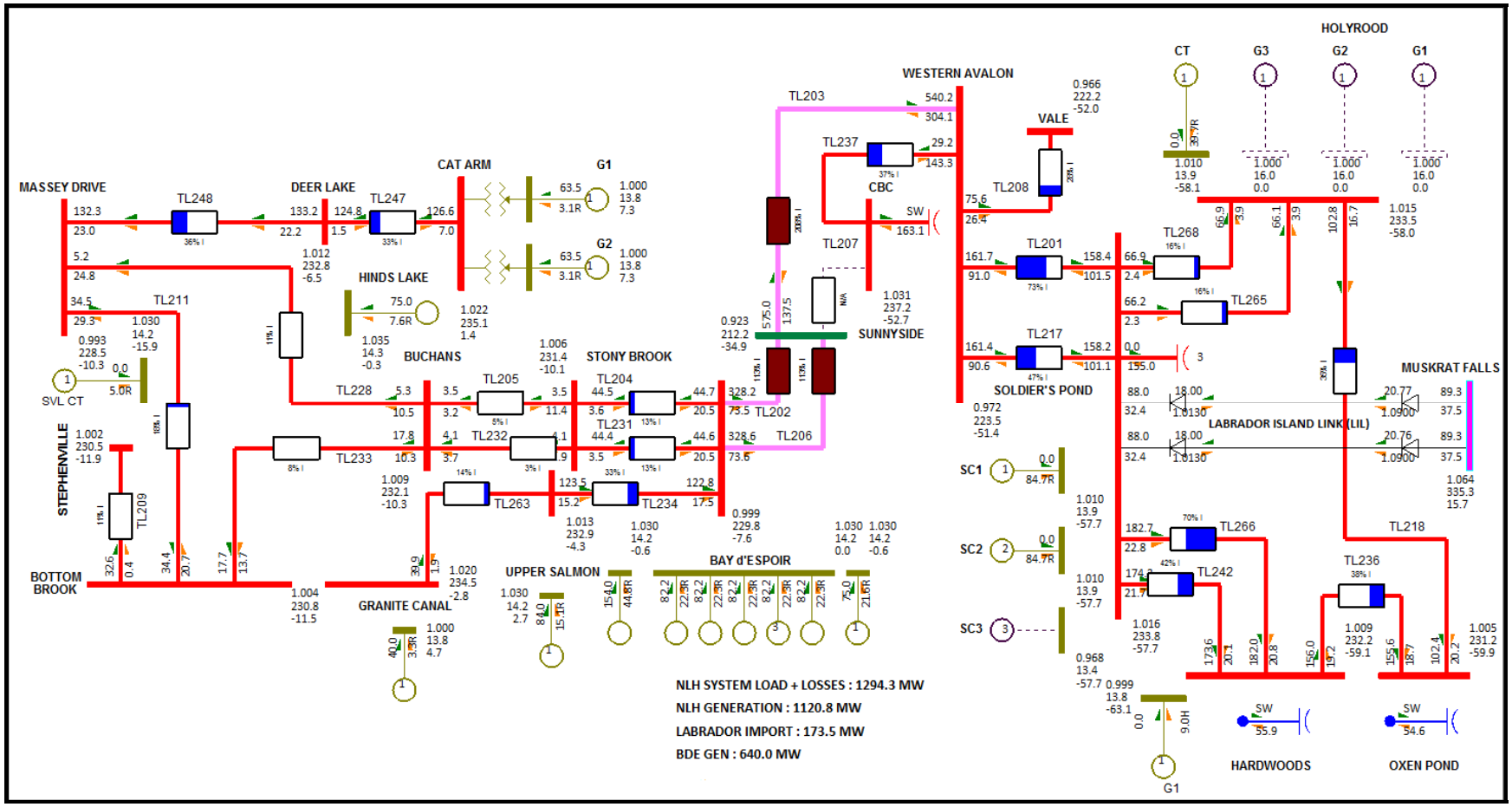


Figure 124 – Base Case 8 (BC8) Load Flow Plot – TL207 Out of Service

TL203/TL202/TL206 Loaded 208/113/113% of Thermal Rating

Existing Bulk 230 kV Transmission System

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

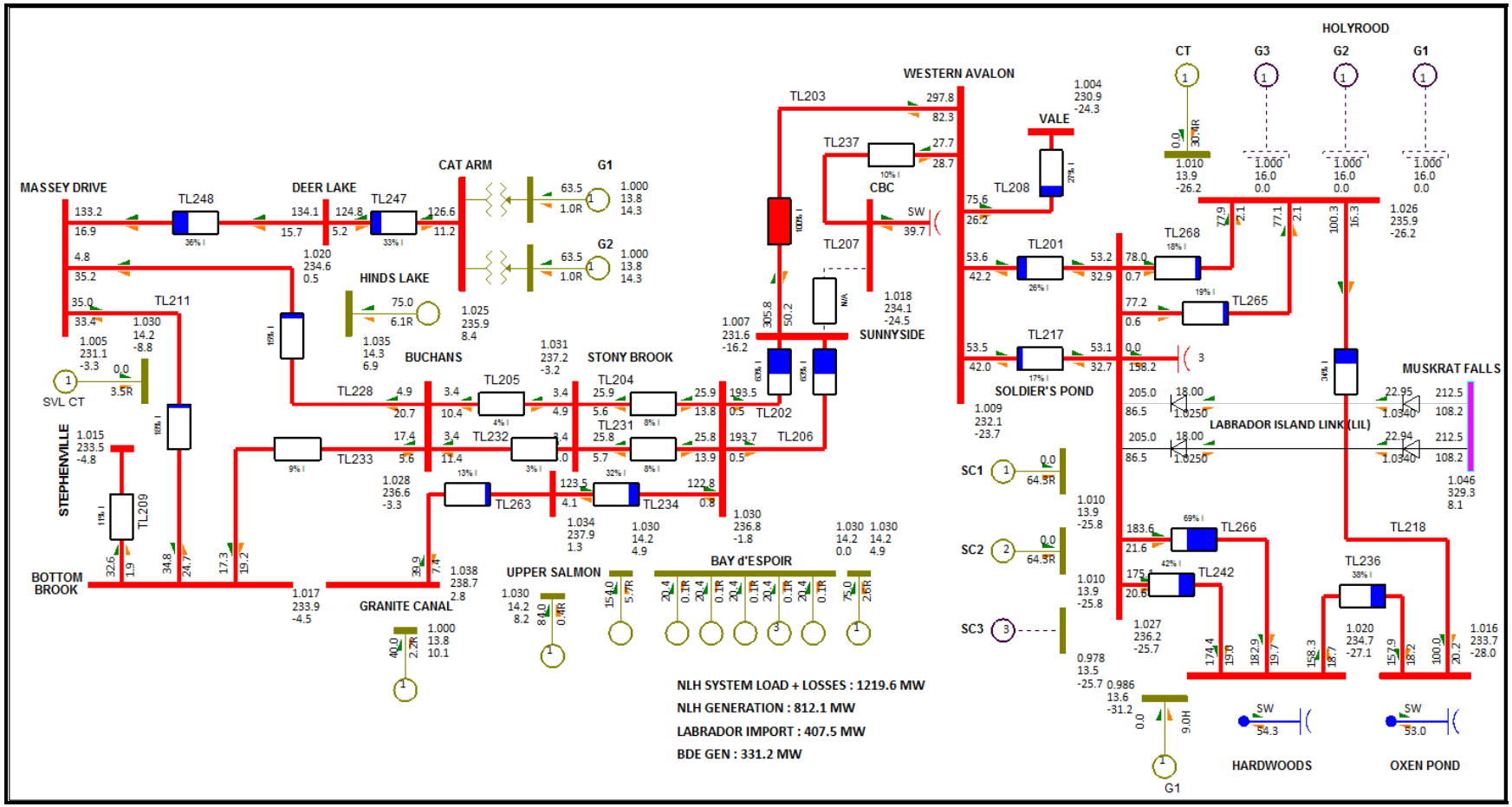


Figure 125 – Base Case 8 (BC8) Load Flow Plot – TL207 Out of Service

TL203 Loaded 100% of Thermal Rating – LIL Import Increased to 408 MW

Existing Bulk 230 kV Transmission System

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

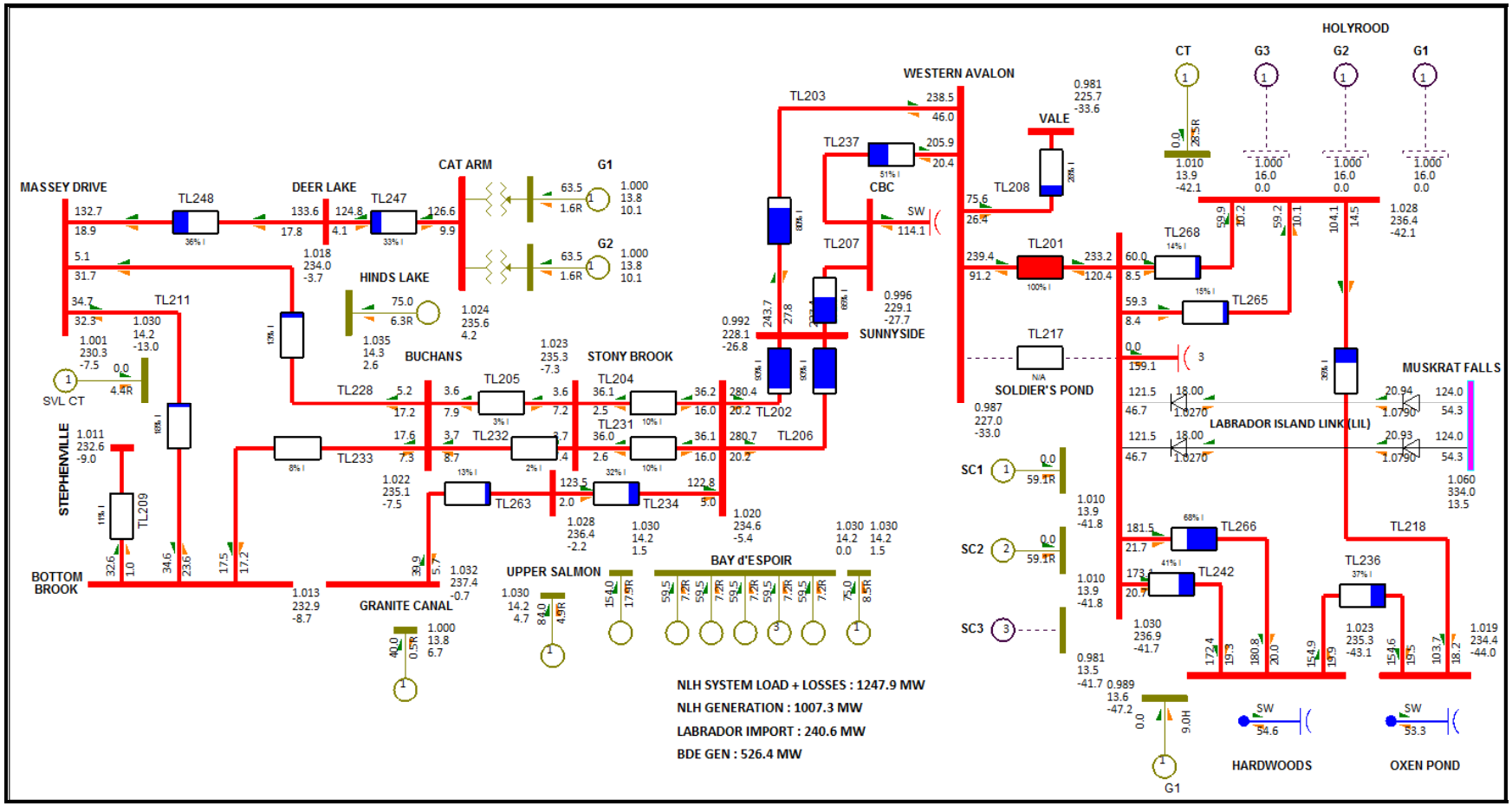


Figure 126 – Base Case 8 (BC8) Load Flow Plot – TL217 Out of Service

TL201 Loaded 100% of Thermal Rating – LIL Import Increased to 241 MW

Existing Bulk 230 kV Transmission System

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

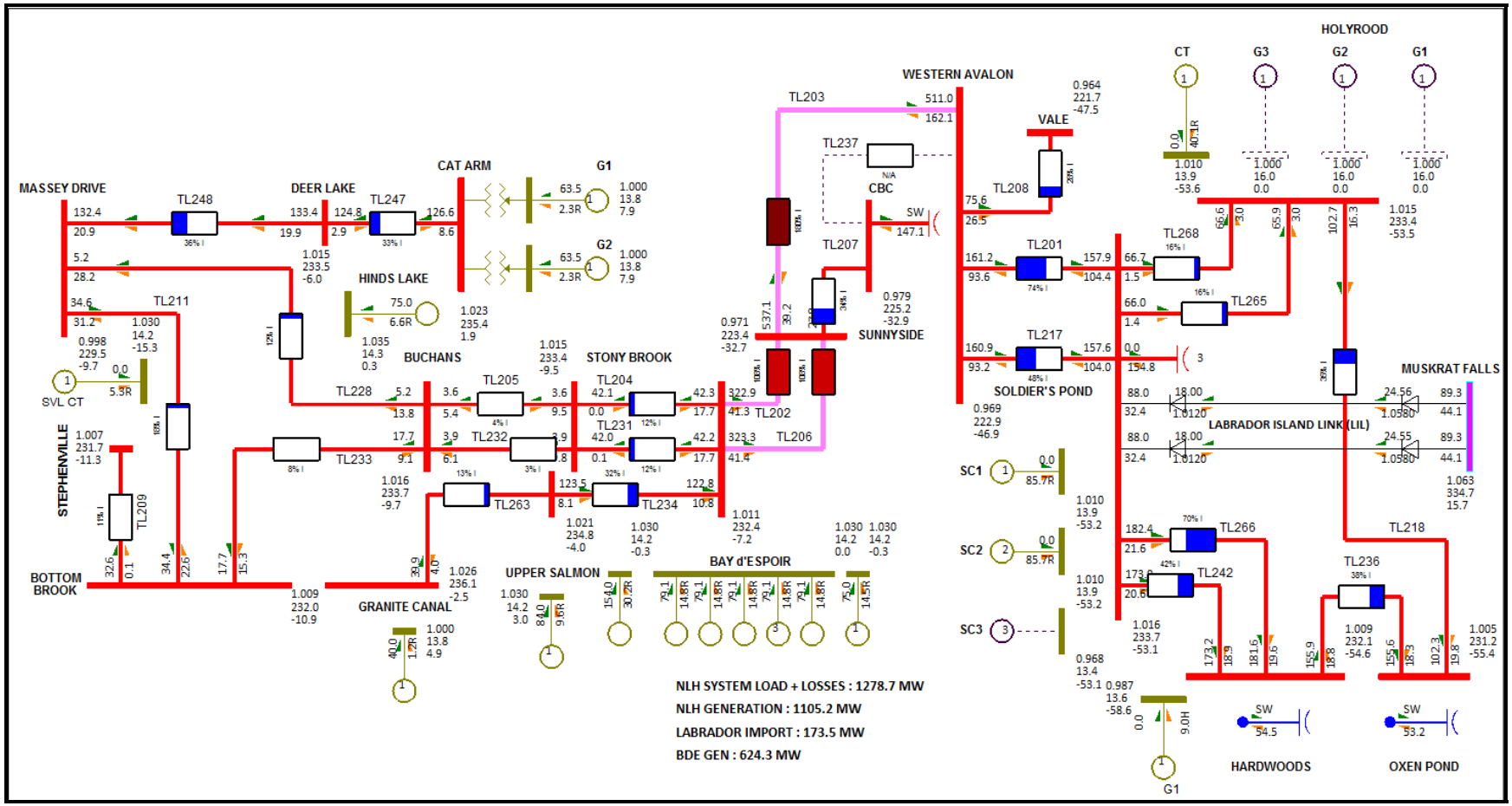


Figure 127 – Base Case 8 (BC8) Load Flow Plot – TL237 Out of Service

TL202/TL206/TL203 Loaded 106/106/180% of Thermal Rating

Existing Bulk 230 kV Transmission System

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

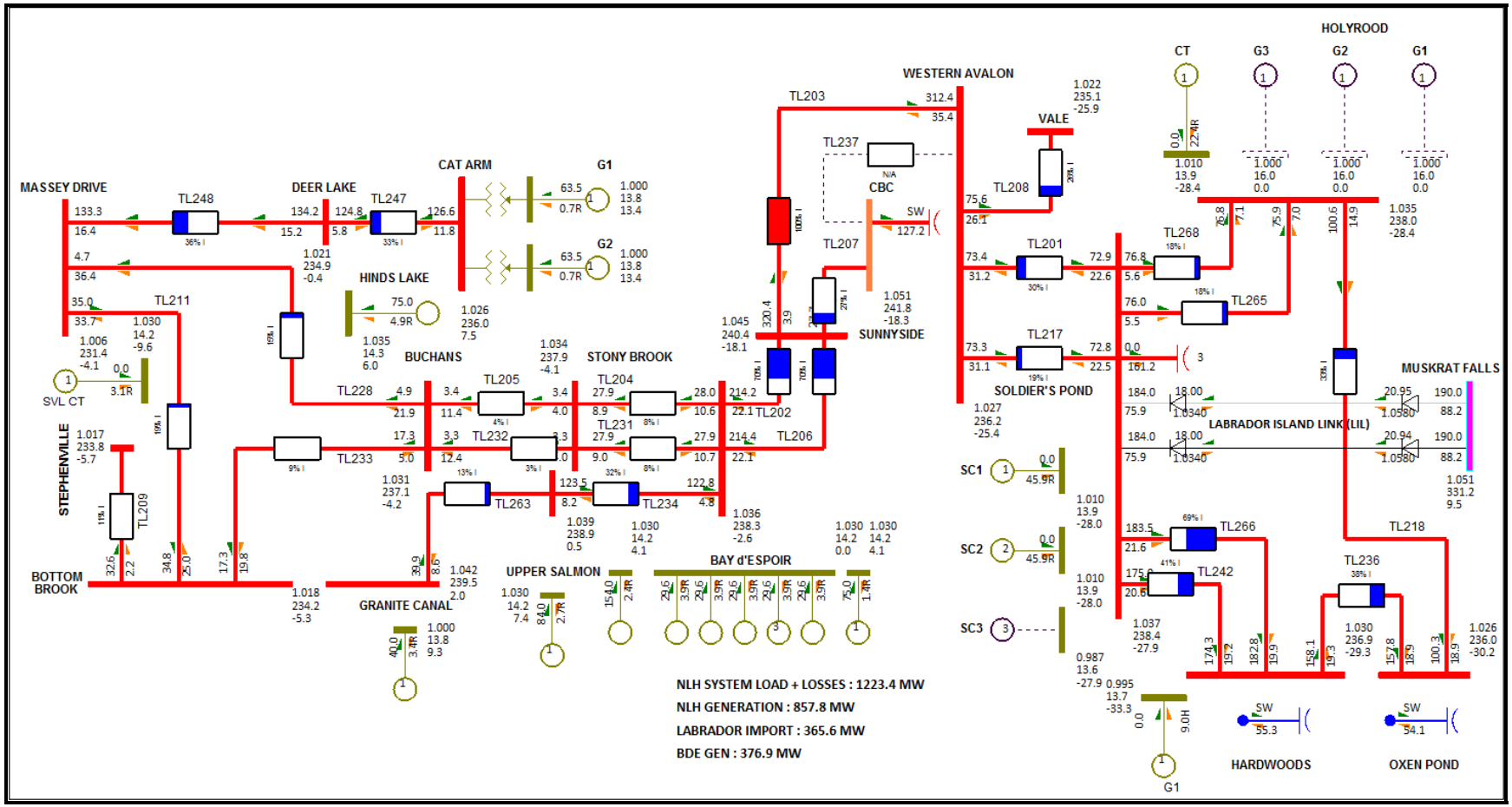


Figure 128 – Base Case 8 (BC8) Load Flow Plot – TL237 Out of Service

TL203 Loaded 100% of Thermal Rating – LIL Import Increased to 366 MW

Existing Bulk 230 kV Transmission System

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

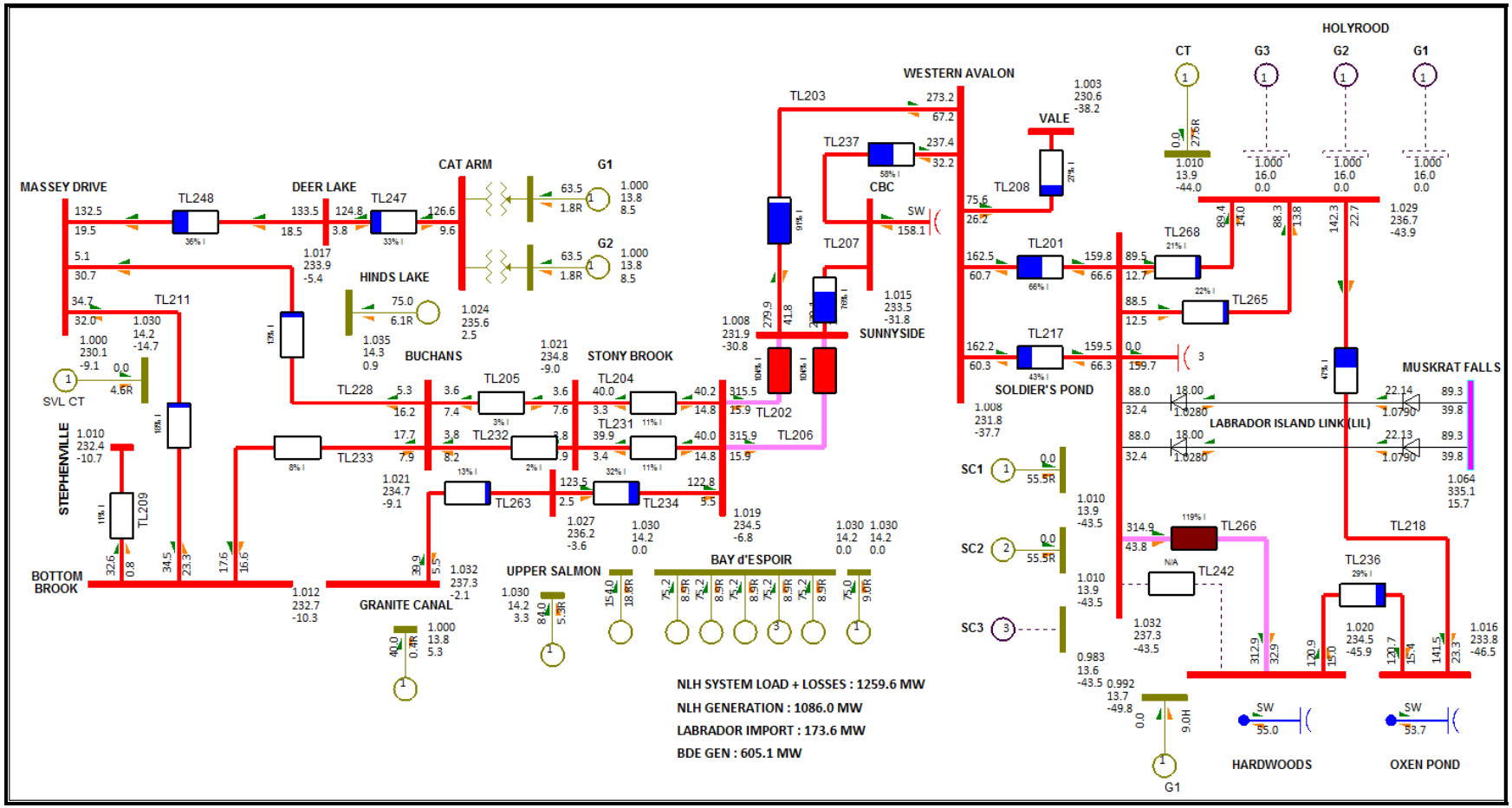


Figure 129 – Base Case 8 (BC8) Load Flow Plot – TL242 Out of Service

TL266 Loaded 119% of Thermal Rating

Existing Bulk 230 kV Transmission System

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

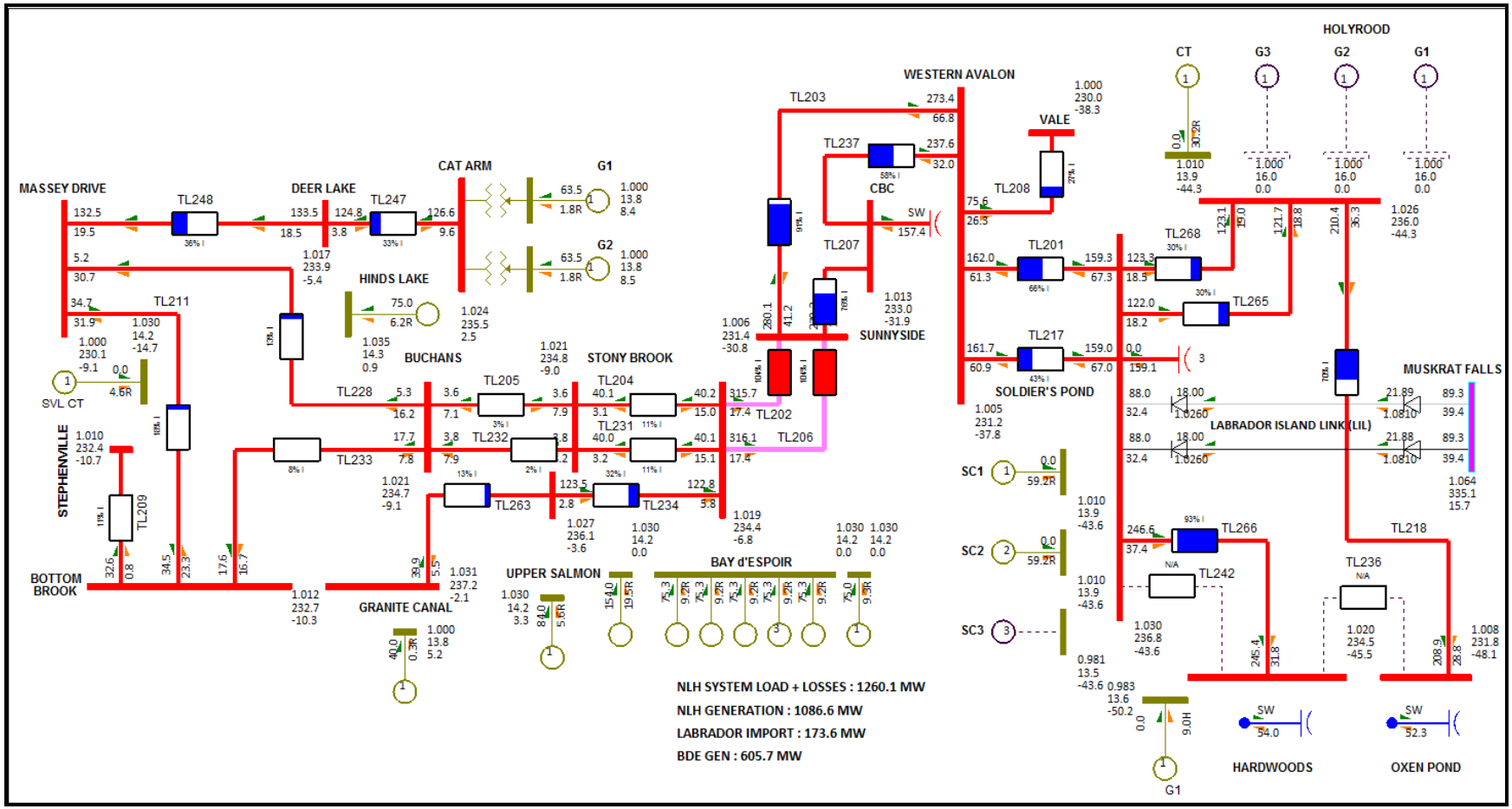


Figure 130 – Base Case 8 (BC8) Load Flow Plot – TL242 Out of Service

TL266 Loaded 93% of Thermal Rating – TL236 Open

Existing Bulk 230 kV Transmission System

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

Alternative 2

Build New 230 kV Transmission Line between BDE and WAV

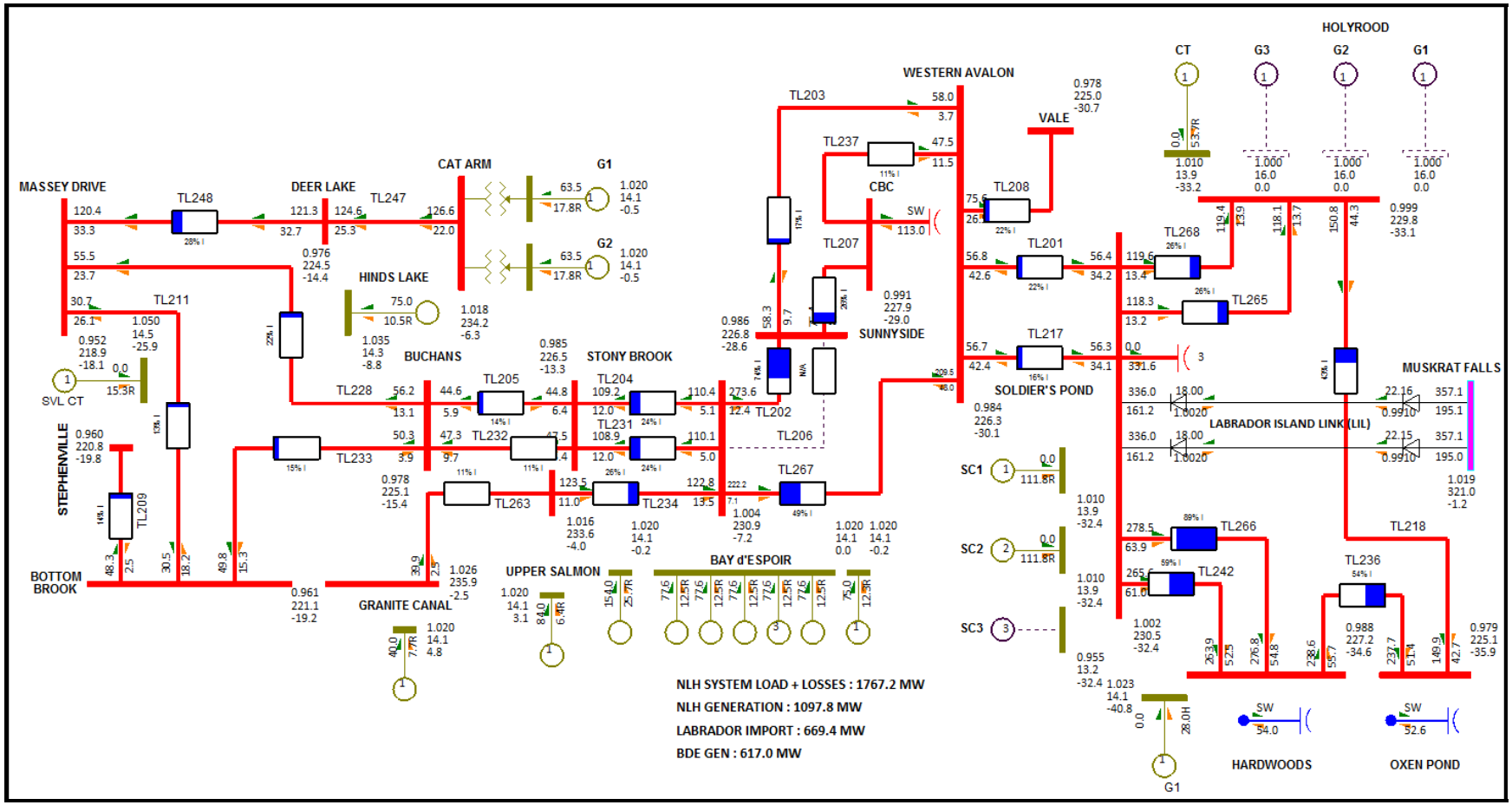


Figure 131 – Base Case 1 (BC1) Load Flow Plot – TL206 Out of Service

TL202 Loaded 74% of Thermal Rating

New 230 kV Transmission Line Installed Between BDE and WAV

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

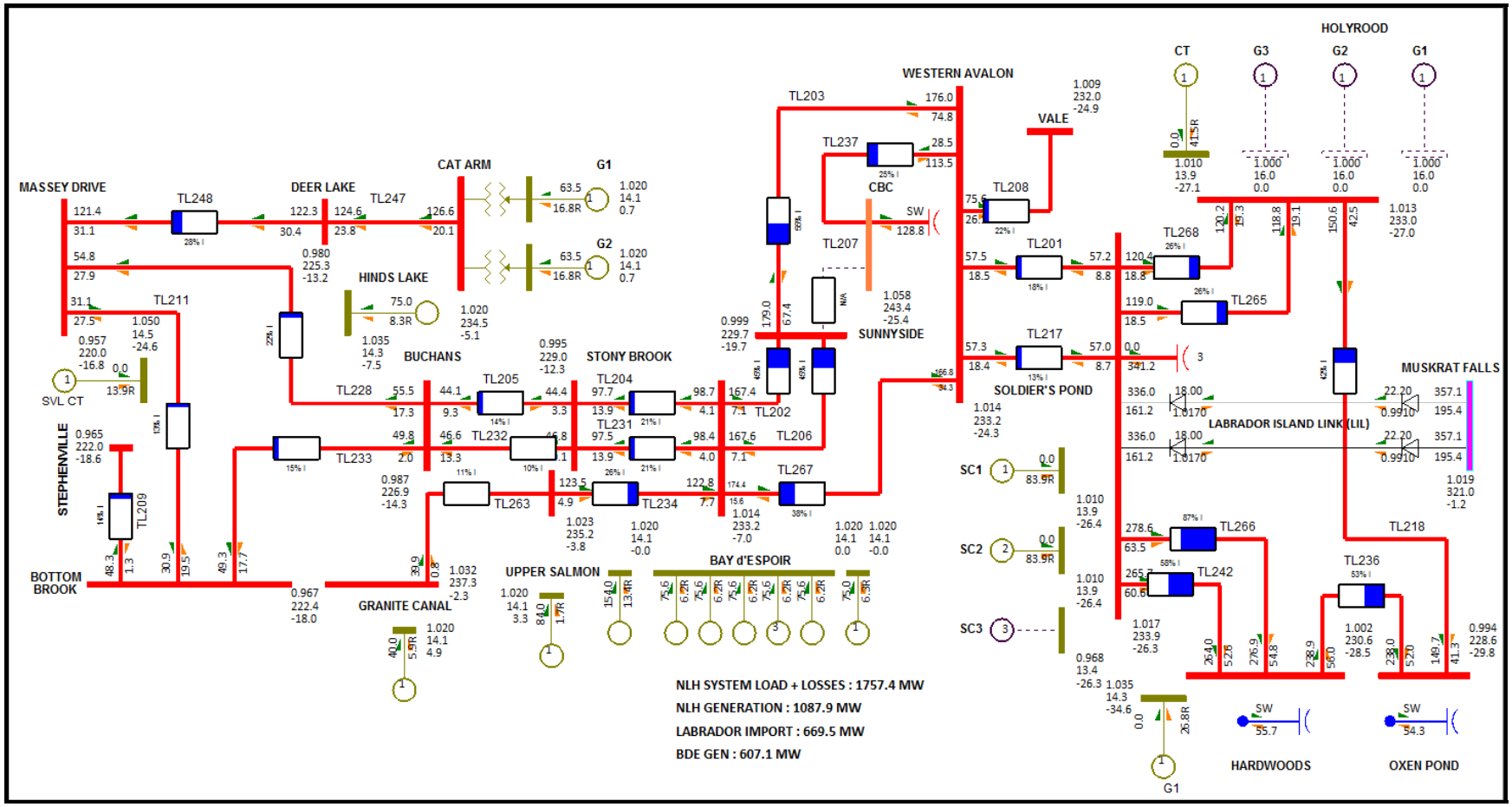


Figure 132 – Base Case 1 (BC1) Load Flow Plot – TL207 Out of Service

New 230 kV Transmission Line Installed Between BDE and WAV

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

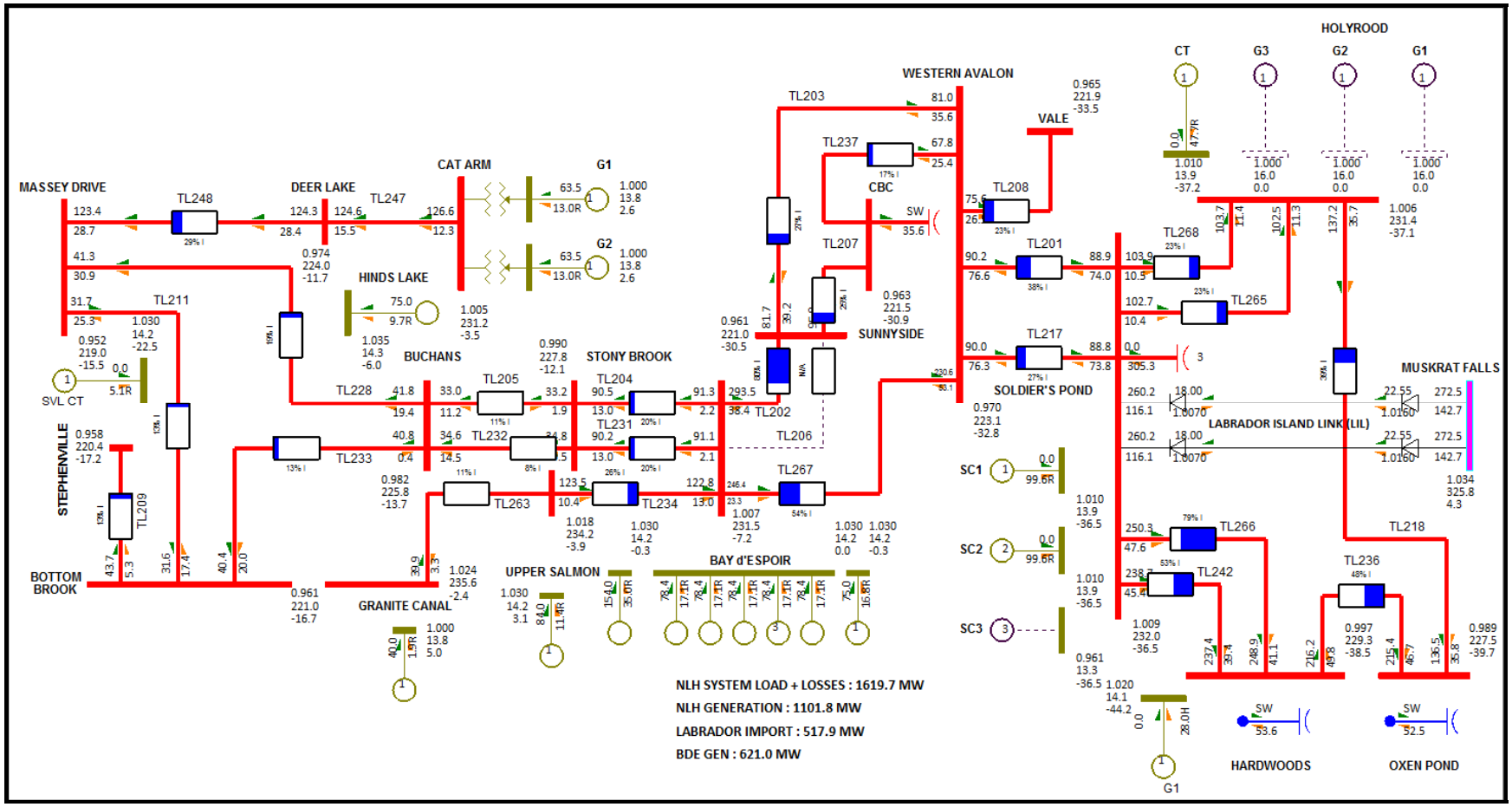


Figure 133 – Base Case 3 (BC3) Load Flow Plot – TL206 Out of Service

New 230 kV Transmission Line Installed Between BDE and WAV

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

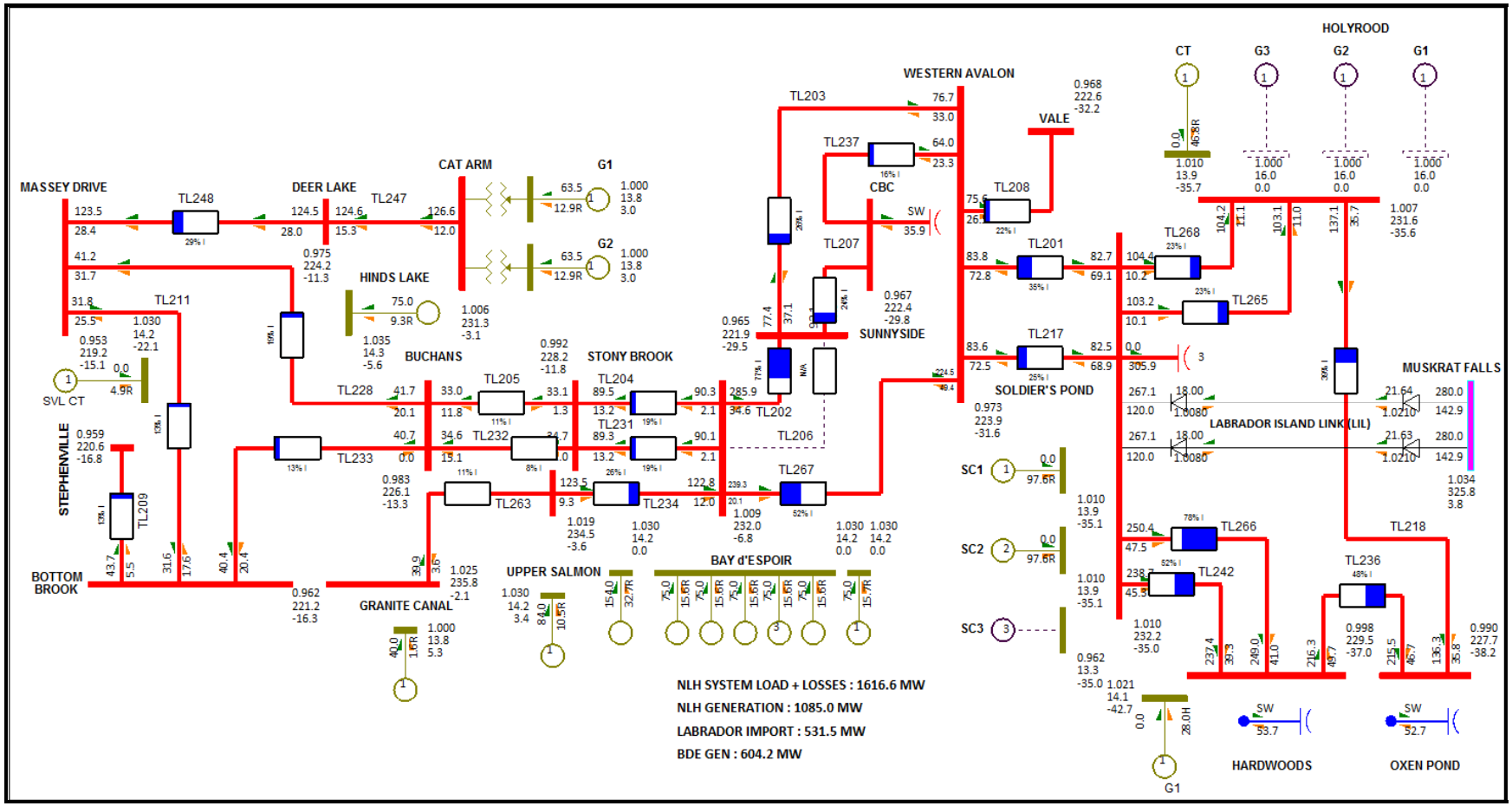


Figure 134 – Base Case 3 (BC3) Load Flow Plot – TL206 Out of Service – LIL Increased to 532 MW

New 230 kV Transmission Line Installed Between BDE and WAV

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

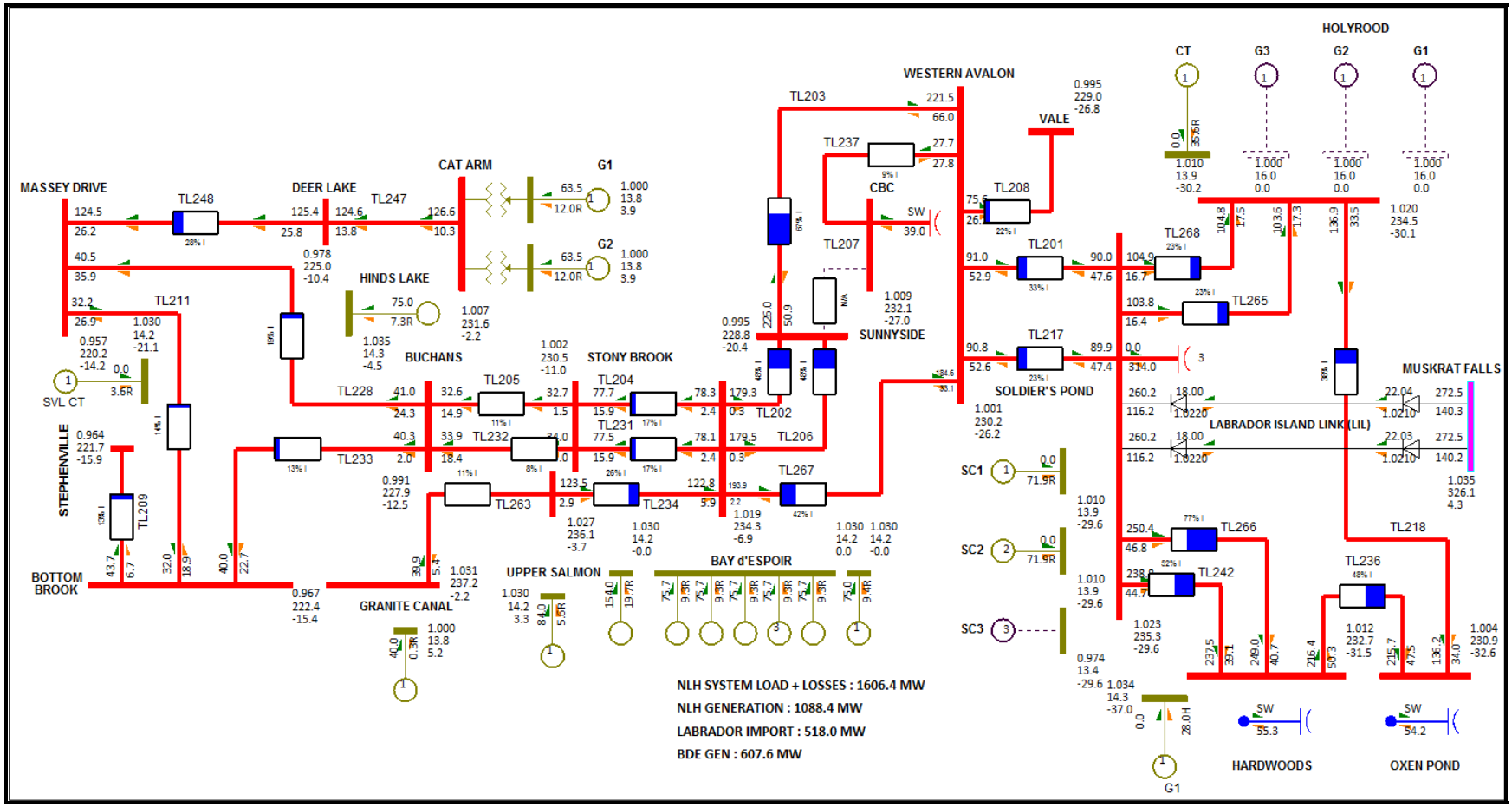


Figure 135 – Base Case 3 (BC3) Load Flow Plot – TL207 Out of Service

New 230 kV Transmission Line Installed Between BDE and WAV

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

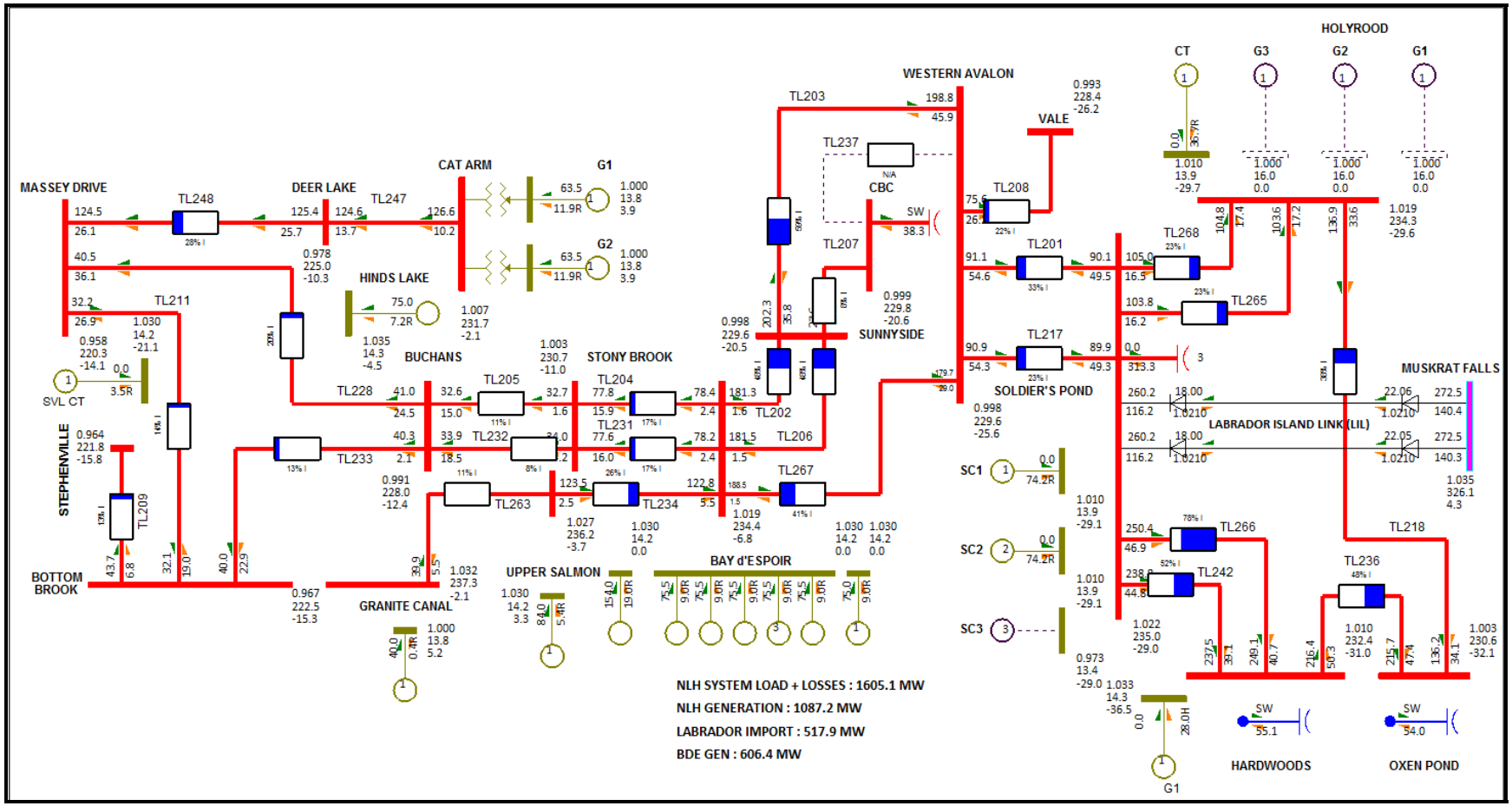


Figure 136 – Base Case 3 (BC3) Load Flow Plot – TL237 Out of Service

New 230 kV Transmission Line Installed Between BDE and WAV

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

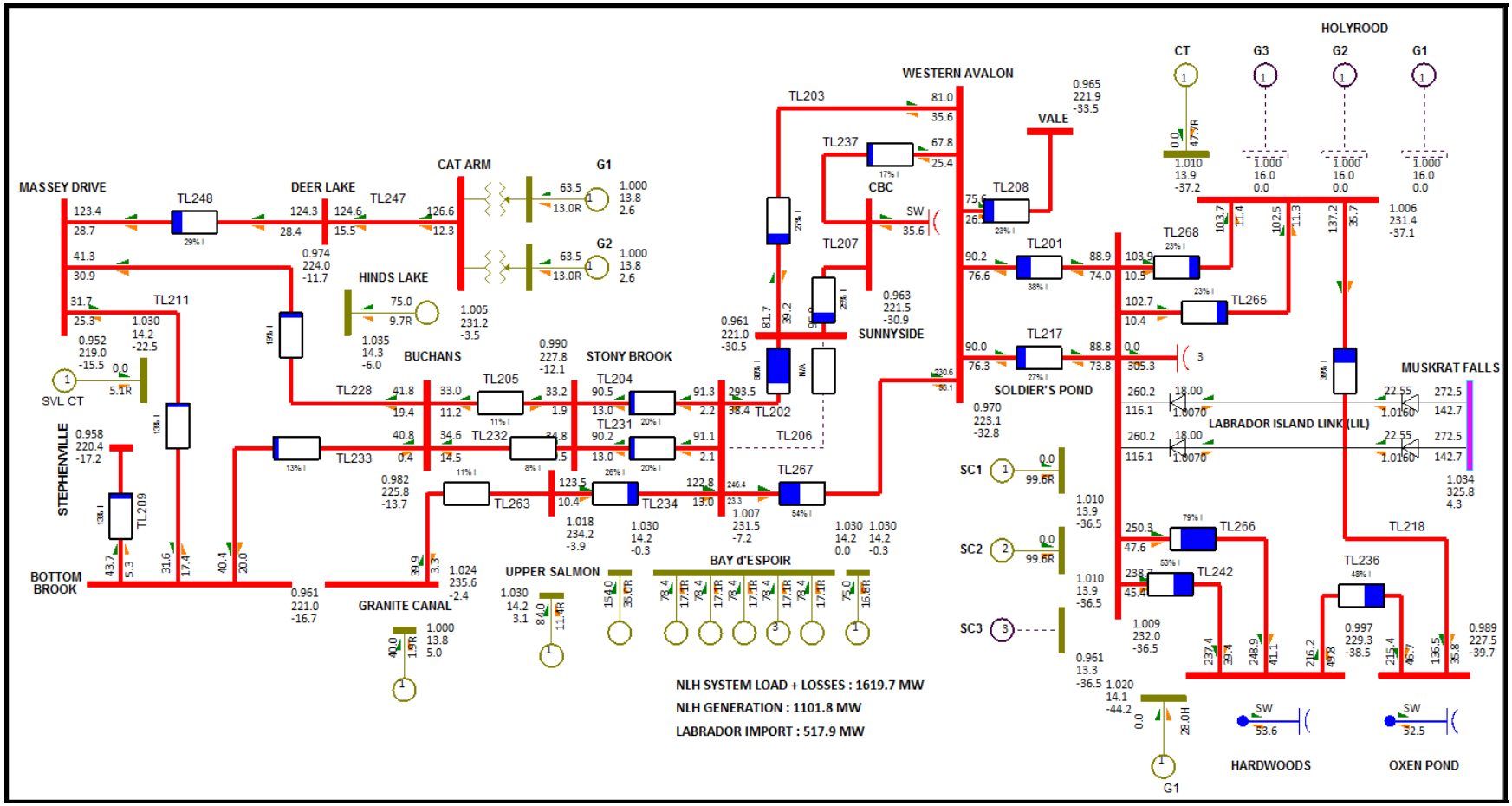


Figure 137 – Base Case 4 (BC4) Load Flow Plot – TL206 Out of Service

New 230 kV Transmission Line Installed Between BDE and WAV

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

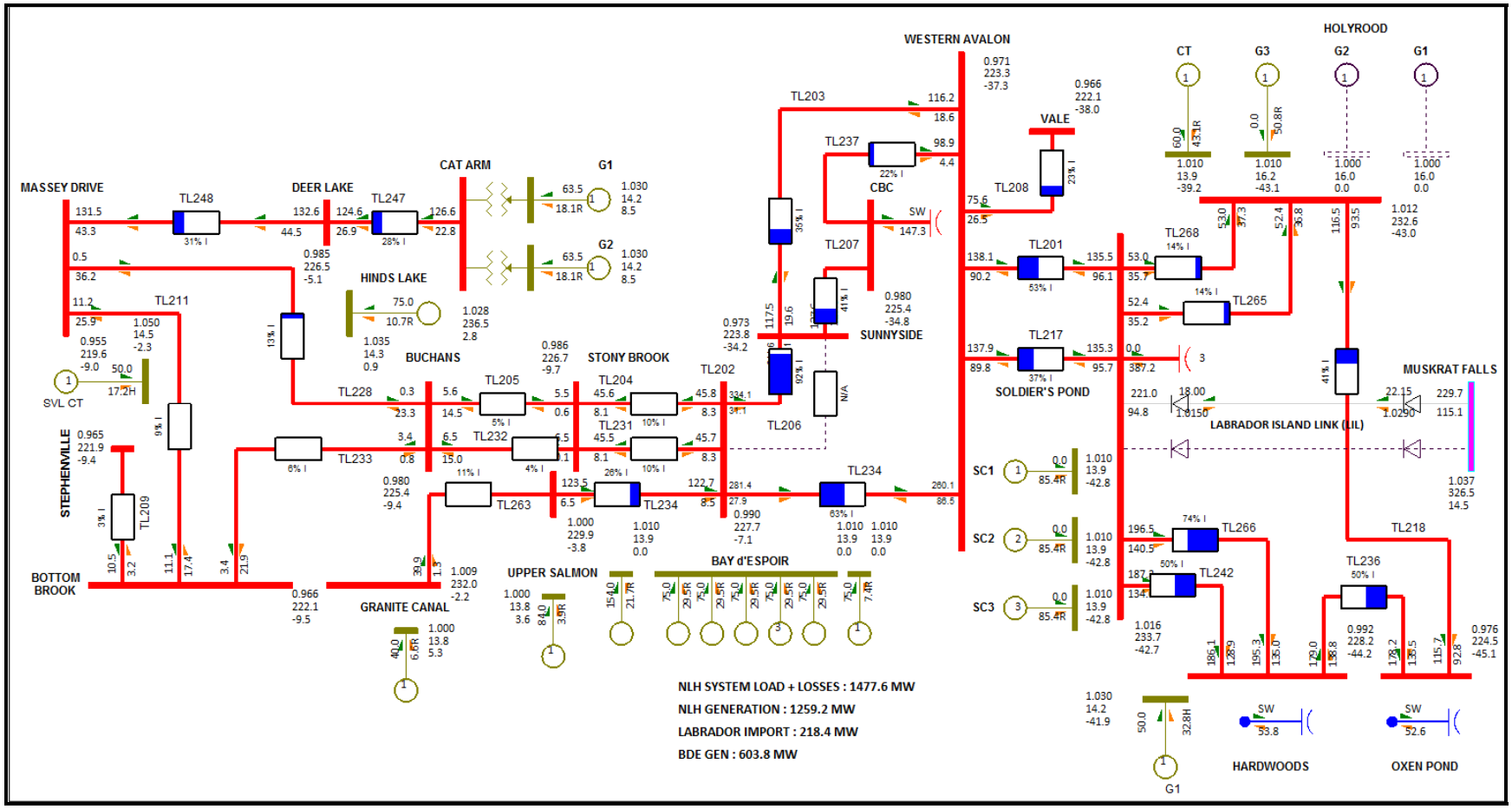


Figure 138 – Base Case 4 (BC4) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 218 MW

New 230 kV Transmission Line Installed Between BDE and WAV

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

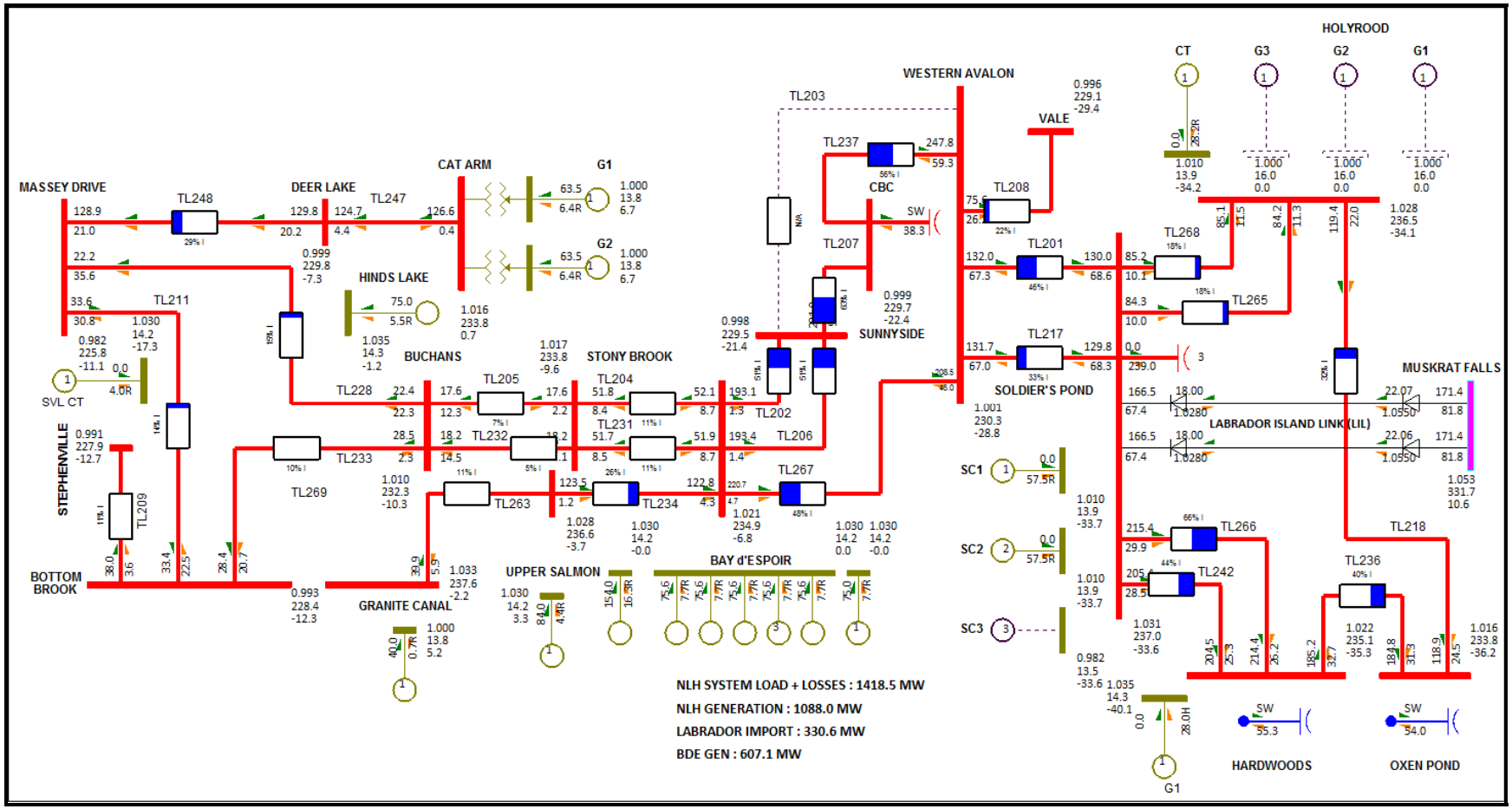


Figure 139 – Base Case 6 (BC6) Load Flow Plot – TL203 Out of Service

New 230 kV Transmission Line Installed Between BDE and WAV

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

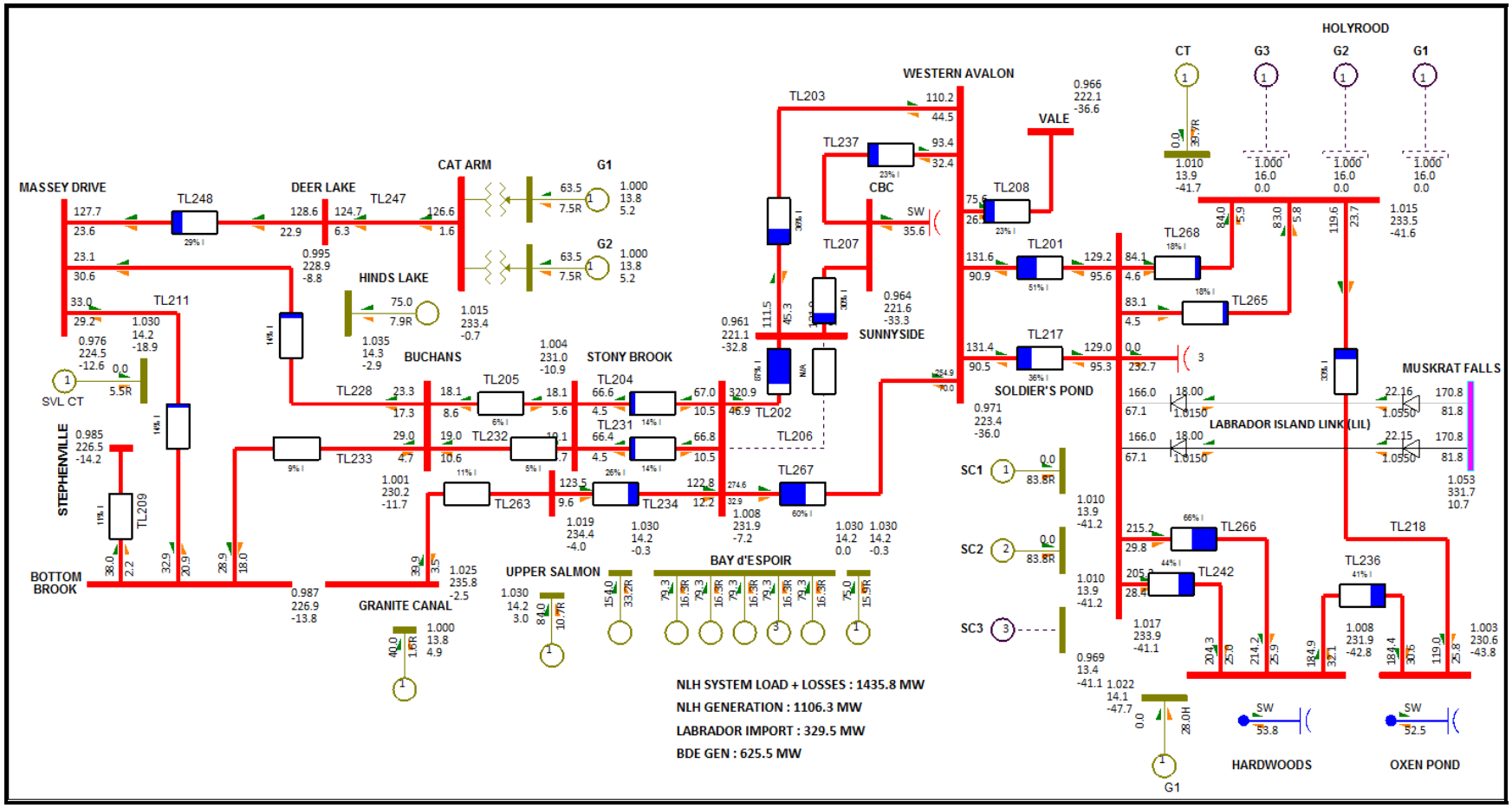


Figure 140 – Base Case 6 (BC6) Load Flow Plot – TL206 Out of Service

New 230 kV Transmission Line Installed Between BDE and WAV

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

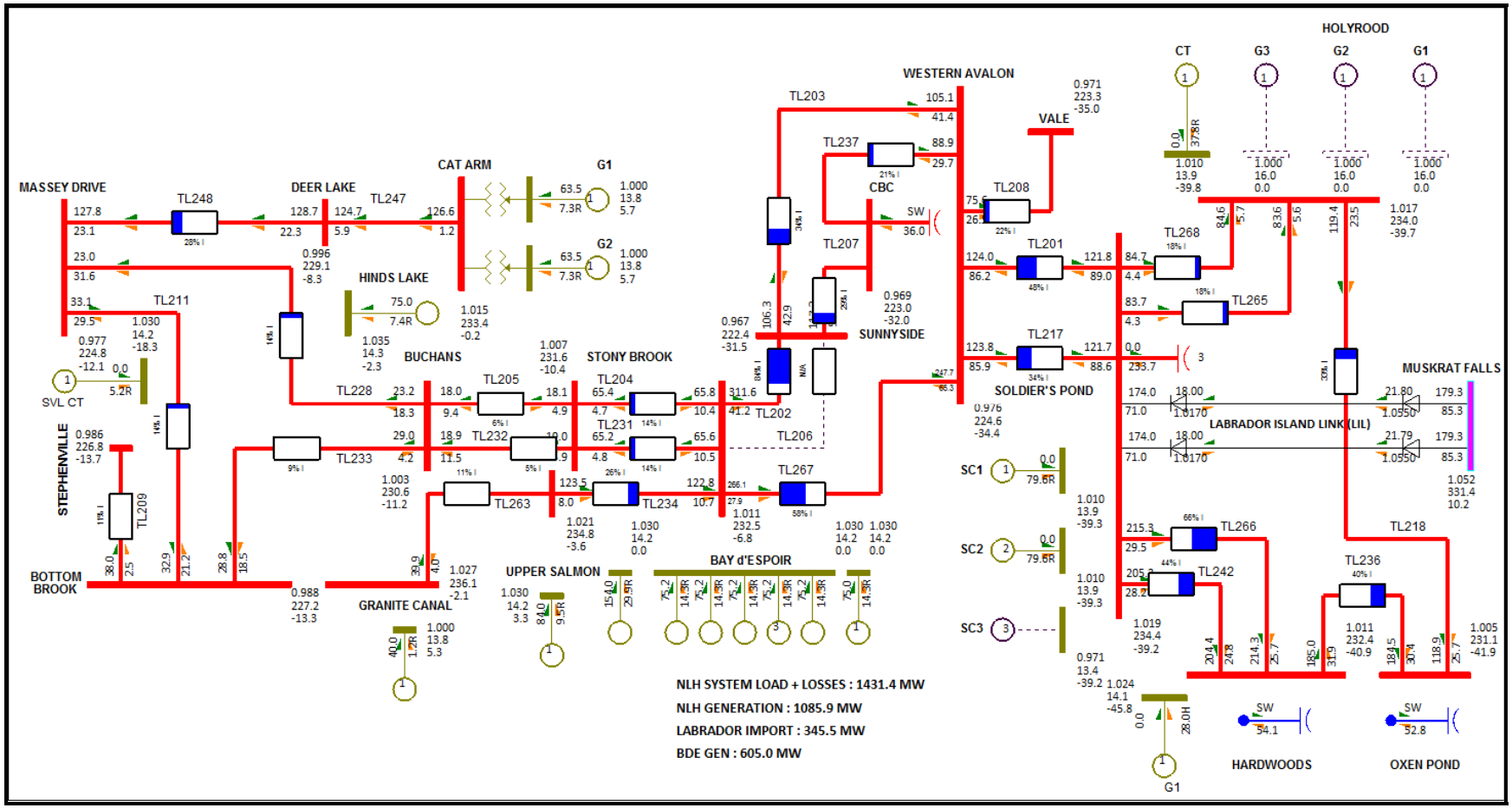


Figure 141 – Base Case 6 (BC6) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 346 MW

New 230 kV Transmission Line Installed Between BDE and WAV

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

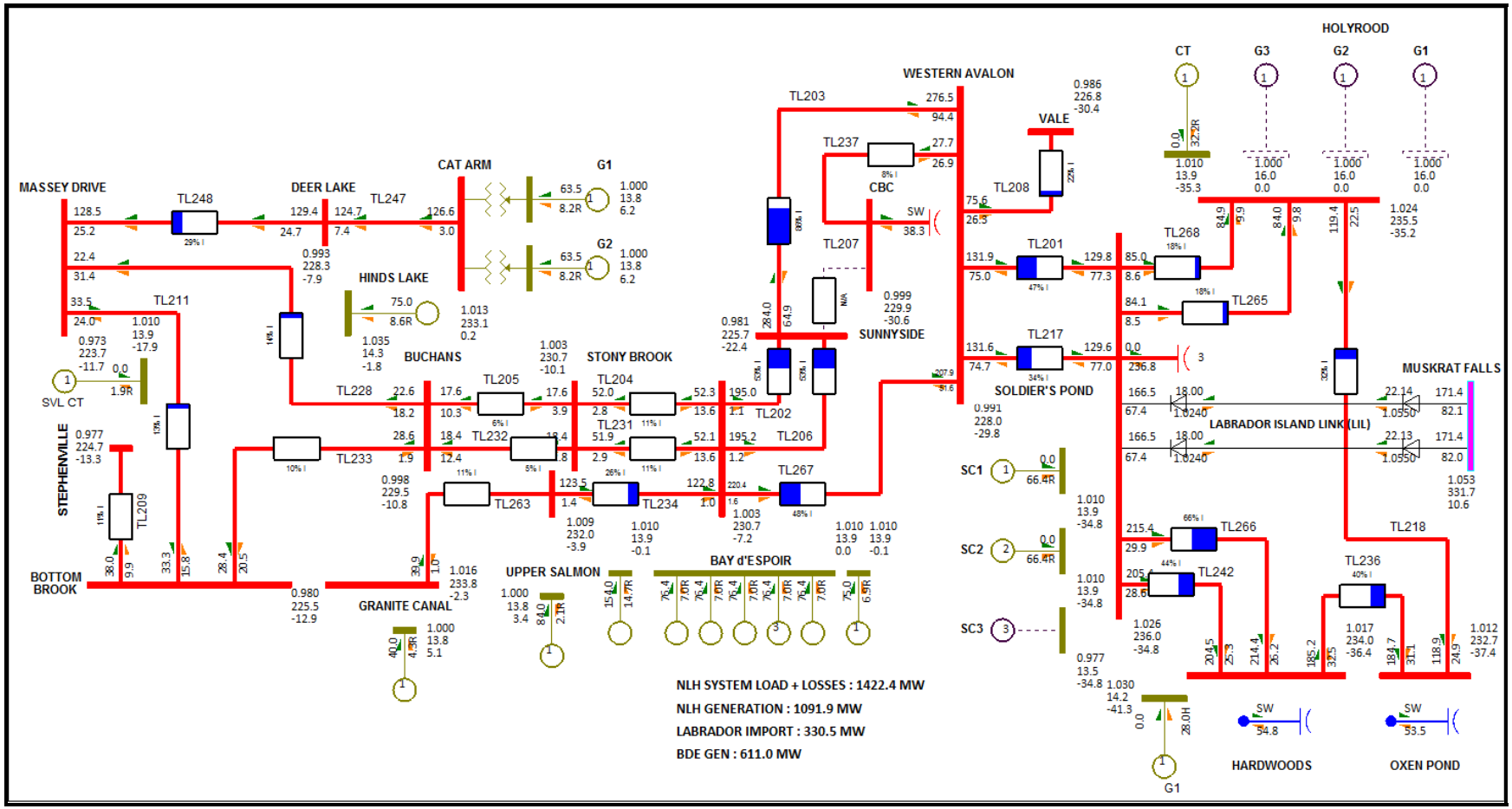


Figure 142 – Base Case 6 (BC6) Load Flow Plot – TL207 Out of Service

New 230 kV Transmission Line Installed Between BDE and WAV

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

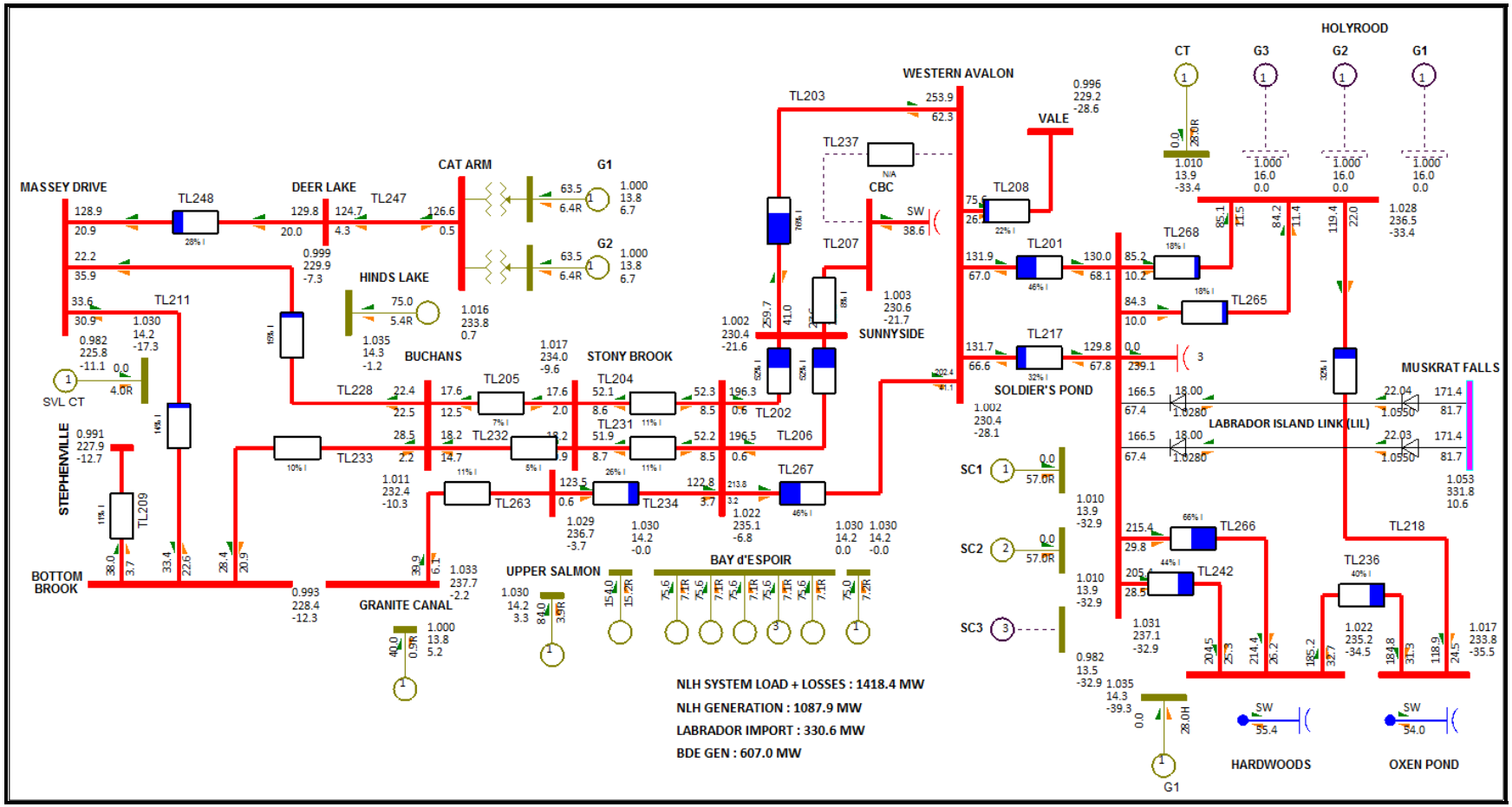


Figure 143 – Base Case 6 (BC6) Load Flow Plot – TL237 Out of Service

New 230 kV Transmission Line Installed Between BDE and WAV

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

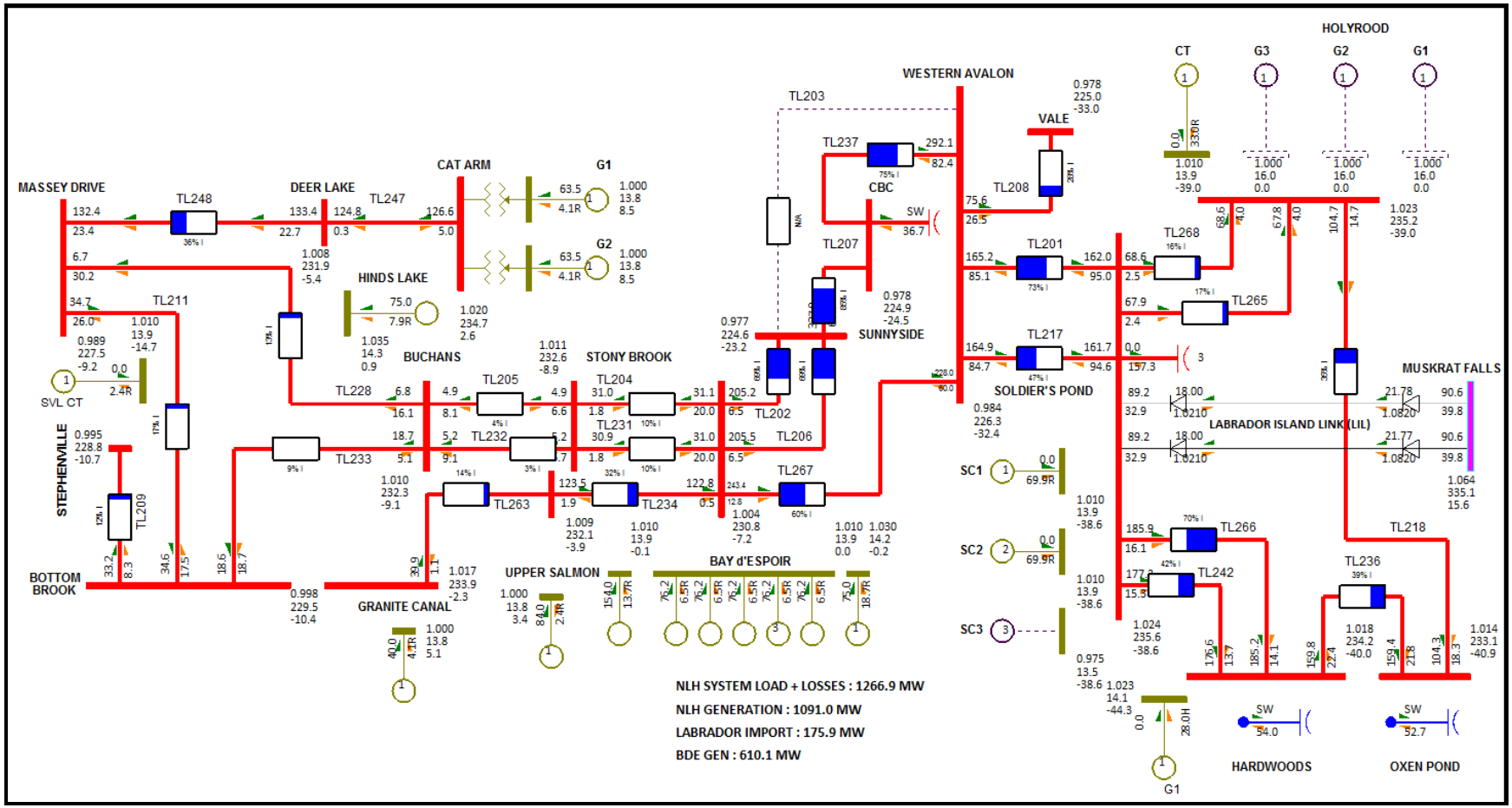


Figure 144 – Base Case 8 (BC8) Load Flow Plot – TL203 Out of Service

New 230 kV Transmission Line Installed Between BDE and WAV

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

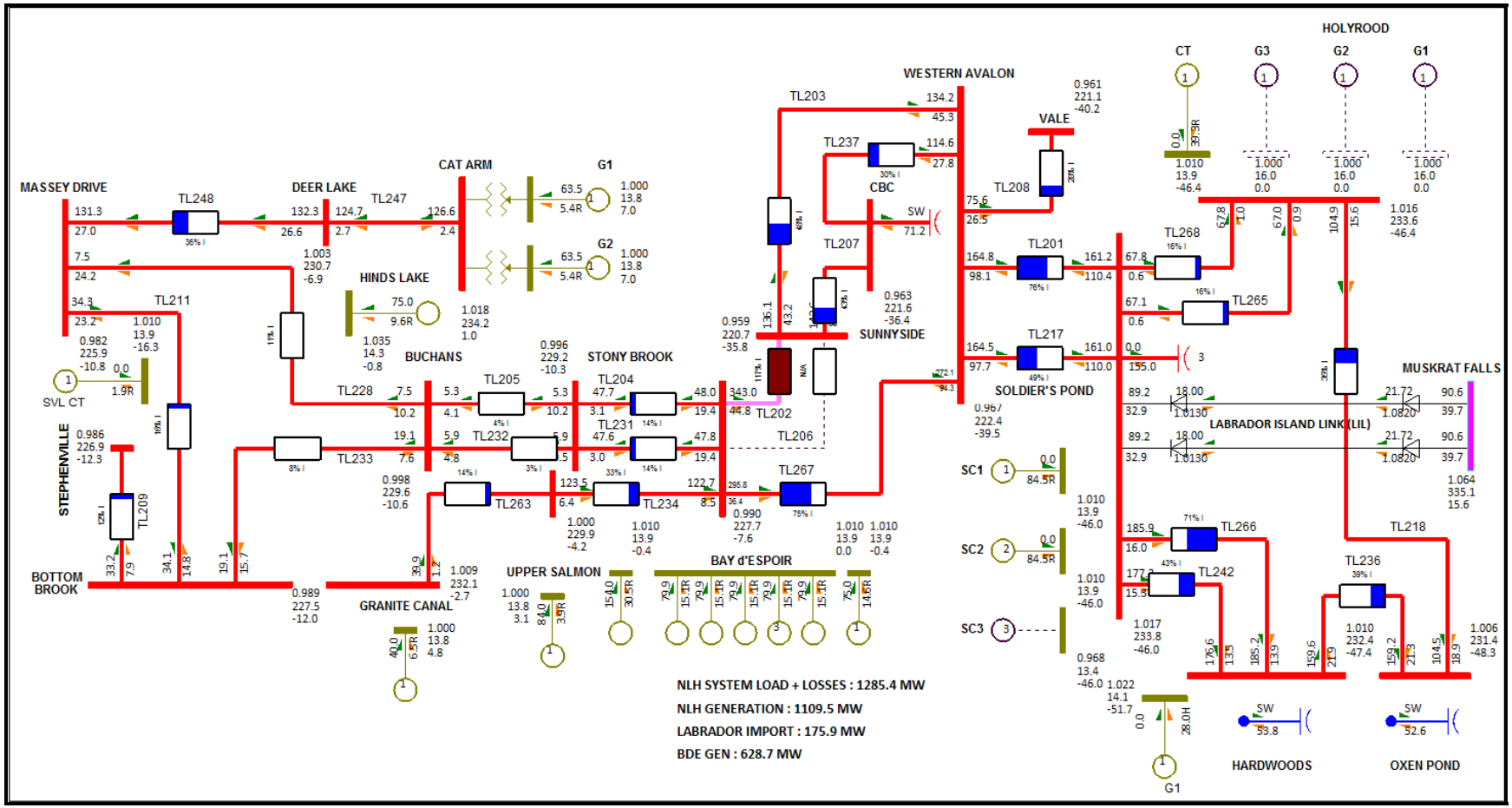


Figure 145 – Base Case 8 (BC8) Load Flow Plot – TL206 Out of Service

TL202 Loaded 117% of Thermal Rating

New 230 kV Transmission Line Installed Between BDE and WAV

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

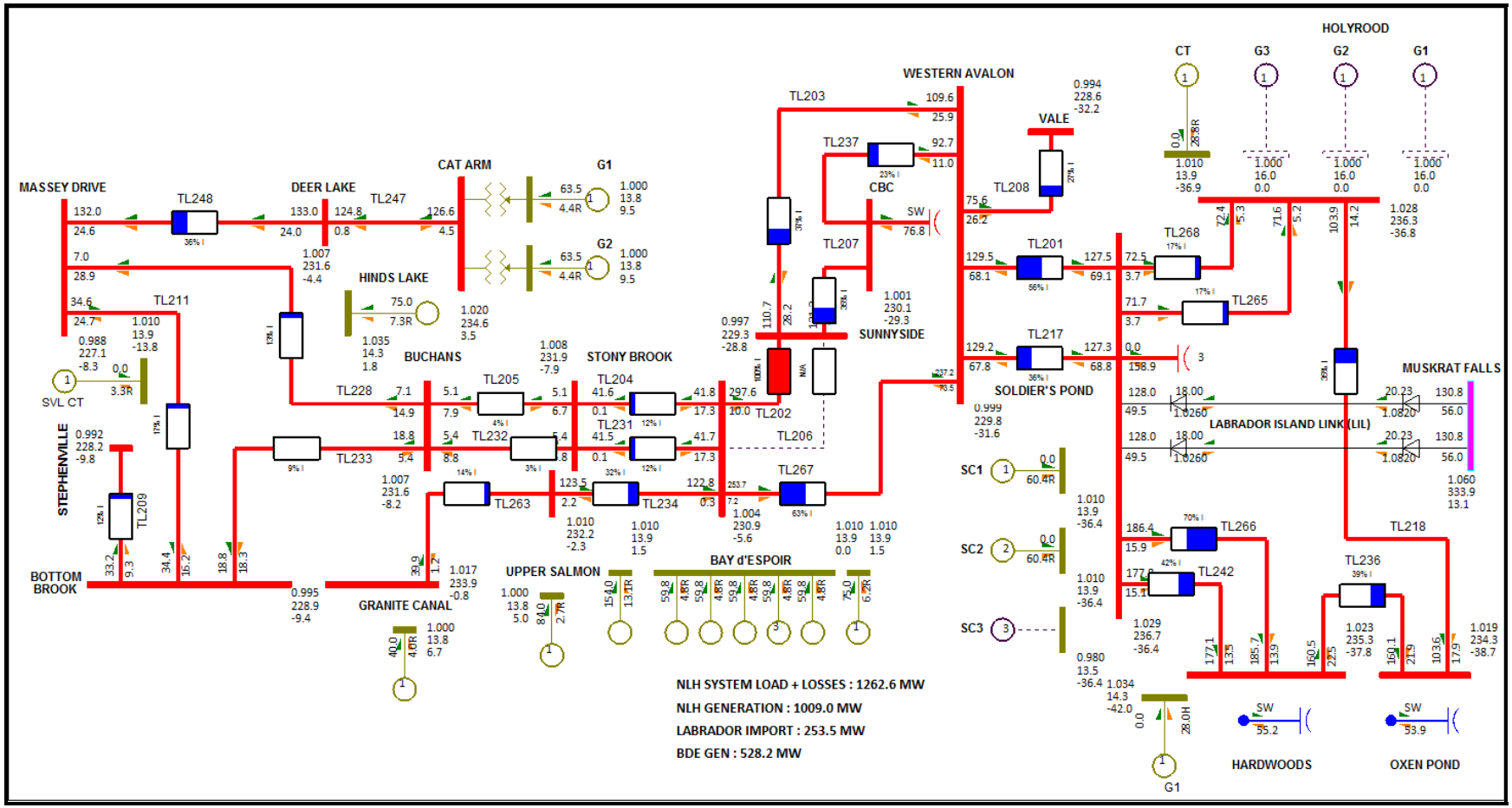


Figure 146 – Base Case 8 (BC8) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 254 MW

TL202 Loaded 100% of Thermal Rating

New 230 kV Transmission Line Installed Between BDE and WAV

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

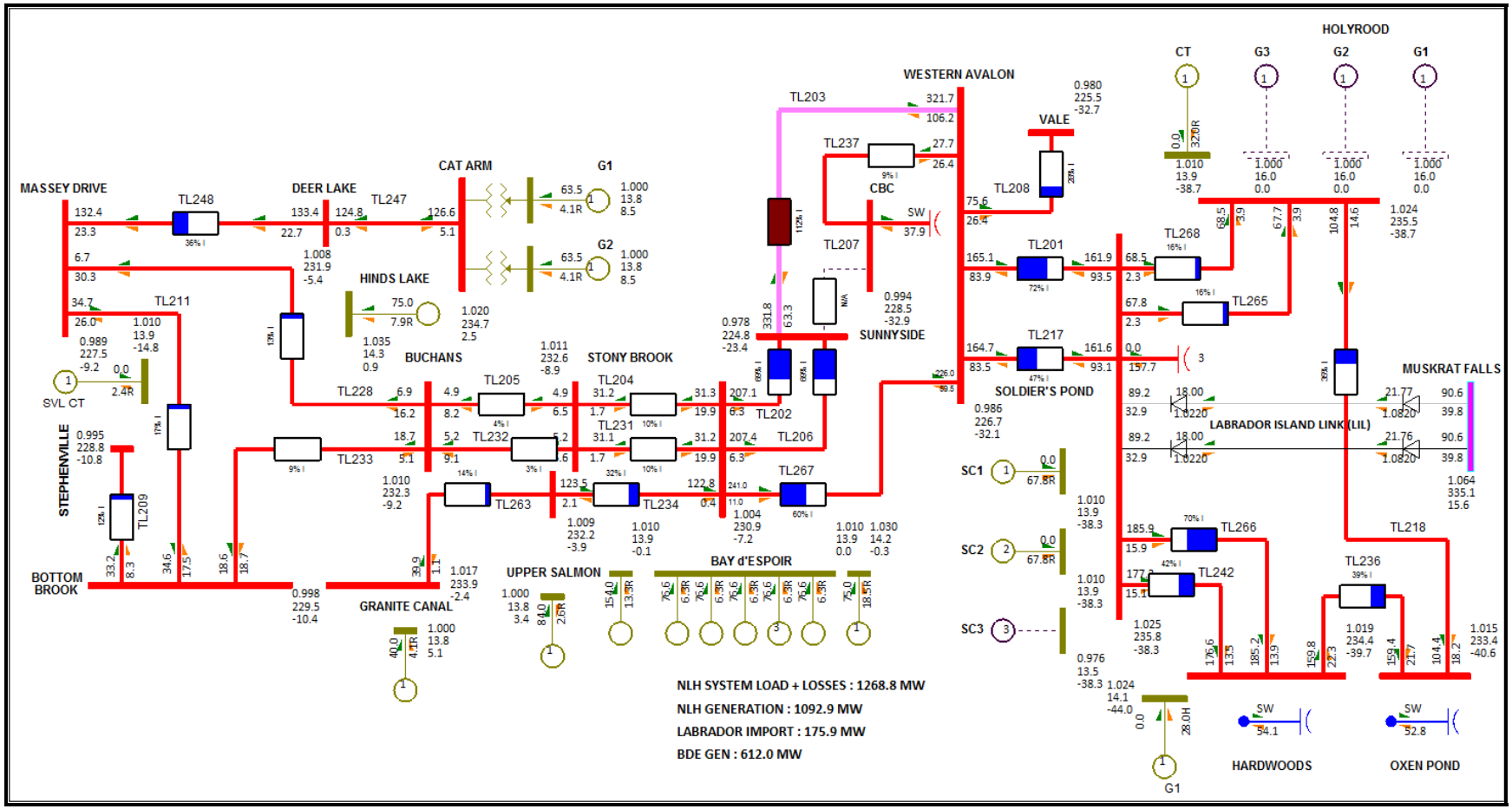


Figure 147 – Base Case 8 (BC8) Load Flow Plot – TL207 Out of Service

TL203 Loaded 112% of Thermal Rating

New 230 kV Transmission Line Installed Between BDE and WAV

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

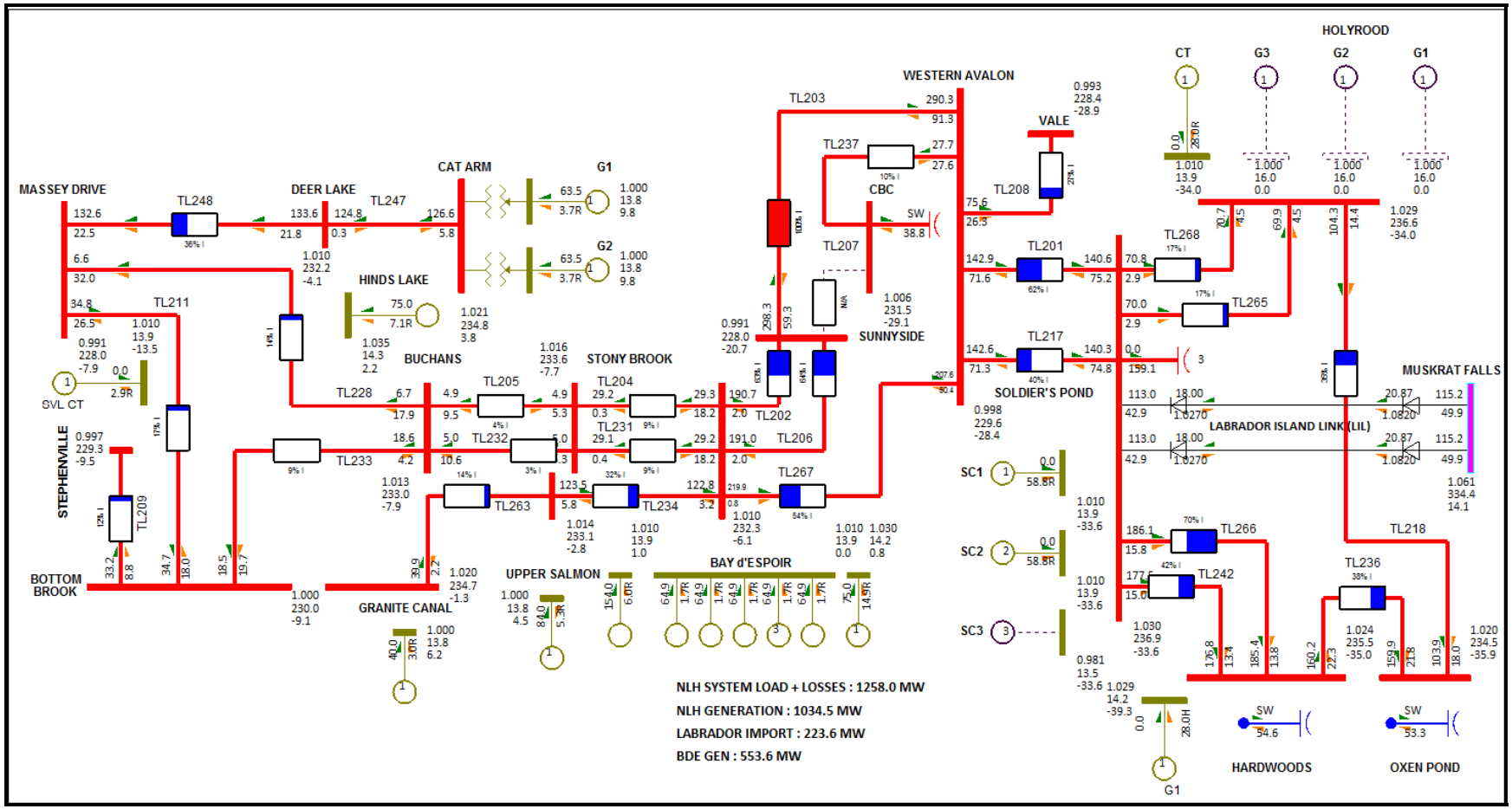


Figure 148 – Base Case 8 (BC8) Load Flow Plot – TL207 Out of Service

TL203 Loaded 100% of Thermal Rating – LIL Import Increased to 224 MW

New 230 kV Transmission Line Installed Between BDE and WAV

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

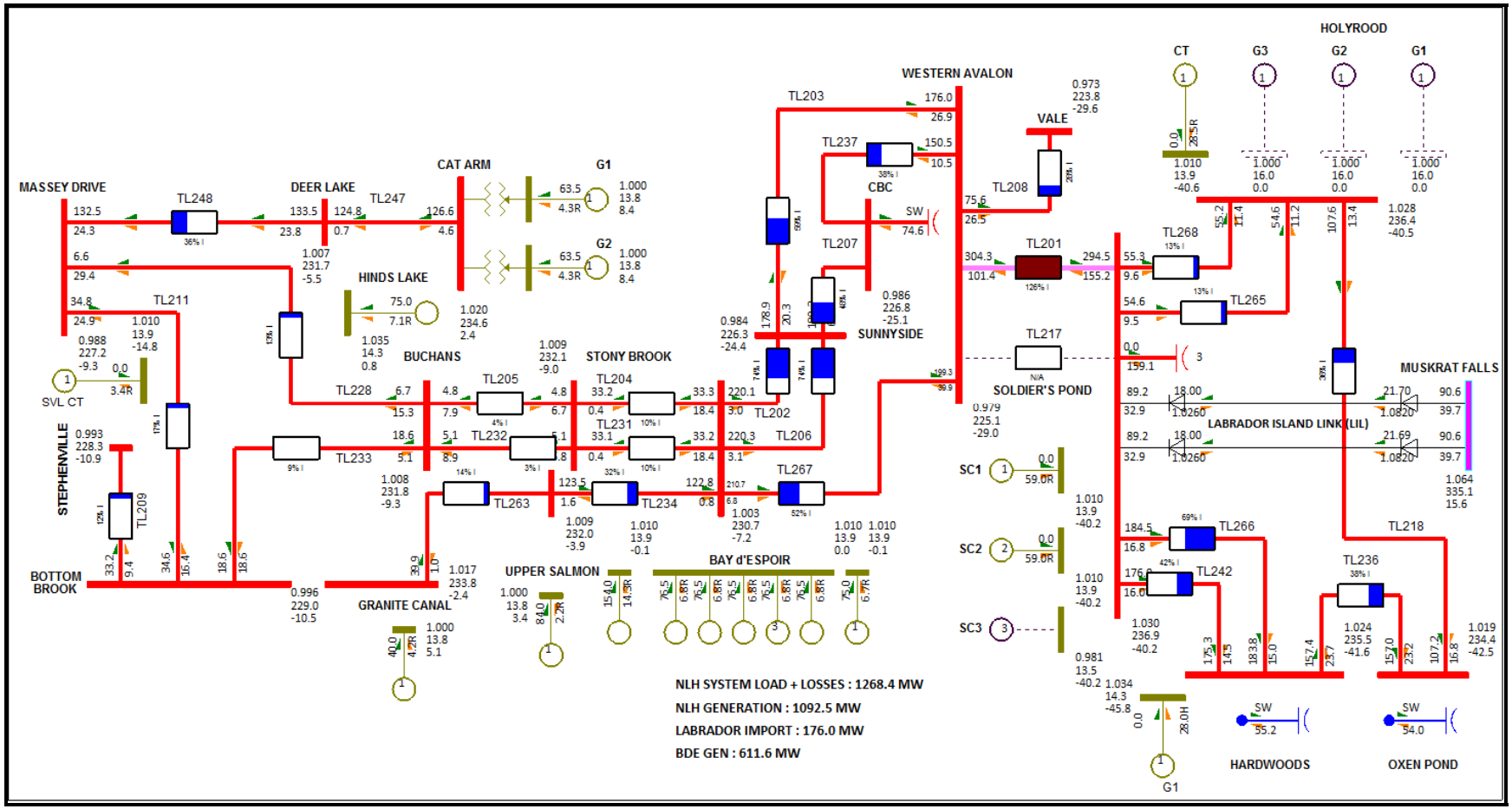


Figure 149 – Base Case 8 (BC8) Load Flow Plot – TL217 Out of Service

TL201 Loaded 126% of Thermal Rating

New 230 kV Transmission Line Installed Between BDE and WAV

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

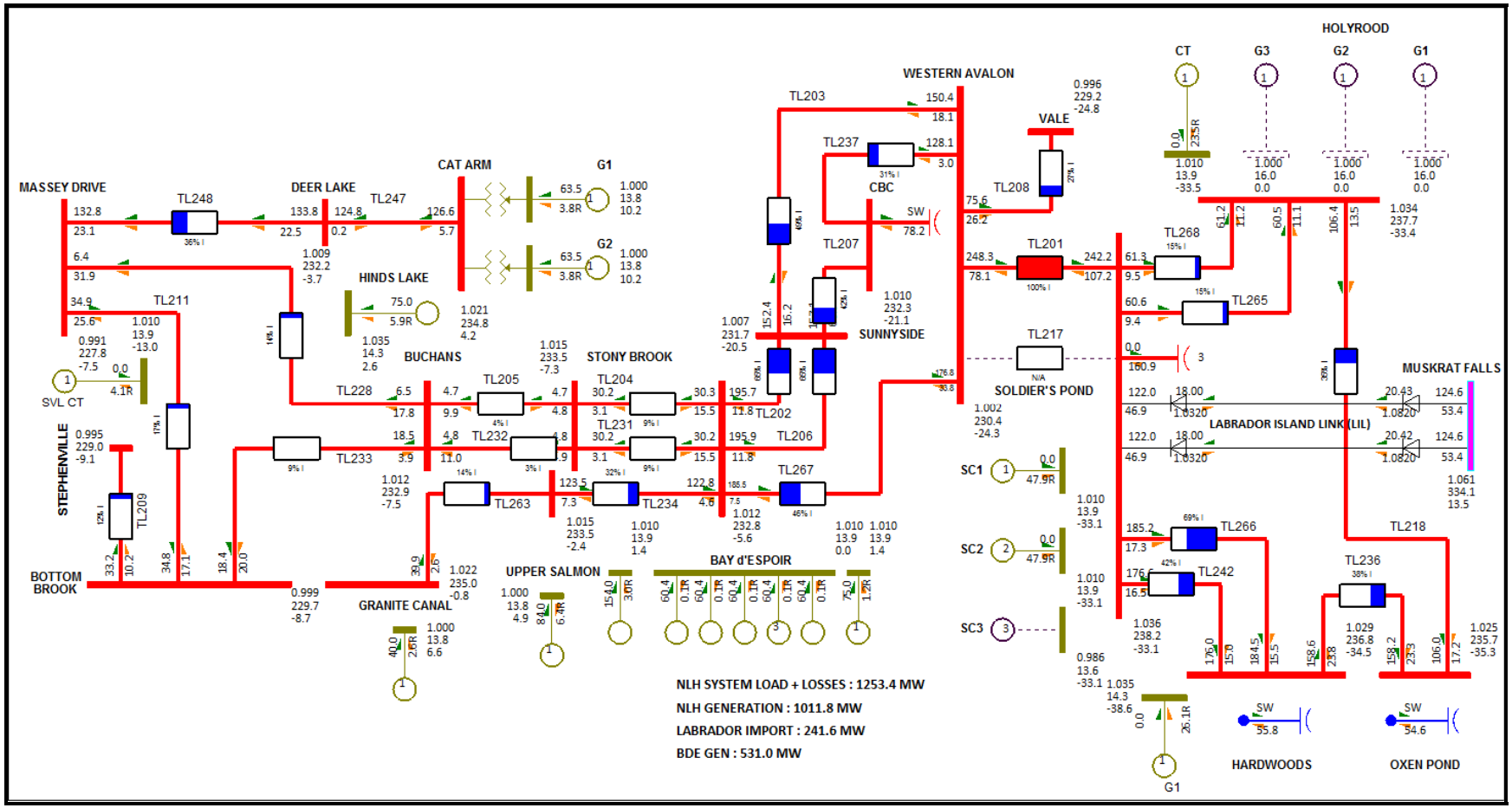


Figure 150 – Base Case 8 (BC8) Load Flow Plot – TL217 Out of Service

TL201 Loaded 100% of Thermal Rating – LIL Import Increased to 242 MW

New 230 kV Transmission Line Installed Between BDE and WAV

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

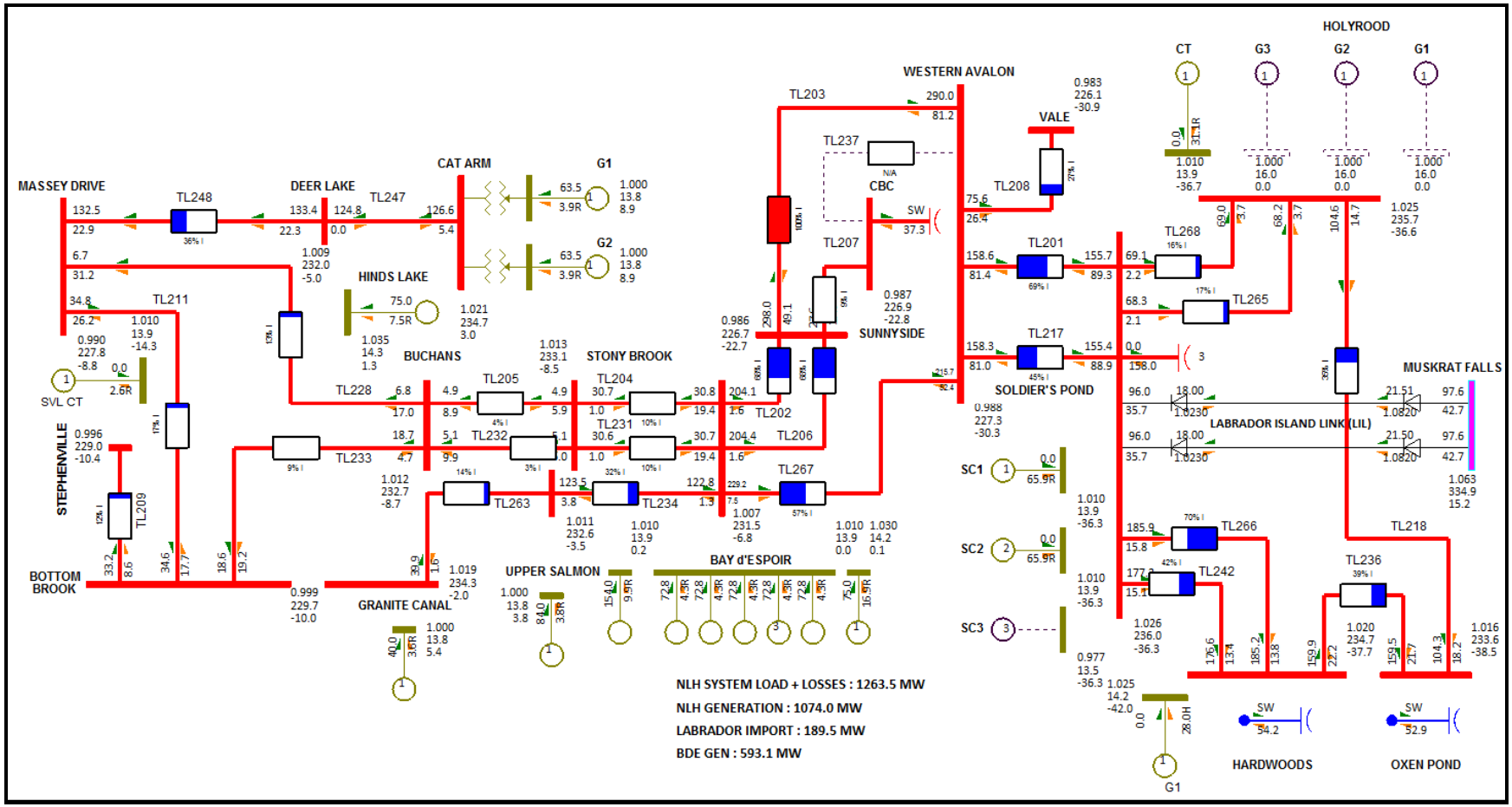


Figure 151 – Base Case 8 (BC8) Load Flow Plot – TL237 Out of Service

TL203 Loaded 103% of Thermal Rating

New 230 kV Transmission Line Installed Between BDE and WAV

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

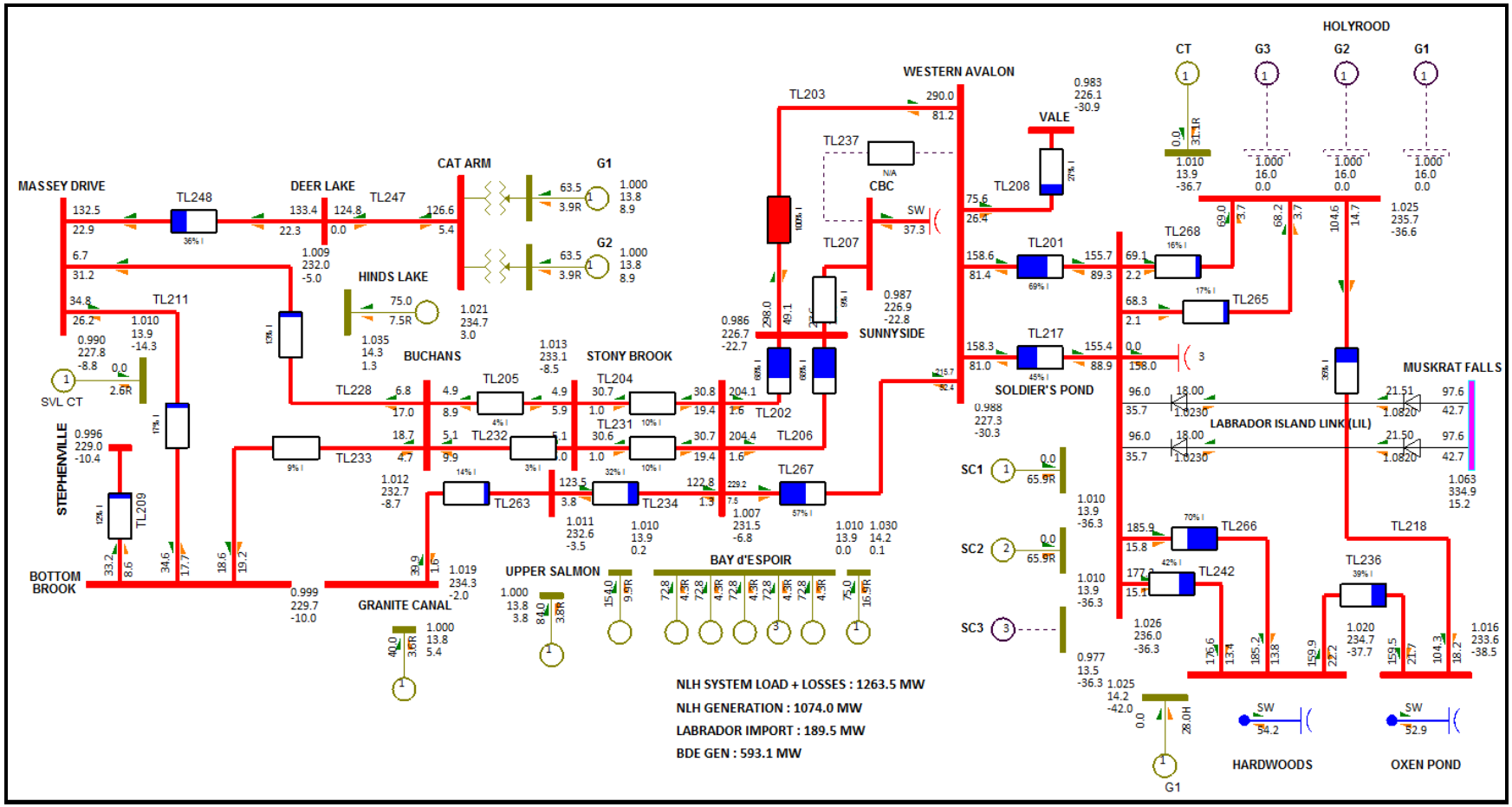


Figure 152 – Base Case 8 (BC8) Load Flow Plot – TL237 Out of Service

TL203 Loaded 100% of Thermal Rating – LIL Import Increased to 190 MW

New 230 kV Transmission Line Installed Between BDE and WAV

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

Alternative 3

Complete 75°C Thermal Uprate on TL202/TL206, Series Compensate TL202/TL206 by 25% and Rebuild TL203 with 804 kcmil AACSR/TW Conductor

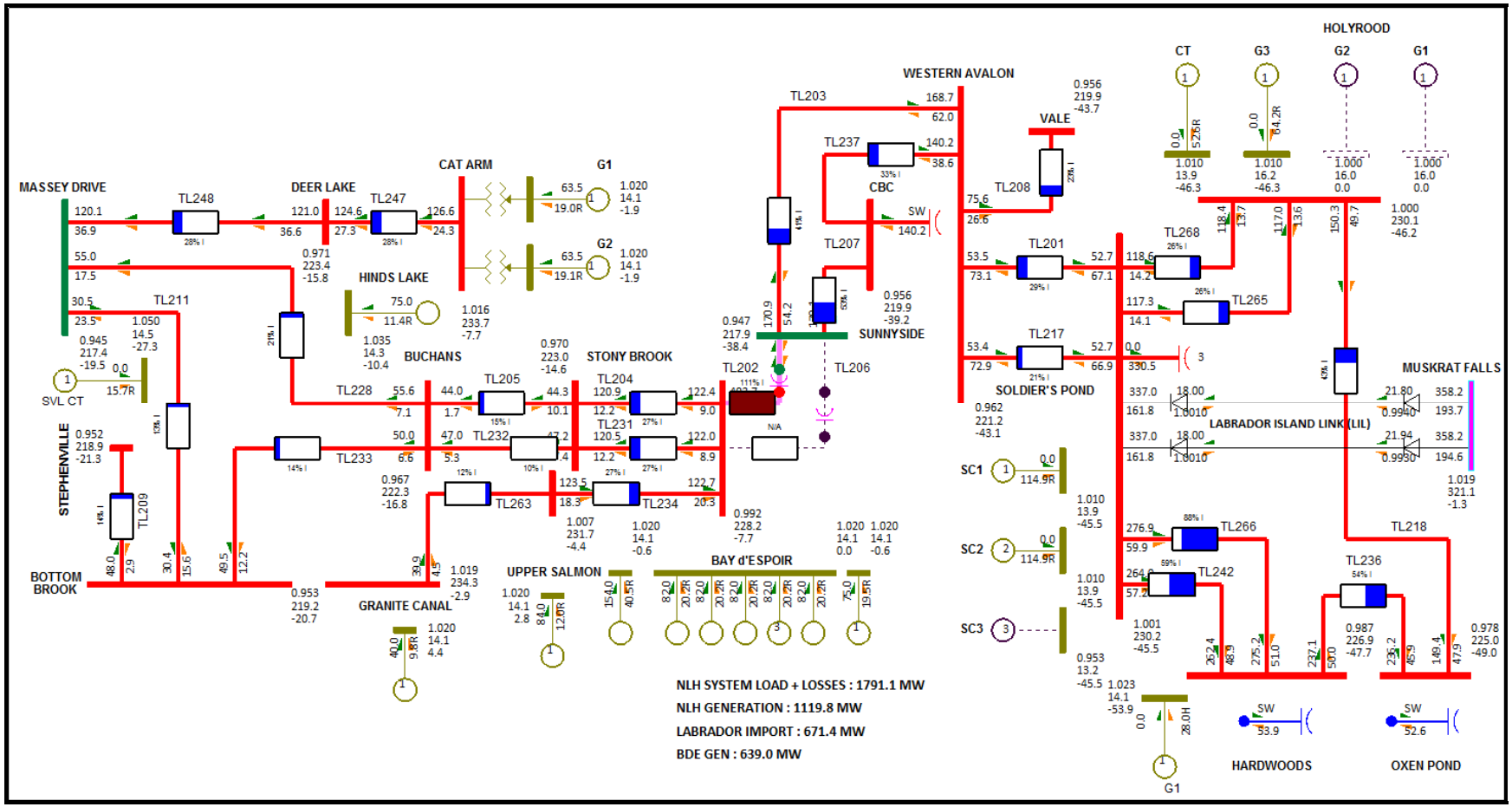


Figure 153 – Base Case 1 (BC1) Load Flow Plot – TL206 Out of Service

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

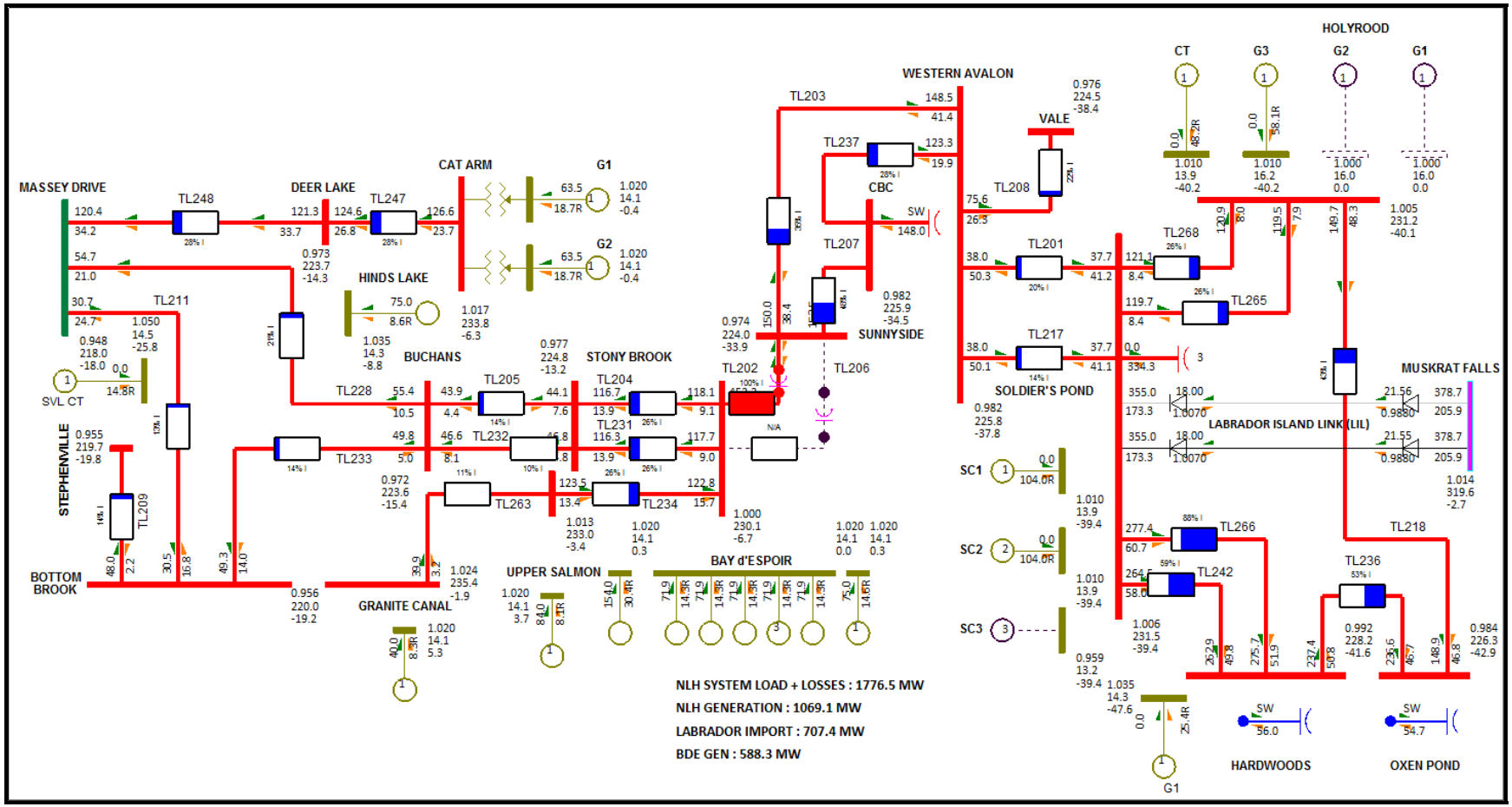


Figure 154 – Base Case 1 (BC1) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 707 MW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

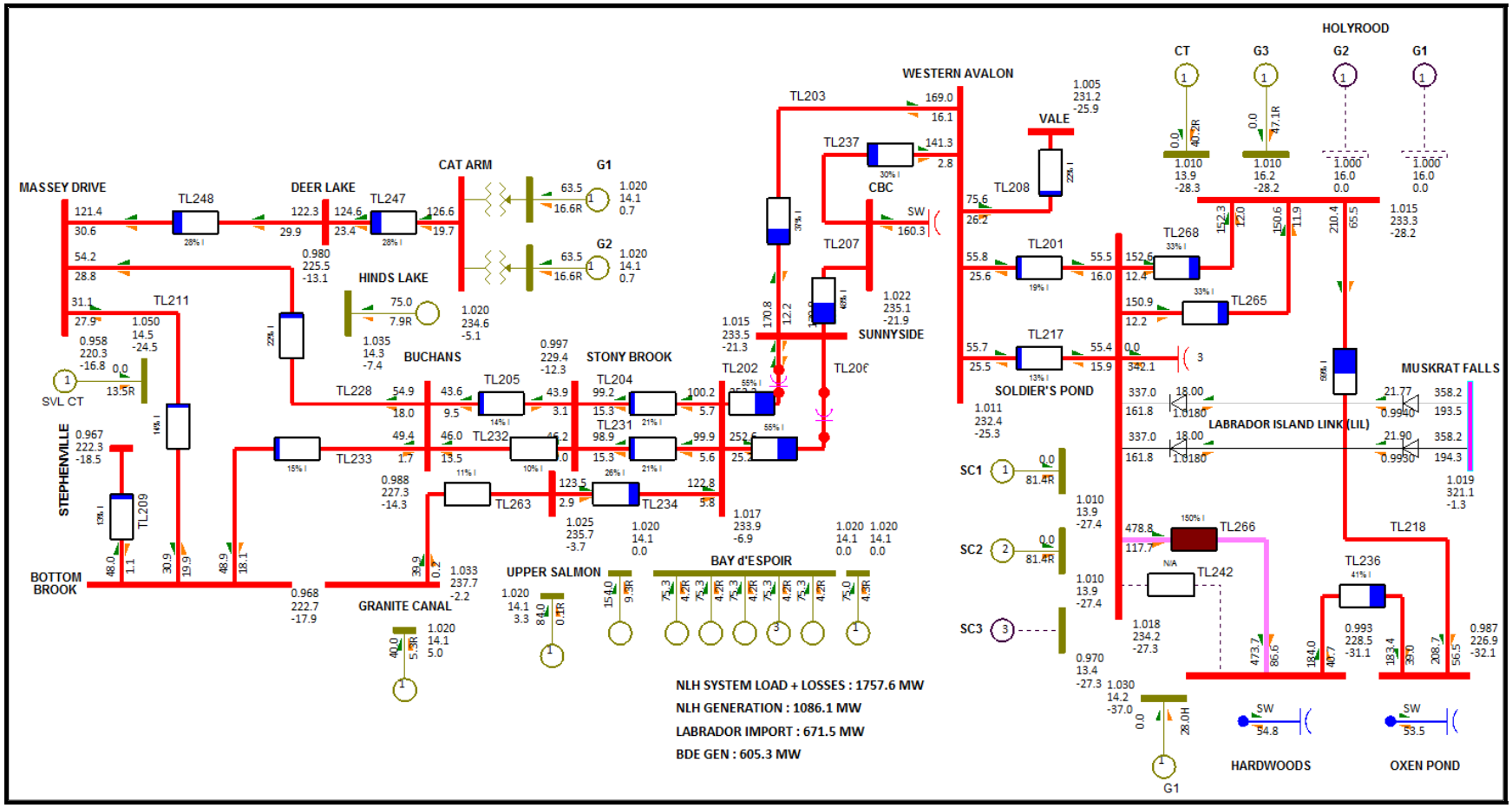


Figure 155 – Base Case 1 (BC1) Load Flow Plot – TL242 Out of Service

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

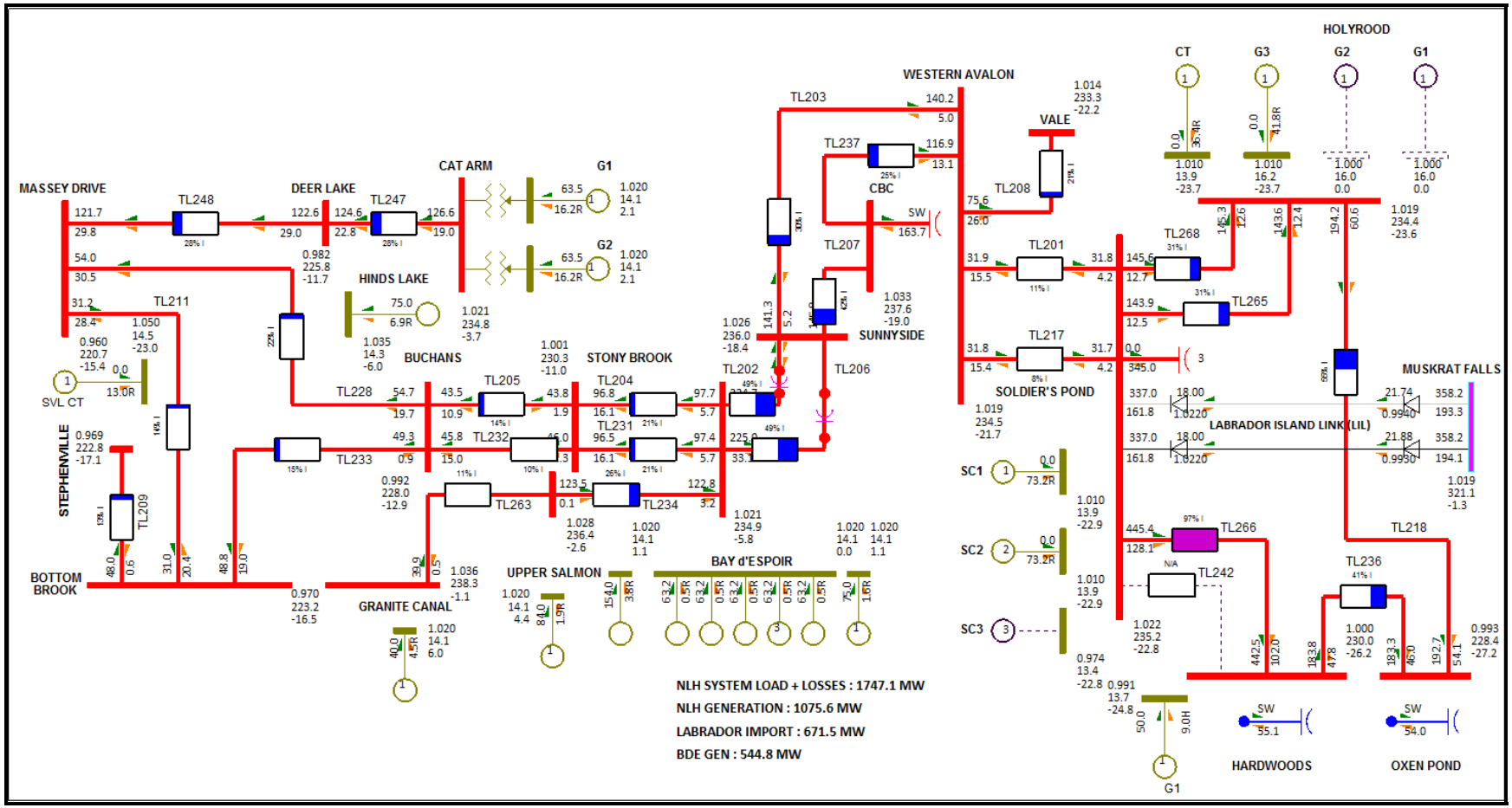


Figure 156 – Base Case 1 (BC1) Load Flow Plot – TL242 Out of Service

TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor – HWD CT Generating 50 MW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

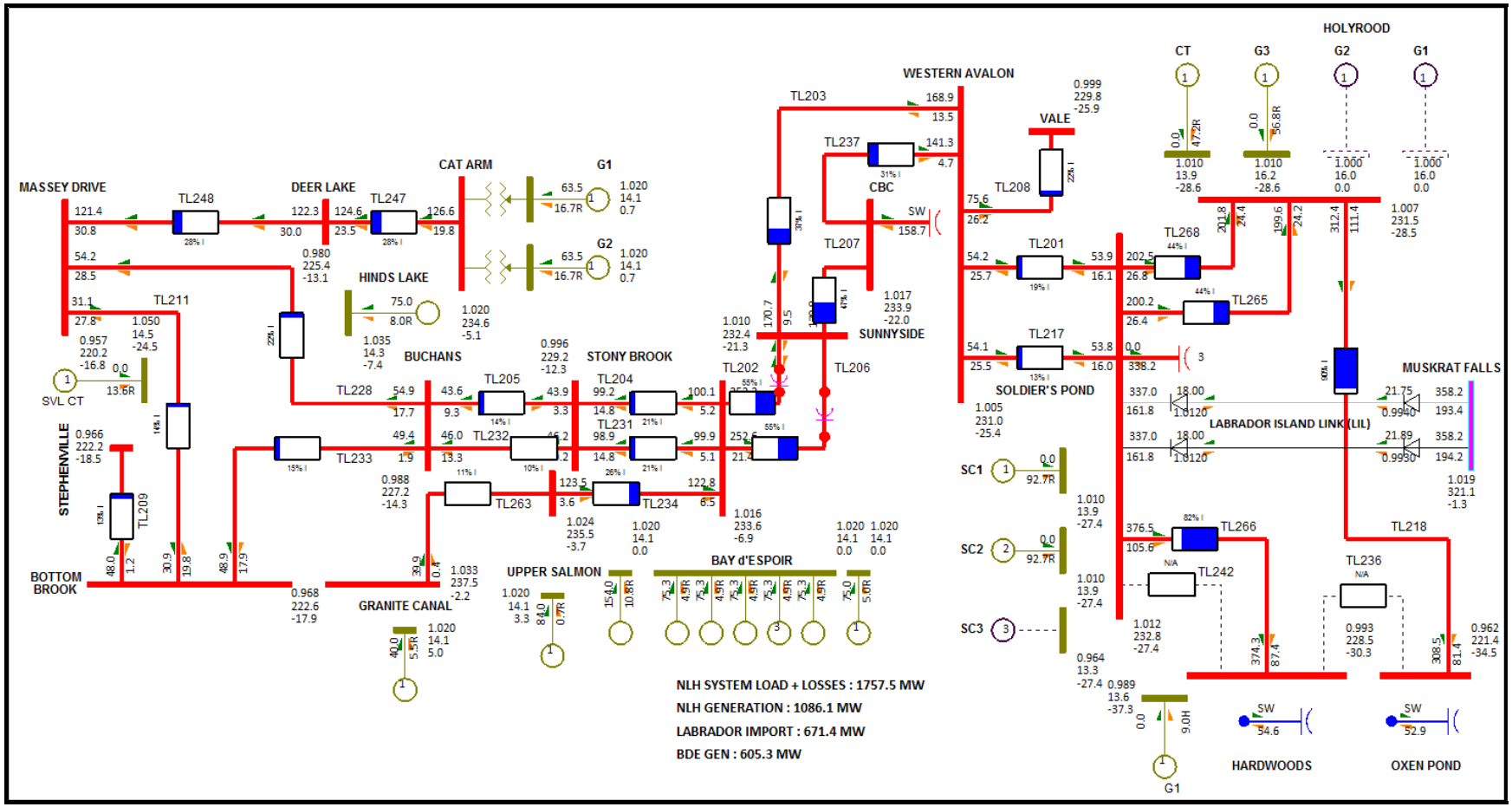


Figure 157 – Base Case 1 (BC1) Load Flow Plot – TL242 Out of Service

TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor – TL236 Open

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

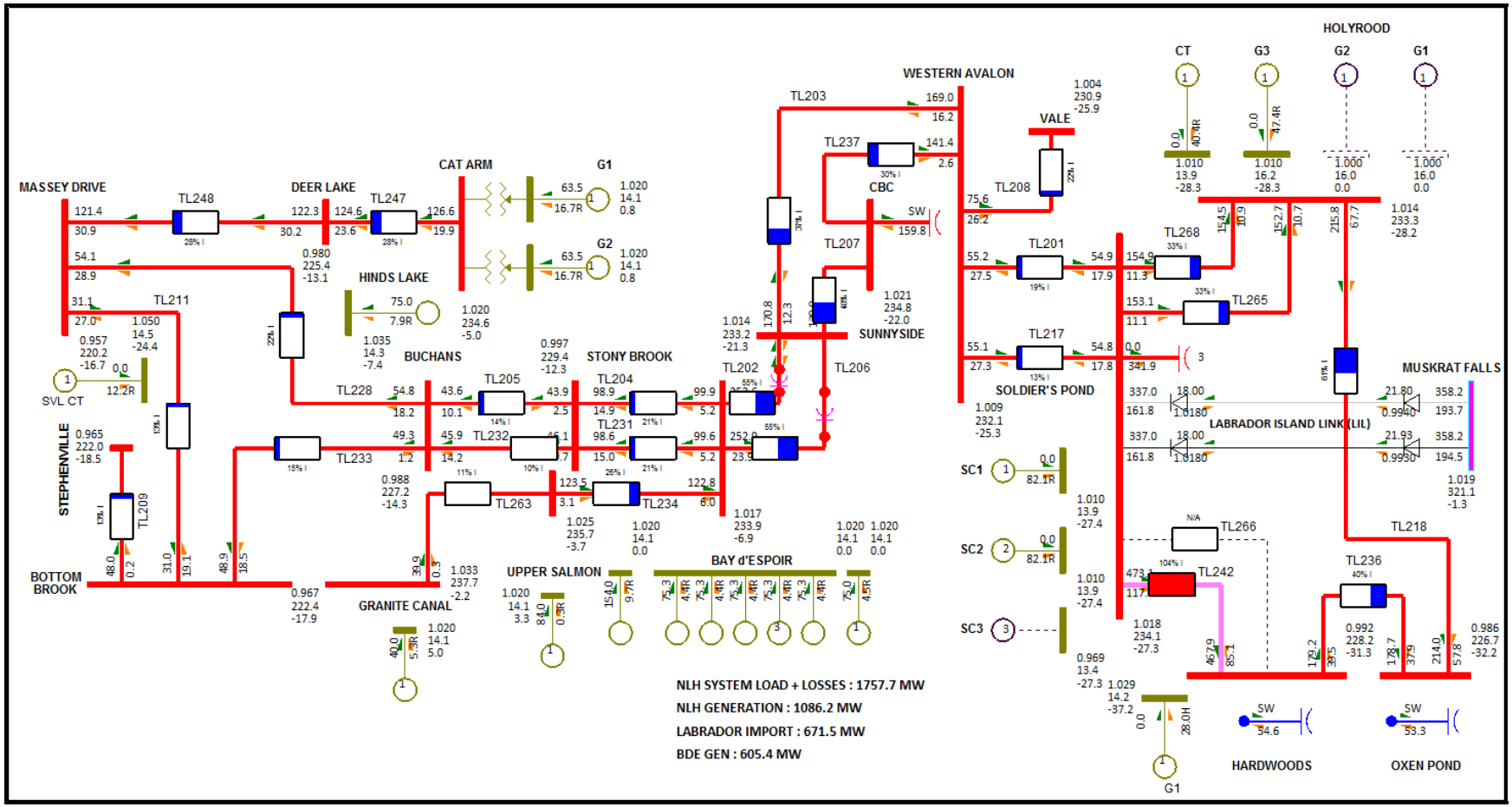


Figure 158 – Base Case 1 (BC1) Load Flow Plot – TL266 Out of Service

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

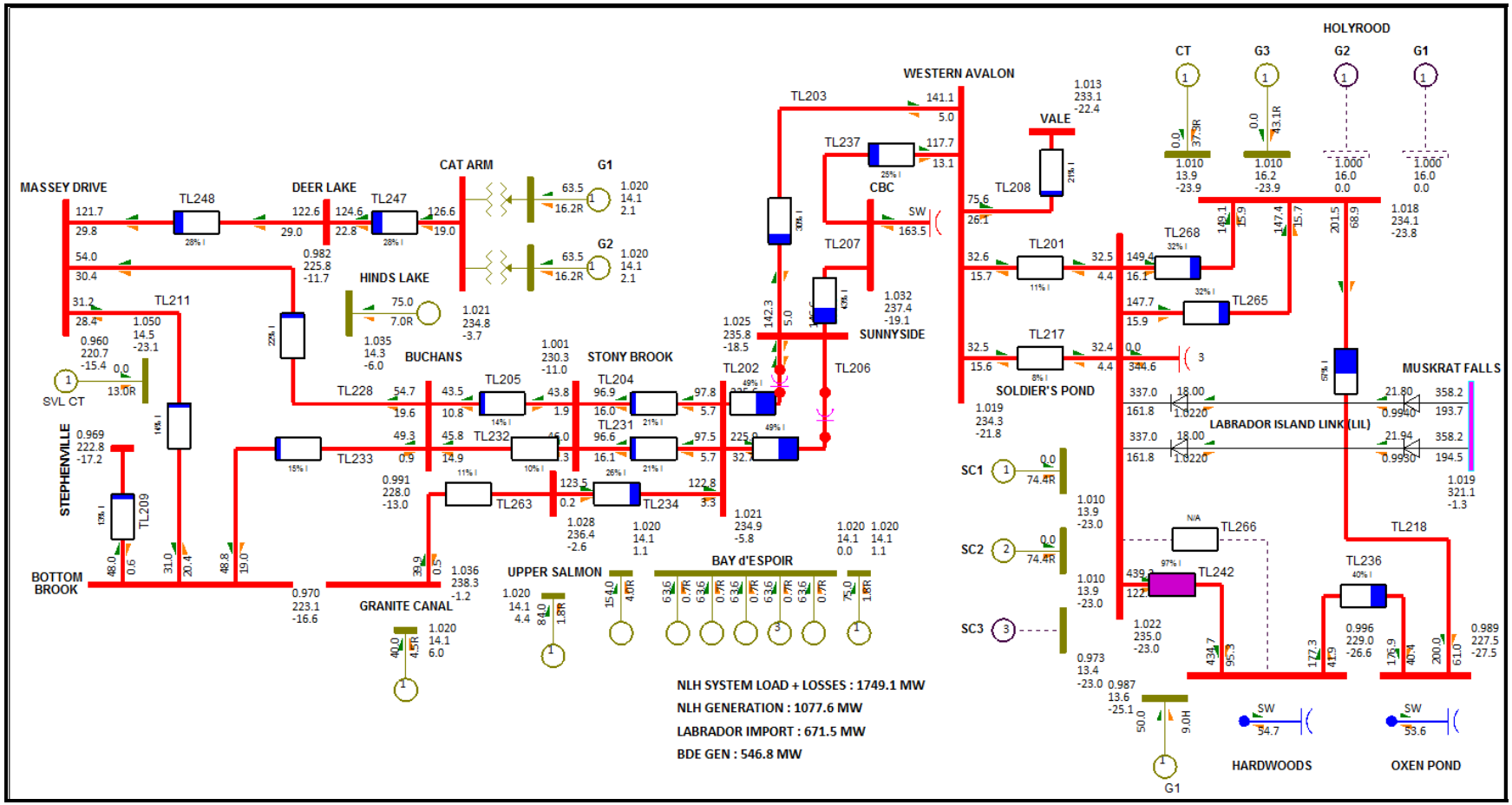


Figure 159 – Base Case 1 (BC1) Load Flow Plot – TL266 Out of Service – HWD CT Generating 50 MW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

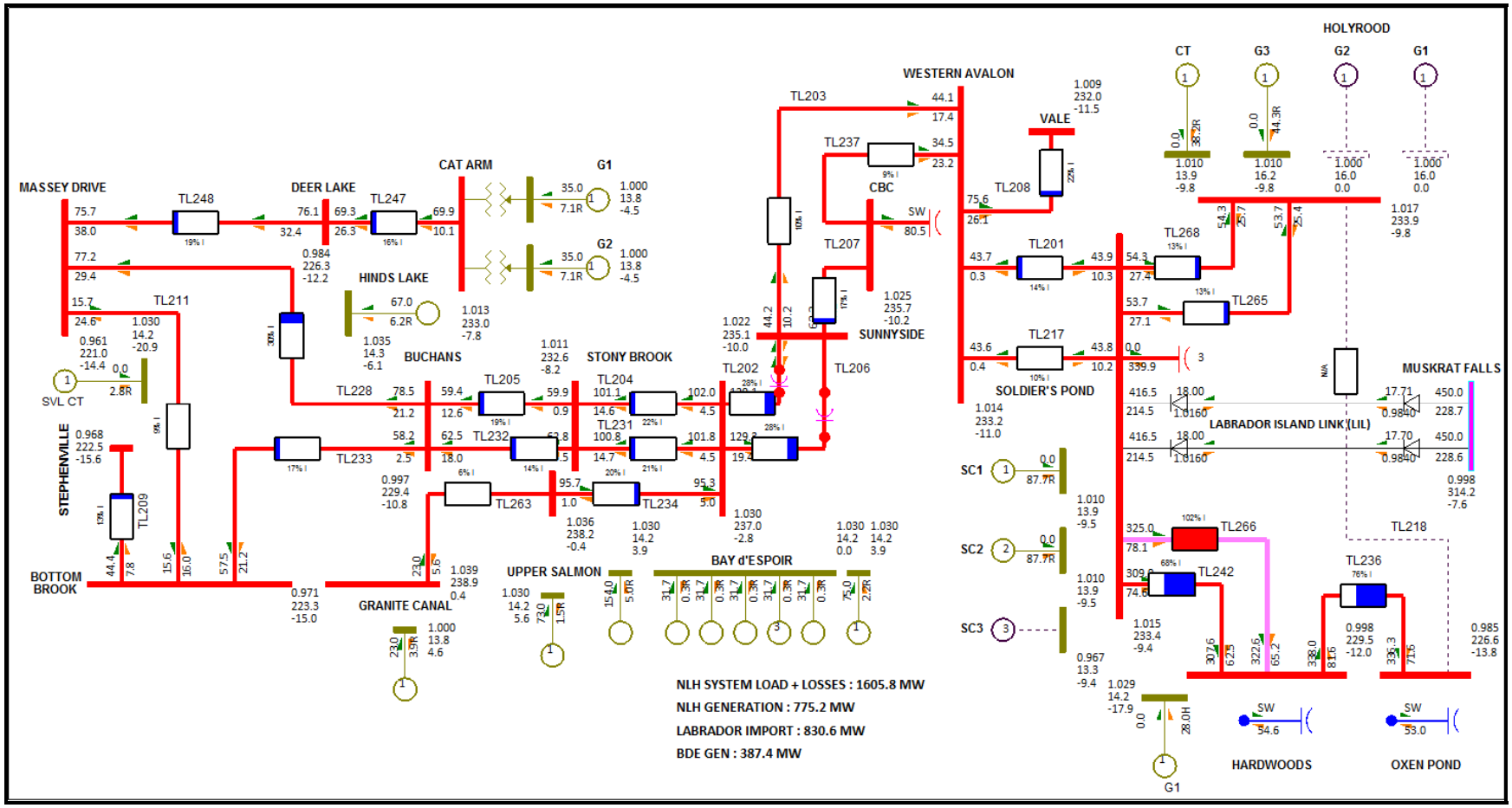


Figure 160 – Base Case 2 (BC2) Load Flow Plot – TL218 Out of Service

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (773 MW)

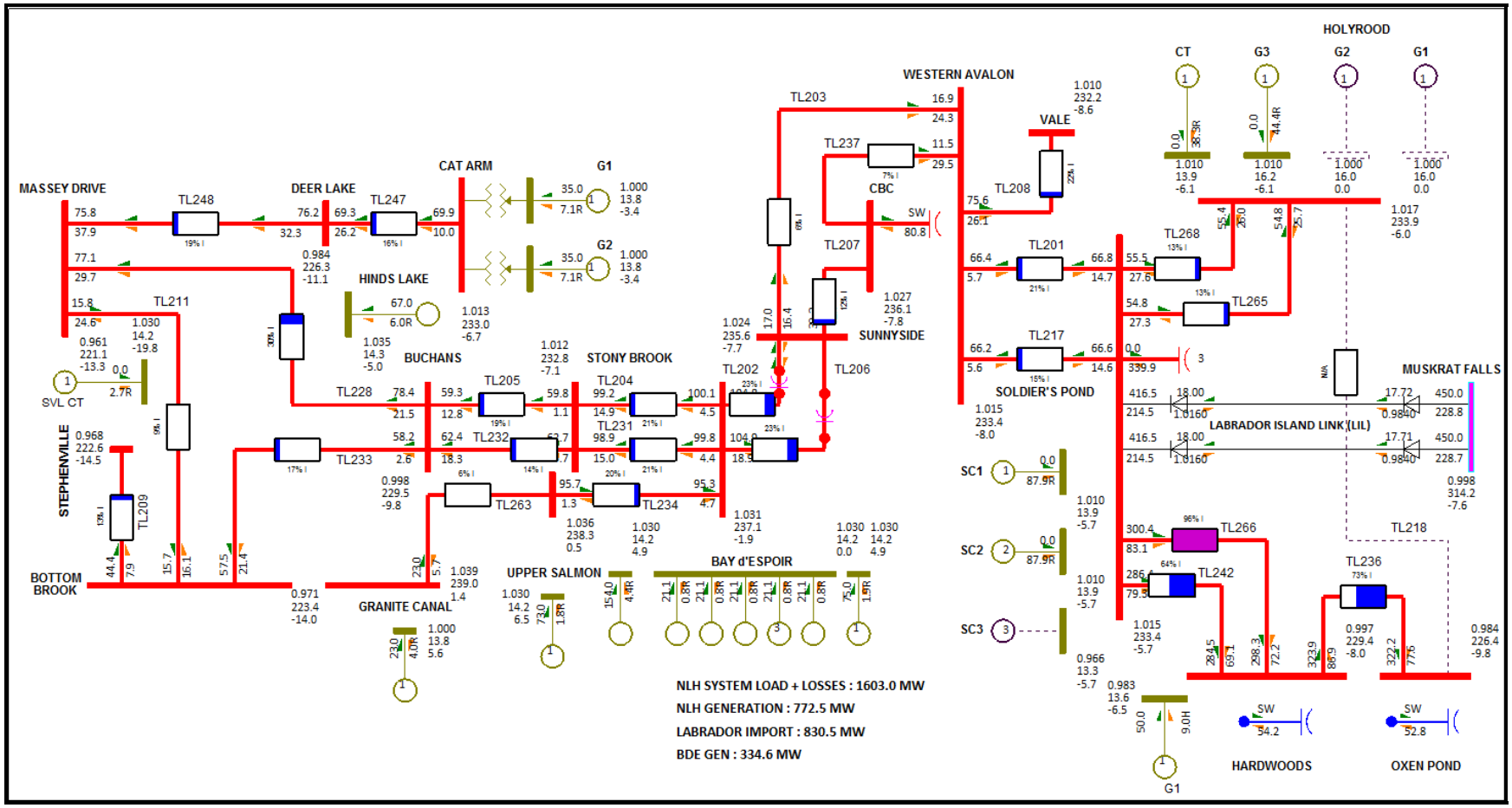


Figure 161 – Base Case 2 (BC2) Load Flow Plot – TL218 Out of Service – HWD CT Generating 50 MW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (773 MW)

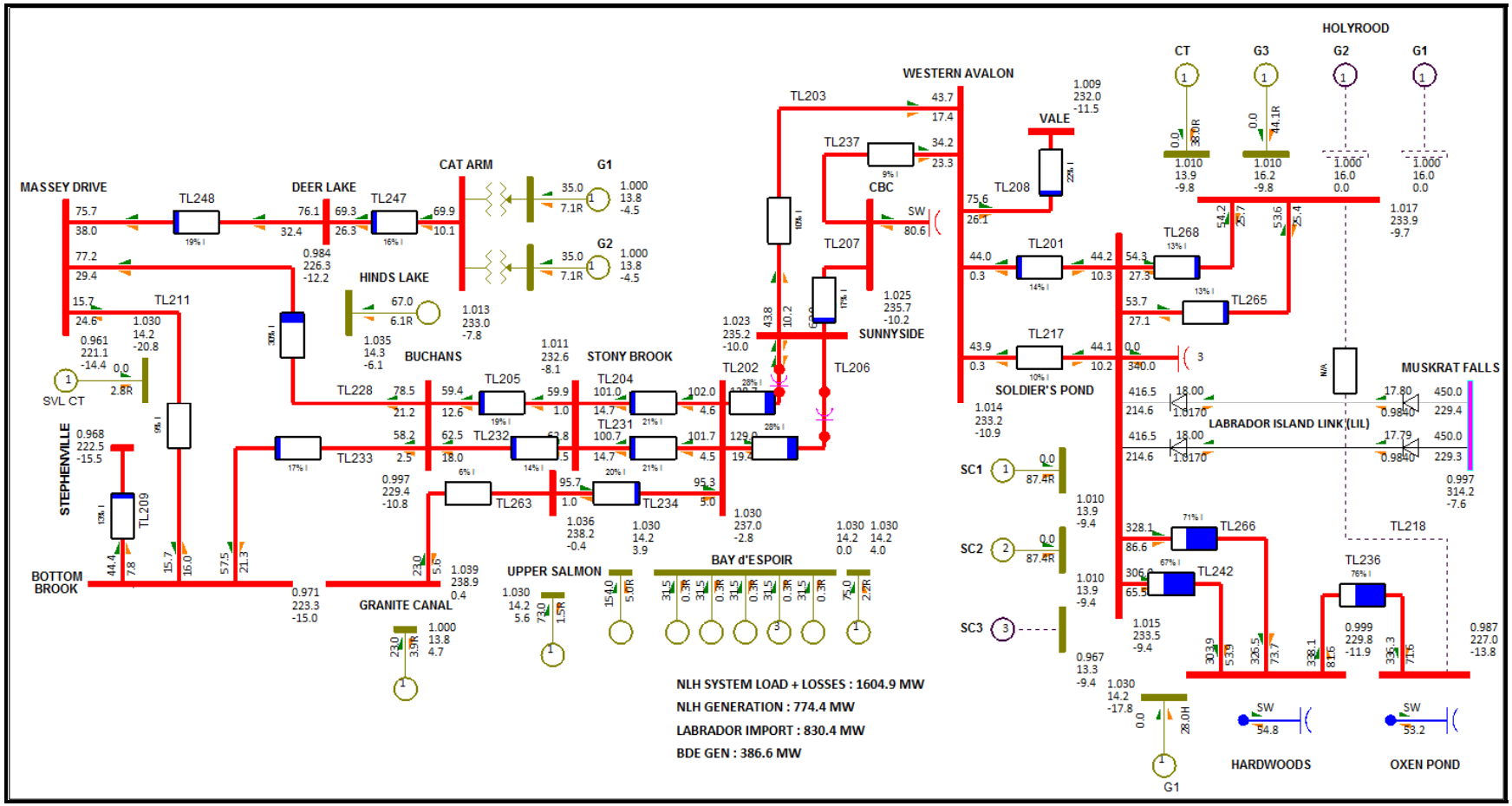


Figure 162 – Base Case 2 (BC2) Load Flow Plot – TL218 Out of Service

TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (773 MW)

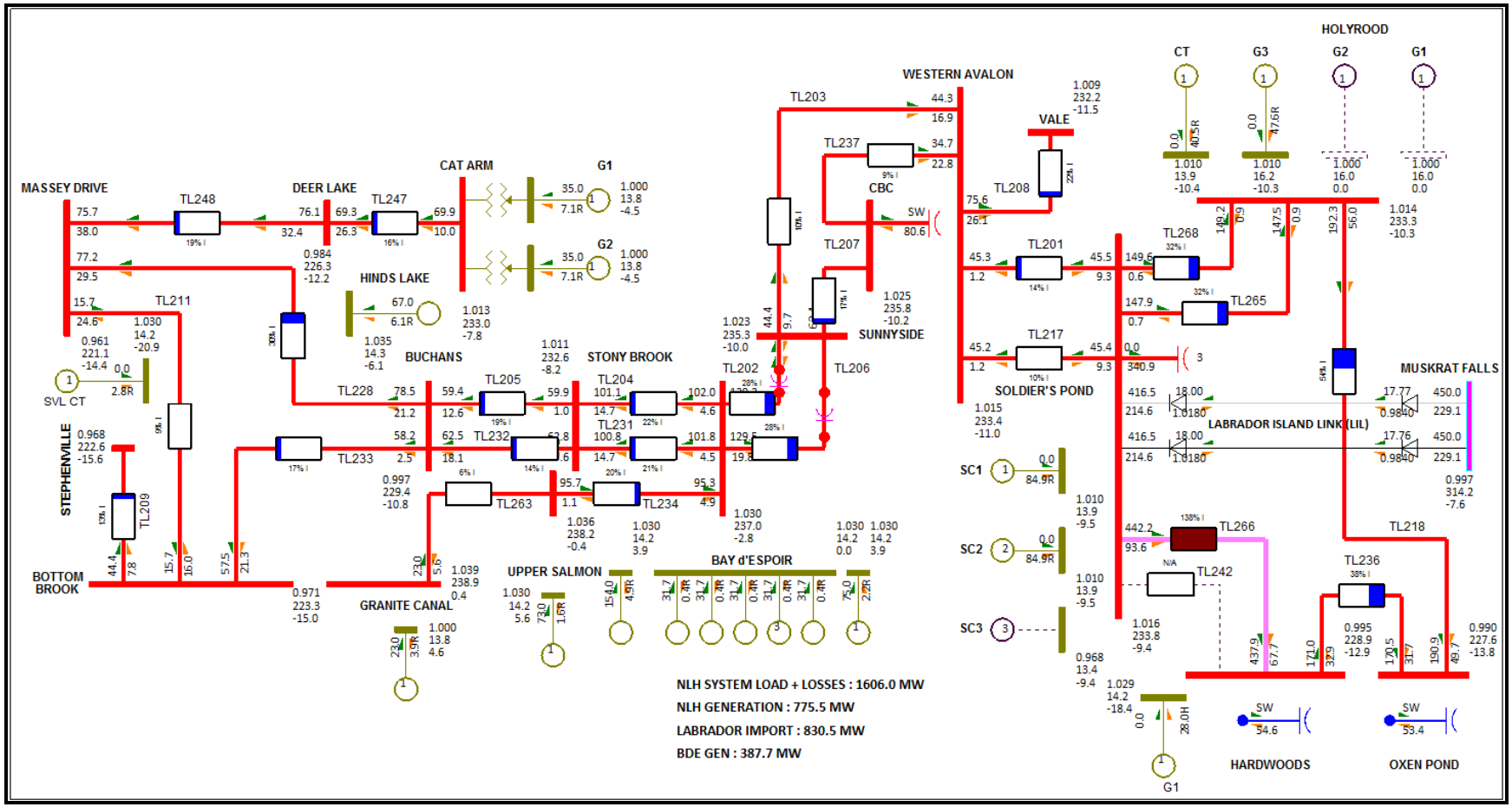


Figure 163 – Base Case 2 (BC2) Load Flow Plot – TL242 Out of Service

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (773 MW)

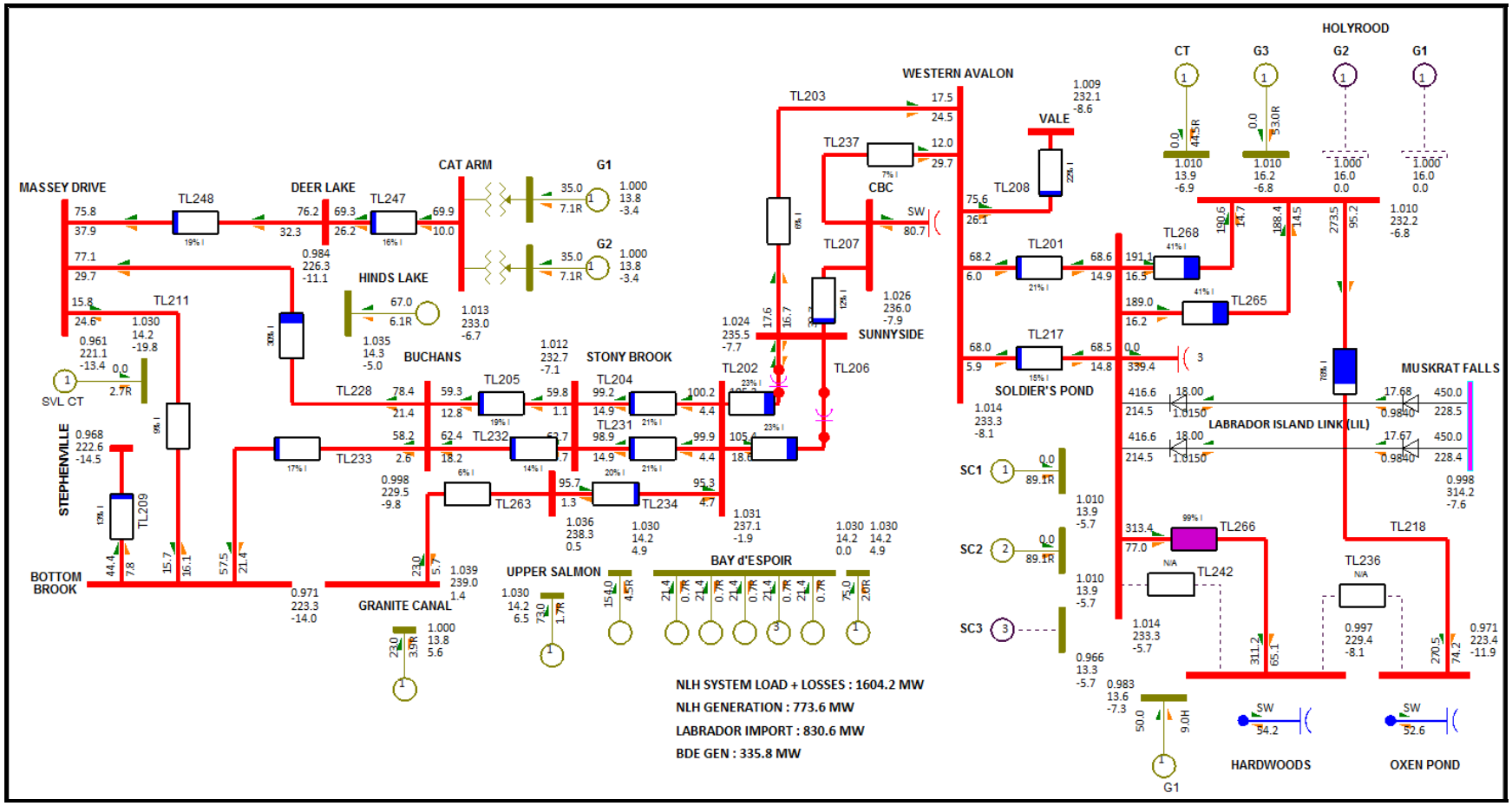


Figure 164 – Base Case 2 (BC2) Load Flow Plot – TL242 Out of Service – HWD CT Generating 50 MW and TL236 Open

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (773 MW)

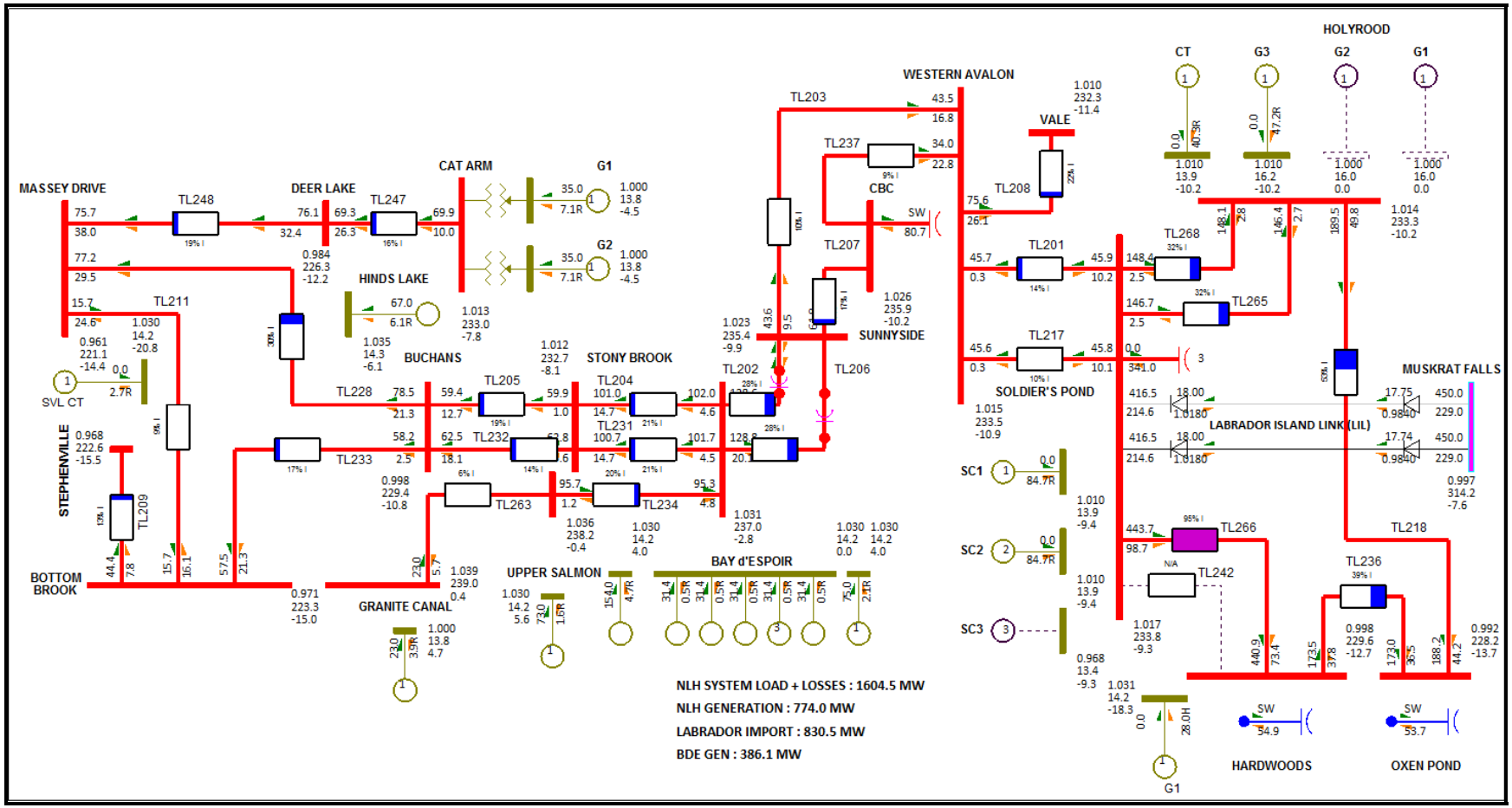


Figure 165 – Base Case 2 (BC2) Load Flow Plot – TL242 Out of Service

TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (773 MW)

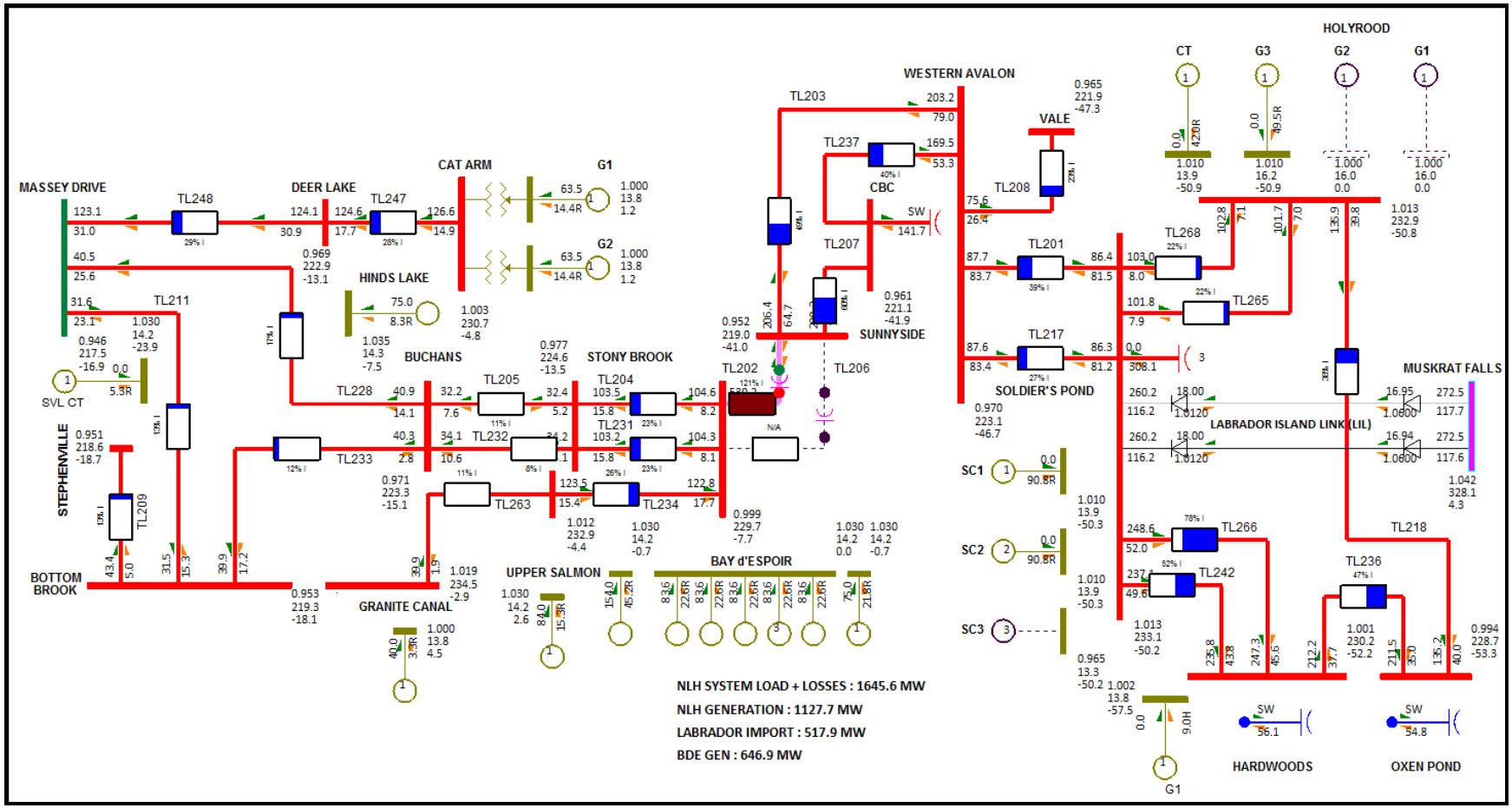


Figure 166 – Base Case 3 (BC3) Load Flow Plot – TL206 Out of Service

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

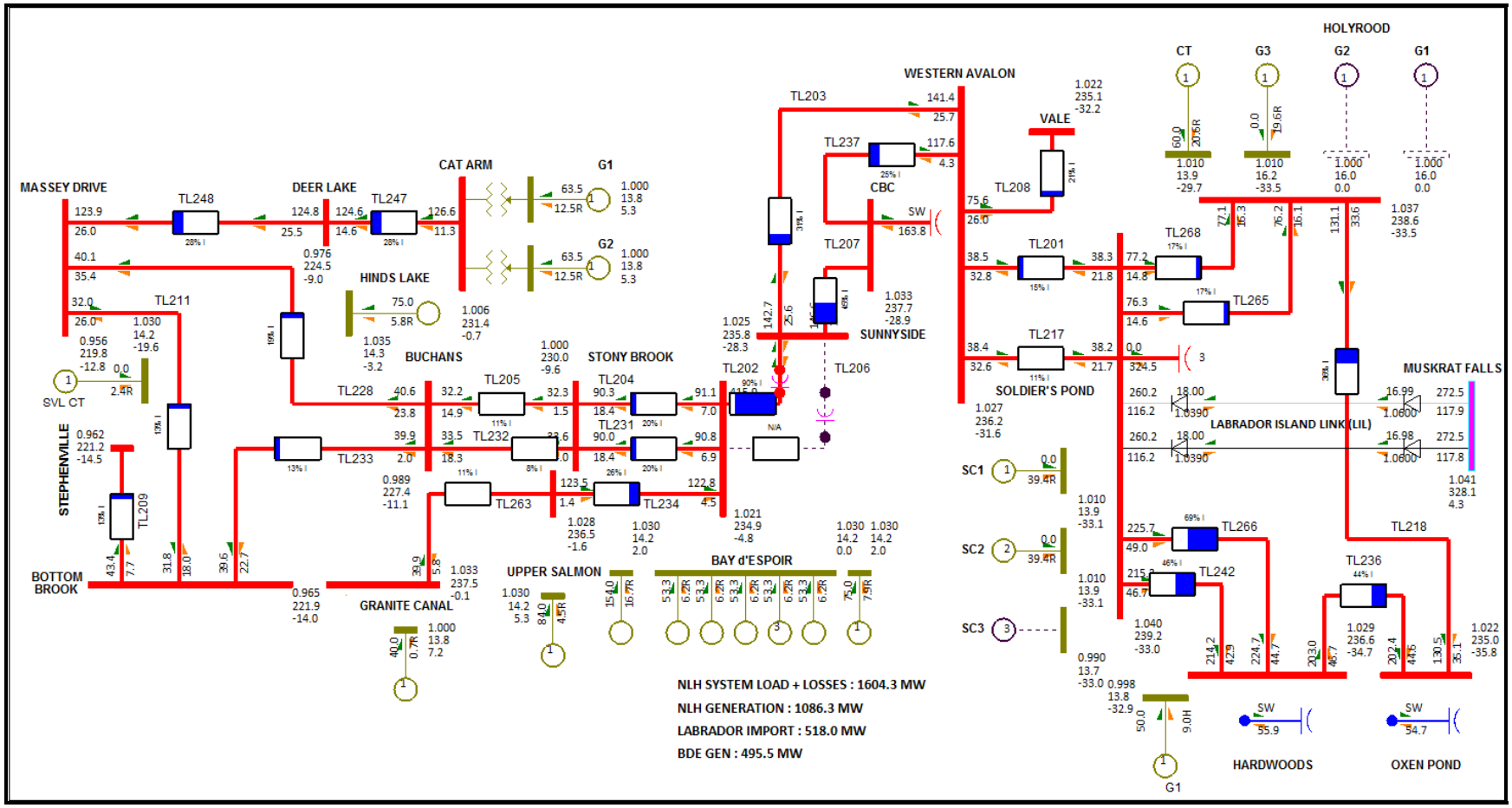


Figure 167 – Base Case 3 (BC3) Load Flow Plot – TL206 Out of Service – HWD CT and HRD CT Generating 110 MW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

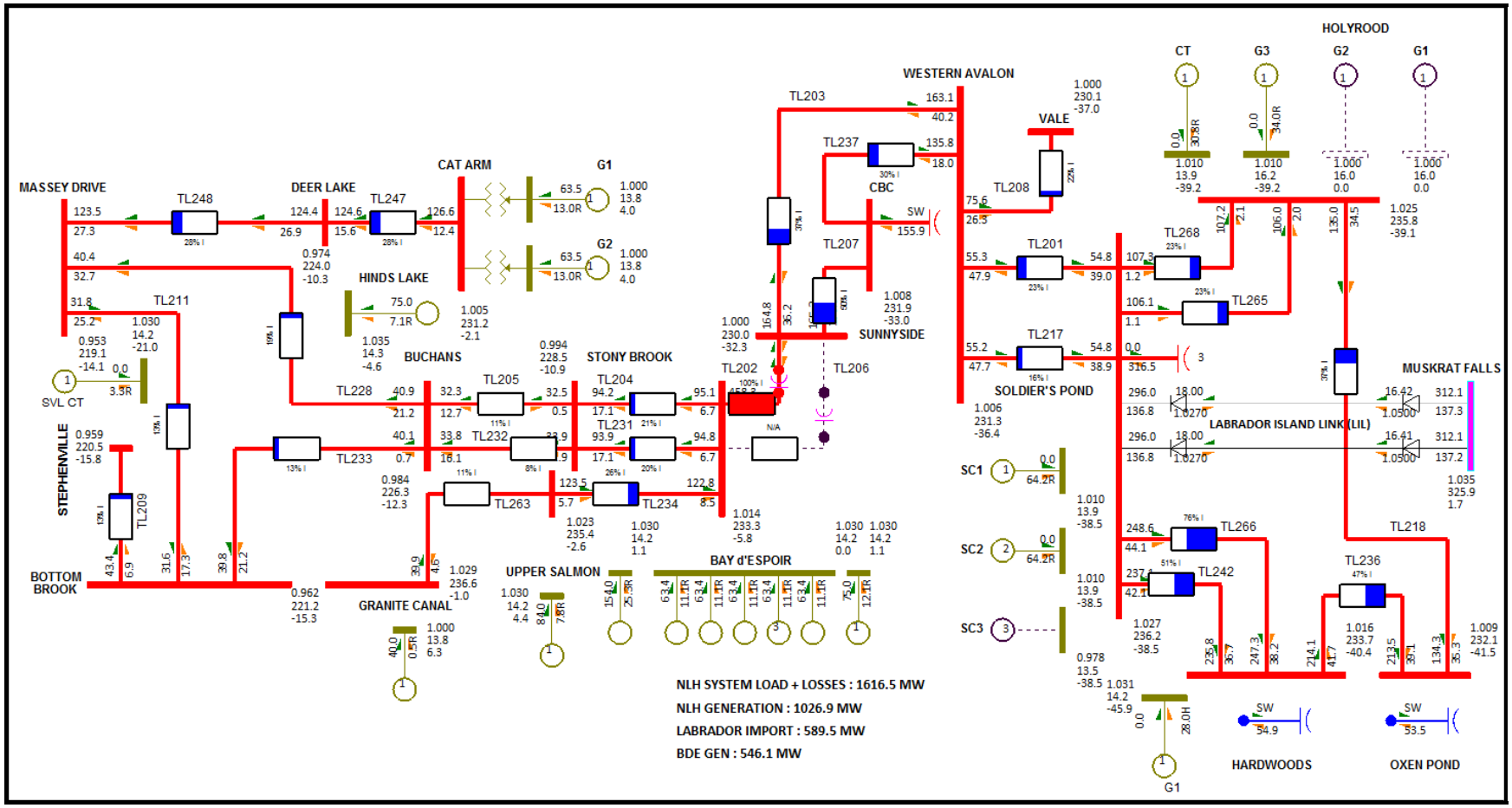


Figure 168 – Base Case 3 (BC3) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 590 MW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

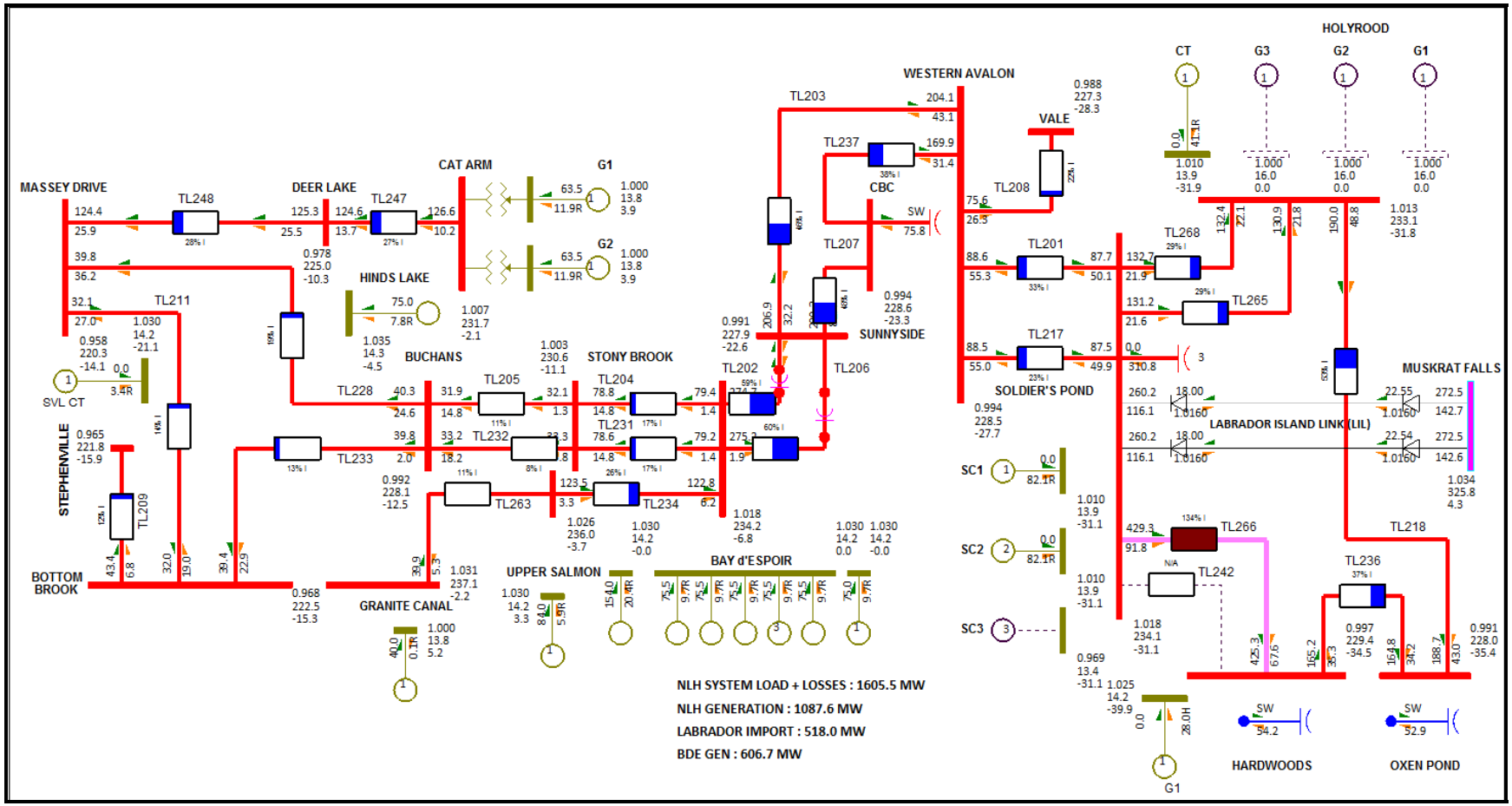


Figure 169 – Base Case 3 (BC3) Load Flow Plot – TL242 Out of Service

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

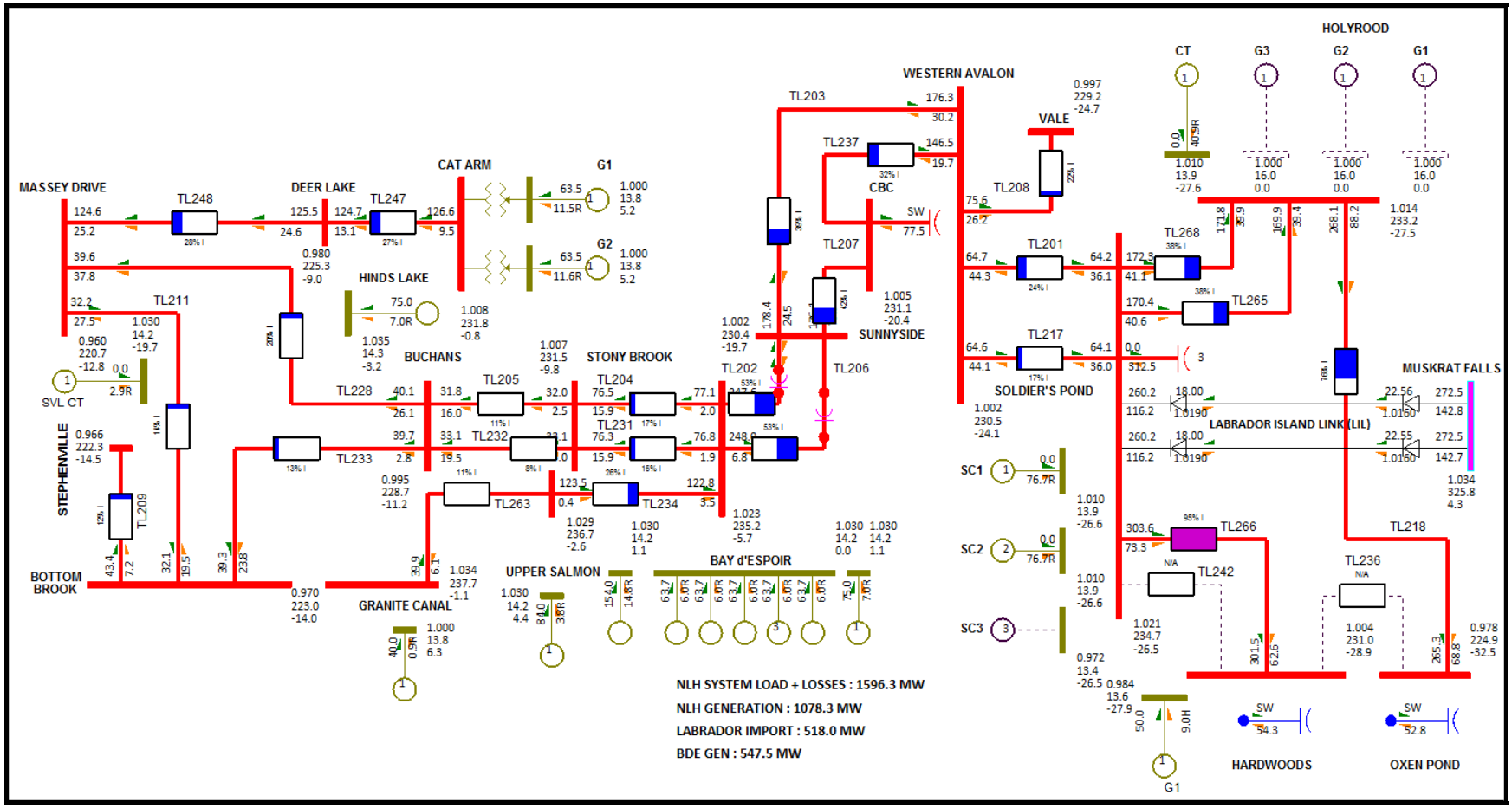


Figure 170 – Base Case 3 (BC3) Load Flow Plot – TL242 Out of Service – HWD CT Generating 50 MW and TL236 Open

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

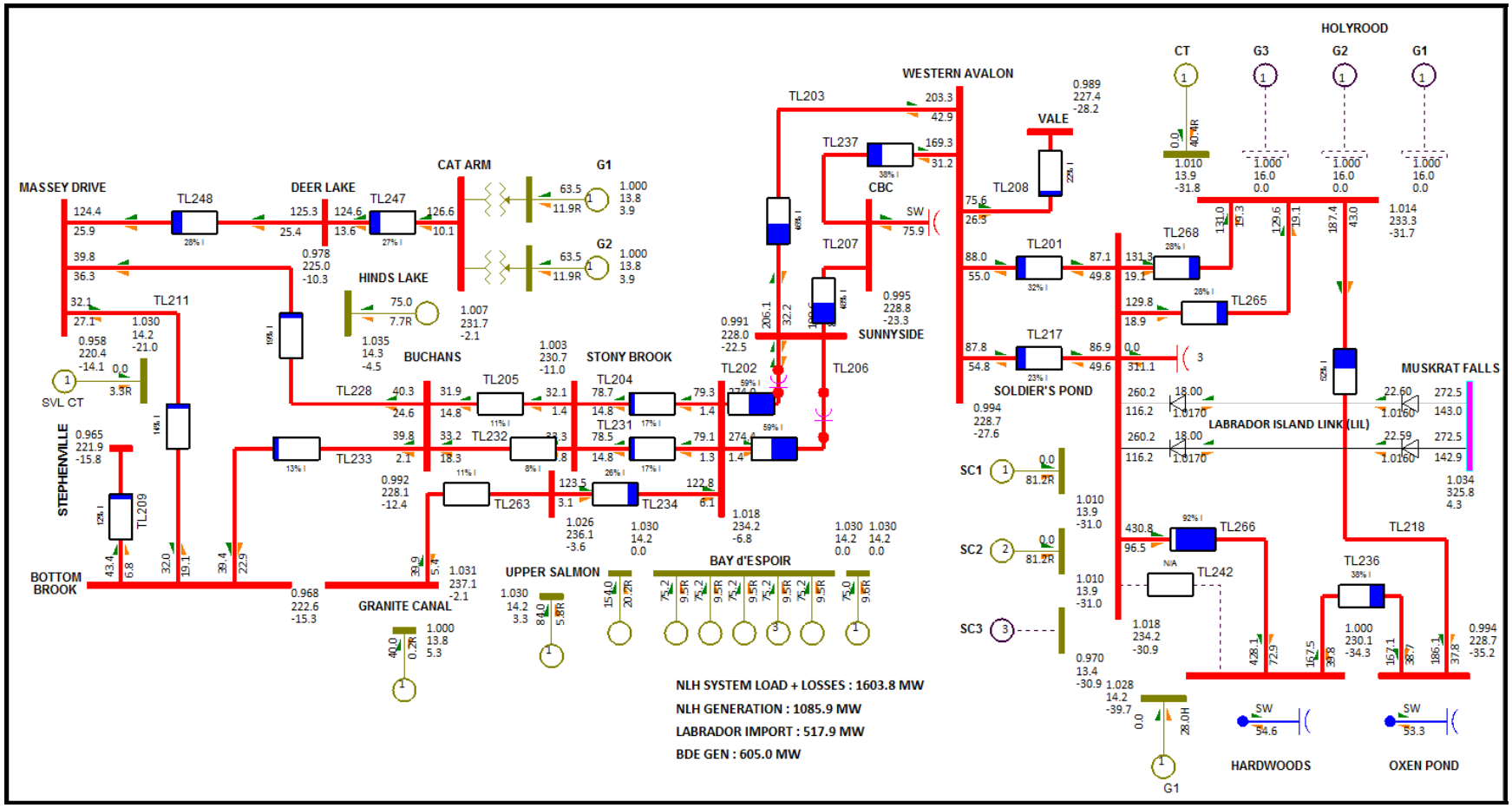


Figure 171 – Base Case 3 (BC3) Load Flow Plot – TL242 Out of Service

TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

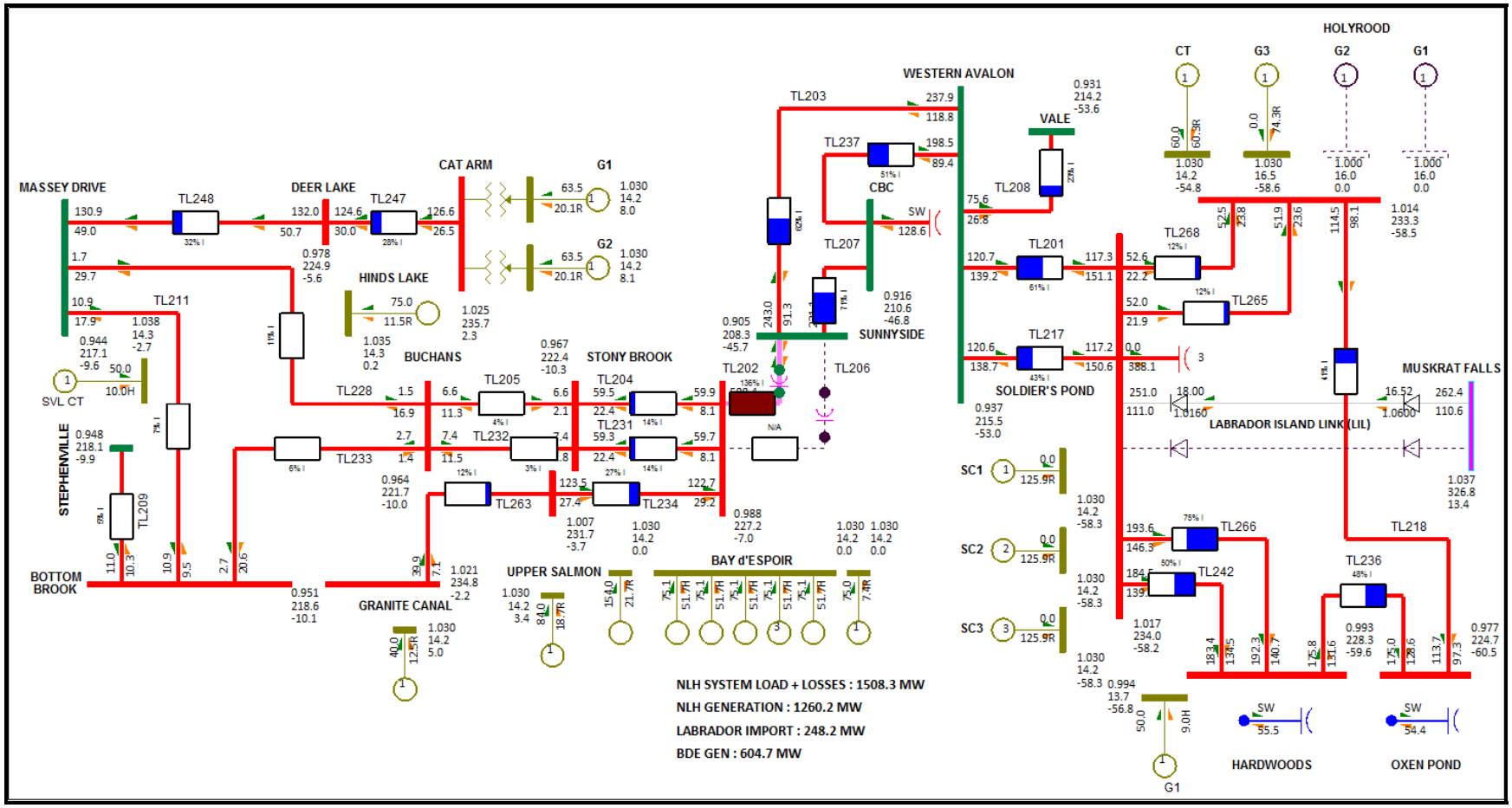


Figure 172 – Base Case 4 (BC4) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 248 MW to Maintain Adequate Generation

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

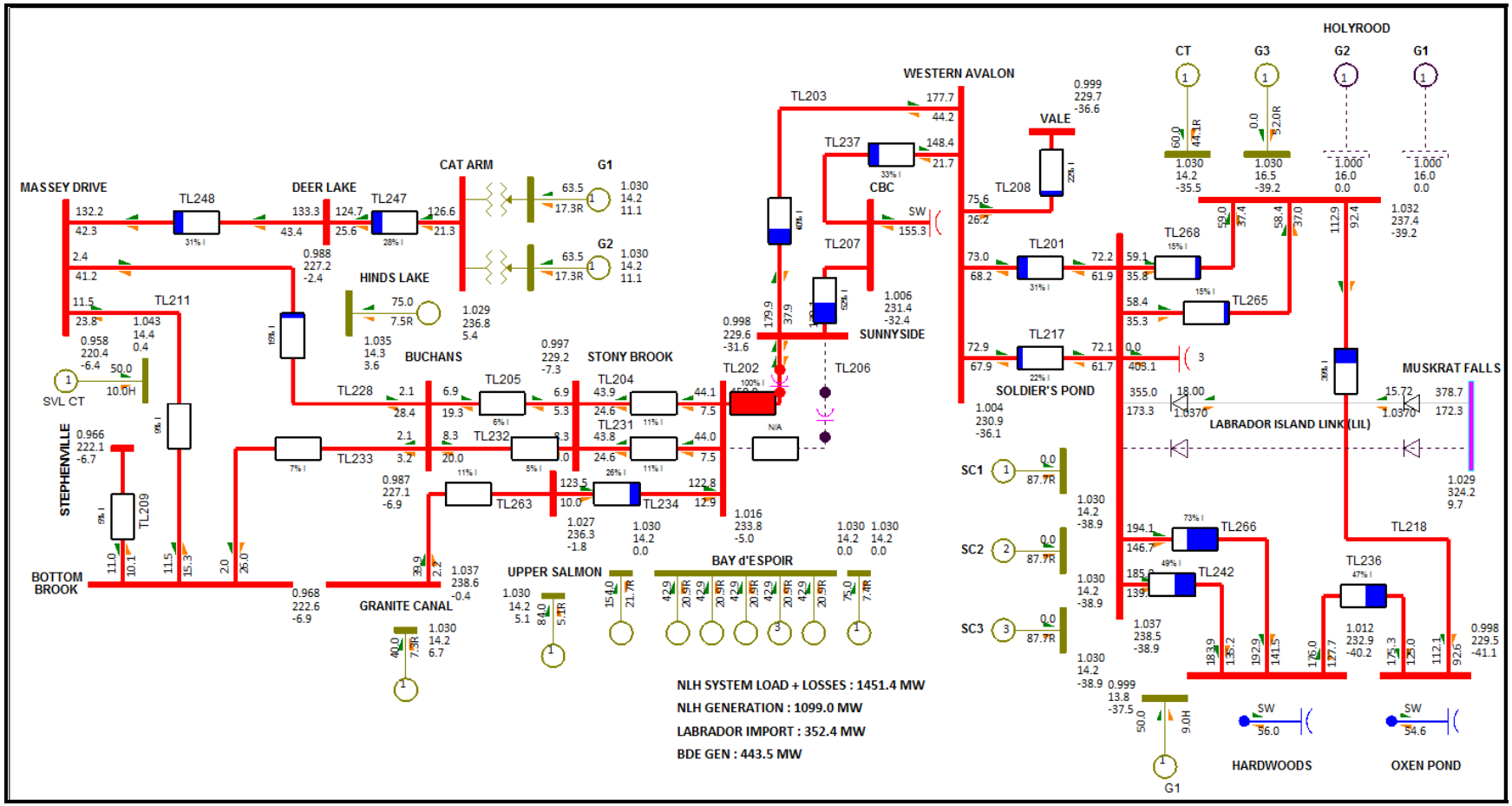


Figure 173 – Base Case 4 (BC4) Load Flow Plot – TL206 Out of Service – LIL Import Increased 352 MW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

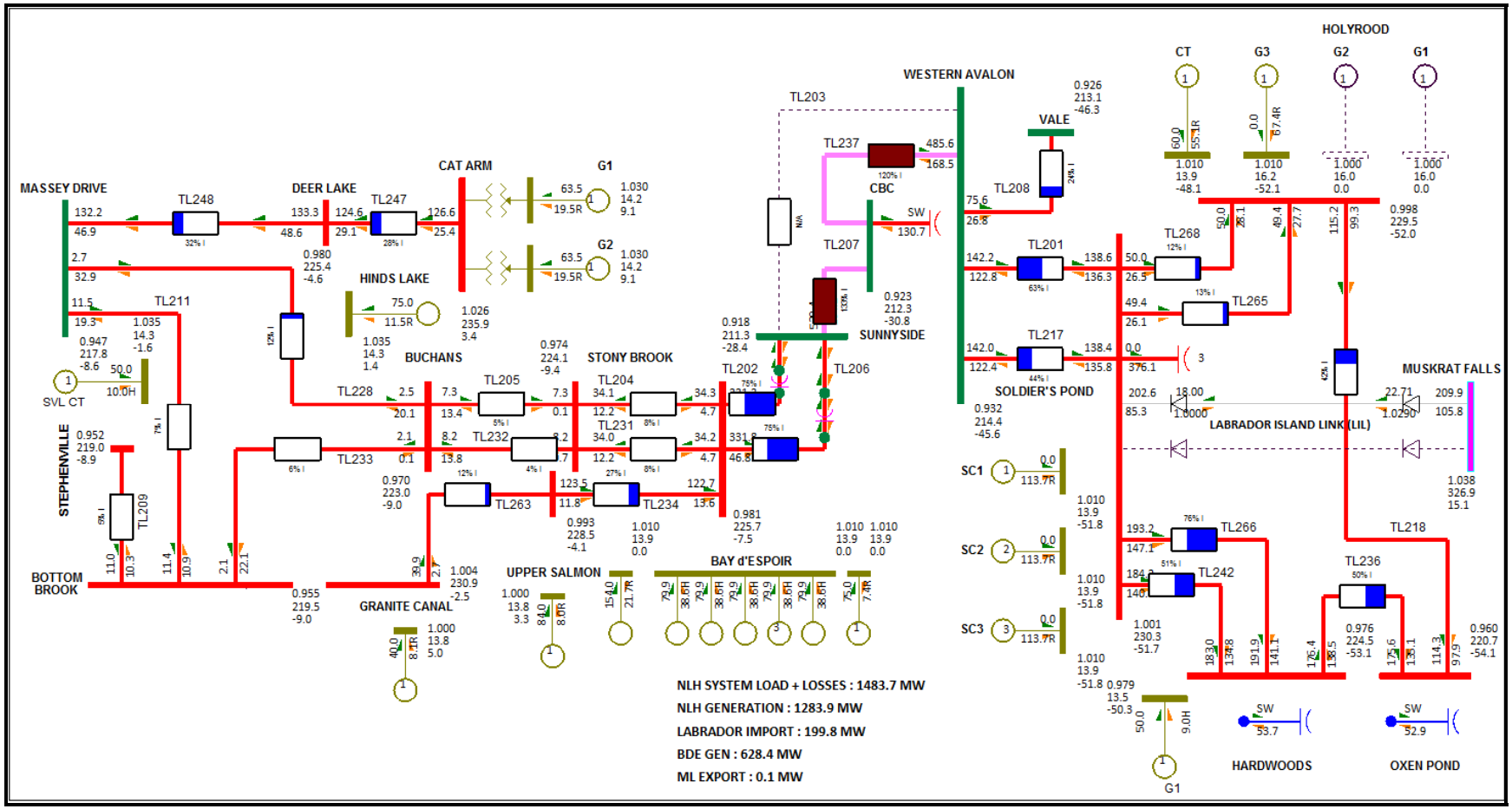


Figure 174 – Base Case 4 (BC4) Load Flow Plot – TL203 Out of Service

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

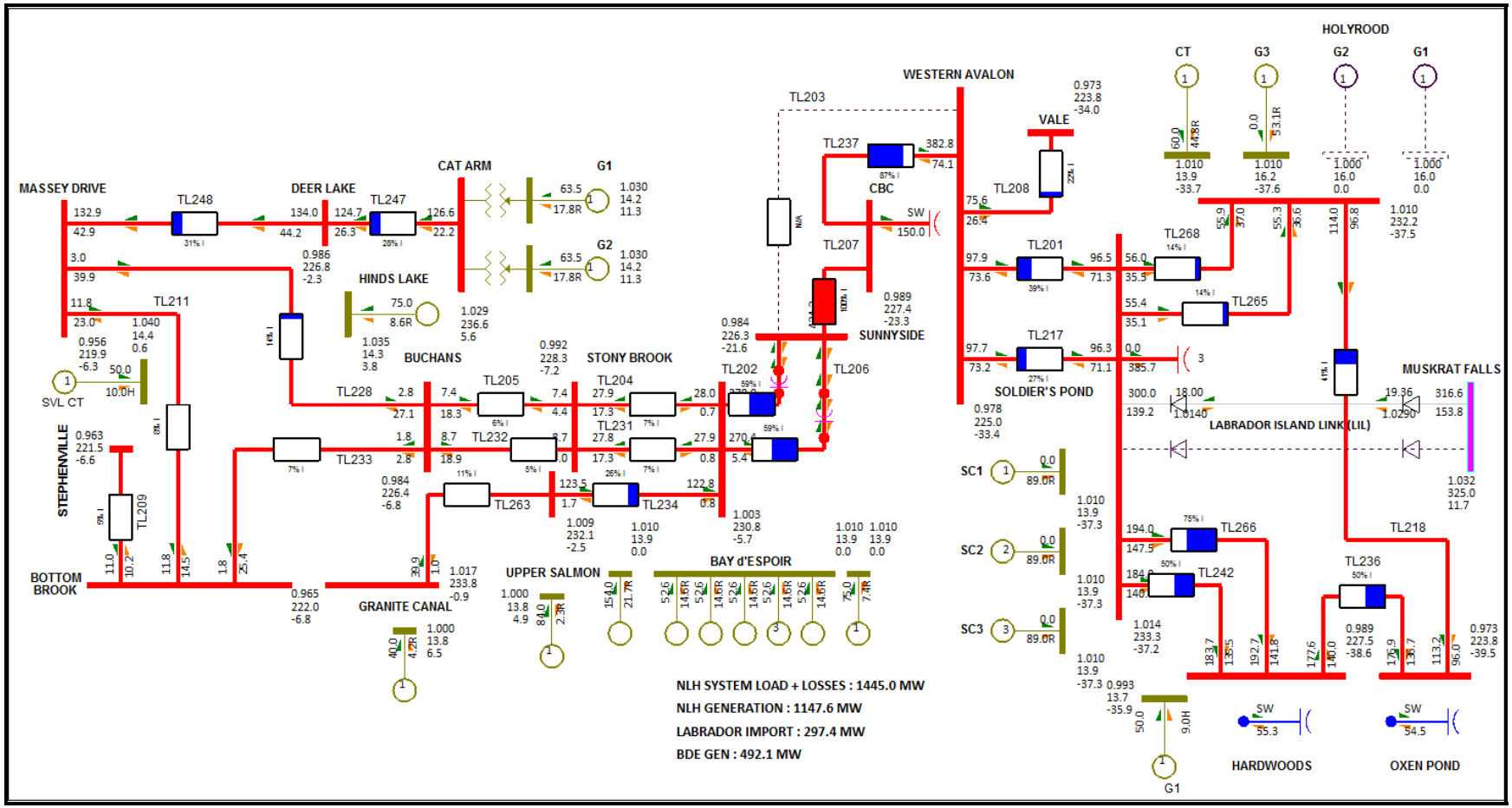


Figure 175 – Base Case 4 (BC4) Load Flow Plot – TL203 Out of Service – LIL Import Increased to 297 MW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

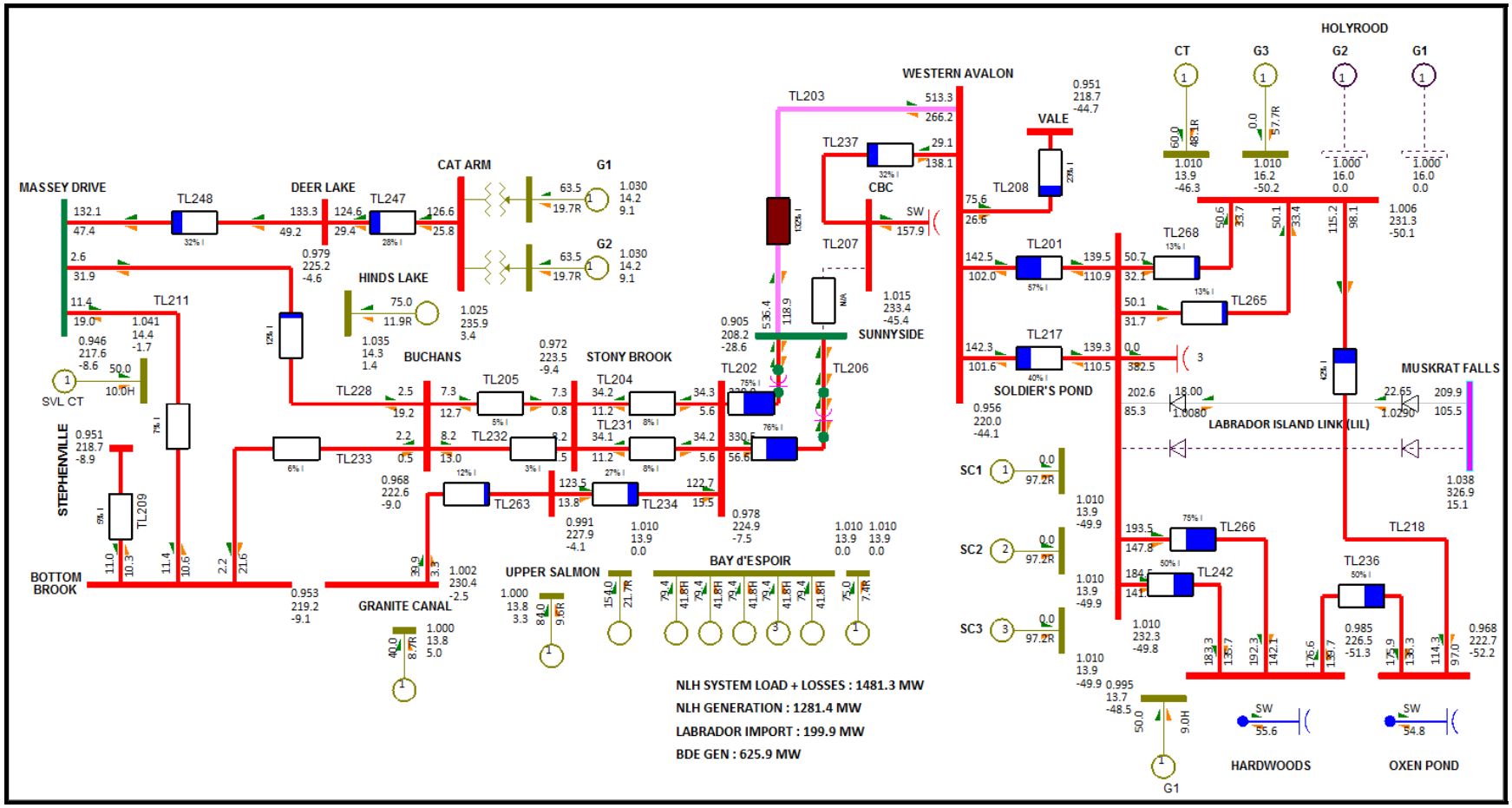


Figure 176 – Base Case 4 (BC4) Load Flow Plot – TL207 Out of Service

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

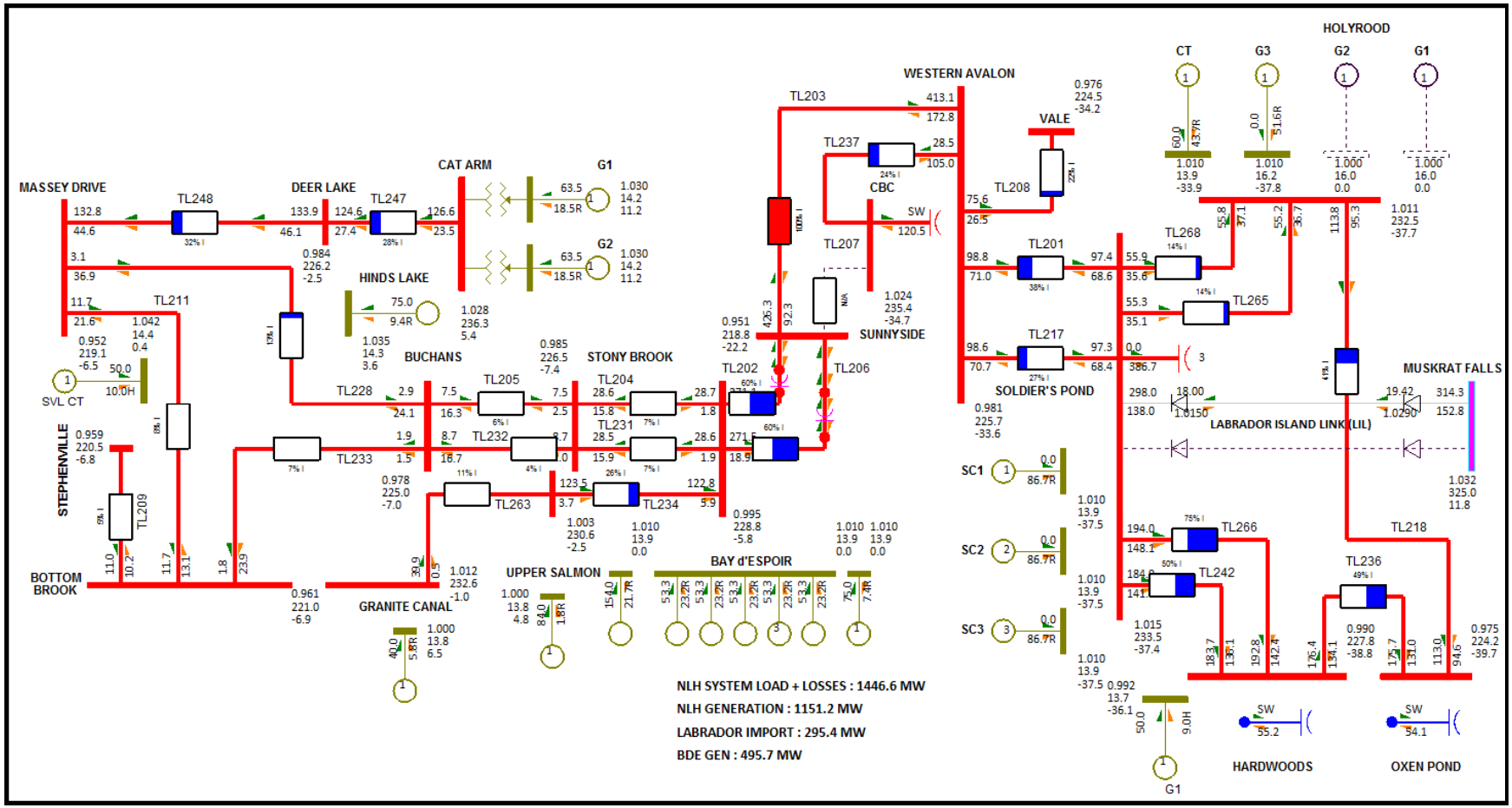


Figure 177 – Base Case 4 (BC4) Load Flow Plot – TL207 Out of Service – LIL Import Increased to 295 MW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

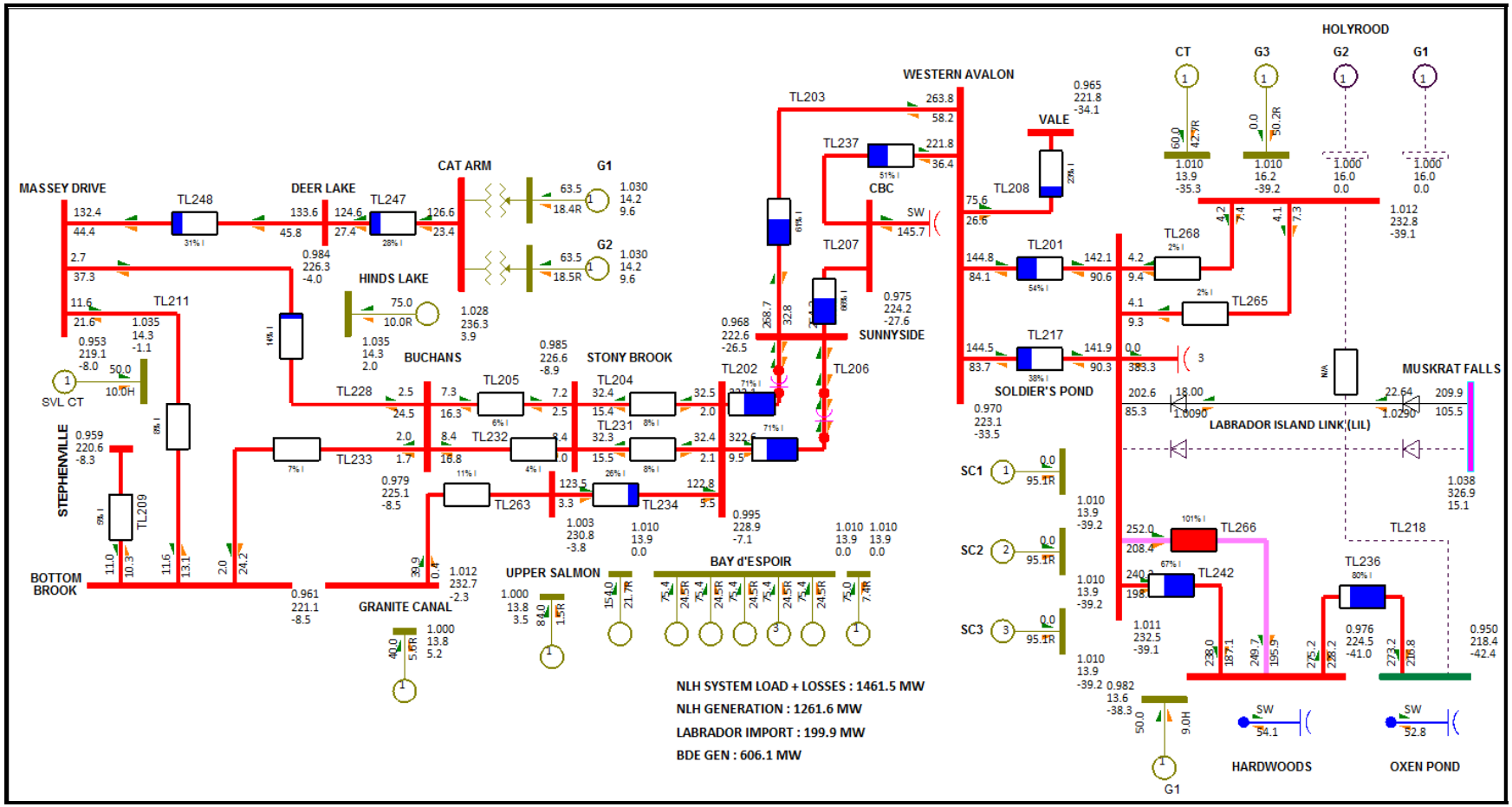


Figure 178 – Base Case 4 (BC4) Load Flow Plot – TL218 Out of Service

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

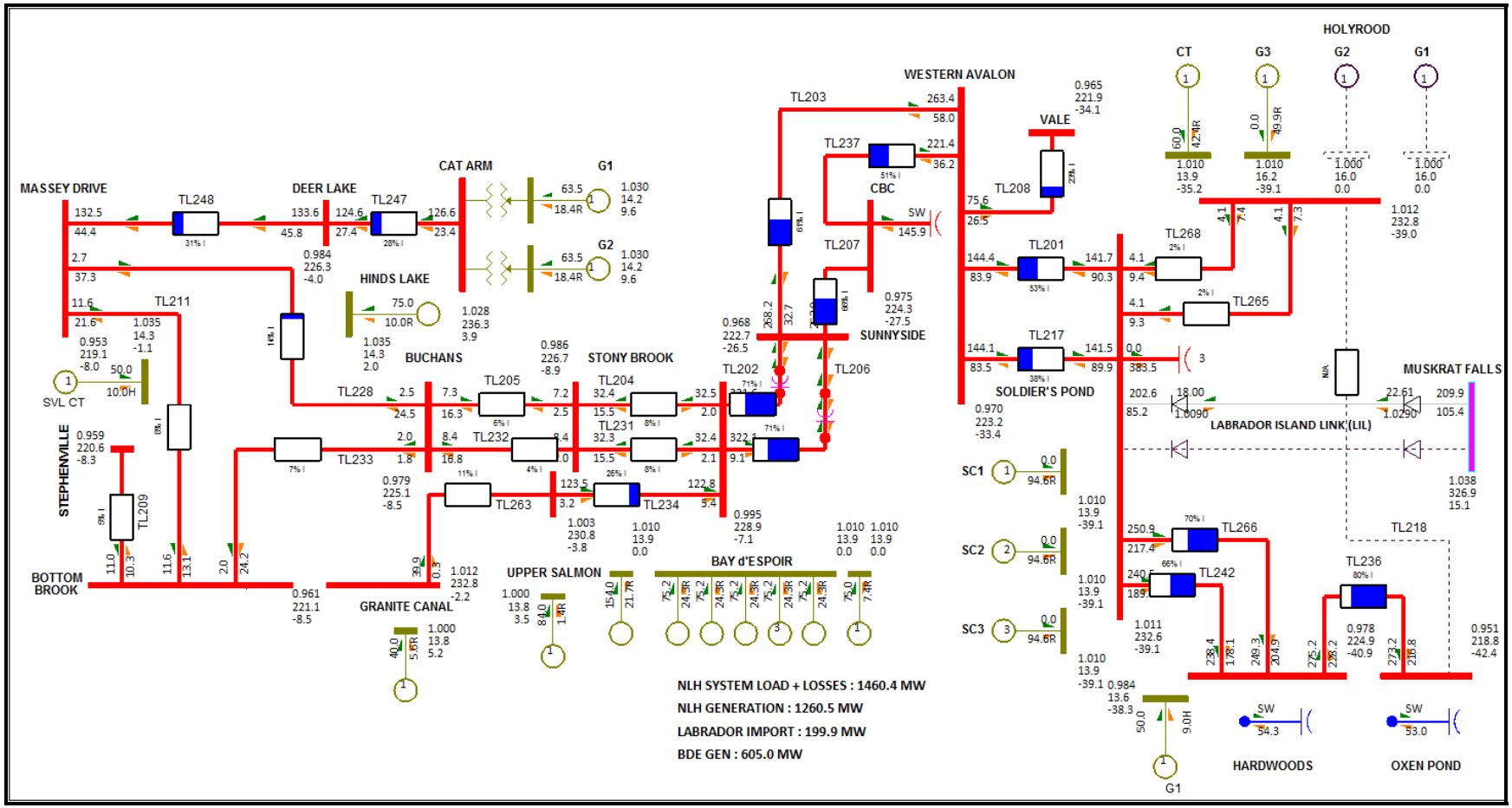


Figure 179 – Base Case 4 (BC4) Load Flow Plot – TL218 Out of Service

TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

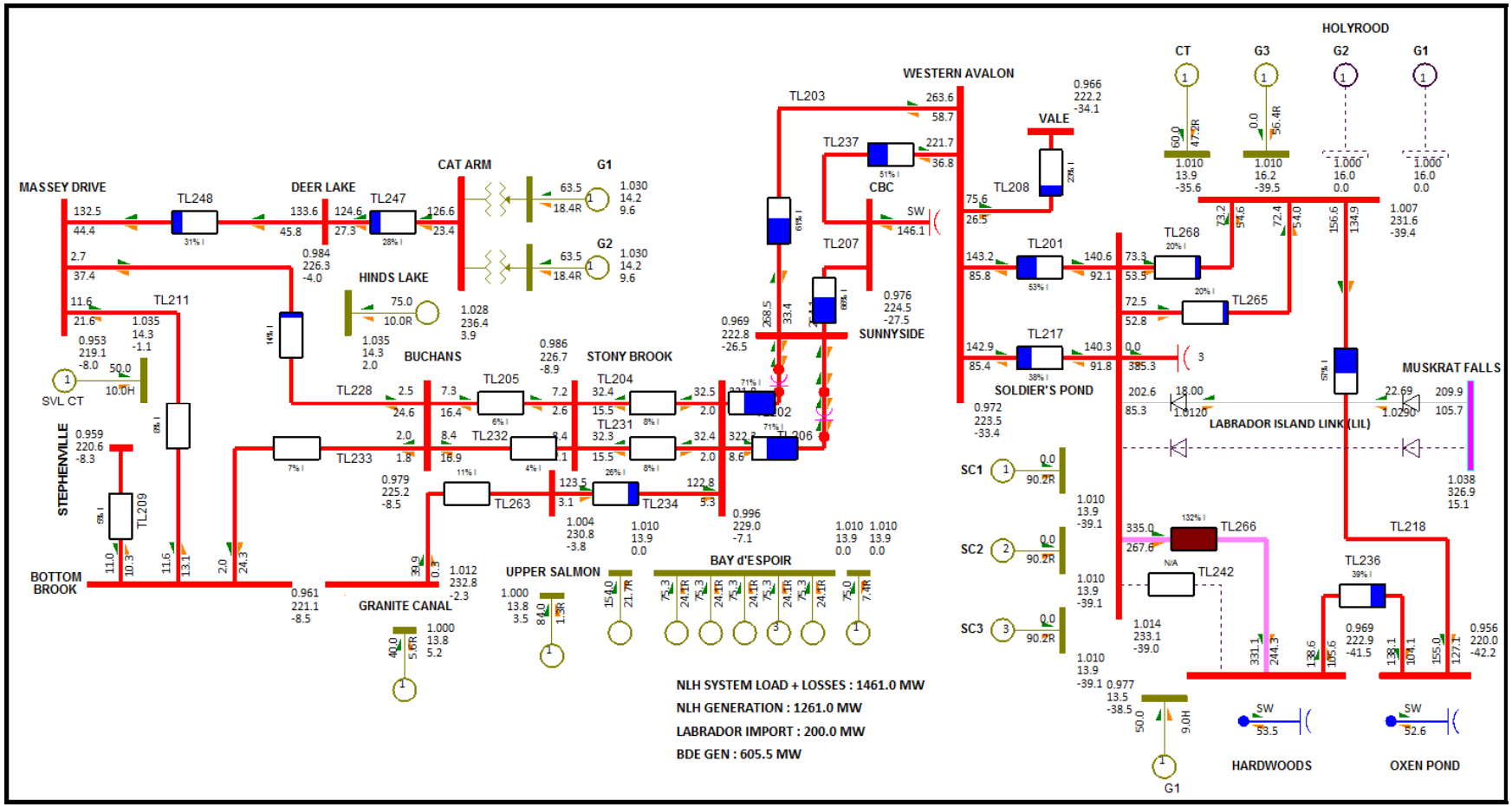


Figure 180 – Base Case 4 (BC4) Load Flow Plot – TL242 Out of Service

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

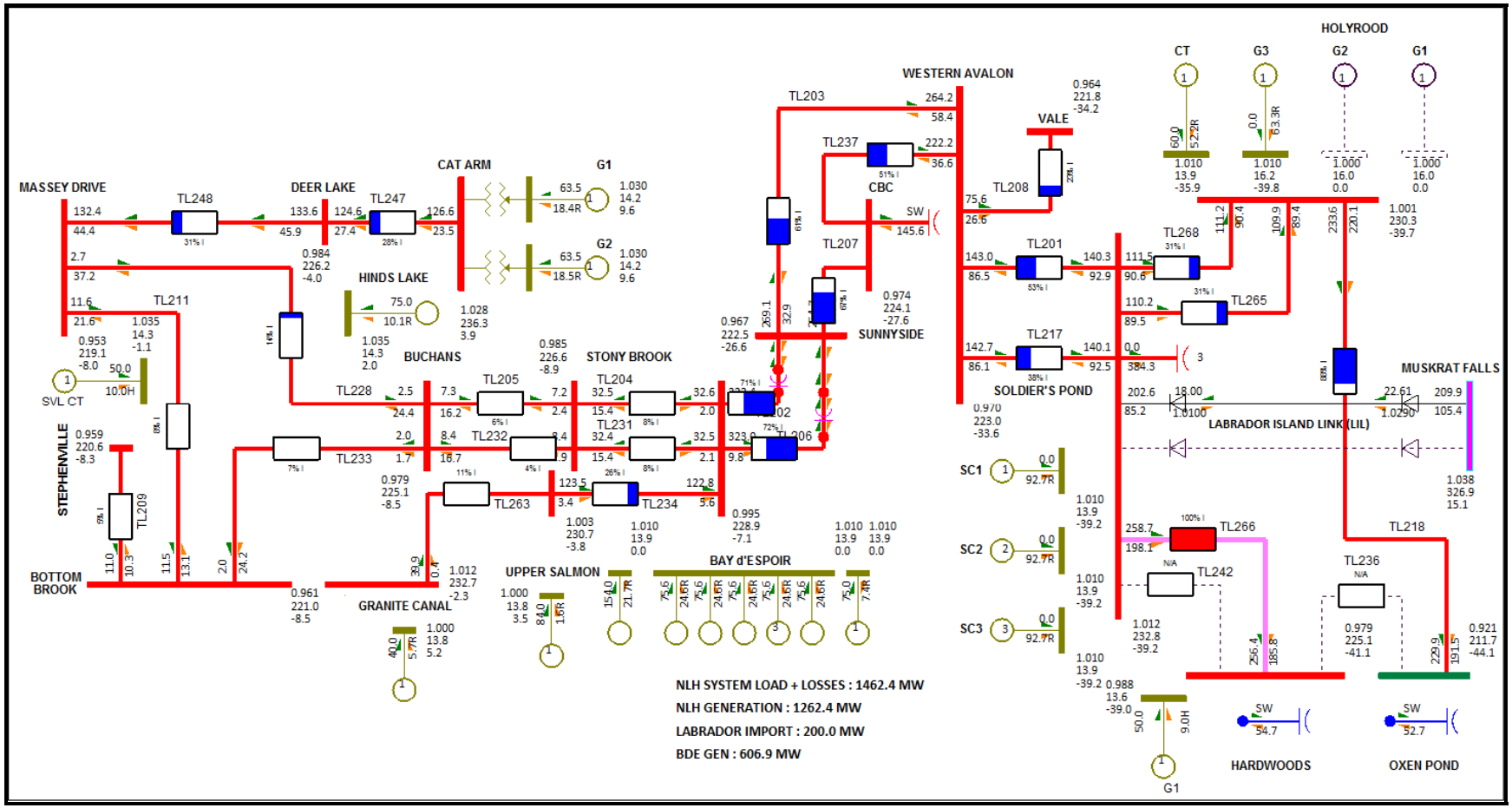


Figure 181 – Base Case 4 (BC4) Load Flow Plot – TL242 Out of Service – TL236 Open

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

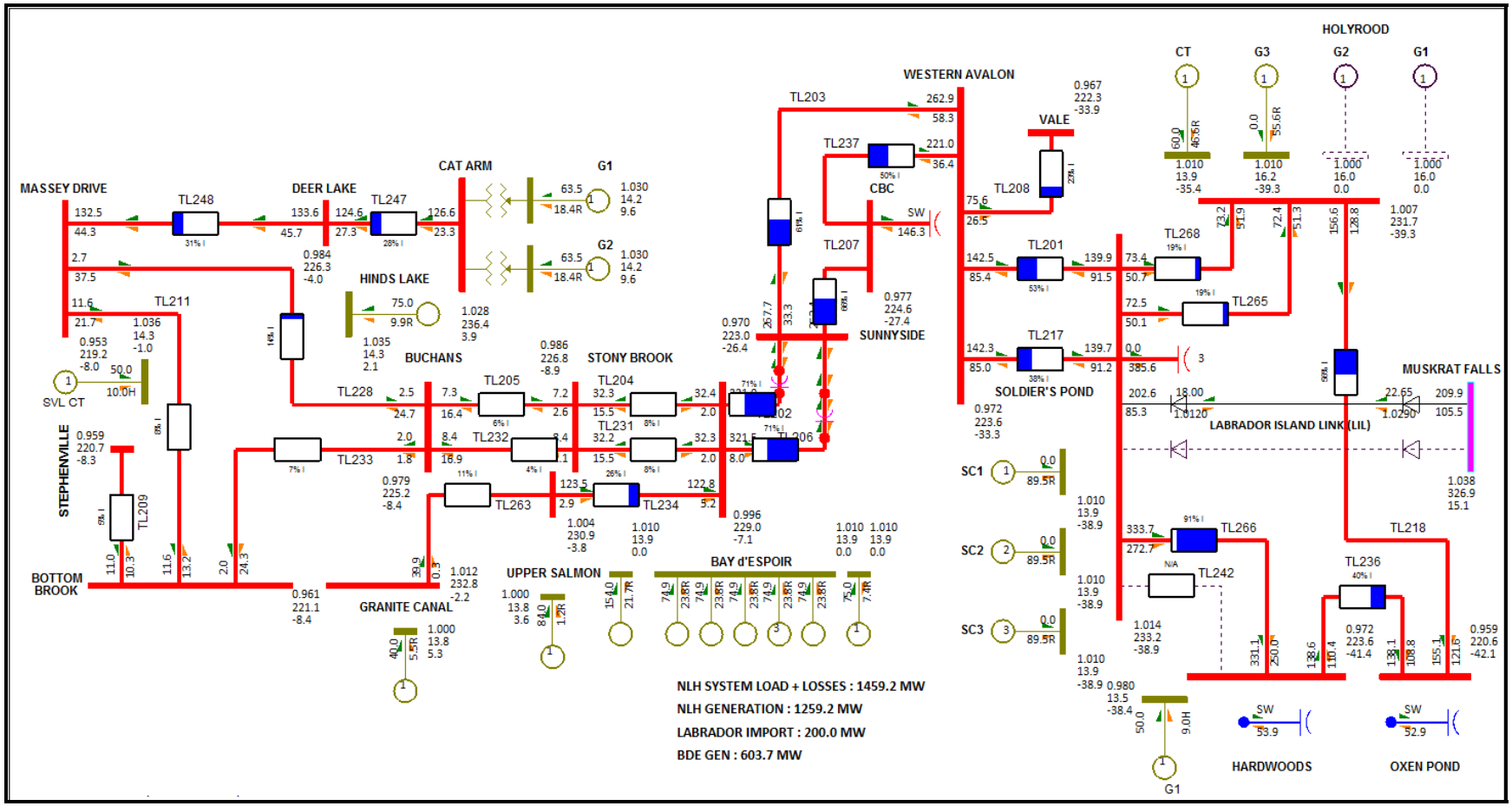


Figure 182 – Base Case 4 (BC4) Load Flow Plot – TL242 Out of Service

TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

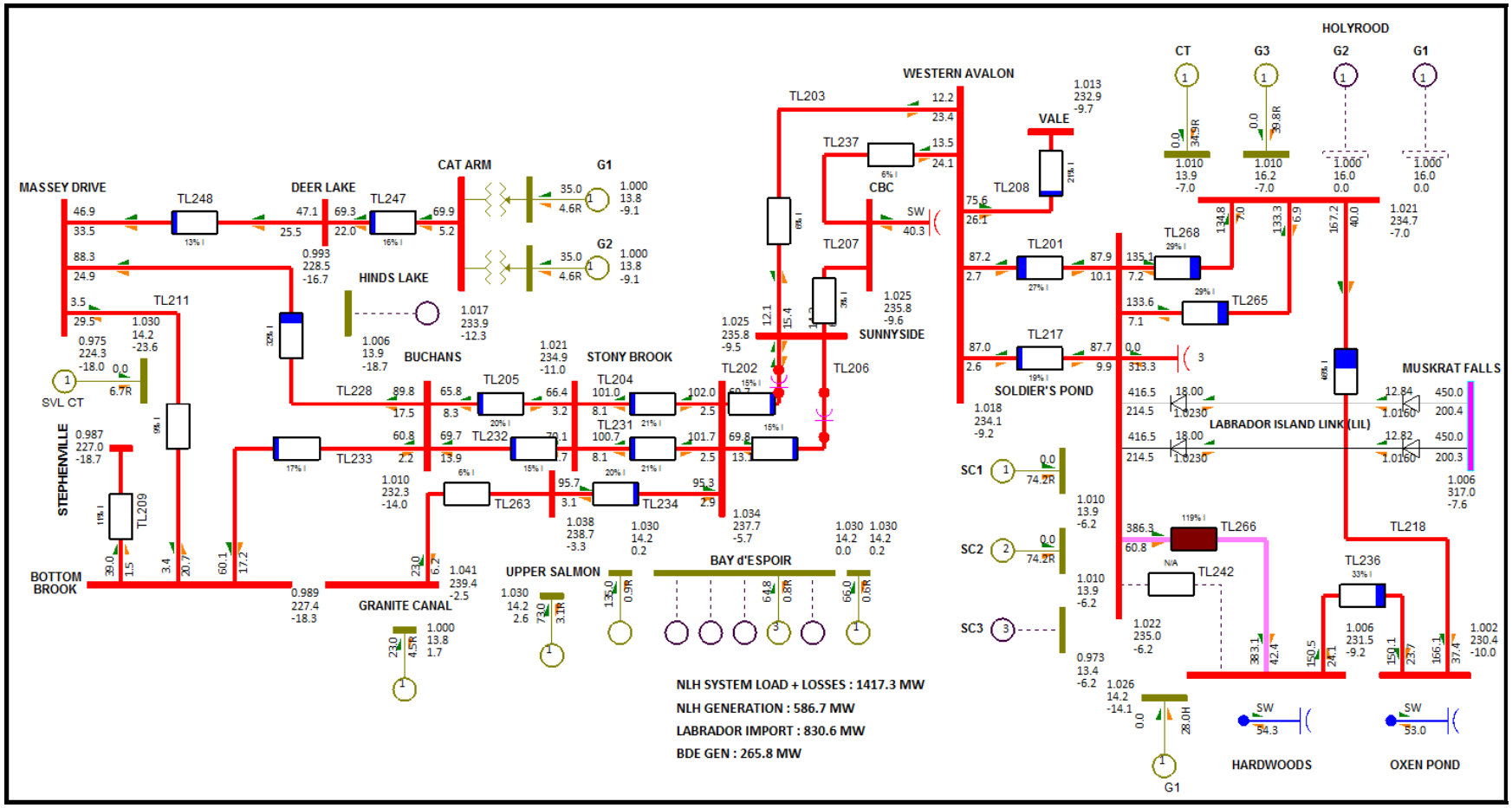


Figure 183 – Base Case 5 (BC5) Load Flow Plot – TL242 Out of Service

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (585 MW)

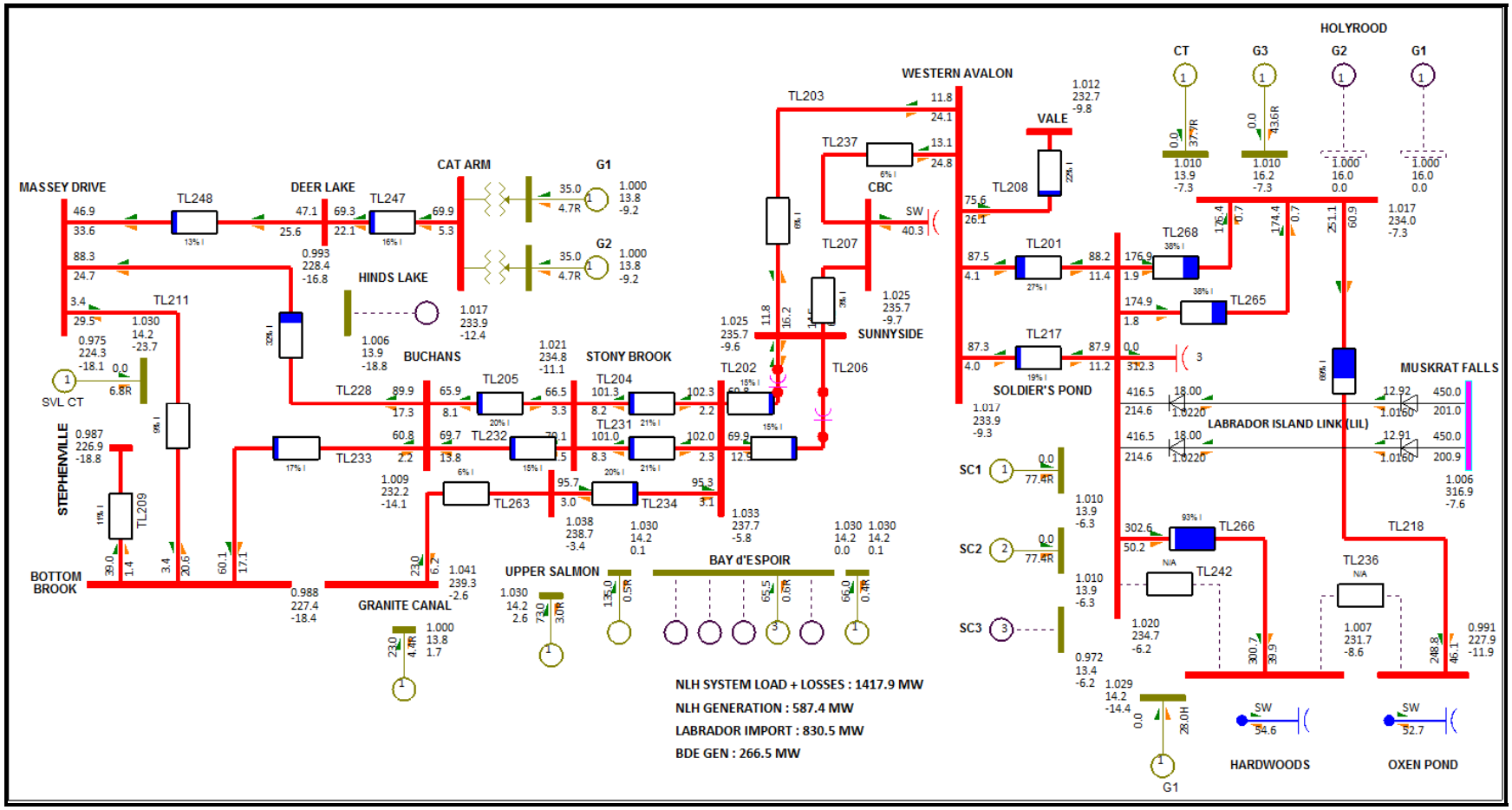


Figure 184 – Base Case 5 (BC5) Load Flow Plot – TL242 Out of Service – TL236 Open

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (585 MW)

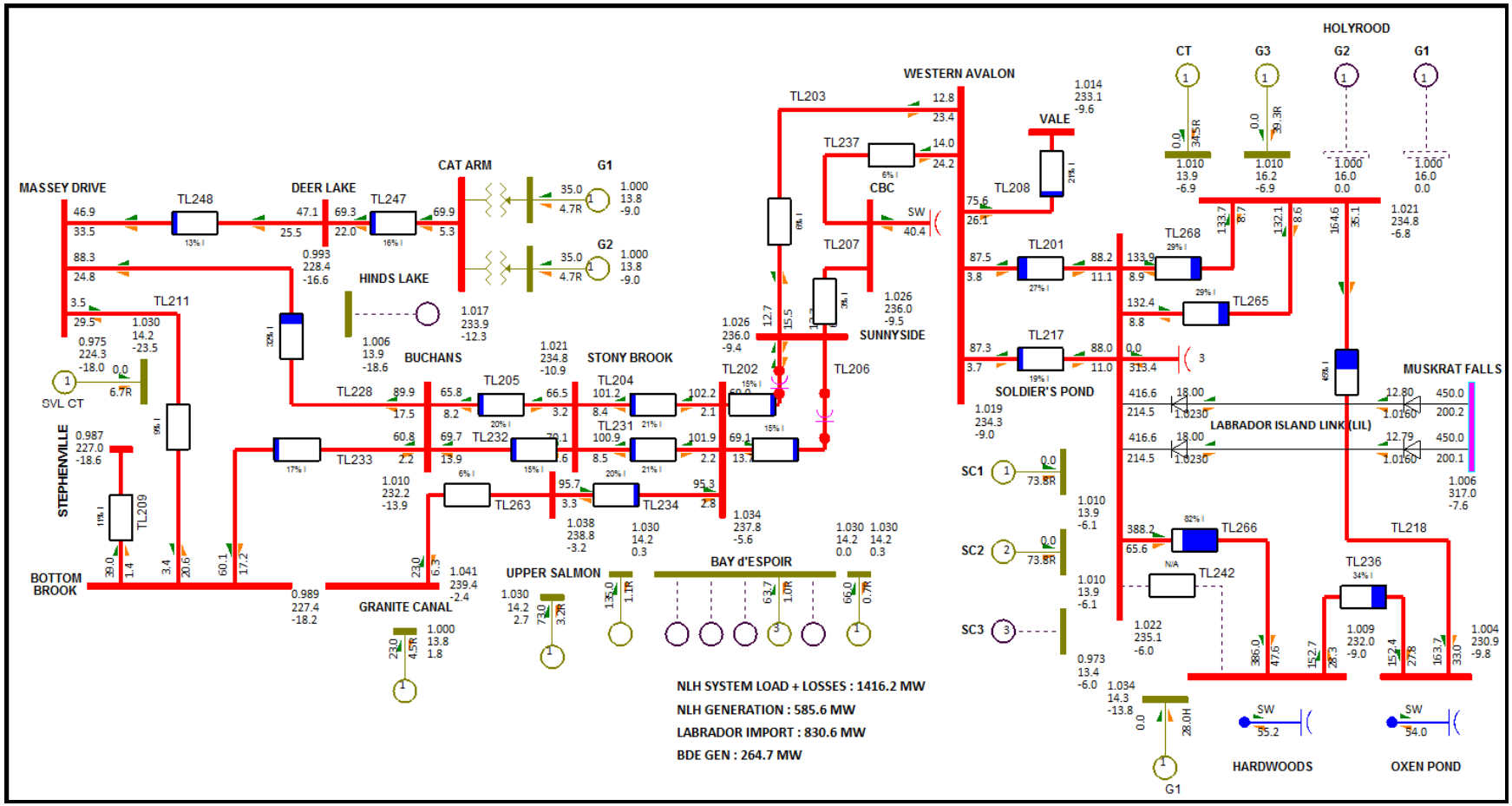


Figure 185 – Base Case 5 (BC5) Load Flow Plot – TL242 Out of Service

TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (585 MW)

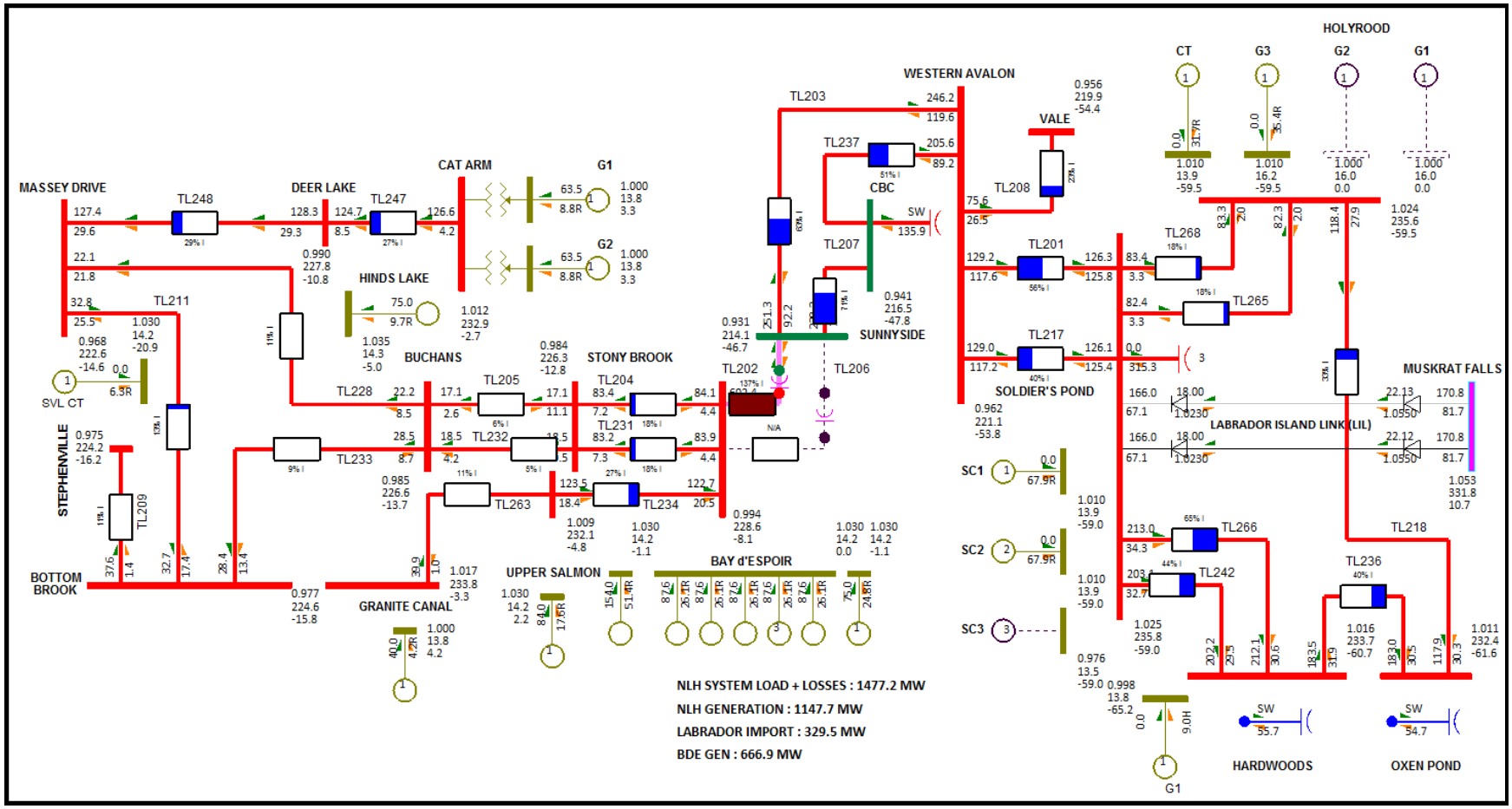


Figure 186 – Base Case 6 (BC6) Load Flow Plot – TL206 Out of Service

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

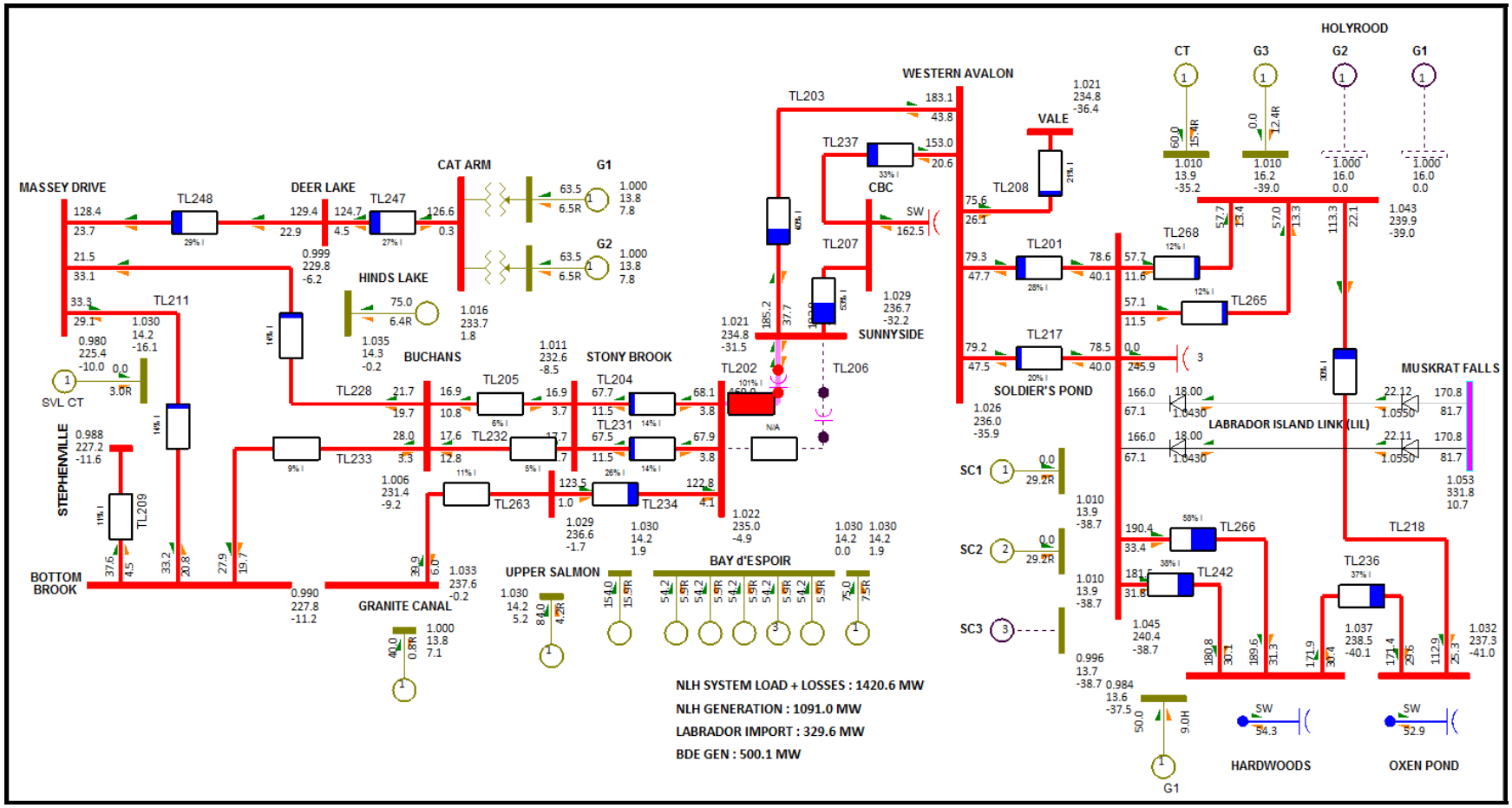


Figure 187 – Base Case 6 (BC6) Load Flow Plot – TL206 Out of Service – HWD CT and HRD CT Generating 110 MW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

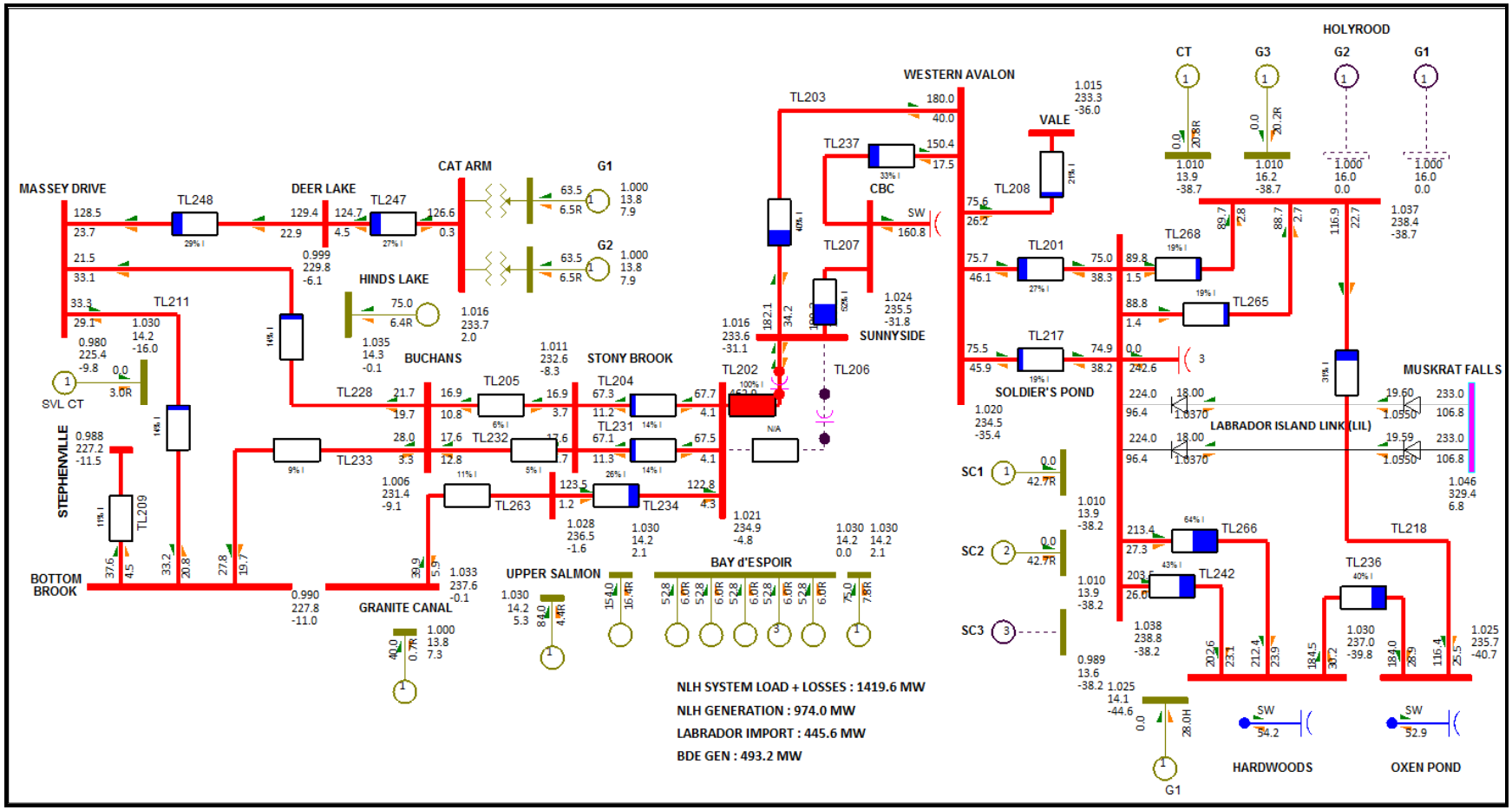


Figure 188 – Base Case 6 (BC6) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 446 MW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

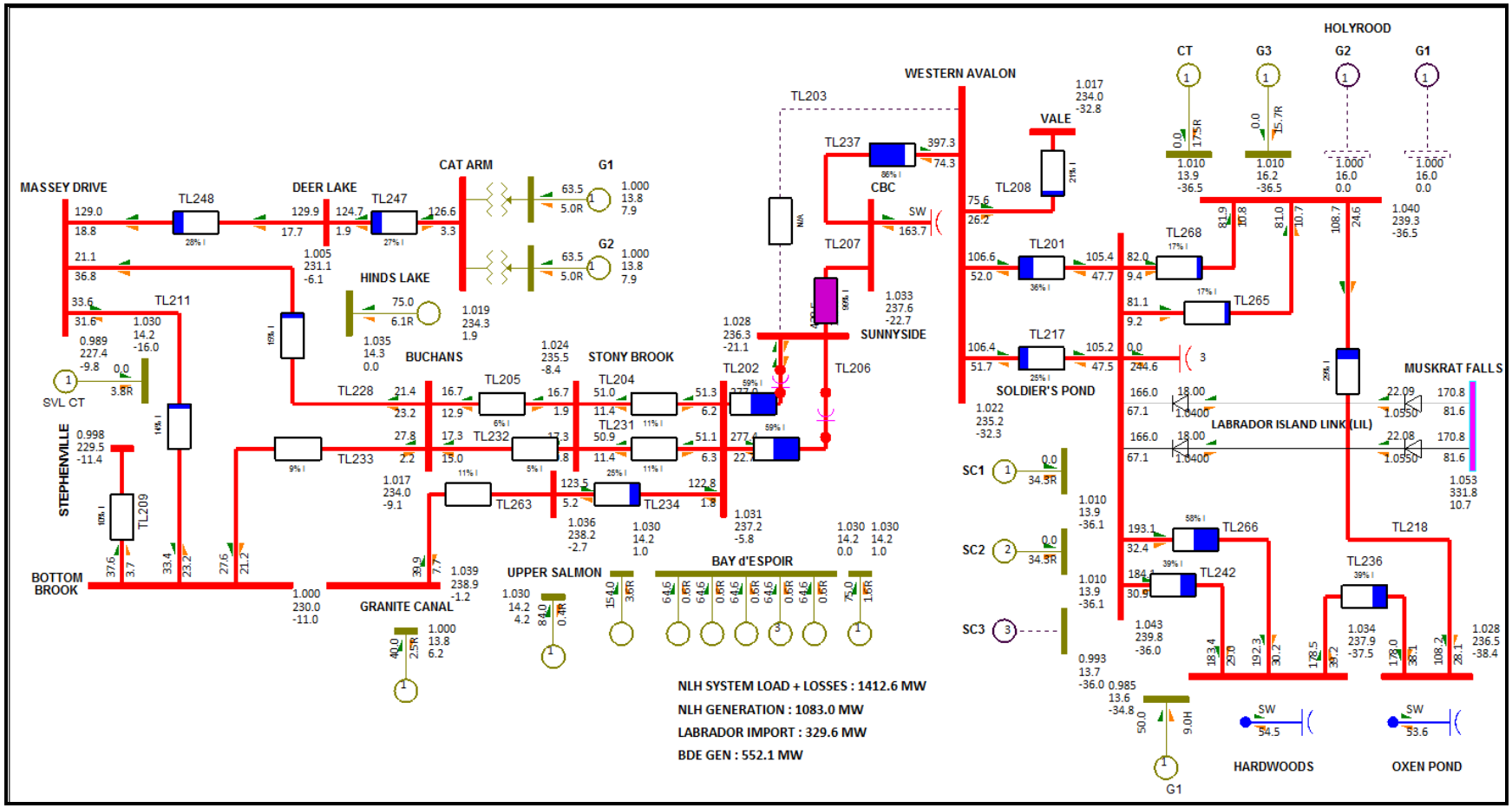


Figure 189 – Base Case 6 (BC6) Load Flow Plot – TL203 Out of Service – HWD CT Generating 50 MW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

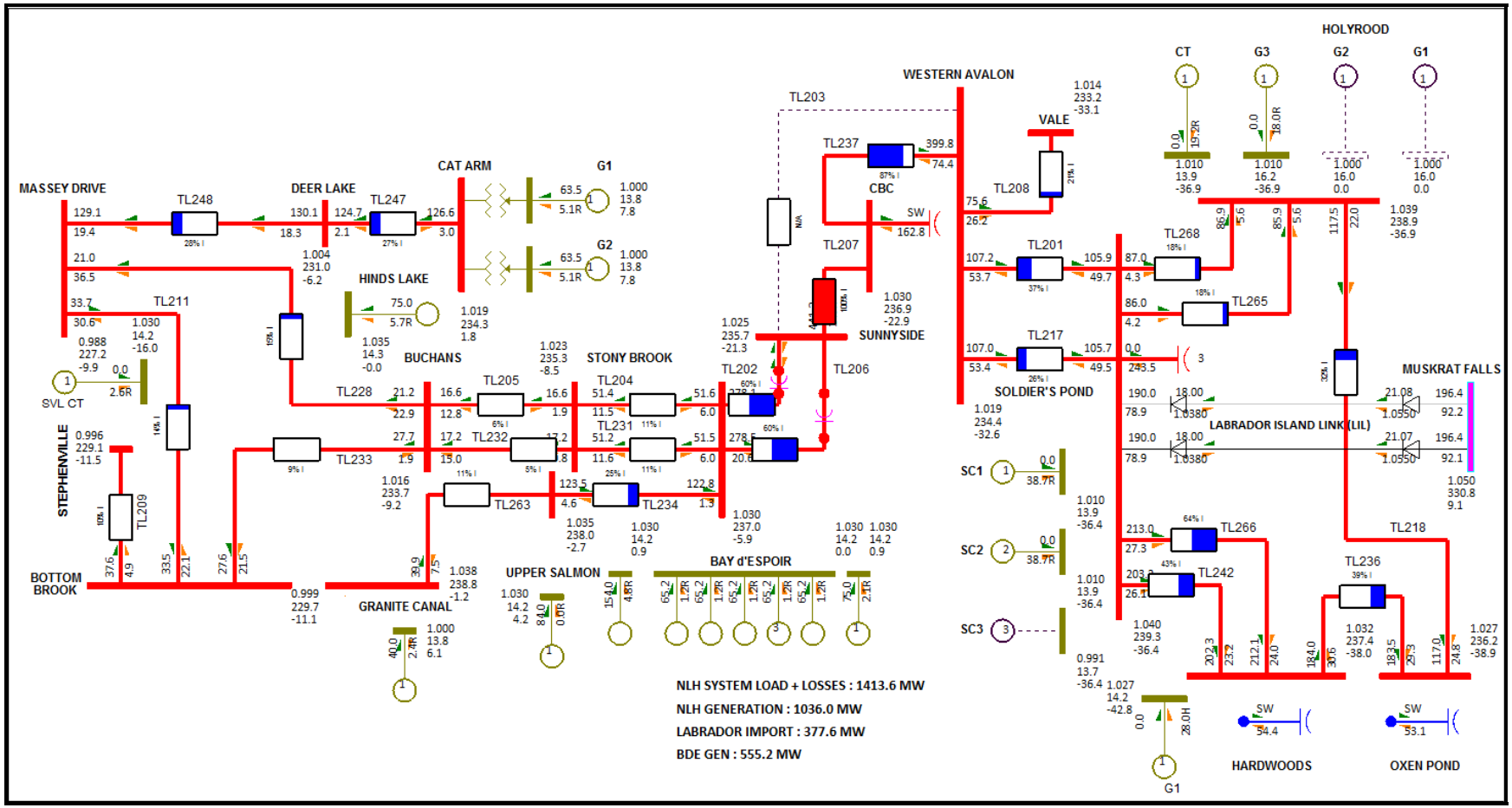


Figure 190 – Base Case 6 (BC6) Load Flow Plot – TL203 Out of Service – LIL Import Increased to 378 MW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

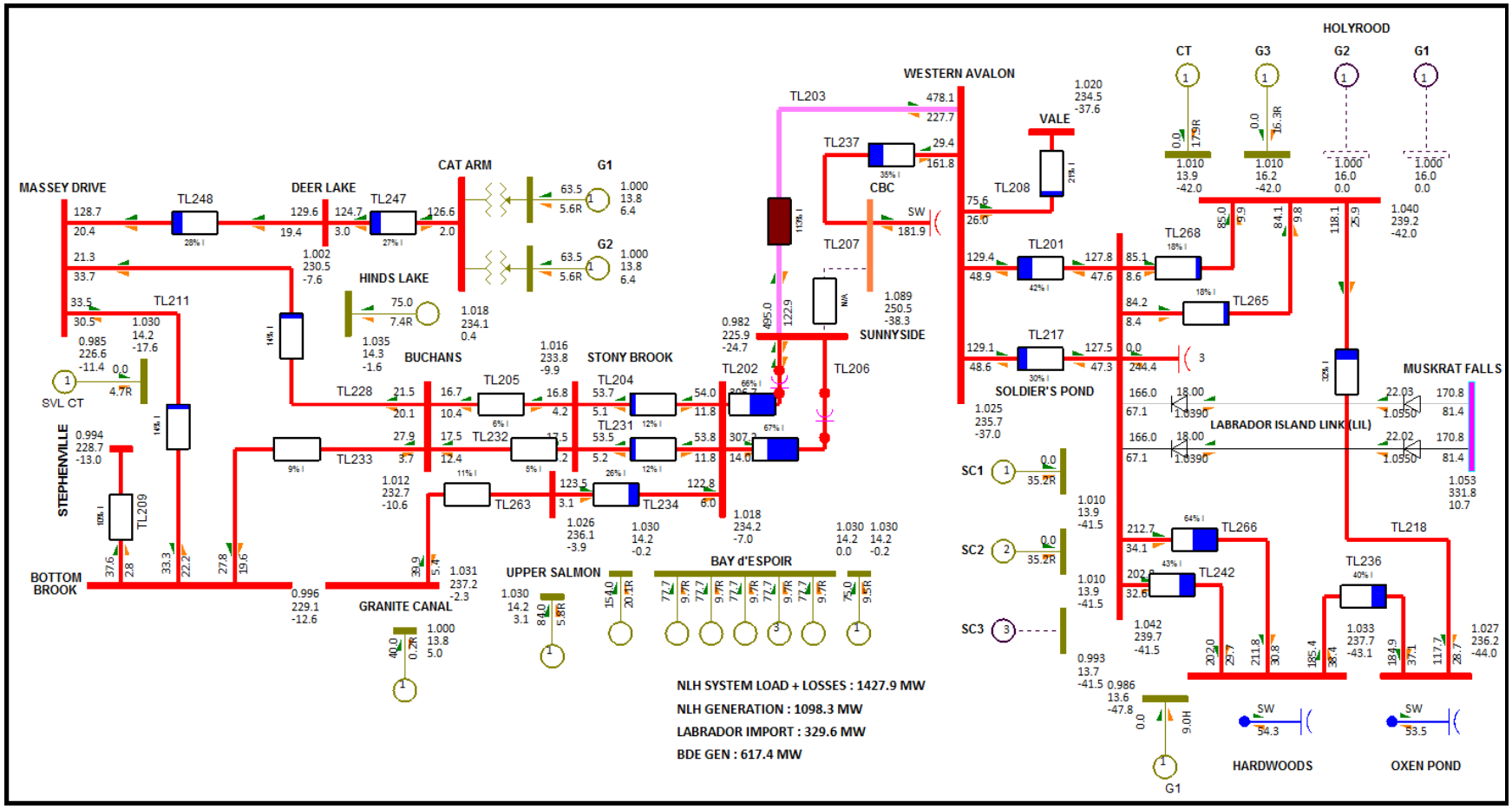


Figure 191 – Base Case 6 (BC6) Load Flow Plot – TL207 Out of Service

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

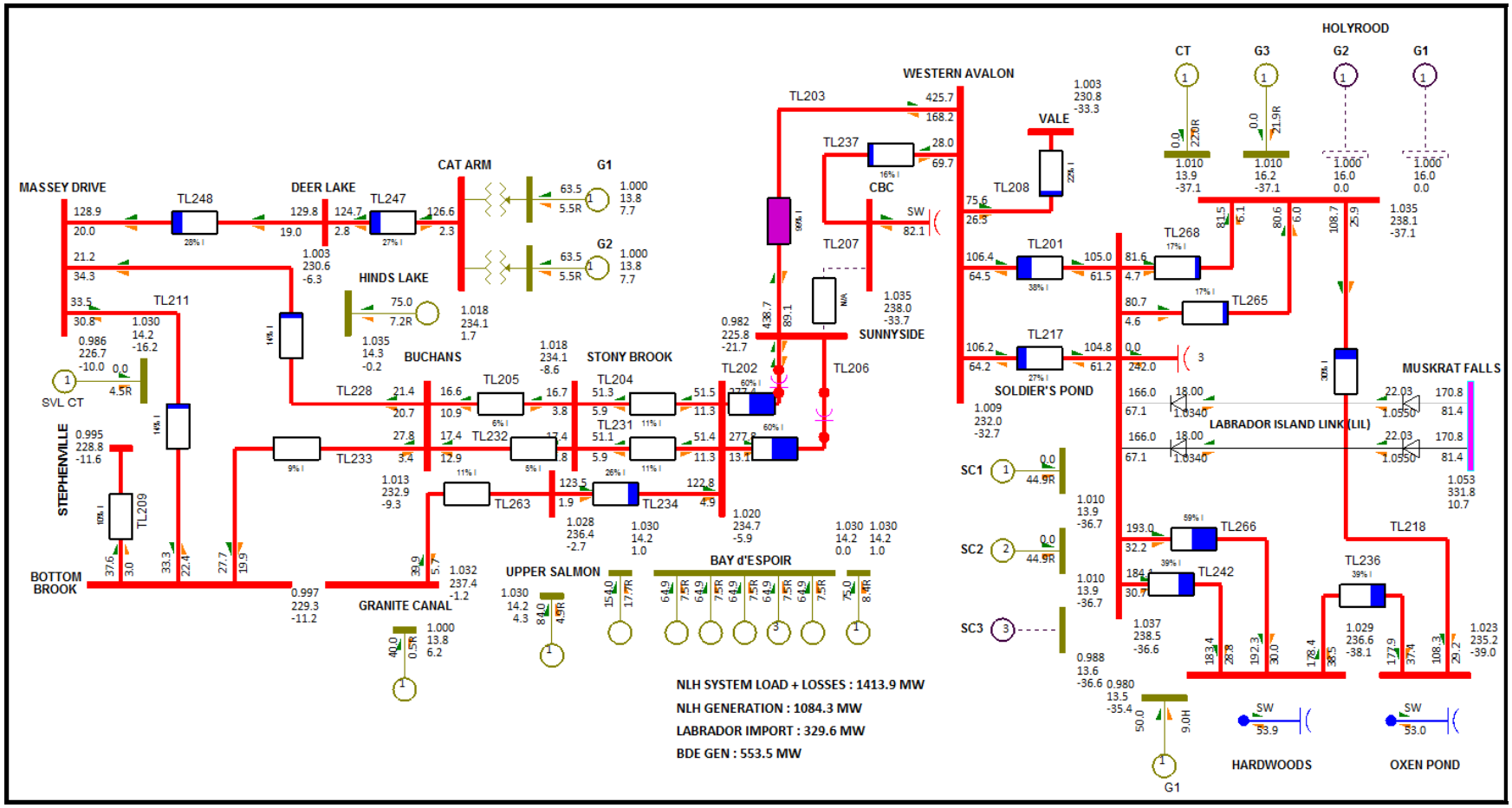


Figure 192 – Base Case 6 (BC6) Load Flow Plot – TL207 Out of Service – HWD CT Generating 50 MW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

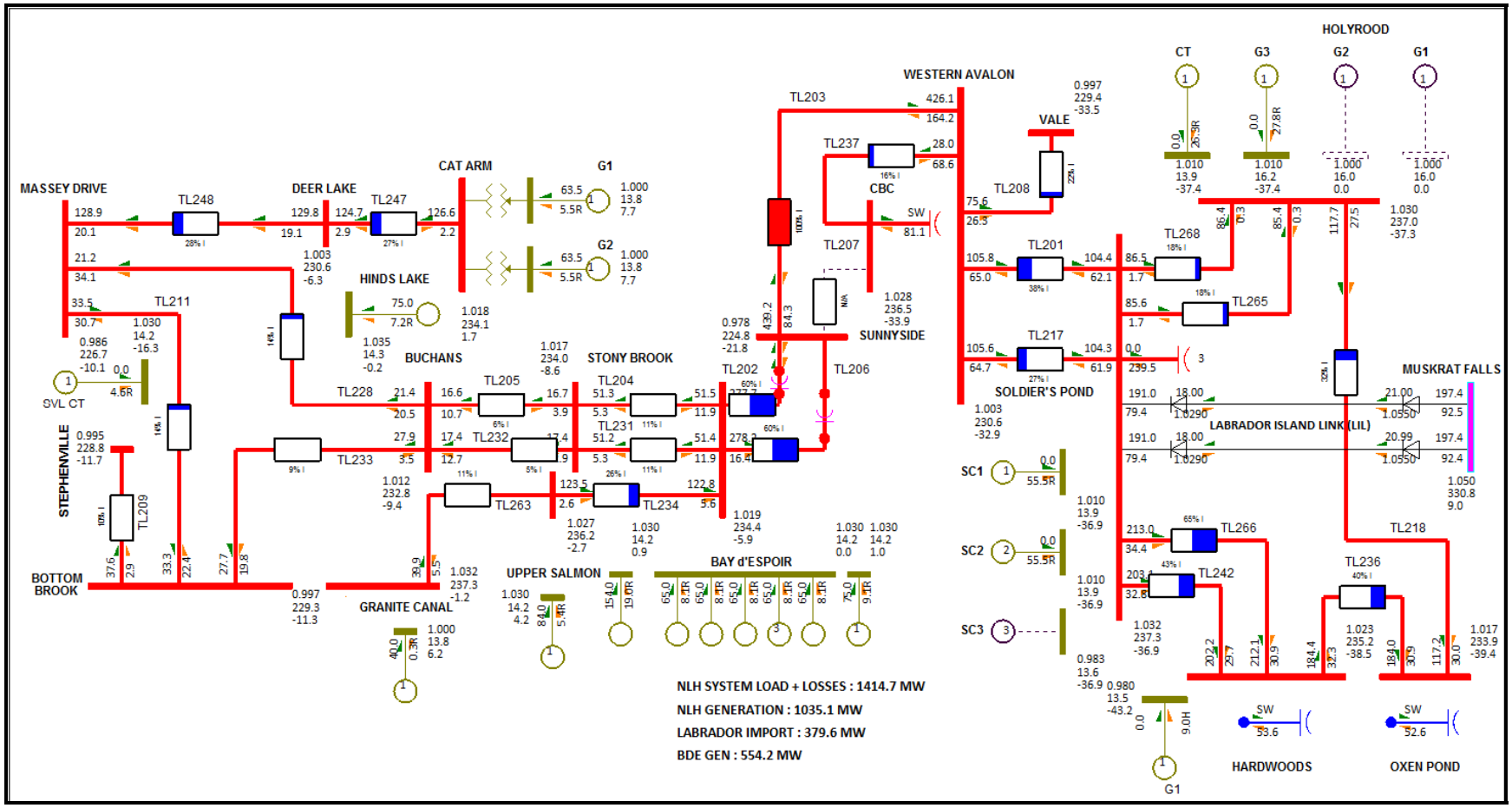


Figure 193 – Base Case 6 (BC6) Load Flow Plot – TL207 Out of Service – LIL Import Increased to 380 MW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

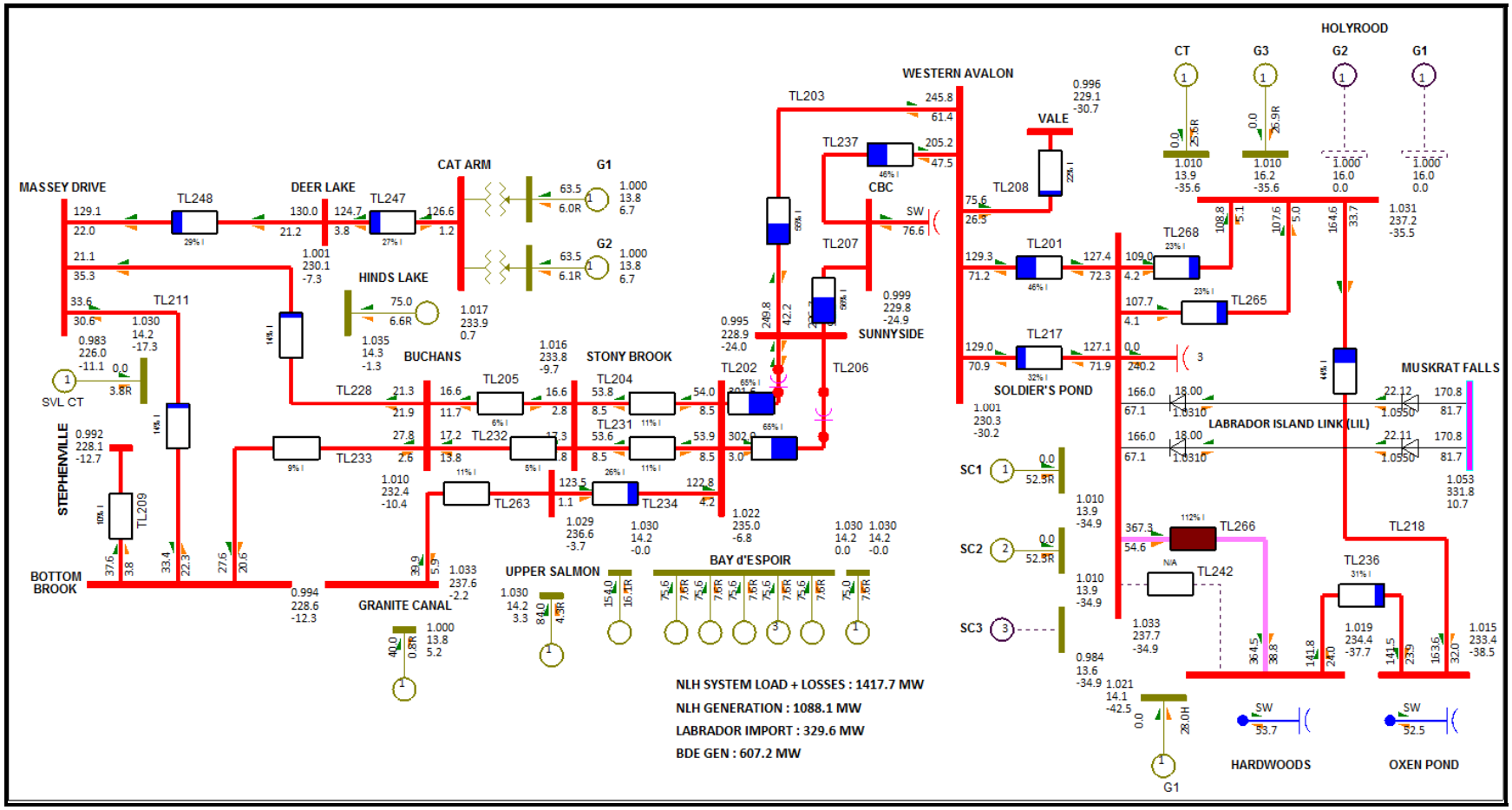


Figure 194 – Base Case 6 (BC6) Load Flow Plot – TL242 Out of Service

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

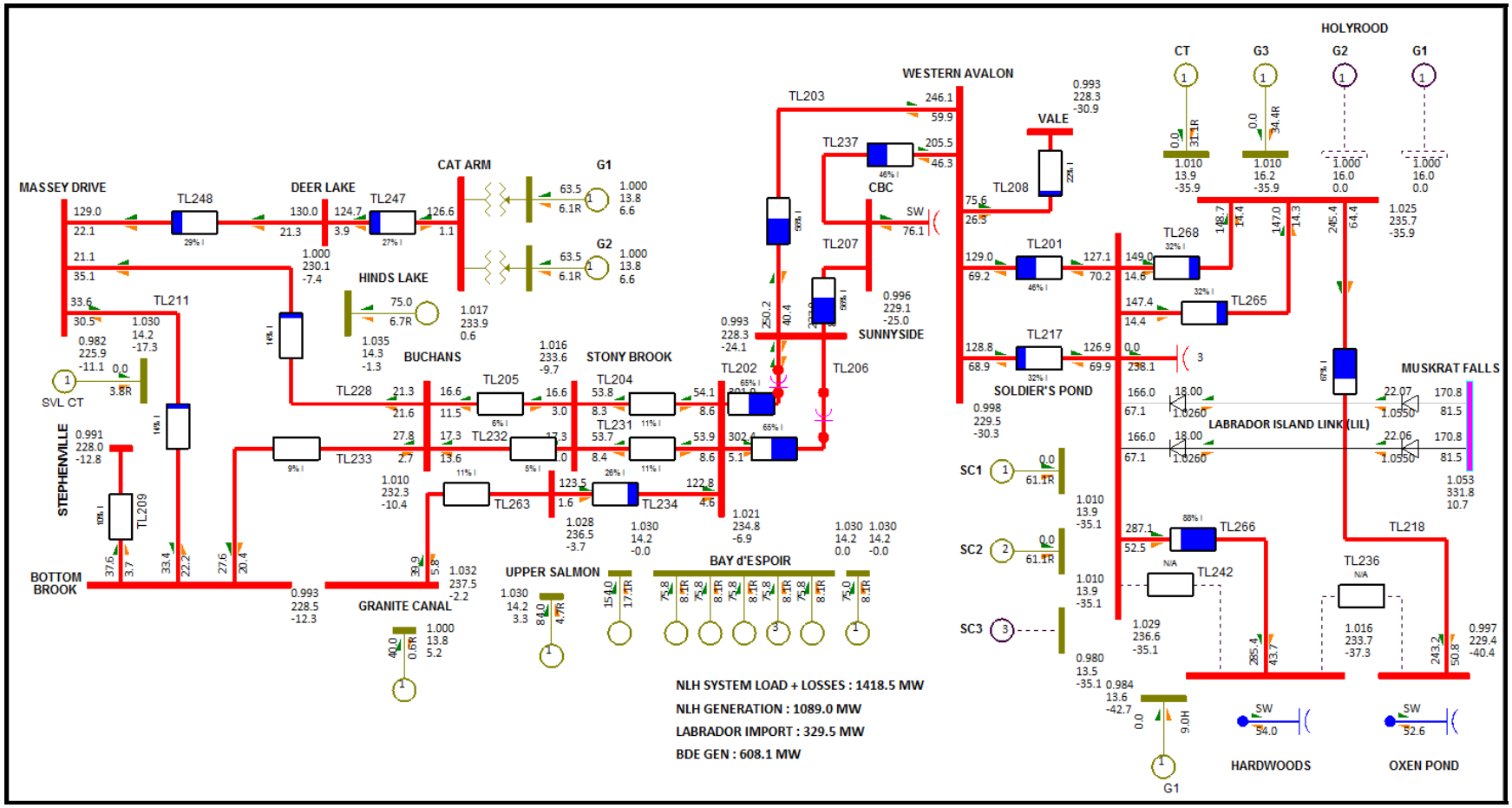


Figure 195 – Base Case 6 (BC6) Load Flow Plot – TL242 Out of Service – TL236 Open

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

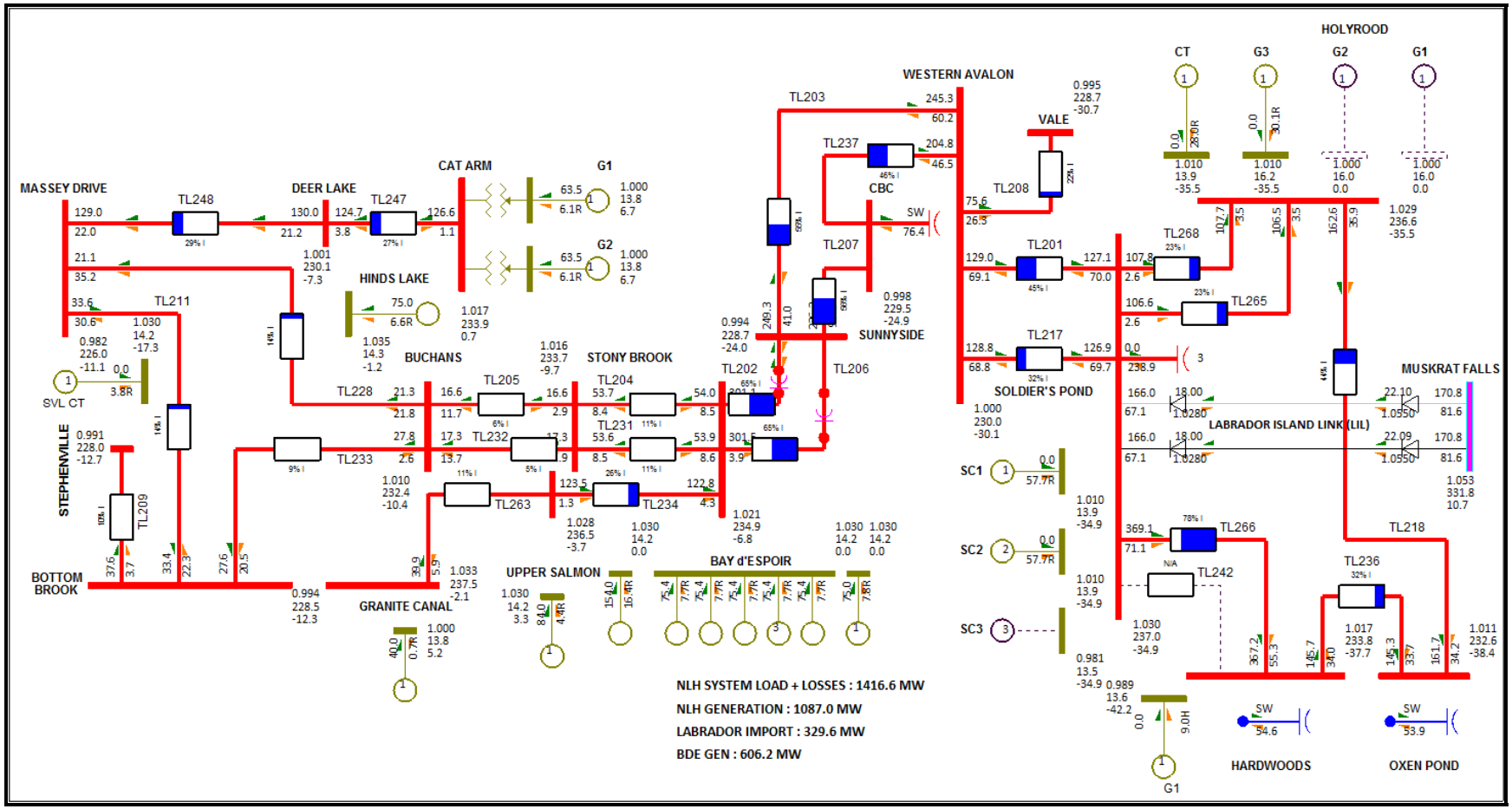


Figure 196 – Base Case 6 (BC6) Load Flow Plot – TL242 Out of Service

TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

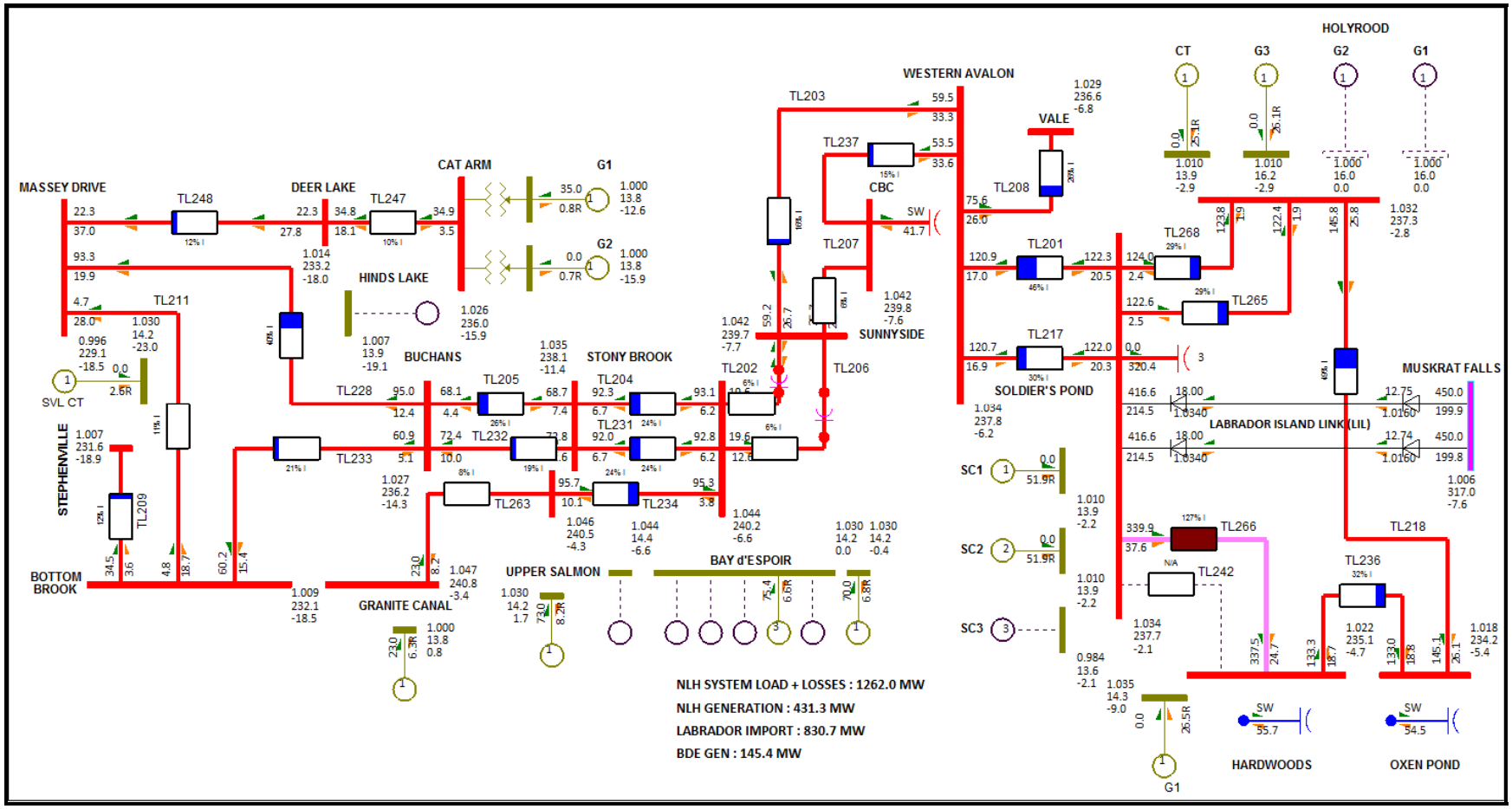


Figure 197 – Base Case 7 (BC7) Load Flow Plot – TL242 Out of Service

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (431 MW)

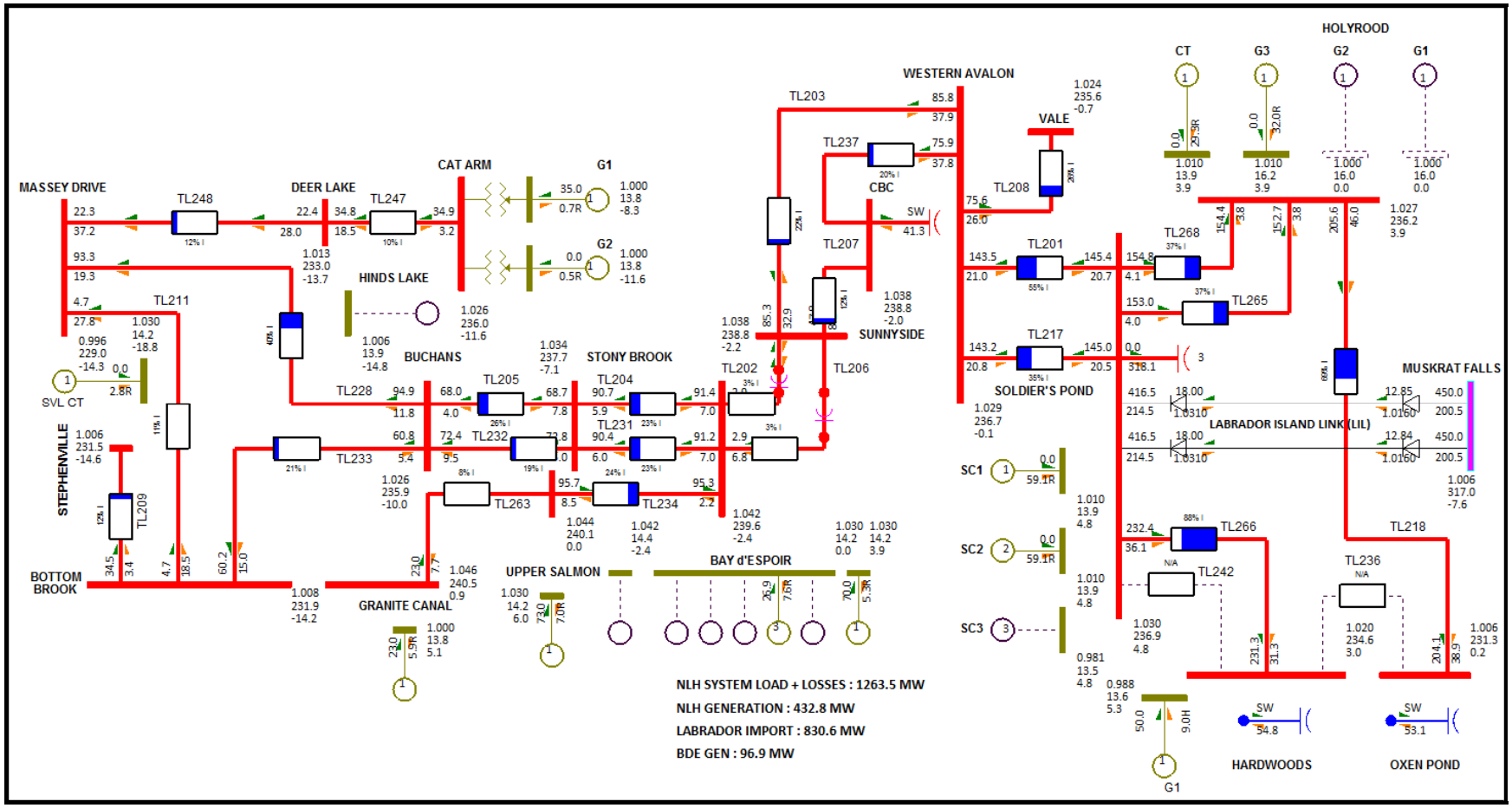


Figure 198 – Base Case 7 (BC7) Load Flow Plot – TL242 Out of Service – HWD CT Generating 50 MW and TL236 Open

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (431 MW)

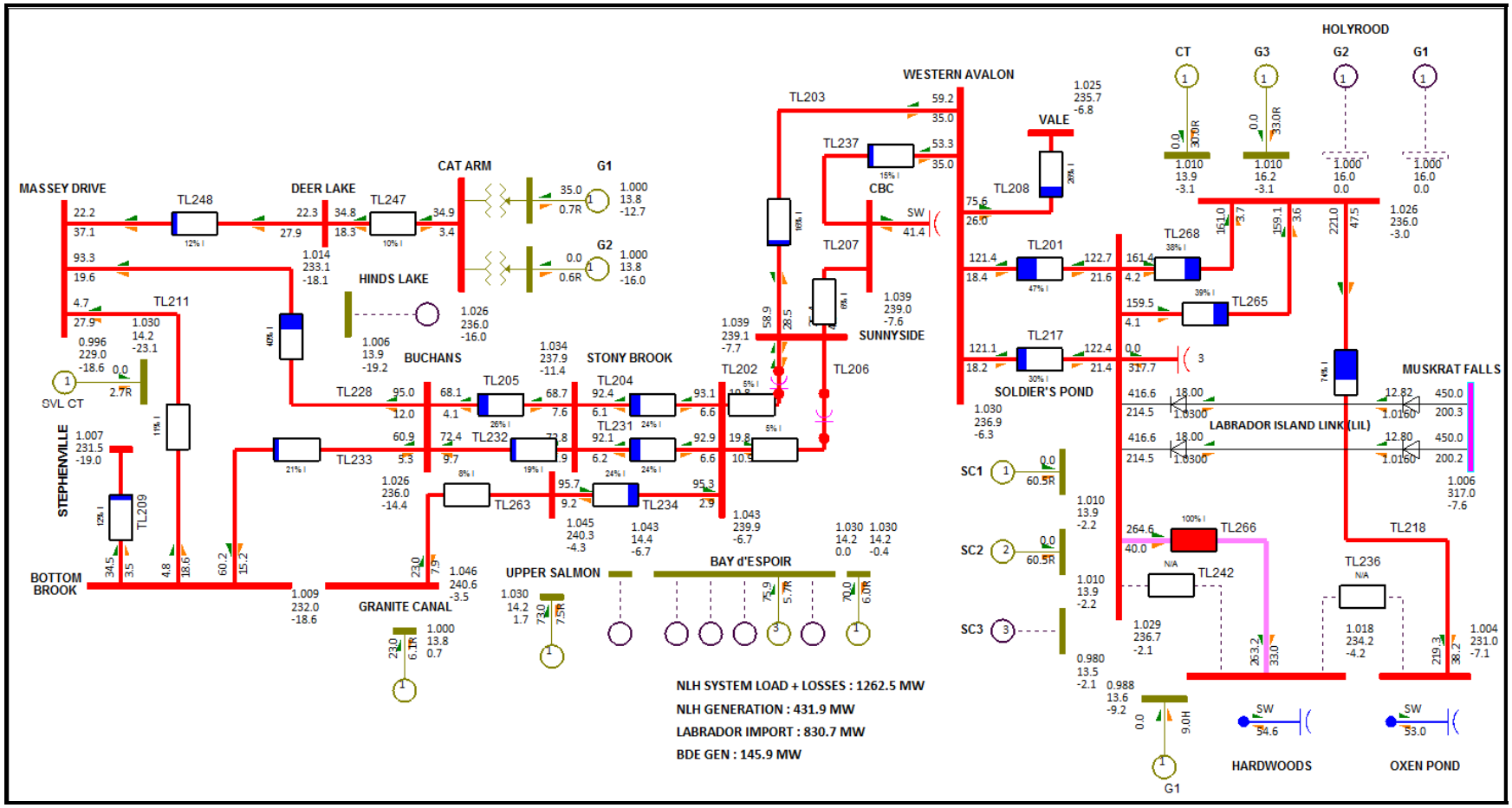


Figure 199 – Base Case 7 (BC7) Load Flow Plot – TL242 Out of Service – TL236 Open

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (431 MW)

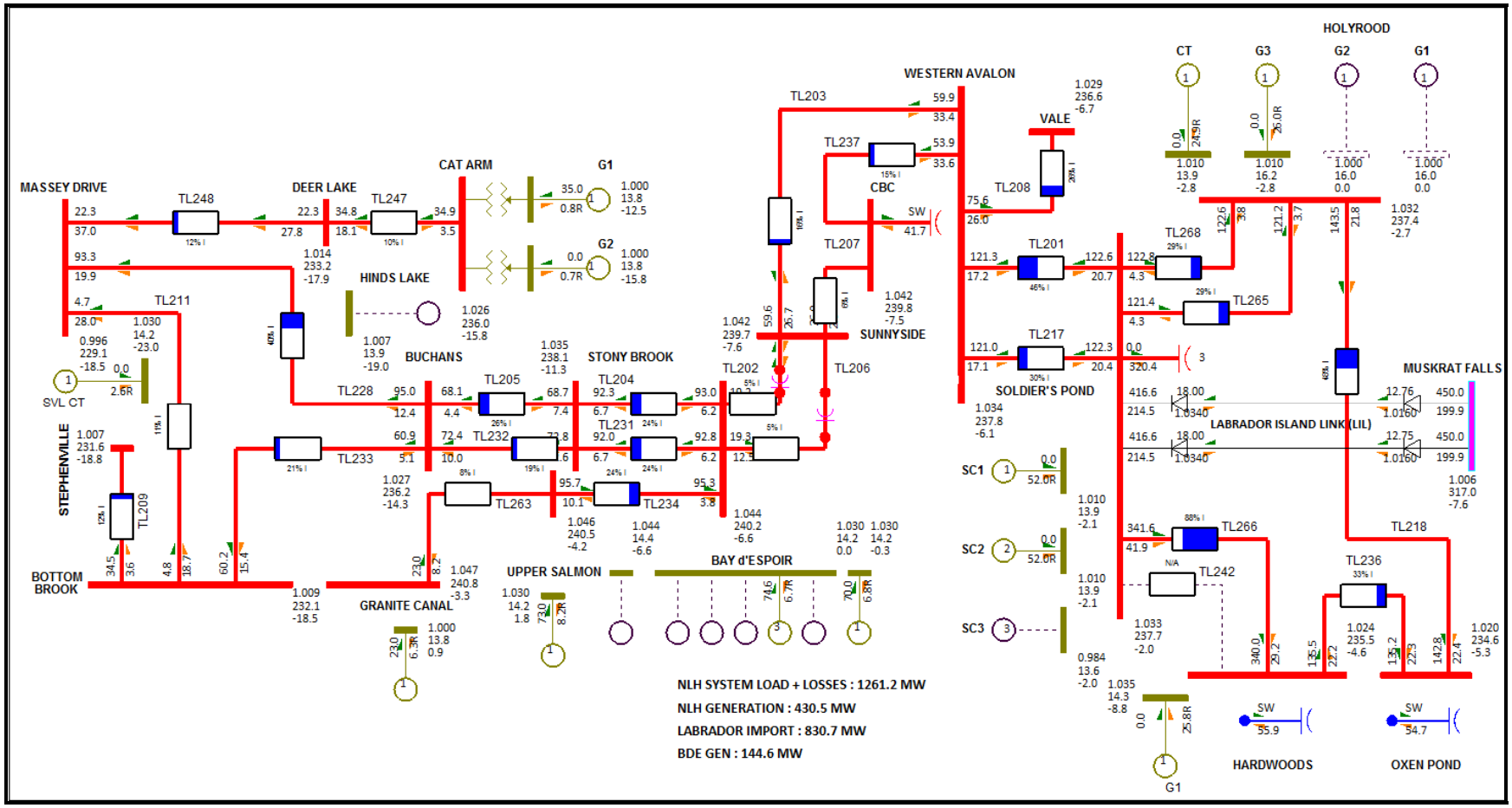


Figure 200 – Base Case 7 (BC7) Load Flow Plot – TL242 Out of Service

TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (431 MW)

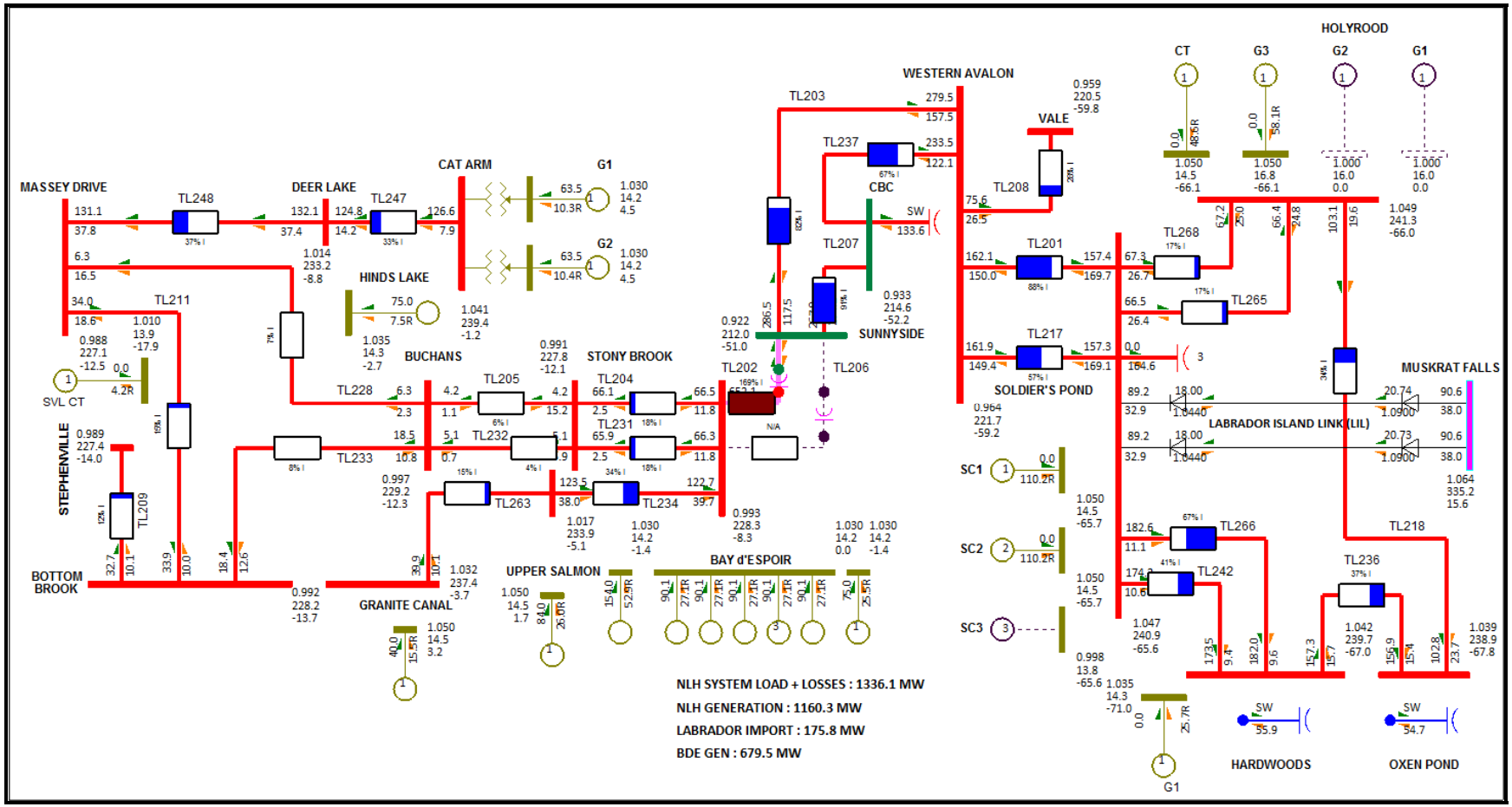


Figure 201 – Base Case 8 (BC8) Load Flow Plot – TL206 Out of Service

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

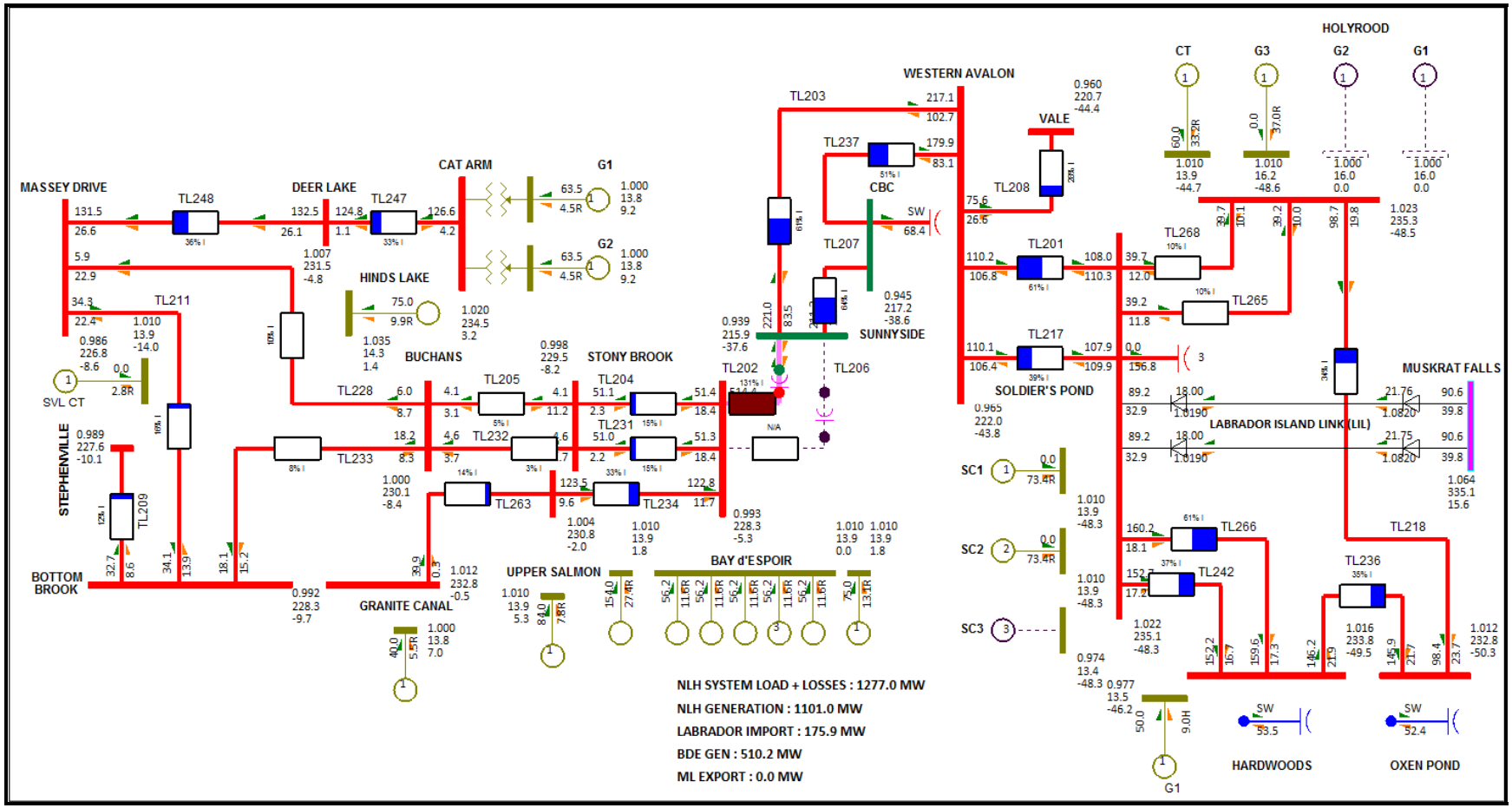


Figure 202 – Base Case 8 (BC8) Load Flow Plot – TL206 Out of Service – HWD CT and HRD CT Generating 110 MW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

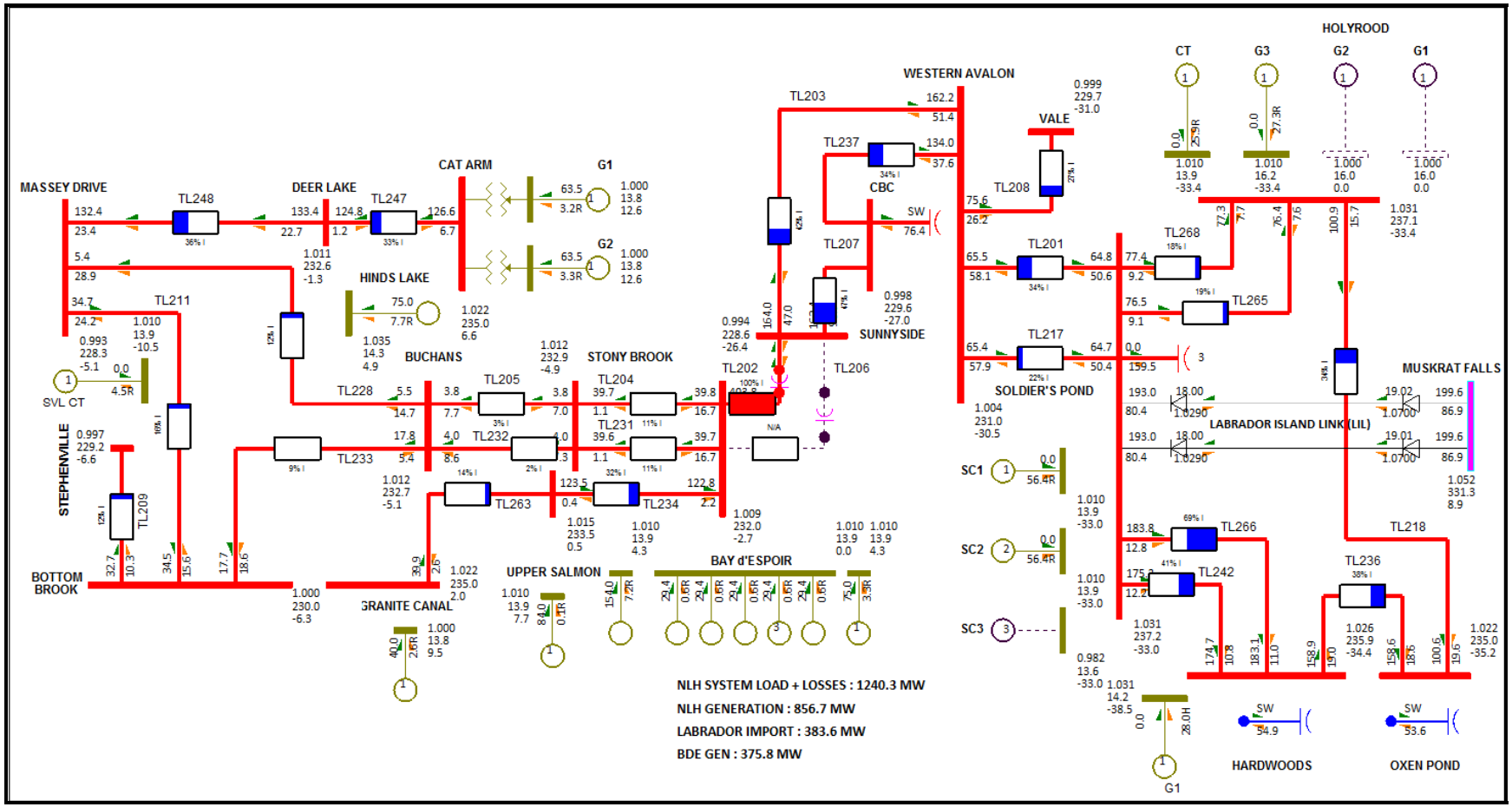


Figure 203 – Base Case 8 (BC8) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 384 MW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

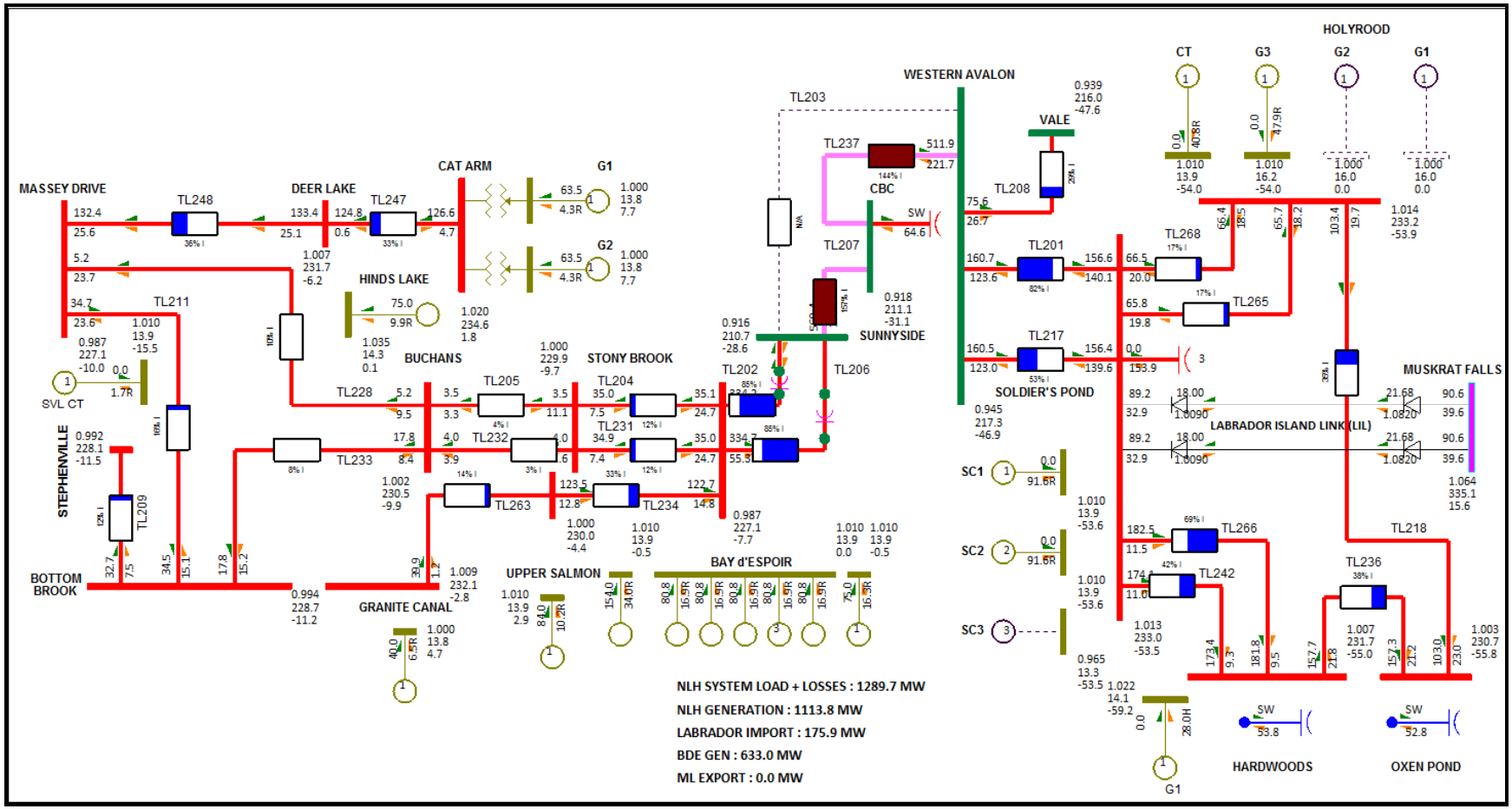


Figure 204 – Base Case 8 (BC8) Load Flow Plot – TL203 Out of Service

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

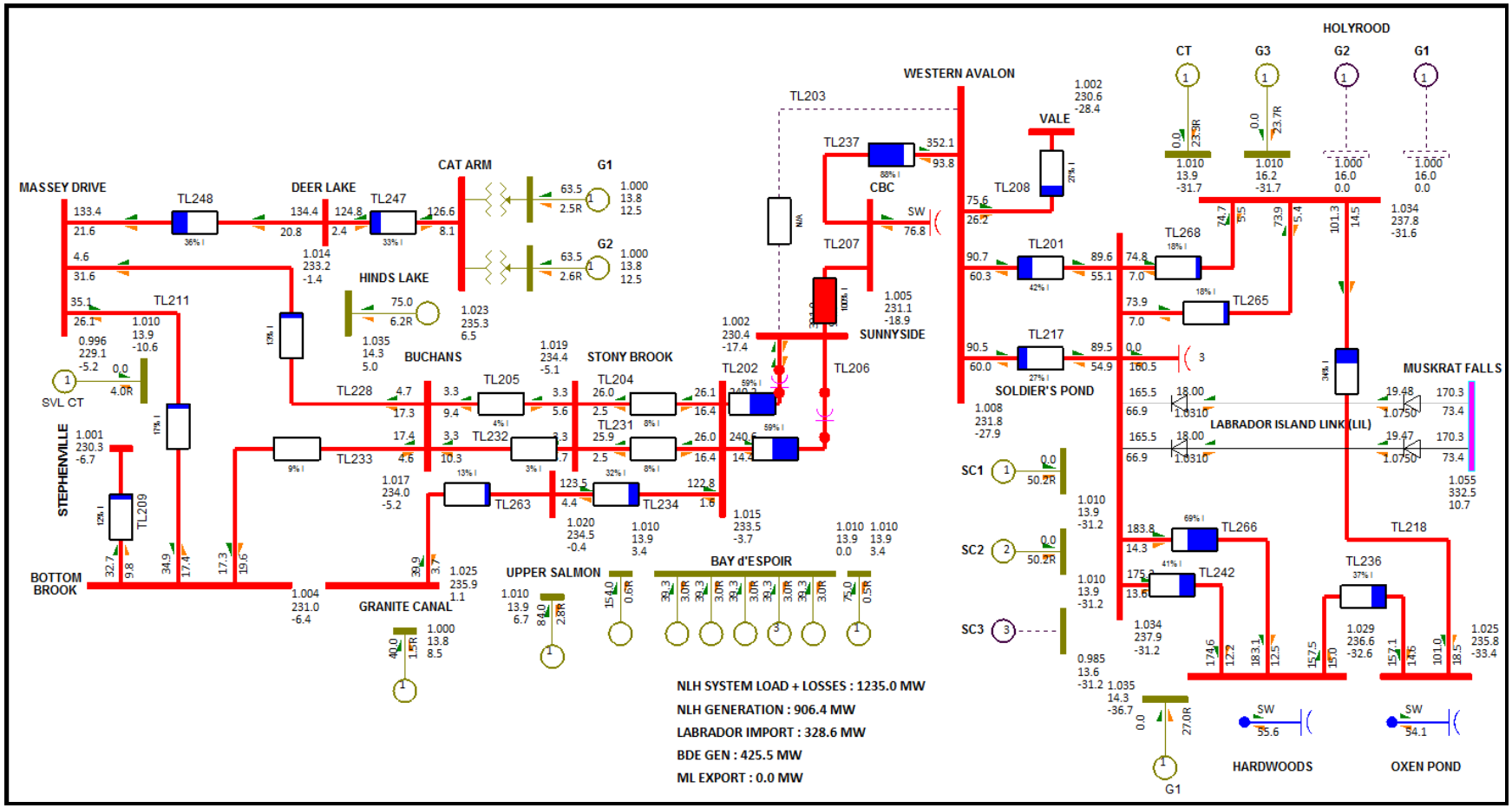


Figure 205 – Base Case 8 (BC8) Load Flow Plot – TL203 Out of Service – LIL Import Increased to 329 MW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

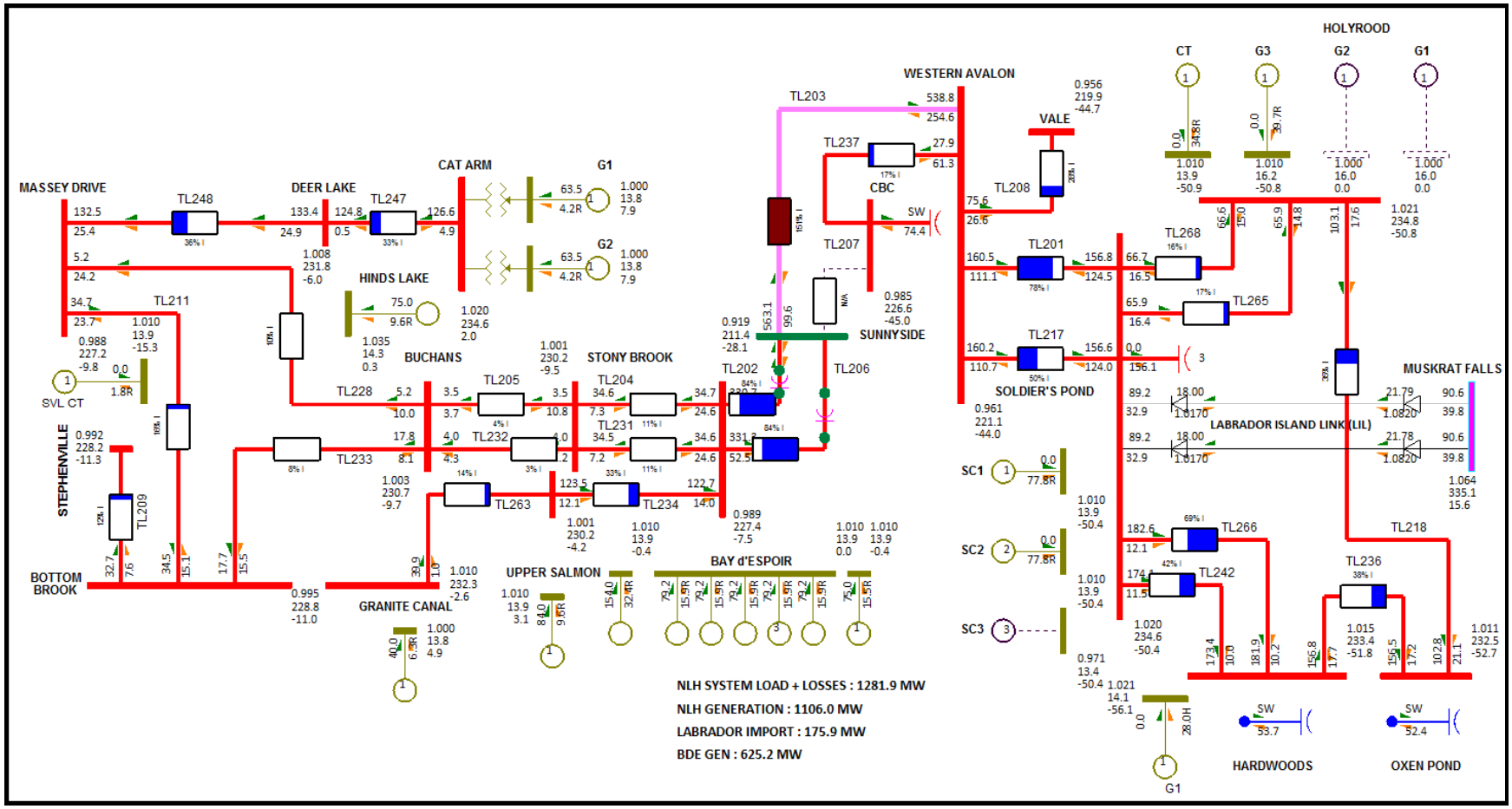


Figure 206 – Base Case 8 (BC8) Load Flow Plot – TL207 Out of Service

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

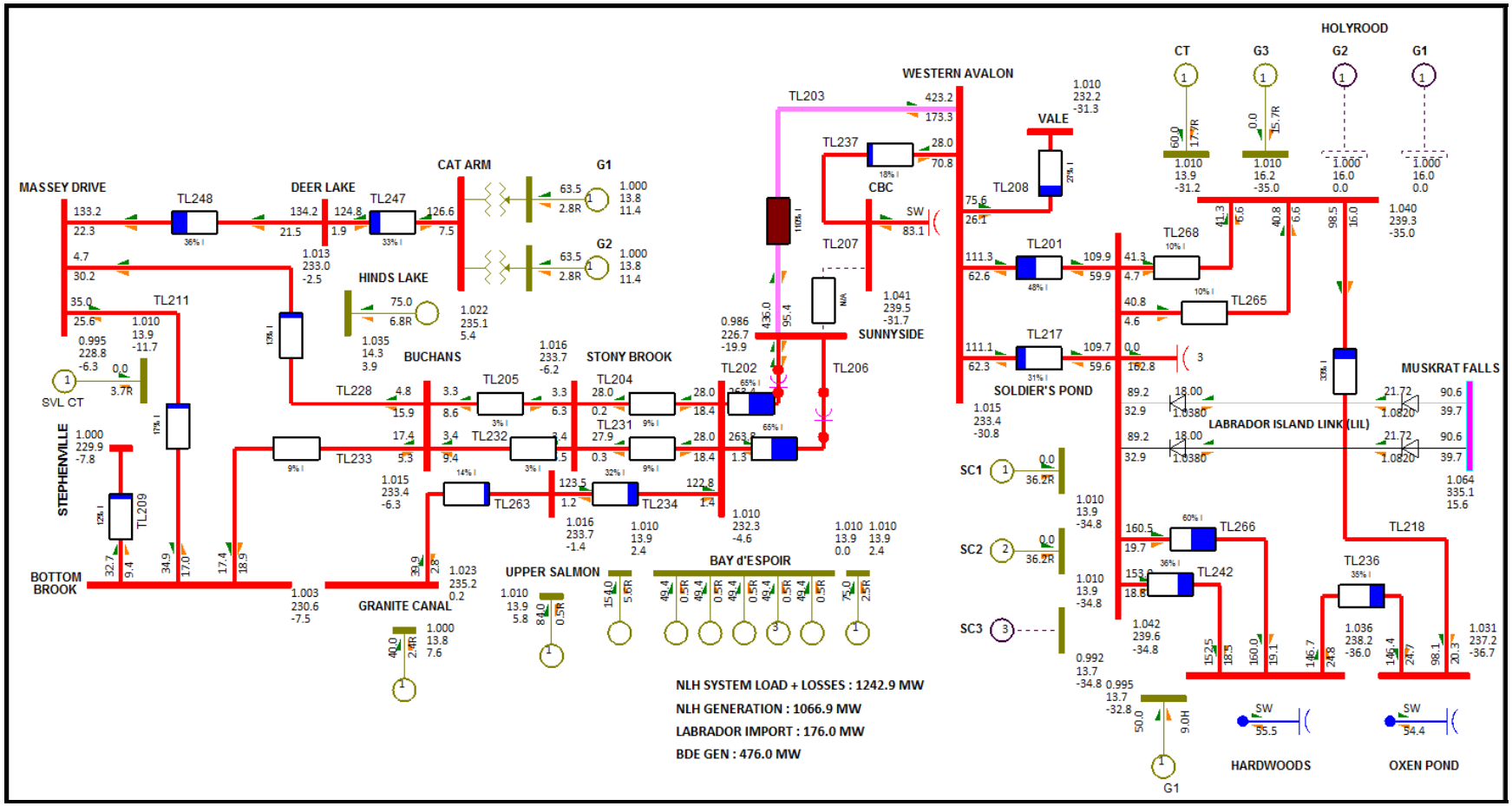


Figure 207 – Base Case 8 (BC8) Load Flow Plot – TL207 Out of Service – HWD CT and HRD CT Generating 110 MW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

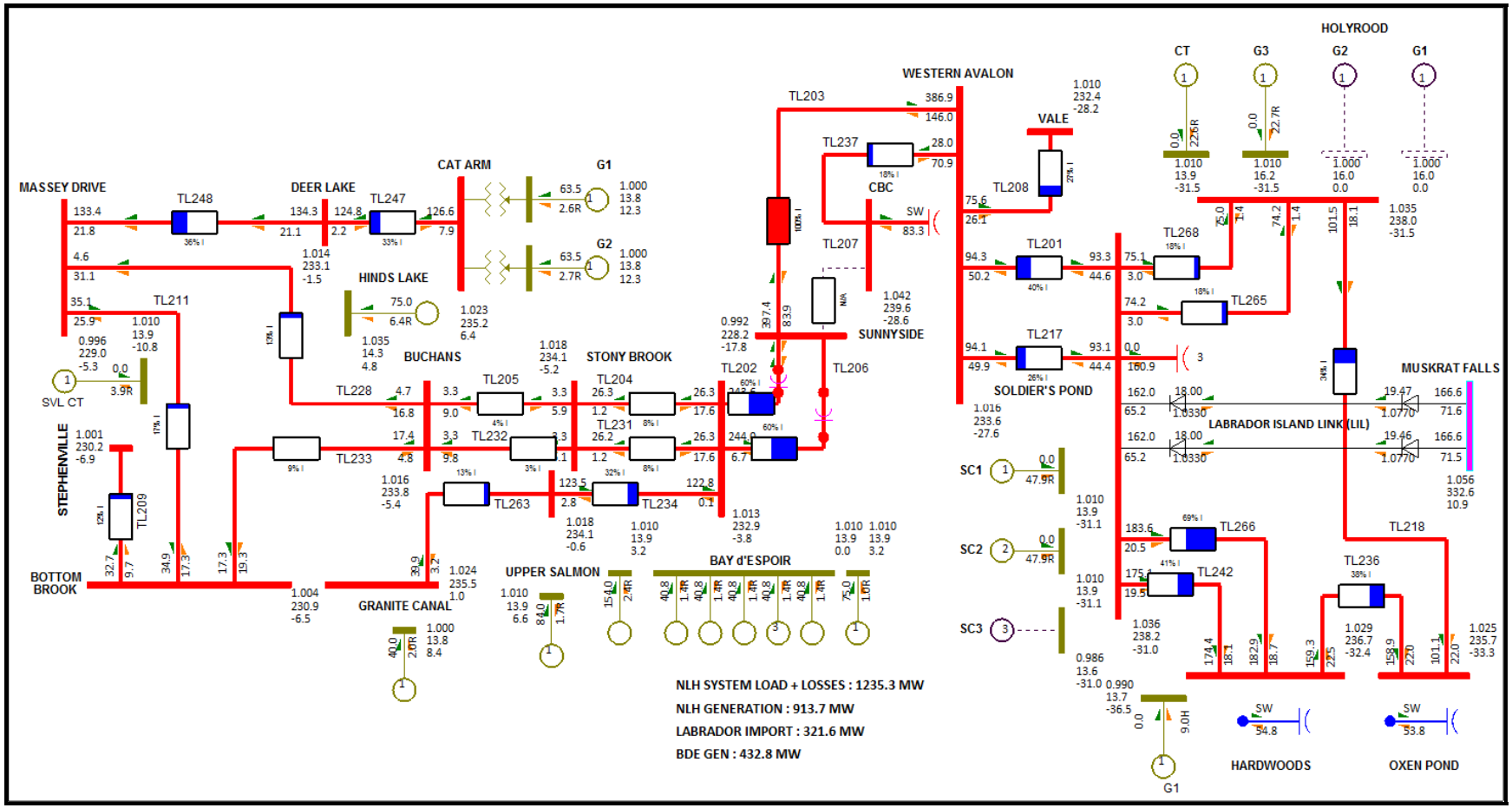


Figure 208 – Base Case 8 (BC8) Load Flow Plot – TL207 Out of Service – LIL Import Increased to 322 MW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

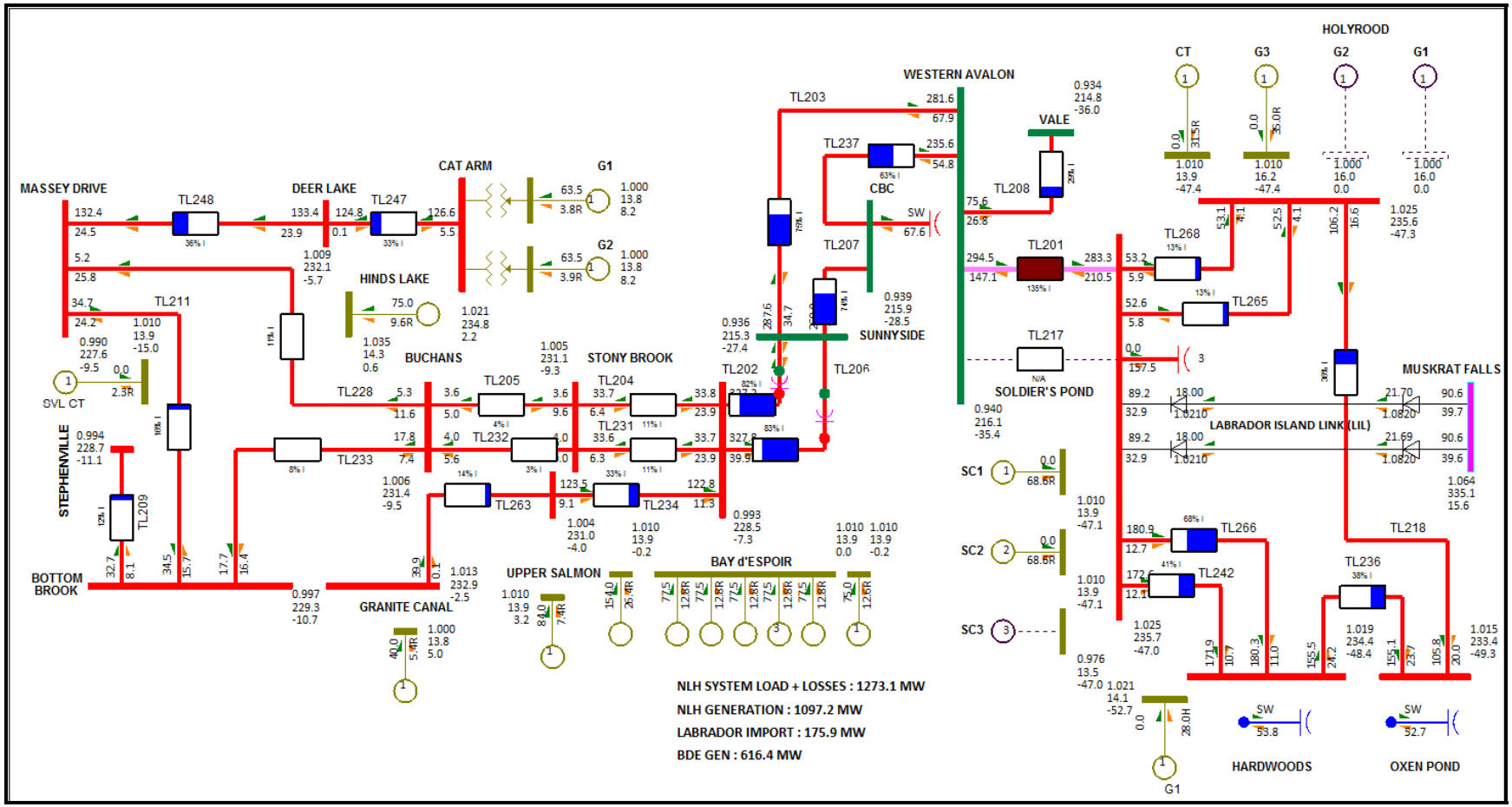


Figure 209 – Base Case 8 (BC8) Load Flow Plot – TL217 Out of Service

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

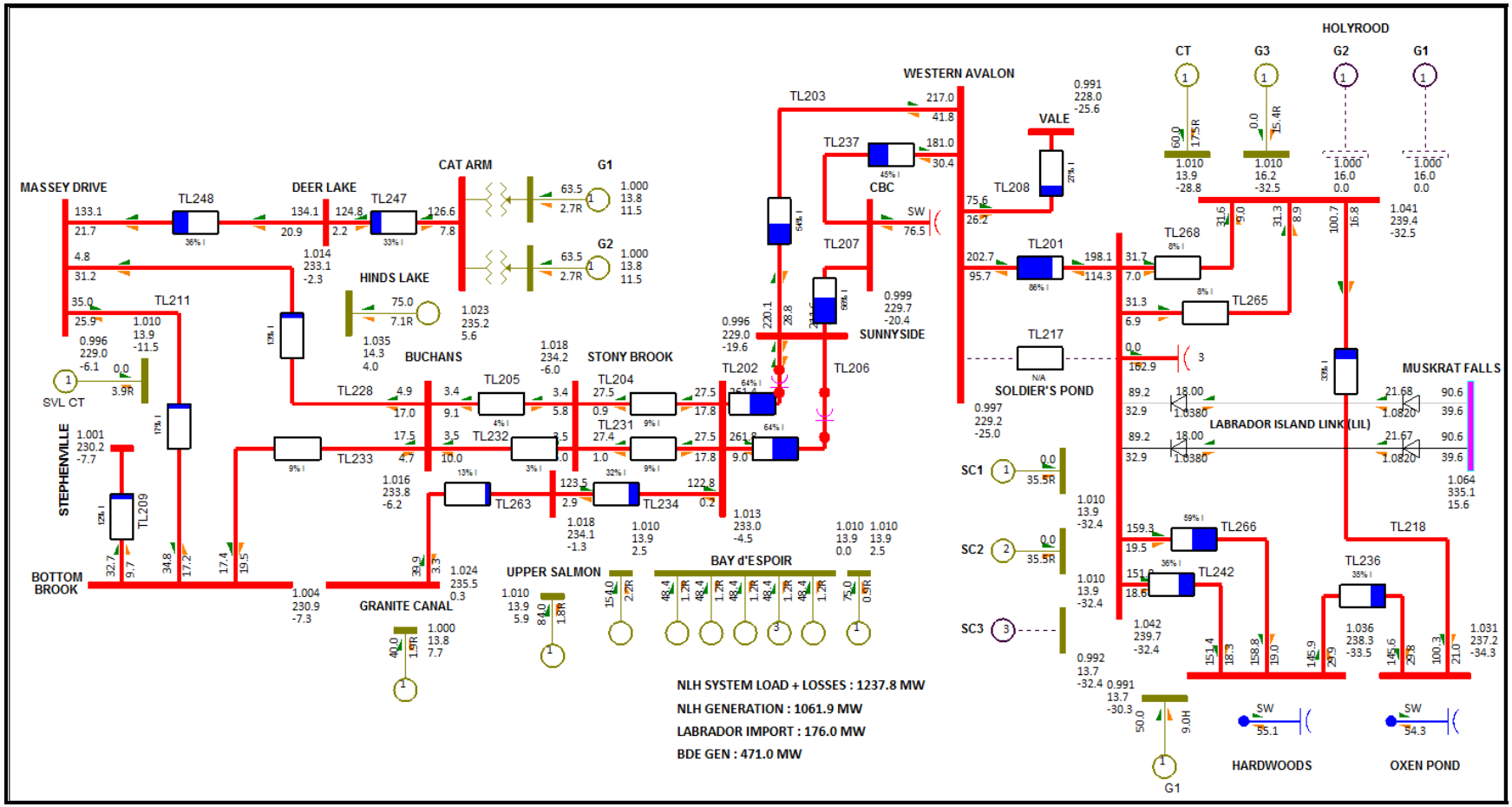


Figure 210 – Base Case 8 (BC8) Load Flow Plot – TL217 Out of Service – HWD CT and HRD CT Generating 110 MW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

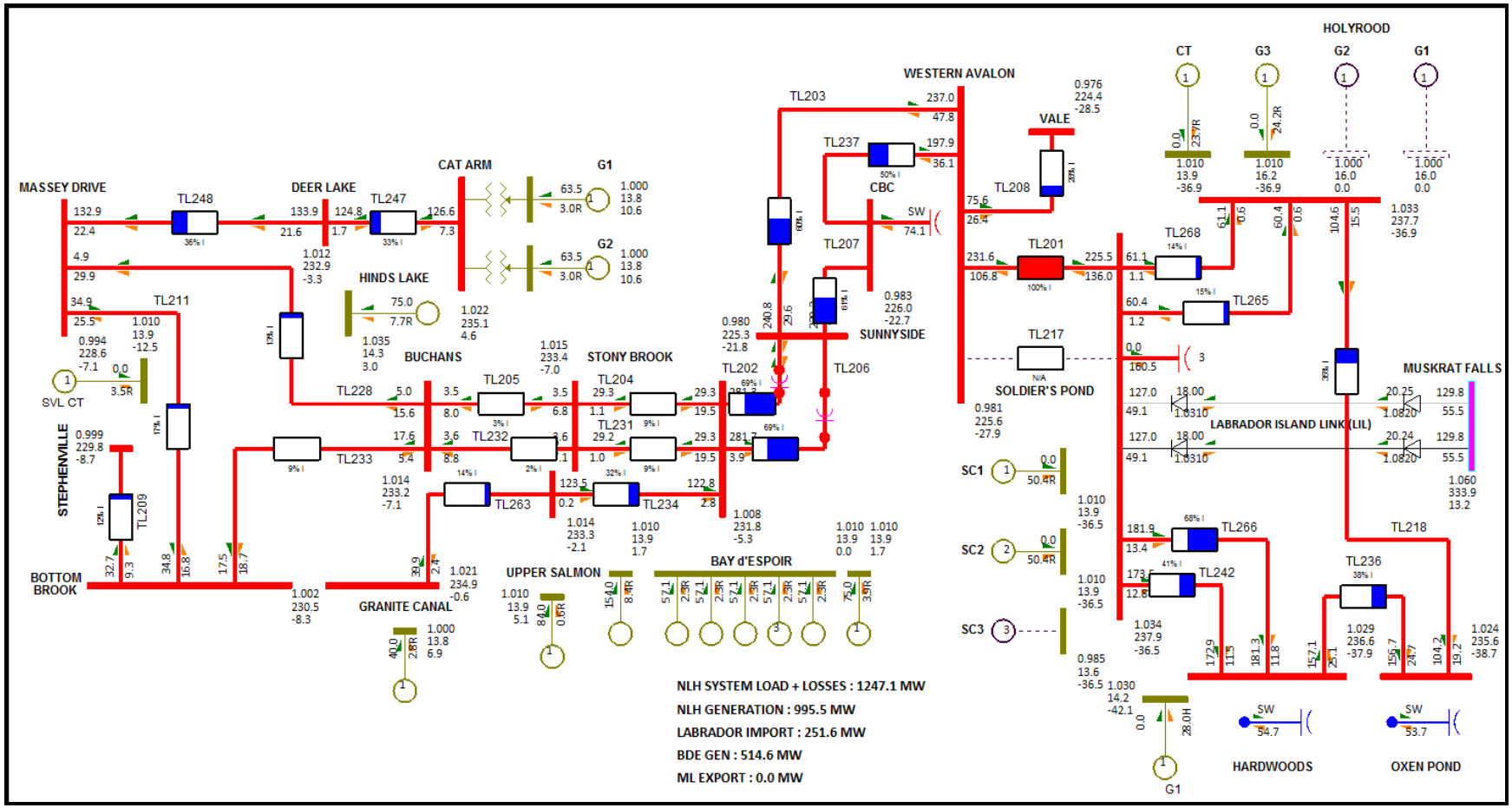


Figure 211 – Base Case 8 (BC8) Load Flow Plot – TL217 Out of Service – LIL Import Increased to 252 MW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

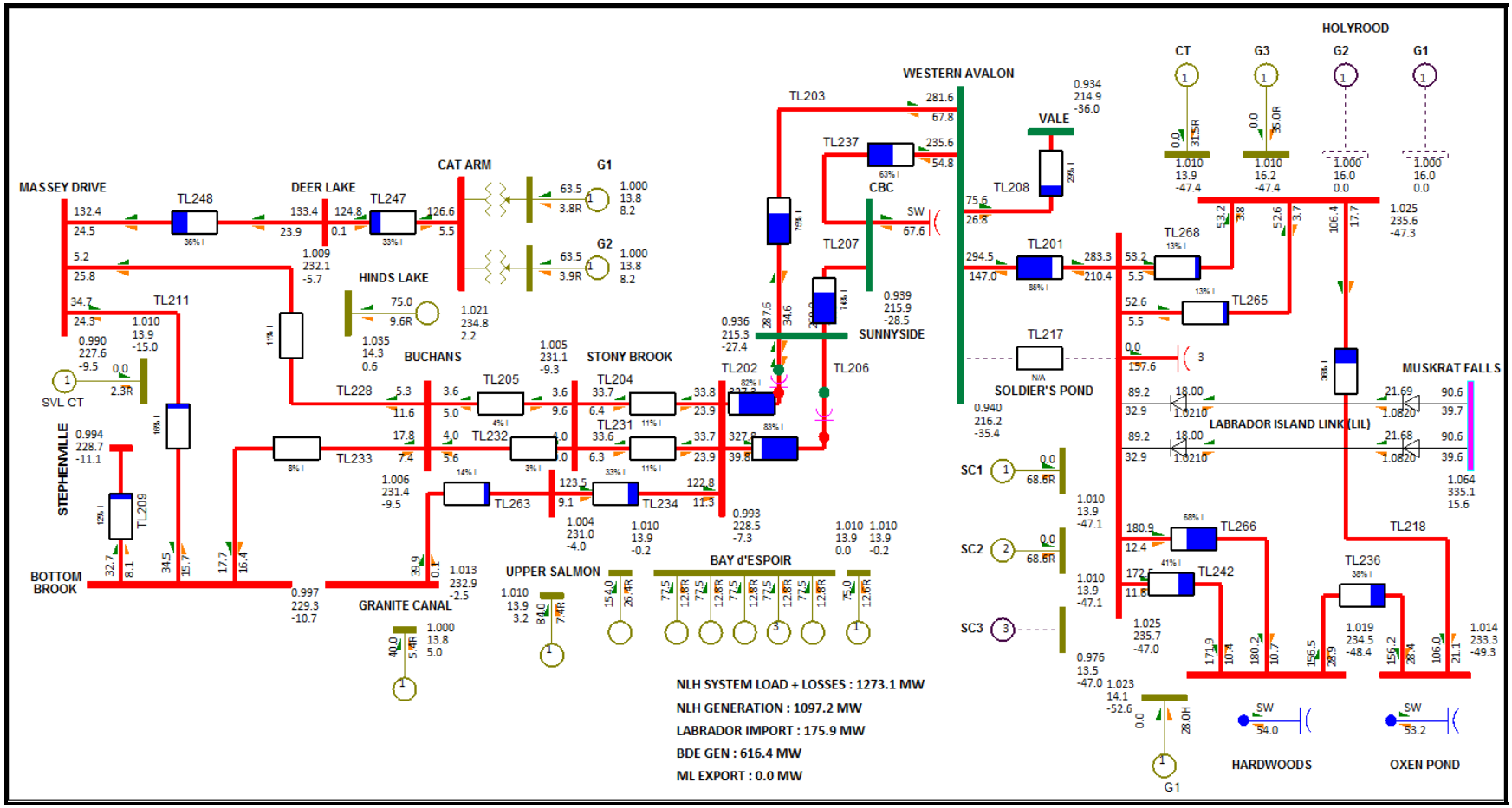


Figure 212 – Base Case 8 (BC8) Load Flow Plot – TL217 Out of Service – T201 Rebuilt to 804 kcmil AACSR/TW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

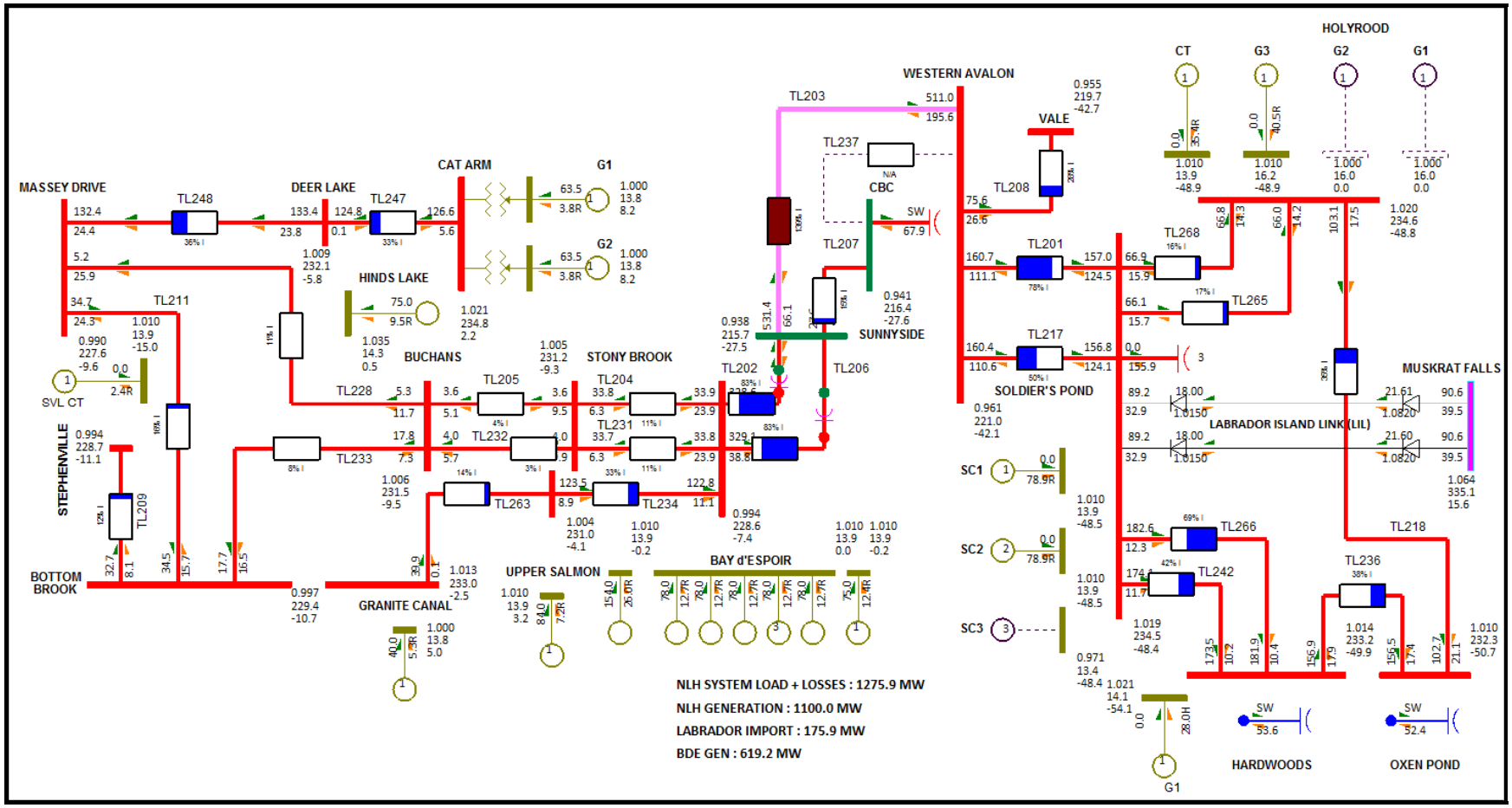


Figure 213 – Base Case 8 (BC8) Load Flow Plot – TL237 Out of Service

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

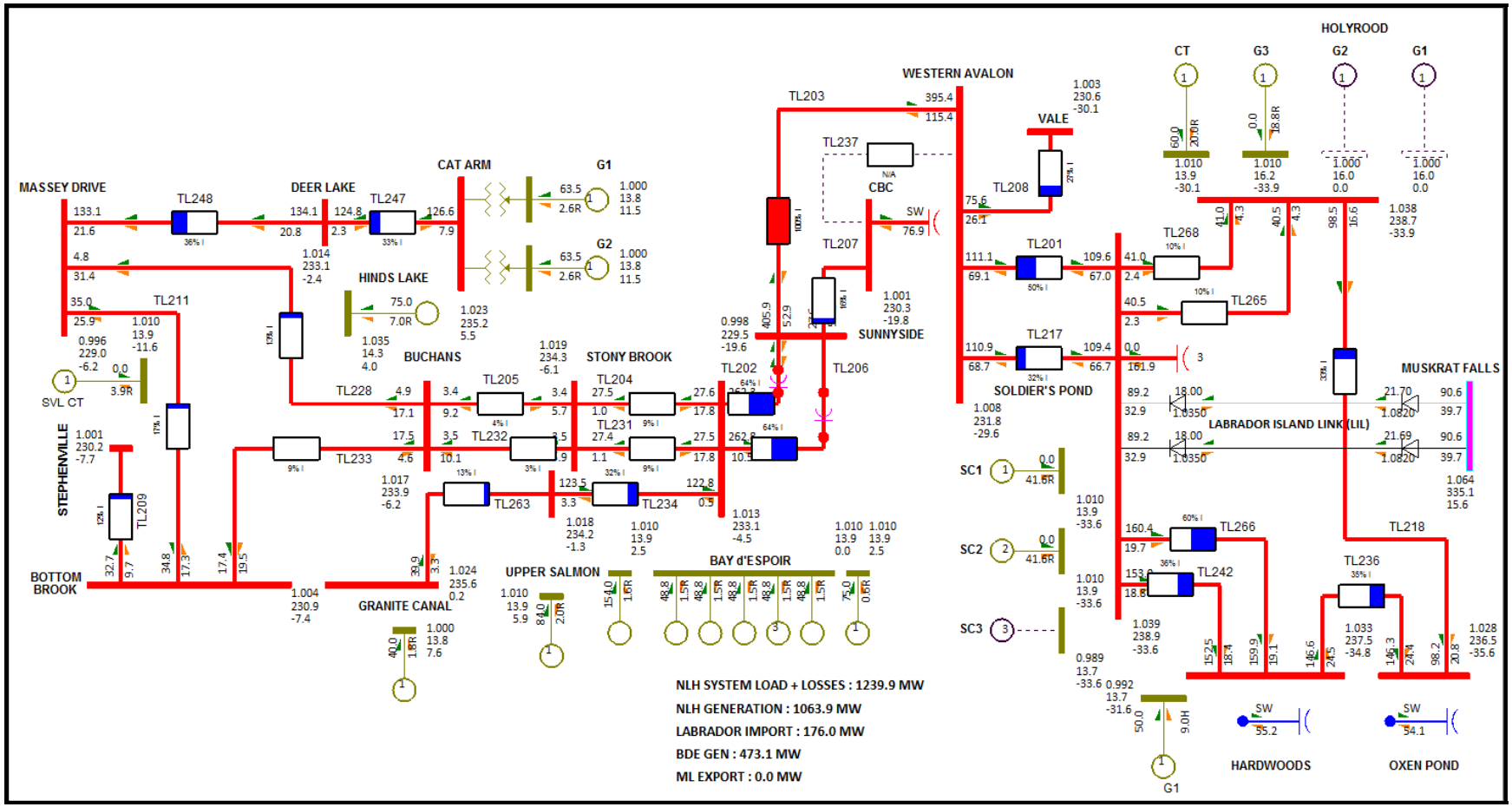


Figure 214 – Base Case 8 (BC8) Load Flow Plot – TL237 Out of Service – HWD CT and HRD CT Generating 110 MW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

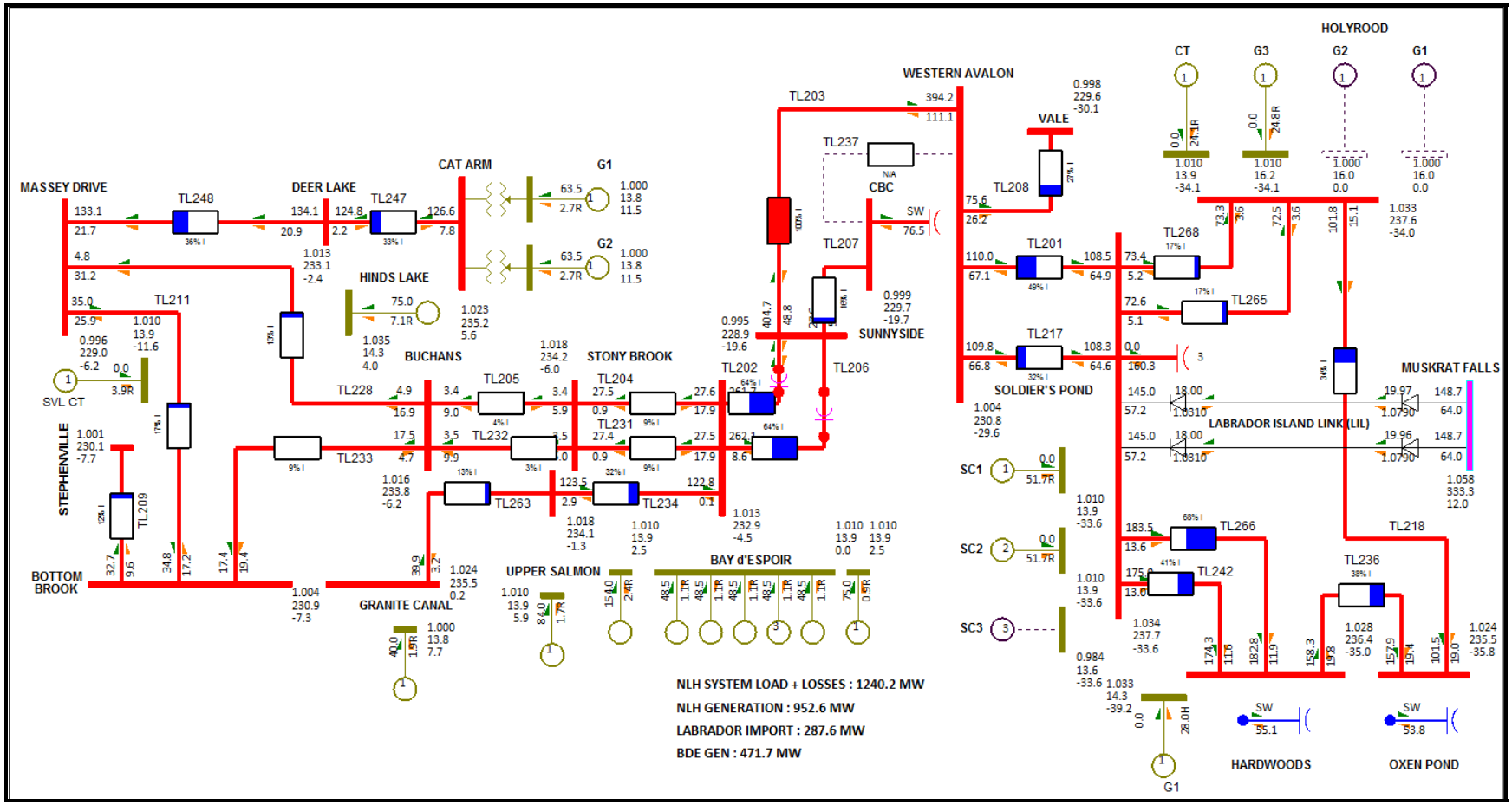


Figure 215 – Base Case 8 (BC8) Load Flow Plot – TL237 Out of Service – LIL Import Increased to 288 MW

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

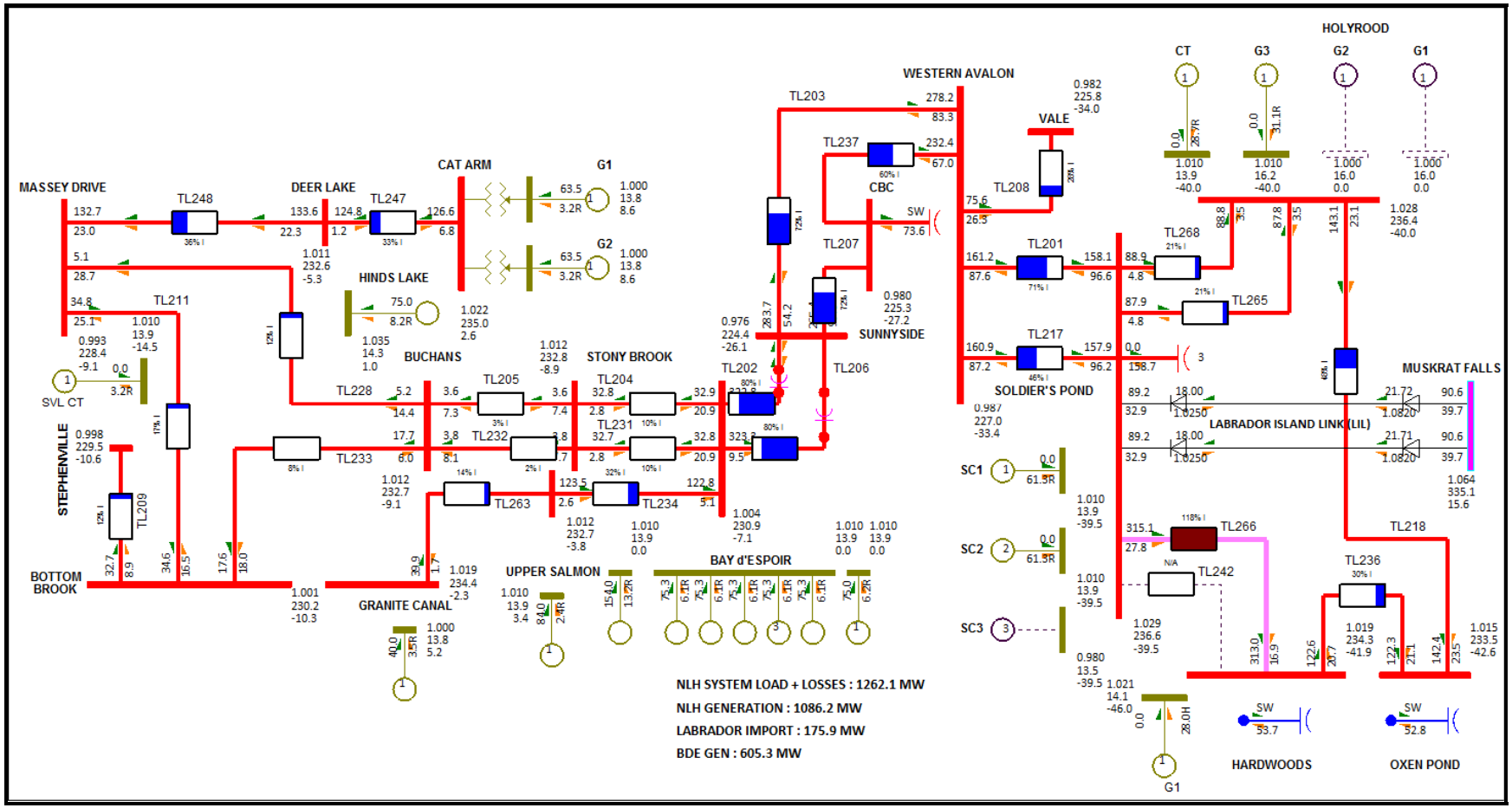


Figure 216 – Base Case 8 (BC8) Load Flow Plot – TL242 Out of Service

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

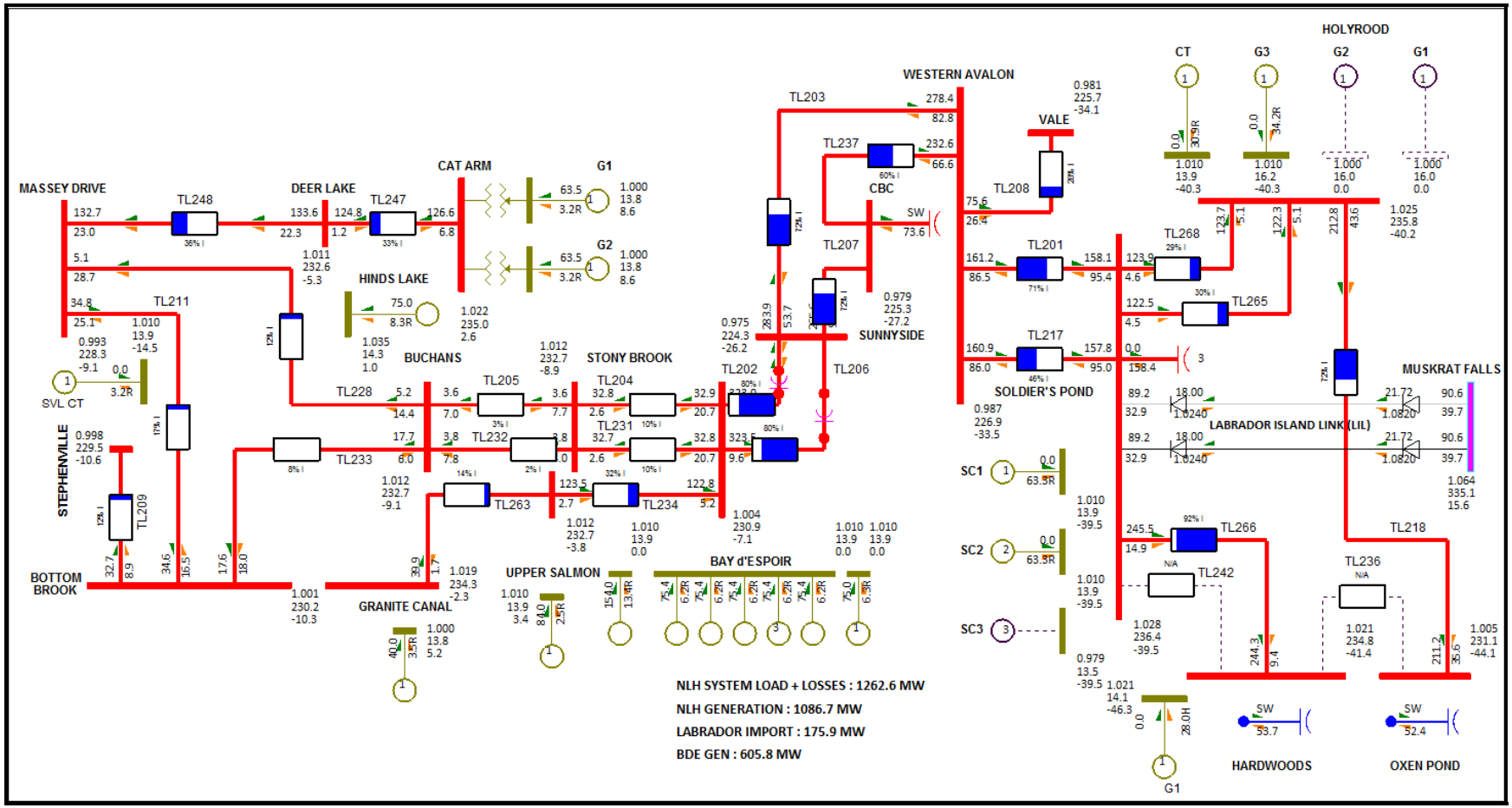


Figure 217 – Base Case 8 (BC8) Load Flow Plot – TL242 Out of Service – TL236 Open

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

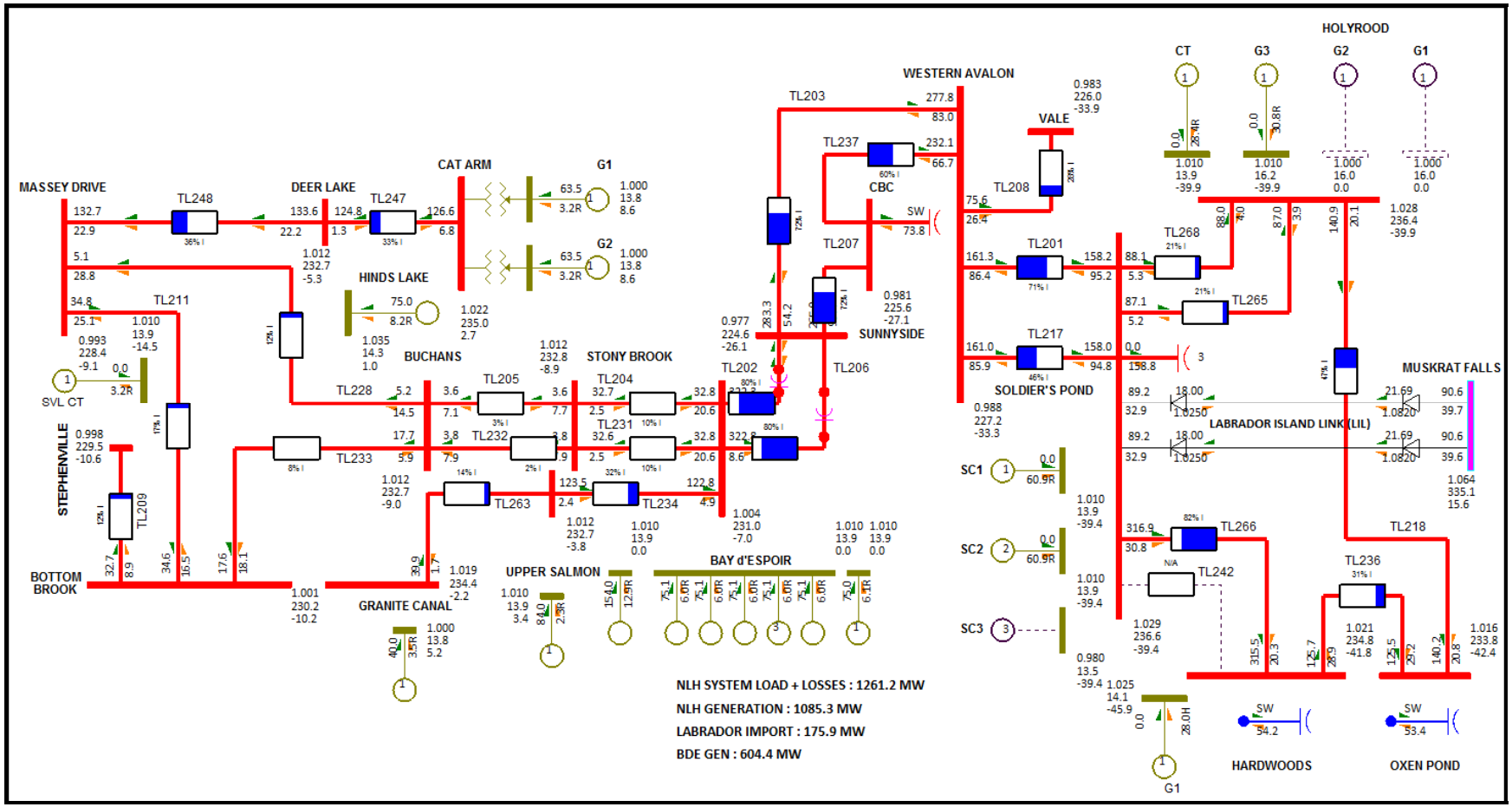


Figure 218 – Base Case 8 (BC8) Load Flow Plot – TL242 Out of Service

TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

Alternative 4

Complete 75°C Thermal Uprate and 50% Series Compensation on TL202/TL206 and Rebuild TL203 with 804 kcmil AACSR/TW Conductor

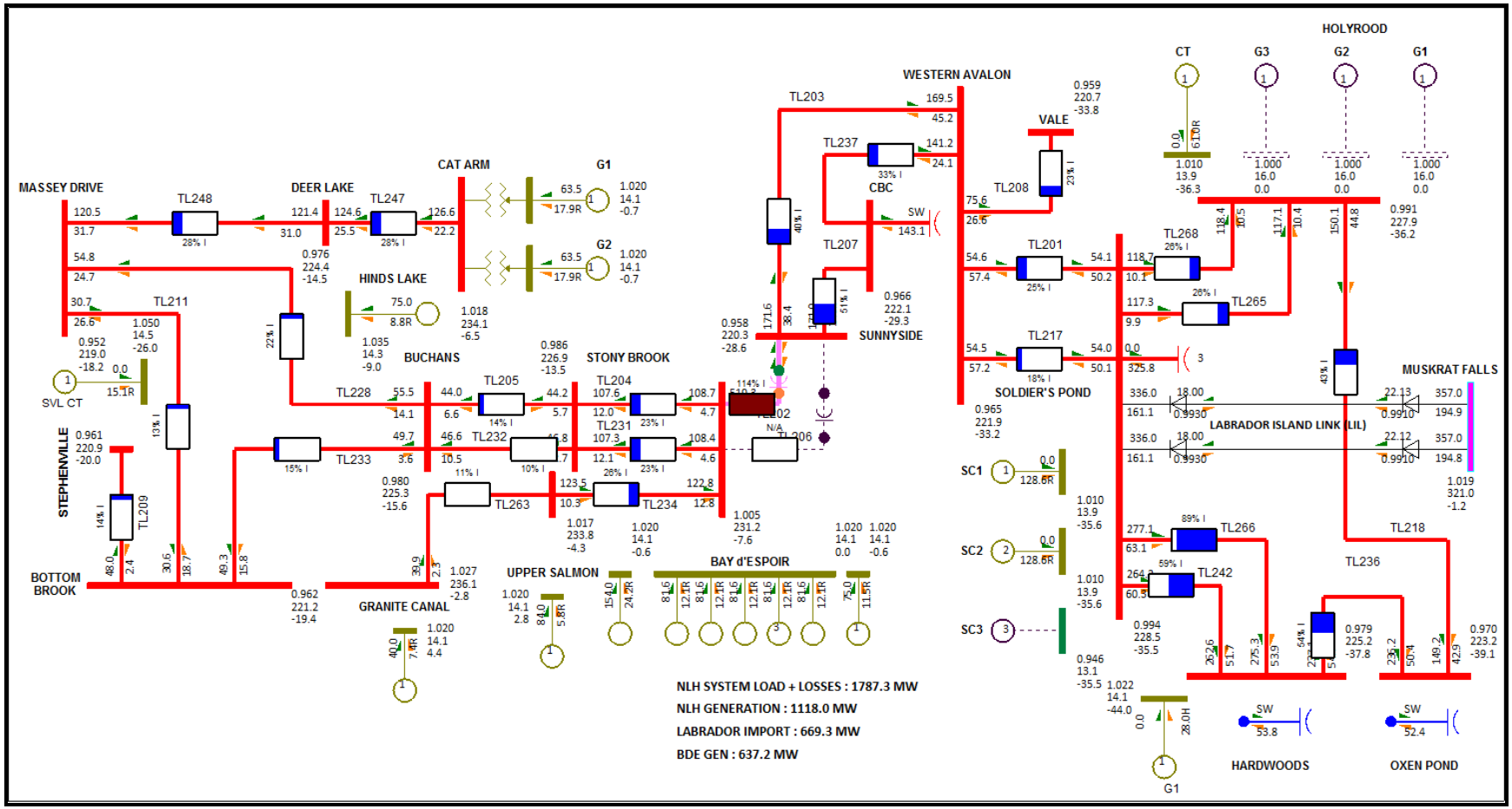


Figure 219 – Base Case 1 (BC1) Load Flow Plot – TL206 Out of Service

TL202 Loaded 114% of Thermal Rating

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

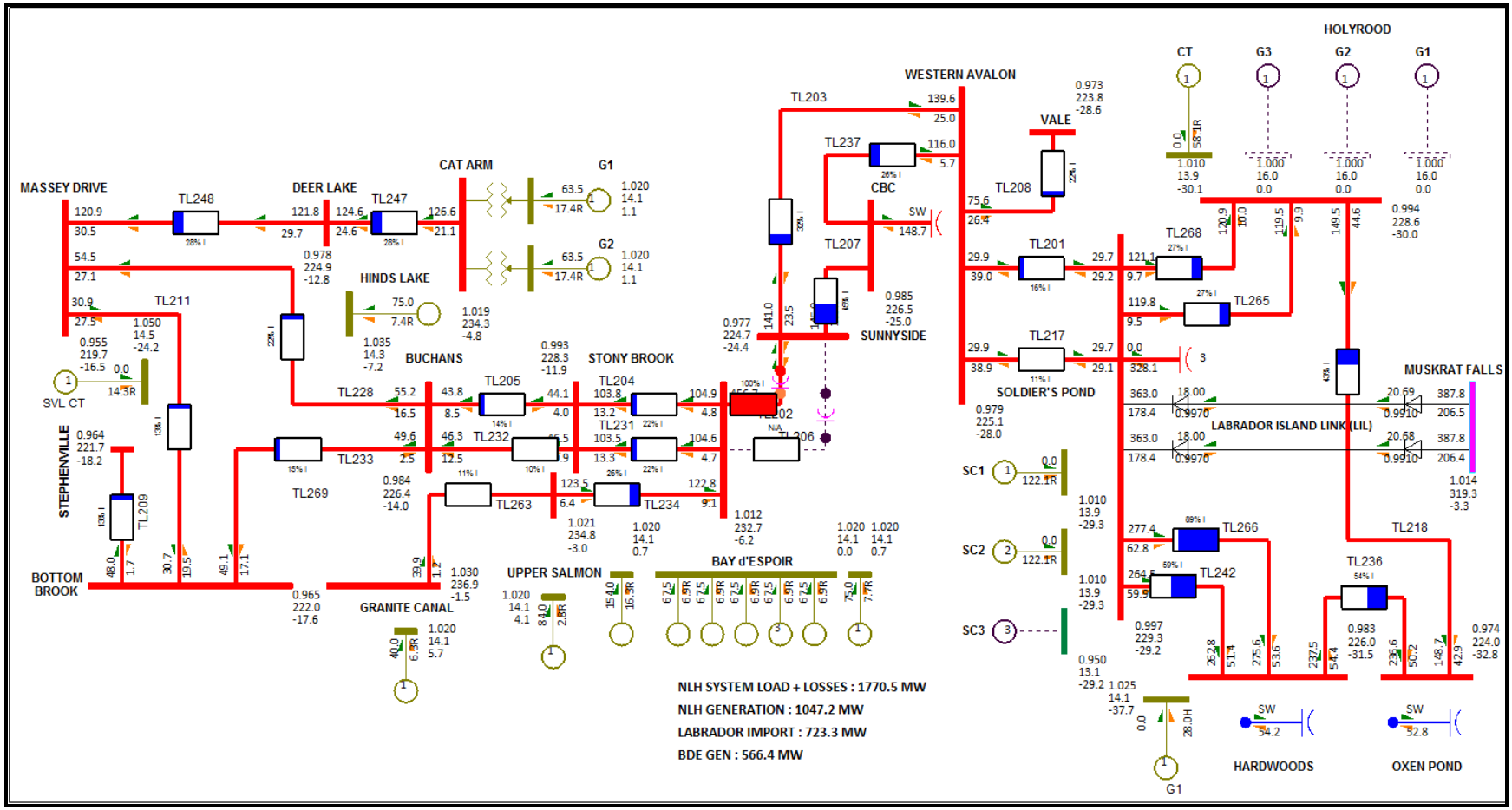


Figure 220 – Base Case 1 (BC1) Load Flow Plot – TL206 Out of Service

TL202 Loaded 100% of Thermal Rating – LIL Import Increased to 723 MW

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

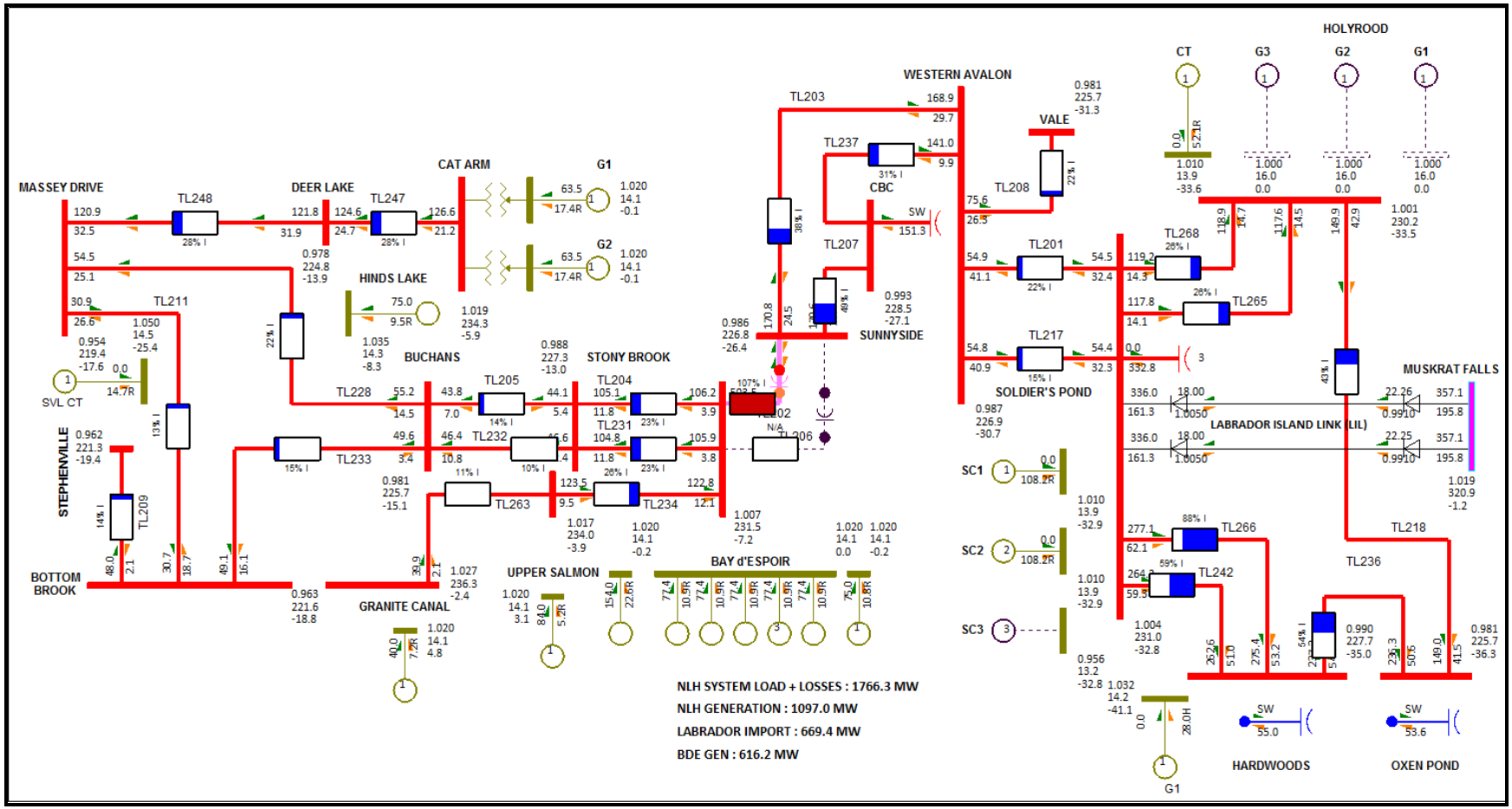


Figure 221 – Base Case 1 (BC1) Load Flow Plot – TL206 Out of Service

TL202 Loaded 107% of Thermal Rating – TL202 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

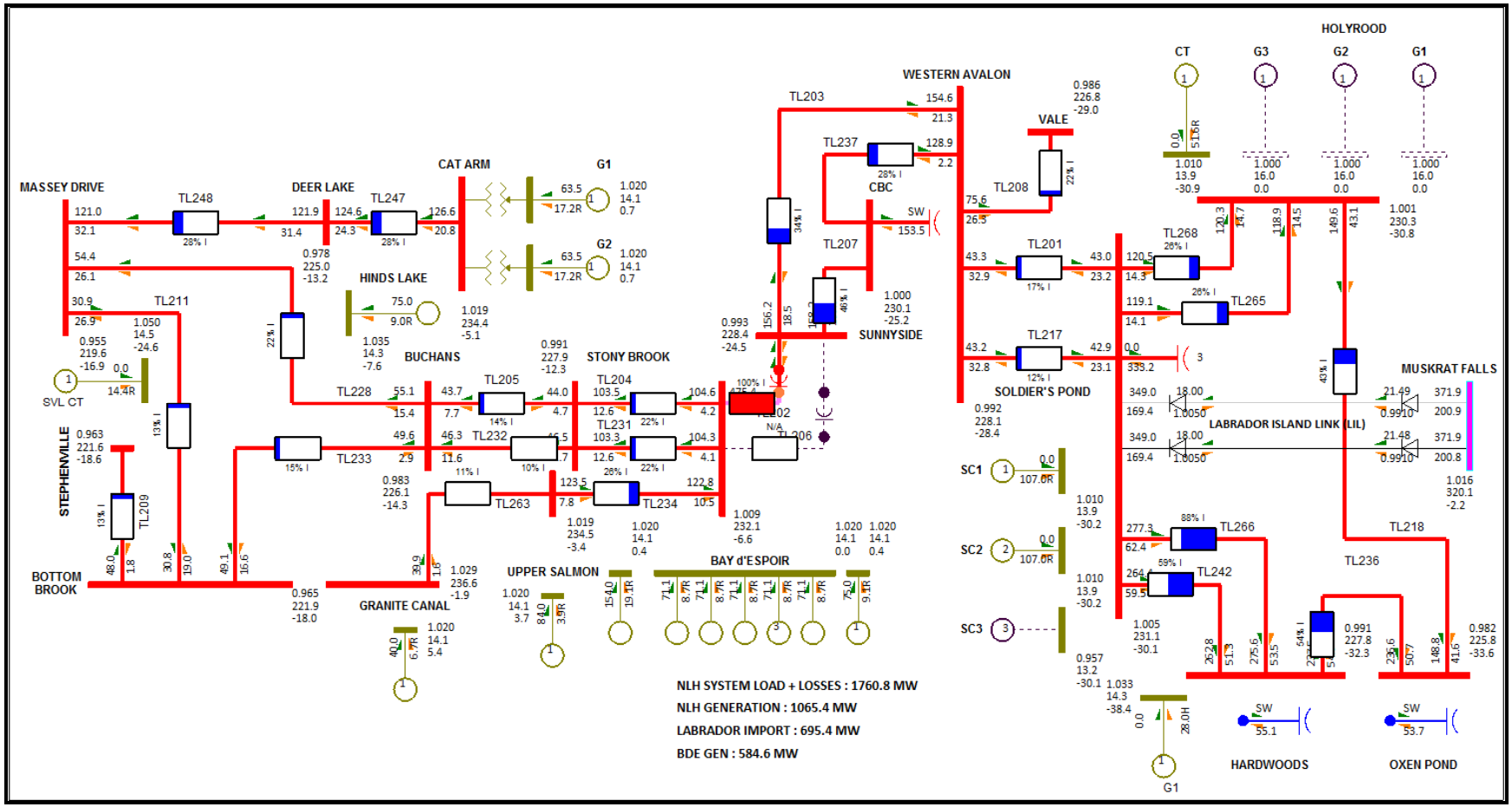


Figure 222 – Base Case 1 (BC1) Load Flow Plot – TL206 Out of Service

TL202 Loaded 107% of Thermal Rating – TL202 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor – LIL Increased to 695 MW

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

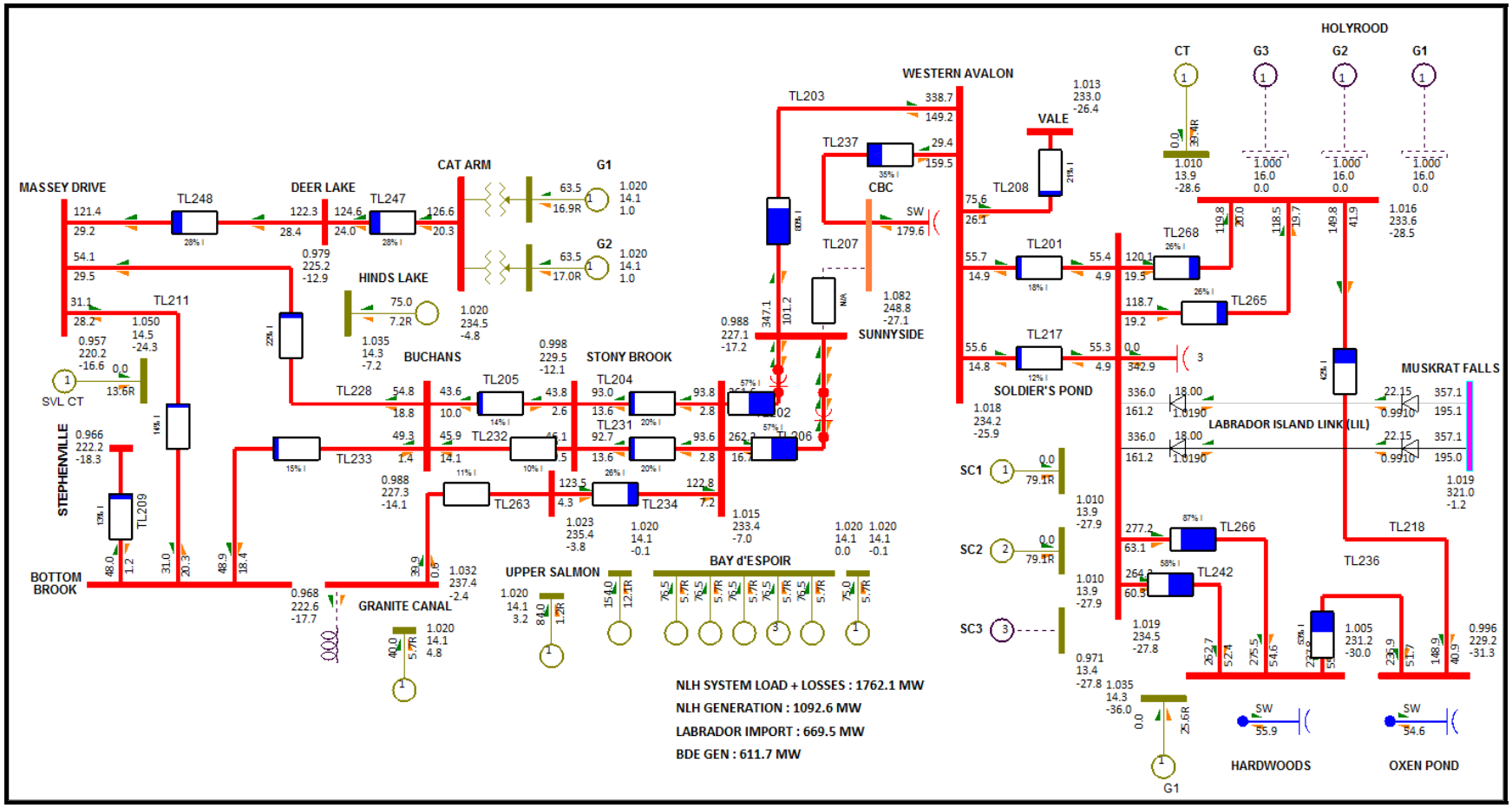


Figure 223 – Base Case 1 (BC1) Load Flow Plot – TL207 Out of Service

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

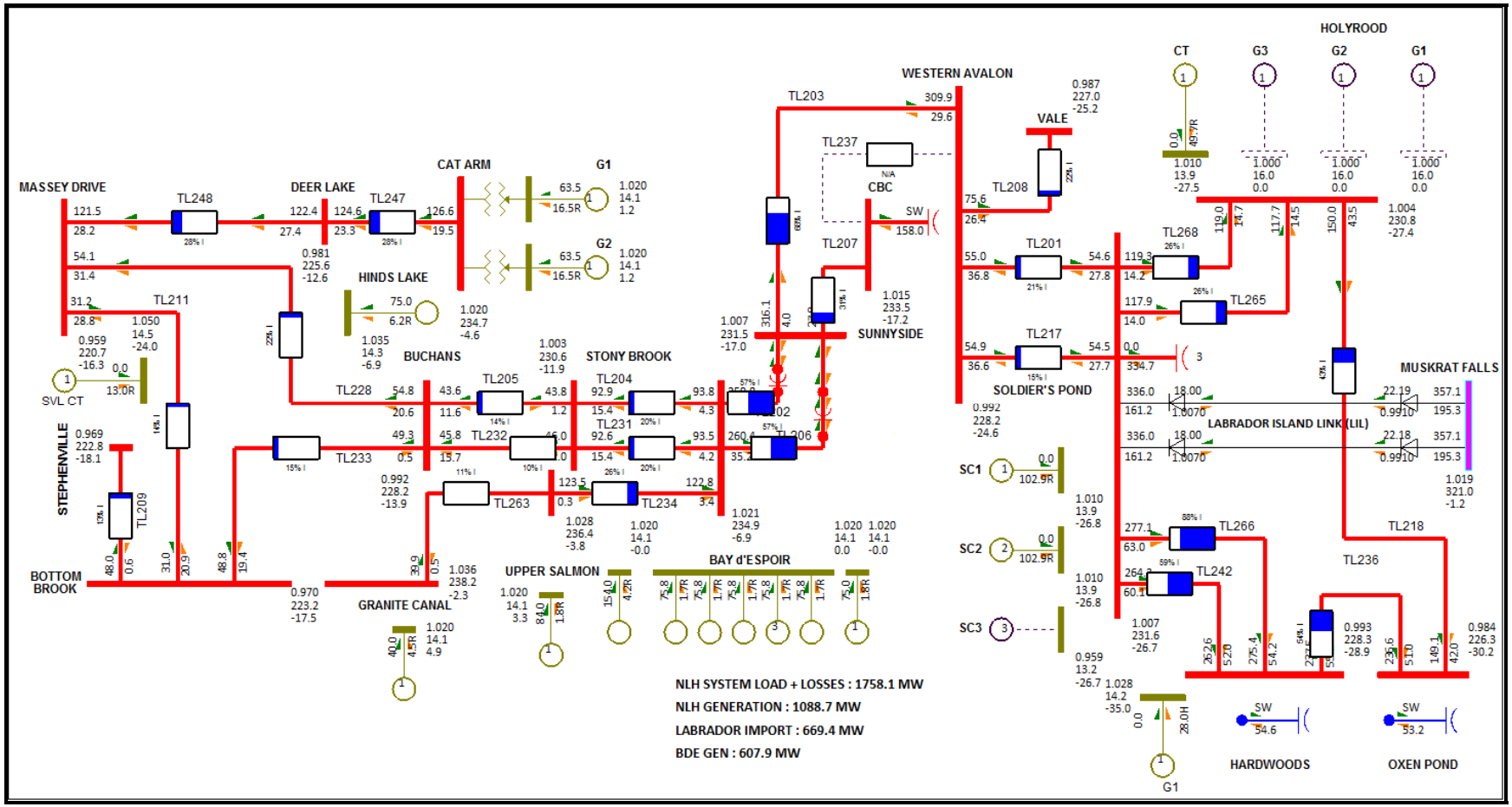


Figure 224 – Base Case 1 (BC1) Load Flow Plot – TL237 Out of Service

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

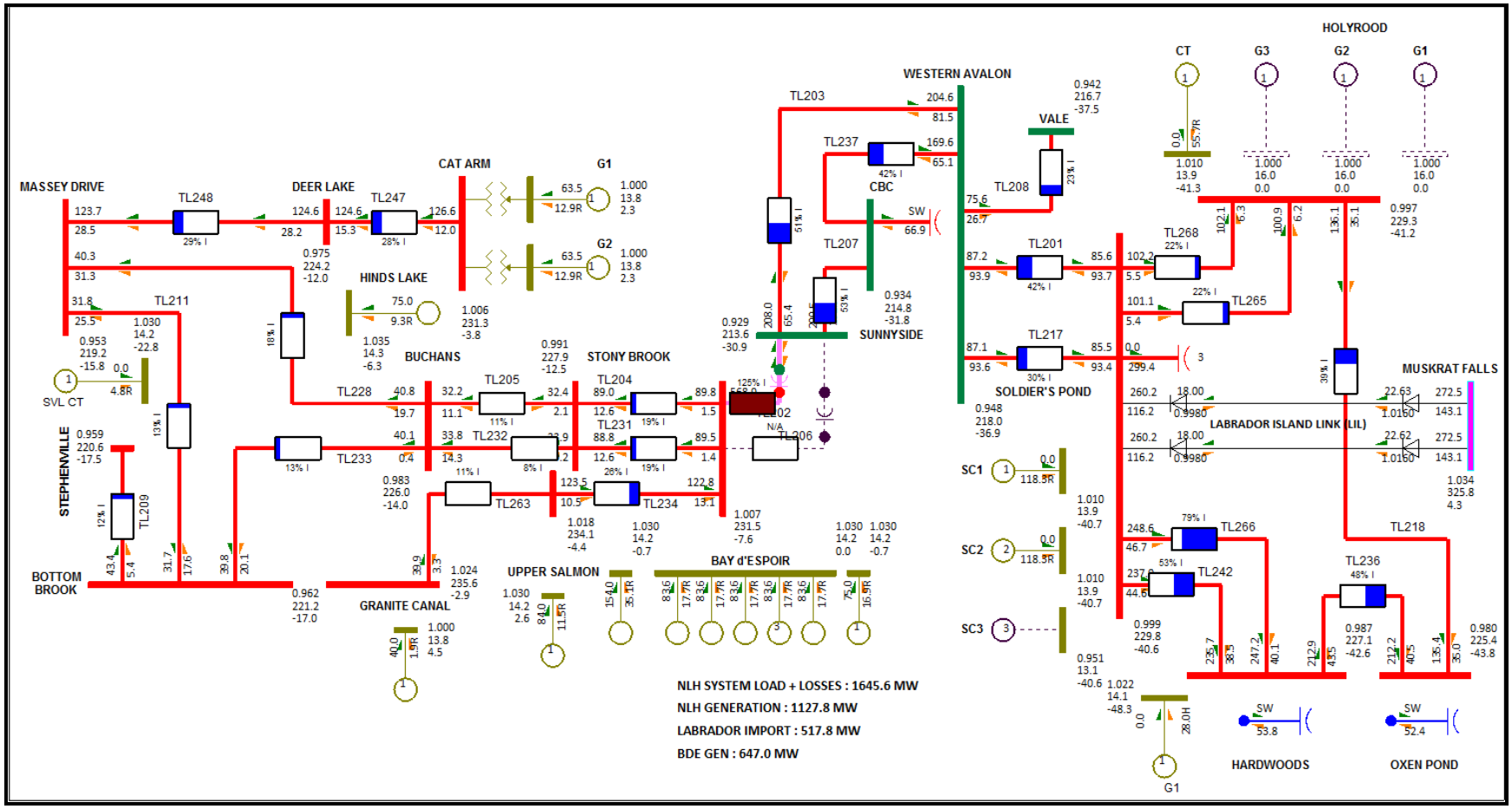


Figure 225 – Base Case 3 (BC3) Load Flow Plot – TL206 Out of Service

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

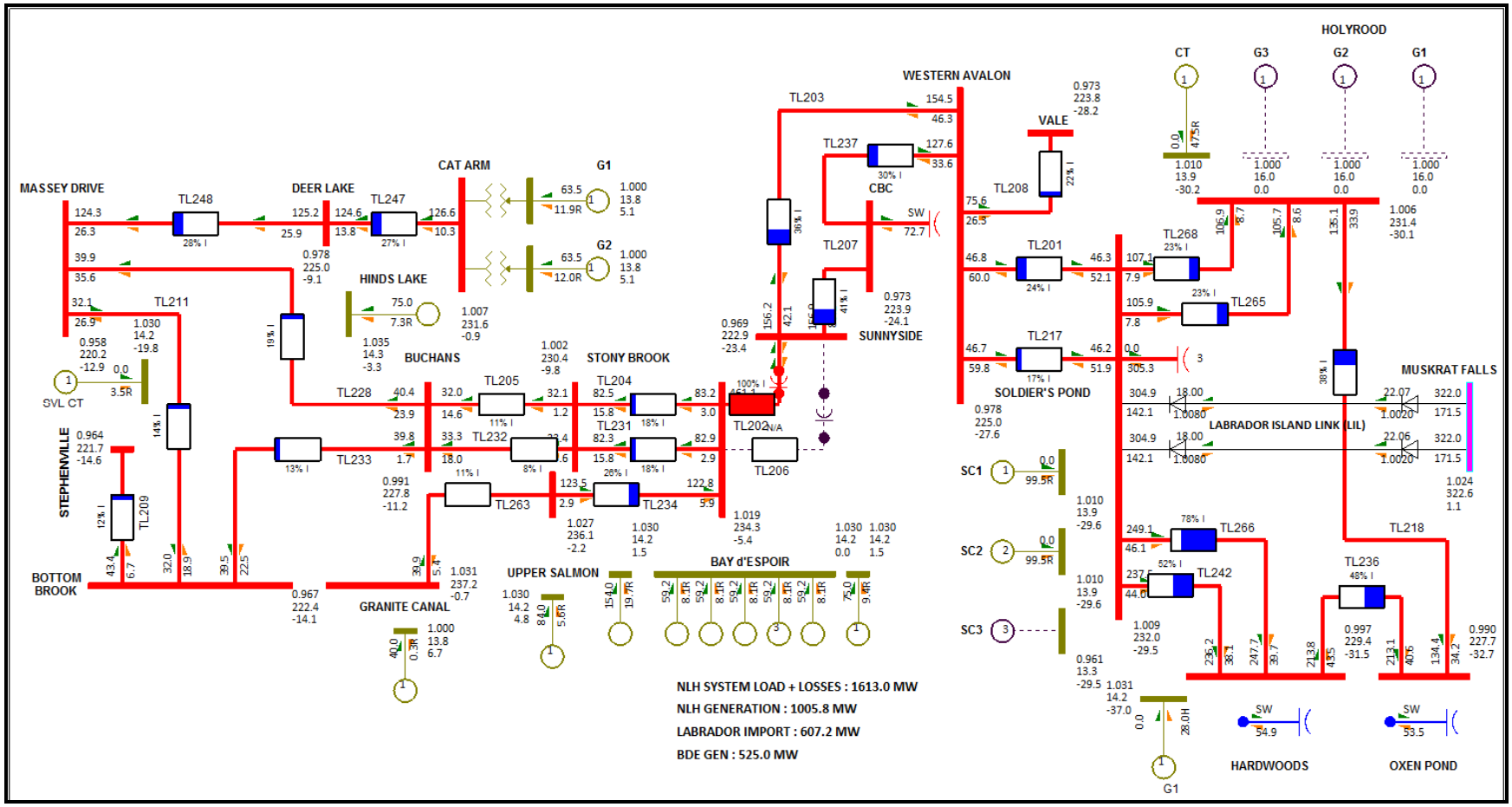


Figure 226 – Base Case 3 (BC3) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 607 MW

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

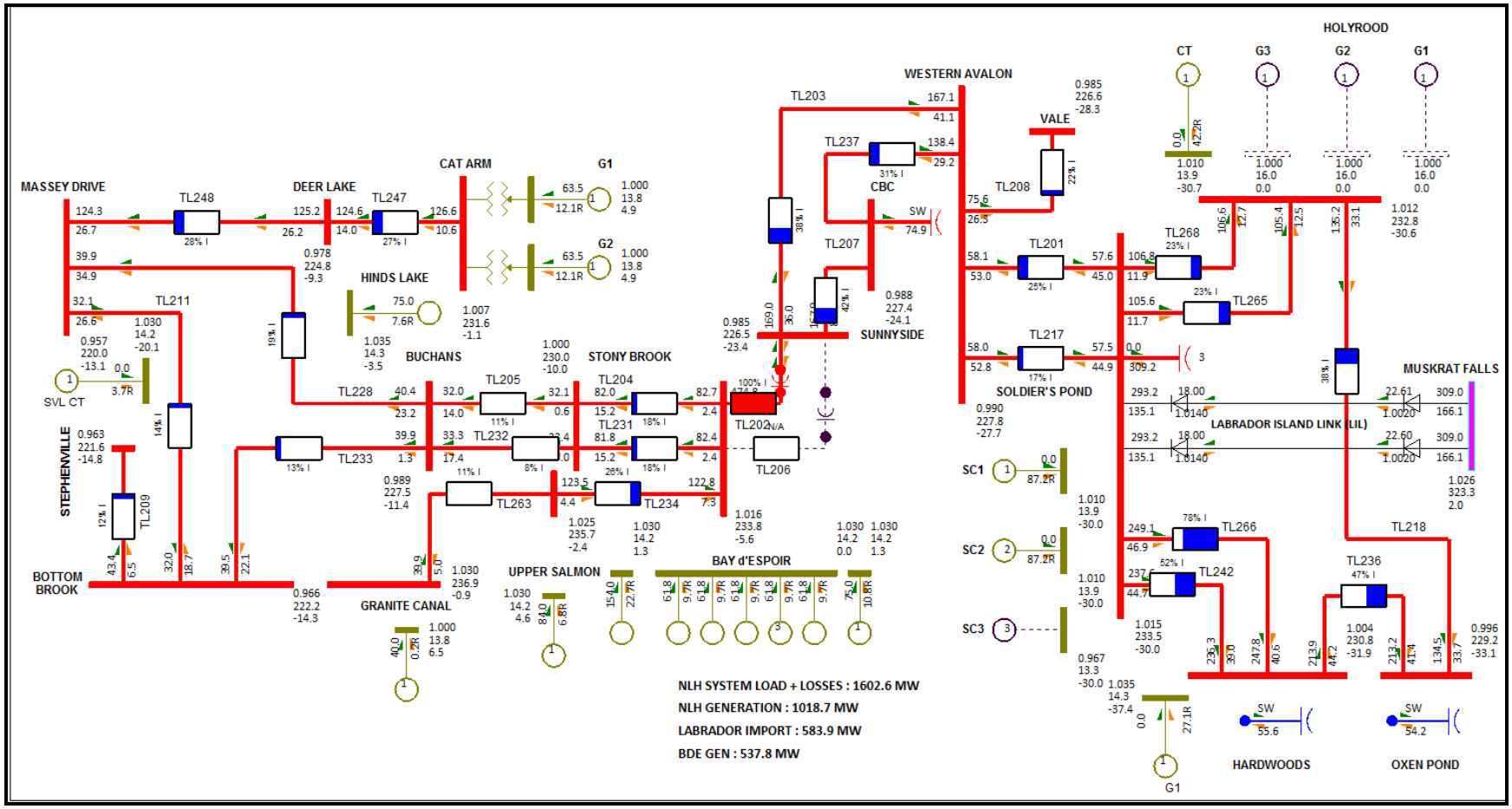


Figure 227 – Base Case 3 (BC3) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 584 MW

TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

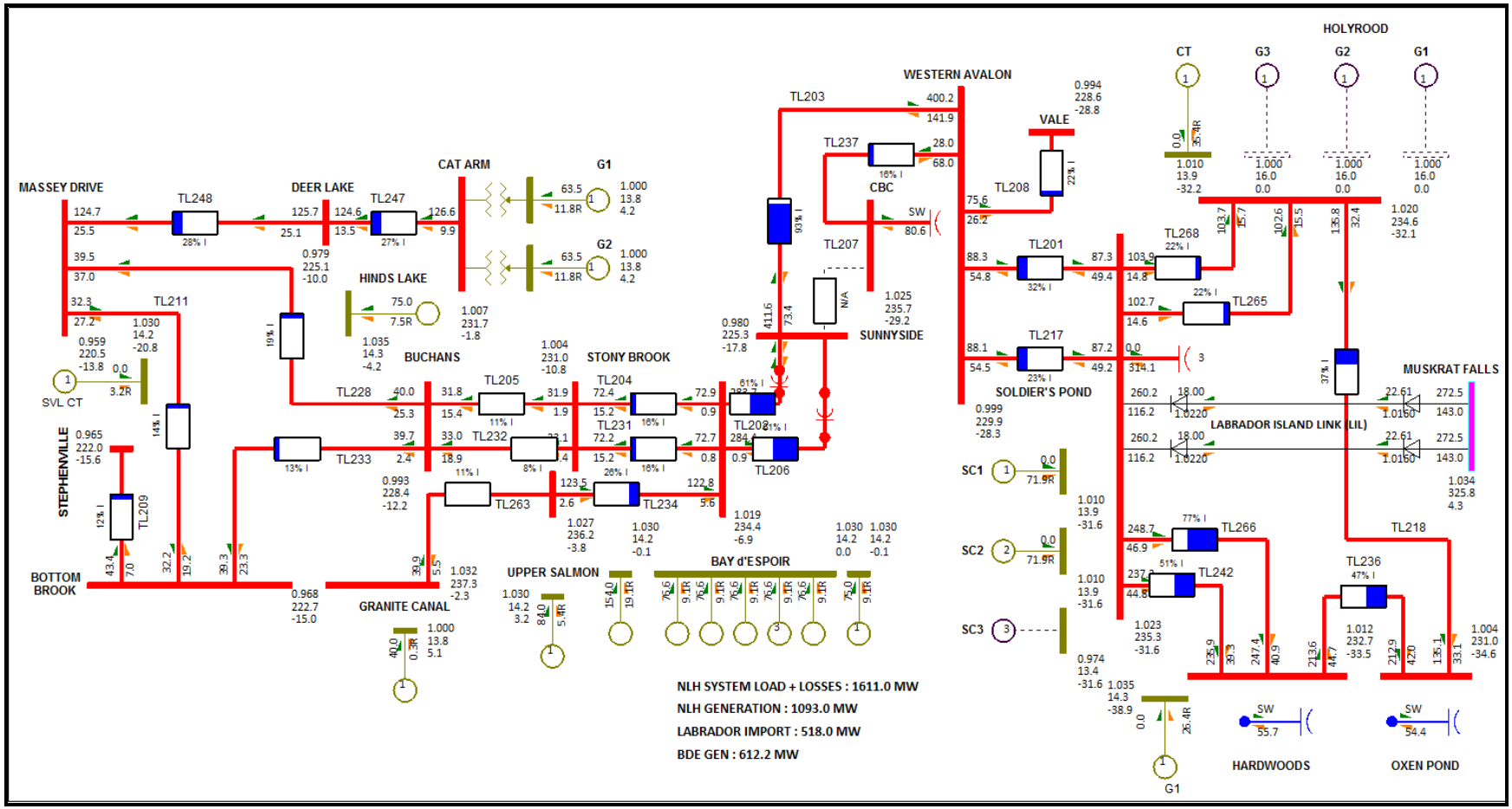


Figure 228 – Base Case 3 (BC3) Load Flow Plot – TL207 Out of Service

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

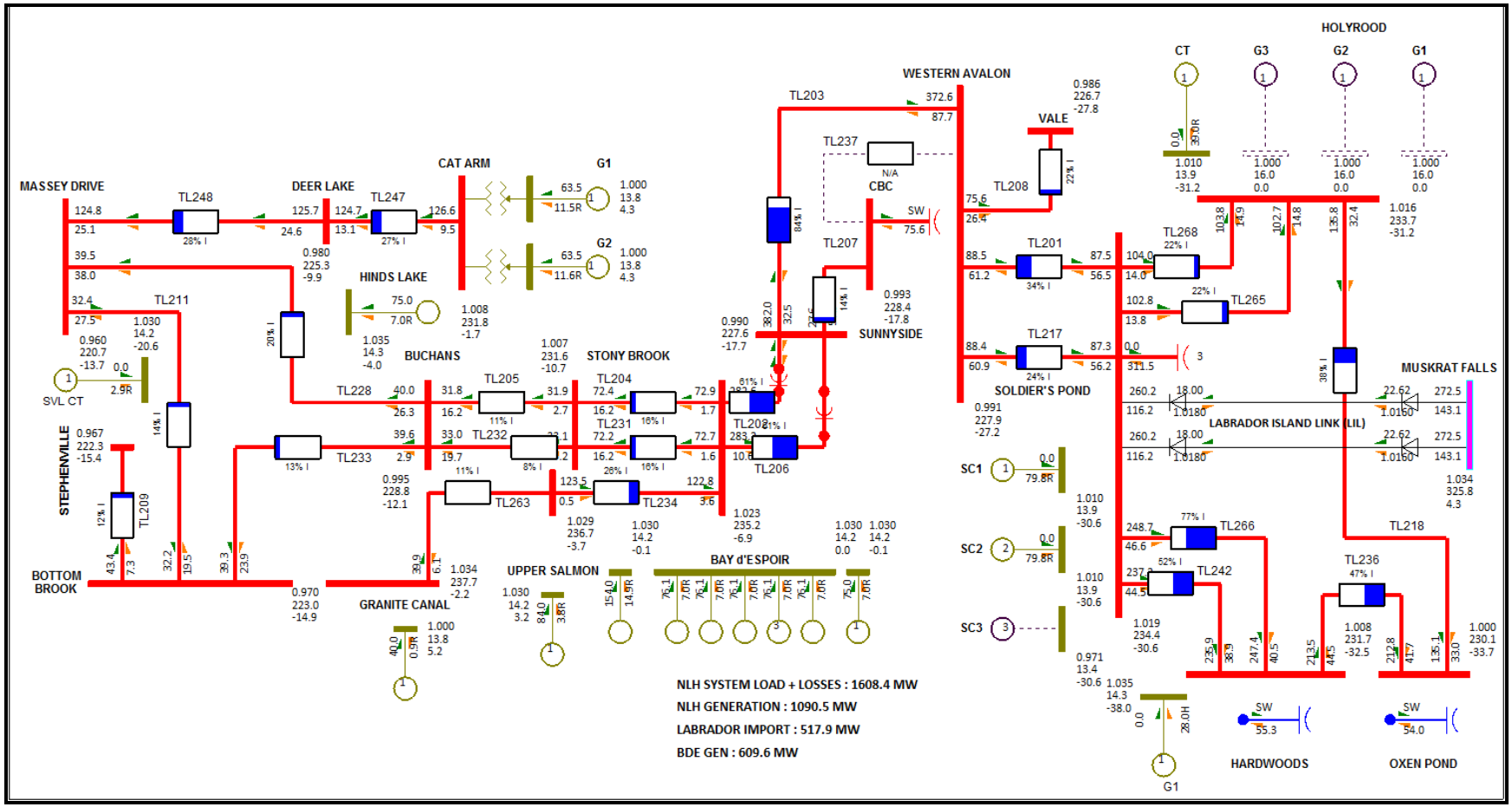


Figure 229 – Base Case 3 (BC3) Load Flow Plot – TL237 Out of Service

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

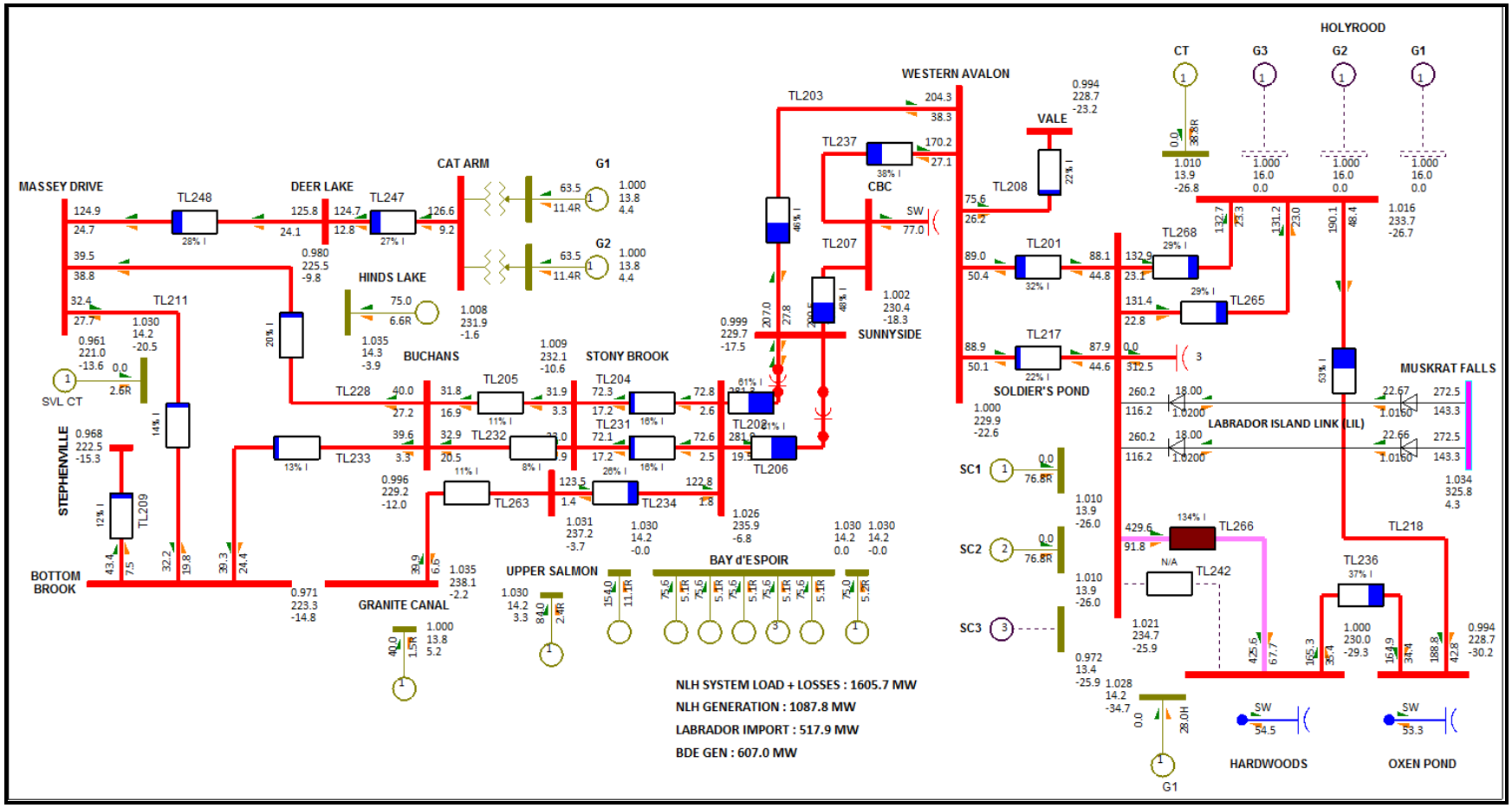


Figure 230 – Base Case 3 (BC3) Load Flow Plot – TL242 Out of Service

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

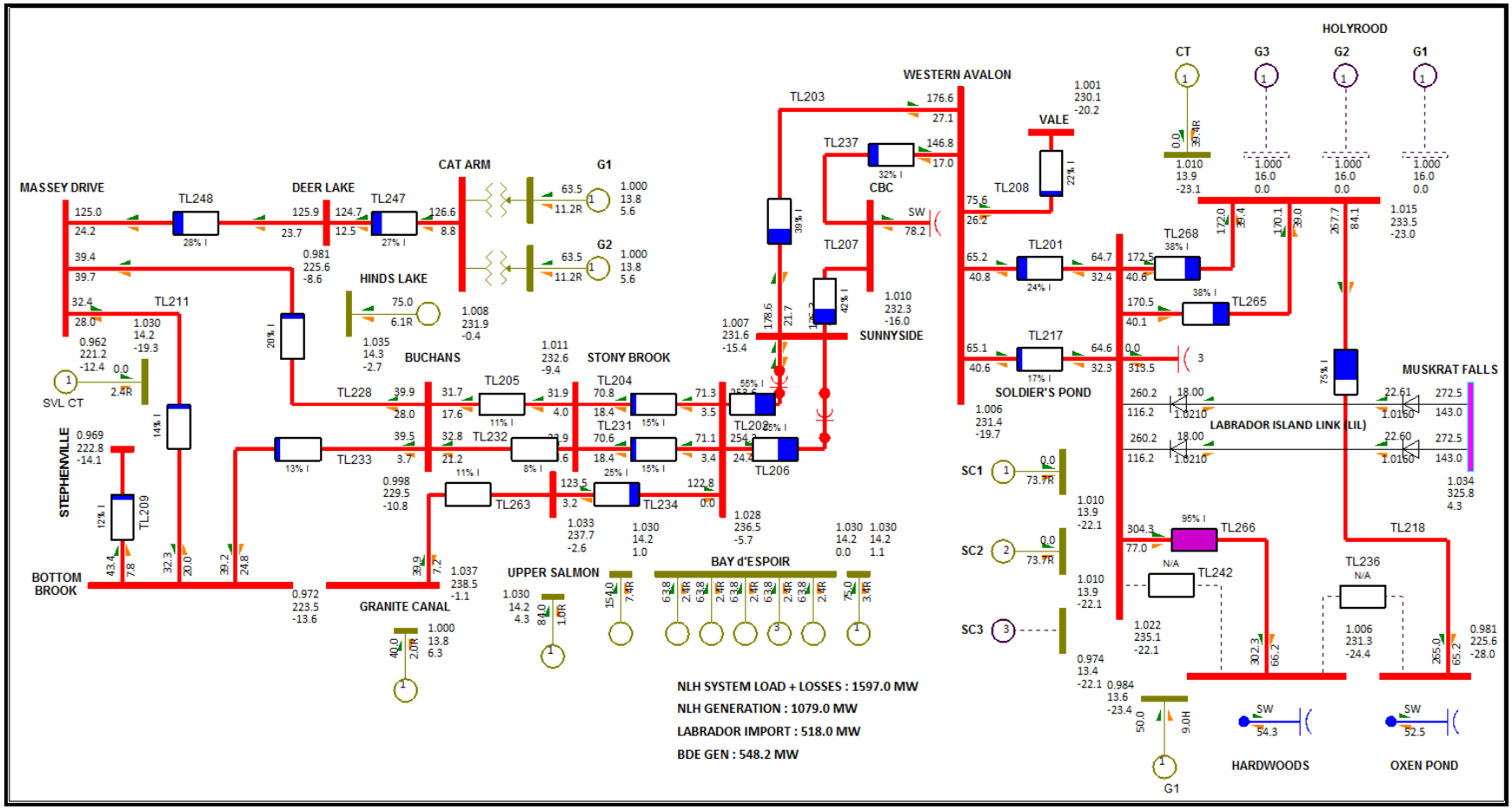


Figure 231 – Base Case 3 (BC3) Load Flow Plot – TL242 Out of Service – HWD CT Generating 50 MW + TL236 Open

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

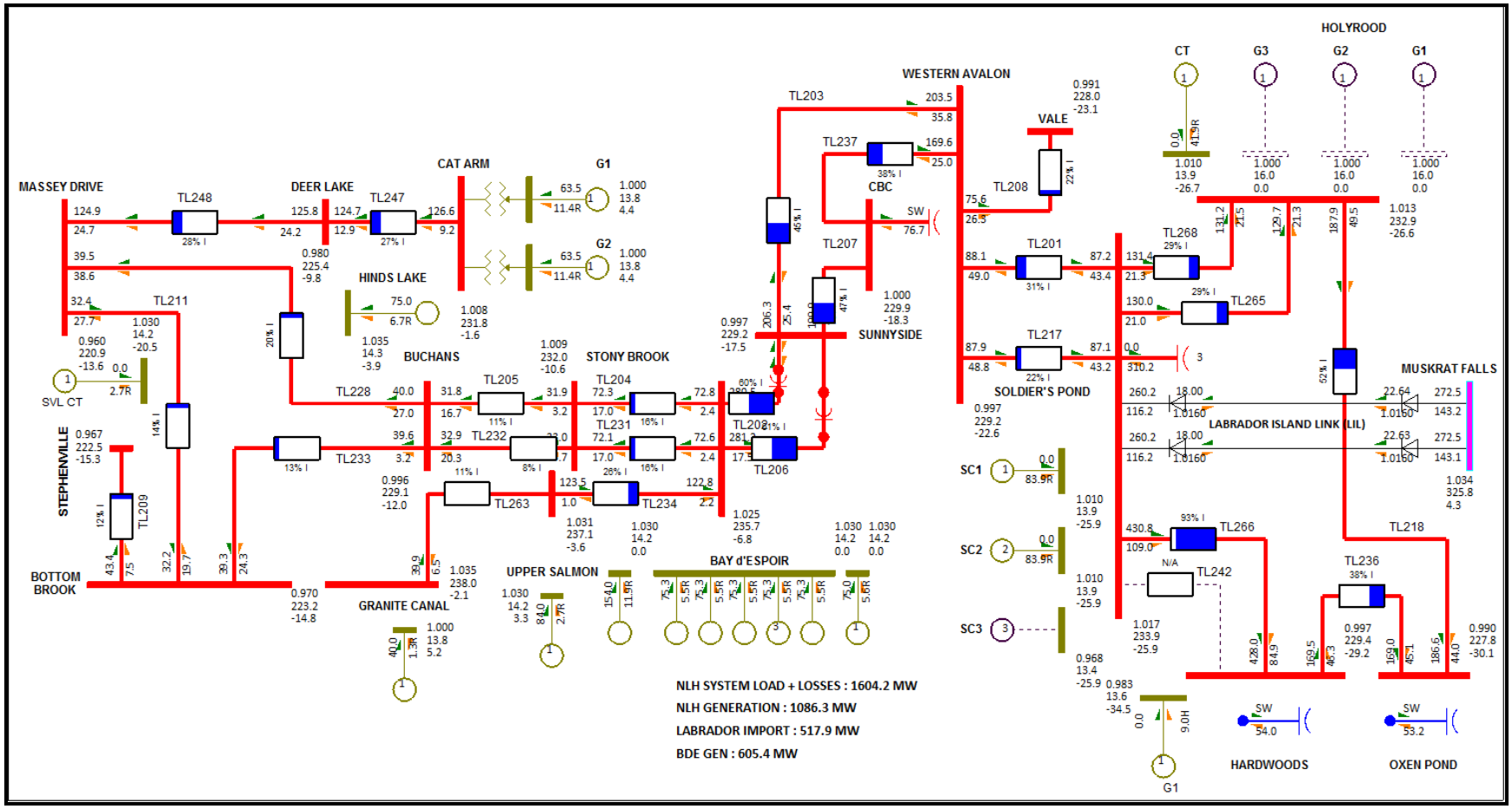


Figure 232 – Base Case 3 (BC3) Load Flow Plot – TL242 Out of Service

TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

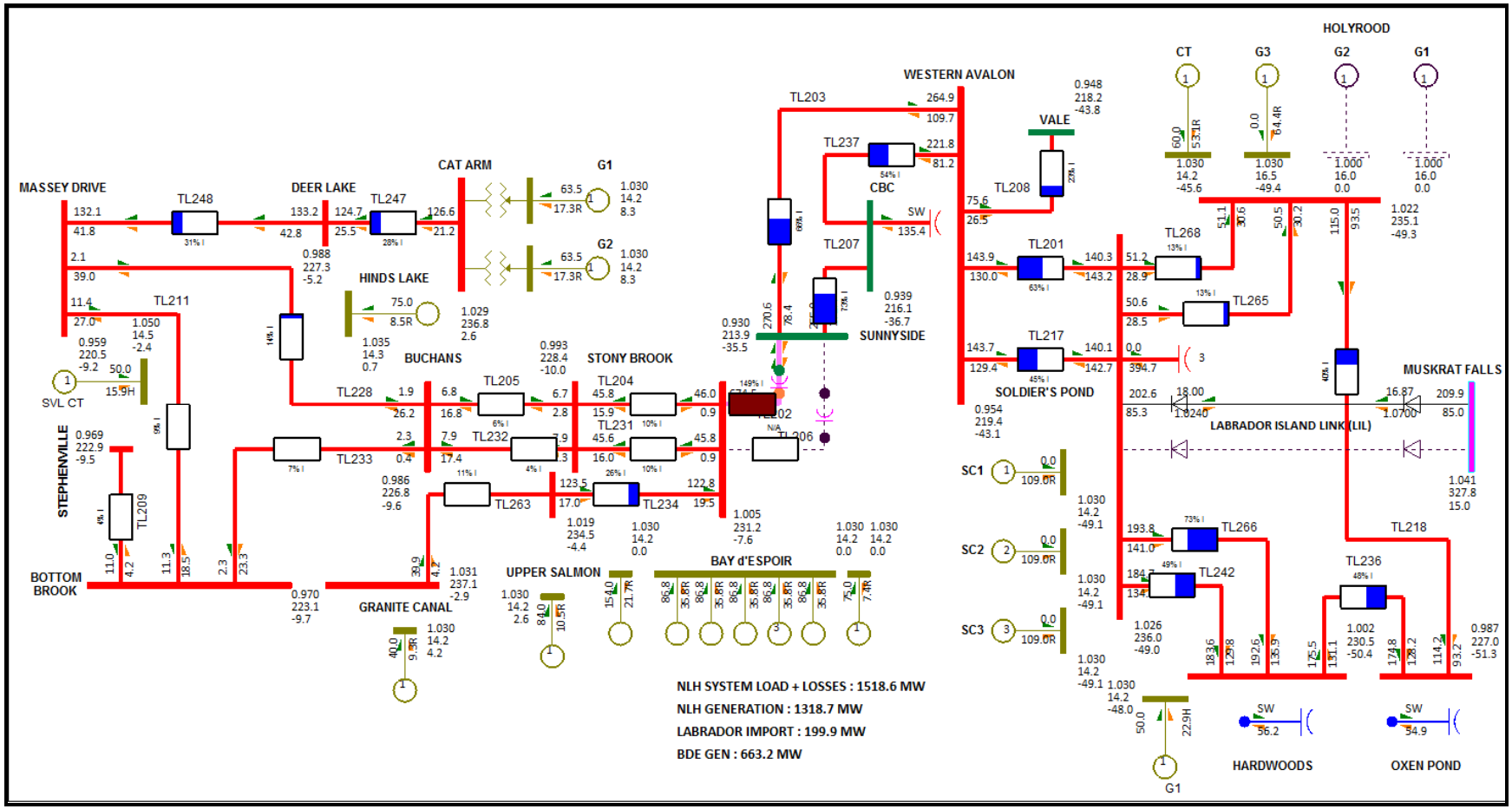


Figure 233 – Base Case 4 (BC4) Load Flow Plot – TL206 Out of Service

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

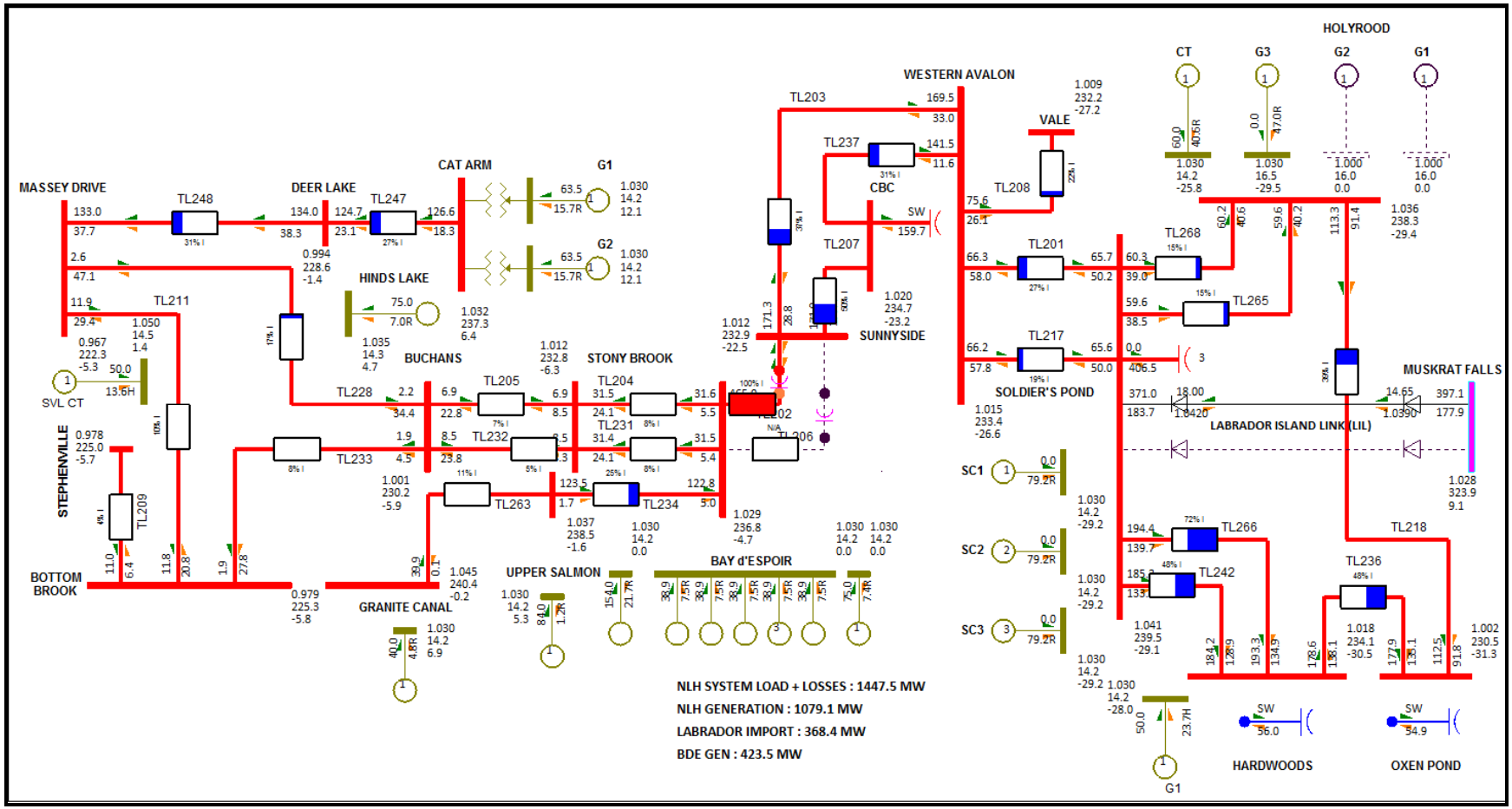


Figure 234 – Base Case 4 (BC4) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 368 MW

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

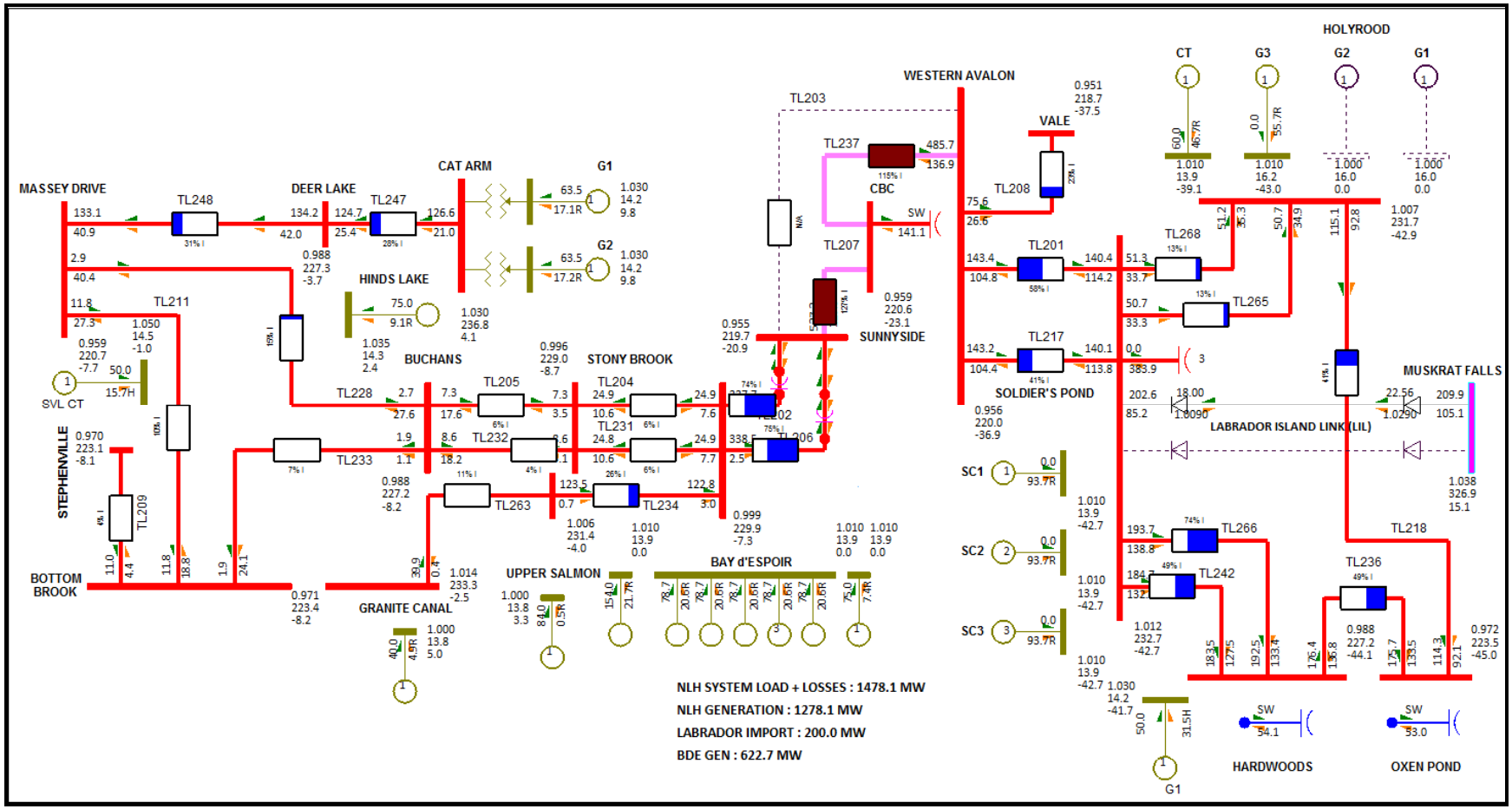


Figure 235 – Base Case 4 (BC4) Load Flow Plot – TL203 Out of Service

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

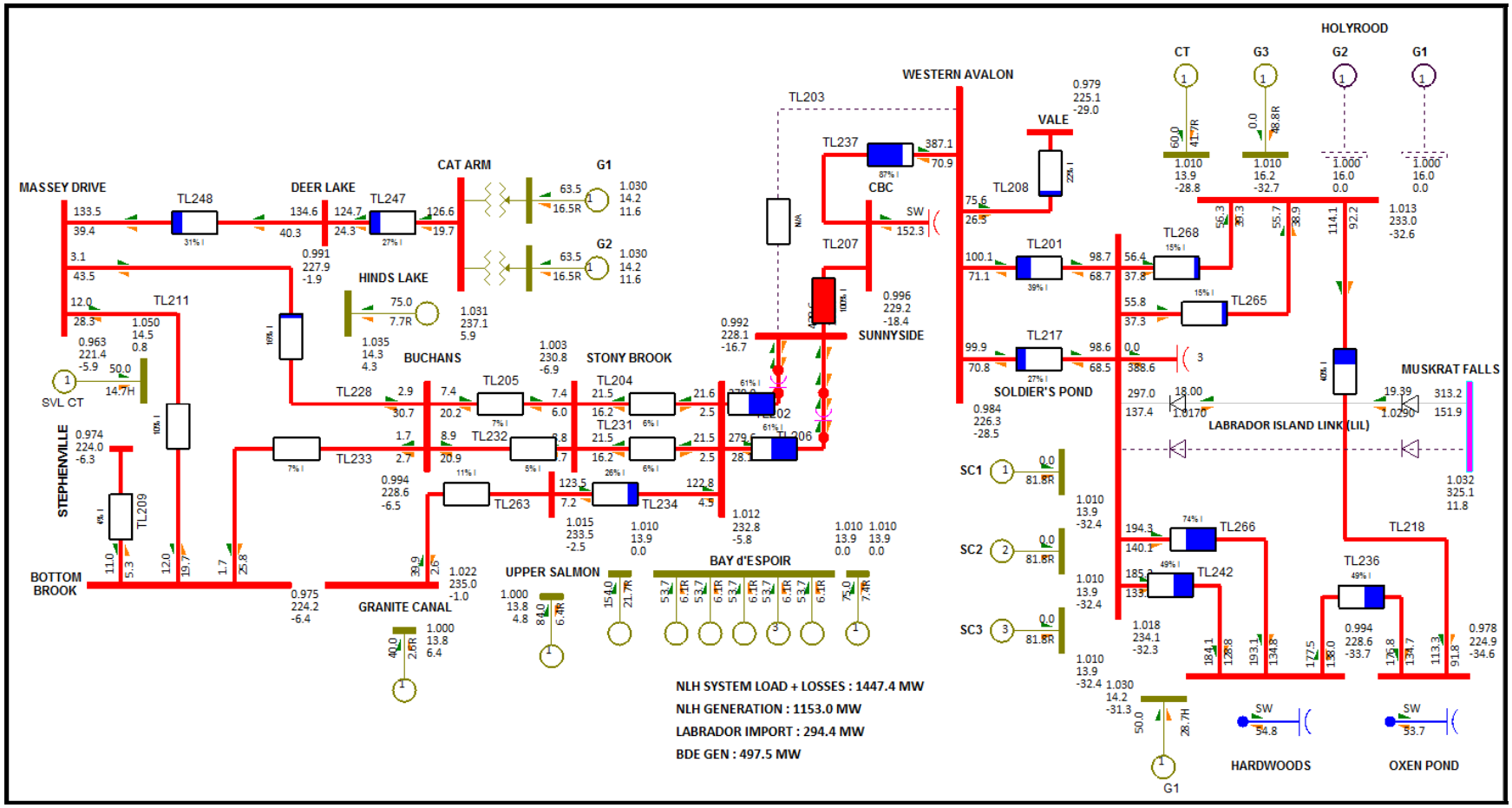


Figure 236 – Base Case 4 (BC4) Load Flow Plot – TL203 Out of Service – LIL Import Increased to 294 MW

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

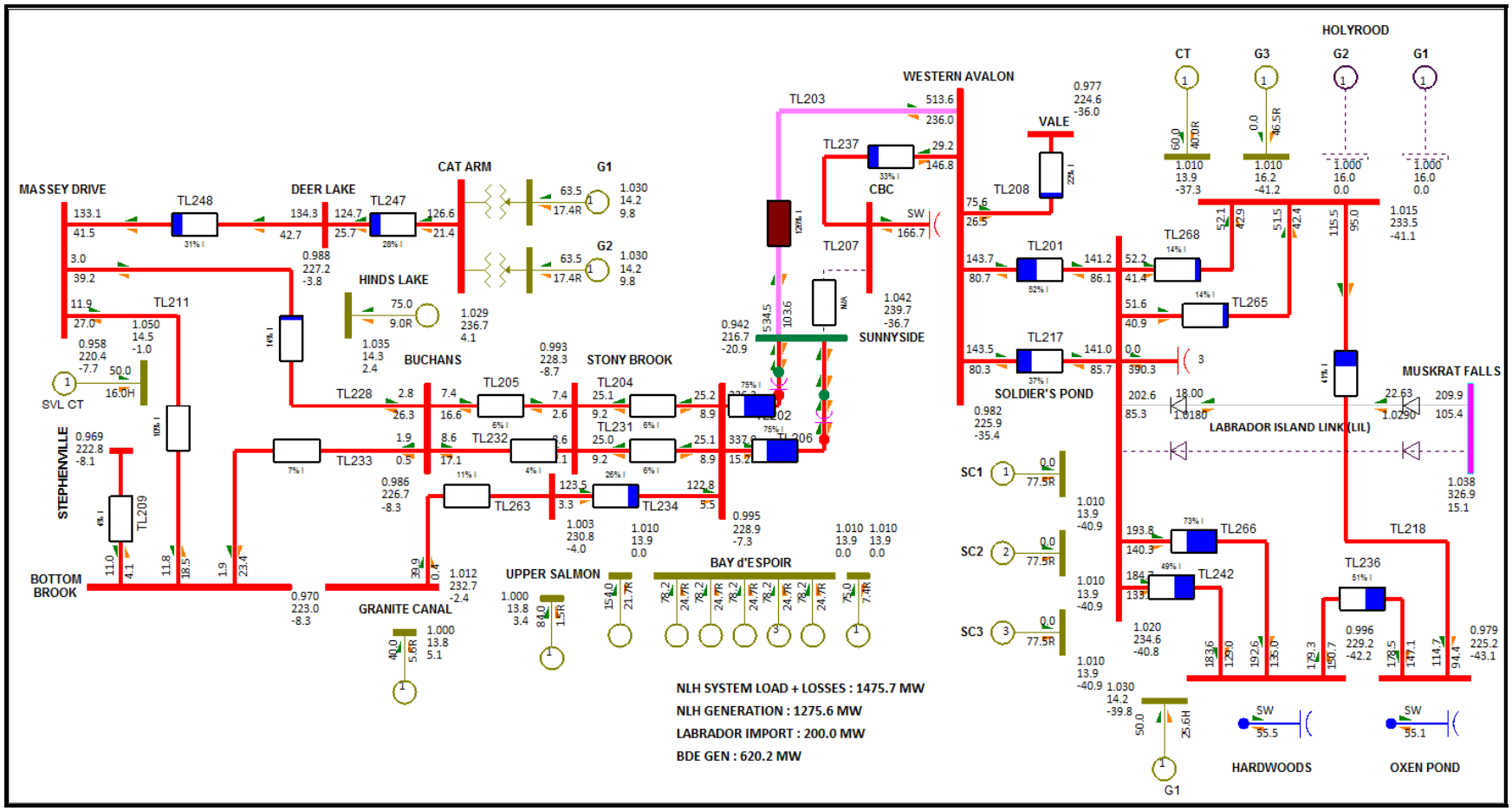


Figure 237 – Base Case 4 (BC4) Load Flow Plot – TL207 Out of Service

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

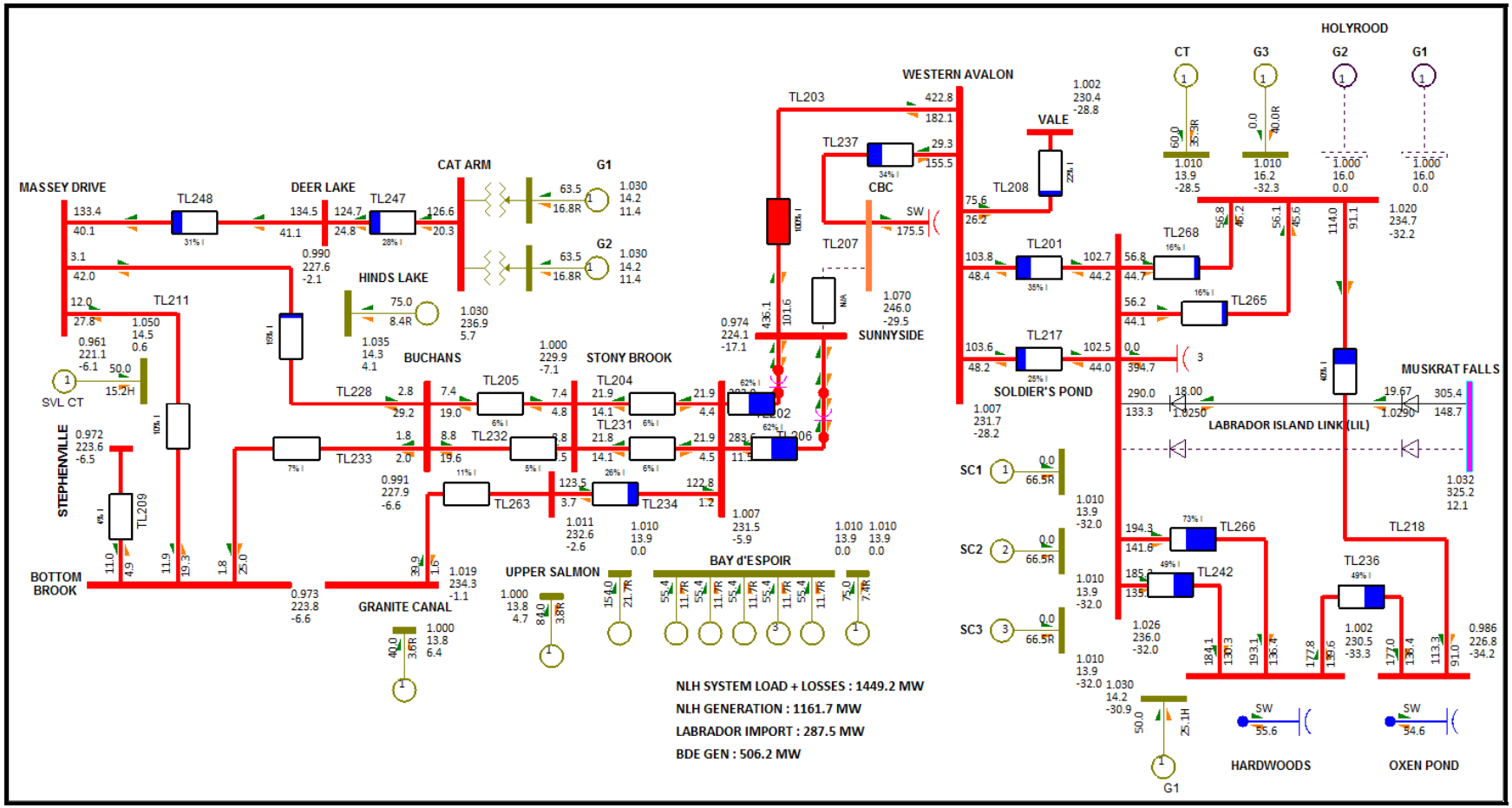


Figure 238 – Base Case 4 (BC4) Load Flow Plot – TL207 Out of Service – LIL Import Increased to 288 MW

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

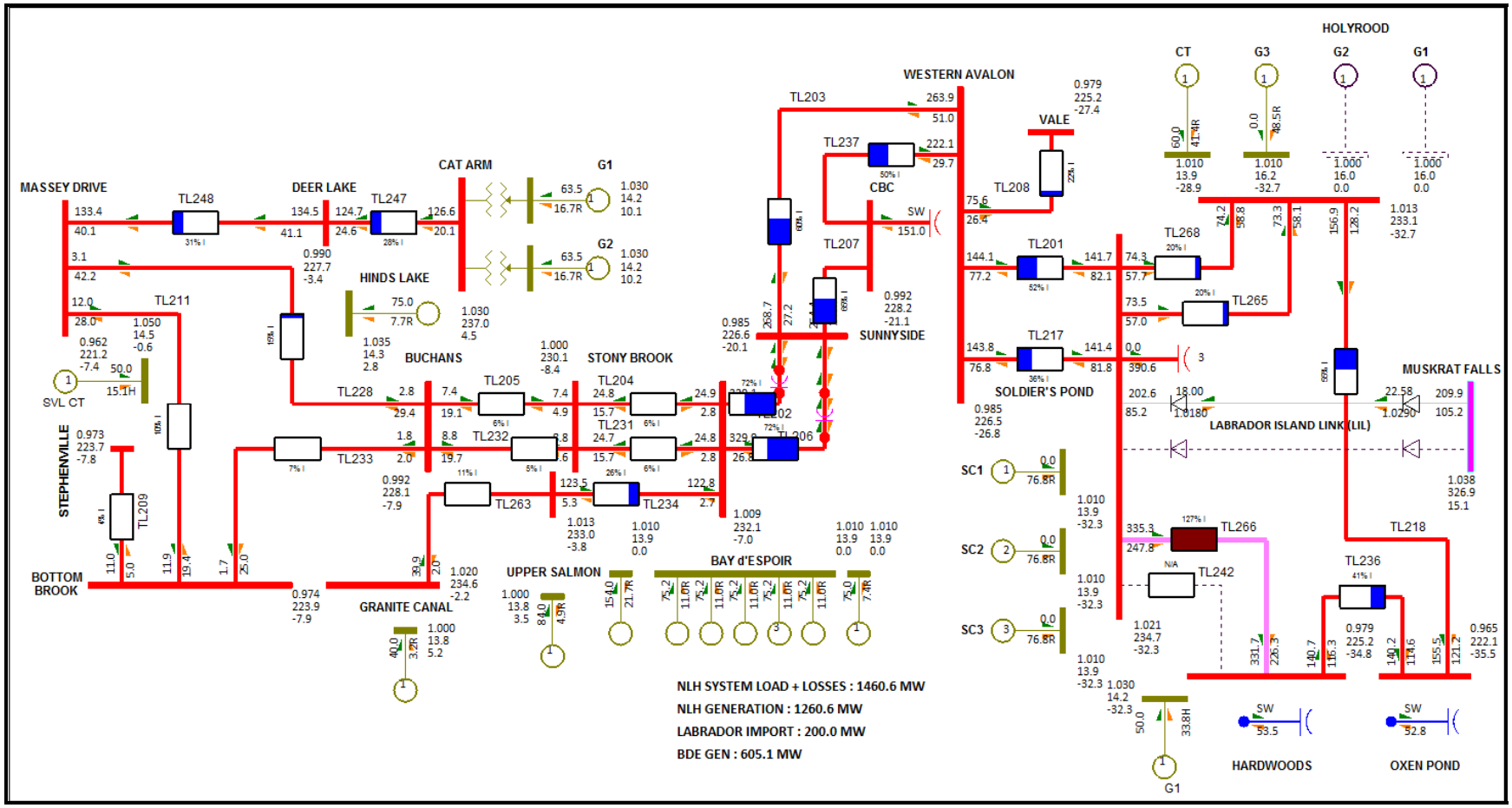


Figure 239 – Base Case 4 (BC4) Load Flow Plot – TL242 Out of Service

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

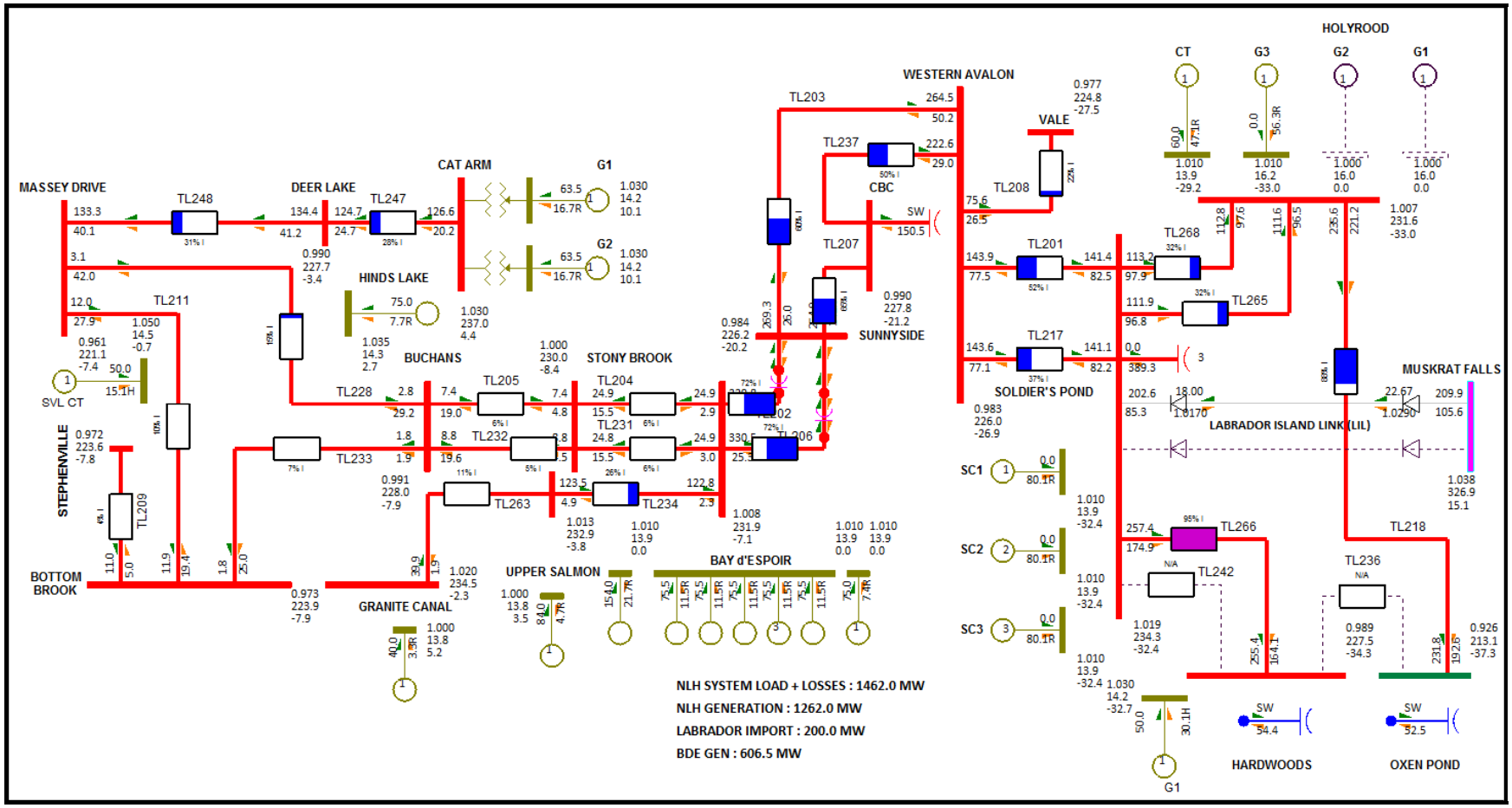


Figure 240 – Base Case 4 (BC4) Load Flow Plot – TL242 Out of Service – TL236 Open

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

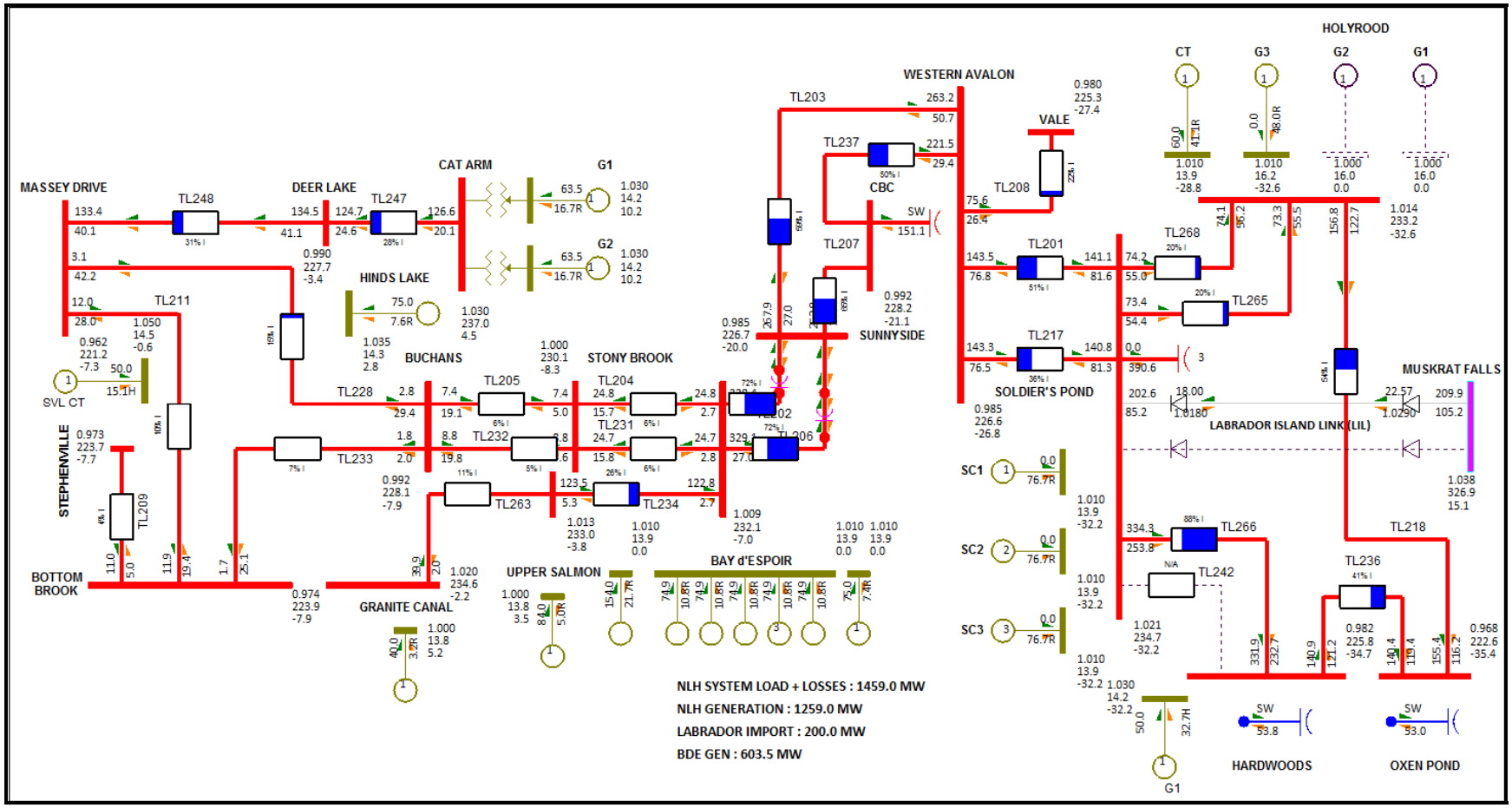


Figure 241 – Base Case 4 (BC4) Load Flow Plot – TL242 Out of Service

TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

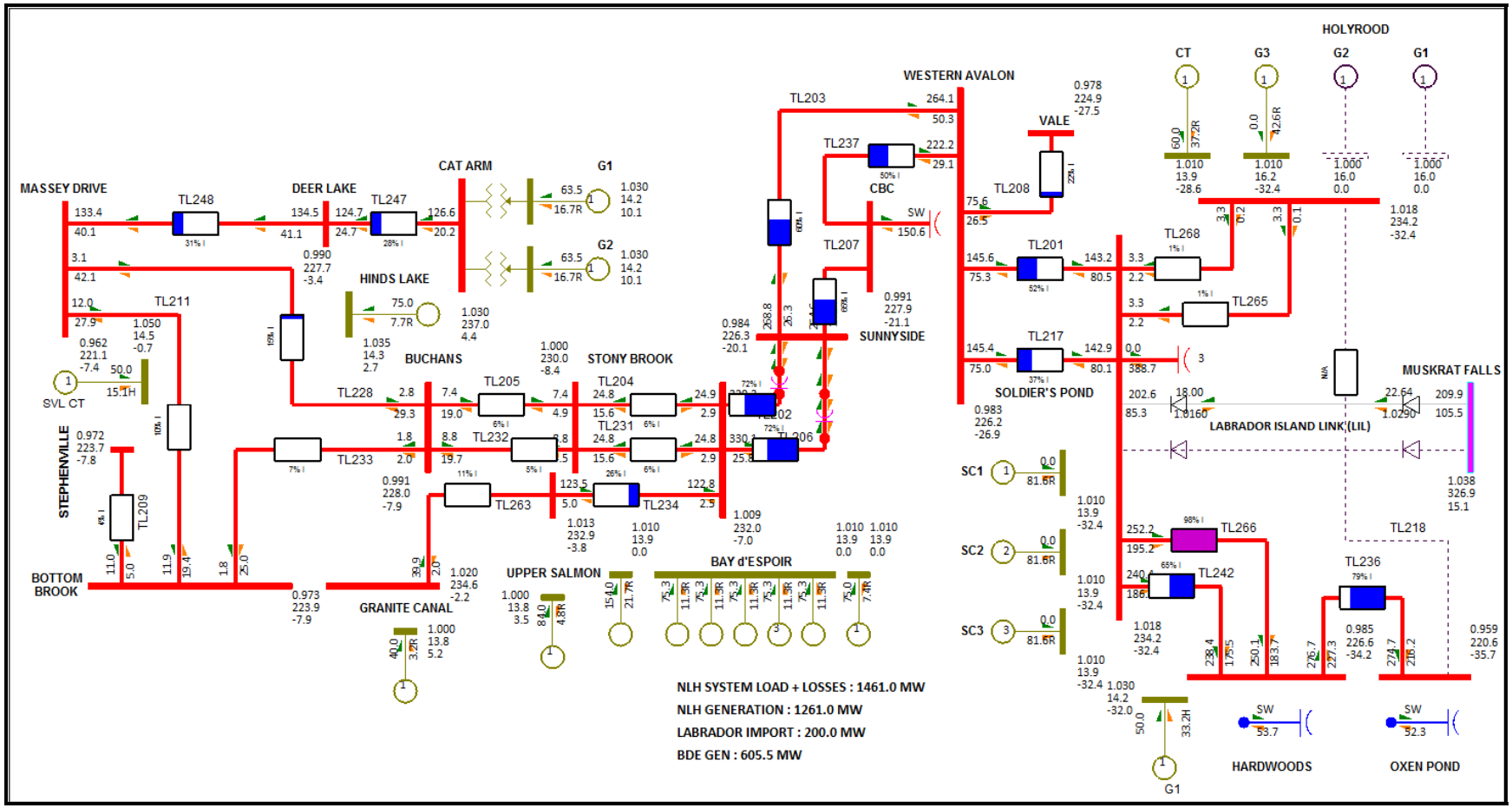


Figure 242 – Base Case 4 (BC4) Load Flow Plot – TL218 Out of Service

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

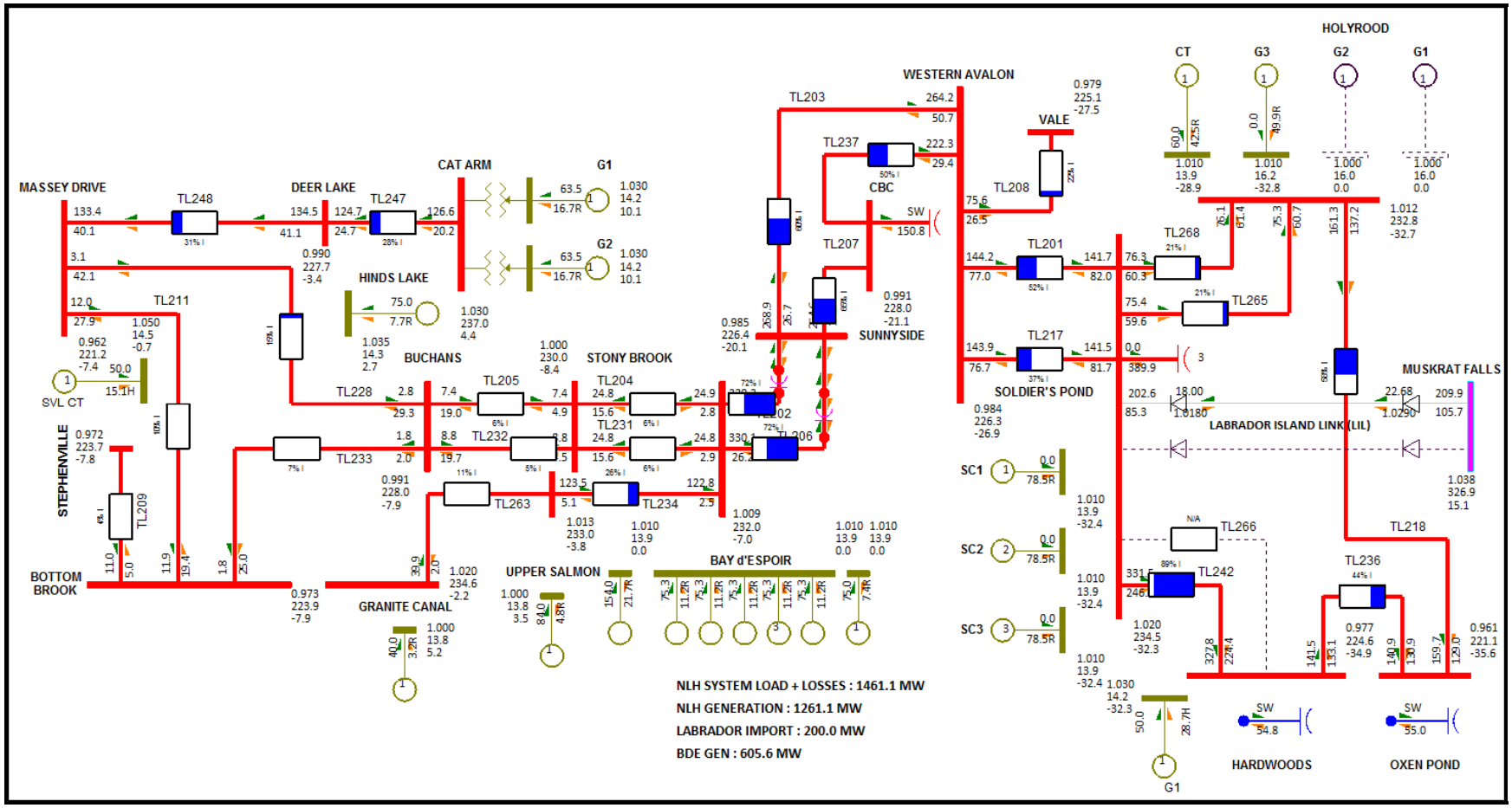


Figure 243 – Base Case 4 (BC4) Load Flow Plot – TL266 Out of Service

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1548 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (290 MW)

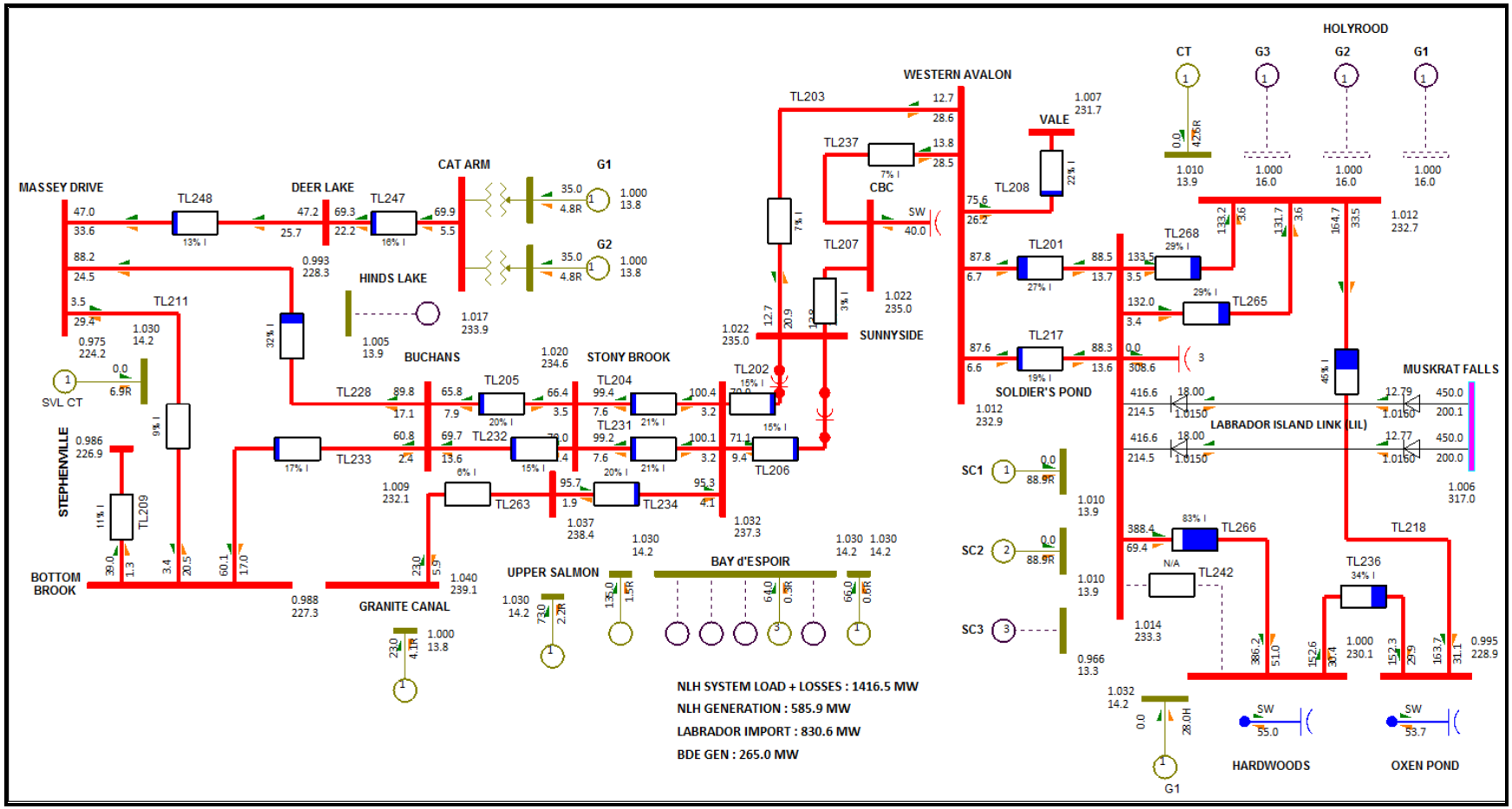


Figure 244 – Base Case 5 (BC5) Load Flow Plot – TL242 Out of Service

TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (585 MW)

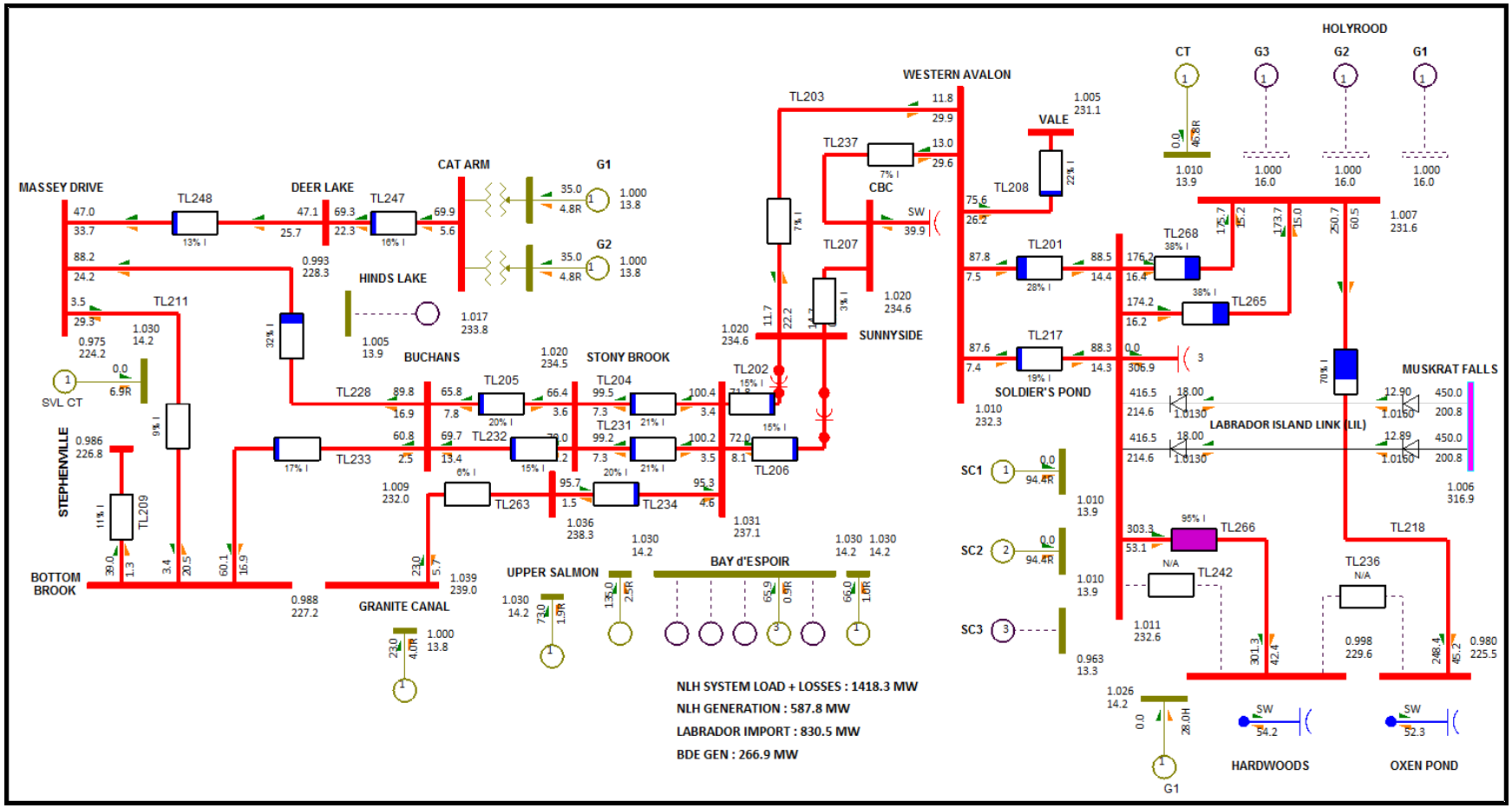


Figure 245 – Base Case 5 (BC5) Load Flow Plot – TL242 Out of Service – TL236 Open

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (585 MW)

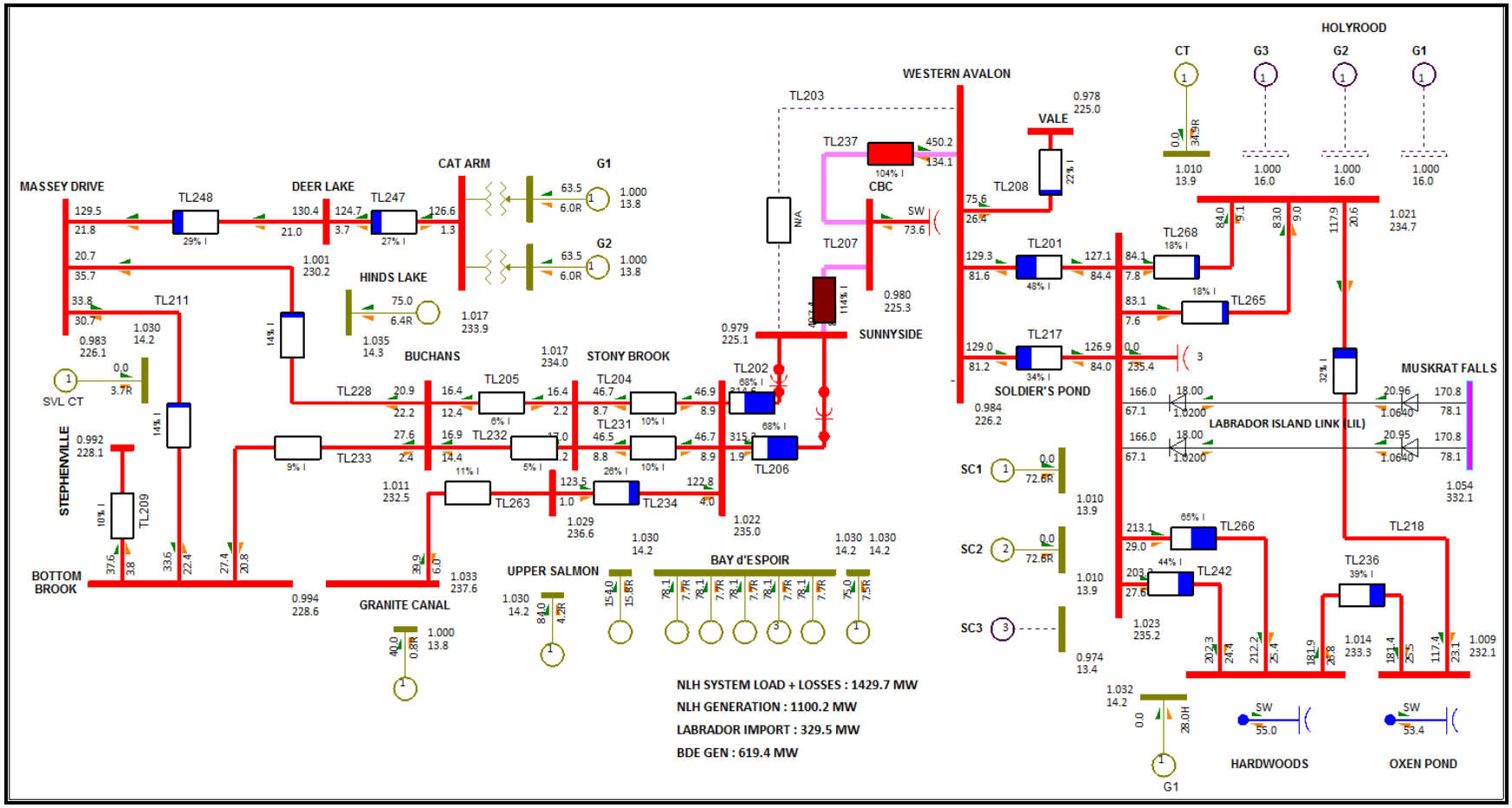


Figure 246 – Base Case 6 (BC6) Load Flow Plot – TL203 Out of Service

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

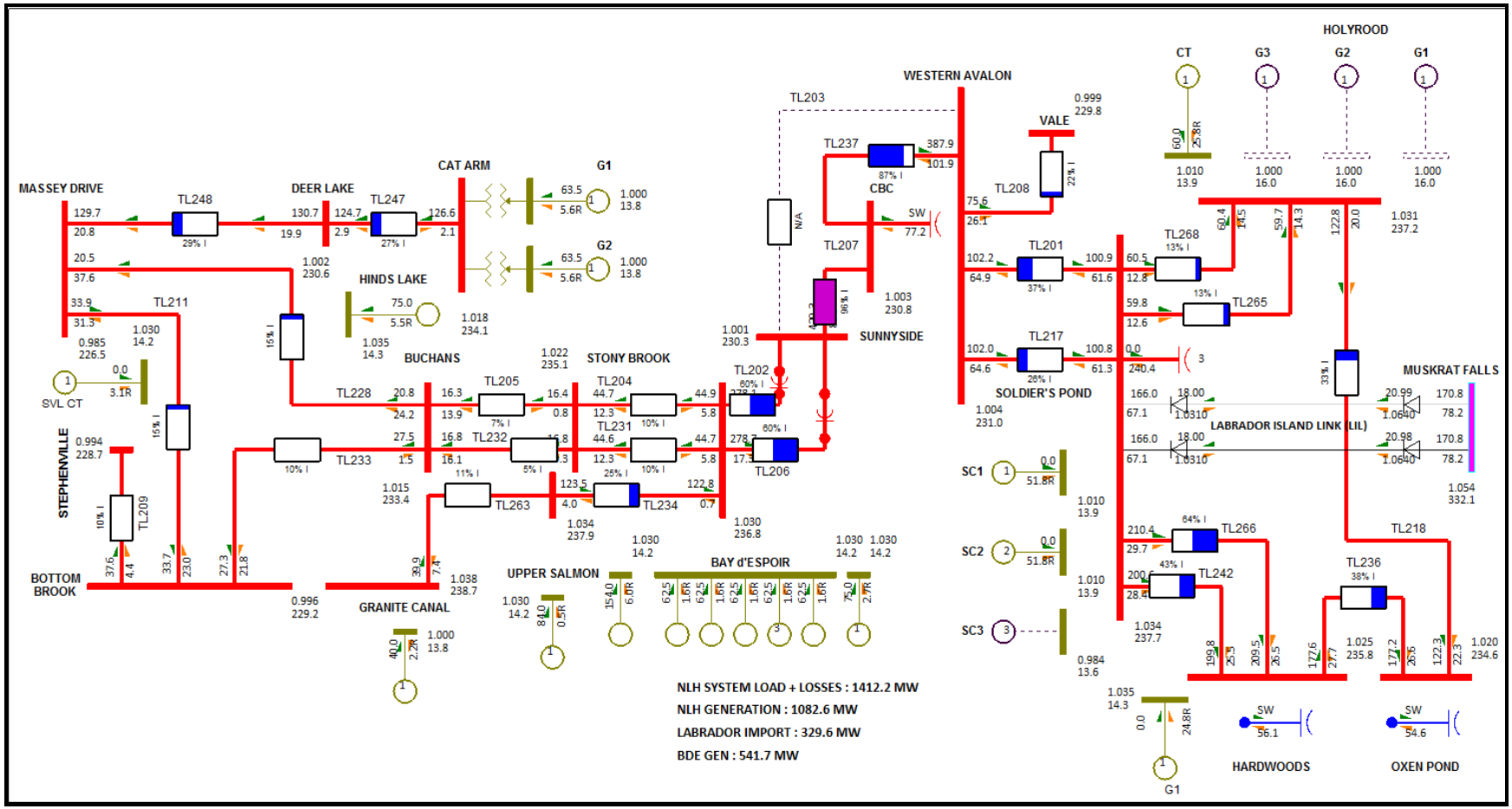


Figure 247 – Base Case 6 (BC6) Load Flow Plot – TL203 Out of Service – HRD CT Generating 60 MW

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

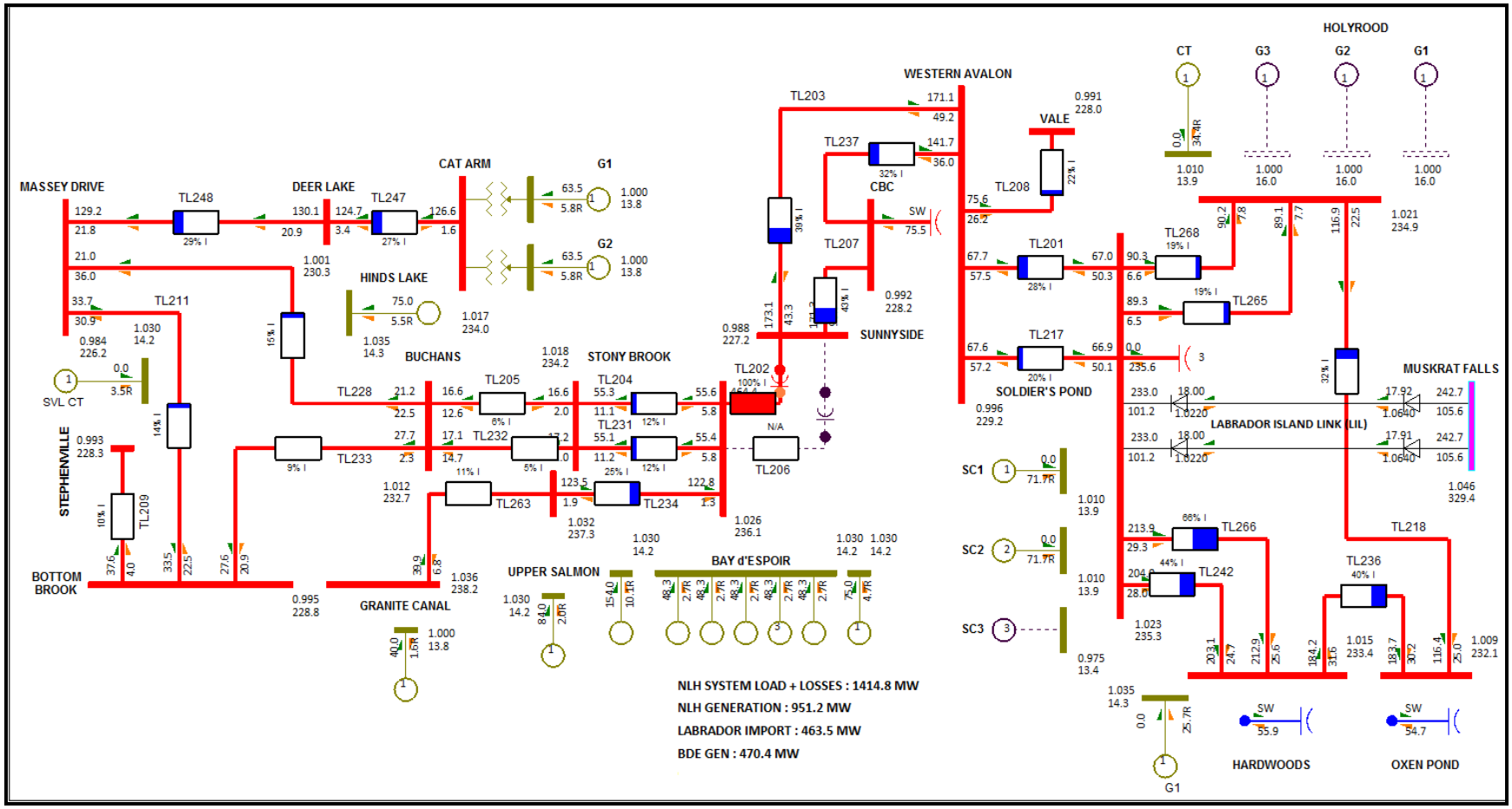


Figure 248 – Base Case 6 (BC6) Load Flow Plot – TL206 Out of Service

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

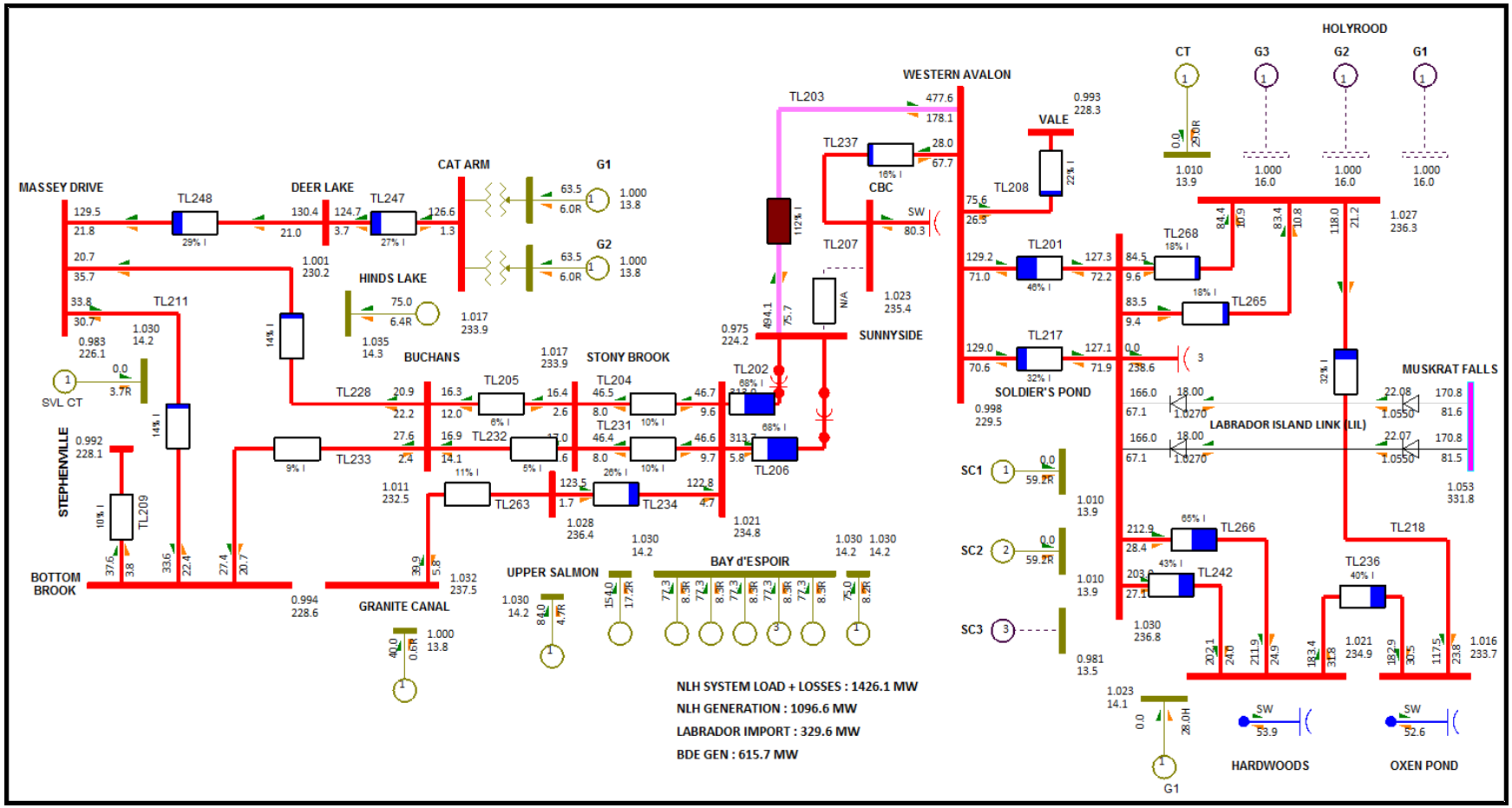


Figure 249 – Base Case 6 (BC6) Load Flow Plot – TL207 Out of Service

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

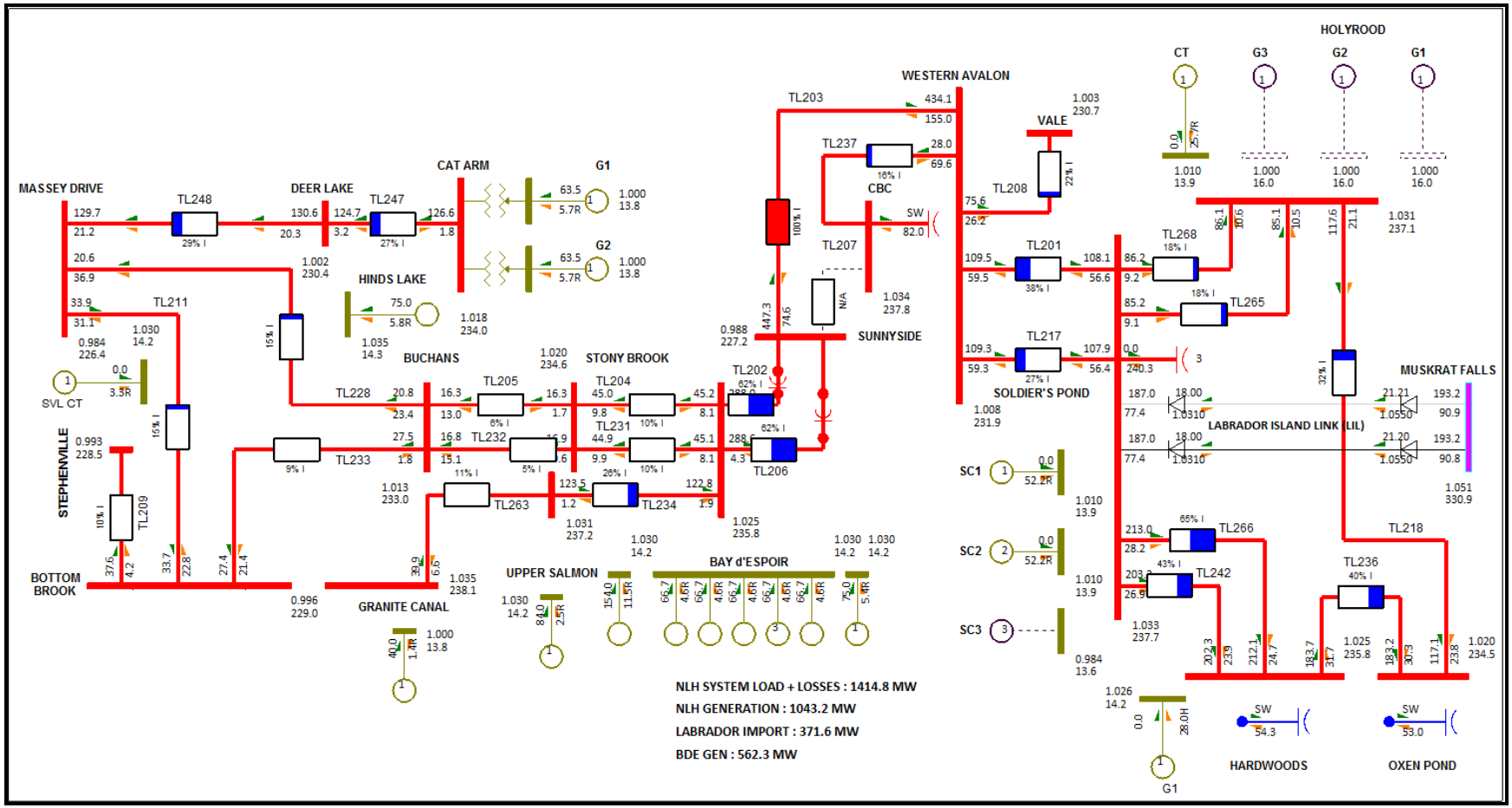


Figure 250 – Base Case 6 (BC6) Load Flow Plot – TL207 Out of Service – LIL Import Increased to 372 MW

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

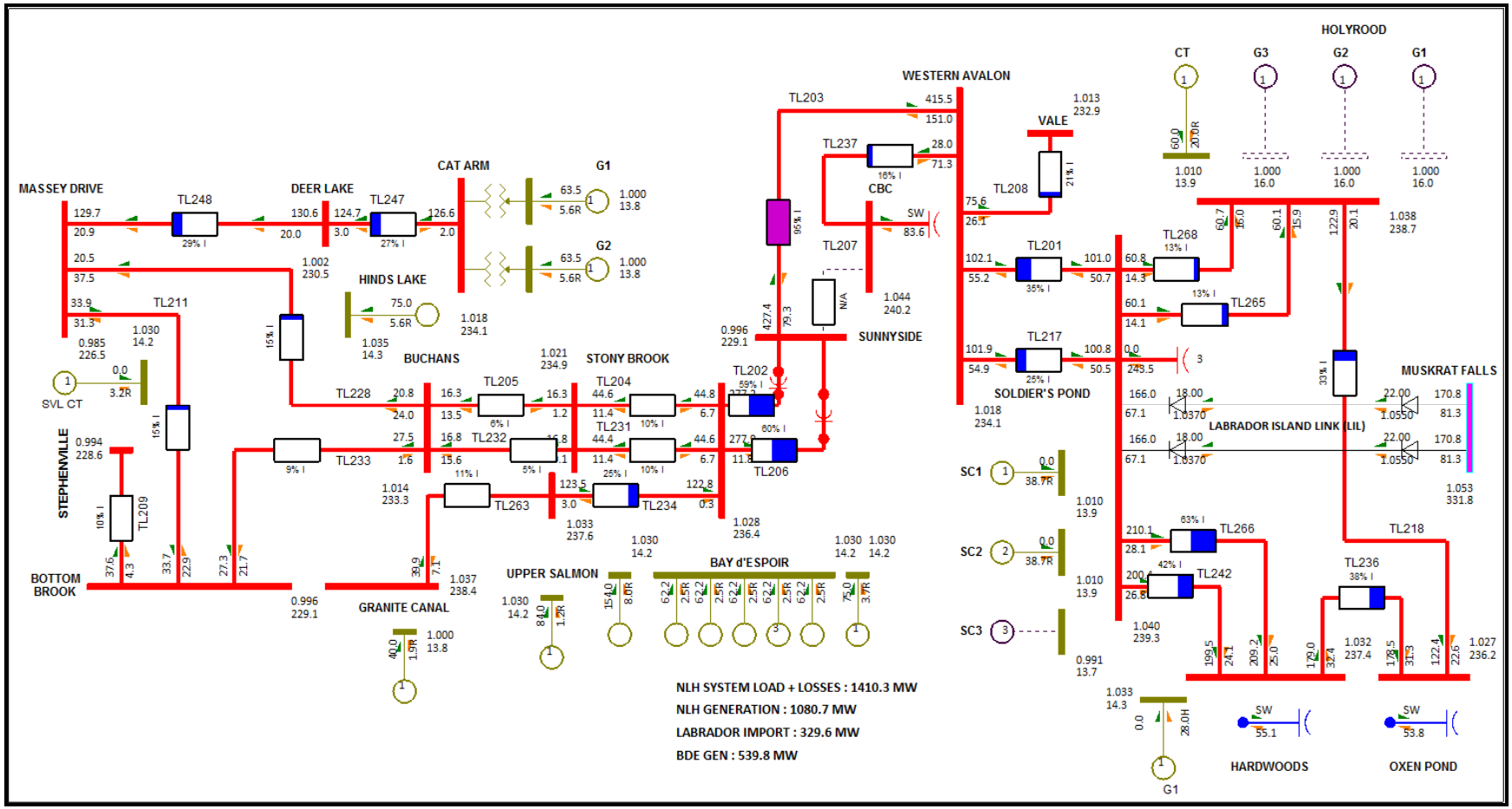


Figure 251 – Base Case 6 (BC6) Load Flow Plot – TL207 Out of Service – HRD CT Generating 60 MW

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

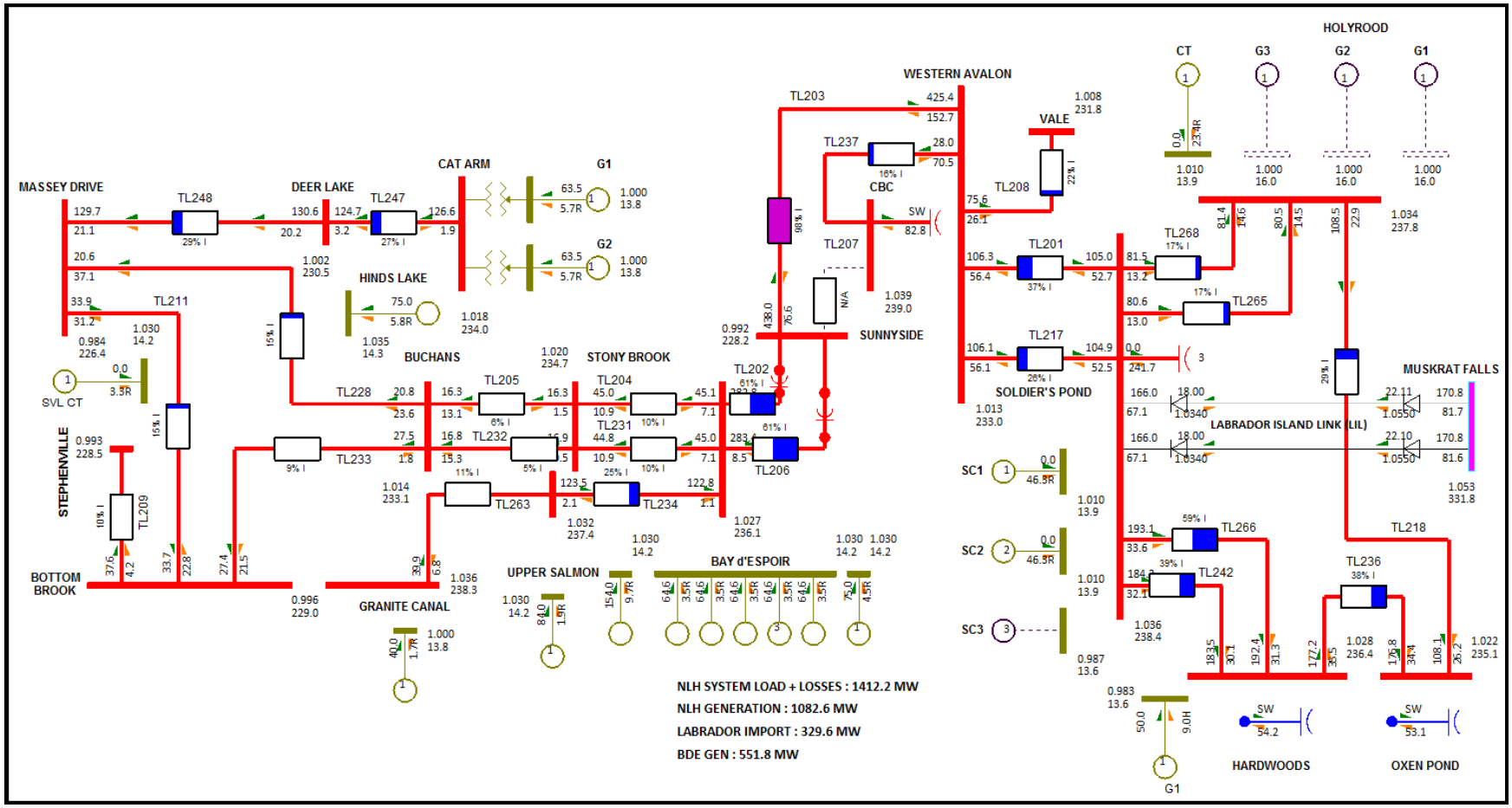


Figure 252 – Base Case 6 (BC6) Load Flow Plot – TL207 Out of Service – HWD CT Generating 50 MW

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

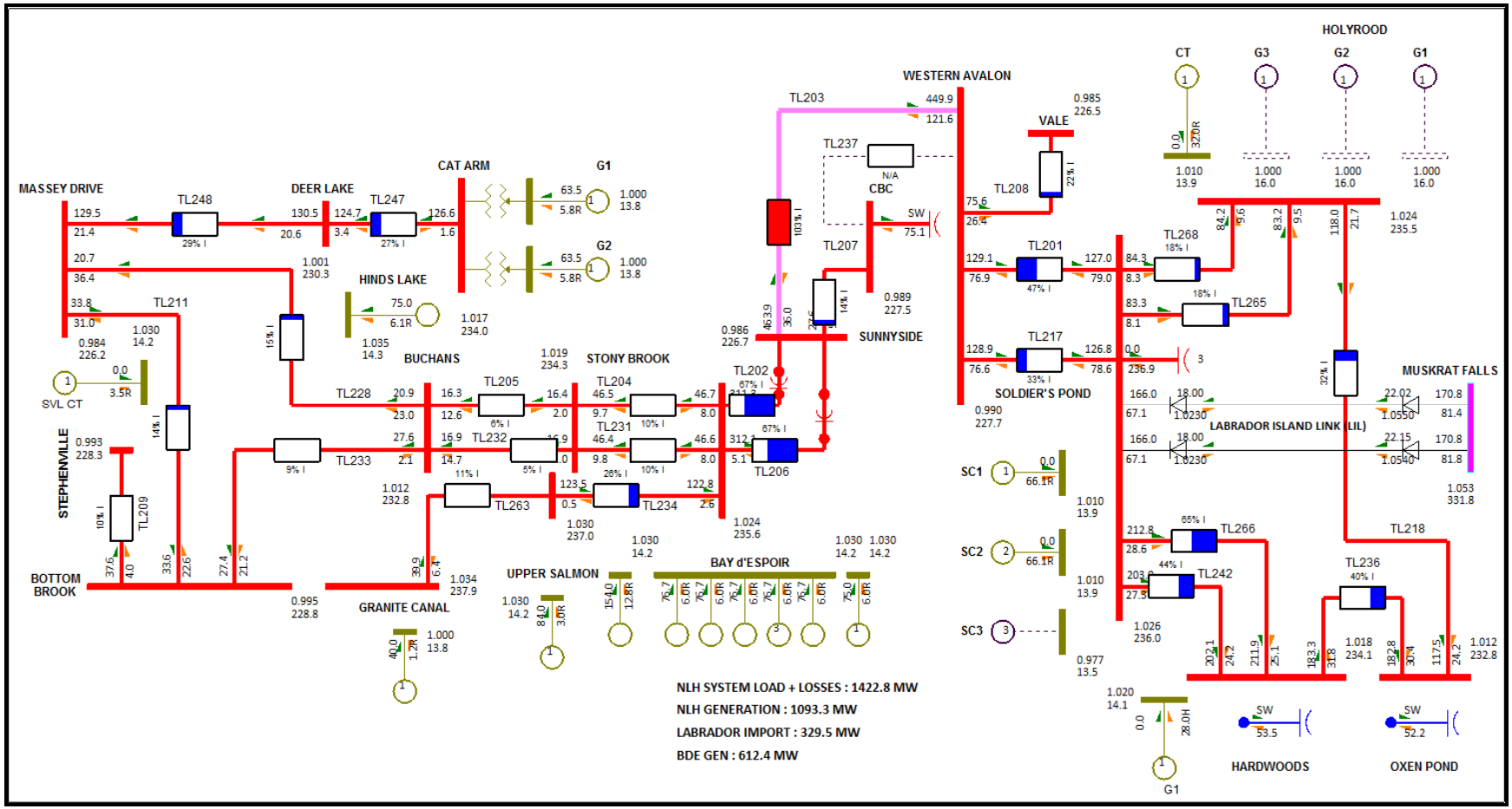


Figure 253 – Base Case 6 (BC6) Load Flow Plot – TL237 Out of Service

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

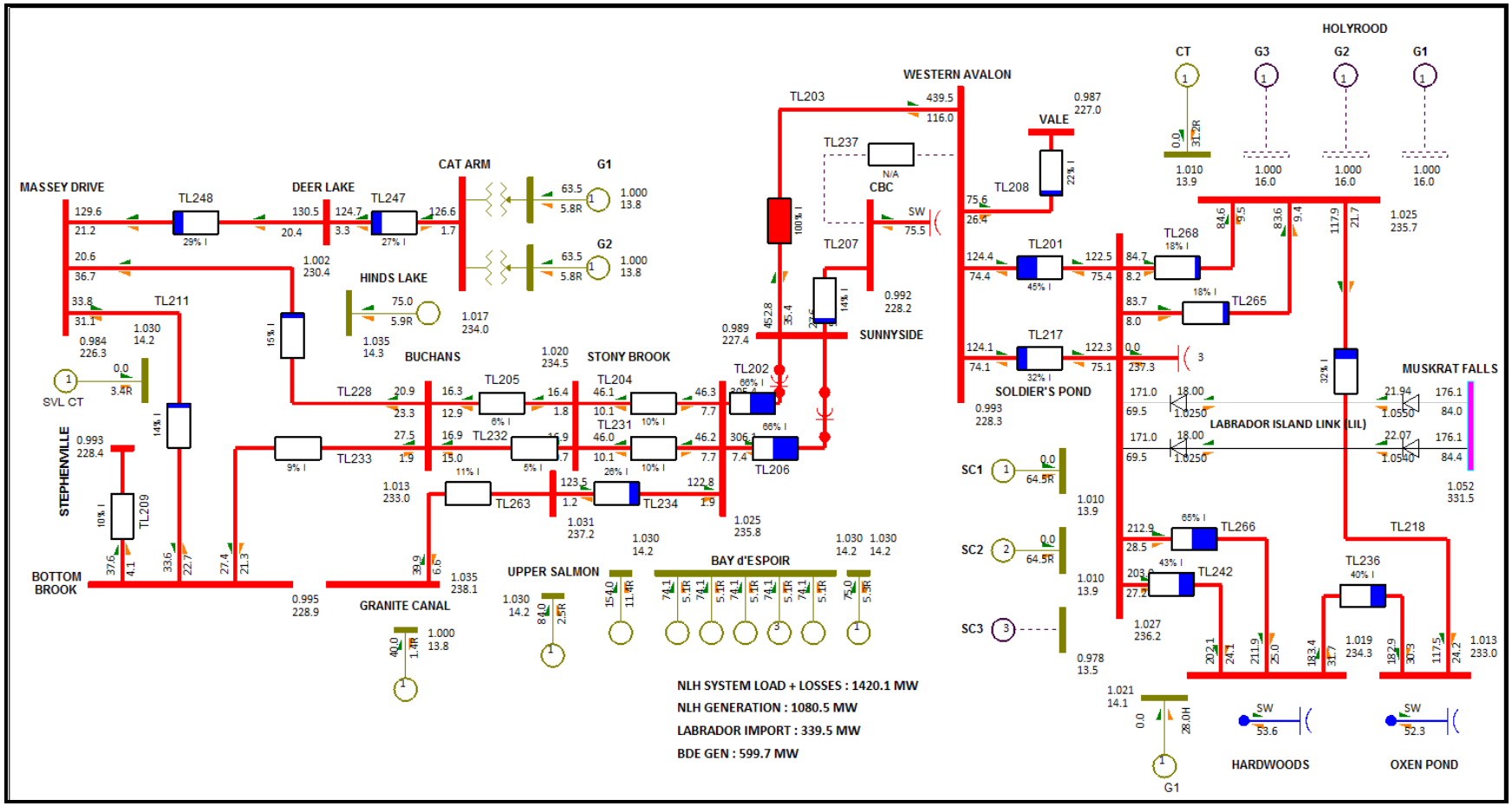


Figure 254 – Base Case 6 (BC6) Load Flow Plot – TL237 Out of Service – LIL Import Increased to 340 MW

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

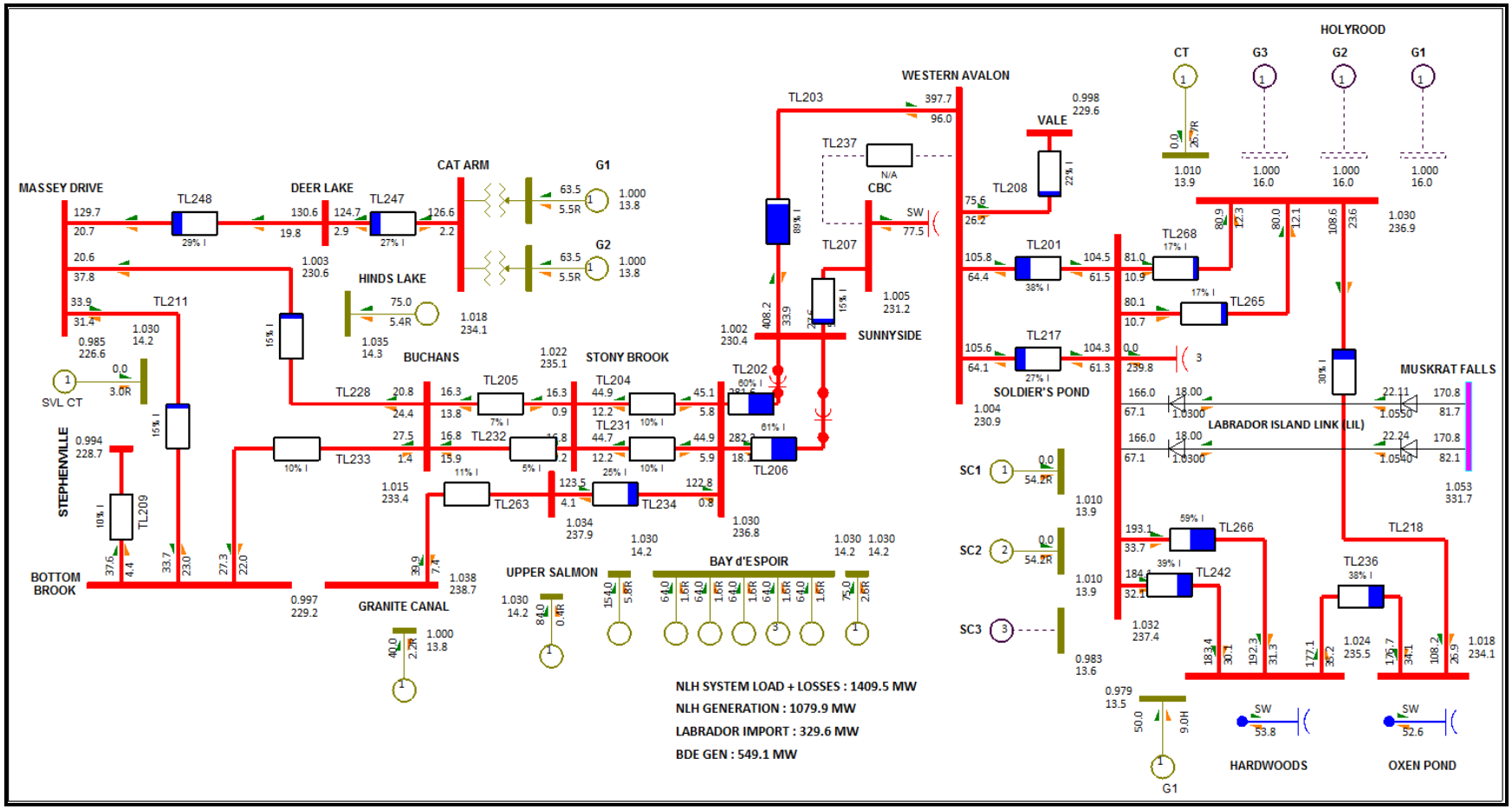


Figure 255 – Base Case 6 (BC6) Load Flow Plot – TL237 Out of Service – HWD CT Generating 50 MW

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

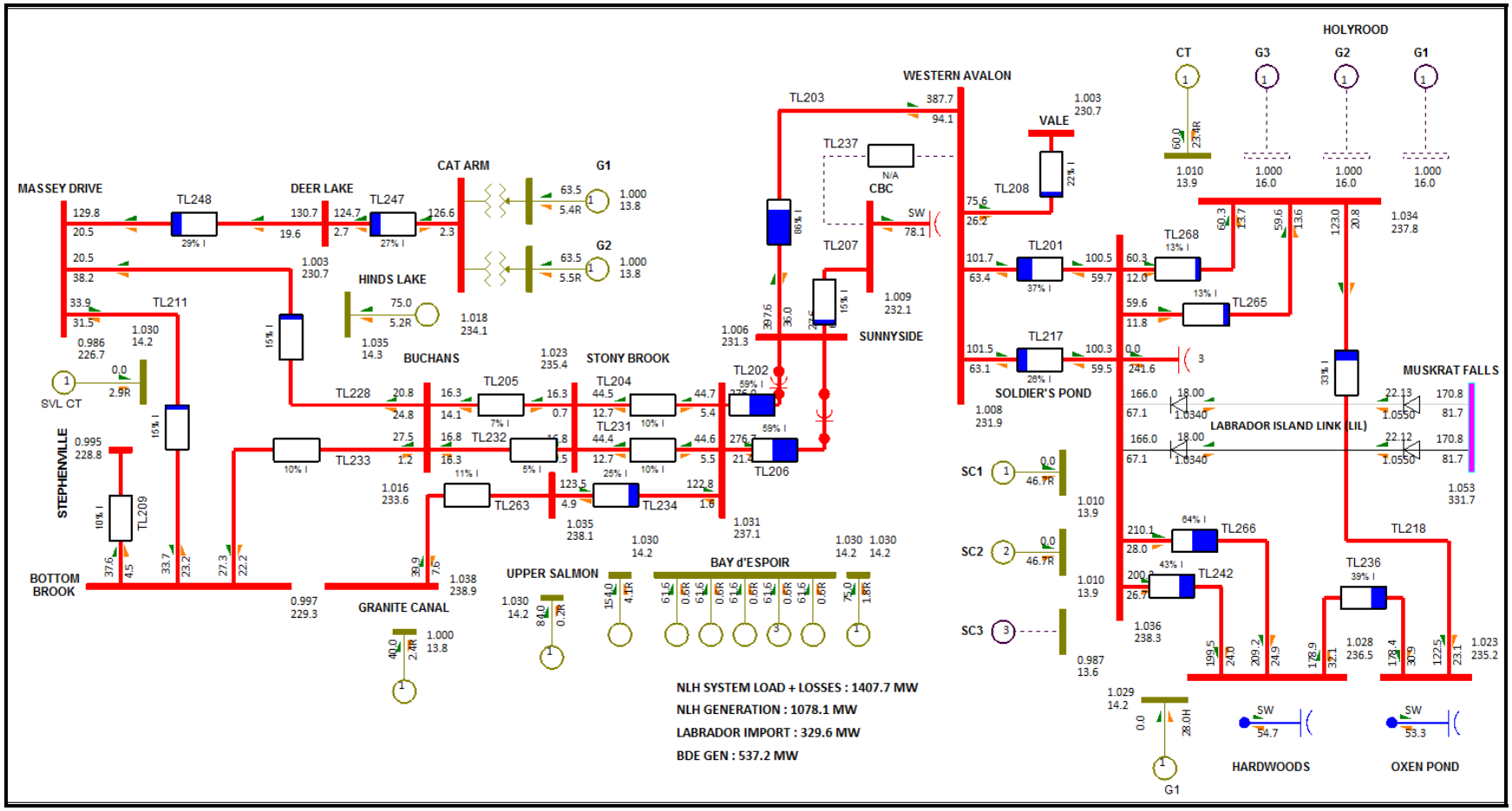


Figure 256 – Base Case 6 (BC6) Load Flow Plot – TL237 Out of Service – HRD CT Generating 60 MW

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

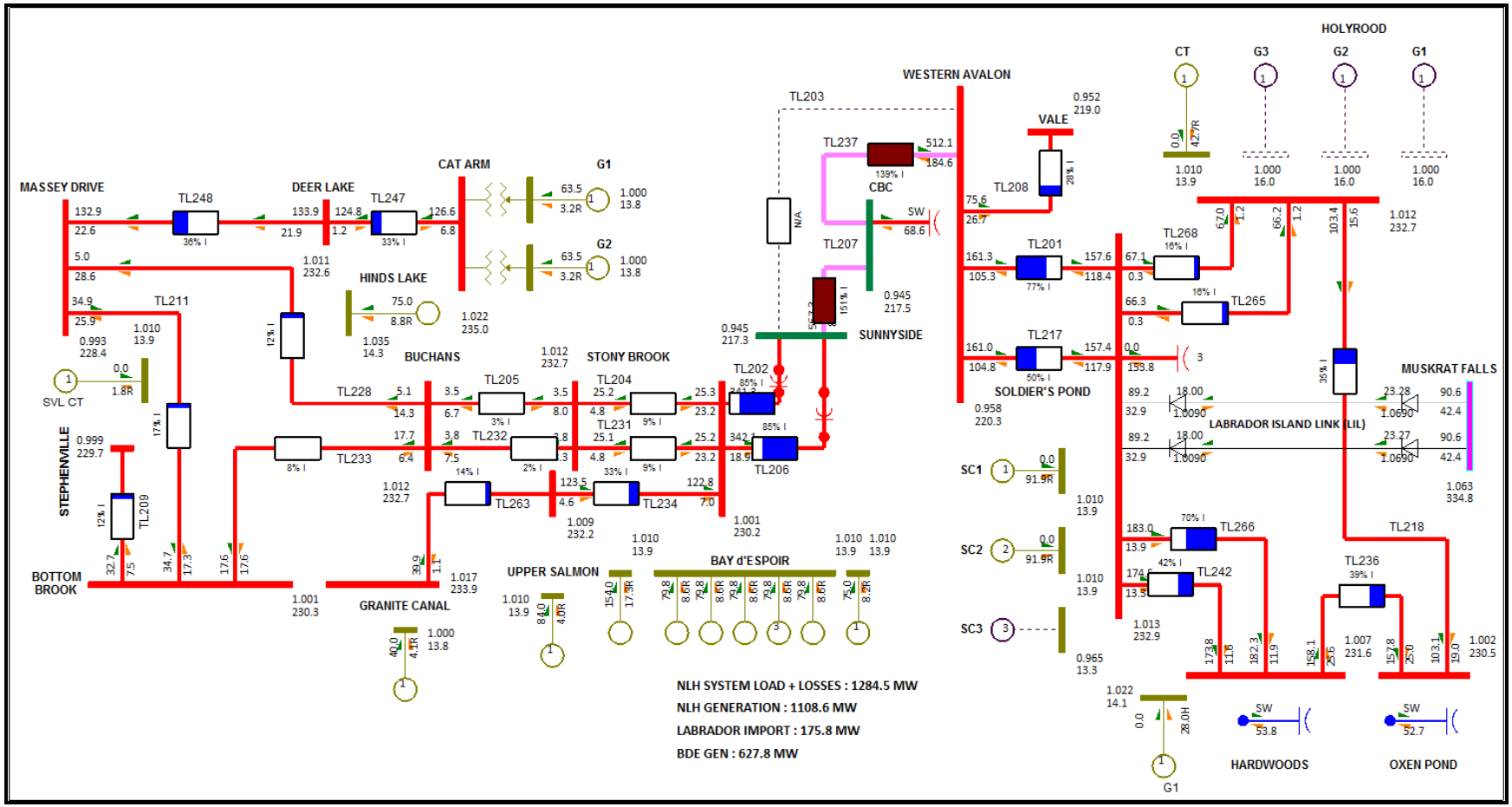


Figure 257 – Base Case 8 (BC8) Load Flow Plot – TL203 Out of Service

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

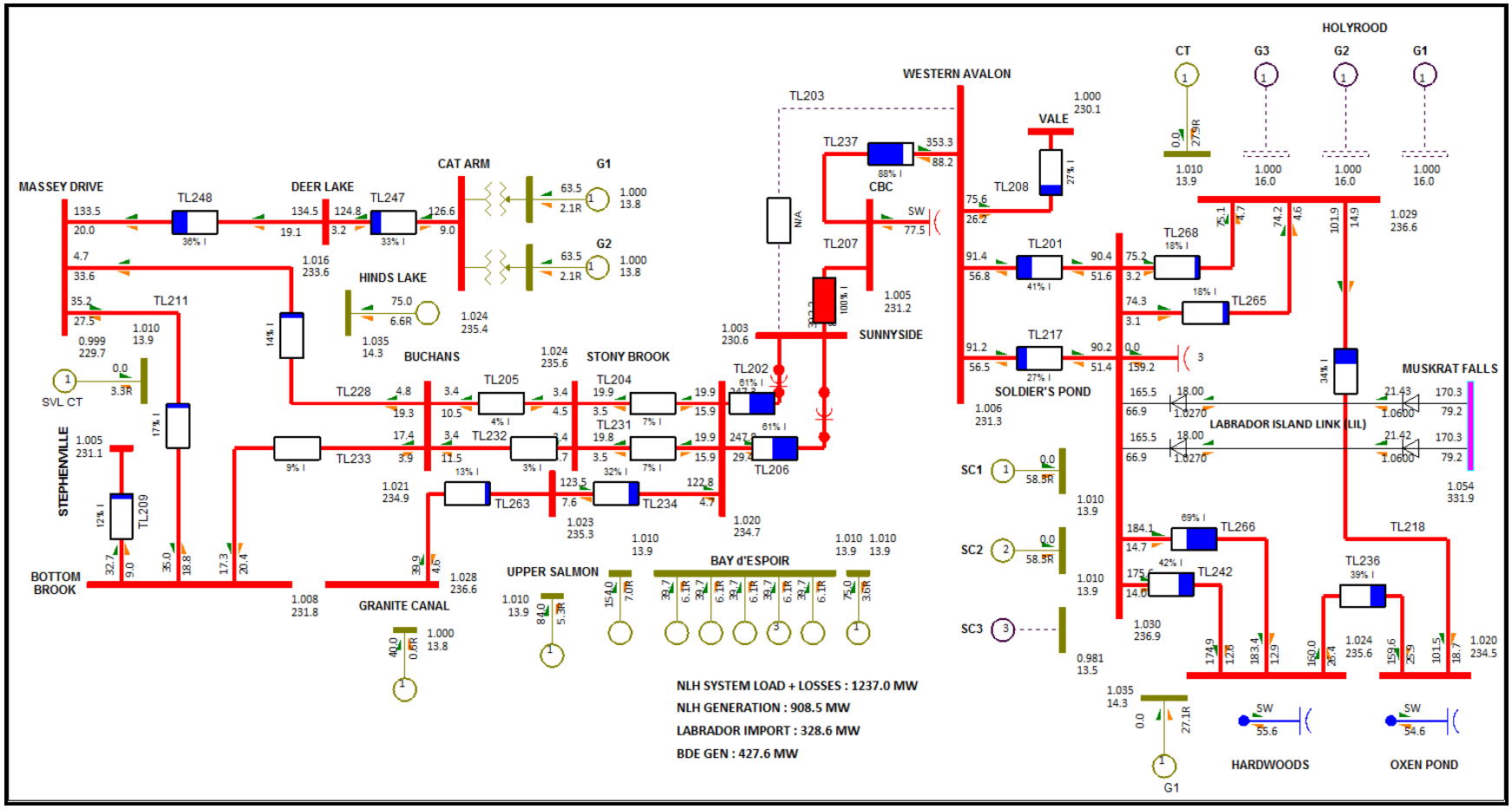


Figure 258 – Base Case 8 (BC8) Load Flow Plot – TL203 Out of Service – LIL Import Increased to 329 MW

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

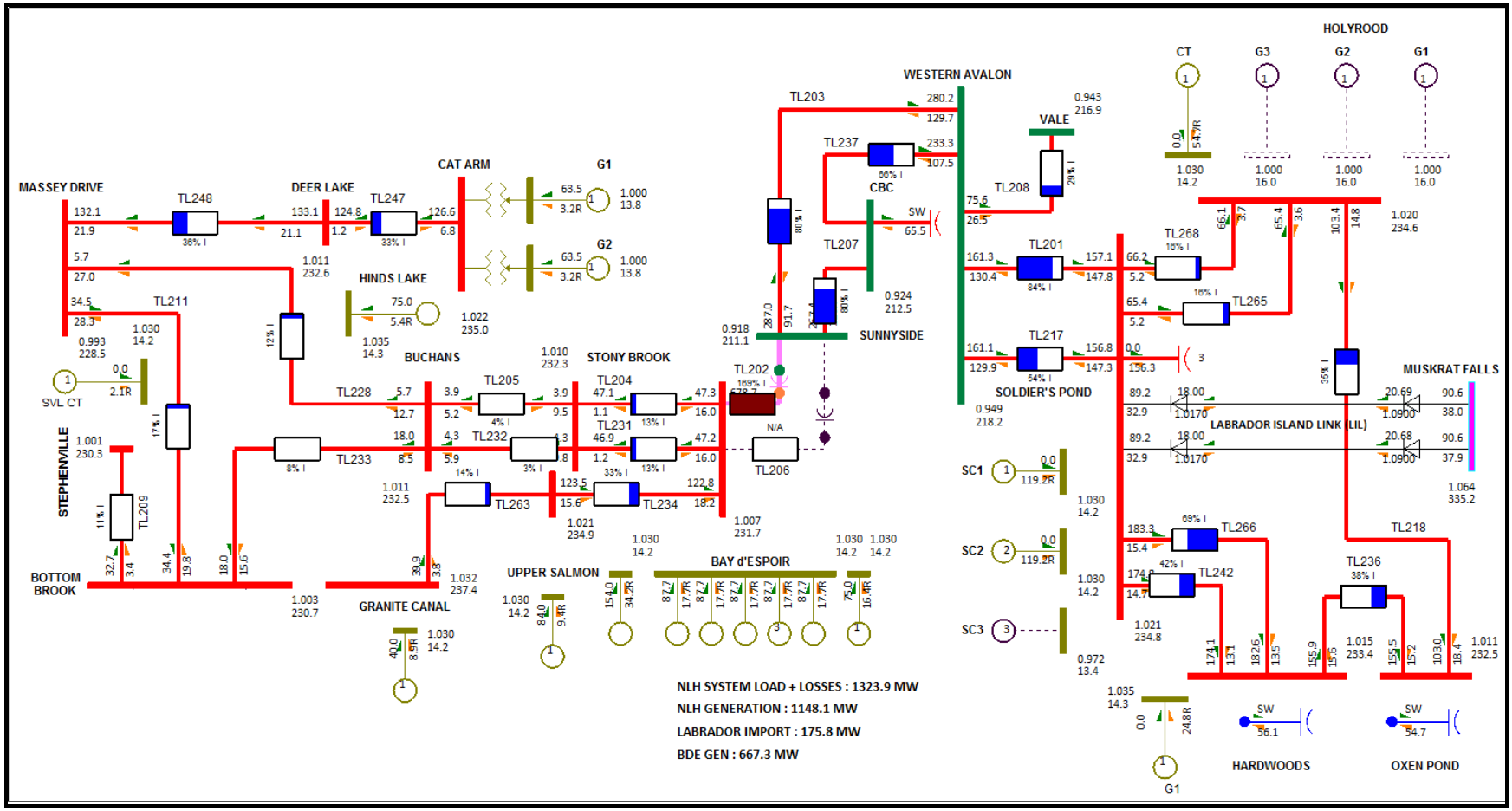


Figure 259 – Base Case 8 (BC8) Load Flow Plot – TL206 Out of Service

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

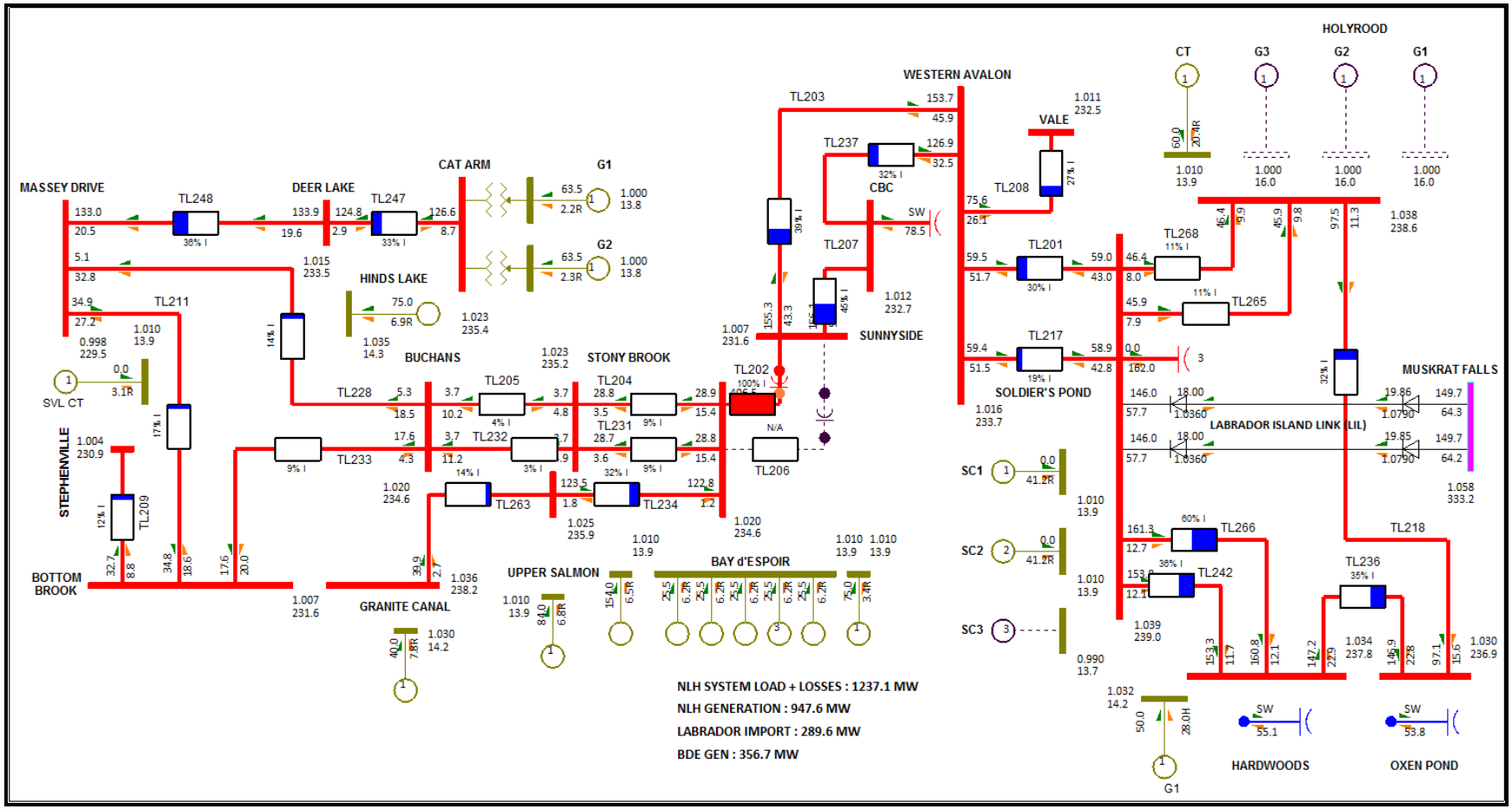


Figure 260 – Base Case 8 (BC8) Load Flow Plot – TL206 Out of Service – HWD CT and HRD CT Generating 110 MW – LIL Import Increased to 290 MW

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

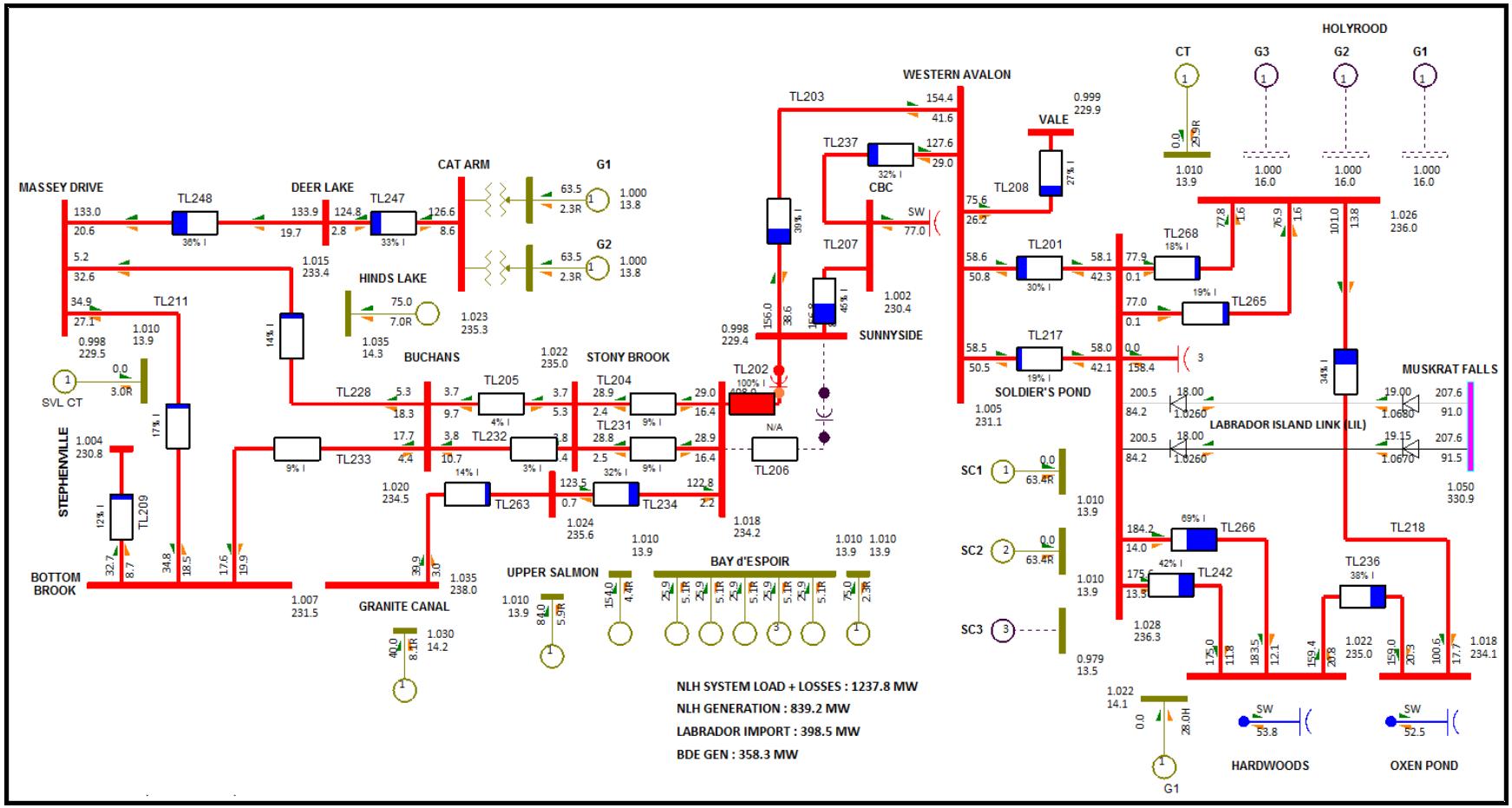


Figure 261 – Base Case 8 (BC8) Load Flow Plot – TL206 Out of Service –LIL Import Increased to 399 MW

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

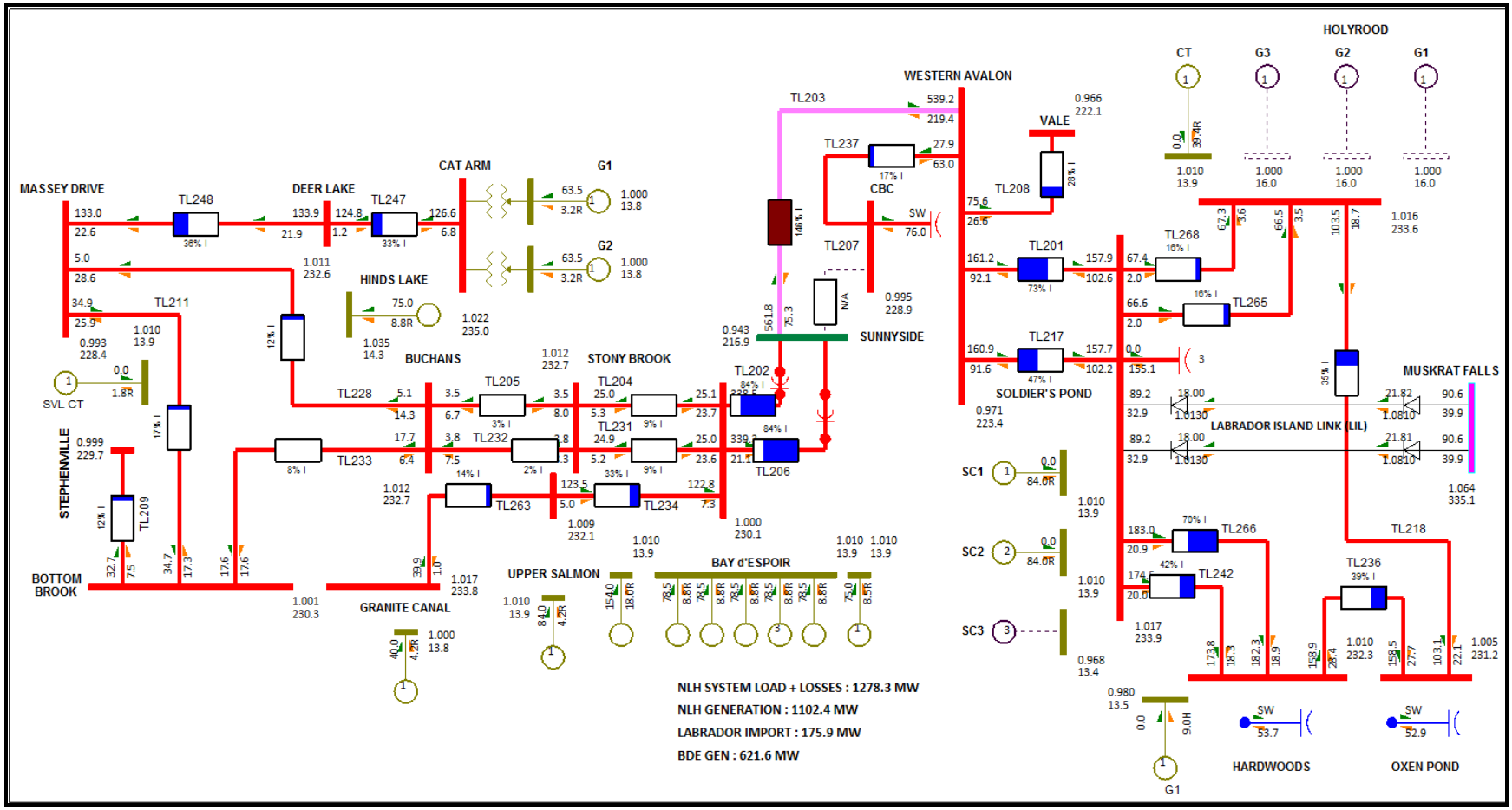


Figure 262 – Base Case 8 (BC8) Load Flow Plot – TL207 Out of Service

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

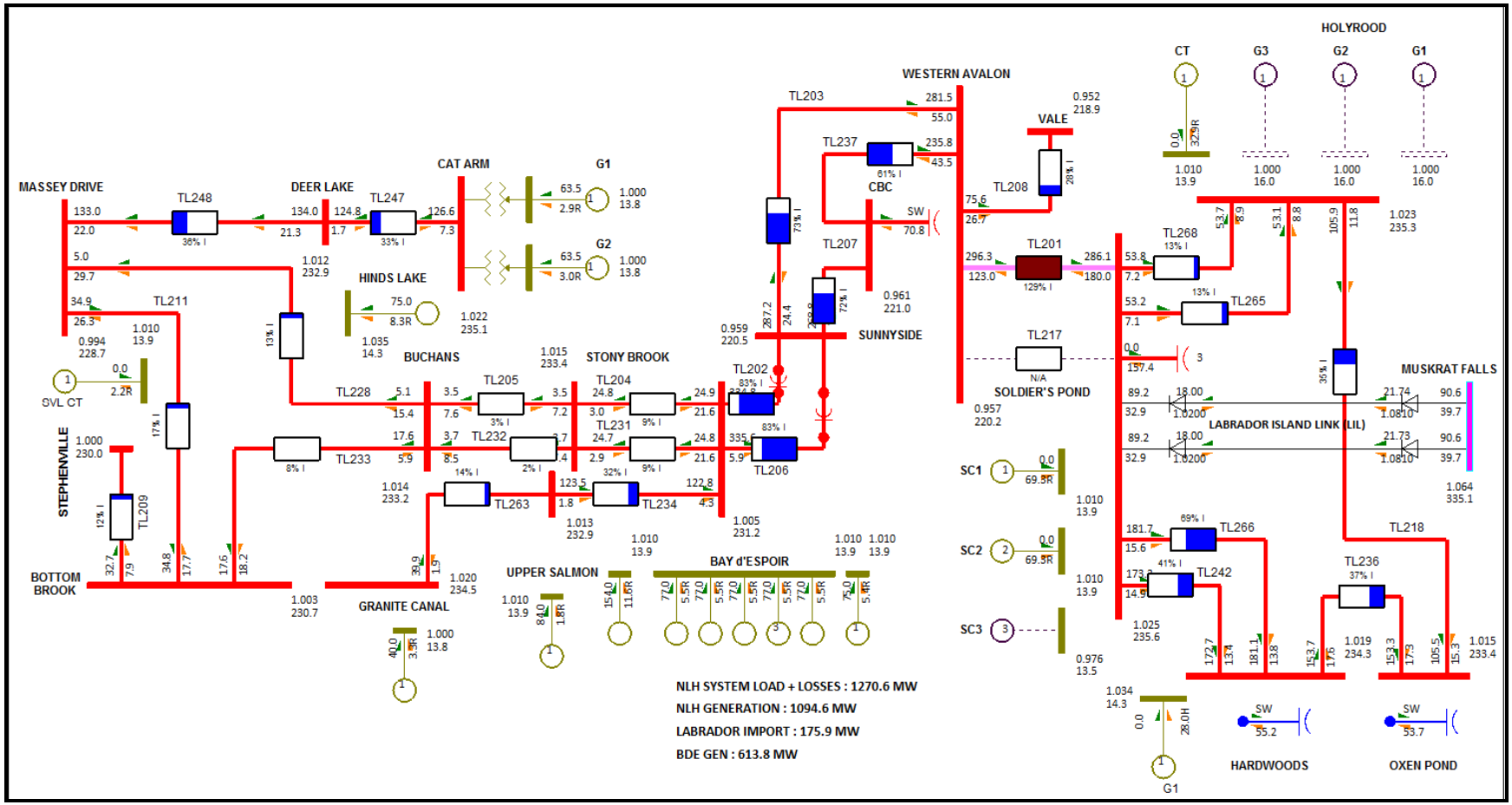


Figure 263 – Base Case 8 (BC8) Load Flow Plot – TL217 Out of Service

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

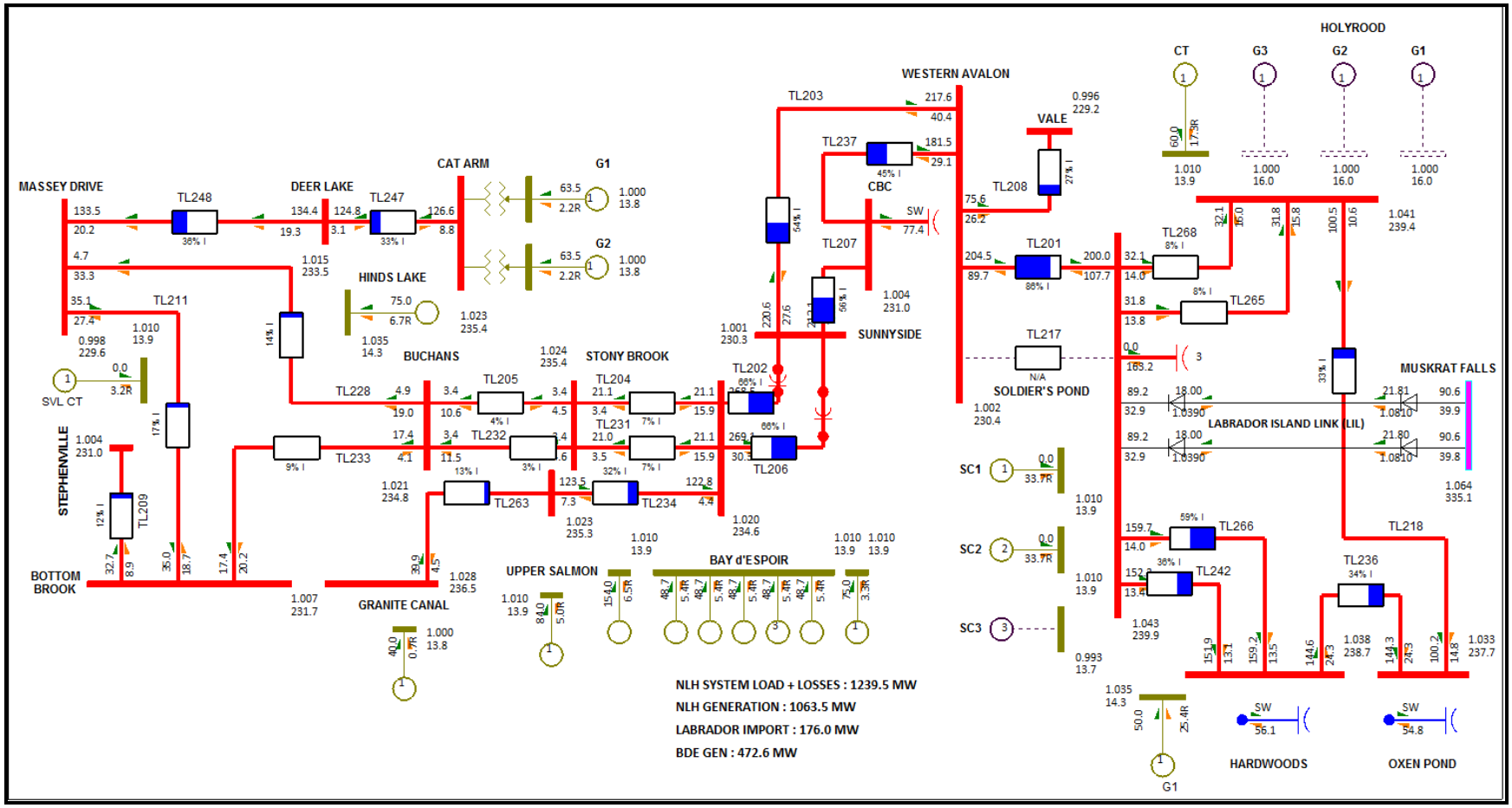


Figure 264 – Base Case 8 (BC8) Load Flow Plot – TL217 Out of Service – HRD CT and HWD CT Generating 110 MW

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

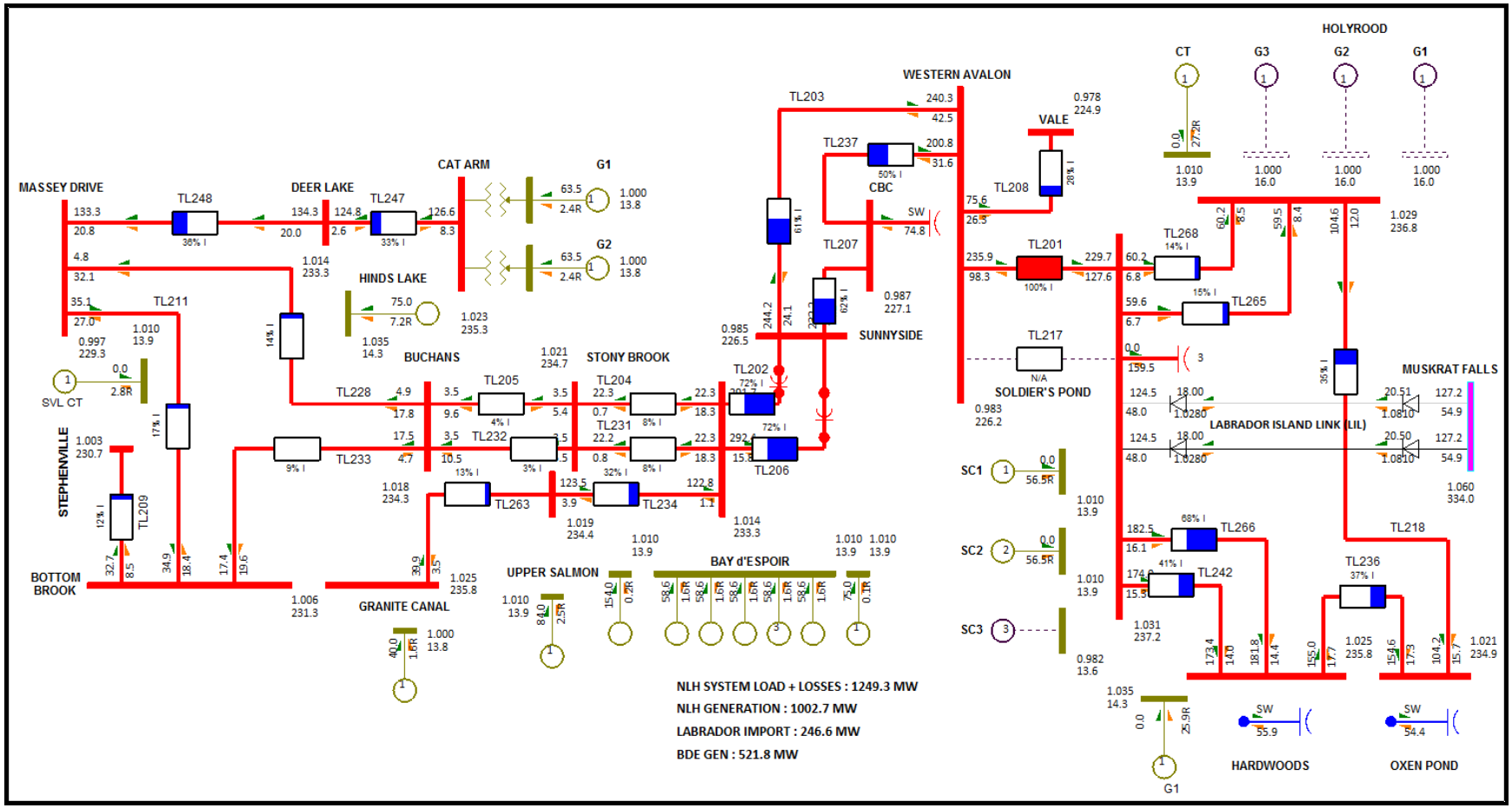


Figure 265 – Base Case 8 (BC8) Load Flow Plot – TL217 Out of Service – LIL Import Increased to 247 MW

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

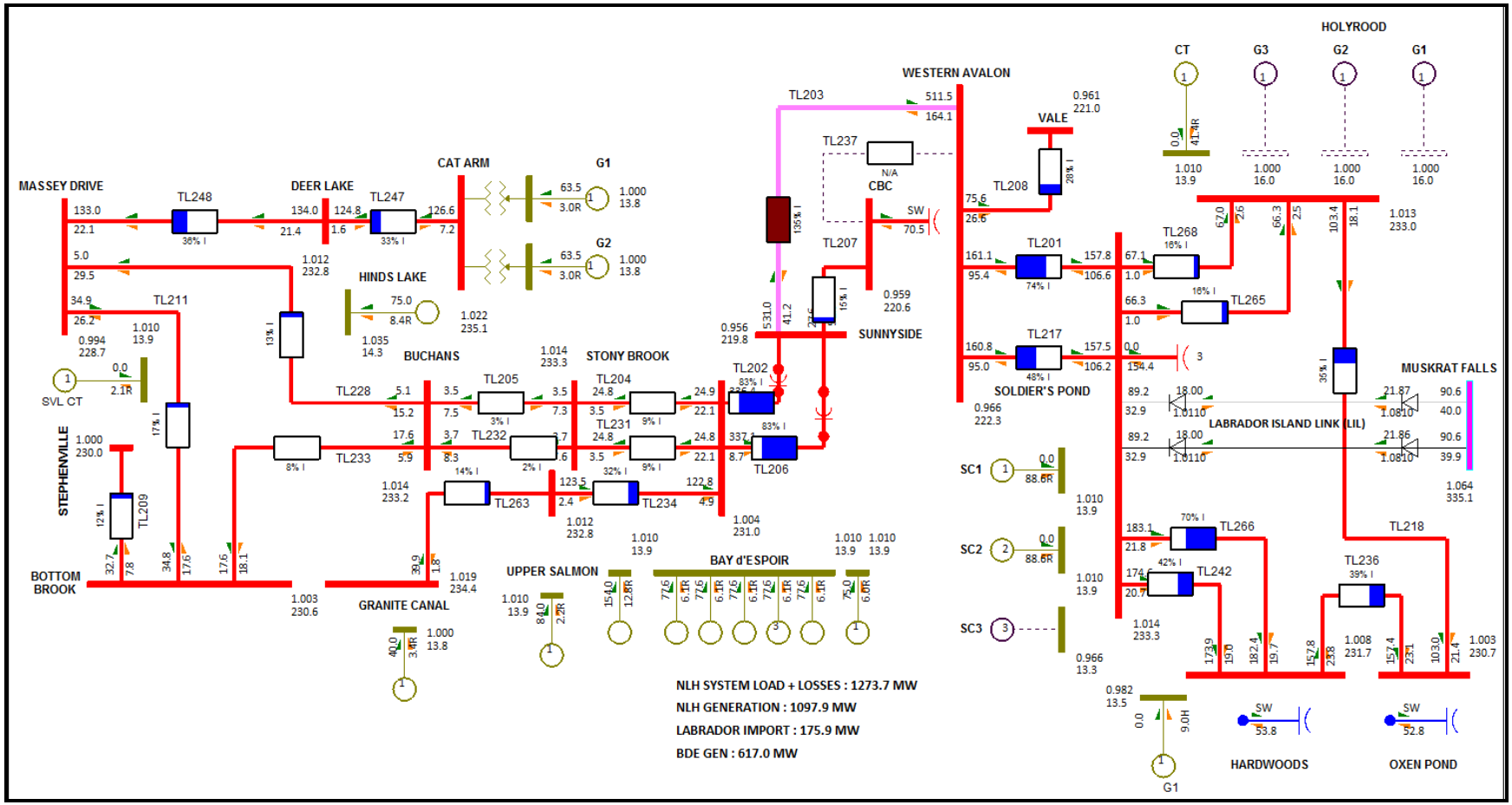


Figure 266 – Base Case 8 (BC8) Load Flow Plot – TL237 Out of Service

TL202/TL206 with 50% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

Alternative 5

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

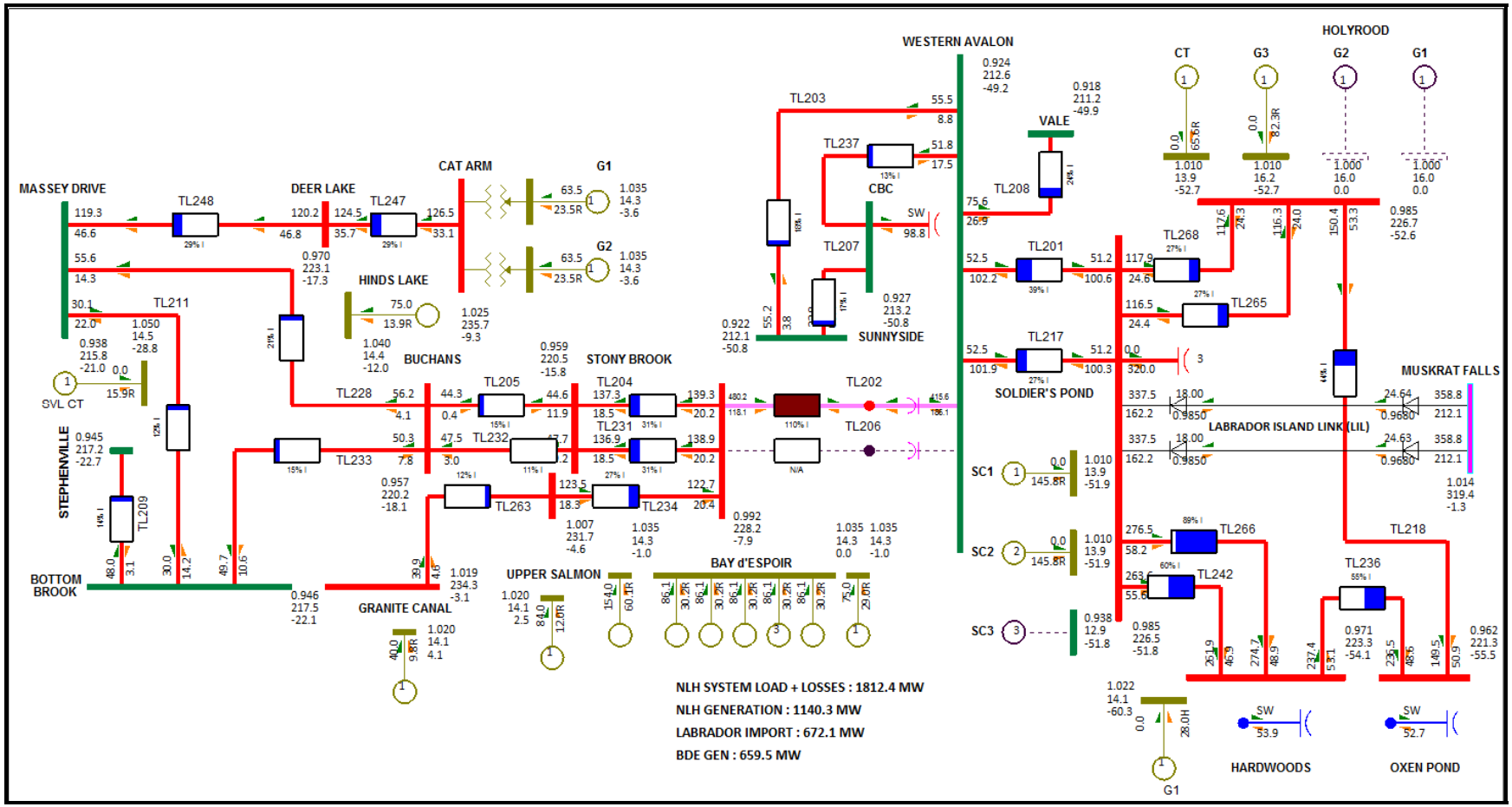


Figure 267 – Base Case 1 (BC1) Load Flow Plot – TL206 Out of Service

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

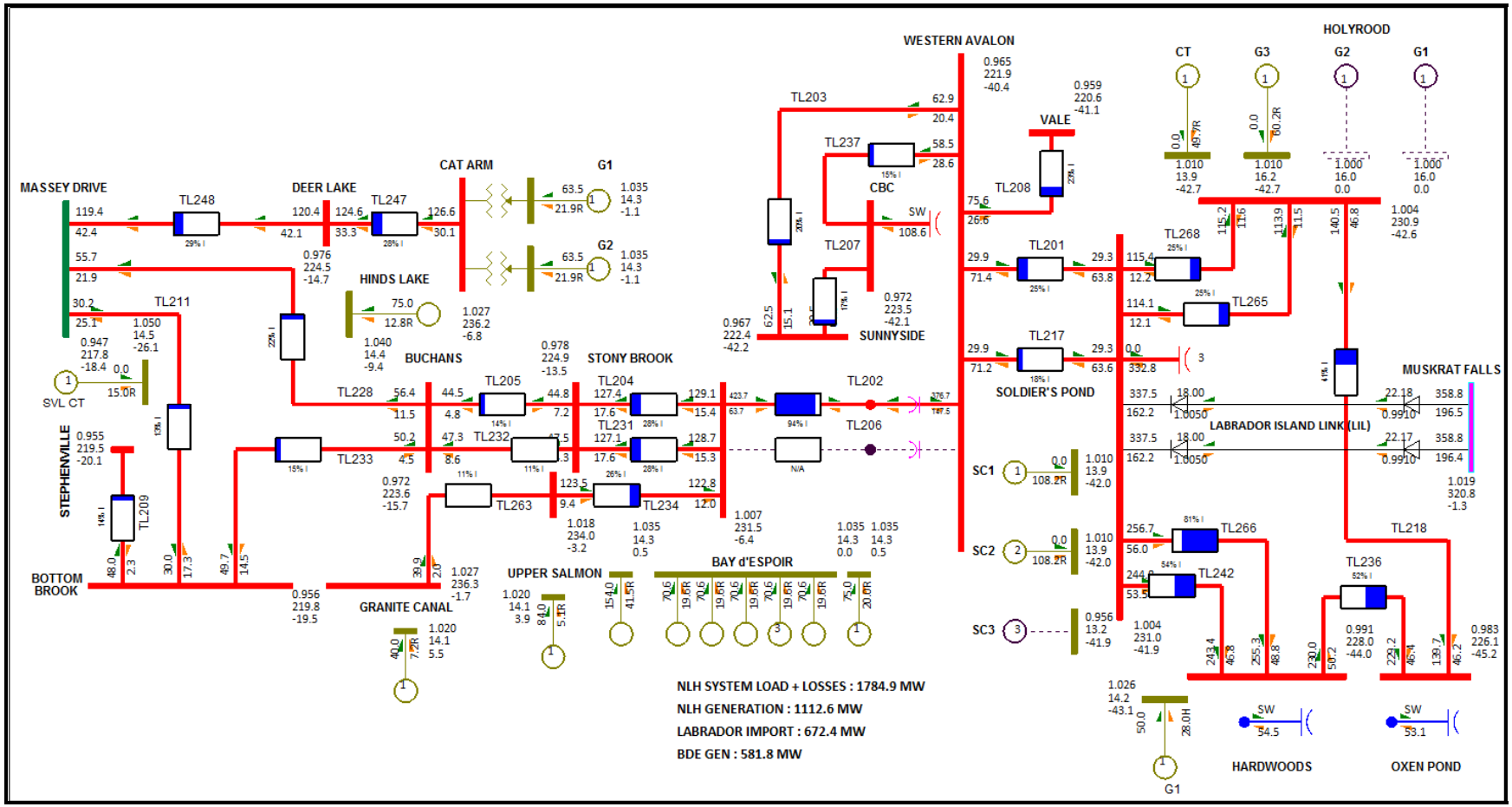


Figure 268 – Base Case 1 (BC1) Load Flow Plot – TL206 Out of Service – HWD CT Generating 50 MW

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

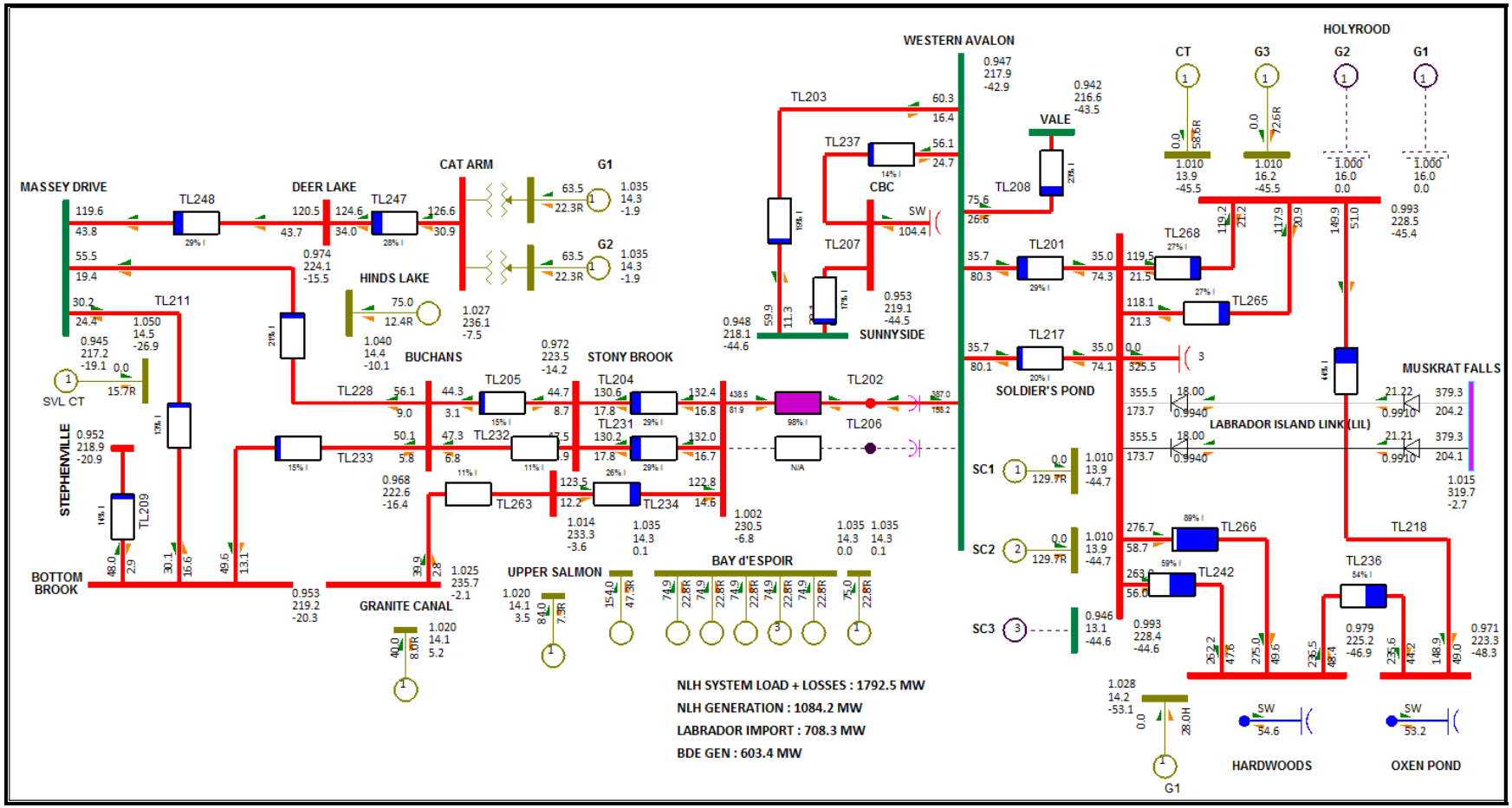


Figure 269 – Base Case 1 (BC1) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 708 MW

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

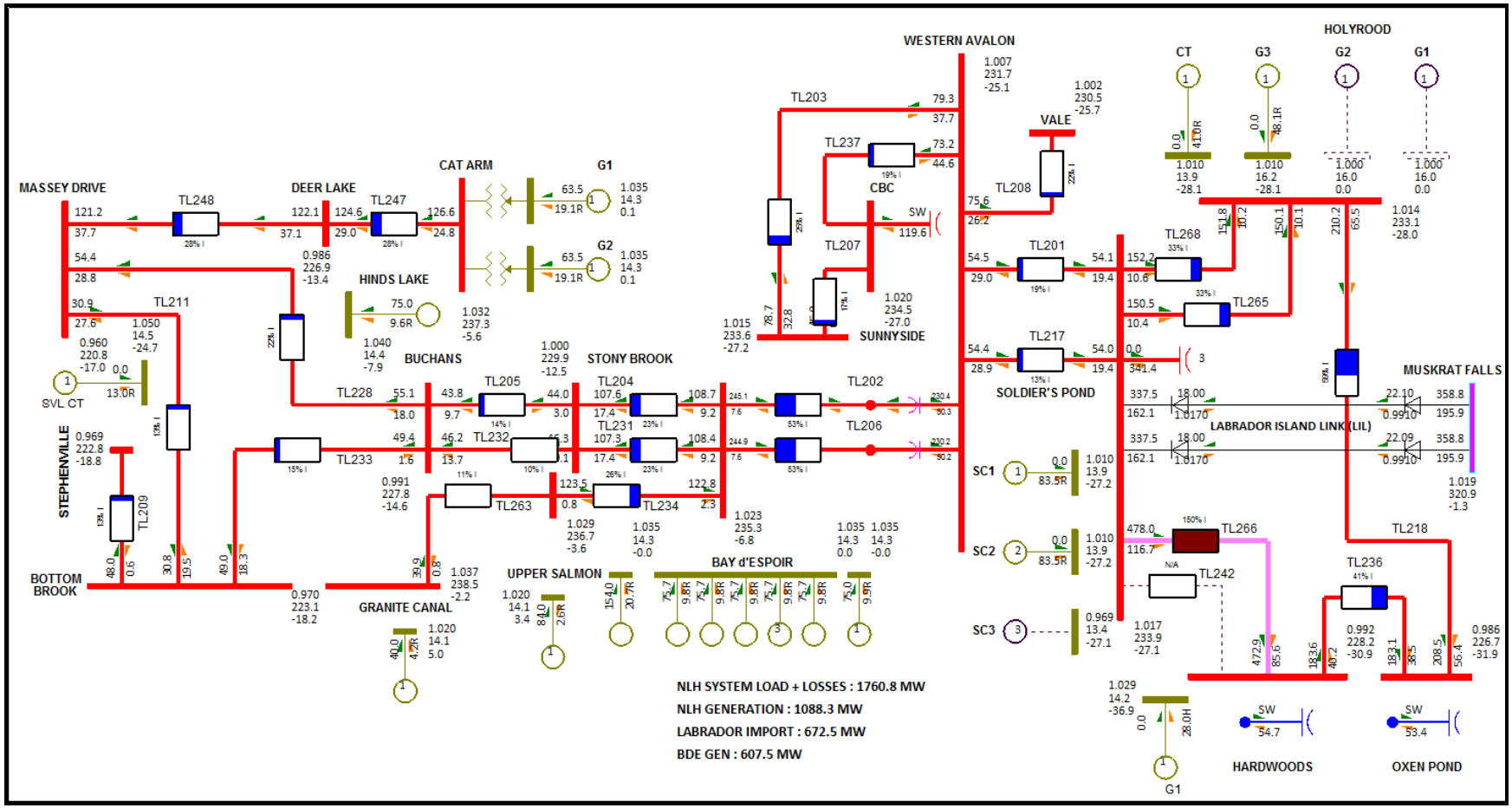


Figure 270 – Base Case 1 (BC1) Load Flow Plot – TL242 Out of Service

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

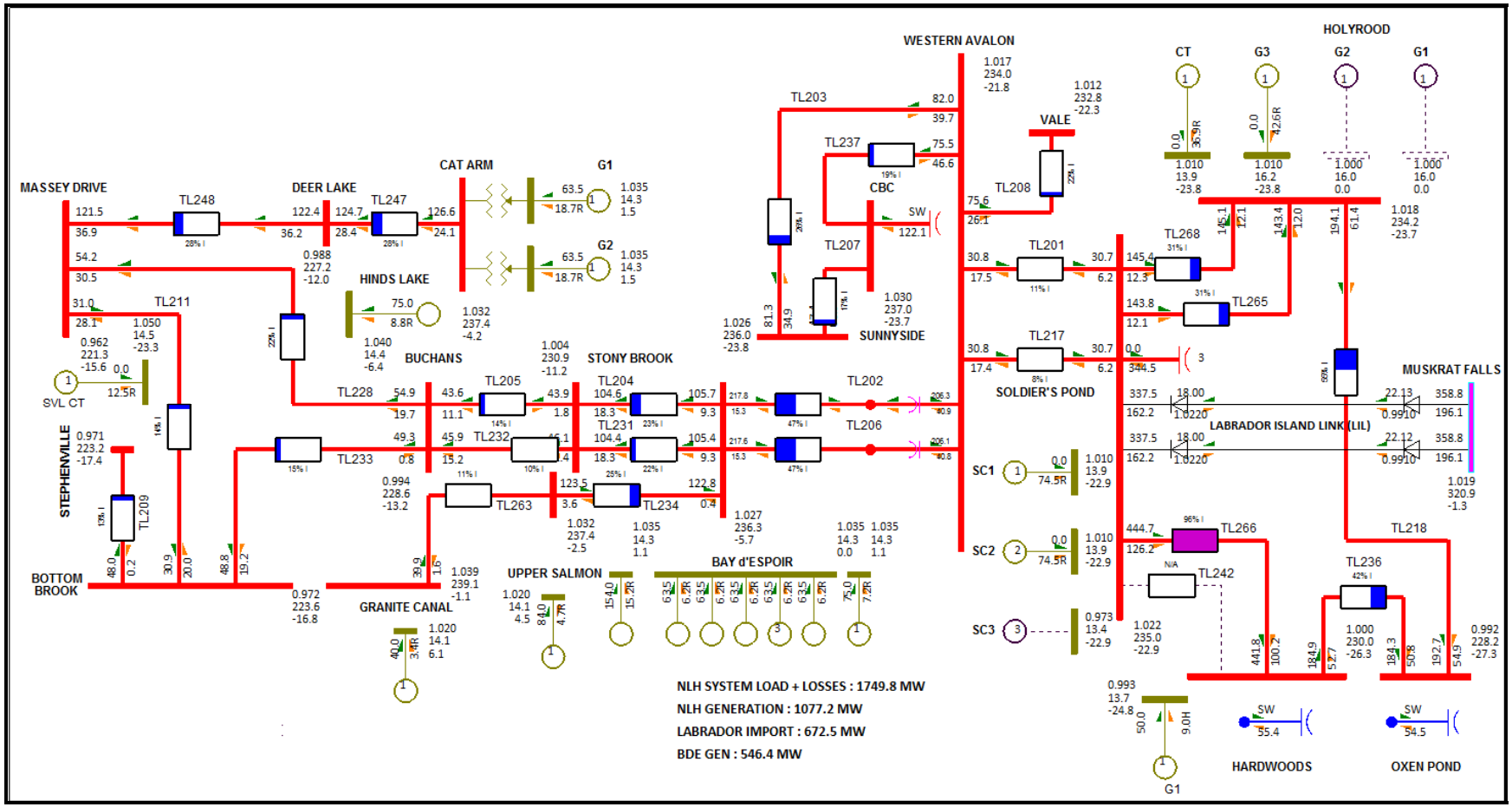


Figure 271 – Base Case 1 (BC1) Load Flow Plot – TL242 Out of Service – HWD CT Generating 50 MW

TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

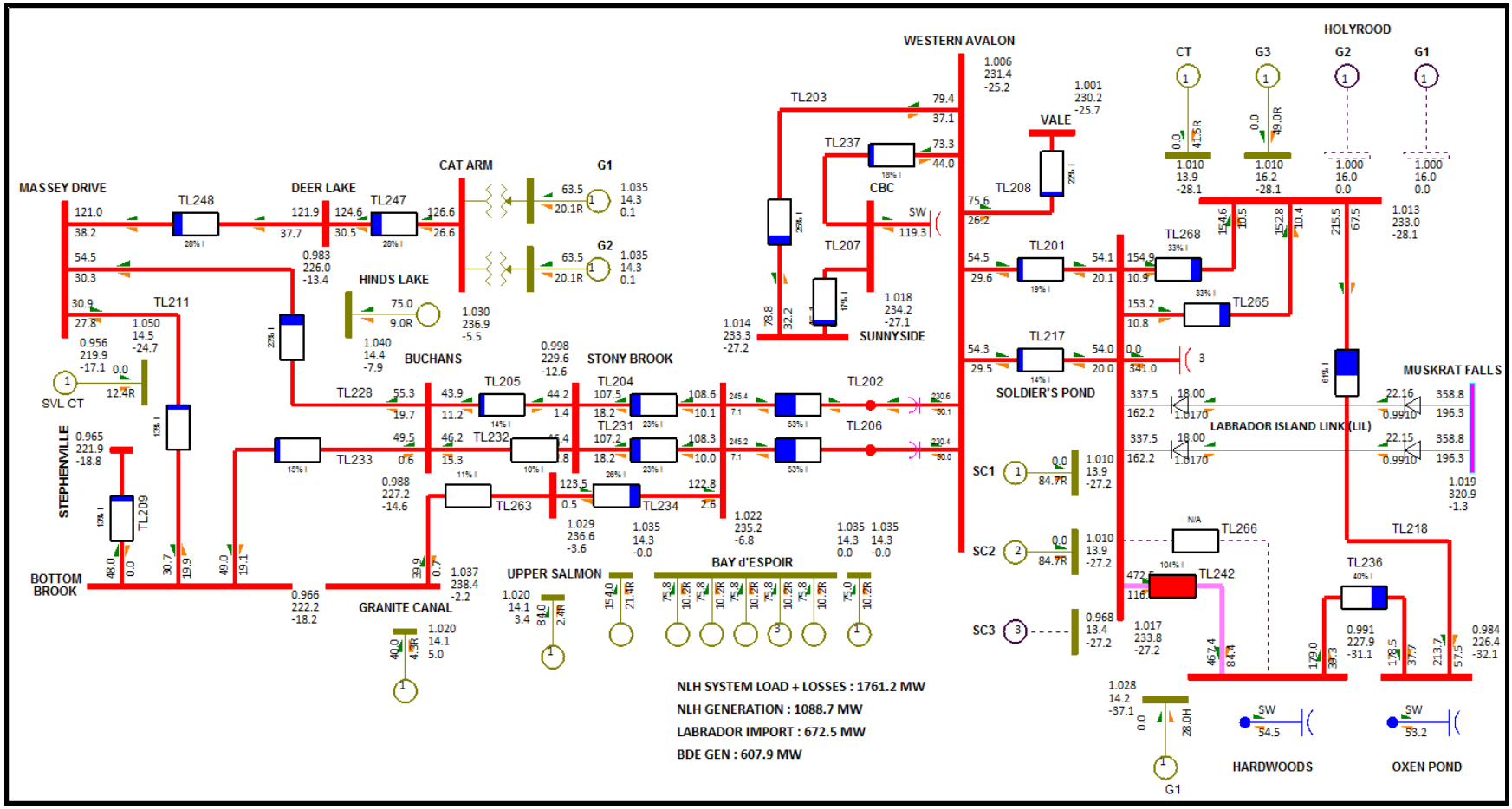


Figure 272 – Base Case 1 (BC1) Load Flow Plot – TL266 Out of Service

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

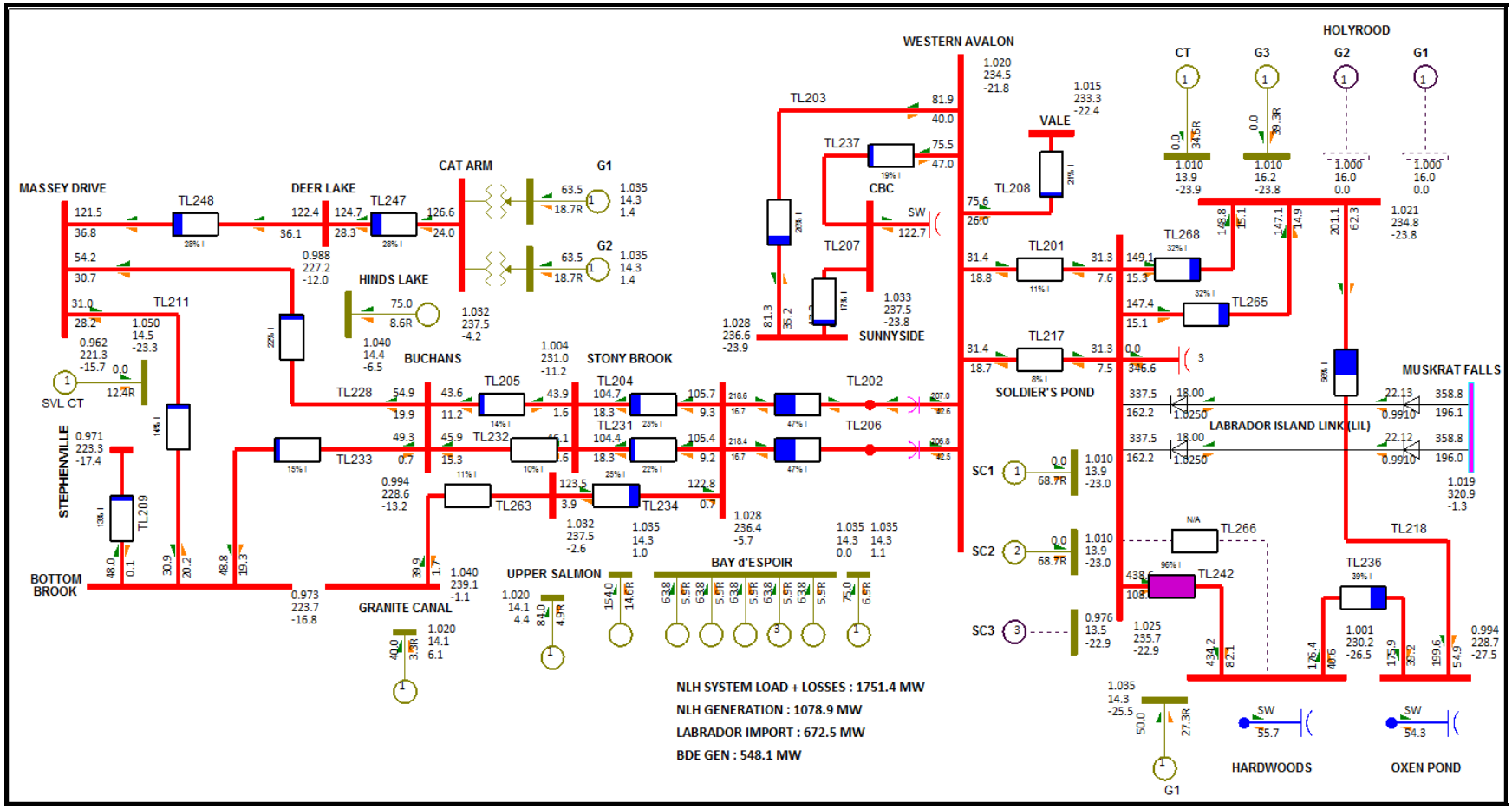


Figure 273 – Base Case 1 (BC1) Load Flow Plot – TL266 Out of Service – HWD CT Generating 50 MW

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

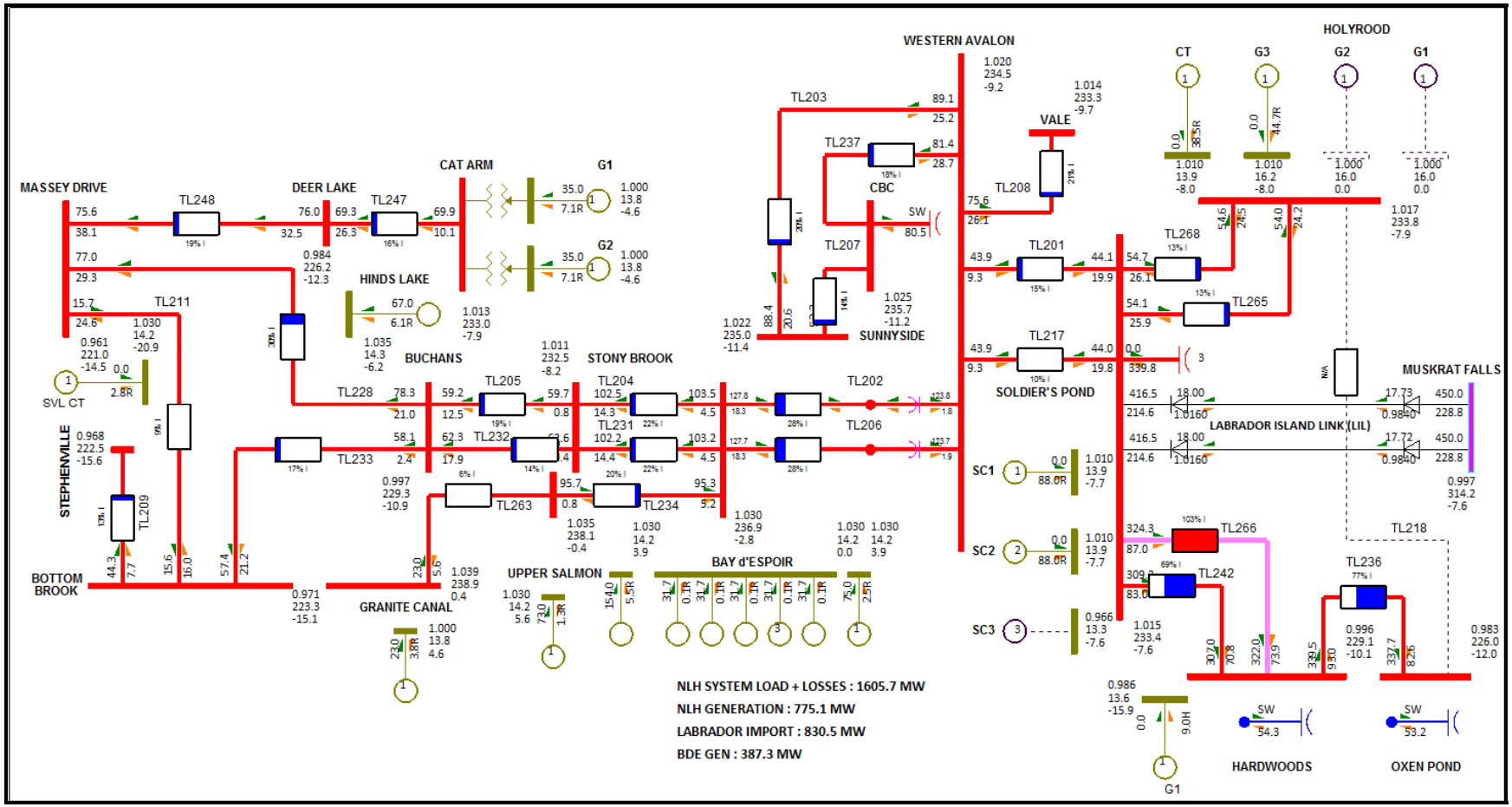


Figure 274 – Base Case 2 (BC2) Load Flow Plot – TL218 Out of Service

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (773 MW)

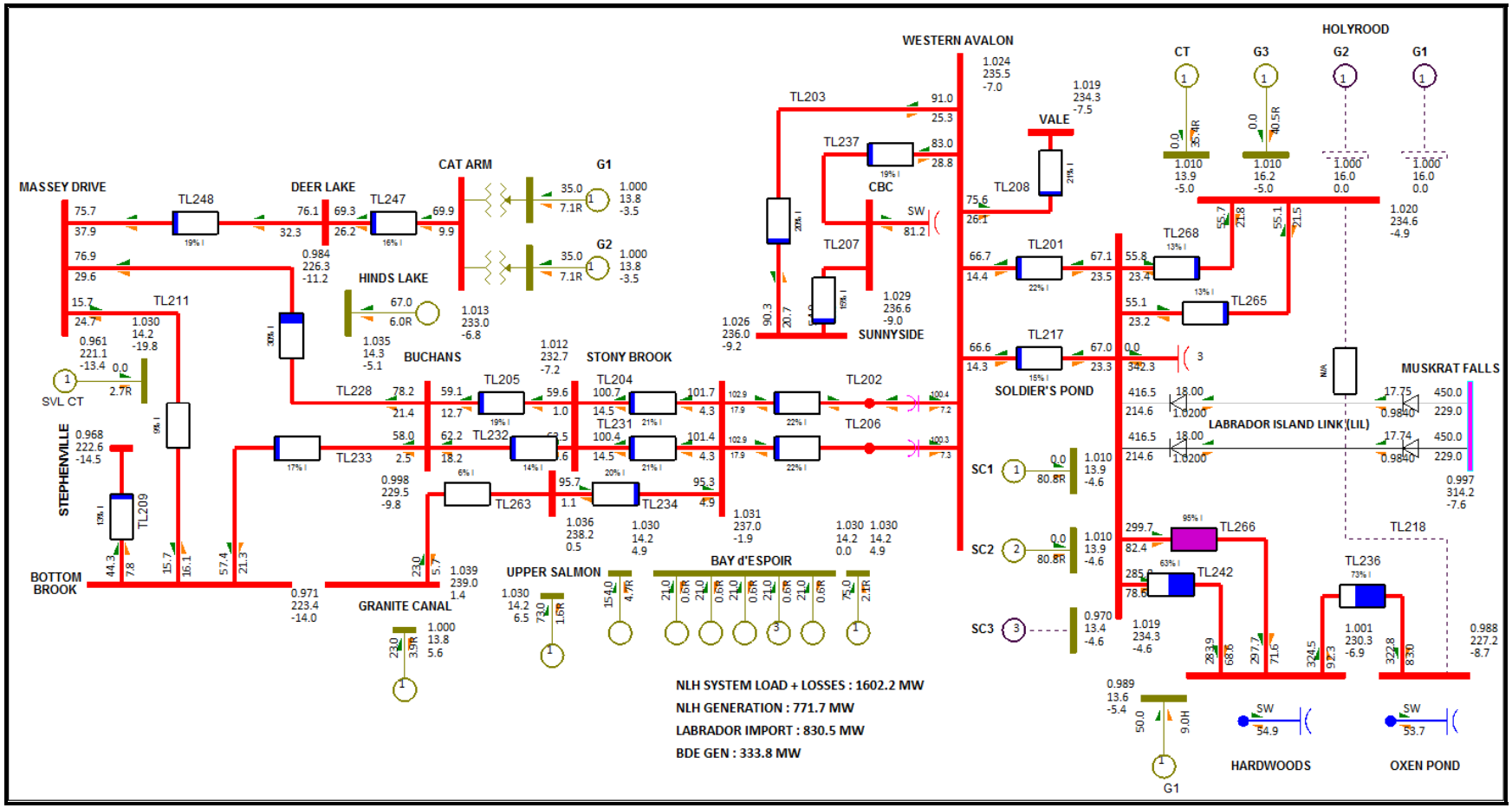


Figure 275 – Base Case 2 (BC2) Load Flow Plot – TL218 Out of Service – HWD CT Generating 50 MW

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (773 MW)

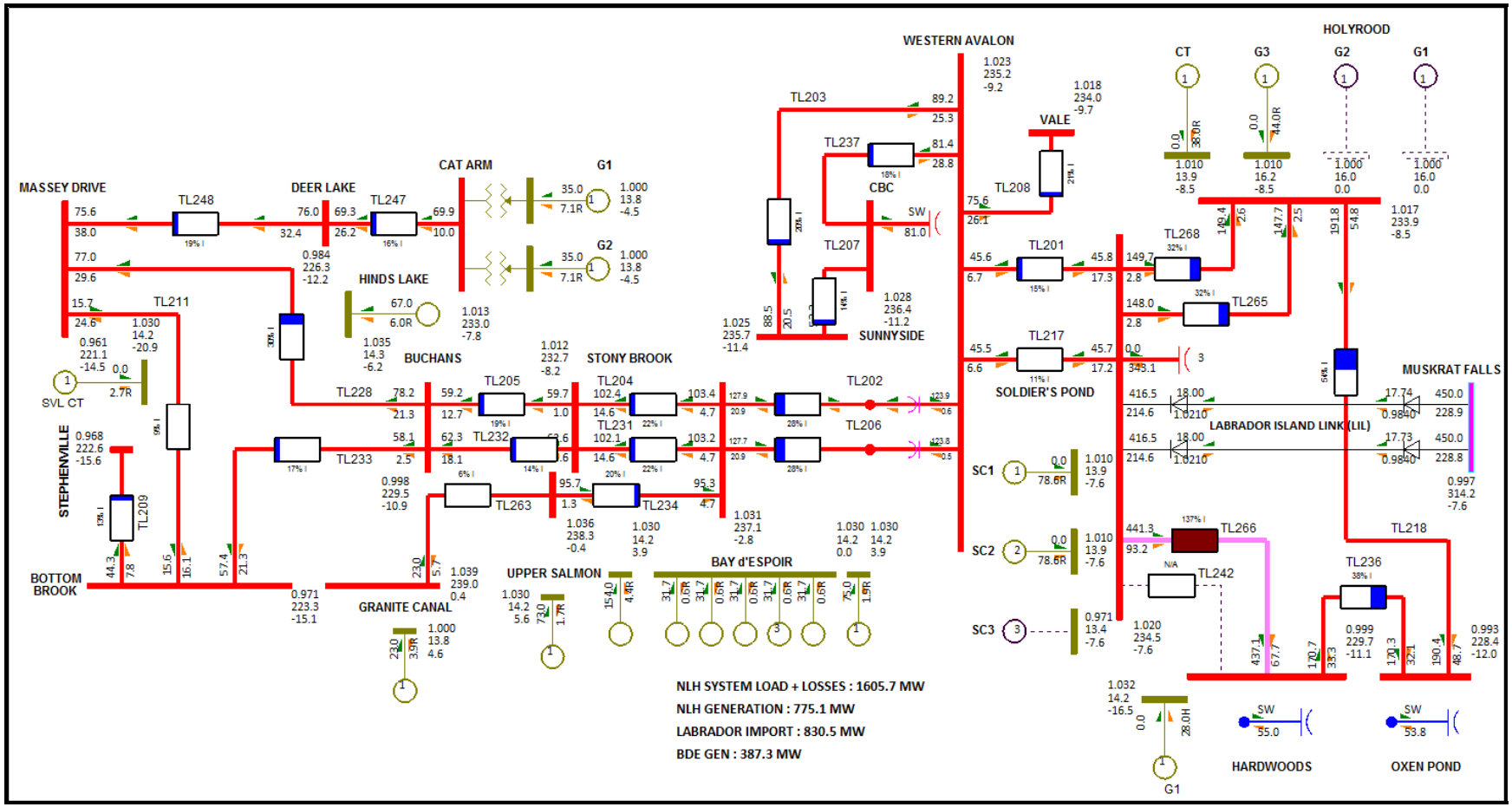


Figure 276 – Base Case 2 (BC2) Load Flow Plot – TL242 Out of Service

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (773 MW)

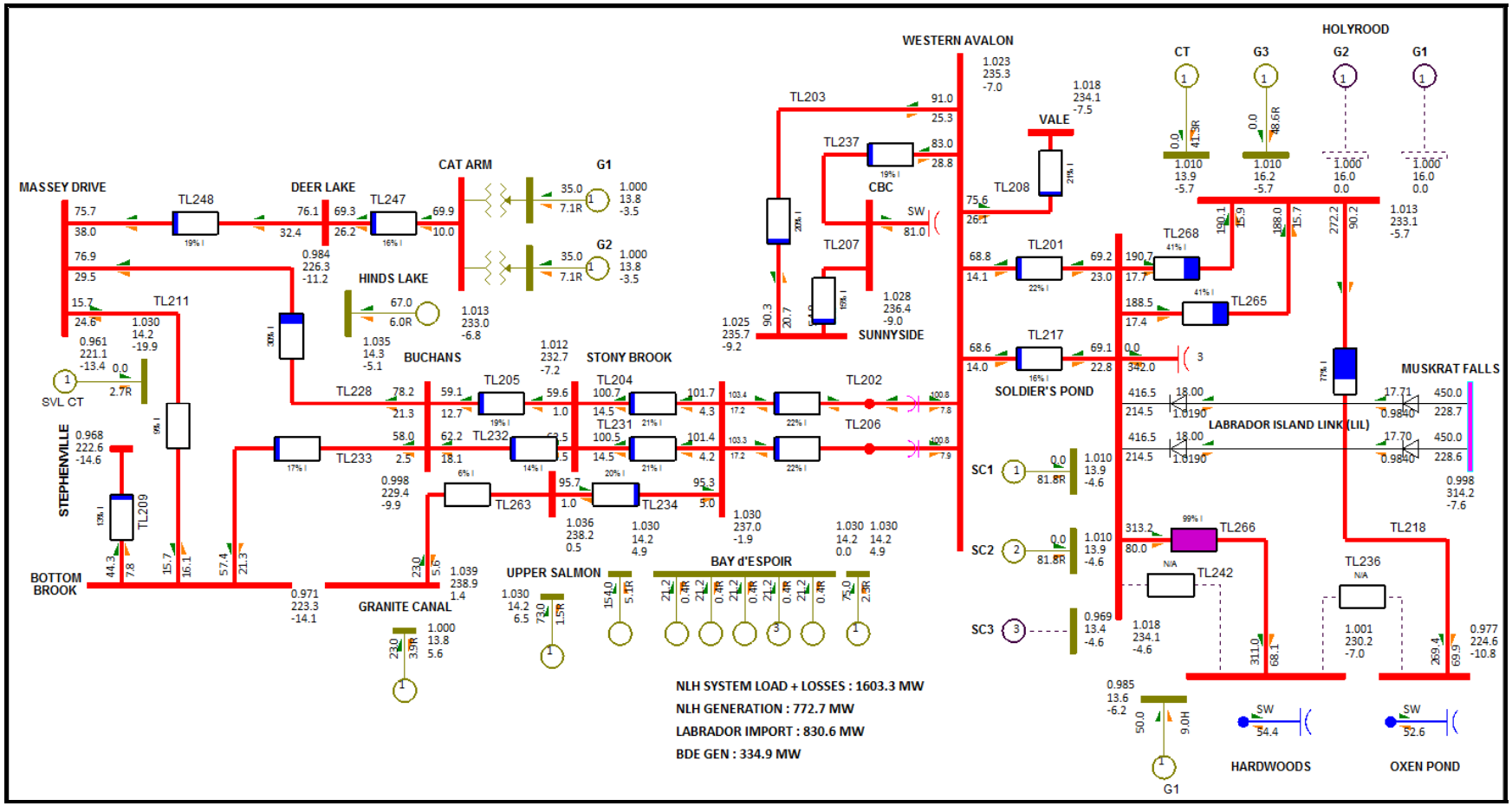


Figure 277 – Base Case 2 (BC2) Load Flow Plot – TL242 Out of Service – HWD CT Generating 50 MW and TL236 Open

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (773 MW)

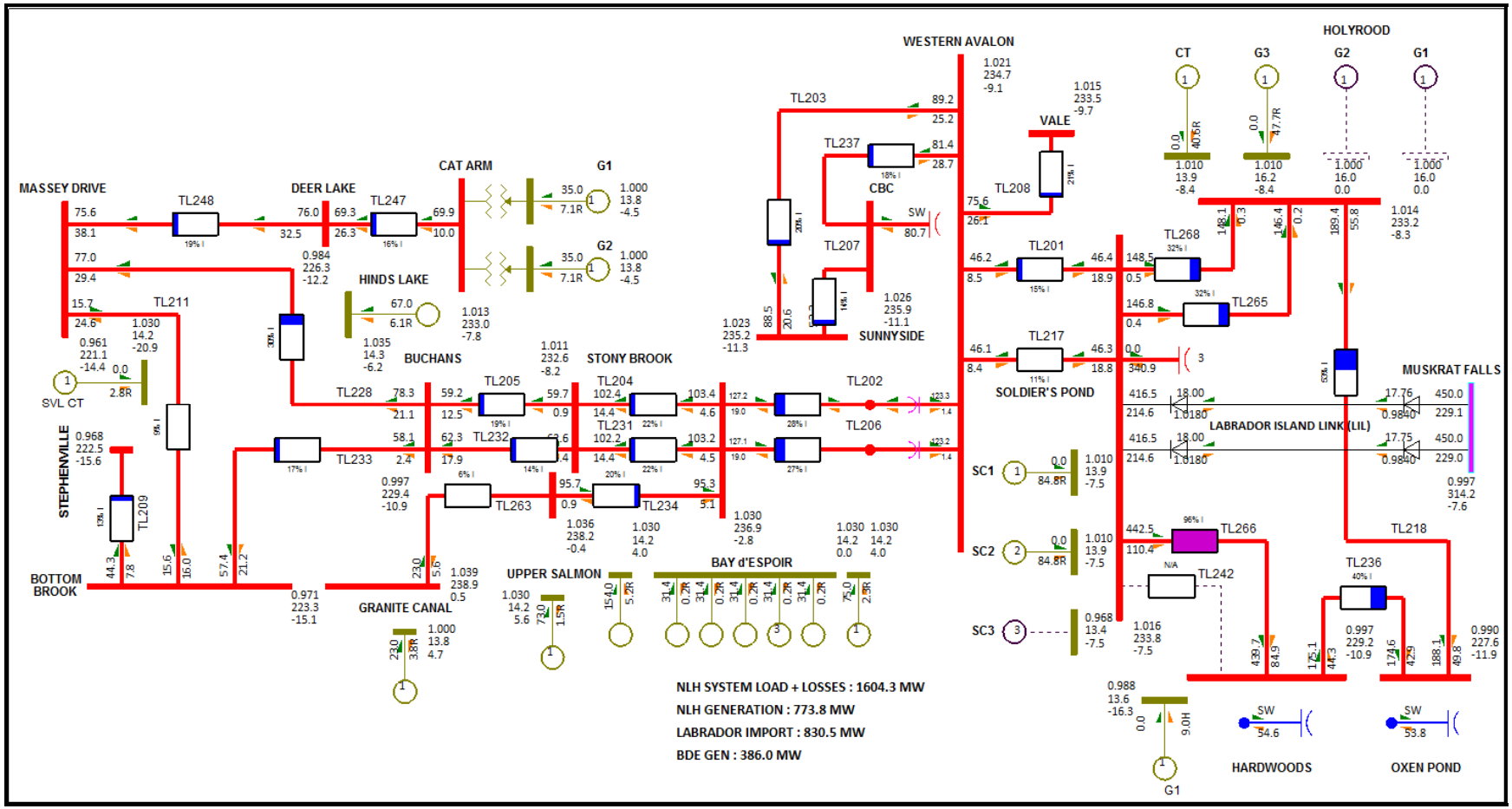


Figure 278 – Base Case 2 (BC2) Load Flow Plot – TL242 Out of Service

TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (773 MW)

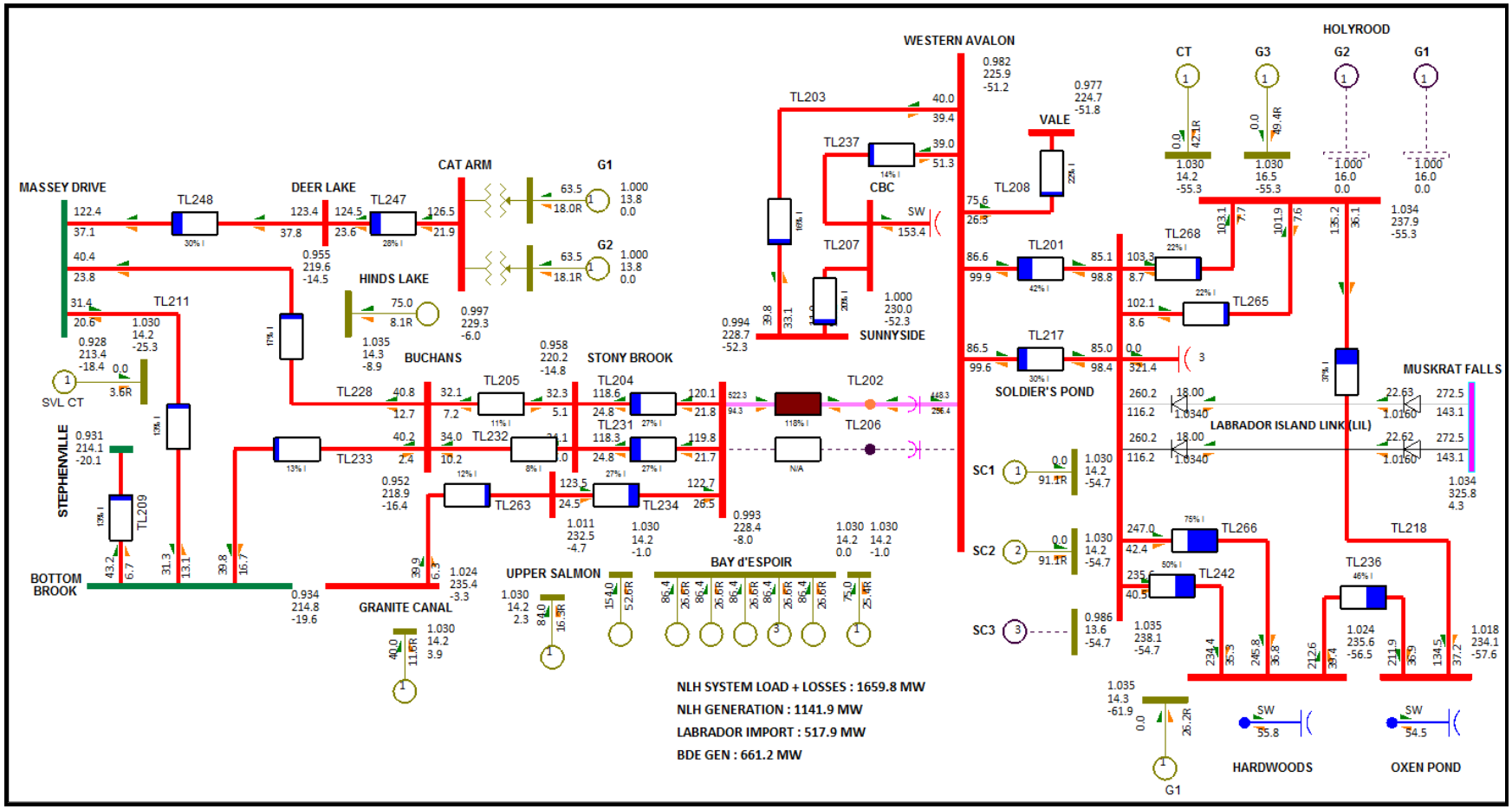


Figure 279 – Base Case 3 (BC3) Load Flow Plot – TL206 Out of Service

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

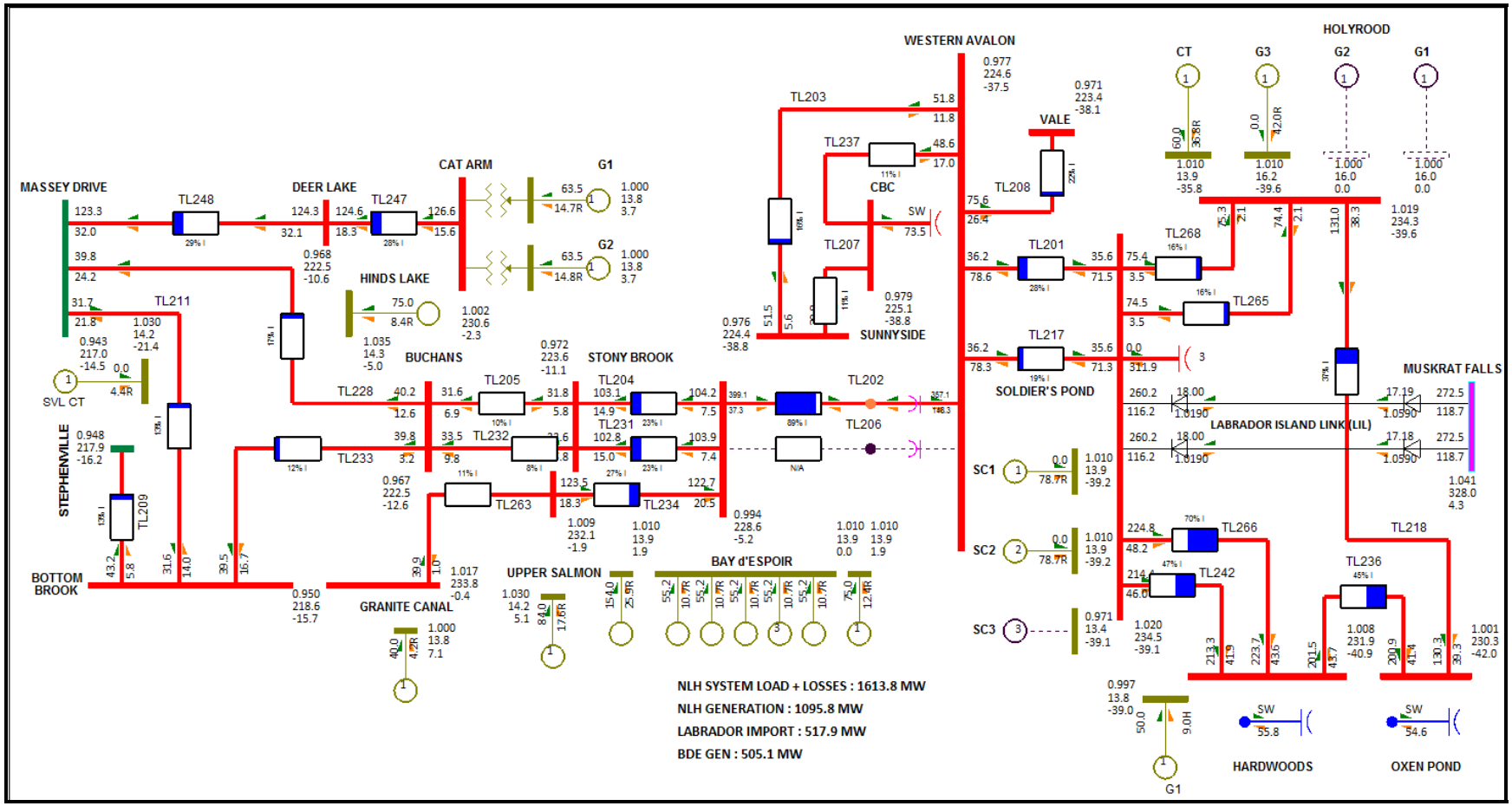


Figure 280 – Base Case 3 (BC3) Load Flow Plot – TL206 Out of Service – HWD CT and HRD CT Generating 110 MW

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

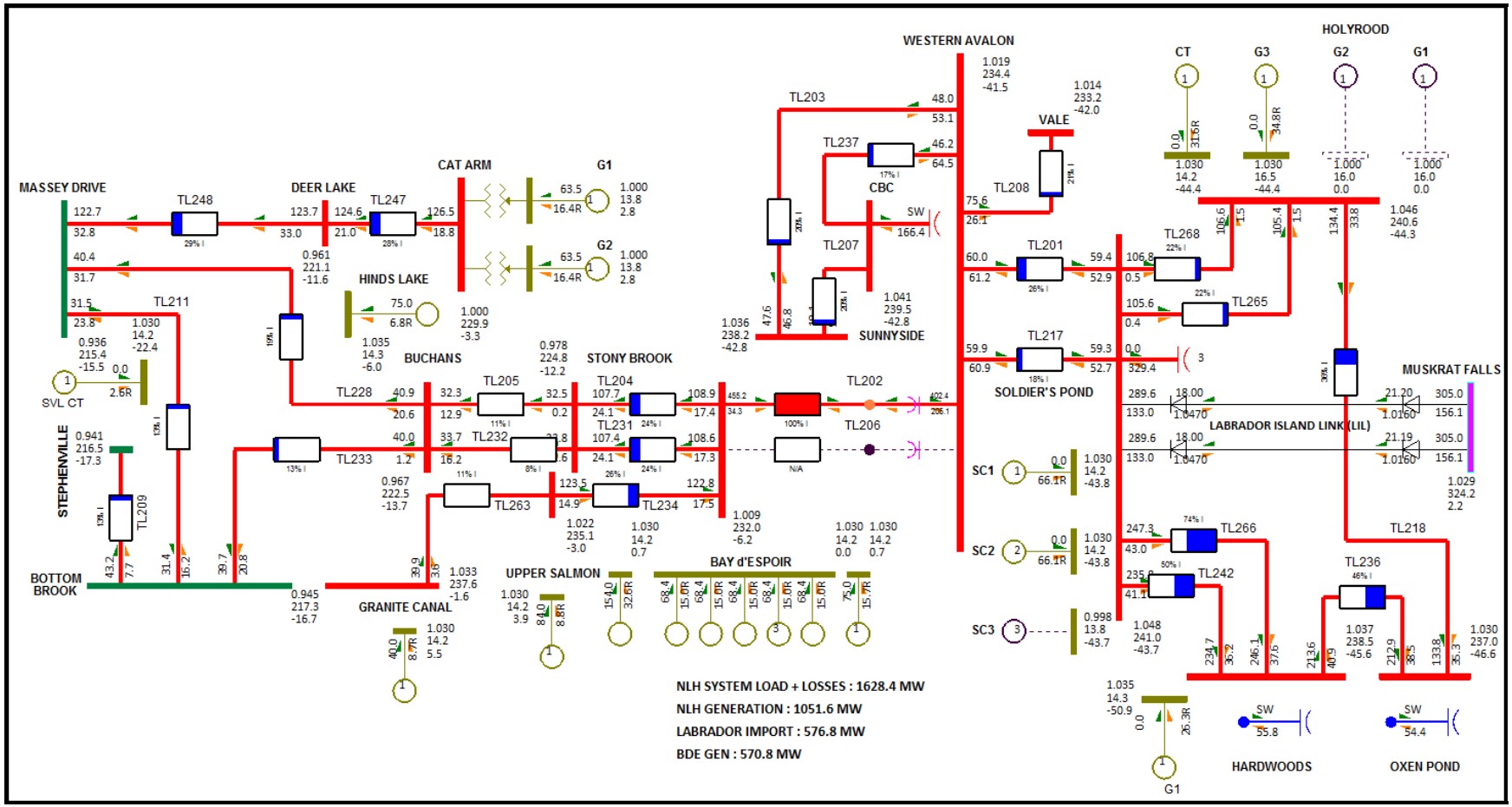


Figure 281 – Base Case 3 (BC3) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 577 MW

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

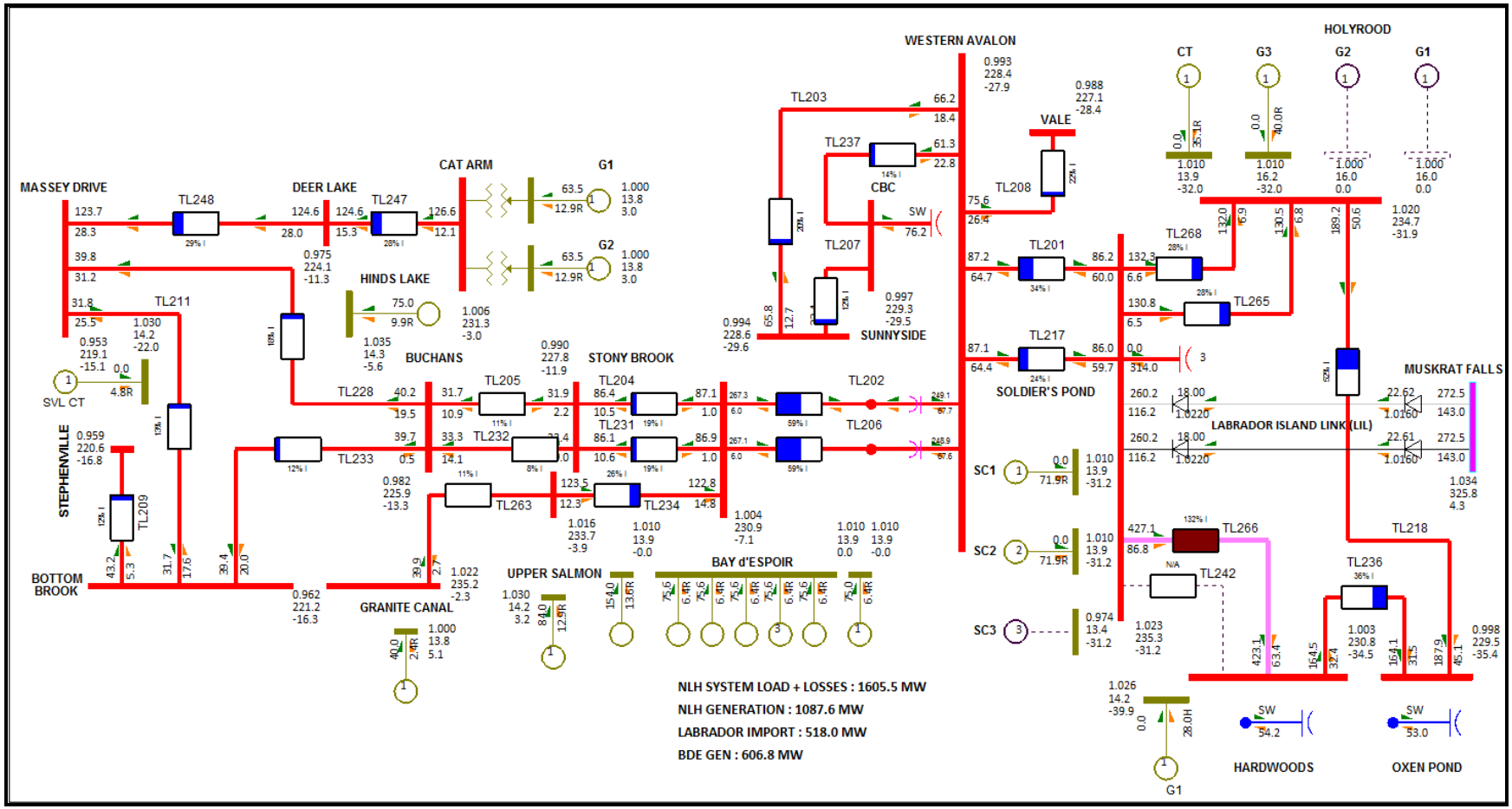


Figure 282 – Base Case 3 (BC3) Load Flow Plot – TL242 Out of Service

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

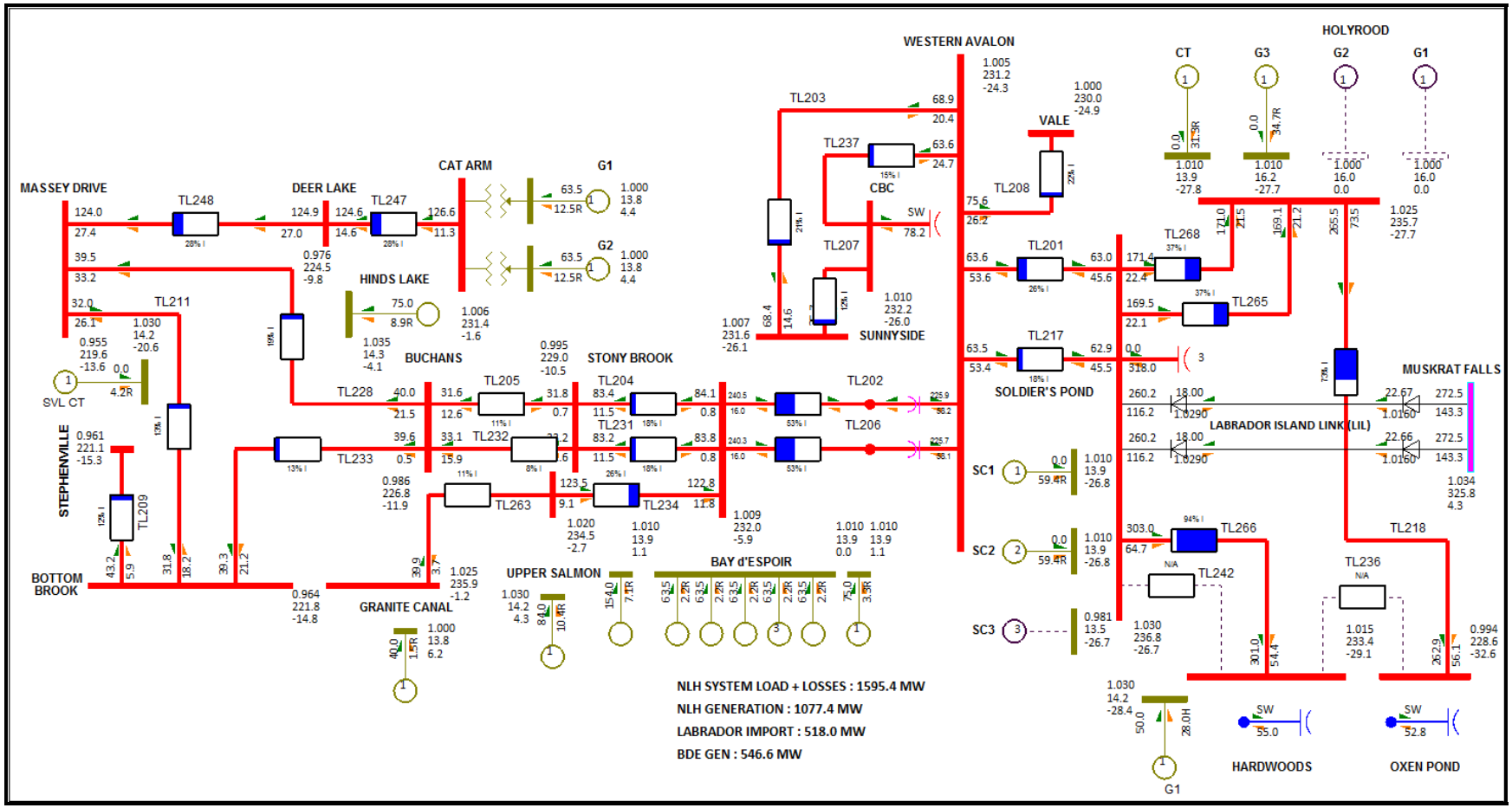


Figure 283 – Base Case 3 (BC3) Load Flow Plot – TL242 Out of Service – HWD CT Generating 50 MW and TL236 Open

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

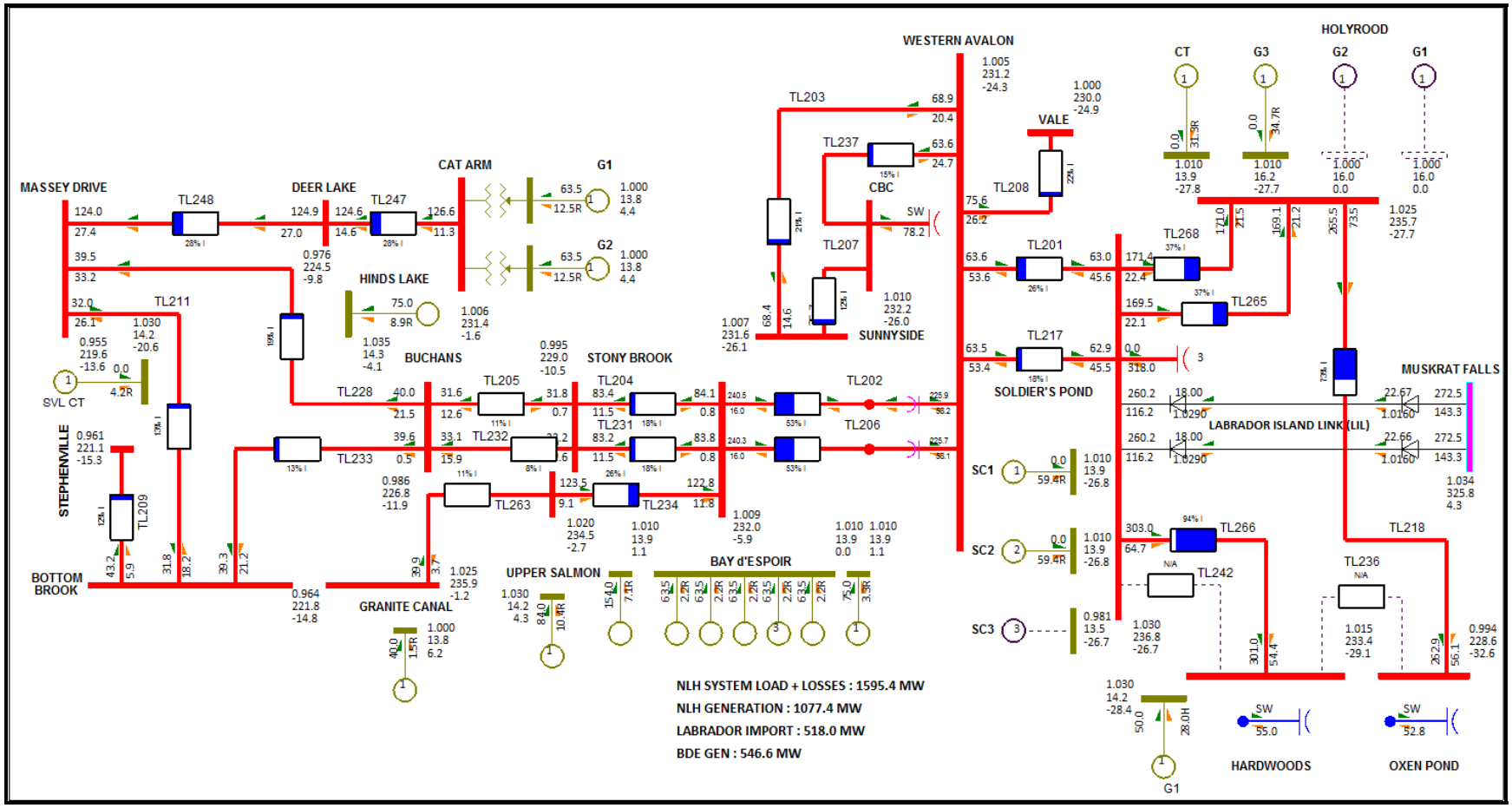


Figure 284 – Base Case 3 (BC3) Load Flow Plot – TL242 Out of Service

TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

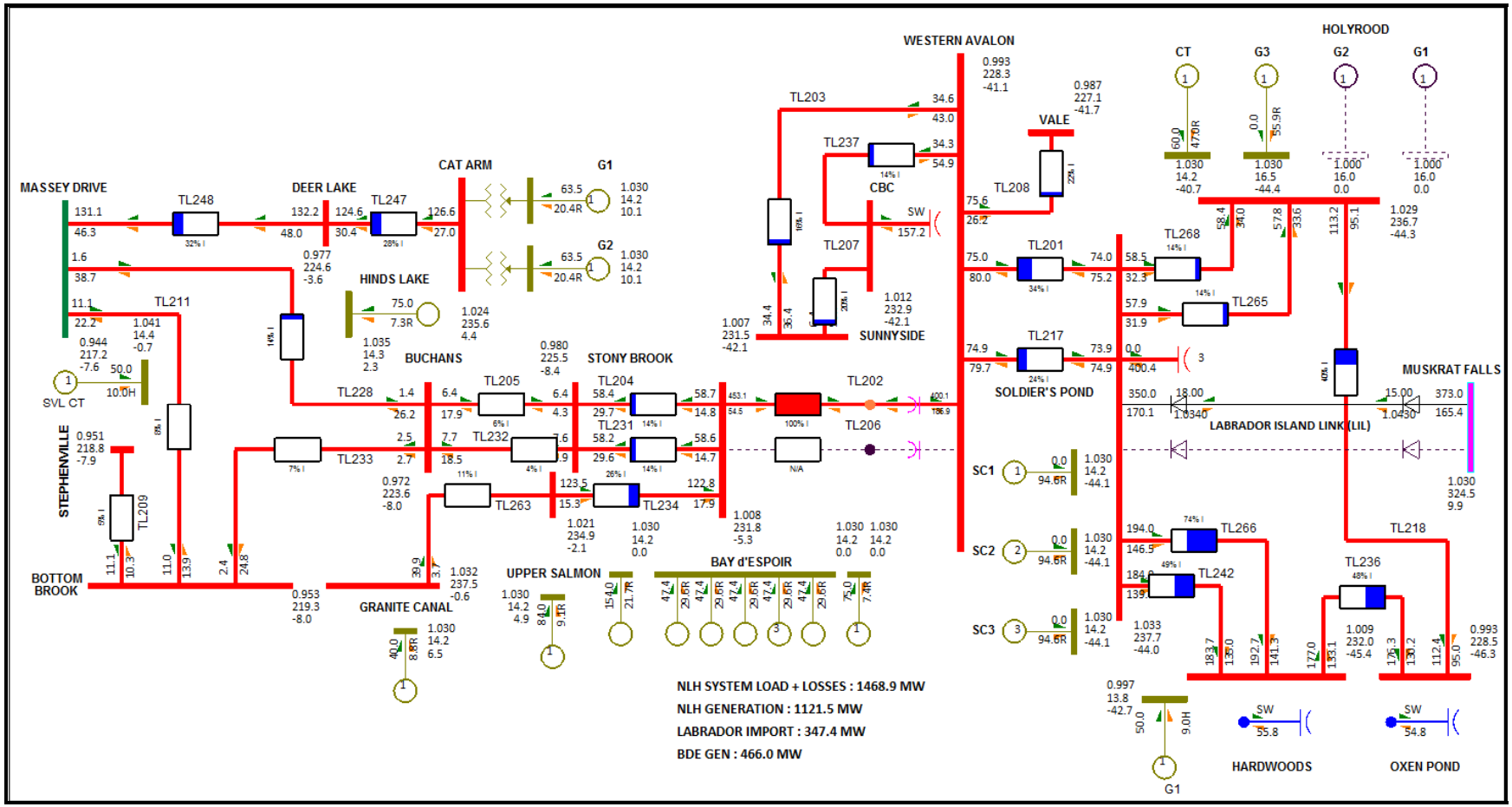


Figure 285 – Base Case 4 (BC4) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 347 MW

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

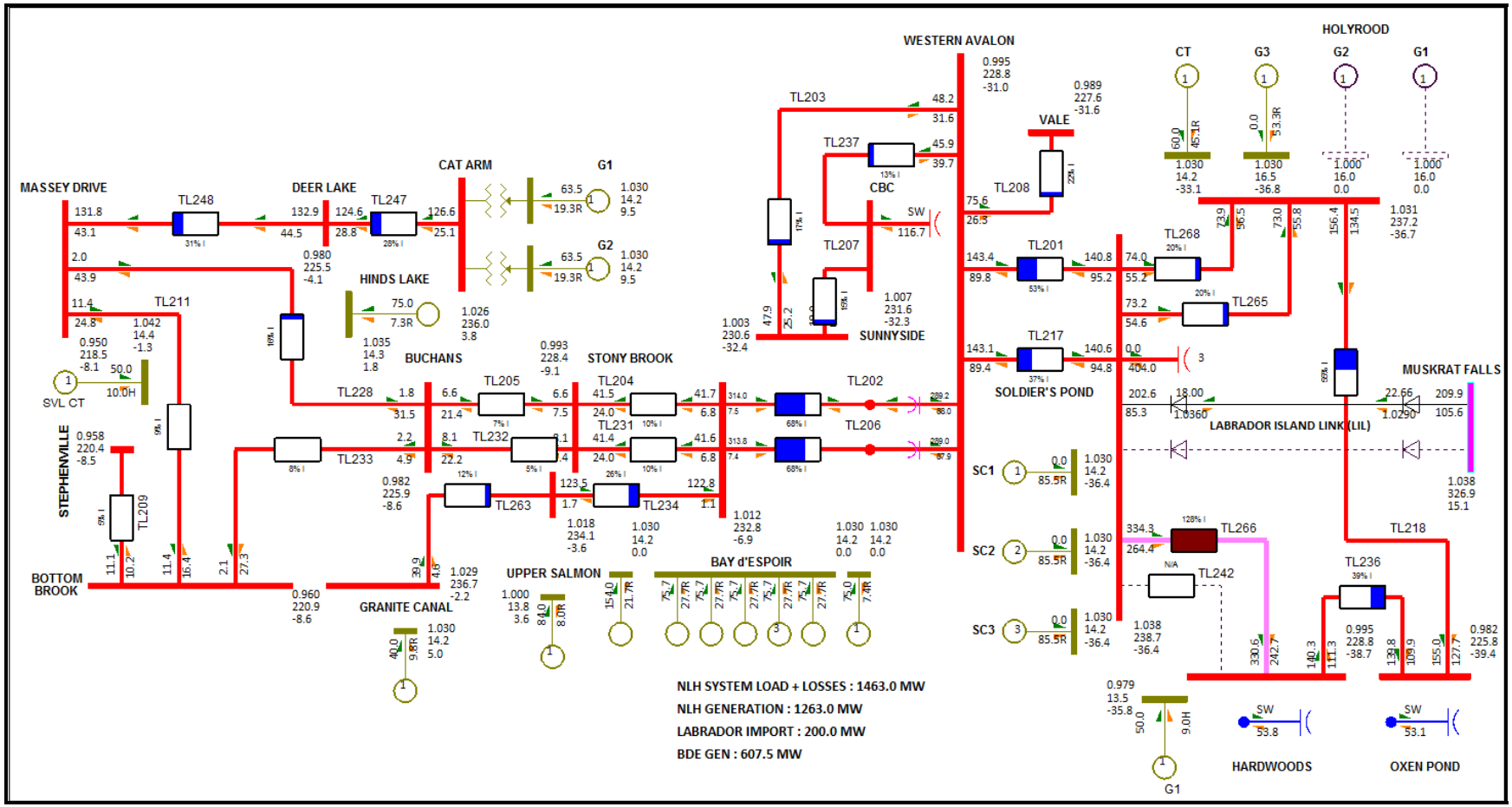


Figure 286 – Base Case 4 (BC4) Load Flow Plot – TL242 Out of Service

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

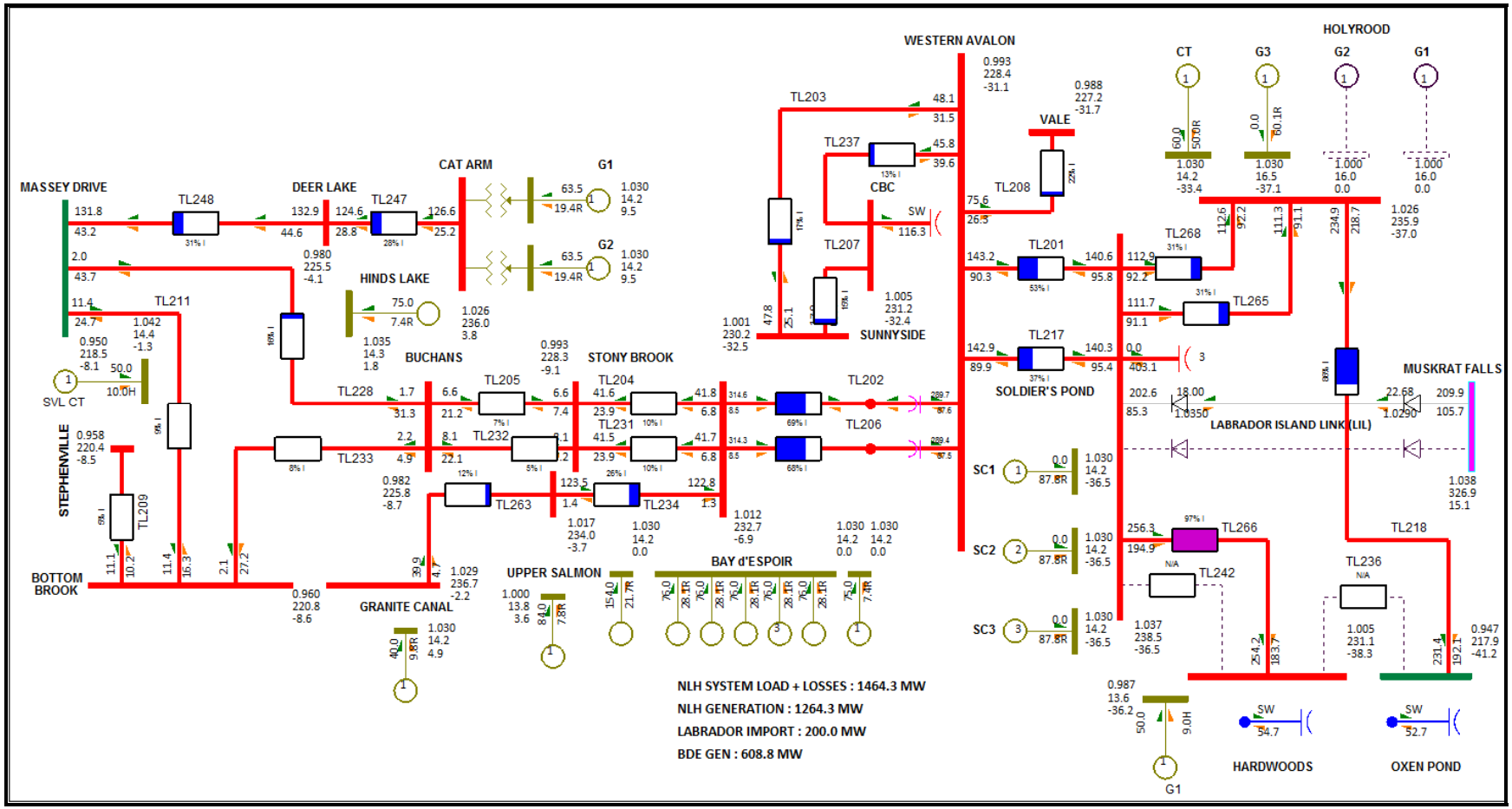


Figure 287 – Base Case 4 (BC4) Load Flow Plot – TL242 Out of Service – TL236 Open

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

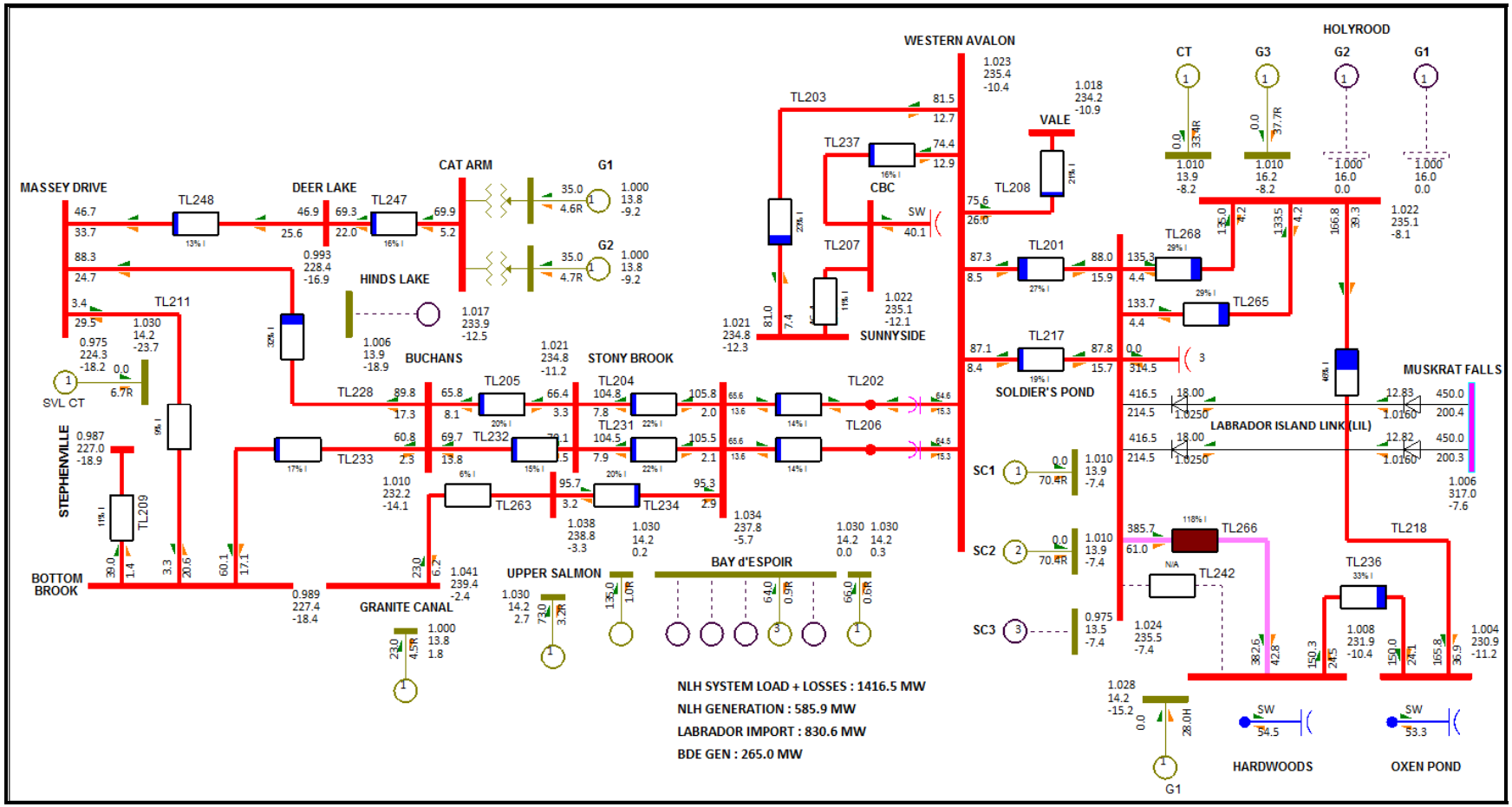


Figure 288 – Base Case 5 (BC5) Load Flow Plot – TL242 Out of Service

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (585 MW)

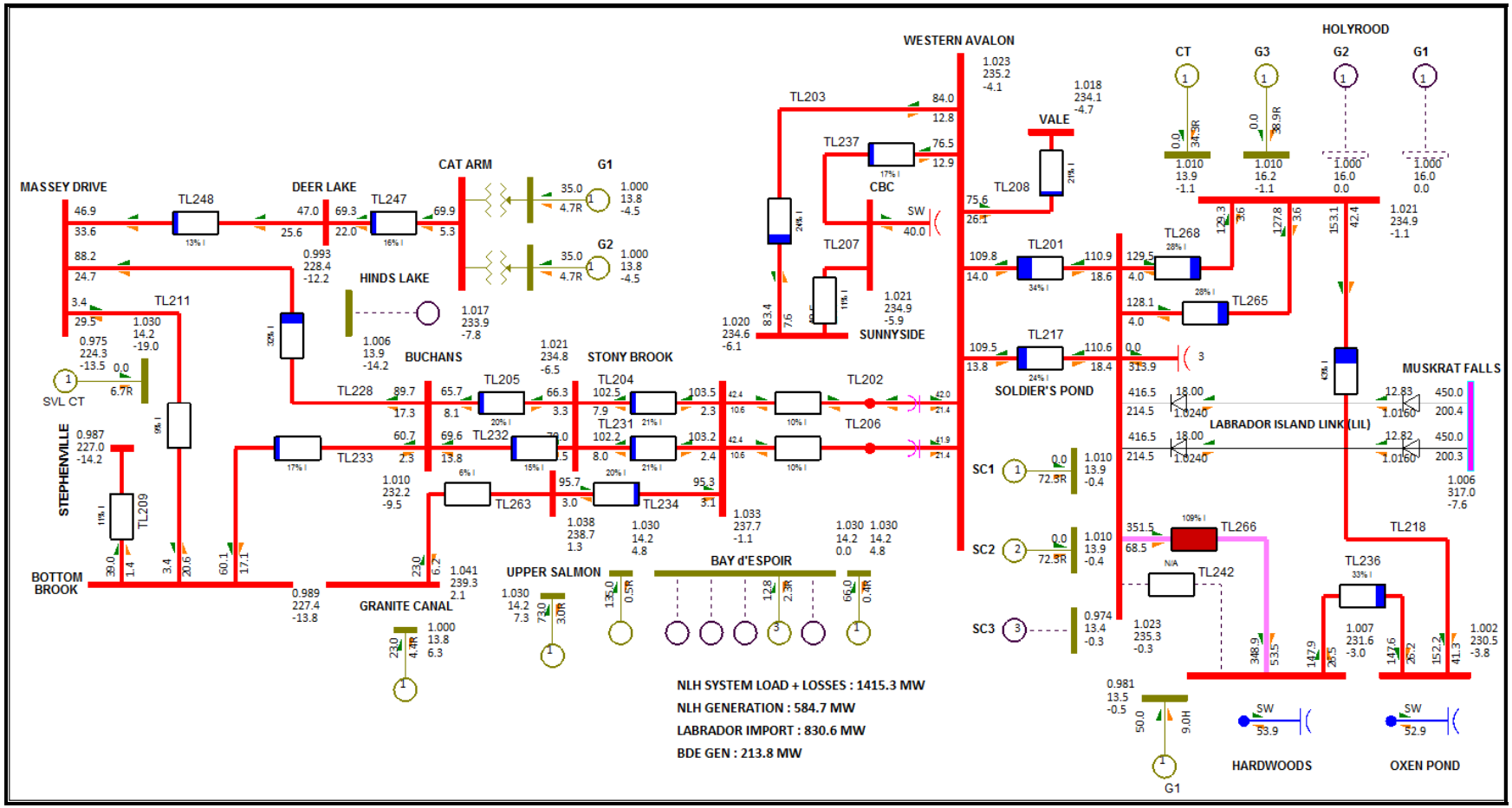


Figure 289 – Base Case 5 (BC5) Load Flow Plot – TL242 Out of Service – HWD CT Generating 50 MW

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (585 MW)

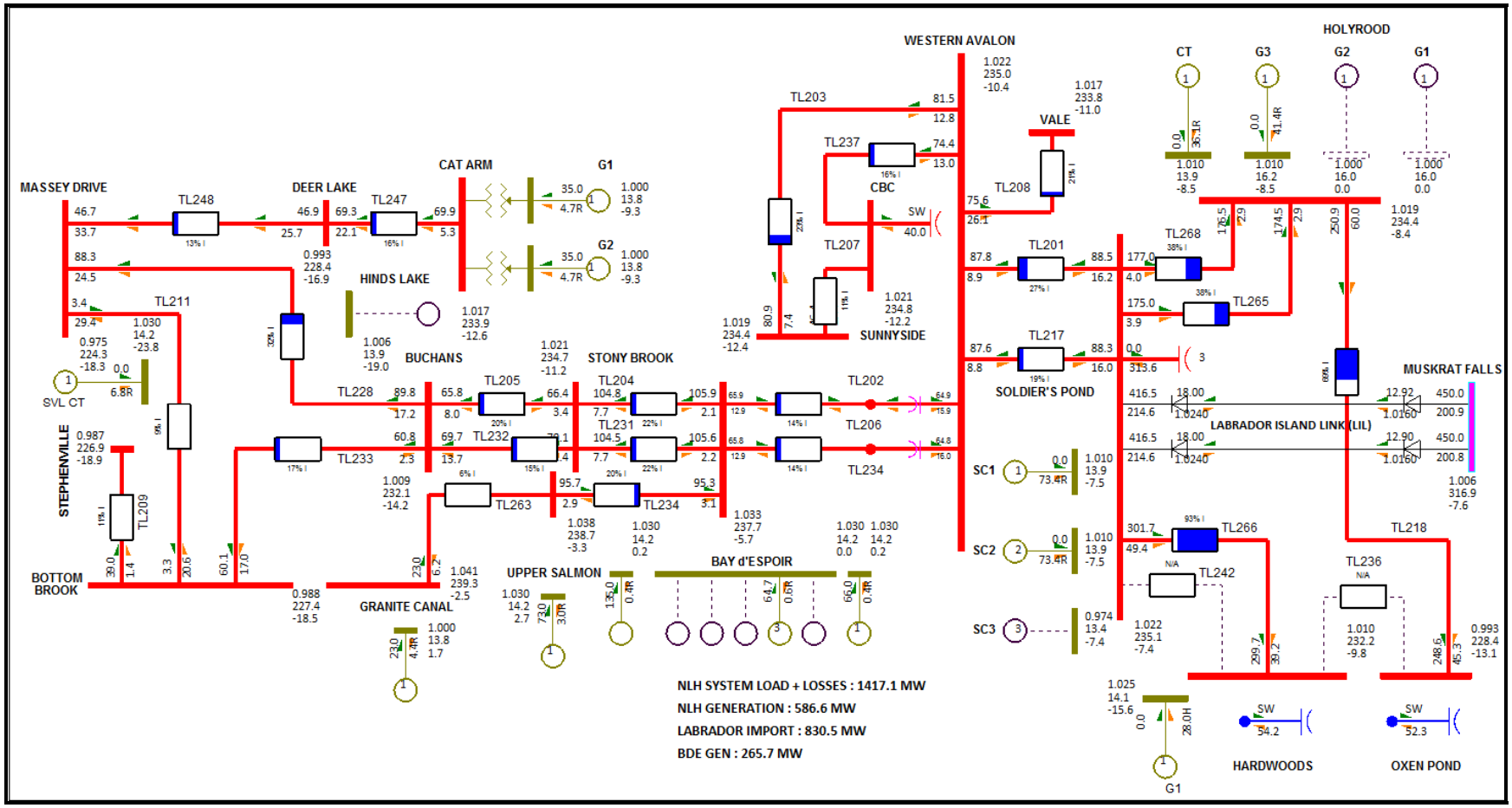


Figure 290 – Base Case 5 (BC5) Load Flow Plot – TL242 Out of Service – TL236 Open

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (585 MW)

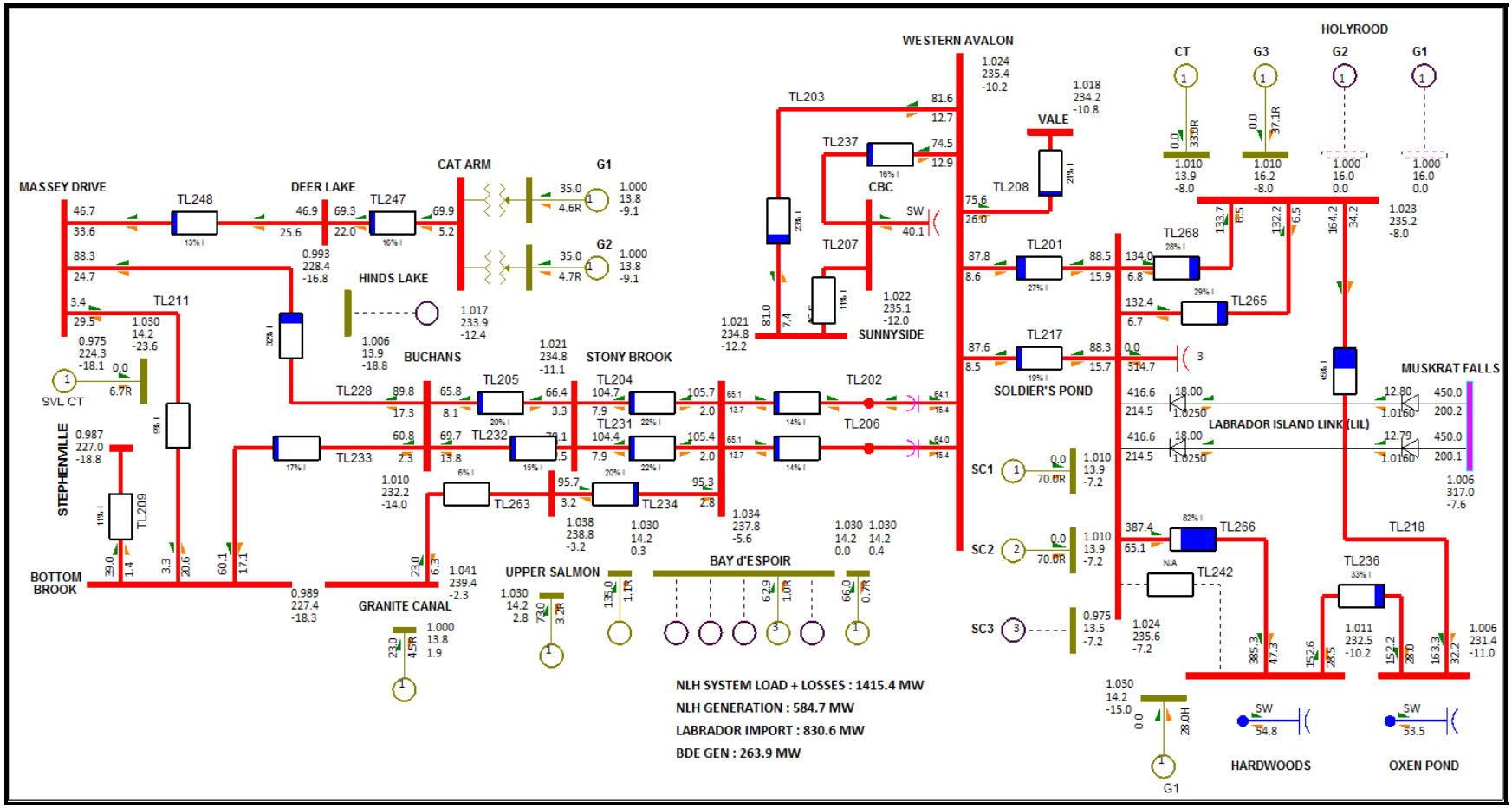


Figure 291 – Base Case 5 (BC5) Load Flow Plot – TL242 Out of Service

TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (585 MW)

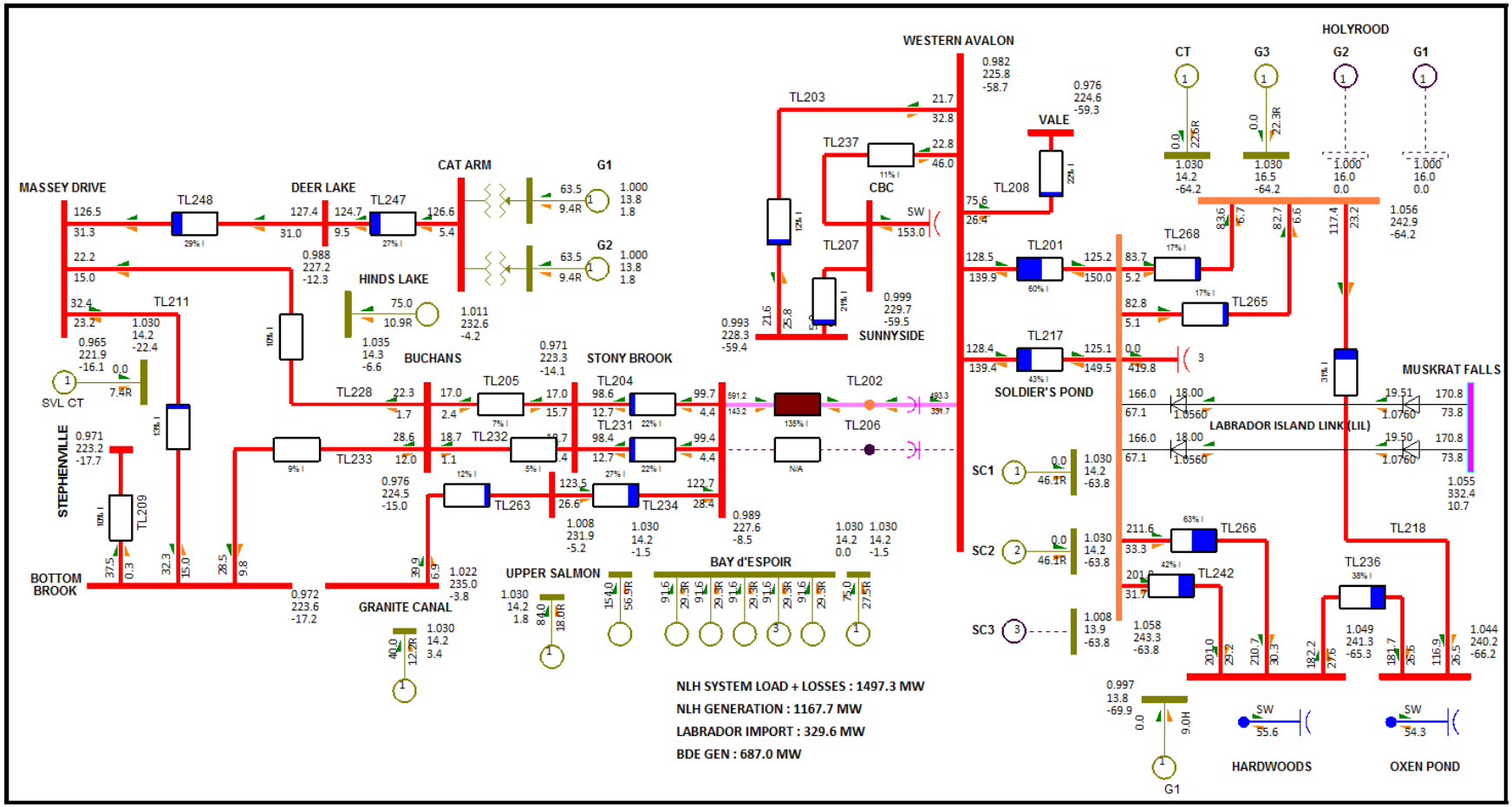


Figure 292 – Base Case 6 (BC6) Load Flow Plot – TL206 Out of Service

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

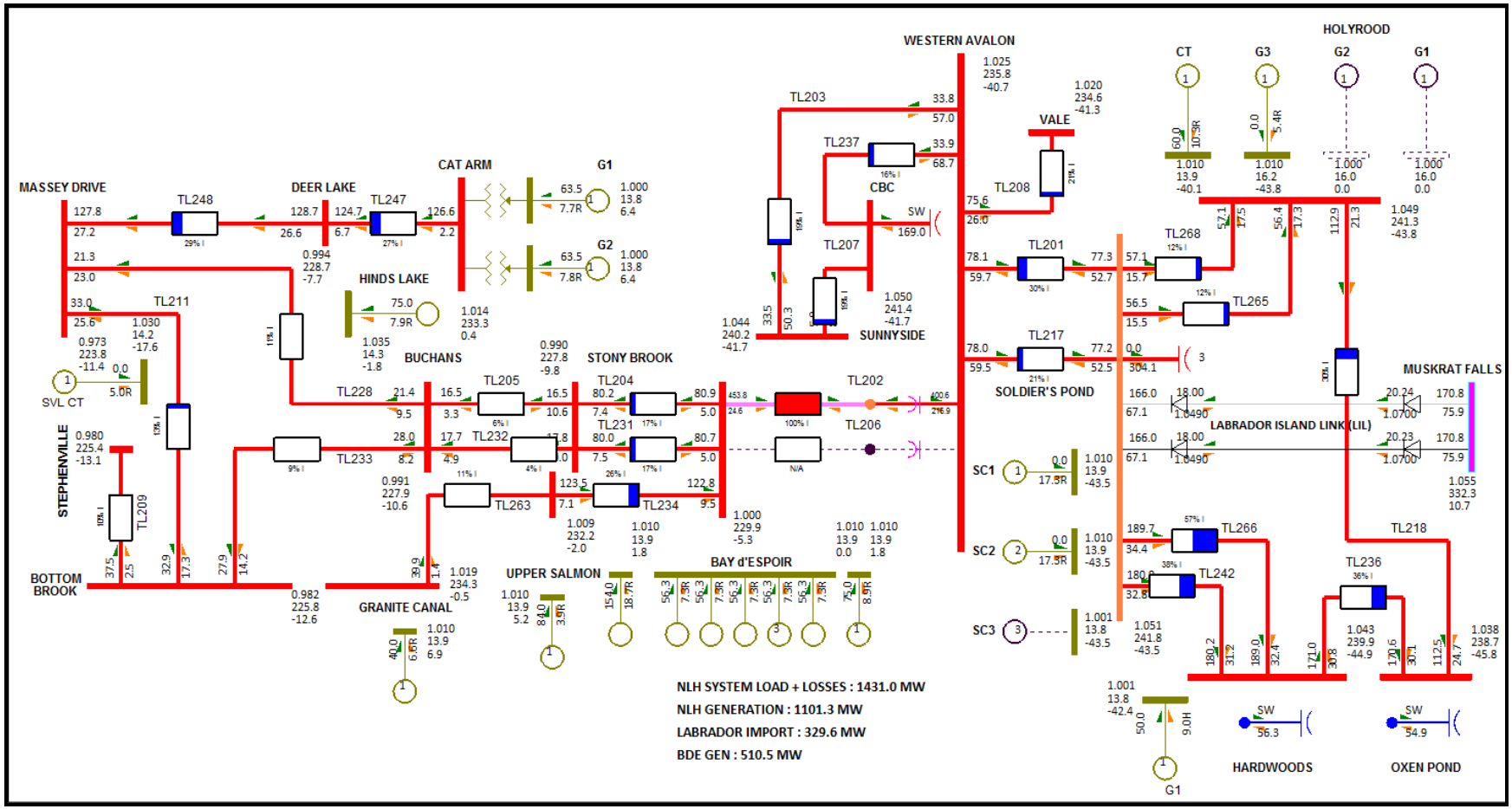


Figure 293 – Base Case 6 (BC6) Load Flow Plot – TL206 Out of Service – HWD CT and HRD CT Generating 110 MW

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

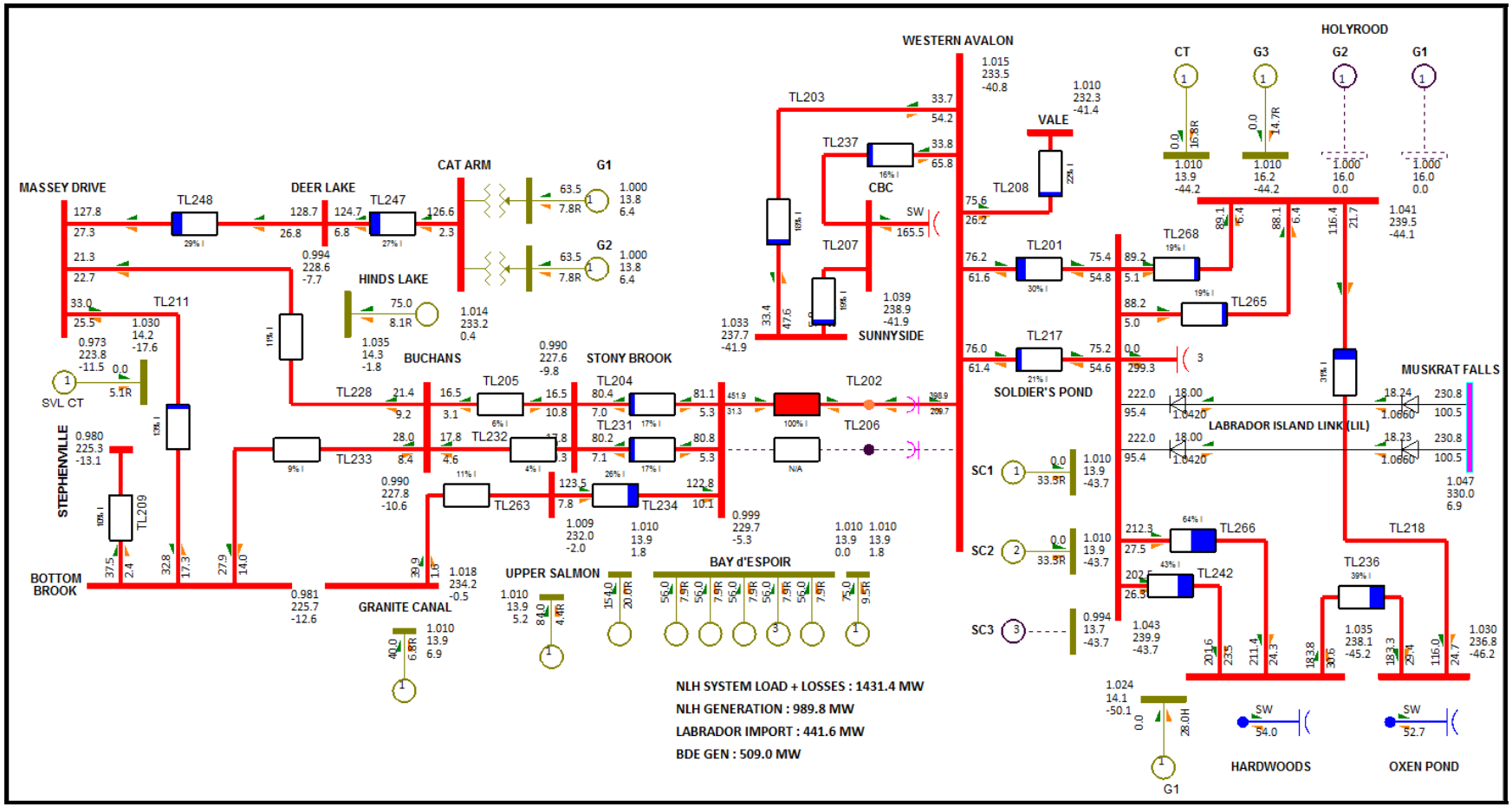


Figure 294 – Base Case 6 (BC6) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 442 MW

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

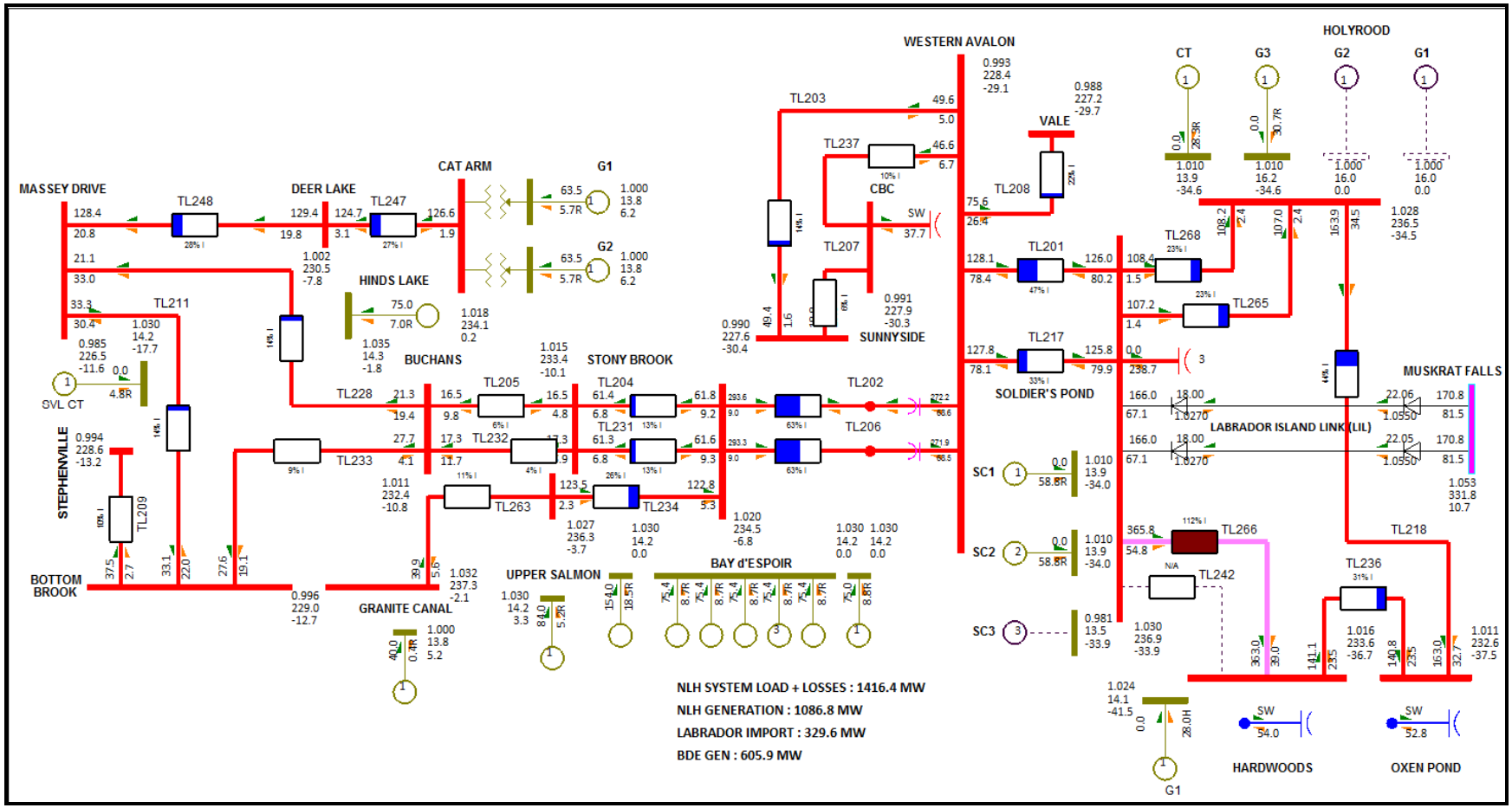


Figure 295 – Base Case 6 (BC6) Load Flow Plot – TL242 Out of Service

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

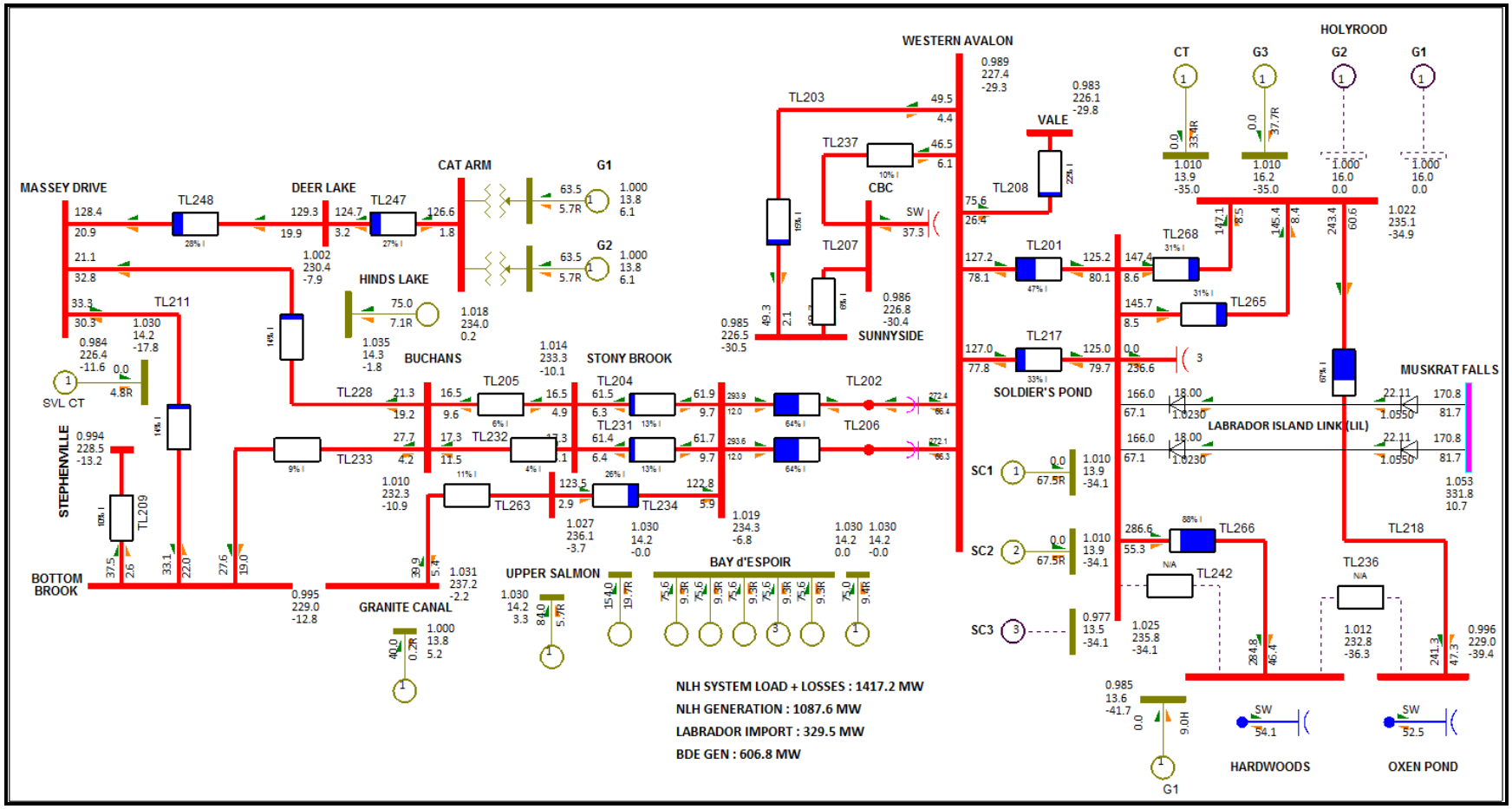


Figure 296 – Base Case 6 (BC6) Load Flow Plot – TL242 Out of Service – TL236 Open

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

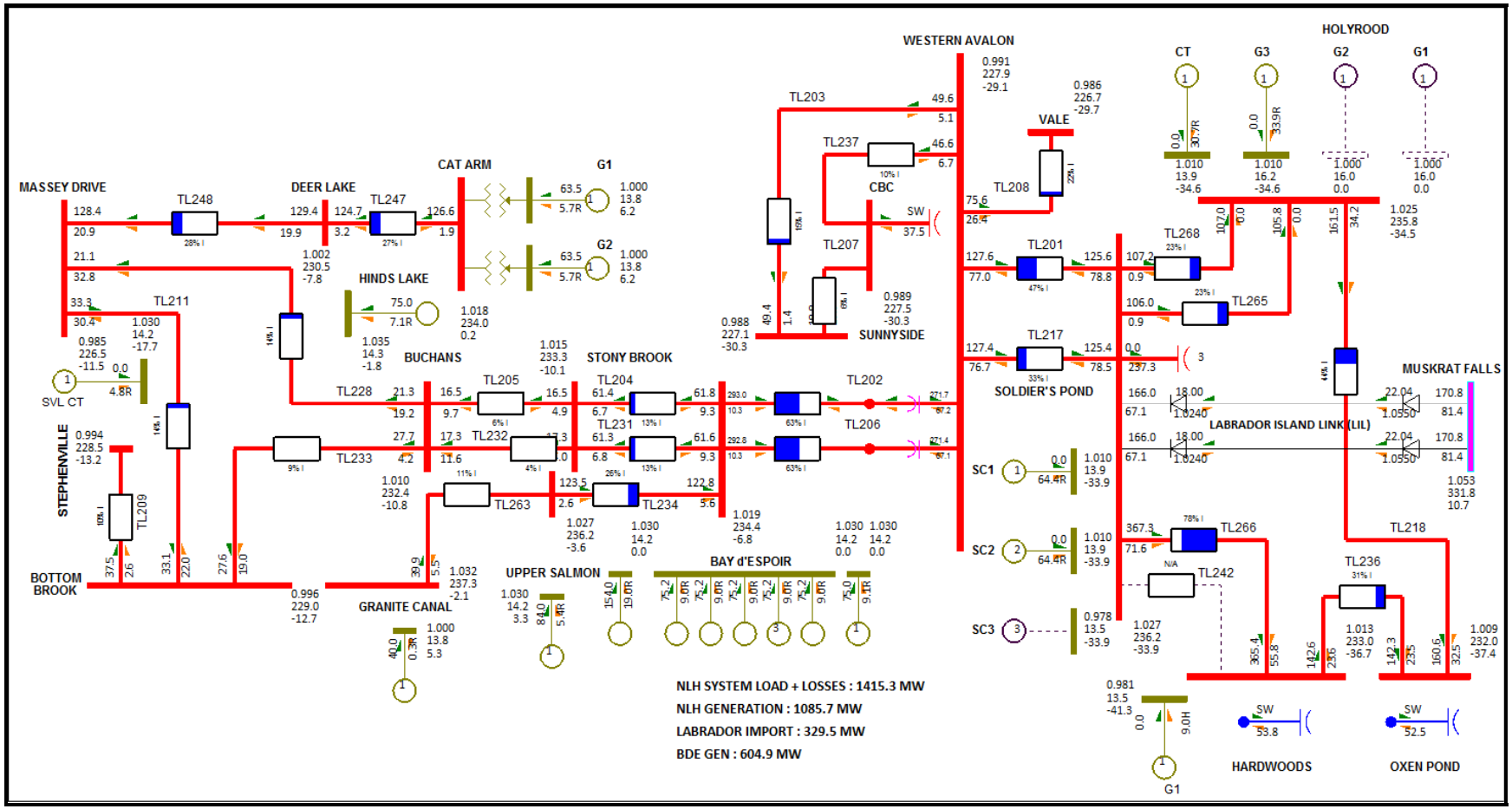


Figure 297 – Base Case 6 (BC6) Load Flow Plot – TL242 Out of Service

TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

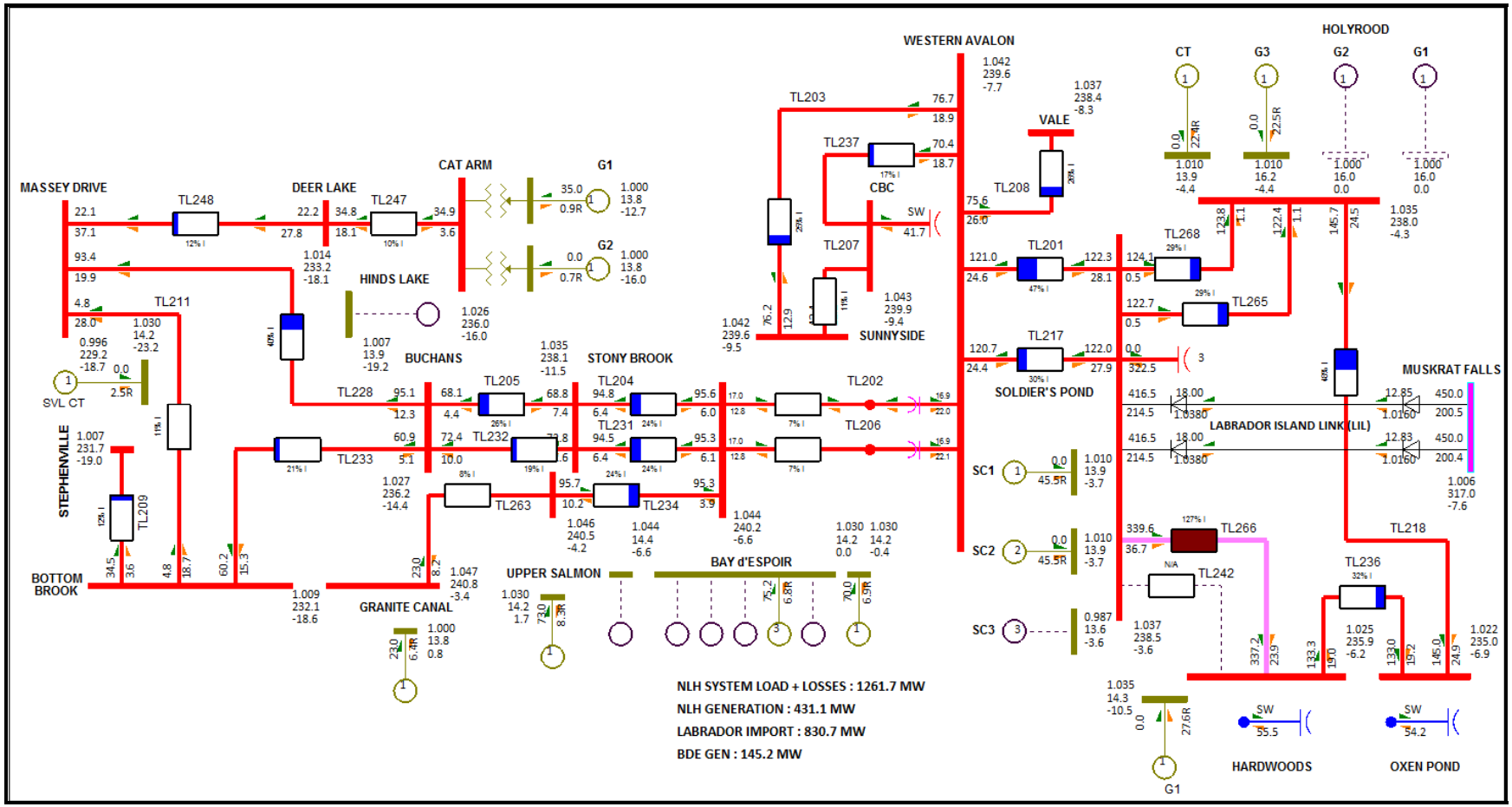


Figure 298 – Base Case 7 (BC7) Load Flow Plot – TL242 Out of Service

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (431 MW)

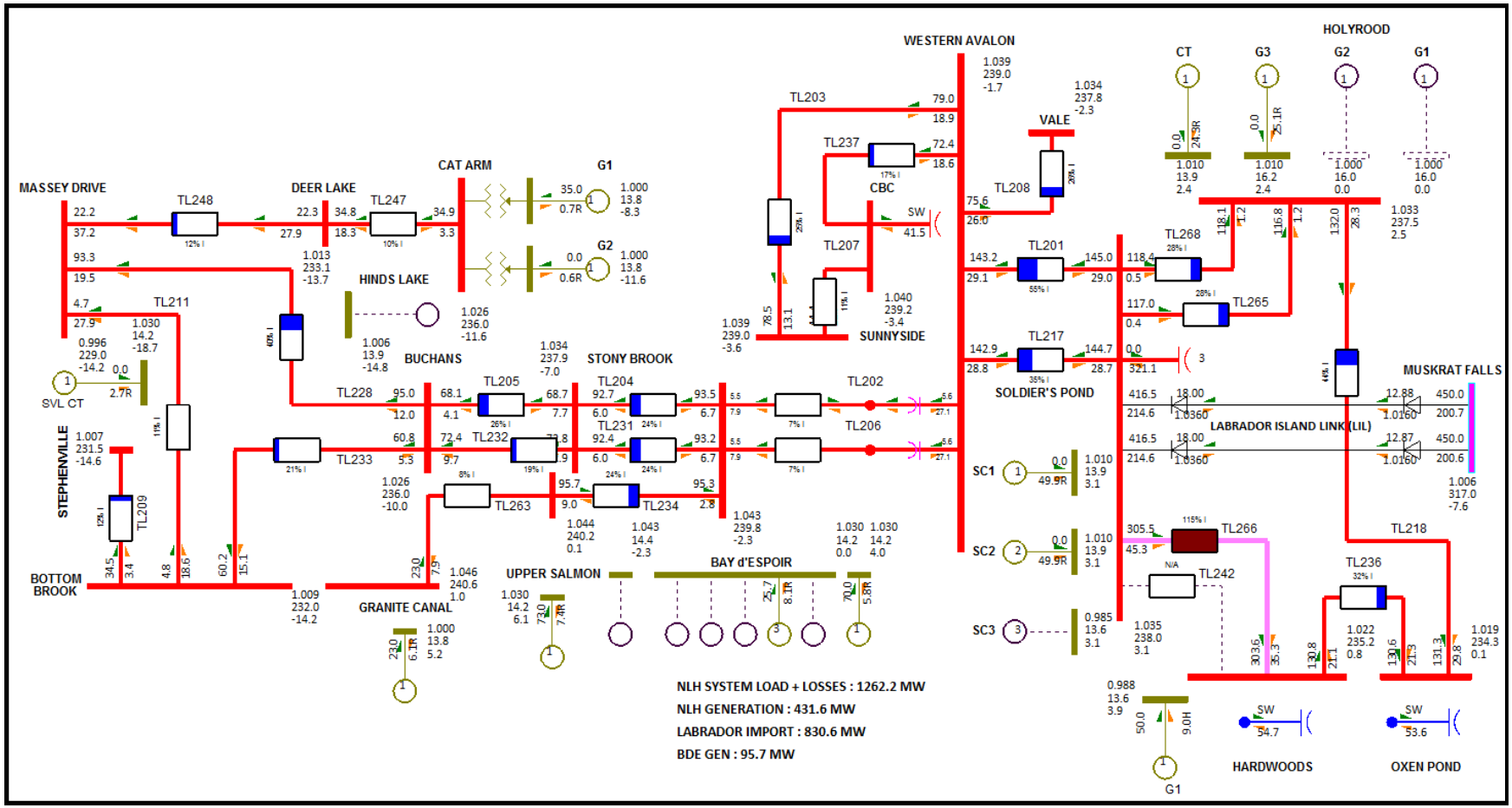


Figure 299 – Base Case 7 (BC7) Load Flow Plot – TL242 Out of Service – HWD CT Generating 50 MW

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (431 MW)

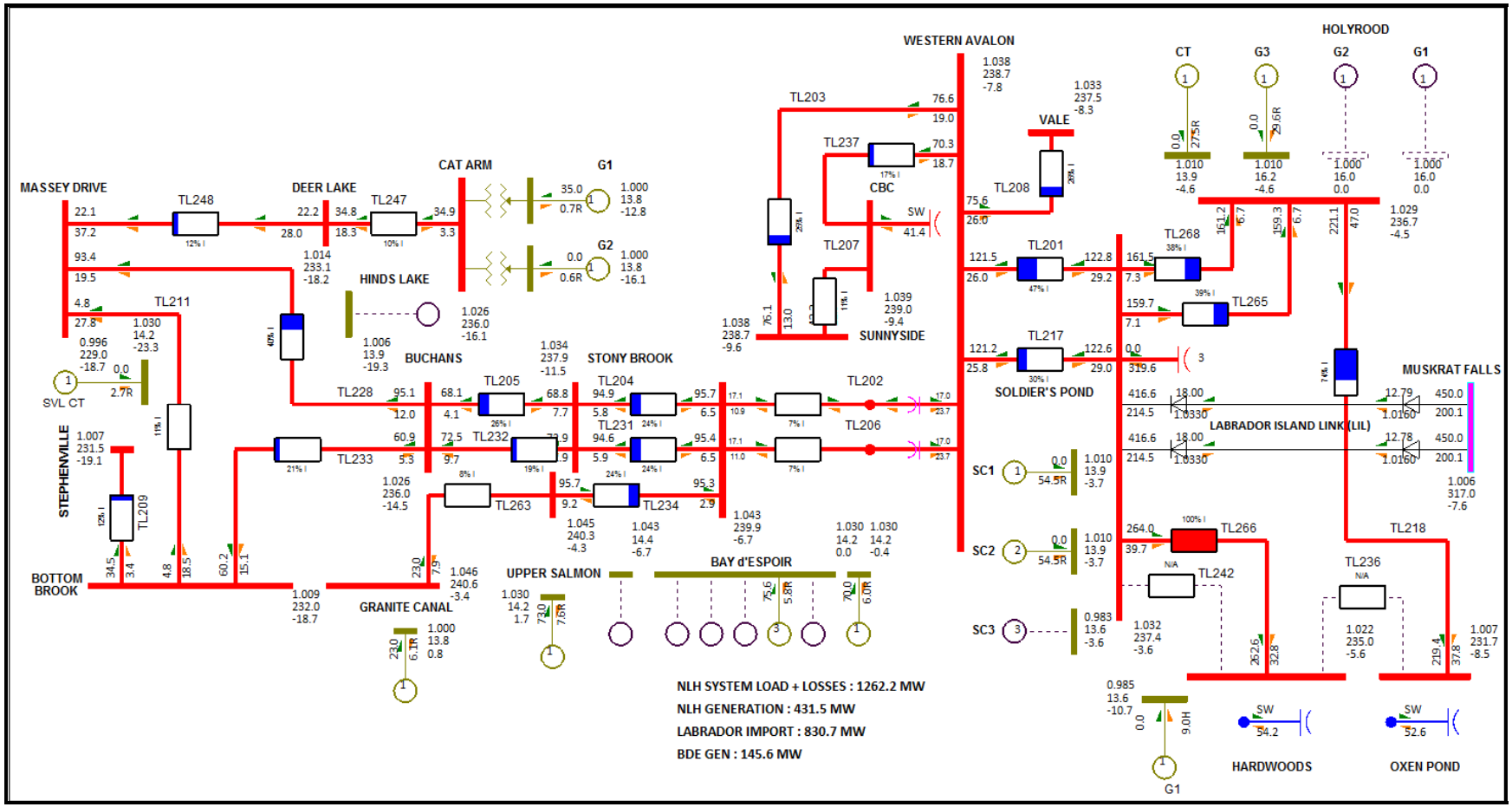


Figure 300 – Base Case 7 (BC7) Load Flow Plot – TL242 Out of Service – TL236 Open

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (431 MW)

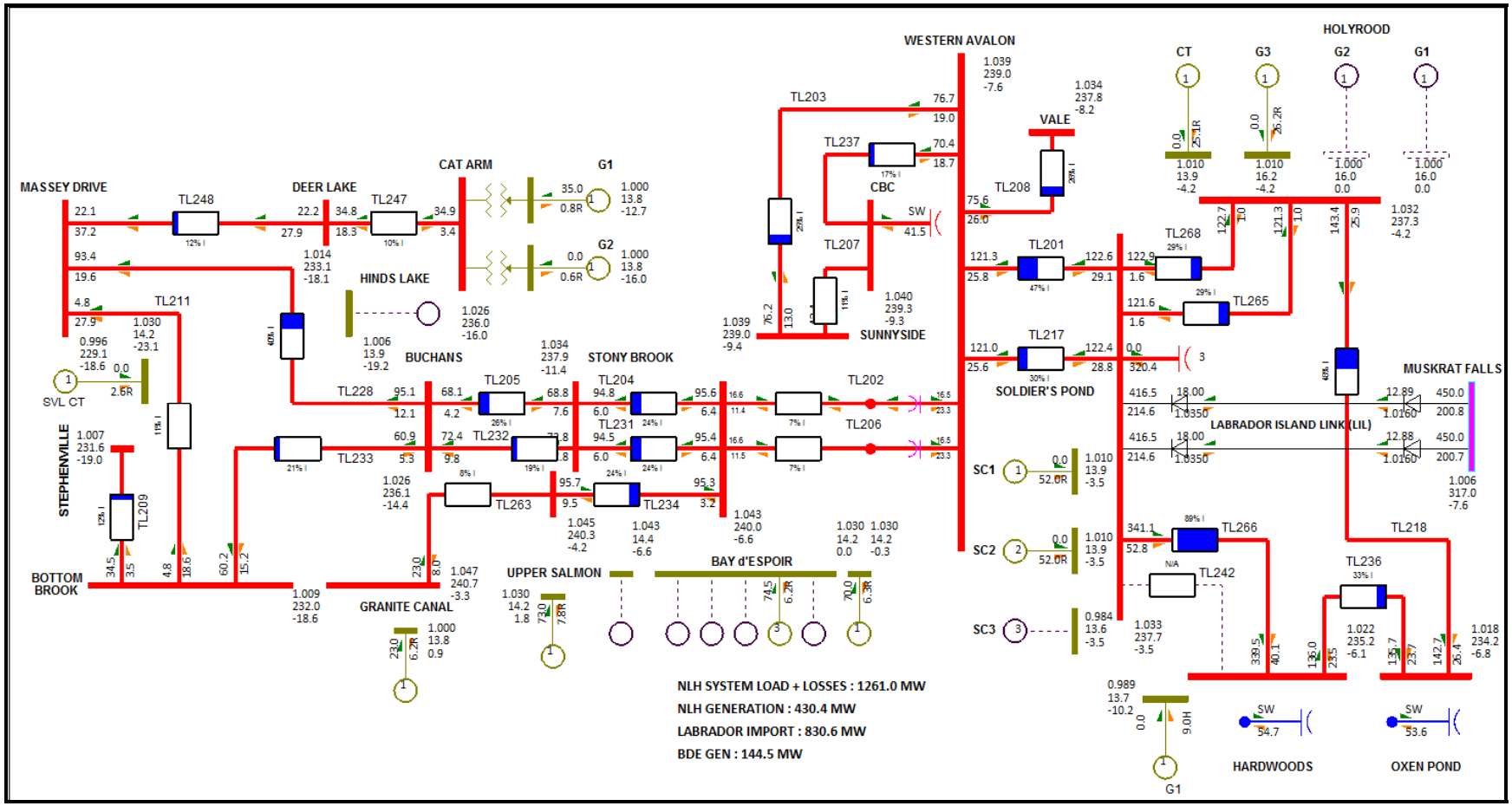


Figure 301 – Base Case 7 (BC7) Load Flow Plot – TL242 Out of Service

TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum LIL Import (830 MW) with Reserve on Island Generation (431 MW)

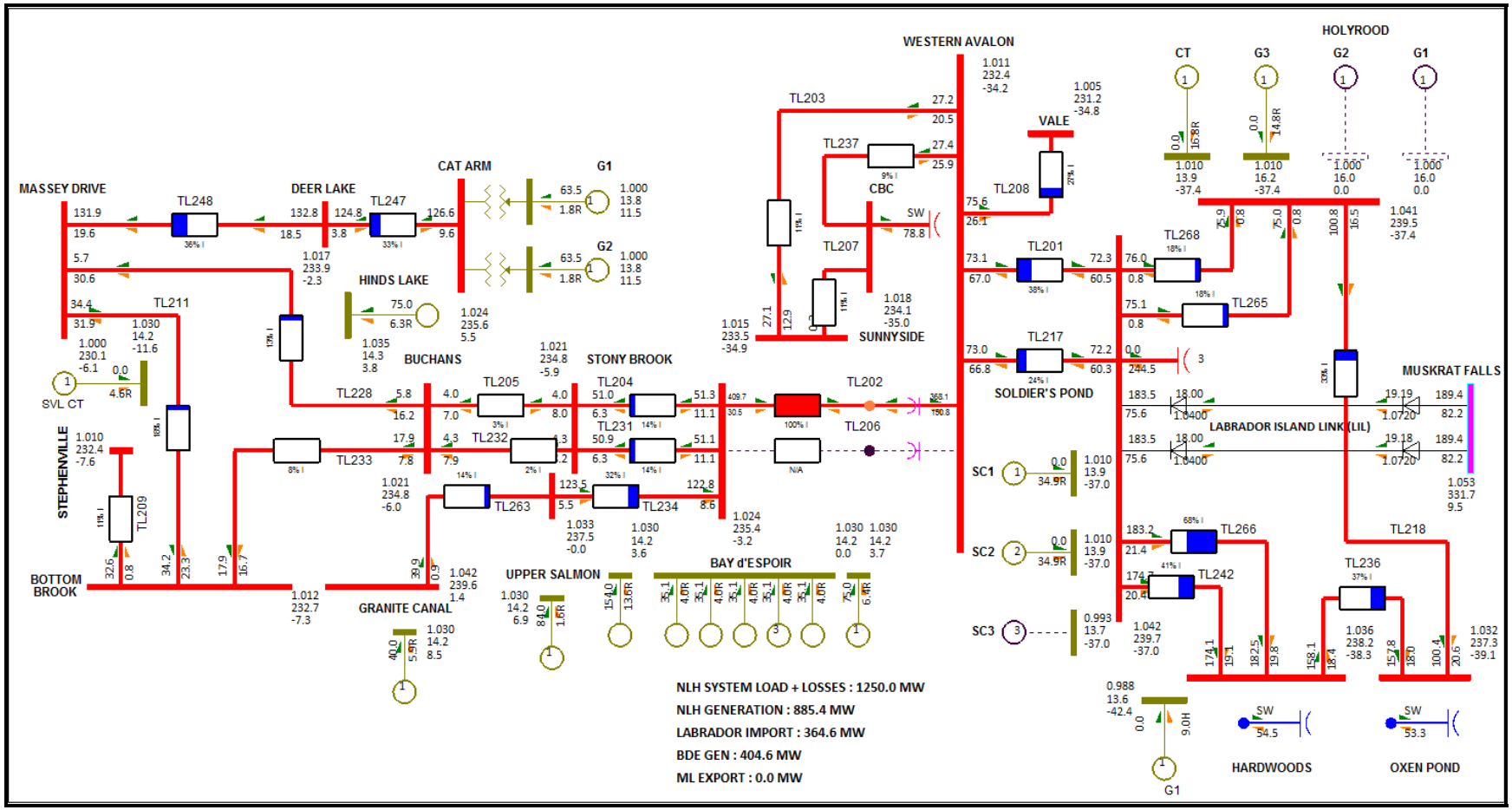


Figure 302 – Base Case 8 (BC8) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 365 MW

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

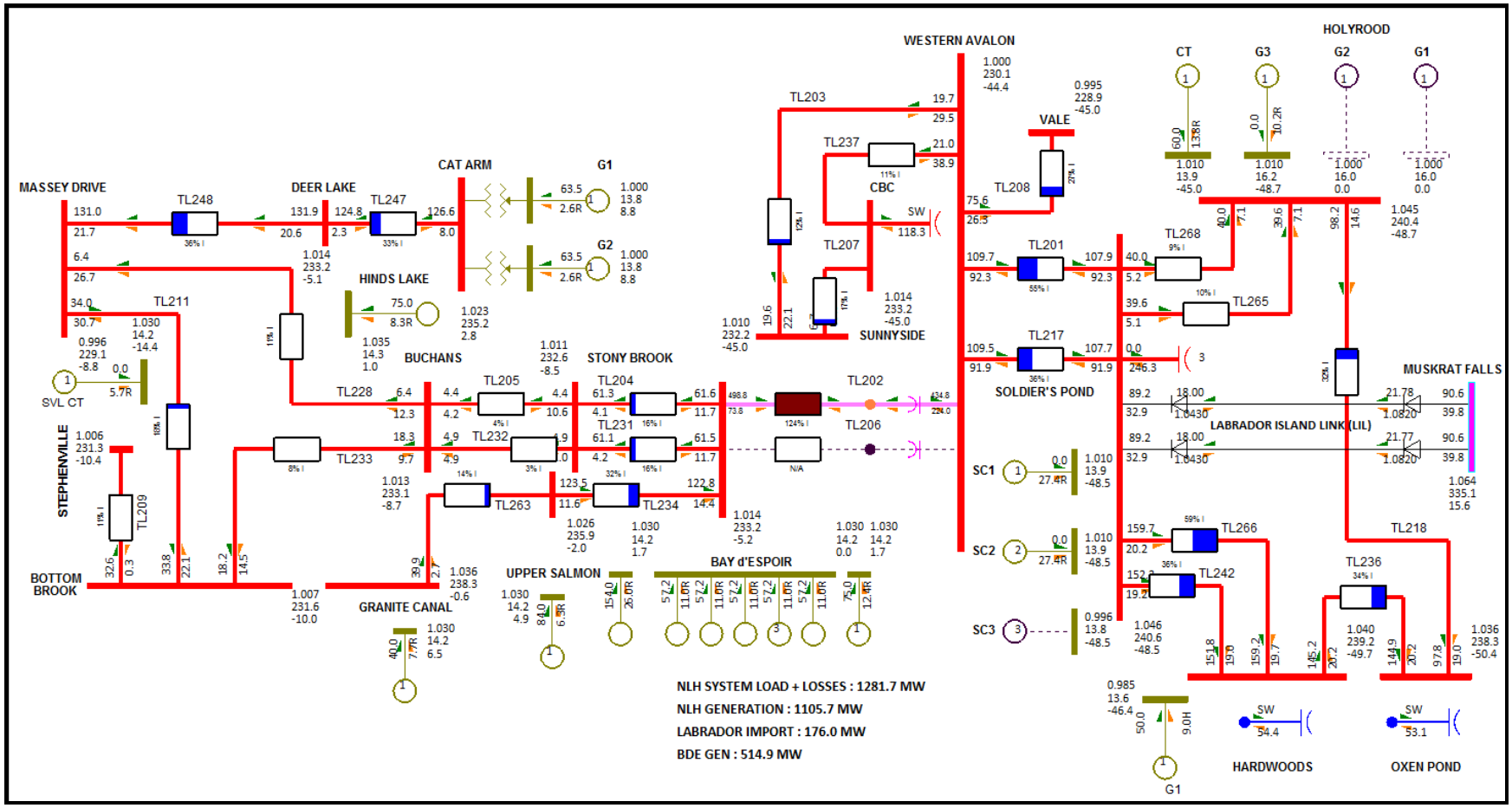


Figure 303 – Base Case 8 (BC8) Load Flow Plot – TL206 Out of Service – HWD CT and HRD CT Generating 110 MW

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

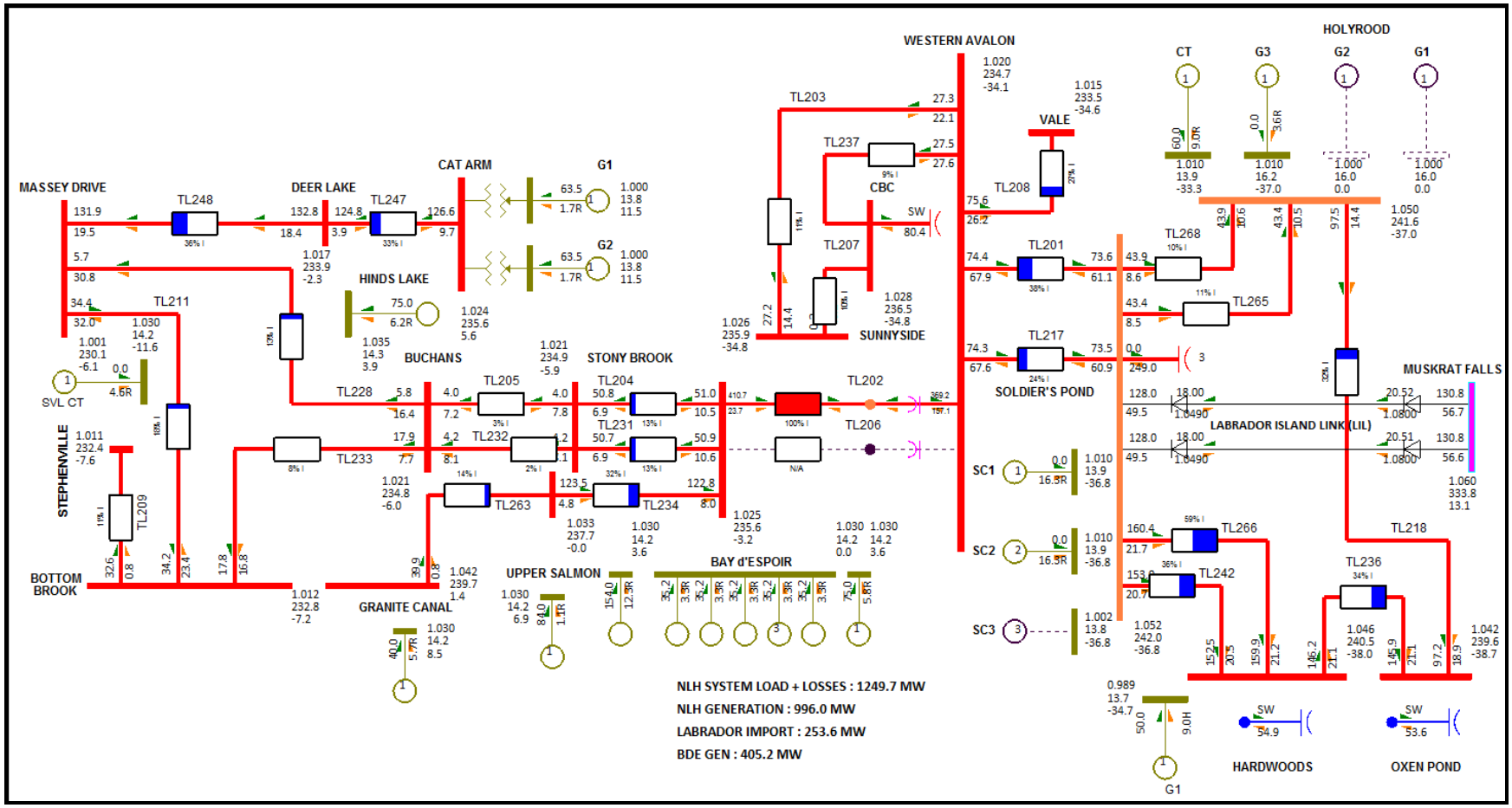


Figure 304 – Base Case 8 (BC8) Load Flow Plot – TL206 Out of Service – HWD CT and HRD CT Generating 110 MW + LIL Import = 254 MW

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

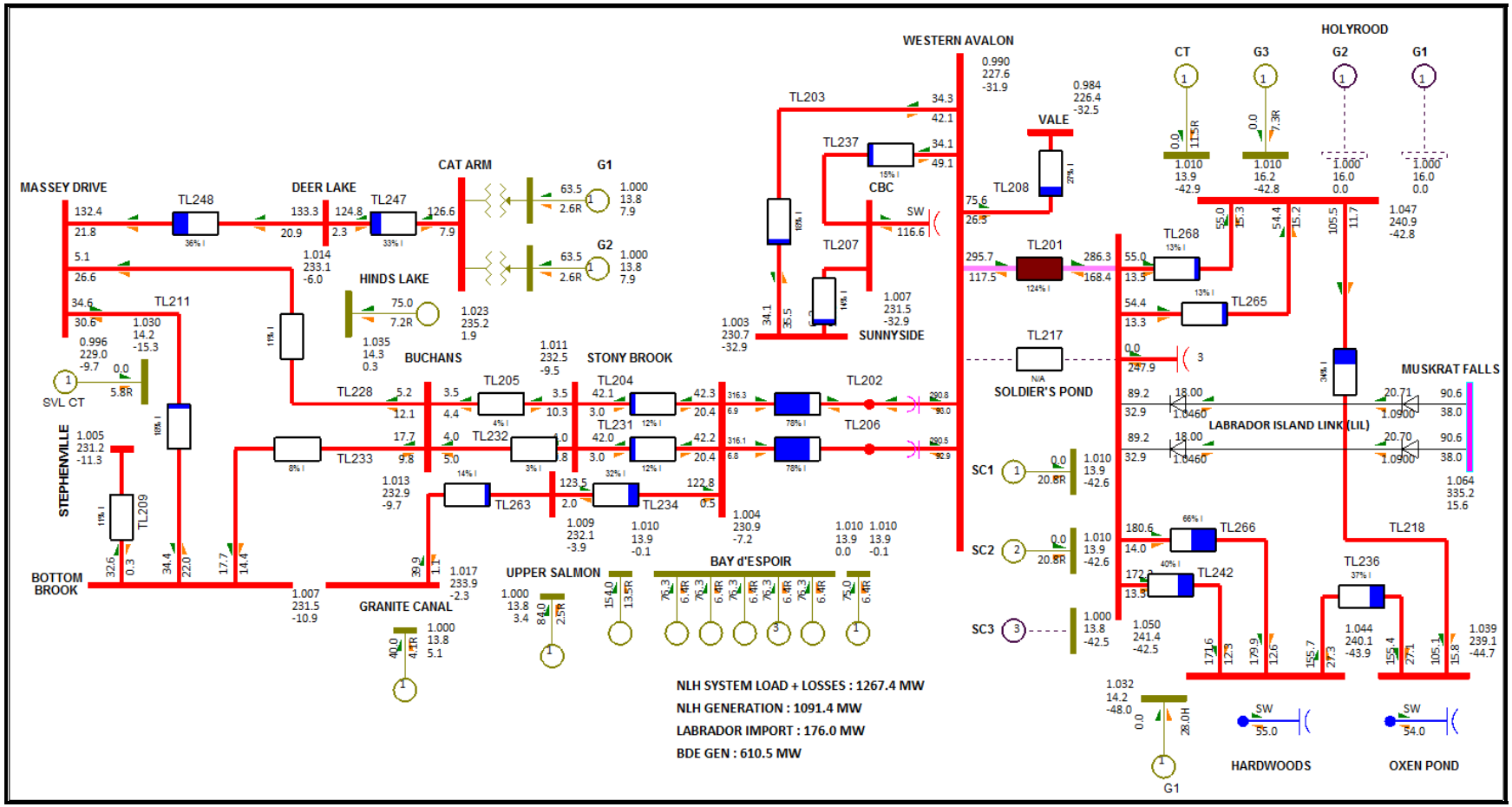


Figure 305 – Base Case 8 (BC8) Load Flow Plot – TL217 Out of Service

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

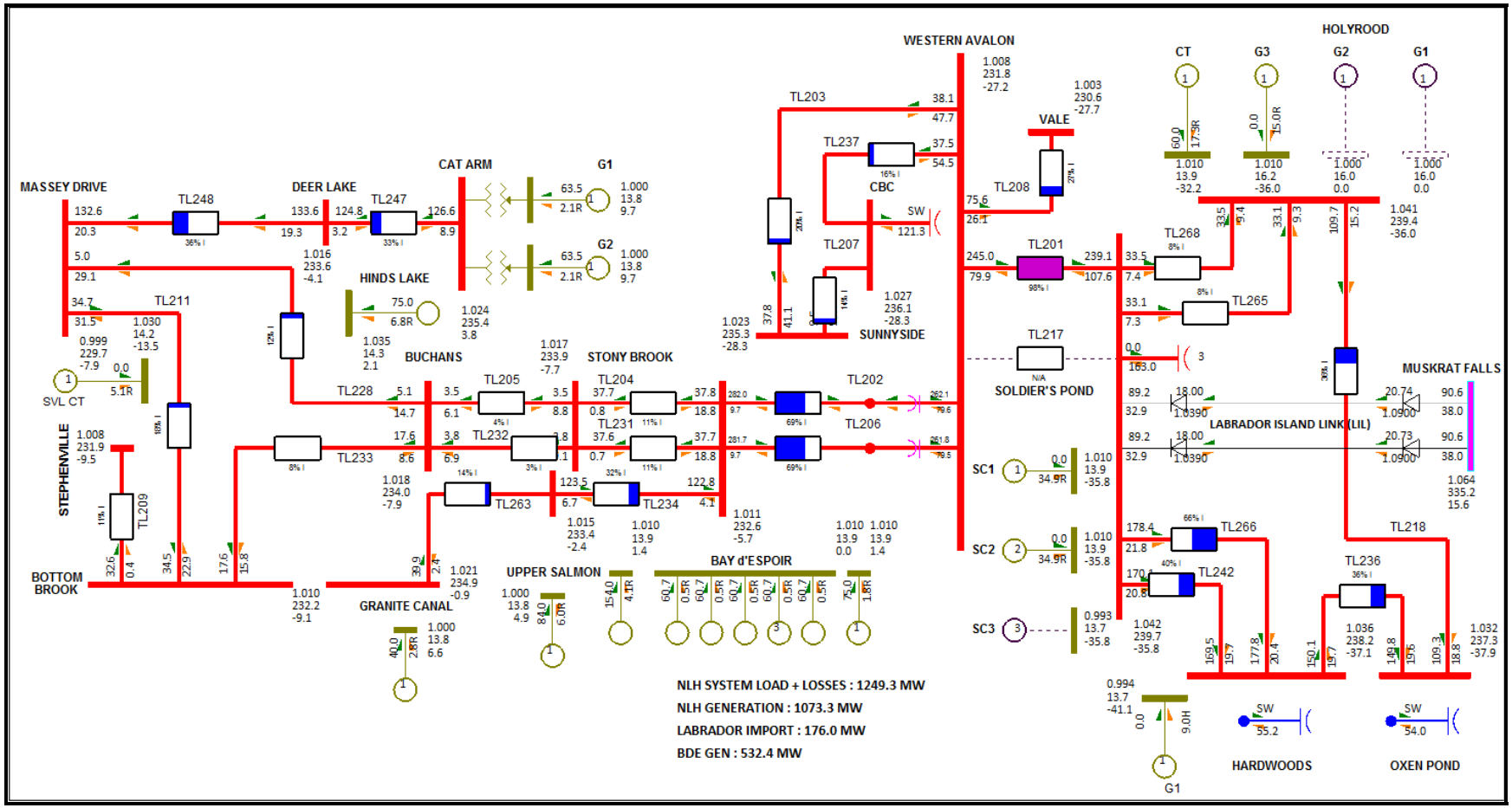


Figure 306 – Base Case 8 (BC8) Load Flow Plot – TL217 Out of Service – HRD CT Generating 60 MW

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

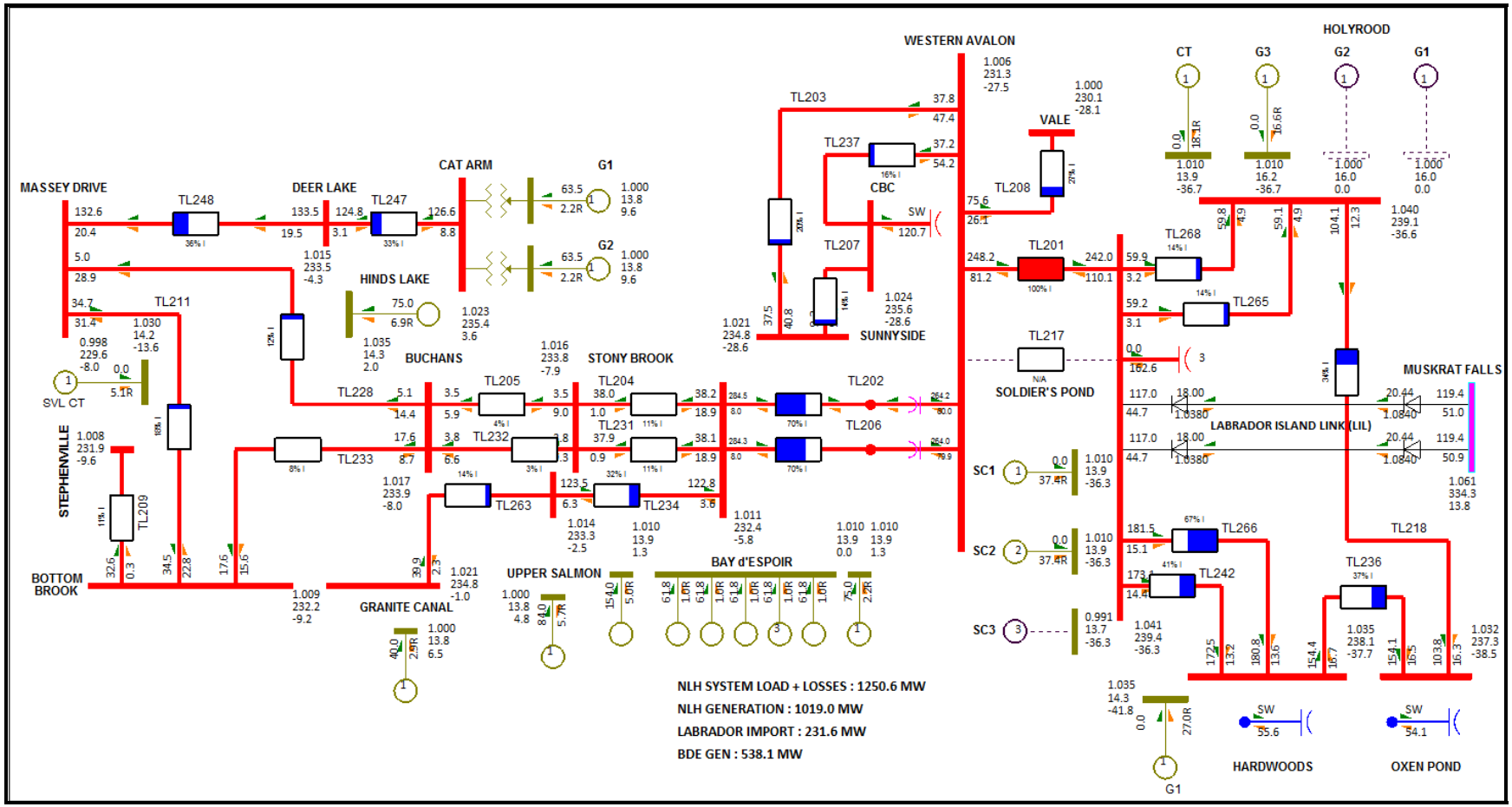


Figure 307 – Base Case 8 (BC8) Load Flow Plot – TL217 Out of Service – LIL Import Increased to 232 MW

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

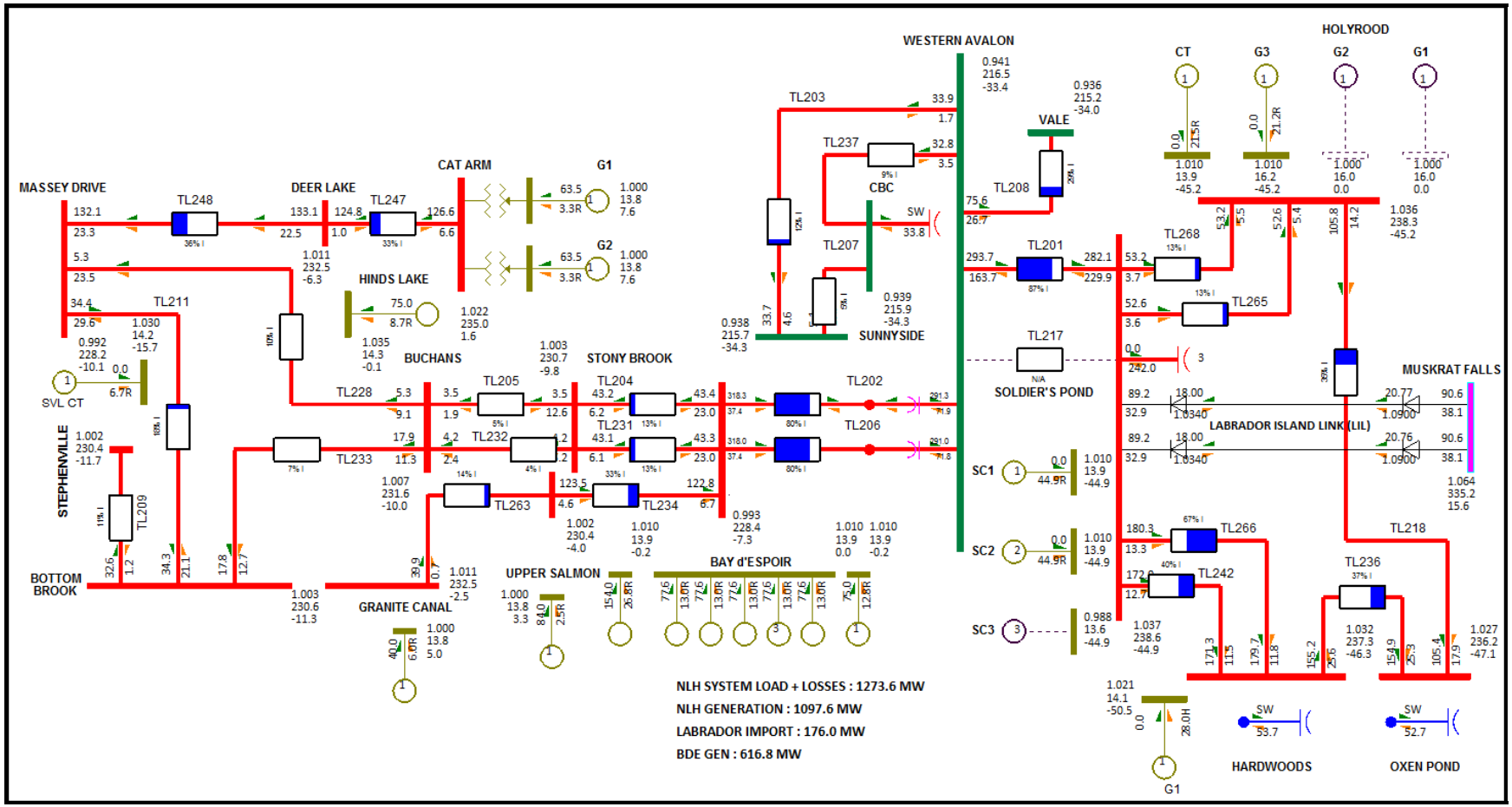


Figure 308 – Base Case 8 (BC8) Load Flow Plot – TL217 Out of Service – TL201 Rebuilt with 804 kcmil AACSR/TW Conductor

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

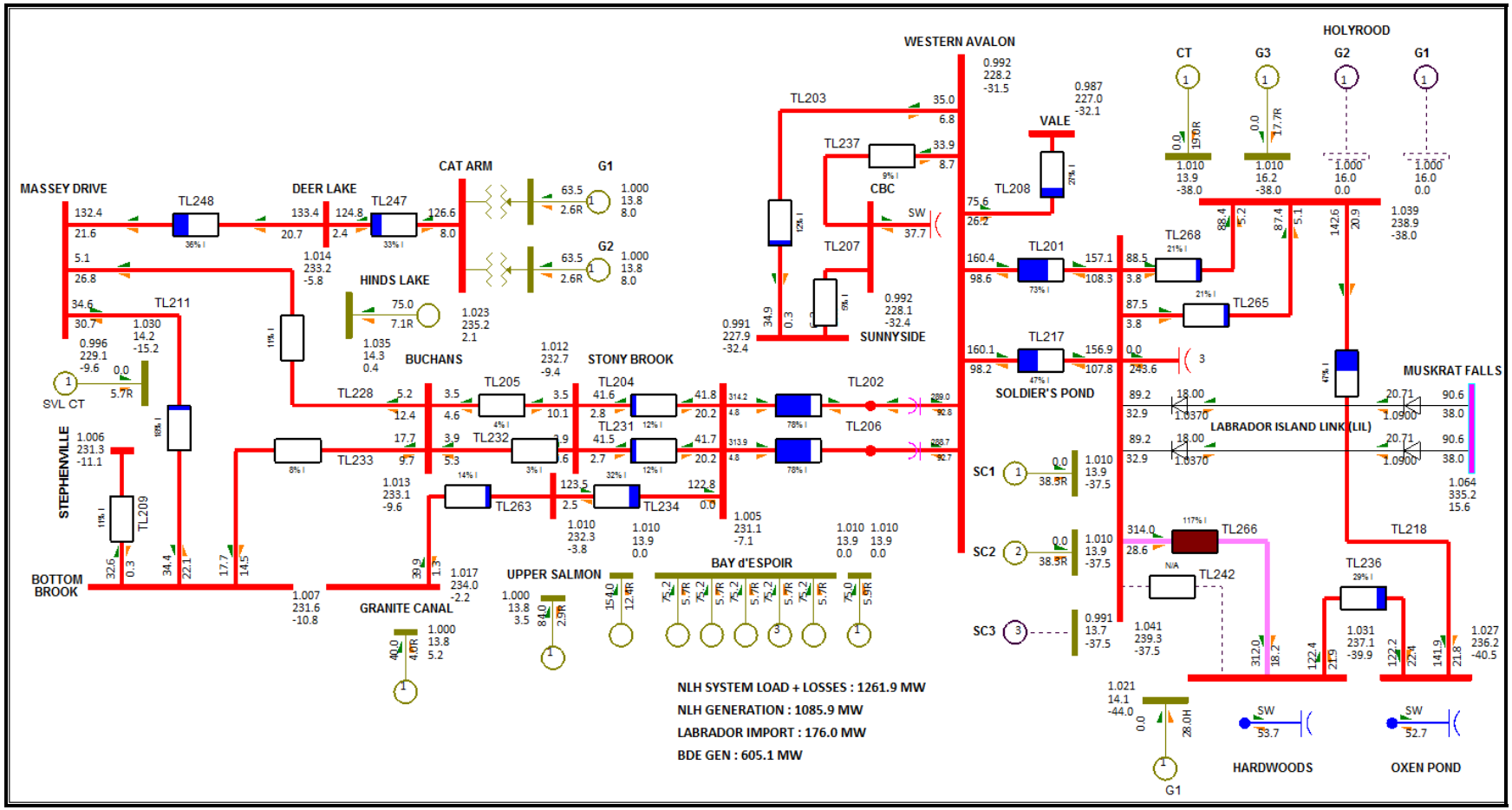


Figure 309 – Base Case 8 (BC8) Load Flow Plot – TL242 Out of Service

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

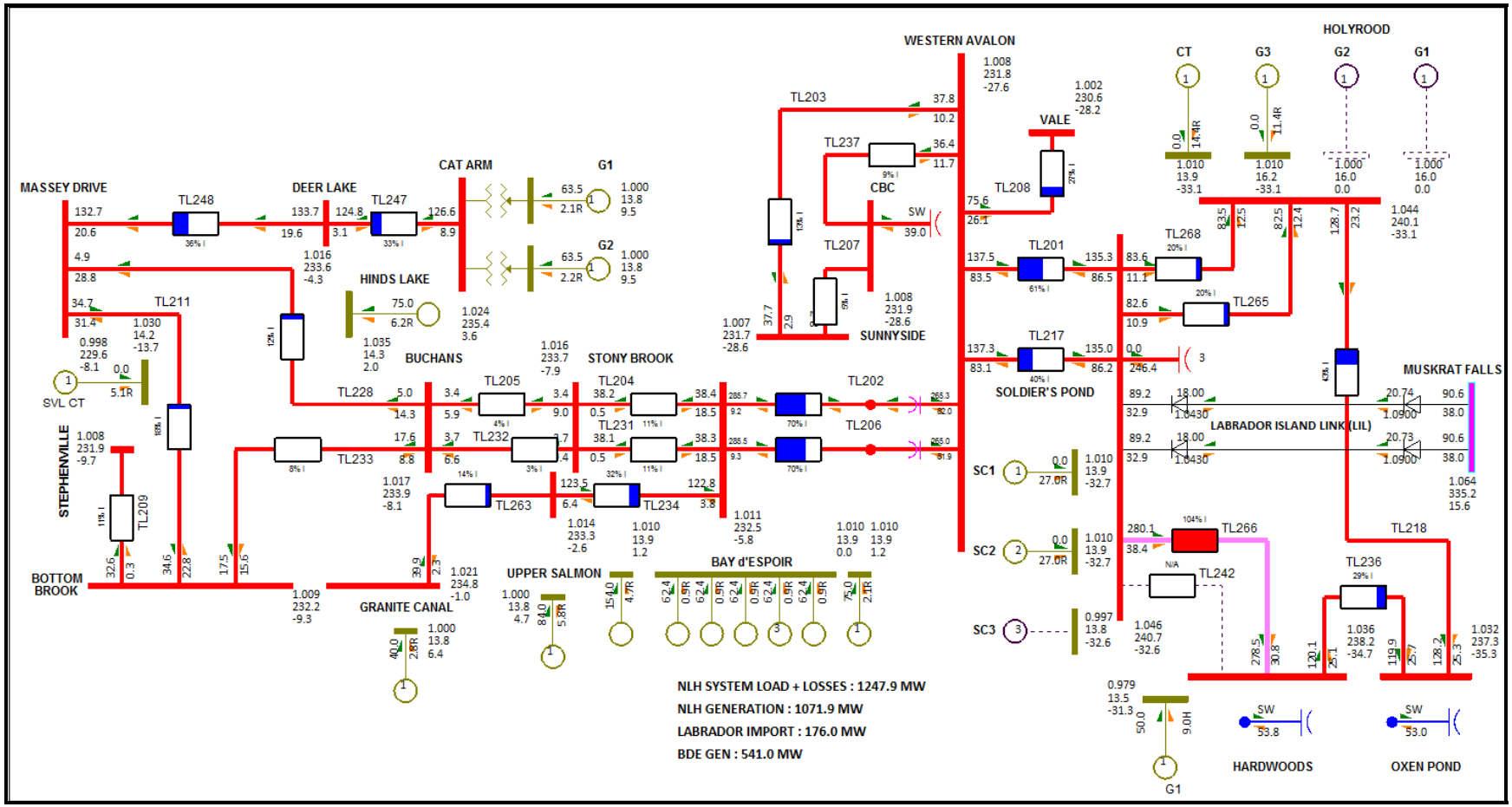


Figure 310 – Base Case 8 (BC8) Load Flow Plot – TL242 Out of Service – HWD CT Generating 50 MW

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

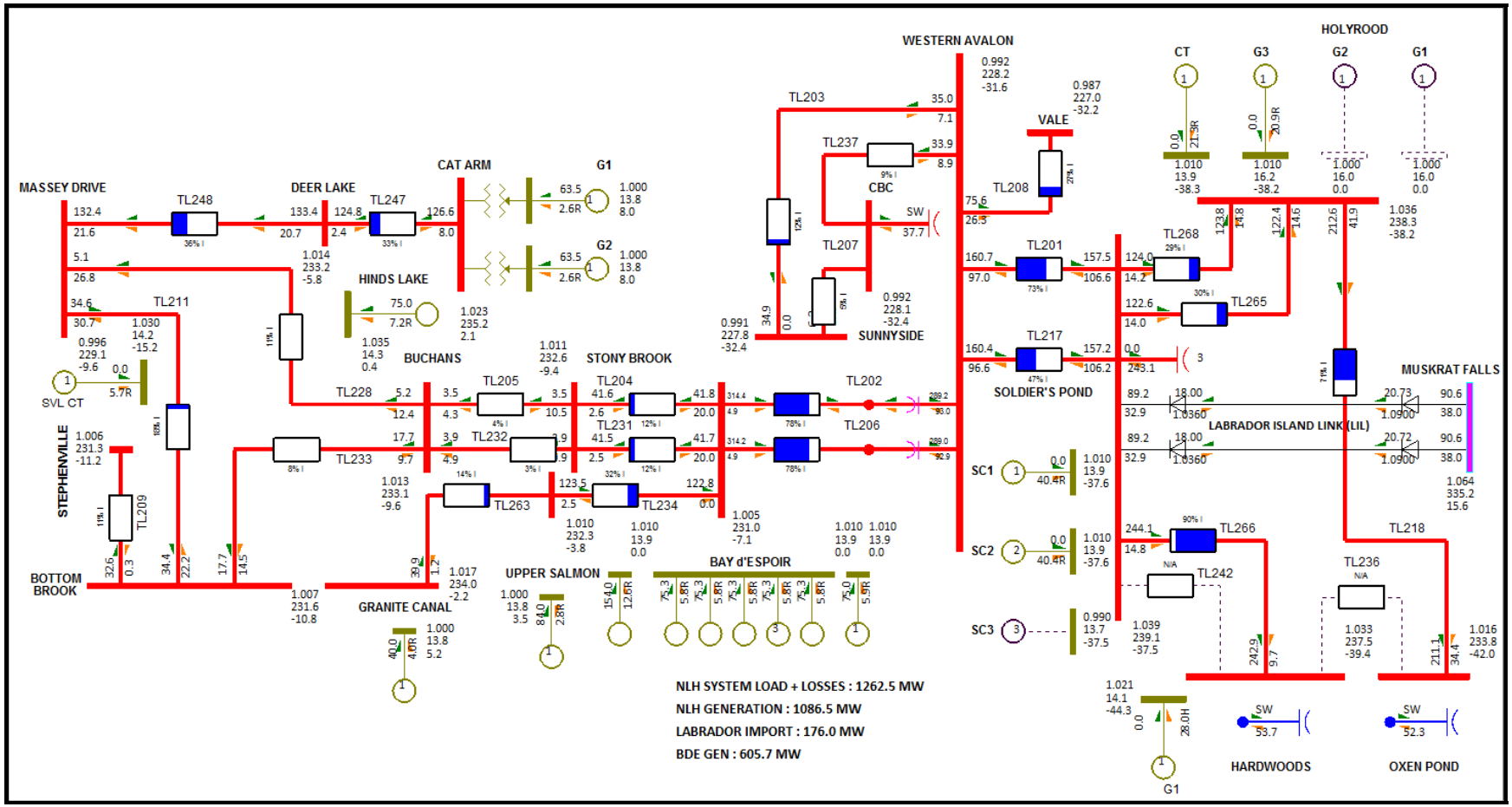


Figure 311 – Base Case 8 (BC8) Load Flow Plot – TL242 Out of Service – TL236 Open

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

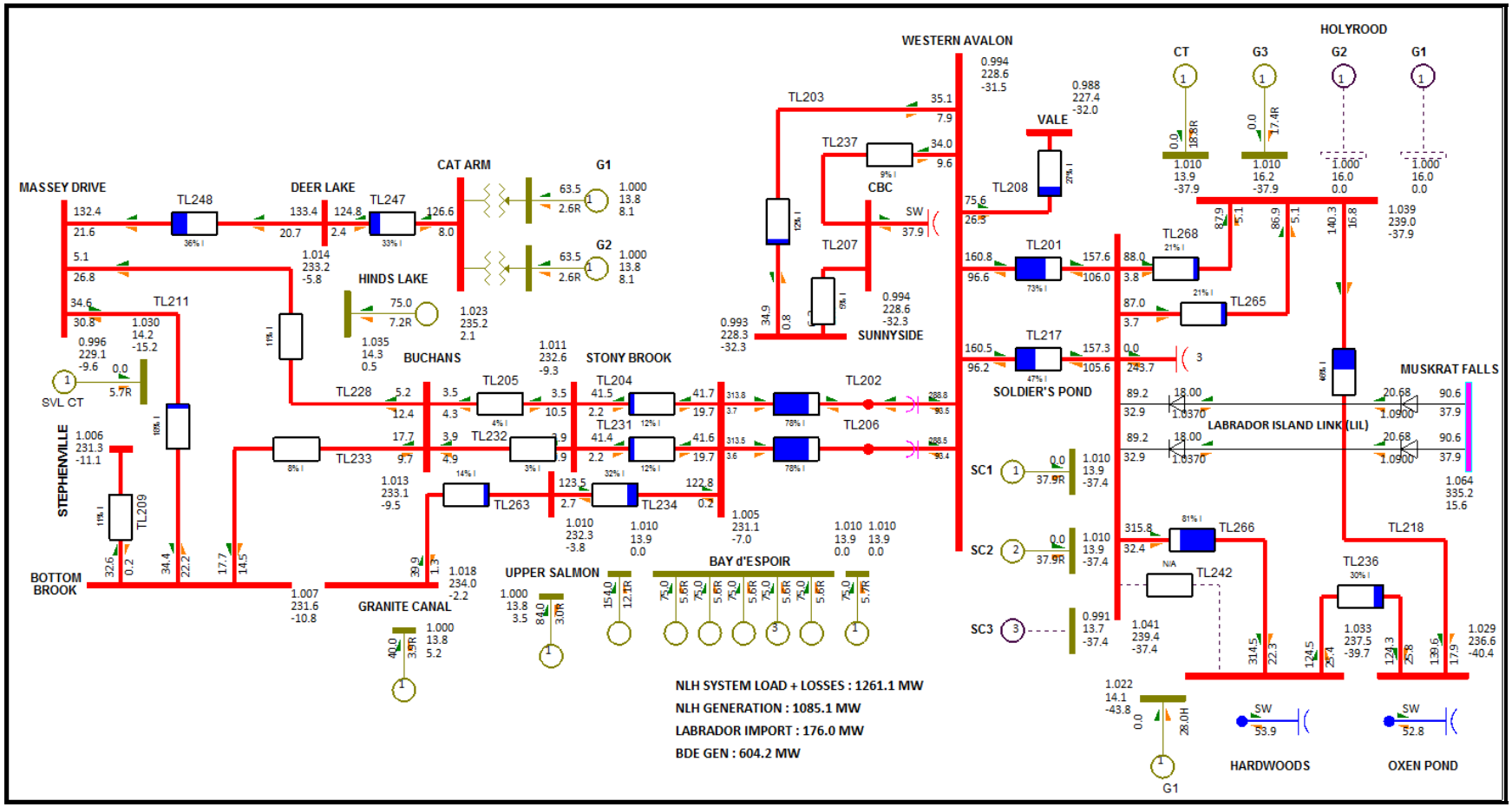


Figure 312 – Base Case 8 (BC8) Load Flow Plot – TL242 Out of Service

TL266 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 Rerouted from SSD to WAV with 25% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

Alternative 6

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

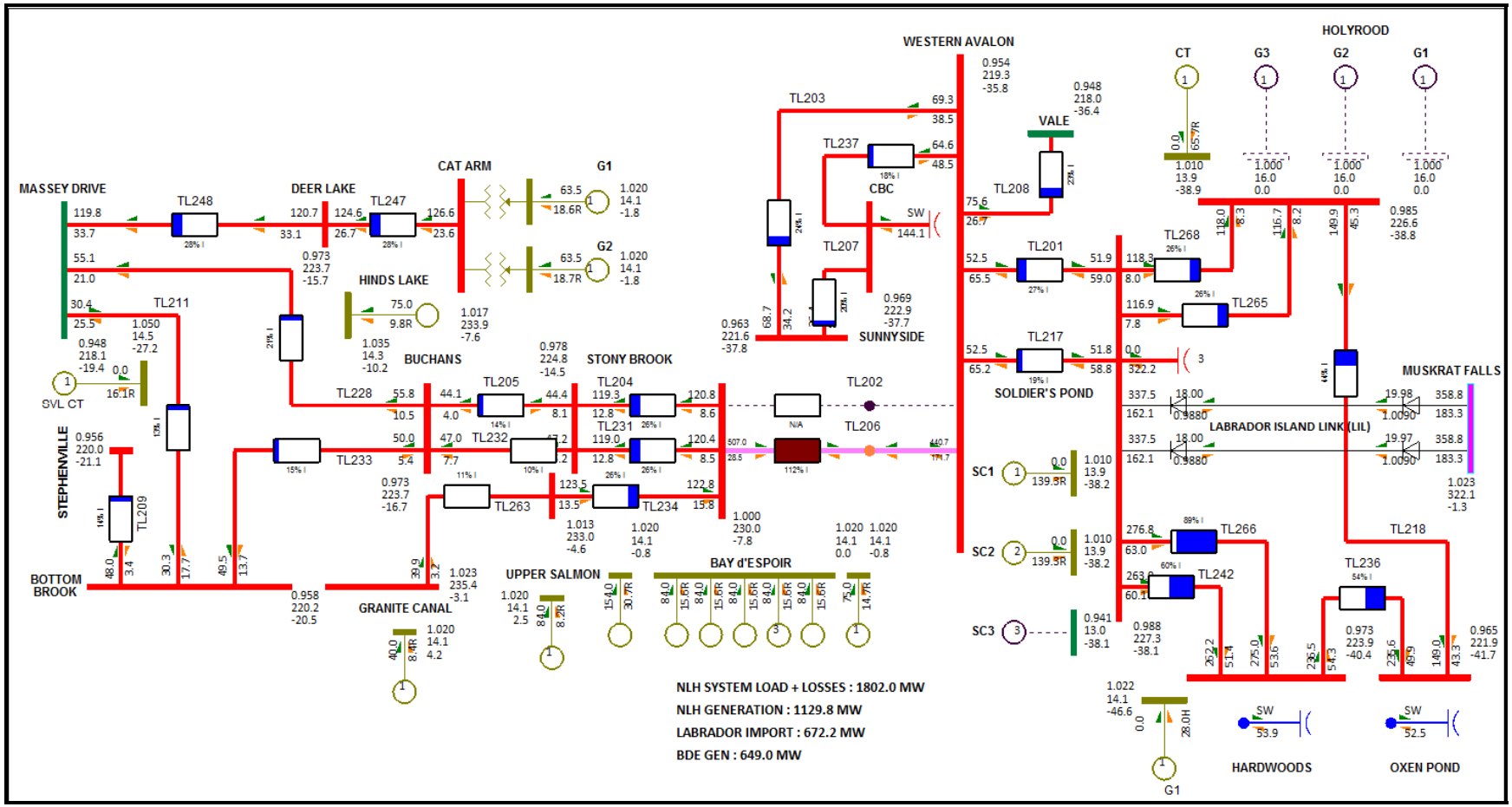


Figure 313 – Base Case 1 (BC1) Load Flow Plot – TL202 Out of Service

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

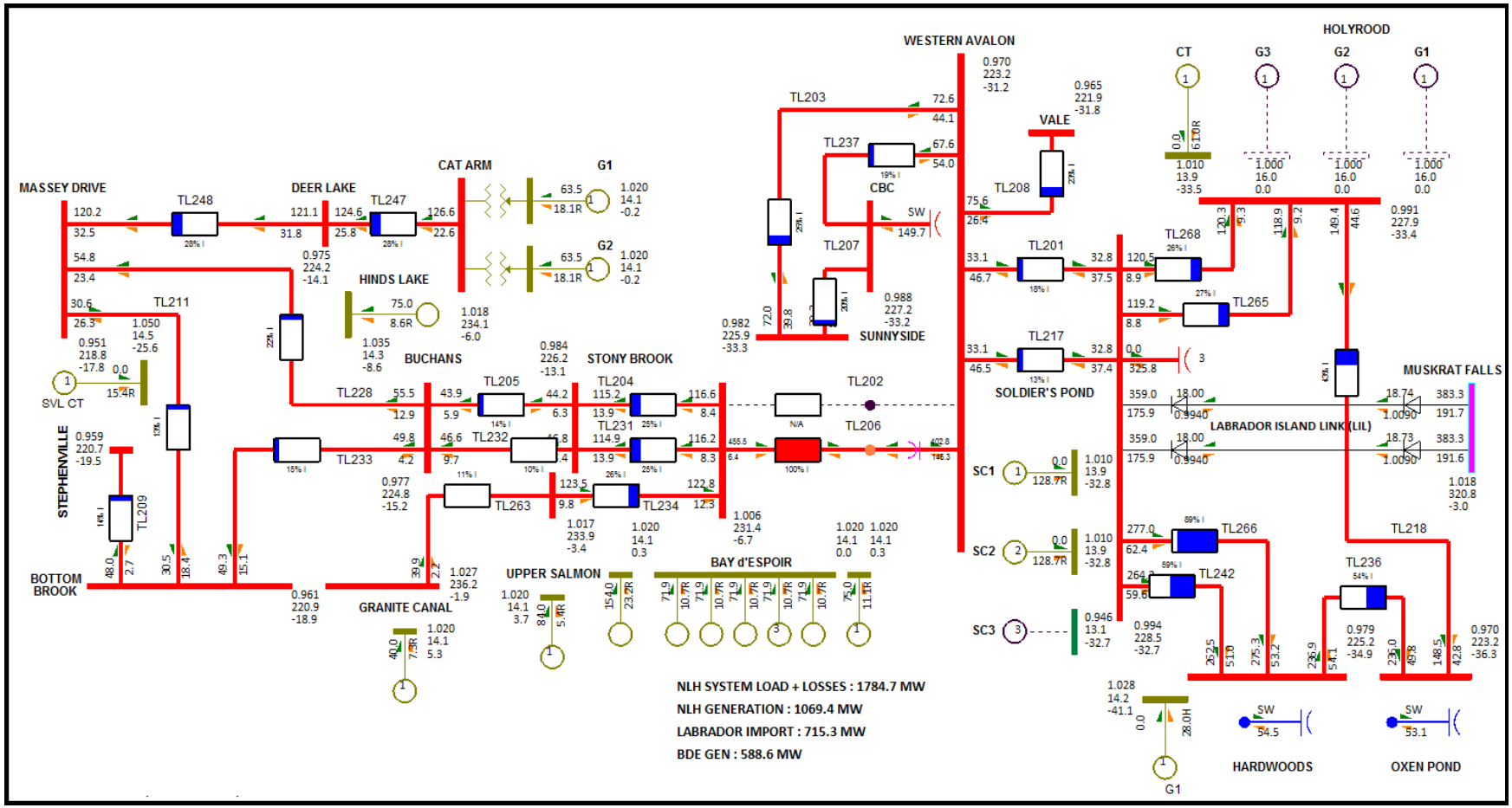


Figure 314 – Base Case 1 (BC1) Load Flow Plot – TL202 Out of Service – LIL Import Increased to 715 MW

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

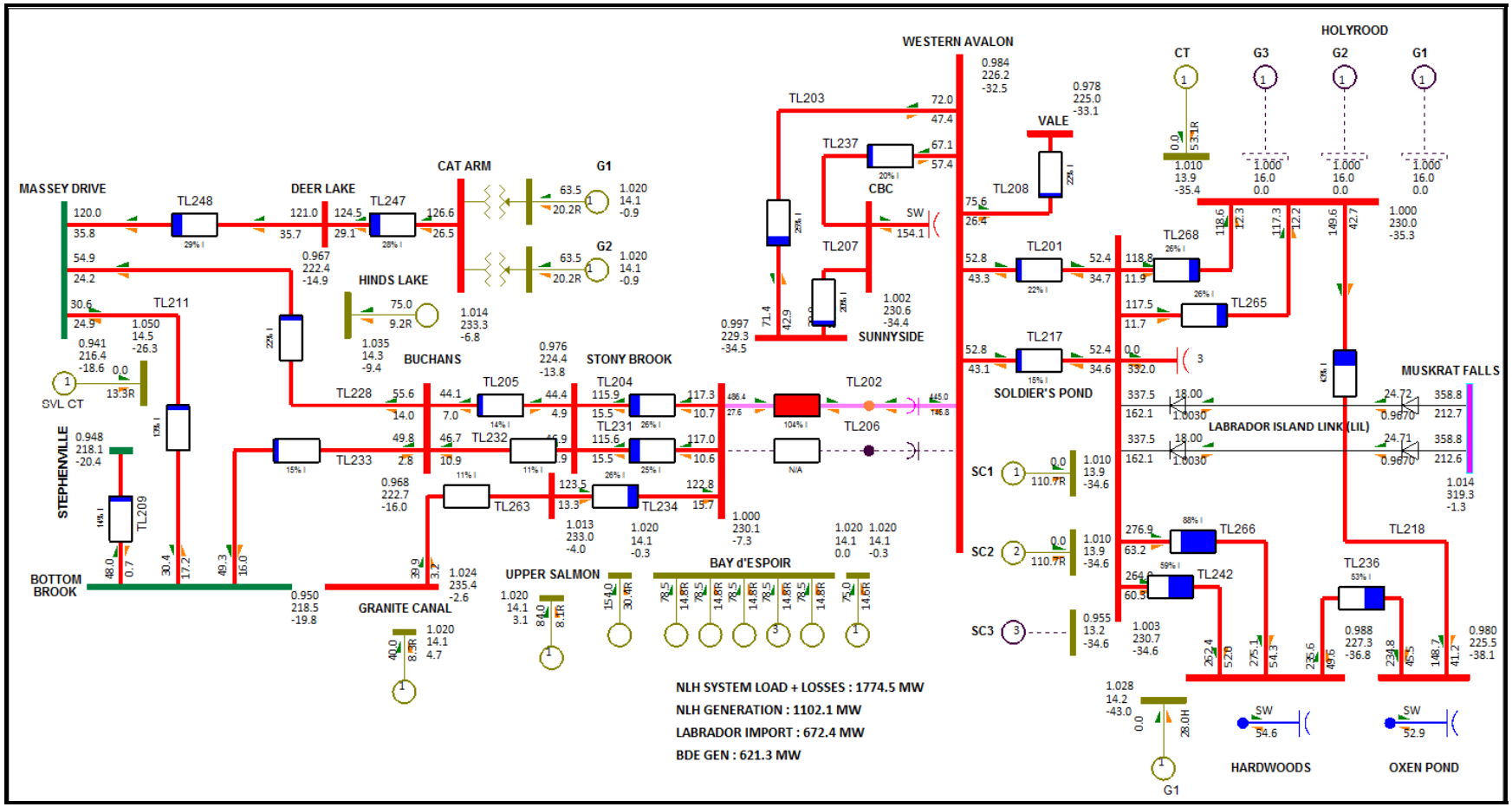


Figure 315 – Base Case 1 (BC1) Load Flow Plot – TL206 Out of Service

TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

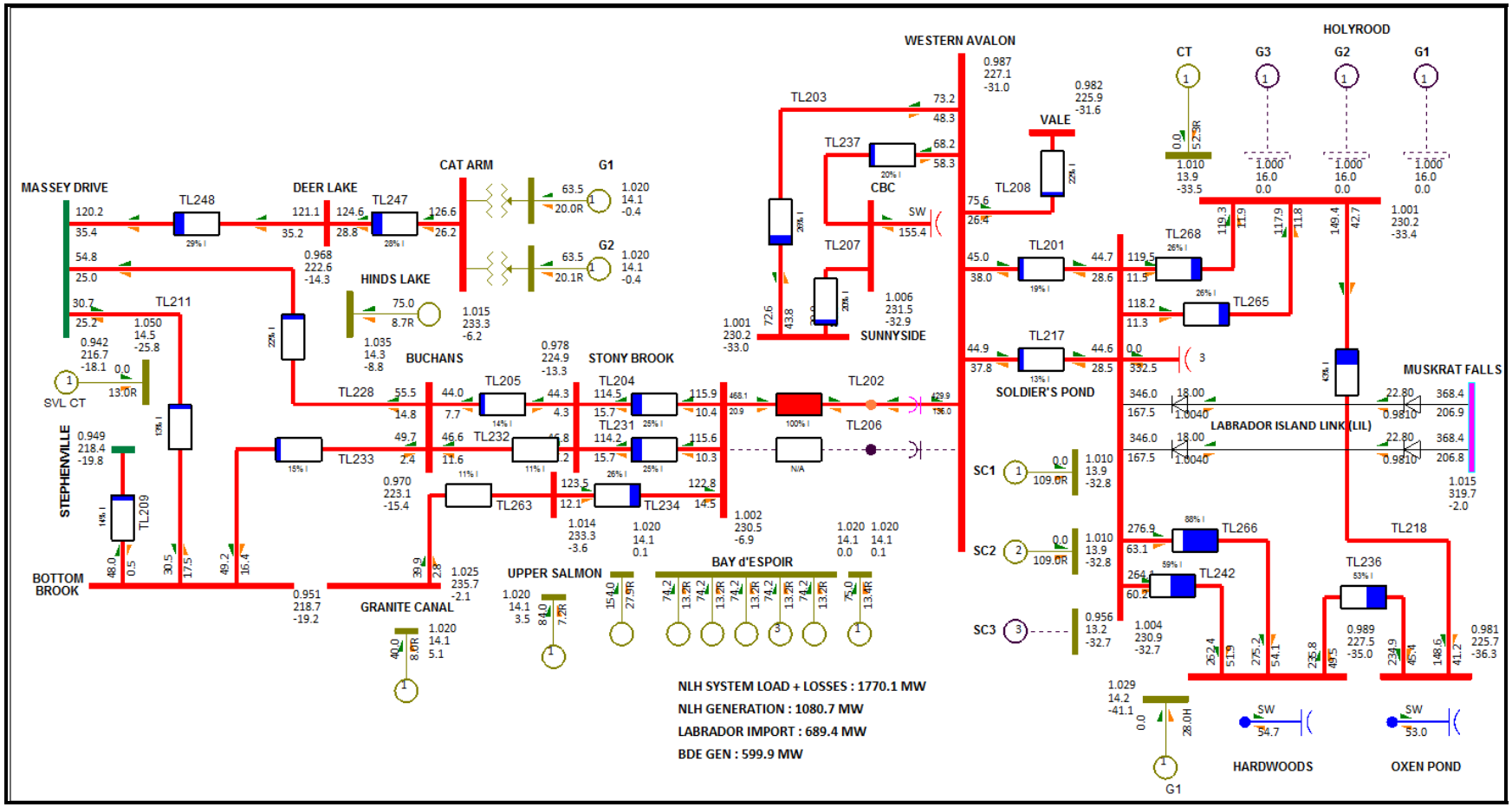


Figure 316 – Base Case 1 (BC1) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 689 MW

TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

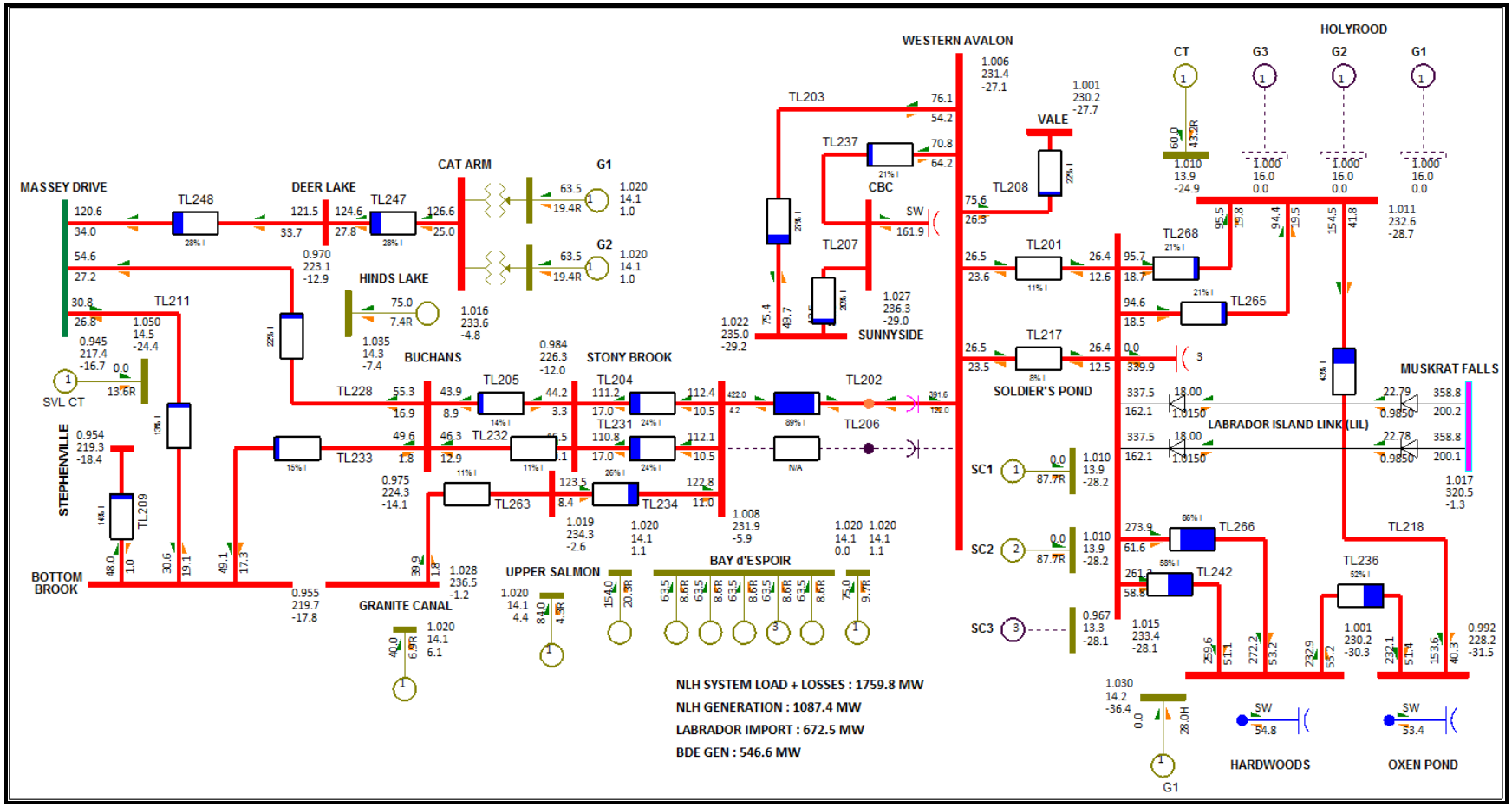


Figure 317 – Base Case 1 (BC1) Load Flow Plot – TL206 Out of Service – HRD CT Generating 60 MW

TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

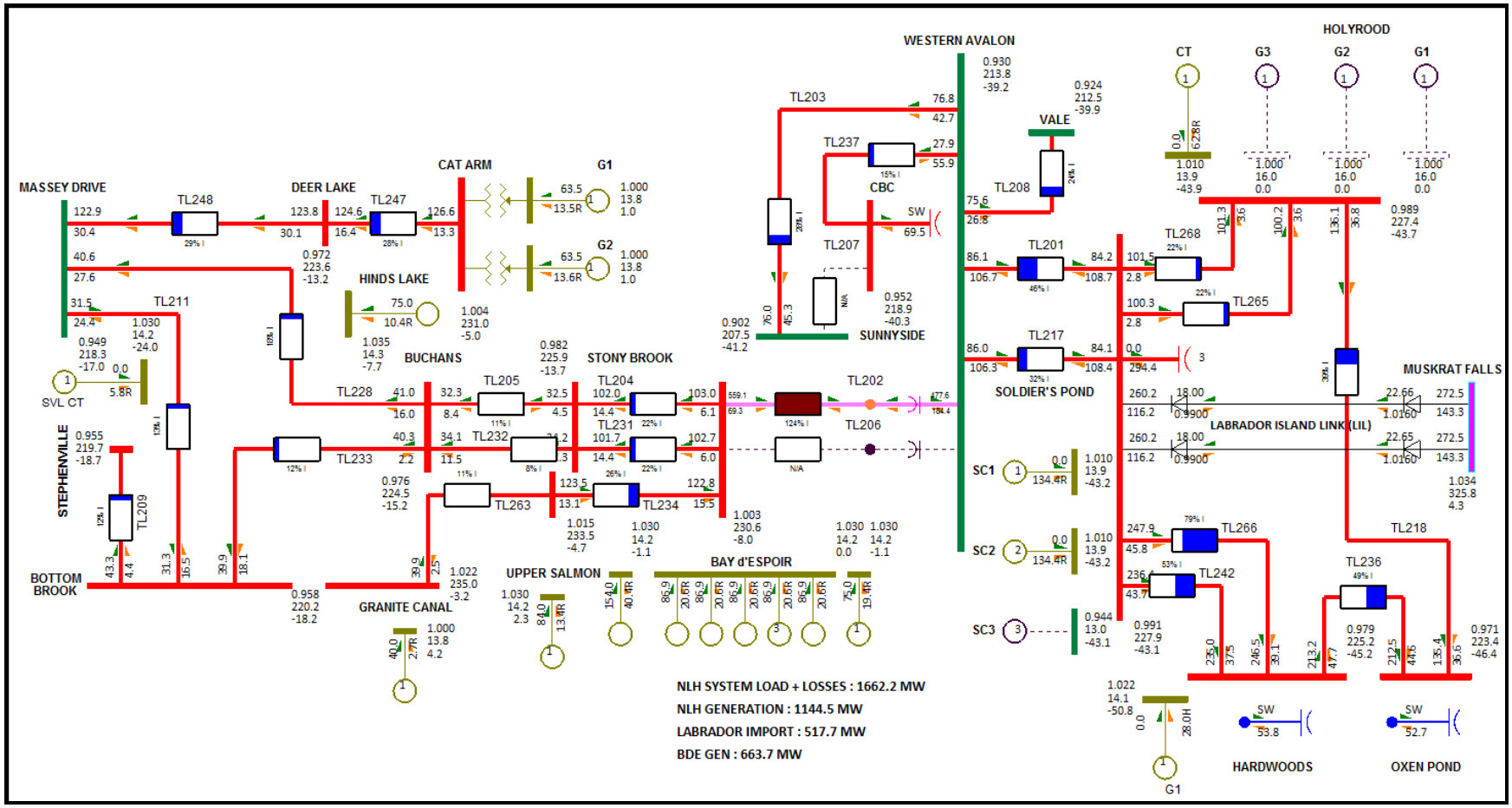


Figure 318 – Base Case 3 (BC3) Load Flow Plot – TL206 Out of Service

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

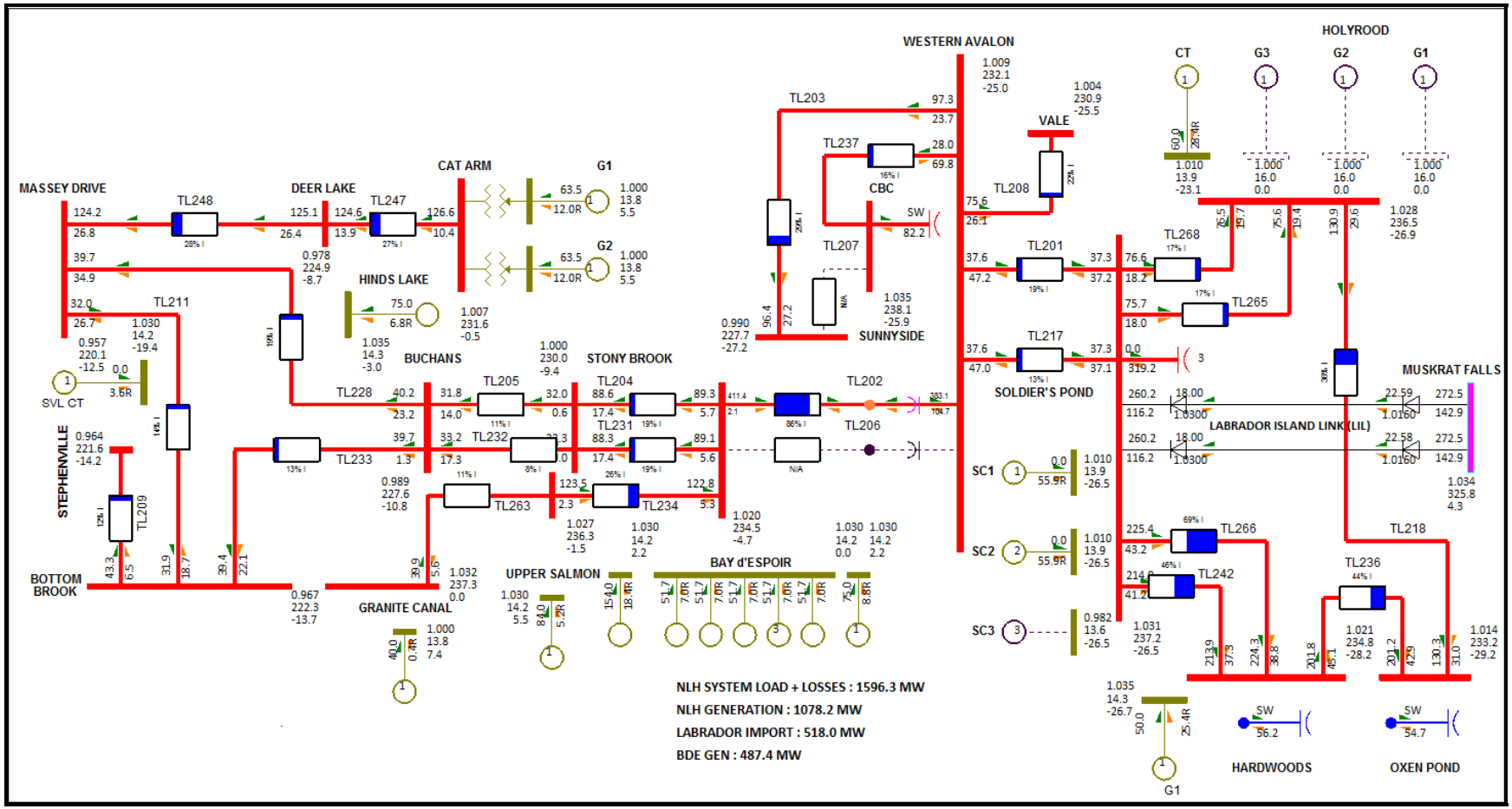


Figure 319 – Base Case 3 (BC3) Load Flow Plot – TL206 Out of Service – HWD CT and HRD CT Generating 110 MW

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

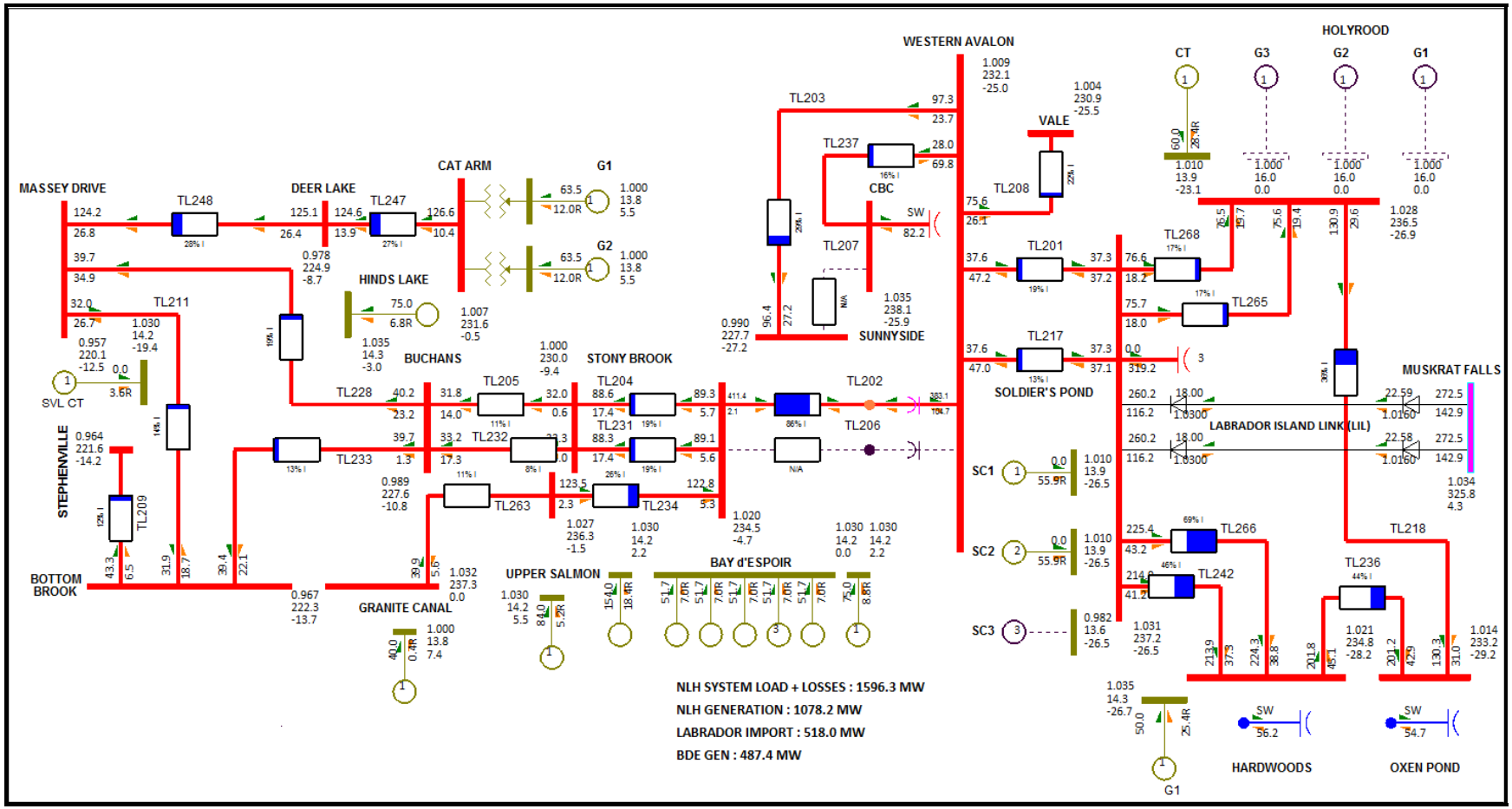


Figure 320 – Base Case 3 (BC3) Load Flow Plot – TL206 Out of Service – HWD CT and HRD CT Generating 110 MW

TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

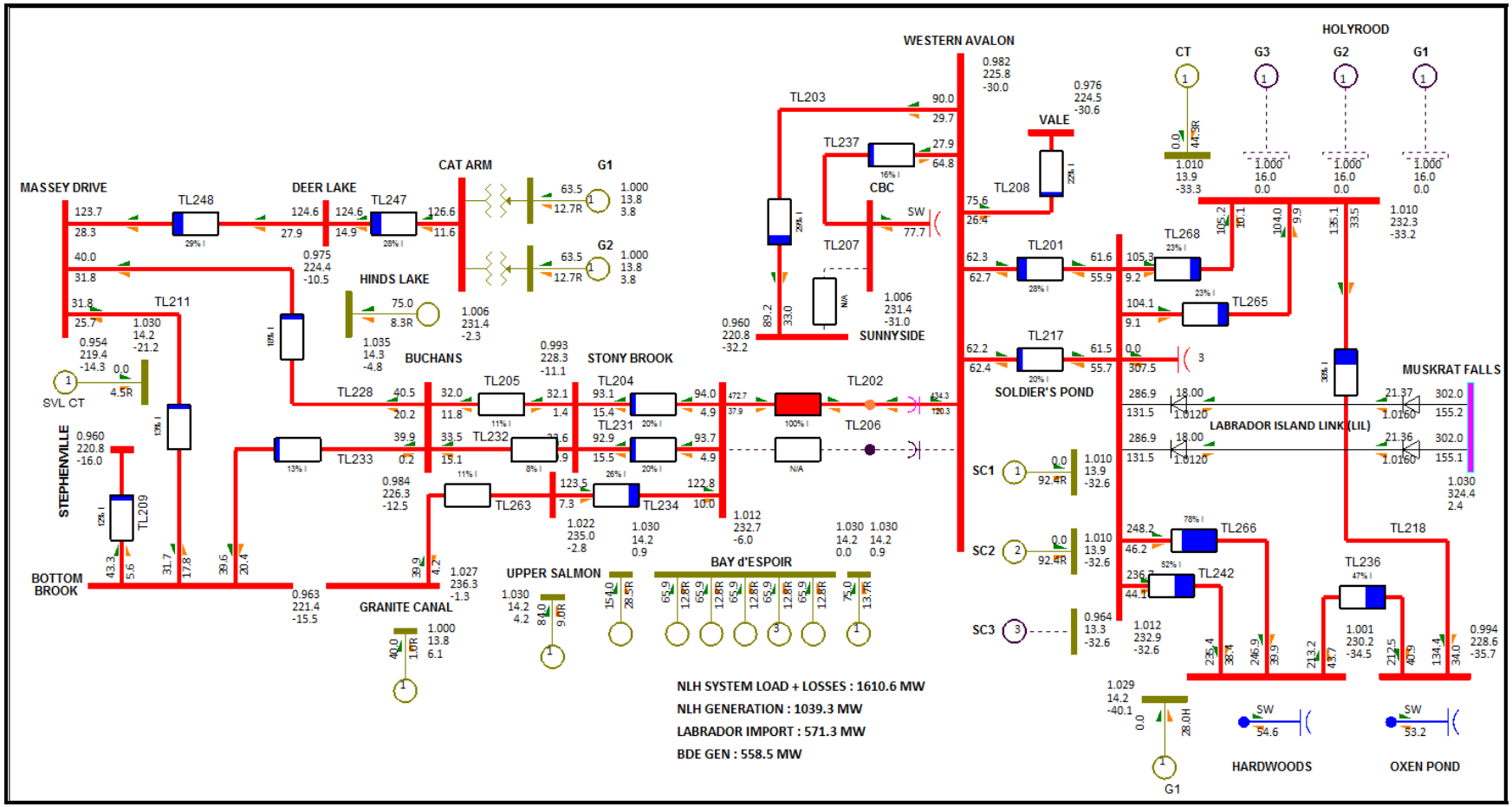


Figure 321 – Base Case 3 (BC3) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 571 MW

TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

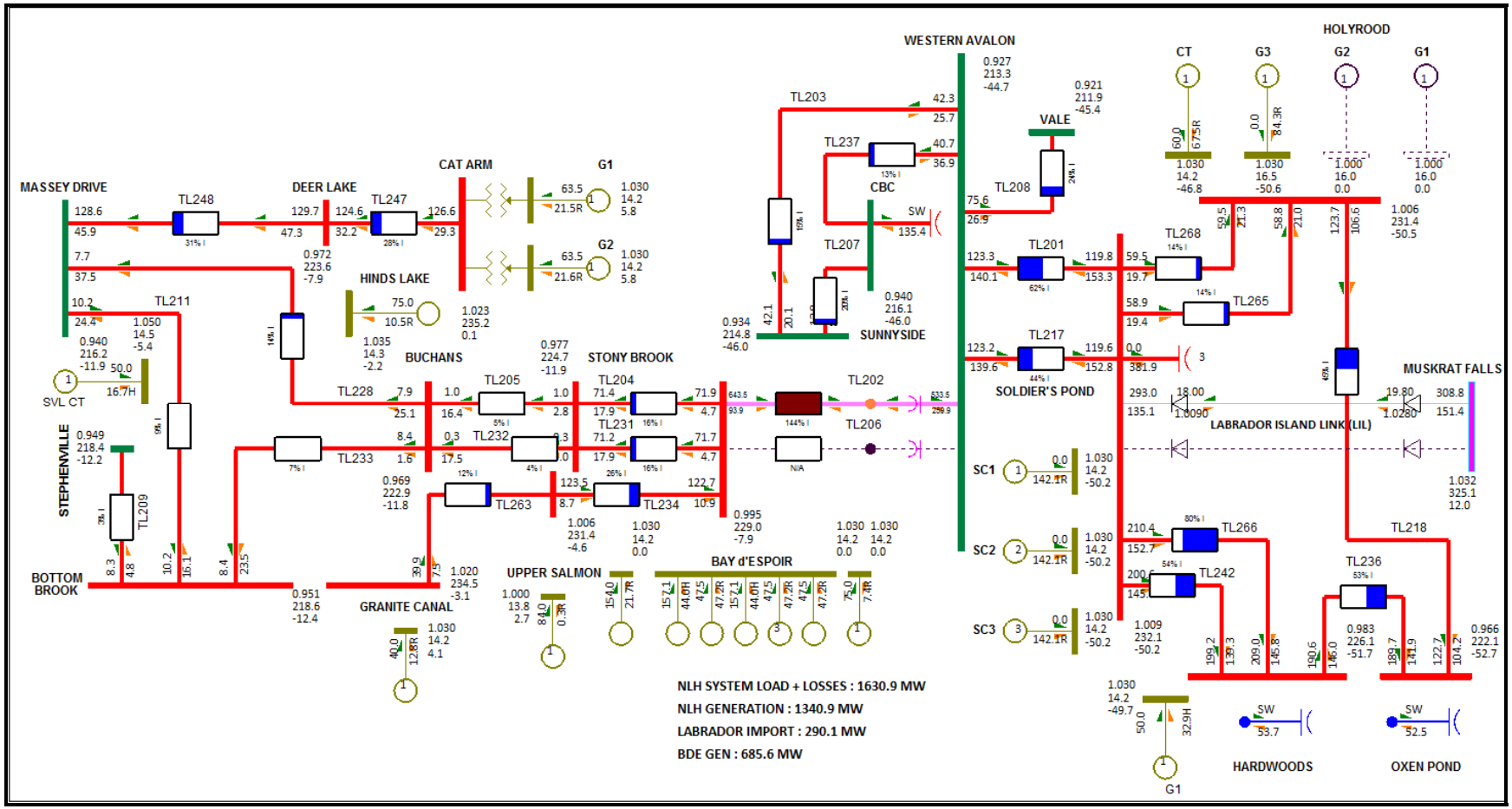


Figure 322 – Base Case 4 (BC4) Load Flow Plot – TL206 Out of Service

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

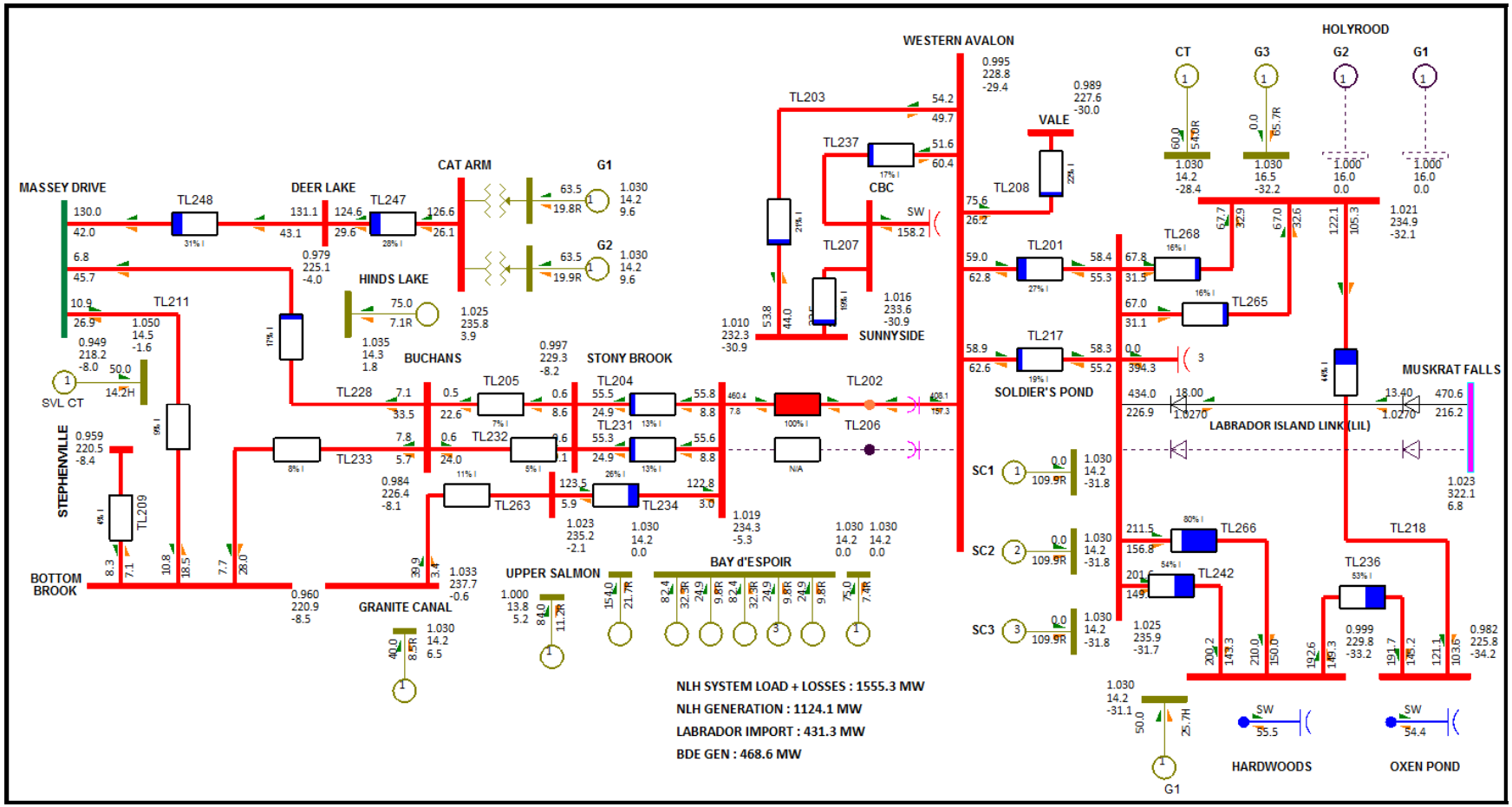


Figure 323 – Base Case 4 (BC4) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 431 MW

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

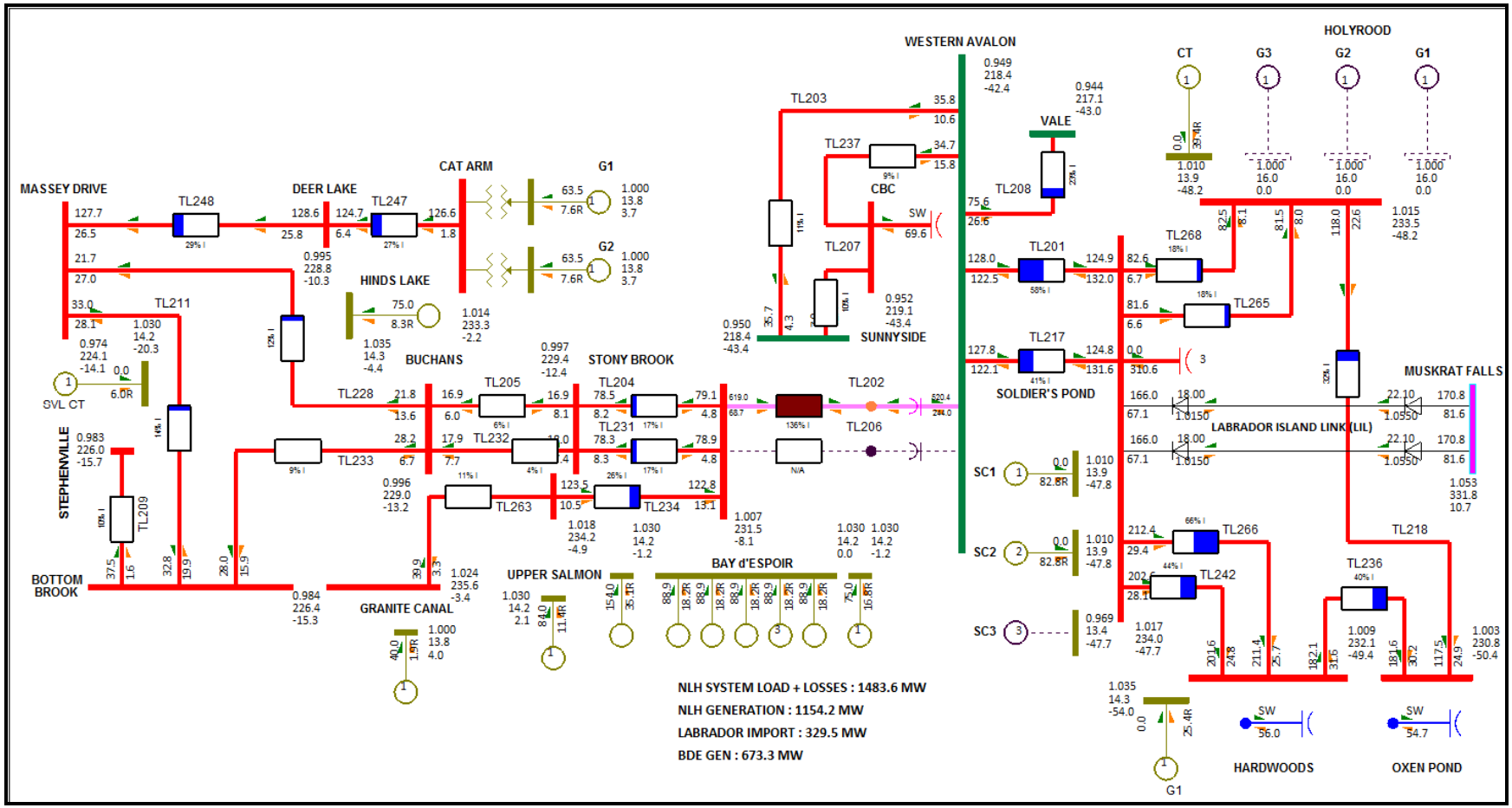


Figure 324 – Base Case 6 (BC6) Load Flow Plot – TL206 Out of Service

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

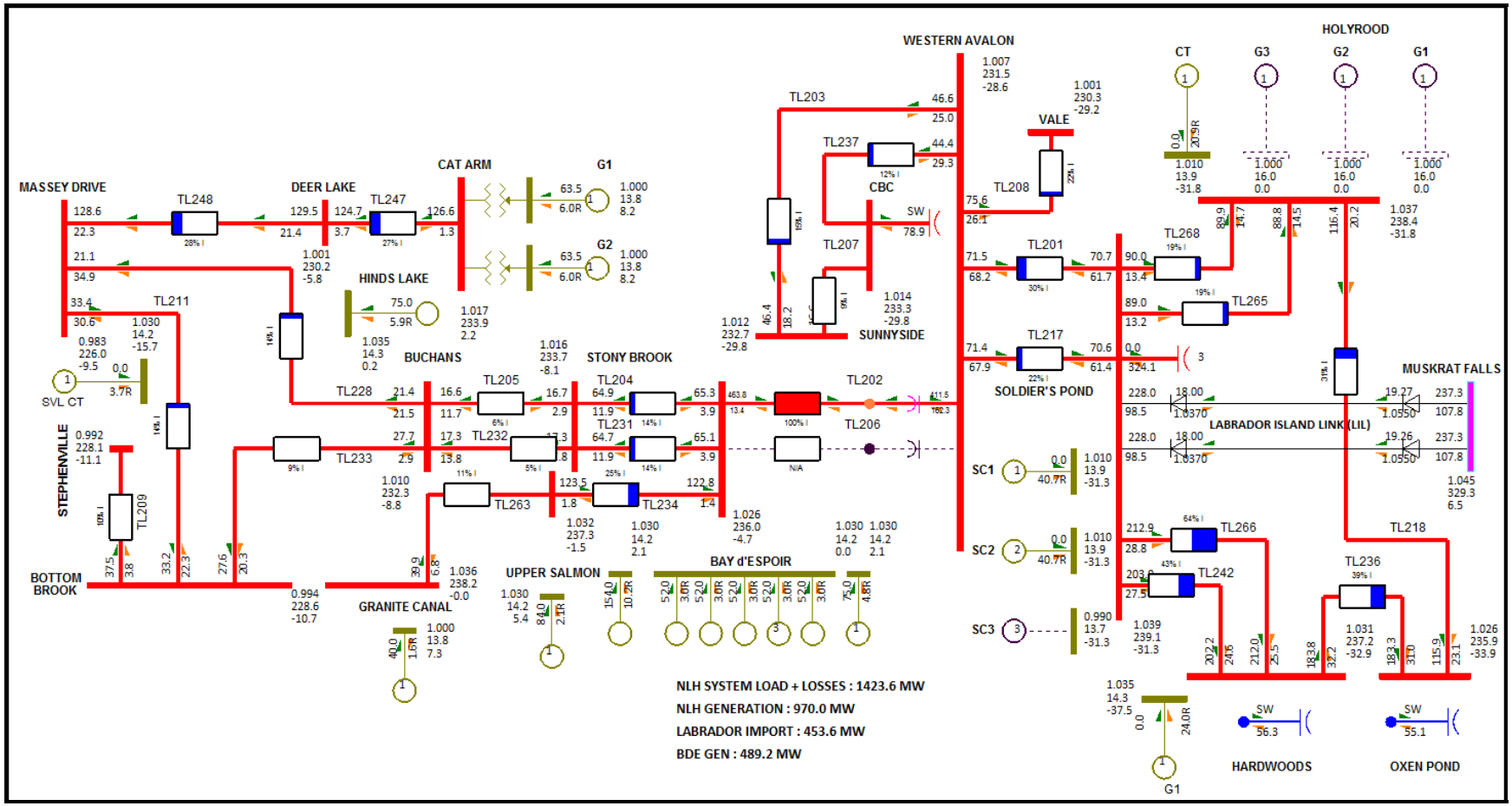


Figure 325 – Base Case 6 (BC6) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 454 MW

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

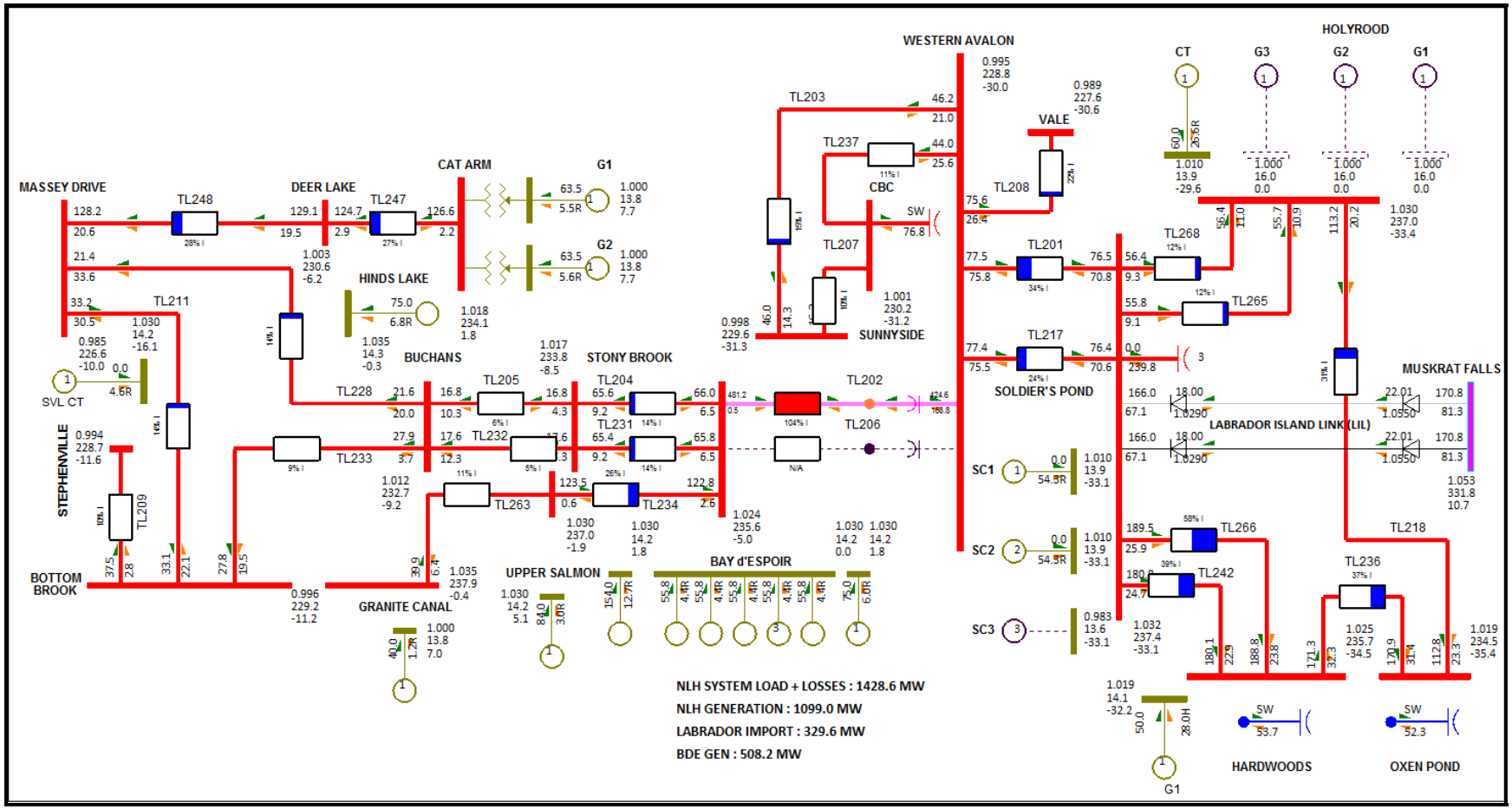


Figure 326 – Base Case 6 (BC6) Load Flow Plot – TL206 Out of Service – HWD CT and HRD CT Generating 110 MW

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

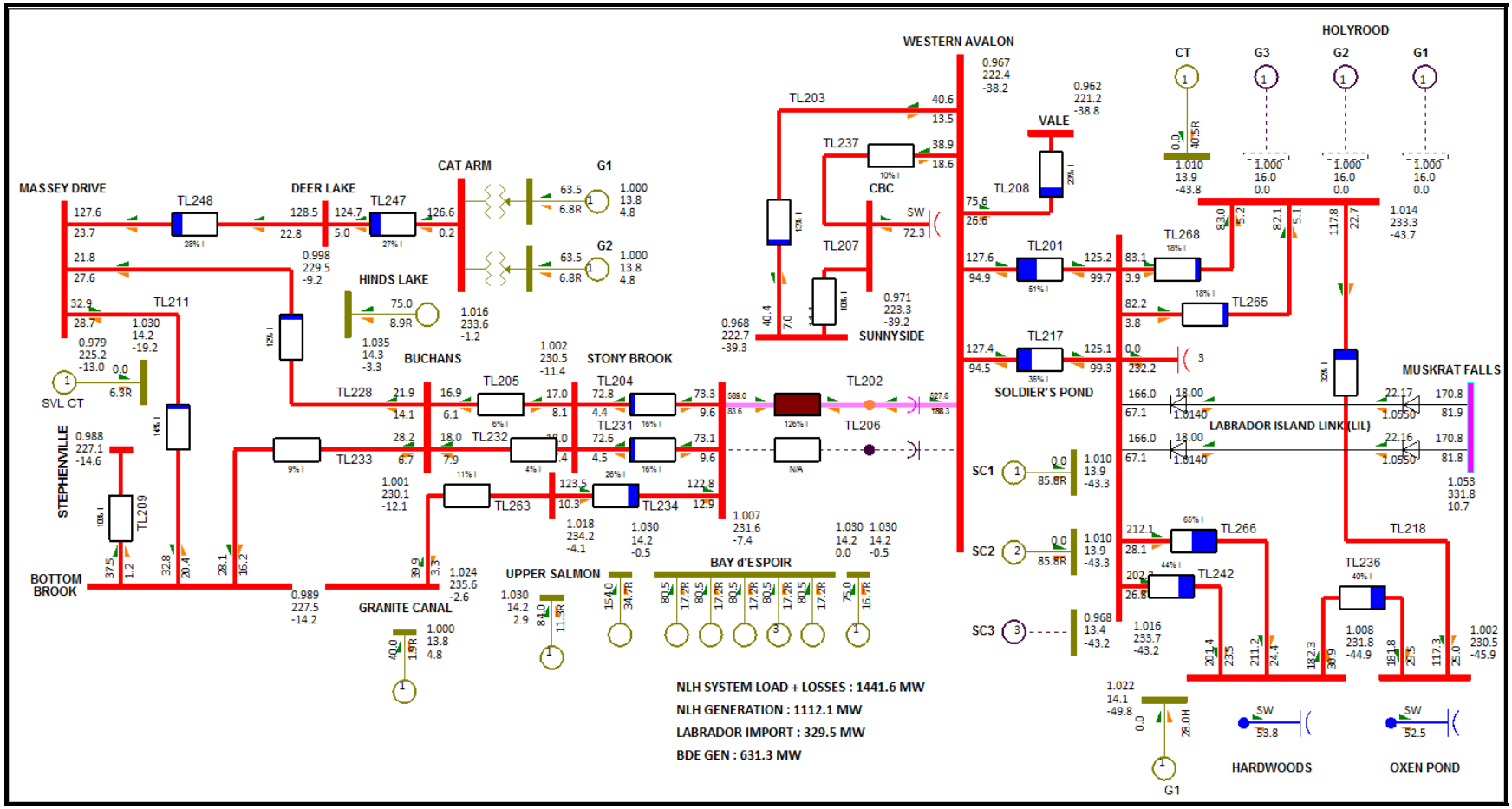


Figure 327 – Base Case 6 (BC6) Load Flow Plot – TL206 Out of Service

TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

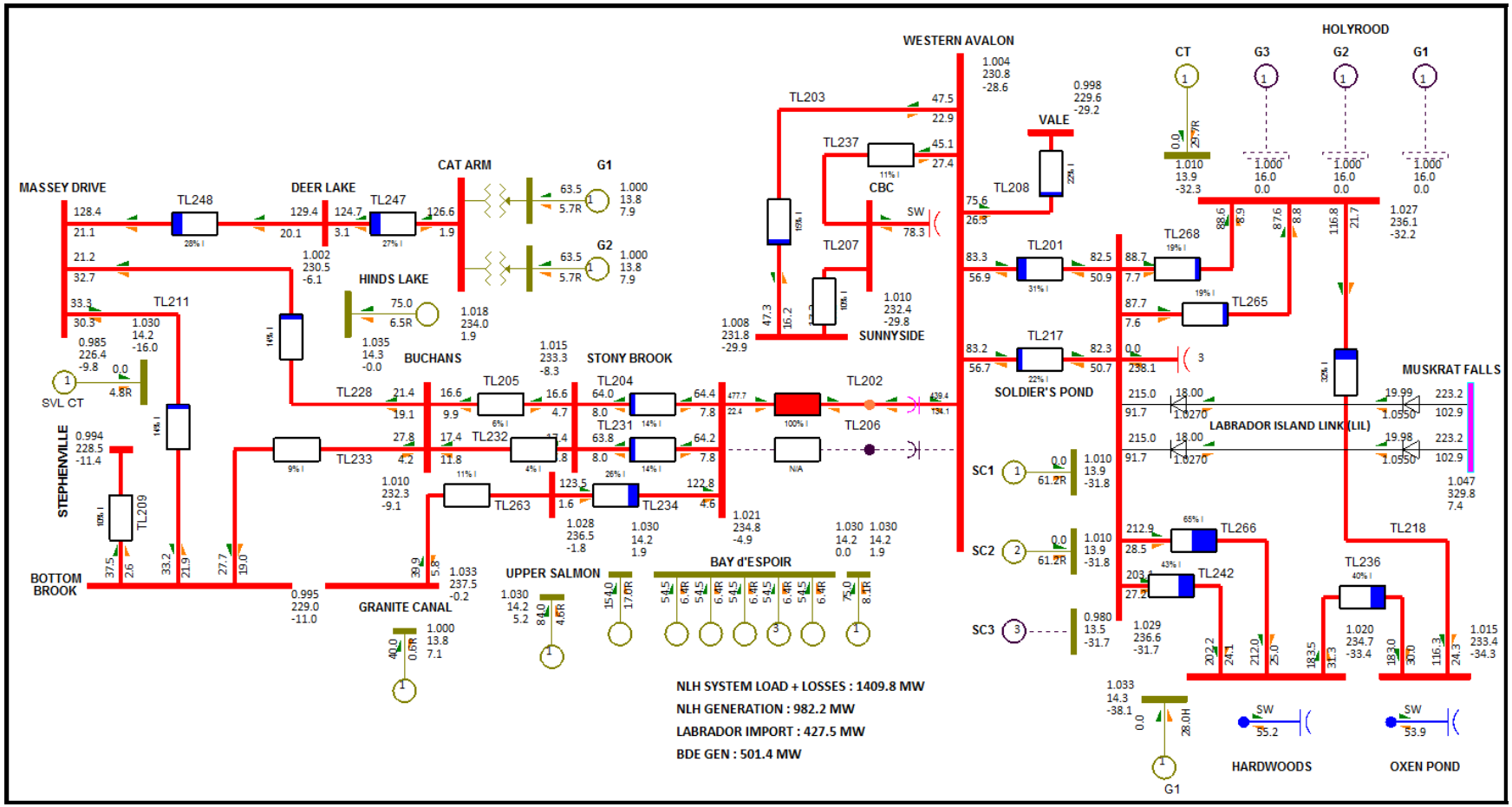


Figure 328 – Base Case 6 (BC6) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 428 MW

TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

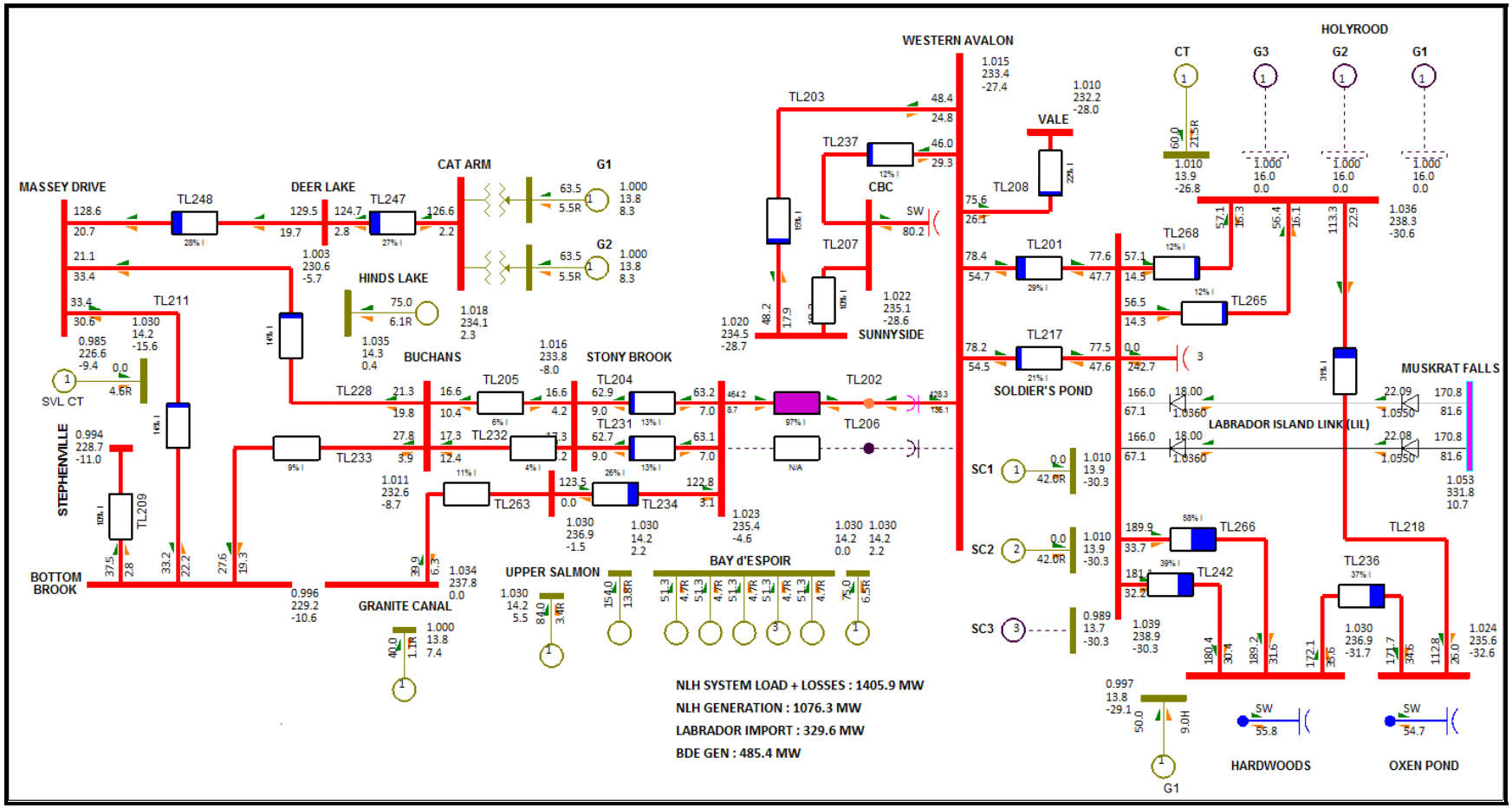


Figure 329 – Base Case 6 (BC6) Load Flow Plot – TL206 Out of Service – HWD CT and HRD CT Generating 110 MW

TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

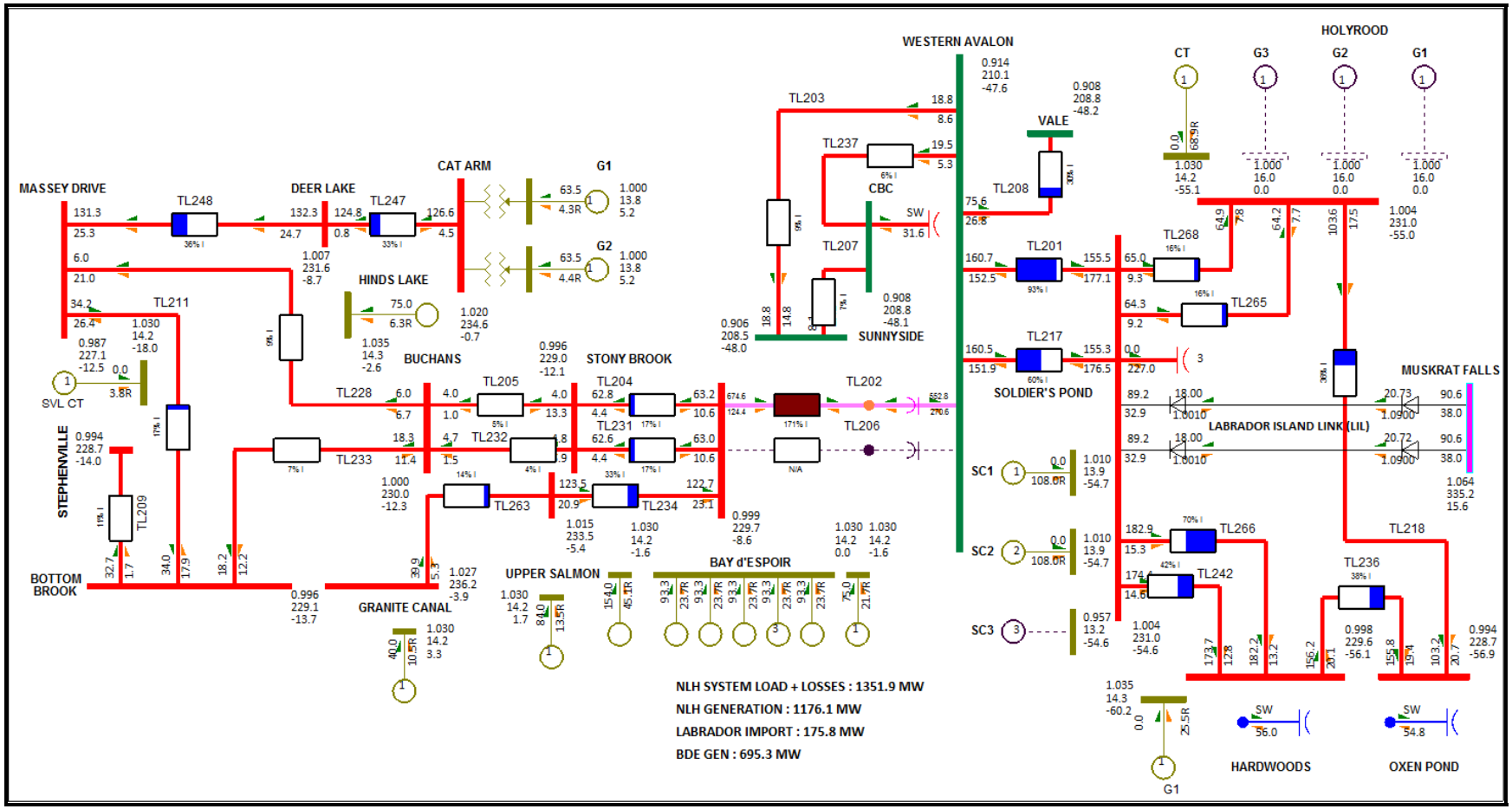


Figure 330 – Base Case 8 (BC8) Load Flow Plot – TL206 Out of Service

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

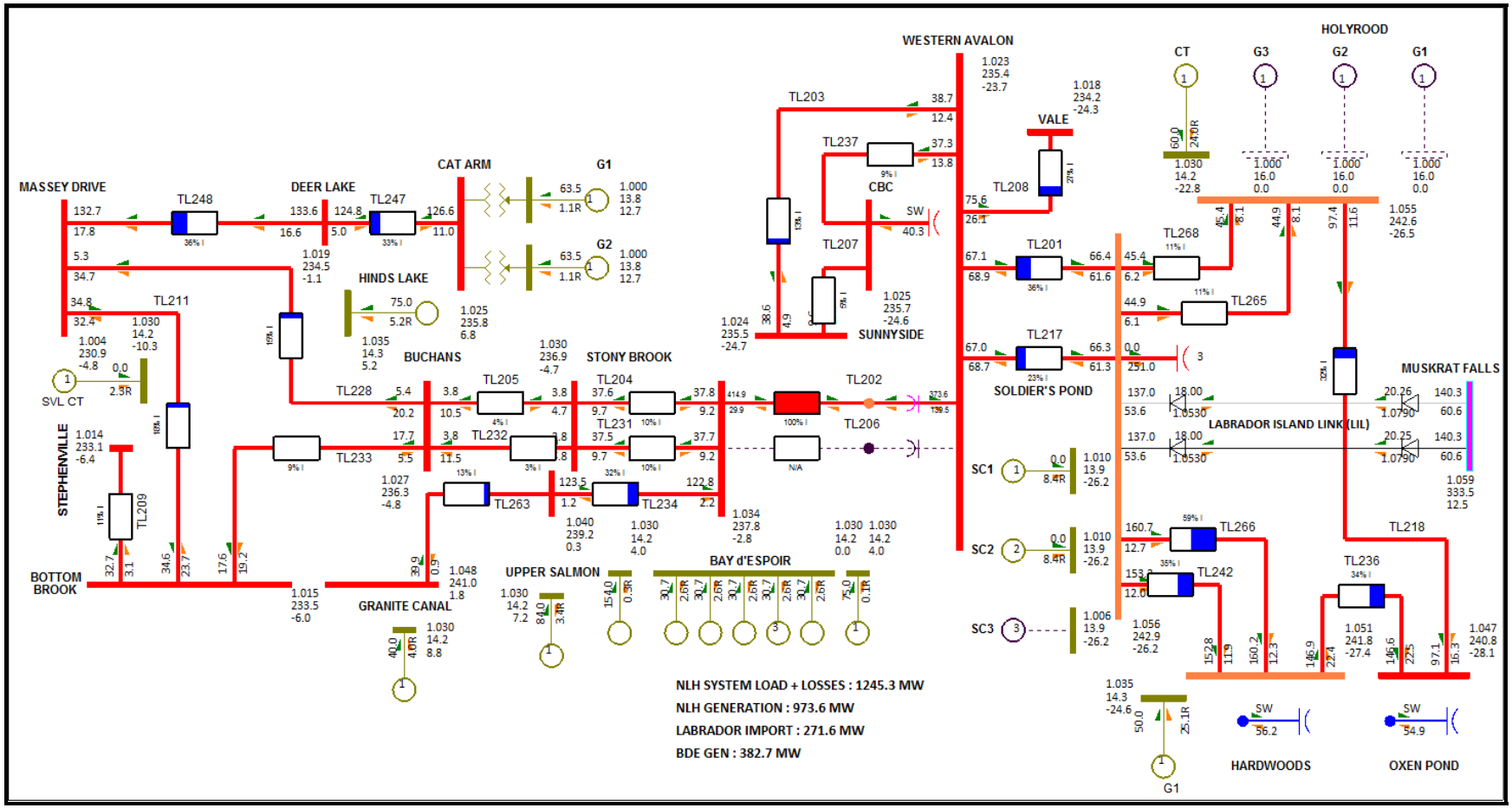


Figure 331 – Base Case 8 (BC8) Load Flow Plot – TL206 Out of Service – HWD CT and HRD CT Generating 110 MW – LIL Import Increased to 272 MW

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

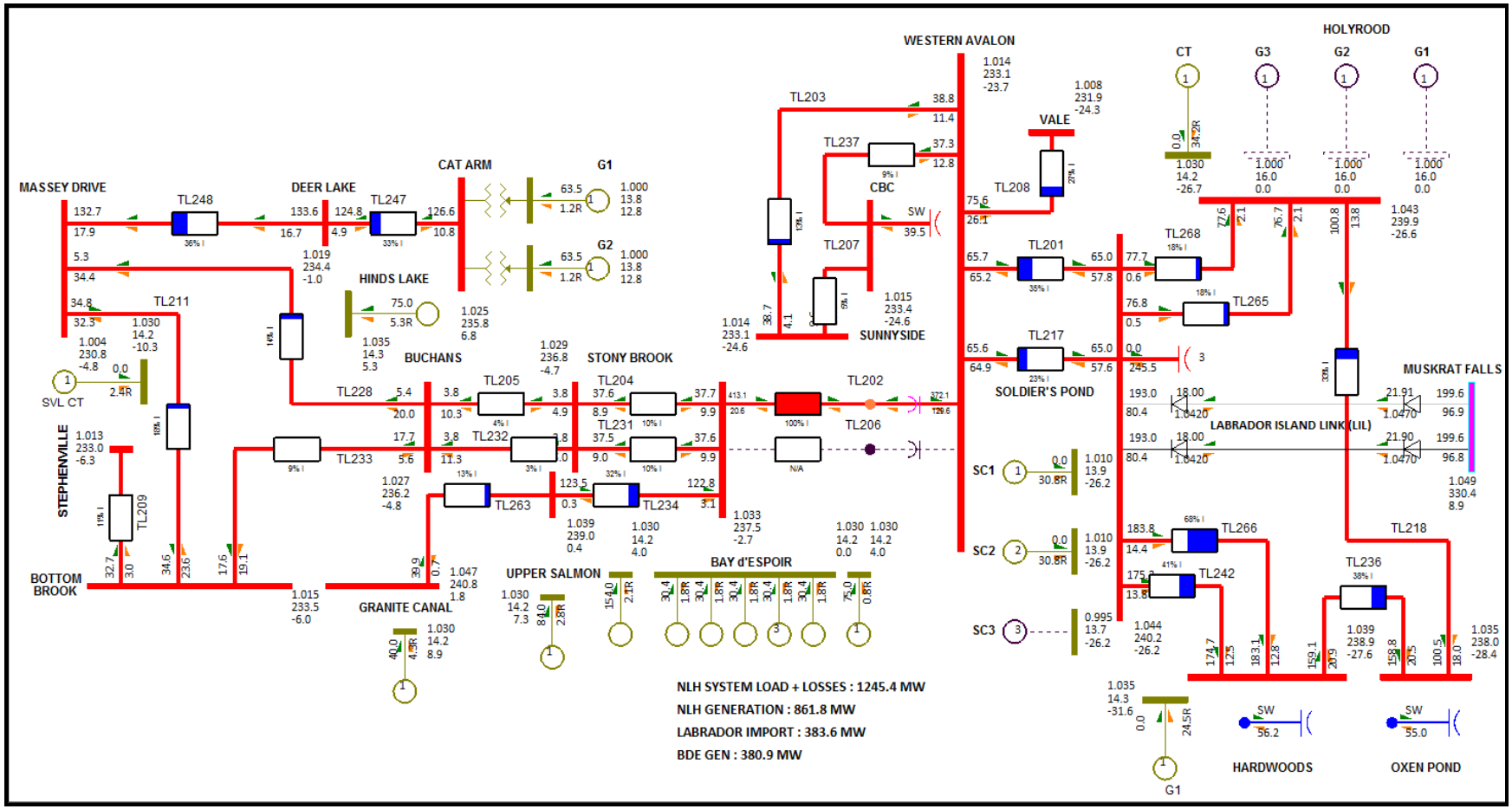


Figure 332 – Base Case 8 (BC8) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 384 MW

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

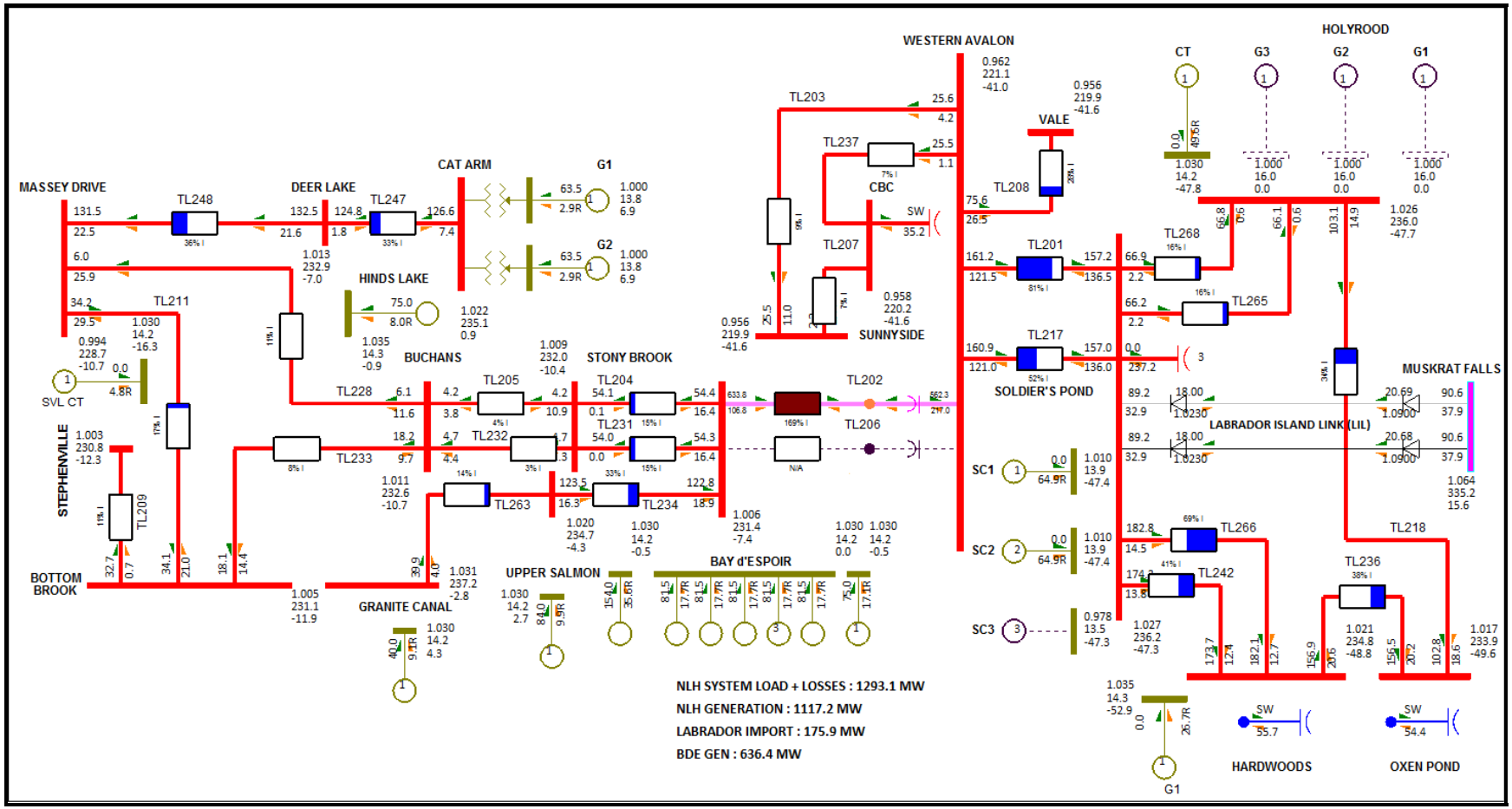


Figure 333 – Base Case 8 (BC8) Load Flow Plot – TL206 Out of Service

TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

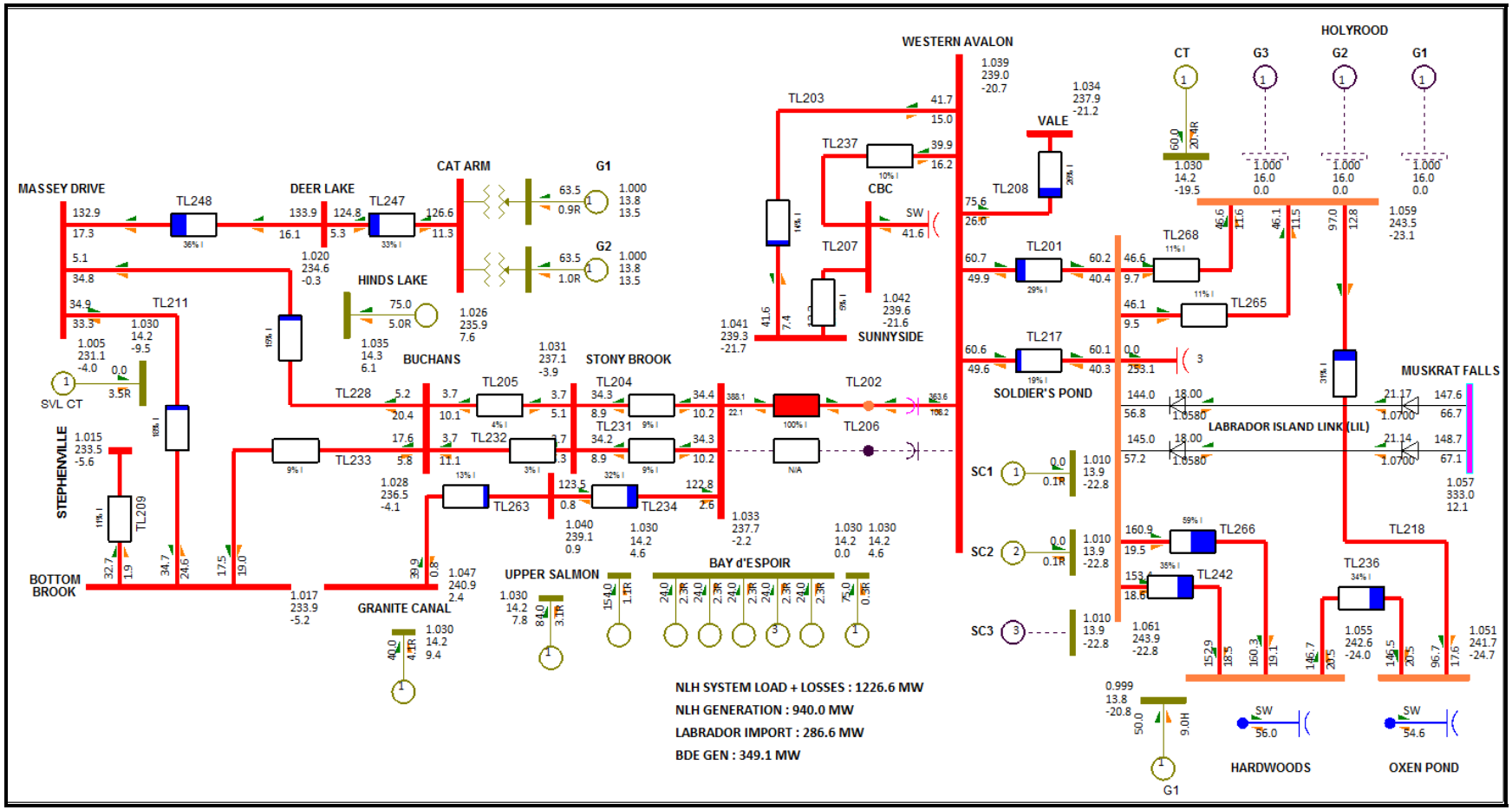


Figure 334 – Base Case 8 (BC8) Load Flow Plot – TL206 Out of Service – HWD CT and HRD CT Generating 110 MW – LIL Import Increased to 287 MW

TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

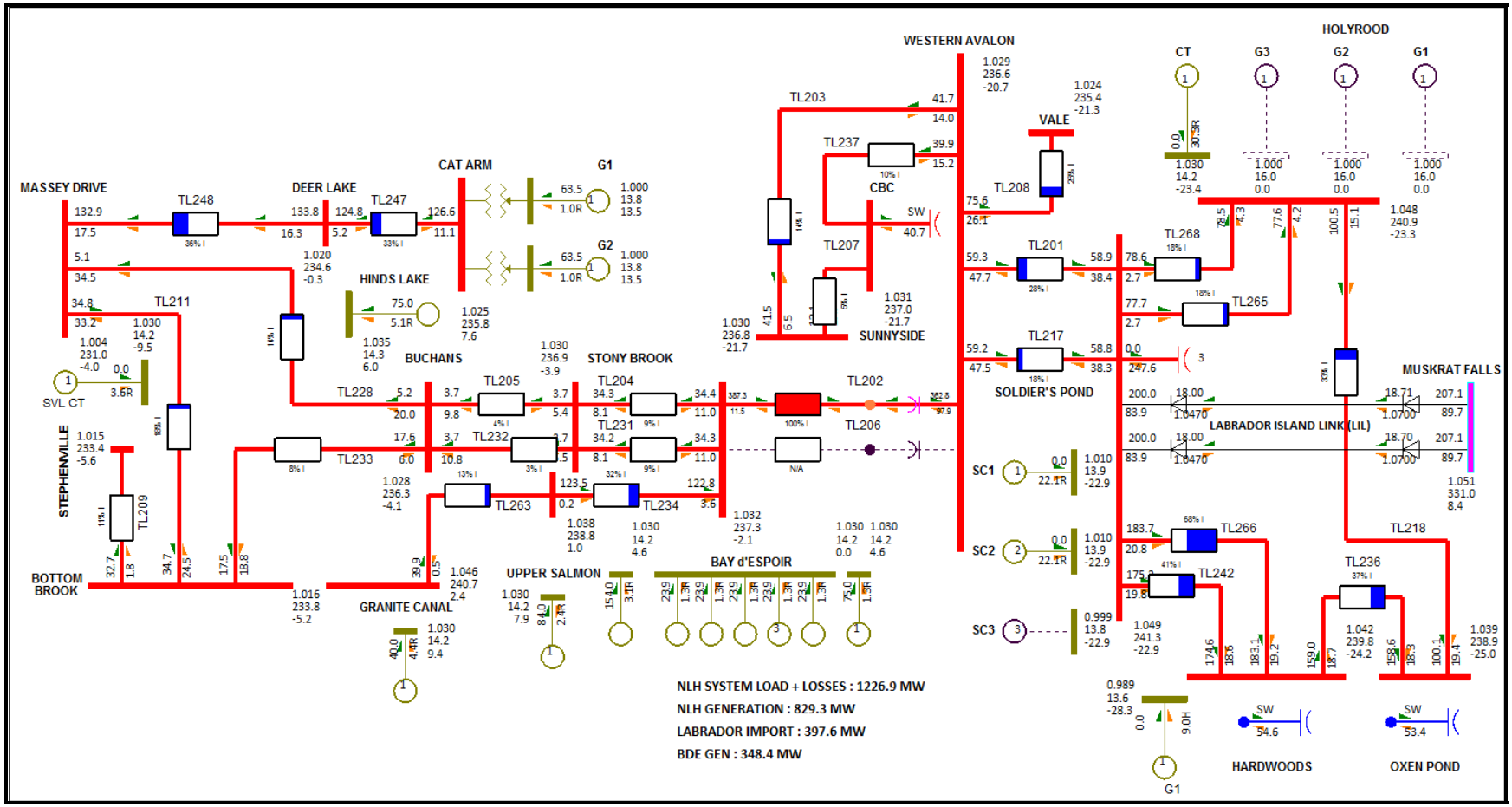


Figure 335 – Base Case 8 (BC8) Load Flow Plot – TL206 Out of Service - LIL Import Increased to 398 MW

TL202/TL206 Rebuilt with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

TL202/TL206 Rerouted from SSD to WAV with 50% Series Compensation and 75°C Thermal Upgrade

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

Alternative 7

Increase Number of HISCs at SOP

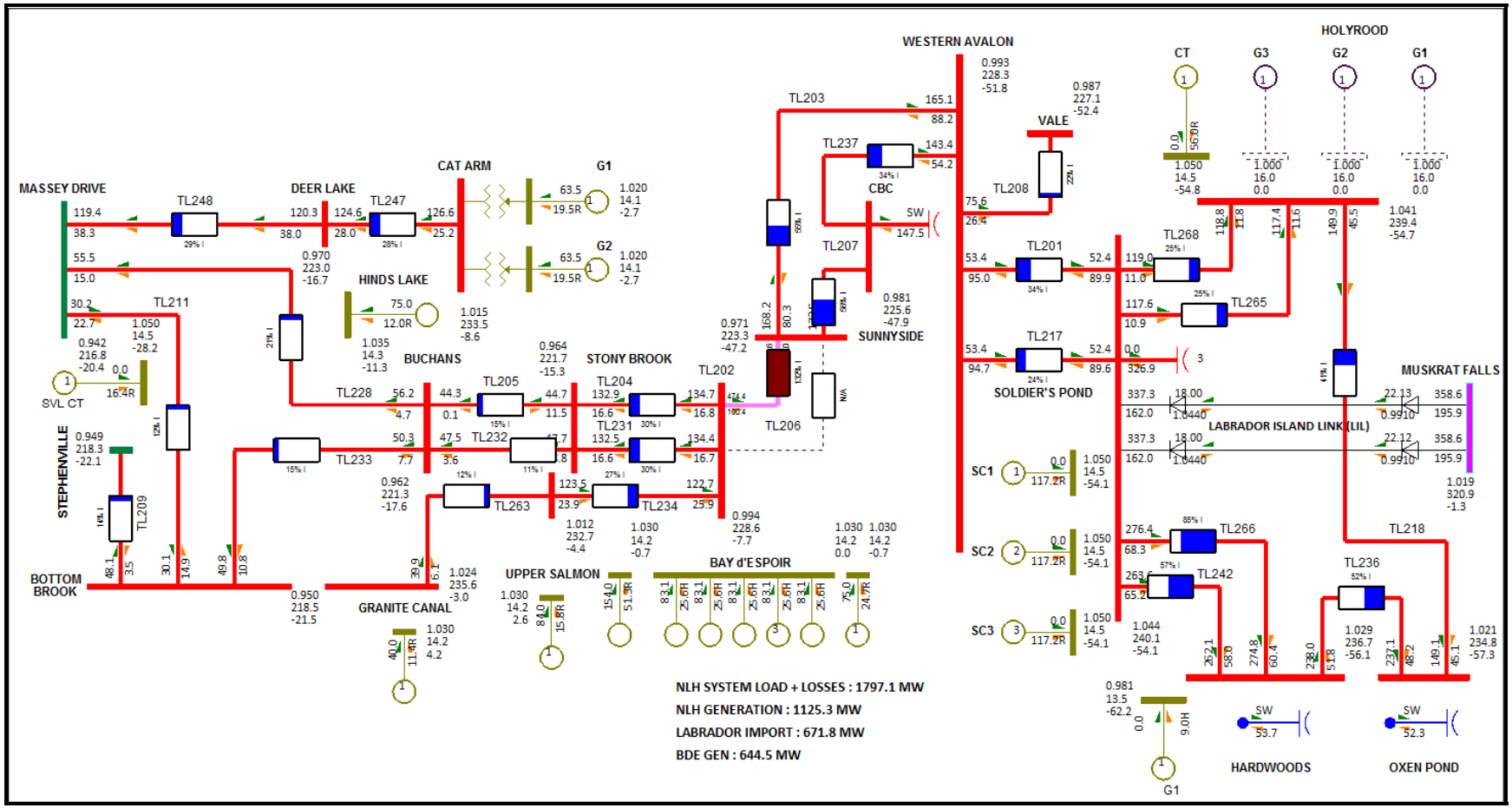


Figure 336 – Base Case 1 (BC1) Load Flow Plot – TL206 Out of Service

3x175 High Inertia Synchronous Condensers in Service at SOP

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

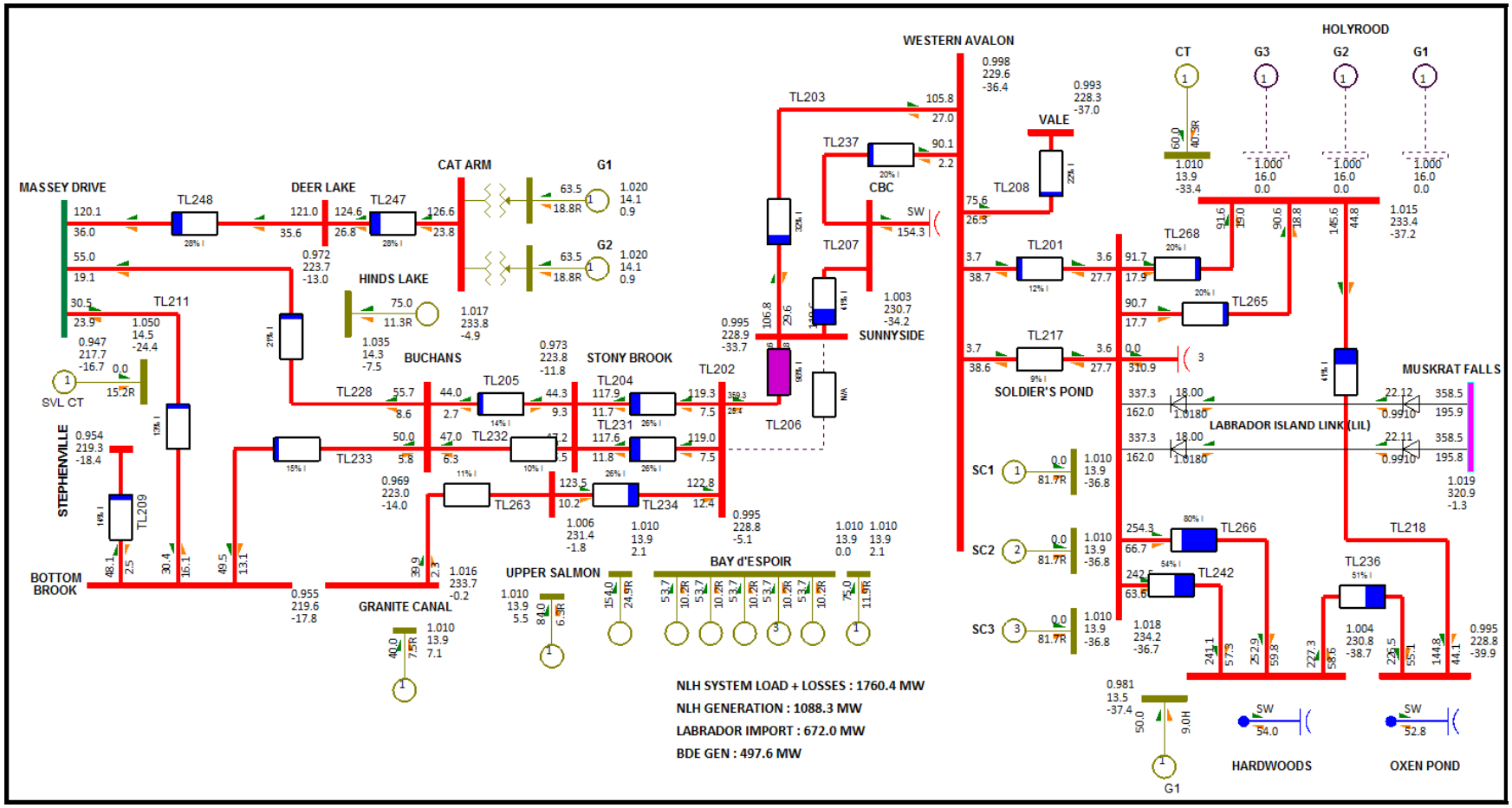


Figure 337 – Base Case 1 (BC1) Load Flow Plot – TL206 Out of Service – HWD CT and HRD CT Generating 110 MW

3x175 High Inertia Synchronous Condensers in Service at SOP

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

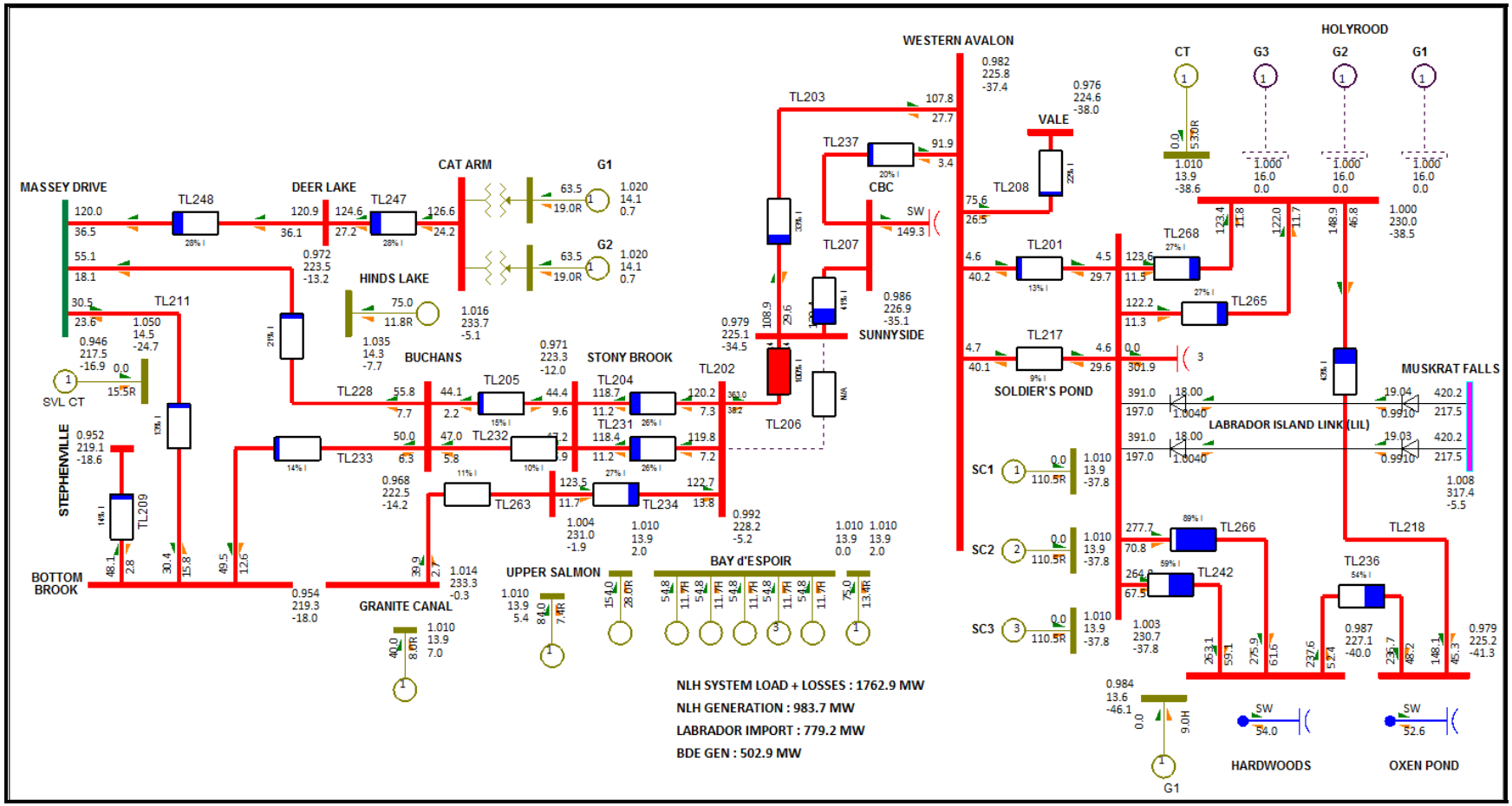


Figure 338 – Base Case 1 (BC1) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 779 MW

3x175 High Inertia Synchronous Condensers in Service at SOP

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

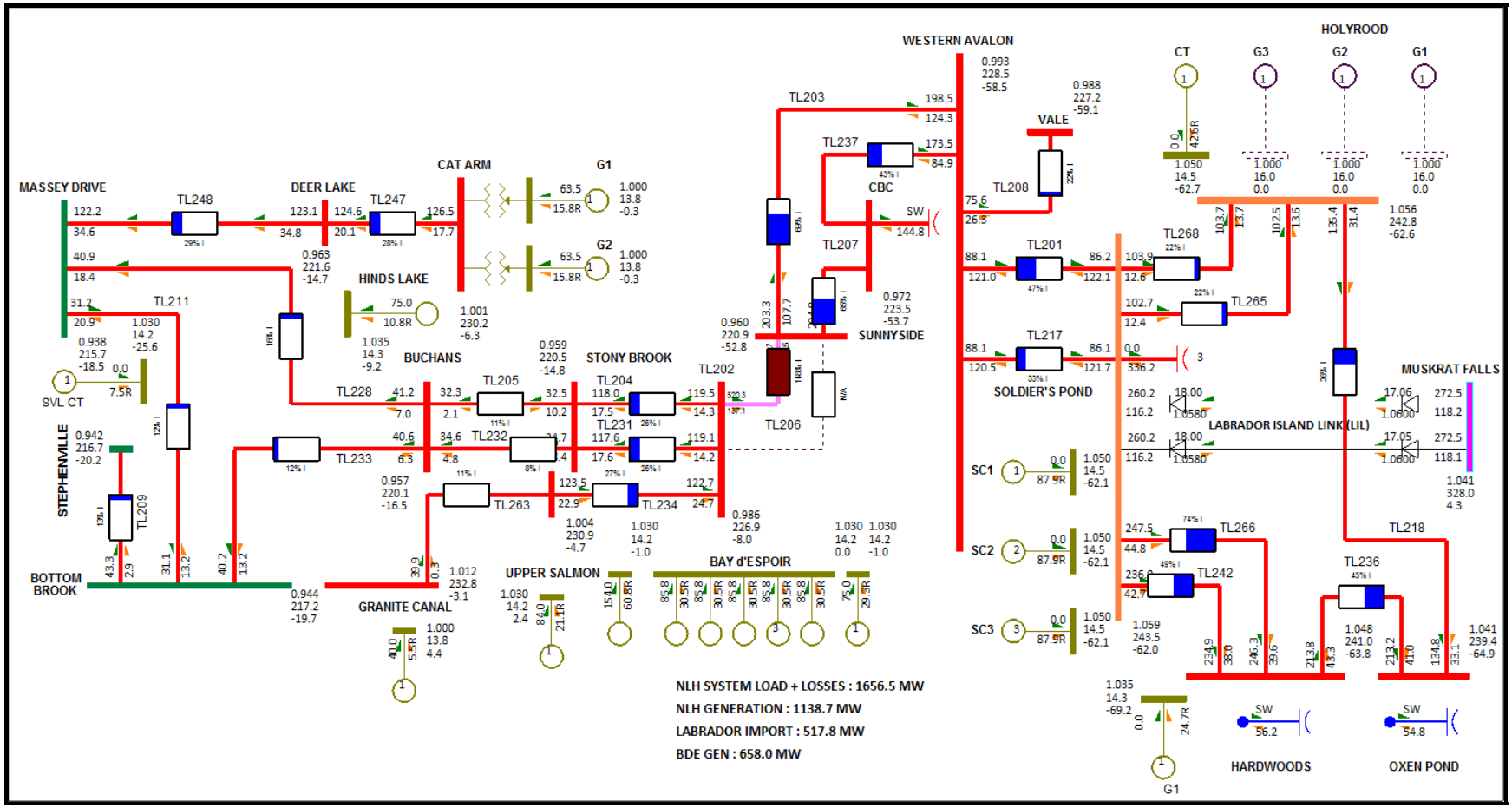


Figure 339 – Base Case 3 (BC3) Load Flow Plot – TL206 Out of Service

3x175 High Inertia Synchronous Condensers in Service at SOP

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

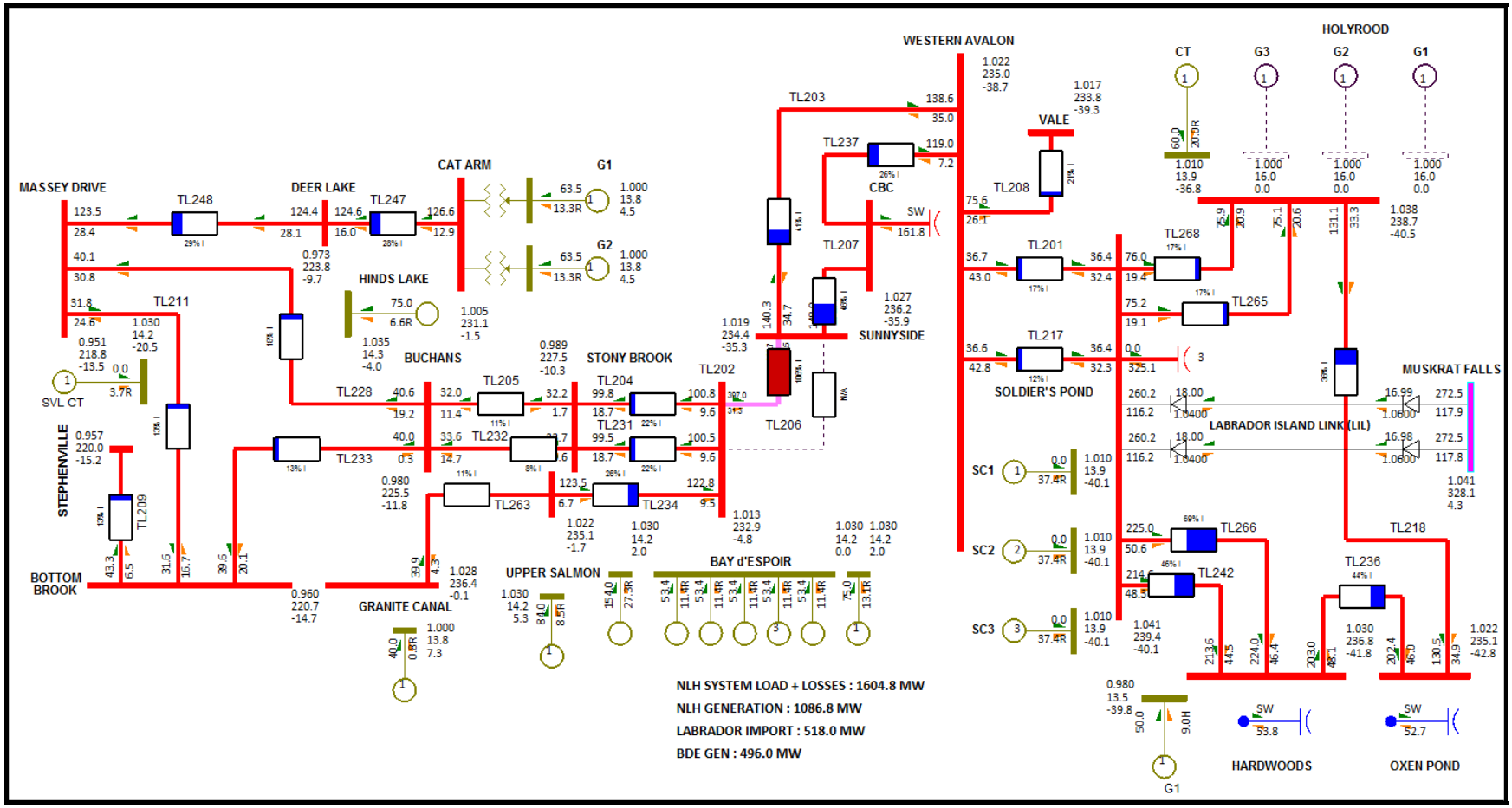


Figure 340 – Base Case 3 (BC3) Load Flow Plot – TL206 Out of Service – HWD CT and HRD CT Generating 110 MW

3x175 High Inertia Synchronous Condensers in Service at SOP

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

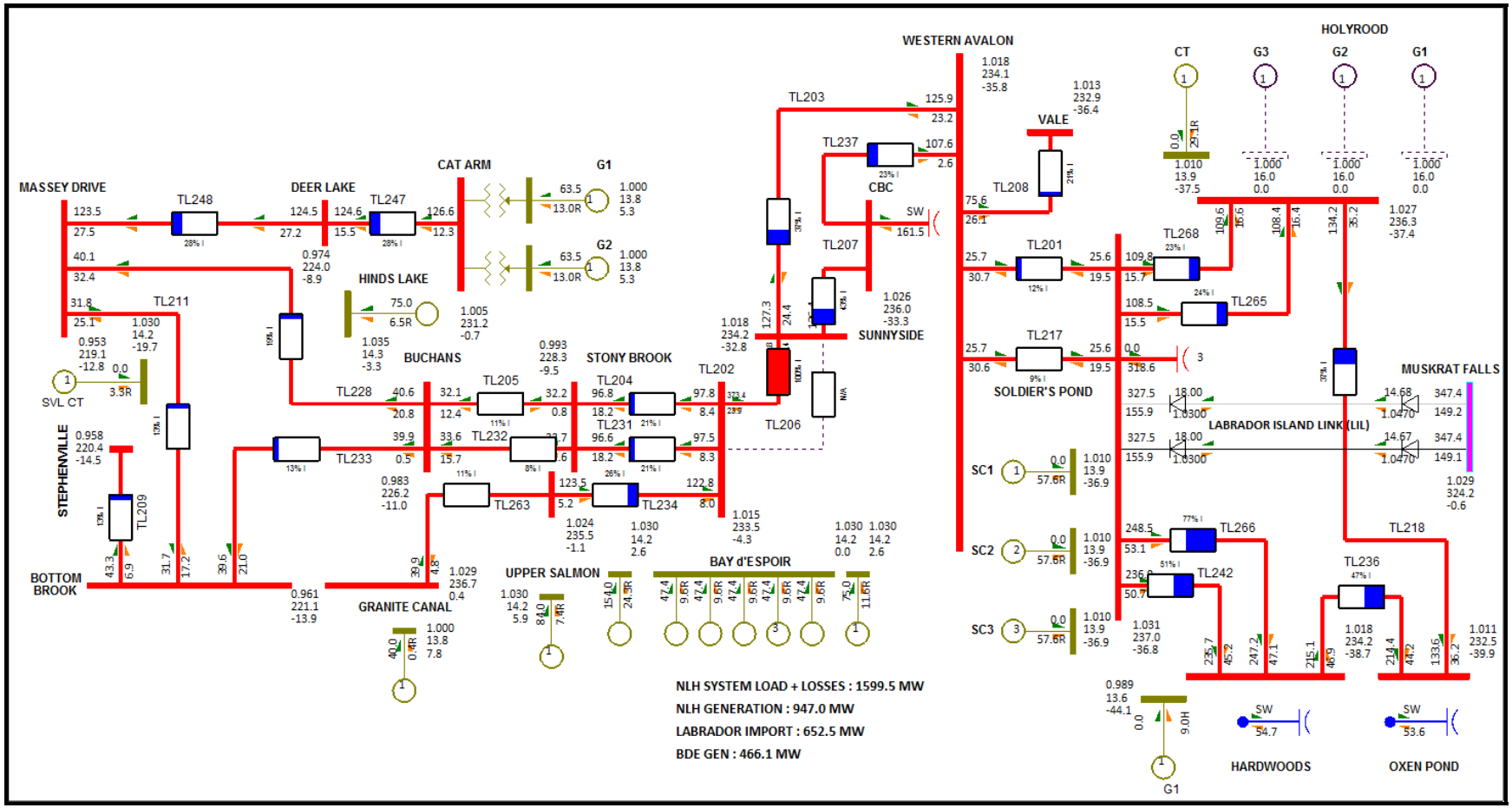


Figure 341 – Base Case 3 (BC3) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 653 MW

3x175 High Inertia Synchronous Condensers in Service at SOP

Winter Peak (1603 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (518 MW)

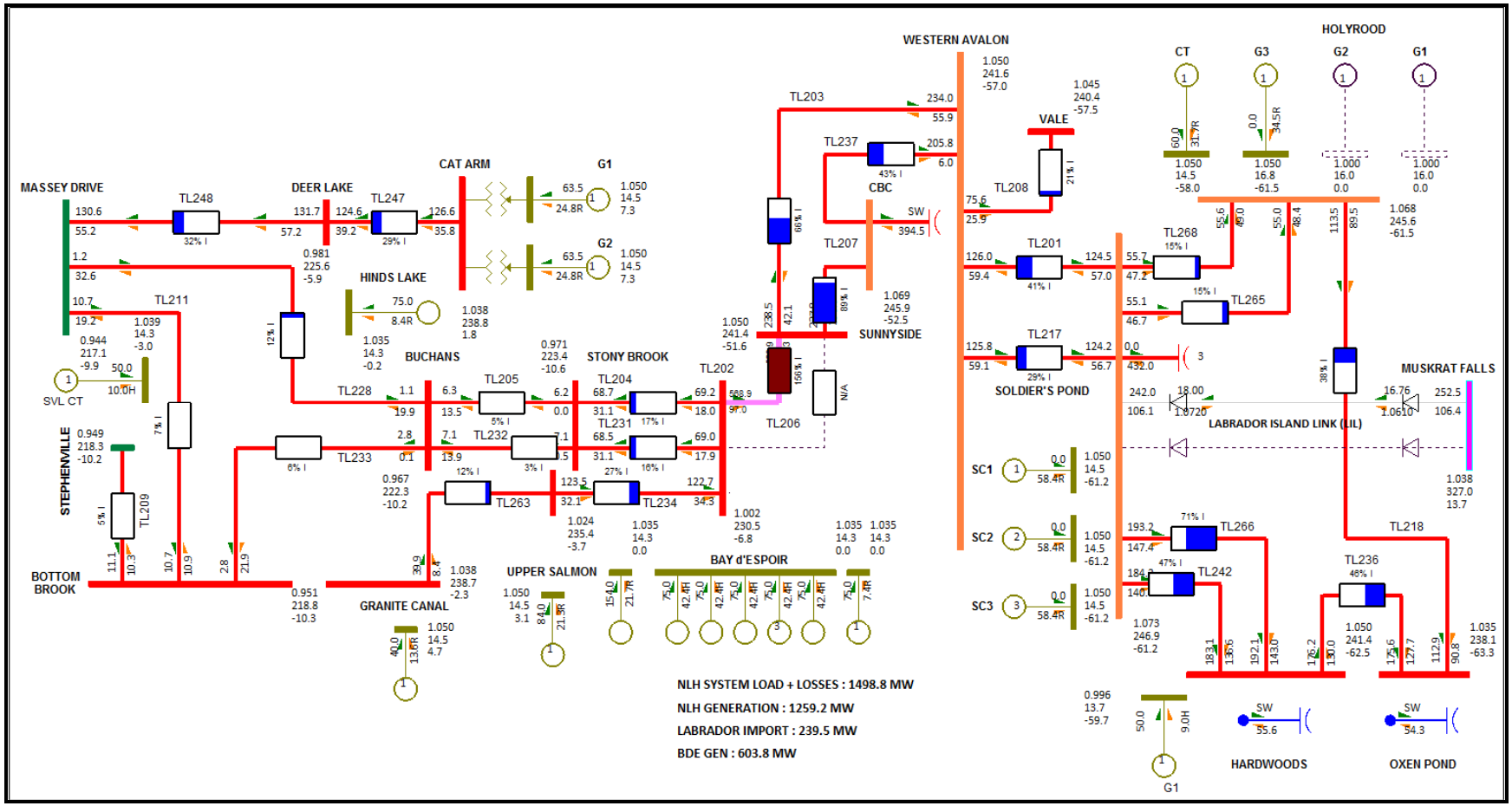


Figure 342 – Base Case 4 (BC4) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 240 MW

3x175 High Inertia Synchronous Condensers in Service at SOP – Additional 191.75 MVAR Cap Bank at CBC

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

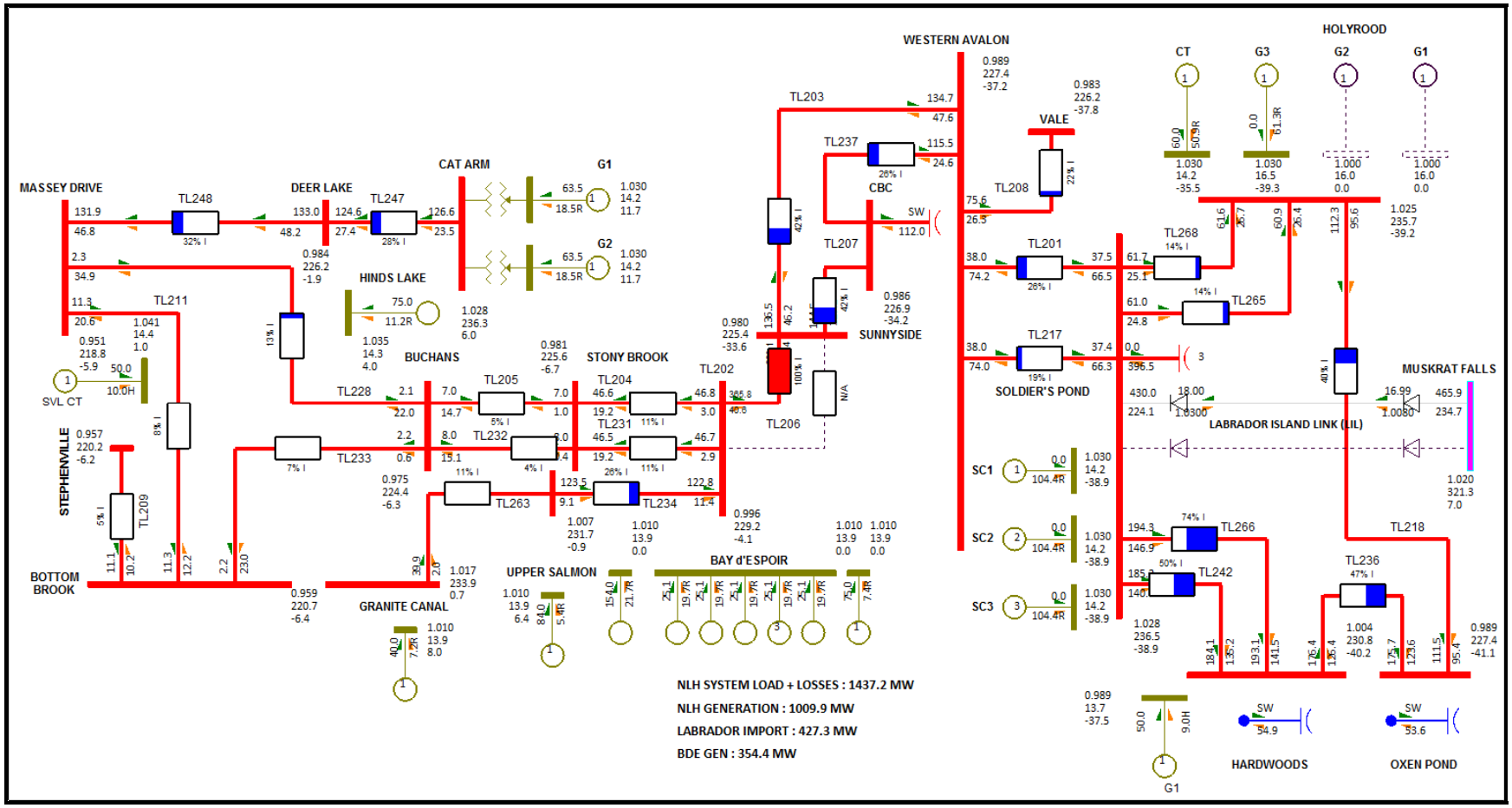


Figure 343 – Base Case 4 (BC4) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 427 MW

3x175 High Inertia Synchronous Condensers in Service at SOP – No Additional Cap Bank at CBC

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

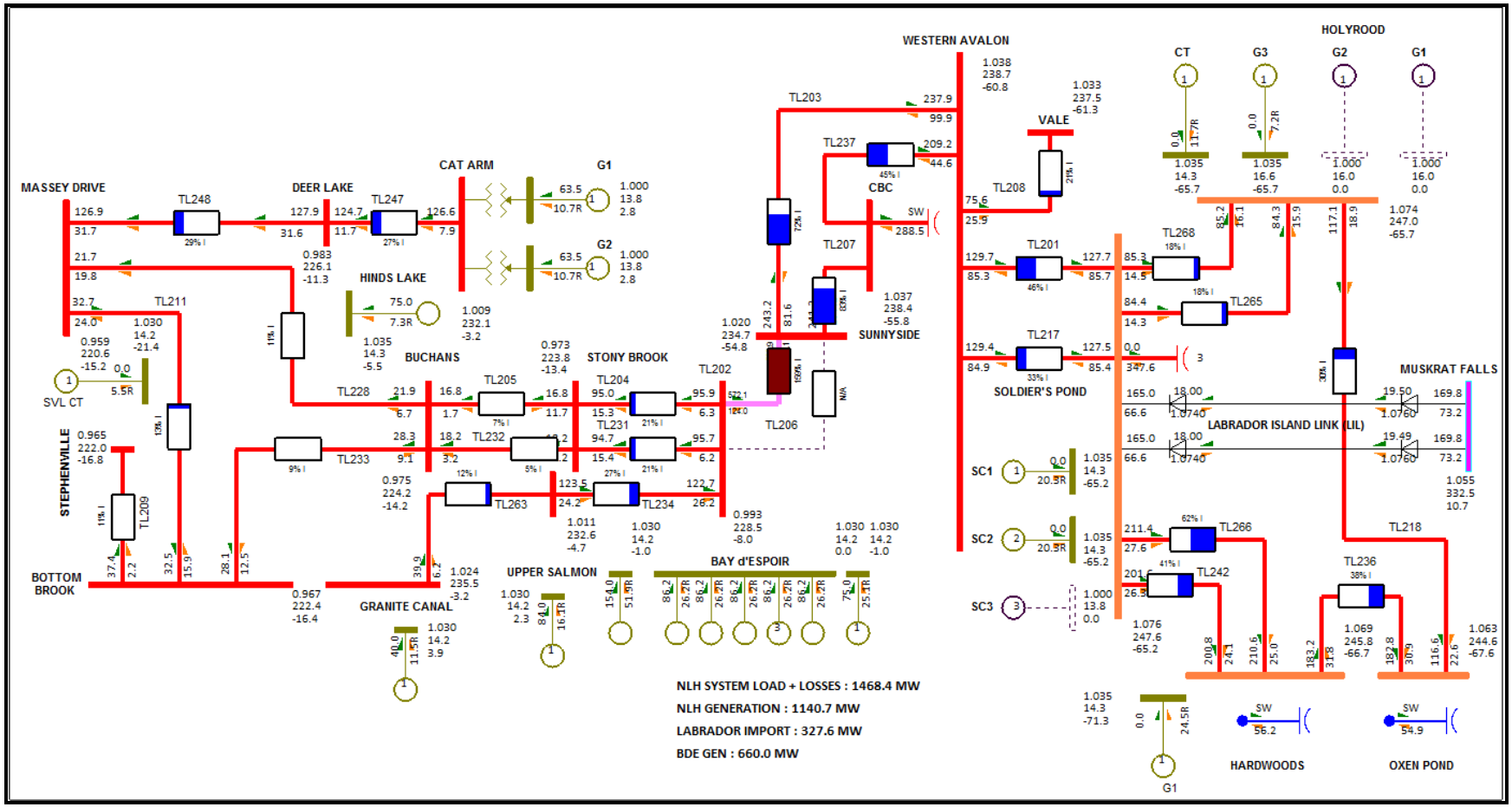


Figure 344 – Base Case 6 (BC6) Load Flow Plot – TL206 Out of Service

3x175 High Inertia Synchronous Condensers in Service at SOP – Additional 115.05 MVAR Cap Bank at CBC

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

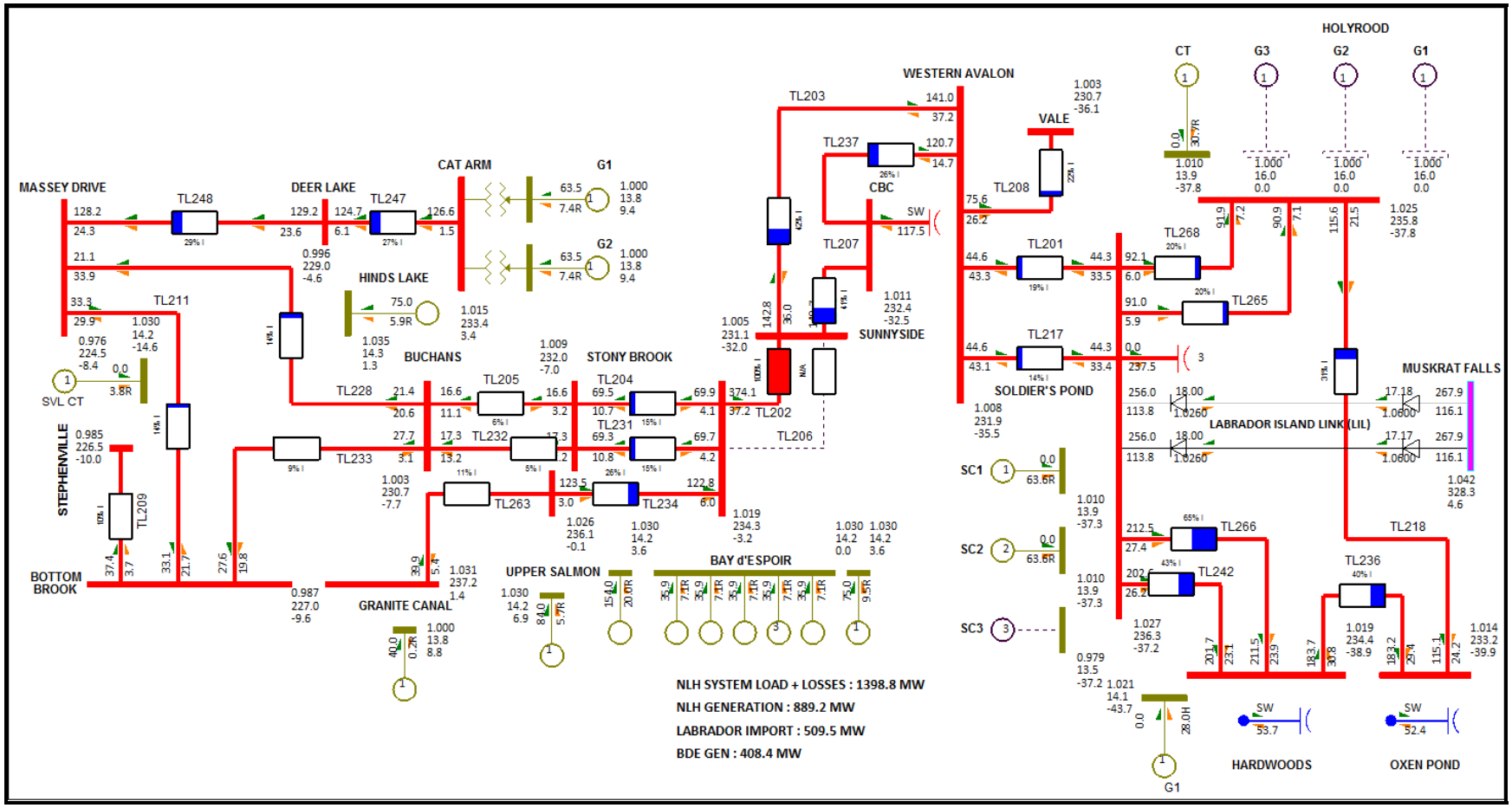


Figure 345 – Base Case 6 (BC6) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 510 MW

3x175 High Inertia Synchronous Condensers in Service at SOP – No Additional Cap Bank at CBC

Winter Day (1415 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (330 MW)

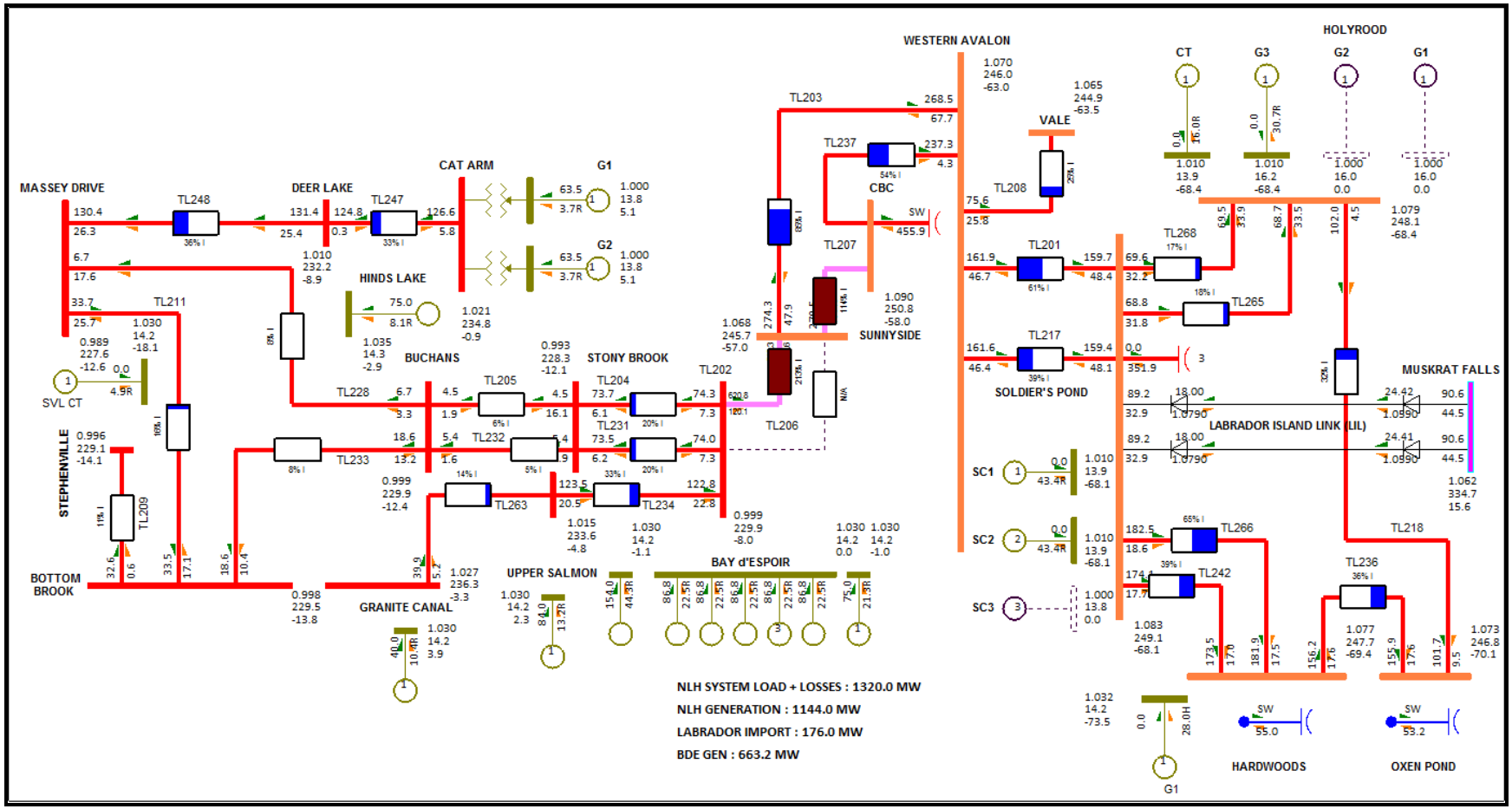


Figure 346 – Base Case 8 (BC8) Load Flow Plot – TL206 Out of Service

3x175 High Inertia Synchronous Condensers in Service at SOP – Additional 230.1 MVAR Cap Bank at CBC

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

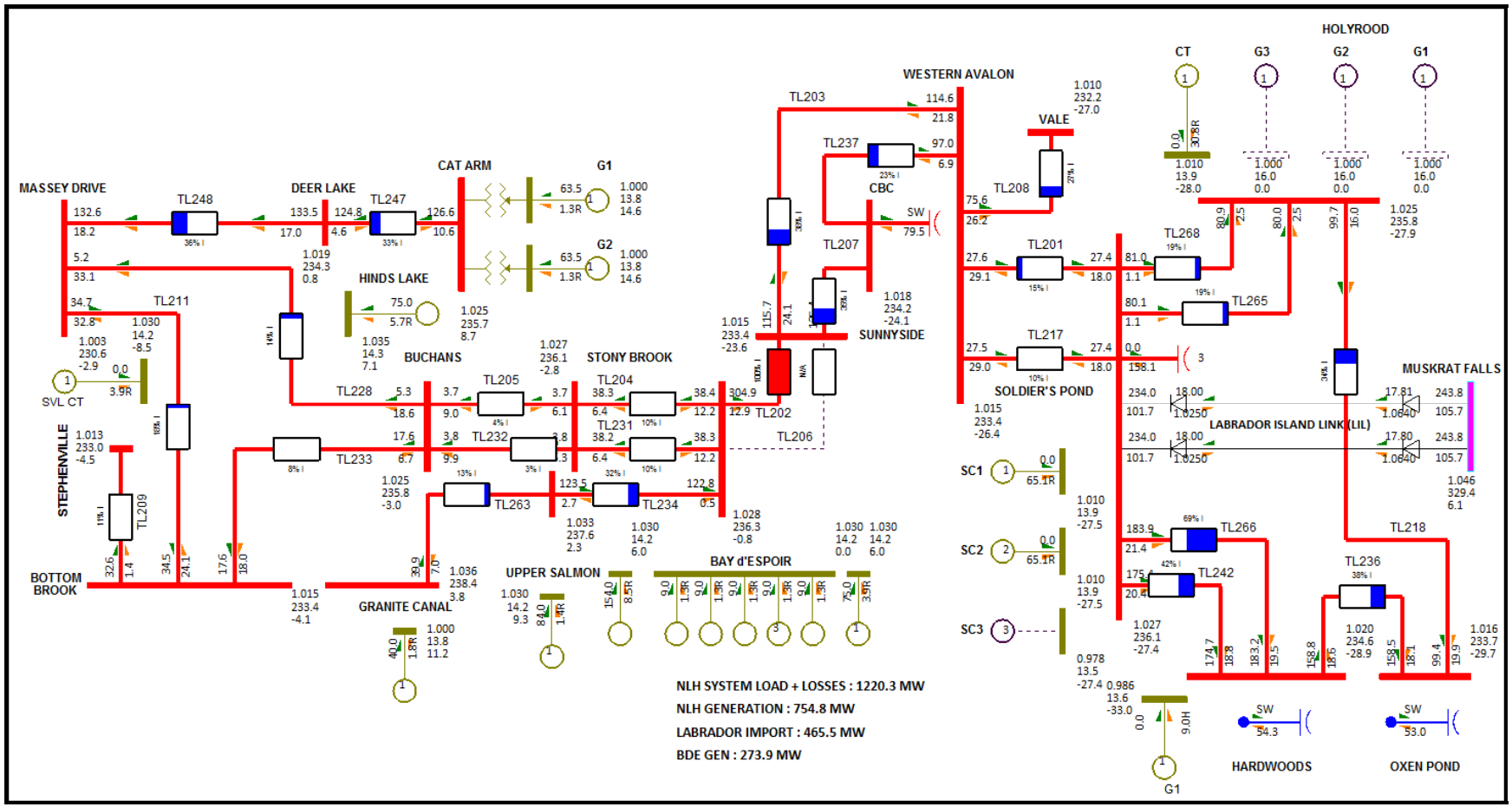


Figure 347 – Base Case 8 (BC8) Load Flow Plot – TL206 Out of Service – LIL Import Increased to 468 MW

3x175 High Inertia Synchronous Condensers in Service at SOP – No Additional Cap Bank at CBC

Spring/Fall Day (1261 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (176 MW)

TL267 Conductor Optimization

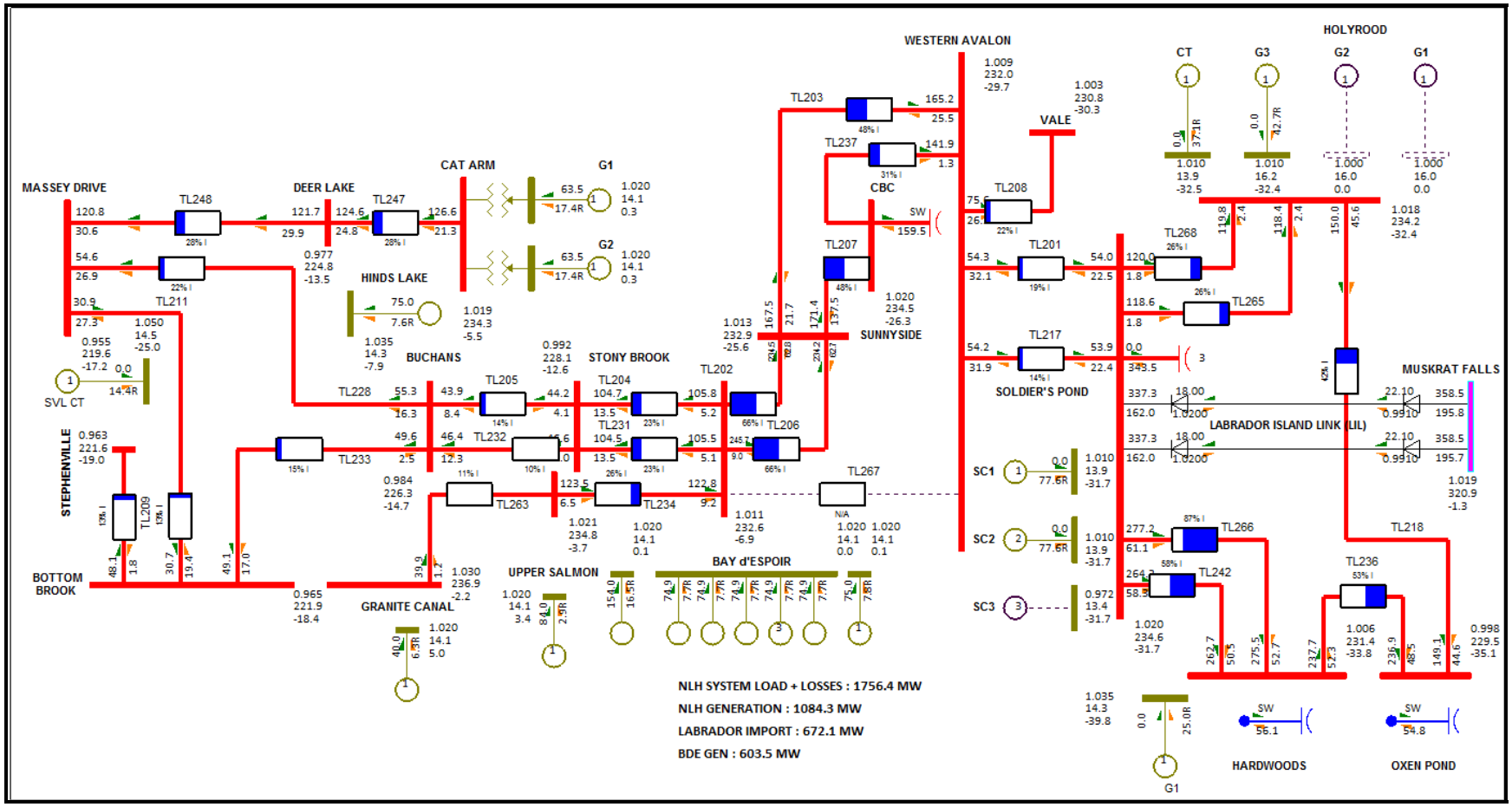


Figure 348 – Base Case 1 (BC1) Load Flow Plot – TL267 Out of Service

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

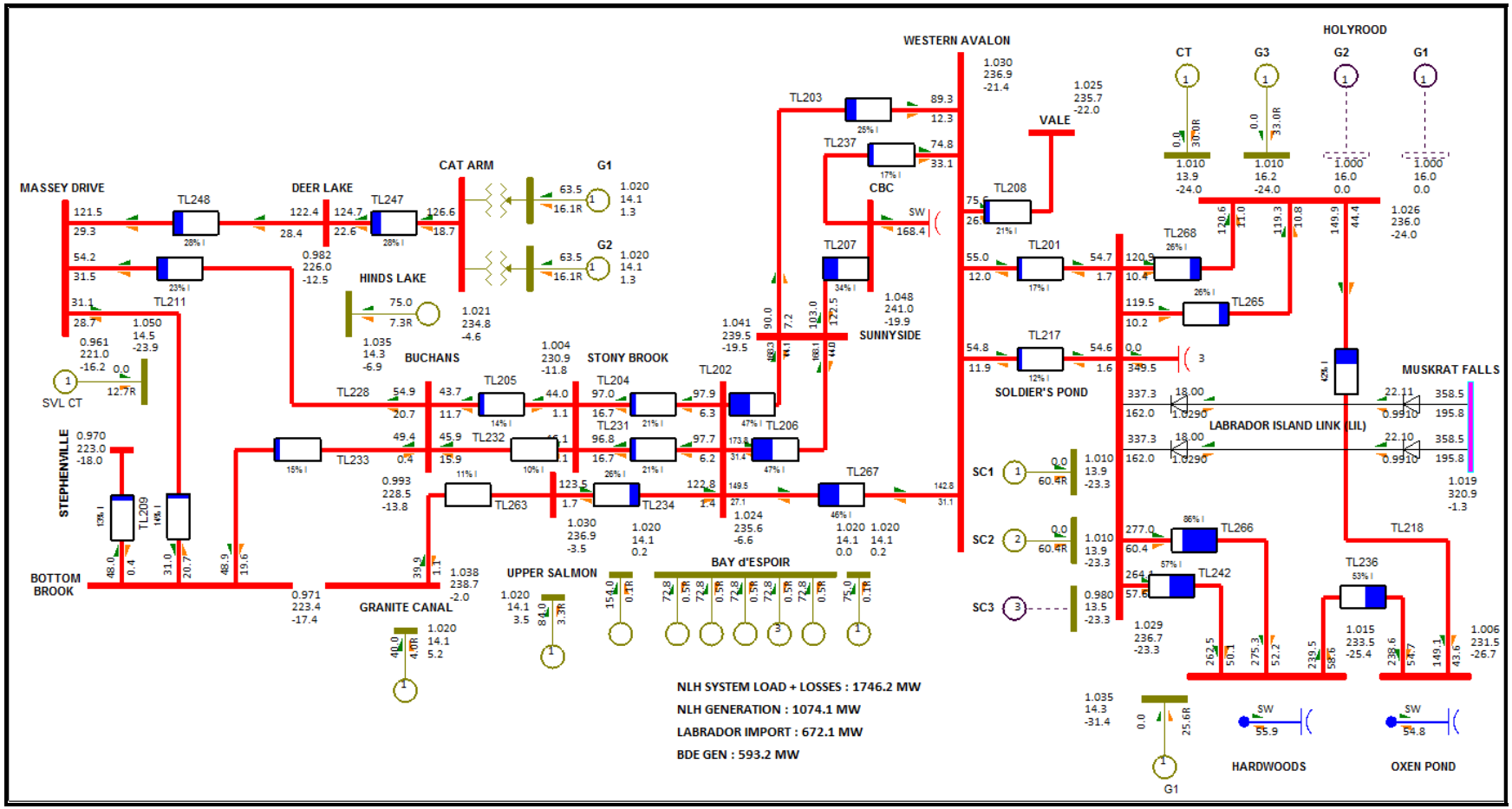


Figure 349 – Base Case 1 (BC1) Load Flow Plot – TL267 Built with 636 kcmil 26/7 ACSR GROSBEAK Conductor

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

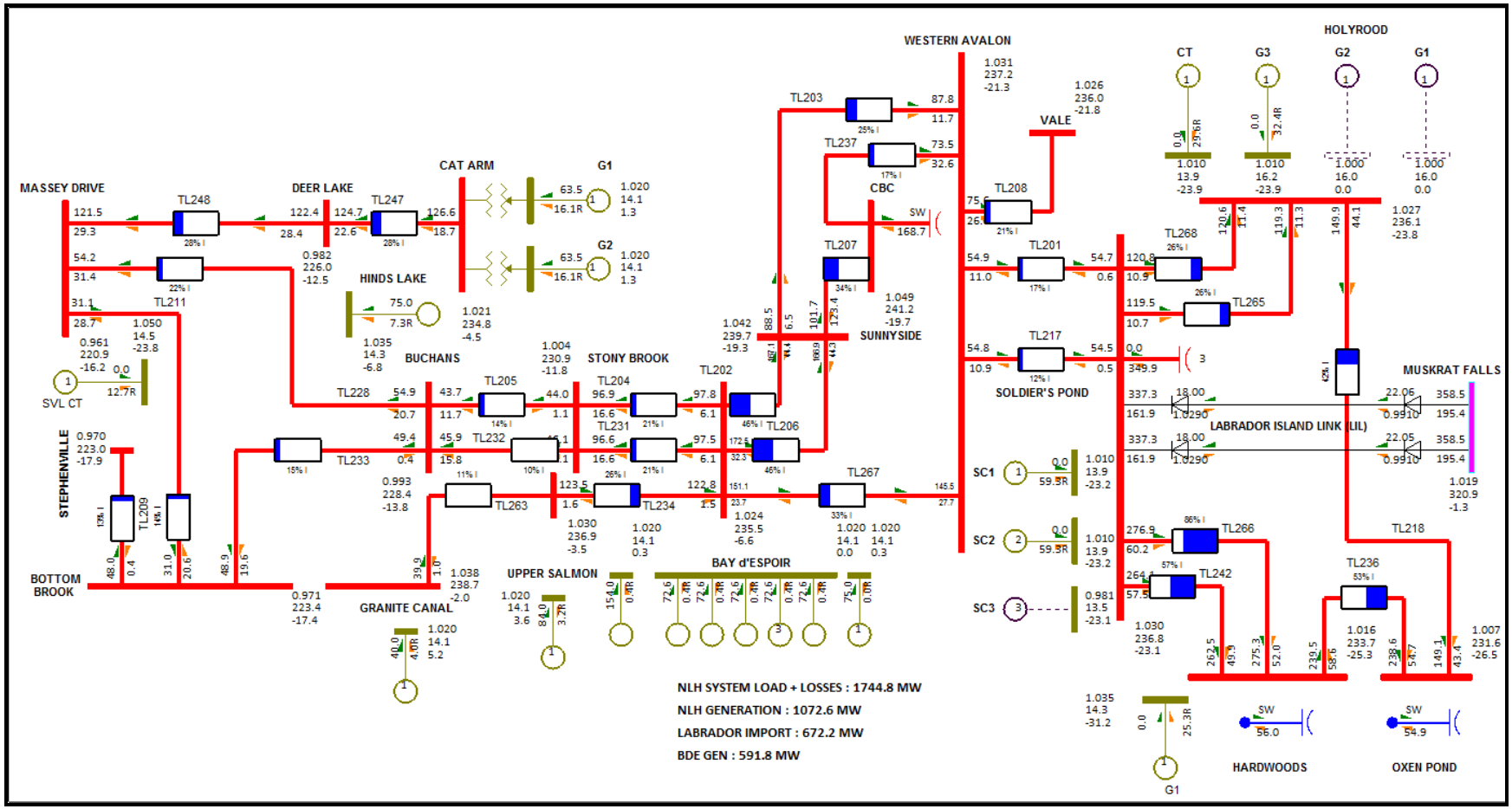


Figure 350 – Base Case 1 (BC1) Load Flow Plot – TL267 Built with 795 kcmil 26/7 ACSR DRAKE Conductor

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

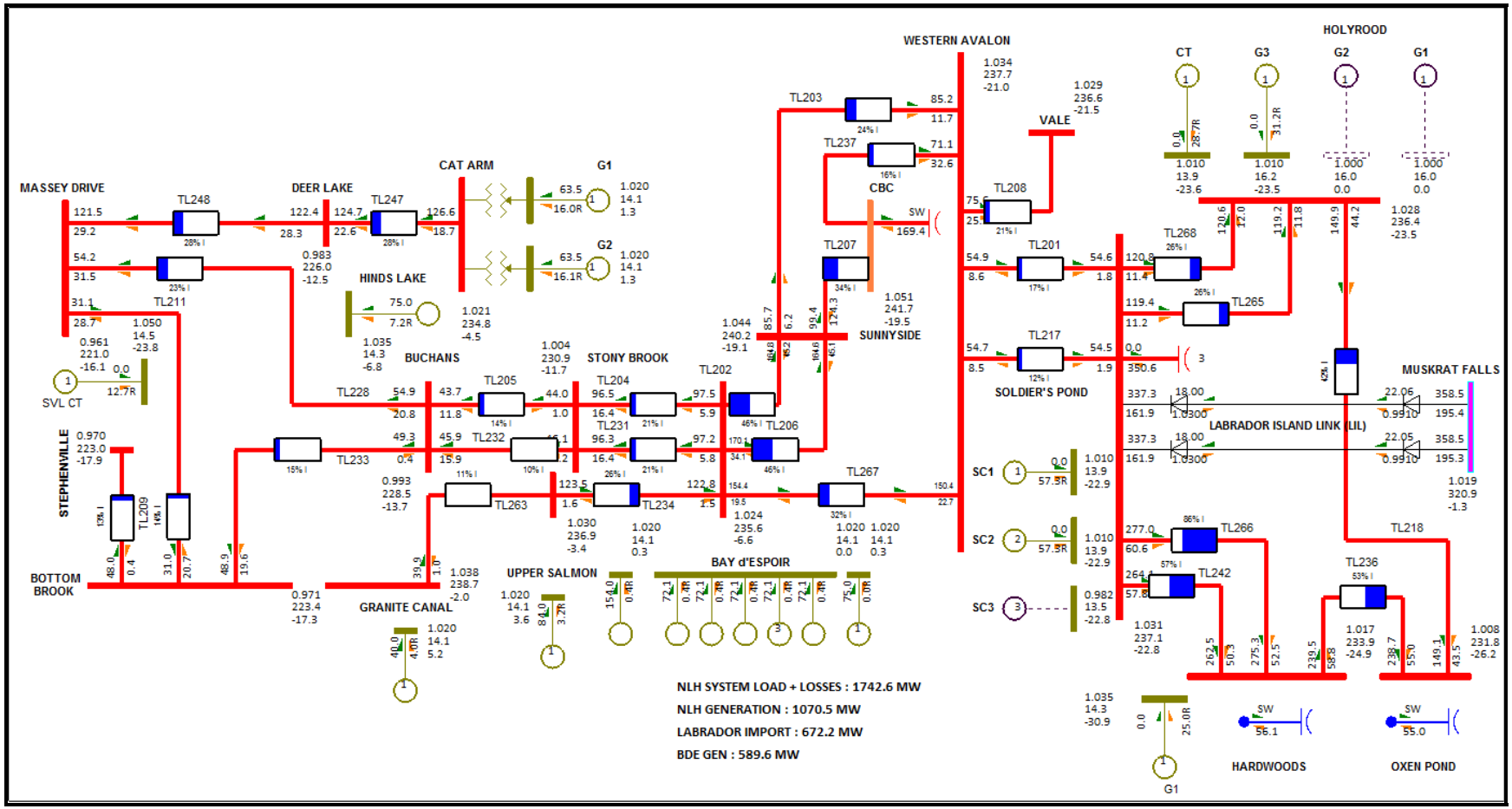


Figure 351 – Base Case 1 (BC1) Load Flow Plot – TL267 Built with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

Existing Bulk 230 kV Transmission System

Future Winter Peak (1757 MW) – Maximum Island Generation (1085 MW) with Reserve on LIL (672 MW)

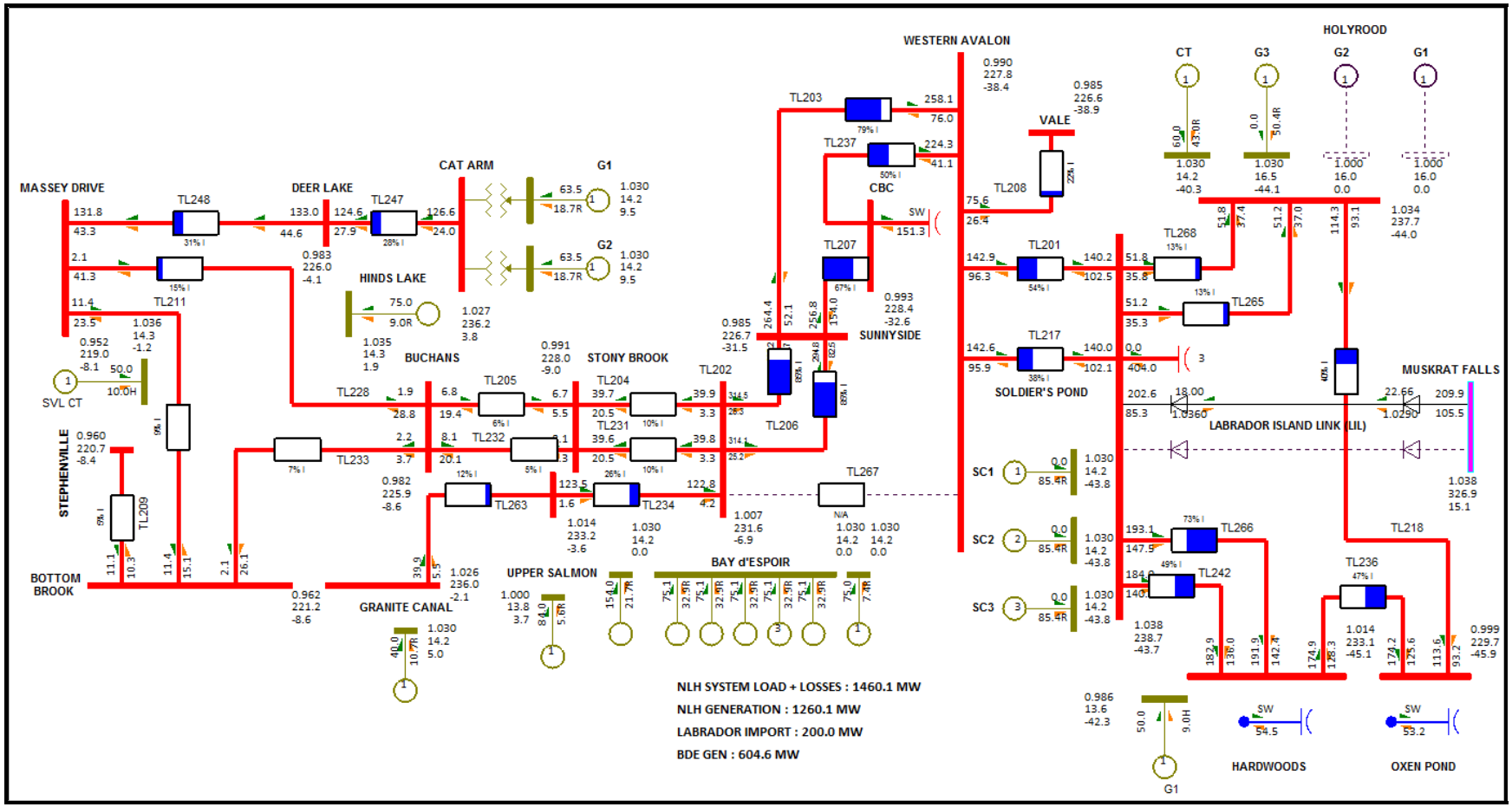


Figure 352 – Base Case 4 (BC4) Load Flow Plot – TL267 Out of Service

Existing Bulk 230 kV Transmission System

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

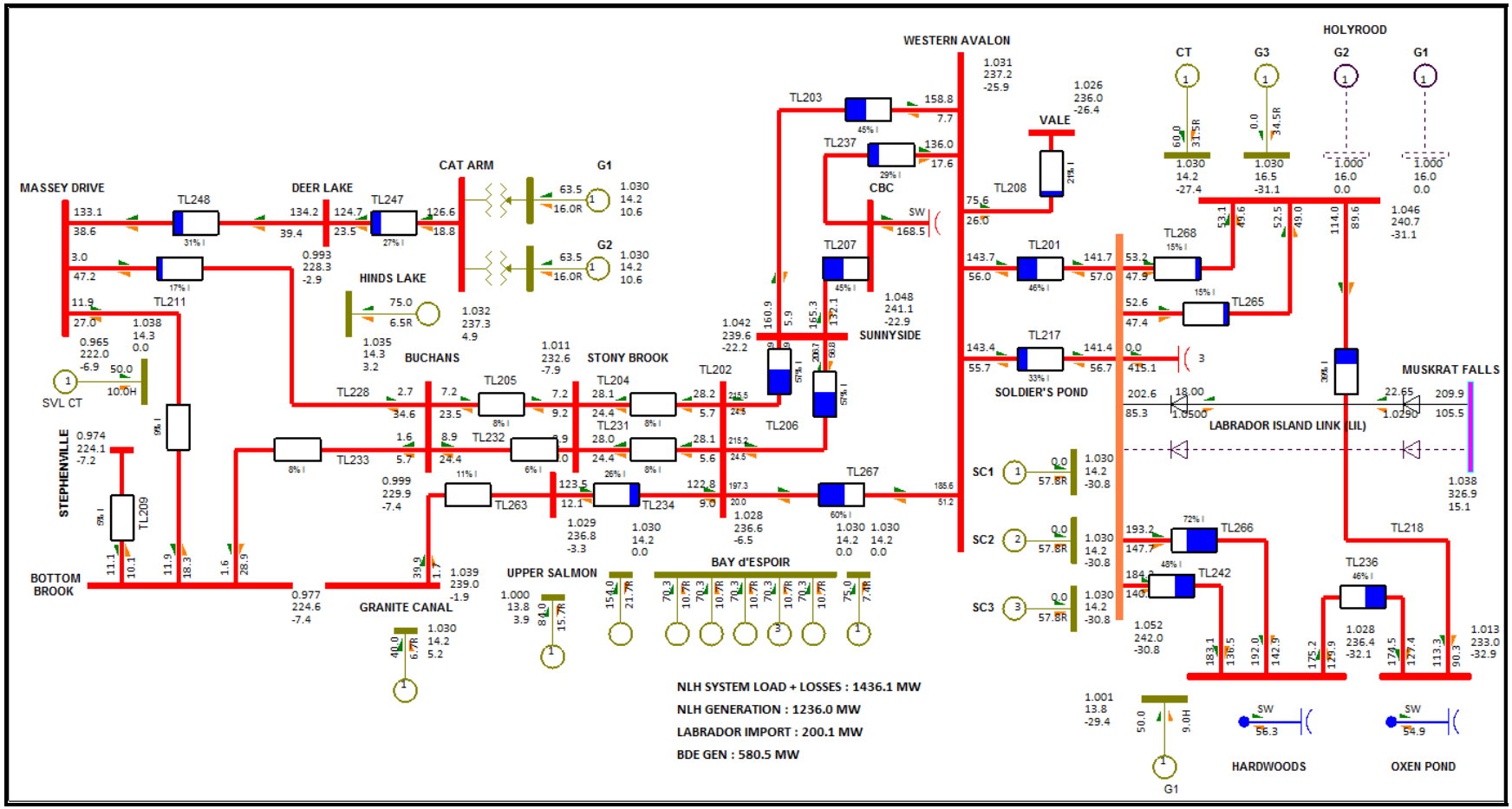


Figure 353 – Base Case 4 (BC4) Load Flow Plot – TL267 Built with 636 kcmil 26/7 ACSR GROSBEAK Conductor

Existing Bulk 230 kV Transmission System

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

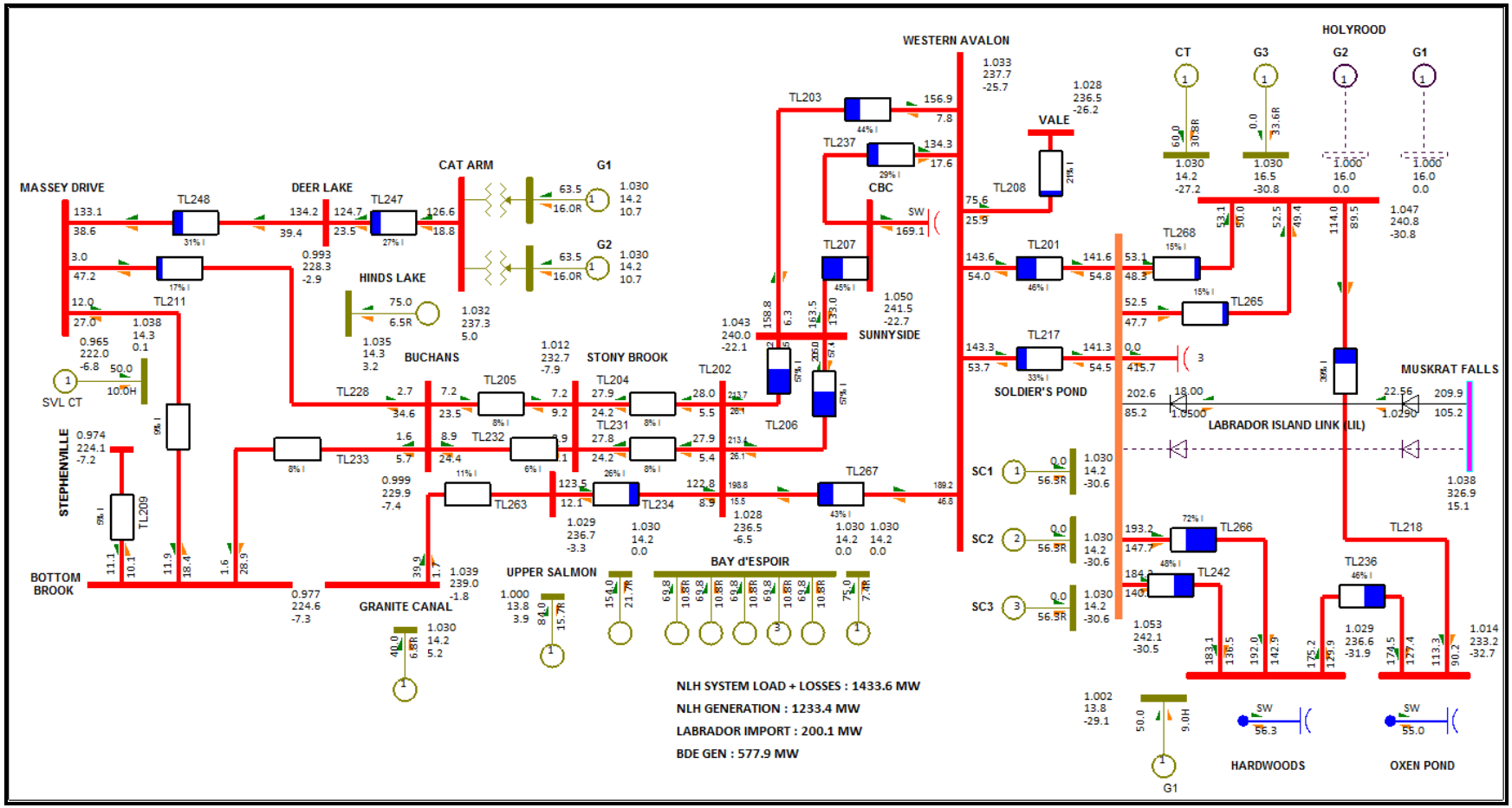


Figure 354 – Base Case 4 (BC4) Load Flow Plot – TL267 Built with 795 kcmil 26/7 ACSR DRAKE Conductor

Existing Bulk 230 kV Transmission System

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

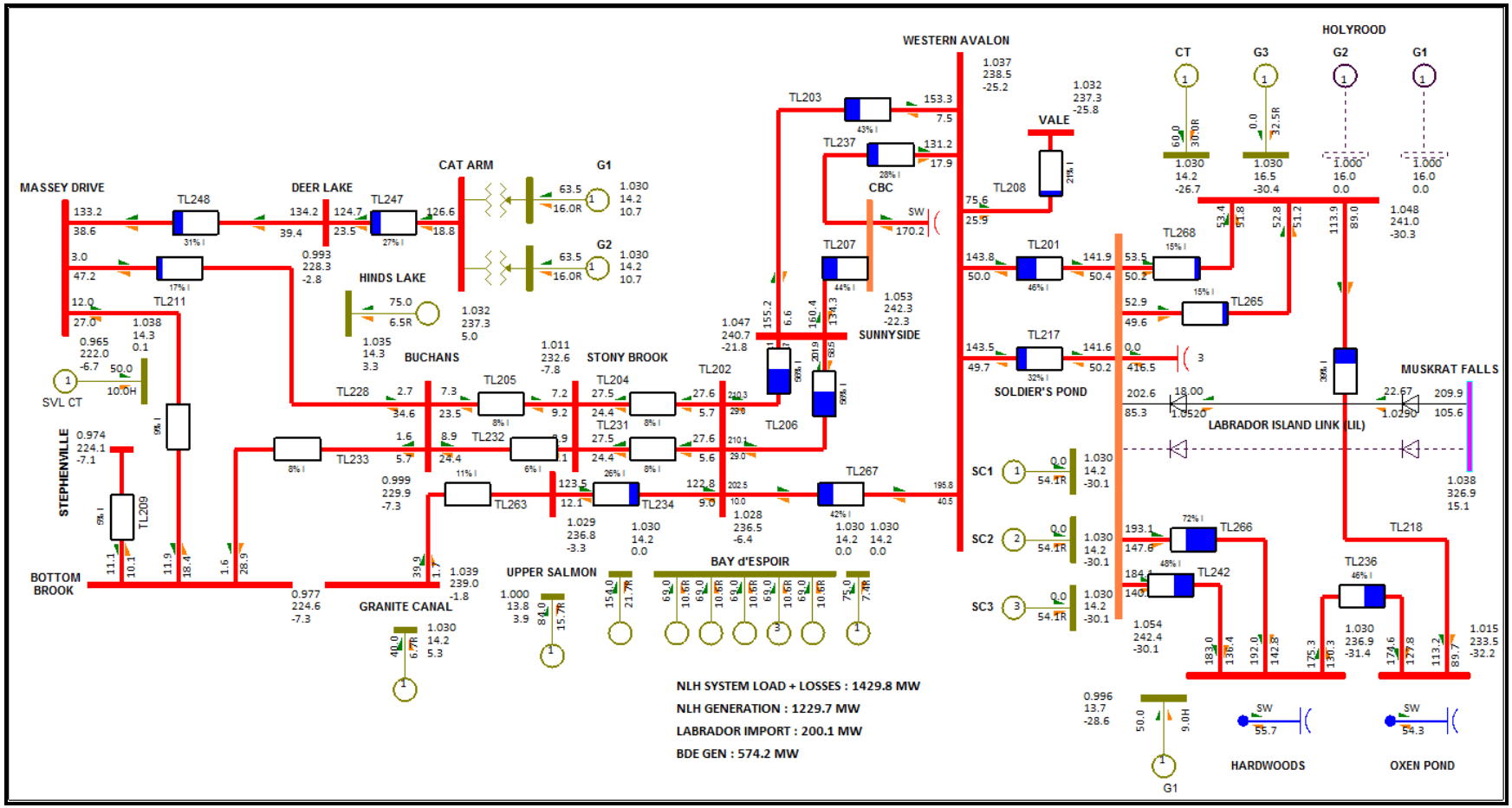


Figure 355 – Base Case 4 (BC4) Load Flow Plot – TL267 Built with 1192.5 kcmil 54/19 ACSR GRACKLE Conductor

Existing Bulk 230 kV Transmission System

Monopole Winter Peak (1458 MW) – Maximum Island Generation + CTs (1258 MW) with Reserve on LIL (200 MW)

APPENDIX B – TRANSIENT STABILITY PLOTS WITH BAY D'ESPOIR TO WESTERN AVALON 230 kV TRANSMISSION LINE ADDED

Figure B 1 - BC1TC - Bipole Fault - Relative Rotor Angle (Degrees)

Figure B 2 - BC1TC - Bipole Fault - System Frequency (Hz)

Figure B 3 - BC1TC - Bipole Fault - Active Power at the Rectifier (MW)

Figure B 4 - BC1TC - Bipole Fault - LIL Dc Voltage (V)

Figure B 5 - BC1TC - Bipole Fault - Bus Ac Voltage (pu)

Figure B 6 - BC1TC - Bipole Fault - Sheddable Load (MW)

Figure B 7 - BC1TC - Permanent Pole Fault - Relative Rotor Angle (Degrees)

Figure B 8 - BC1TC - Permanent Pole Fault - System Frequency (Hz)

Figure B 9 - BC1TC - Permanent Pole Fault - Active Power at the Rectifier (MW)

Figure B 10 - BC1TC - Permanent Pole Fault - LIL Dc Voltage (V)

Figure B 11 - BC1TC - Permanent Pole Fault - Bus Ac Voltage (pu)

Figure B 12 - BC1TC - Permanent Pole Fault - Sheddable Load (MW)

Figure B 13 - BC1TC - SOP SC Fault - Relative Rotor Angle (Degrees)

Figure B 14 - BC1TC - SOP SC Fault - System Frequency (Hz)

Figure B 15 - BC1TC - SOP SC Fault - Active Power at the Rectifier (MW)

Figure B 16 - BC1TC - SOP SC Fault - LIL Dc Voltage (V)

Figure B 17 - BC1TC - SOP SC Fault - Bus Ac Voltage (pu)

Figure B 18 - BC1TC - SOP SC Fault - Sheddable Load (MW)

Figure B 19 - BC1TC - SSD TL206 Fault - Relative Rotor Angle (Degrees)

Figure B 20 - BC1TC - SSD TL206 Fault - System Frequency (Hz)

Figure B 21 - BC1TC - SSD TL206 Fault - Active Power at the Rectifier (MW)

Figure B 22 - BC1TC - SSD TL206 Fault - LIL Dc Voltage (V)

Figure B 23 - BC1TC - SSD TL206 Fault - Bus Ac Voltage (pu)

Figure B 24 - BC1TC - SSD TL206 Fault - Sheddable Load (MW)

Figure B 25 - BC1TC - WAV BDE Line Fault - Relative Rotor Angle (Degrees)

Figure B 26 - BC1TC - WAV BDE Line Fault - System Frequency (Hz)

Figure B 27 - BC1TC - WAV BDE Line Fault - Active Power at the Rectifier (MW)

Figure B 28 - BC1TC - WAV BDE Line Fault - LIL Dc Voltage (V)

Figure B 29 - BC1TC - WAV BDE Line Fault - Bus Ac Voltage (pu)

Figure B 30 - BC1TC - WAV BDE Line Fault - Sheddable Load (MW)

Figure B 31 - BC2TC - Bipole Fault - Relative Rotor Angle (Degrees)

Figure B 32 - BC2TC - Bipole Fault - System Frequency (Hz)

Figure B 33 - BC2TC - Bipole Fault - Active Power at the Rectifier (MW)

Figure B 34 - BC2TC - Bipole Fault - LIL Dc Voltage (V)

Figure B 35 - BC2TC - Bipole Fault - Bus Ac Voltage (pu)

Figure B 36 - BC2TC - Bipole Fault - Sheddable Load (MW)

Figure B 37 - BC2TC - Permanent Pole Fault - Relative Rotor Angle (Degrees)

Figure B 38 - BC2TC - Permanent Pole Fault - System Frequency (Hz)

Figure B 39 - BC2TC - Permanent Pole Fault - Active Power at the Rectifier (MW)

Figure B 40 - BC2TC - Permanent Pole Fault - LIL Dc Voltage (V)

Figure B 41 - BC2TC - Permanent Pole Fault - Bus Ac Voltage (pu)

Figure B 42 - BC2TC - Permanent Pole Fault - Sheddable Load (MW)

Figure B 43 - BC2TC - SOP SC Fault - Relative Rotor Angle (Degrees)

Figure B 44 - BC2TC - SOP SC Fault - System Frequency (Hz)

Figure B 45 - BC2TC - SOP SC Fault - Active Power at the Rectifier (MW)

Figure B 46 - BC2TC - SOP SC Fault - LIL Dc Voltage (V)

Figure B 47 - BC2TC - SOP SC Fault - Bus Ac Voltage (pu)

Figure B 48 - BC2TC - SOP SC Fault - Sheddable Load (MW)

Figure B 49 - BC2TC - SSD TL206 Fault - Relative Rotor Angle (Degrees)

Figure B 50 - BC2TC - SSD TL206 Fault - System Frequency (Hz)

Figure B 51 - BC2TC - SSD TL206 Fault - Active Power at the Rectifier (MW)

Figure B 52 - BC2TC - SSD TL206 Fault - LIL Dc Voltage (V)

Figure B 53 - BC2TC - SSD TL206 Fault - Bus Ac Voltage (pu)

Figure B 54 - BC2TC - SSD TL206 Fault - Sheddable Load (MW)

Figure B 55 - BC2TC - WAV BDE Line Fault - Relative Rotor Angle (Degrees)

Figure B 56 - BC2TC - WAV BDE Line Fault - System Frequency (Hz)

Figure B 57 - BC2TC - WAV BDE Line Fault - Active Power at the Rectifier (MW)

Figure B 58 - BC2TC - WAV BDE Line Fault - LIL Dc Voltage (V)

Figure B 59 - BC2TC - WAV BDE Line Fault - Bus Ac Voltage (pu)

Figure B 60 - BC2TC - WAV BDE Line Fault - Sheddable Load (MW)

Figure B 61 - BC3TC - Bipole Fault - Relative Rotor Angle (Degrees)

Figure B 62 - BC3TC - Bipole Fault - System Frequency (Hz)

Figure B 63 - BC3TC - Bipole Fault - Active Power at the Rectifier (MW)

Figure B 64 - BC3TC - Bipole Fault - LIL Dc Voltage (V)

Figure B 65 - BC3TC - Bipole Fault - Bus Ac Voltage (pu)

Figure B 66 - BC3TC - Bipole Fault - Sheddable Load (MW)

Figure B 67 - BC3TC - Permanent Pole Fault - Relative Rotor Angle (Degrees)

Figure B 68 - BC3TC - Permanent Pole Fault - System Frequency (Hz)

Figure B 69 - BC3TC - Permanent Pole Fault - Active Power at the Rectifier (MW)

Figure B 70 - BC3TC - Permanent Pole Fault - LIL Dc Voltage (V)

Figure B 71 - BC3TC - Permanent Pole Fault - Bus Ac Voltage (pu)

Figure B 72 - BC3TC - Permanent Pole Fault - Sheddable Load (MW)

Figure B 73 - BC3TC - SOP SC Fault - Relative Rotor Angle (Degrees)

Figure B 74 - BC3TC - SOP SC Fault - System Frequency (Hz)

Figure B 75 - BC3TC - SOP SC Fault - Active Power at the Rectifier (MW)

Figure B 76 - BC3TC - SOP SC Fault - LIL Dc Voltage (V)

Figure B 77 - BC3TC - SOP SC Fault - Bus Ac Voltage (pu)

Figure B 78 - BC3TC - SOP SC Fault - Sheddable Load (MW)

Figure B 79 - BC3TC - SSD TL206 Fault - Relative Rotor Angle (Degrees)

Figure B 80 - BC3TC - SSD TL206 Fault - System Frequency (Hz)

Figure B 81 - BC3TC - SSD TL206 Fault - Active Power at the Rectifier (MW)

Figure B 82 - BC3TC - SSD TL206 Fault - LIL Dc Voltage (V)

Figure B 83 - BC3TC - SSD TL206 Fault - Bus Ac Voltage (pu)

Figure B 84 - BC3TC - SSD TL206 Fault - Sheddable Load (MW)

Figure B 85 - BC3TC - WAV BDE Line Fault - Relative Rotor Angle (Degrees)

Figure B 86 - BC3TC - WAV BDE Line Fault - System Frequency (Hz)

Figure B 87 - BC3TC - WAV BDE Line Fault - Active Power at the Rectifier (MW)

Figure B 88 - BC3TC - WAV BDE Line Fault - LIL Dc Voltage (V)

Figure B 89 - BC3TC - WAV BDE Line Fault - Bus Ac Voltage (pu)

Figure B 90 - BC3TC - WAV BDE Line Fault - Sheddable Load (MW)

Figure B 91 - BC4TC - Bipole Fault - Relative Rotor Angle (Degrees)

Figure B 92 - BC4TC - Bipole Fault - System Frequency (Hz)

Figure B 93 - BC4TC - Bipole Fault - Active Power at the Rectifier (MW)

Figure B 94 - BC4TC - Bipole Fault - LIL Dc Voltage (V)

Figure B 95 - BC4TC - Bipole Fault - Bus Ac Voltage (pu)

Figure B 96 - BC4TC - Bipole Fault - Sheddable Load (MW)

Figure B 97 - BC4TC - Permanent Pole Fault - Relative Rotor Angle (Degrees)

Figure B 98 - BC4TC - Permanent Pole Fault - System Frequency (Hz)

Figure B 99 - BC4TC - Permanent Pole Fault - Active Power at the Rectifier (MW)

Figure B 100 - BC4TC - Permanent Pole Fault - LIL Dc Voltage (V)

Figure B 101 - BC4TC - Permanent Pole Fault - Bus Ac Voltage (pu)

Figure B 102 - BC4TC - Permanent Pole Fault - Sheddable Load (MW)

Figure B 103 - BC4TC - SOP SC Fault - Relative Rotor Angle (Degrees)

Figure B 104 - BC4TC - SOP SC Fault - System Frequency (Hz)

Figure B 105 - BC4TC - SOP SC Fault - Active Power at the Rectifier (MW)

Figure B 106 - BC4TC - SOP SC Fault - LIL Dc Voltage (V)

Figure B 107 - BC4TC - SOP SC Fault - Bus Ac Voltage (pu)

Figure B 108 - BC4TC - SOP SC Fault - Sheddable Load (MW)

Figure B 109 - BC4TC - SSD TL206 Fault - Relative Rotor Angle (Degrees)

Figure B 110 - BC4TC - SSD TL206 Fault - System Frequency (Hz)

Figure B 111 - BC4TC - SSD TL206 Fault - Active Power at the Rectifier (MW)

Figure B 112 - BC4TC - SSD TL206 Fault - LIL Dc Voltage (V)

Figure B 113 - BC4TC - SSD TL206 Fault - Bus Ac Voltage (pu)

Figure B 114 - BC4TC - SSD TL206 Fault - Sheddable Load (MW)

Figure B 115 - BC4TC - WAV BDE Line Fault - Relative Rotor Angle (Degrees)

Figure B 116 - BC4TC - WAV BDE Line Fault - System Frequency (Hz)

Figure B 117 - BC4TC - WAV BDE Line Fault - Active Power at the Rectifier (MW)

Figure B 118 - BC4TC - WAV BDE Line Fault - LIL Dc Voltage (V)

Figure B 119 - BC4TC - WAV BDE Line Fault - Bus Ac Voltage (pu)

Figure B 120 - BC4TC - WAV BDE Line Fault - Sheddable Load (MW)

Figure B 121 - BC5TC - Bipole Fault - Relative Rotor Angle (Degrees)

Figure B 122 - BC5TC - Bipole Fault - System Frequency (Hz)

Figure B 123 - BC5TC - Bipole Fault - Active Power at the Rectifier (MW)

Figure B 124 - BC5TC - Bipole Fault - LIL Dc Voltage (V)

Figure B 125 - BC5TC - Bipole Fault - Bus Ac Voltage (pu)

Figure B 126 - BC5TC - Bipole Fault - Sheddable Load (MW)

Figure B 127 - BC5TC - Permanent Pole Fault - Relative Rotor Angle (Degrees)

Figure B 128 - BC5TC - Permanent Pole Fault - System Frequency (Hz)

Figure B 129 - BC5TC - Permanent Pole Fault - Active Power at the Rectifier (MW)

Figure B 130 - BC5TC - Permanent Pole Fault - LIL Dc Voltage (V)

Figure B 131 - BC5TC - Permanent Pole Fault - Bus Ac Voltage (pu)

Figure B 132 - BC5TC - Permanent Pole Fault - Sheddable Load (MW)

Figure B 133 - BC5TC - SOP SC Fault - Relative Rotor Angle (Degrees)

Figure B 134 - BC5TC - SOP SC Fault - System Frequency (Hz)

Figure B 135 - BC5TC - SOP SC Fault - Active Power at the Rectifier (MW)

Figure B 136 - BC5TC - SOP SC Fault - LIL Dc Voltage (V)

Figure B 137 - BC5TC - SOP SC Fault - Bus Ac Voltage (pu)

Figure B 138 - BC5TC - SOP SC Fault - Sheddable Load (MW)

Figure B 139 - BC5TC - SSD TL206 Fault - Relative Rotor Angle (Degrees)

Figure B 140 - BC5TC - SSD TL206 Fault - System Frequency (Hz)

Figure B 141 - BC5TC - SSD TL206 Fault - Active Power at the Rectifier (MW)

Figure B 142 - BC5TC - SSD TL206 Fault - LIL Dc Voltage (V)

Figure B 143 - BC5TC - SSD TL206 Fault - Bus Ac Voltage (pu)

Figure B 144 - BC5TC - SSD TL206 Fault - Sheddable Load (MW)

Figure B 145 - BC5TC - WAV BDE Line Fault - Relative Rotor Angle (Degrees)

Figure B 146 - BC5TC - WAV BDE Line Fault - System Frequency (Hz)

Figure B 147 - BC5TC - WAV BDE Line Fault - Active Power at the Rectifier (MW)

Figure B 148 - BC5TC - WAV BDE Line Fault - LIL Dc Voltage (V)

Figure B 149 - BC5TC - WAV BDE Line Fault - Bus Ac Voltage (pu)

Figure B 150 - BC5TC - WAV BDE Line Fault - Sheddable Load (MW)

Figure B 151 - BC6TC - Bipole Fault - Relative Rotor Angle (Degrees)

Figure B 152 - BC6TC - Bipole Fault - System Frequency (Hz)

Figure B 153 - BC6TC - Bipole Fault - Active Power at the Rectifier (MW)

Figure B 154 - BC6TC - Bipole Fault - LIL Dc Voltage (V)

Figure B 155 - BC6TC - Bipole Fault - Bus Ac Voltage (pu)

Figure B 156 - BC6TC - Bipole Fault - Sheddable Load (MW)

Figure B 157 - BC6TC - Permanent Pole Fault - Relative Rotor Angle (Degrees)

Figure B 158 - BC6TC - Permanent Pole Fault - System Frequency (Hz)

Figure B 159 - BC6TC - Permanent Pole Fault - Active Power at the Rectifier (MW)

Figure B 160 - BC6TC - Permanent Pole Fault - LIL Dc Voltage (V)

Figure B 161 - BC6TC - Permanent Pole Fault - Bus Ac Voltage (pu)

Figure B 162 - BC6TC - Permanent Pole Fault - Sheddable Load (MW)

Figure B 163 - BC6TC - SOP SC Fault - Relative Rotor Angle (Degrees)

Figure B 164 - BC6TC - SOP SC Fault - System Frequency (Hz)

Figure B 165 - BC6TC - SOP SC Fault - Active Power at the Rectifier (MW)

Figure B 166 - BC6TC - SOP SC Fault - LIL Dc Voltage (V)

Figure B 167 - BC6TC - SOP SC Fault - Bus Ac Voltage (pu)

Figure B 168 - BC6TC - SOP SC Fault - Sheddable Load (MW)

Figure B 169 - BC6TC - SSD TL206 Fault - Relative Rotor Angle (Degrees)

Figure B 170 - BC6TC - SSD TL206 Fault - System Frequency (Hz)

Figure B 171 - BC6TC - SSD TL206 Fault - Active Power at the Rectifier (MW)

Figure B 172 - BC6TC - SSD TL206 Fault - LIL Dc Voltage (V)

Figure B 173 - BC6TC - SSD TL206 Fault - Bus Ac Voltage (pu)

Figure B 174 - BC6TC - SSD TL206 Fault - Sheddable Load (MW)

Figure B 175 - BC6TC - WAV BDE Line Fault - Relative Rotor Angle (Degrees)

Figure B 176 - BC6TC - WAV BDE Line Fault - System Frequency (Hz)

Figure B 177 - BC6TC - WAV BDE Line Fault - Active Power at the Rectifier (MW)

Figure B 178 - BC6TC - WAV BDE Line Fault - LIL Dc Voltage (V)

Figure B 179 - BC6TC - WAV BDE Line Fault - Bus Ac Voltage (pu)

Figure B 180 - BC6TC - WAV BDE Line Fault - Sheddable Load (MW)

Figure B 181 - BC7TC - Bipole Fault - Relative Rotor Angle (Degrees)

Figure B 182 - BC7TC - Bipole Fault - System Frequency (Hz)

Figure B 183 - BC7TC - Bipole Fault - Active Power at the Rectifier (MW)

Figure B 184 - BC7TC - Bipole Fault - LIL Dc Voltage (V)

Figure B 185 - BC7TC - Bipole Fault - Bus Ac Voltage (pu)

Figure B 186 - BC7TC - Bipole Fault - Sheddable Load (MW)

Figure B 187 - BC7TC - Permanent Pole Fault - Relative Rotor Angle (Degrees)

Figure B 188 - BC7TC - Permanent Pole Fault - System Frequency (Hz)

Figure B 189 - BC7TC - Permanent Pole Fault - Active Power at the Rectifier (MW)

Figure B 190 - BC7TC - Permanent Pole Fault - LIL Dc Voltage (V)

Figure B 191 - BC7TC - Permanent Pole Fault - Bus Ac Voltage (pu)

Figure B 192 - BC7TC - Permanent Pole Fault - Sheddable Load (MW)

Figure B 193 - BC7TC - SOP SC Fault - Relative Rotor Angle (Degrees)

Figure B 194 - BC7TC - SOP SC Fault - System Frequency (Hz)

Figure B 195 - BC7TC - SOP SC Fault - Active Power at the Rectifier (MW)

Figure B 196 - BC7TC - SOP SC Fault - LIL Dc Voltage (V)

Figure B 197 - BC7TC - SOP SC Fault - Bus Ac Voltage (pu)

Figure B 198 - BC7TC - SOP SC Fault - Sheddable Load (MW)

Figure B 199 - BC7TC - SSD TL206 Fault - Relative Rotor Angle (Degrees)

Figure B 200 - BC7TC - SSD TL206 Fault - System Frequency (Hz)

Figure B 201 - BC7TC - SSD TL206 Fault - Active Power at the Rectifier (MW)

Figure B 202 - BC7TC - SSD TL206 Fault - LIL Dc Voltage (V)

Figure B 203 - BC7TC - SSD TL206 Fault - Bus Ac Voltage (pu)

Figure B 204 - BC7TC - SSD TL206 Fault - Sheddable Load (MW)

Figure B 205 - BC7TC - WAV BDE Line Fault - Relative Rotor Angle (Degrees)

Figure B 206 - BC7TC - WAV BDE Line Fault - System Frequency (Hz)

Figure B 207 - BC7TC - WAV BDE Line Fault - Active Power at the Rectifier (MW)

Figure B 208 - BC7TC - WAV BDE Line Fault - LIL Dc Voltage (V)

Figure B 209 - BC7TC - WAV BDE Line Fault - Bus Ac Voltage (pu)

Figure B 210 - BC7TC - WAV BDE Line Fault - Sheddable Load (MW)

Figure B 211 - BC8TC - Bipole Fault - Relative Rotor Angle (Degrees)

Figure B 212 - BC8TC - Bipole Fault - System Frequency (Hz)

Figure B 213 - BC8TC - Bipole Fault - Active Power at the Rectifier (MW)

Figure B 214 - BC8TC - Bipole Fault - LIL Dc Voltage (V)

Figure B 215 - BC8TC - Bipole Fault - Bus Ac Voltage (pu)

Figure B 216 - BC8TC - Bipole Fault - Sheddable Load (MW)

Figure B 217 - BC8TC - Permanent Pole Fault - Relative Rotor Angle (Degrees)

Figure B 218 - BC8TC - Permanent Pole Fault - System Frequency (Hz)

Figure B 219 - BC8TC - Permanent Pole Fault - Active Power at the Rectifier (MW)

Figure B 220 - BC8TC - Permanent Pole Fault - LIL Dc Voltage (V)

Figure B 221 - BC8TC - Permanent Pole Fault - Bus Ac Voltage (pu)

Figure B 222 - BC8TC - Permanent Pole Fault - Sheddable Load (MW)

Figure B 223 - BC8TC - SOP SC Fault - Relative Rotor Angle (Degrees)

Figure B 224 - BC8TC - SOP SC Fault - System Frequency (Hz)

Figure B 225 - BC8TC - SOP SC Fault - Active Power at the Rectifier (MW)

Figure B 226 - BC8TC - SOP SC Fault - LIL Dc Voltage (V)

Figure B 227 - BC8TC - SOP SC Fault - Bus Ac Voltage (pu)

Figure B 228 - BC8TC - SOP SC Fault - Sheddable Load (MW)

Figure B 229 - BC8TC - SSD TL206 Fault - Relative Rotor Angle (Degrees)

Figure B 230 - BC8TC - SSD TL206 Fault - System Frequency (Hz)

Figure B 231 - BC8TC - SSD TL206 Fault - Active Power at the Rectifier (MW)

Figure B 232 - BC8TC - SSD TL206 Fault - LIL Dc Voltage (V)

Figure B 233 - BC8TC - SSD TL206 Fault - Bus Ac Voltage (pu)

Figure B 234 - BC8TC - SSD TL206 Fault - Sheddable Load (MW)

Figure B 235 - BC8TC - WAV BDE Line Fault - Relative Rotor Angle (Degrees)

Figure B 236 - BC8TC - WAV BDE Line Fault - System Frequency (Hz)

Figure B 237 - BC8TC - WAV BDE Line Fault - Active Power at the Rectifier (MW)

Figure B 238 - BC8TC - WAV BDE Line Fault - LIL Dc Voltage (V)

Figure B 239 - BC8TC - WAV BDE Line Fault - Bus Ac Voltage (pu)

Figure B 240 - BC8TC - WAV BDE Line Fault - Sheddable Load (MW)

Figure B 241 - BC9TC - Bipole Fault - Relative Rotor Angle (Degrees)

Figure B 242 - BC9TC - Bipole Fault - System Frequency (Hz)

Figure B 243 - BC9TC - Bipole Fault - Active Power at the Rectifier (MW)

Figure B 244 - BC9TC - Bipole Fault - LIL Dc Voltage (V)

Figure B 245 - BC9TC - Bipole Fault - Bus Ac Voltage (pu)

Figure B 246 - BC9TC - Bipole Fault - Sheddable Load (MW)

Figure B 247 - BC9TC - Permanent Pole Fault - Relative Rotor Angle (Degrees)

Figure B 248 - BC9TC - Permanent Pole Fault - System Frequency (Hz)

Figure B 249 - BC9TC - Permanent Pole Fault - Active Power at the Rectifier (MW)

Figure B 250 - BC9TC - Permanent Pole Fault - LIL Dc Voltage (V)

Figure B 251 - BC9TC - Permanent Pole Fault - Bus Ac Voltage (pu)

Figure B 252 - BC9TC - Permanent Pole Fault - Sheddable Load (MW)

Figure B 253 - BC9TC - SOP SC Fault - Relative Rotor Angle (Degrees)

Figure B 254 - BC9TC - SOP SC Fault - System Frequency (Hz)

Figure B 255 - BC9TC - SOP SC Fault - Active Power at the Rectifier (MW)

Figure B 256 - BC9TC - SOP SC Fault - LIL Dc Voltage (V)

Figure B 257 - BC9TC - SOP SC Fault - Bus Ac Voltage (pu)

Figure B 258 - BC9TC - SOP SC Fault - Sheddable Load (MW)

Figure B 259 - BC9TC - SSD TL206 Fault - Relative Rotor Angle (Degrees)

Figure B 260 - BC9TC - SSD TL206 Fault - System Frequency (Hz)

Figure B 261 - BC9TC - SSD TL206 Fault - Active Power at the Rectifier (MW)

Figure B 262 - BC9TC - SSD TL206 Fault - LIL Dc Voltage (V)

Figure B 263 - BC9TC - SSD TL206 Fault - Bus Ac Voltage (pu)

Figure B 264 - BC9TC - SSD TL206 Fault - Sheddable Load (MW)

Figure B 265 - BC9TC - WAV BDE Line Fault - Relative Rotor Angle (Degrees)

Figure B 266 - BC9TC - WAV BDE Line Fault - System Frequency (Hz)

Figure B 267 - BC9TC - WAV BDE Line Fault - Active Power at the Rectifier (MW)

Figure B 268 - BC9TC - WAV BDE Line Fault - LIL Dc Voltage (V)

Figure B 269 - BC9TC - WAV BDE Line Fault - Bus Ac Voltage (pu)

Figure B 270 - BC9TC - WAV BDE Line Fault - Sheddable Load (MW)

Figure B 271 - BC10TC - Bipole Fault - Relative Rotor Angle (Degrees)

Figure B 272 - BC10TC - Bipole Fault - System Frequency (Hz)

Figure B 273 - BC10TC - Bipole Fault - Active Power at the Rectifier (MW)

Figure B 274 - BC10TC - Bipole Fault - LIL Dc Voltage (V)

Figure B 275 - BC10TC - Bipole Fault - Bus Ac Voltage (pu)

Figure B 276 - BC10TC - Bipole Fault - Sheddable Load (MW)

Figure B 277 - BC10TC - Permanent Pole Fault - Relative Rotor Angle (Degrees)

Figure B 278 - BC10TC - Permanent Pole Fault - System Frequency (Hz)

Figure B 279 - BC10TC - Permanent Pole Fault - Active Power at the Rectifier (MW)

Figure B 280 - BC10TC - Permanent Pole Fault - LIL Dc Voltage (V)

Figure B 281 - BC10TC - Permanent Pole Fault - Bus Ac Voltage (pu)

Figure B 282 - BC10TC - Permanent Pole Fault - Sheddable Load (MW)

Figure B 283 - BC10TC - SOP SC Fault - Relative Rotor Angle (Degrees)

Figure B 284 - BC10TC - SOP SC Fault - System Frequency (Hz)

Figure B 285 - BC10TC - SOP SC Fault - Active Power at the Rectifier (MW)

Figure B 286 - BC10TC - SOP SC Fault - LIL Dc Voltage (V)

Figure B 287 - BC10TC - SOP SC Fault - Bus Ac Voltage (pu)

Figure B 288 - BC10TC - SOP SC Fault - Sheddable Load (MW)

Figure B 289 - BC10TC - SSD TL206 Fault - Relative Rotor Angle (Degrees)

Figure B 290 - BC10TC - SSD TL206 Fault - System Frequency (Hz)

Figure B 291 - BC10TC - SSD TL206 Fault - Active Power at the Rectifier (MW)

Figure B 292 - BC10TC - SSD TL206 Fault - LIL Dc Voltage (V)

Figure B 293 - BC10TC - SSD TL206 Fault - Bus Ac Voltage (pu)

Figure B 294 - BC10TC - SSD TL206 Fault - Sheddable Load (MW)

Figure B 295 - BC10TC - WAV BDE Line Fault - Relative Rotor Angle (Degrees)

Figure B 296 - BC10TC - WAV BDE Line Fault - System Frequency (Hz)

Figure B 297 - BC10TC - WAV BDE Line Fault - Active Power at the Rectifier (MW)

Figure B 298 - BC10TC - WAV BDE Line Fault - LIL Dc Voltage (V)

Figure B 299 - BC10TC - WAV BDE Line Fault - Bus Ac Voltage (pu)

Figure B 300 - BC10TC - WAV BDE Line Fault - Sheddable Load (MW)

Figure B 301 - BC11TC - Bipole Fault - Relative Rotor Angle (Degrees)

Figure B 302 - BC11TC - Bipole Fault - System Frequency (Hz)

Figure B 303 - BC11TC - Bipole Fault - Active Power at the Rectifier (MW)

Figure B 304 - BC11TC - Bipole Fault - LIL Dc Voltage (V)

Figure B 305 - BC11TC - Bipole Fault - Bus Ac Voltage (pu)

Figure B 306 - BC11TC - Bipole Fault - Sheddable Load (MW)

Figure B 307 - BC11TC - Permanent Pole Fault - Relative Rotor Angle (Degrees)

Figure B 308 - BC11TC - Permanent Pole Fault - System Frequency (Hz)

Figure B 309 - BC11TC - Permanent Pole Fault - Active Power at the Rectifier (MW)

Figure B 310 - BC11TC - Permanent Pole Fault - LIL Dc Voltage (V)

Figure B 311 - BC11TC - Permanent Pole Fault - Bus Ac Voltage (pu)

Figure B 312 - BC11TC - Permanent Pole Fault - Sheddable Load (MW)

Figure B 313 - BC11TC - SOP SC Fault - Relative Rotor Angle (Degrees)

Figure B 314 - BC11TC - SOP SC Fault - System Frequency (Hz)

Figure B 315 - BC11TC - SOP SC Fault - Active Power at the Rectifier (MW)

Figure B 316 - BC11TC - SOP SC Fault - LIL Dc Voltage (V)

Figure B 317 - BC11TC - SOP SC Fault - Bus Ac Voltage (pu)

Figure B 318 - BC11TC - SOP SC Fault - Sheddable Load (MW)

Figure B 319 - BC11TC - SSD TL206 Fault - Relative Rotor Angle (Degrees)

Figure B 320 - BC11TC - SSD TL206 Fault - System Frequency (Hz)

Figure B 321 - BC11TC - SSD TL206 Fault - Active Power at the Rectifier (MW)

Figure B 322 - BC11TC - SSD TL206 Fault - LIL Dc Voltage (V)

Figure B 323 - BC11TC - SSD TL206 Fault - Bus Ac Voltage (pu)

Figure B 324 - BC11TC - SSD TL206 Fault - Sheddable Load (MW)

Figure B 325 - BC11TC - WAV BDE Line Fault - Relative Rotor Angle (Degrees)

Figure B 326 - BC11TC - WAV BDE Line Fault - System Frequency (Hz)

Figure B 327 - BC11TC - WAV BDE Line Fault - Active Power at the Rectifier (MW)

Figure B 328 - BC11TC - WAV BDE Line Fault - LIL Dc Voltage (V)

Figure B 329 - BC11TC - WAV BDE Line Fault - Bus Ac Voltage (pu)

Figure B 330 - BC11TC - WAV BDE Line Fault - Sheddable Load (MW)

APPENDIX B – TRANSIENT STABILITY PLOTS

With Bay d'Espoir to Western Avalon 230 kV Transmission Line Added

1.1. BASE CASE 1 TRANSIENT STABILITY PLOTS

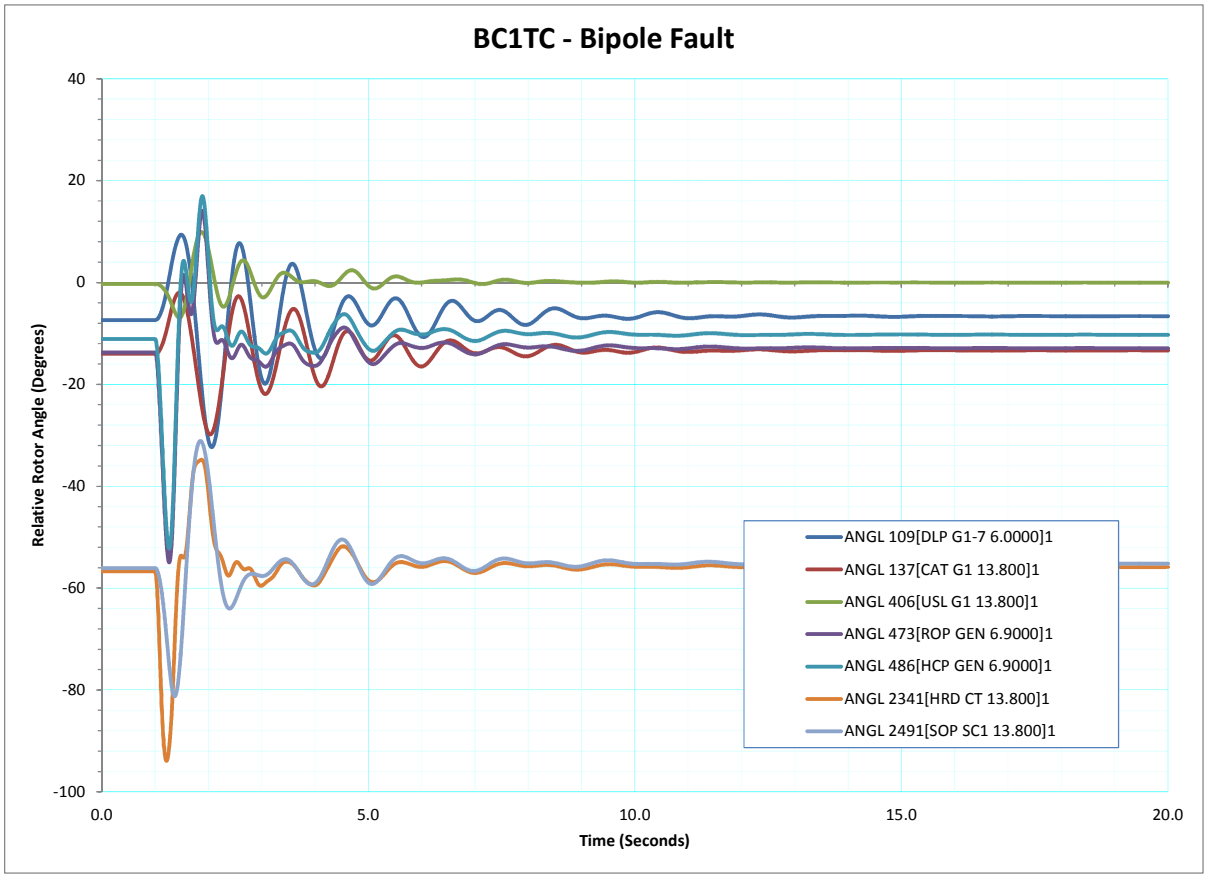


Figure 1 - BC1TC - Bipole Fault - Relative Rotor Angle (Degrees)

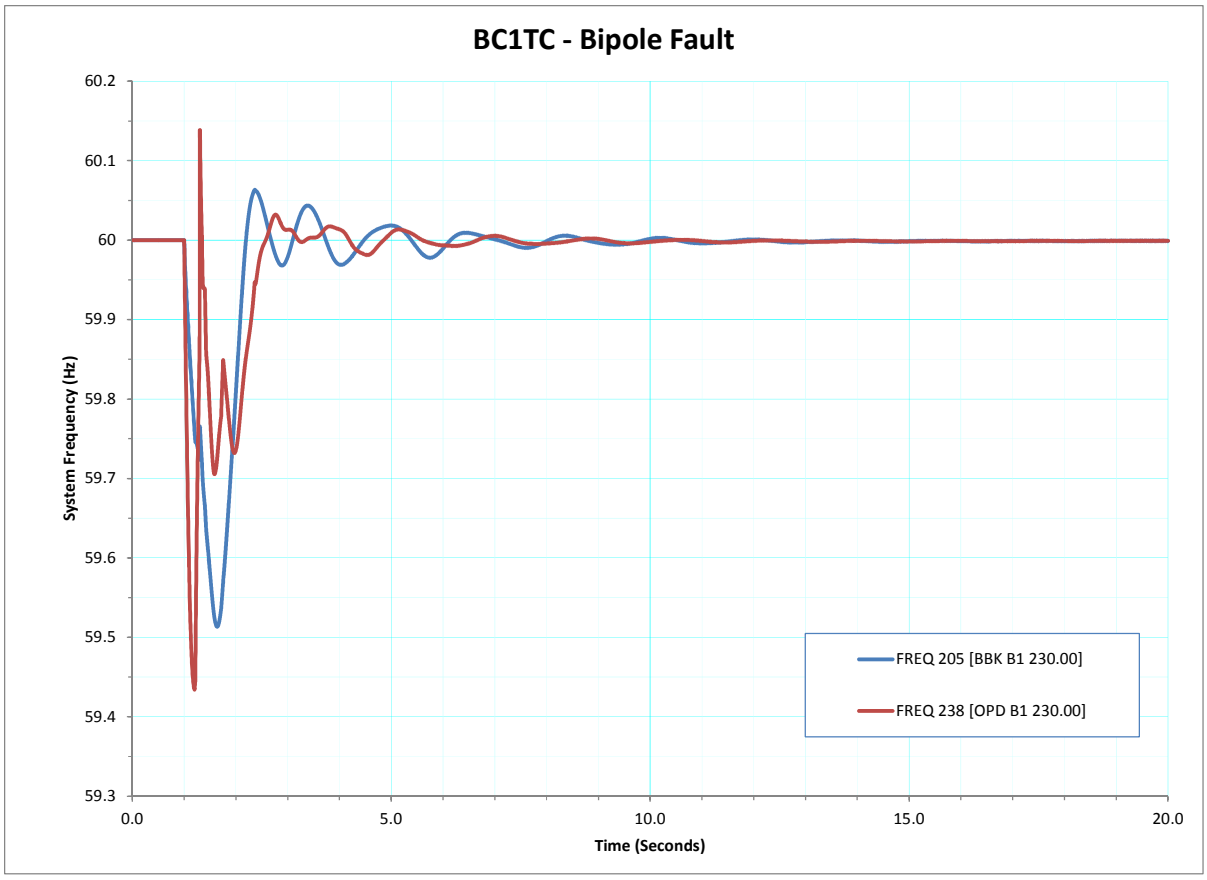


Figure 2 - BC1TC - Bipole Fault - System Frequency (Hz)

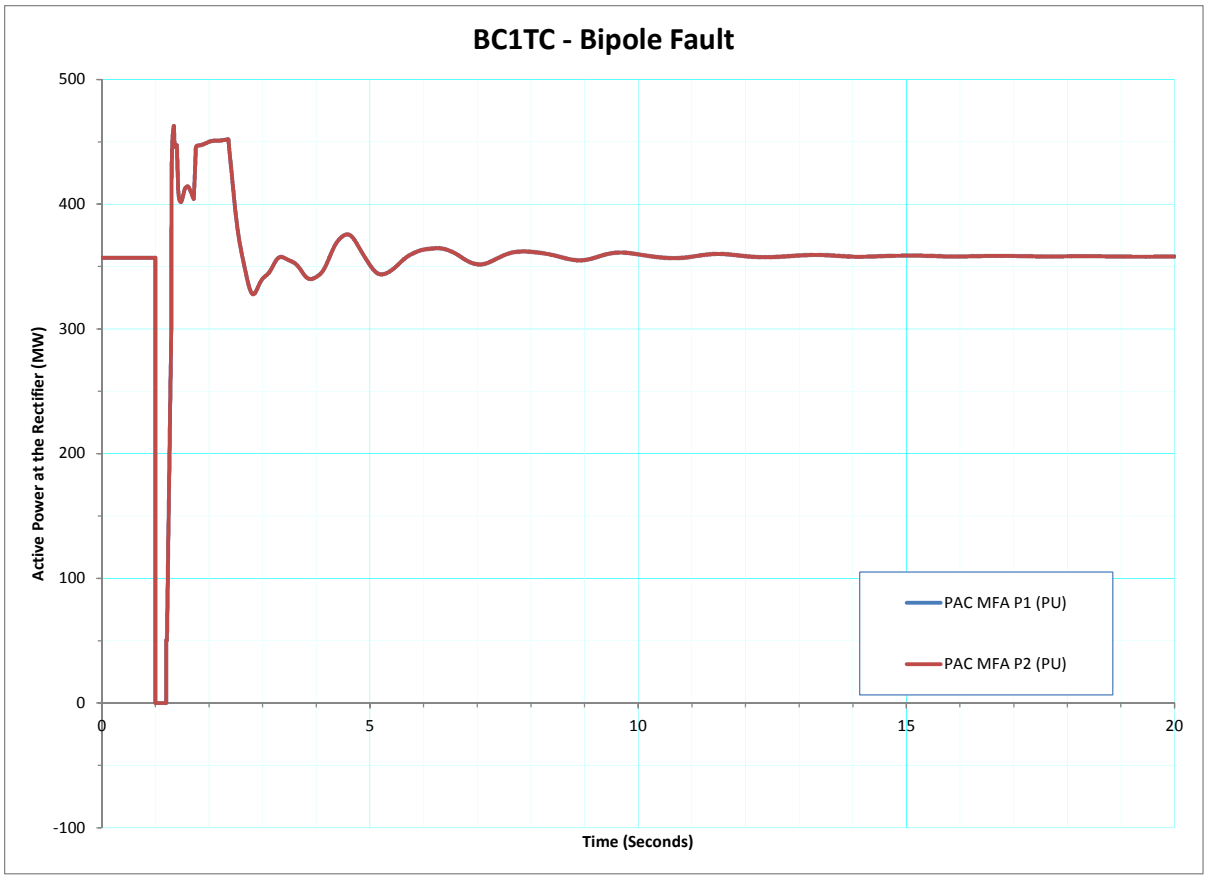


Figure 3 - BC1TC - Bipole Fault - Active Power at the Rectifier (MW)

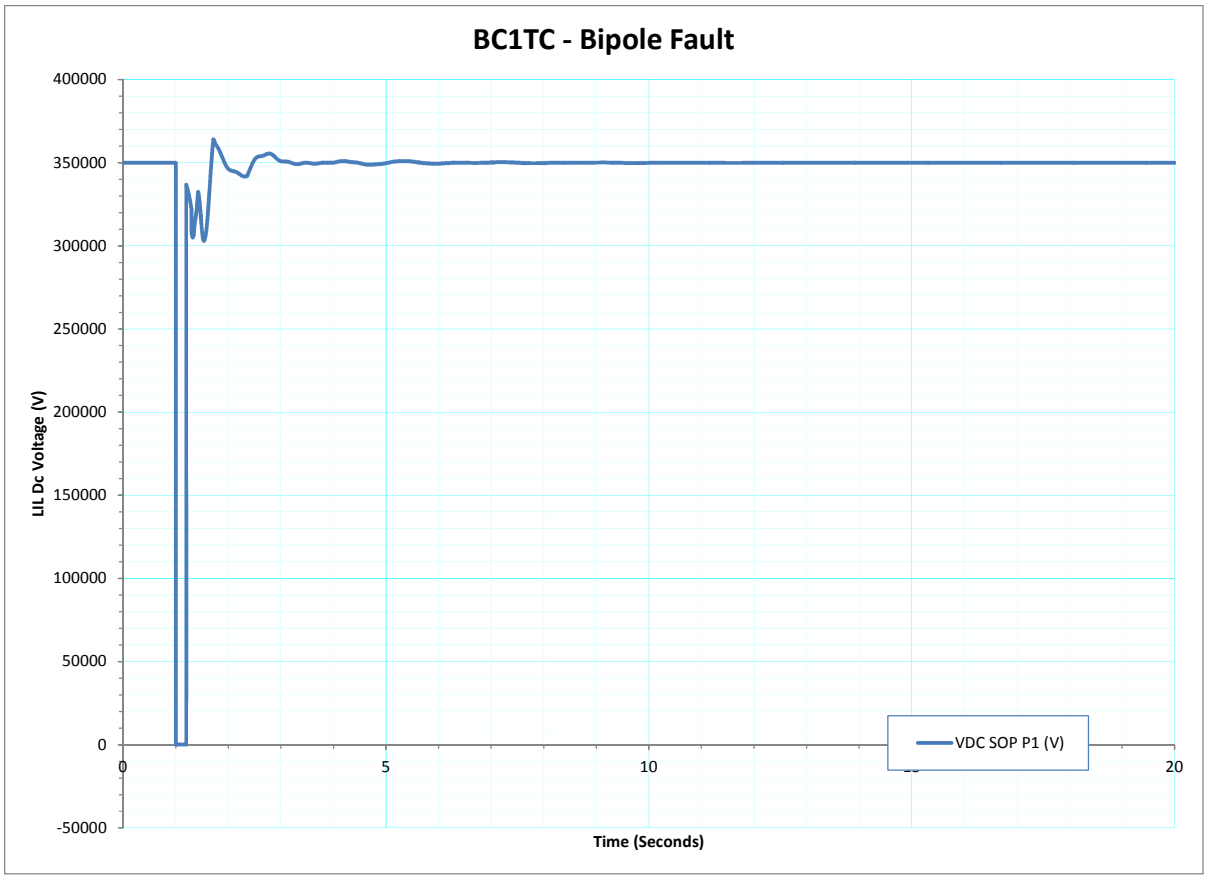


Figure 4 - BC1TC - Bipole Fault - LIL Dc Voltage (V)

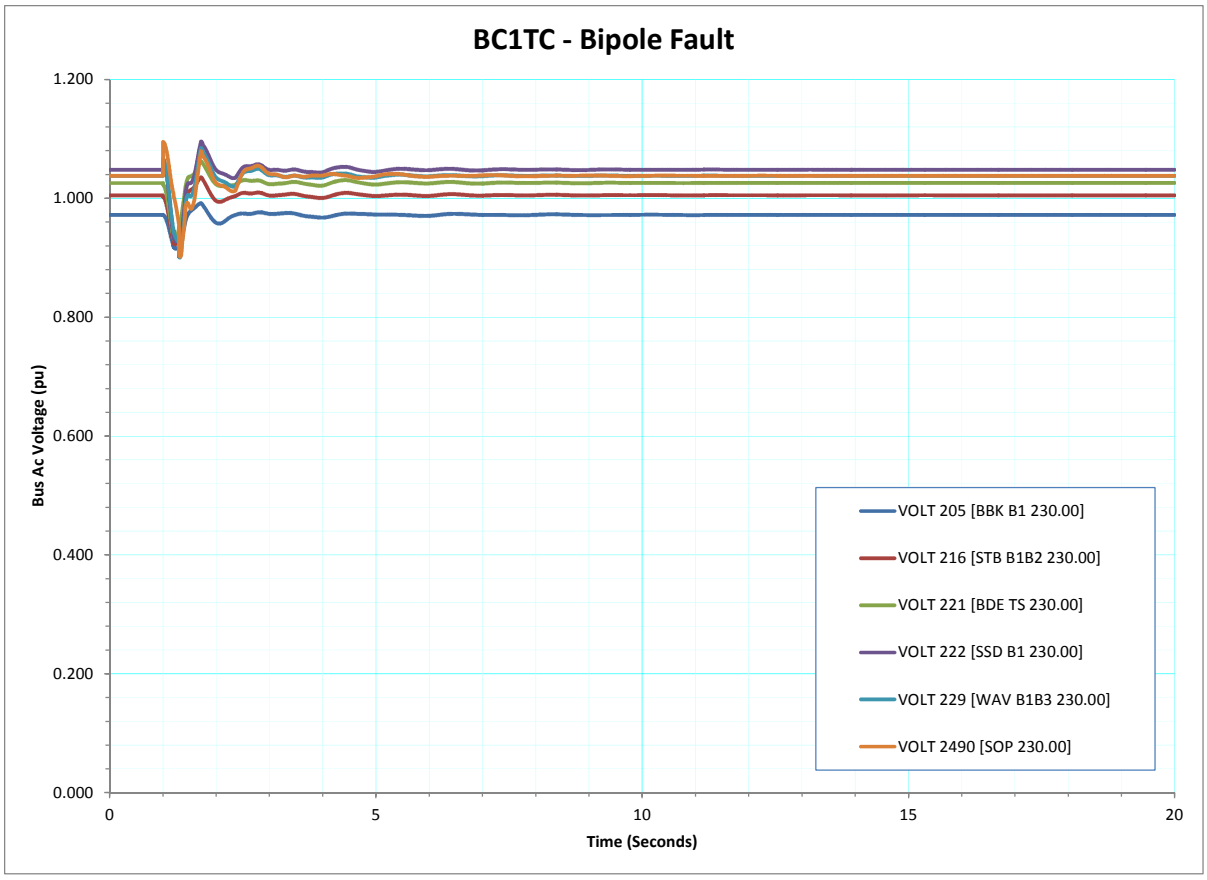


Figure 5 - BC1TC - Bipole Fault - Bus Ac Voltage (pu)

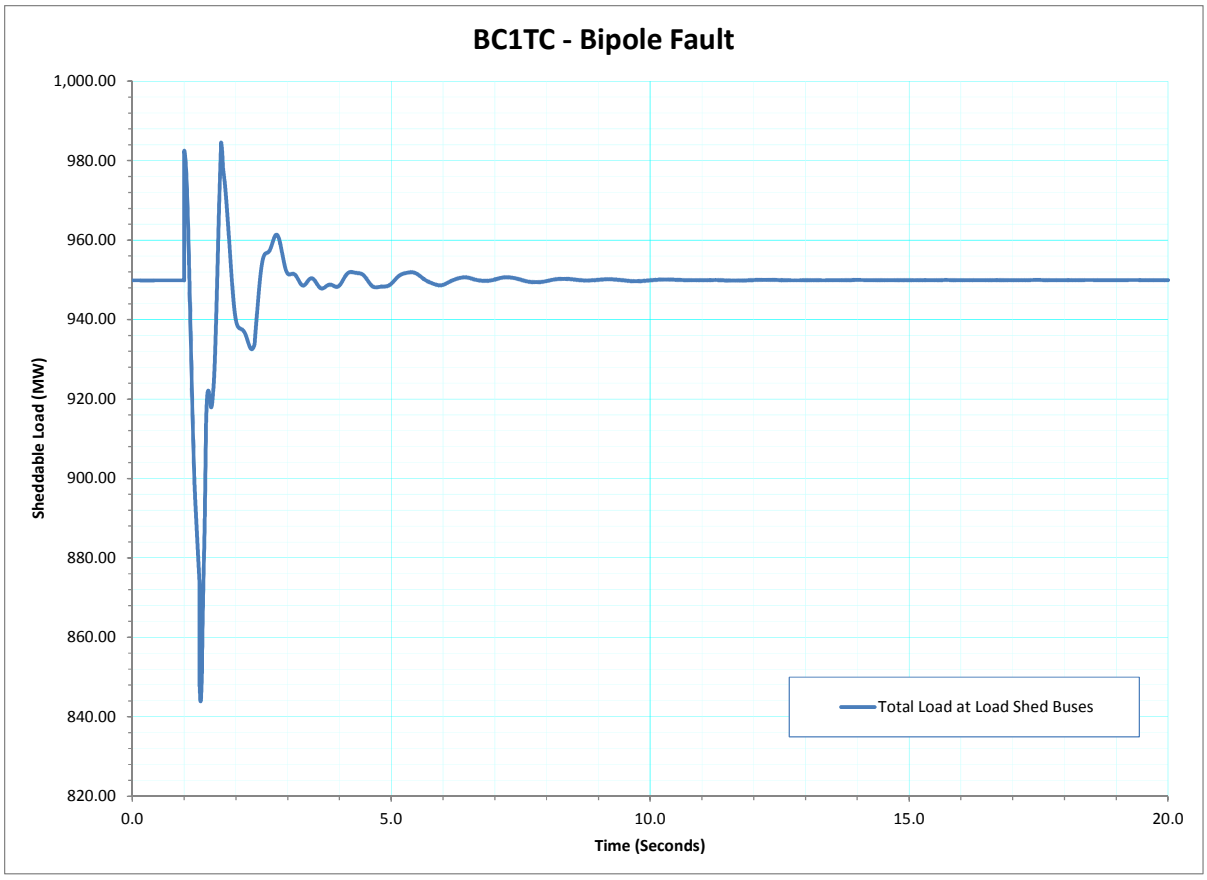


Figure 6 - BC1TC - Bipole Fault - Sheddable Load (MW)

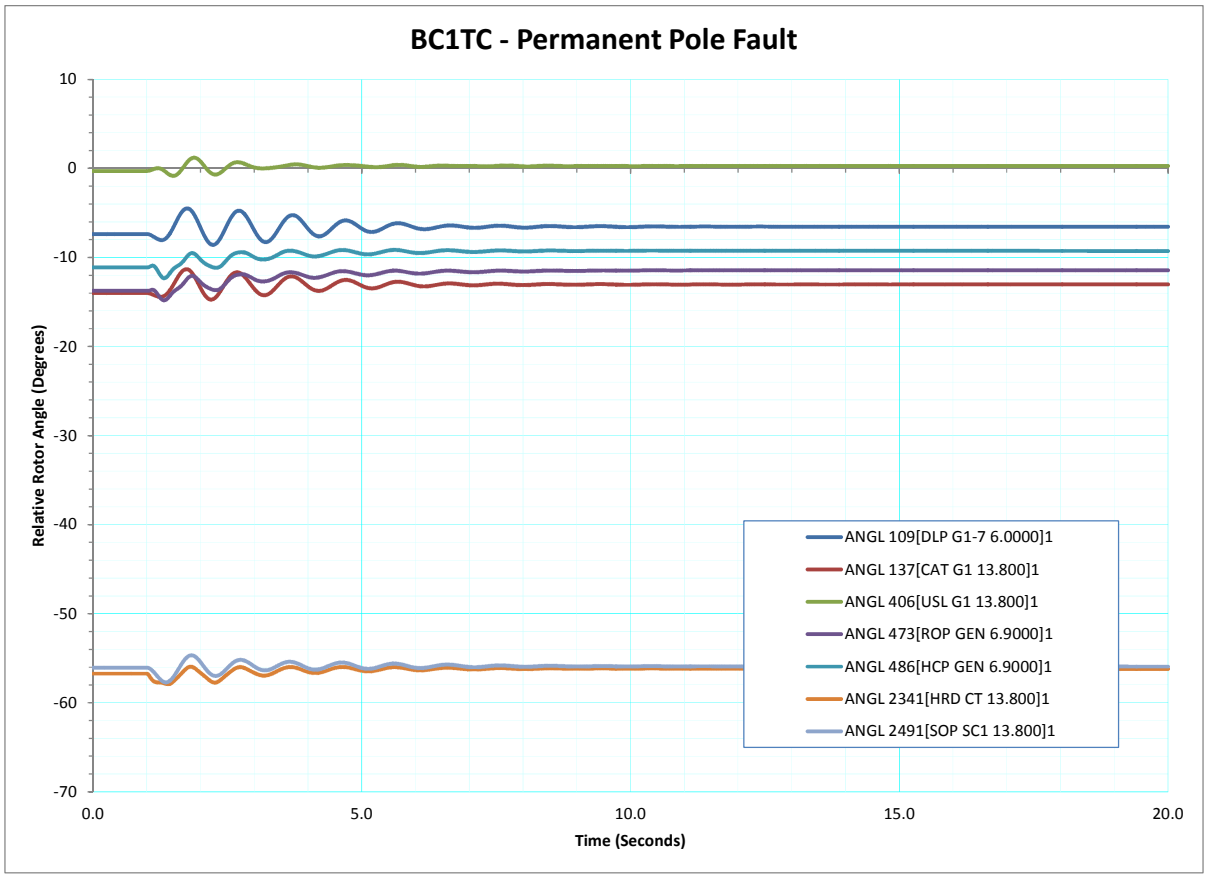


Figure 7 - BC1TC - Permanent Pole Fault - Relative Rotor Angle (Degrees)

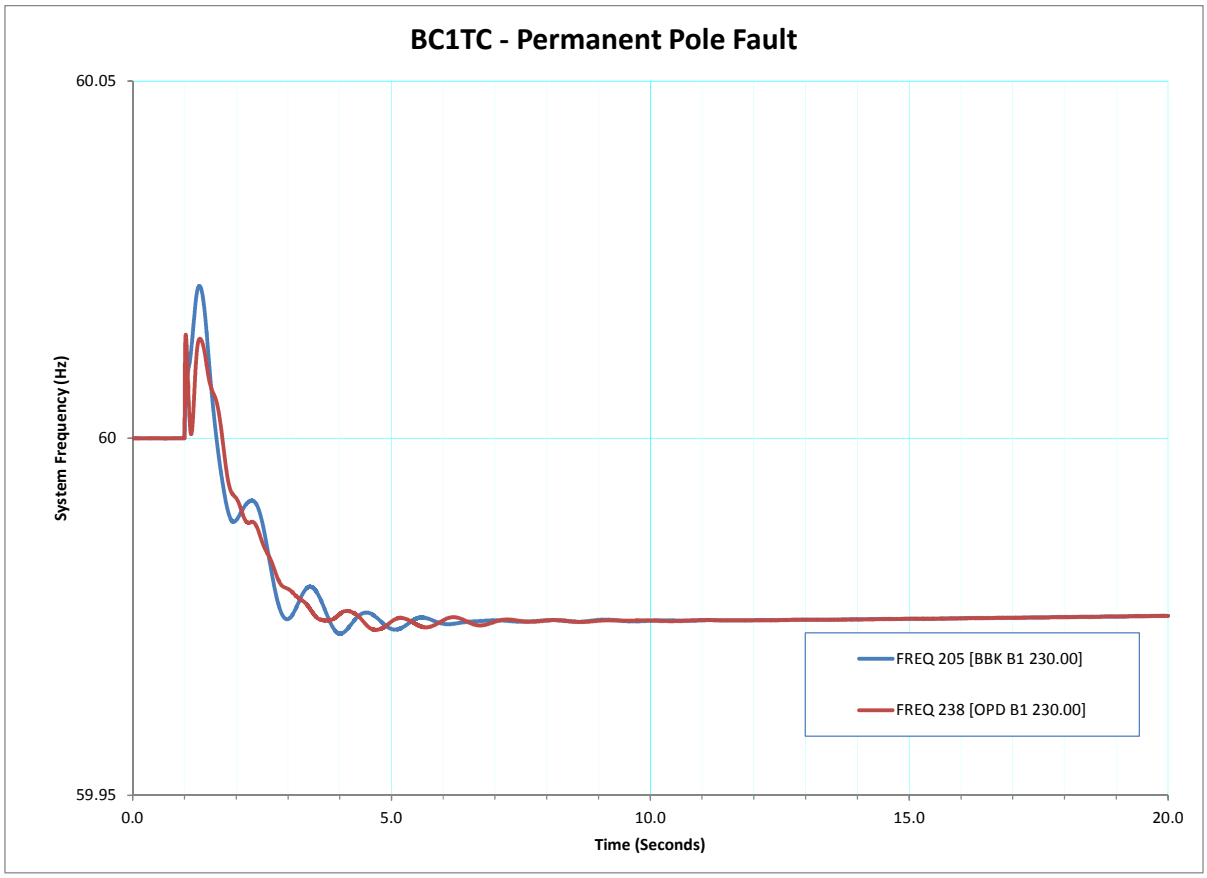


Figure 8 - BC1TC - Permanent Pole Fault - System Frequency (Hz)

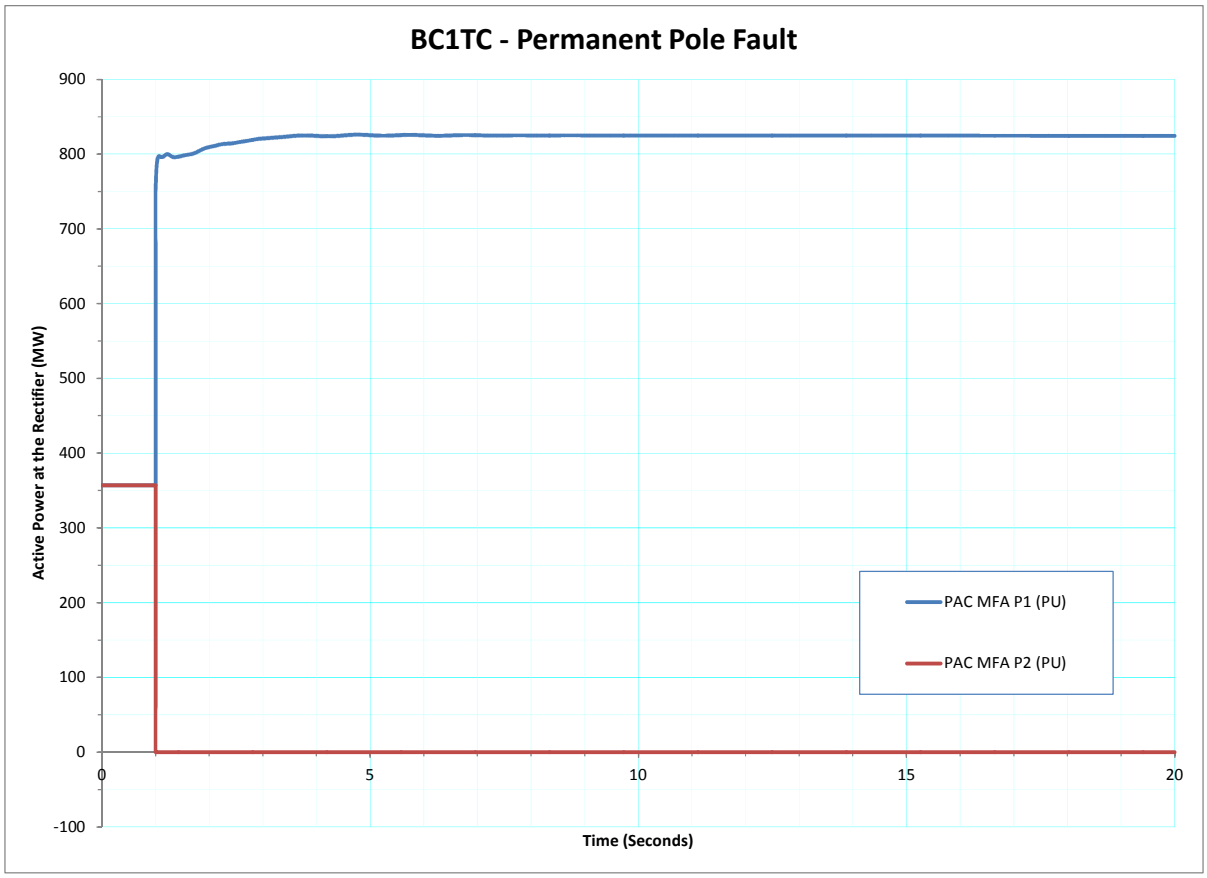


Figure 9 - BC1TC - Permanent Pole Fault - Active Power at the Rectifier (MW)

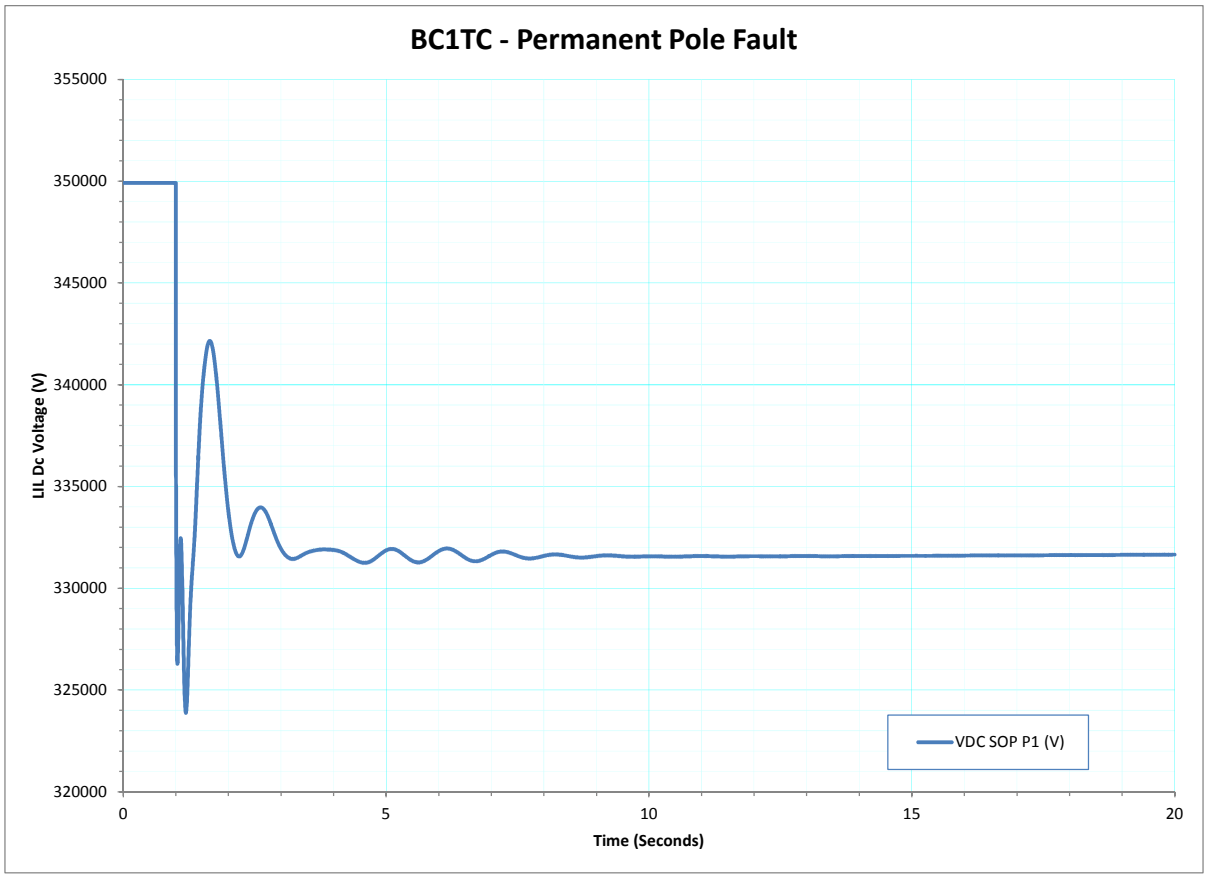


Figure 10 - BC1TC - Permanent Pole Fault - LIL Dc Voltage (V)

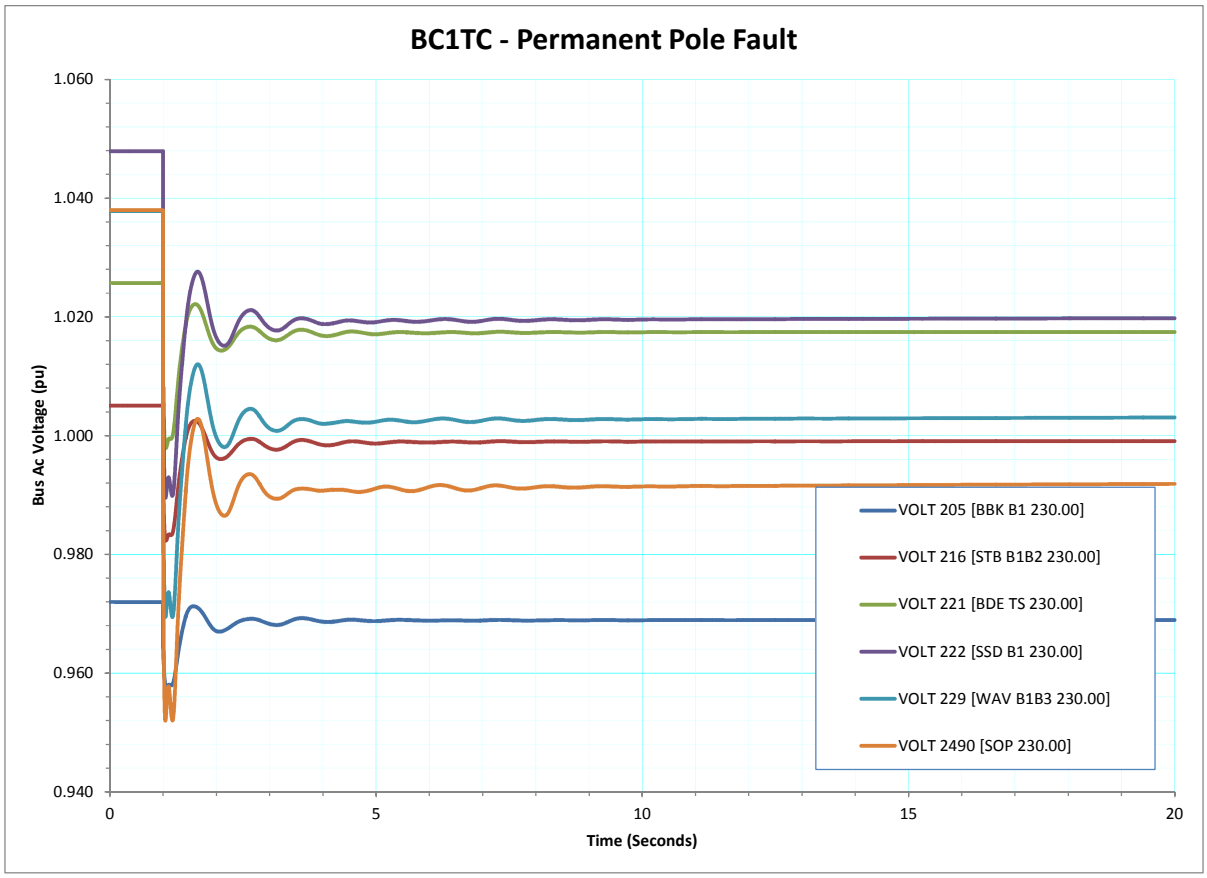


Figure 11 - BC1TC - Permanent Pole Fault - Bus Ac Voltage (pu)

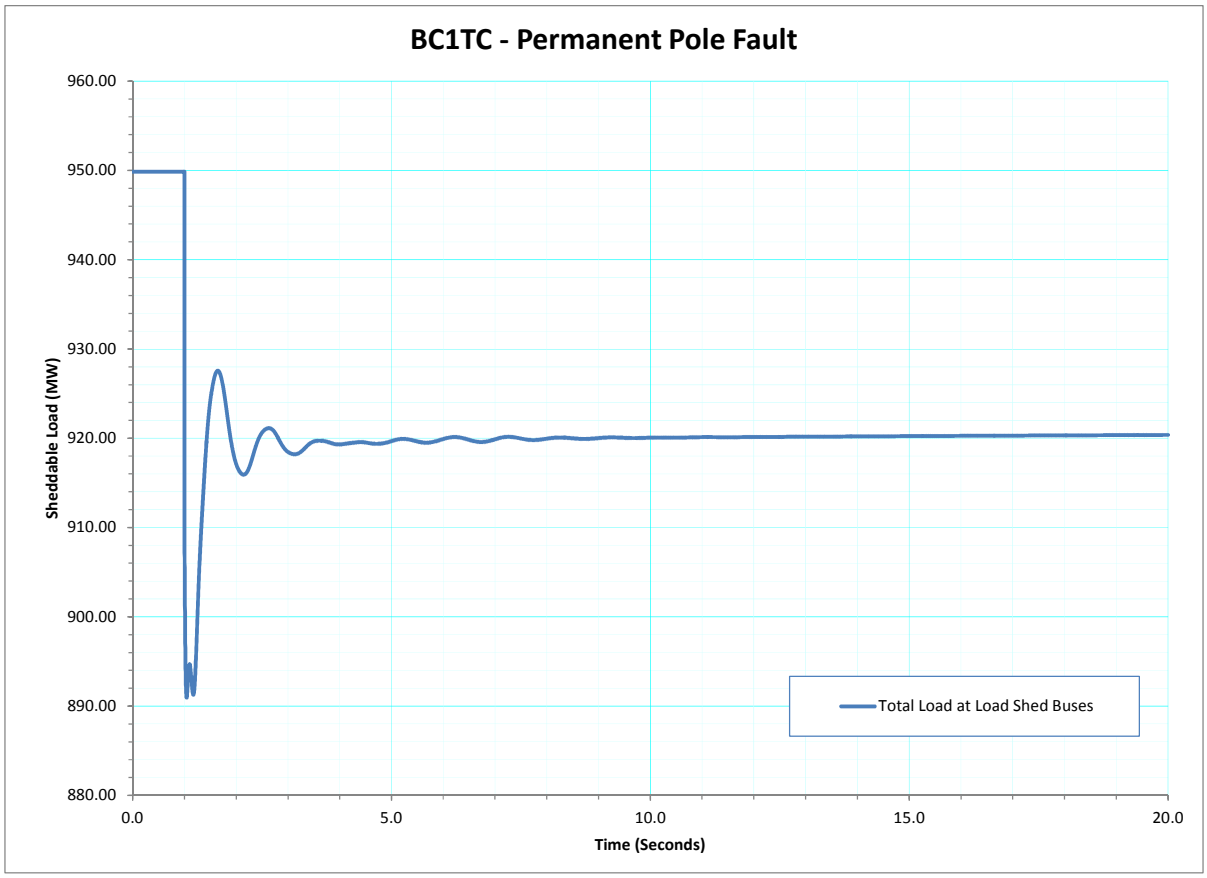


Figure 12 - BC1TC - Permanent Pole Fault - Sheddable Load (MW)

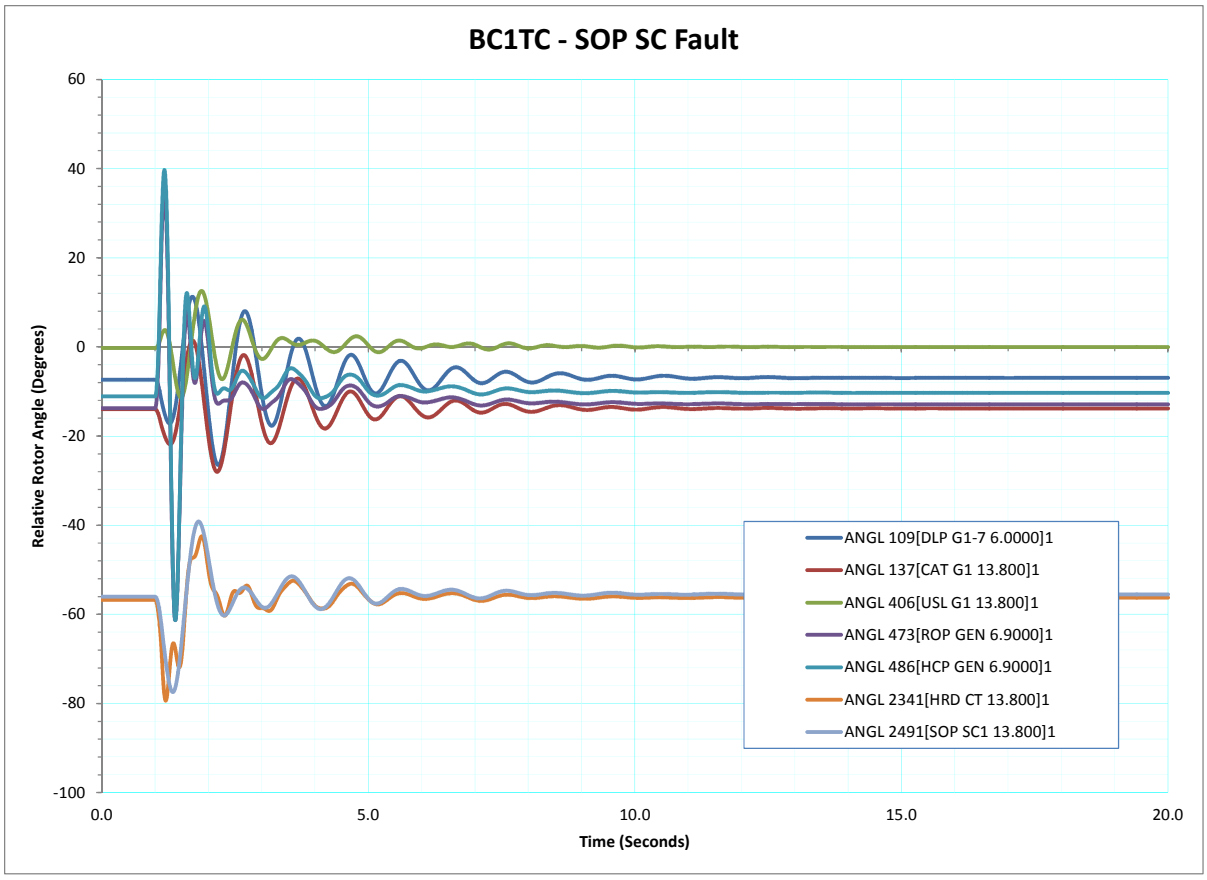


Figure 13 - BC1TC - SOP SC Fault - Relative Rotor Angle (Degrees)

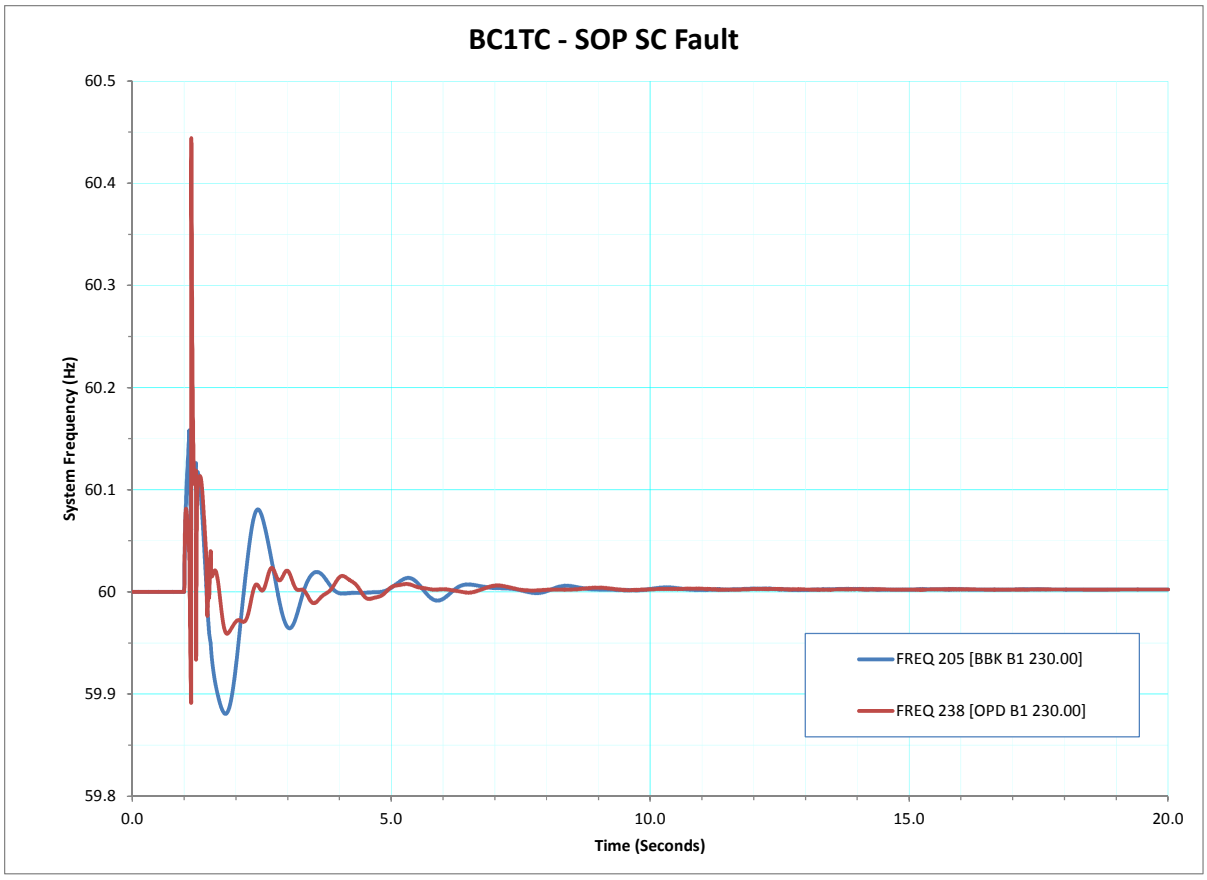


Figure 14 - BC1TC - SOP SC Fault - System Frequency (Hz)

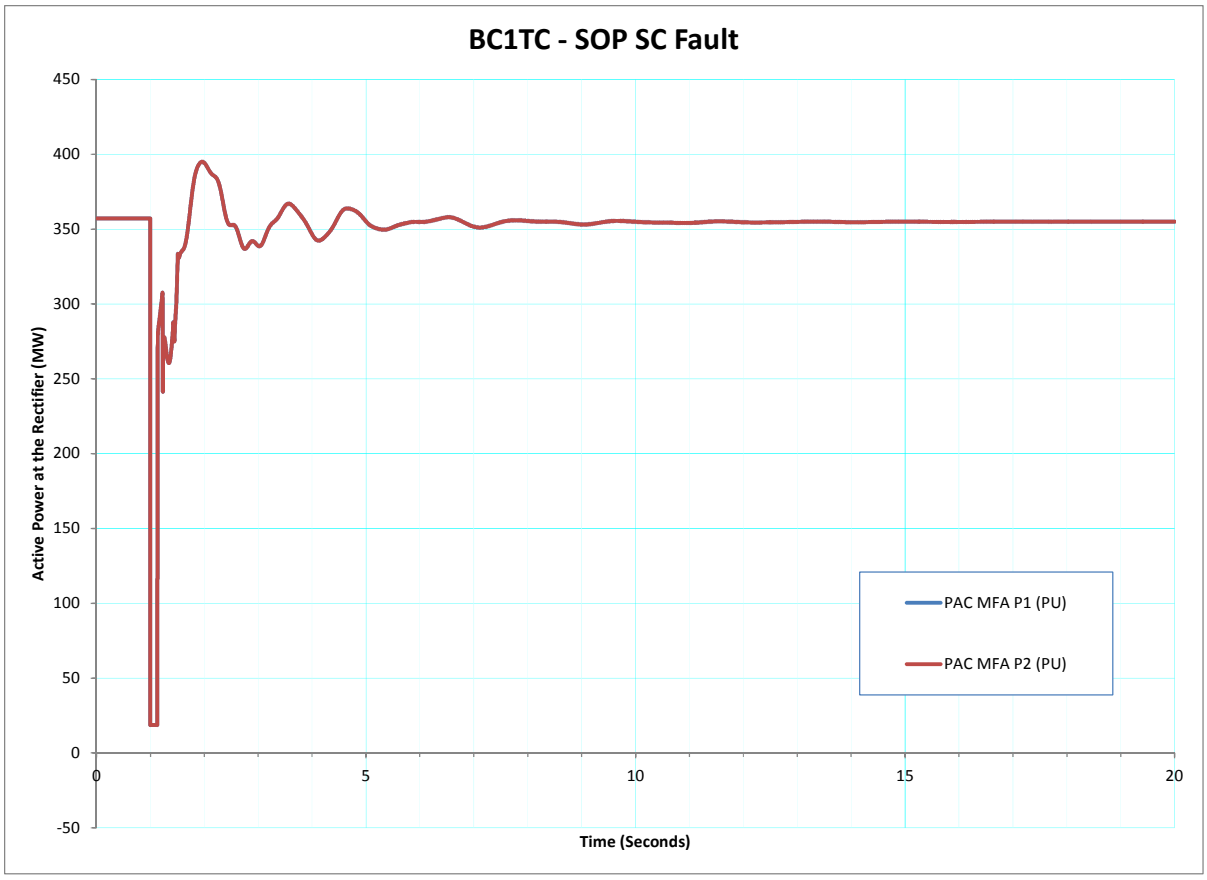


Figure 15 - BC1TC - SOP SC Fault - Active Power at the Rectifier (MW)

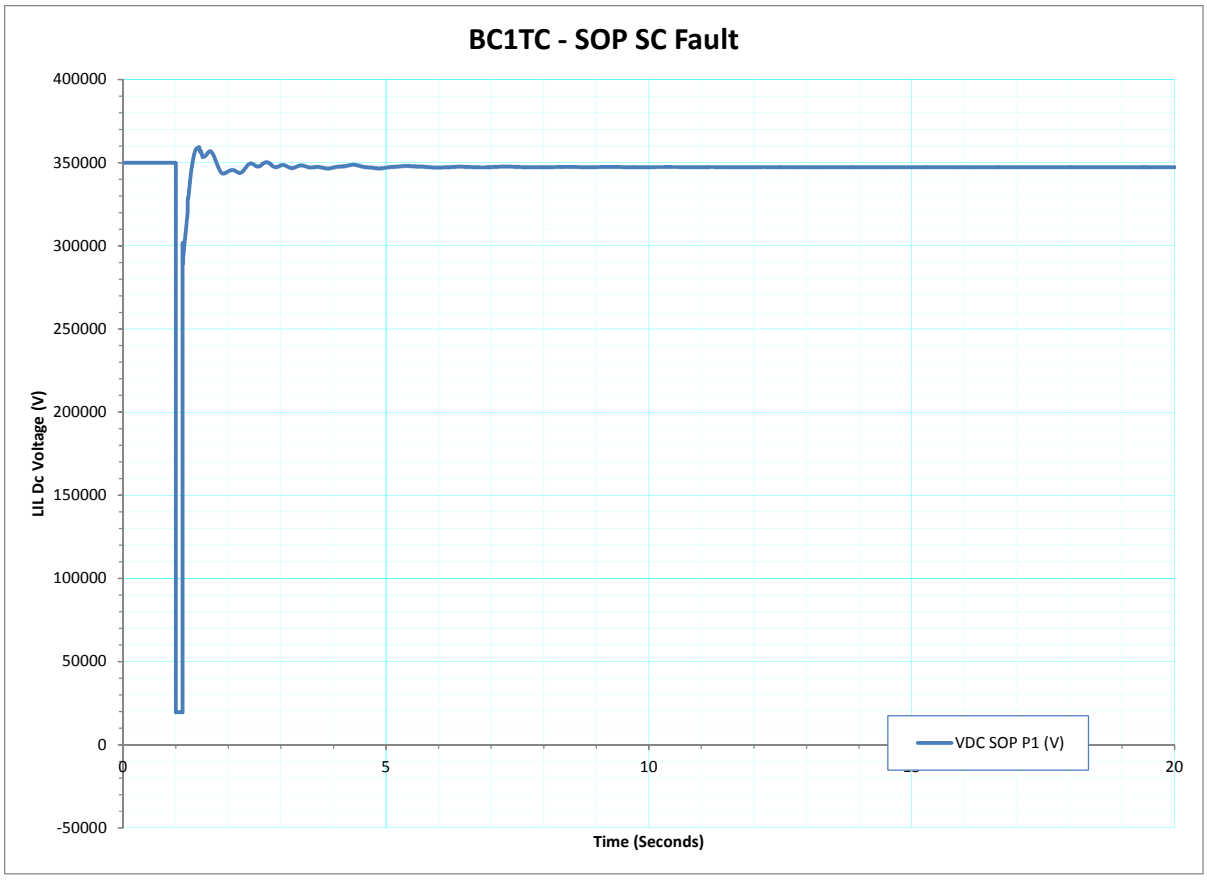


Figure 16 - BC1TC - SOP SC Fault - LIL Dc Voltage (V)

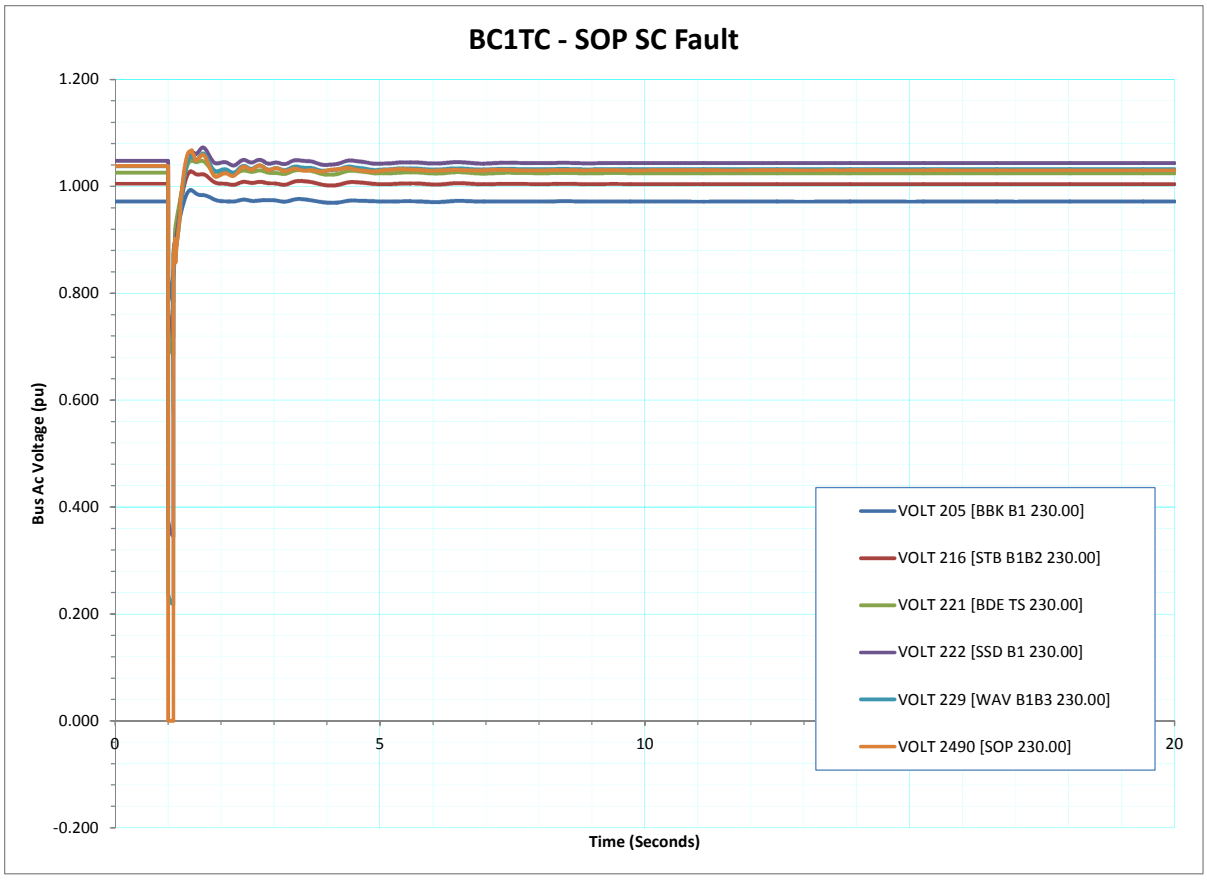


Figure 17 - BC1TC - SOP SC Fault - Bus Ac Voltage (pu)

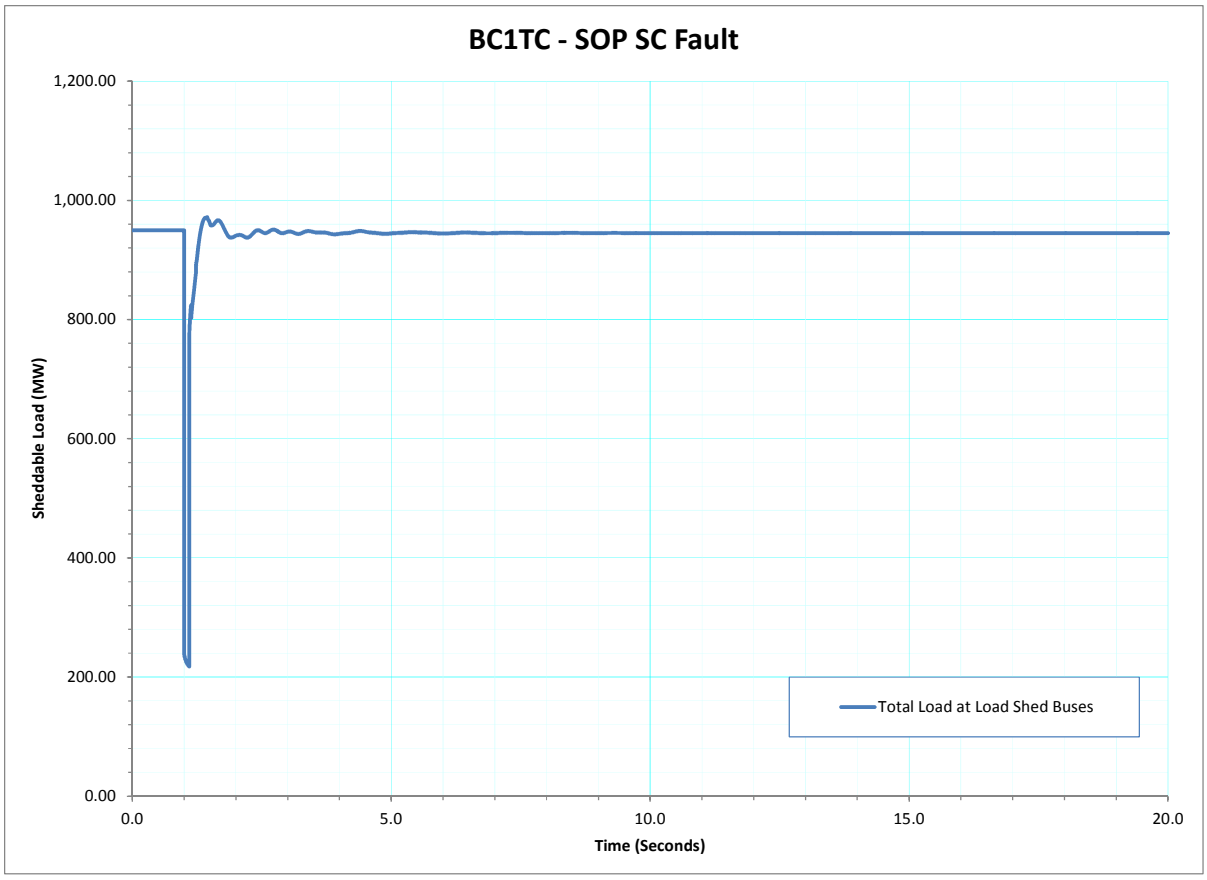


Figure 18 - BC1TC - SOP SC Fault - Sheddable Load (MW)

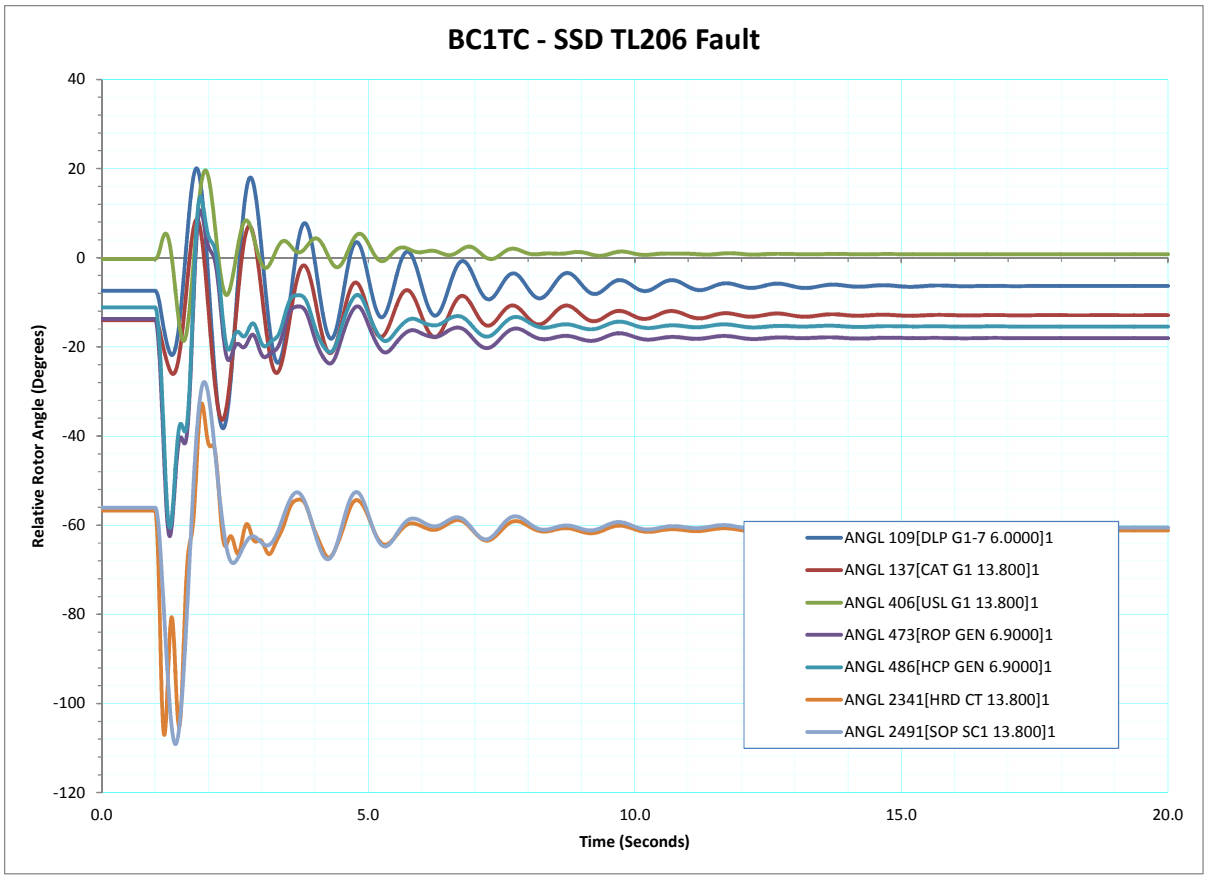


Figure 19 - BC1TC - SSD TL206 Fault - Relative Rotor Angle (Degrees)

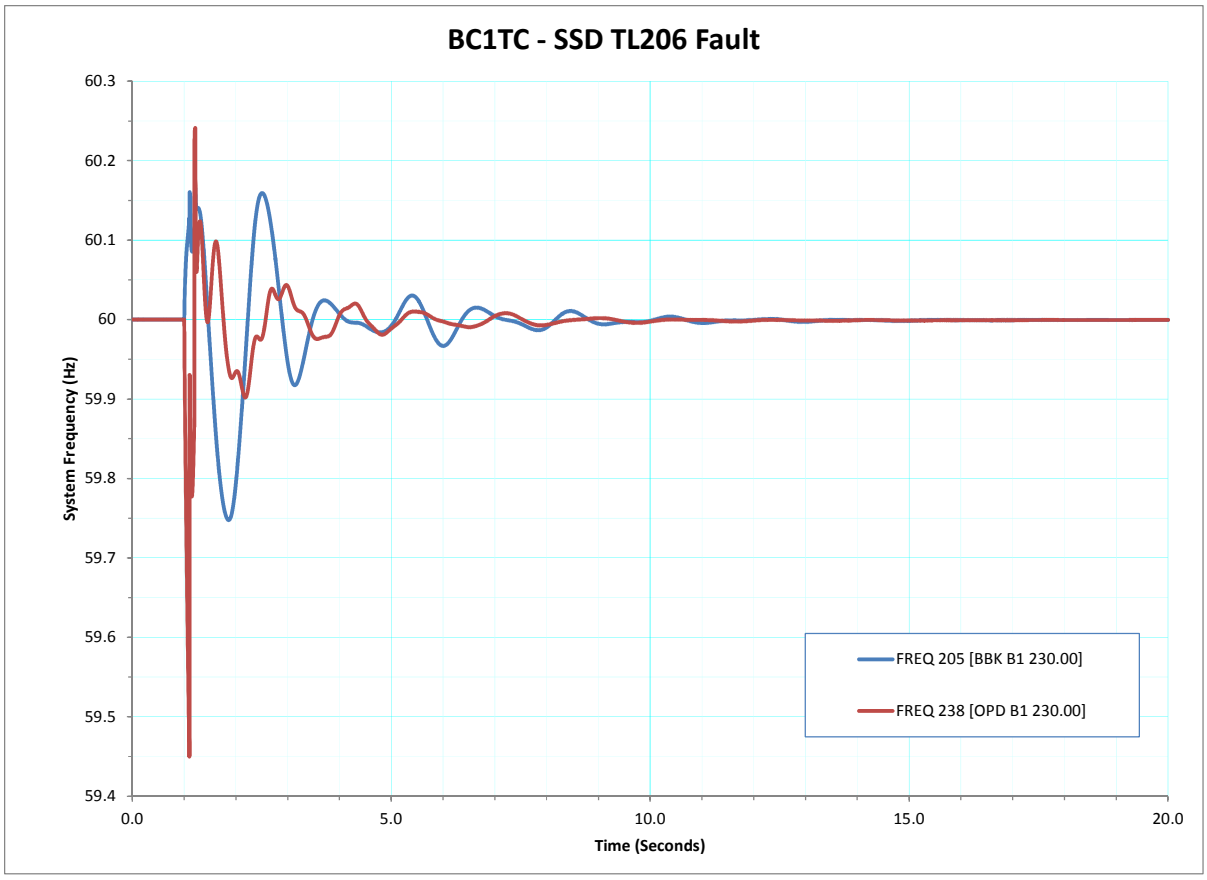


Figure 20 - BC1TC - SSD TL206 Fault - System Frequency (Hz)

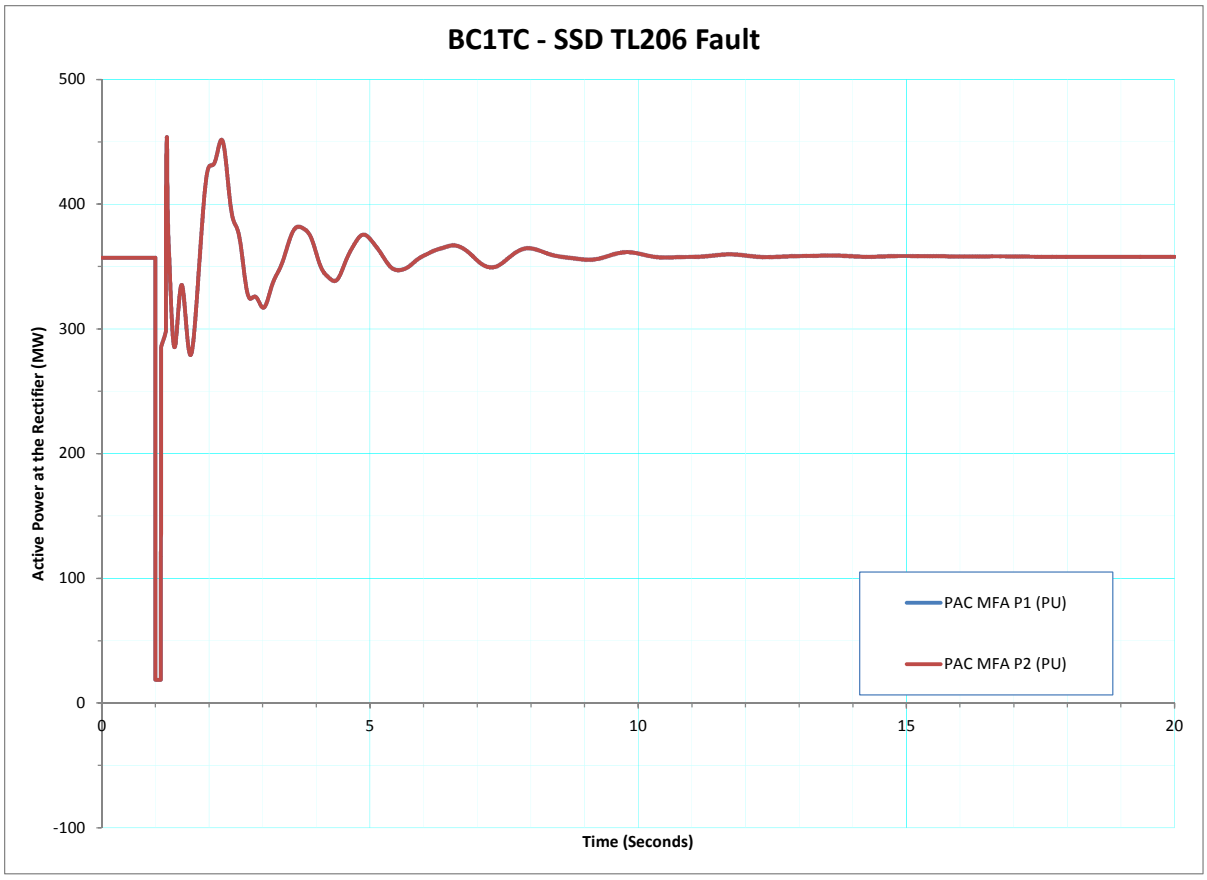


Figure 21 - BC1TC - SSD TL206 Fault - Active Power at the Rectifier (MW)

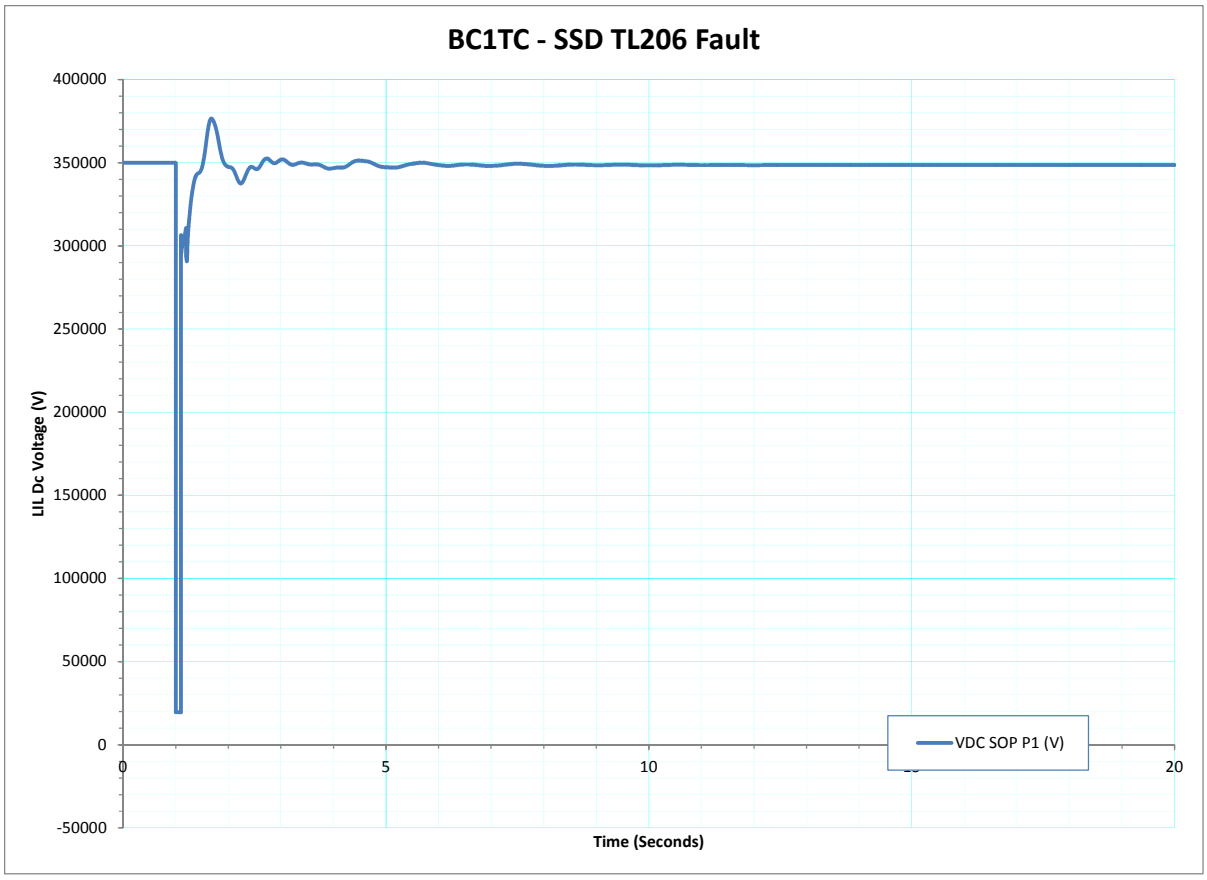


Figure 22 - BC1TC - SSD TL206 Fault - LIL Dc Voltage (V)

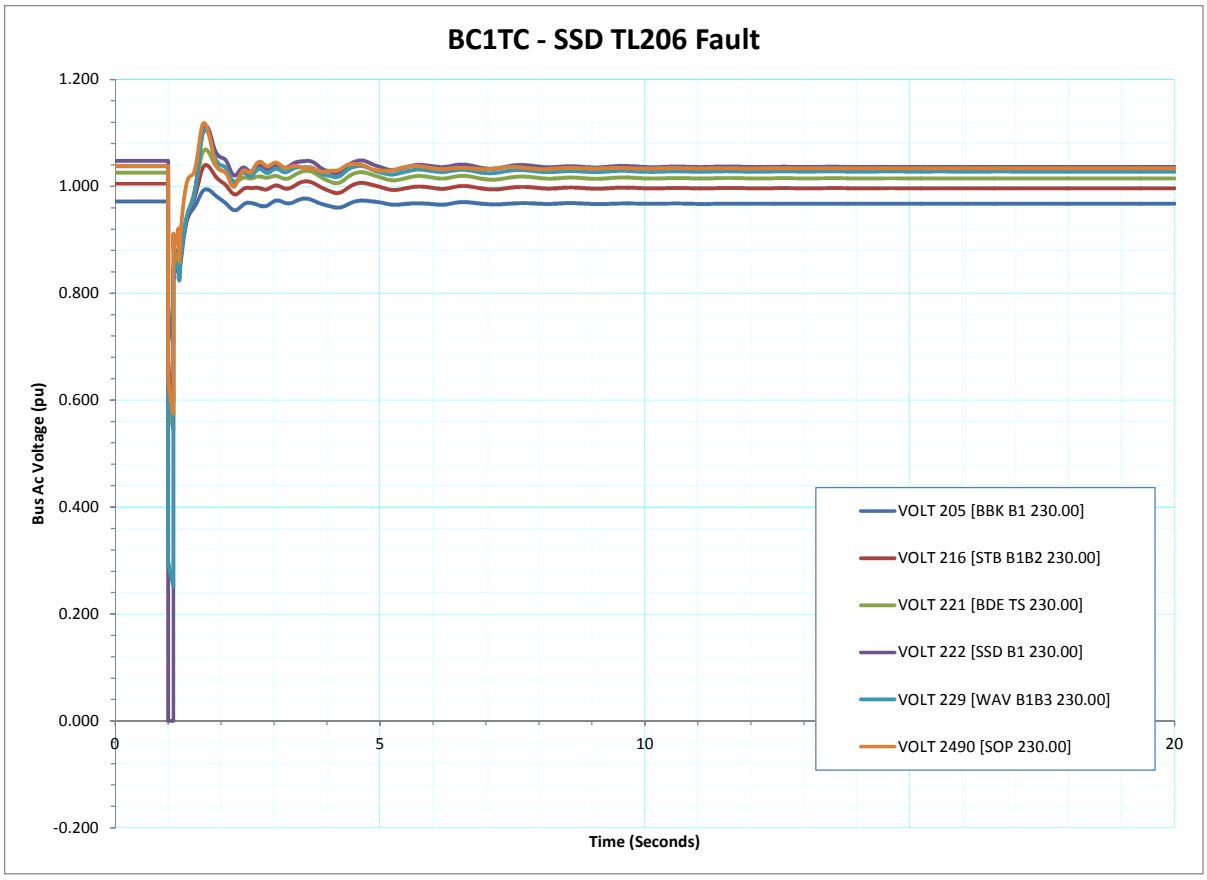


Figure 23 - BC1TC - SSD TL206 Fault - Bus Ac Voltage (pu)

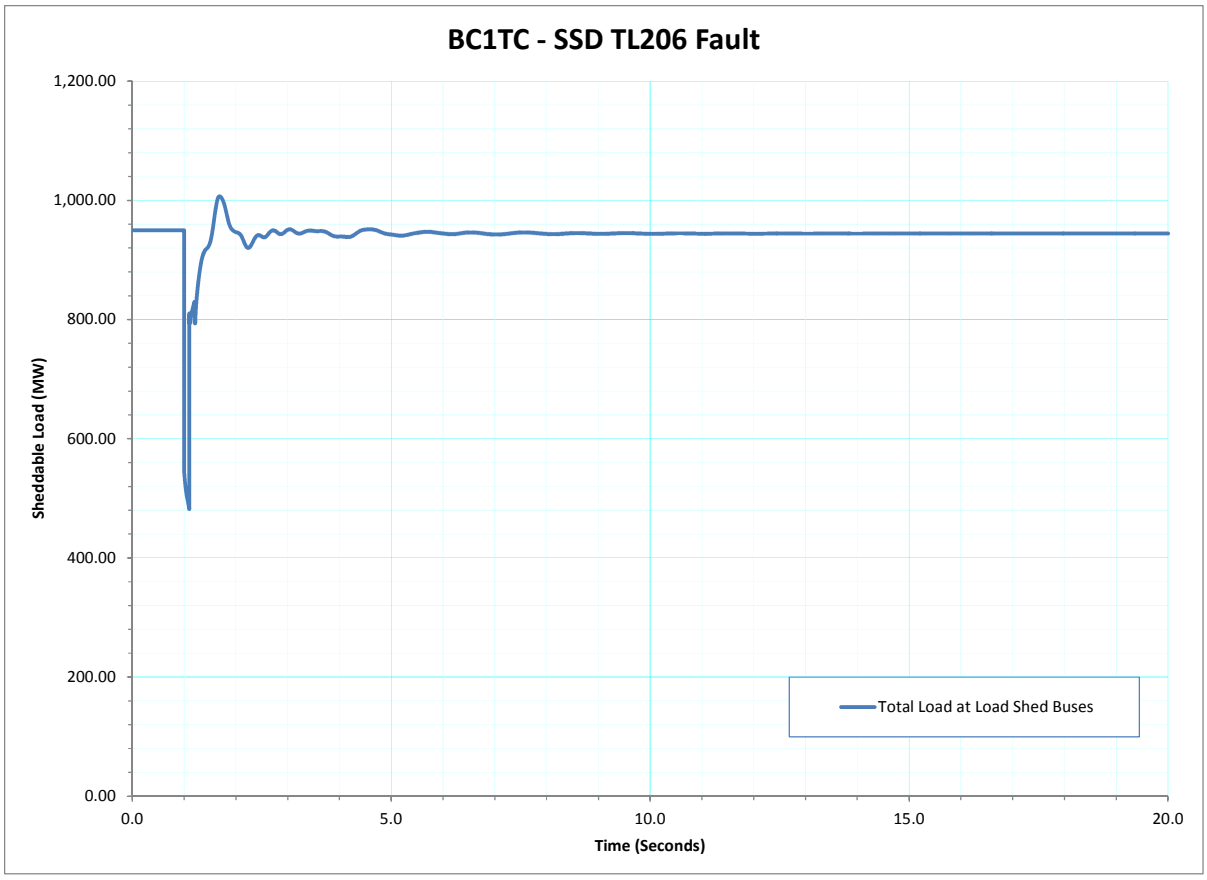


Figure 24 - BC1TC - SSD TL206 Fault - Sheddable Load (MW)

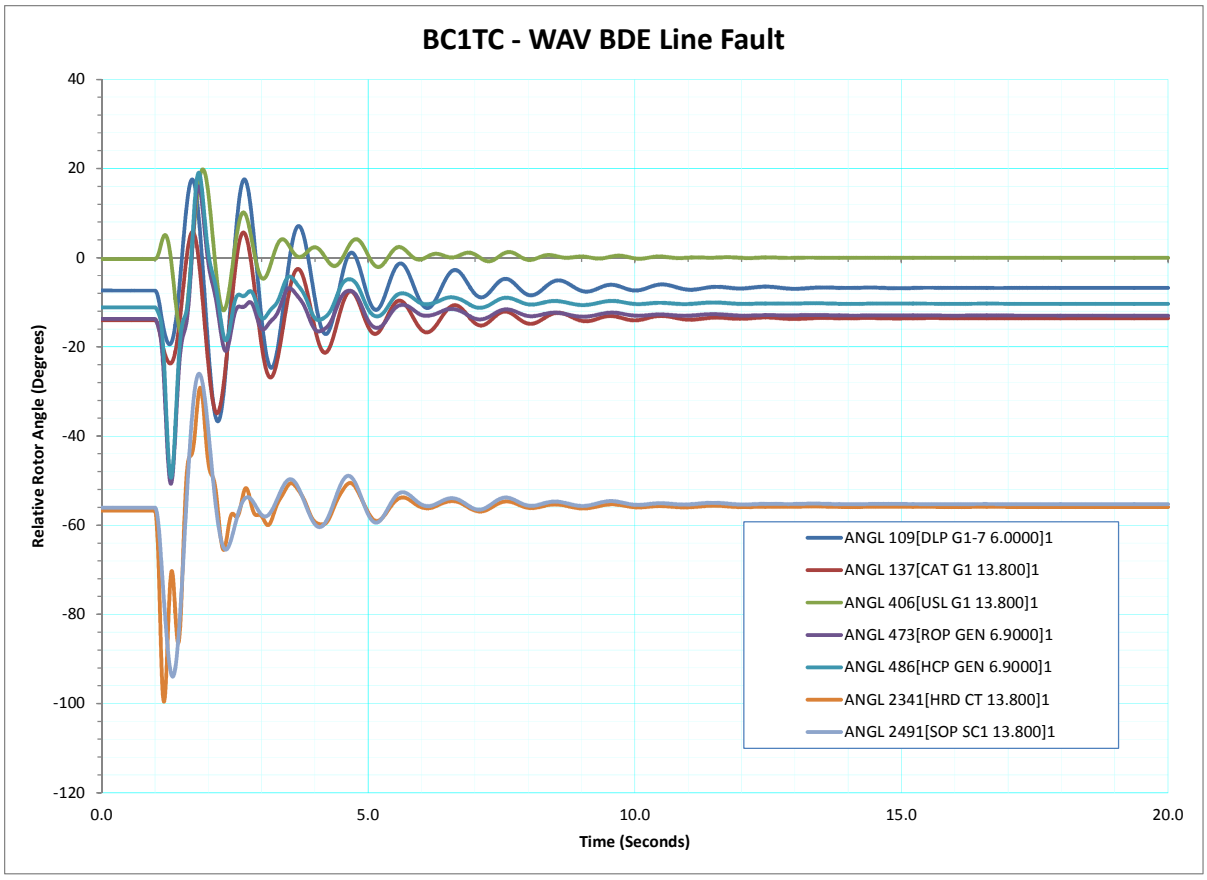


Figure 25 - BC1TC - WAV BDE Line Fault - Relative Rotor Angle (Degrees)

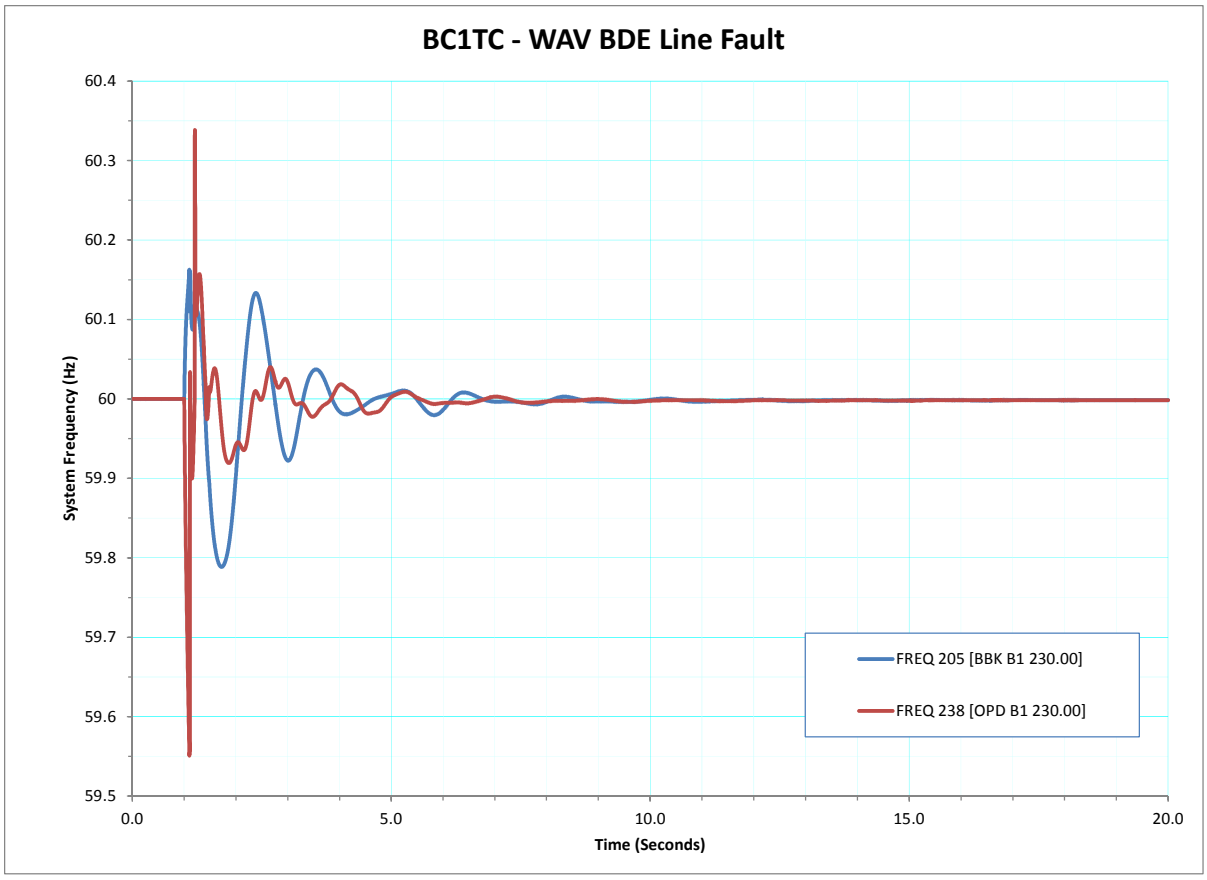


Figure 26 - BC1TC - WAV BDE Line Fault - System Frequency (Hz)

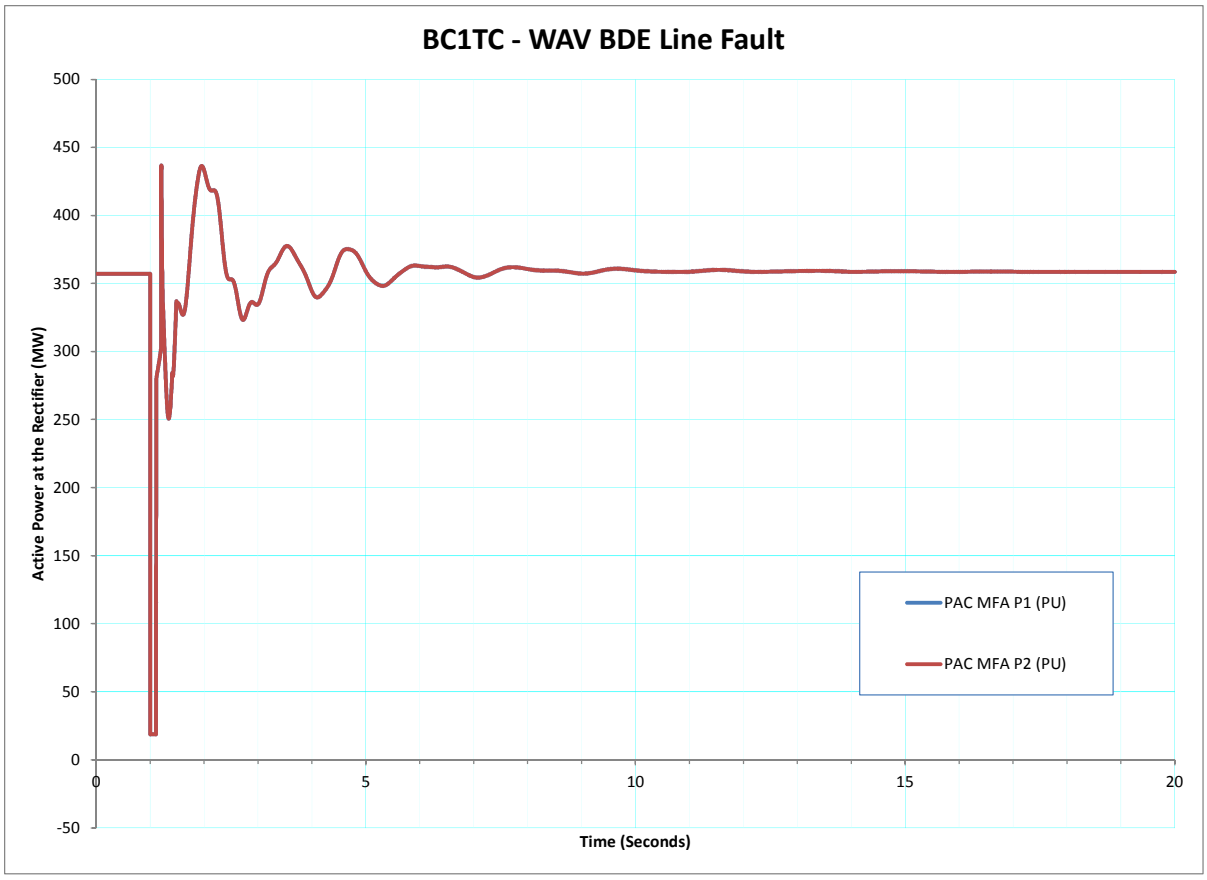


Figure 27 - BC1TC - WAV BDE Line Fault - Active Power at the Rectifier (MW)

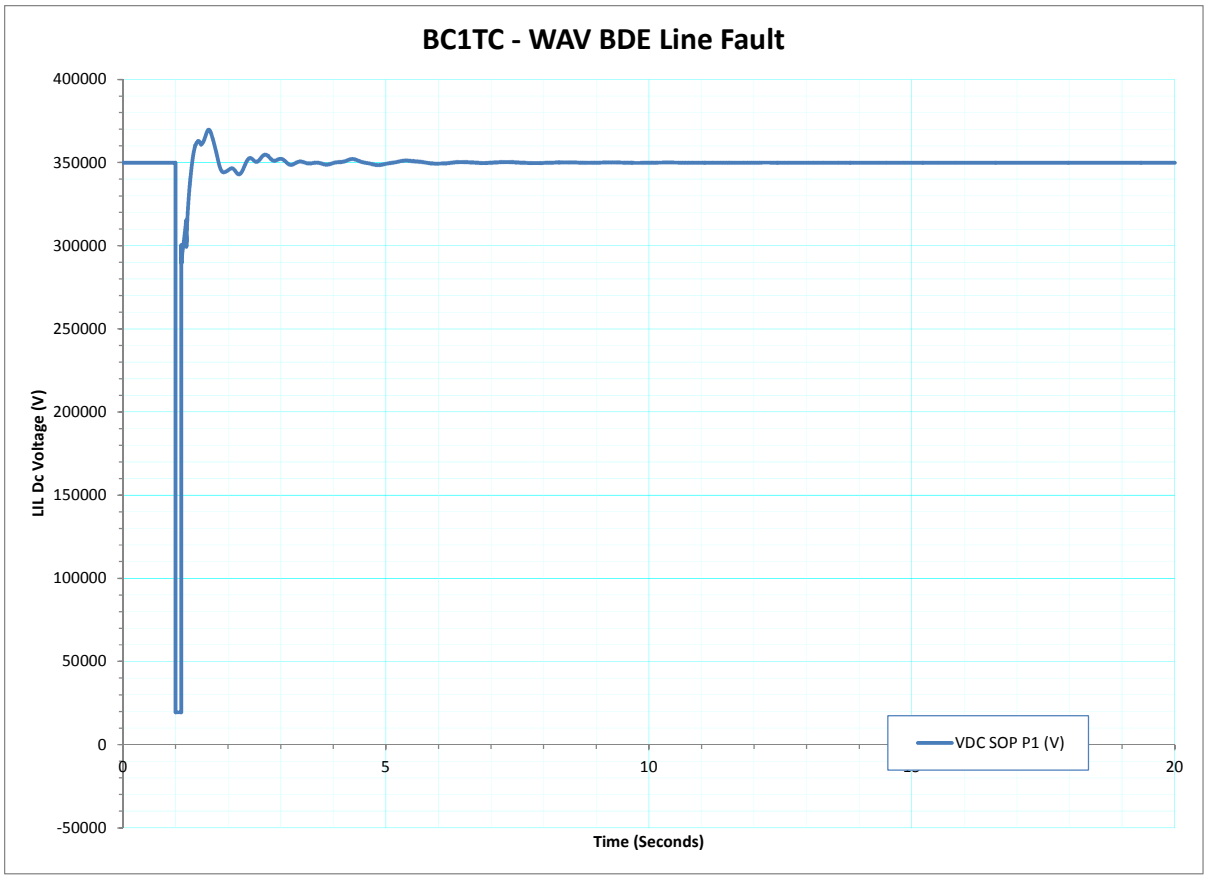


Figure 28 - BC1TC - WAV BDE Line Fault - LIL Dc Voltage (V)

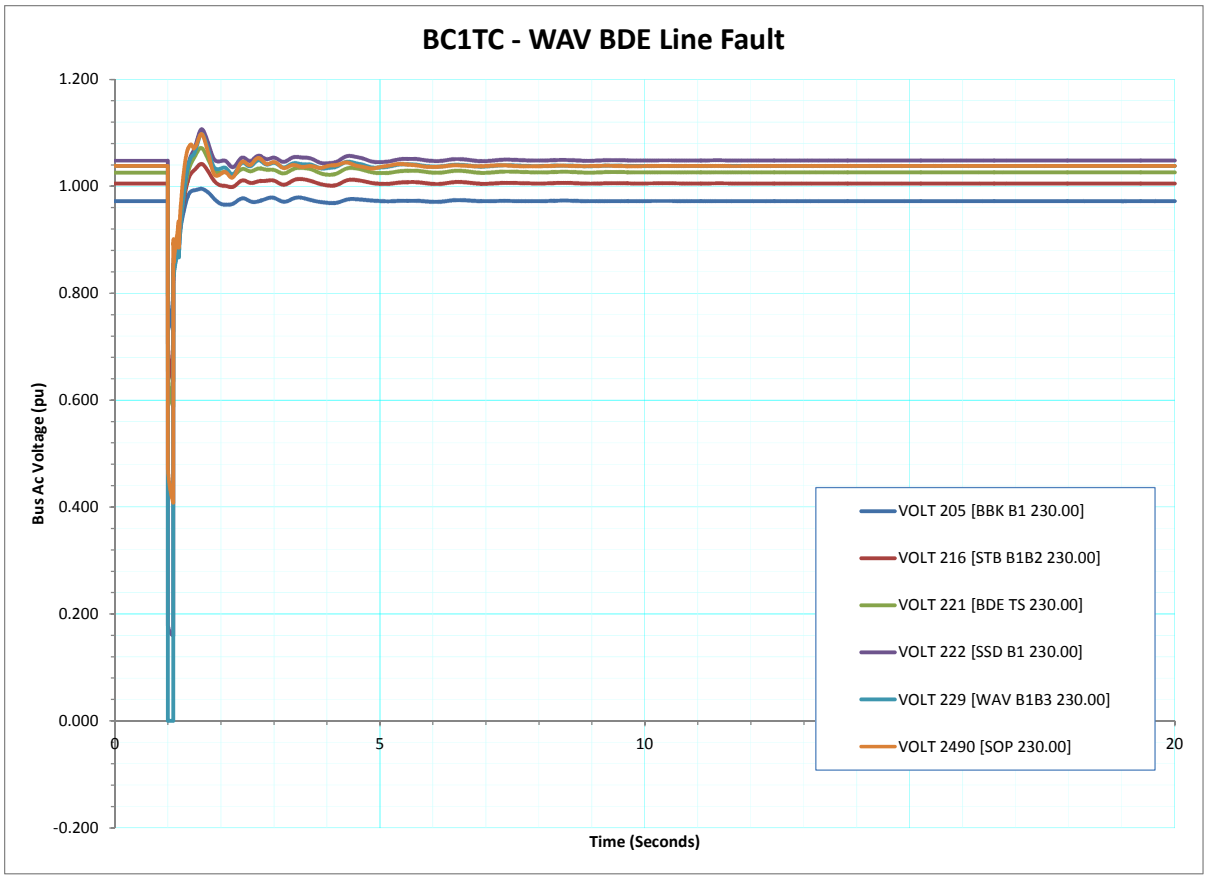


Figure 29 - BC1TC - WAV BDE Line Fault - Bus Ac Voltage (pu)

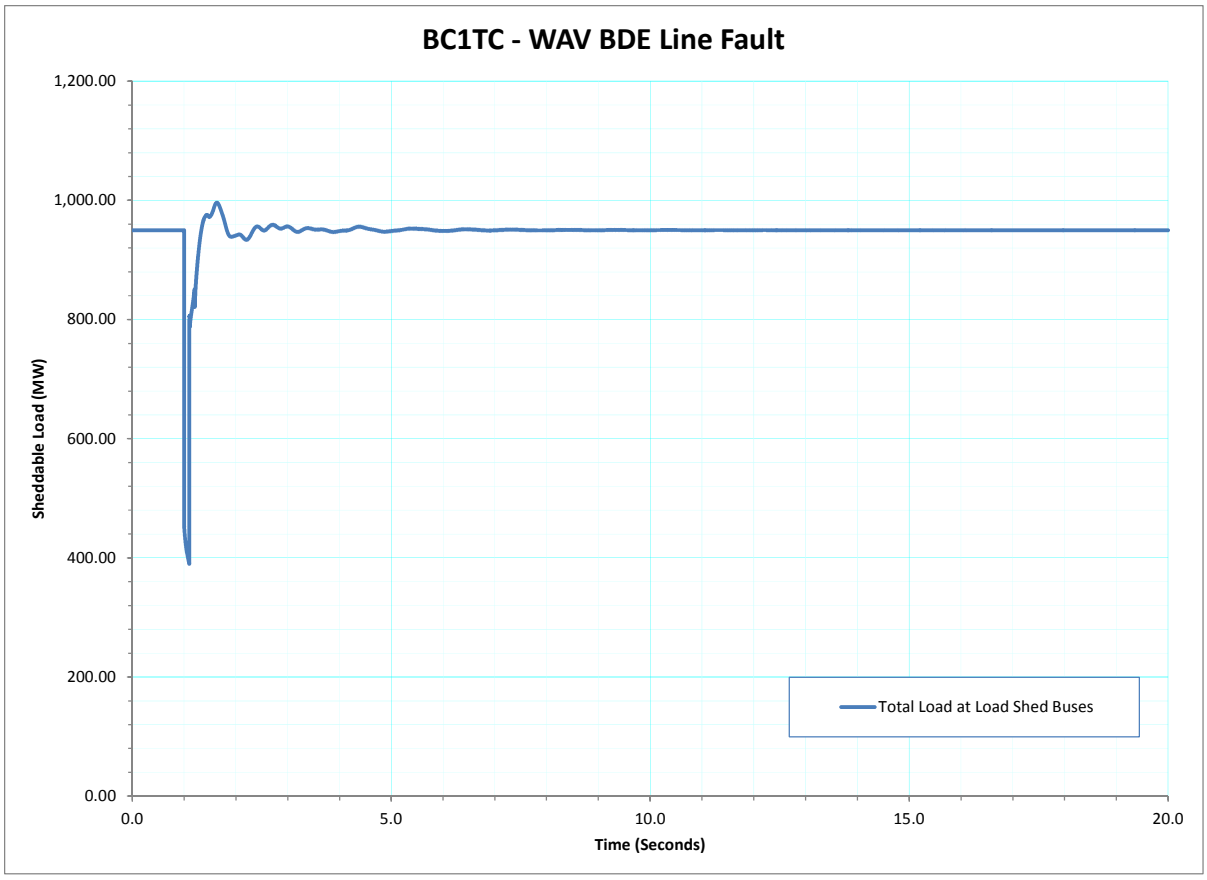


Figure 30 - BC1TC - WAV BDE Line Fault - Sheddable Load (MW)

1.2. BASE CASE 2 TRANSIENT STABILITY PLOTS

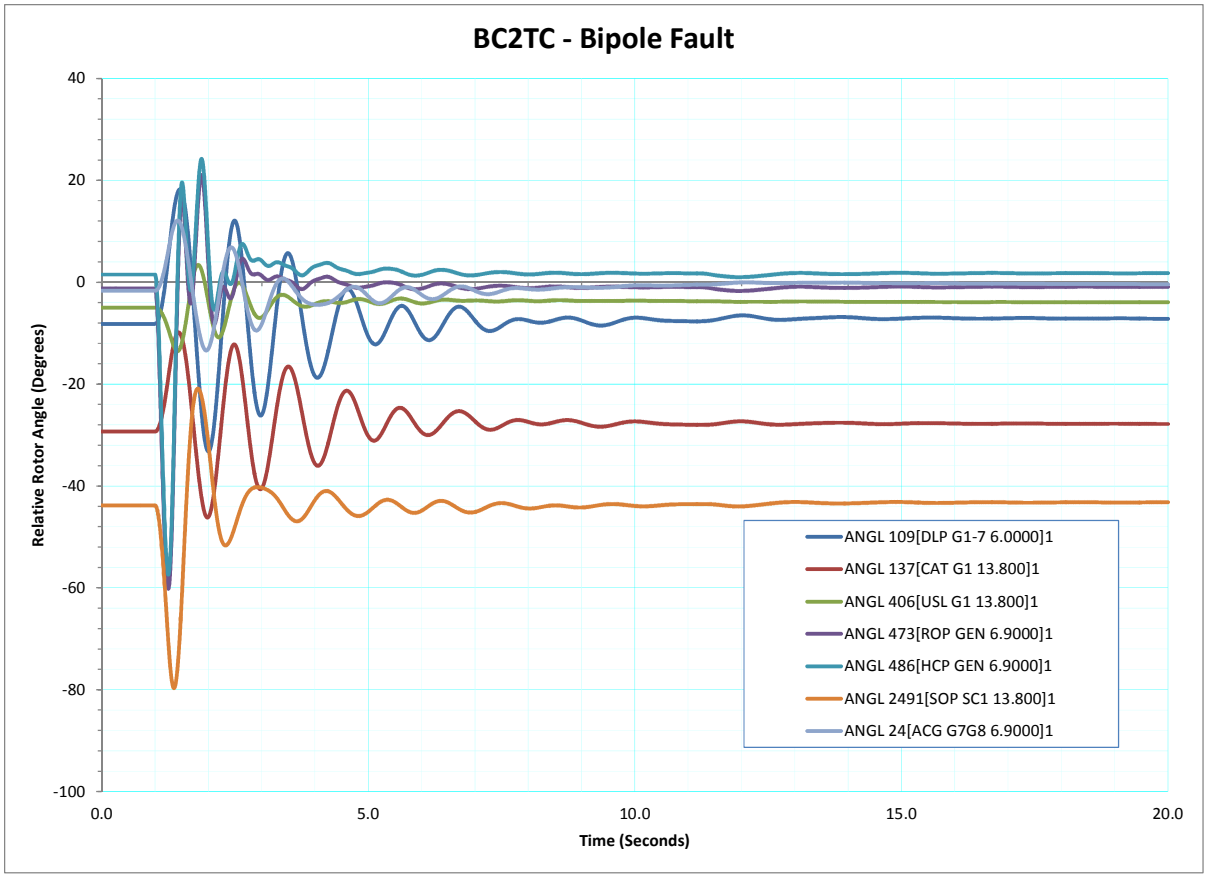


Figure 31 - BC2TC - Bipole Fault - Relative Rotor Angle (Degrees)

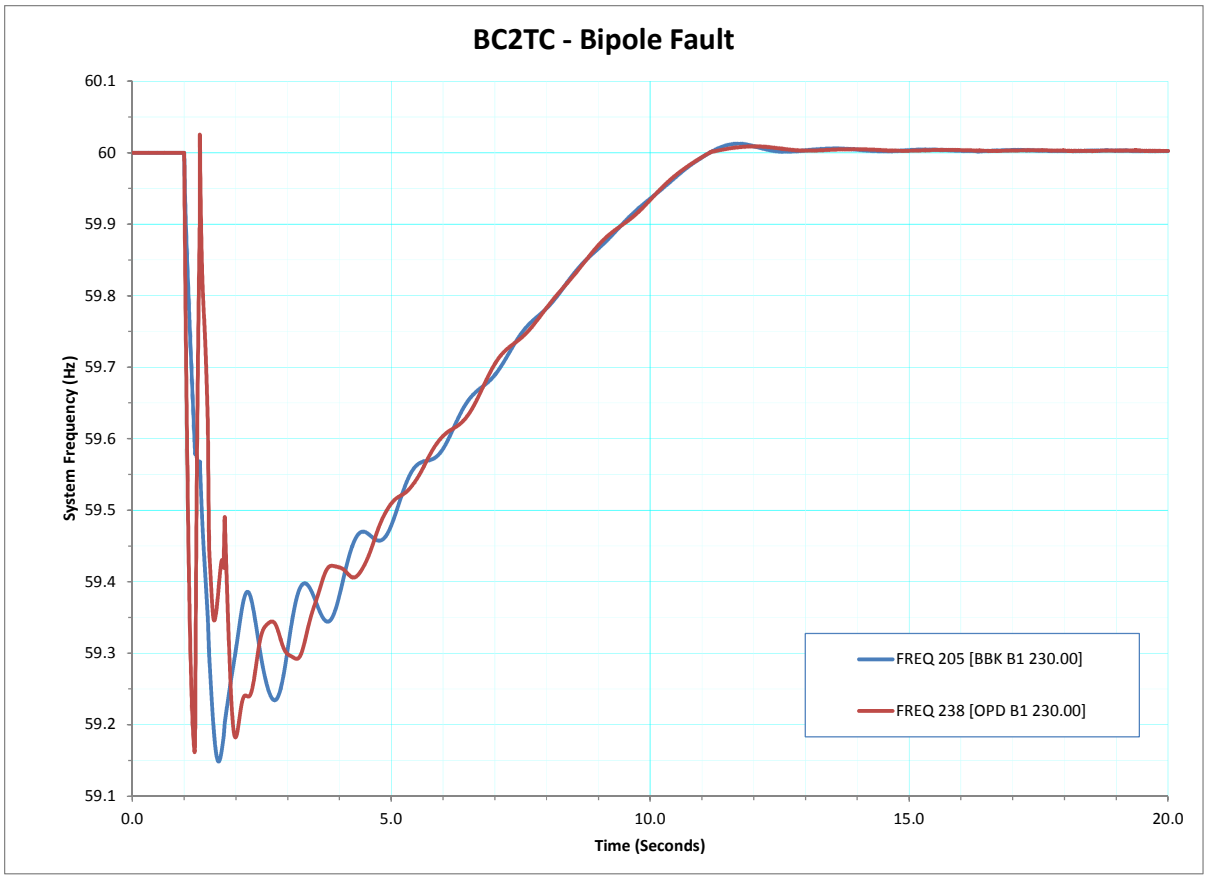


Figure 32 - BC2TC - Bipole Fault - System Frequency (Hz)

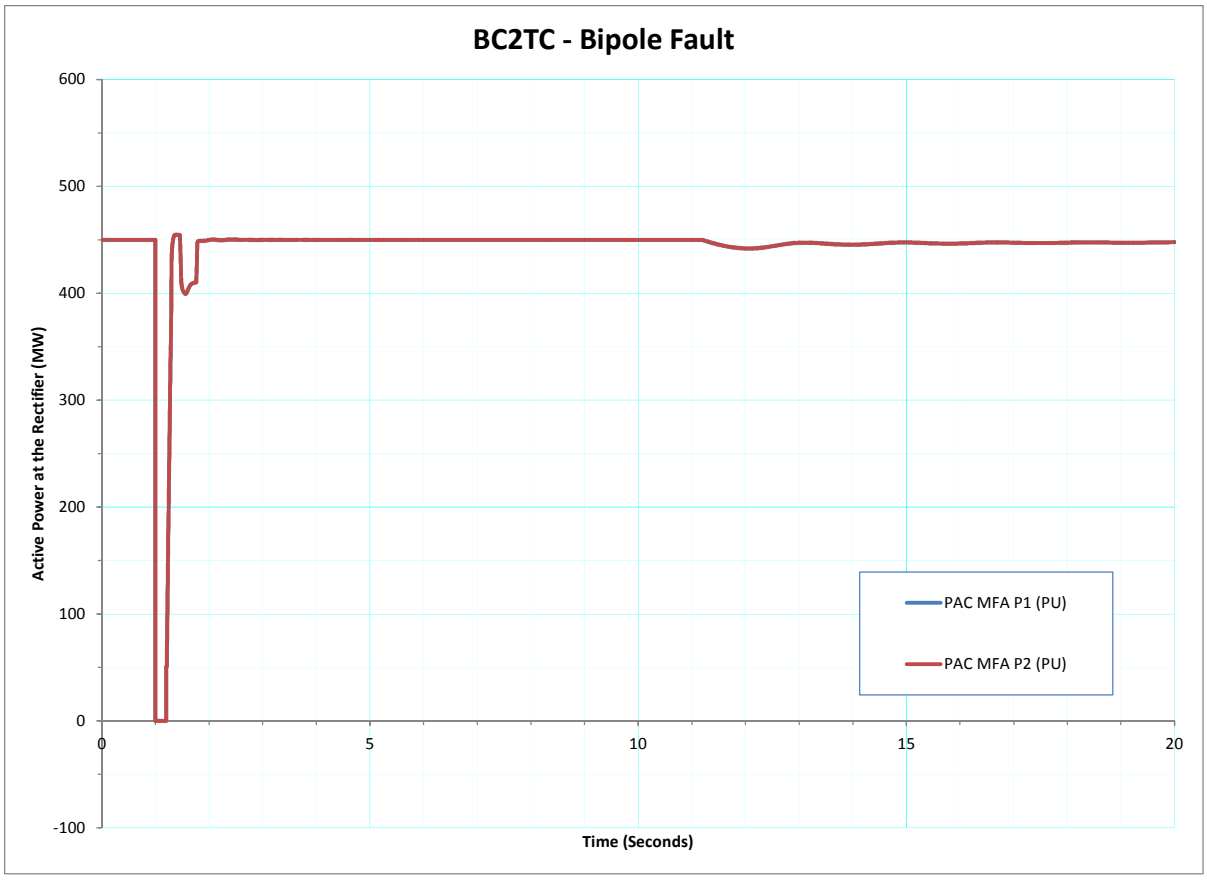


Figure 33 - BC2TC - Bipole Fault - Active Power at the Rectifier (MW)

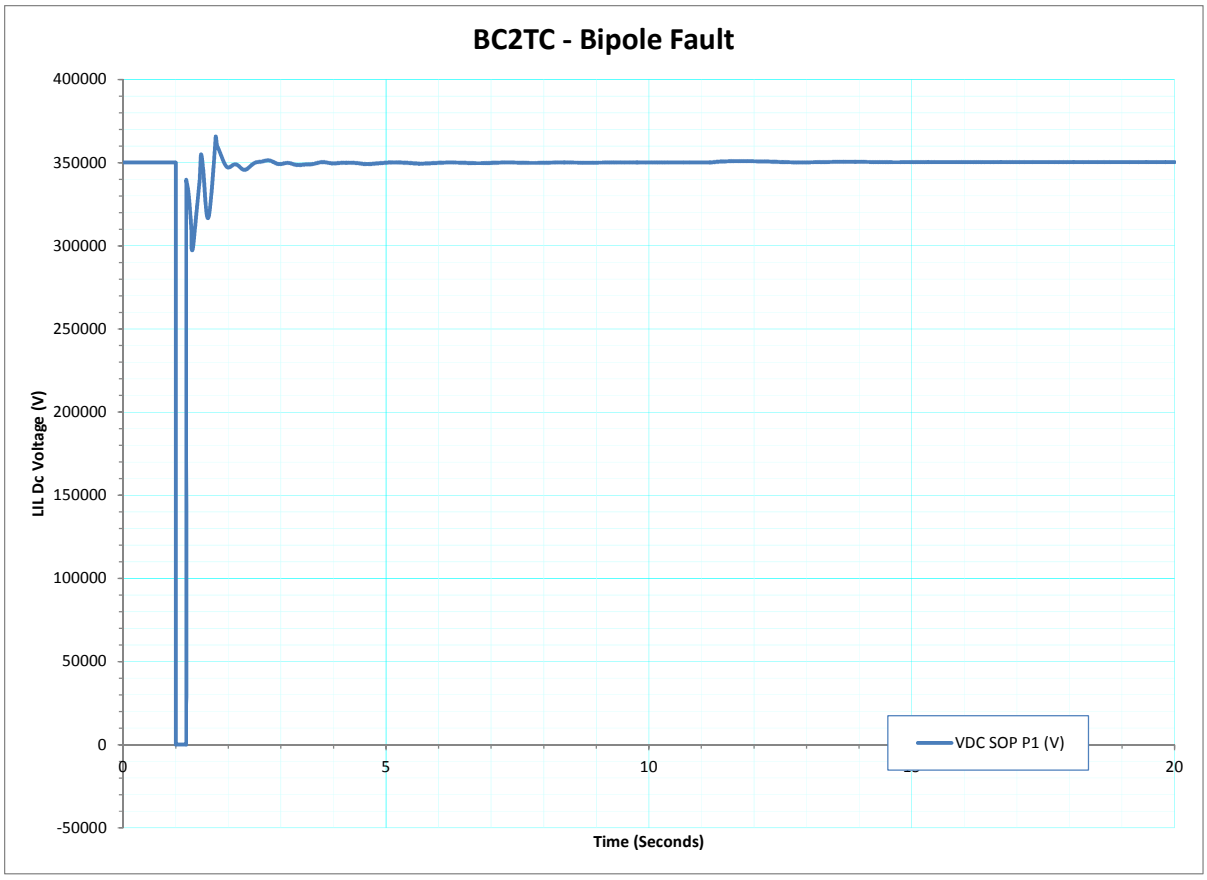


Figure 34 - BC2TC - Bipole Fault - LIL Dc Voltage (V)

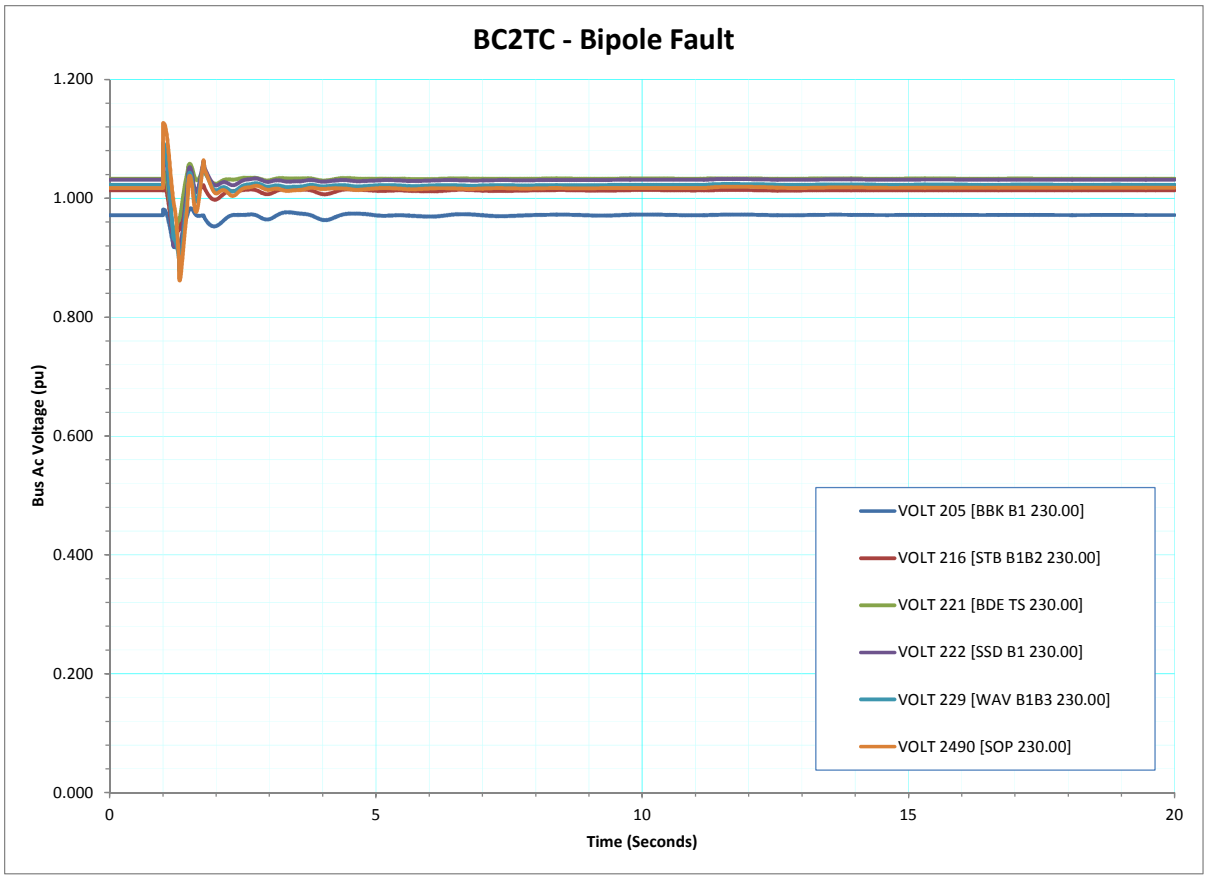


Figure 35 - BC2TC - Bipole Fault - Bus Ac Voltage (pu)

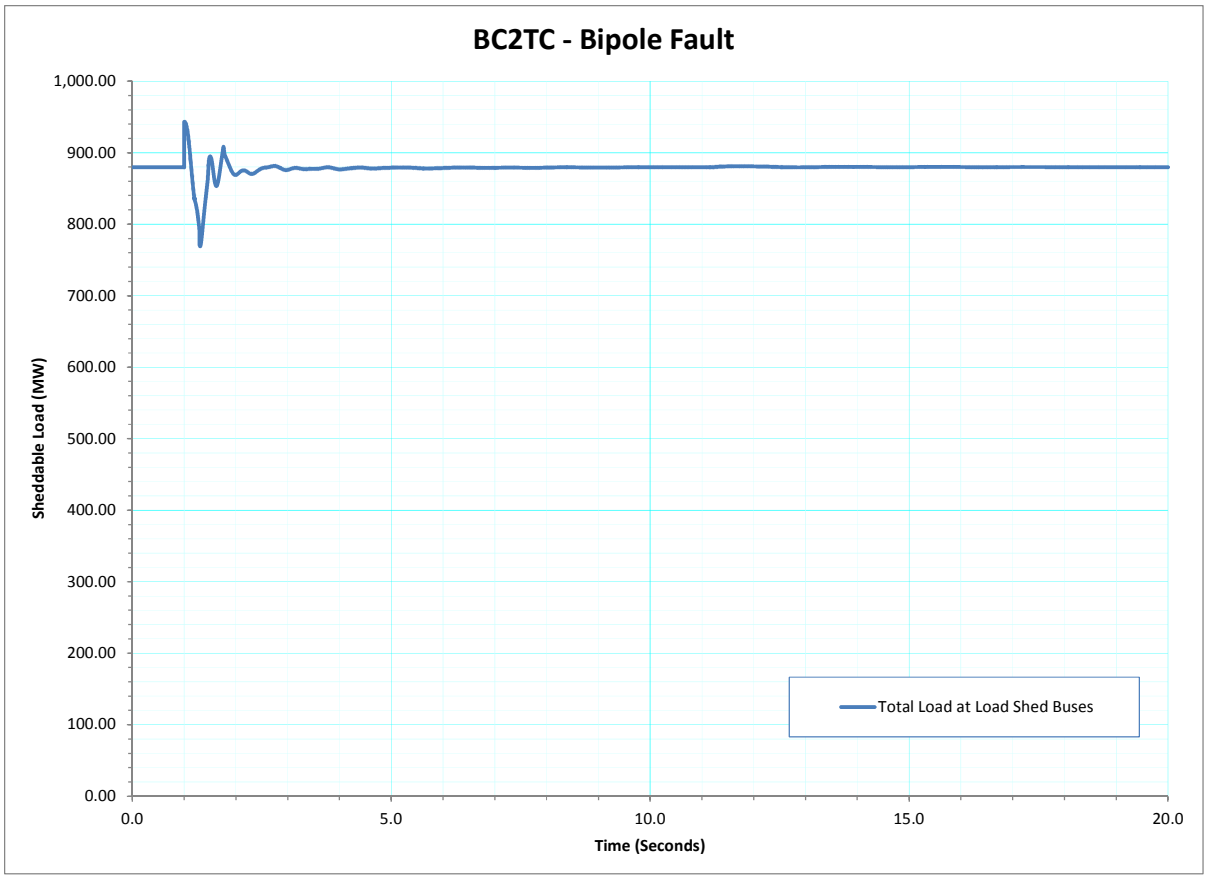


Figure 36 - BC2TC - Bipole Fault - Sheddable Load (MW)

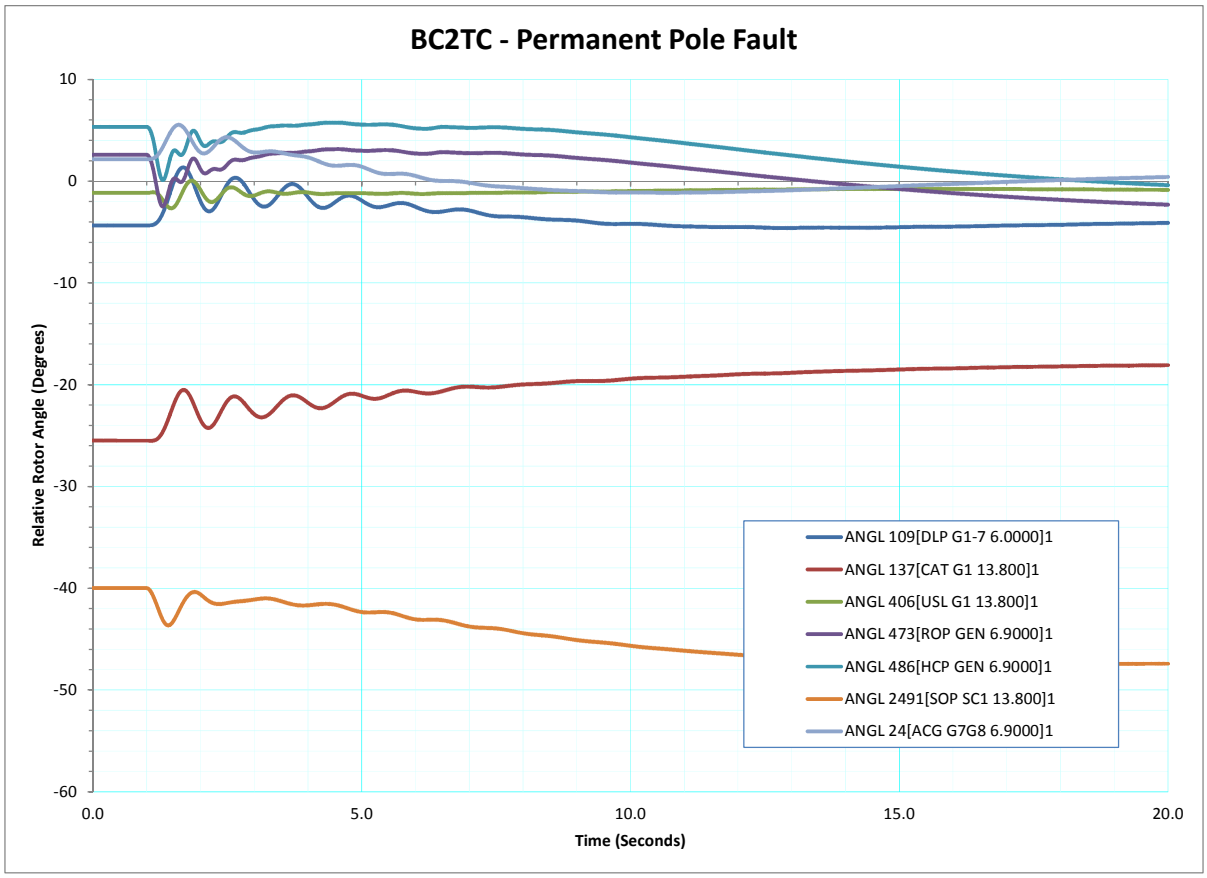


Figure 37 - BC2TC - Permanent Pole Fault - Relative Rotor Angle (Degrees)

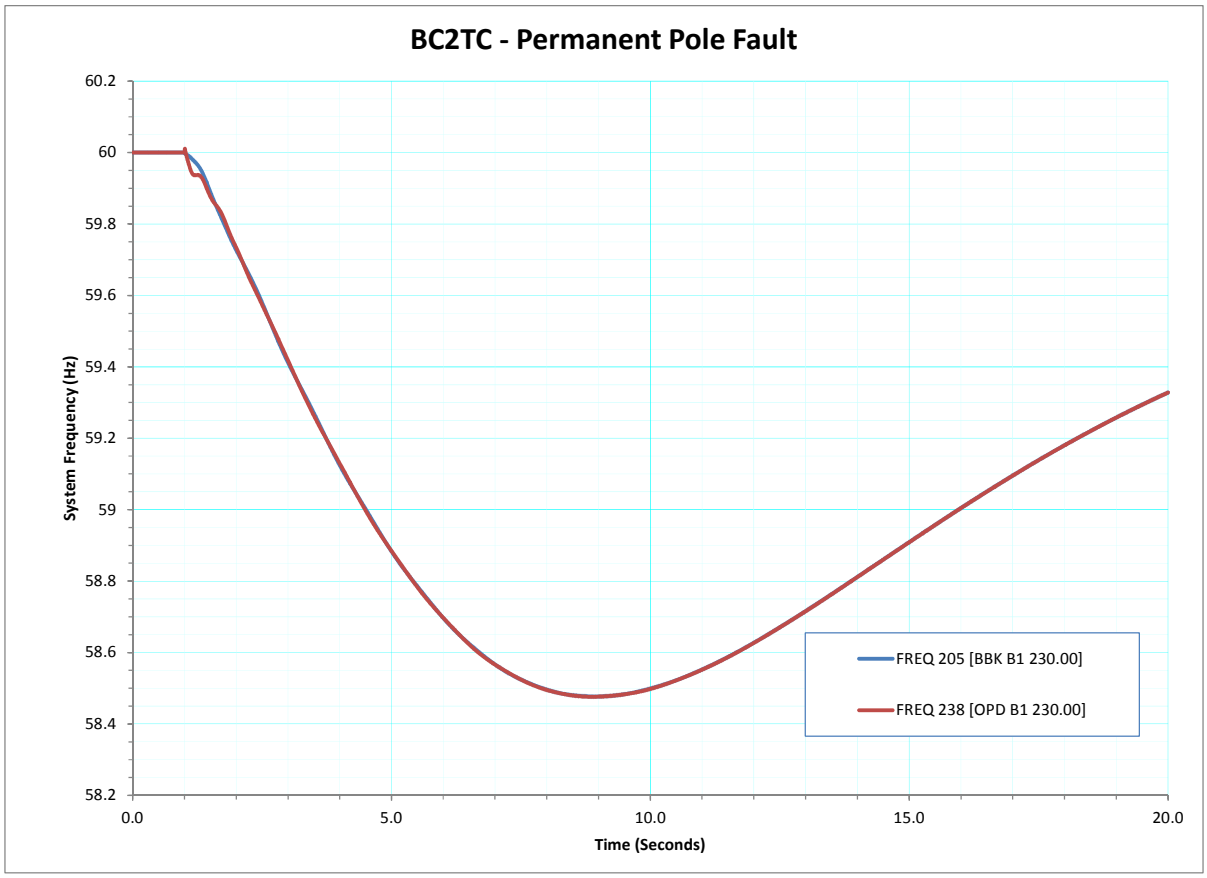


Figure 38 - BC2TC - Permanent Pole Fault - System Frequency (Hz)

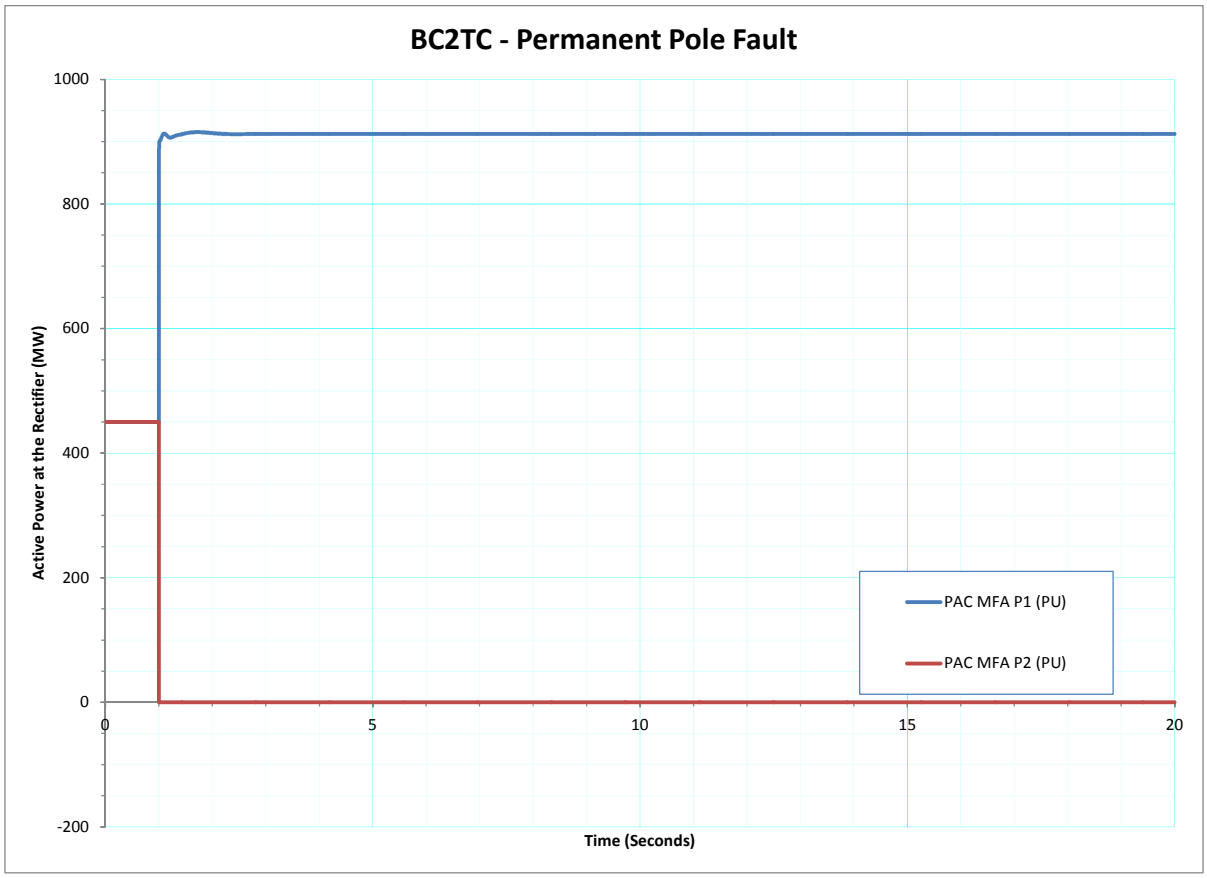


Figure 39 - BC2TC - Permanent Pole Fault - Active Power at the Rectifier (MW)

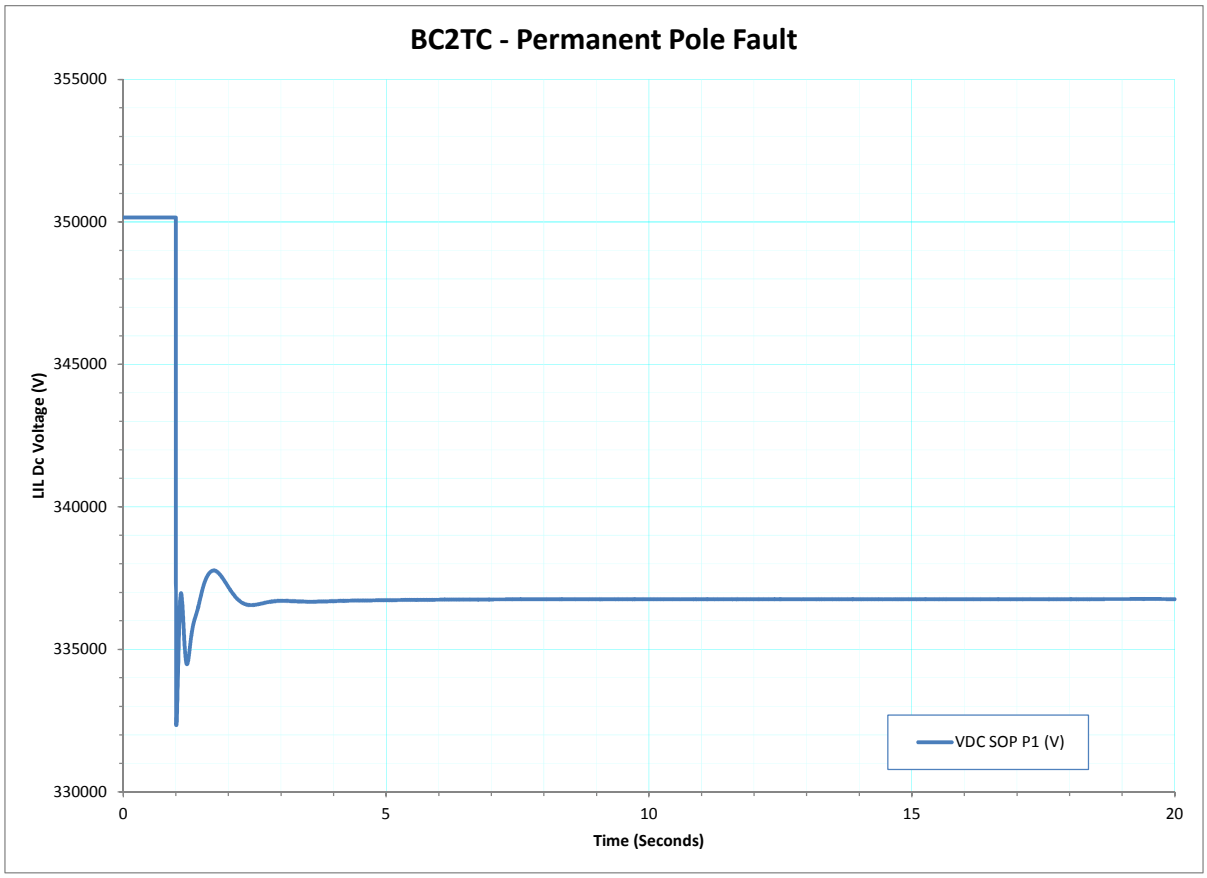


Figure 40 - BC2TC - Permanent Pole Fault - LIL Dc Voltage (V)

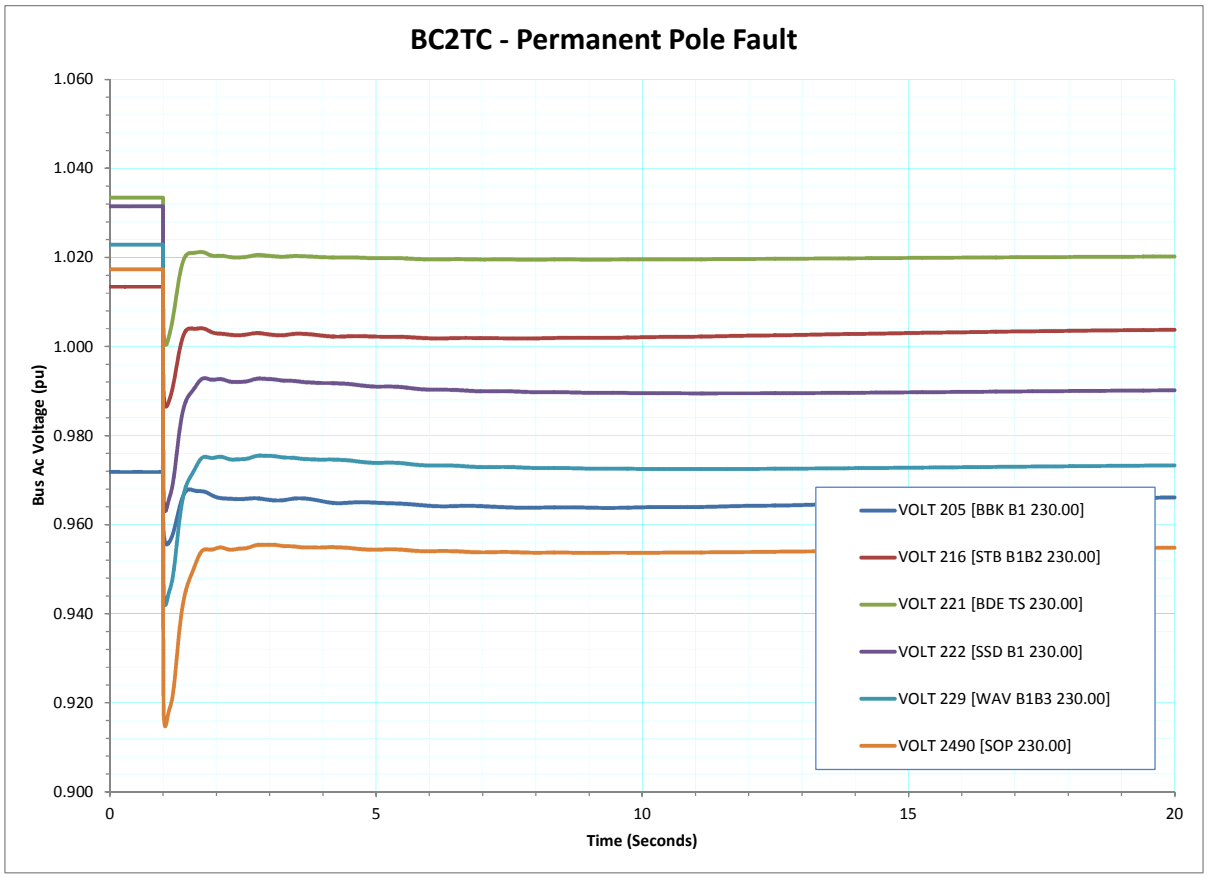


Figure 41 - BC2TC - Permanent Pole Fault - Bus Ac Voltage (pu)

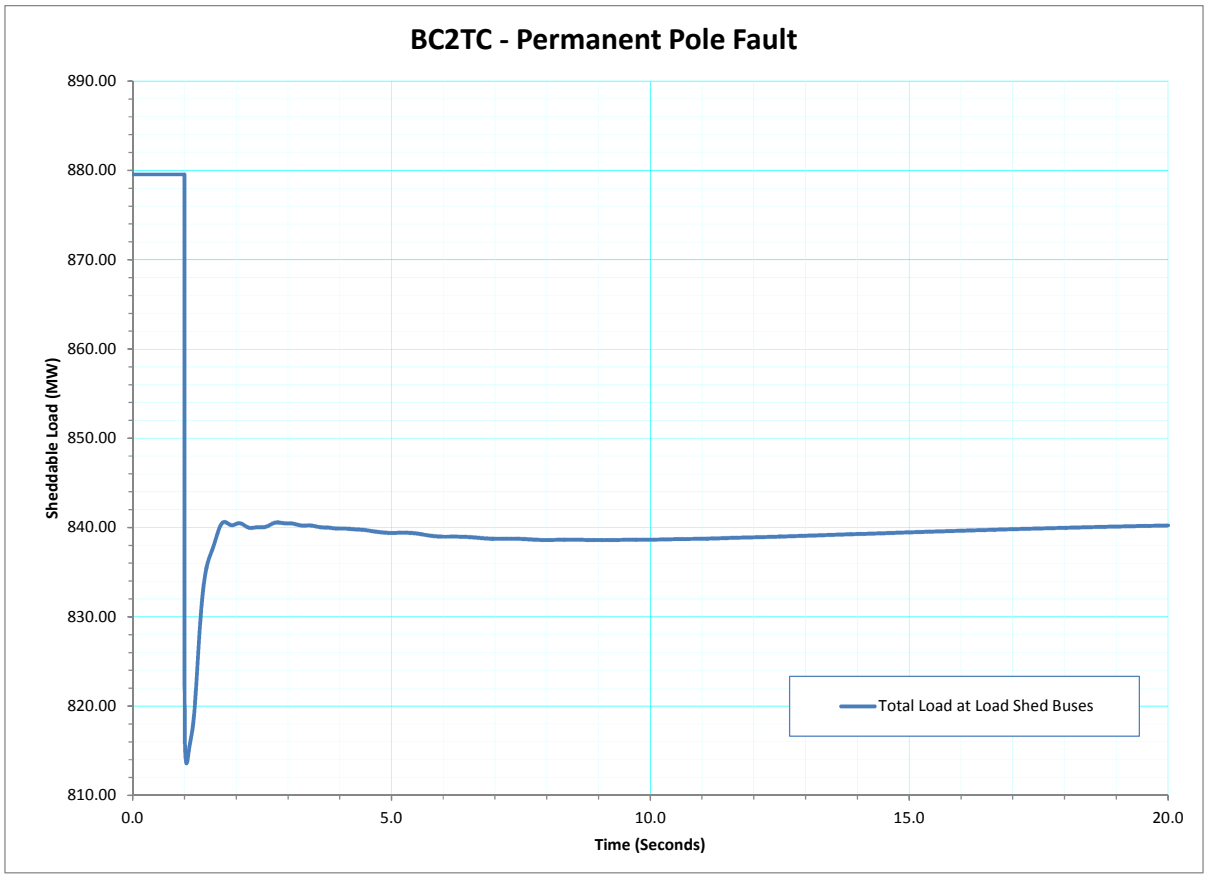


Figure 42 - BC2TC - Permanent Pole Fault - Sheddable Load (MW)

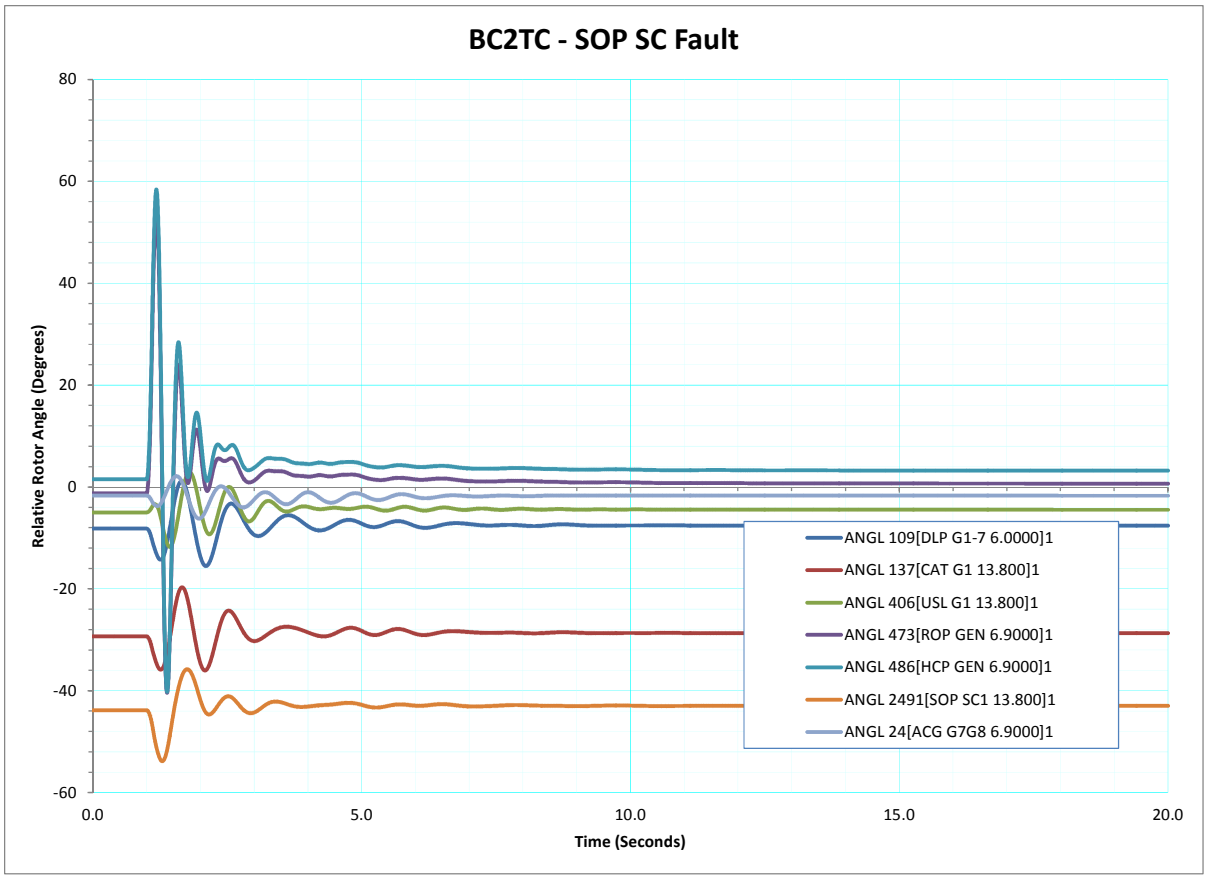


Figure 43 - BC2TC - SOP SC Fault - Relative Rotor Angle (Degrees)

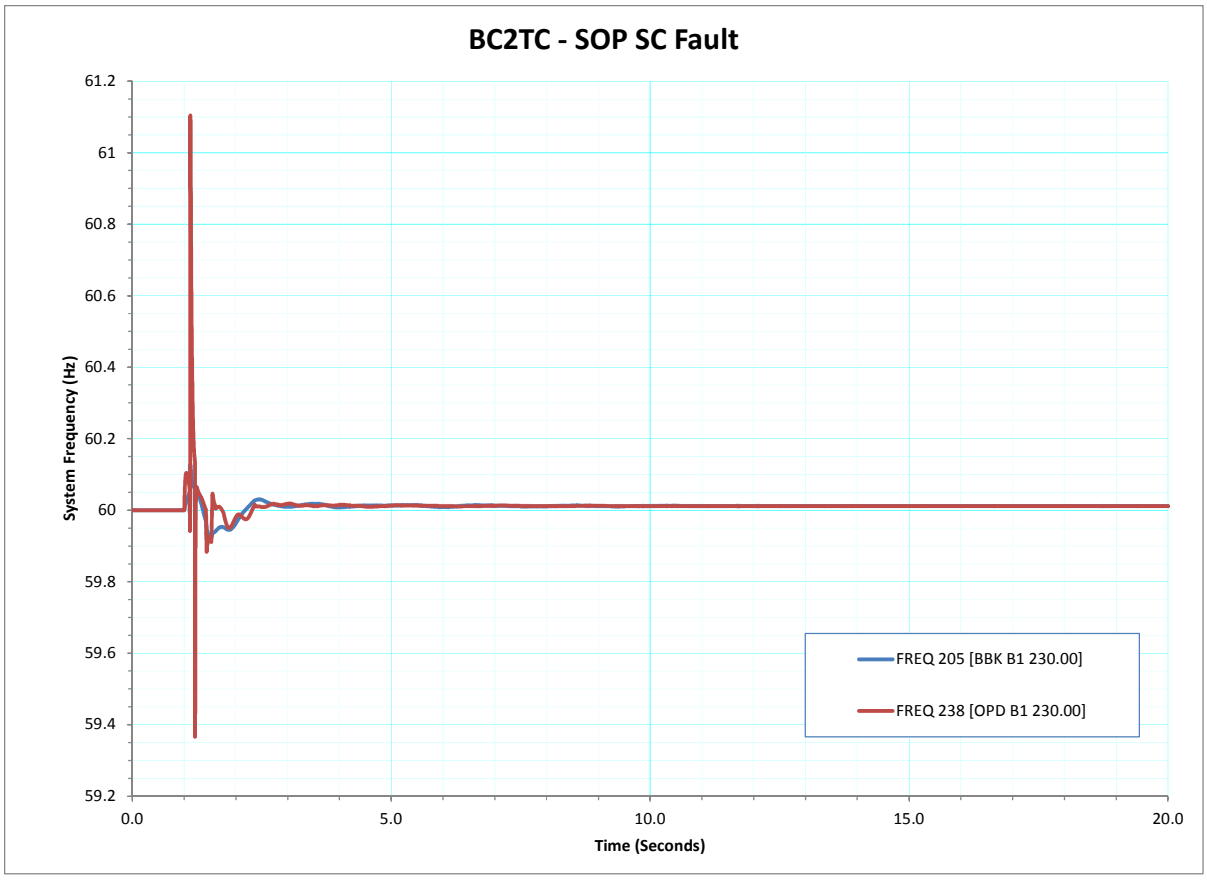


Figure 44 - BC2TC - SOP SC Fault - System Frequency (Hz)

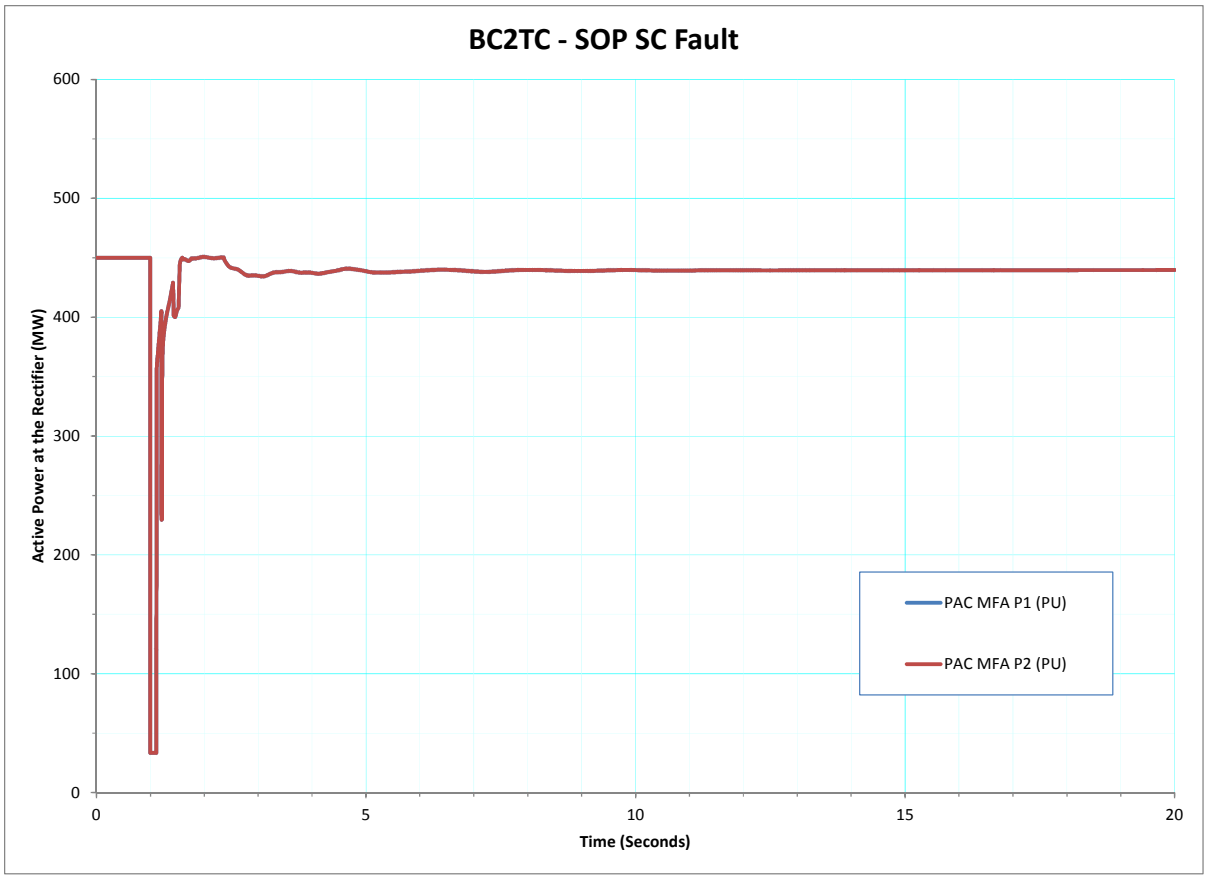


Figure 45 - BC2TC - SOP SC Fault - Active Power at the Rectifier (MW)

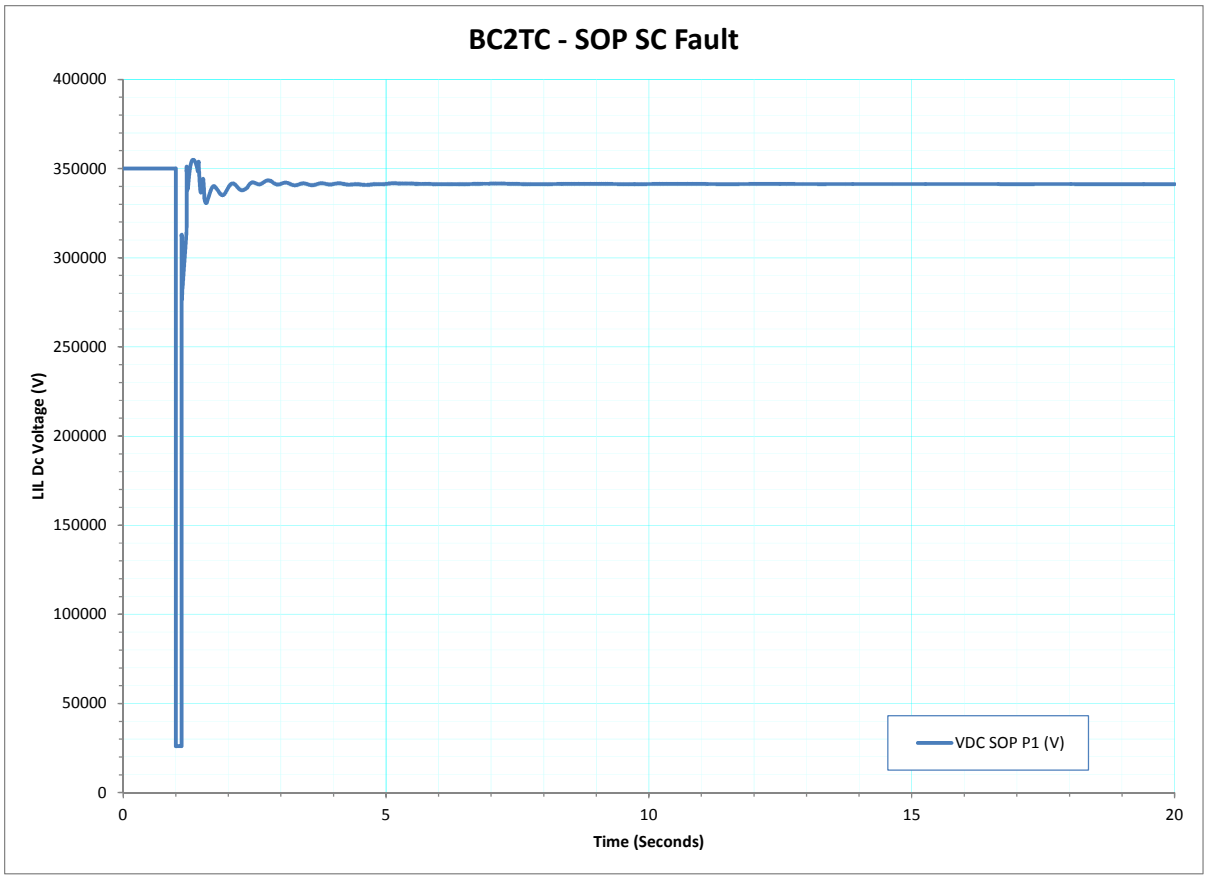


Figure 46 - BC2TC - SOP SC Fault - LIL Dc Voltage (V)

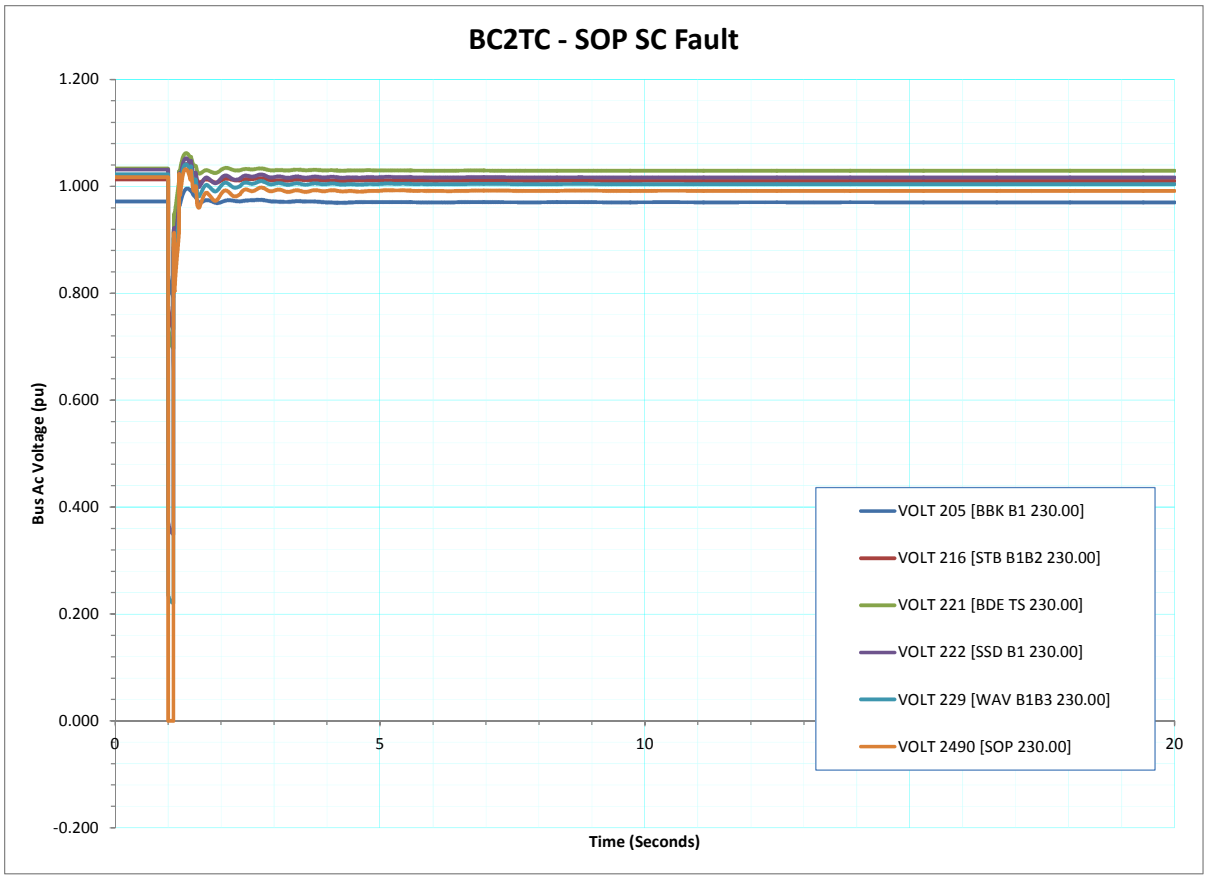


Figure 47 - BC2TC - SOP SC Fault - Bus Ac Voltage (pu)

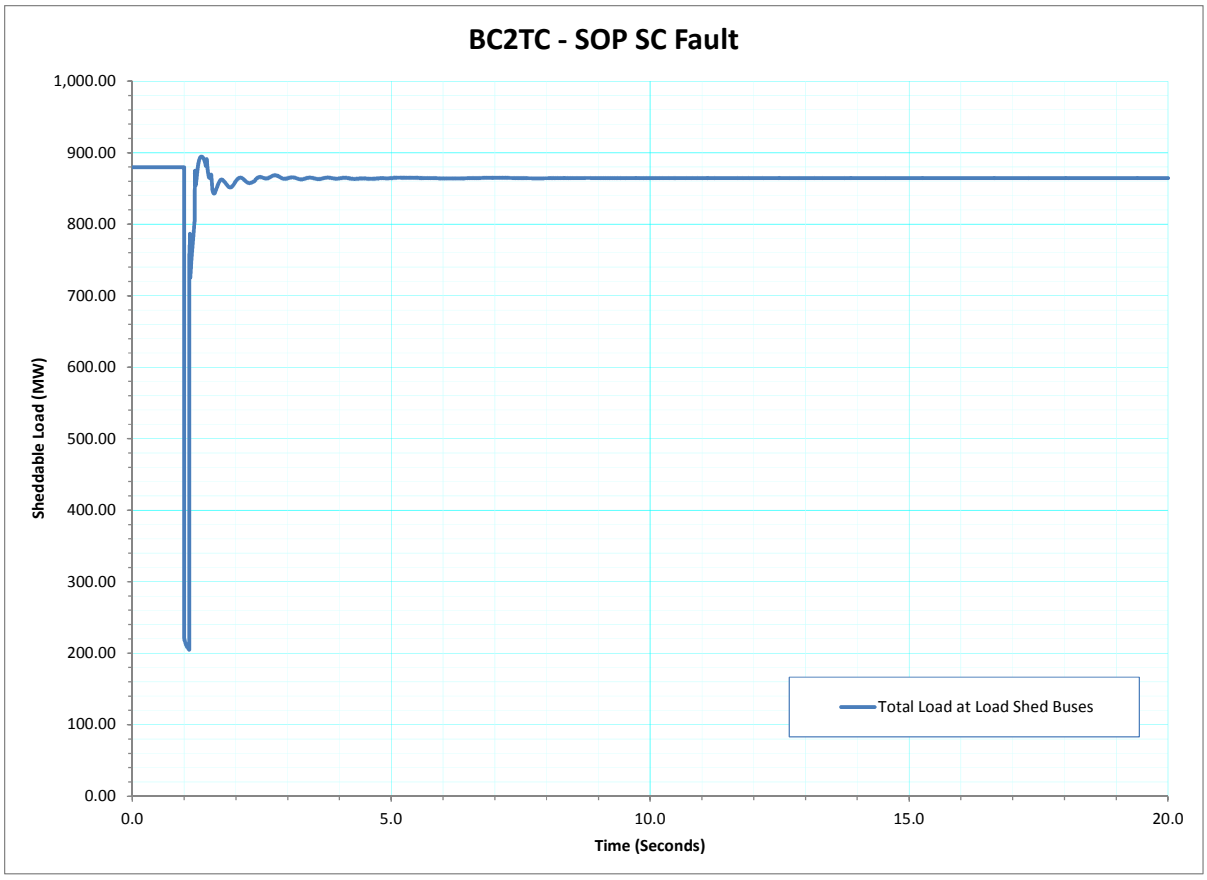


Figure 48 - BC2TC - SOP SC Fault - Sheddable Load (MW)

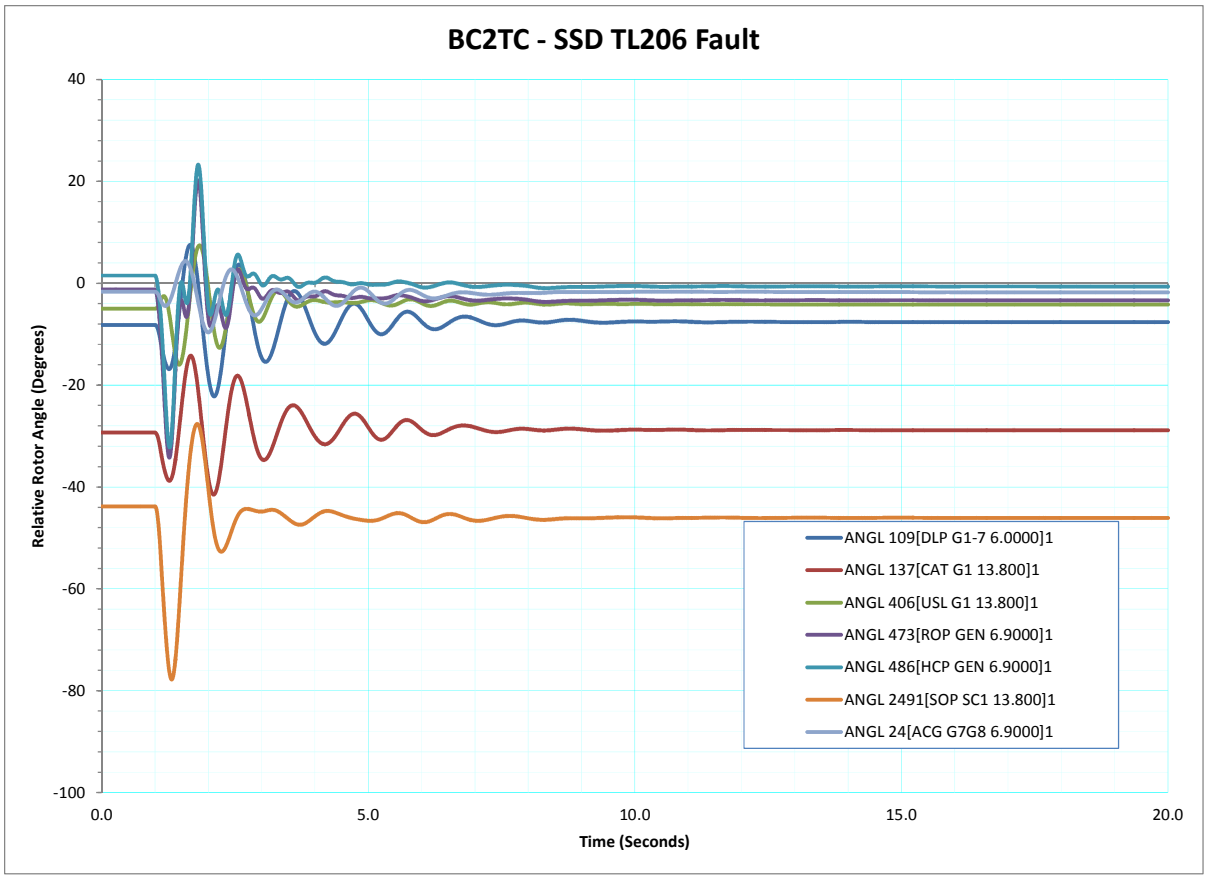


Figure 49 - BC2TC - SSD TL206 Fault - Relative Rotor Angle (Degrees)

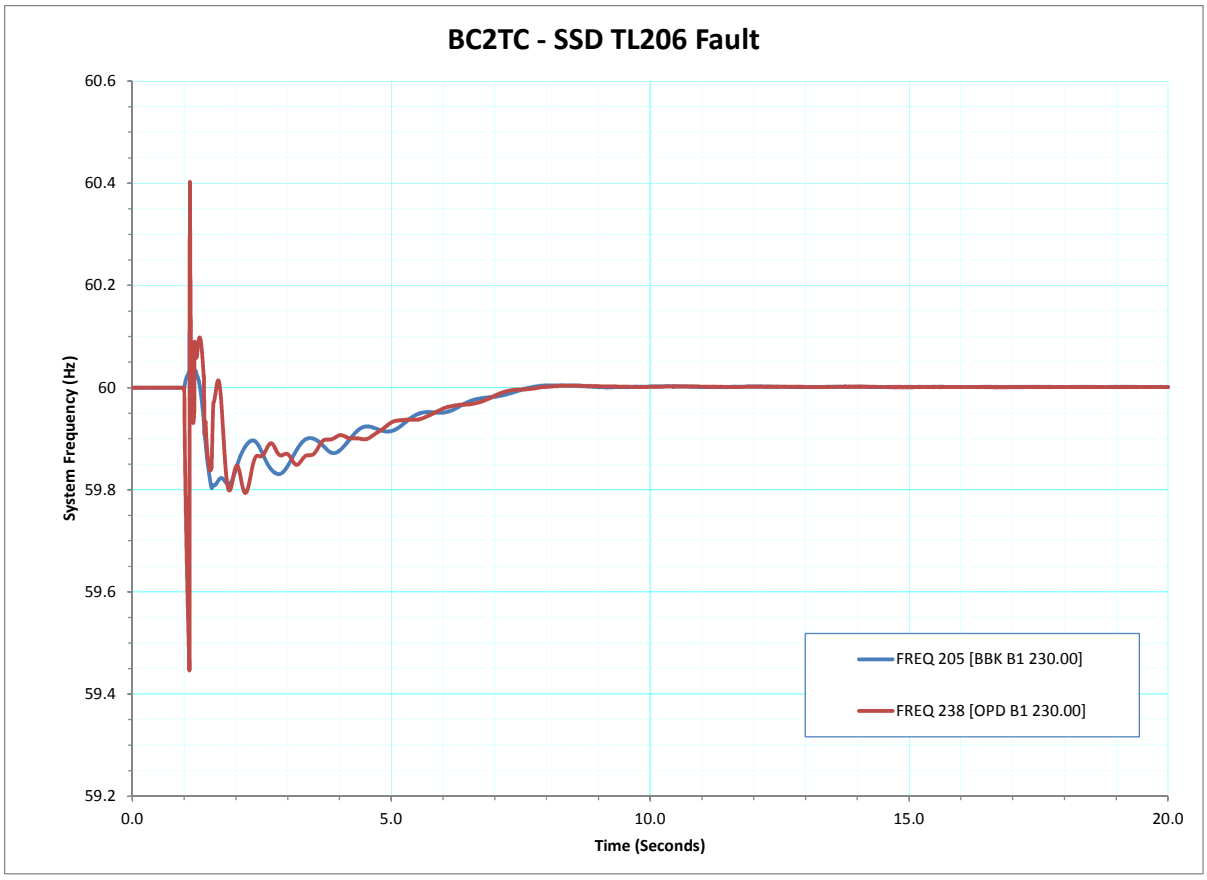


Figure 50 - BC2TC - SSD TL206 Fault - System Frequency (Hz)

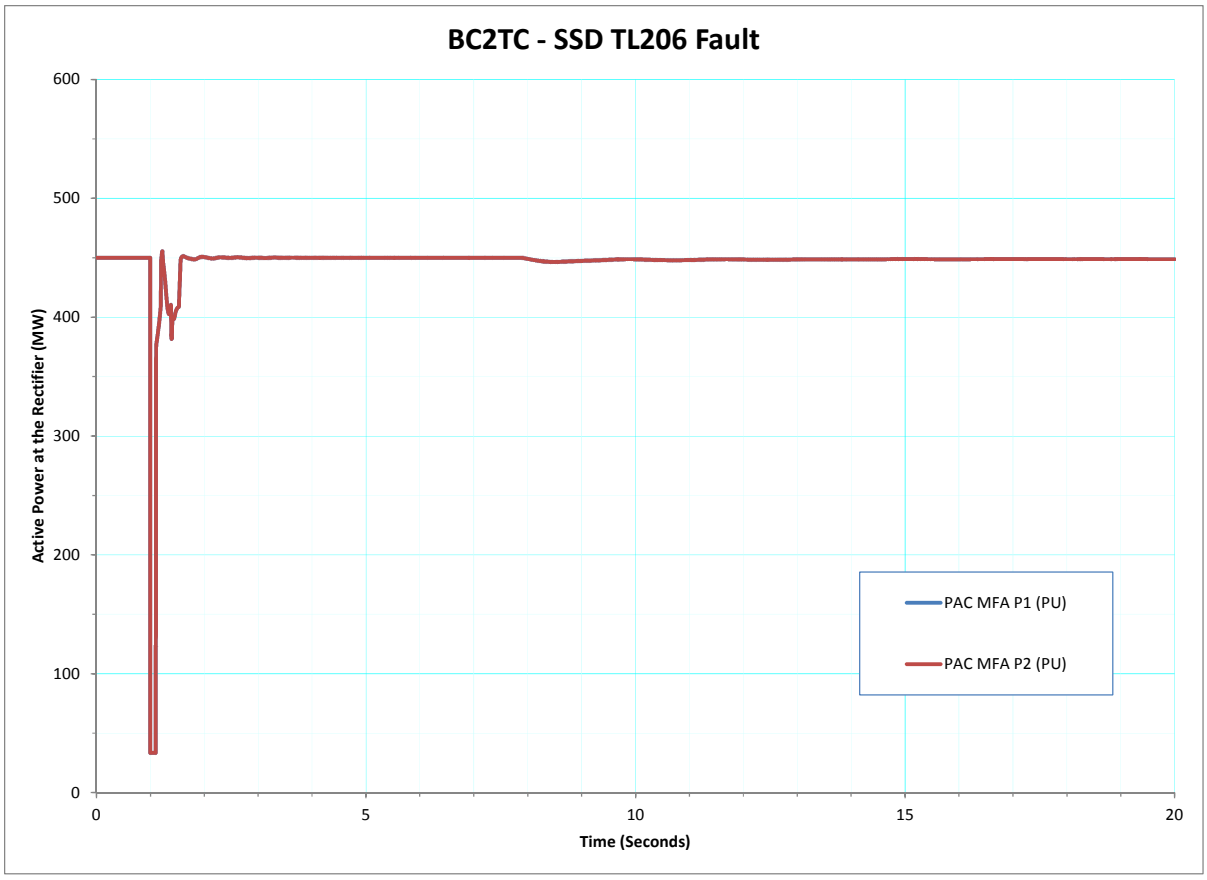


Figure 51 - BC2TC - SSD TL206 Fault - Active Power at the Rectifier (MW)

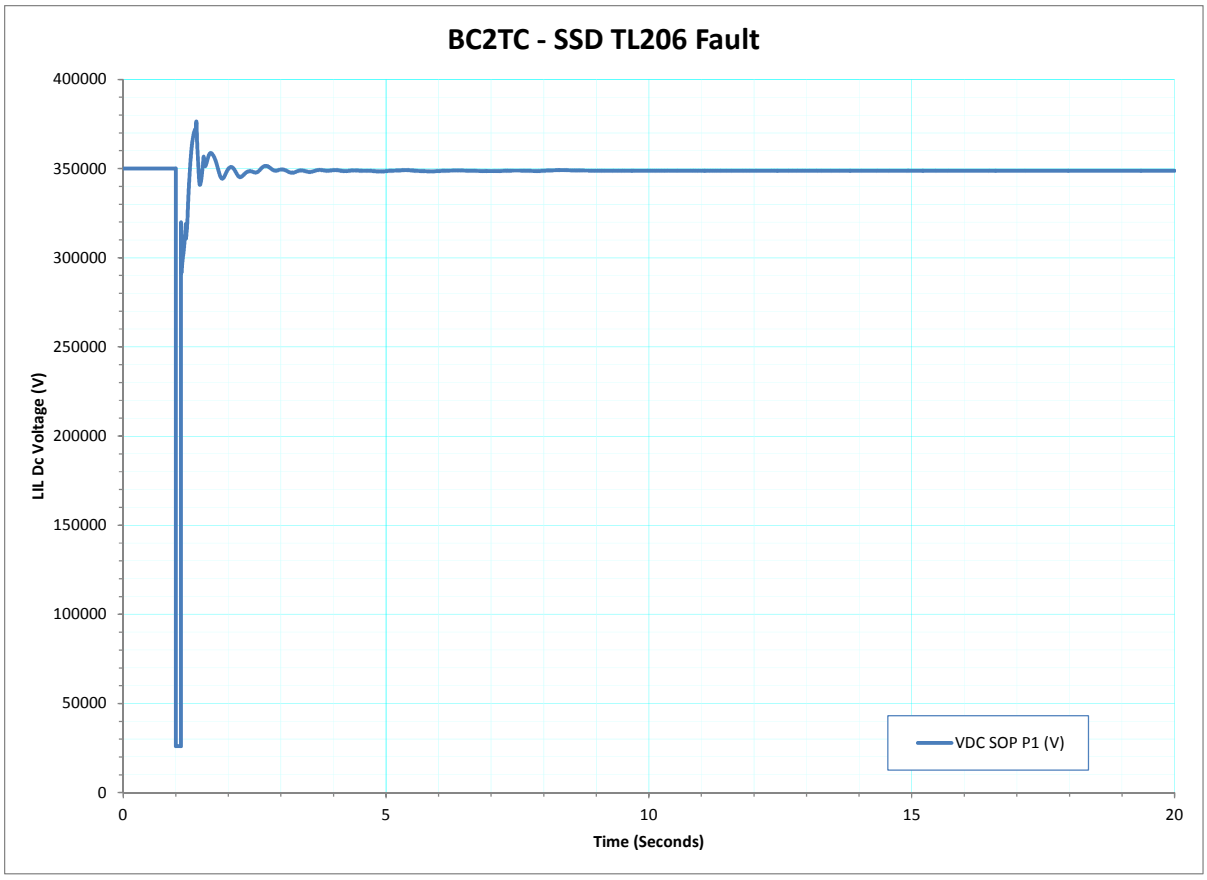


Figure 52 - BC2TC - SSD TL206 Fault - LIL Dc Voltage (V)

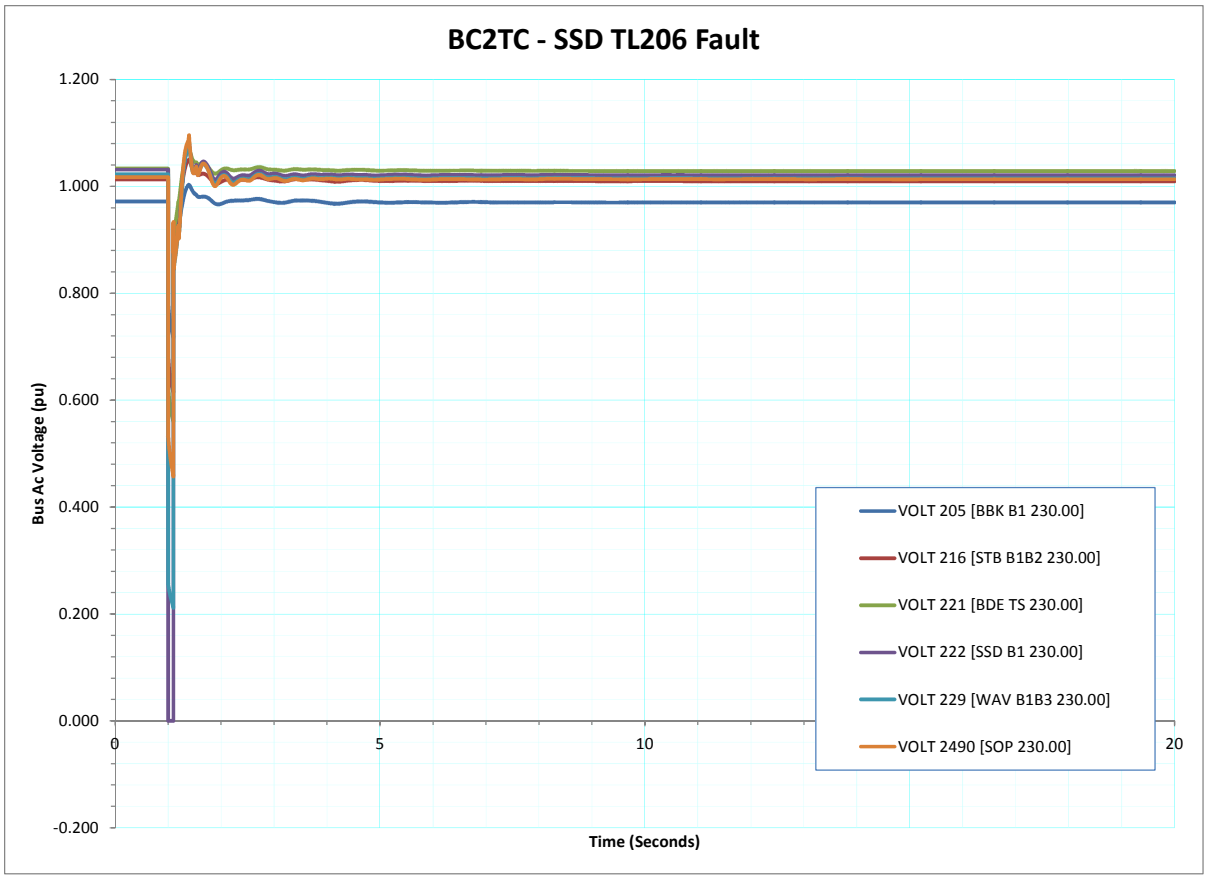


Figure 53 - BC2TC - SSD TL206 Fault - Bus Ac Voltage (pu)

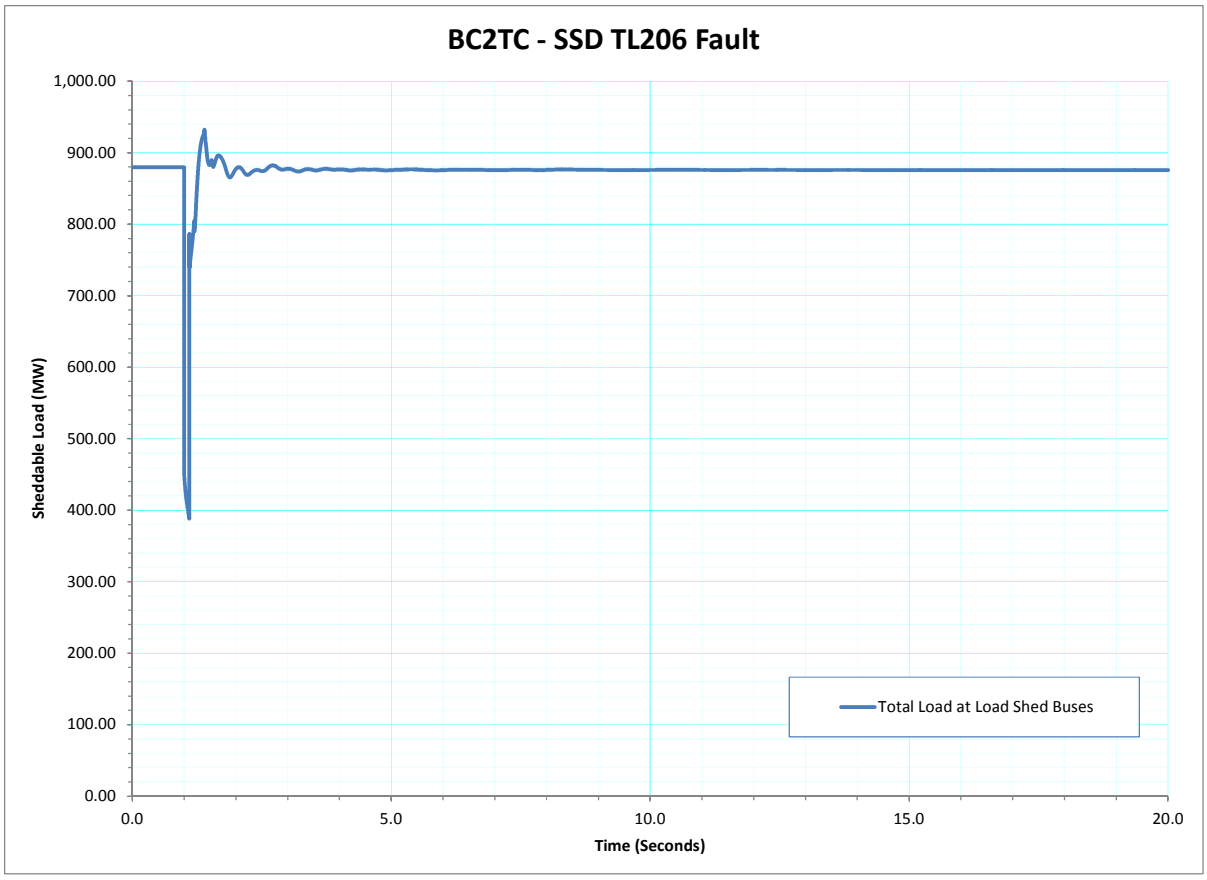


Figure 54 - BC2TC - SSD TL206 Fault - Sheddable Load (MW)

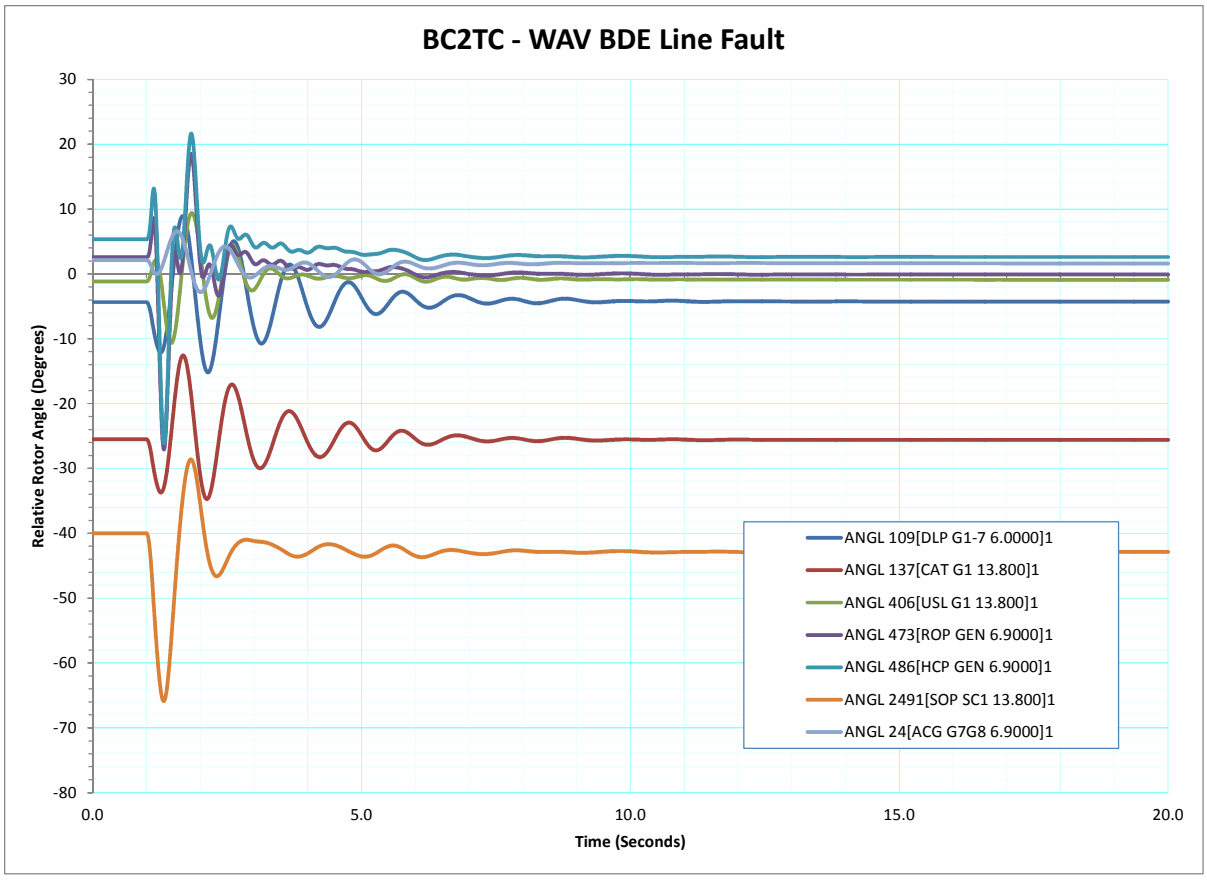


Figure 55 - BC2TC - WAV BDE Line Fault - Relative Rotor Angle (Degrees)

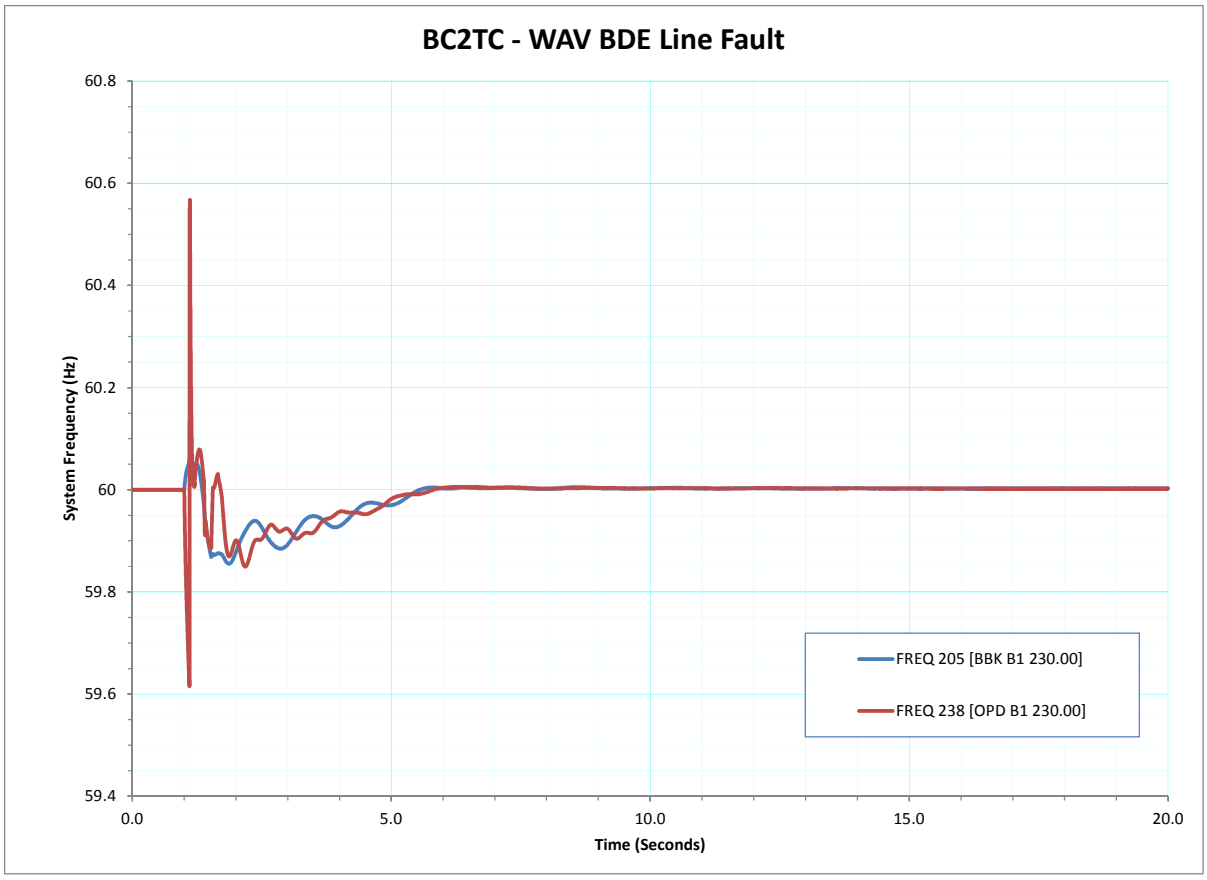


Figure 56 - BC2TC - WAV BDE Line Fault - System Frequency (Hz)

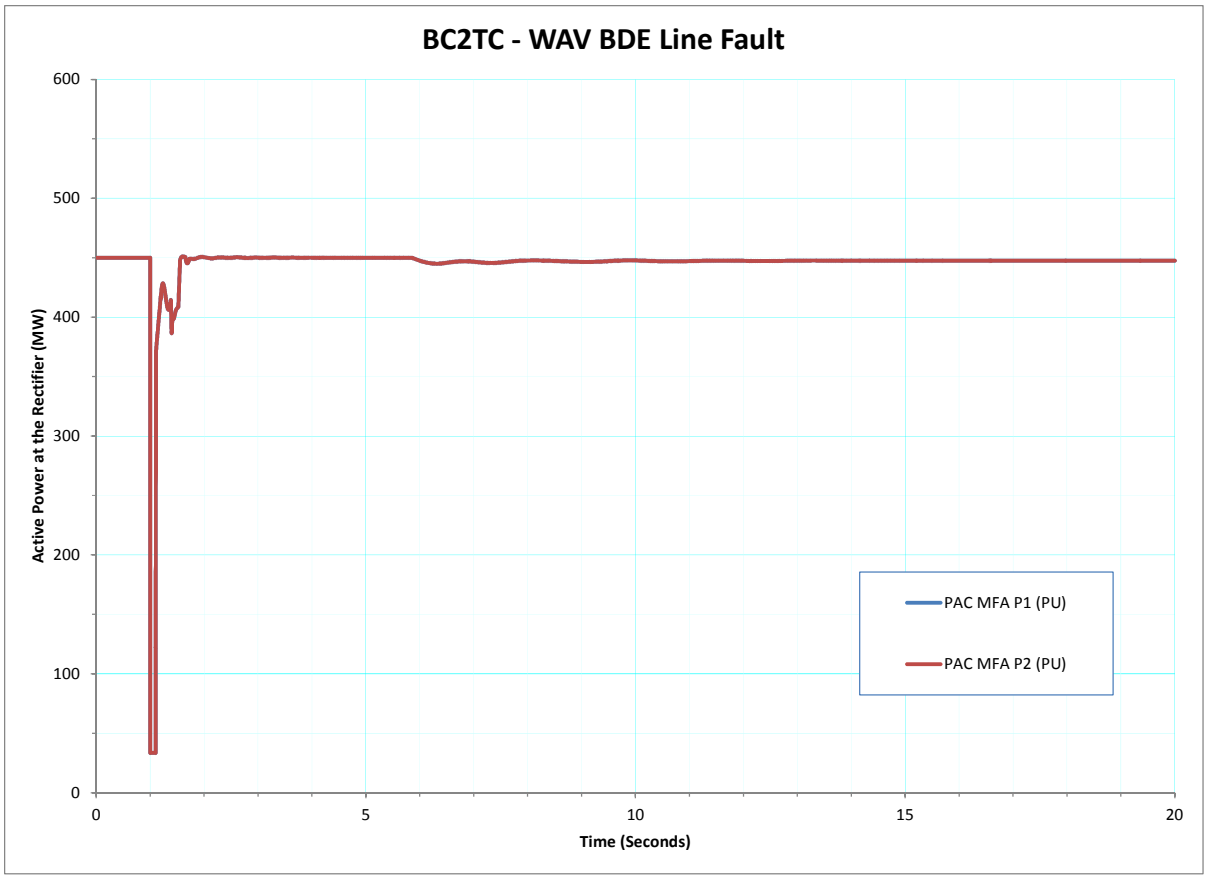


Figure 57 - BC2TC - WAV BDE Line Fault - Active Power at the Rectifier (MW)

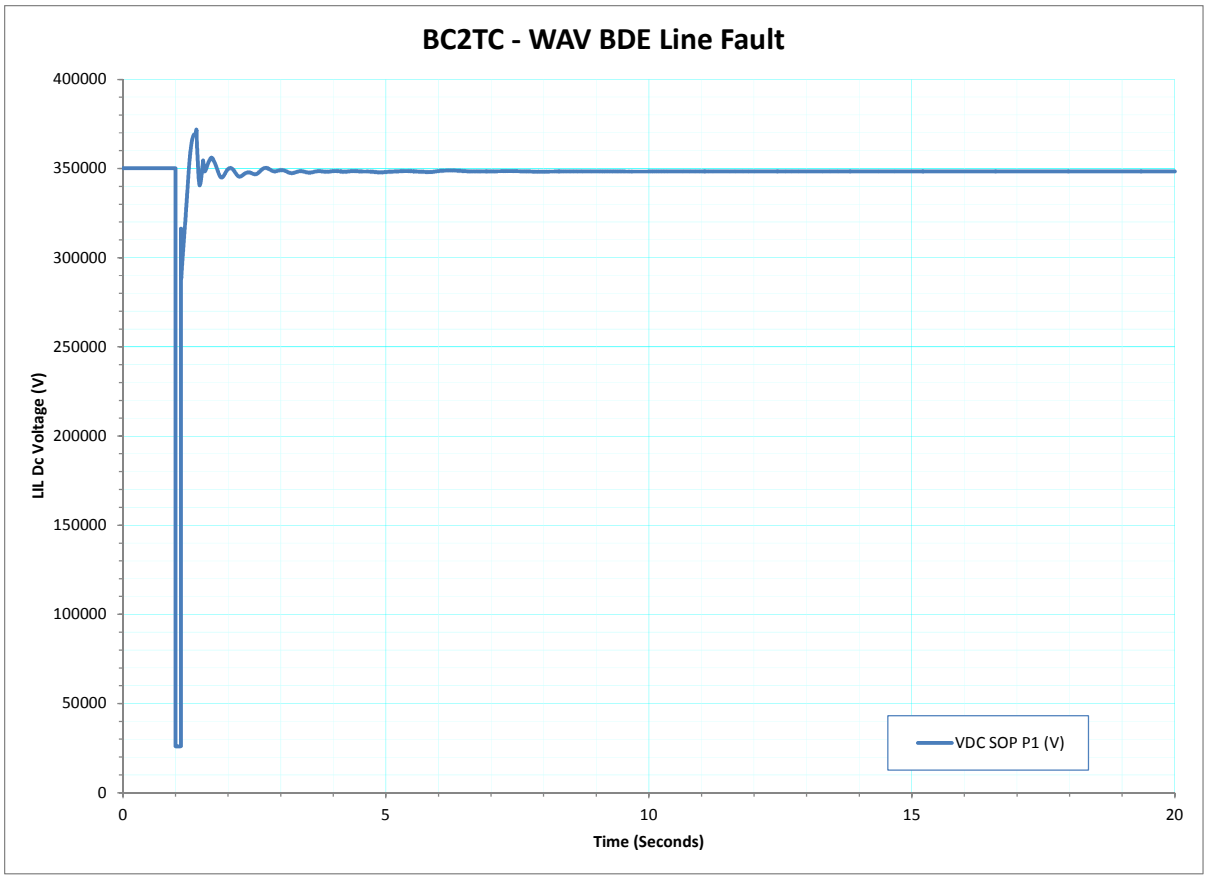


Figure 58 - BC2TC - WAV BDE Line Fault - LIL Dc Voltage (V)

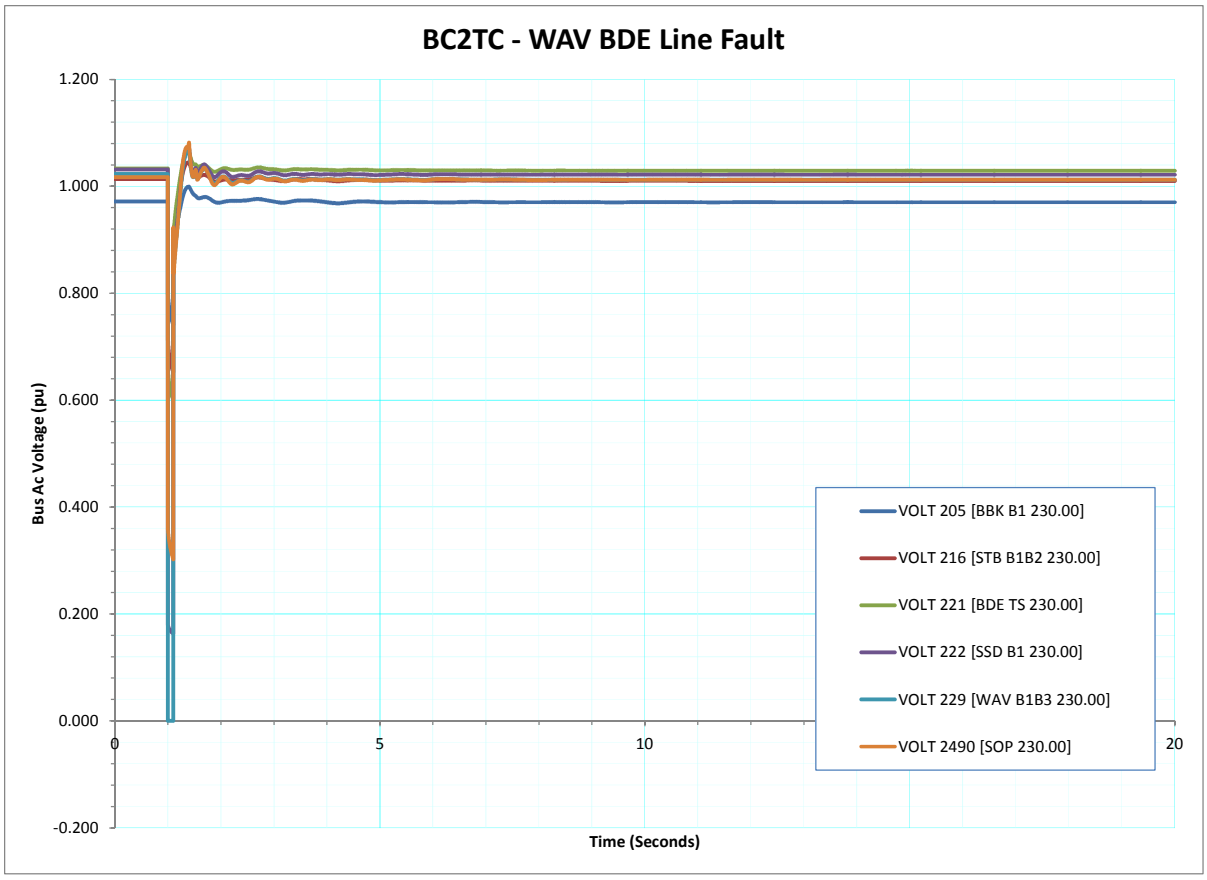


Figure 59 - BC2TC - WAV BDE Line Fault - Bus Ac Voltage (pu)

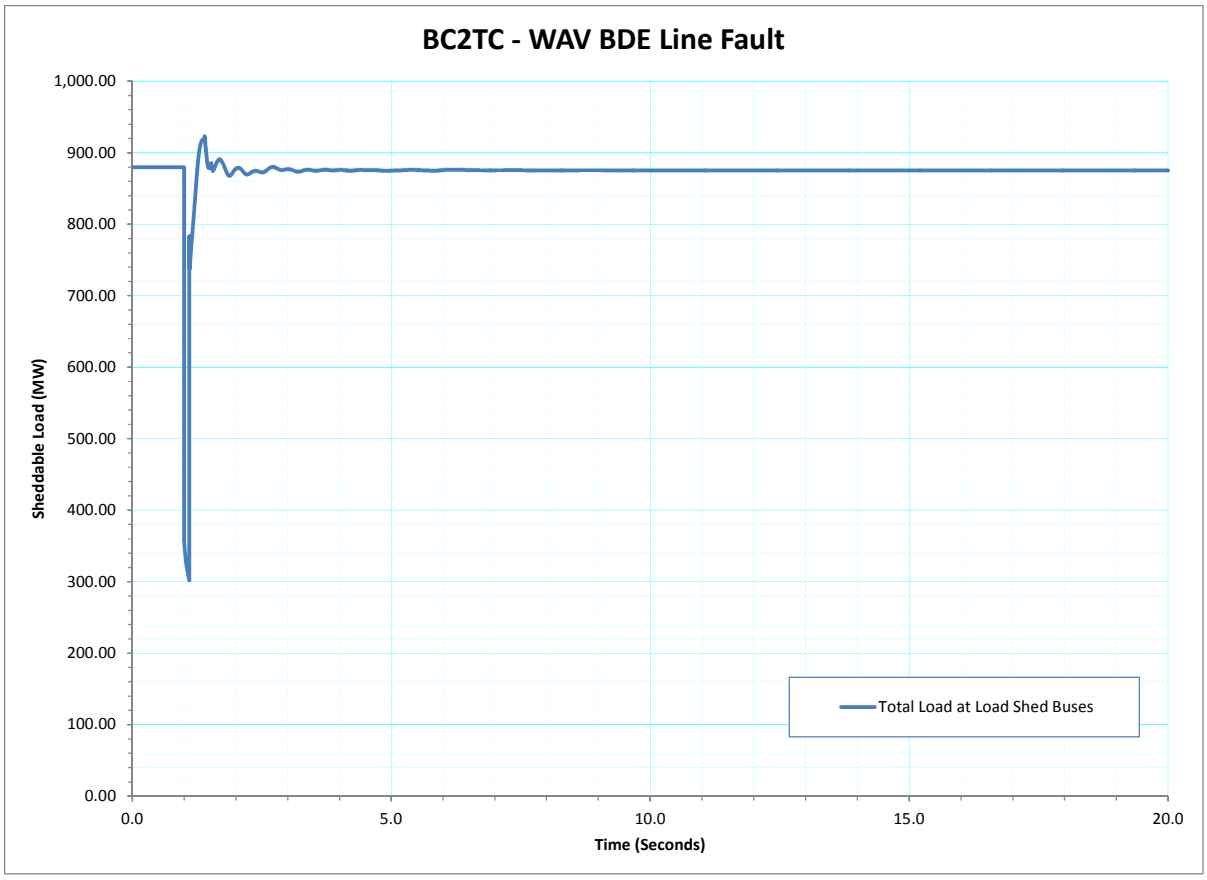


Figure 60 - BC2TC - WAV BDE Line Fault - Sheddable Load (MW)

1.3. BASE CASE 3 TRANSIENT STABILITY PLOTS

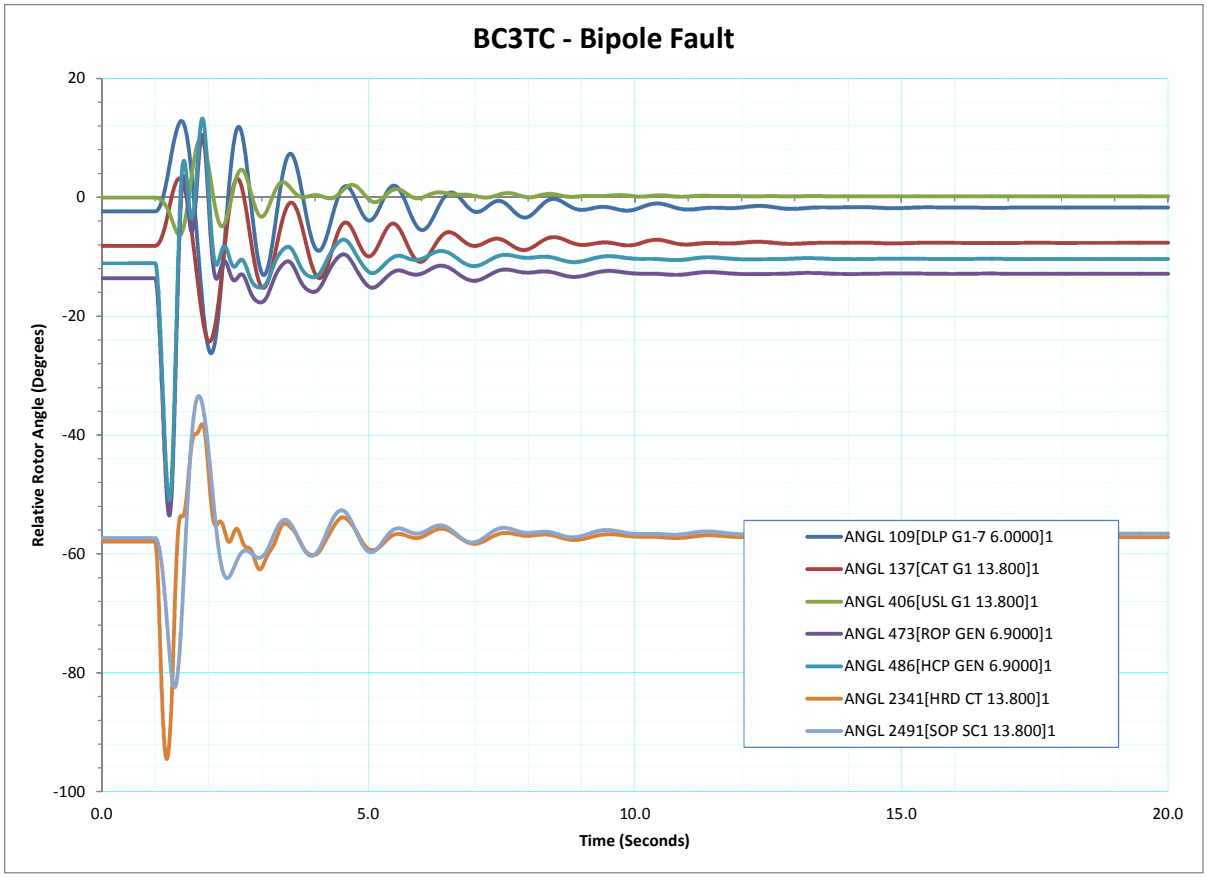


Figure 61 - BC3TC - Bipole Fault - Relative Rotor Angle (Degrees)

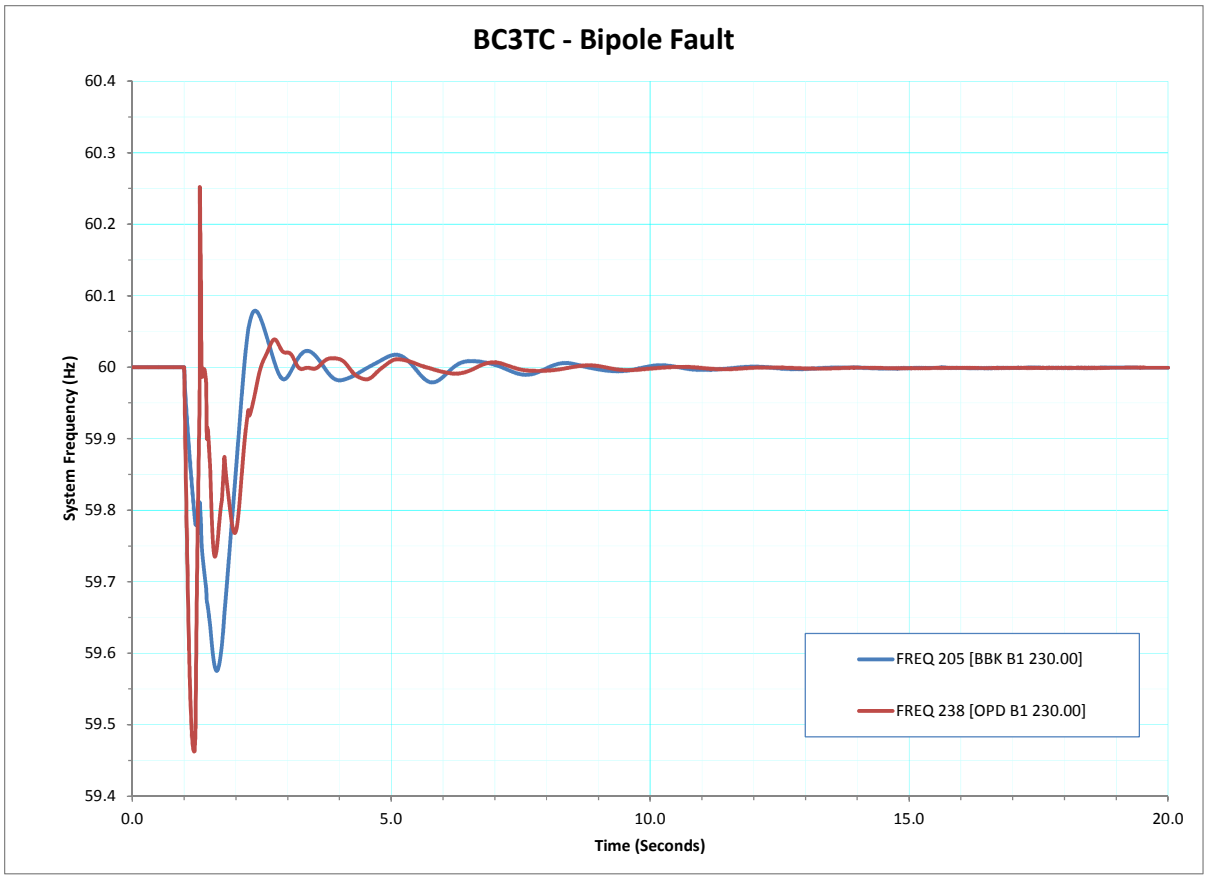


Figure 62 - BC3TC - Bipole Fault - System Frequency (Hz)

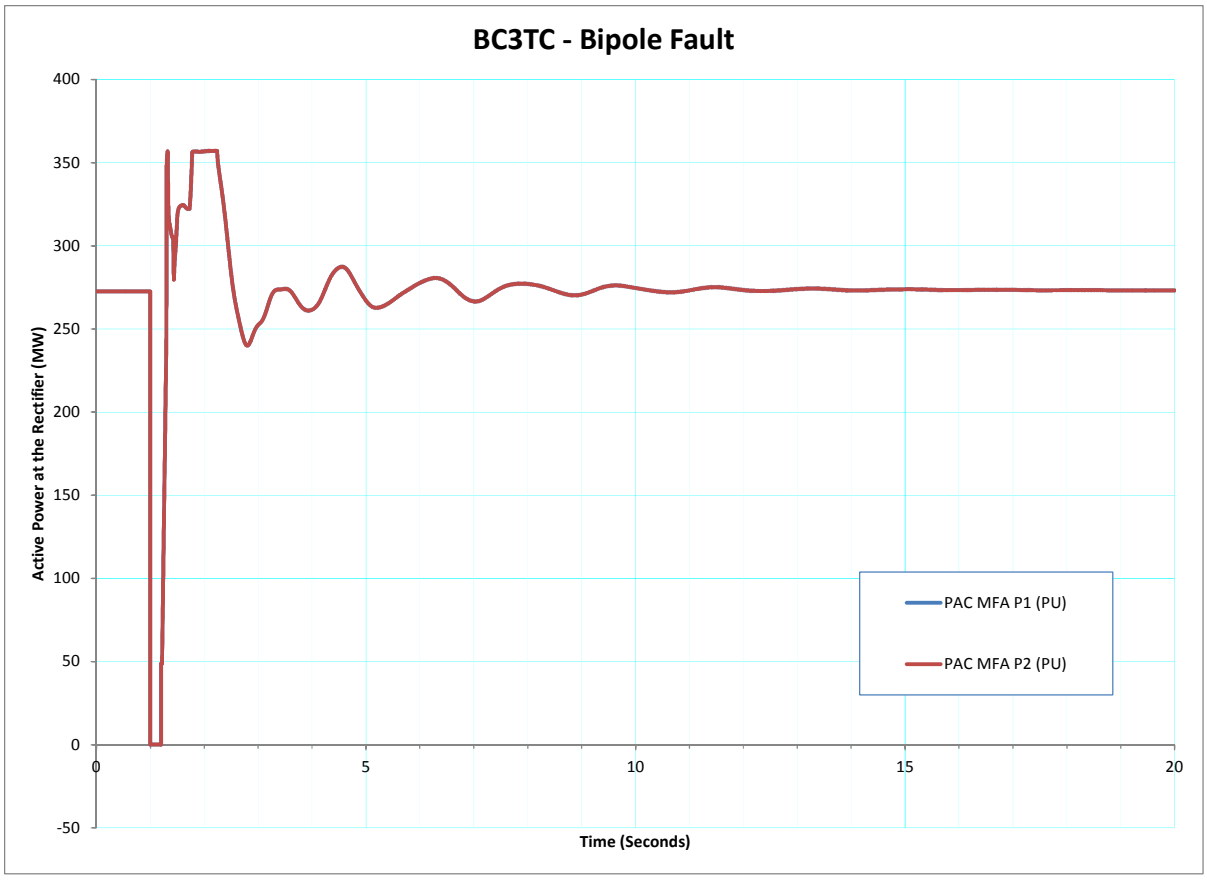


Figure 63 - BC3TC - Bipole Fault - Active Power at the Rectifier (MW)

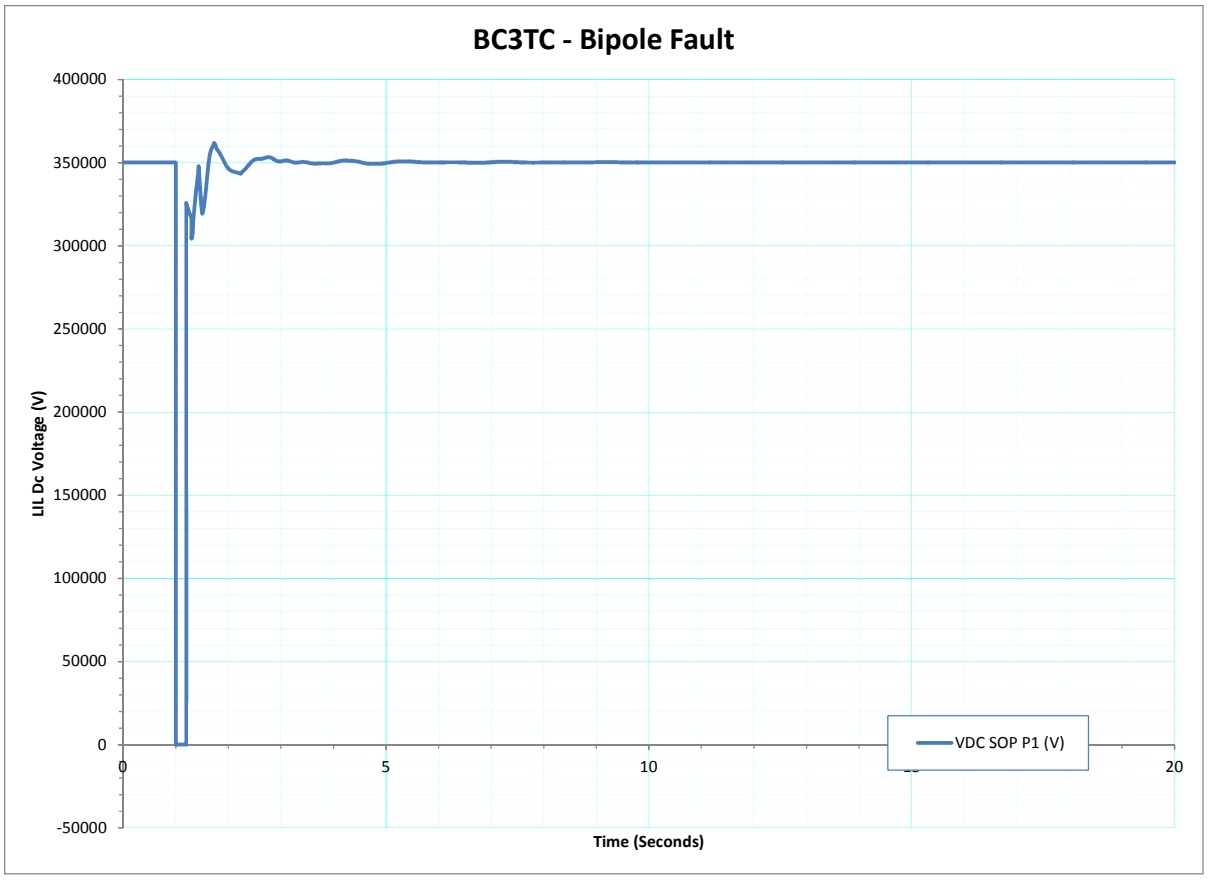


Figure 64 - BC3TC - Bipole Fault - LIL Dc Voltage (V)

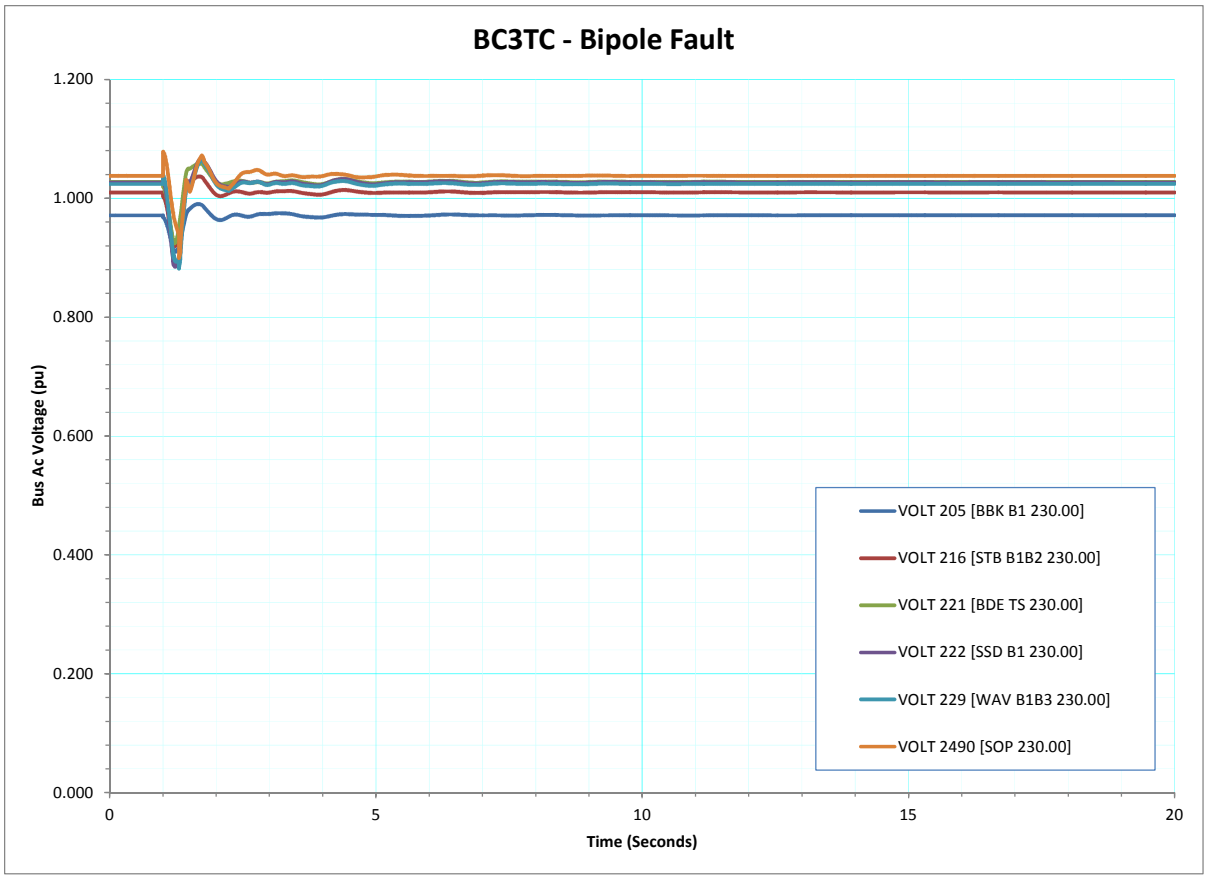


Figure 65 - BC3TC - Bipole Fault - Bus Ac Voltage (pu)

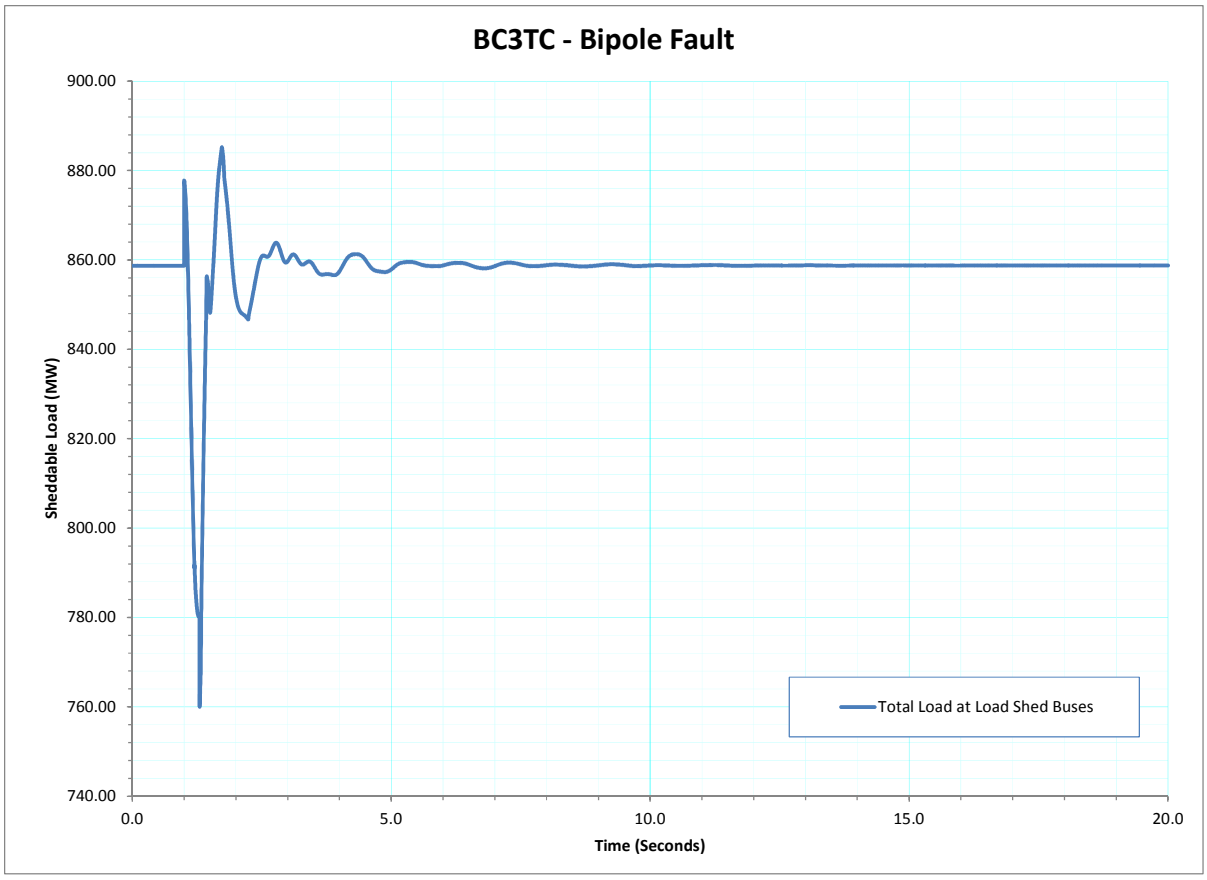


Figure 66 - BC3TC - Bipole Fault - Sheddable Load (MW)

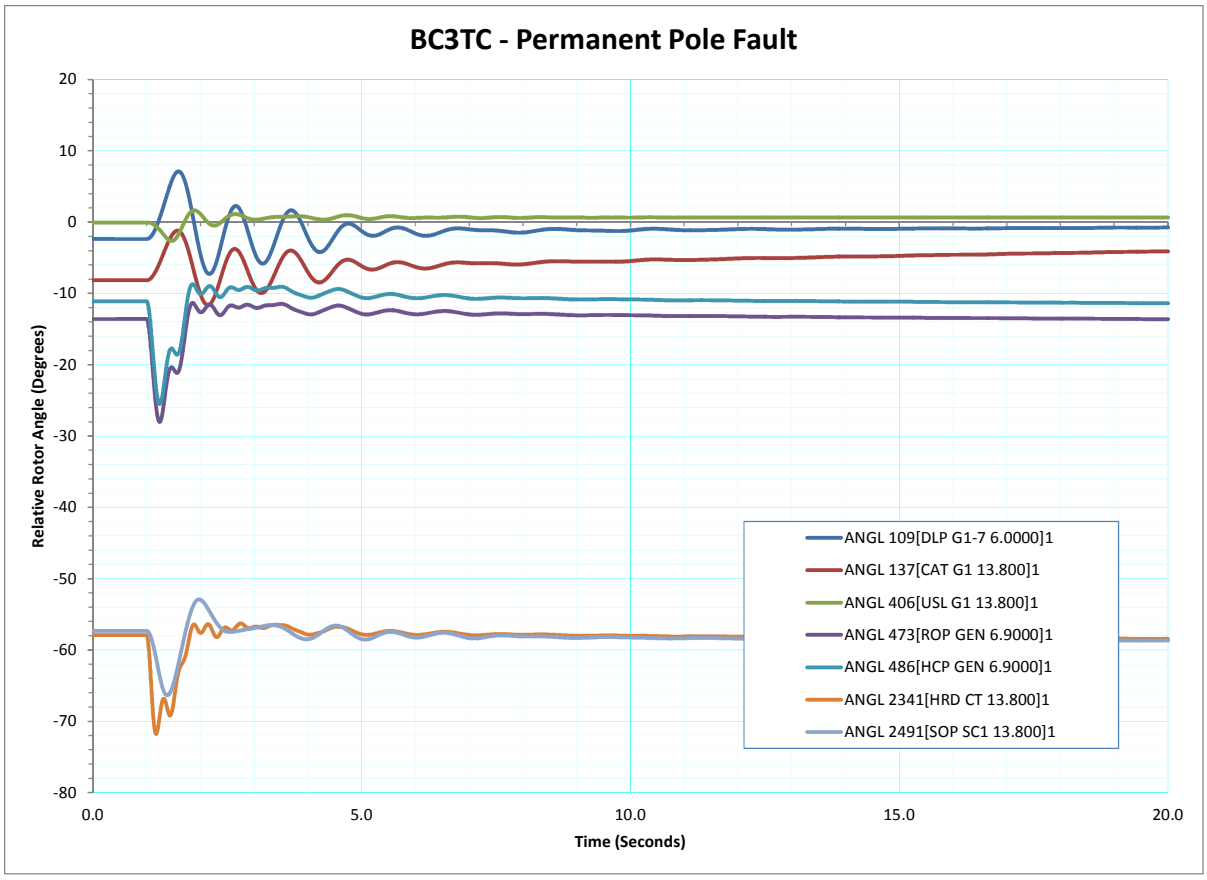


Figure 67 - BC3TC - Permanent Pole Fault - Relative Rotor Angle (Degrees)

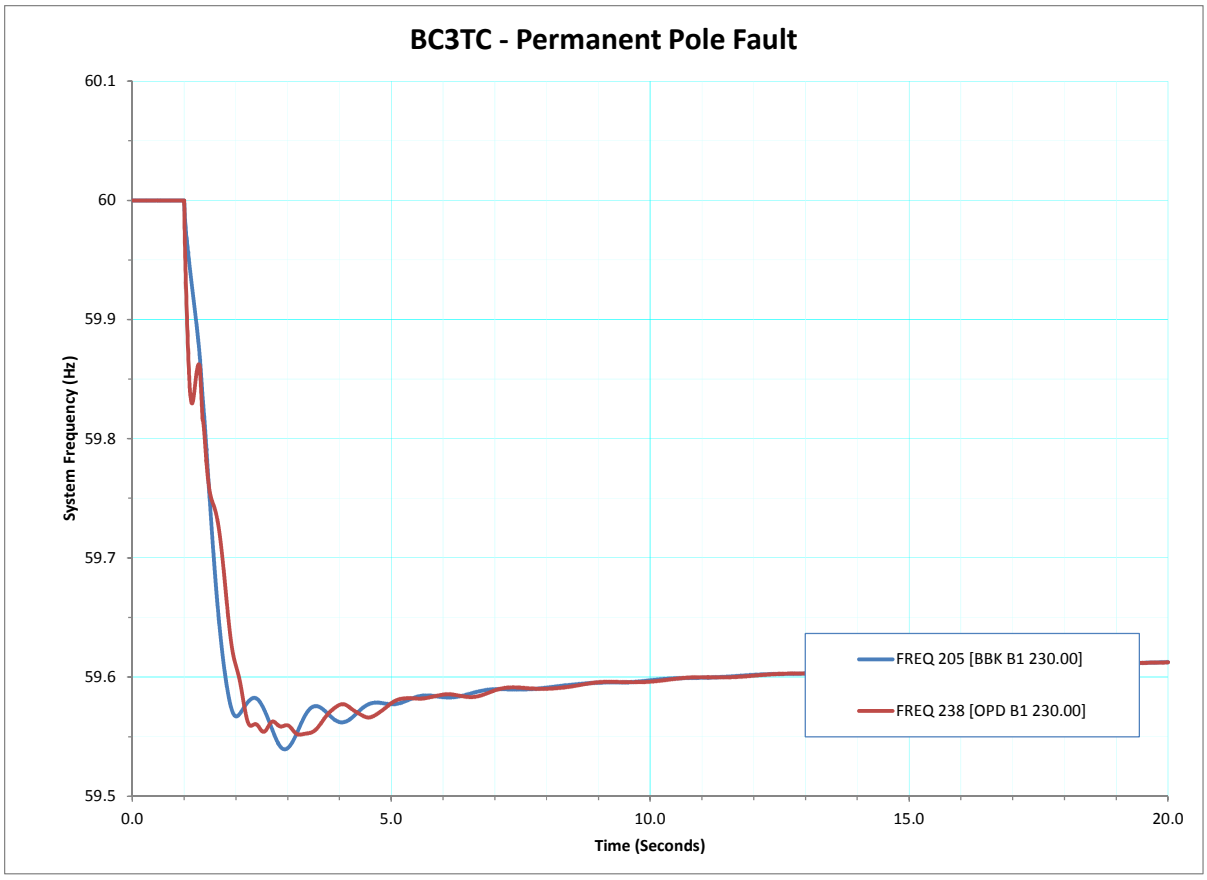


Figure 68 - BC3TC - Permanent Pole Fault - System Frequency (Hz)

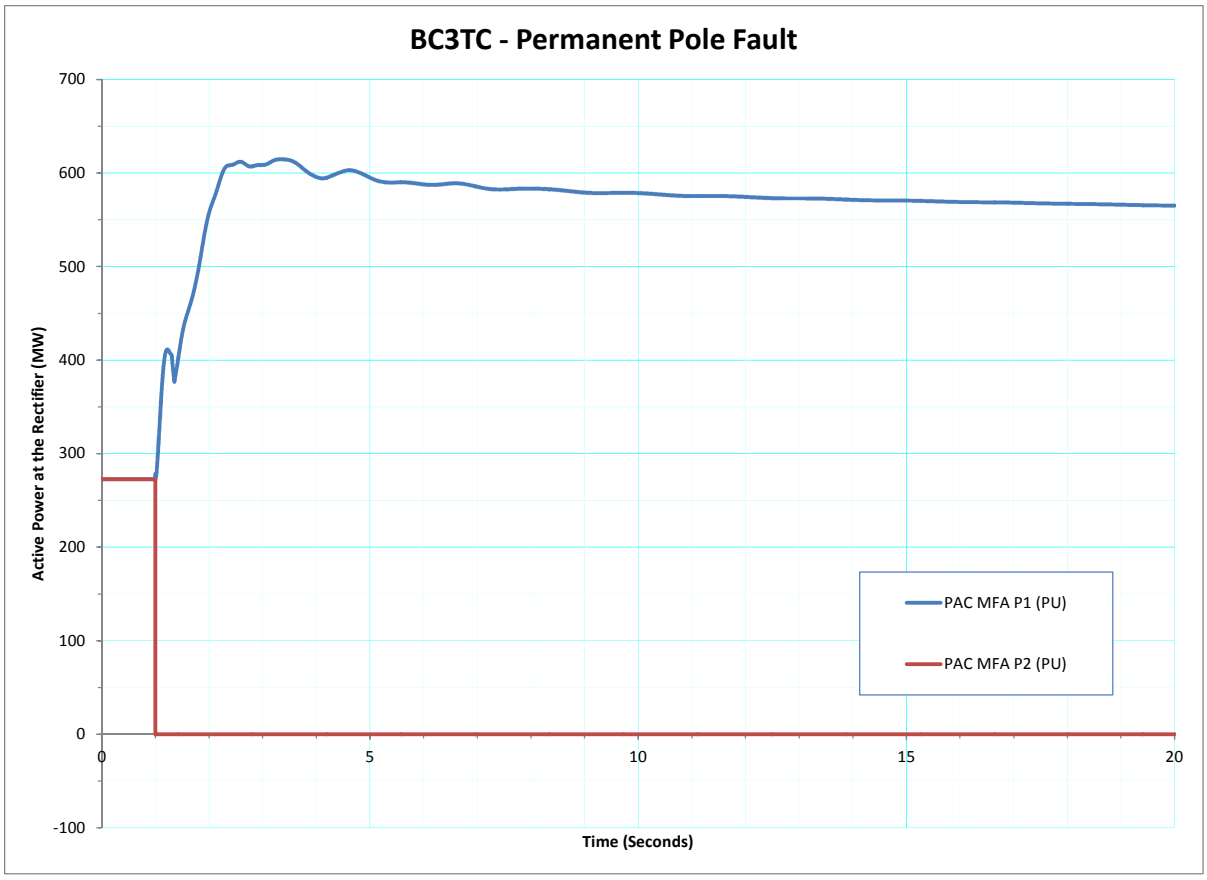


Figure 69 - BC3TC - Permanent Pole Fault - Active Power at the Rectifier (MW)

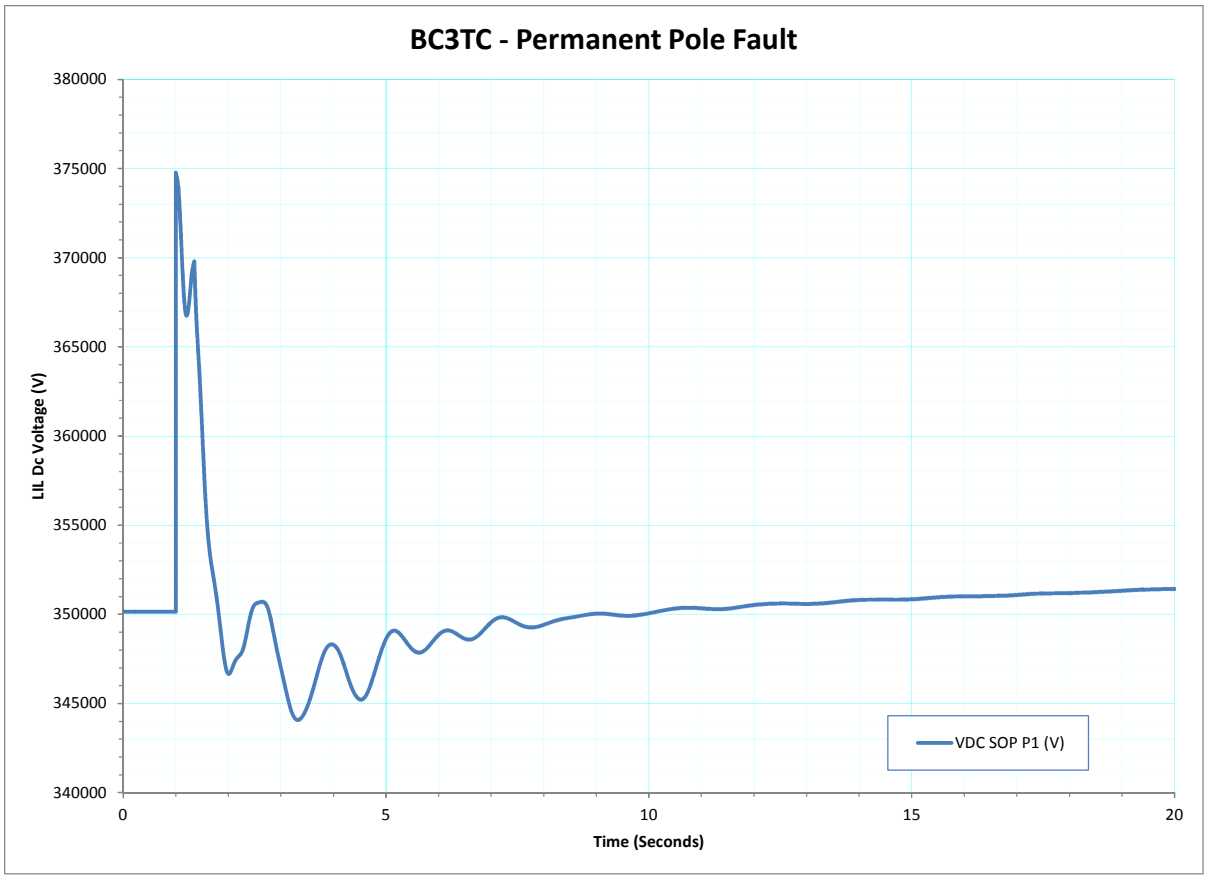


Figure 70 - BC3TC - Permanent Pole Fault - LIL Dc Voltage (V)

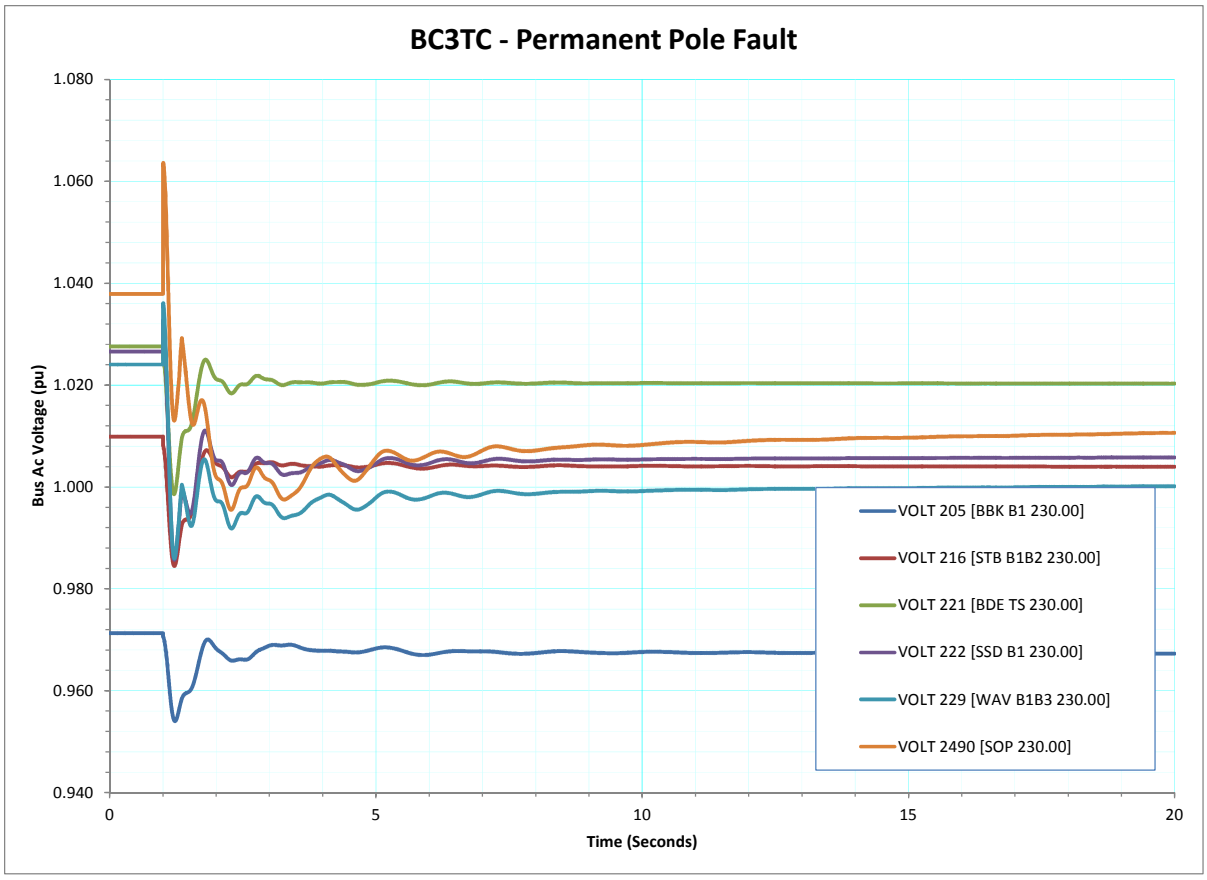


Figure 71 - BC3TC - Permanent Pole Fault - Bus Ac Voltage (pu)

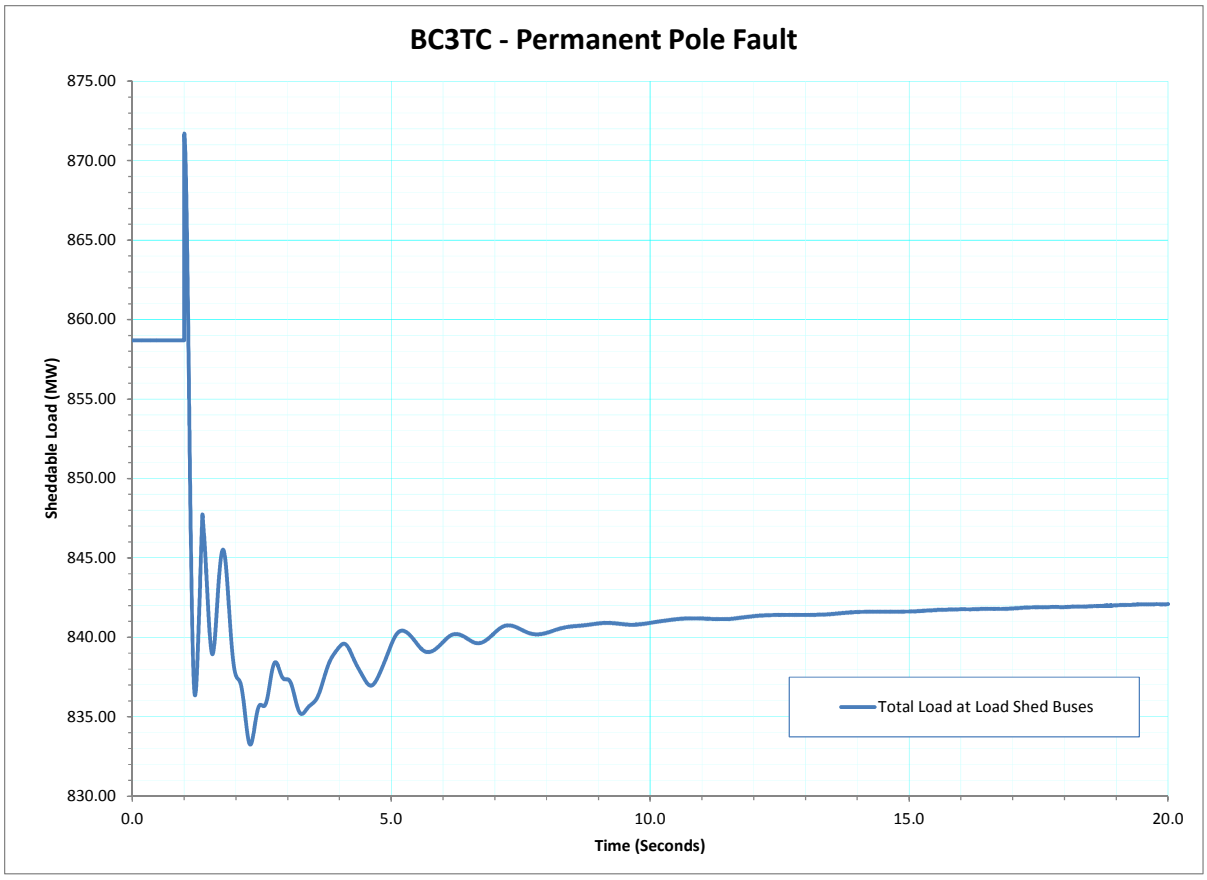


Figure 72 - BC3TC - Permanent Pole Fault - Sheddable Load (MW)

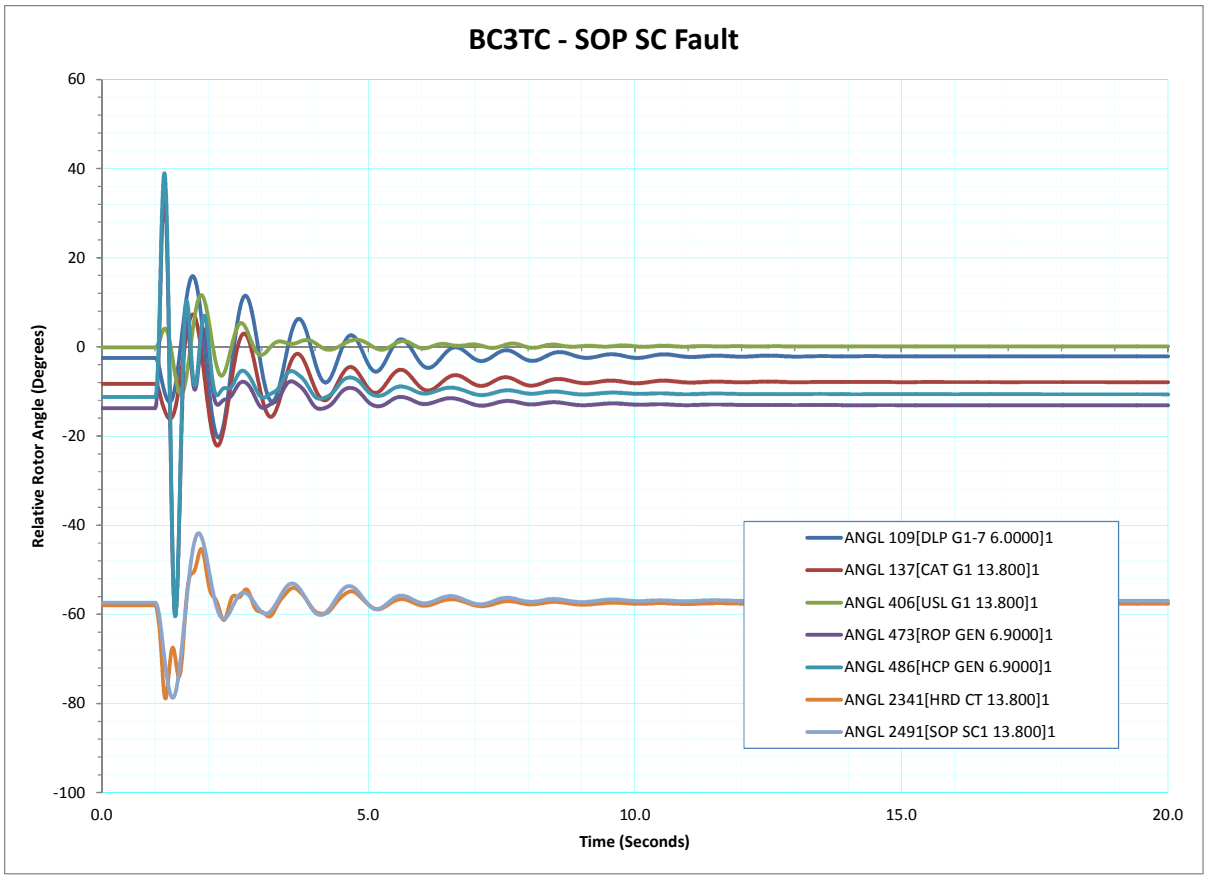


Figure 73 - BC3TC - SOP SC Fault - Relative Rotor Angle (Degrees)

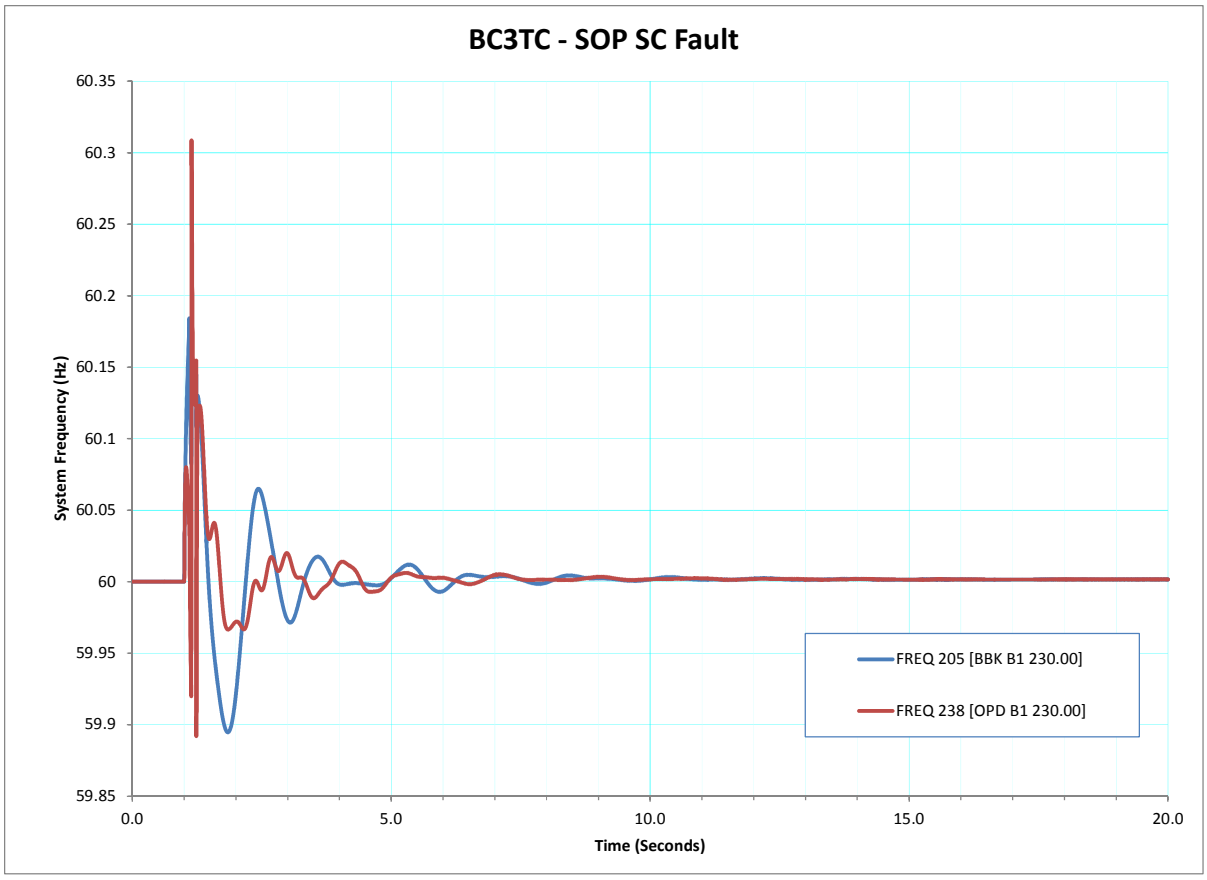


Figure 74 - BC3TC - SOP SC Fault - System Frequency (Hz)

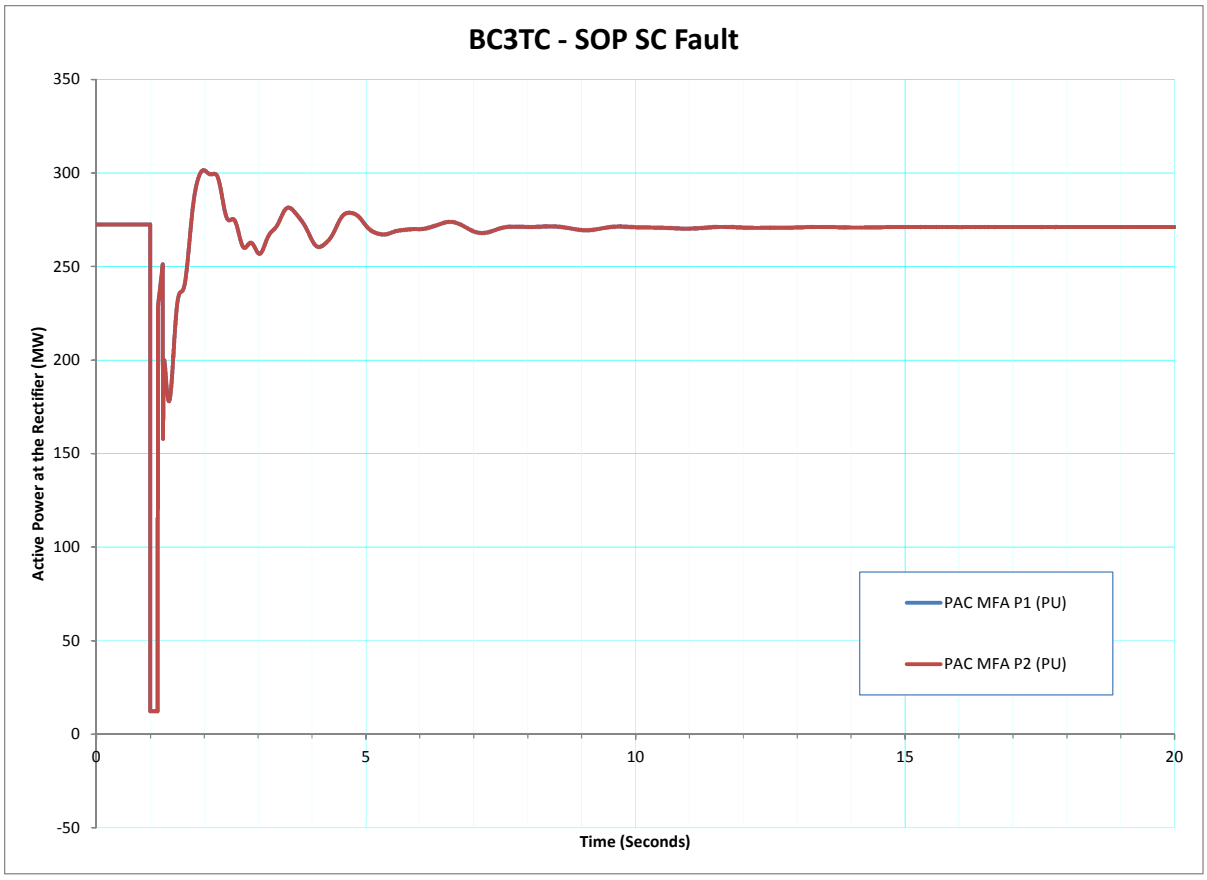


Figure 75 - BC3TC - SOP SC Fault - Active Power at the Rectifier (MW)

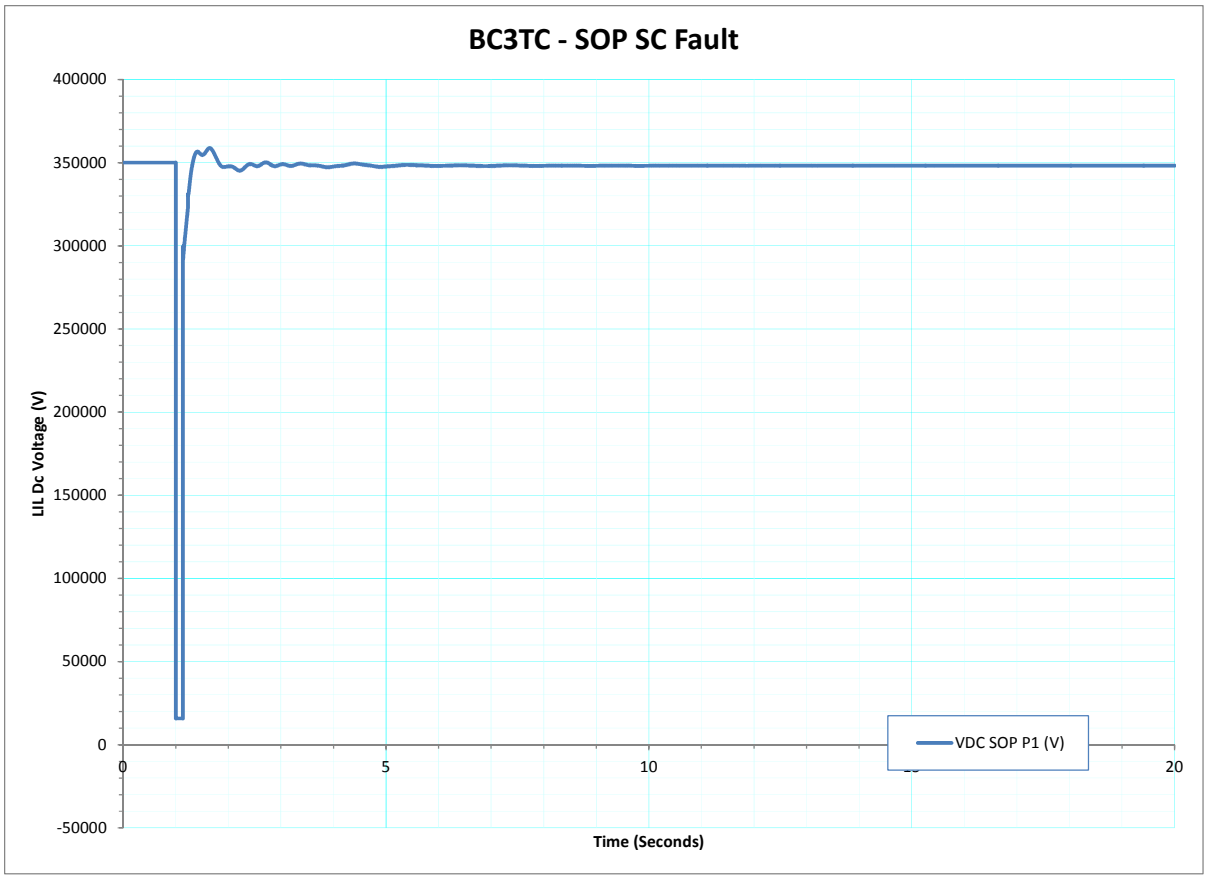


Figure 76 - BC3TC - SOP SC Fault - LIL Dc Voltage (V)

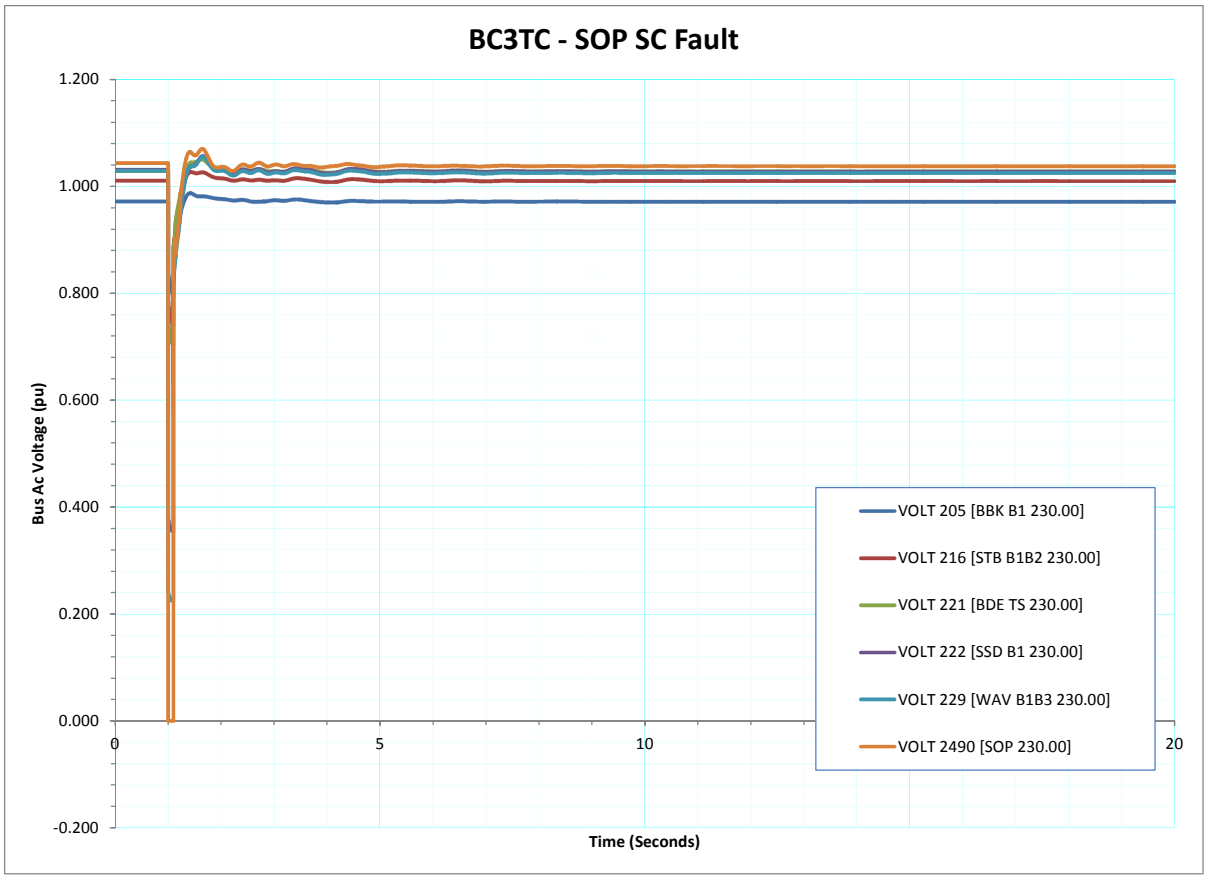


Figure 77 - BC3TC - SOP SC Fault - Bus Ac Voltage (pu)

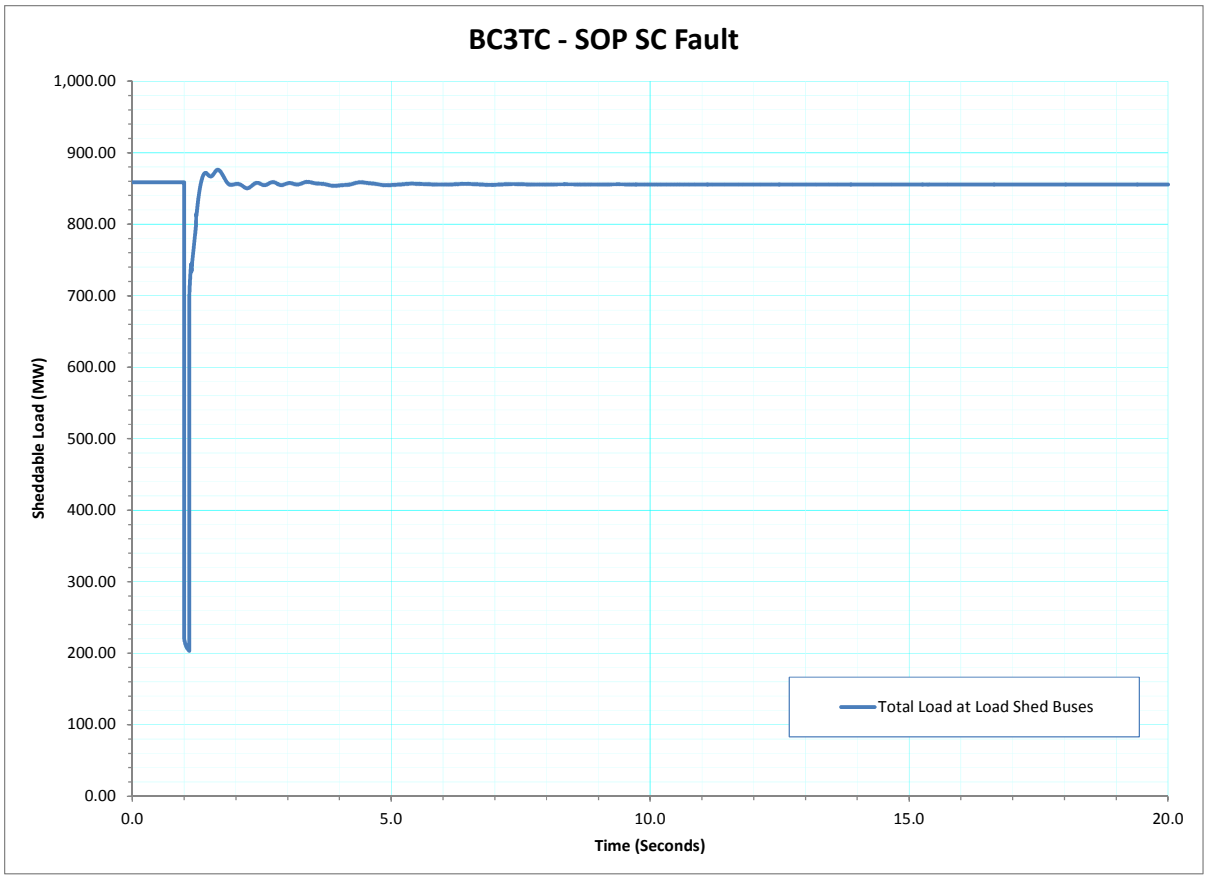


Figure 78 - BC3TC - SOP SC Fault - Sheddable Load (MW)

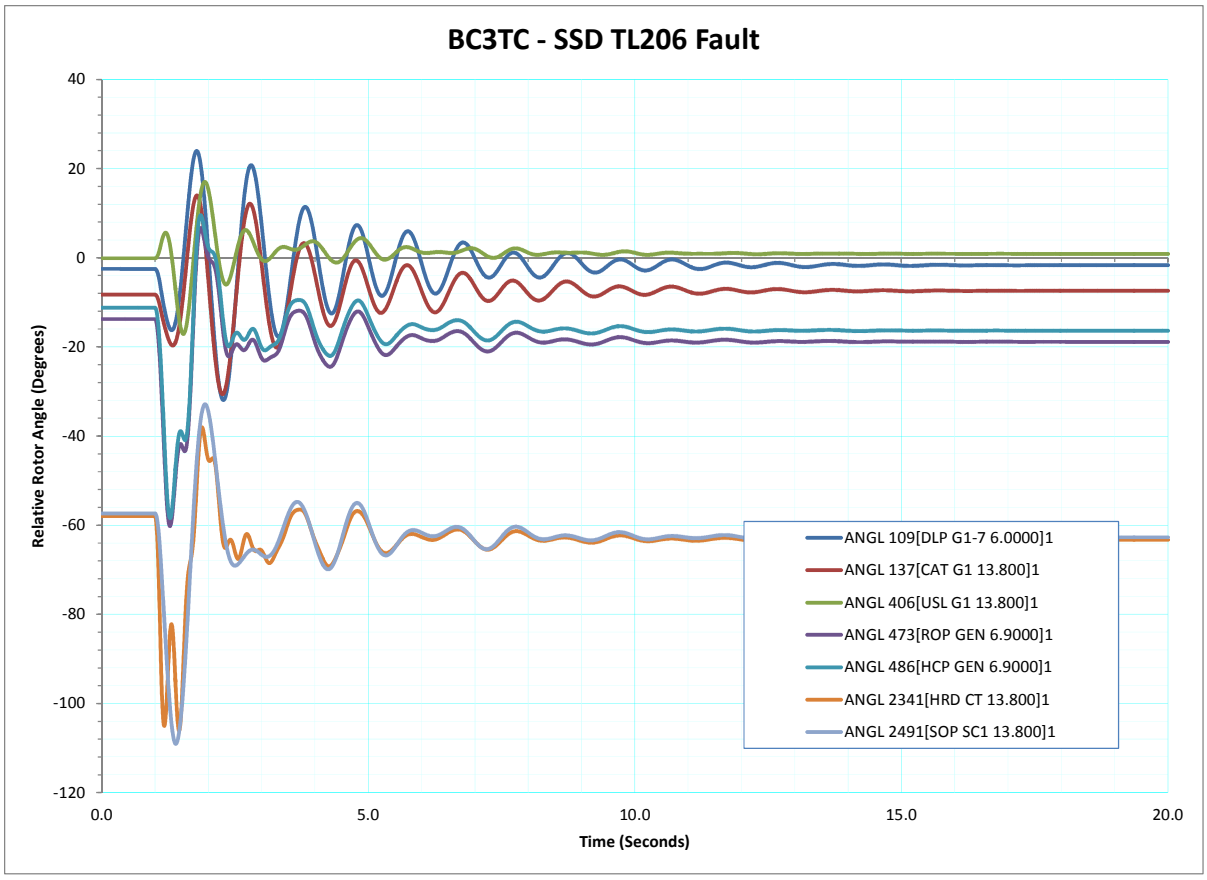


Figure 79 - BC3TC - SSD TL206 Fault - Relative Rotor Angle (Degrees)

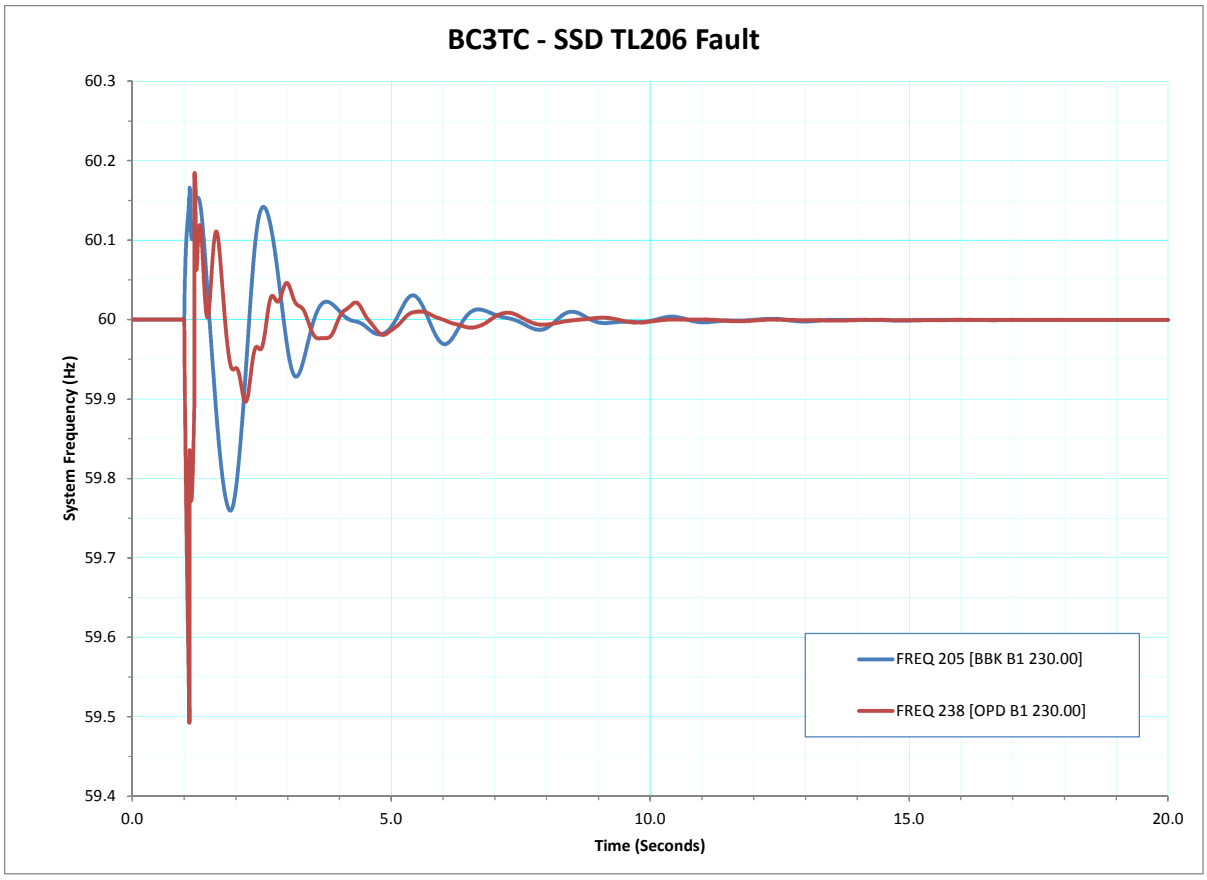


Figure 80 - BC3TC - SSD TL206 Fault - System Frequency (Hz)

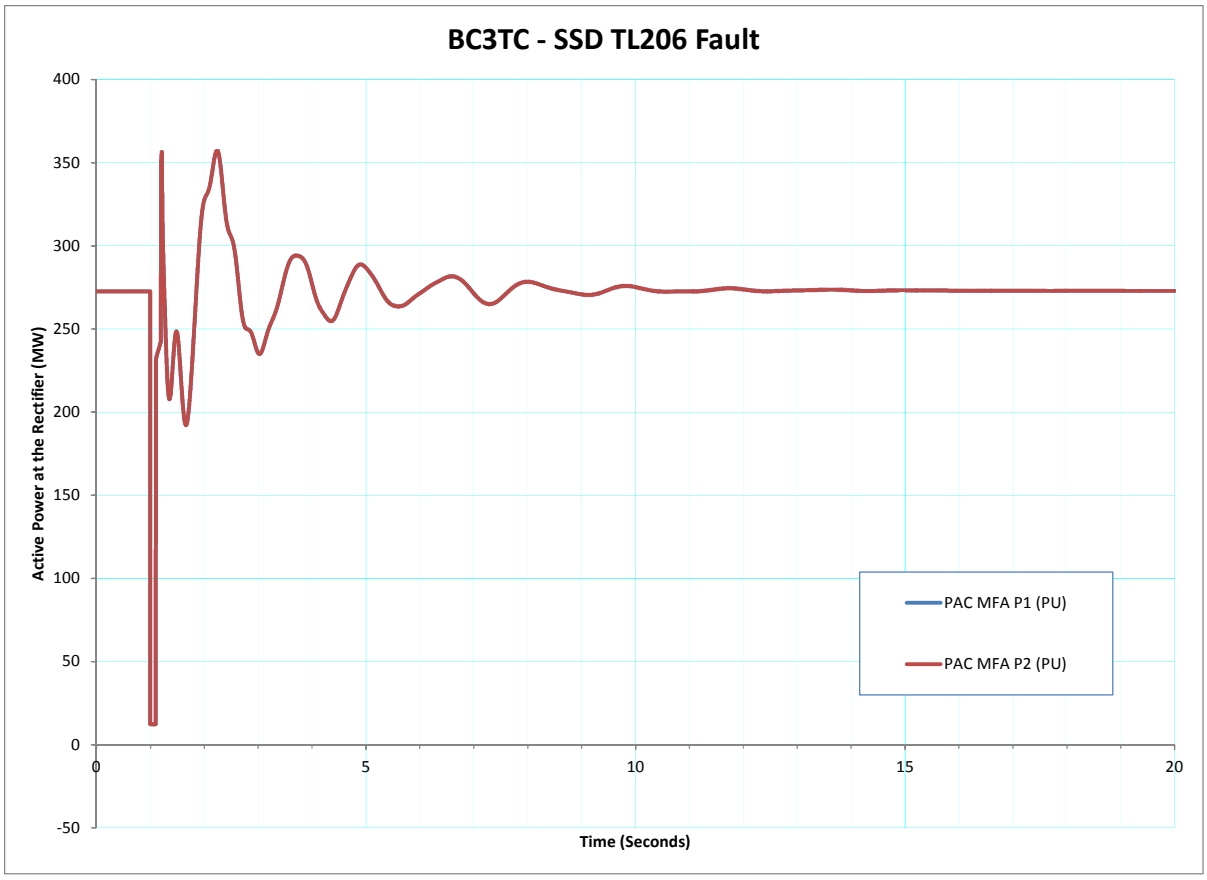


Figure 81 - BC3TC - SSD TL206 Fault - Active Power at the Rectifier (MW)

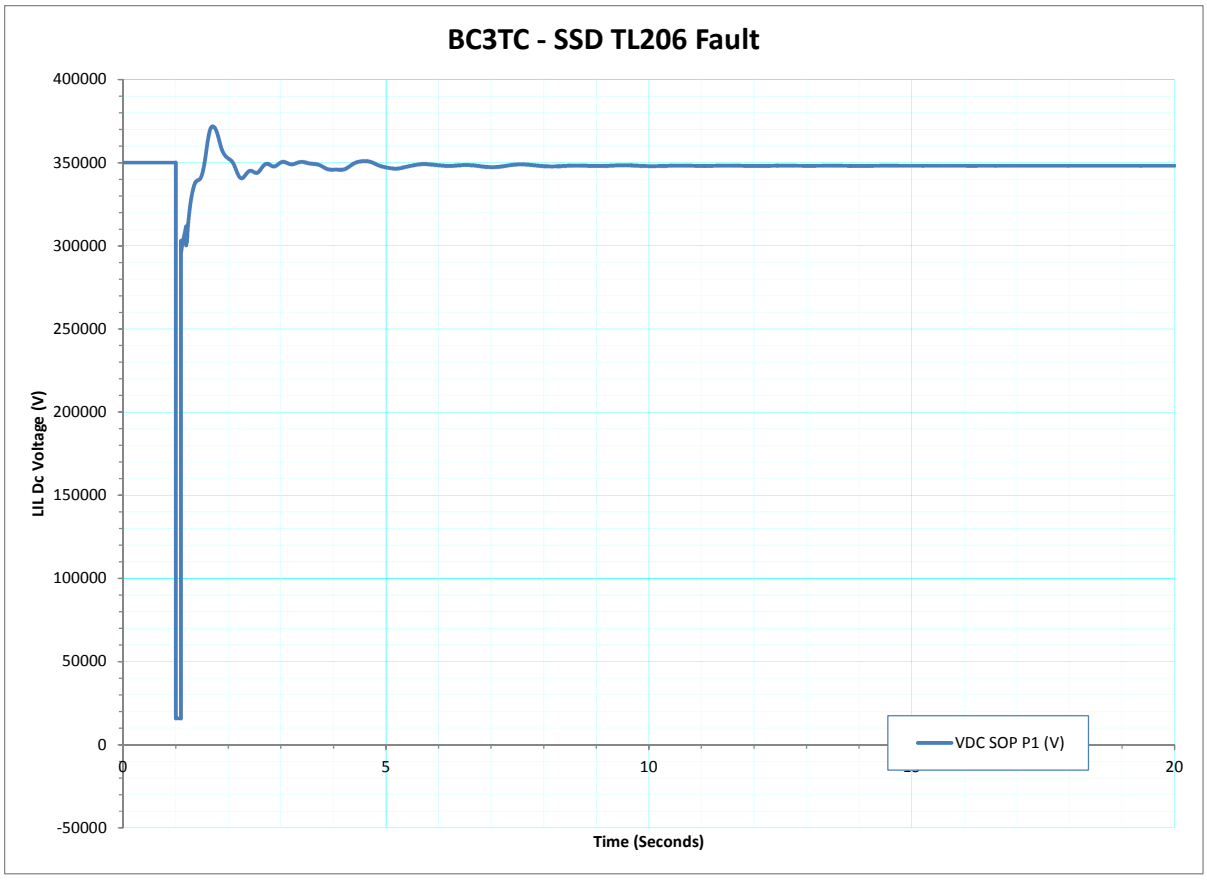


Figure 82 - BC3TC - SSD TL206 Fault - LIL Dc Voltage (V)

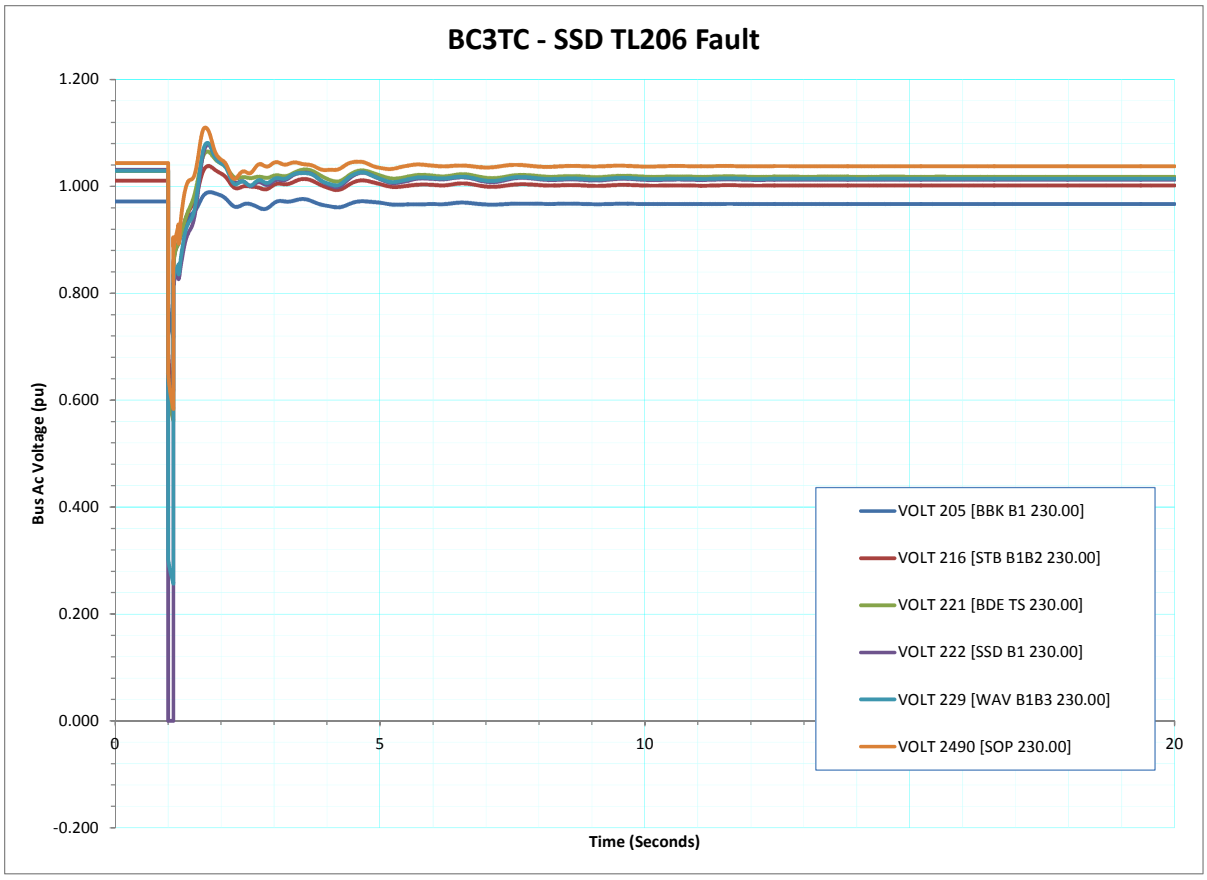


Figure 83 - BC3TC - SSD TL206 Fault - Bus Ac Voltage (pu)

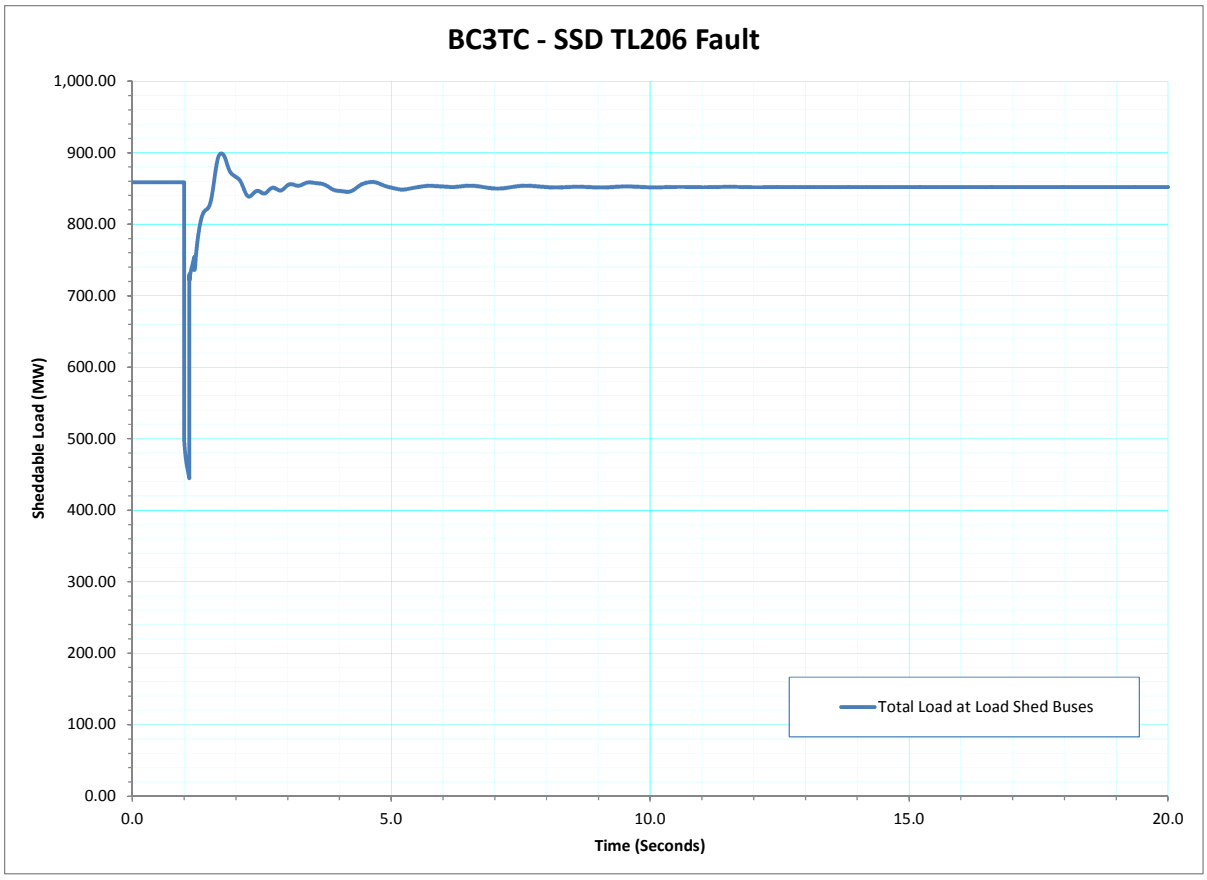


Figure 84 - BC3TC - SSD TL206 Fault - Sheddable Load (MW)

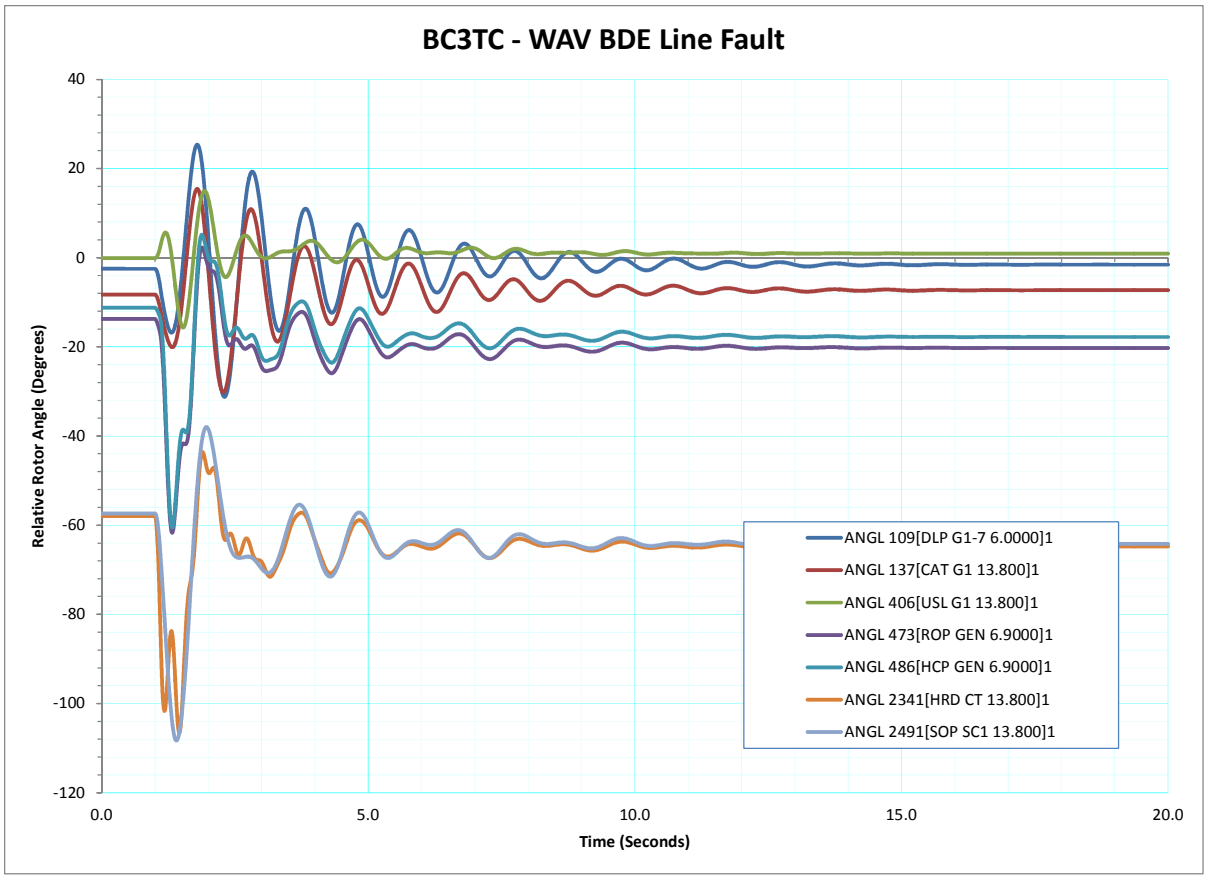


Figure 85 - BC3TC - WAV BDE Line Fault - Relative Rotor Angle (Degrees)

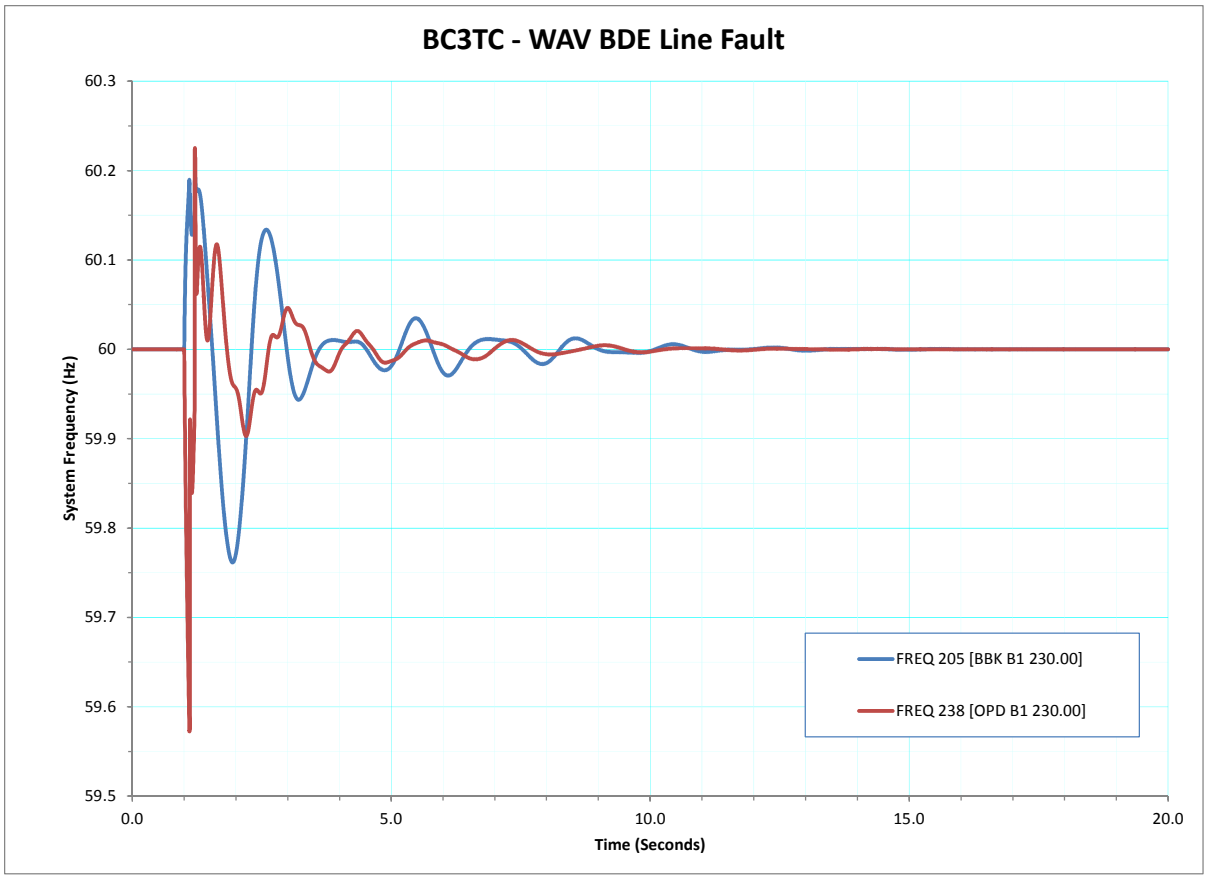


Figure 86 - BC3TC - WAV BDE Line Fault - System Frequency (Hz)

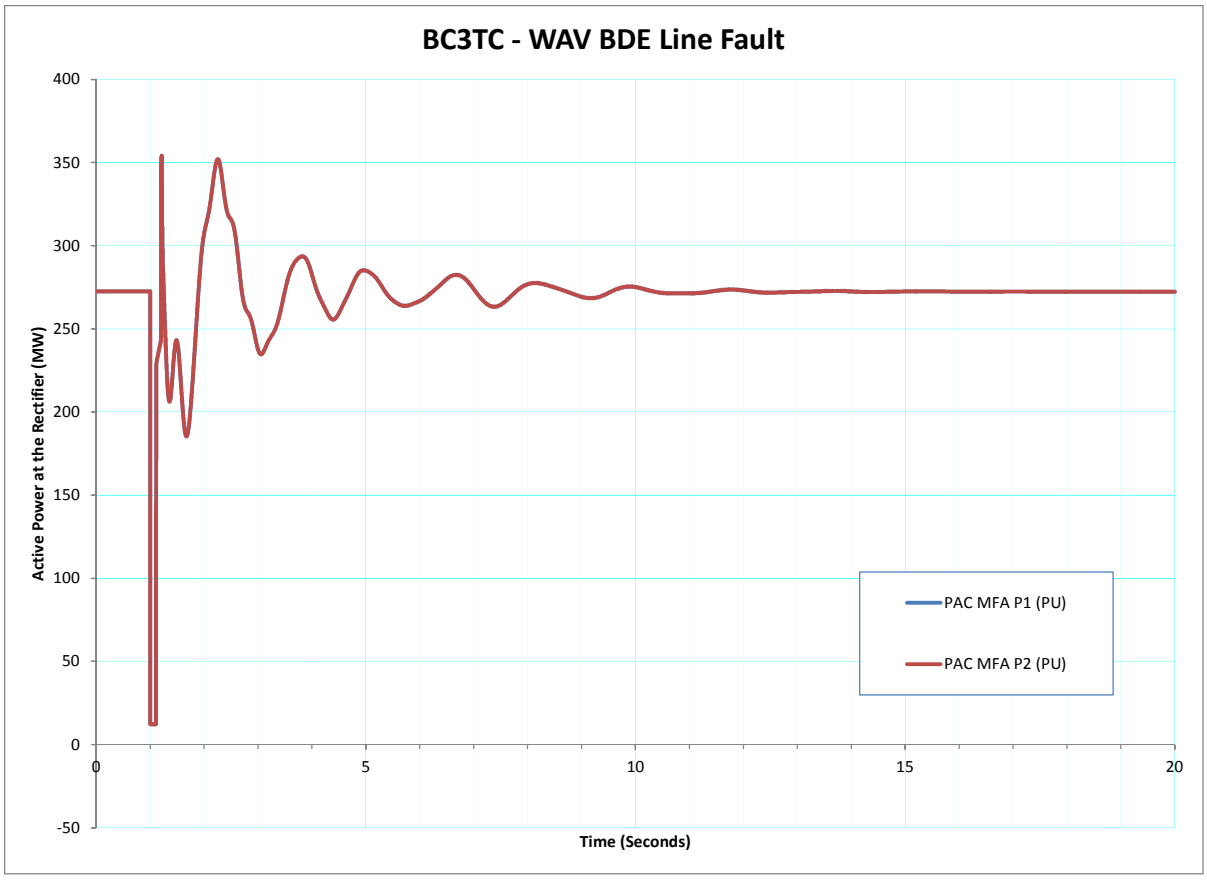


Figure 87 - BC3TC - WAV BDE Line Fault - Active Power at the Rectifier (MW)

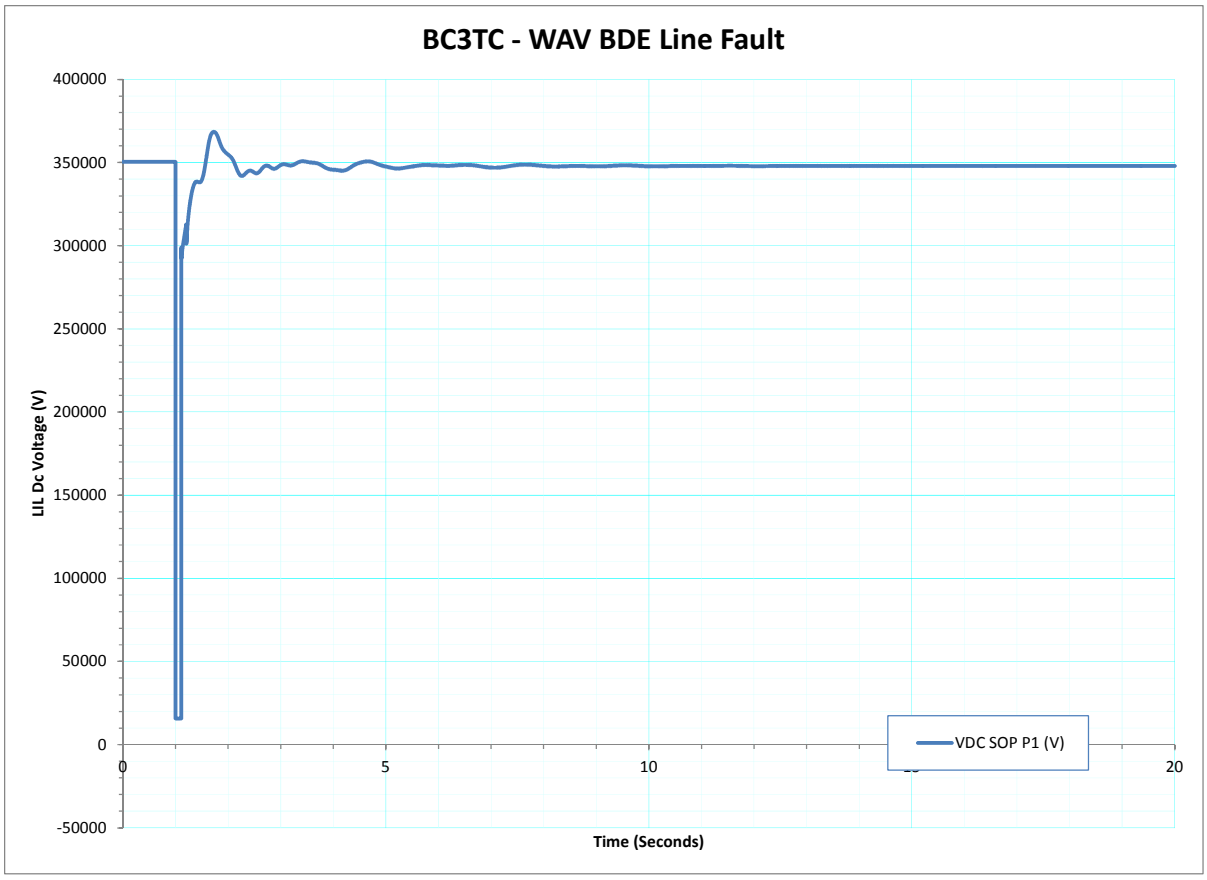


Figure 88 - BC3TC - WAV BDE Line Fault - LIL Dc Voltage (V)

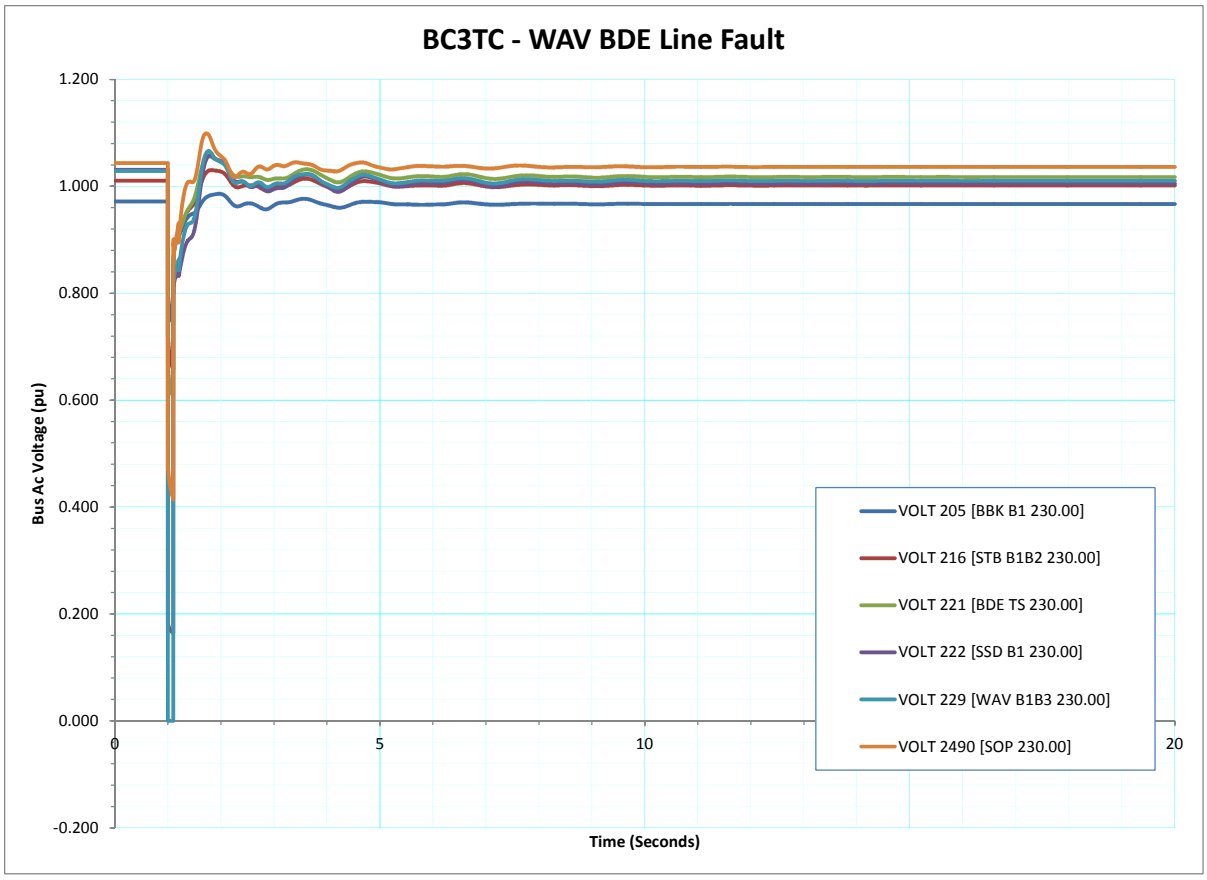


Figure 89 - BC3TC - WAV BDE Line Fault - Bus Ac Voltage (pu)

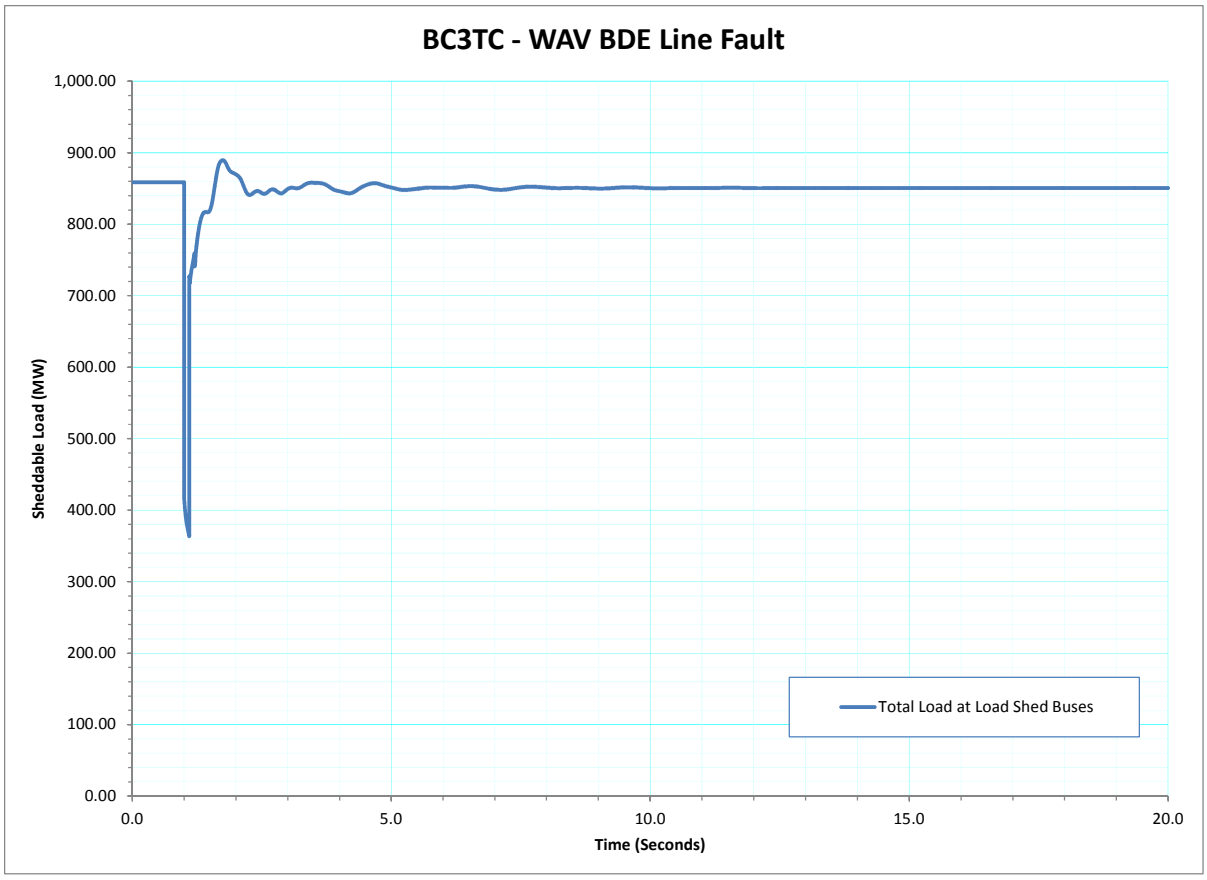


Figure 90 - BC3TC - WAV BDE Line Fault - Sheddable Load (MW)

1.4. BASE CASE 4 TRANSIENT STABILITY PLOTS

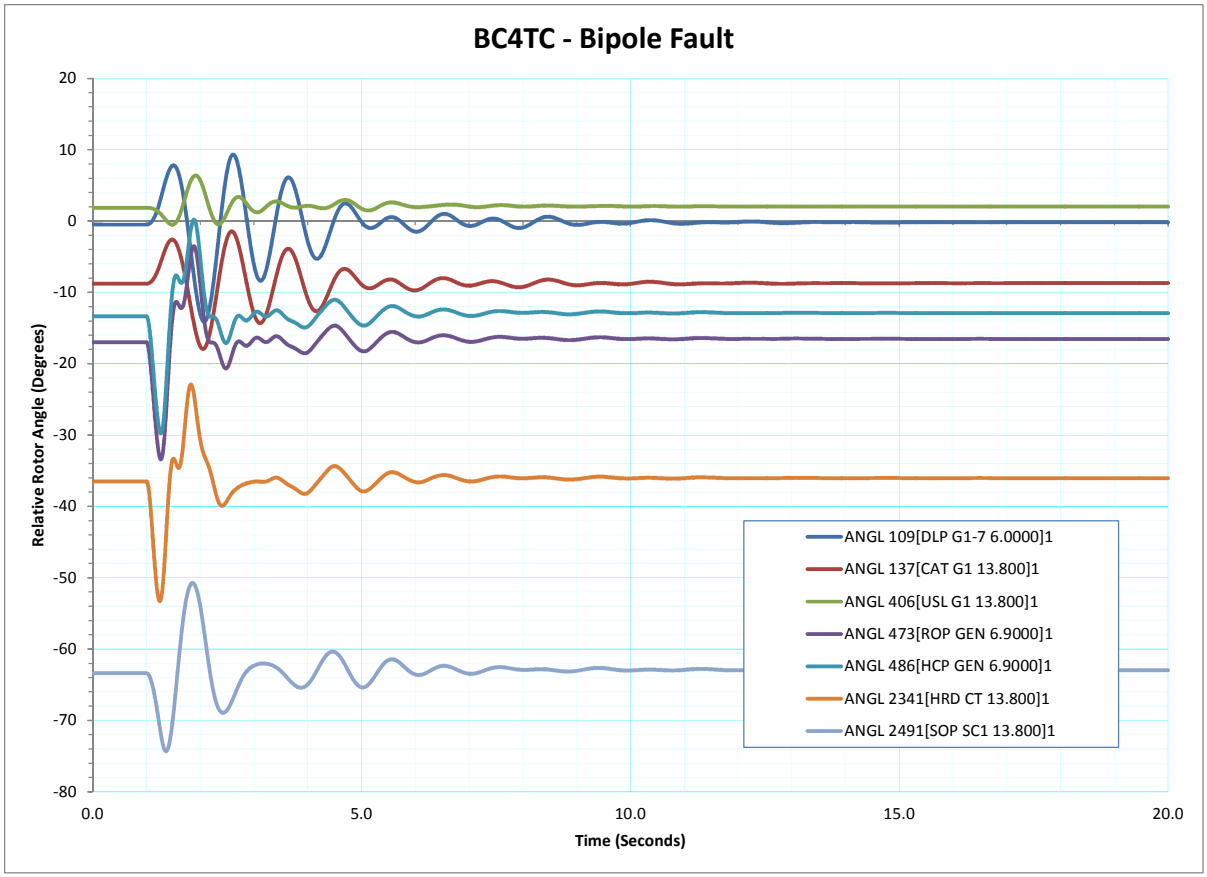


Figure 91 - BC4TC - Bipole Fault - Relative Rotor Angle (Degrees)

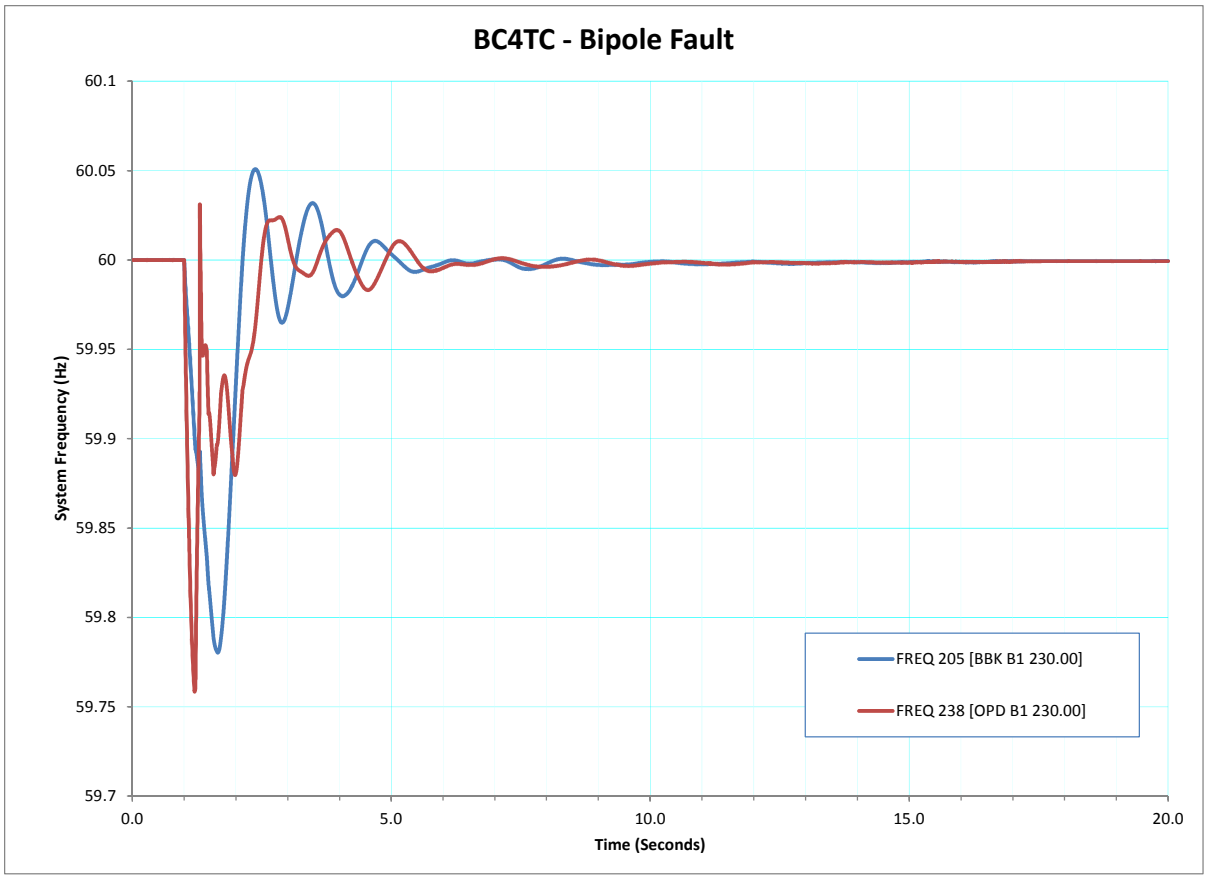


Figure 92 - BC4TC - Bipole Fault - System Frequency (Hz)

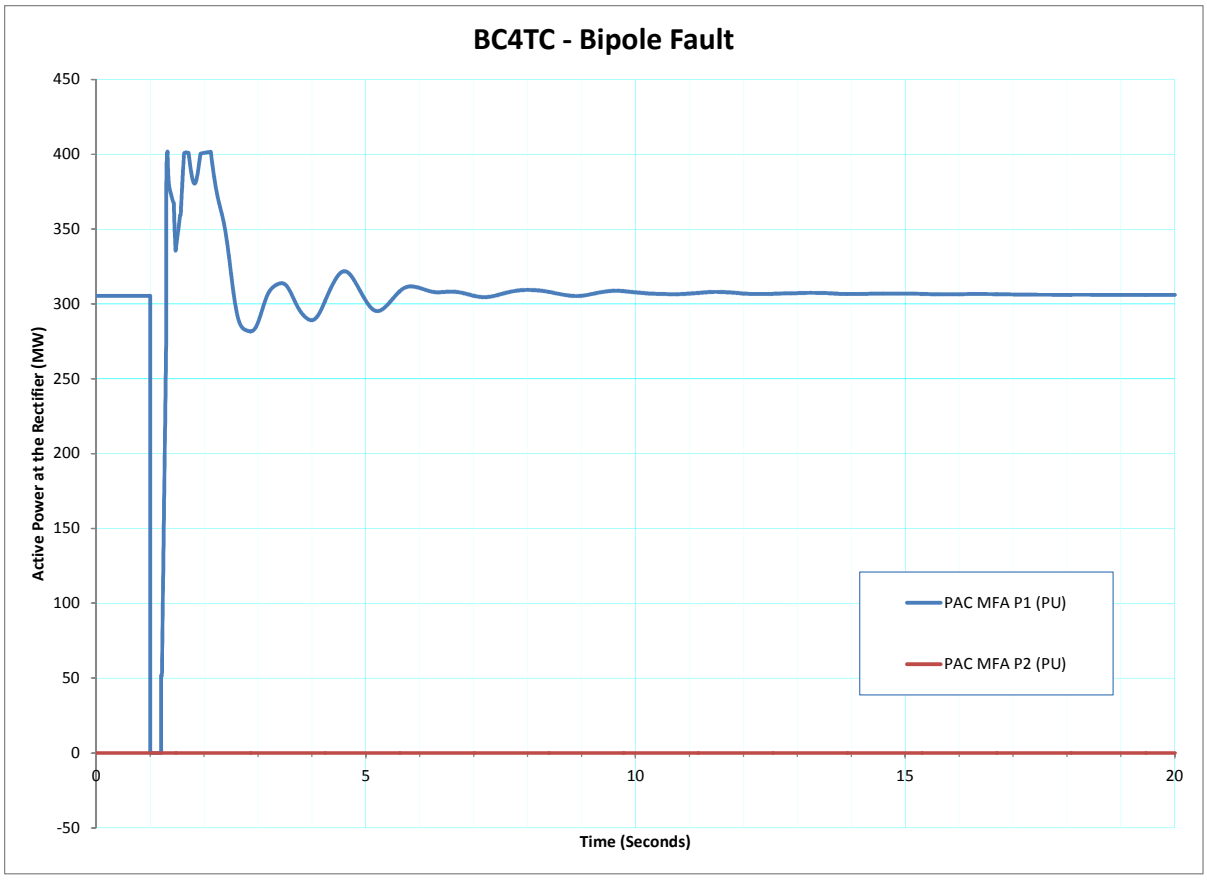


Figure 93 - BC4TC - Bipole Fault - Active Power at the Rectifier (MW)

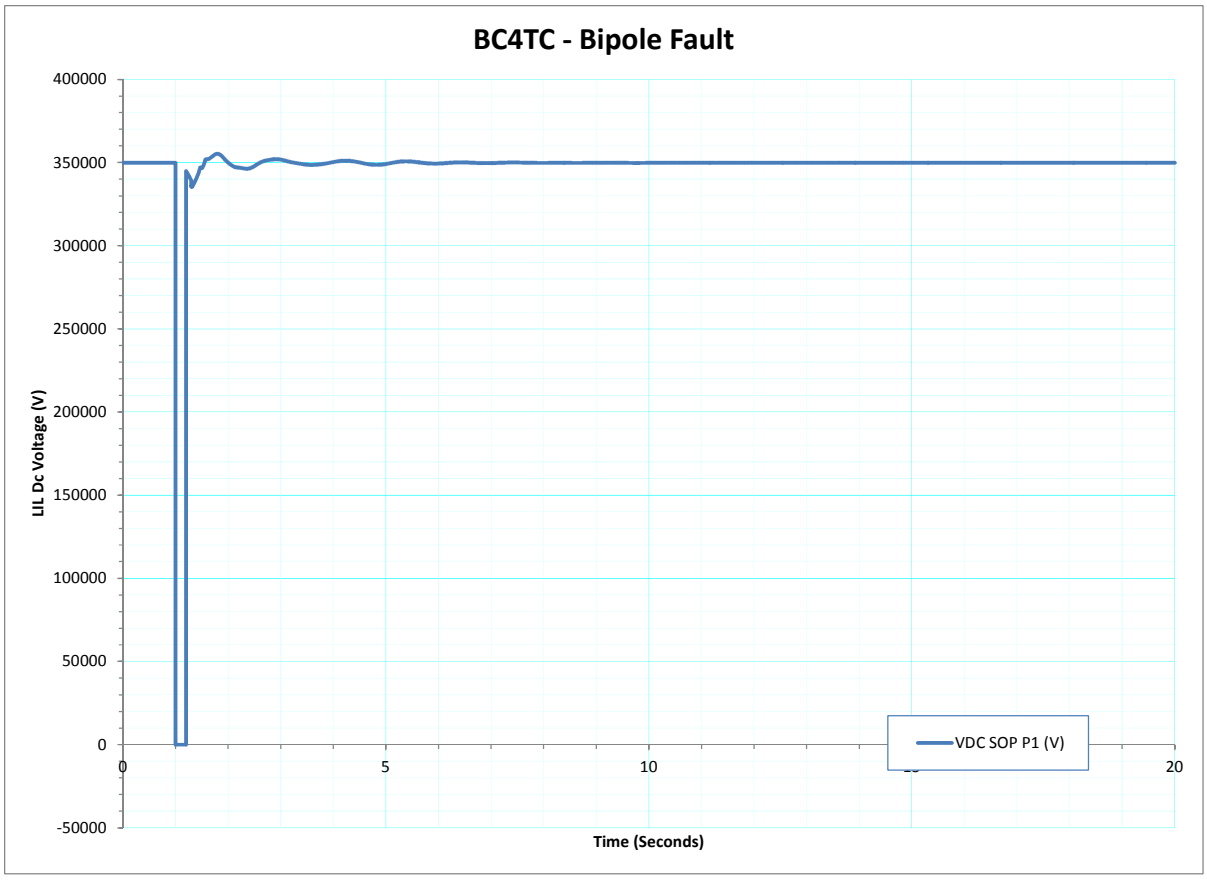


Figure 94 - BC4TC - Bipole Fault - LIL Dc Voltage (V)

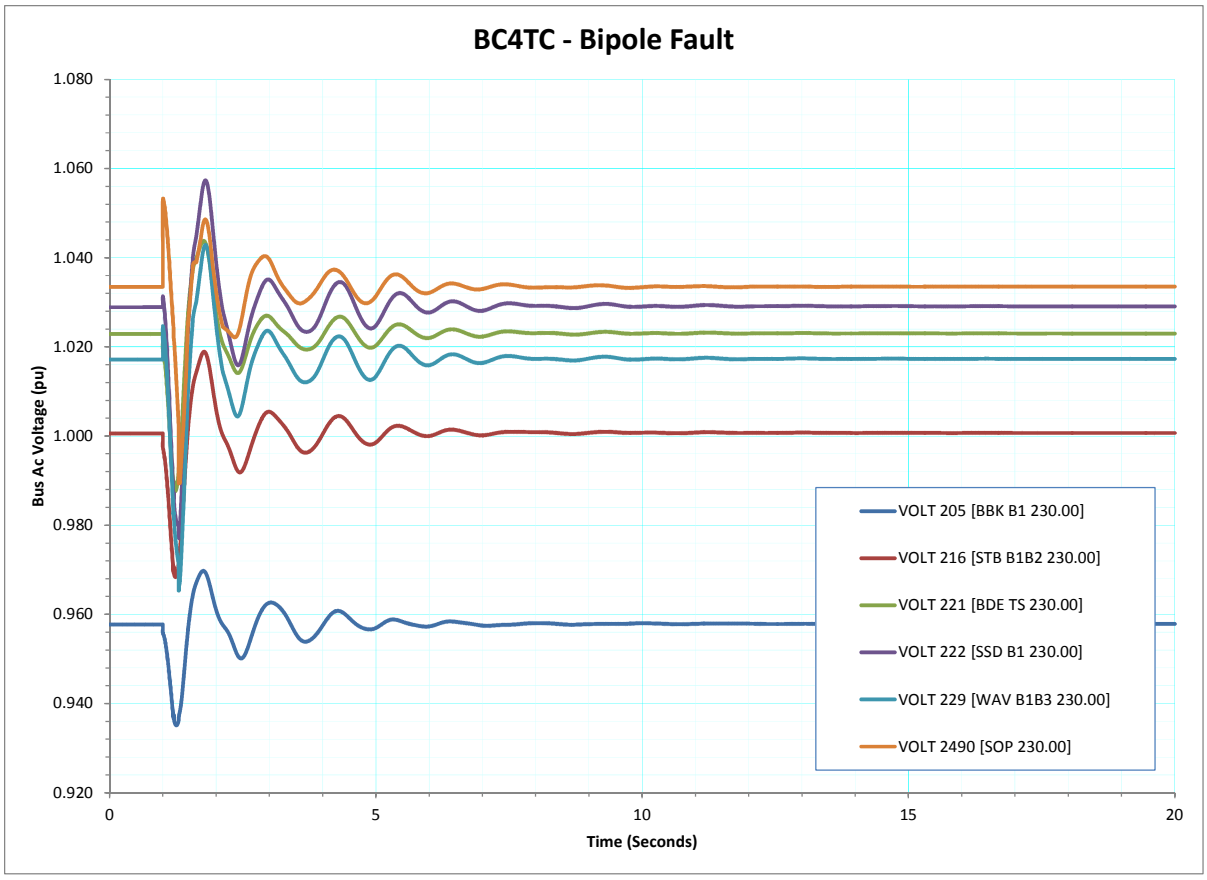


Figure 95 - BC4TC - Bipole Fault - Bus Ac Voltage (pu)

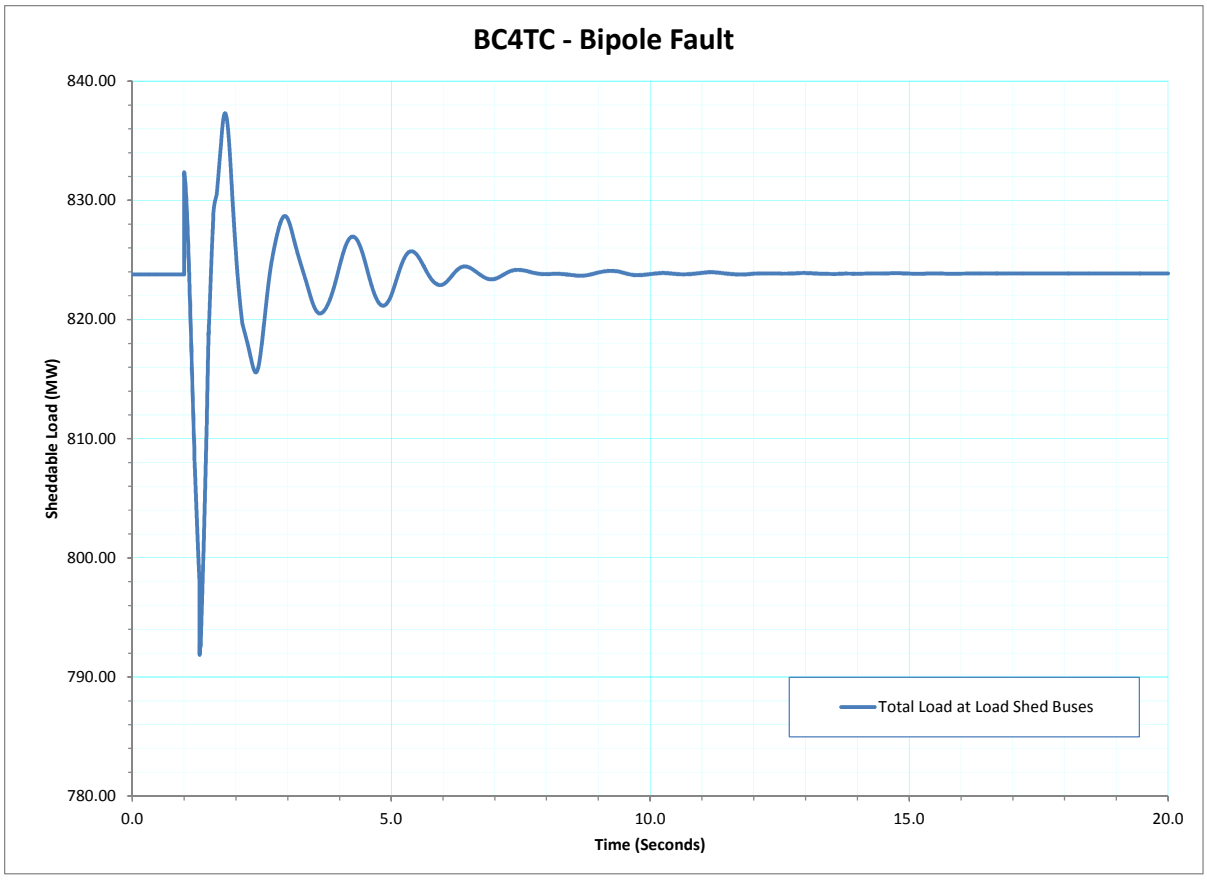


Figure 96 - BC4TC - Bipole Fault - Sheddable Load (MW)

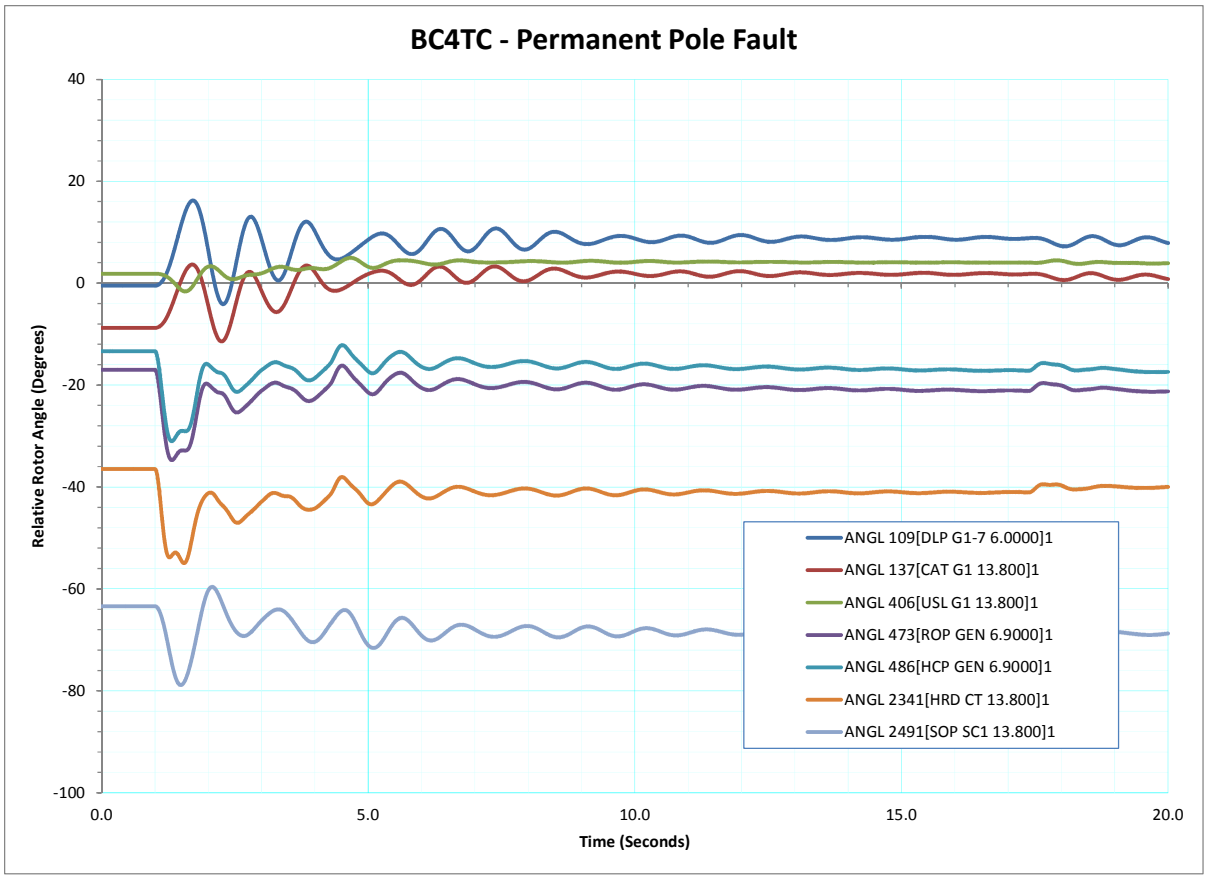


Figure 97 - BC4TC - Permanent Pole Fault - Relative Rotor Angle (Degrees)

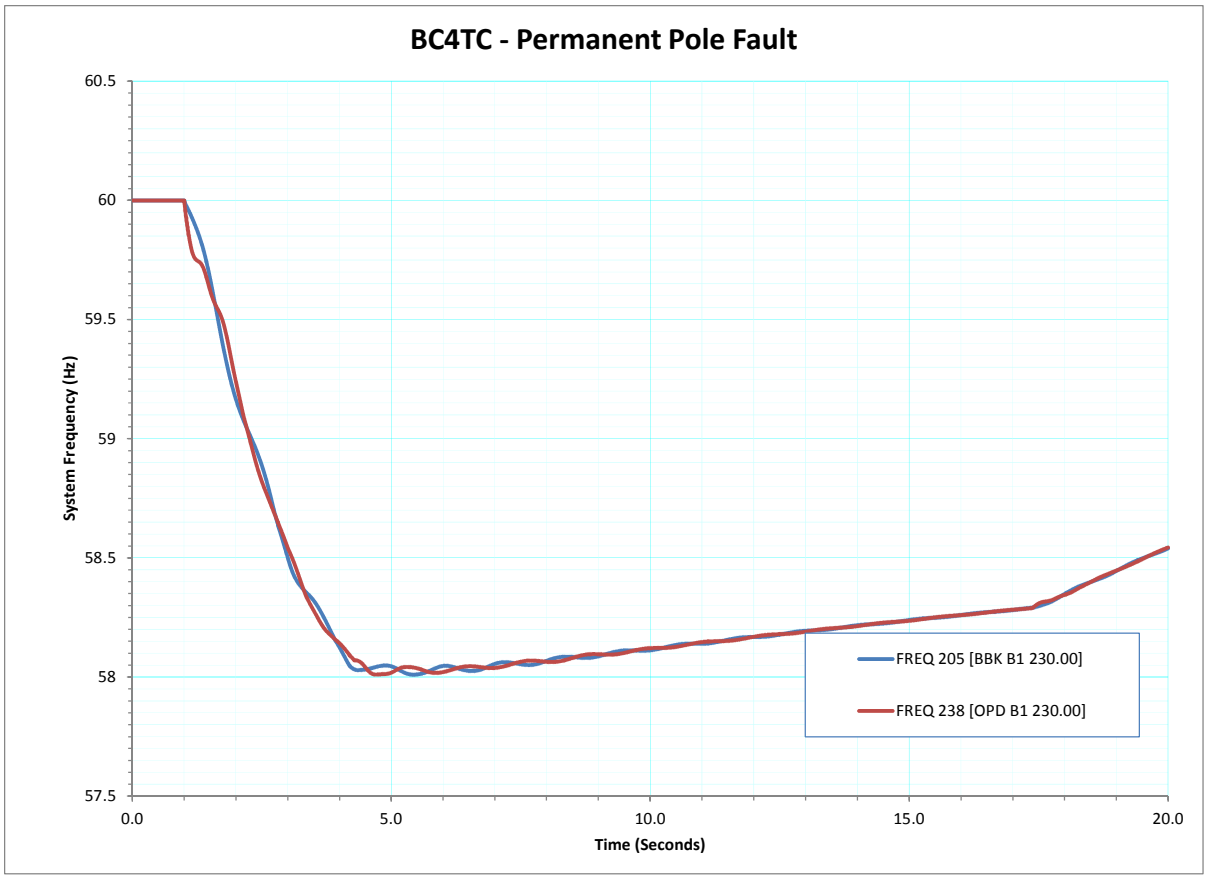


Figure 98 - BC4TC - Permanent Pole Fault - System Frequency (Hz)

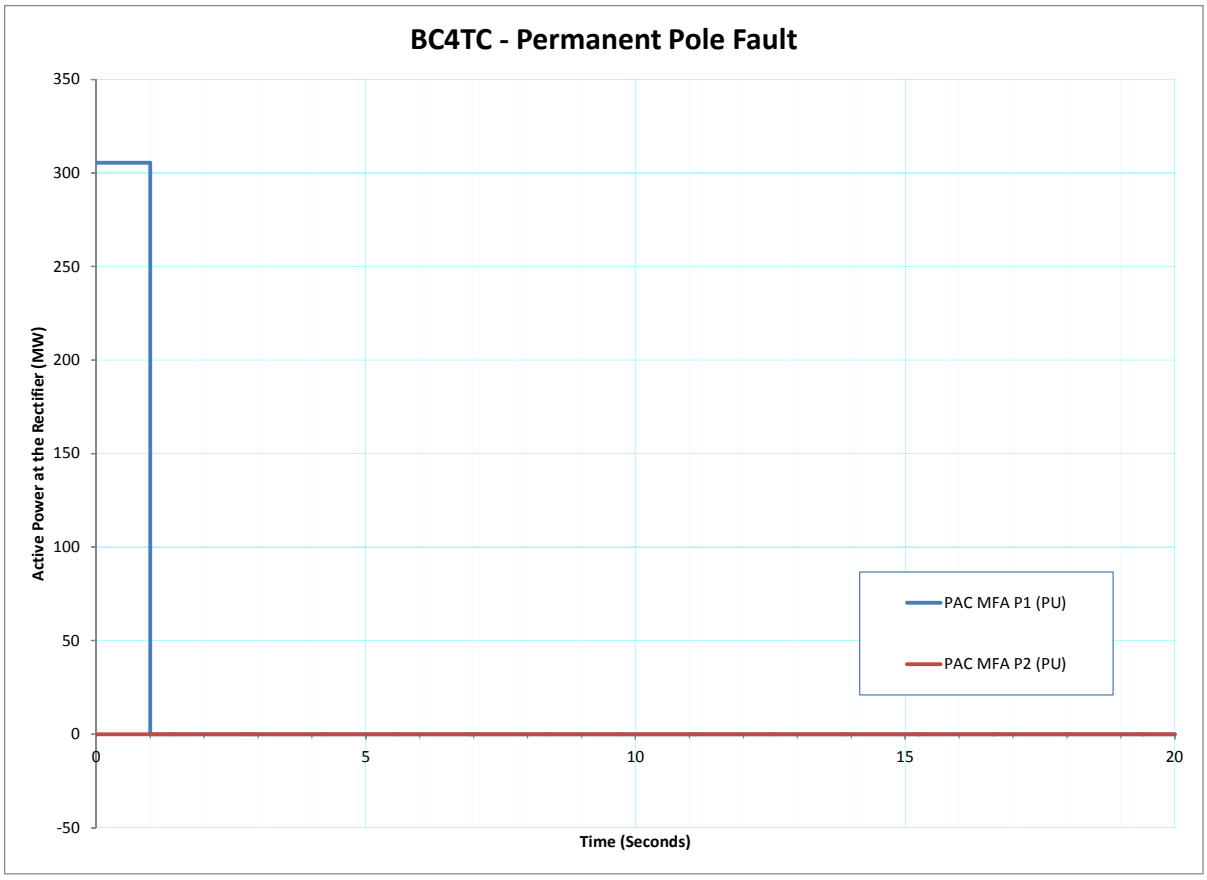


Figure 99 - BC4TC - Permanent Pole Fault - Active Power at the Rectifier (MW)

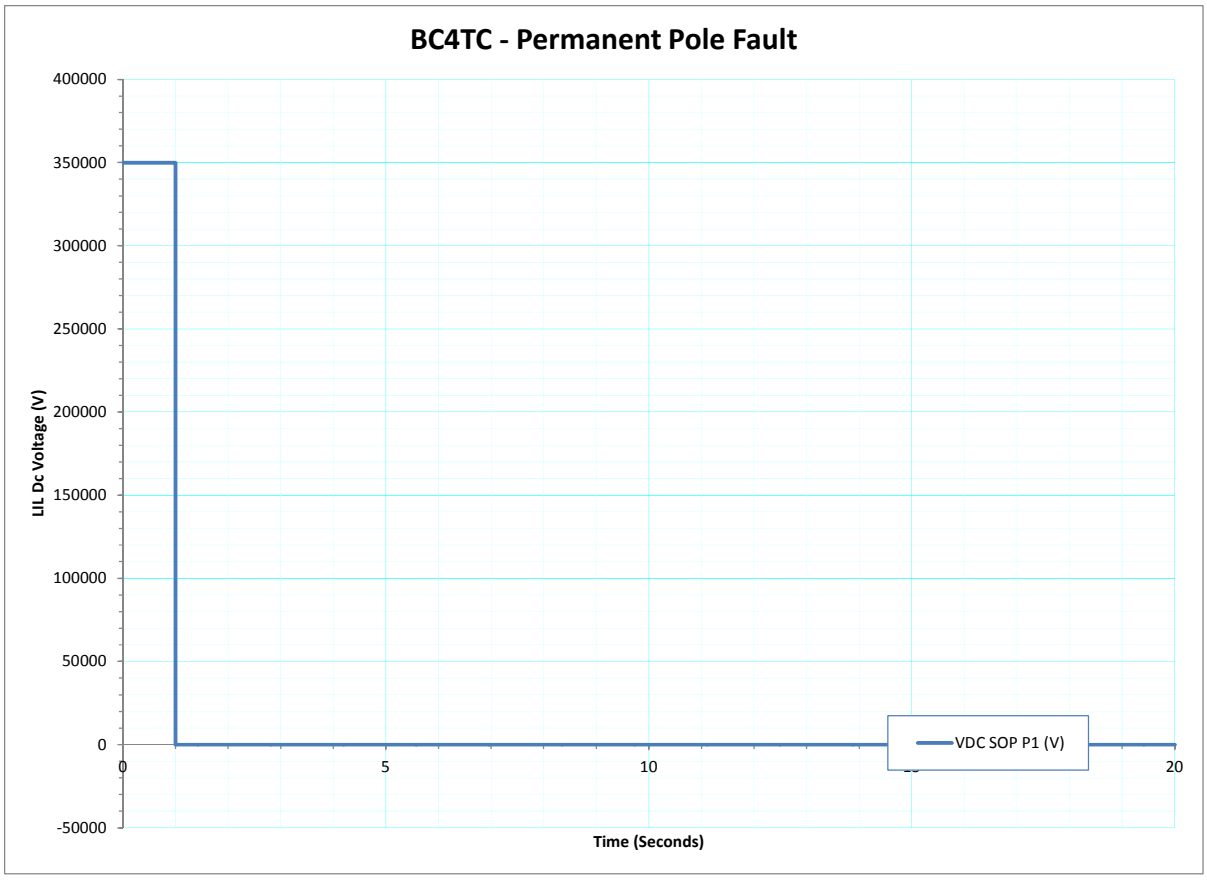


Figure 100 - BC4TC - Permanent Pole Fault - LIL Dc Voltage (V)

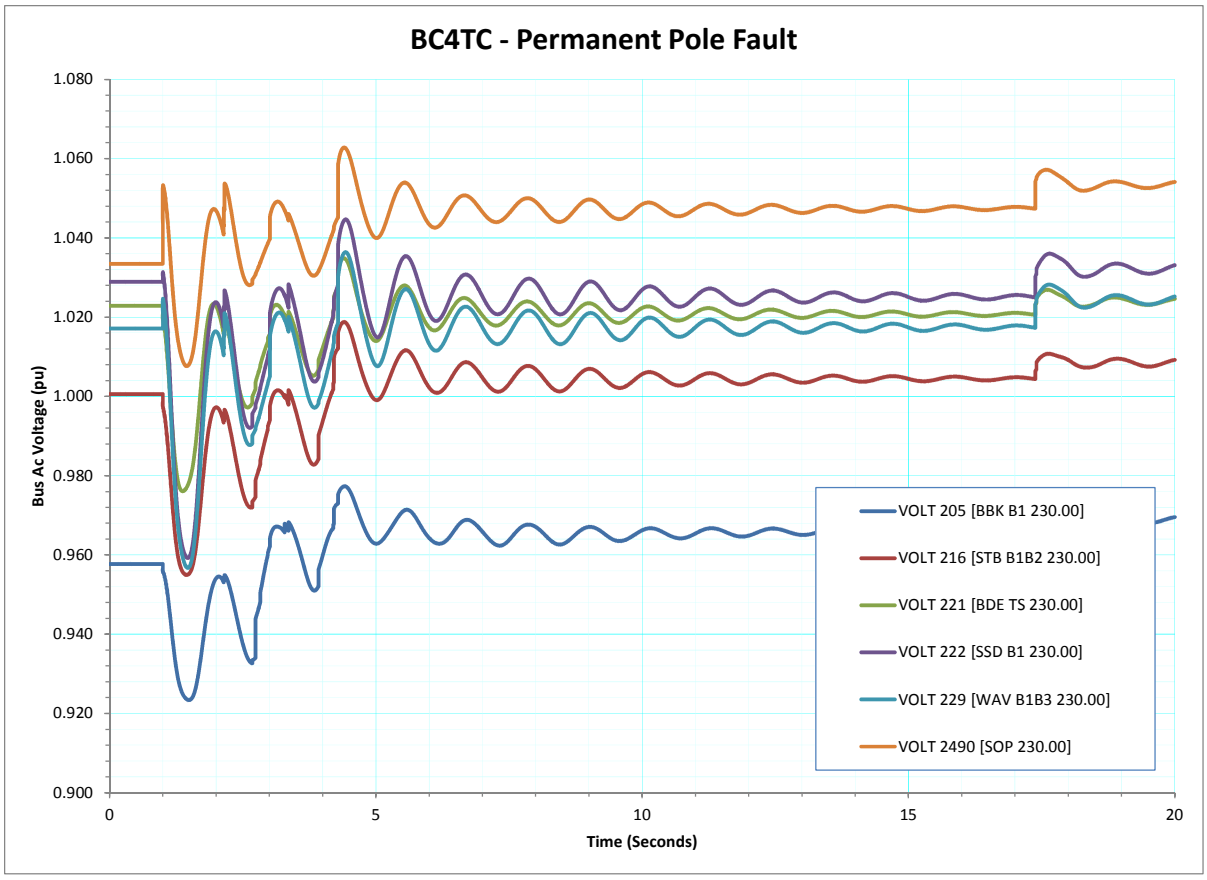


Figure 101 - BC4TC - Permanent Pole Fault - Bus Ac Voltage (pu)

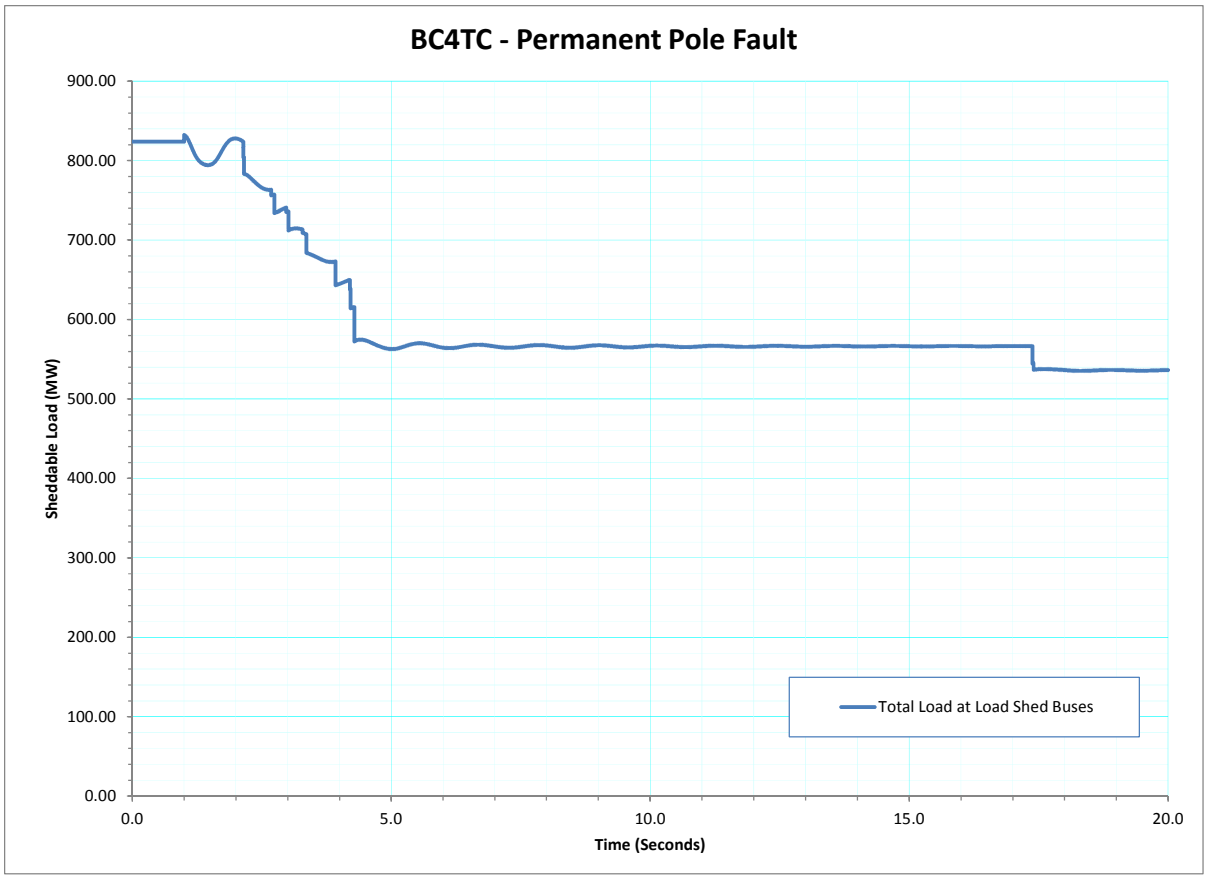


Figure 102 - BC4TC - Permanent Pole Fault - Sheddable Load (MW)

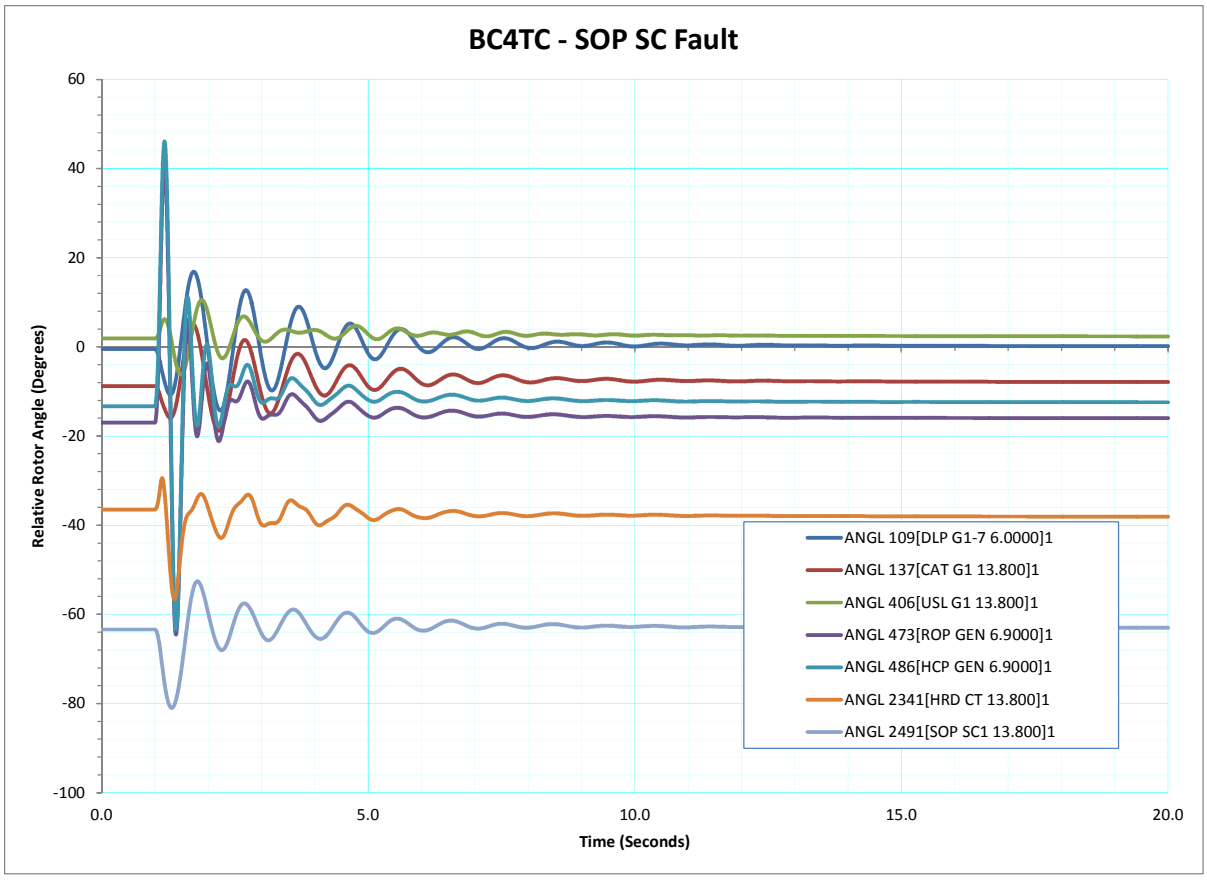


Figure 103 - BC4TC - SOP SC Fault - Relative Rotor Angle (Degrees)

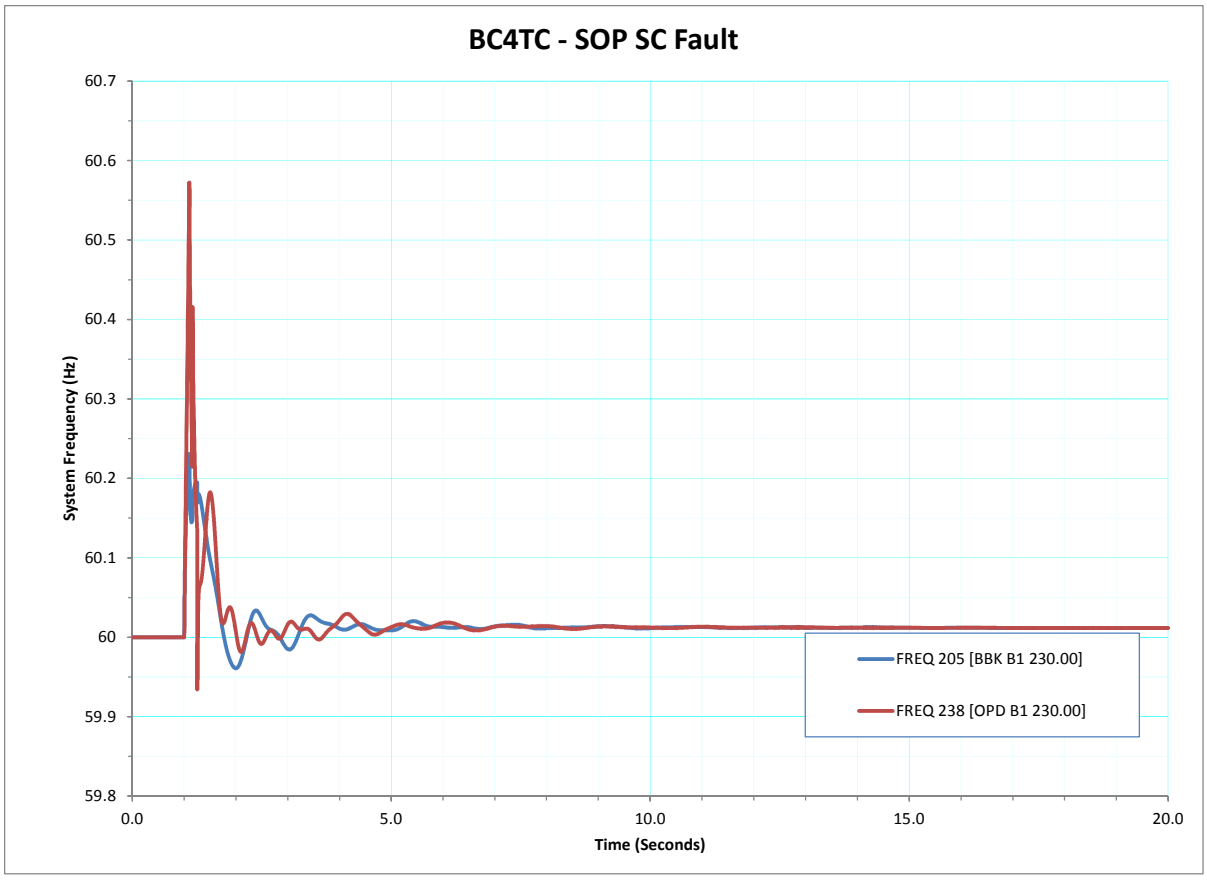


Figure 104 - BC4TC - SOP SC Fault - System Frequency (Hz)

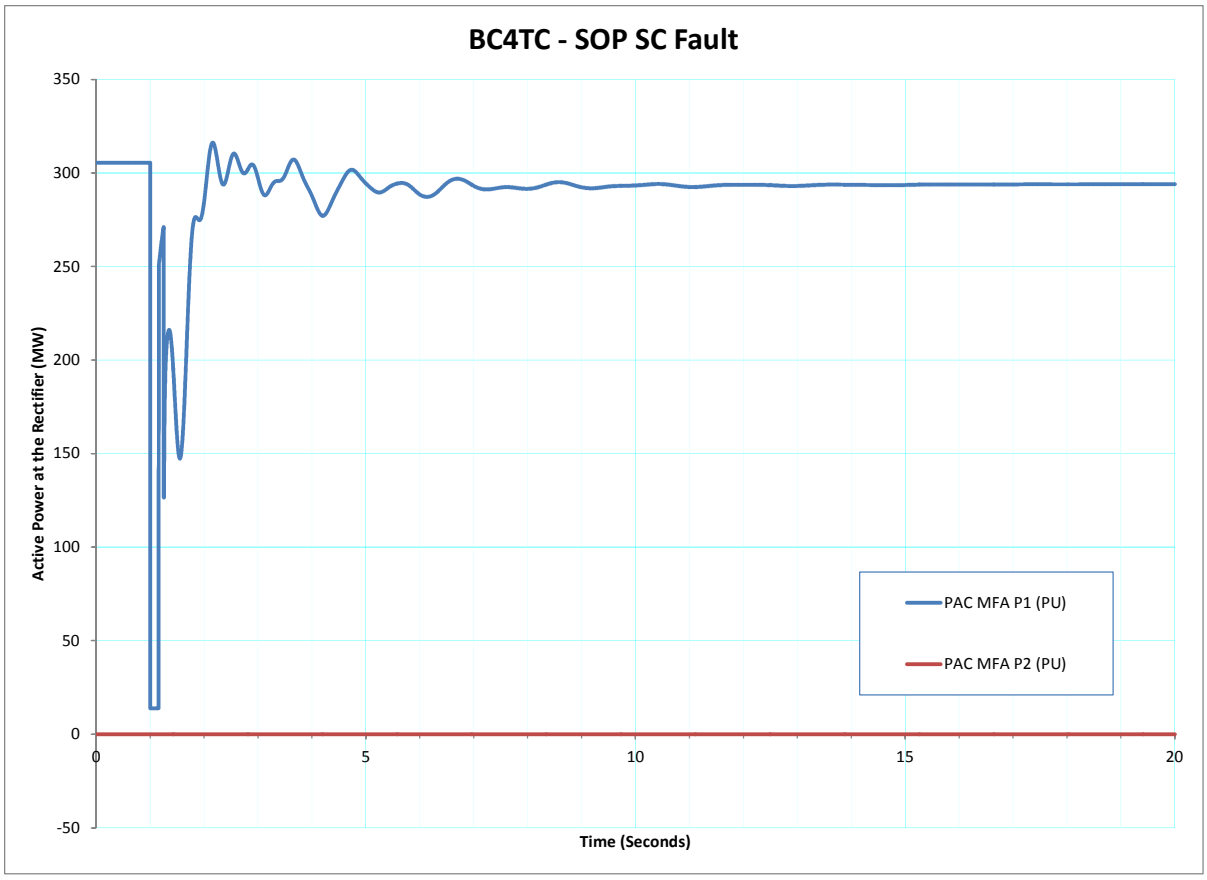


Figure 105 - BC4TC - SOP SC Fault - Active Power at the Rectifier (MW)

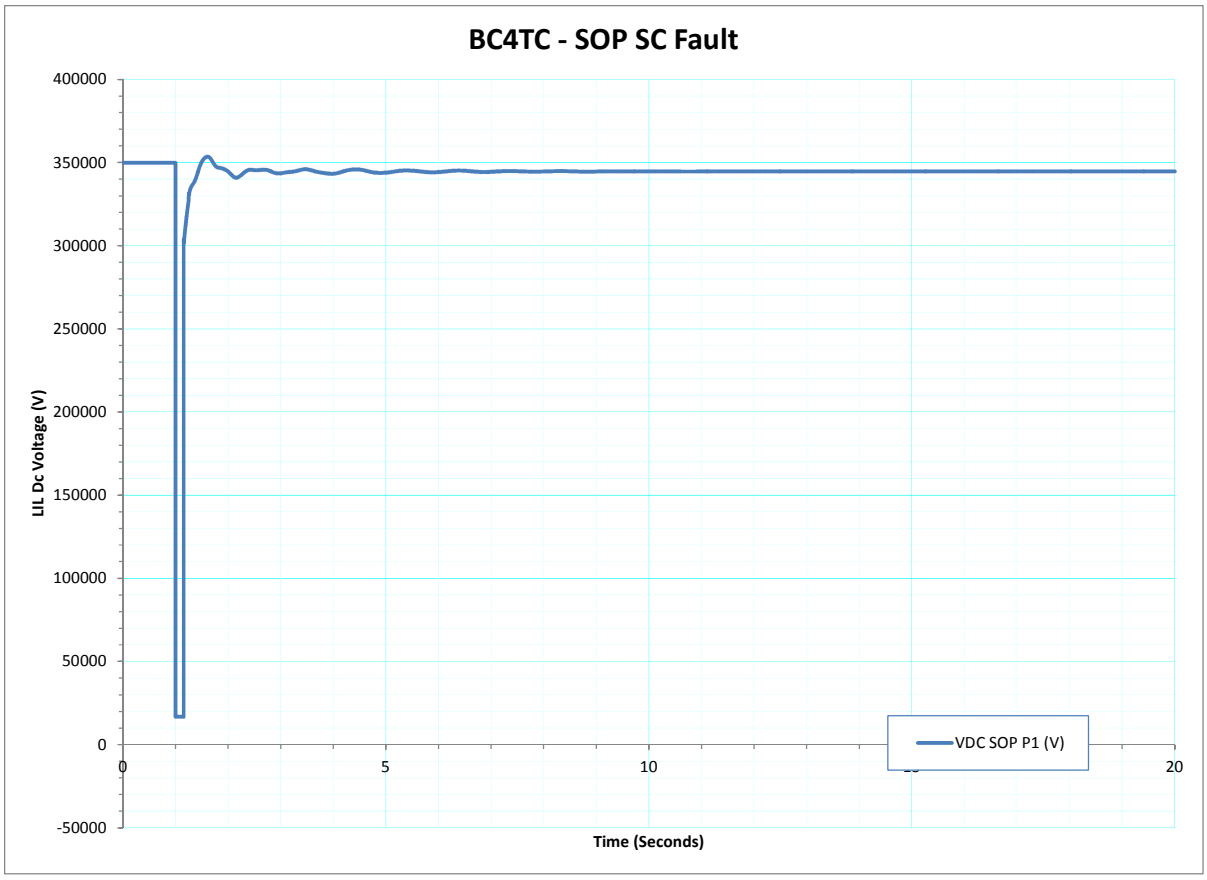


Figure 106 - BC4TC - SOP SC Fault - LIL Dc Voltage (V)

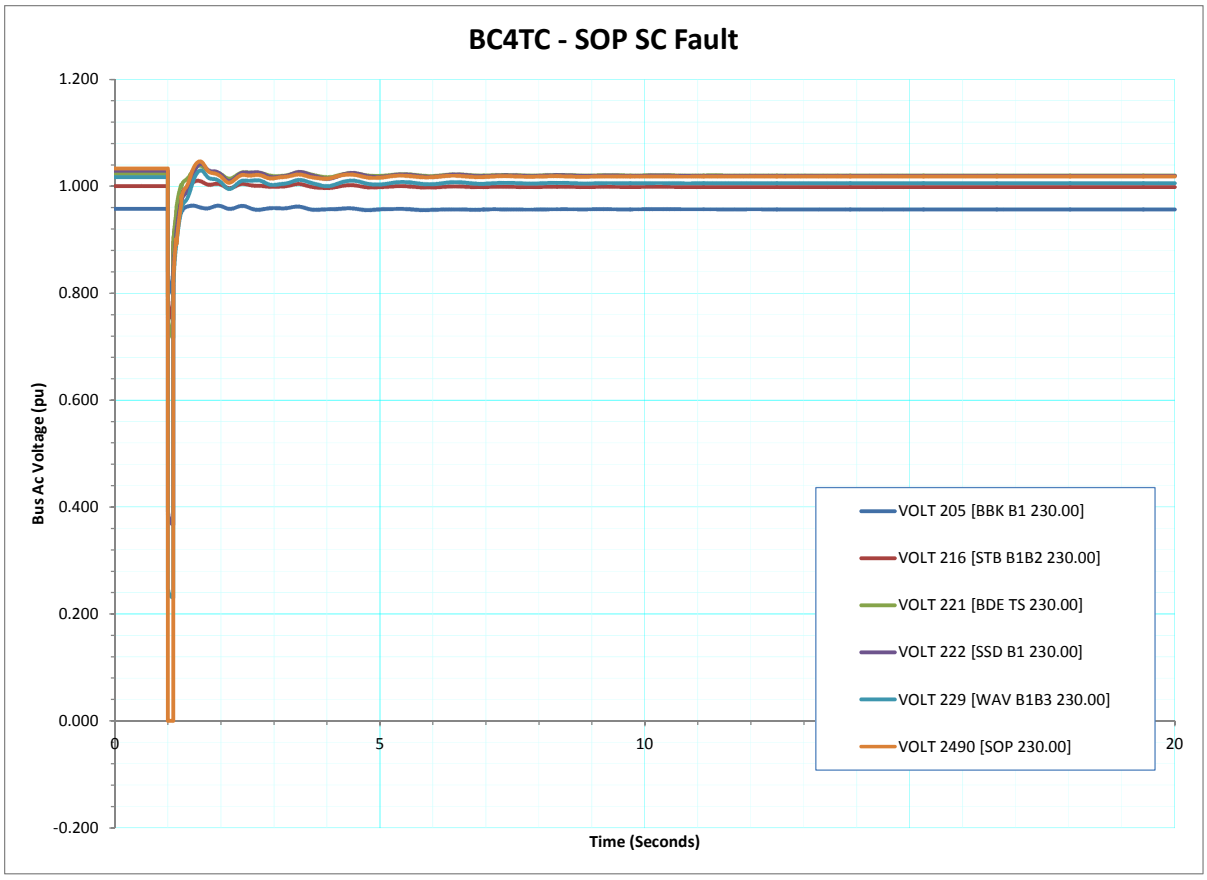


Figure 107 - BC4TC - SOP SC Fault - Bus Ac Voltage (pu)

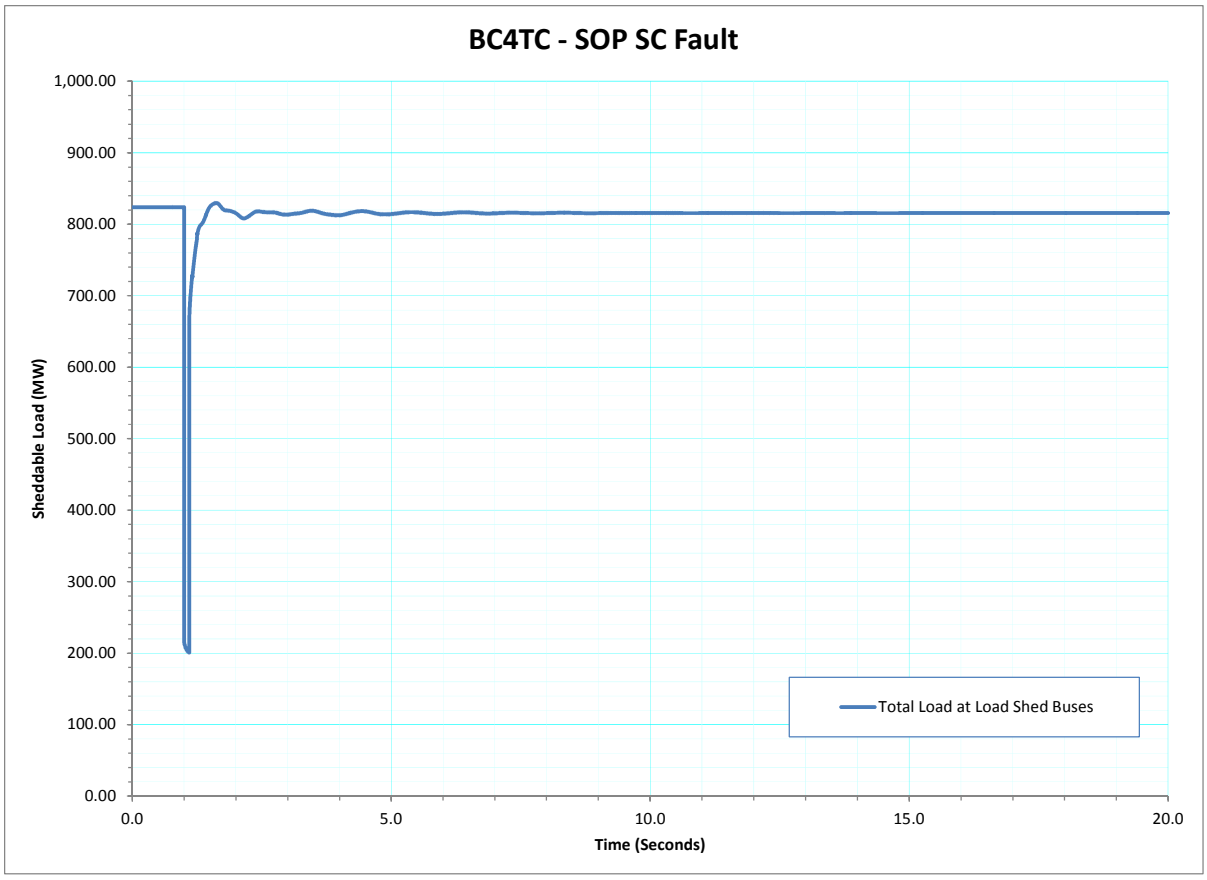


Figure 108 - BC4TC - SOP SC Fault - Sheddable Load (MW)

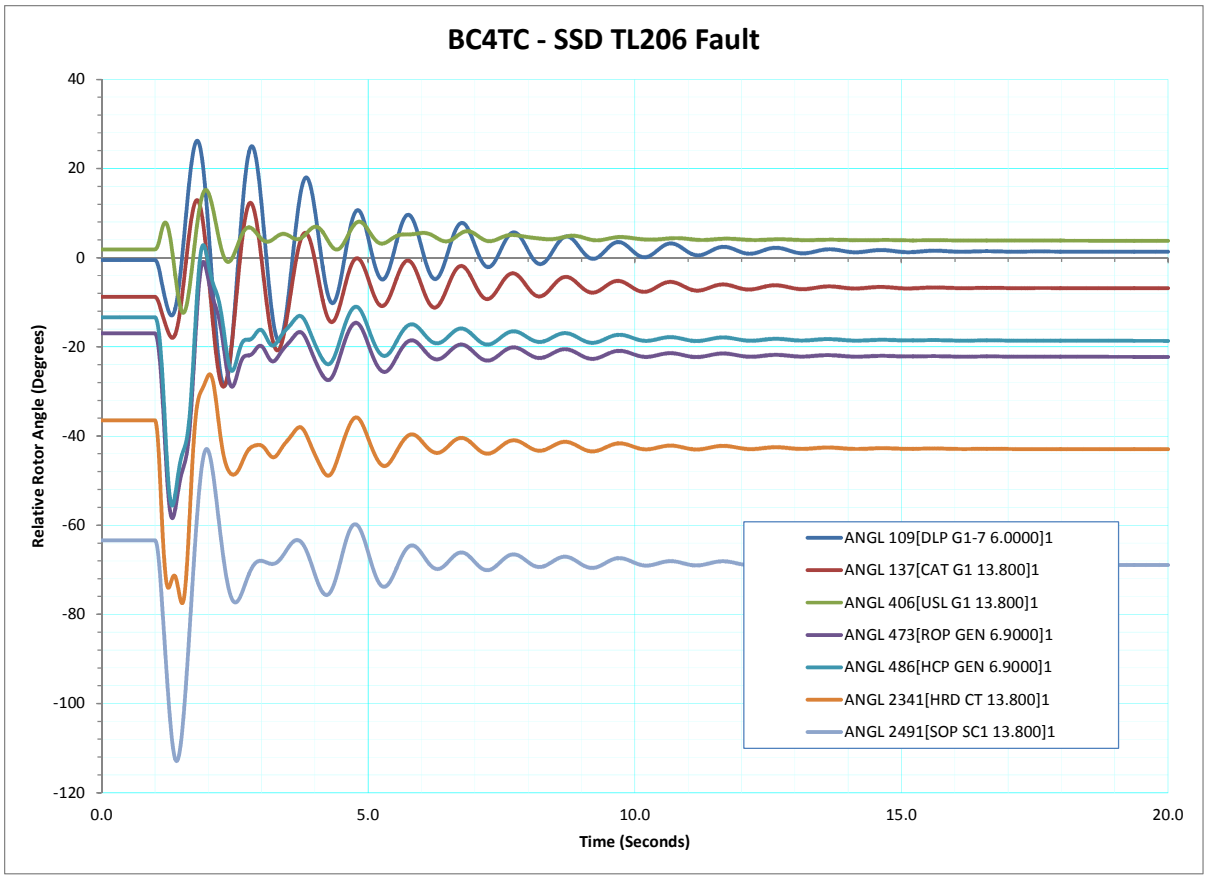


Figure 109 - BC4TC - SSD TL206 Fault - Relative Rotor Angle (Degrees)

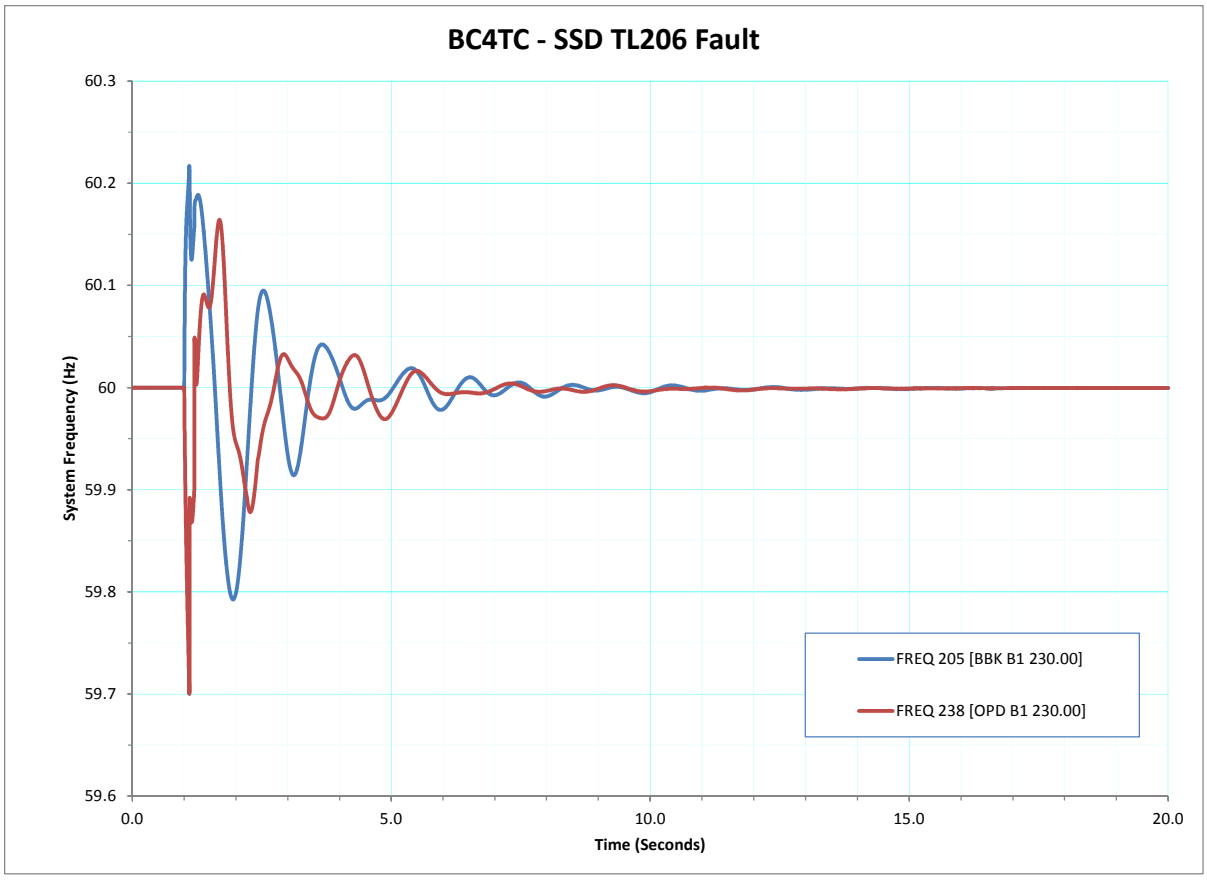


Figure 110 - BC4TC - SSD TL206 Fault - System Frequency (Hz)

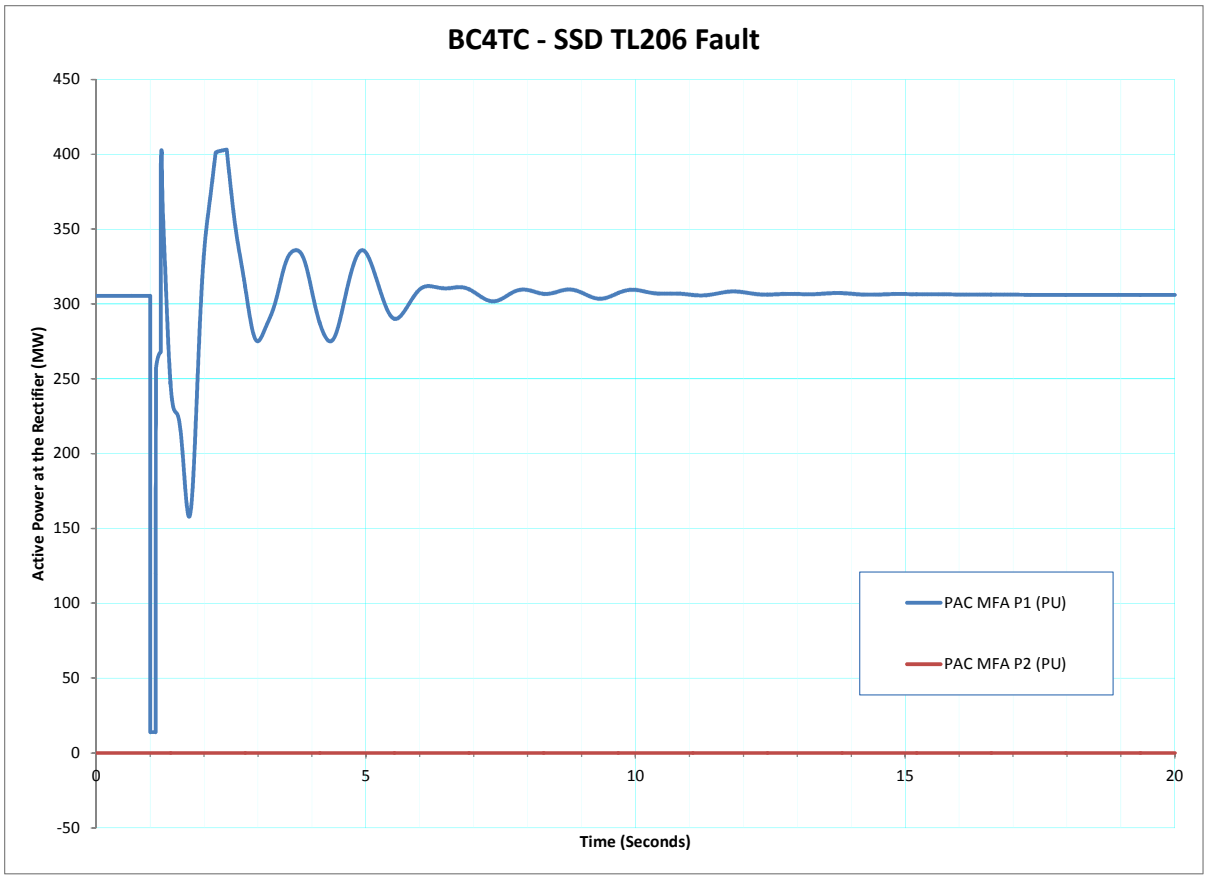


Figure 111 - BC4TC - SSD TL206 Fault - Active Power at the Rectifier (MW)

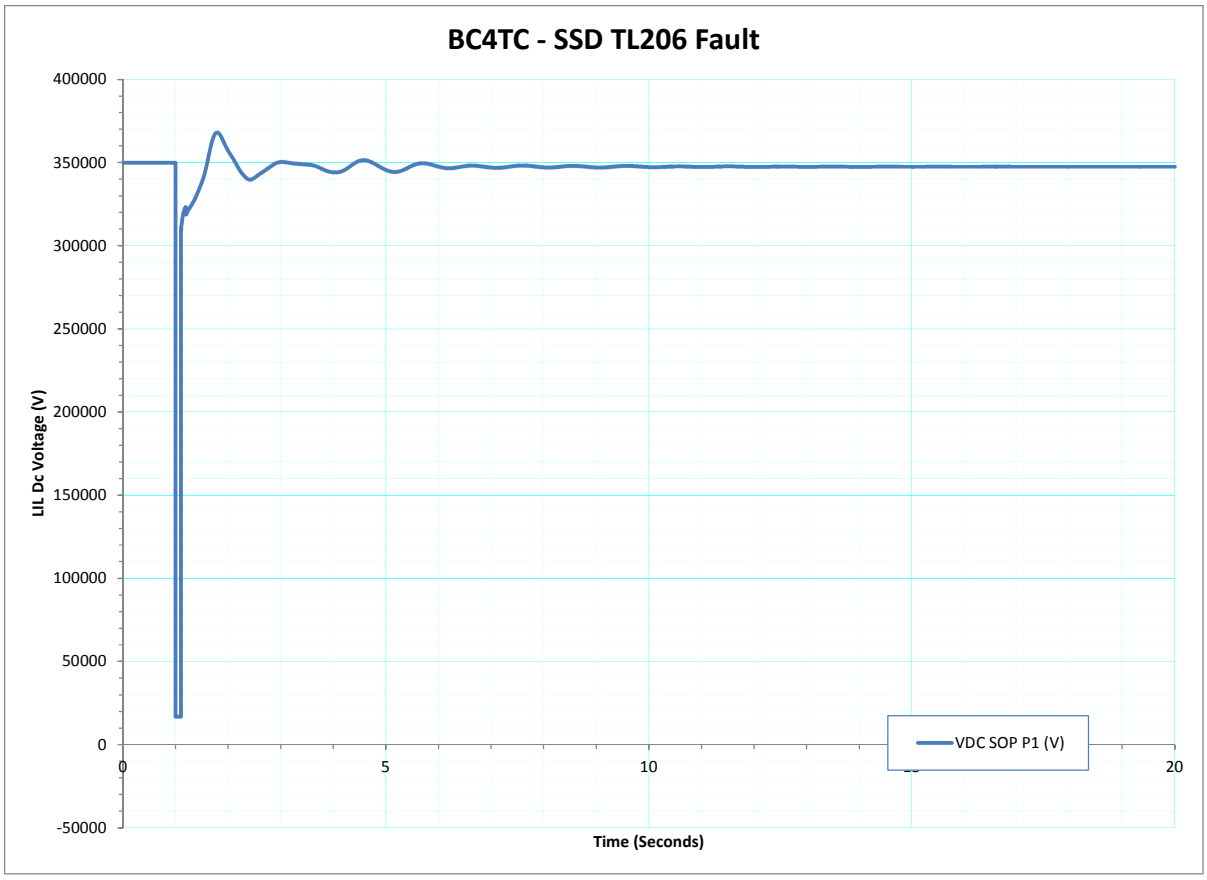


Figure 112 - BC4TC - SSD TL206 Fault - LIL Dc Voltage (V)

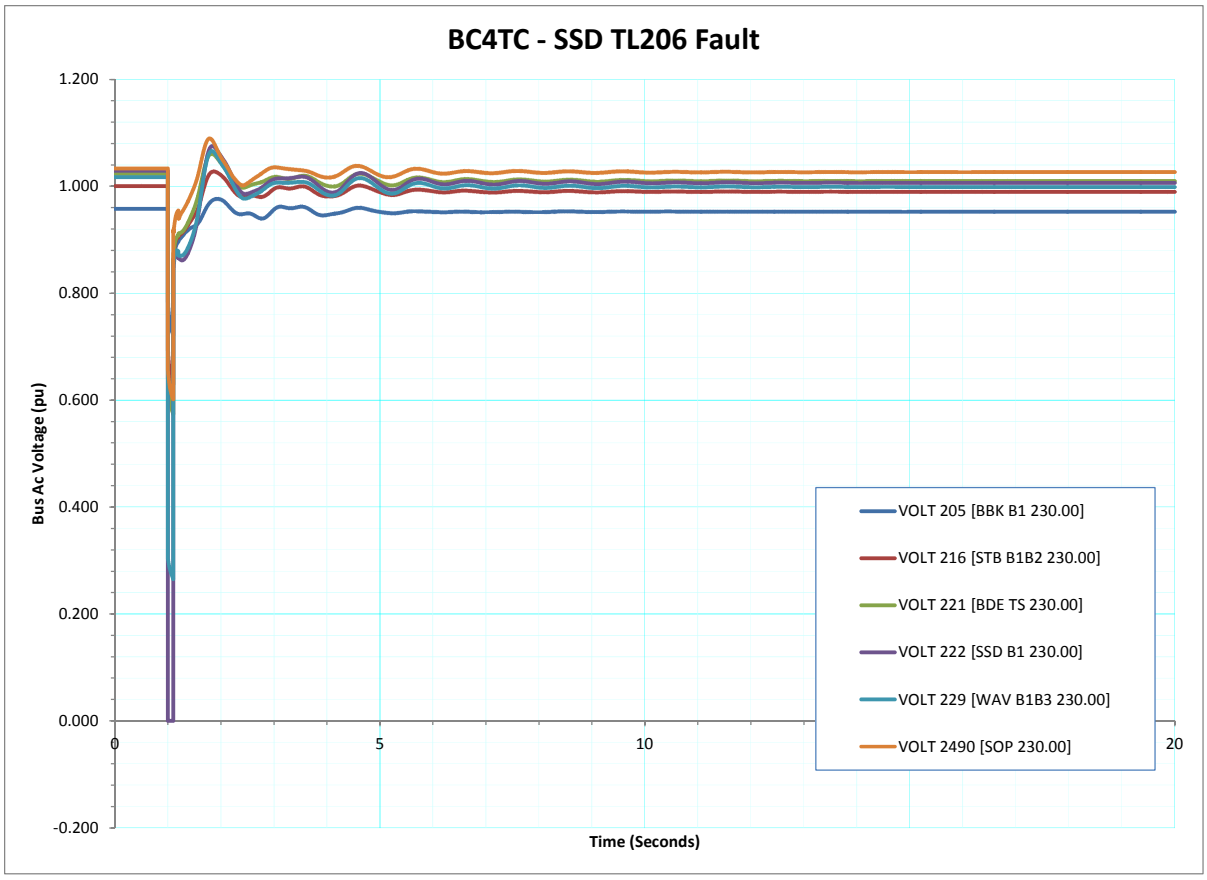


Figure 113 - BC4TC - SSD TL206 Fault - Bus Ac Voltage (pu)

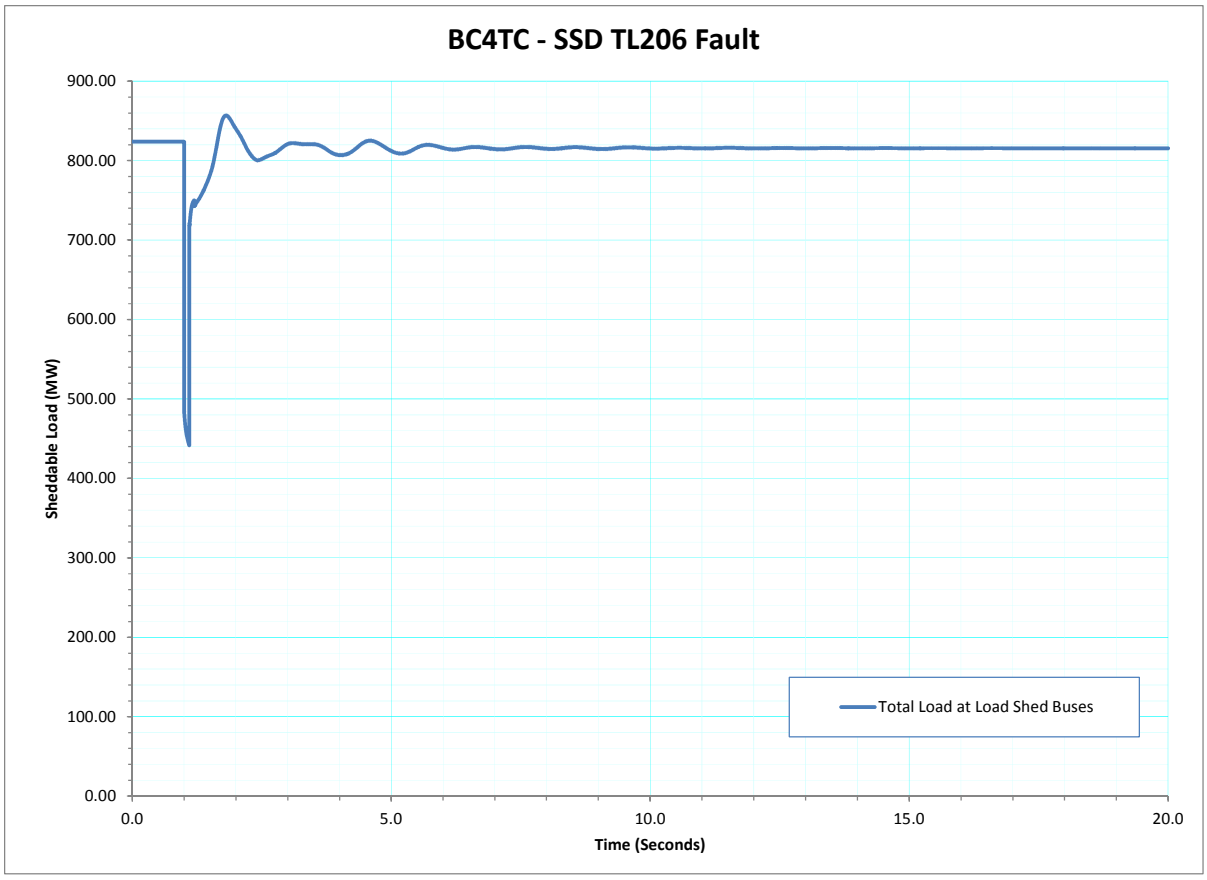


Figure 114 - BC4TC - SSD TL206 Fault - Sheddable Load (MW)

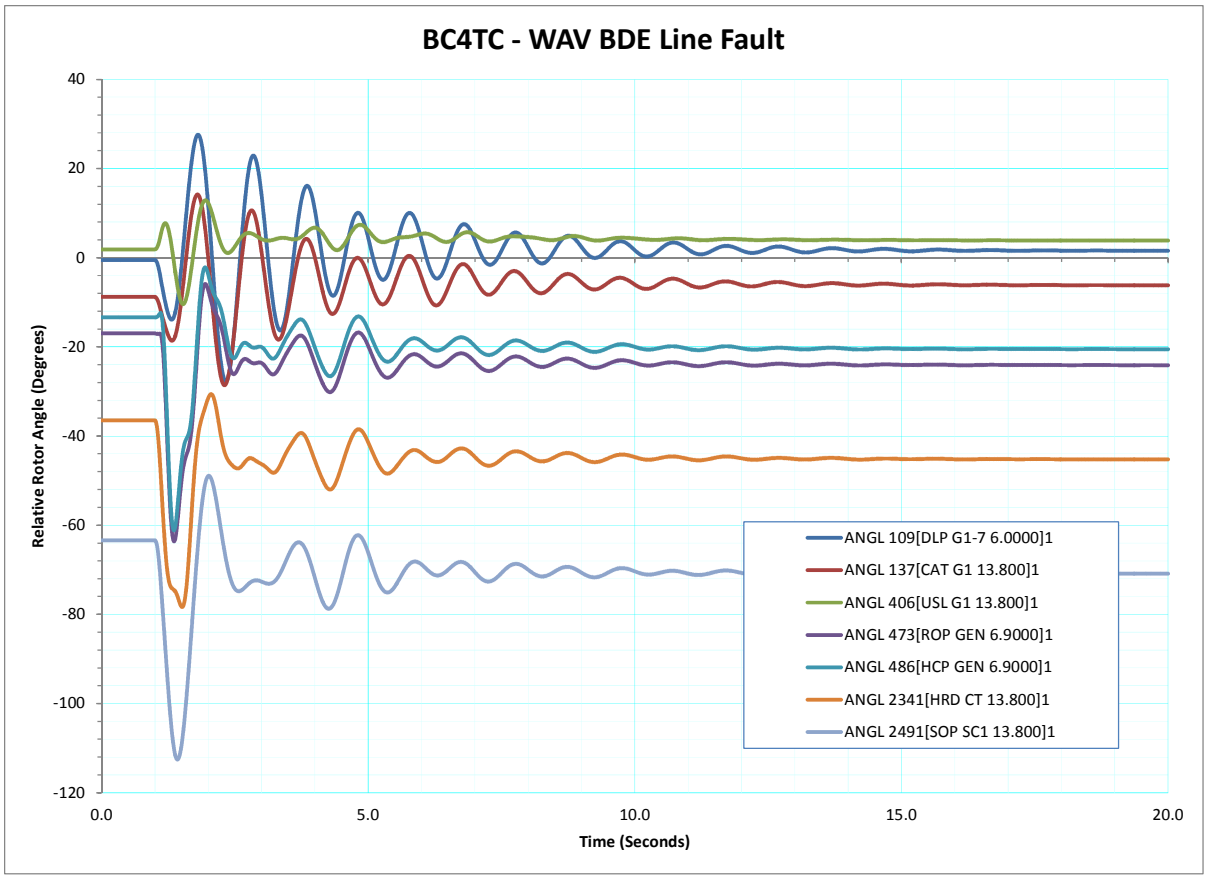


Figure 115 - BC4TC - WAV BDE Line Fault - Relative Rotor Angle (Degrees)

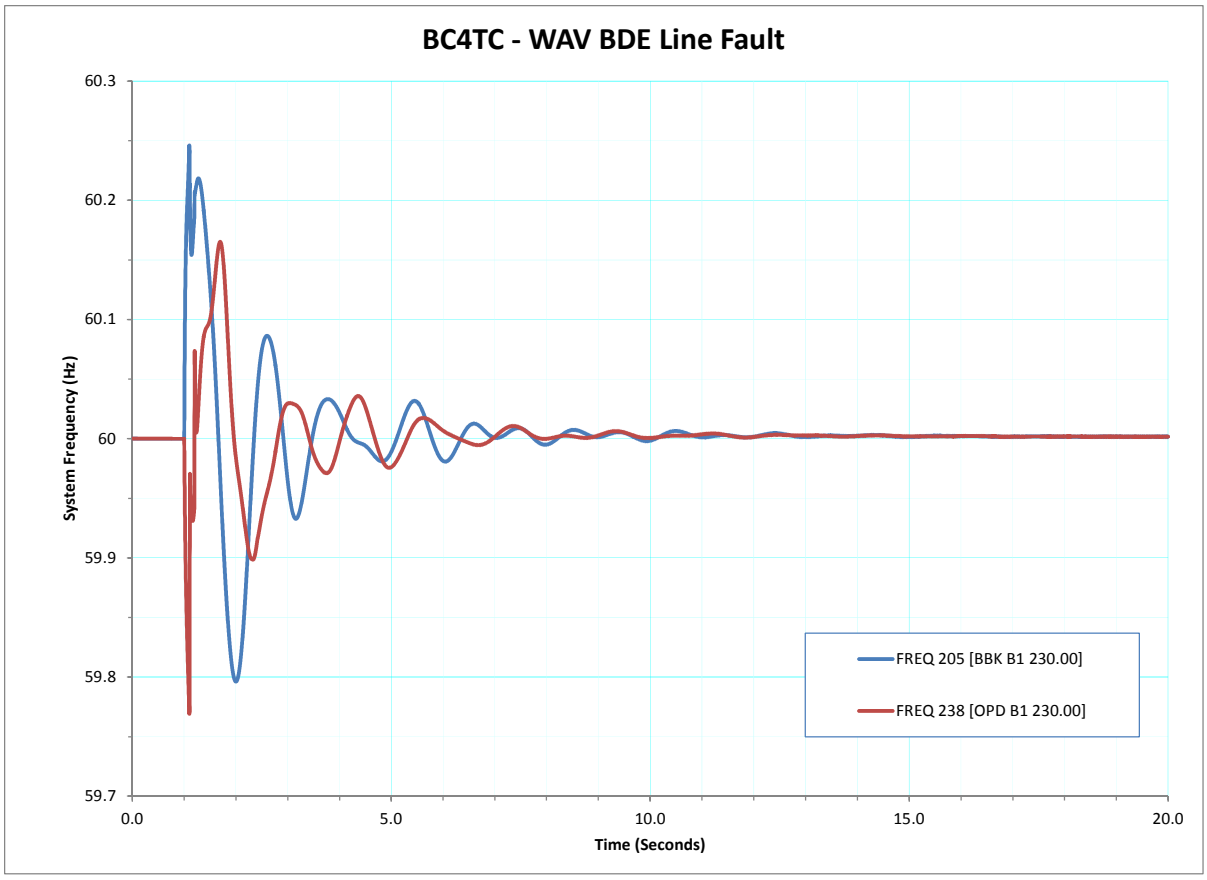


Figure 116 - BC4TC - WAV BDE Line Fault - System Frequency (Hz)

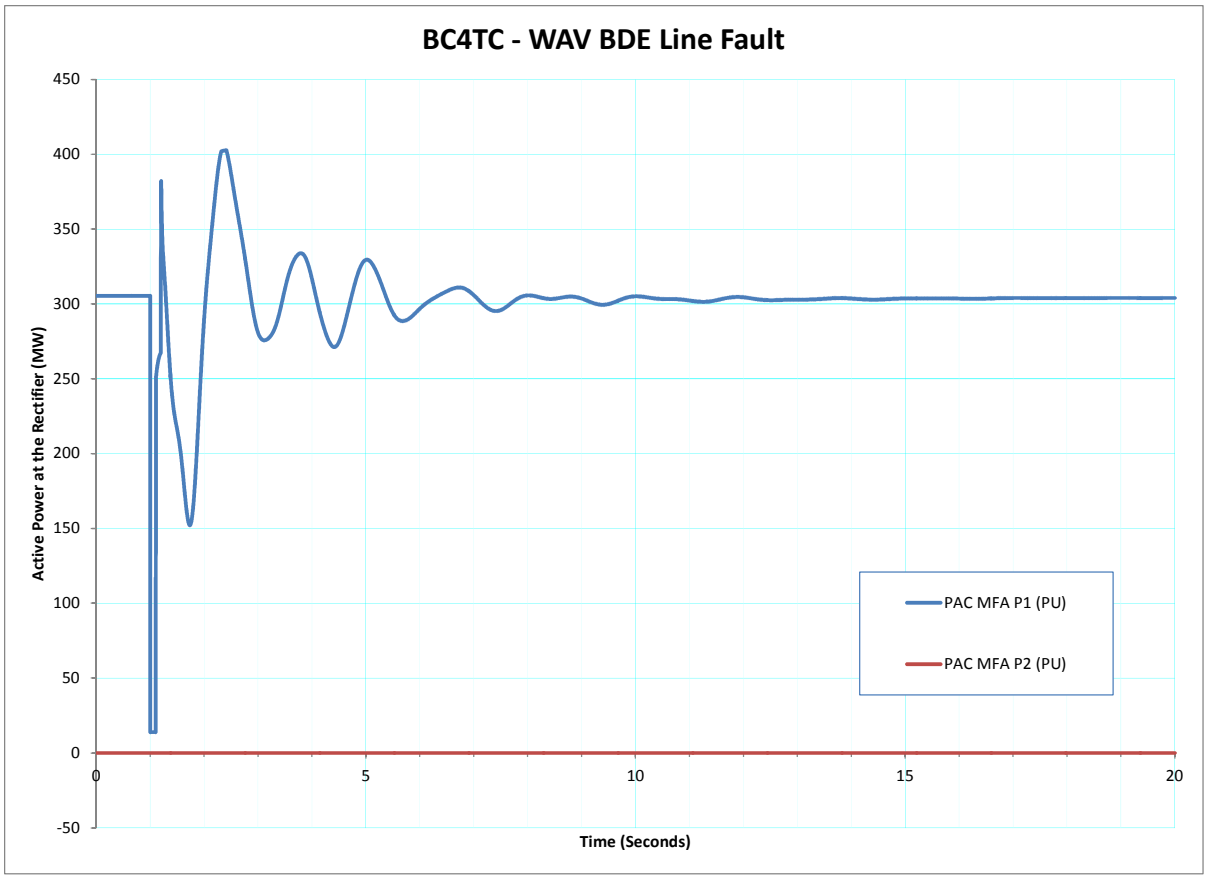


Figure 117 - BC4TC - WAV BDE Line Fault - Active Power at the Rectifier (MW)

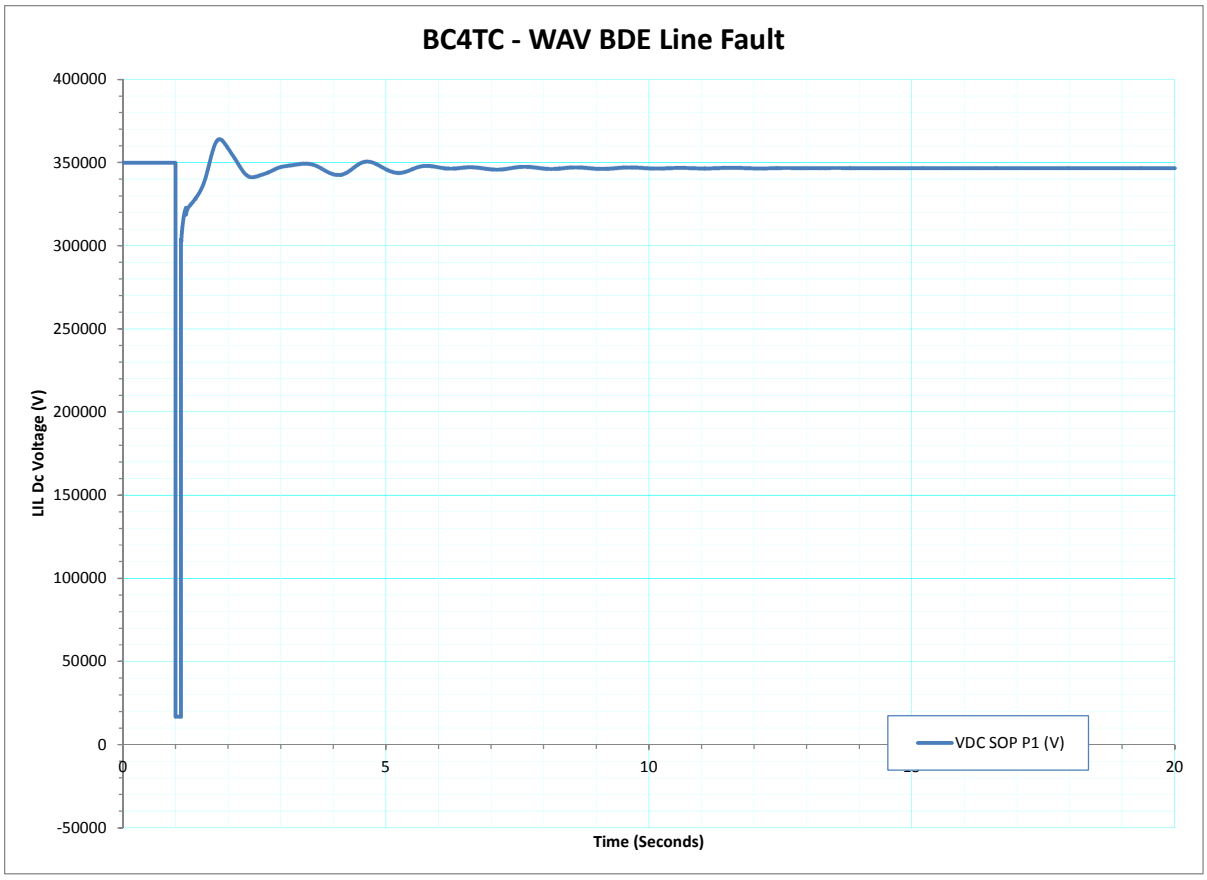


Figure 118 - BC4TC - WAV BDE Line Fault - LIL Dc Voltage (V)

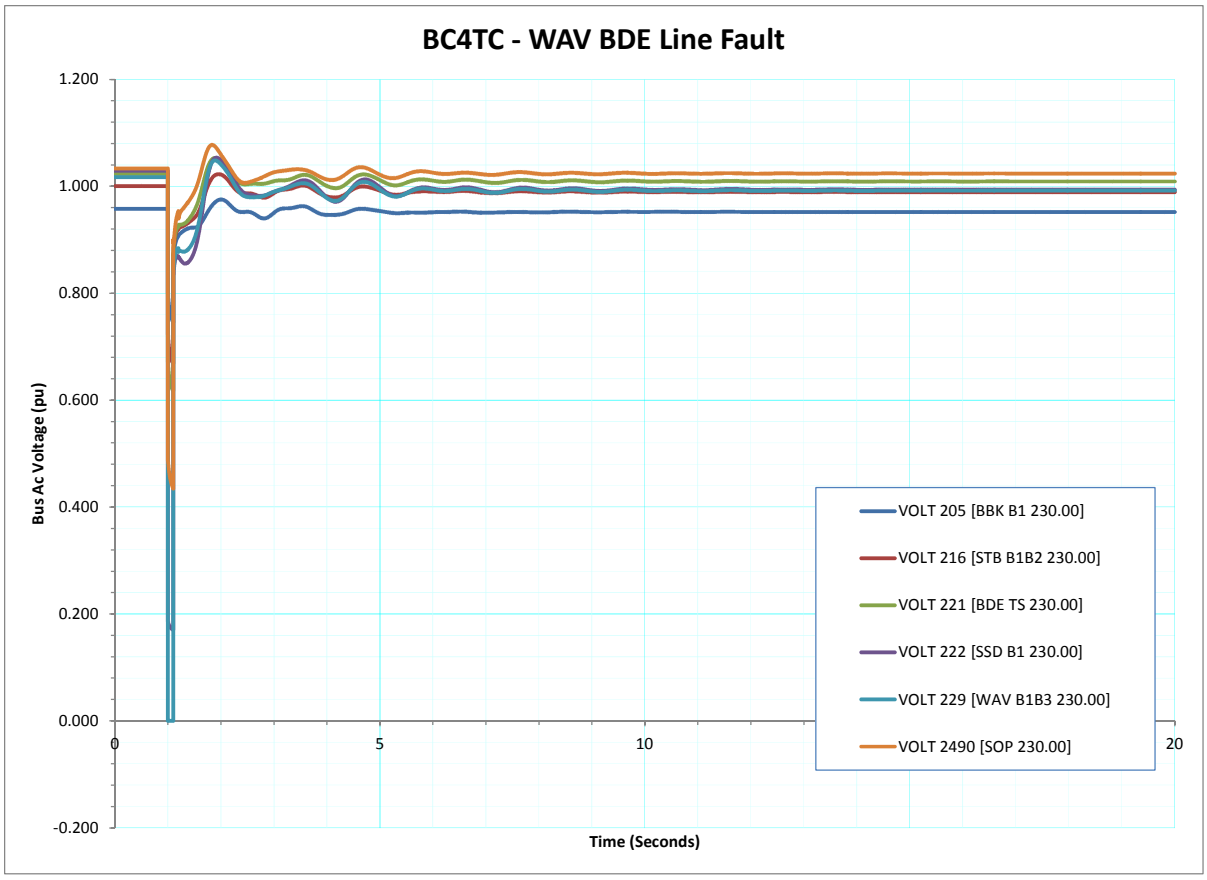


Figure 119 - BC4TC - WAV BDE Line Fault - Bus Ac Voltage (pu)

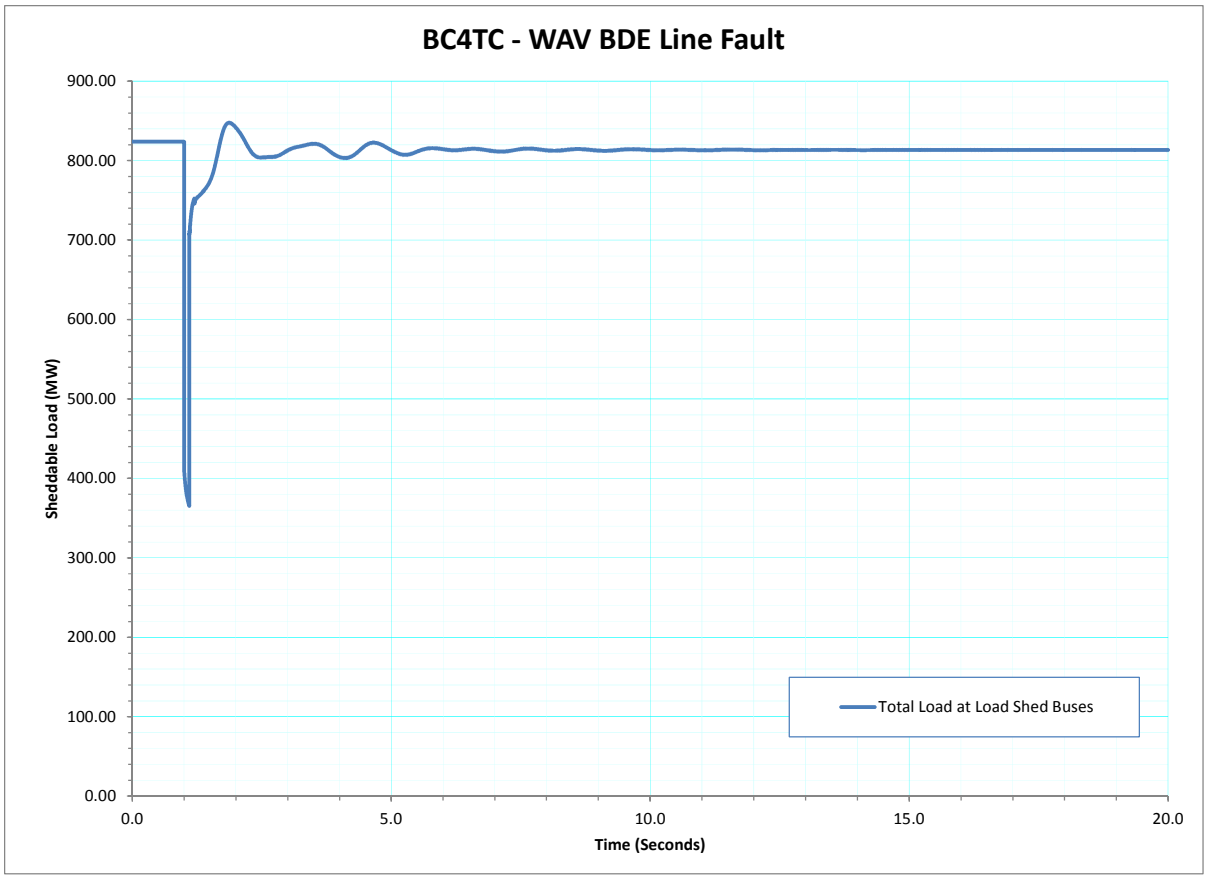


Figure 120 - BC4TC - WAV BDE Line Fault - Sheddable Load (MW)

1.5. BASE CASE 5 TRANSIENT STABILITY PLOTS

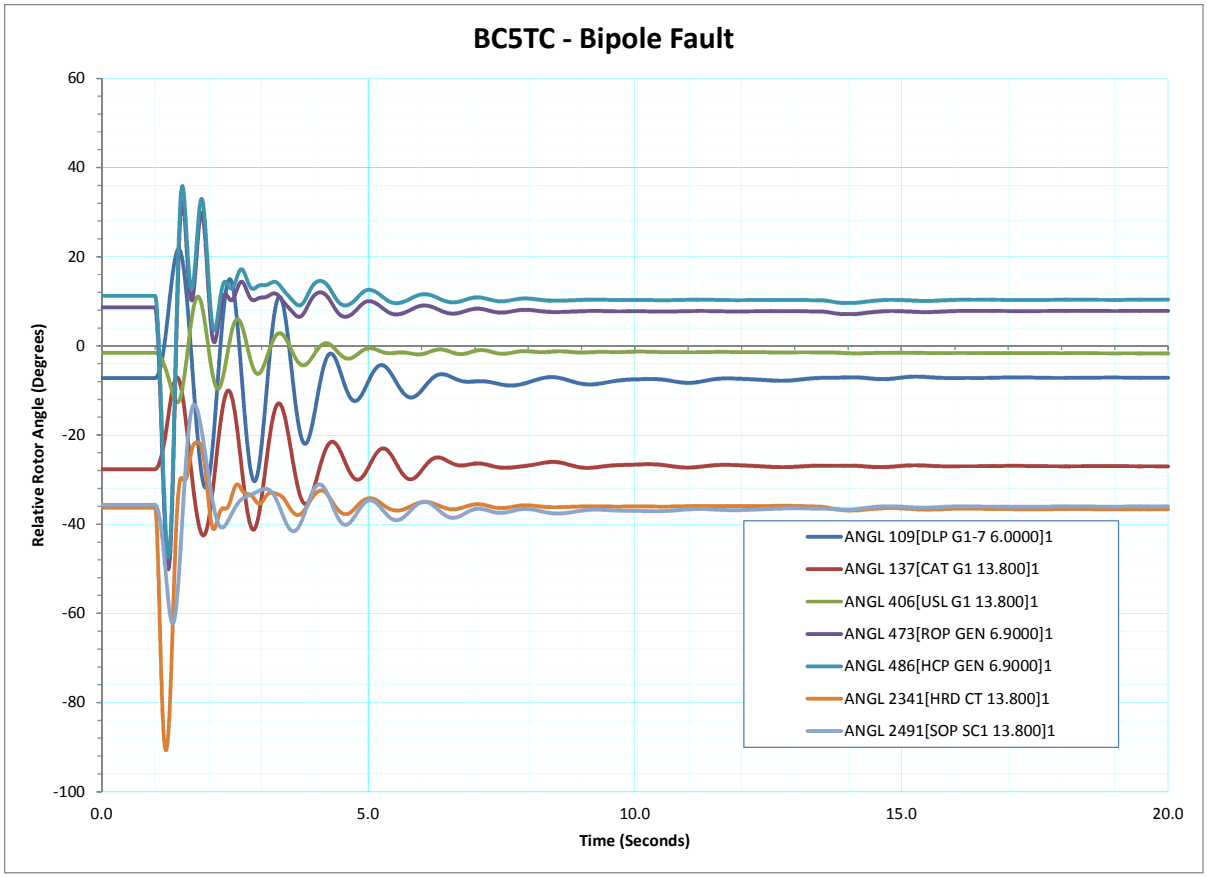


Figure 121 - BC5TC - Bipole Fault - Relative Rotor Angle (Degrees)

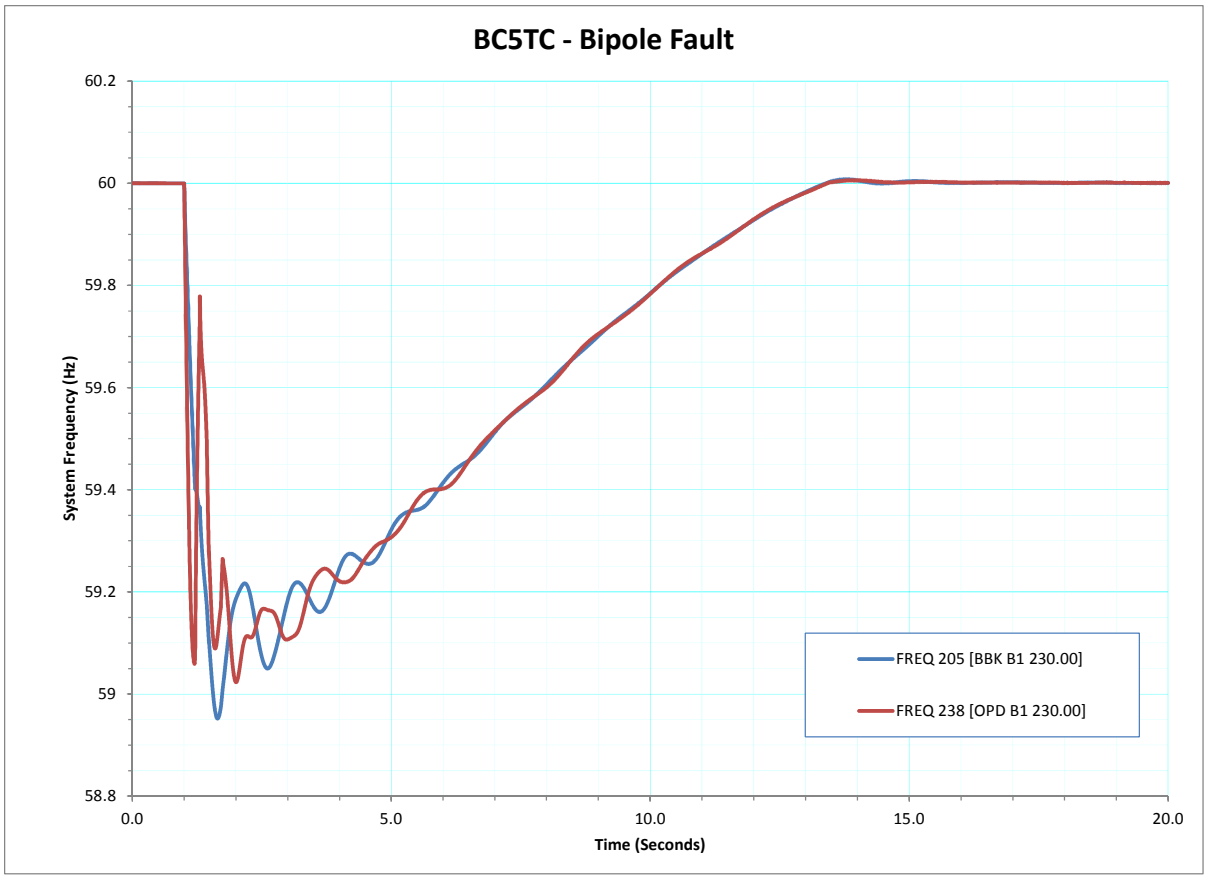


Figure 122 - BC5TC - Bipole Fault - System Frequency (Hz)

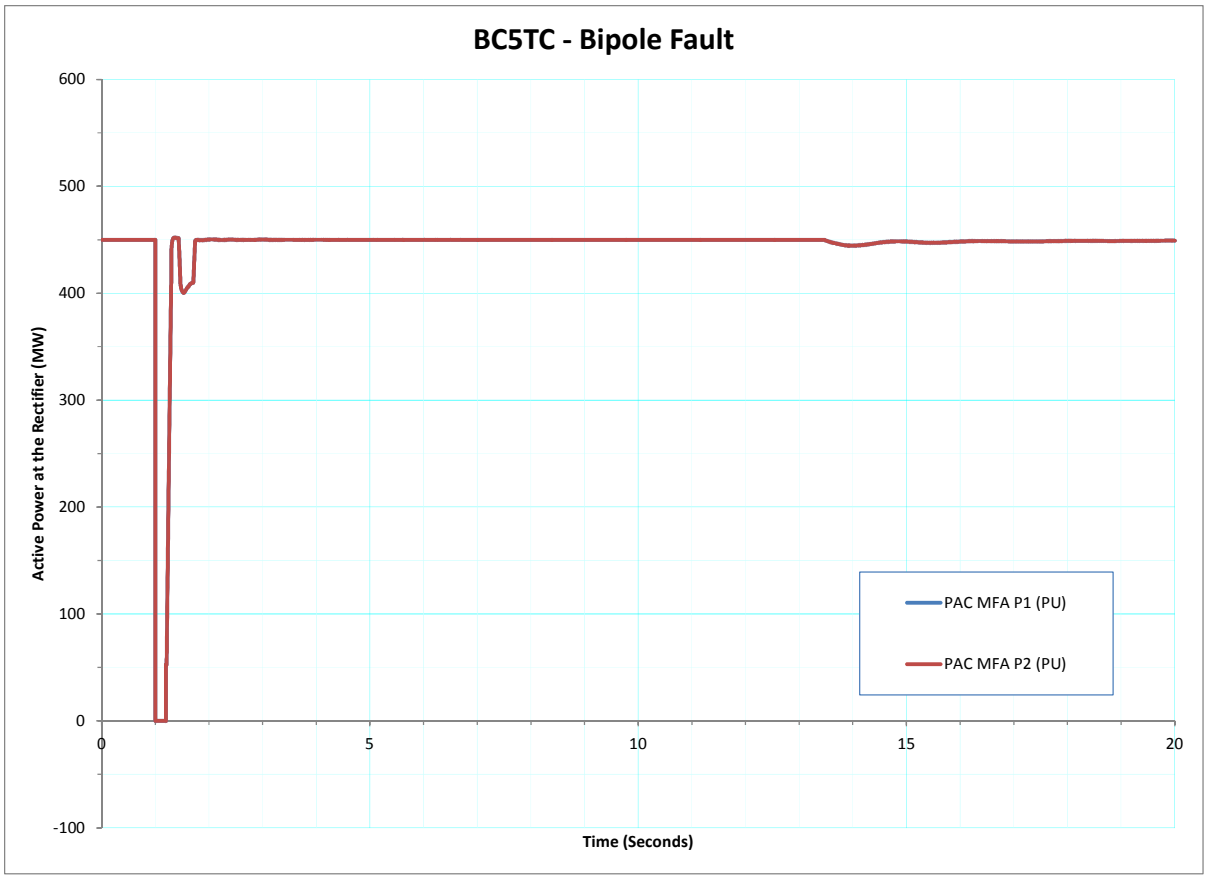


Figure 123 - BC5TC - Bipole Fault - Active Power at the Rectifier (MW)

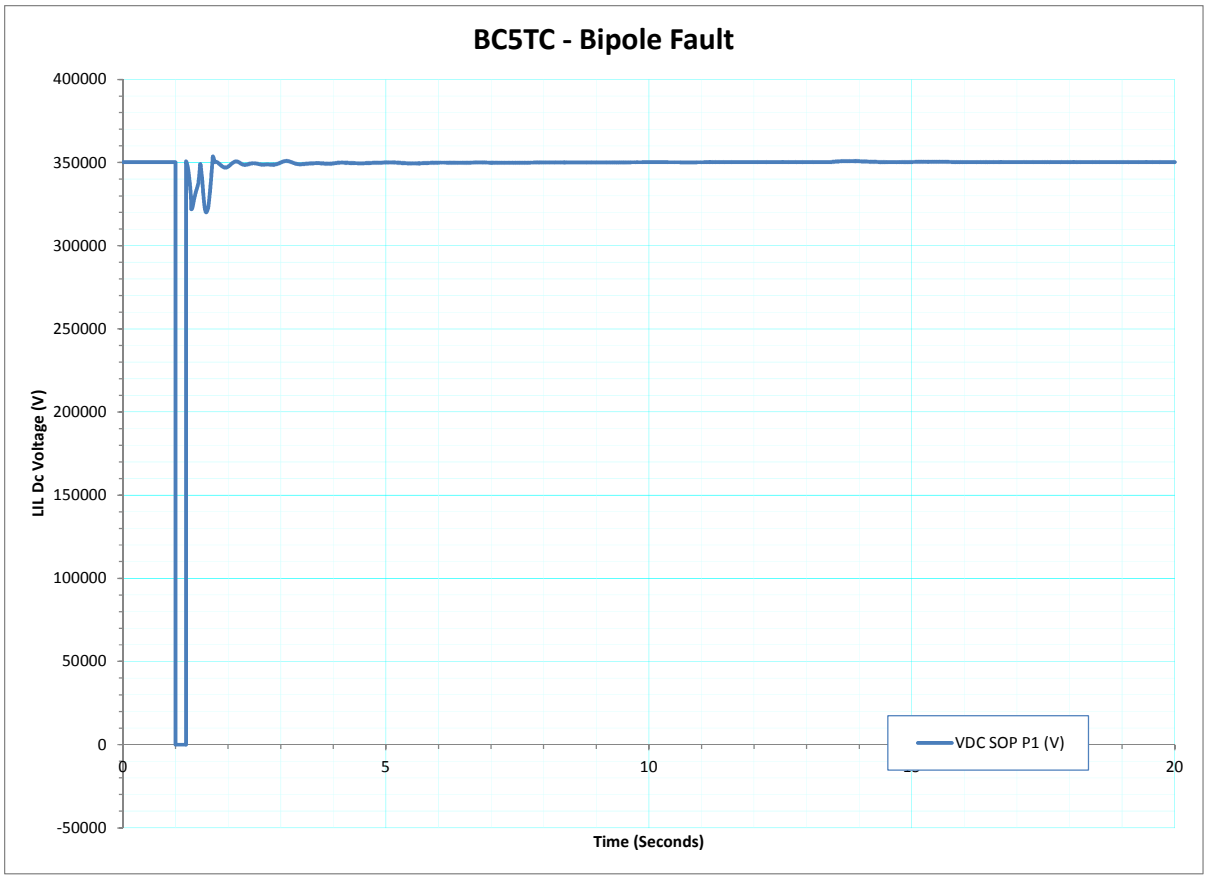


Figure 124 - BC5TC - Bipole Fault - LIL Dc Voltage (V)

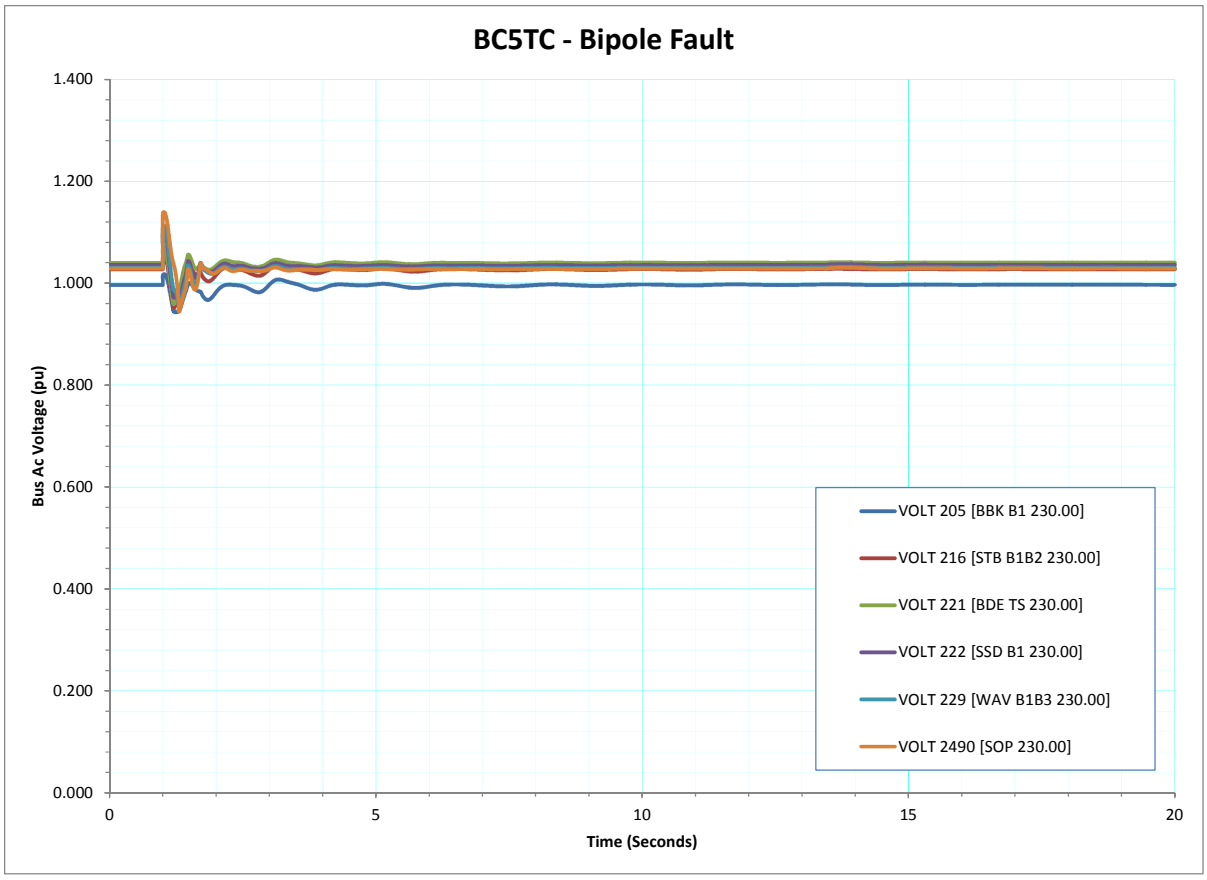


Figure 125 - BC5TC - Bipole Fault - Bus Ac Voltage (pu)

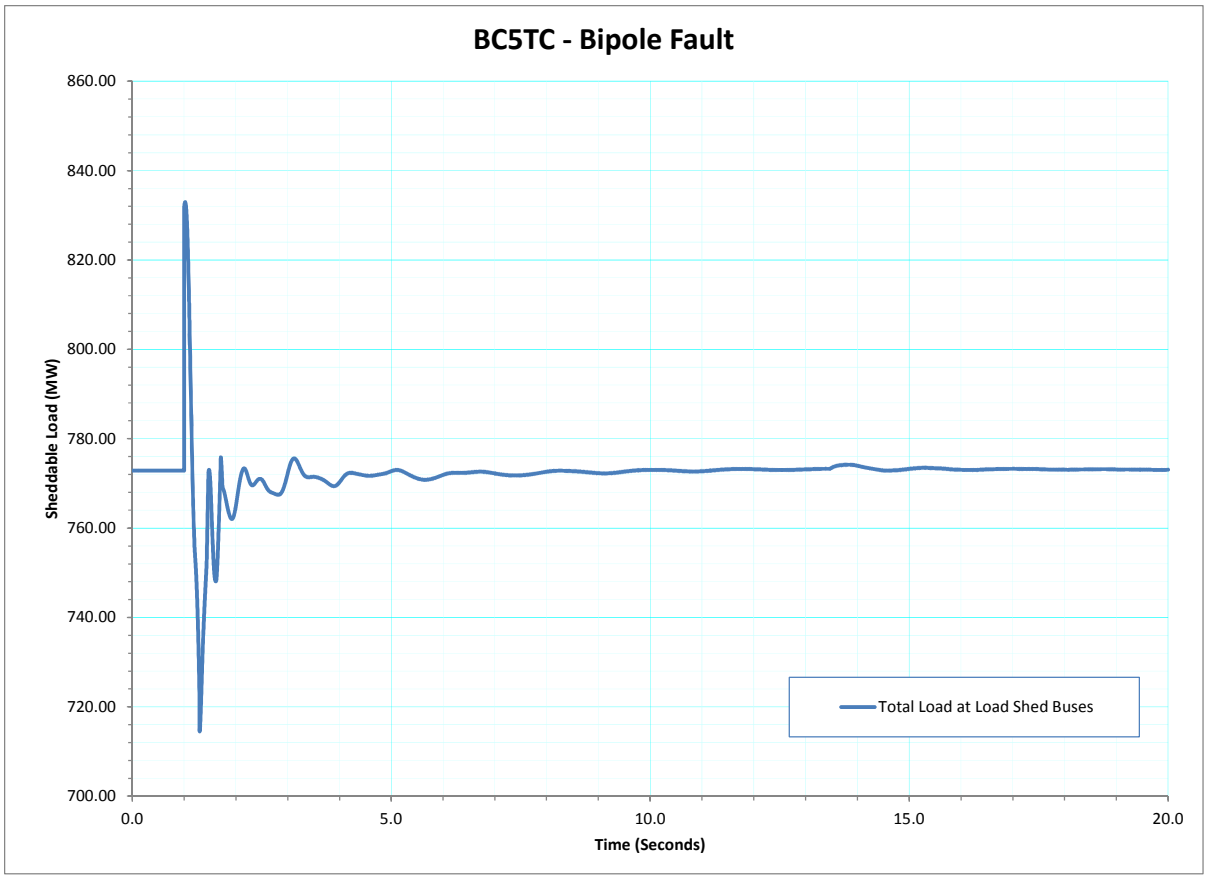


Figure 126 - BC5TC - Bipole Fault - Sheddable Load (MW)

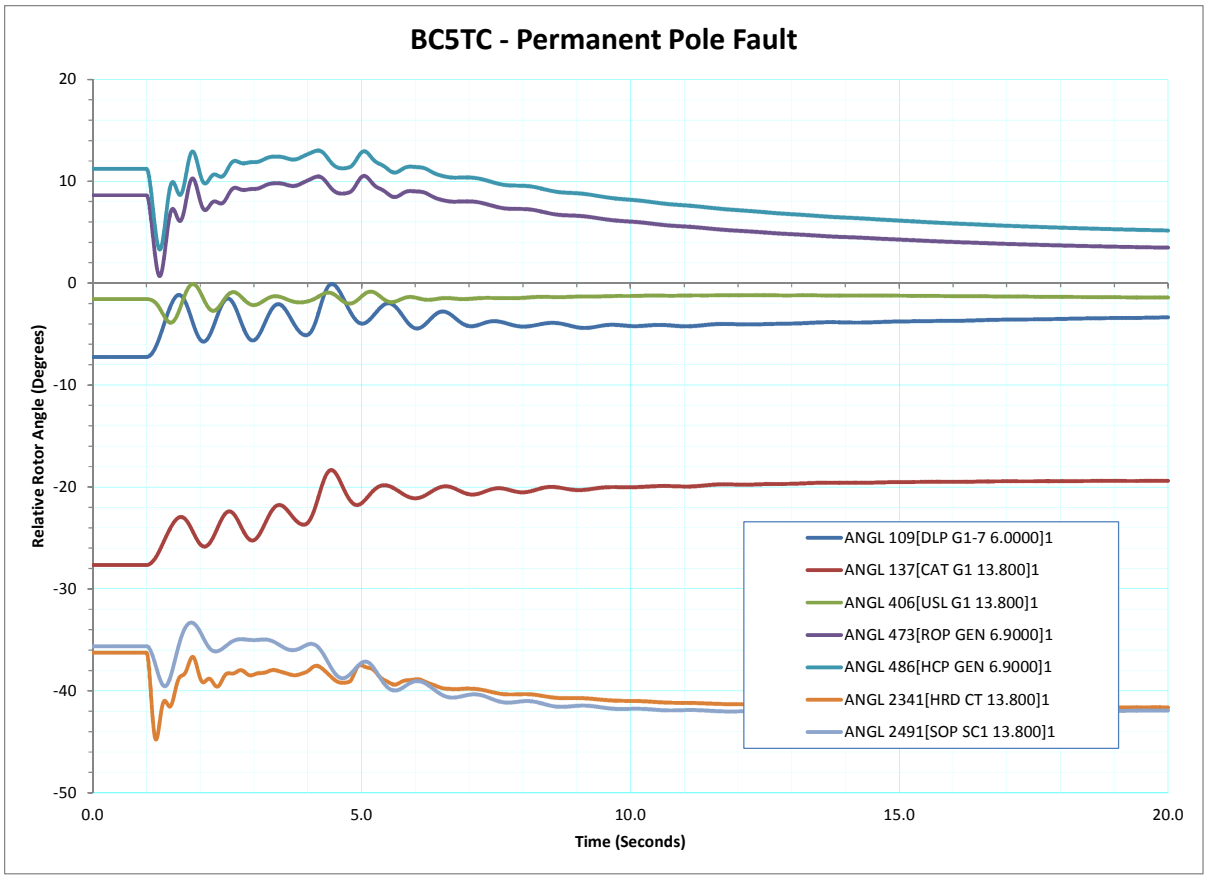


Figure 127 - BC5TC - Permanent Pole Fault - Relative Rotor Angle (Degrees)

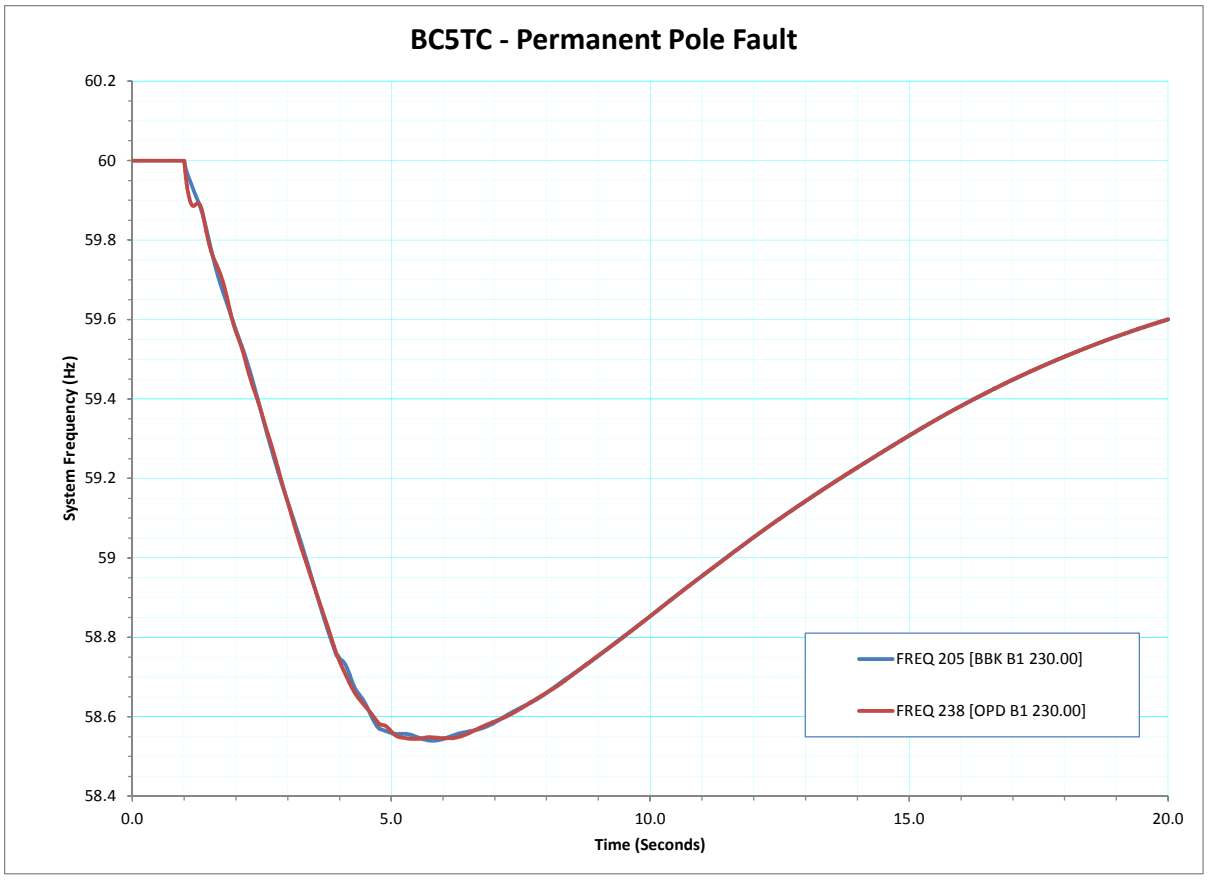


Figure 128 - BC5TC - Permanent Pole Fault - System Frequency (Hz)

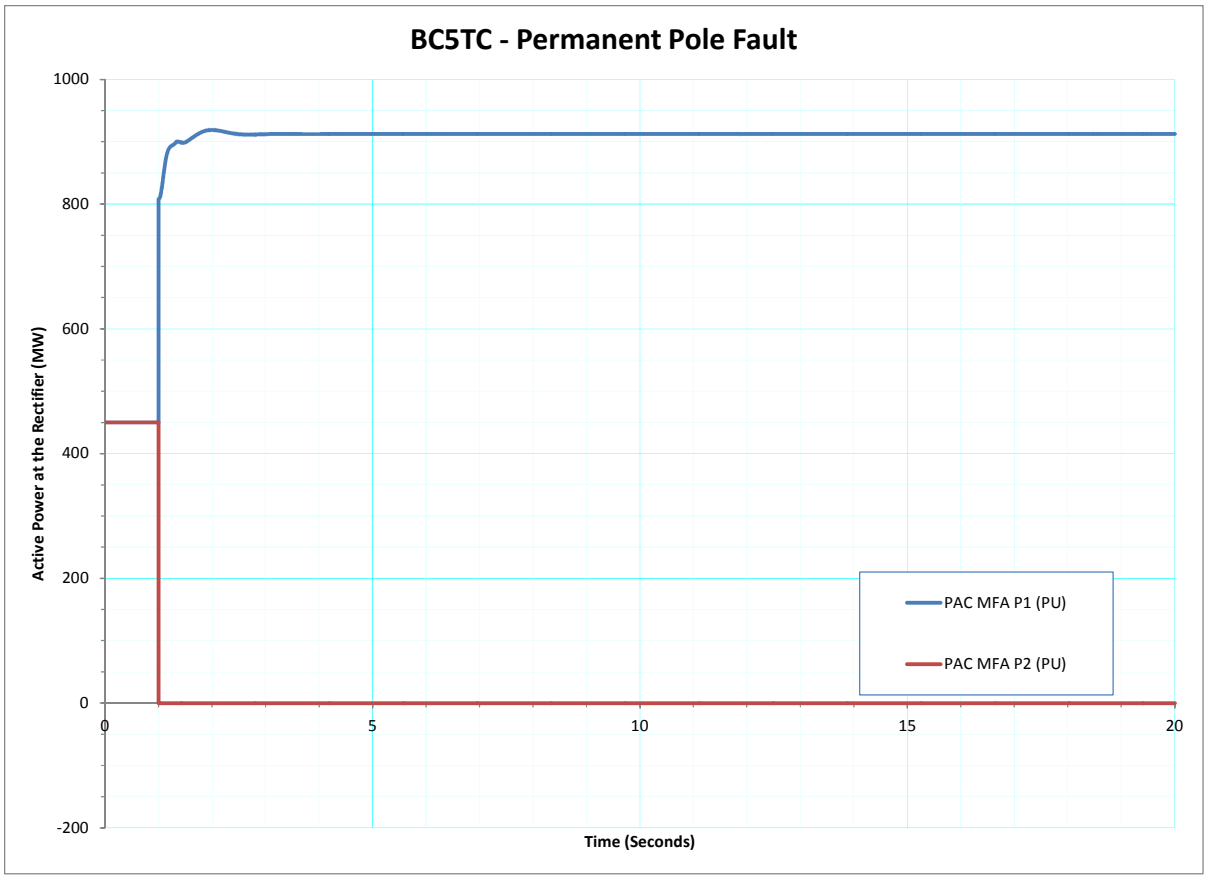


Figure 129 - BC5TC - Permanent Pole Fault - Active Power at the Rectifier (MW)

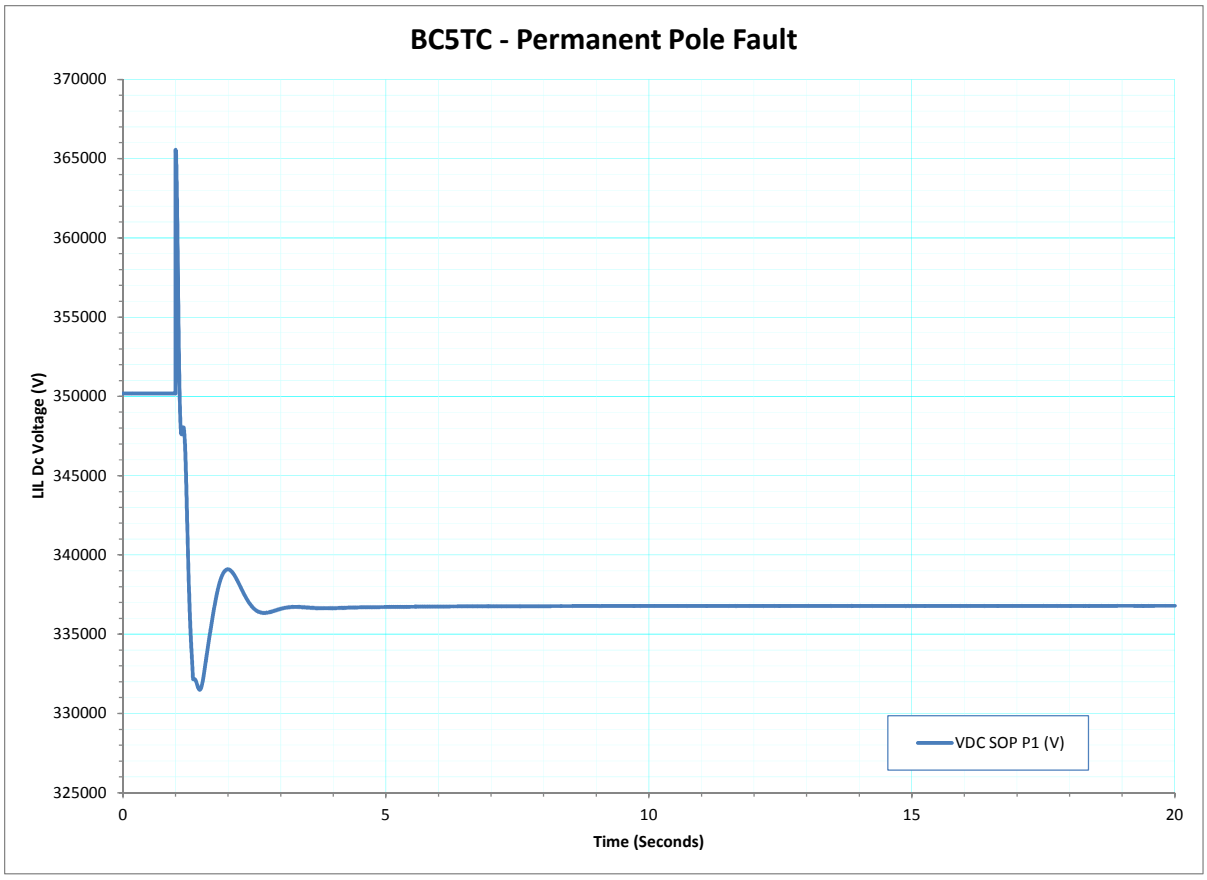


Figure 130 - BC5TC - Permanent Pole Fault - LIL Dc Voltage (V)

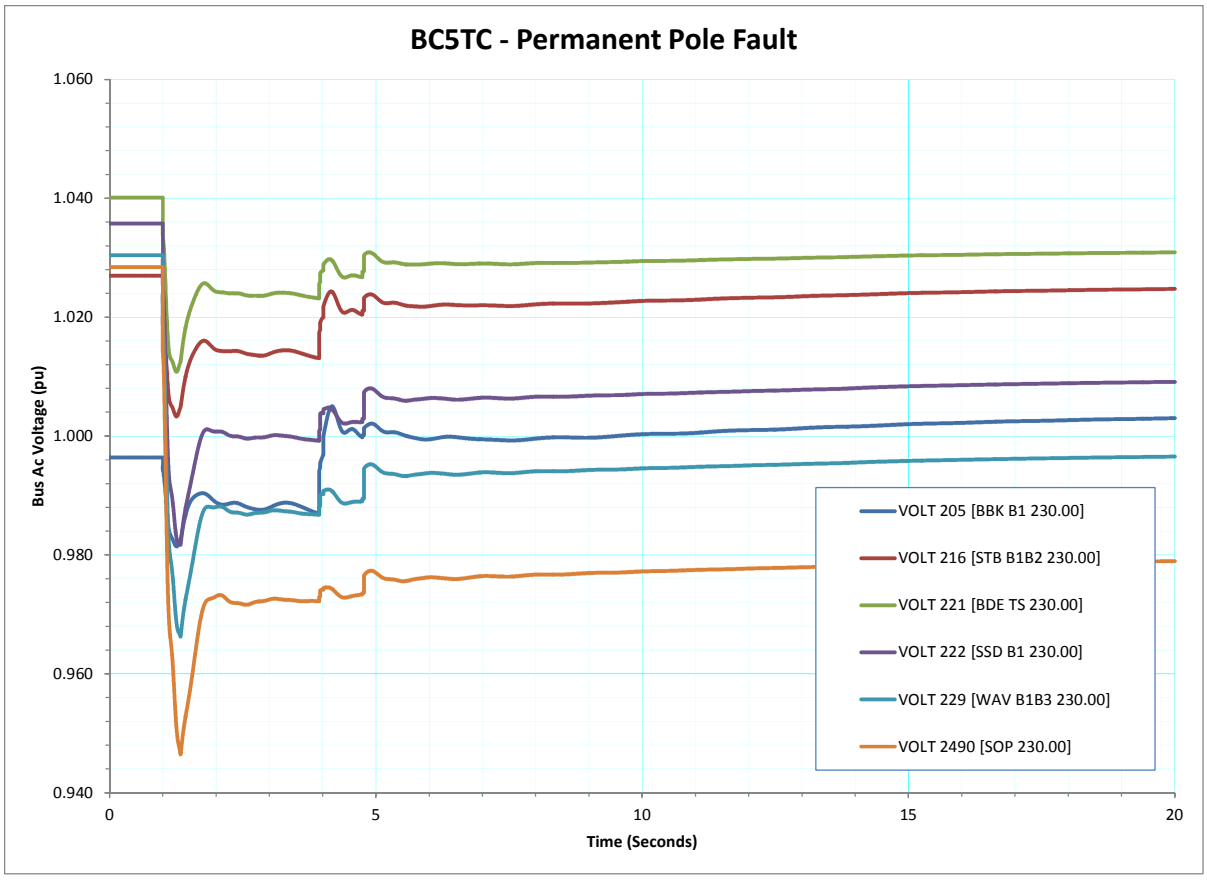


Figure 131 - BC5TC - Permanent Pole Fault - Bus Ac Voltage (pu)

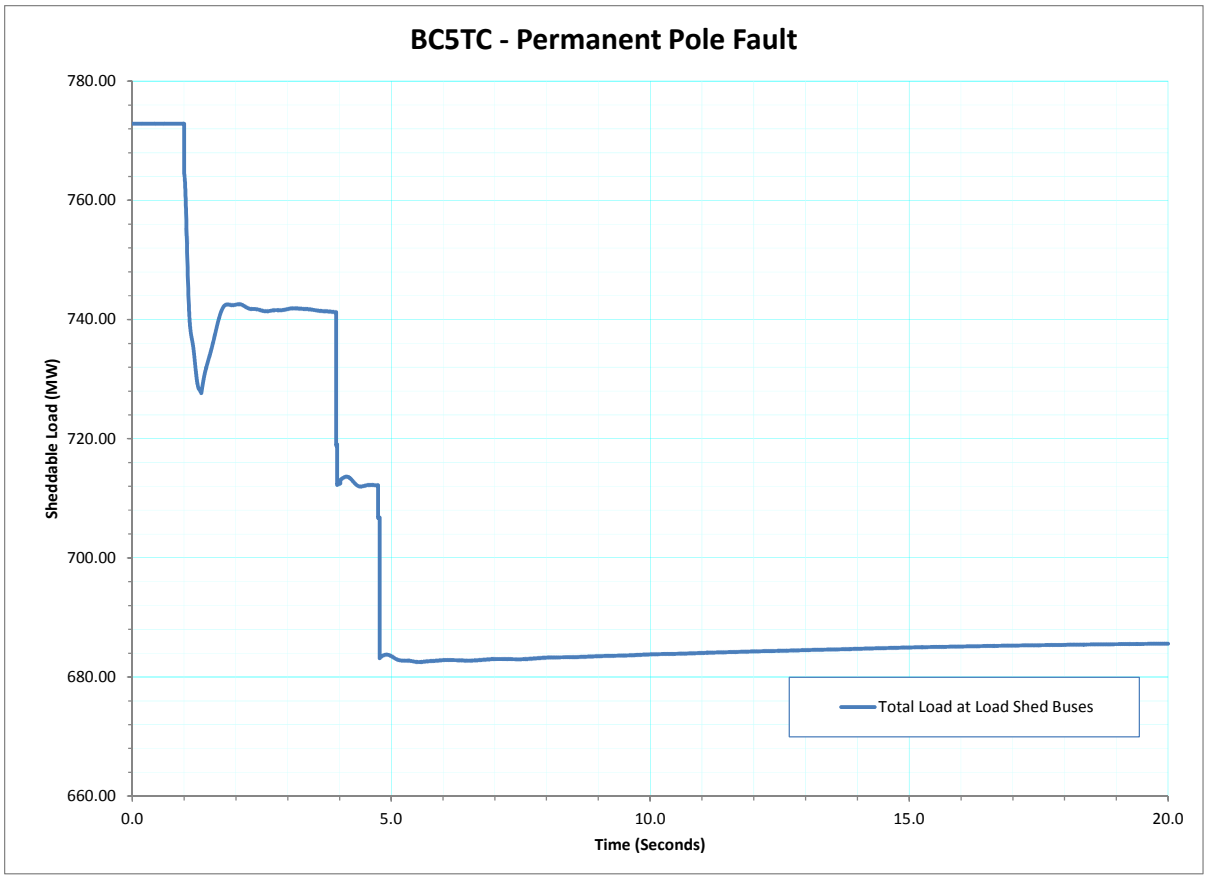


Figure 132 - BC5TC - Permanent Pole Fault - Sheddable Load (MW)

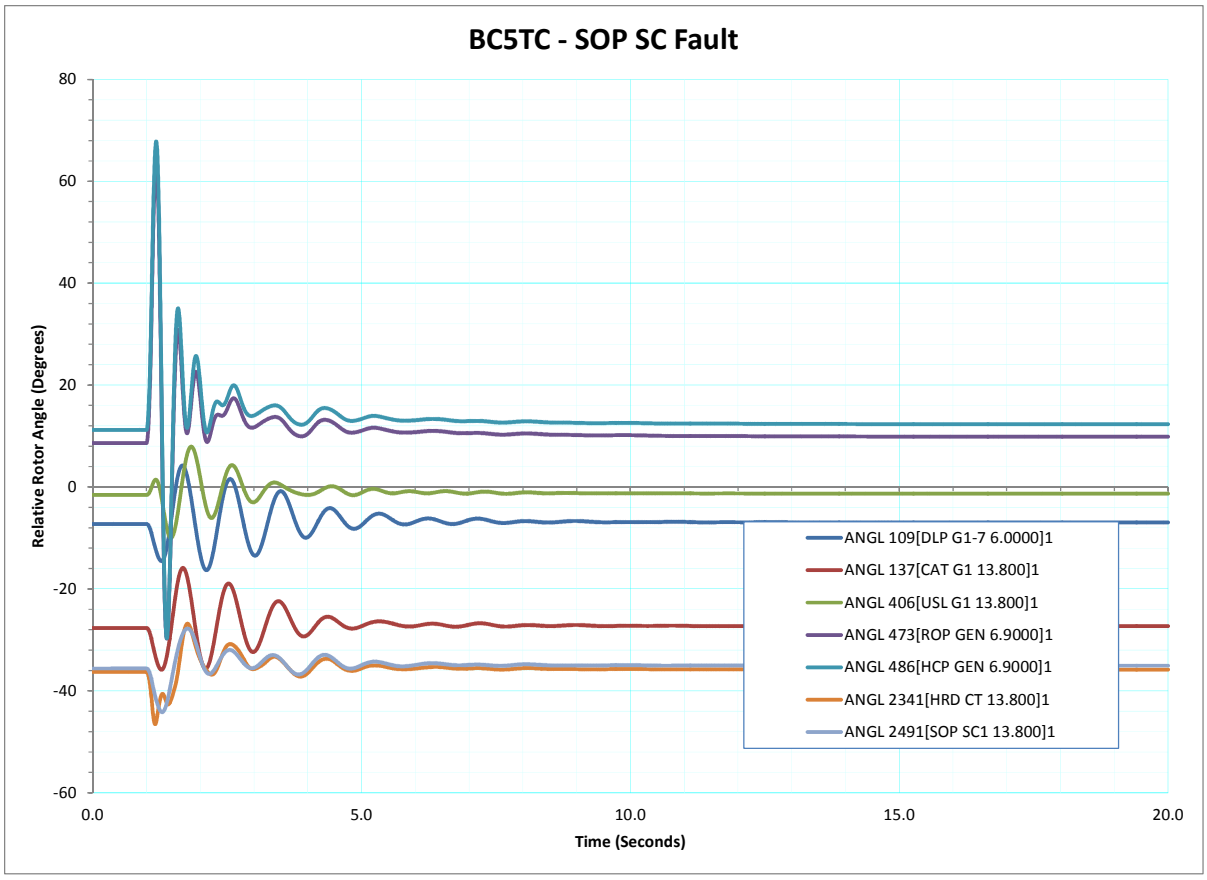


Figure 133 - BC5TC - SOP SC Fault - Relative Rotor Angle (Degrees)

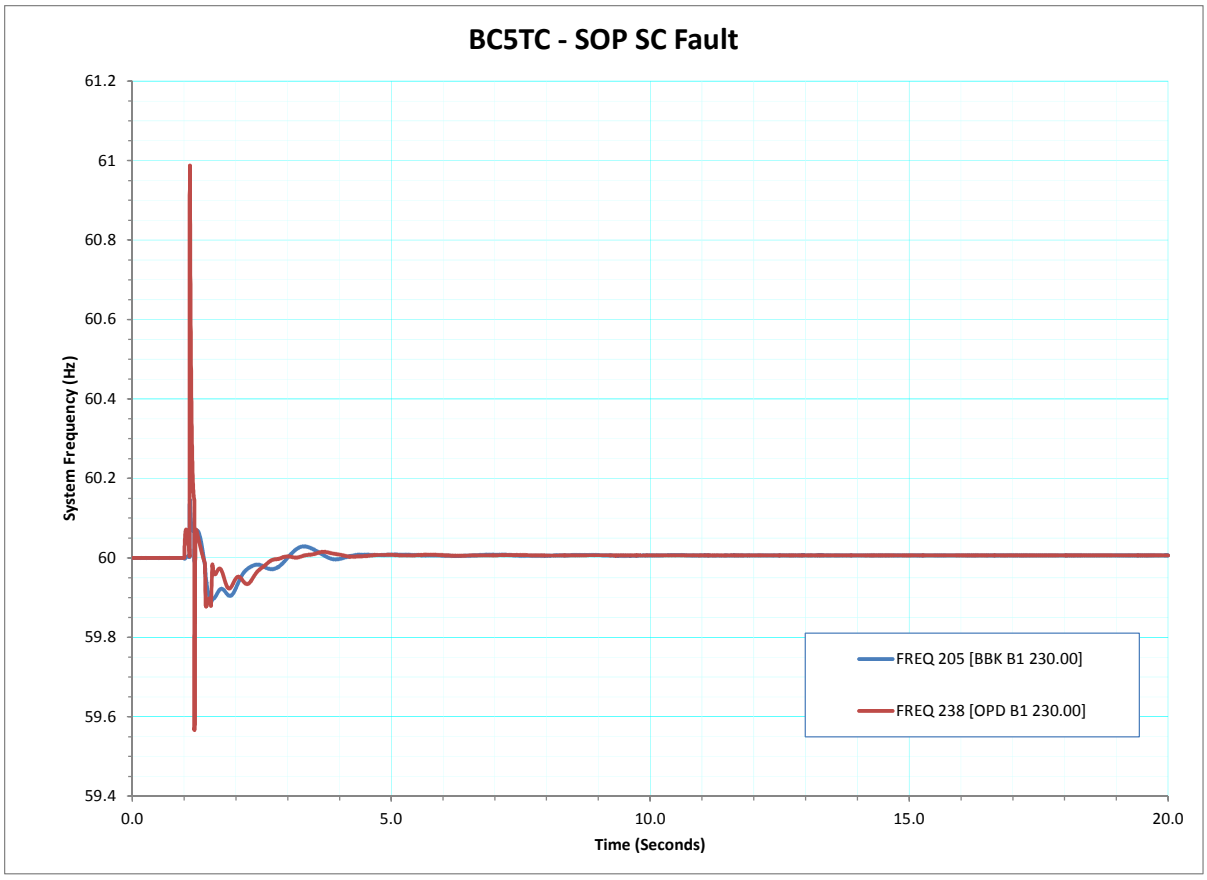


Figure 134 - BC5TC - SOP SC Fault - System Frequency (Hz)

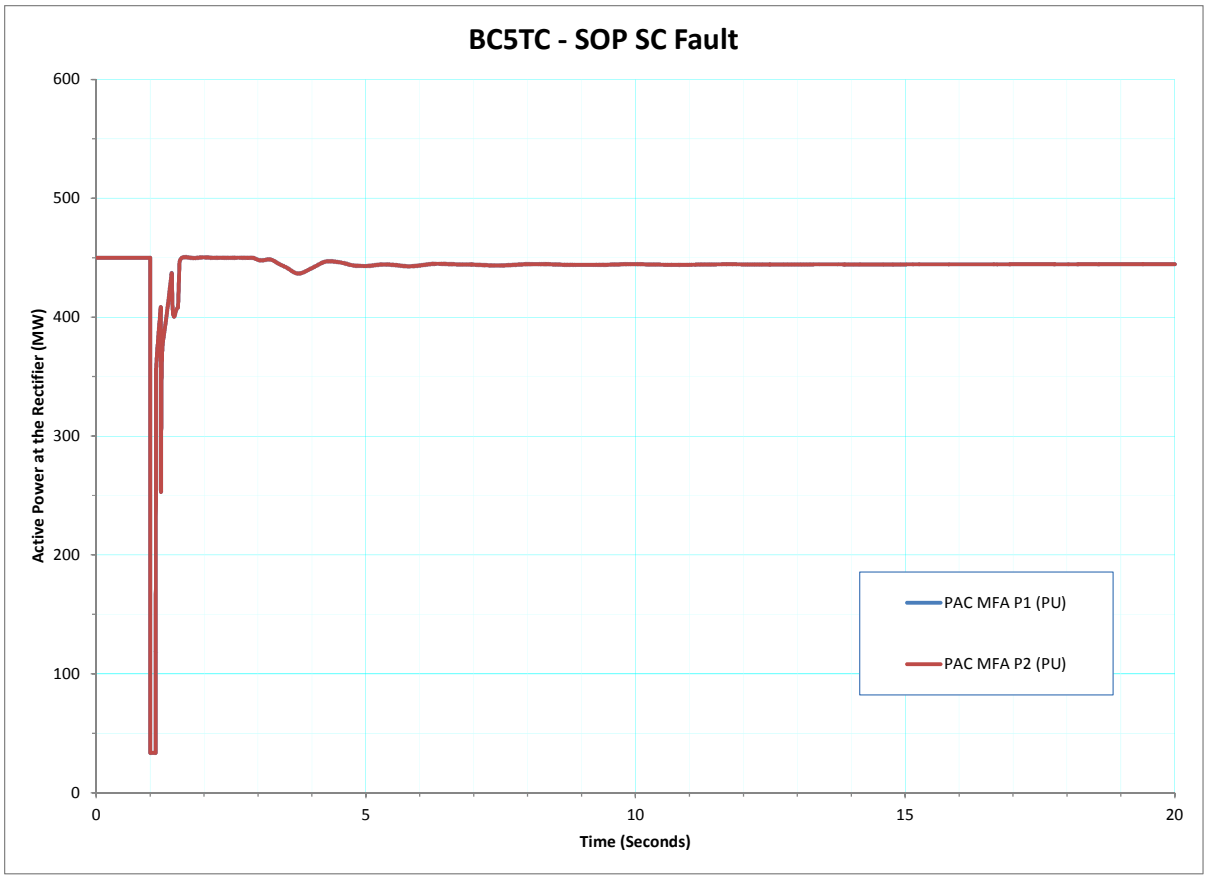


Figure 135 - BC5TC - SOP SC Fault - Active Power at the Rectifier (MW)

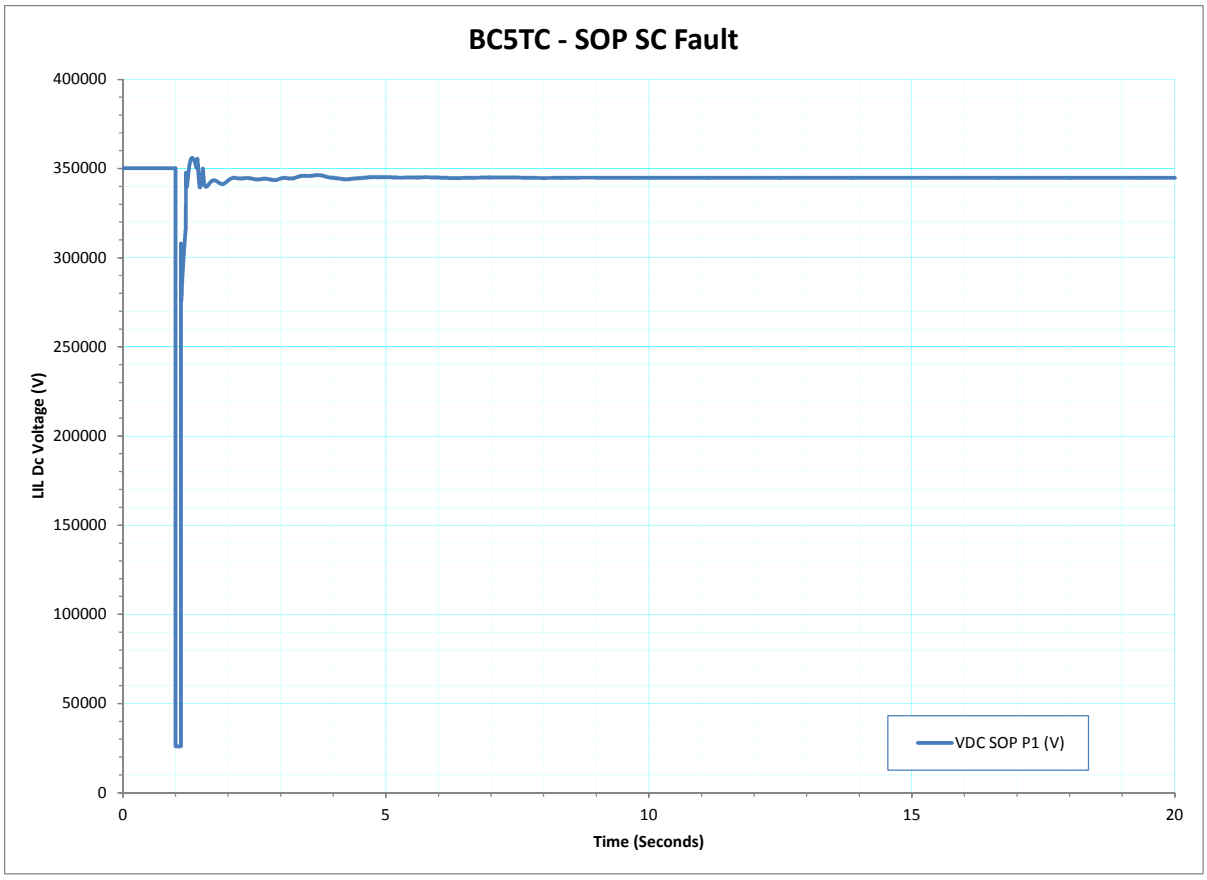


Figure 136 - BC5TC - SOP SC Fault - LIL Dc Voltage (V)

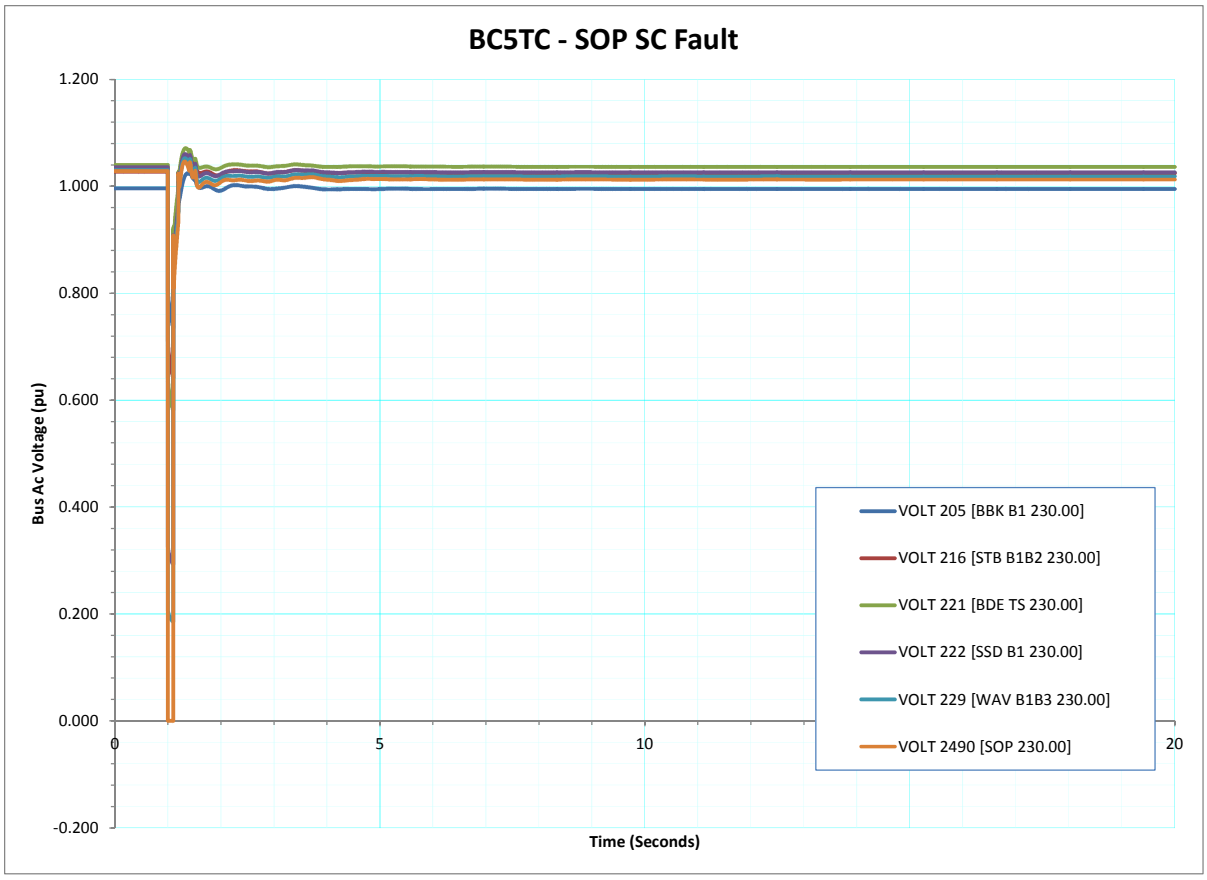


Figure 137 - BC5TC - SOP SC Fault - Bus Ac Voltage (pu)

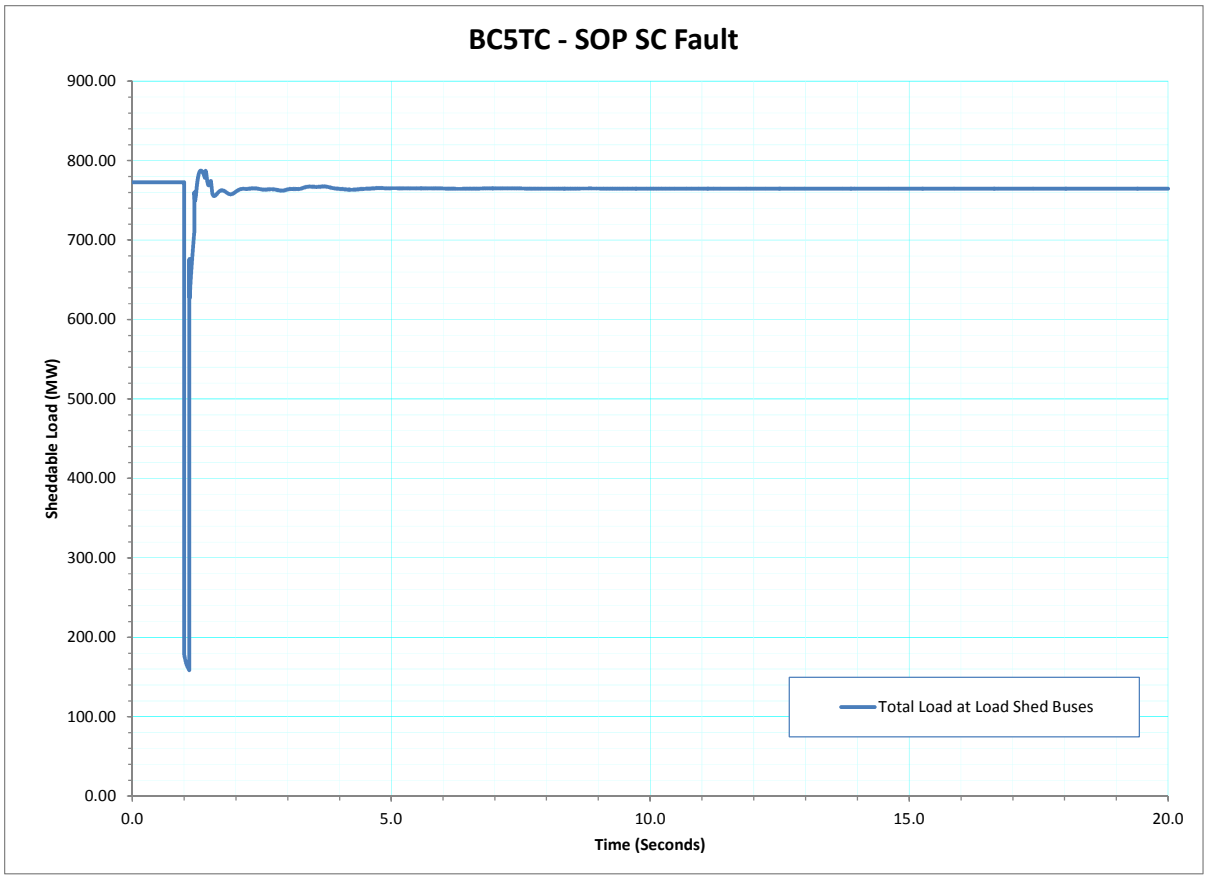


Figure 138 - BC5TC - SOP SC Fault - Sheddable Load (MW)

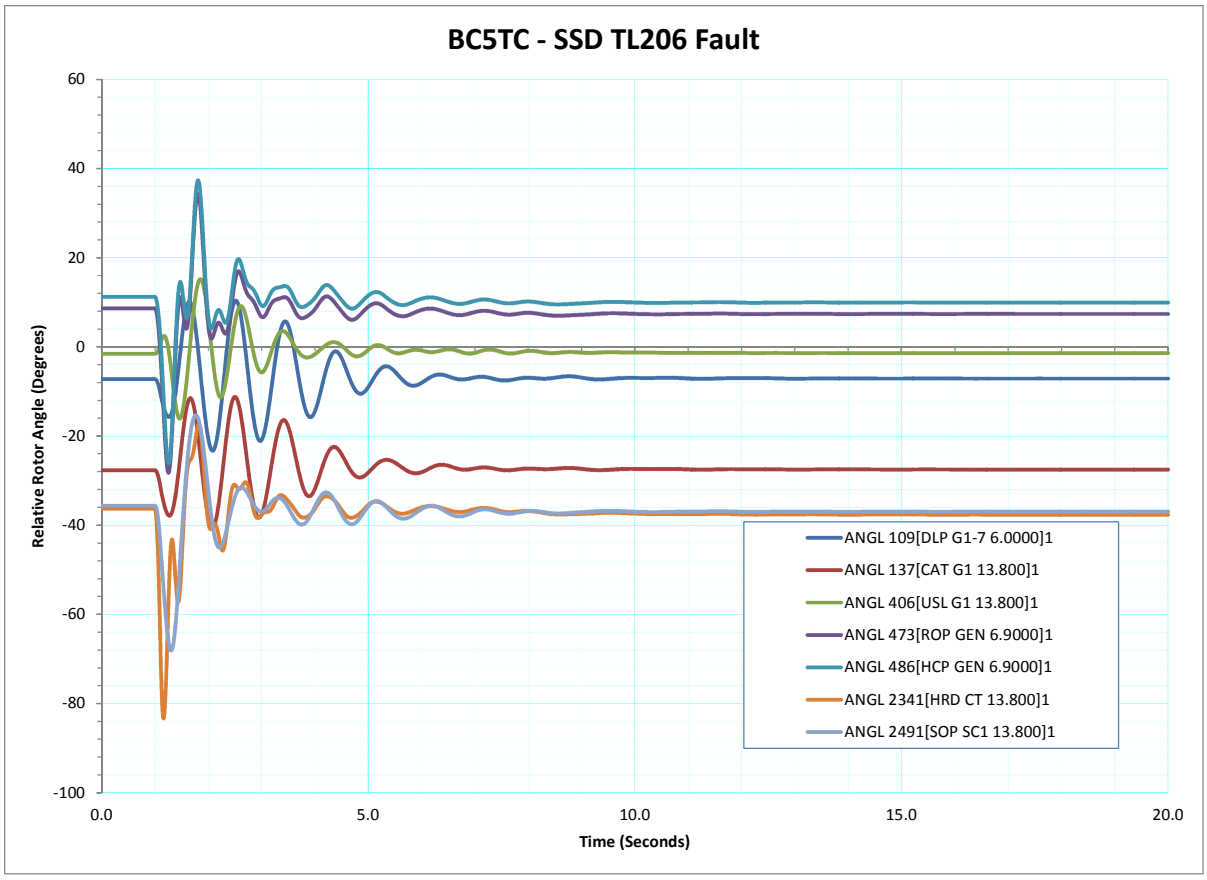


Figure 139 - BC5TC - SSD TL206 Fault - Relative Rotor Angle (Degrees)

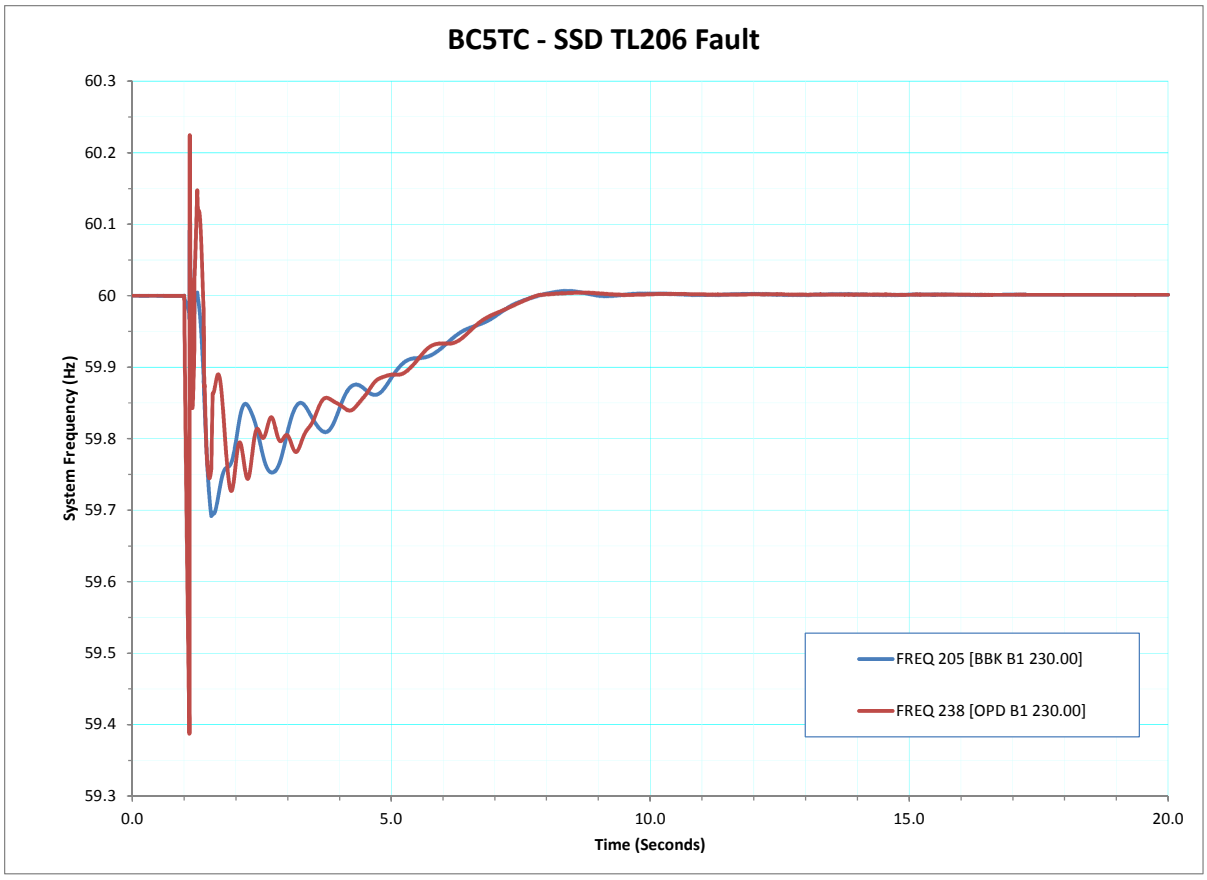


Figure 140 - BC5TC - SSD TL206 Fault - System Frequency (Hz)

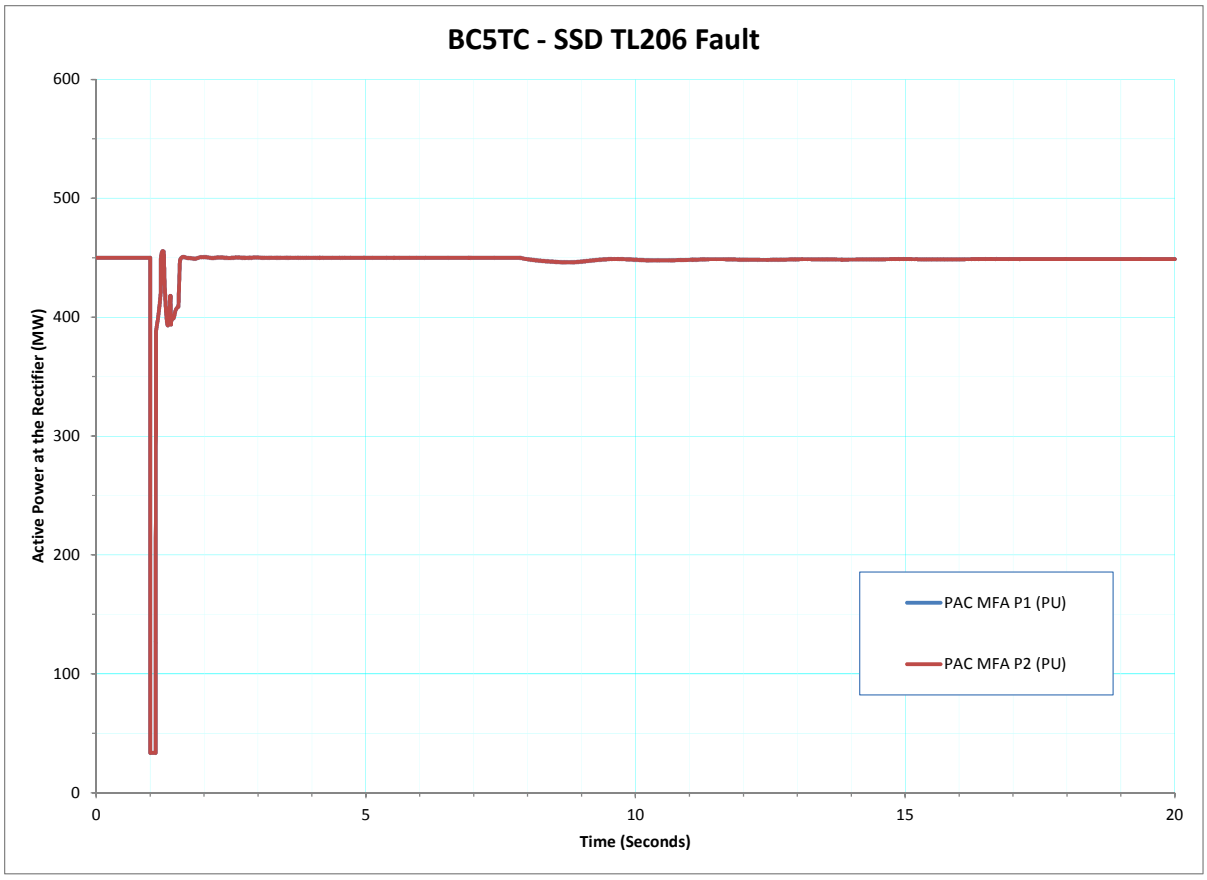


Figure 141 - BC5TC - SSD TL206 Fault - Active Power at the Rectifier (MW)

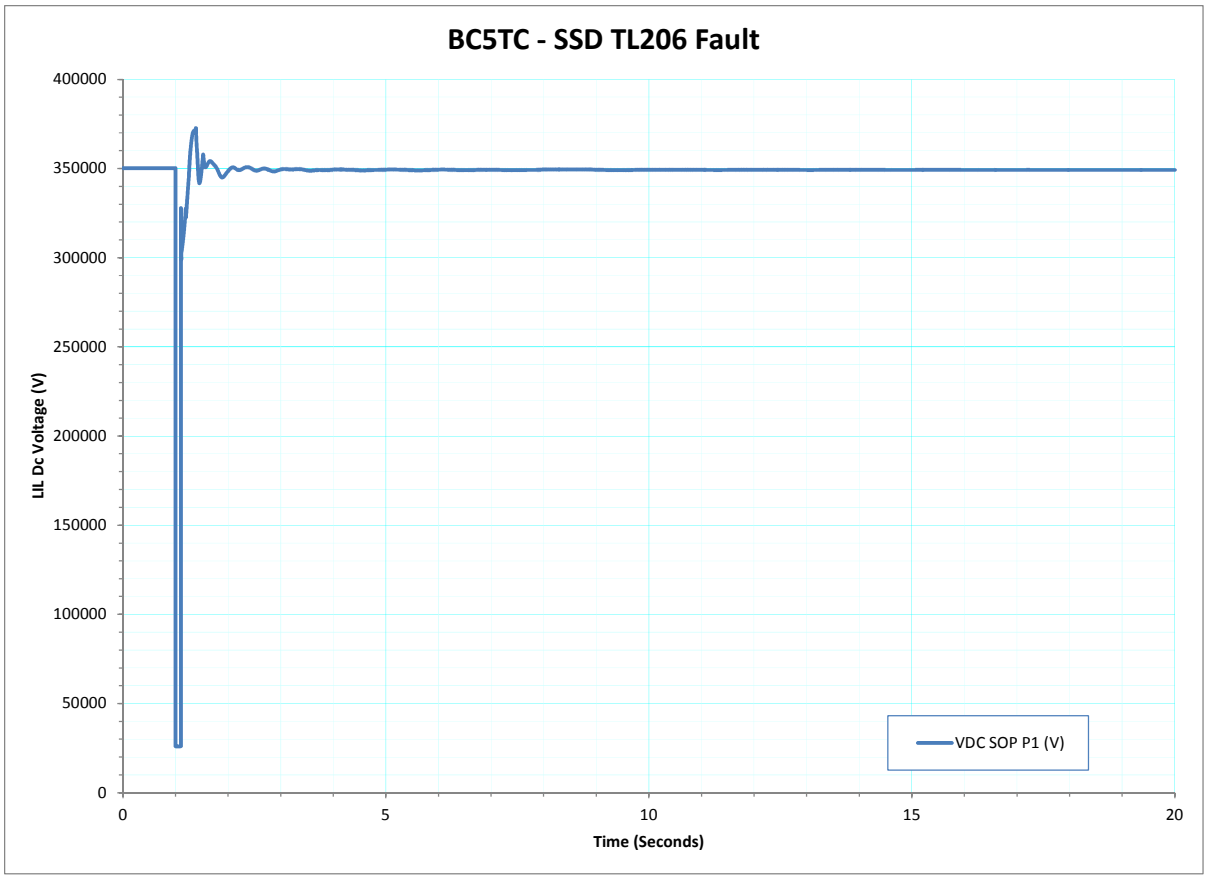


Figure 142 - BC5TC - SSD TL206 Fault - LIL Dc Voltage (V)

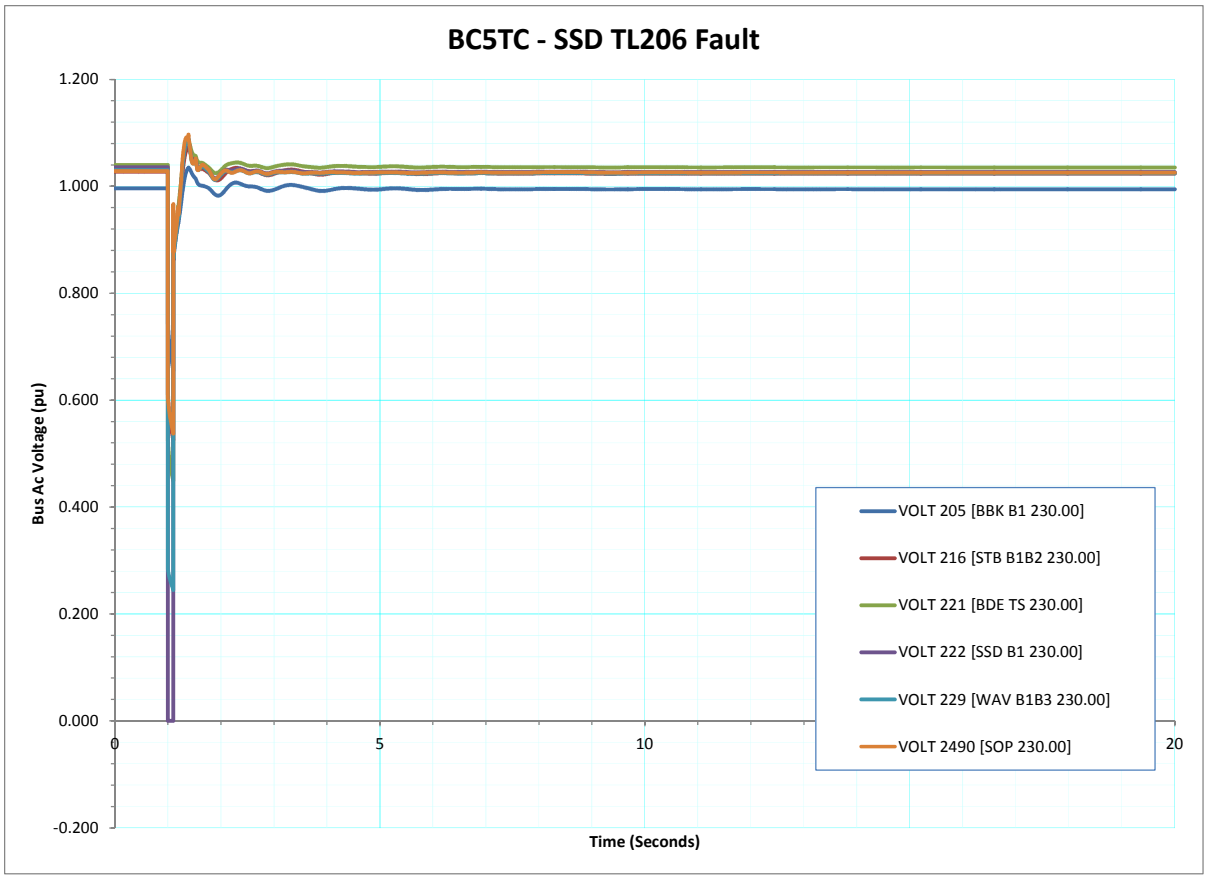


Figure 143 - BC5TC - SSD TL206 Fault - Bus Ac Voltage (pu)

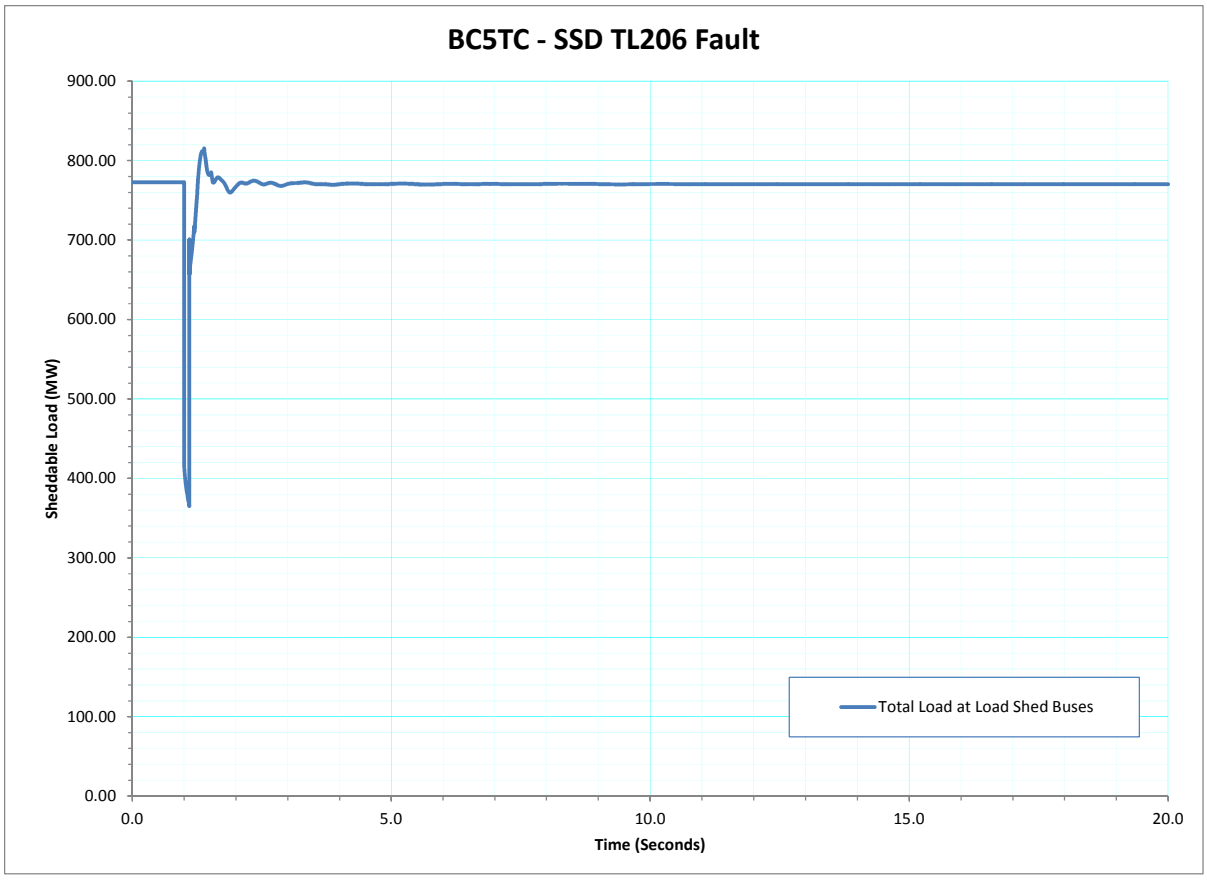


Figure 144 - BC5TC - SSD TL206 Fault - Sheddable Load (MW)

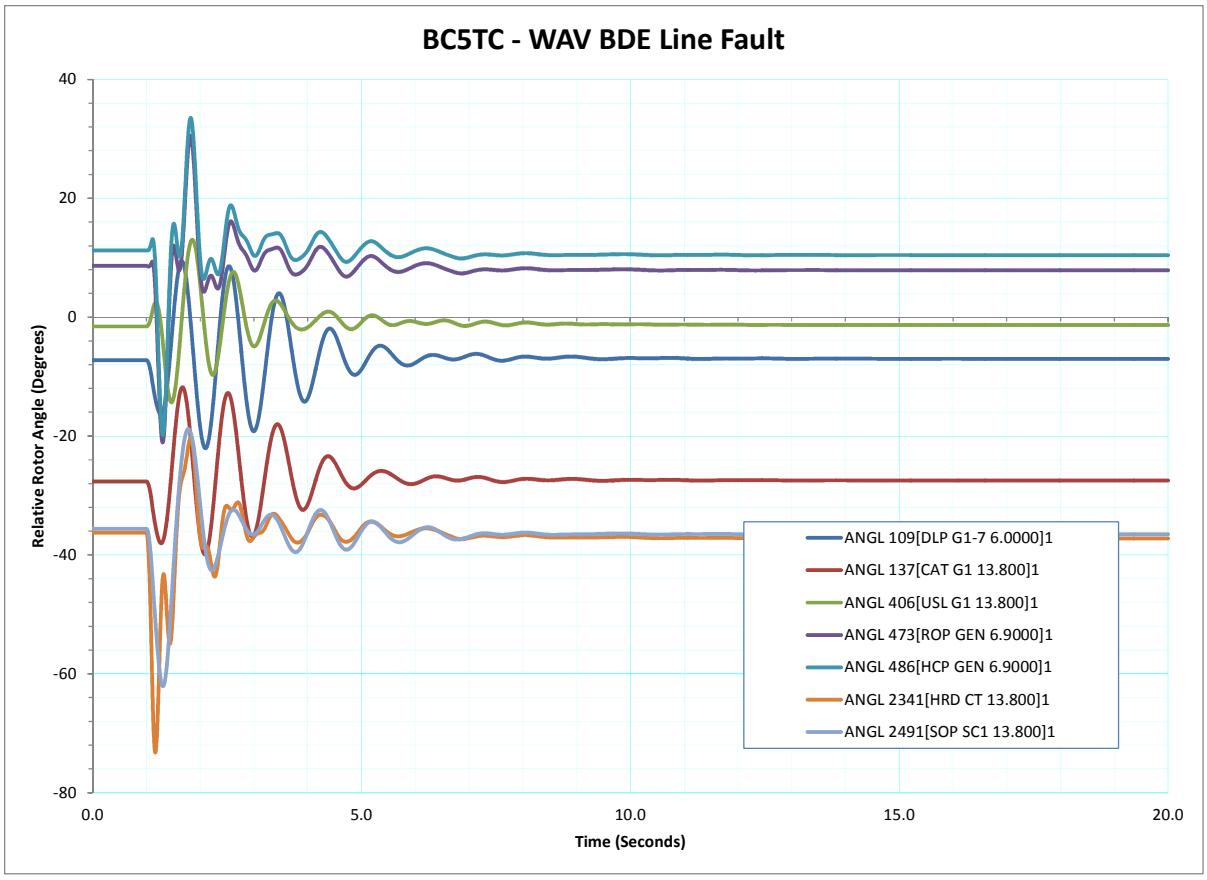


Figure 145 - BC5TC - WAV BDE Line Fault - Relative Rotor Angle (Degrees)

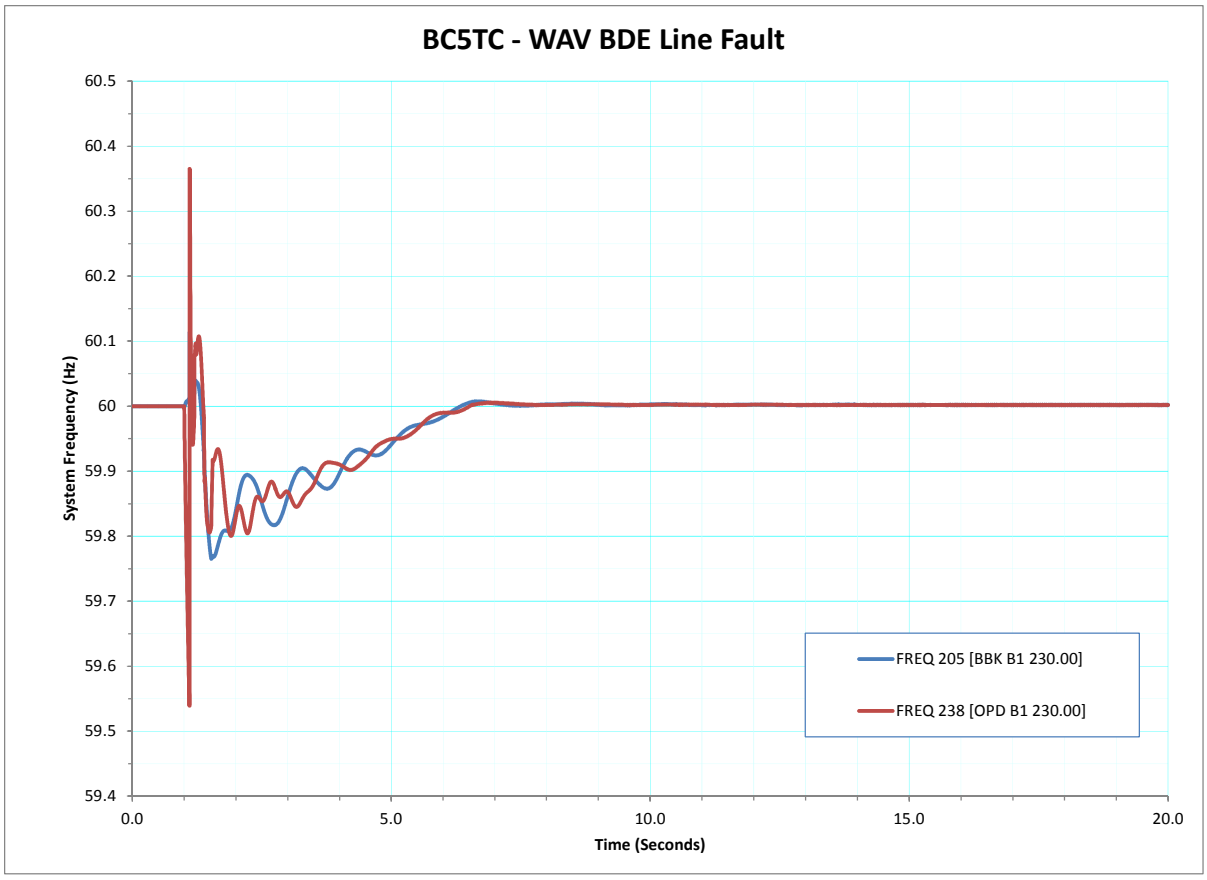


Figure 146 - BC5TC - WAV BDE Line Fault - System Frequency (Hz)

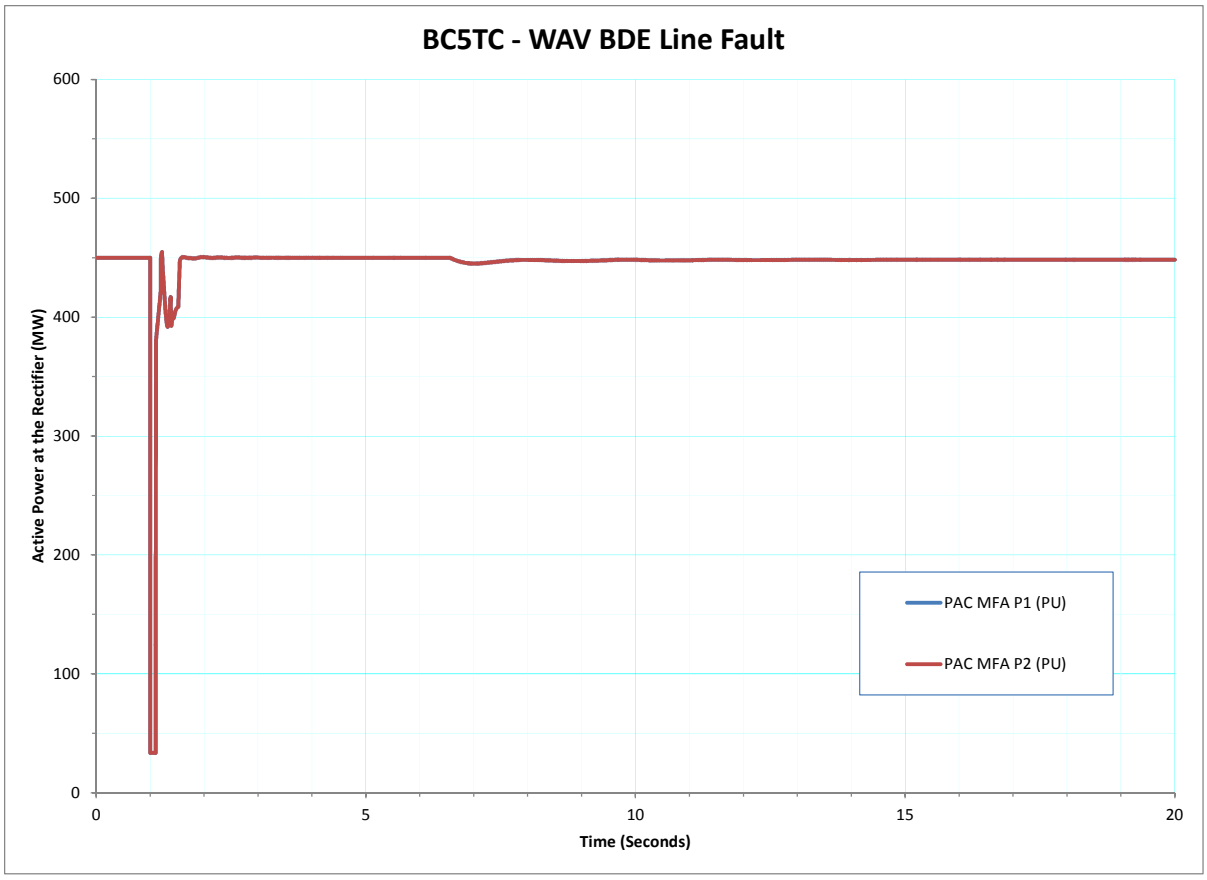


Figure 147 - BC5TC - WAV BDE Line Fault - Active Power at the Rectifier (MW)

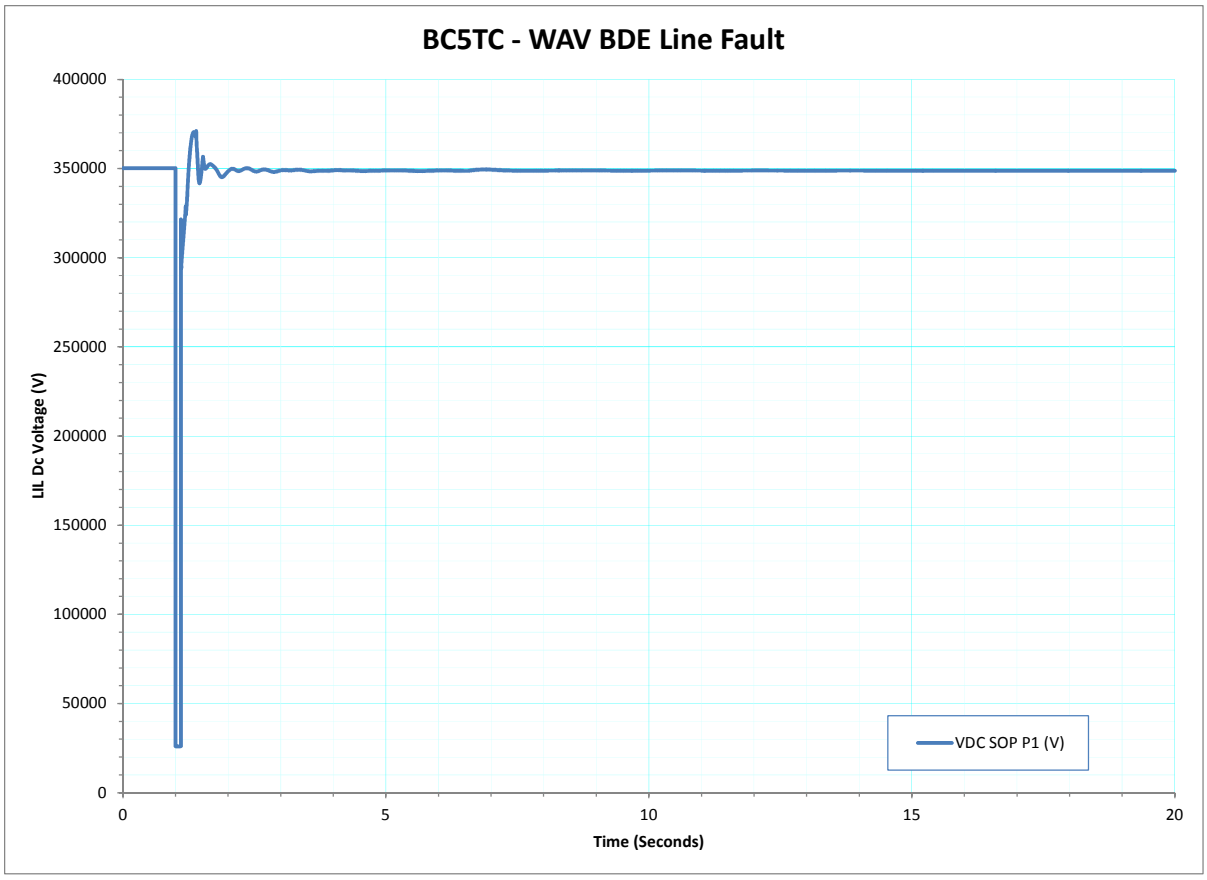


Figure 148 - BC5TC - WAV BDE Line Fault - LIL Dc Voltage (V)

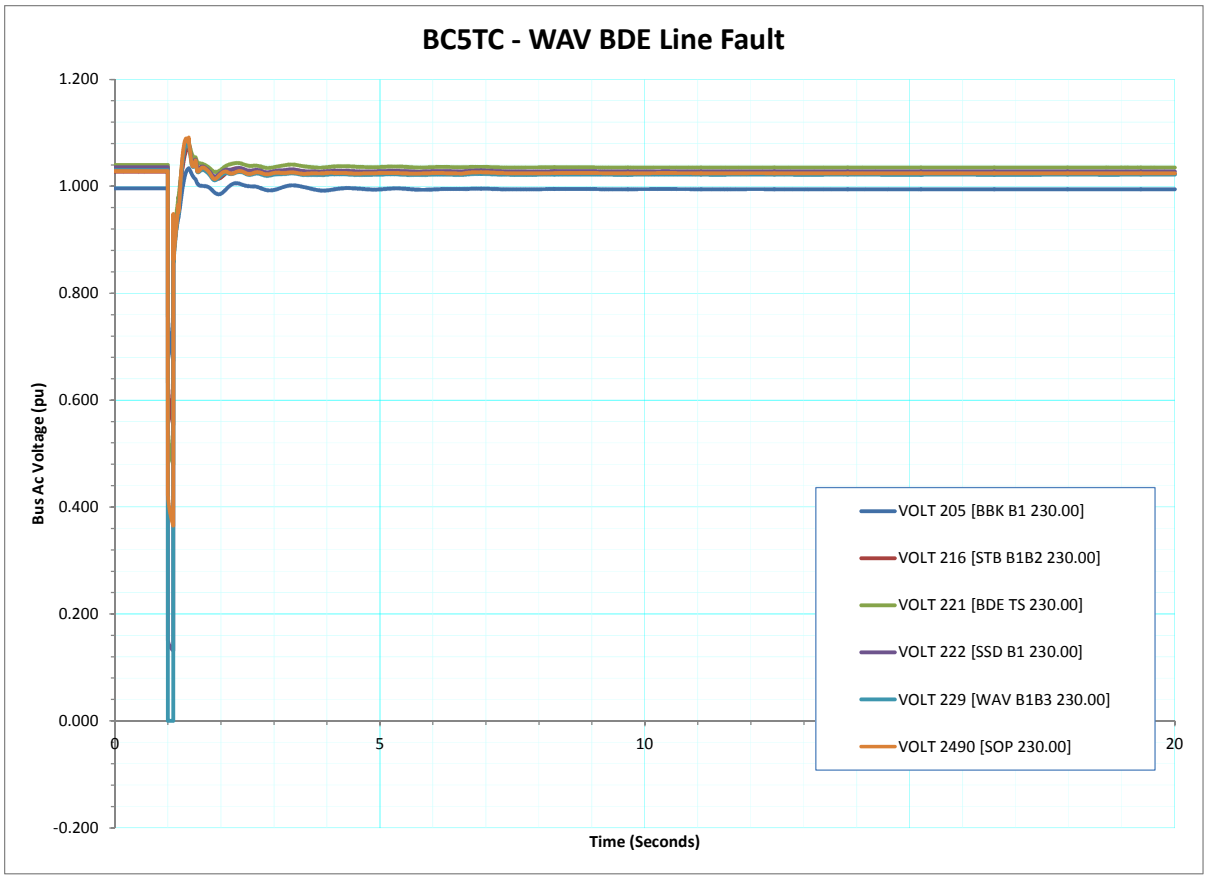


Figure 149 - BC5TC - WAV BDE Line Fault - Bus Ac Voltage (pu)

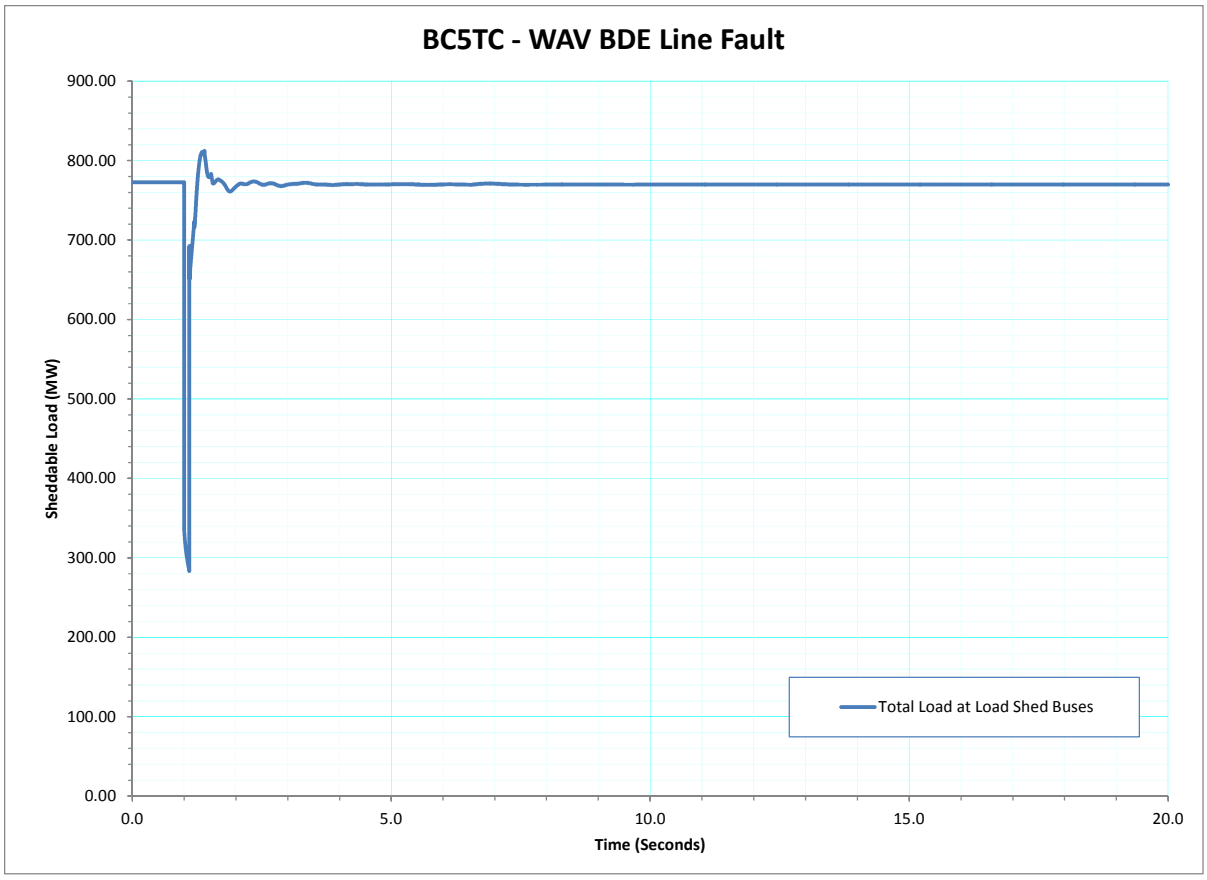


Figure 150 - BC5TC - WAV BDE Line Fault - Sheddable Load (MW)

1.6. BASE CASE 6 TRANSIENT STABILITY PLOTS

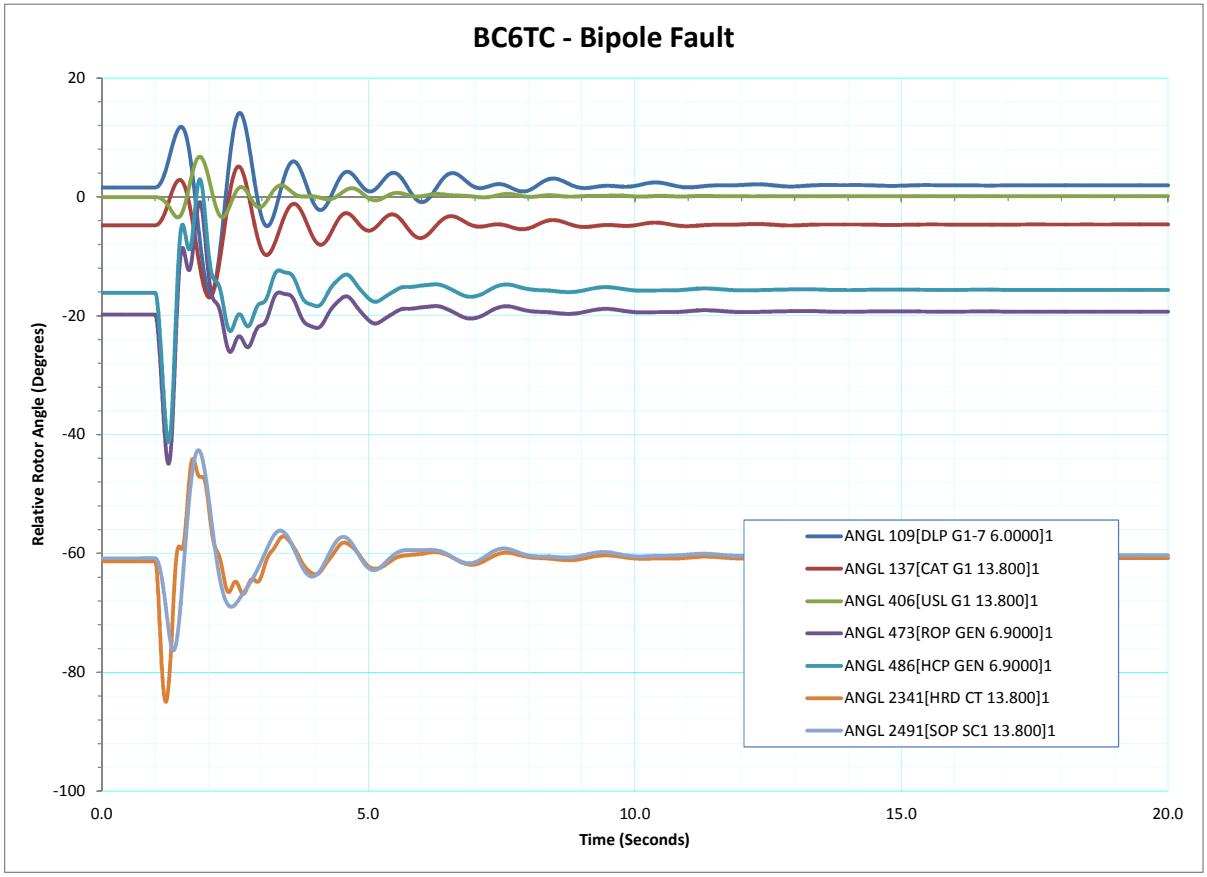


Figure 151 - BC6TC - Bipole Fault - Relative Rotor Angle (Degrees)

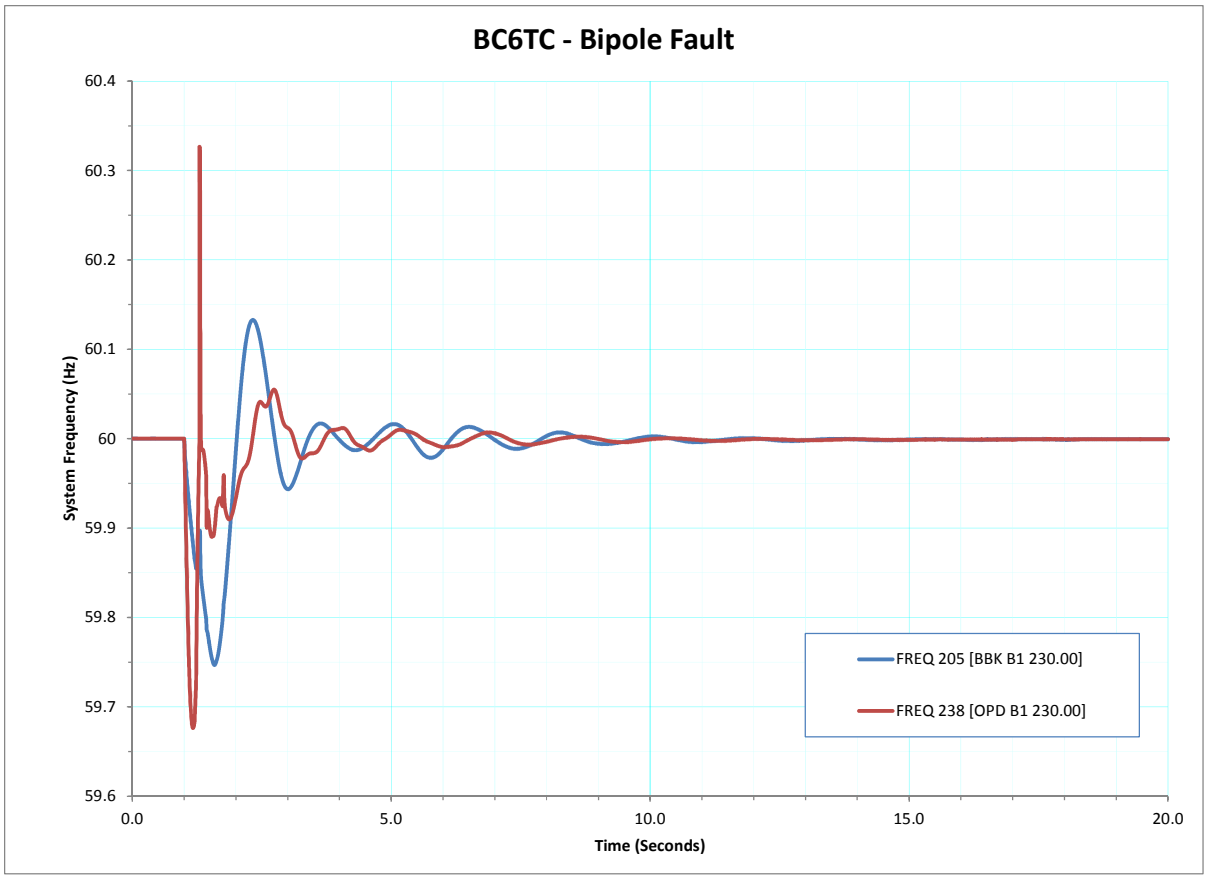


Figure 152 - BC6TC - Bipole Fault - System Frequency (Hz)

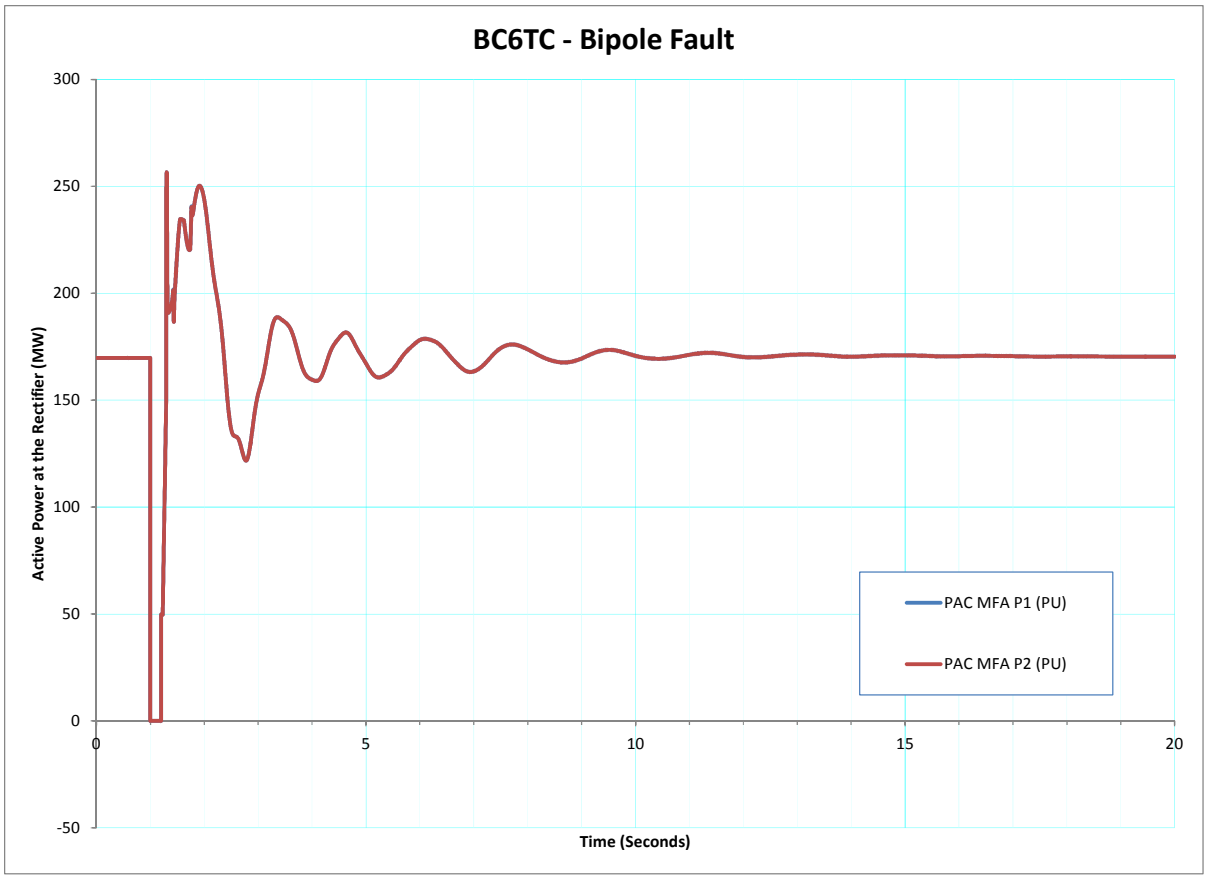


Figure 153 - BC6TC - Bipole Fault - Active Power at the Rectifier (MW)

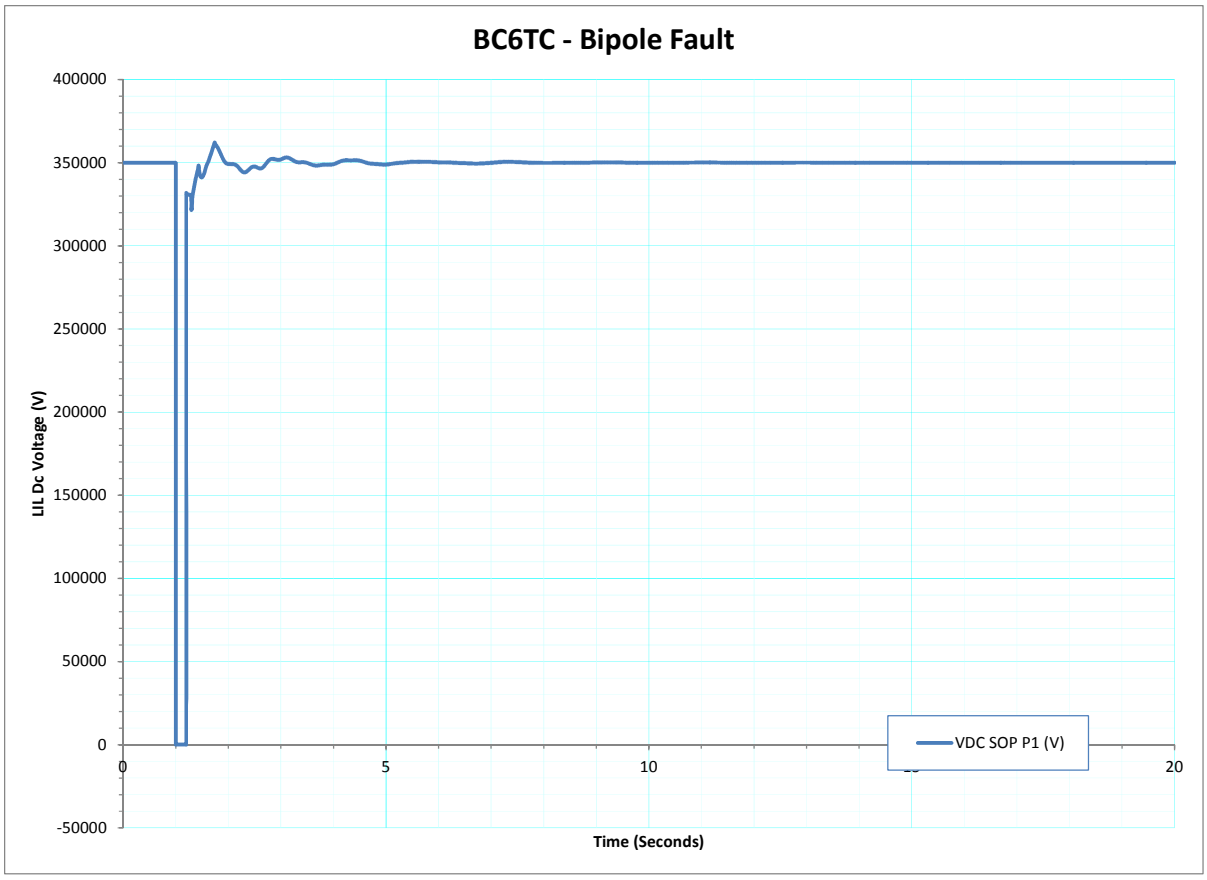


Figure 154 - BC6TC - Bipole Fault - LIL Dc Voltage (V)

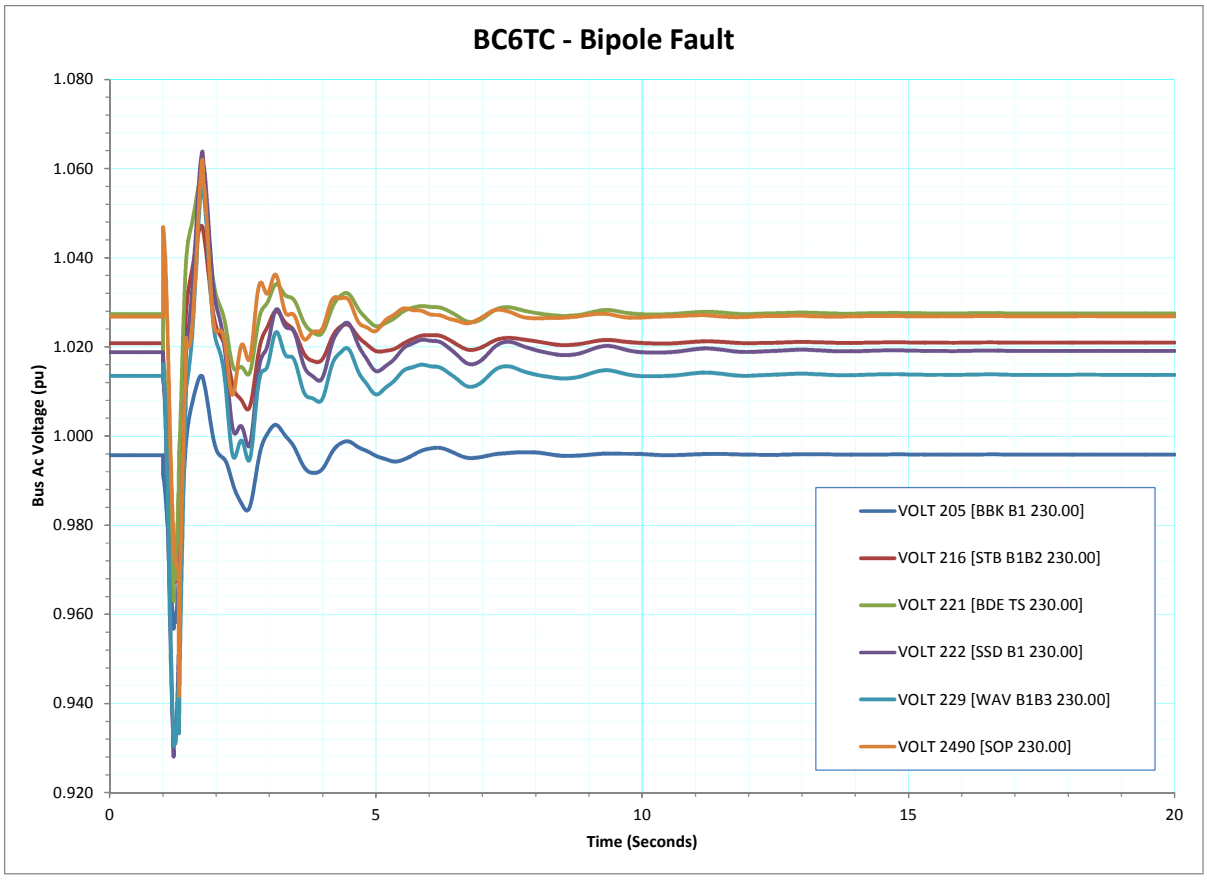


Figure 155 - BC6TC - Bipole Fault - Bus Ac Voltage (pu)

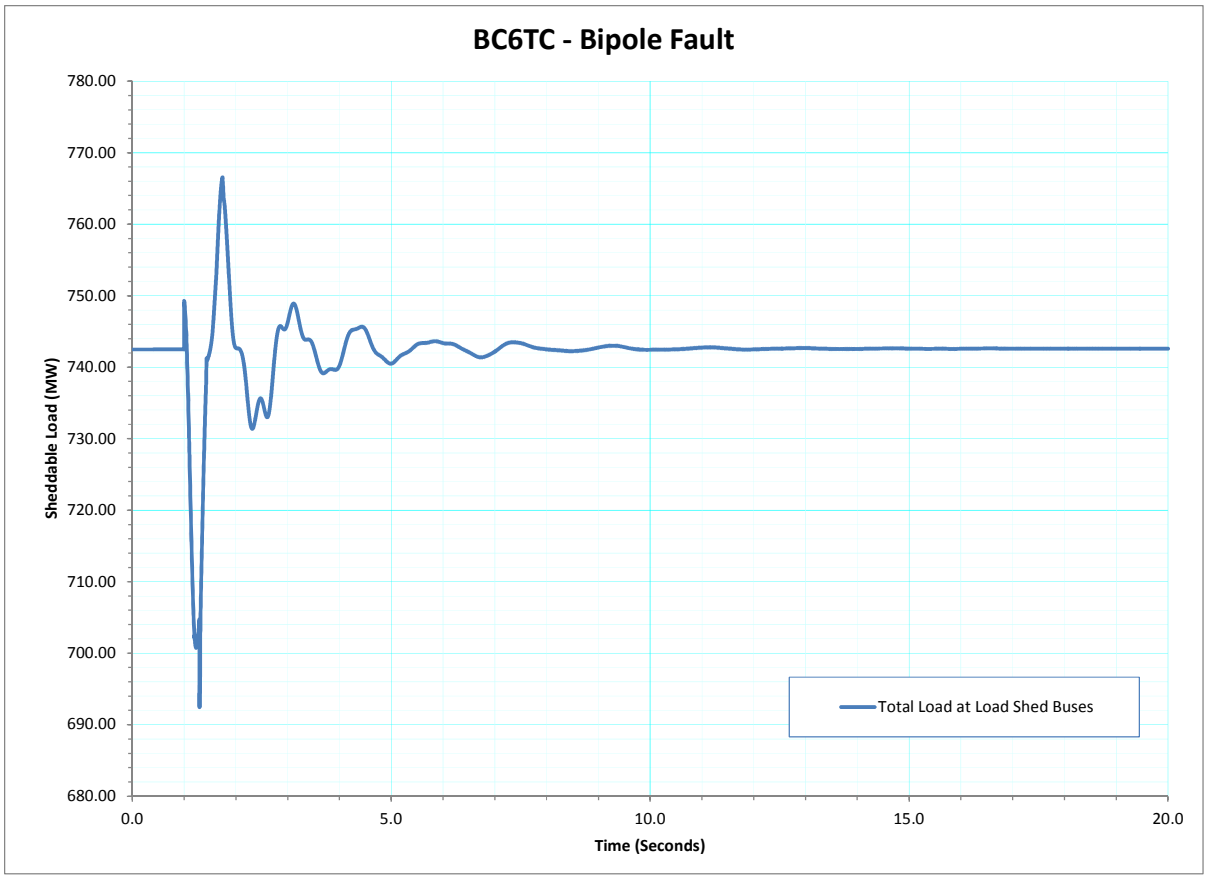


Figure 156 - BC6TC - Bipole Fault - Sheddable Load (MW)

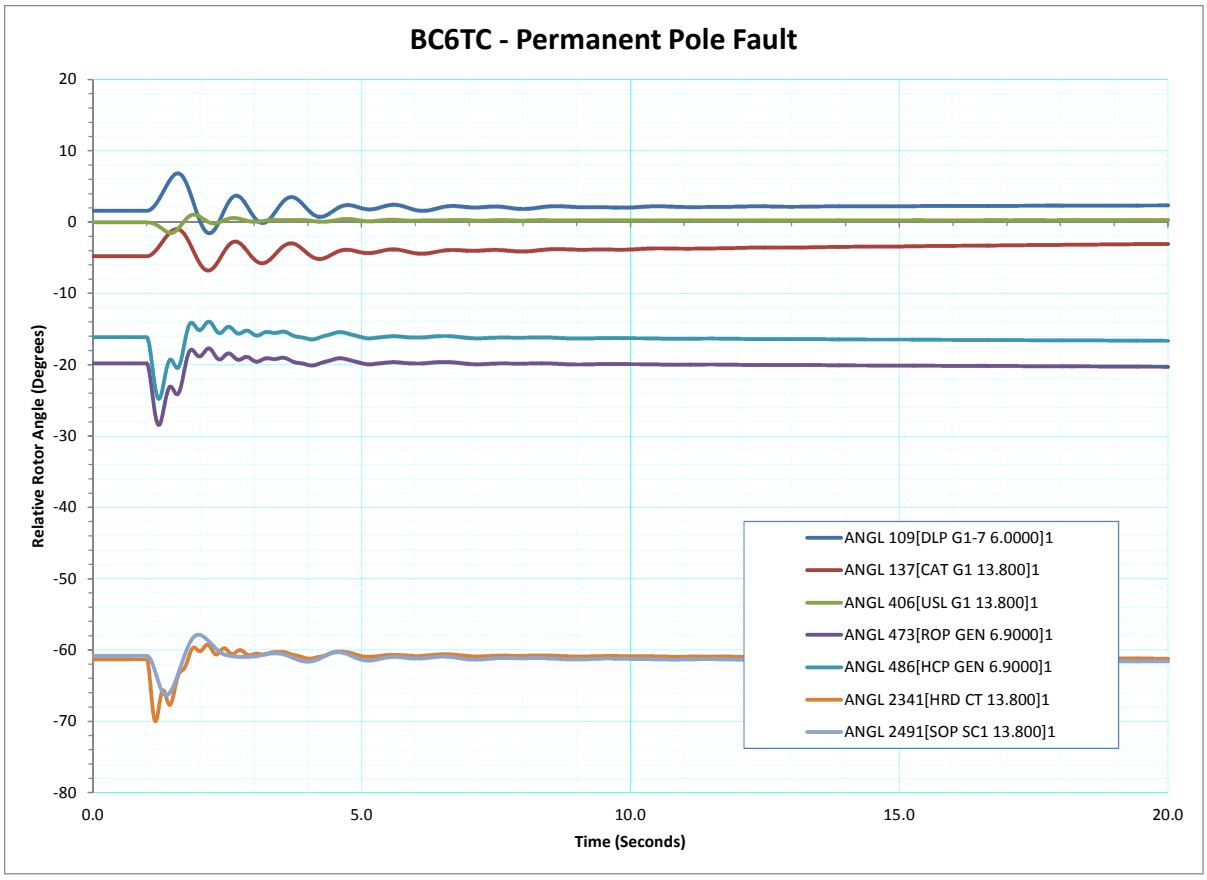


Figure 157 - BC6TC - Permanent Pole Fault - Relative Rotor Angle (Degrees)

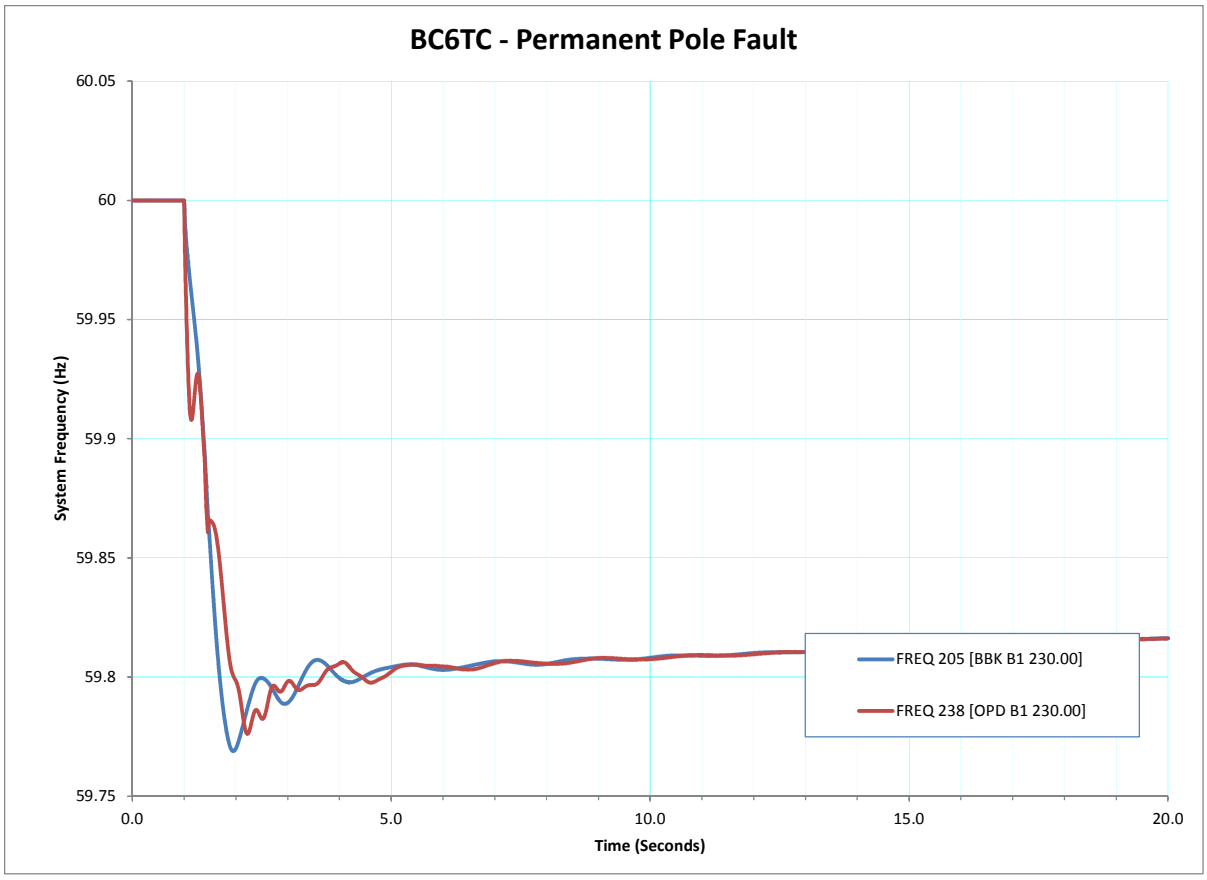


Figure 158 - BC6TC - Permanent Pole Fault - System Frequency (Hz)

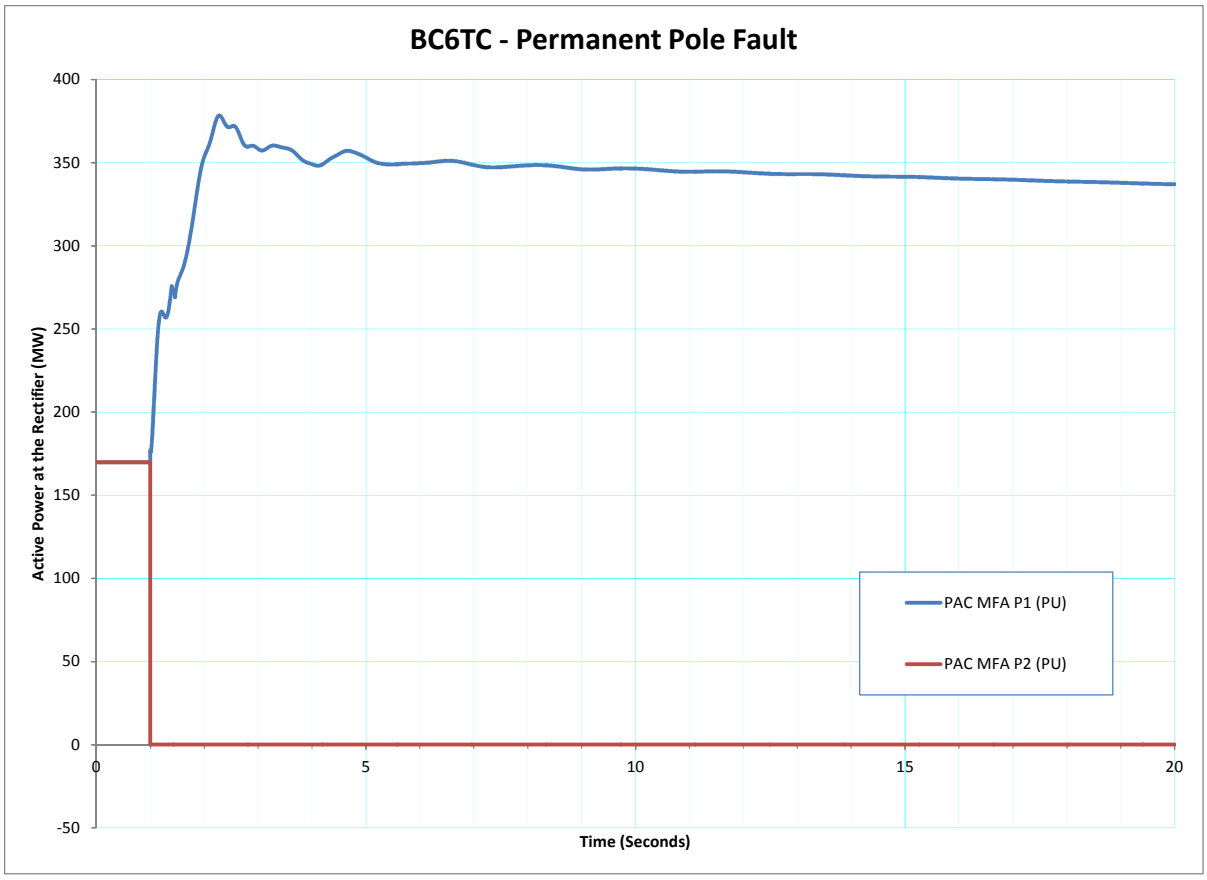


Figure 159 - BC6TC - Permanent Pole Fault - Active Power at the Rectifier (MW)

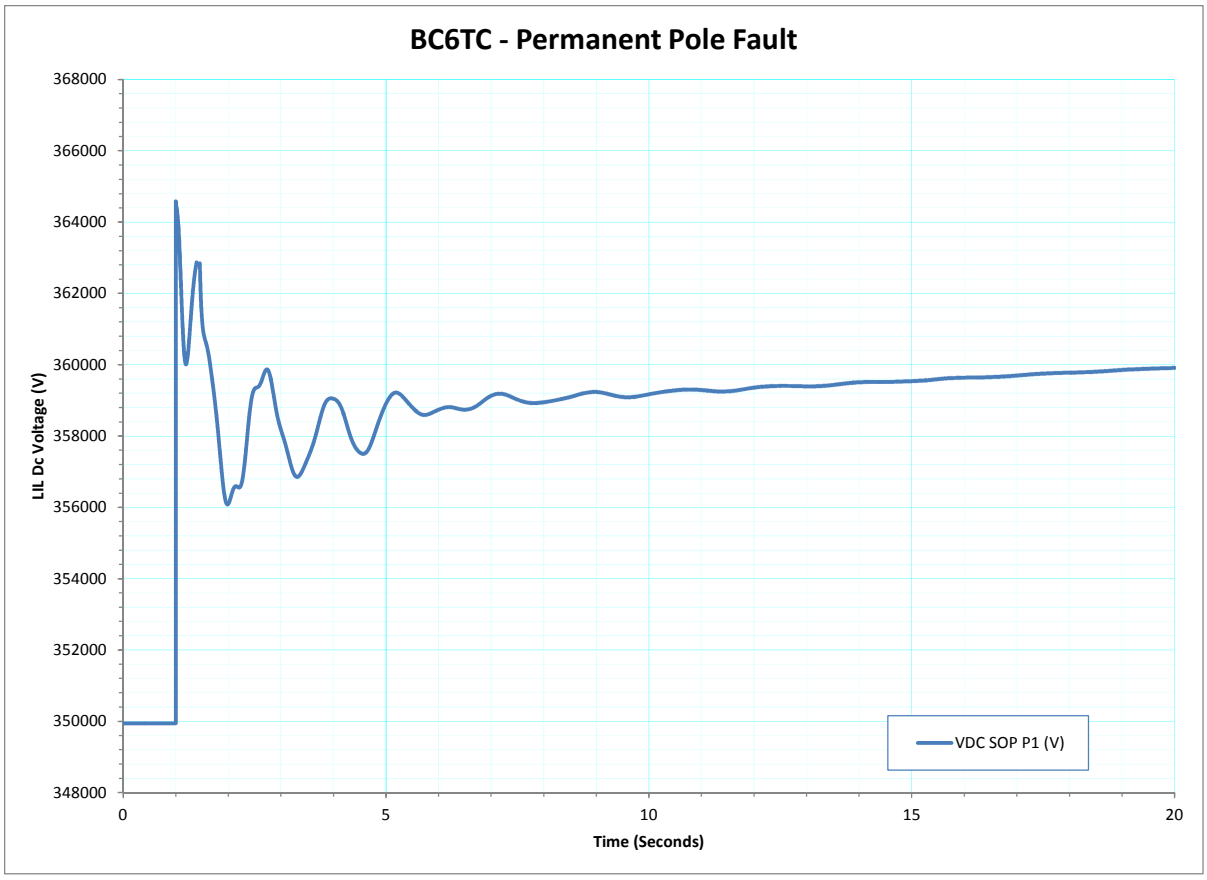


Figure 160 - BC6TC - Permanent Pole Fault - LIL Dc Voltage (V)

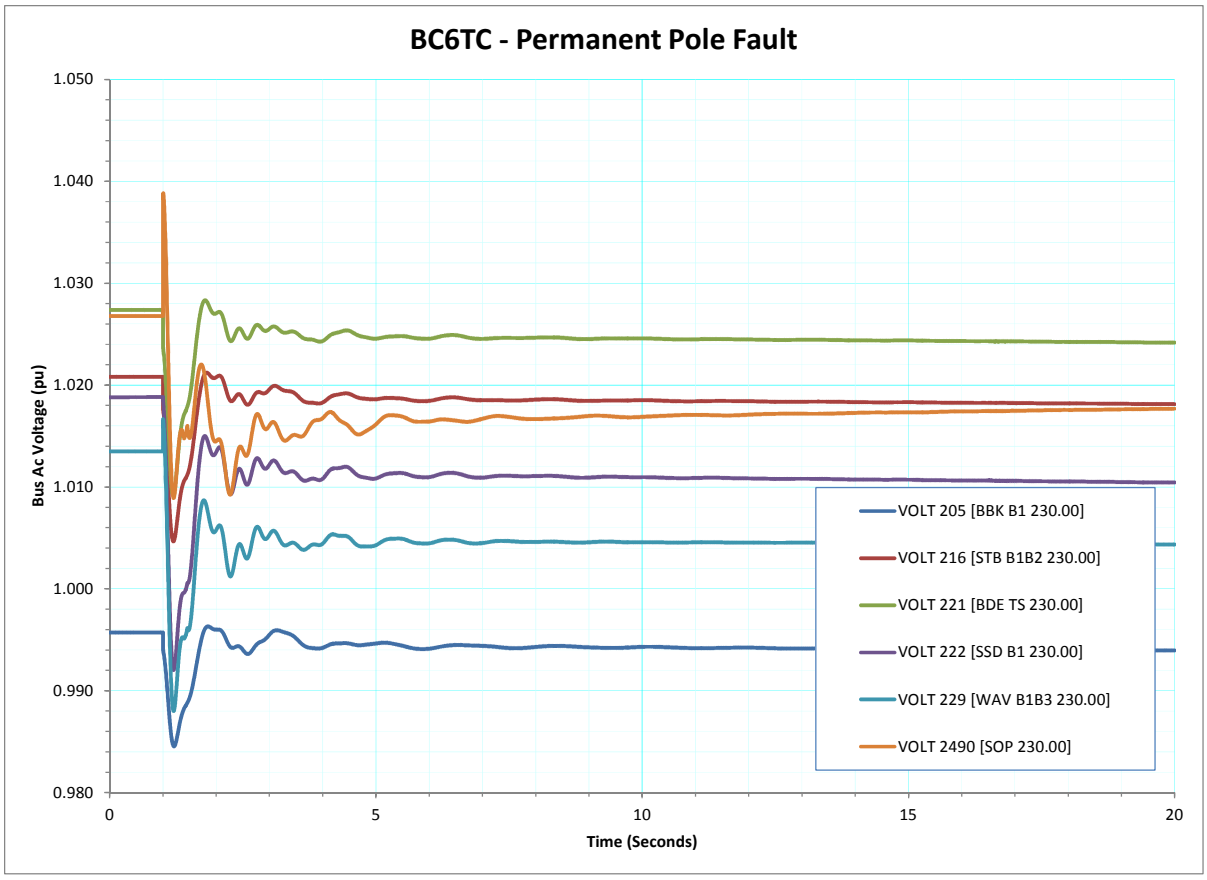


Figure 161 - BC6TC - Permanent Pole Fault - Bus Ac Voltage (pu)

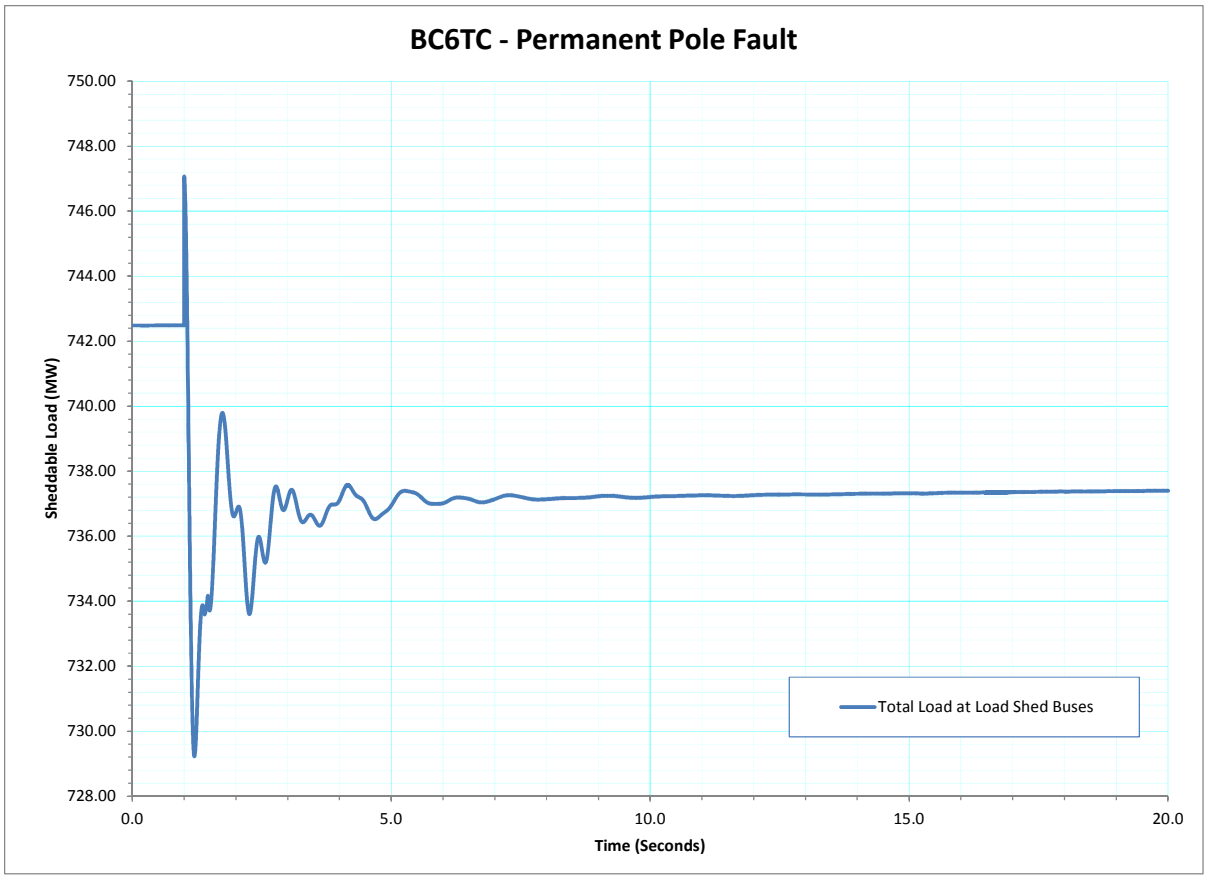


Figure 162 - BC6TC - Permanent Pole Fault - Sheddable Load (MW)

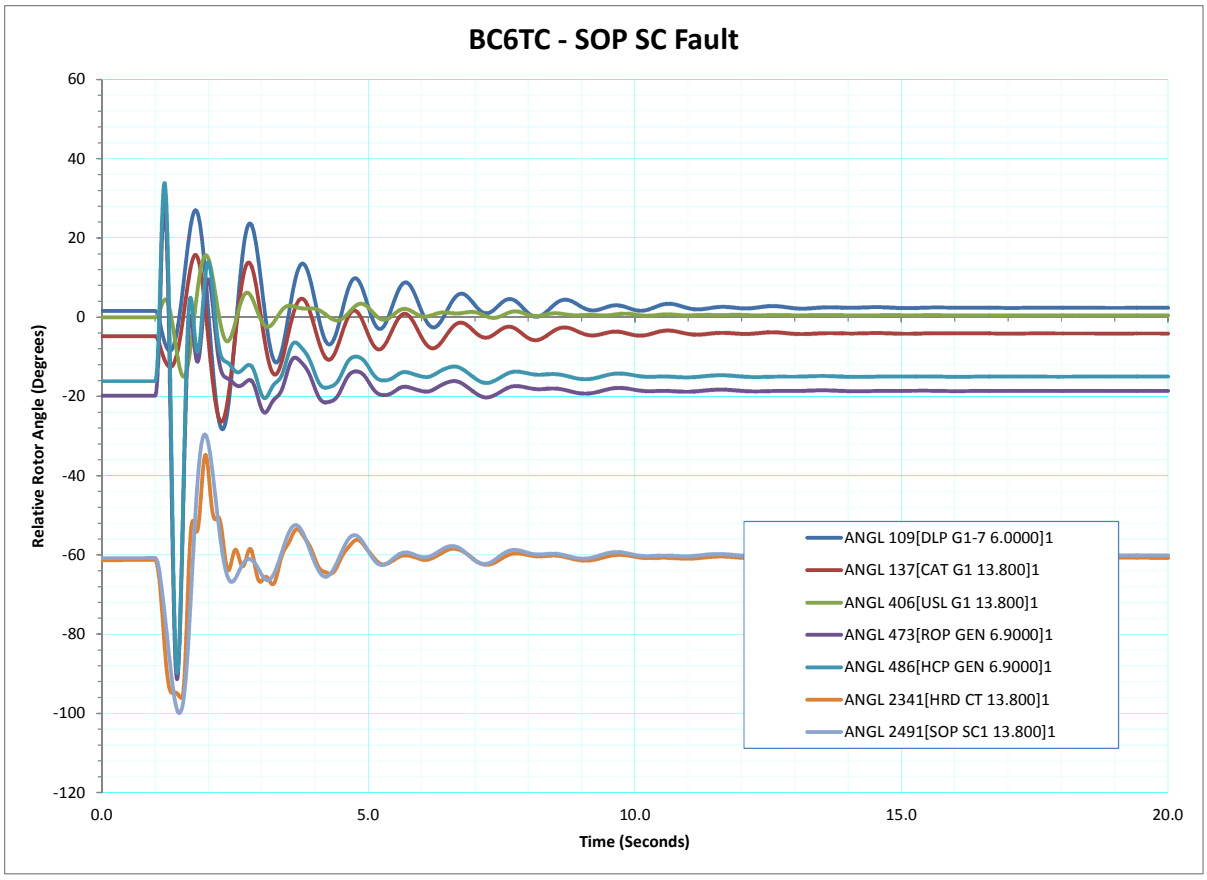


Figure 163 - BC6TC - SOP SC Fault - Relative Rotor Angle (Degrees)

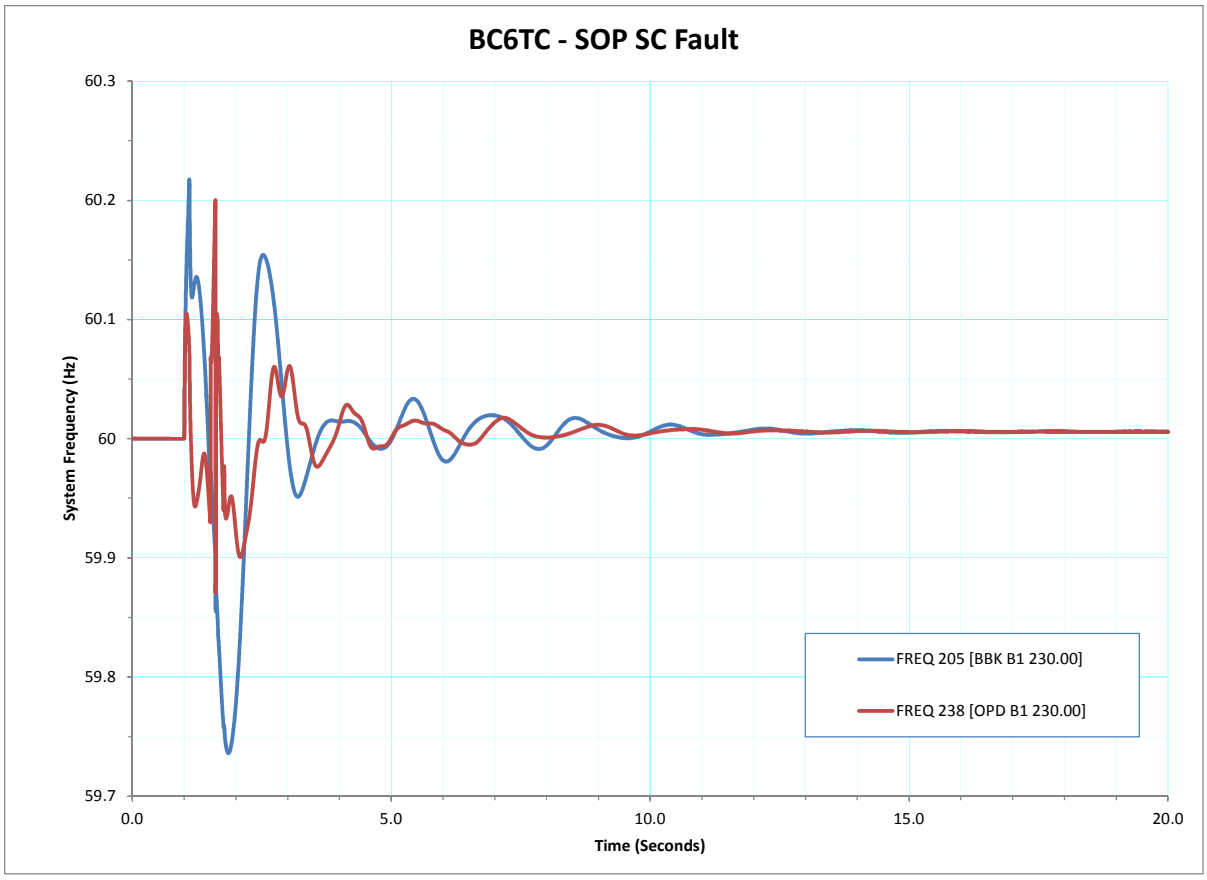


Figure 164 - BC6TC - SOP SC Fault - System Frequency (Hz)

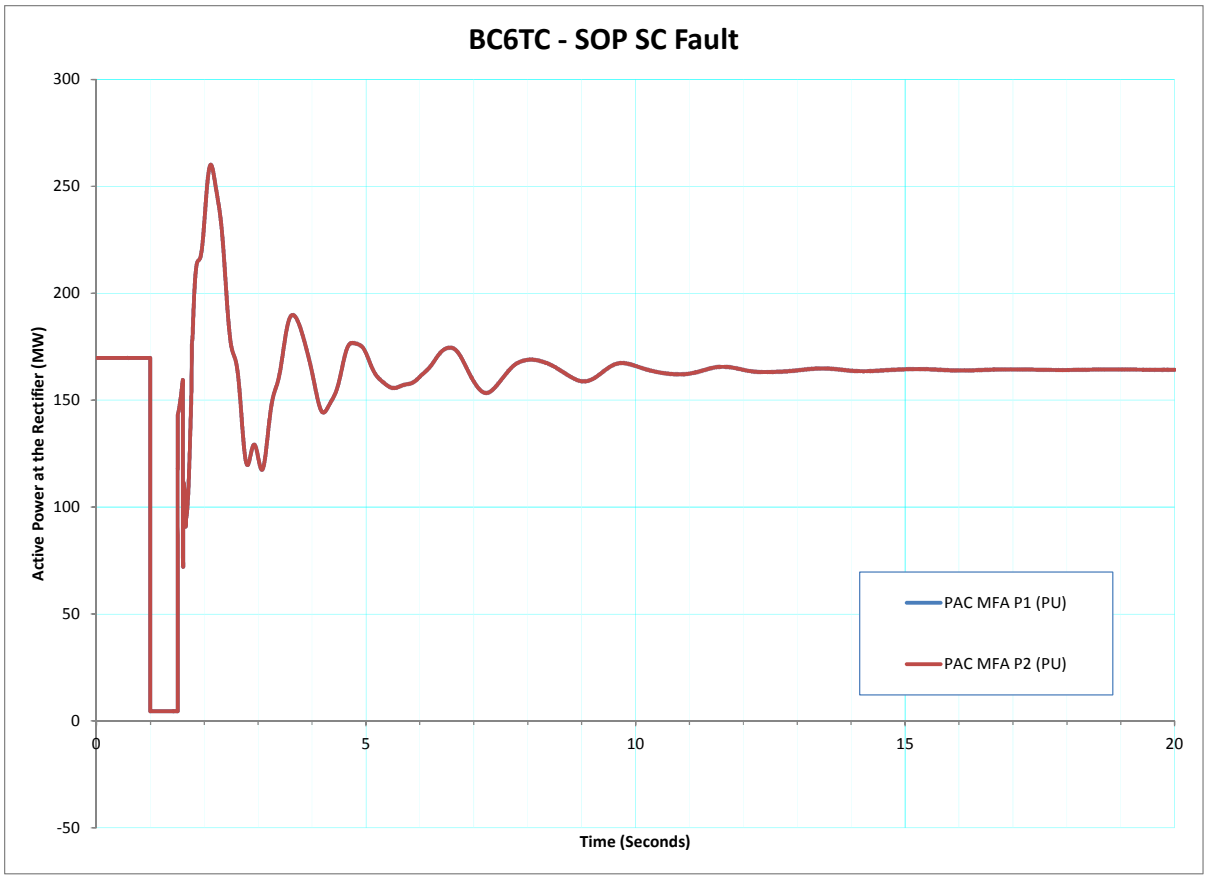


Figure 165 - BC6TC - SOP SC Fault - Active Power at the Rectifier (MW)

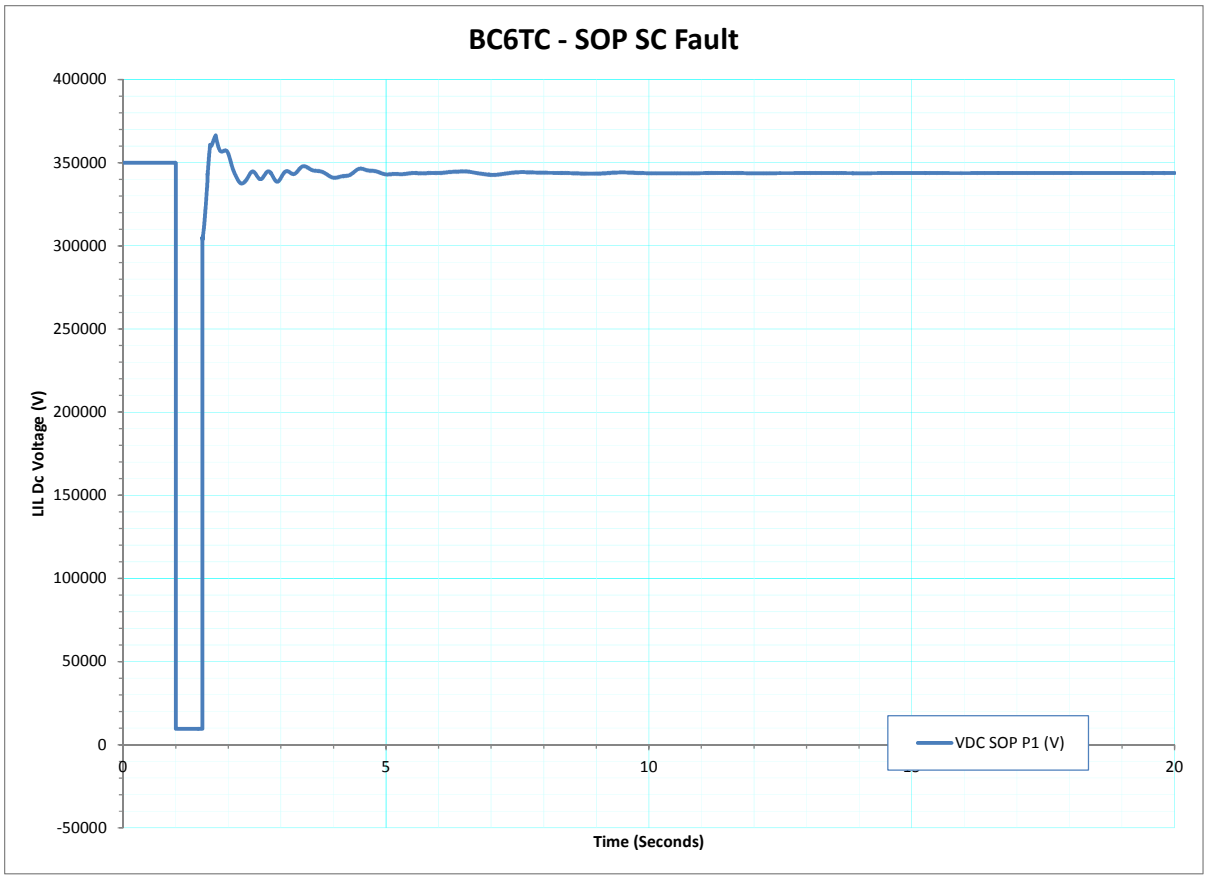


Figure 166 - BC6TC - SOP SC Fault - LIL Dc Voltage (V)

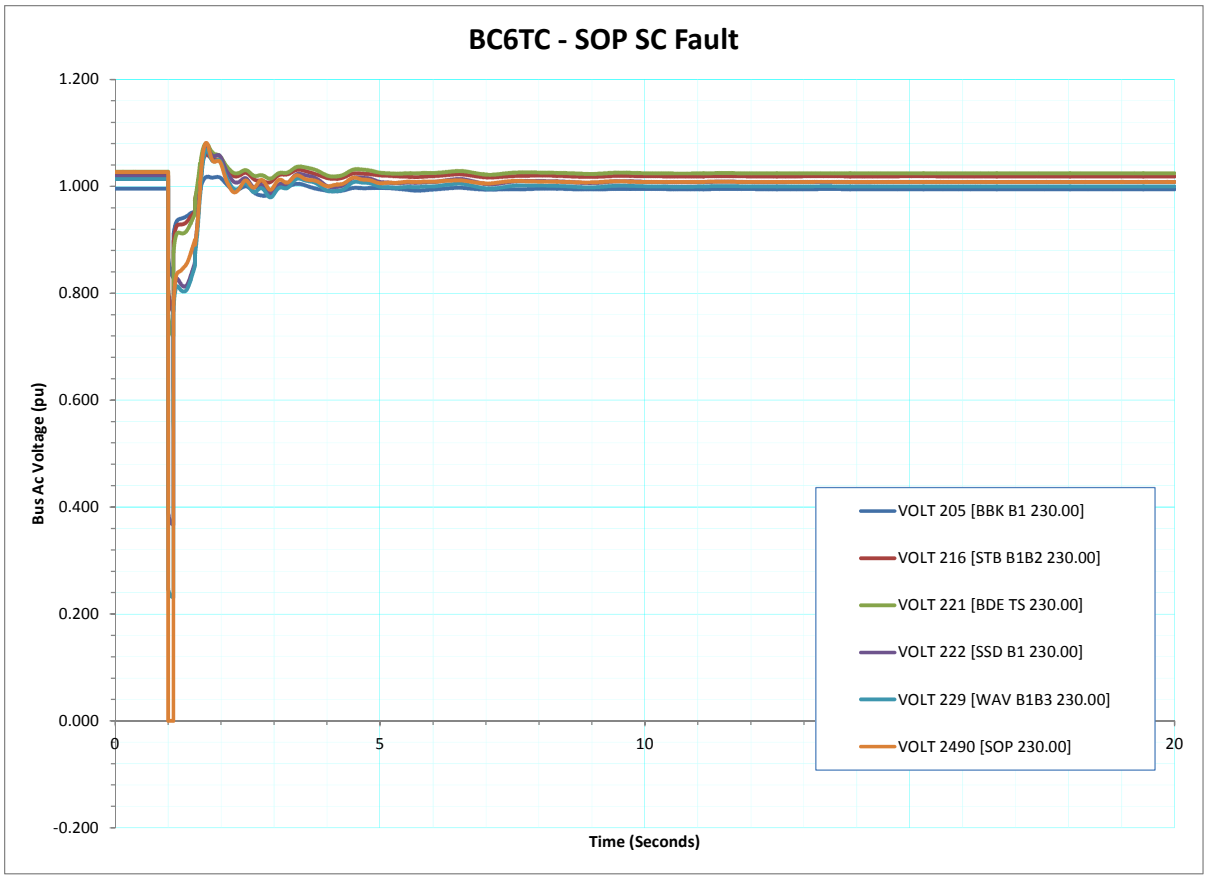


Figure 167 - BC6TC - SOP SC Fault - Bus Ac Voltage (pu)

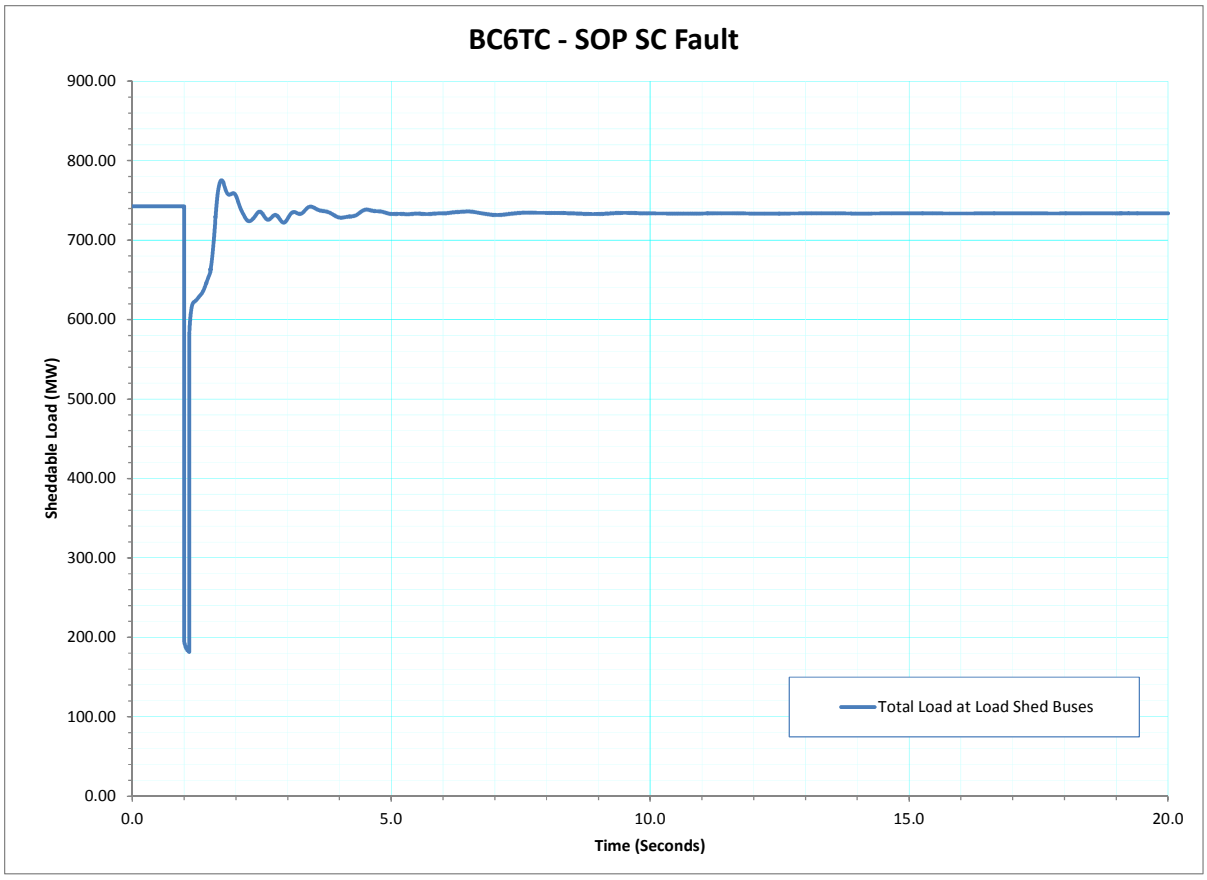


Figure 168 - BC6TC - SOP SC Fault - Sheddable Load (MW)

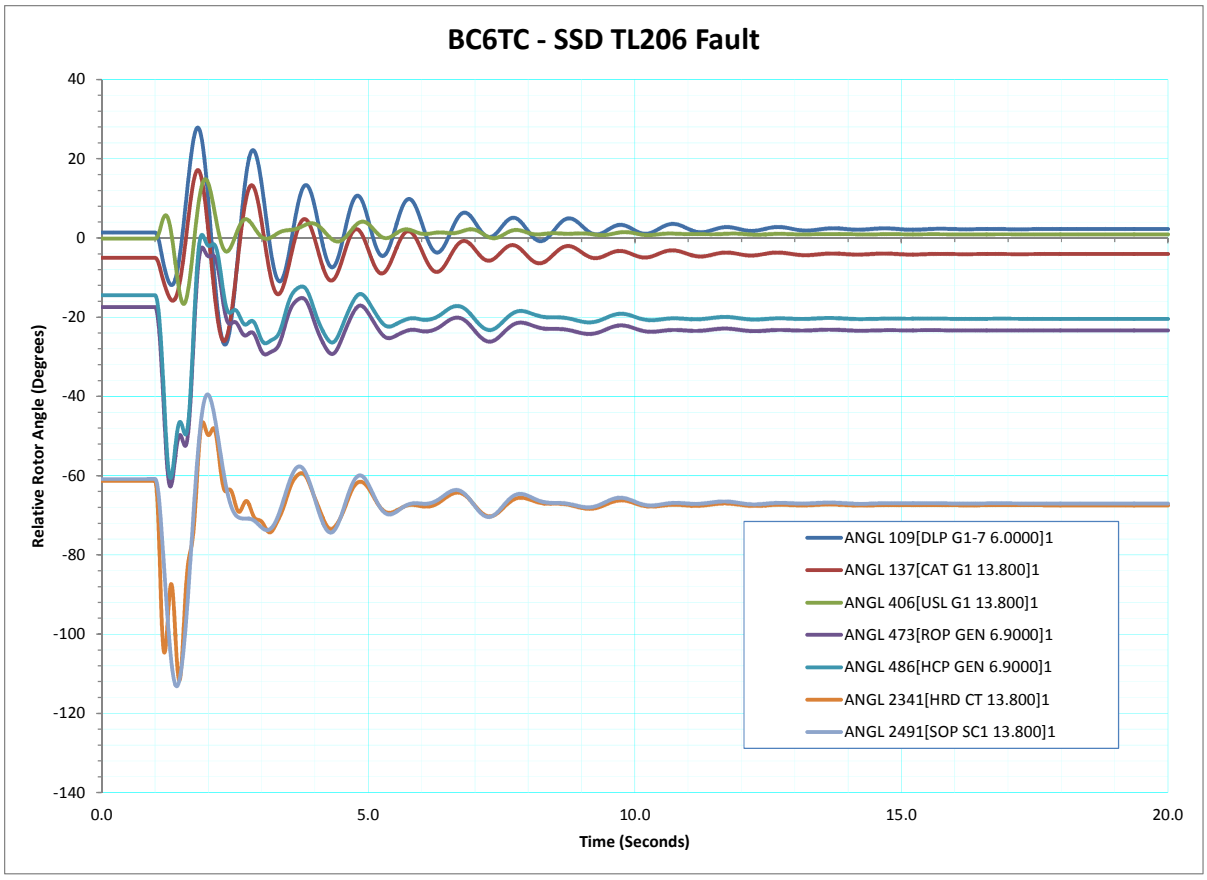


Figure 169 - BC6TC - SSD TL206 Fault - Relative Rotor Angle (Degrees)

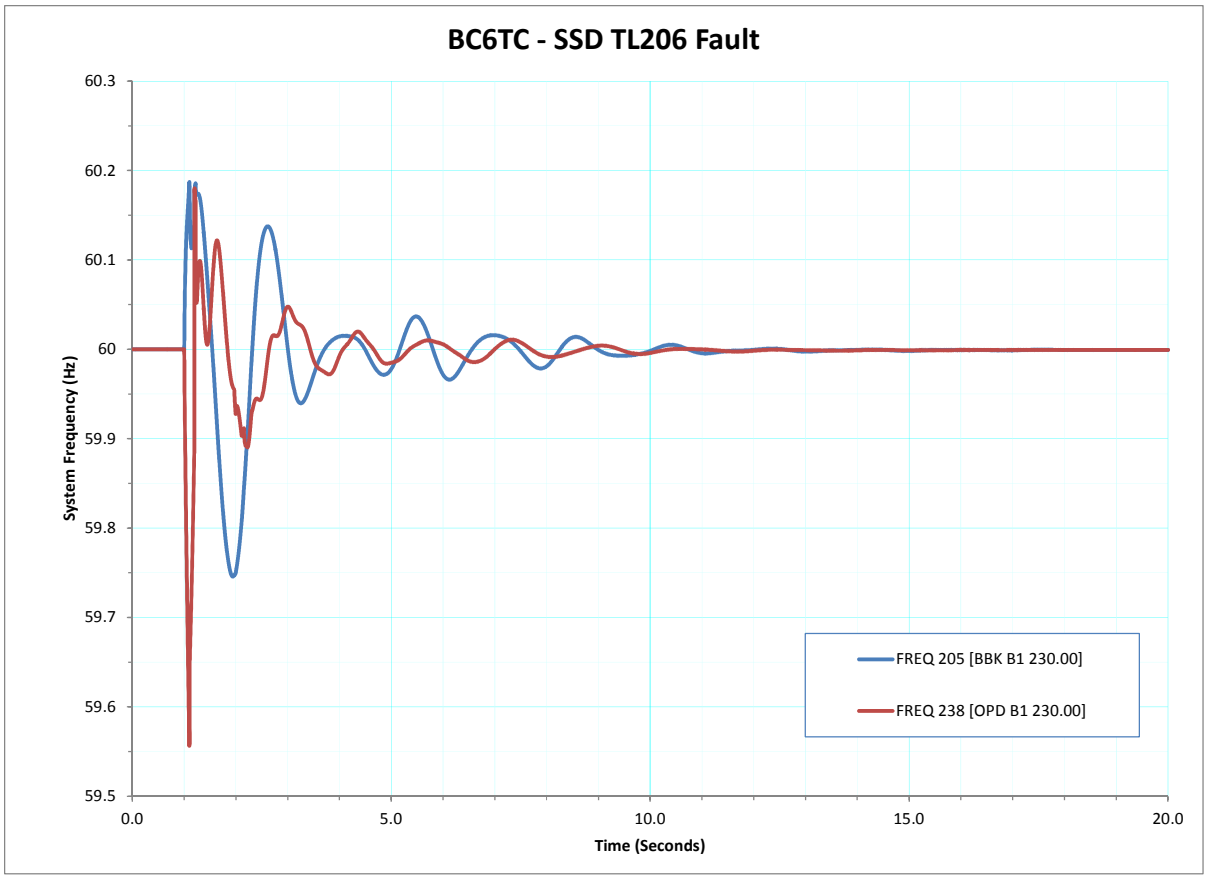


Figure 170 - BC6TC - SSD TL206 Fault - System Frequency (Hz)

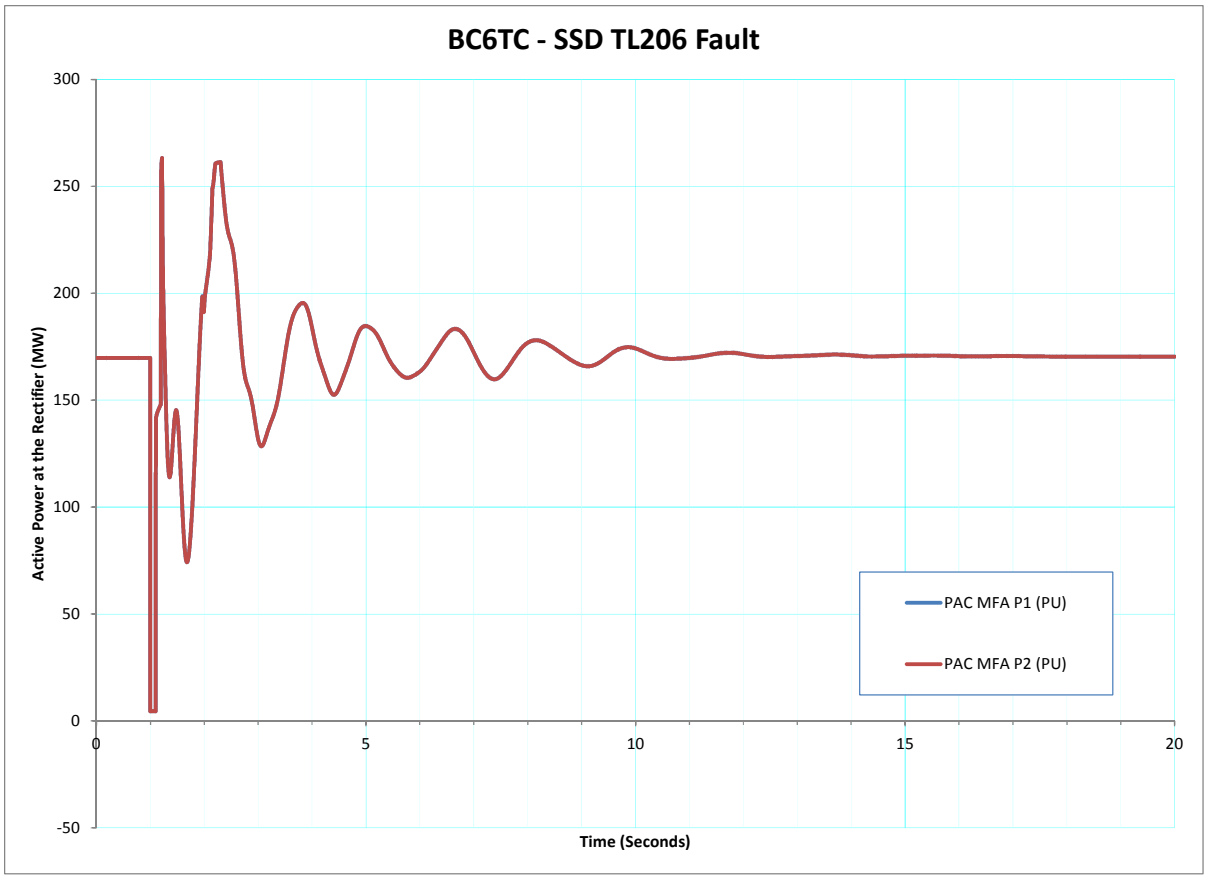


Figure 171 - BC6TC - SSD TL206 Fault - Active Power at the Rectifier (MW)

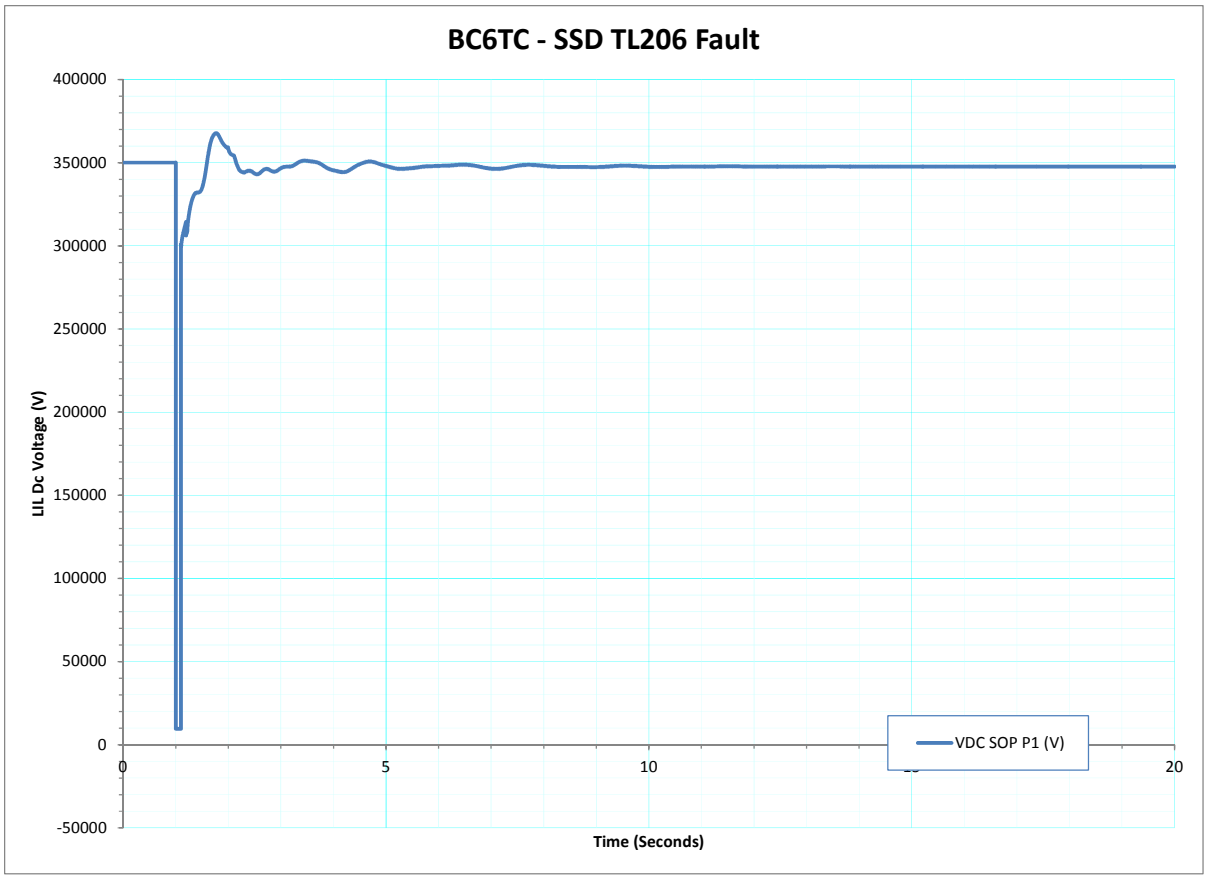


Figure 172 - BC6TC - SSD TL206 Fault - LIL Dc Voltage (V)

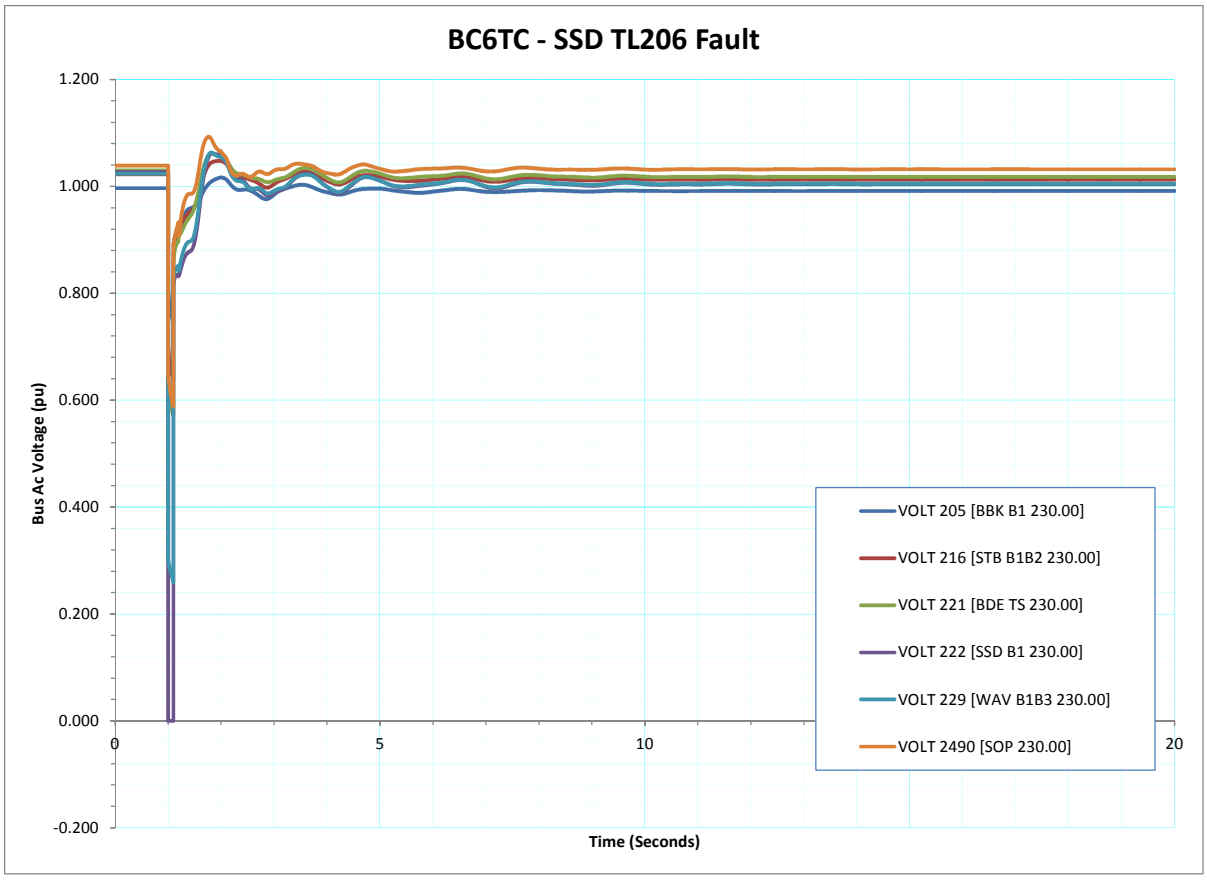


Figure 173 - BC6TC - SSD TL206 Fault - Bus Ac Voltage (pu)

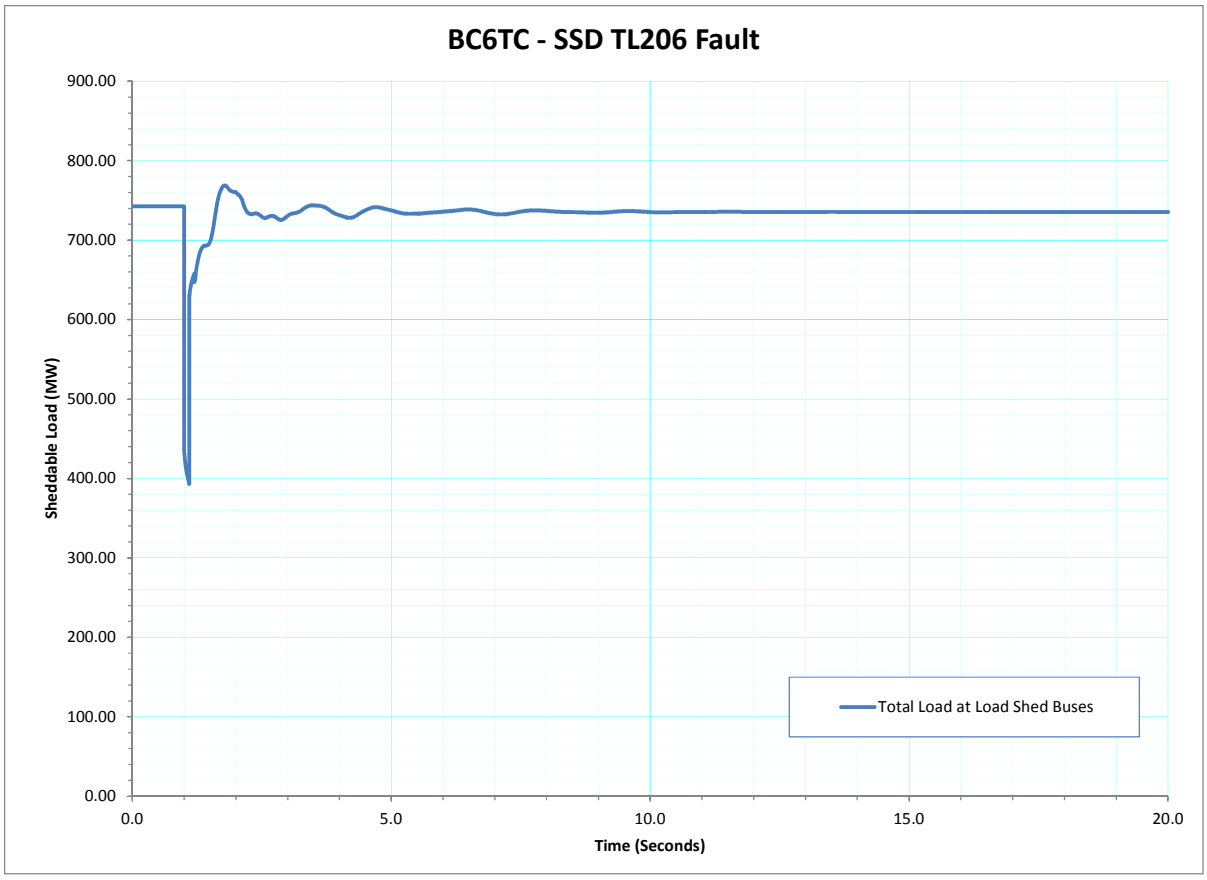


Figure 174 - BC6TC - SSD TL206 Fault - Sheddable Load (MW)

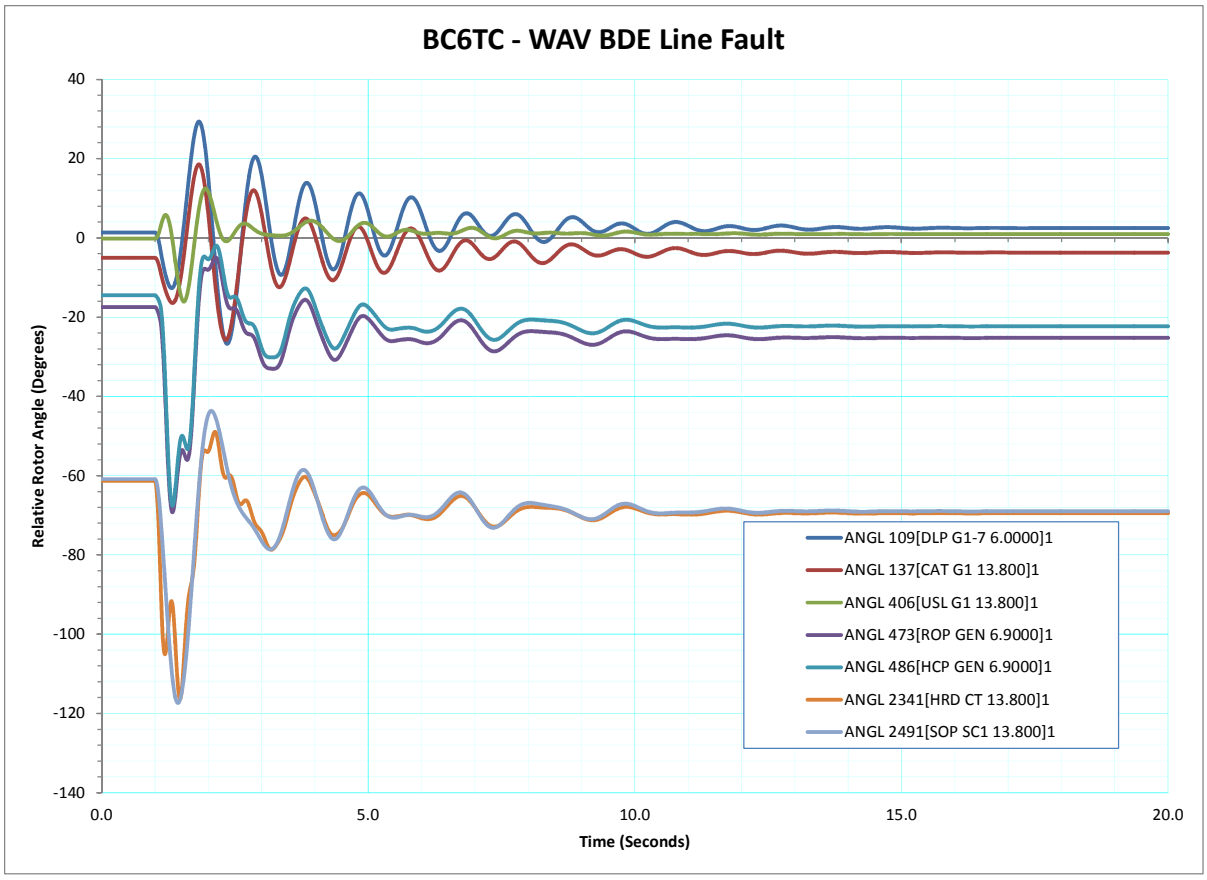


Figure 175 - BC6TC - WAV BDE Line Fault - Relative Rotor Angle (Degrees)

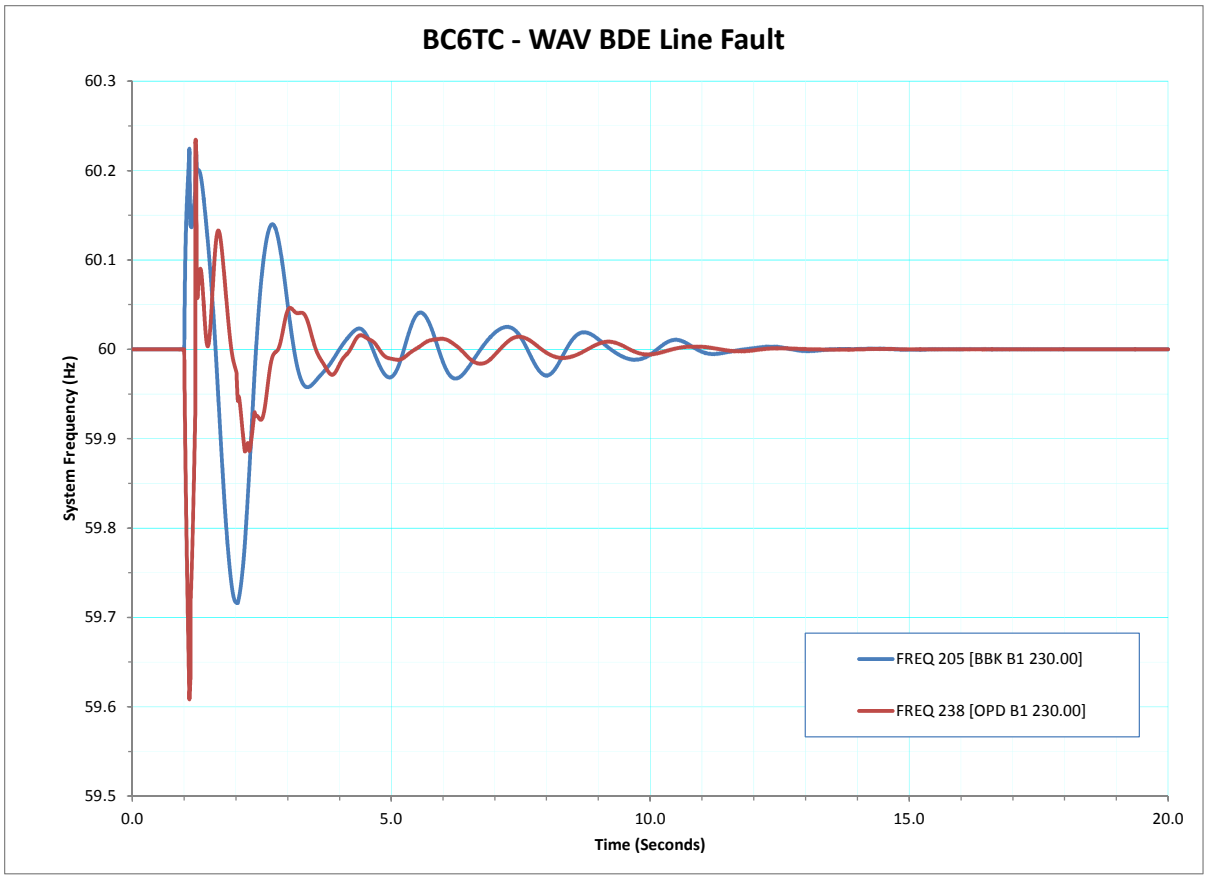


Figure 176 - BC6TC - WAV BDE Line Fault - System Frequency (Hz)

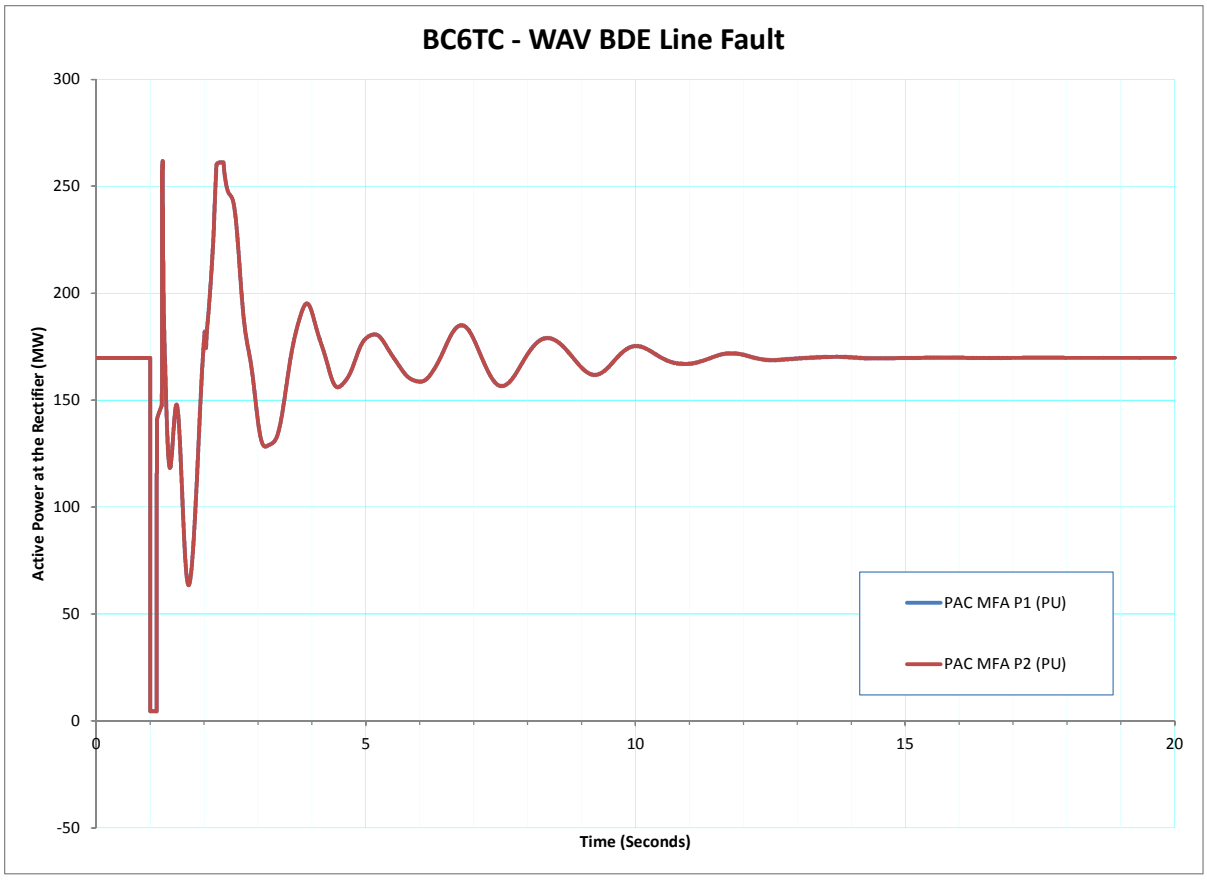


Figure 177 - BC6TC - WAV BDE Line Fault - Active Power at the Rectifier (MW)

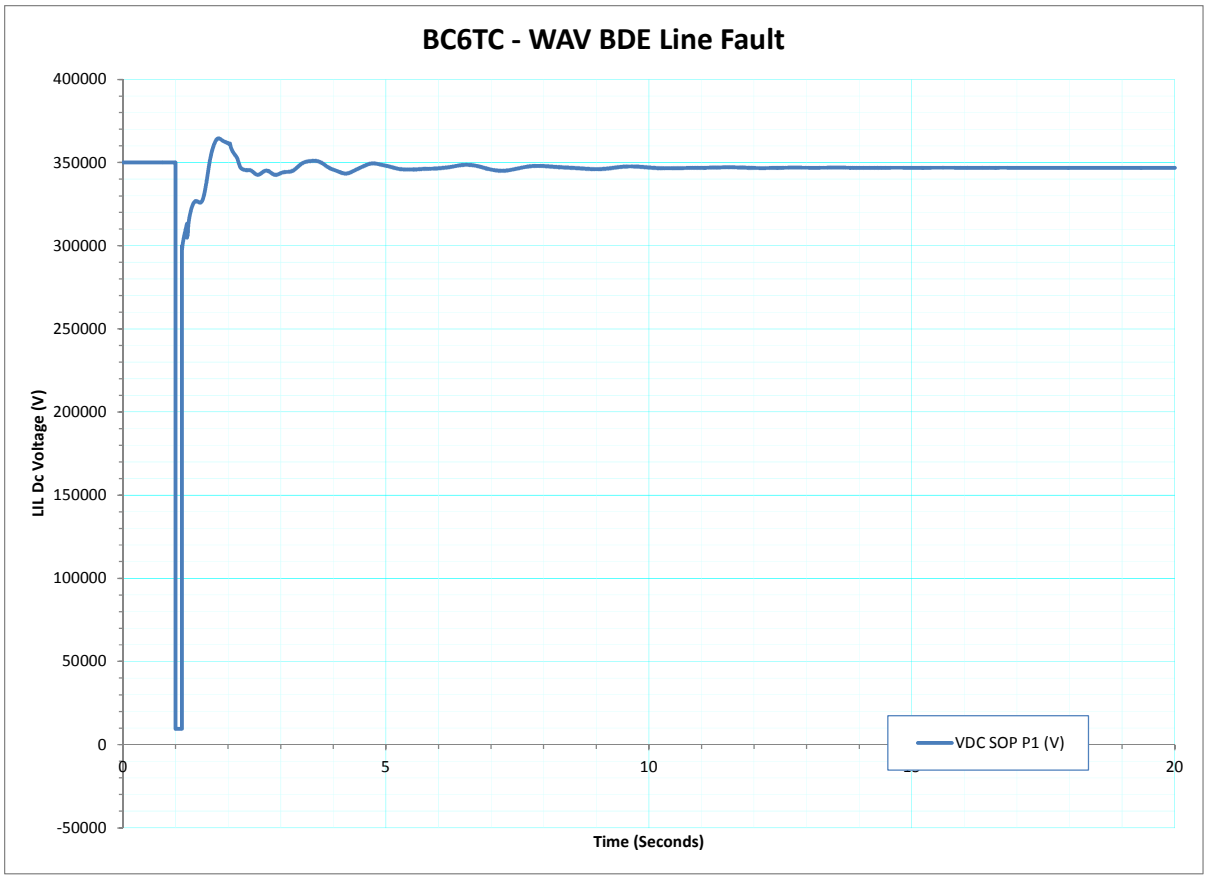


Figure 178 - BC6TC - WAV BDE Line Fault - LIL Dc Voltage (V)

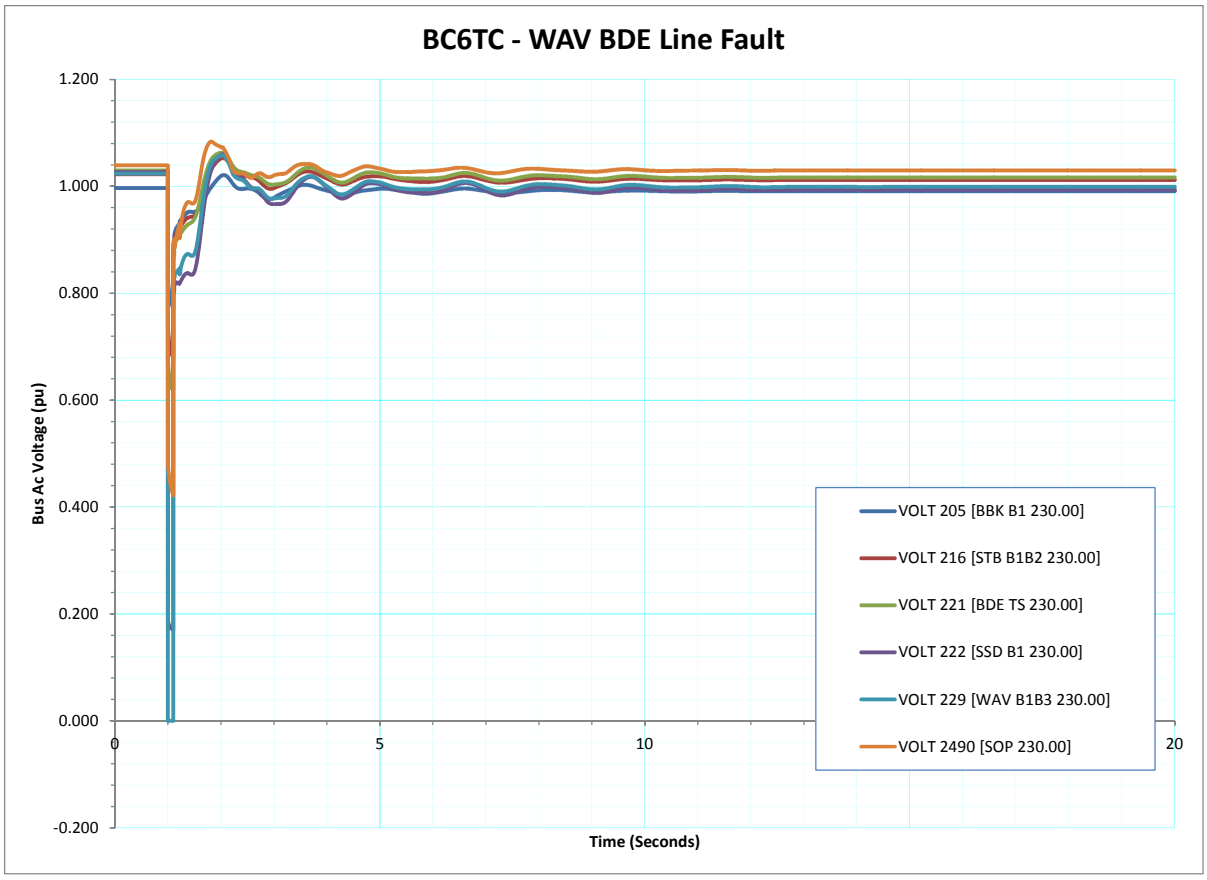


Figure 179 - BC6TC - WAV BDE Line Fault - Bus Ac Voltage (pu)

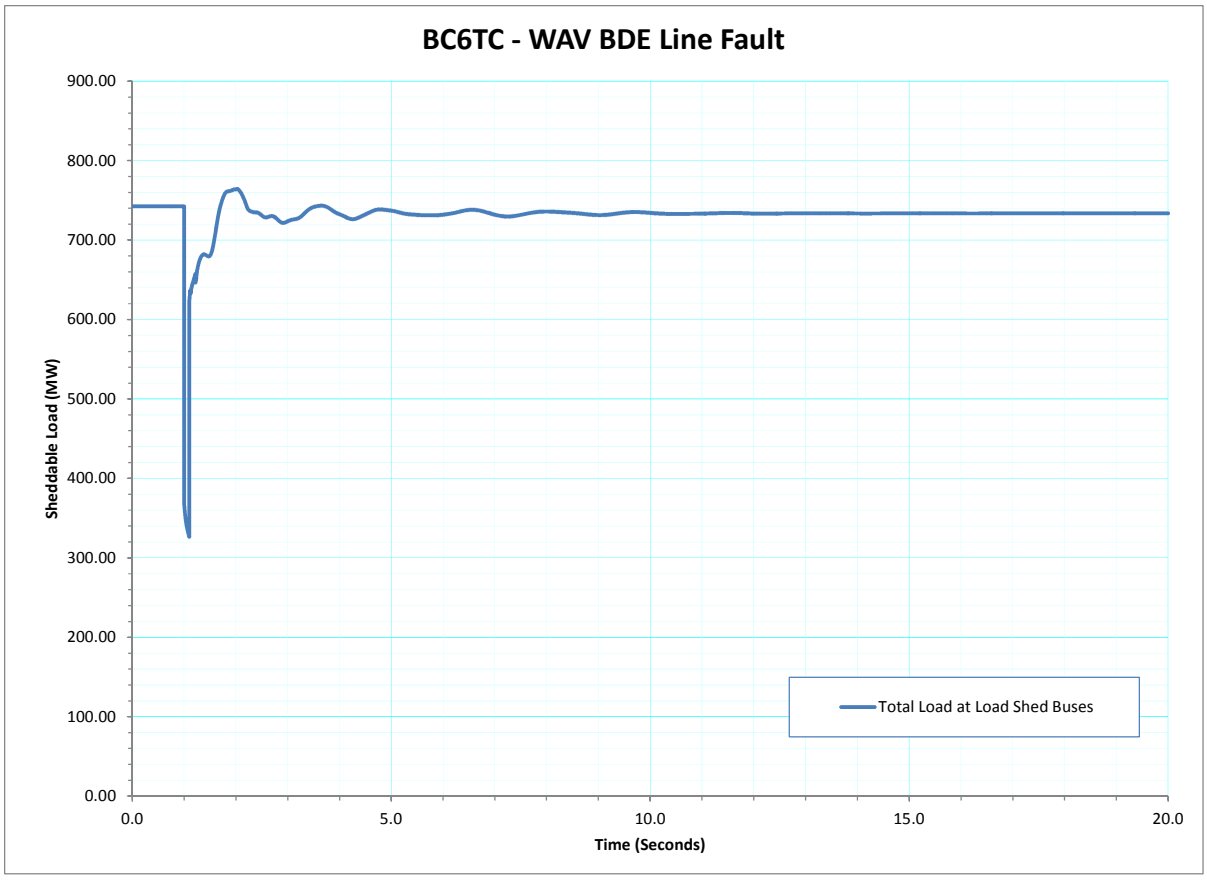


Figure 180 - BC6TC - WAV BDE Line Fault - Sheddable Load (MW)

1.7. BASE CASE 7 TRANSIENT STABILITY PLOTS

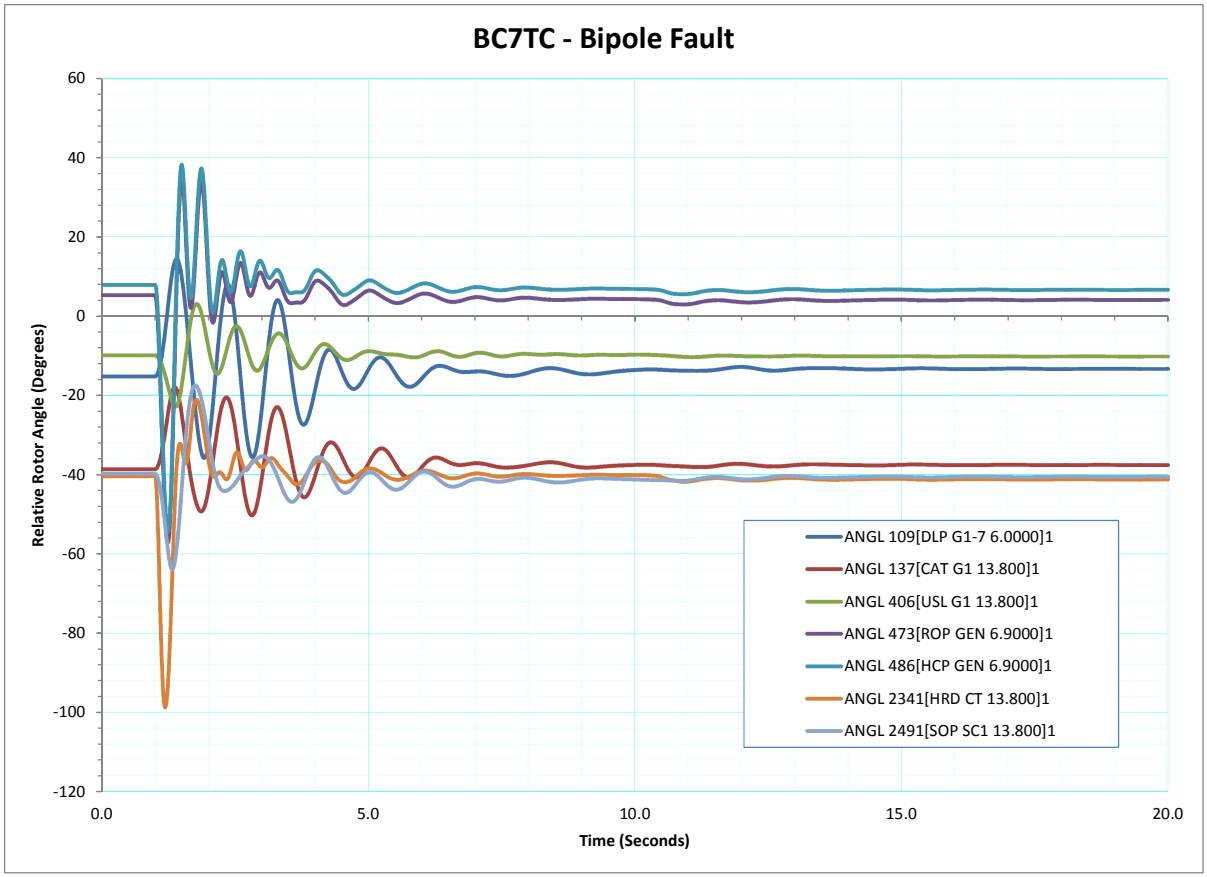


Figure 181 - BC7TC - Bipole Fault - Relative Rotor Angle (Degrees)

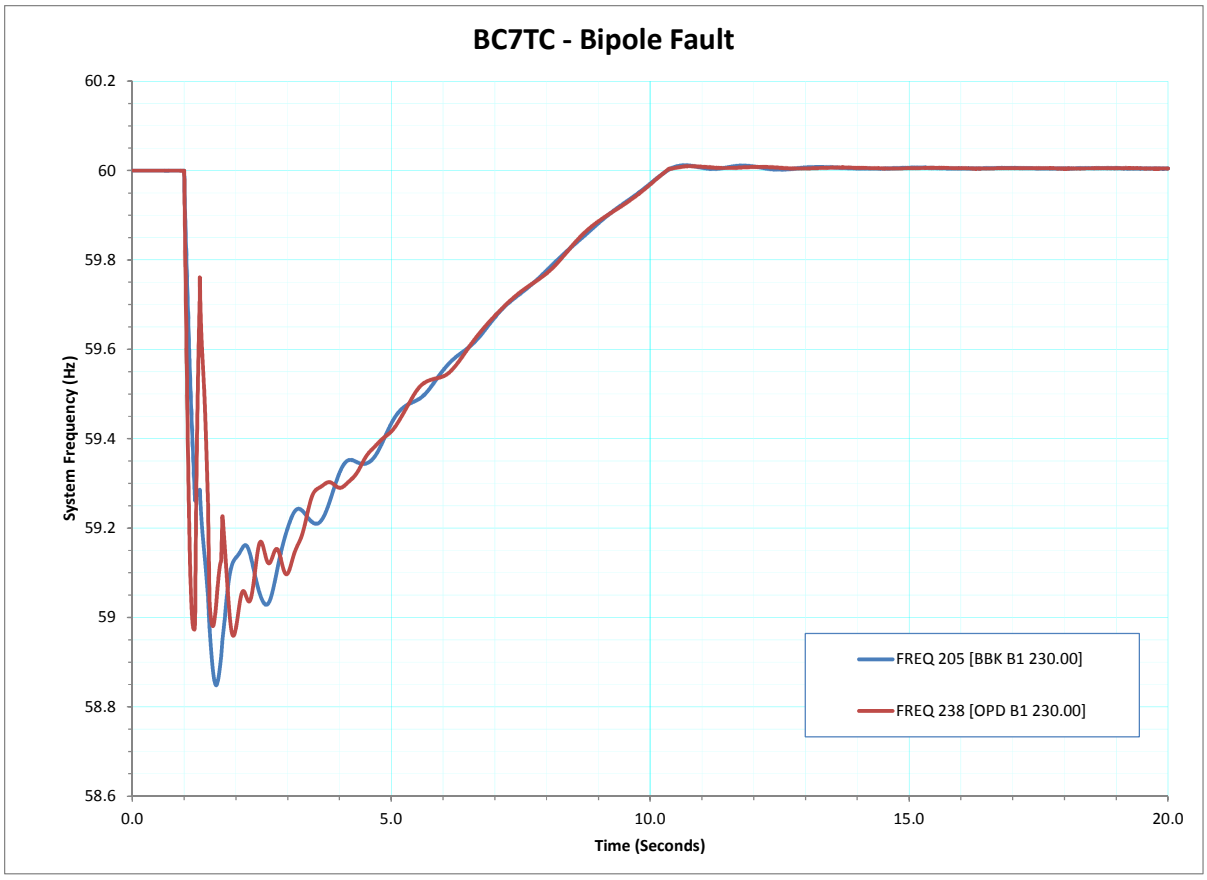


Figure 182 - BC7TC - Bipole Fault - System Frequency (Hz)

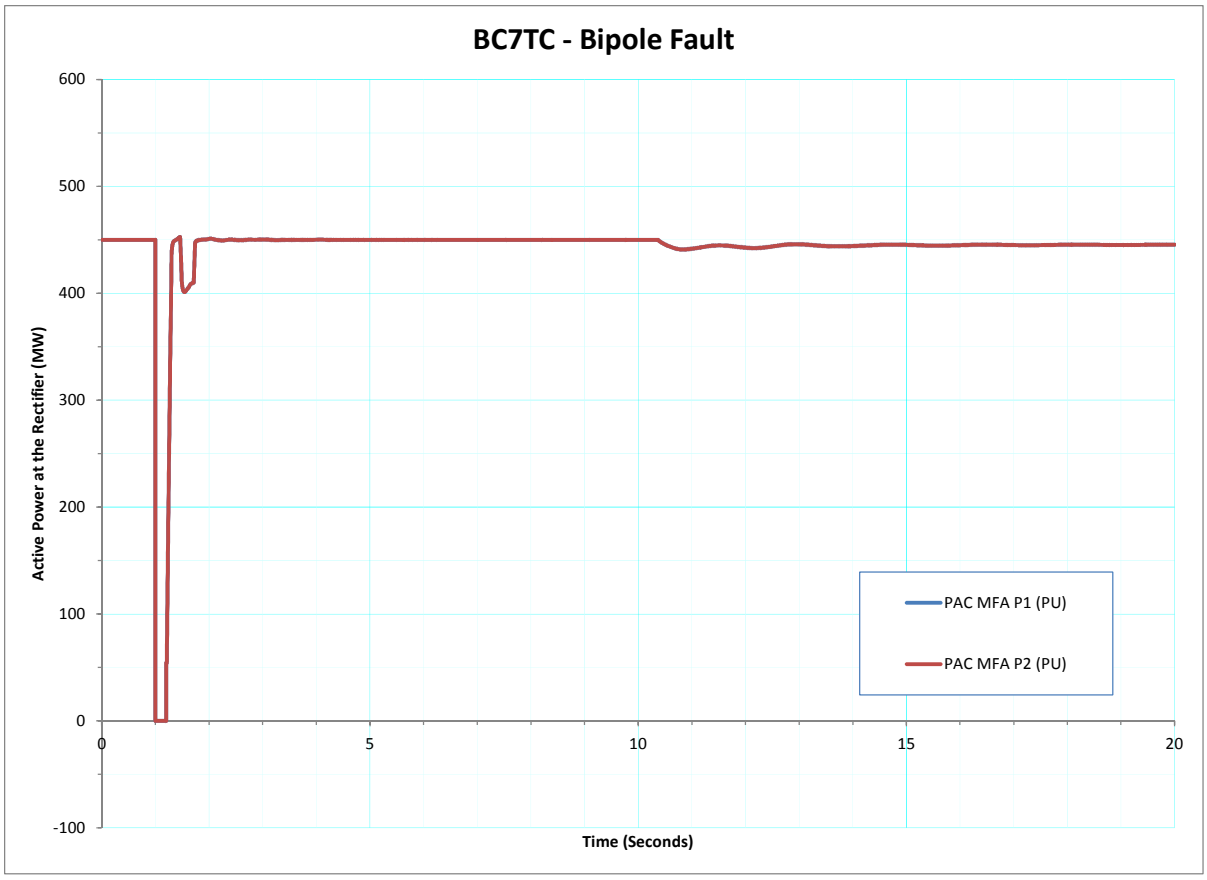


Figure 183 - BC7TC - Bipole Fault - Active Power at the Rectifier (MW)

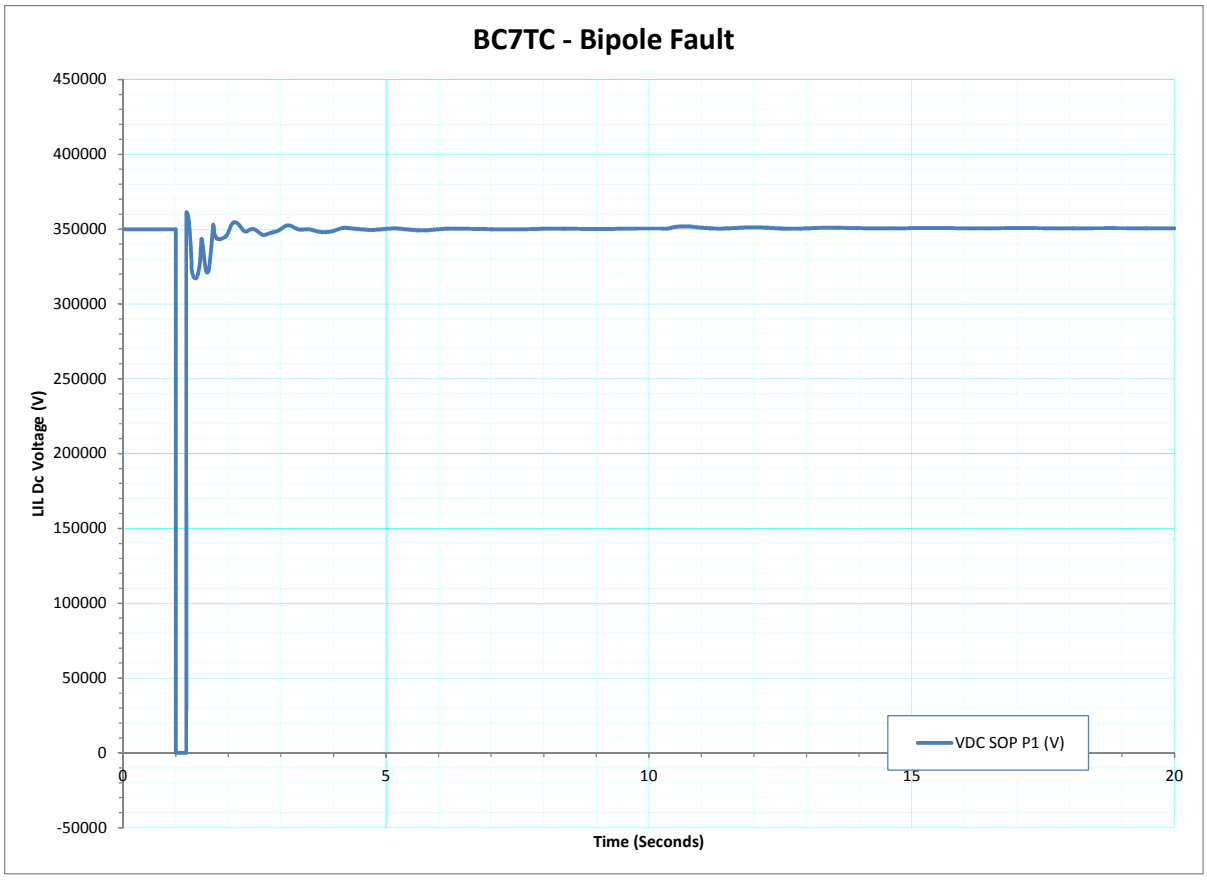


Figure 184 - BC7TC - Bipole Fault - LIL Dc Voltage (V)

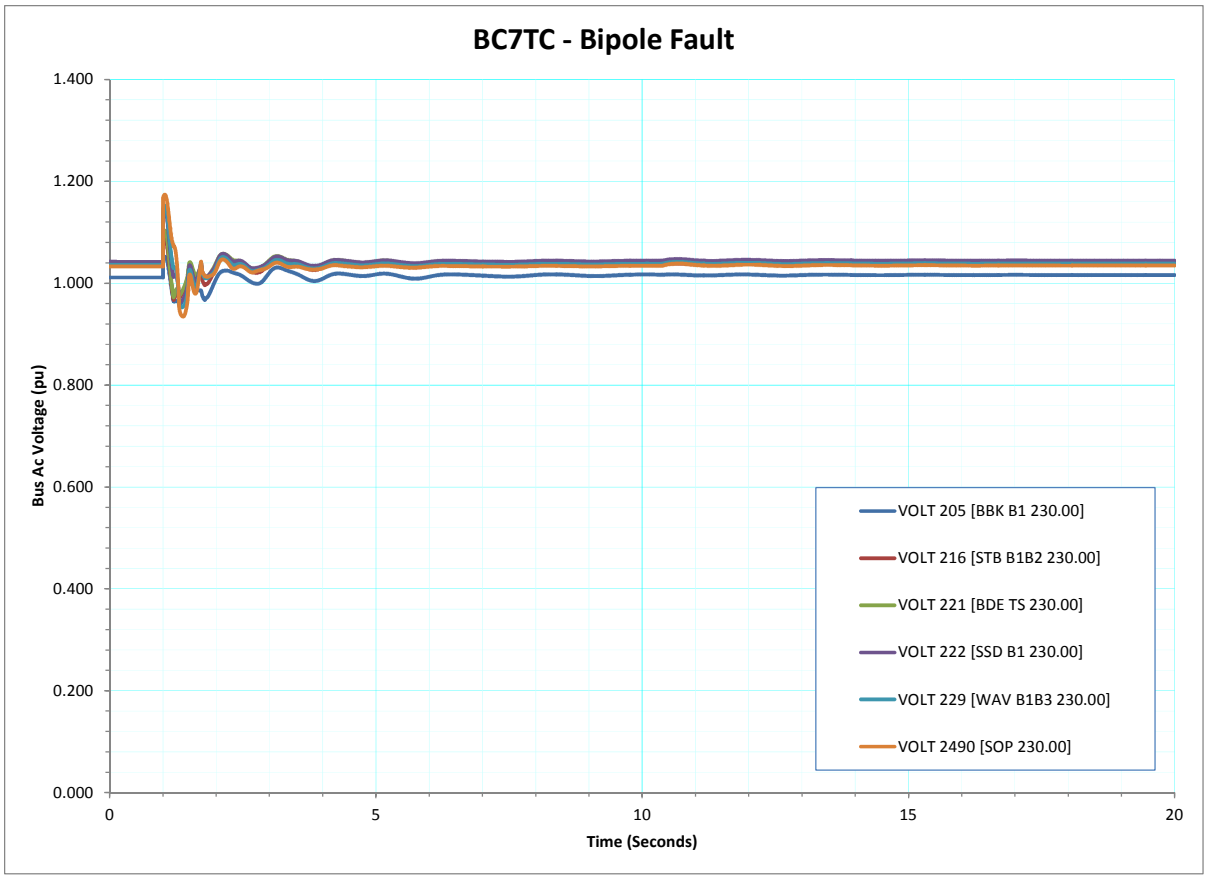


Figure 185 - BC7TC - Bipole Fault - Bus Ac Voltage (pu)

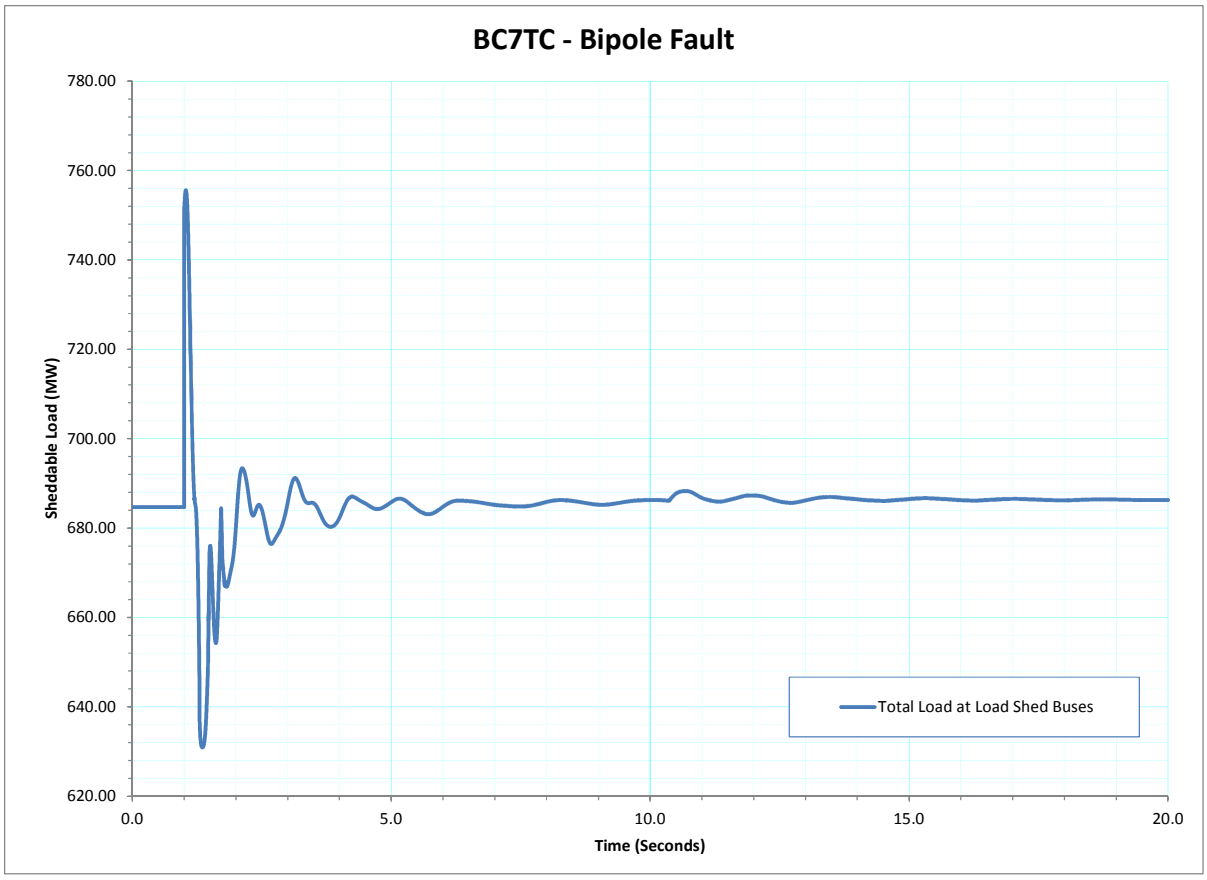


Figure 186 - BC7TC - Bipole Fault - Sheddable Load (MW)

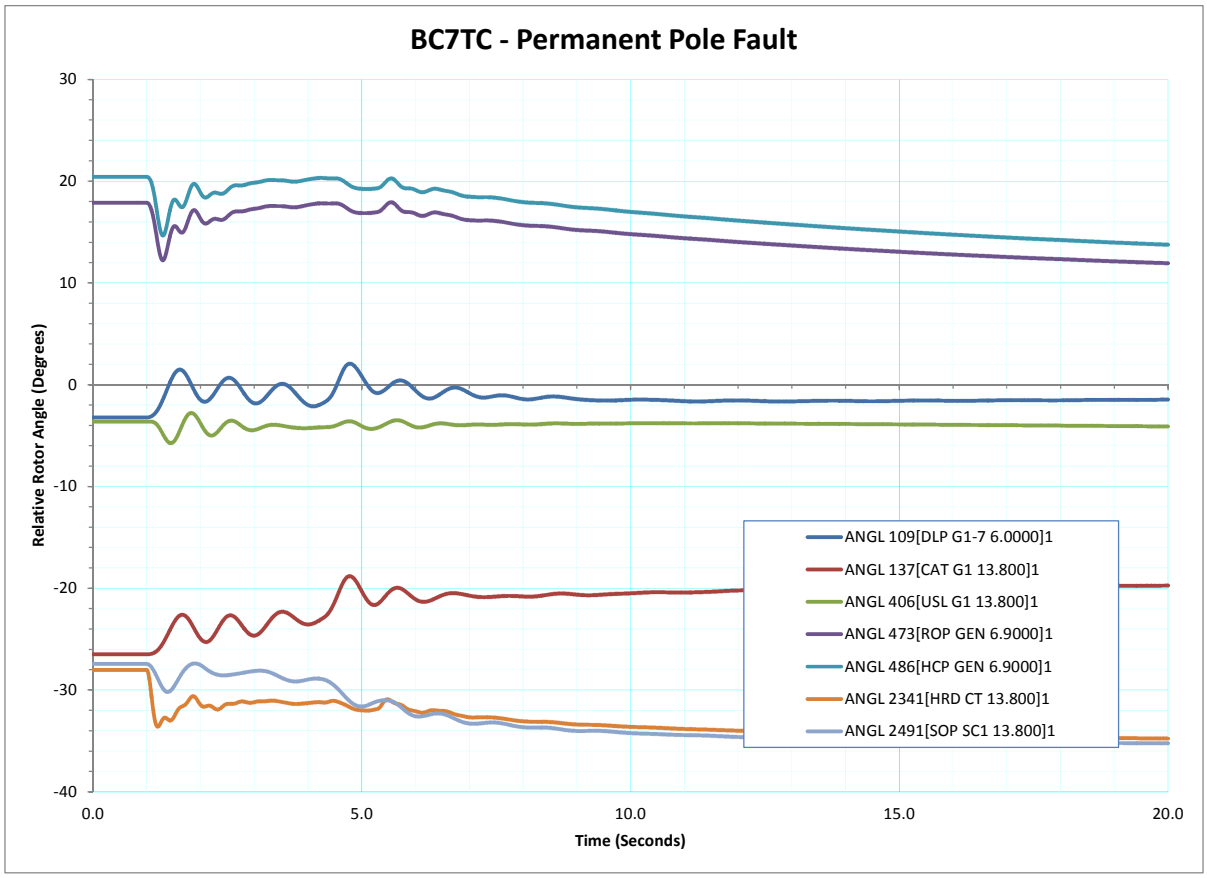


Figure 187 - BC7TC - Permanent Pole Fault - Relative Rotor Angle (Degrees)

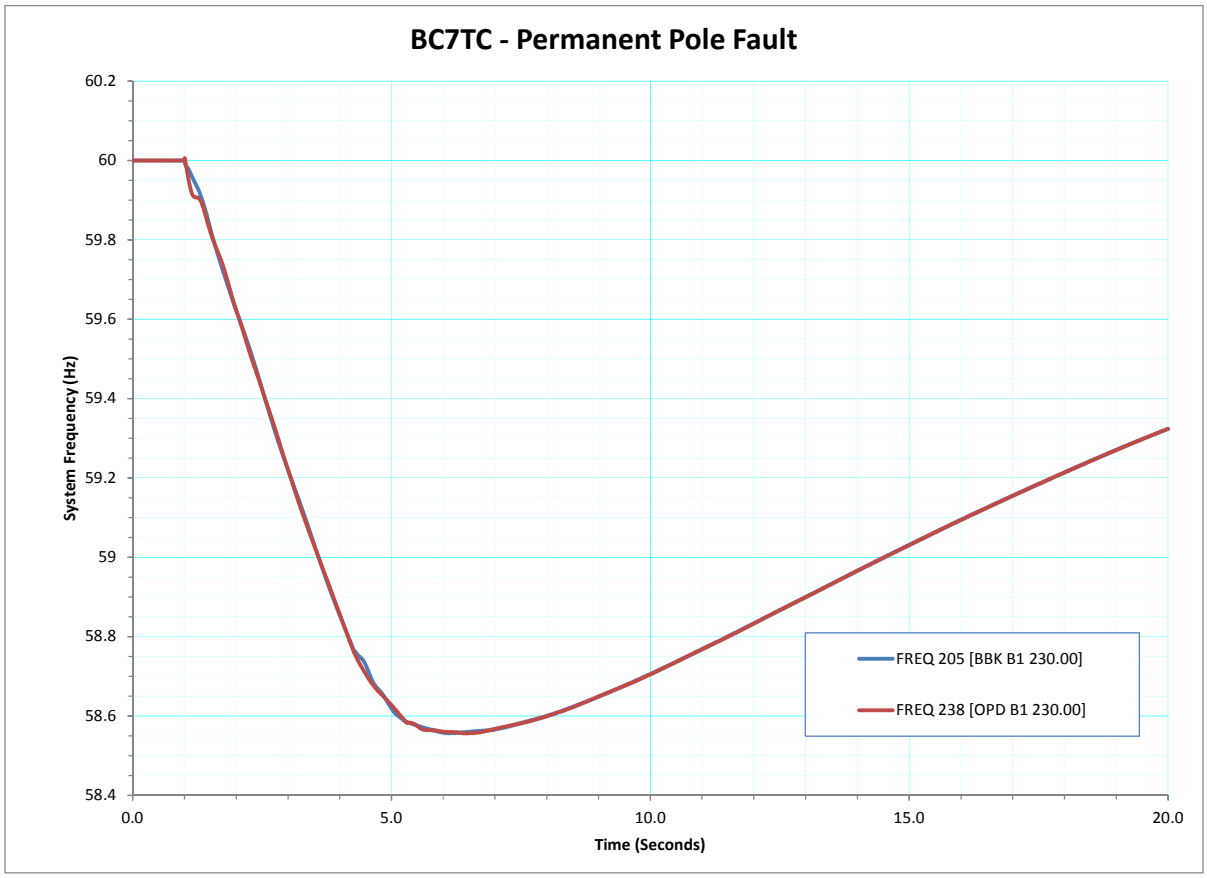


Figure 188 - BC7TC - Permanent Pole Fault - System Frequency (Hz)

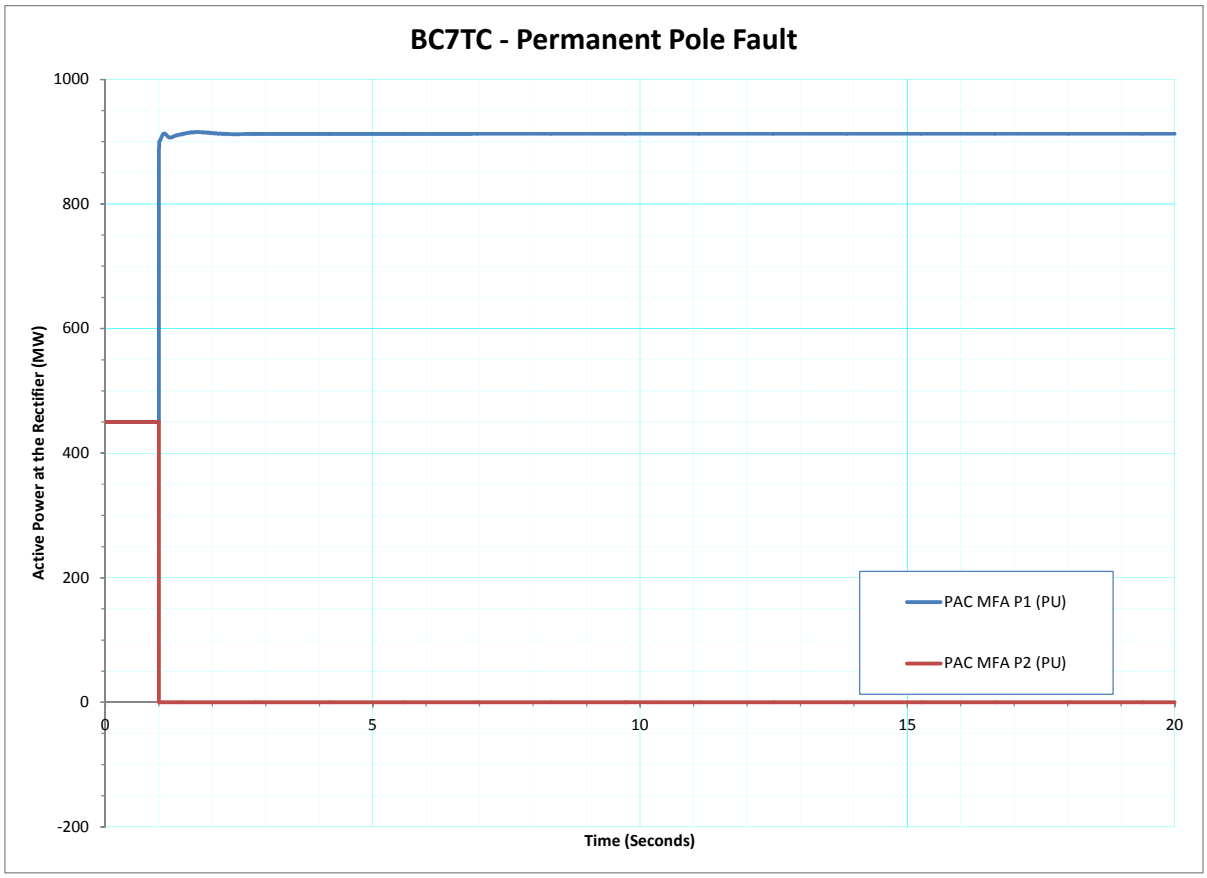


Figure 189 - BC7TC - Permanent Pole Fault - Active Power at the Rectifier (MW)

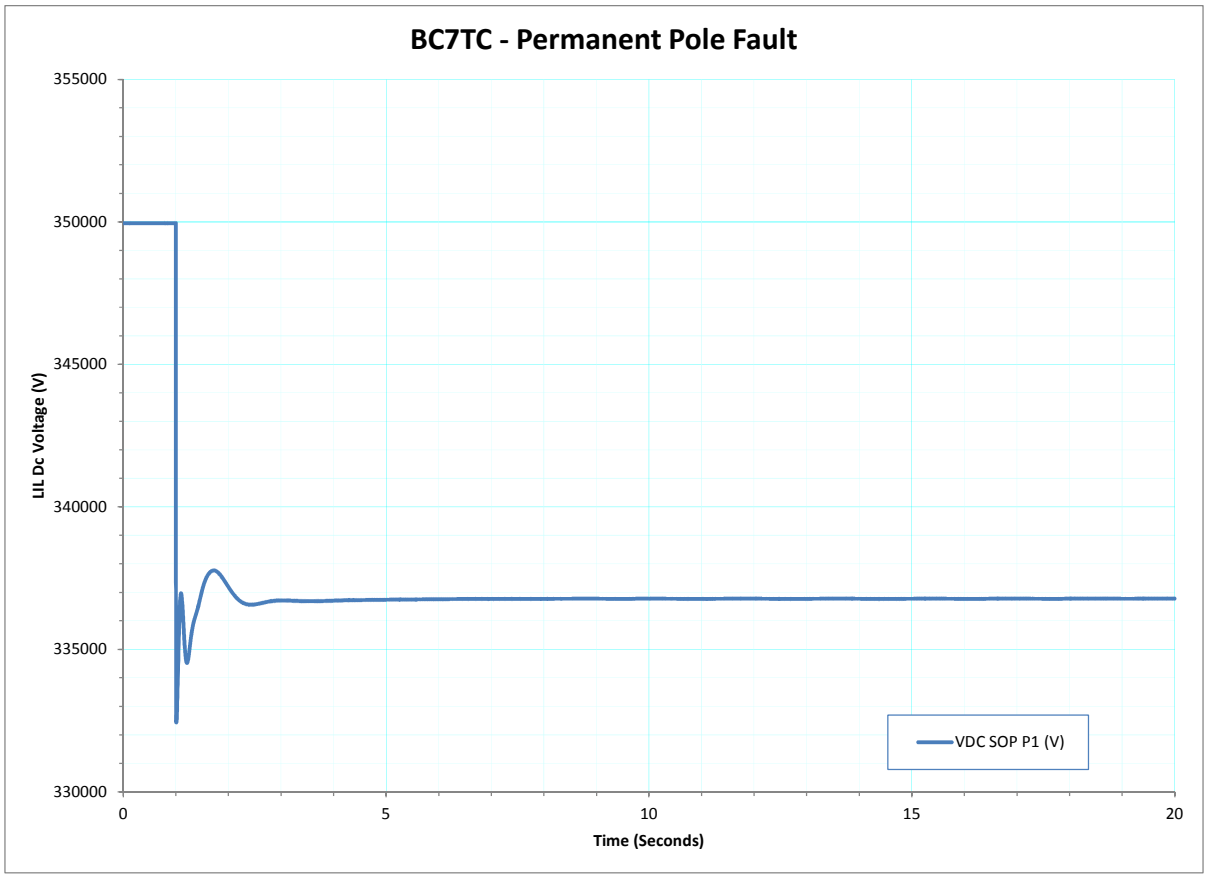


Figure 190 - BC7TC - Permanent Pole Fault - LIL Dc Voltage (V)

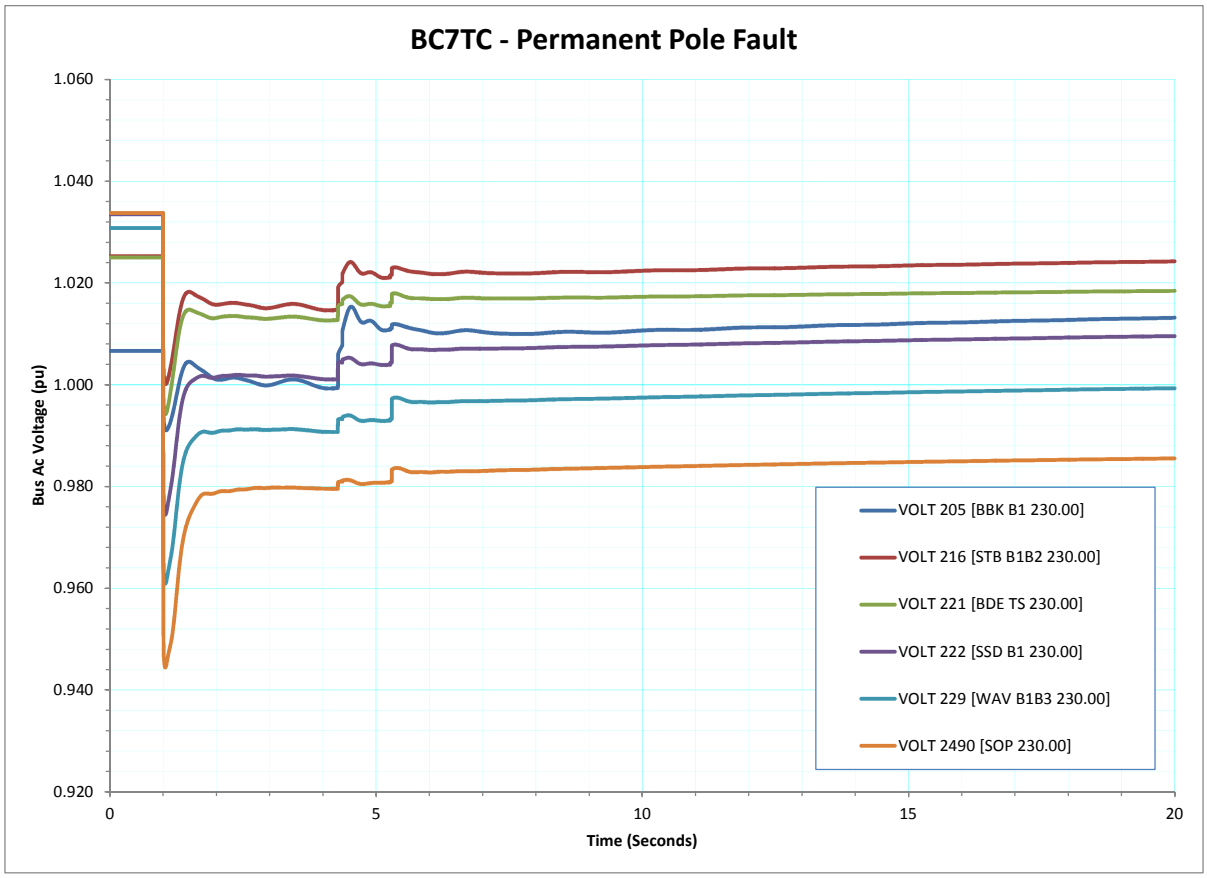


Figure 191 - BC7TC - Permanent Pole Fault - Bus Ac Voltage (pu)

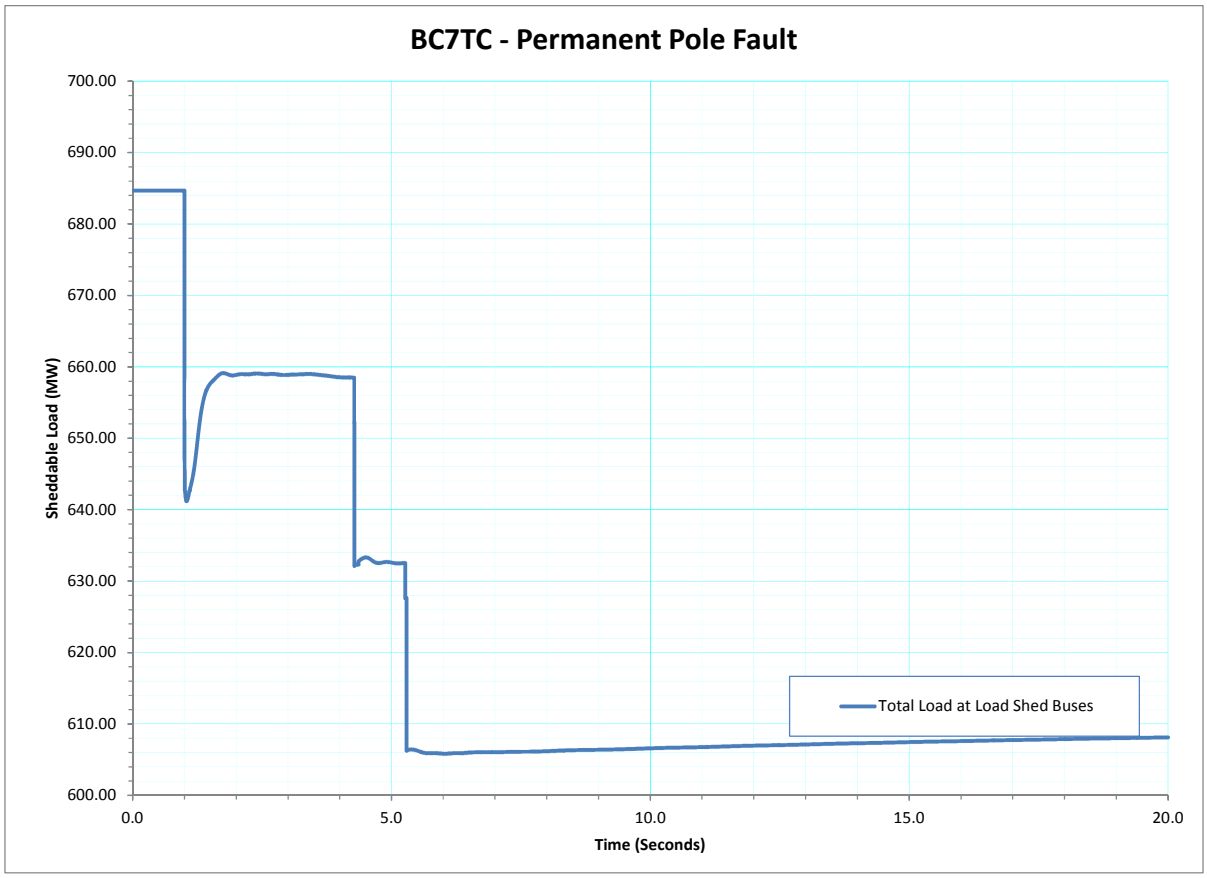


Figure 192 - BC7TC - Permanent Pole Fault - Sheddable Load (MW)

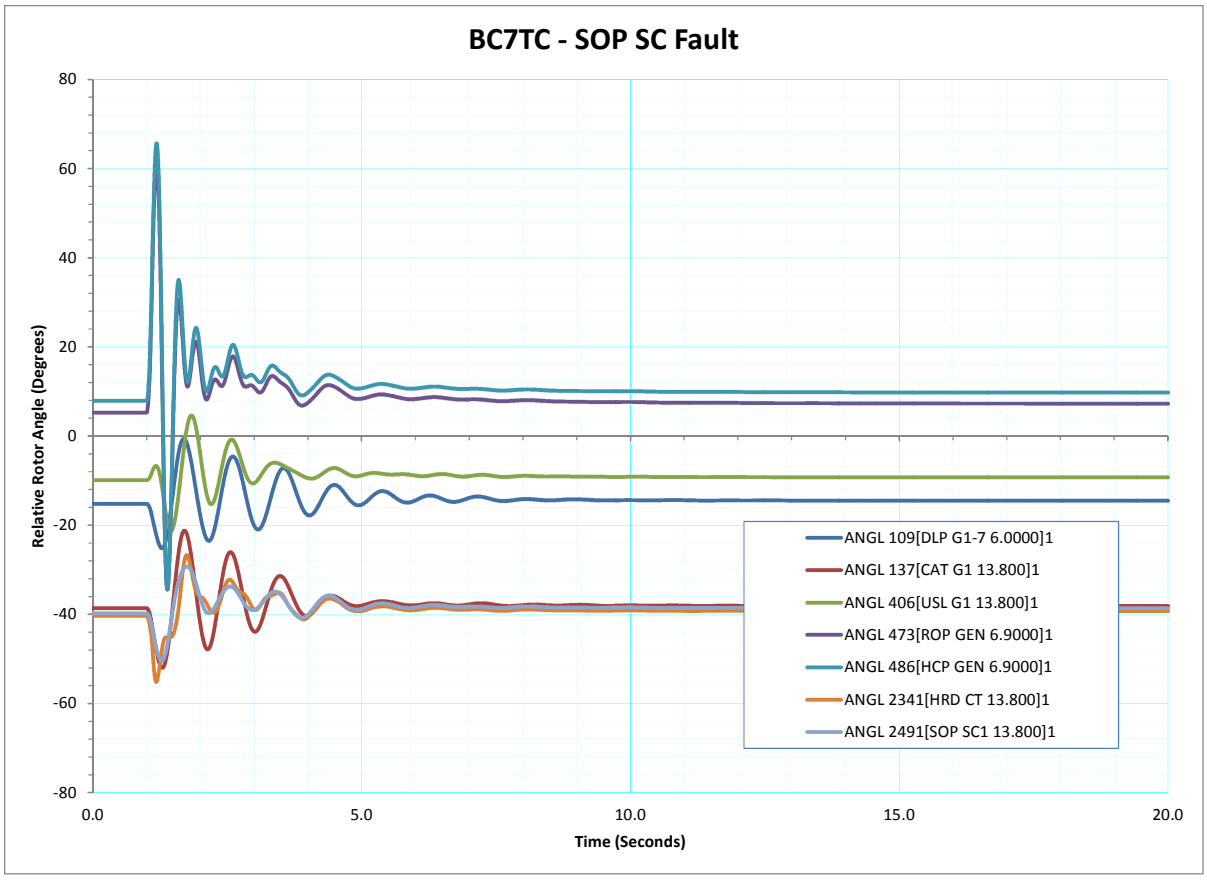


Figure 193 - BC7TC - SOP SC Fault - Relative Rotor Angle (Degrees)

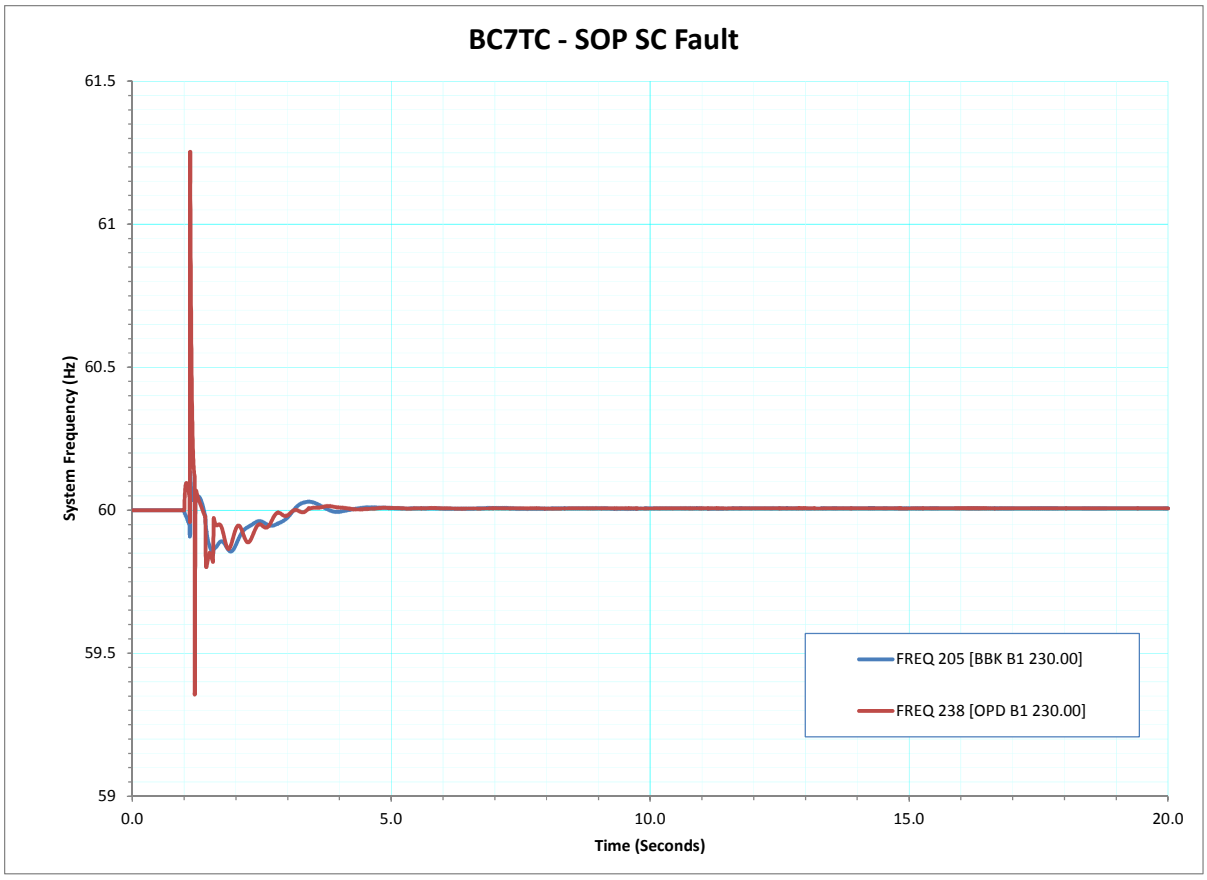


Figure 194 - BC7TC - SOP SC Fault - System Frequency (Hz)

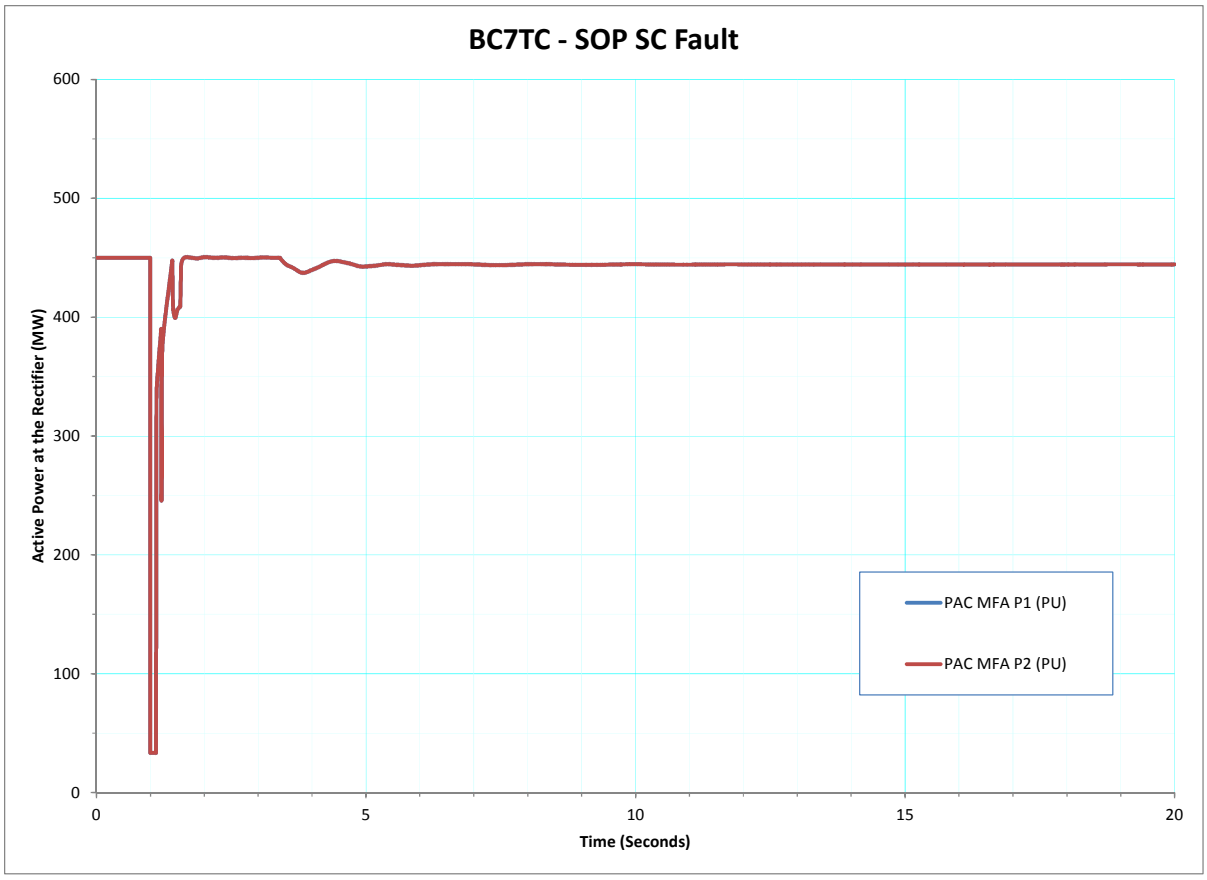


Figure 195 - BC7TC - SOP SC Fault - Active Power at the Rectifier (MW)

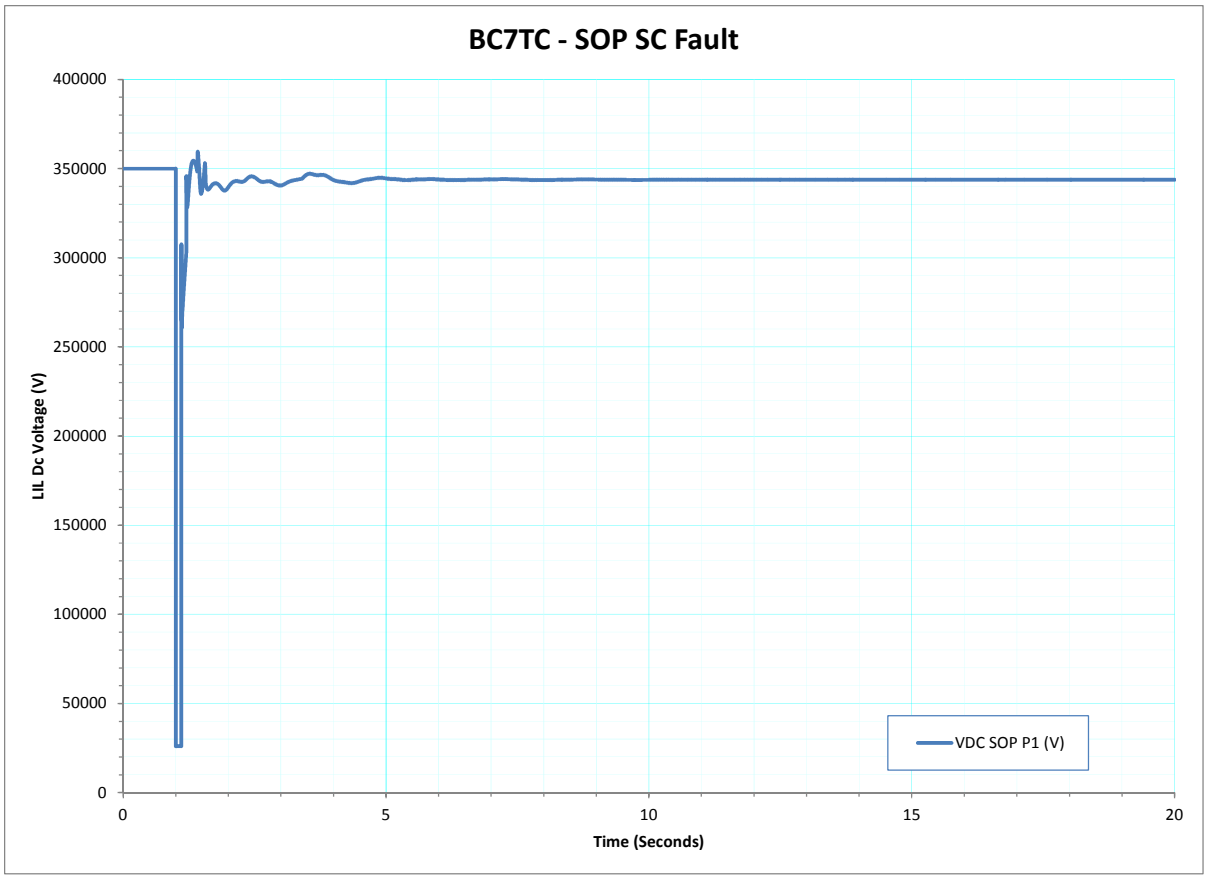


Figure 196 - BC7TC - SOP SC Fault - LIL Dc Voltage (V)

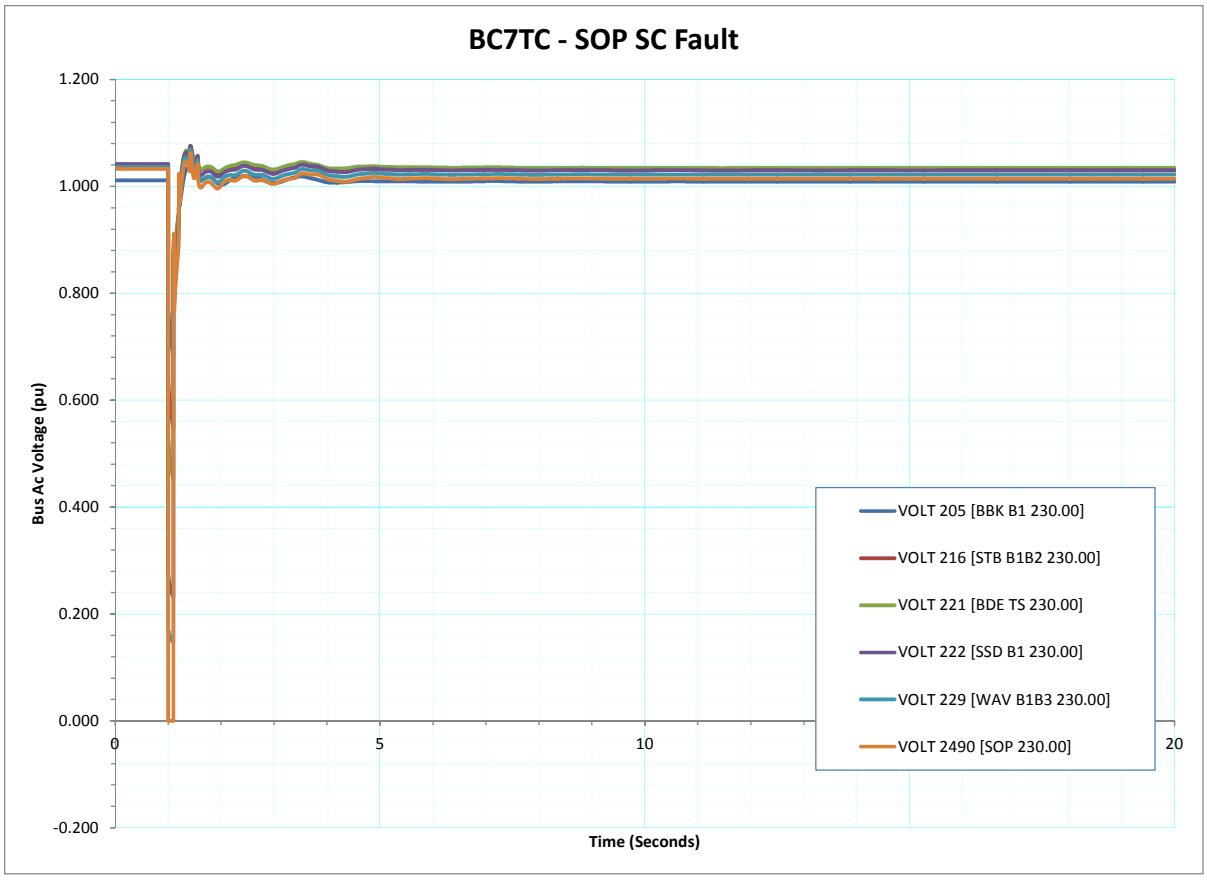


Figure 197 - BC7TC - SOP SC Fault - Bus Ac Voltage (pu)

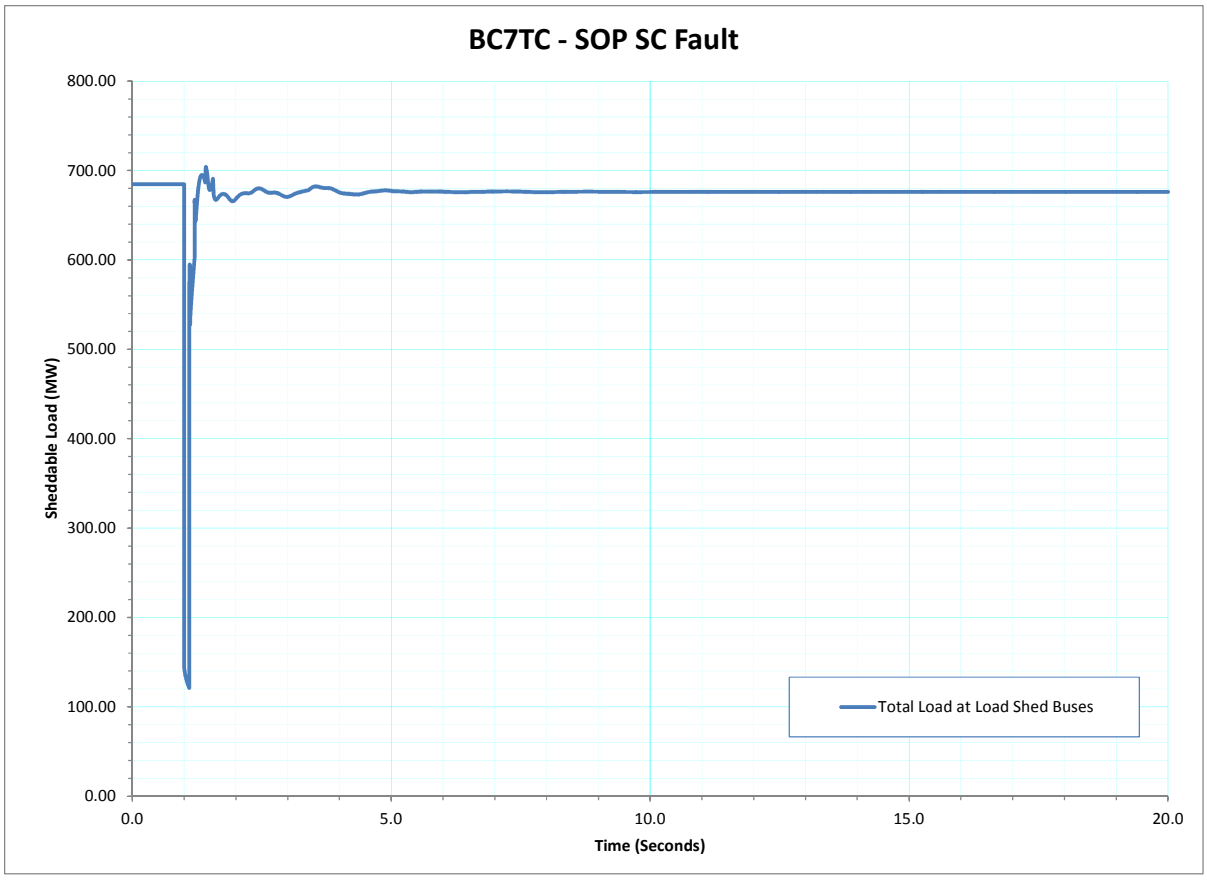


Figure 198 - BC7TC - SOP SC Fault - Sheddable Load (MW)

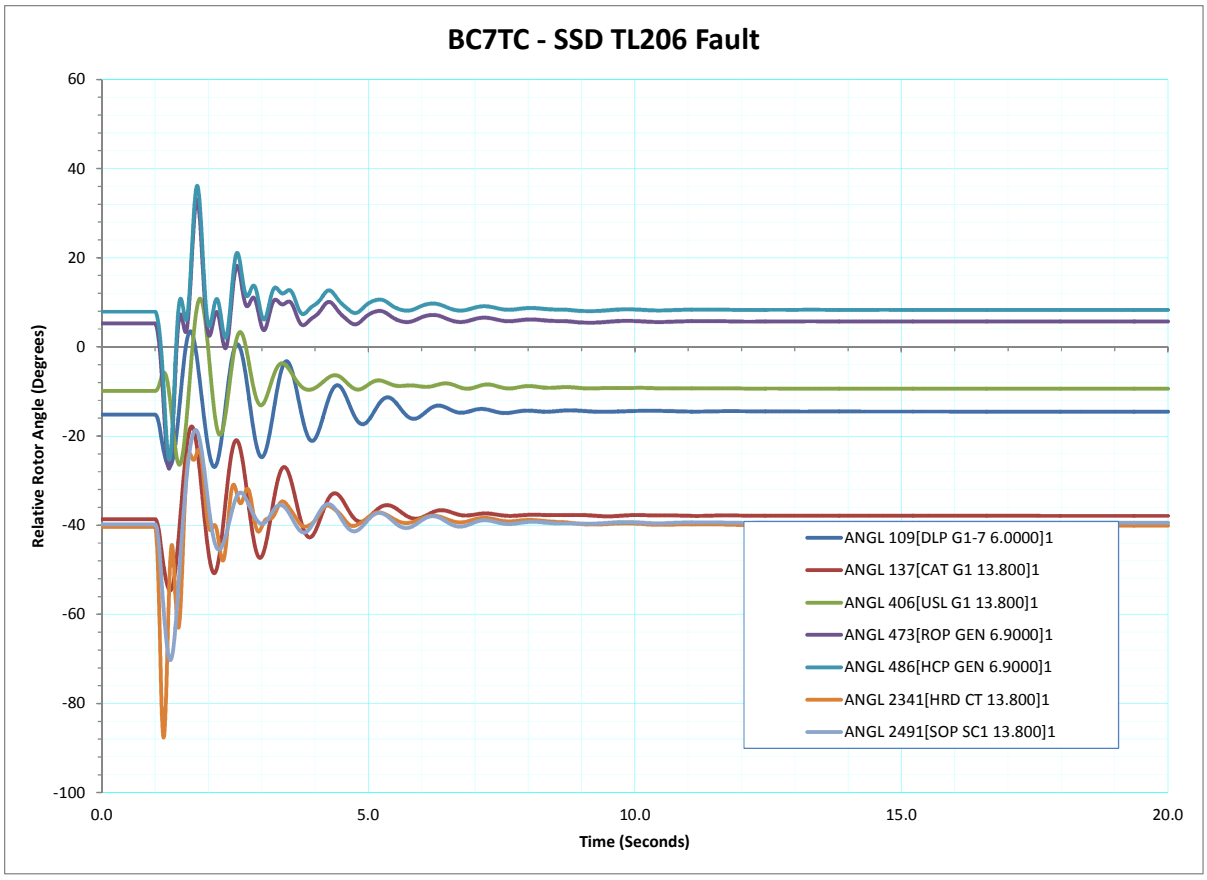


Figure 199 - BC7TC - SSD TL206 Fault - Relative Rotor Angle (Degrees)

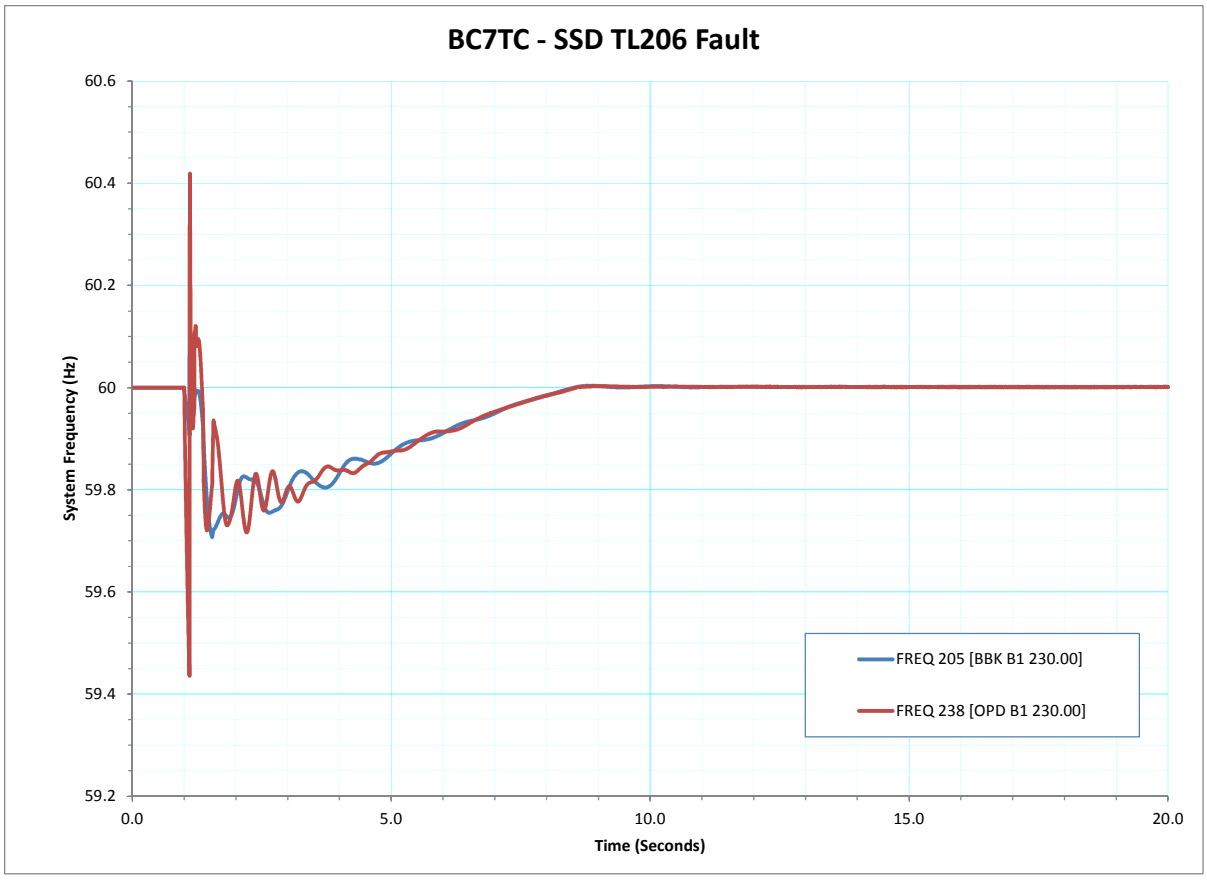


Figure 200 - BC7TC - SSD TL206 Fault - System Frequency (Hz)

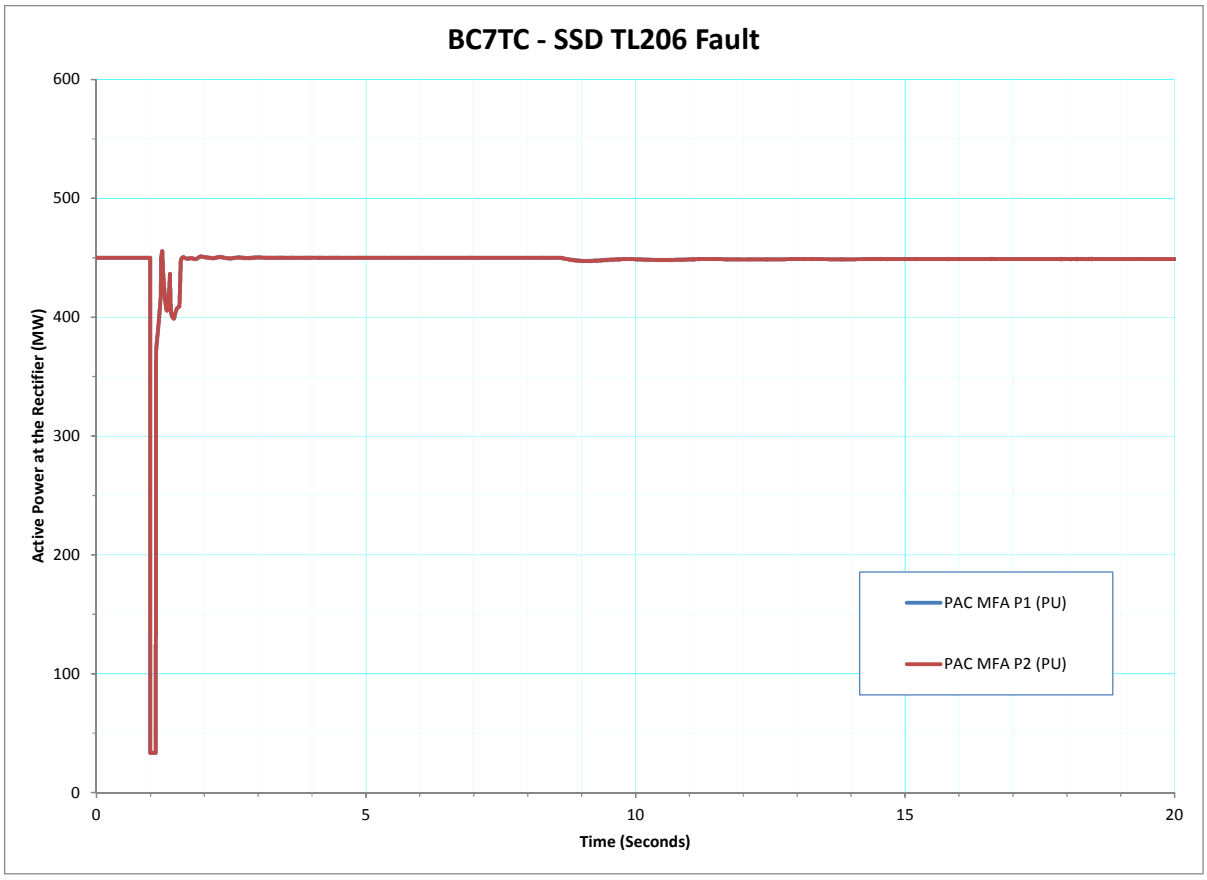


Figure 201 - BC7TC - SSD TL206 Fault - Active Power at the Rectifier (MW)

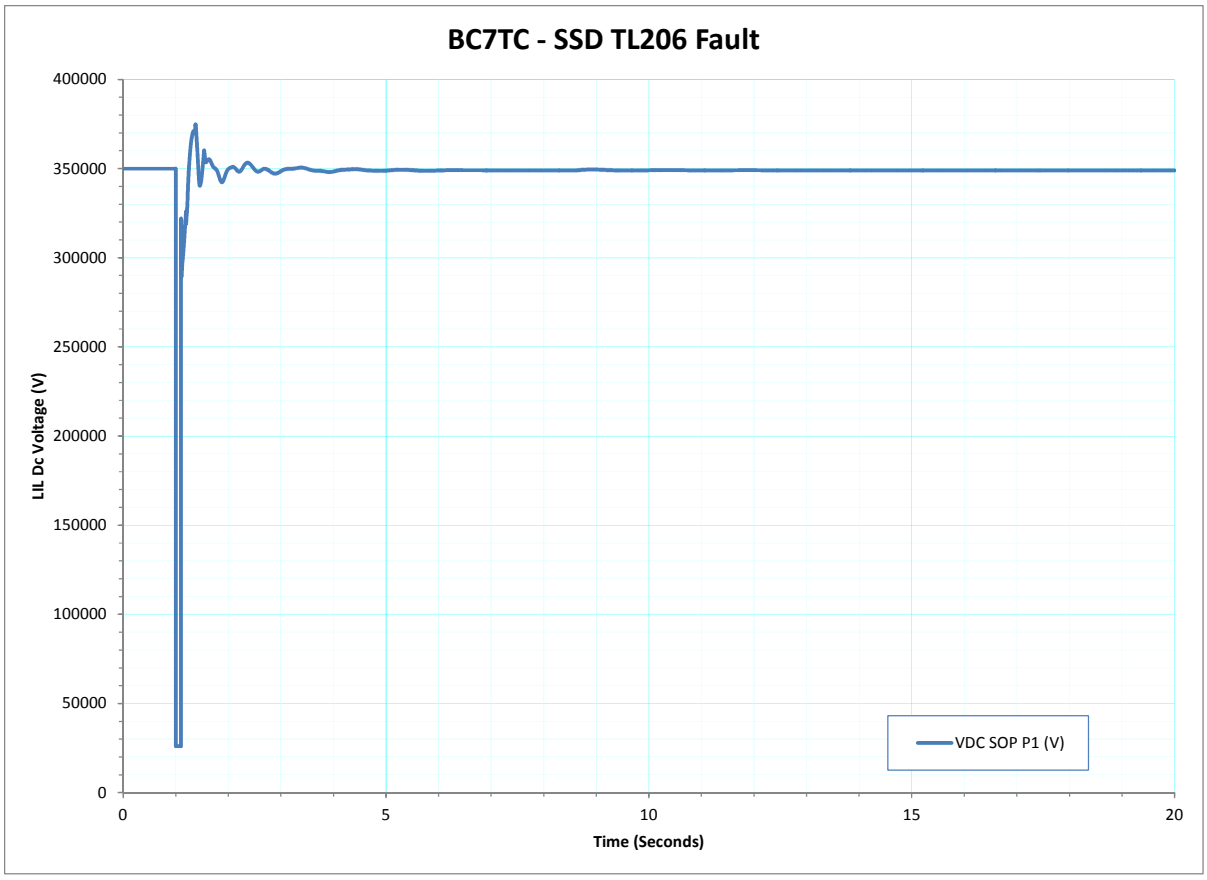


Figure 202 - BC7TC - SSD TL206 Fault - LIL Dc Voltage (V)

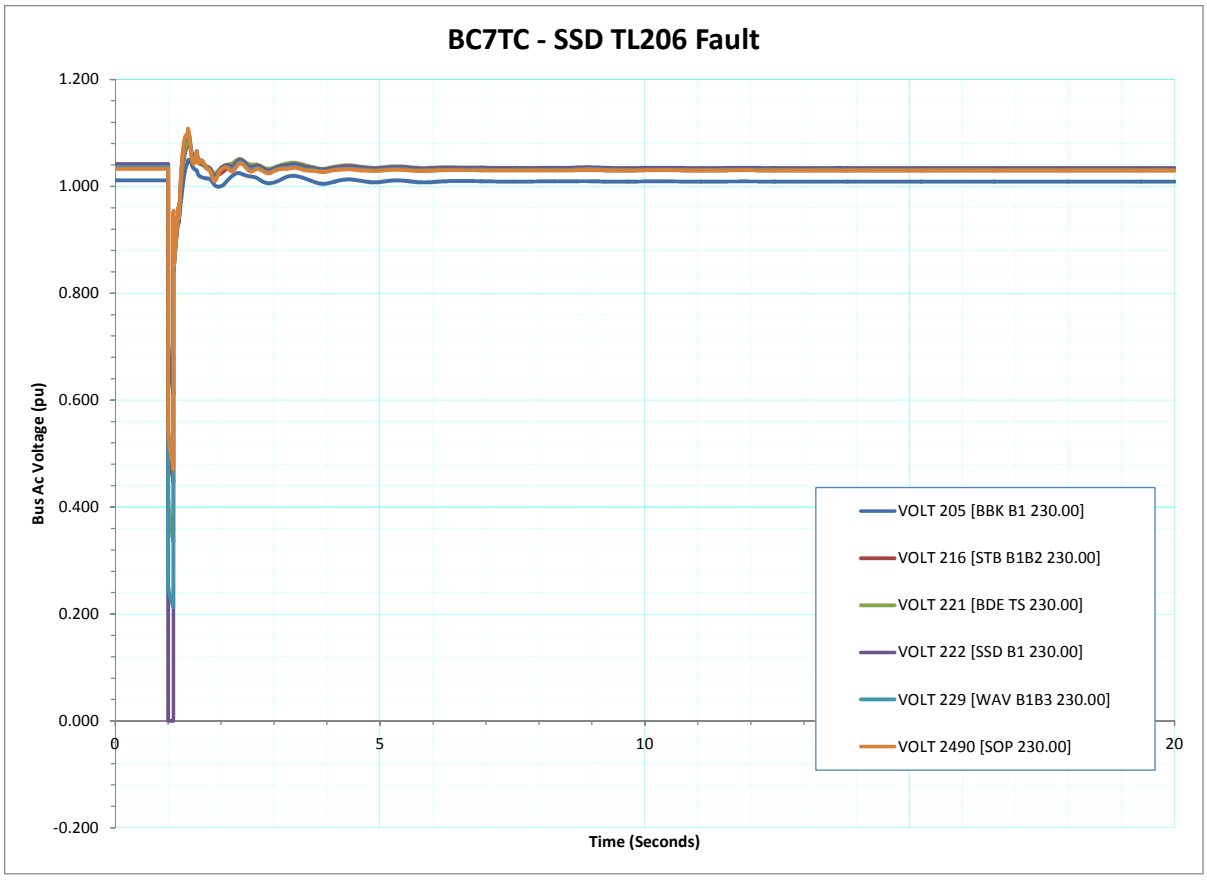


Figure 203 - BC7TC - SSD TL206 Fault - Bus Ac Voltage (pu)

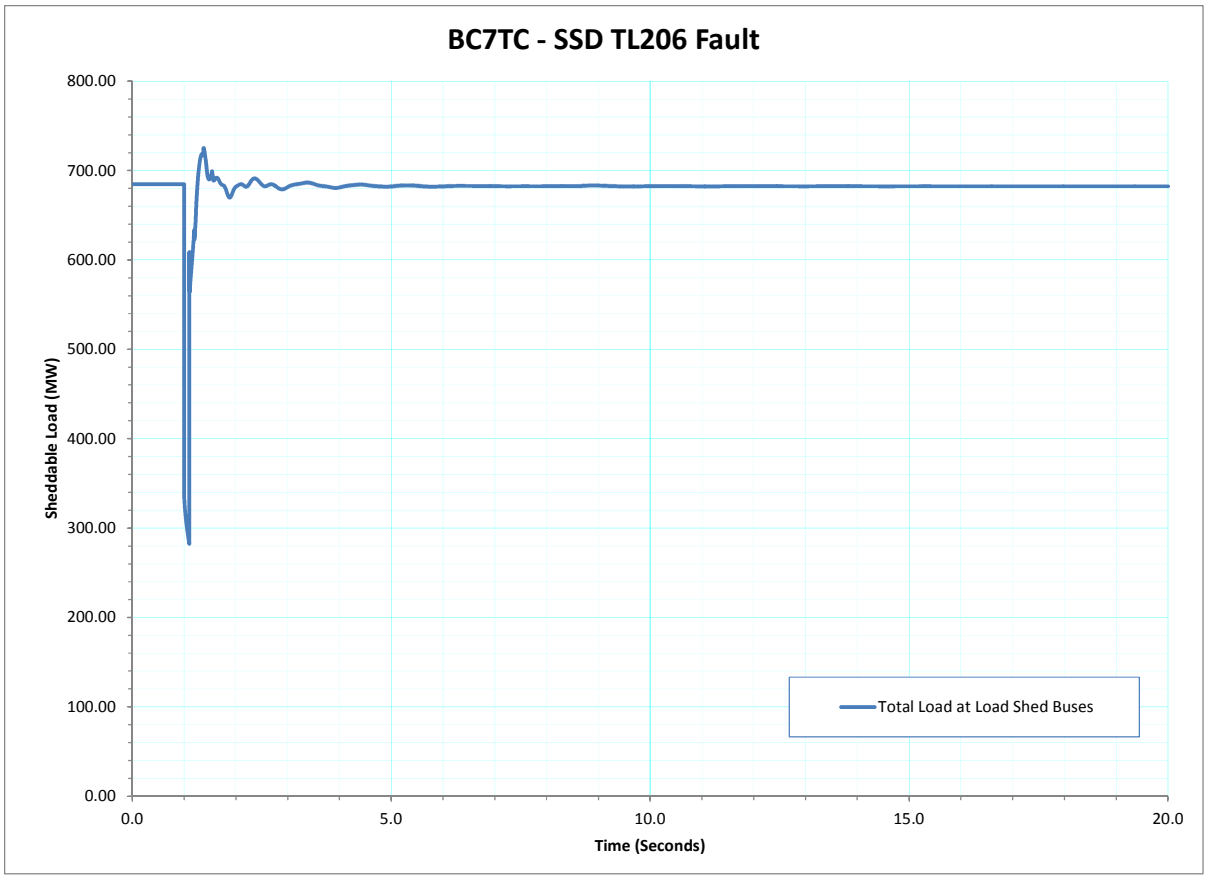


Figure 204 - BC7TC - SSD TL206 Fault - Sheddable Load (MW)

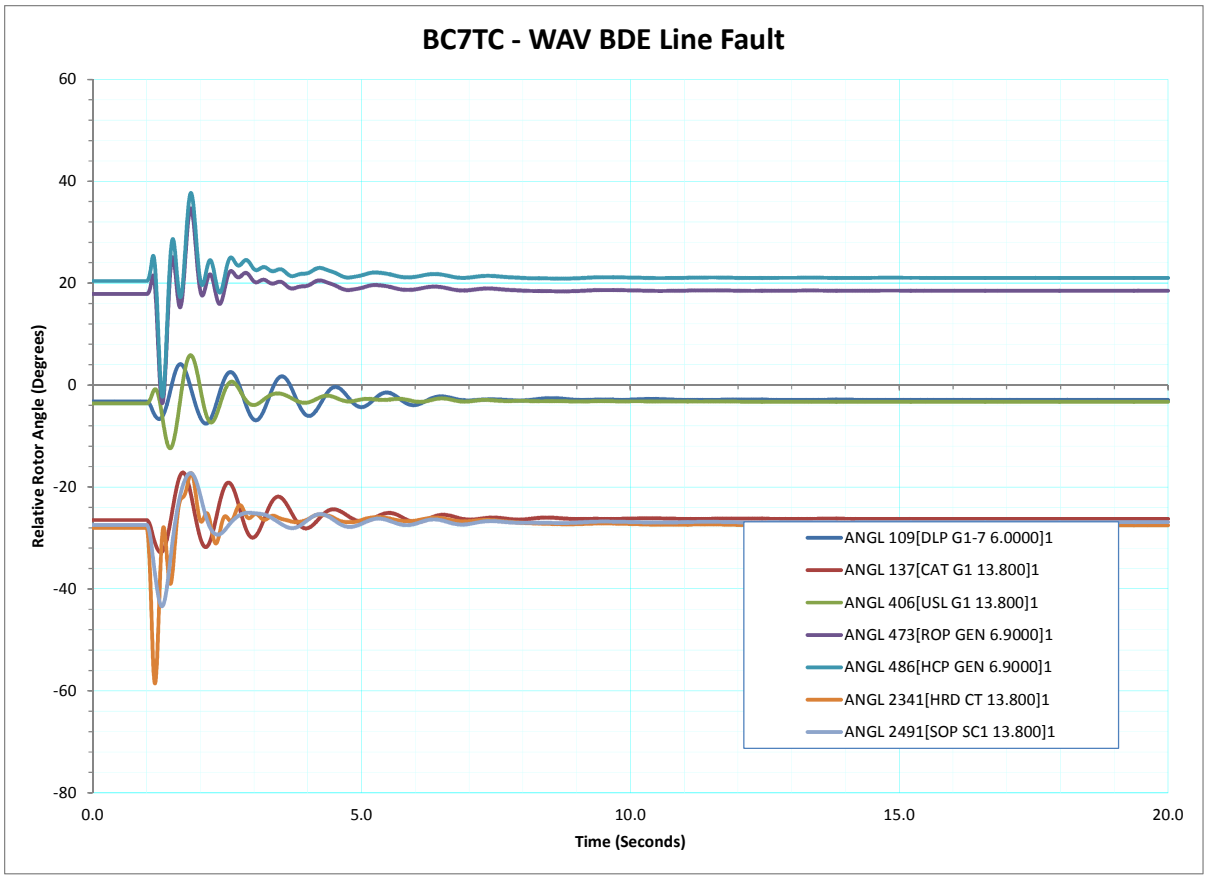


Figure 205 - BC7TC - WAV BDE Line Fault - Relative Rotor Angle (Degrees)

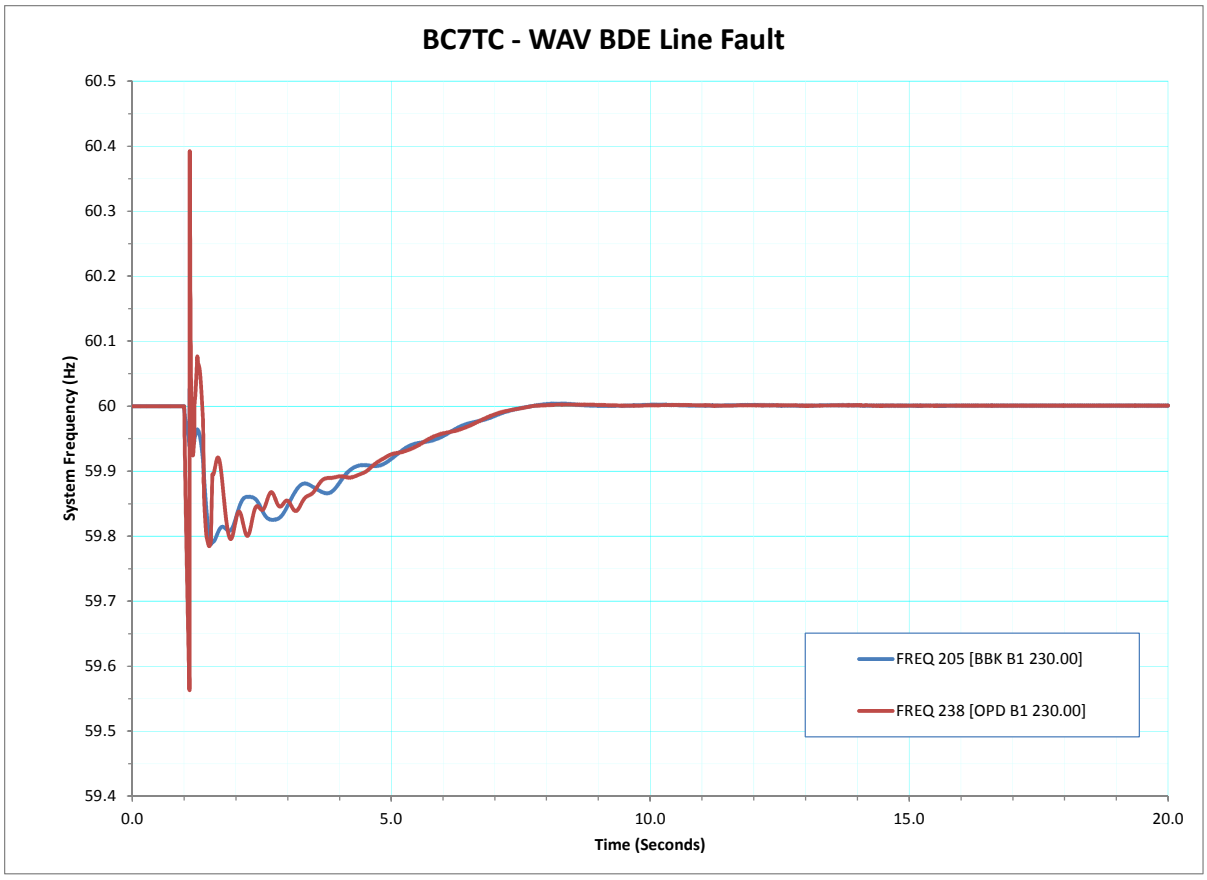


Figure 206 - BC7TC - WAV BDE Line Fault - System Frequency (Hz)

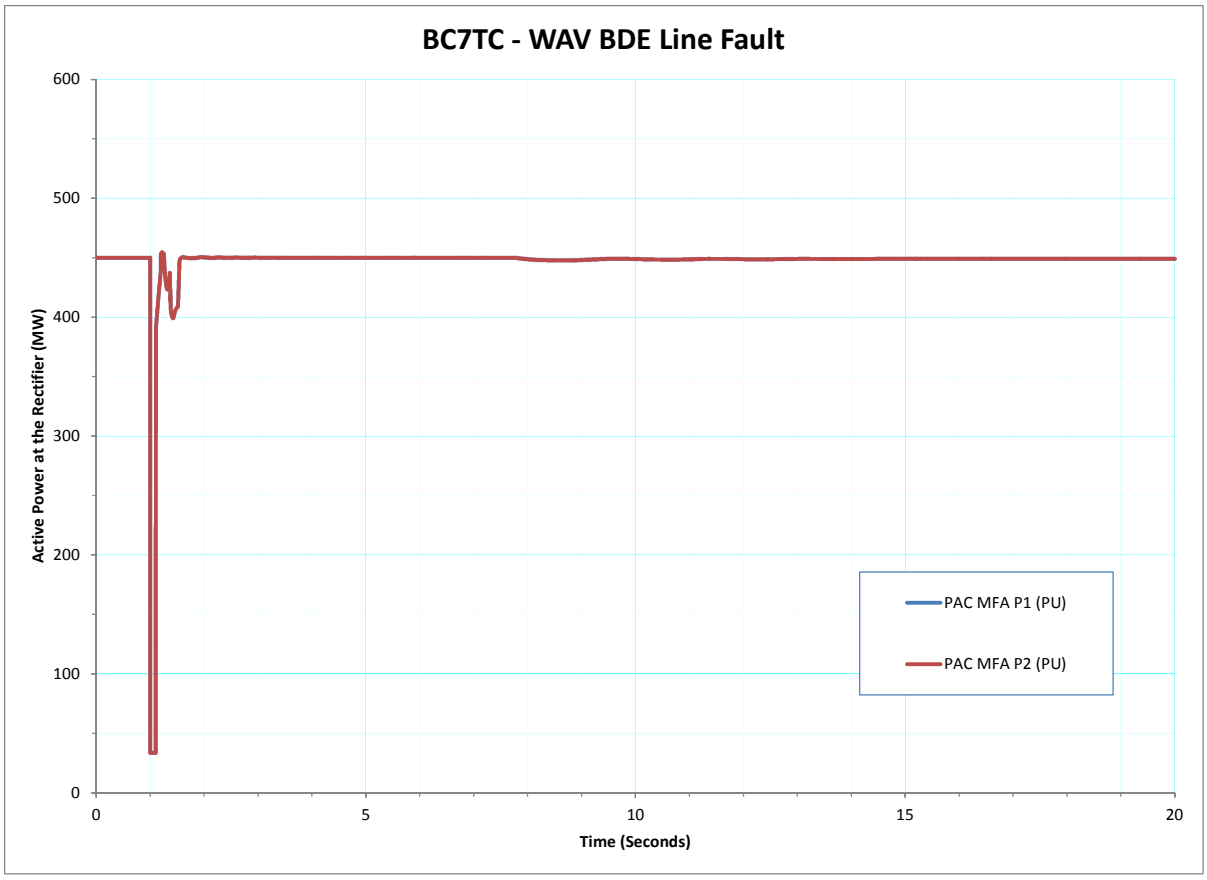


Figure 207 - BC7TC - WAV BDE Line Fault - Active Power at the Rectifier (MW)

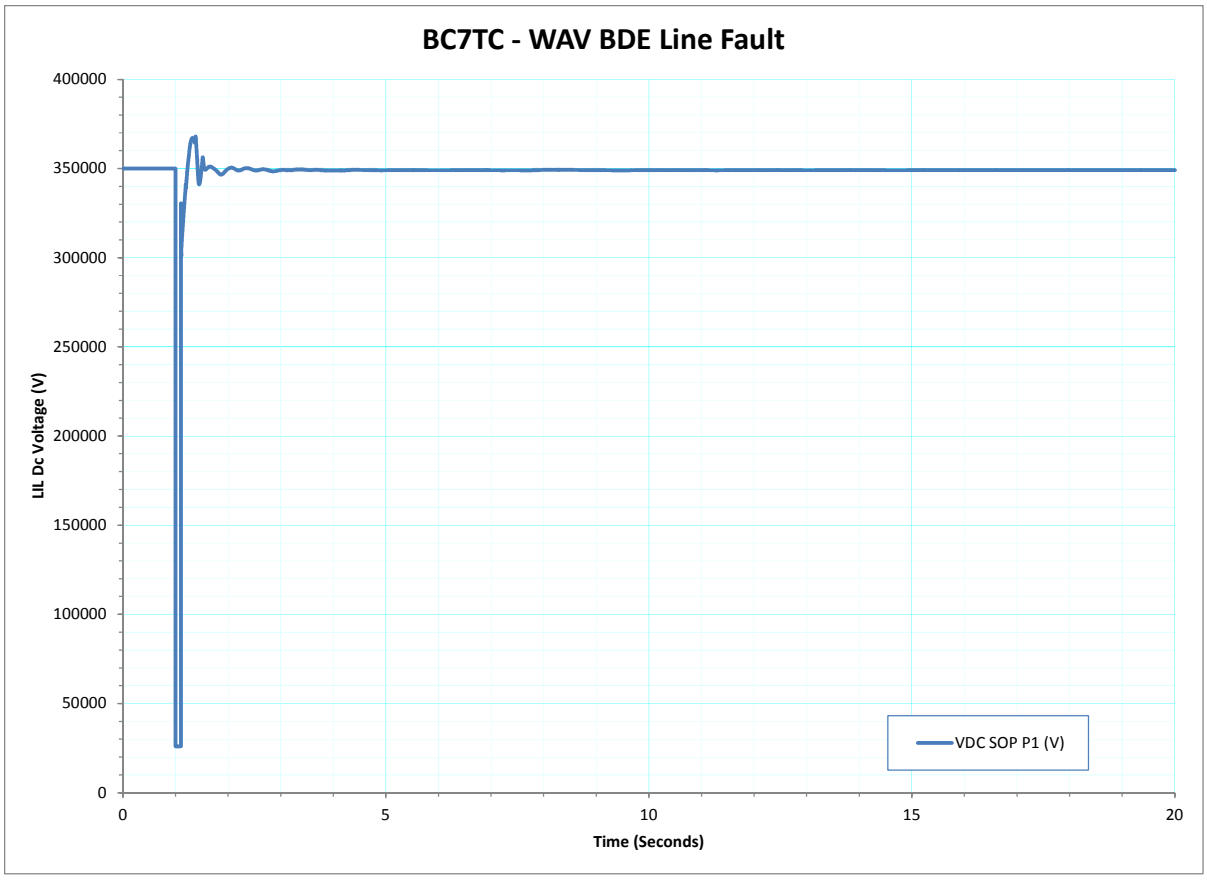


Figure 208 - BC7TC - WAV BDE Line Fault - LIL Dc Voltage (V)

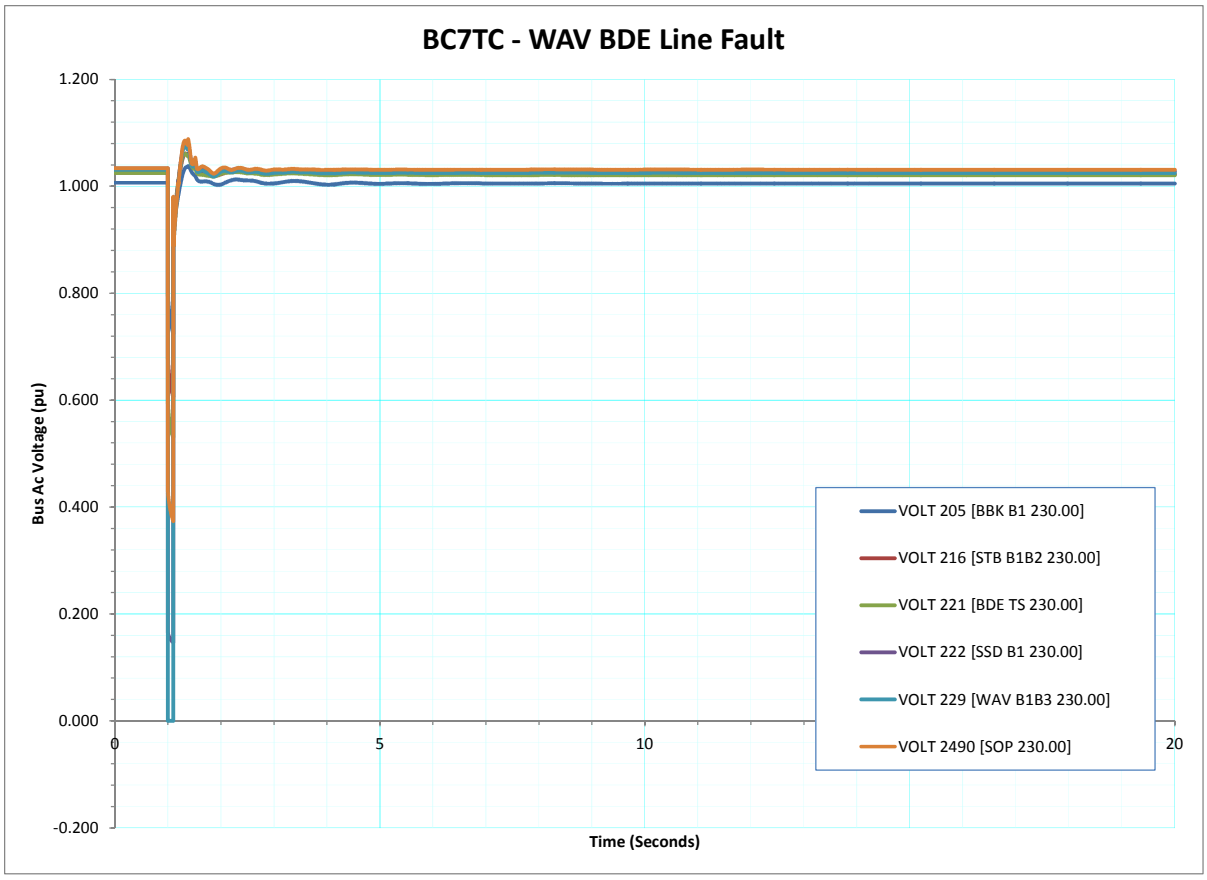


Figure 209 - BC7TC - WAV BDE Line Fault - Bus Ac Voltage (pu)

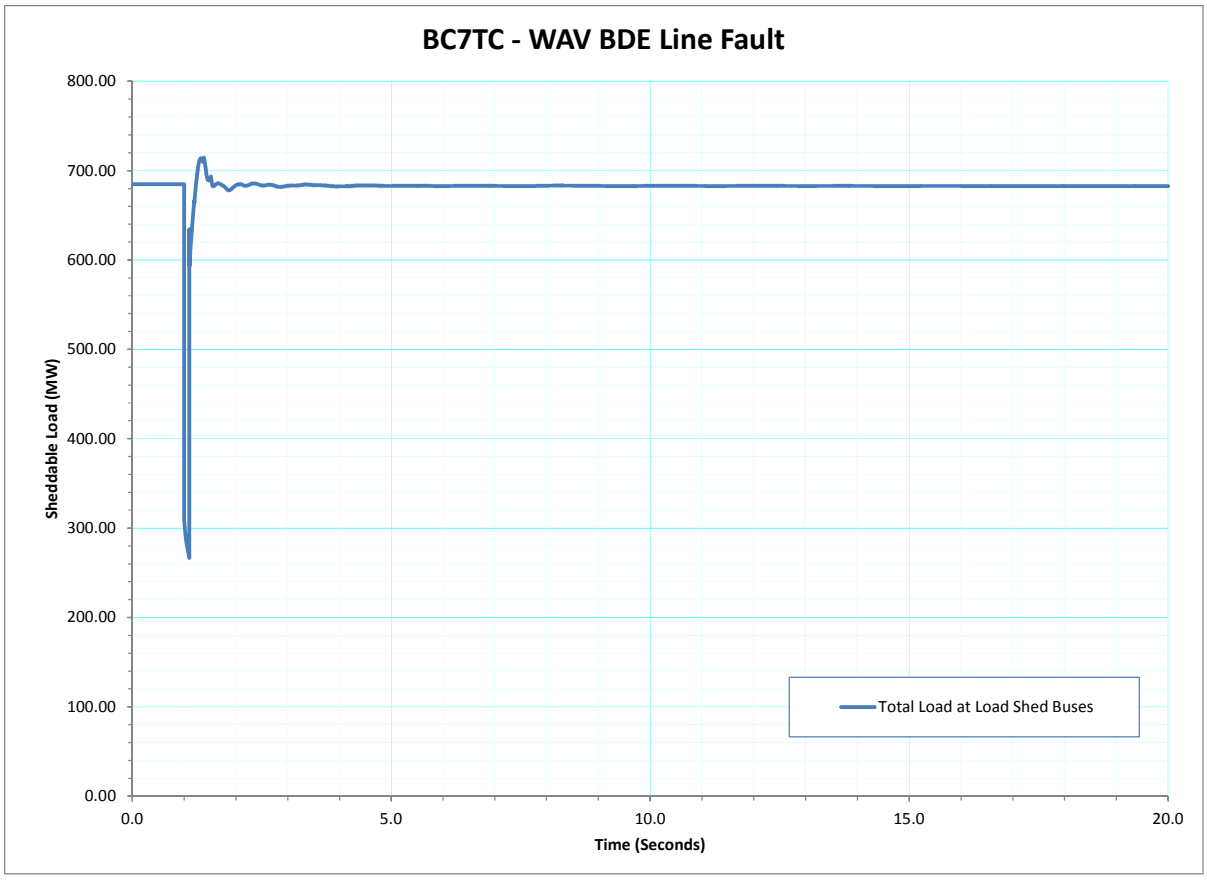


Figure 210 - BC7TC - WAV BDE Line Fault - Sheddable Load (MW)

1.8. BASE CASE 8 TRANSIENT STABILITY PLOTS

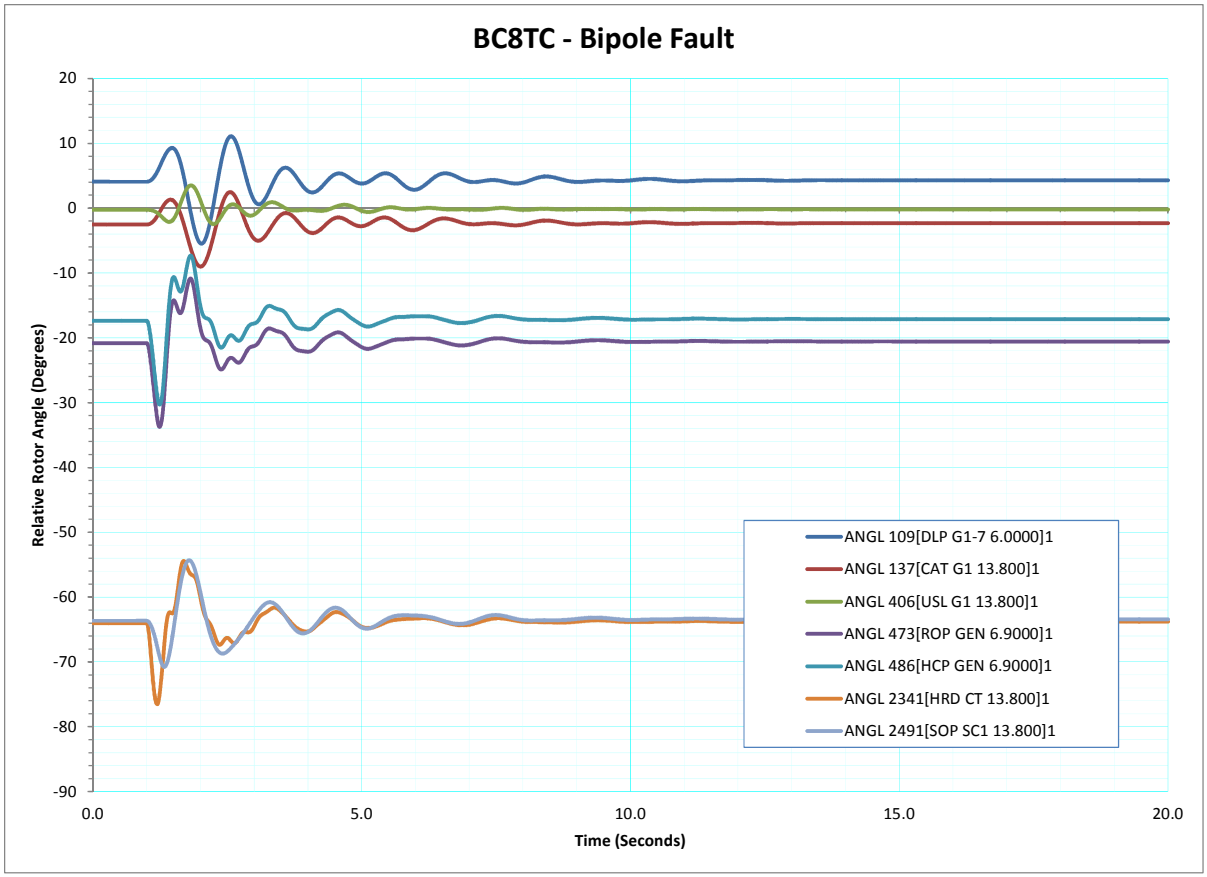


Figure 211 - BC8TC - Bipole Fault - Relative Rotor Angle (Degrees)

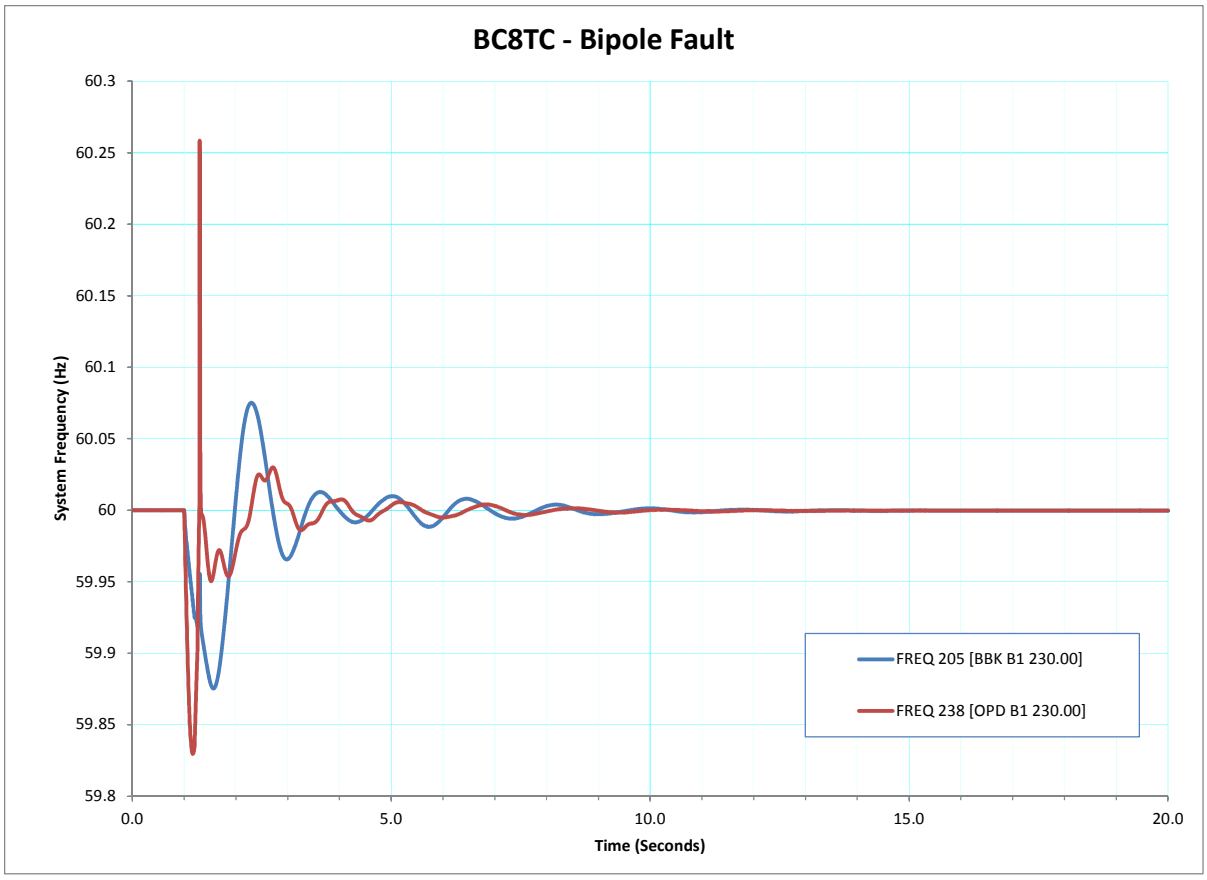


Figure 212 - BC8TC - Bipole Fault - System Frequency (Hz)

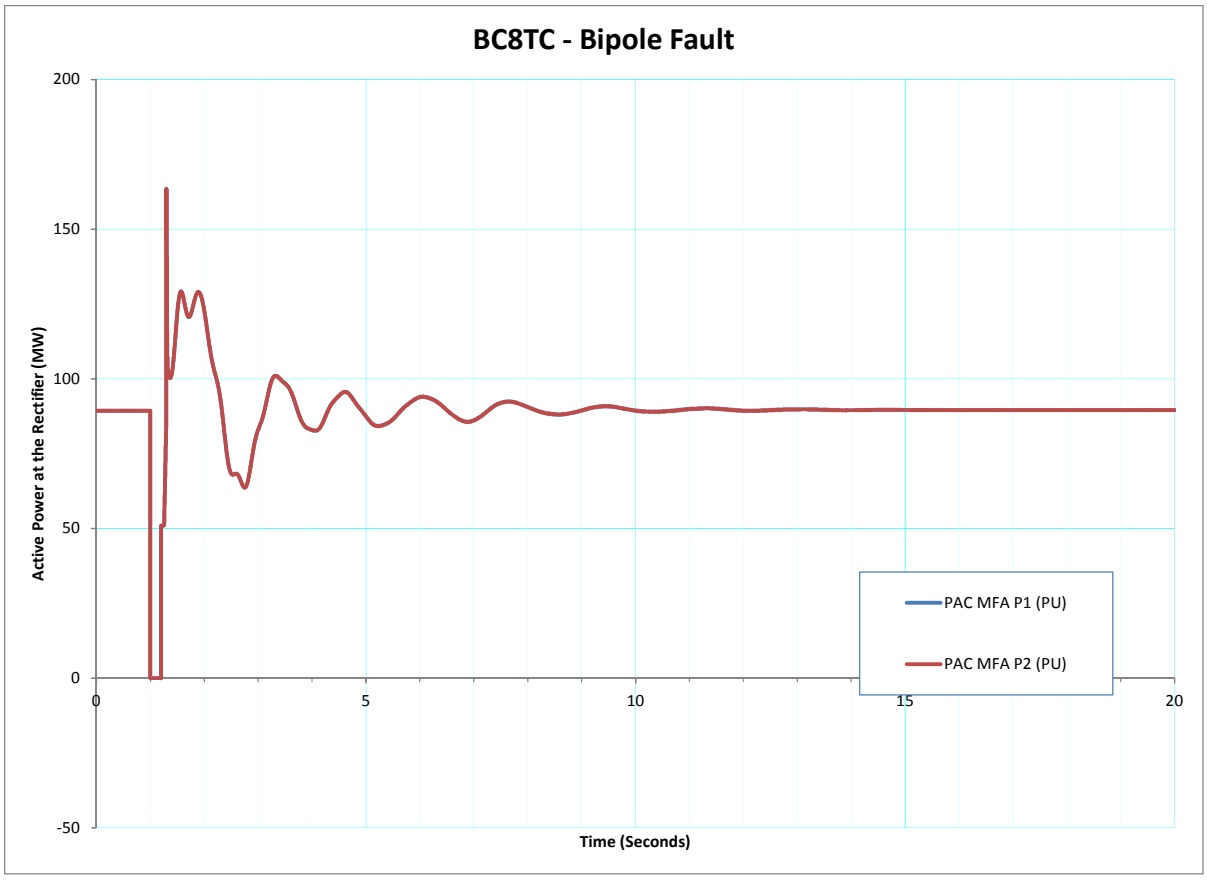


Figure 213 - BC8TC - Bipole Fault - Active Power at the Rectifier (MW)

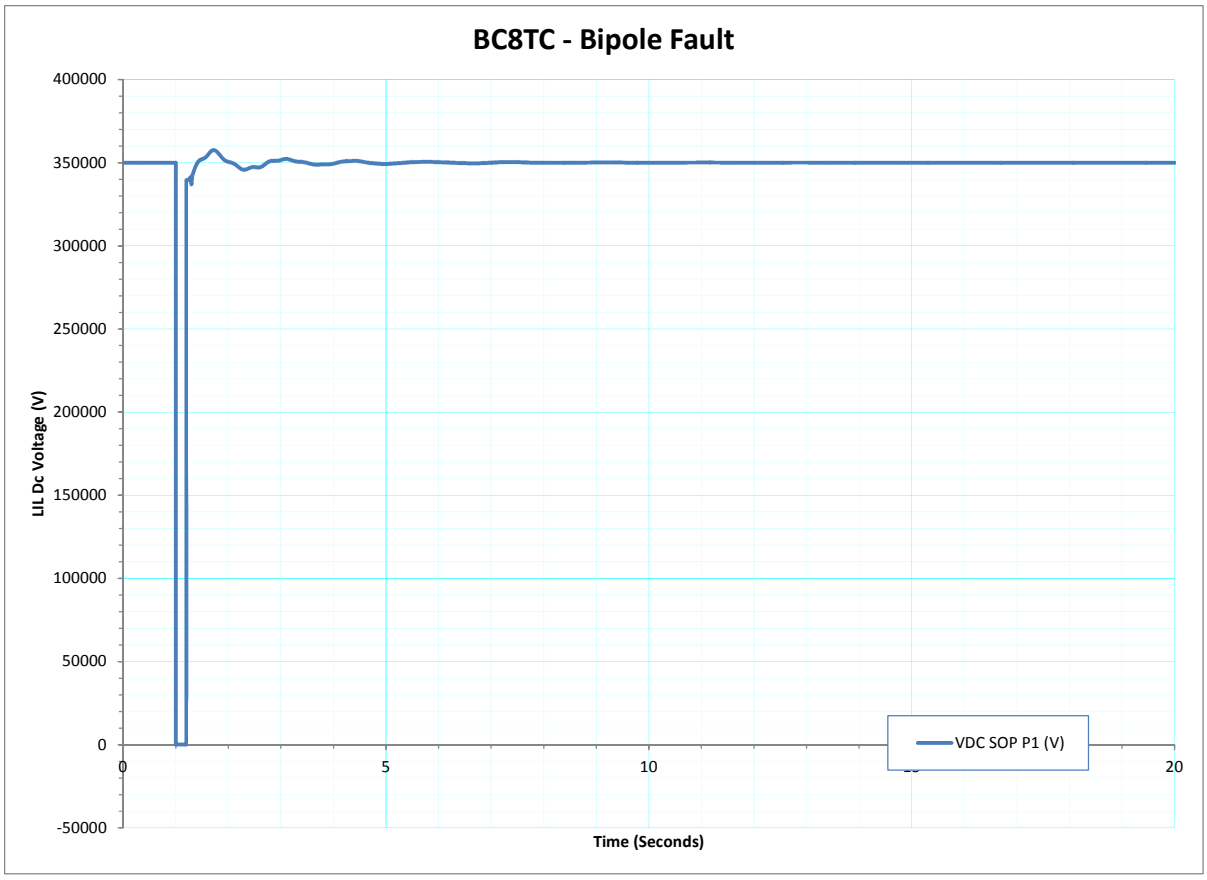


Figure 214 - BC8TC - Bipole Fault - LIL Dc Voltage (V)

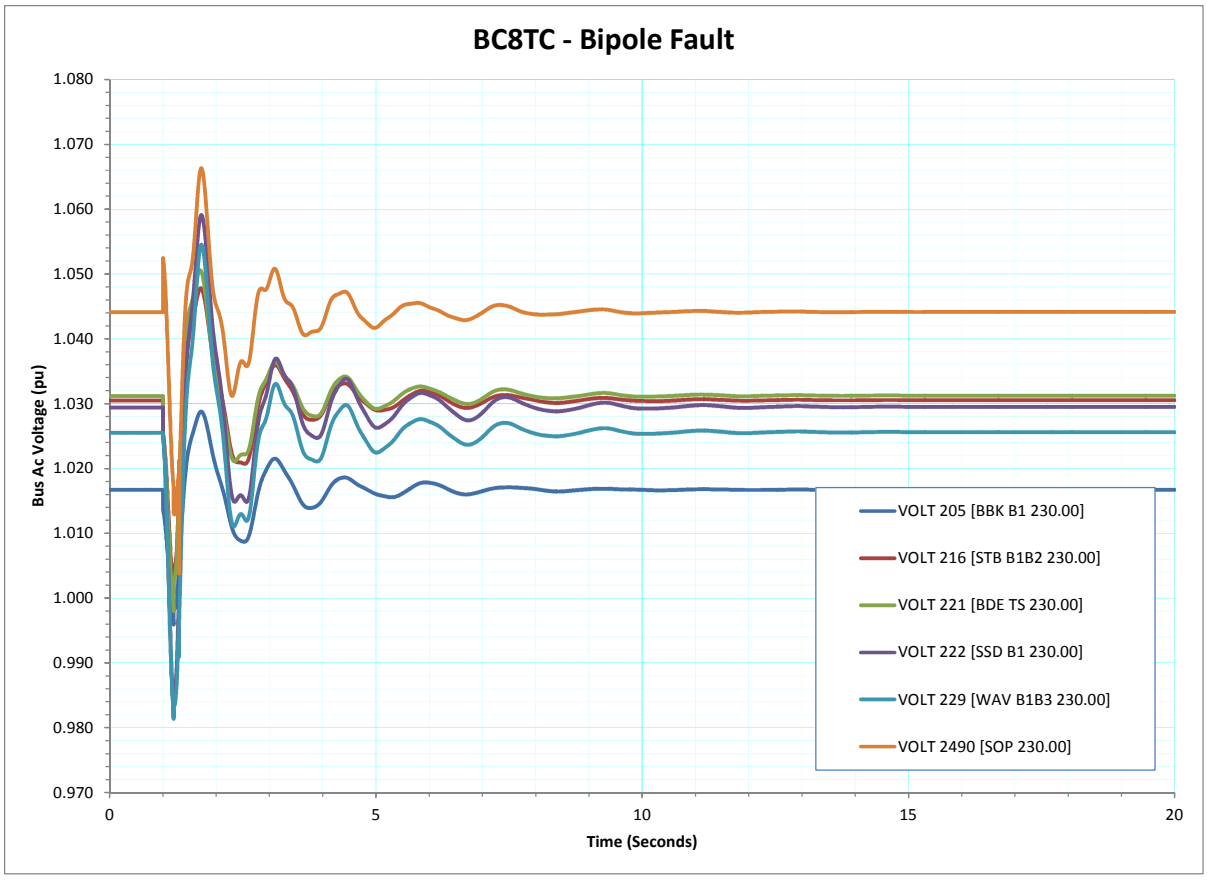


Figure 215 - BC8TC - Bipole Fault - Bus Ac Voltage (pu)

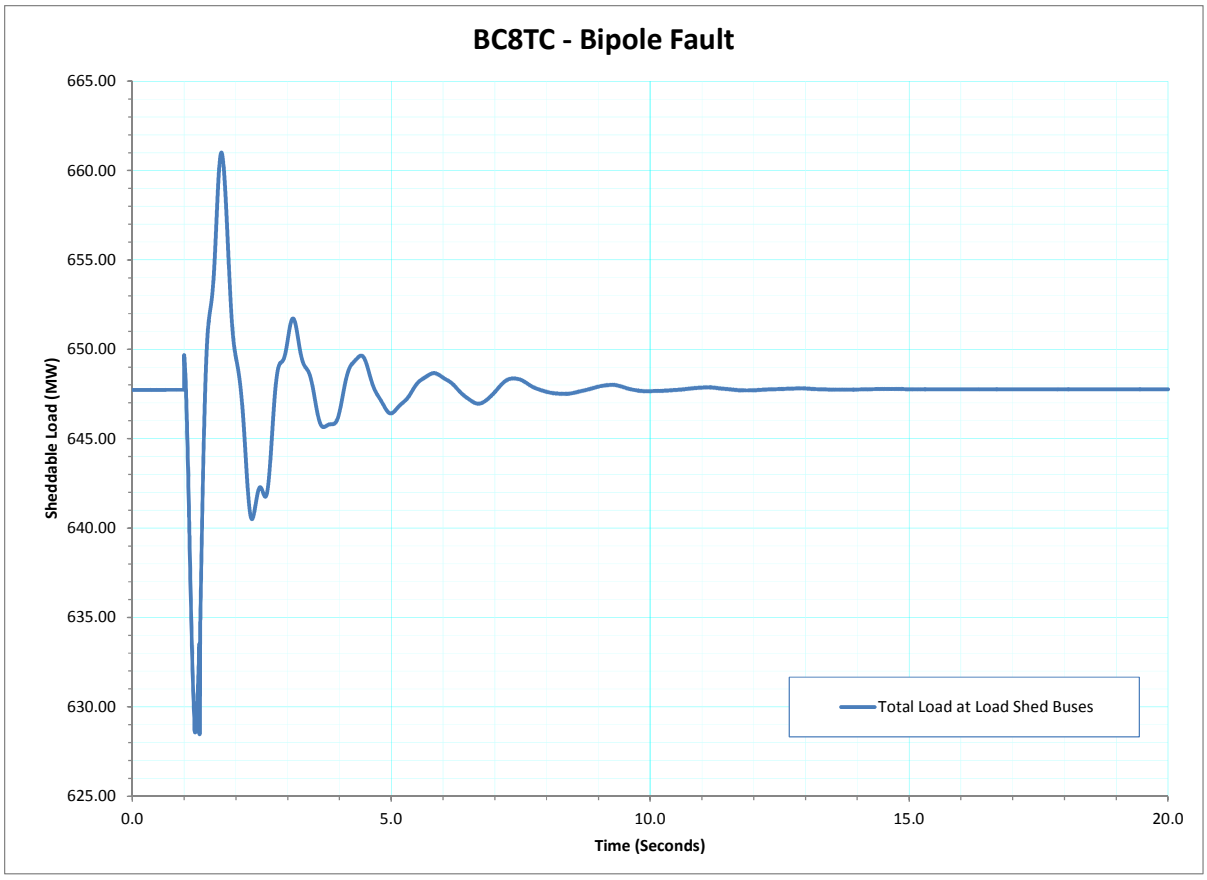


Figure 216 - BC8TC - Bipole Fault - Sheddable Load (MW)

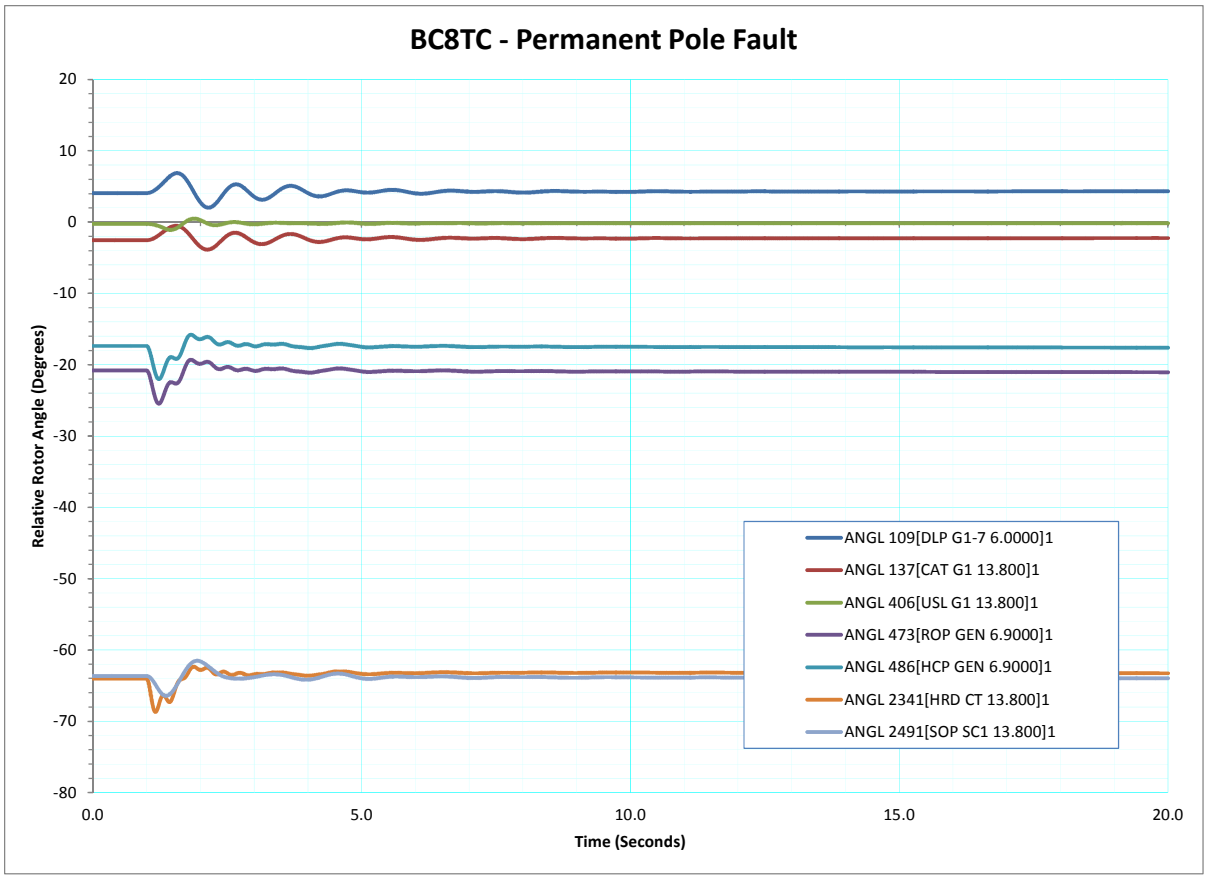


Figure 217 - BC8TC - Permanent Pole Fault - Relative Rotor Angle (Degrees)

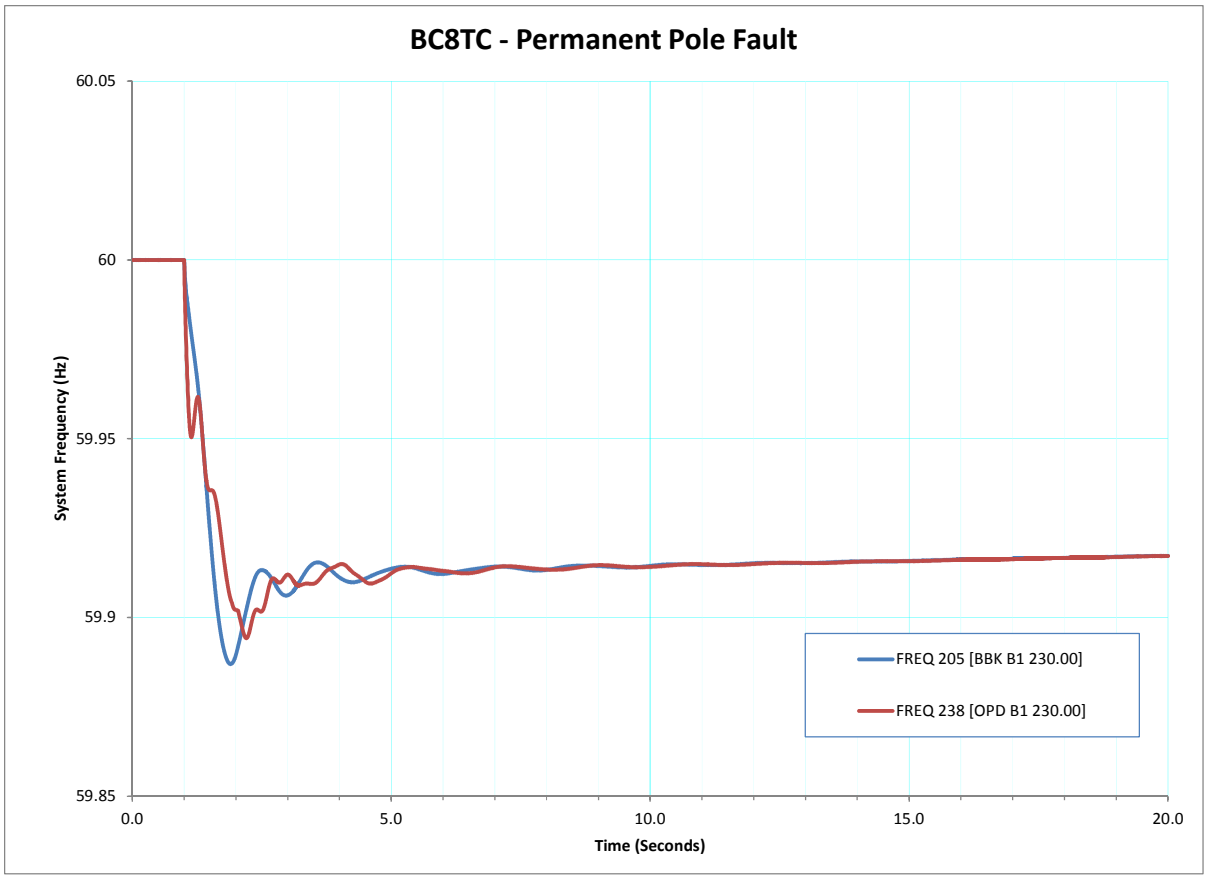


Figure 218 - BC8TC - Permanent Pole Fault - System Frequency (Hz)

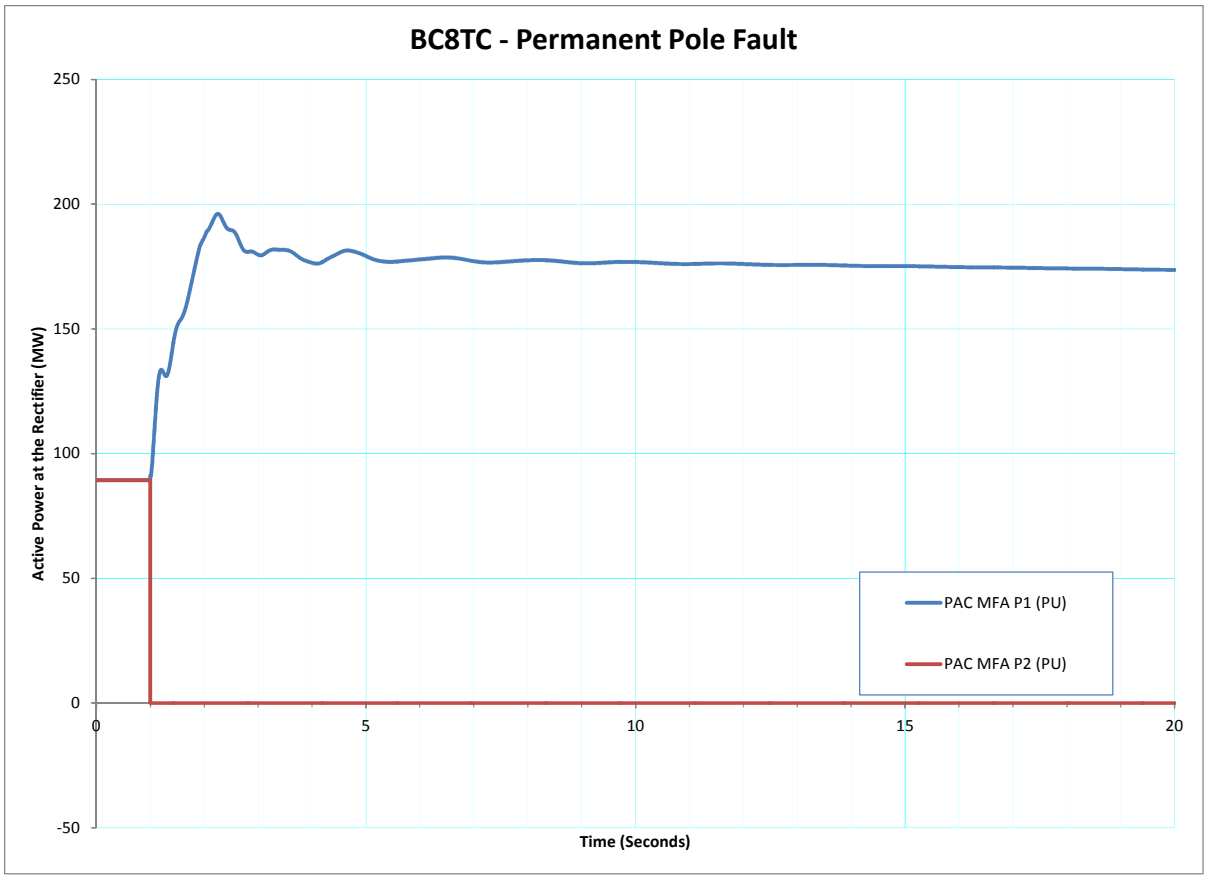


Figure 219 - BC8TC - Permanent Pole Fault - Active Power at the Rectifier (MW)

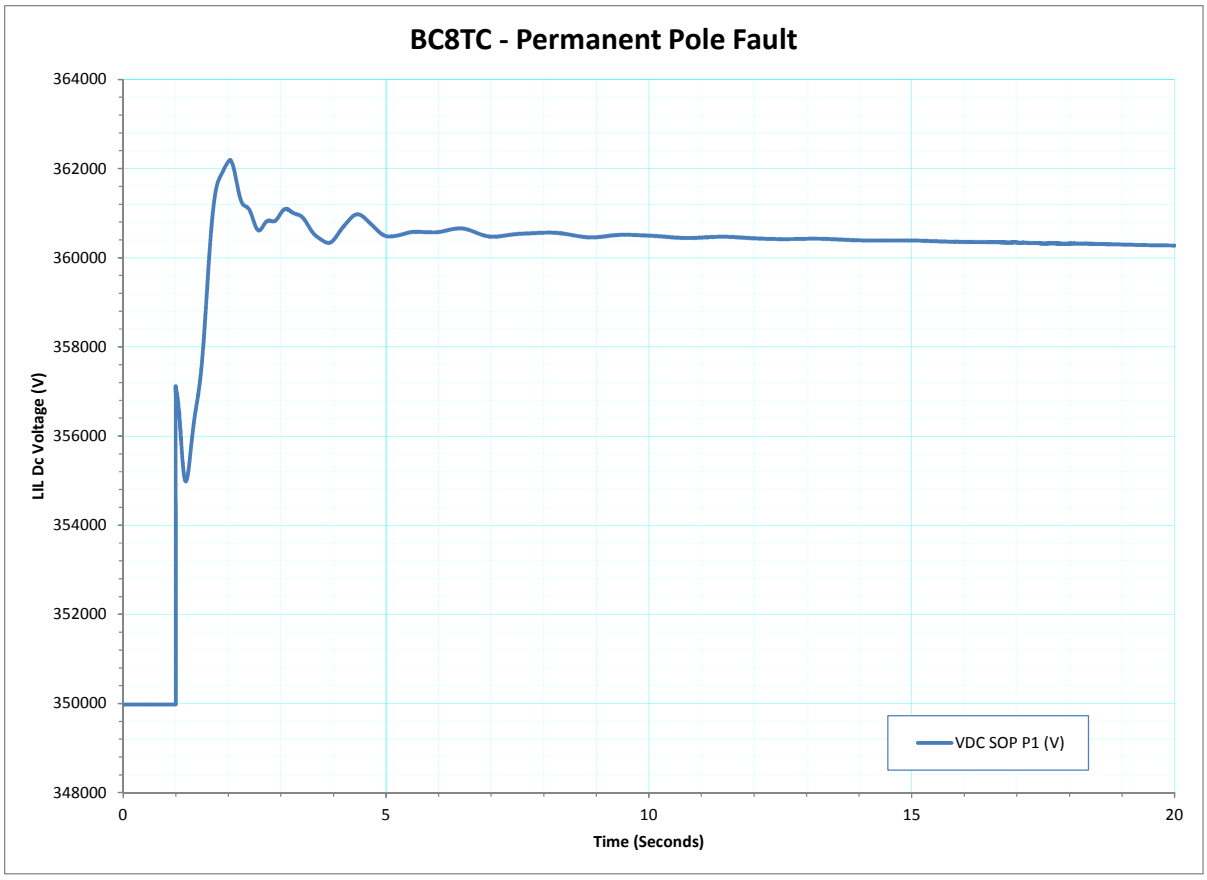


Figure 220 - BC8TC - Permanent Pole Fault - LIL Dc Voltage (V)

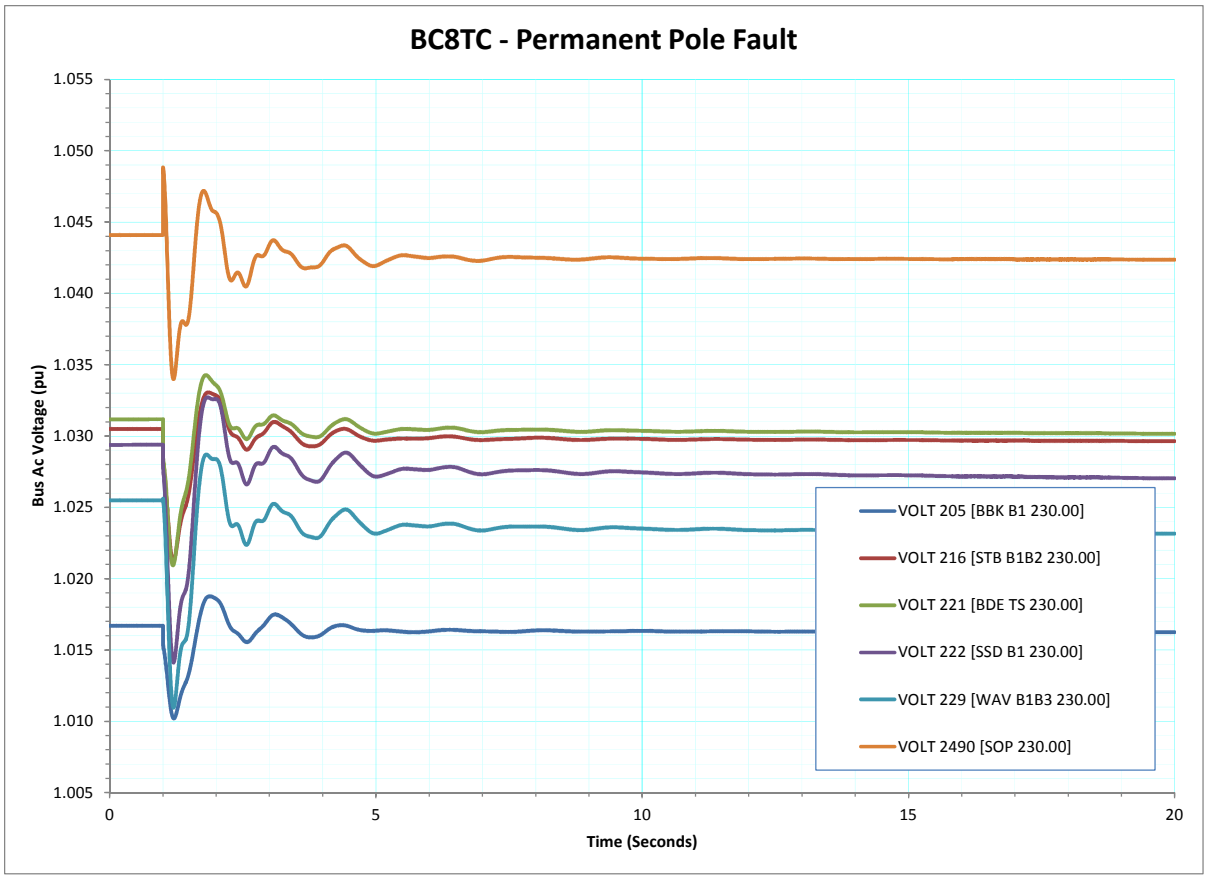


Figure 221 - BC8TC - Permanent Pole Fault - Bus Ac Voltage (pu)

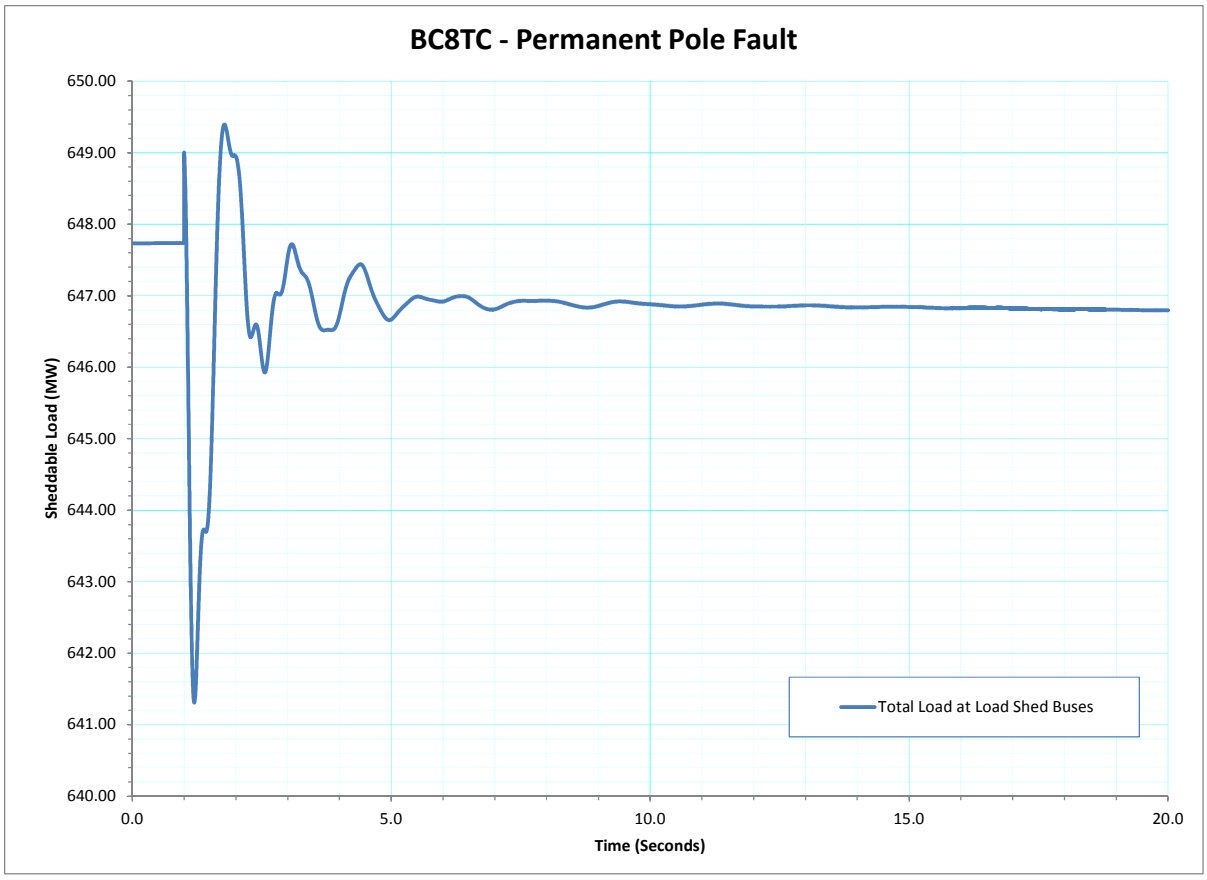


Figure 222 - BC8TC - Permanent Pole Fault - Sheddable Load (MW)

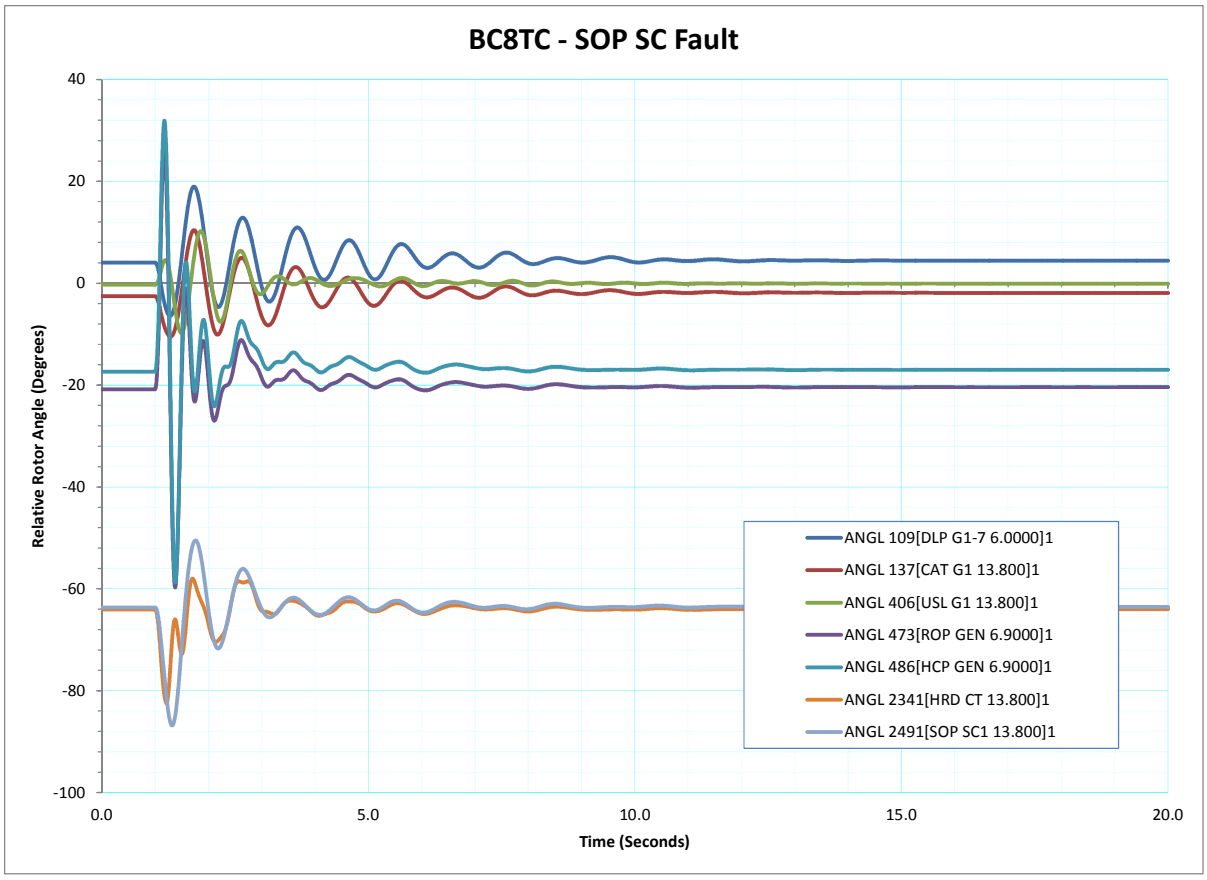


Figure 223 - BC8TC - SOP SC Fault - Relative Rotor Angle (Degrees)

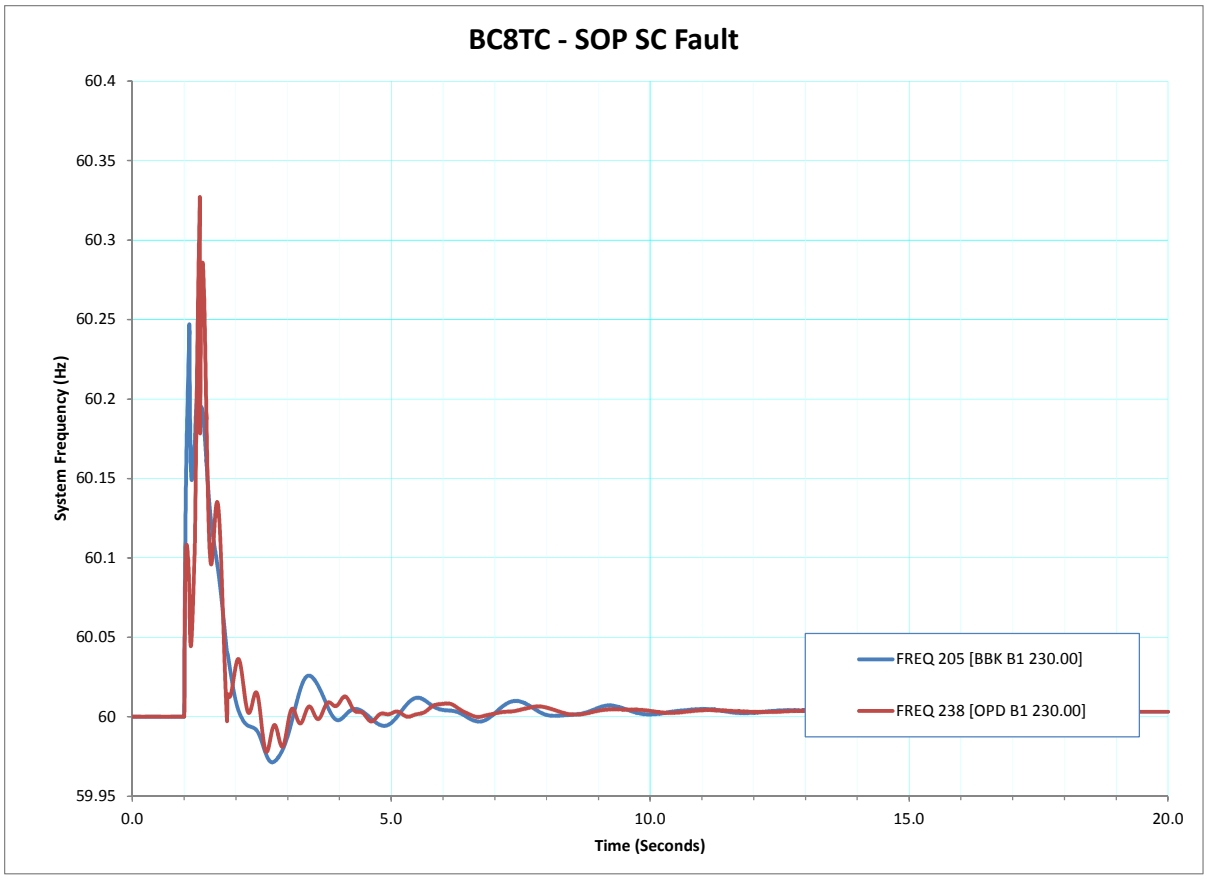


Figure 224 - BC8TC - SOP SC Fault - System Frequency (Hz)

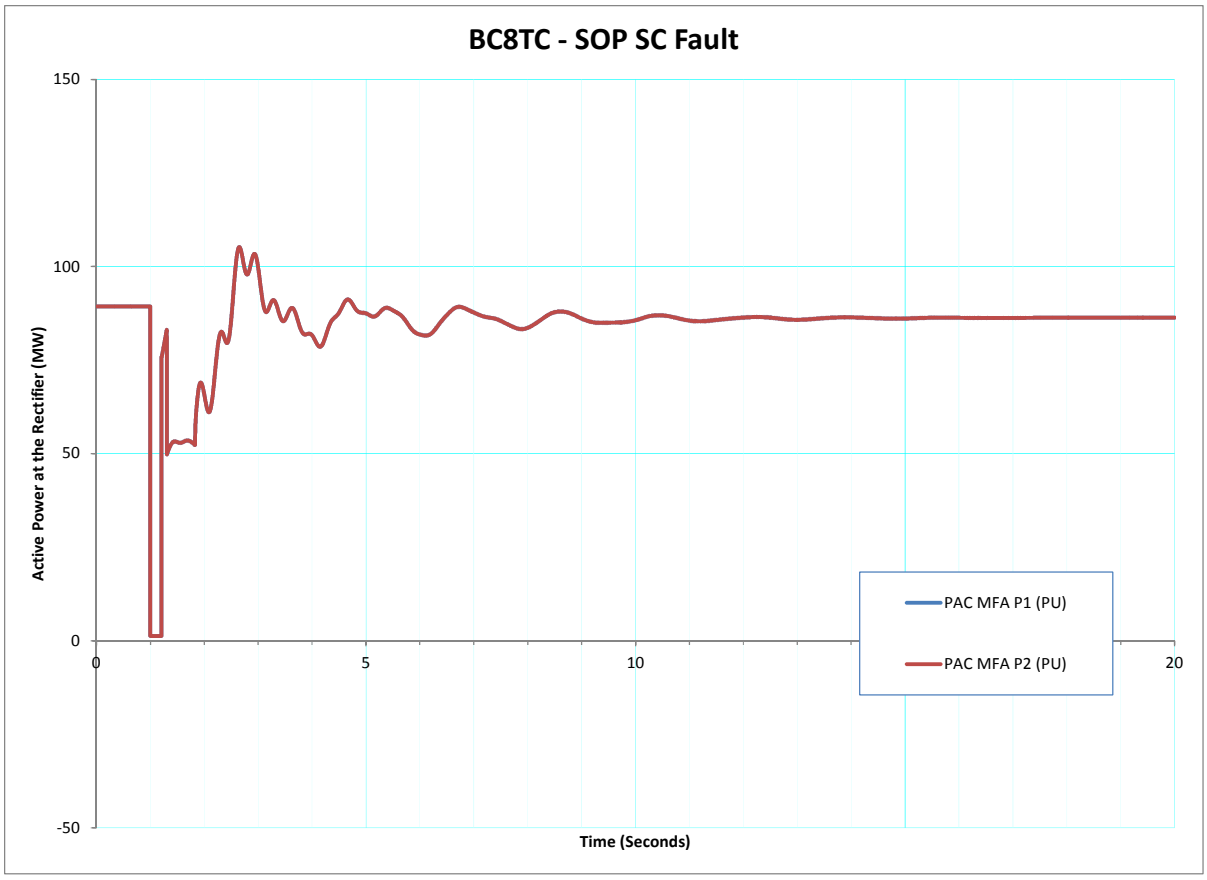


Figure 225 - BC8TC - SOP SC Fault - Active Power at the Rectifier (MW)

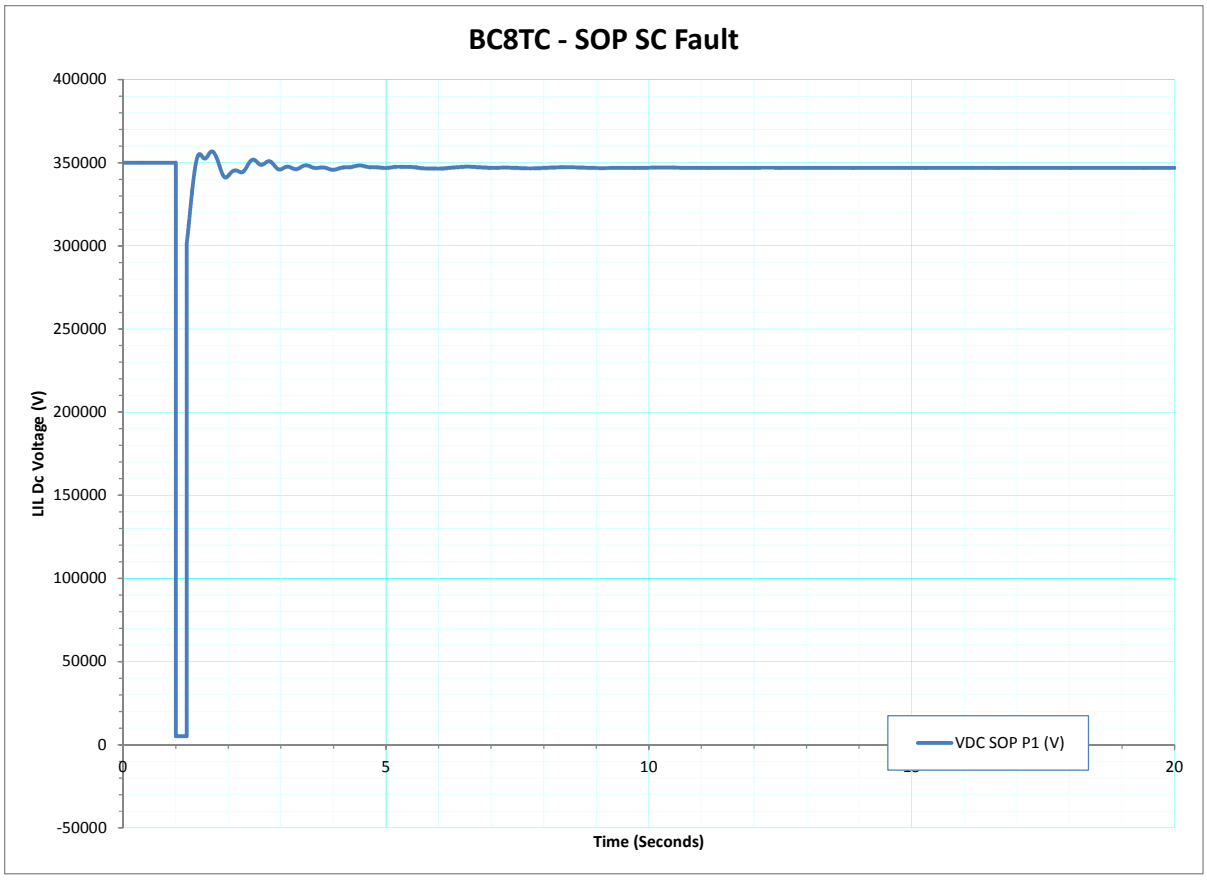


Figure 226 - BC8TC - SOP SC Fault - LIL Dc Voltage (V)

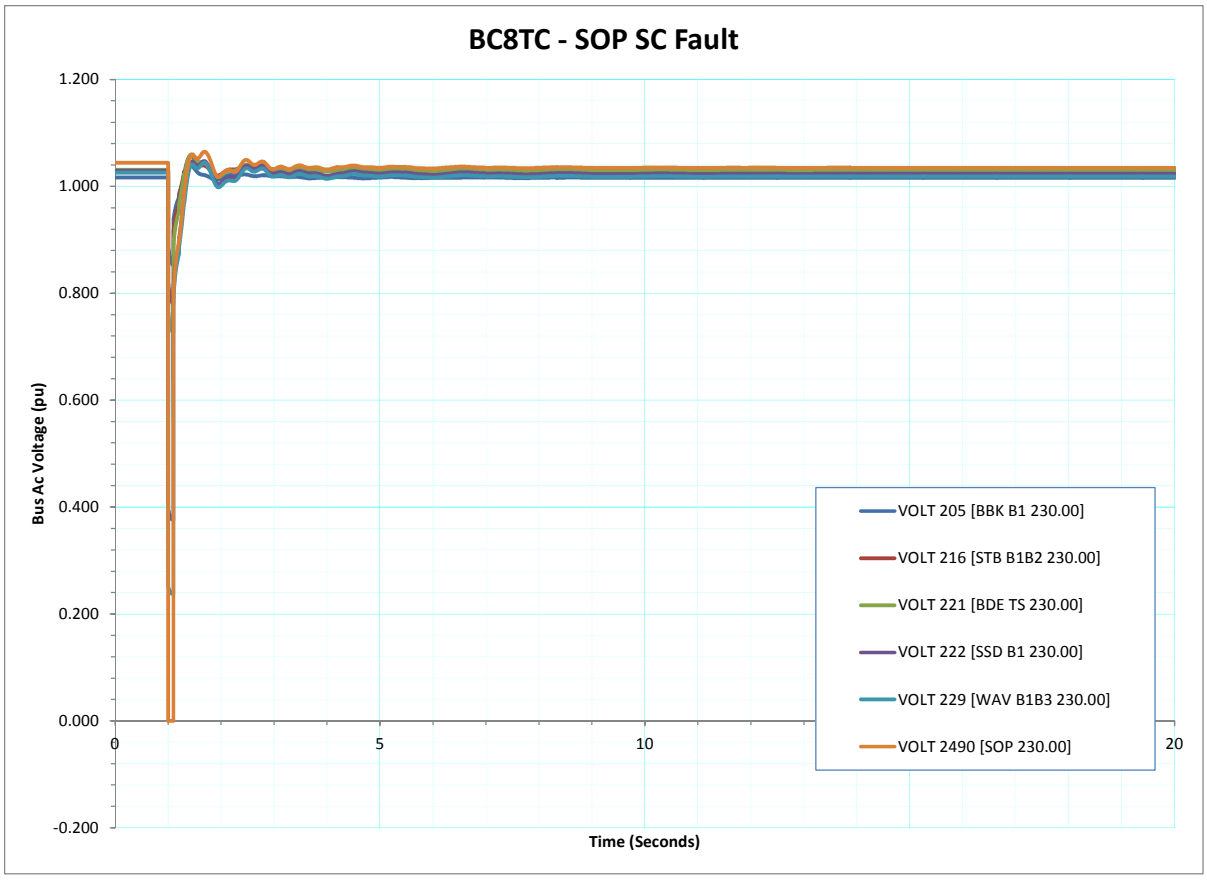


Figure 227 - BC8TC - SOP SC Fault - Bus Ac Voltage (pu)

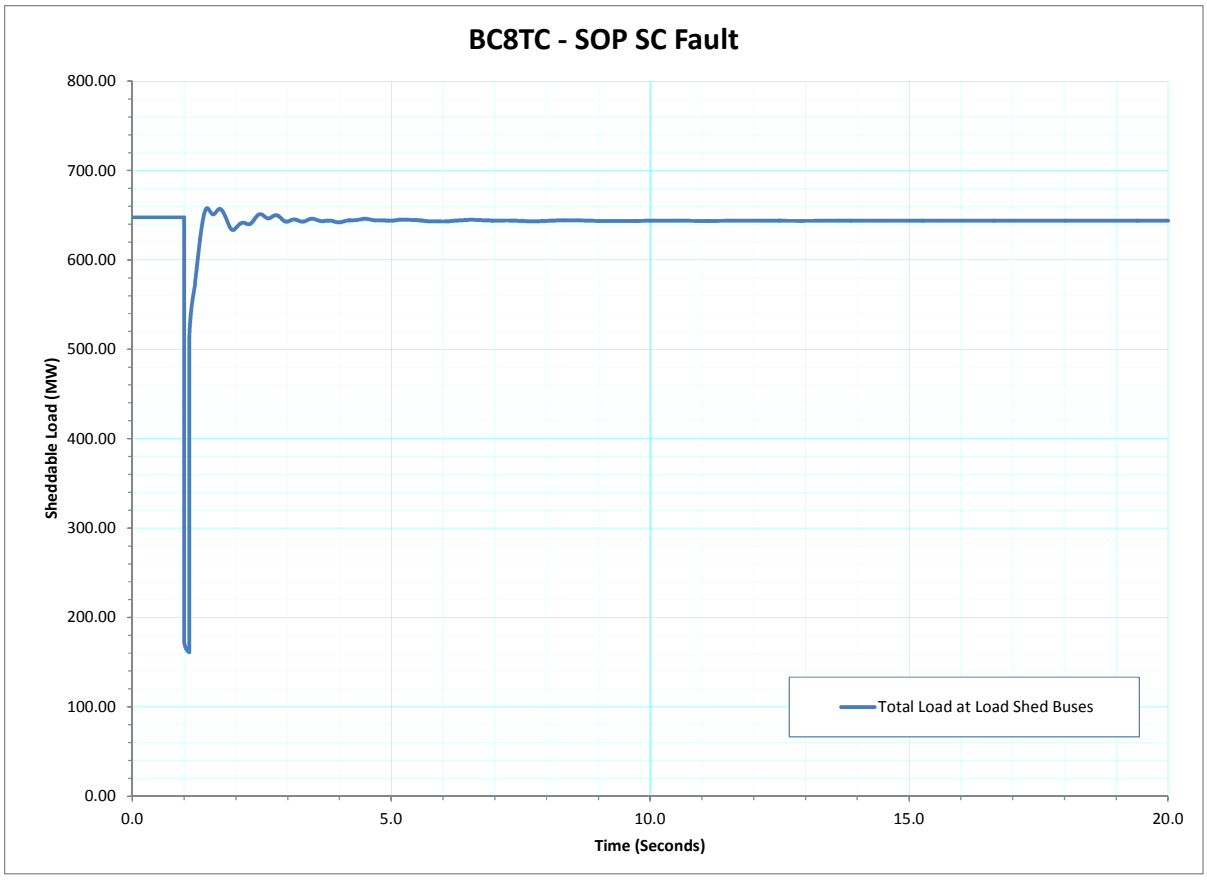


Figure 228 - BC8TC - SOP SC Fault - Sheddable Load (MW)

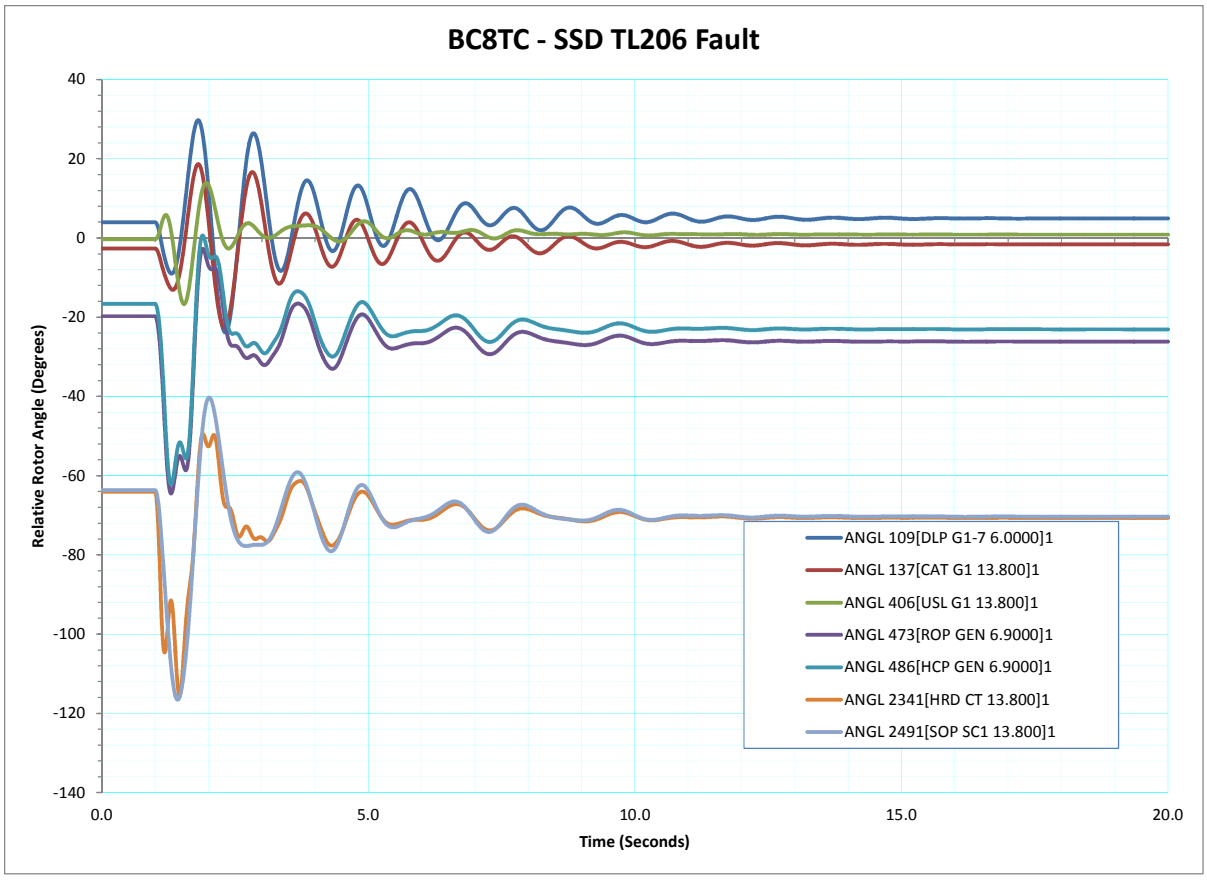


Figure 229 - BC8TC - SSD TL206 Fault - Relative Rotor Angle (Degrees)

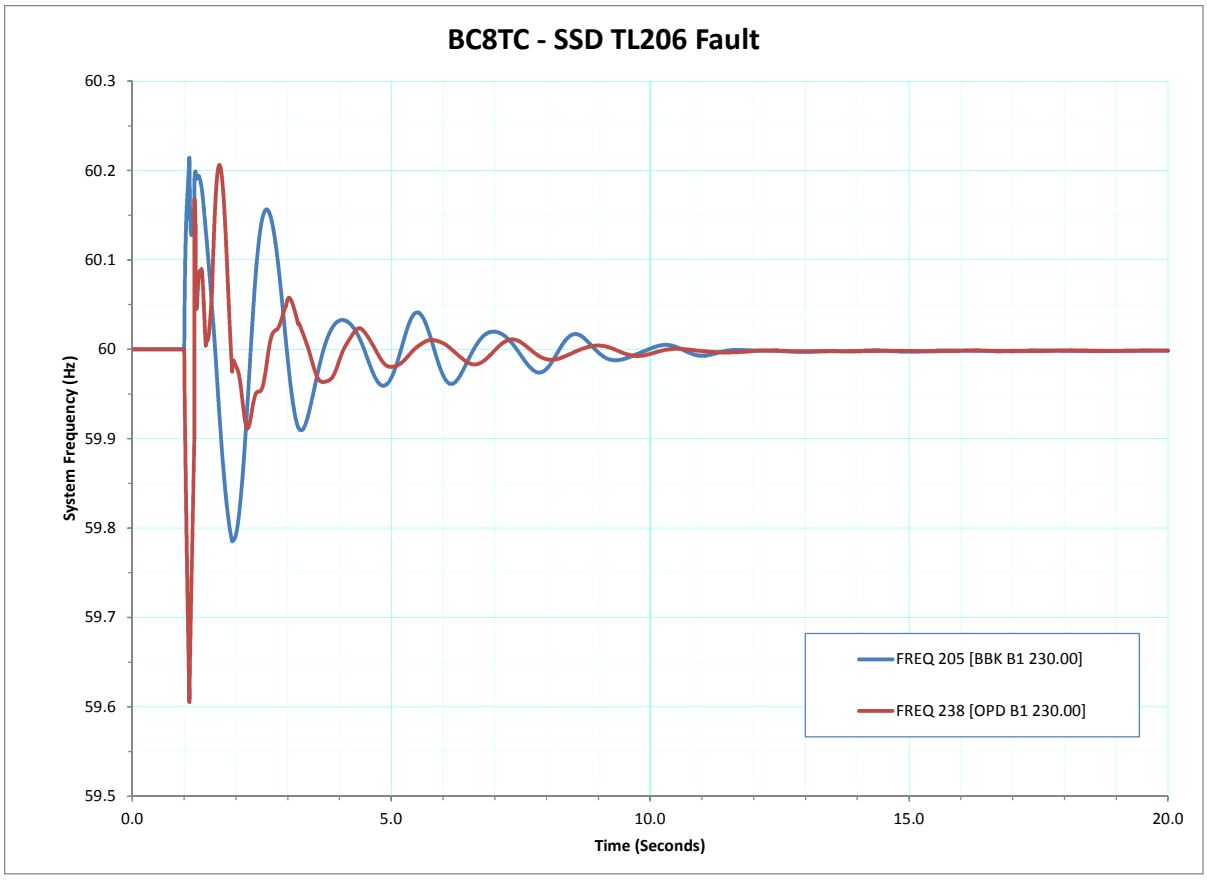


Figure 230 - BC8TC - SSD TL206 Fault - System Frequency (Hz)

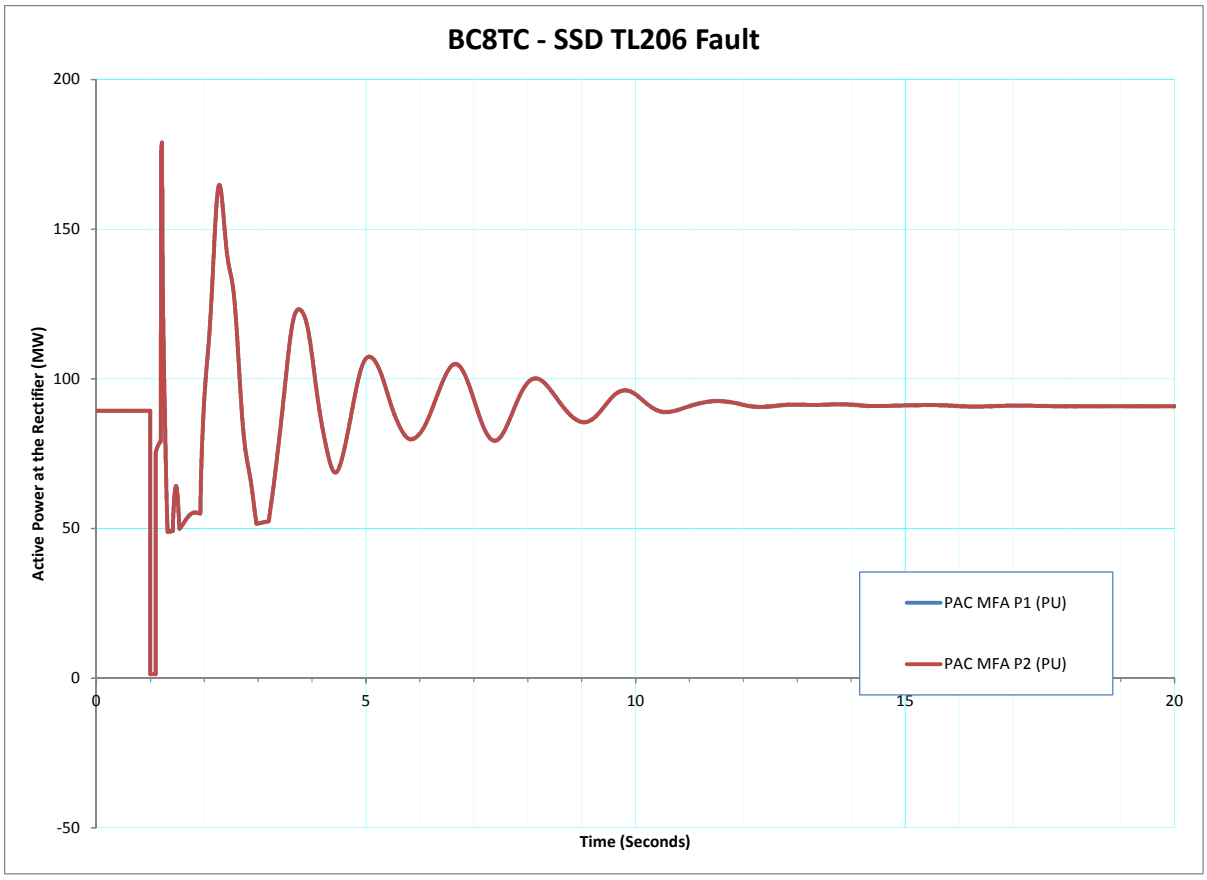


Figure 231 - BC8TC - SSD TL206 Fault - Active Power at the Rectifier (MW)

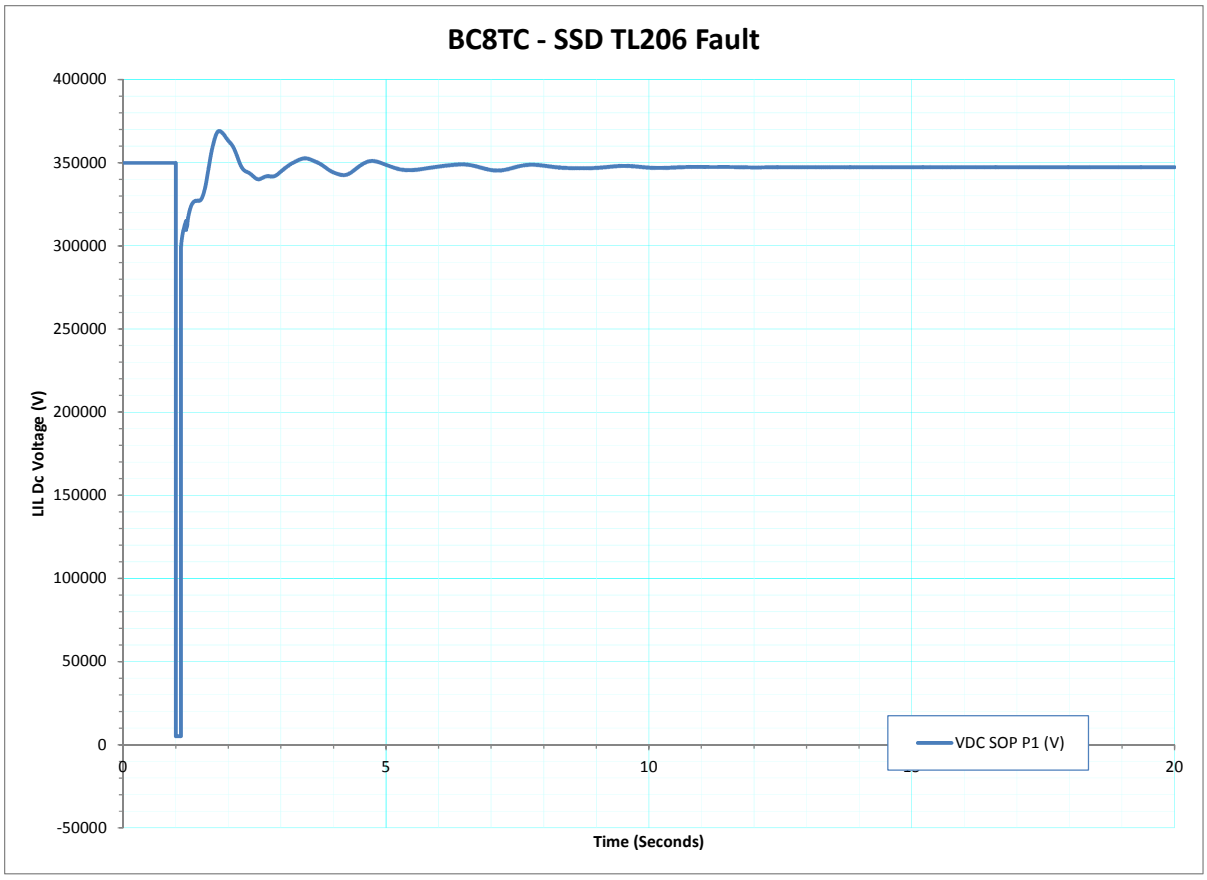


Figure 232 - BC8TC - SSD TL206 Fault - LIL Dc Voltage (V)

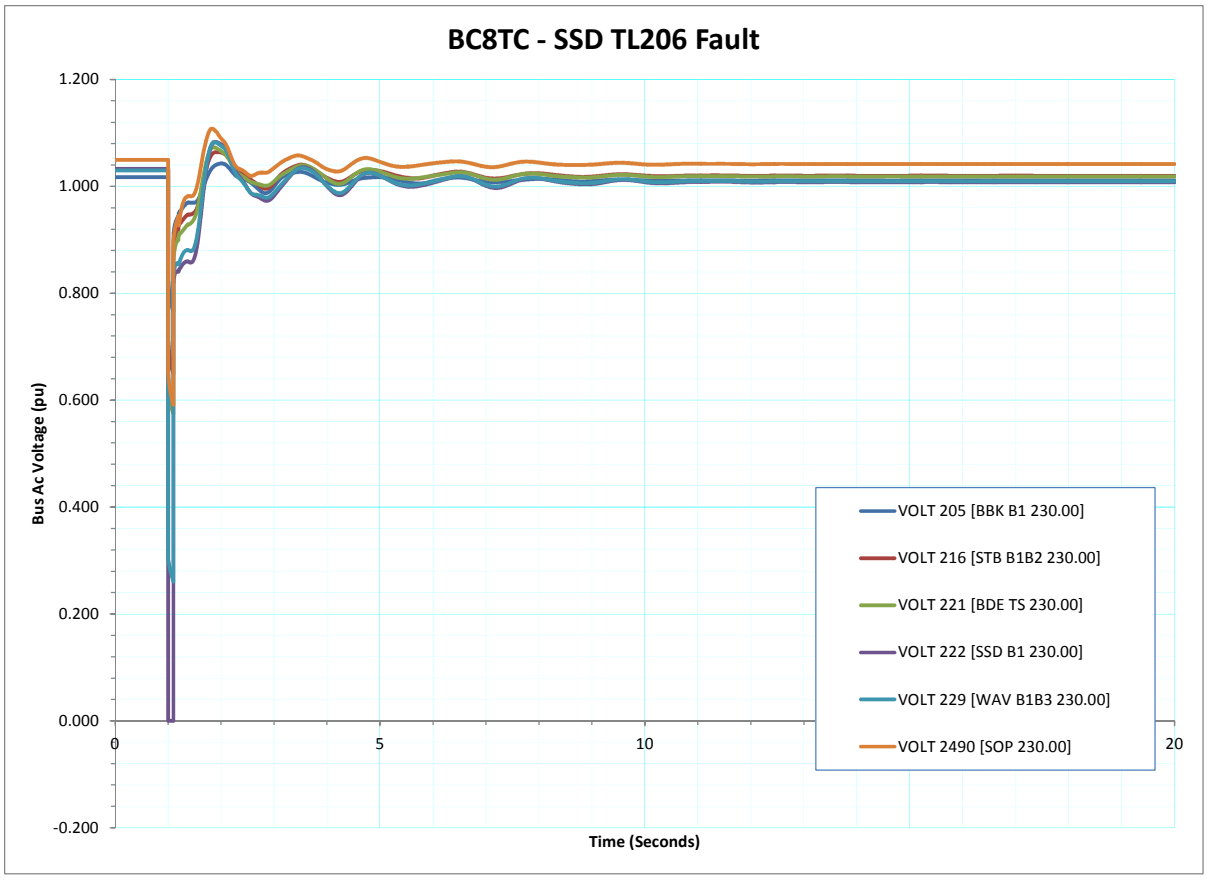


Figure 233 - BC8TC - SSD TL206 Fault - Bus Ac Voltage (pu)

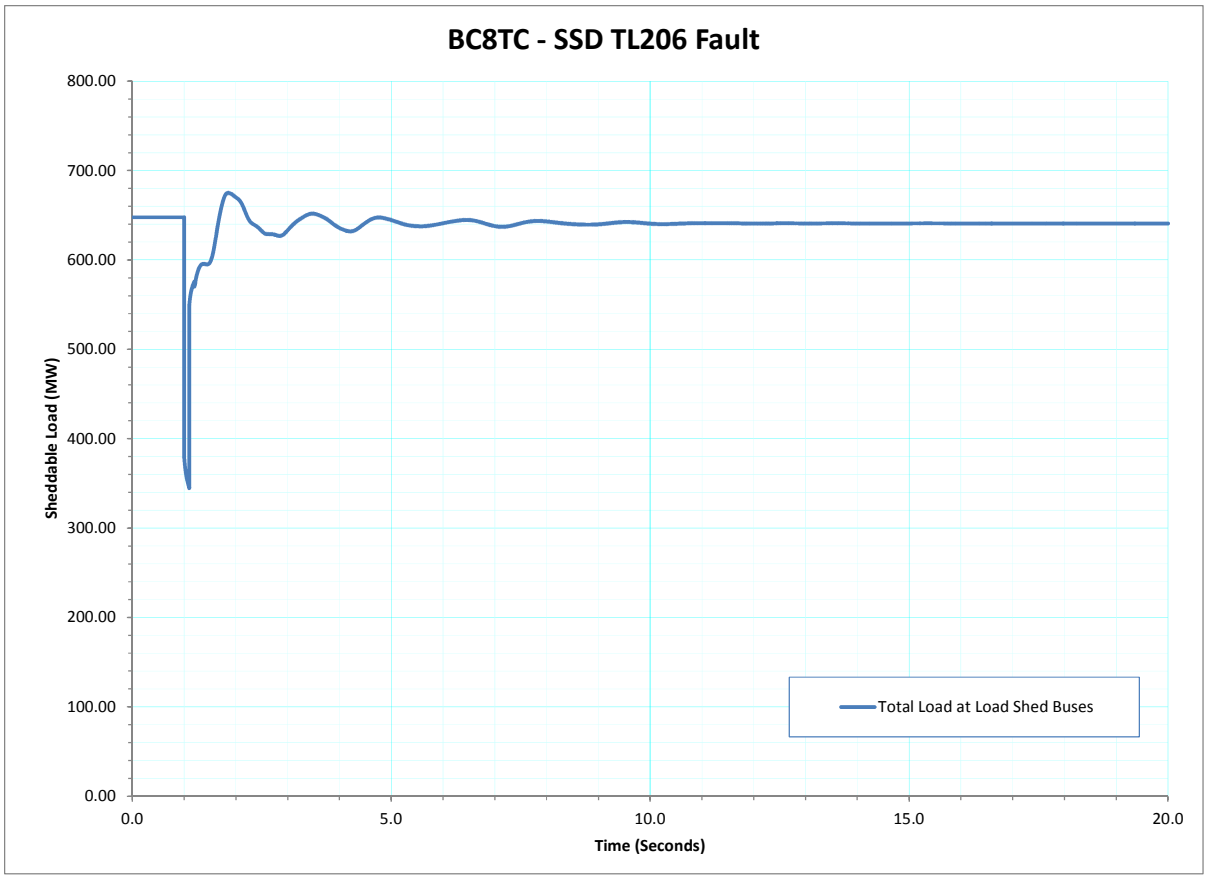


Figure 234 - BC8TC - SSD TL206 Fault - Sheddable Load (MW)

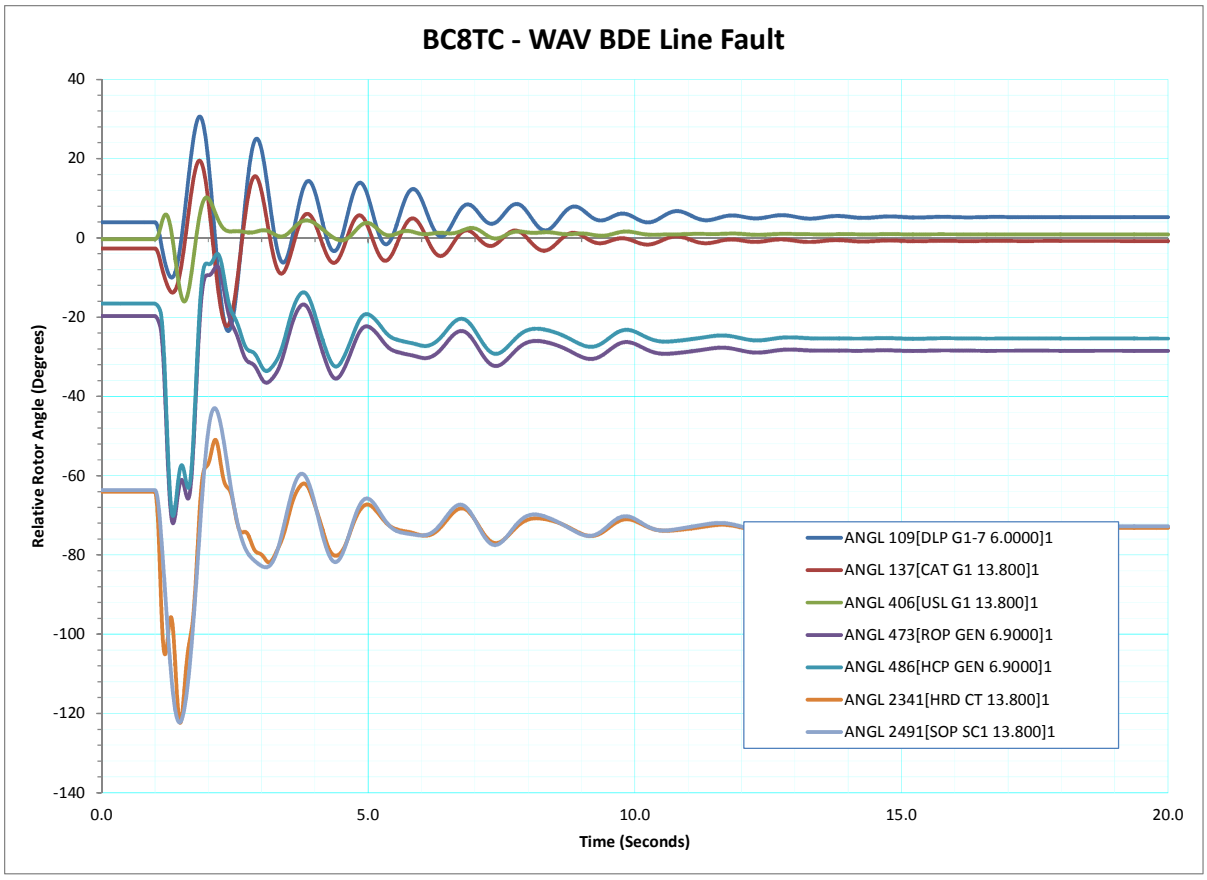


Figure 235 - BC8TC - WAV BDE Line Fault - Relative Rotor Angle (Degrees)

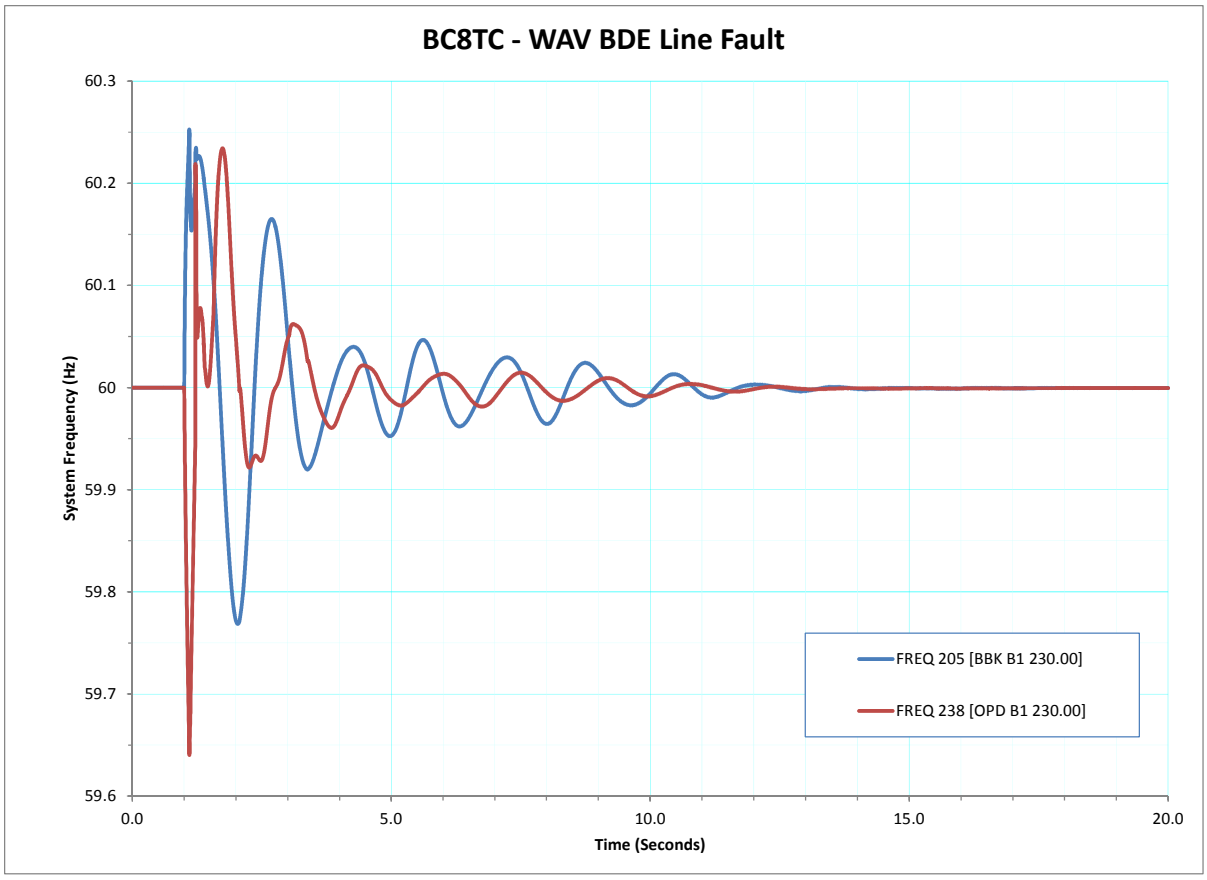


Figure 236 - BC8TC - WAV BDE Line Fault - System Frequency (Hz)

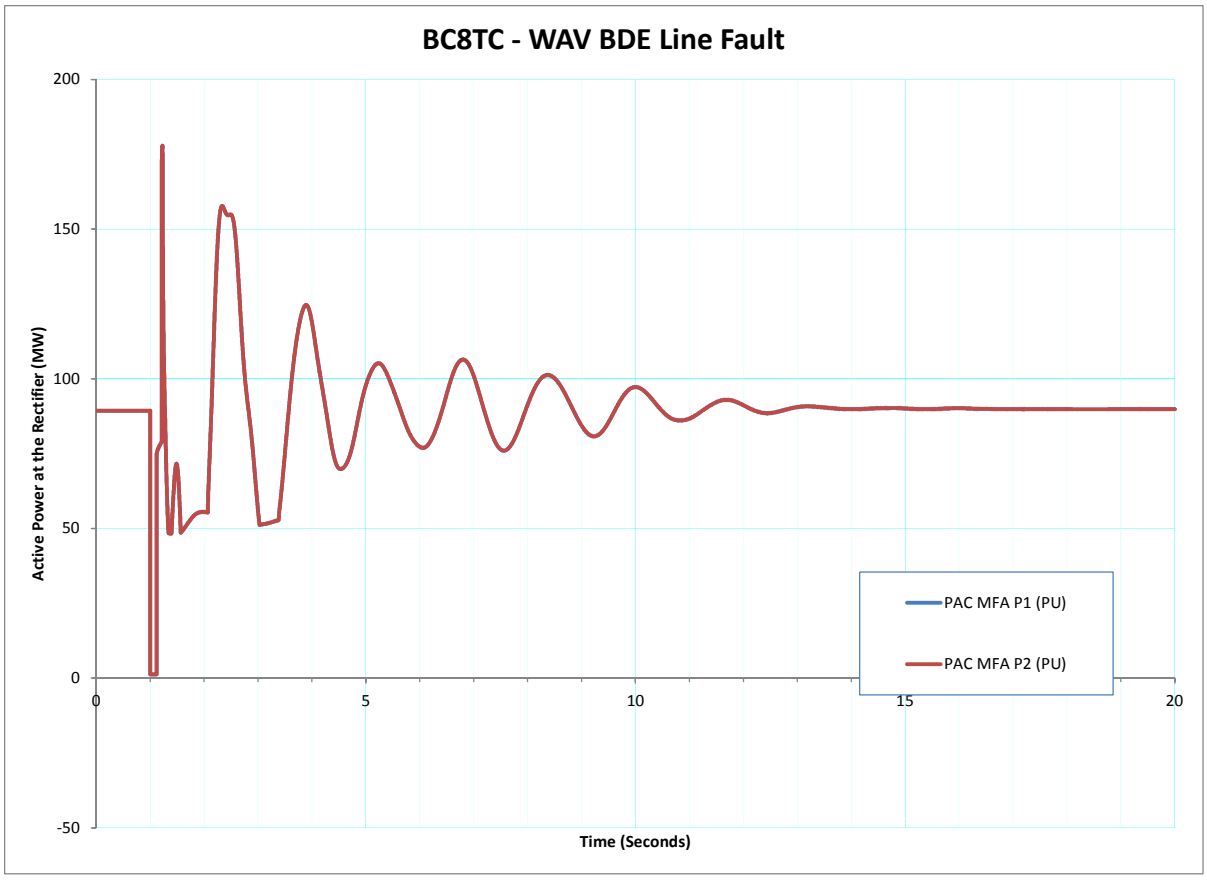


Figure 237 - BC8TC - WAV BDE Line Fault - Active Power at the Rectifier (MW)

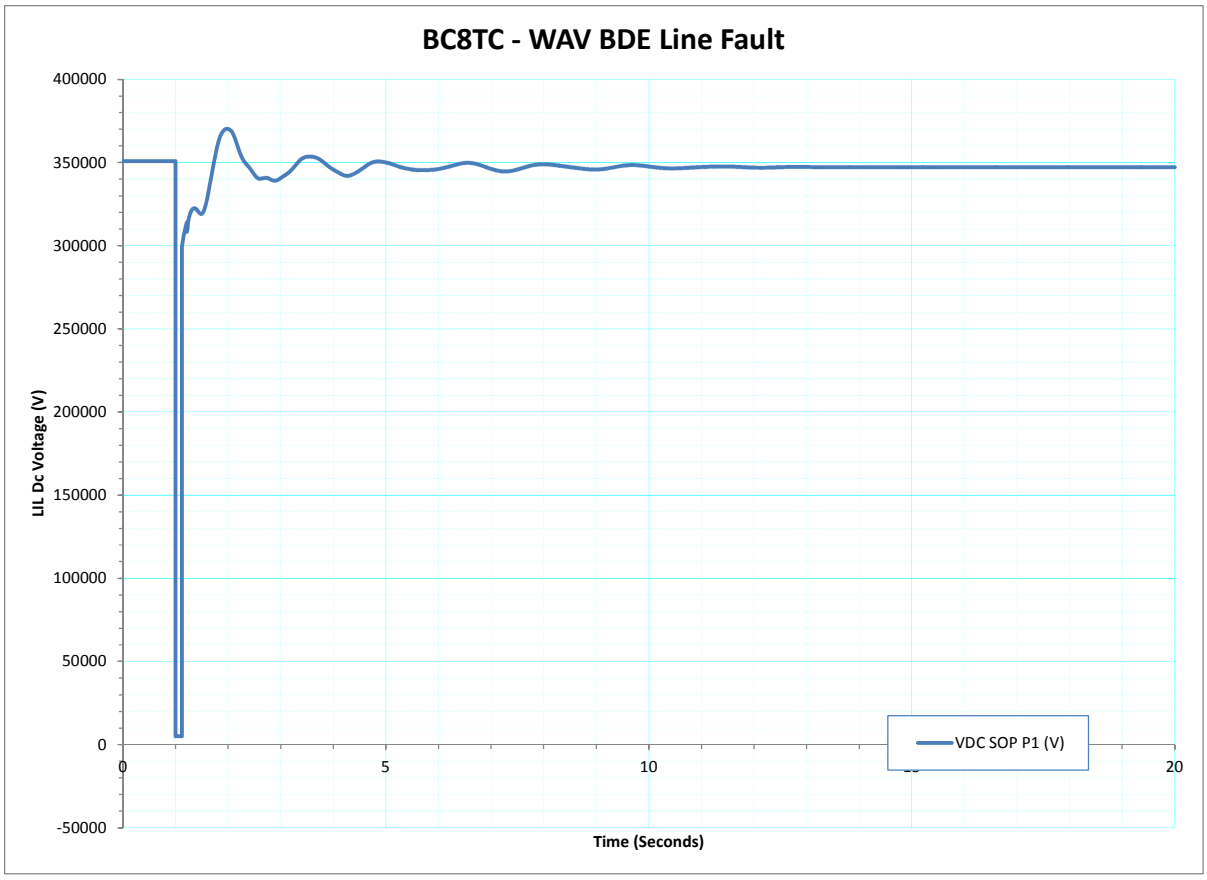


Figure 238 - BC8TC - WAV BDE Line Fault - LIL Dc Voltage (V)

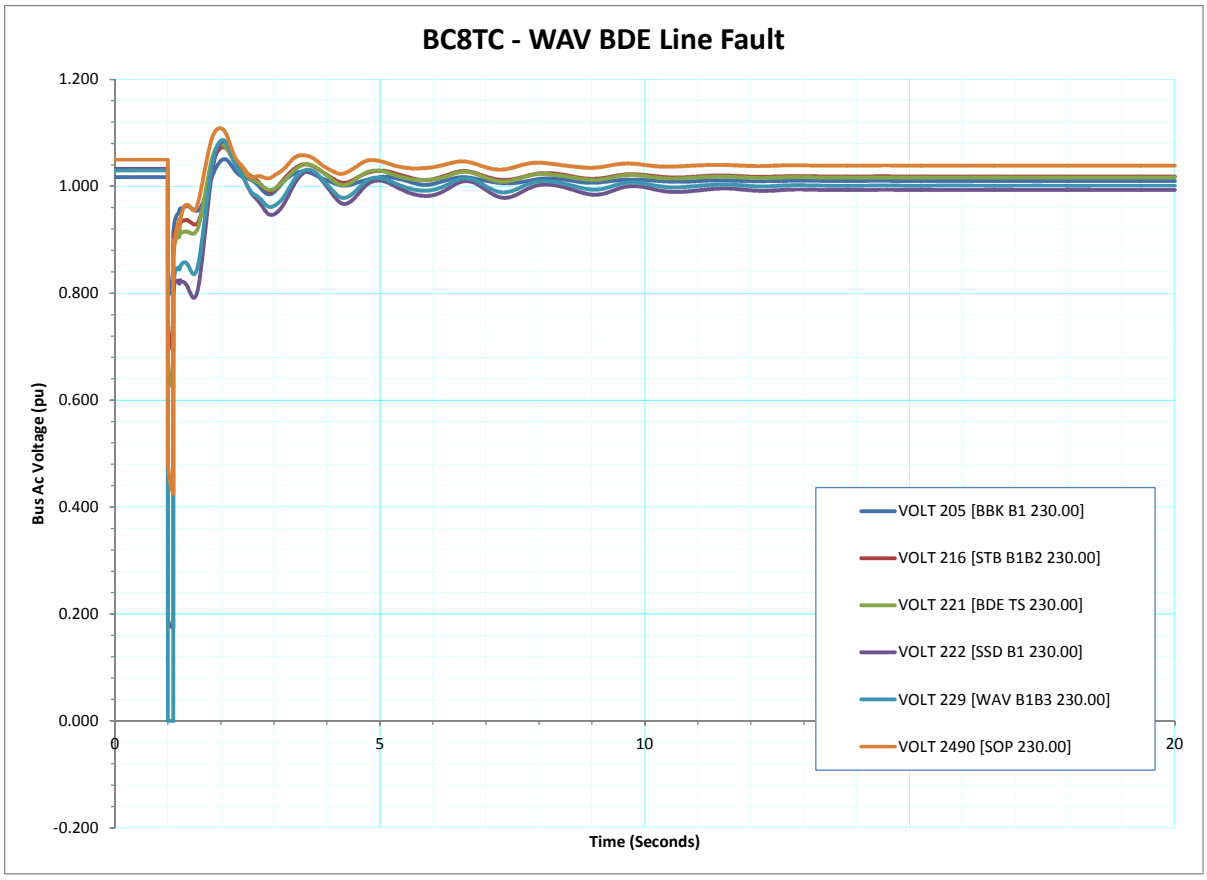


Figure 239 - BC8TC - WAV BDE Line Fault - Bus Ac Voltage (pu)

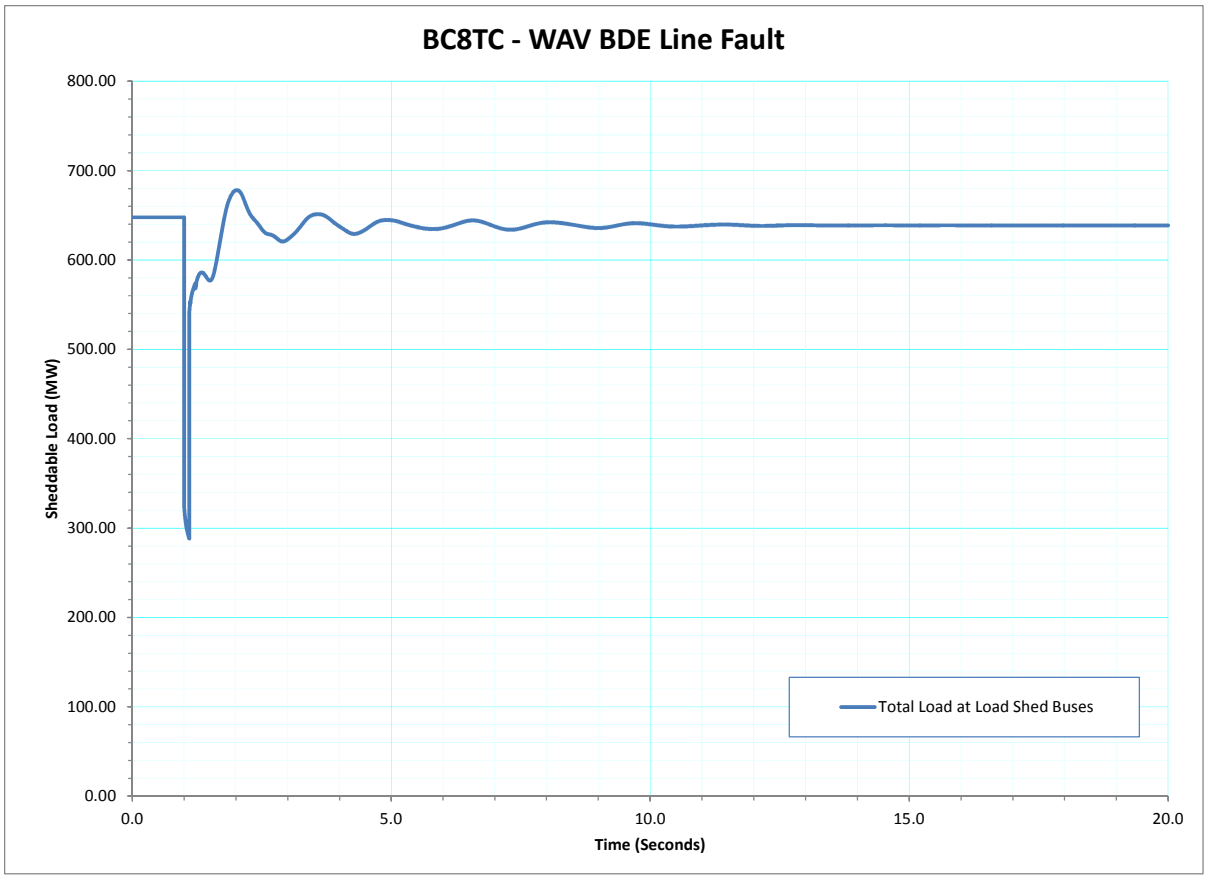


Figure 240 - BC8TC - WAV BDE Line Fault - Sheddable Load (MW)

1.9. BASE CASE 9 TRANSIENT STABILITY PLOTS

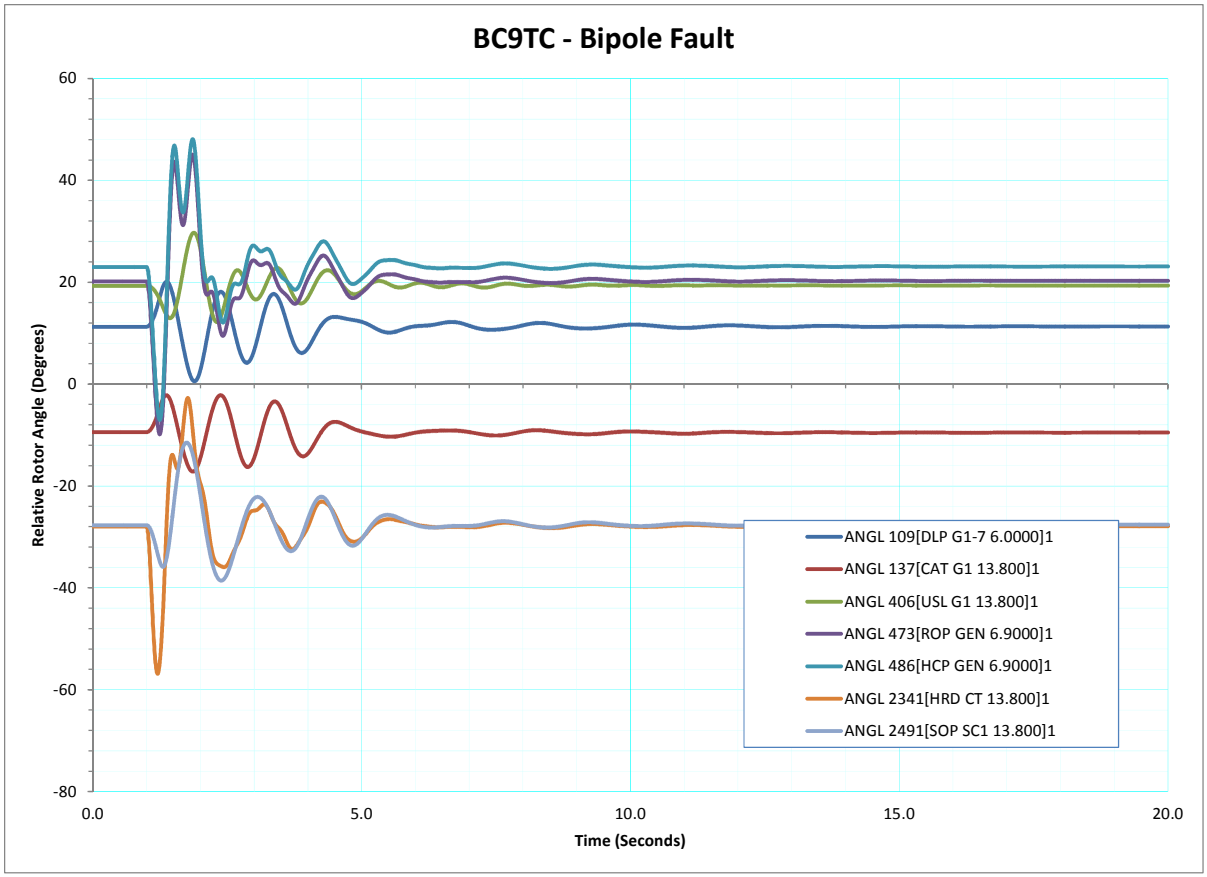


Figure 241 - BC9TC - Bipole Fault - Relative Rotor Angle (Degrees)

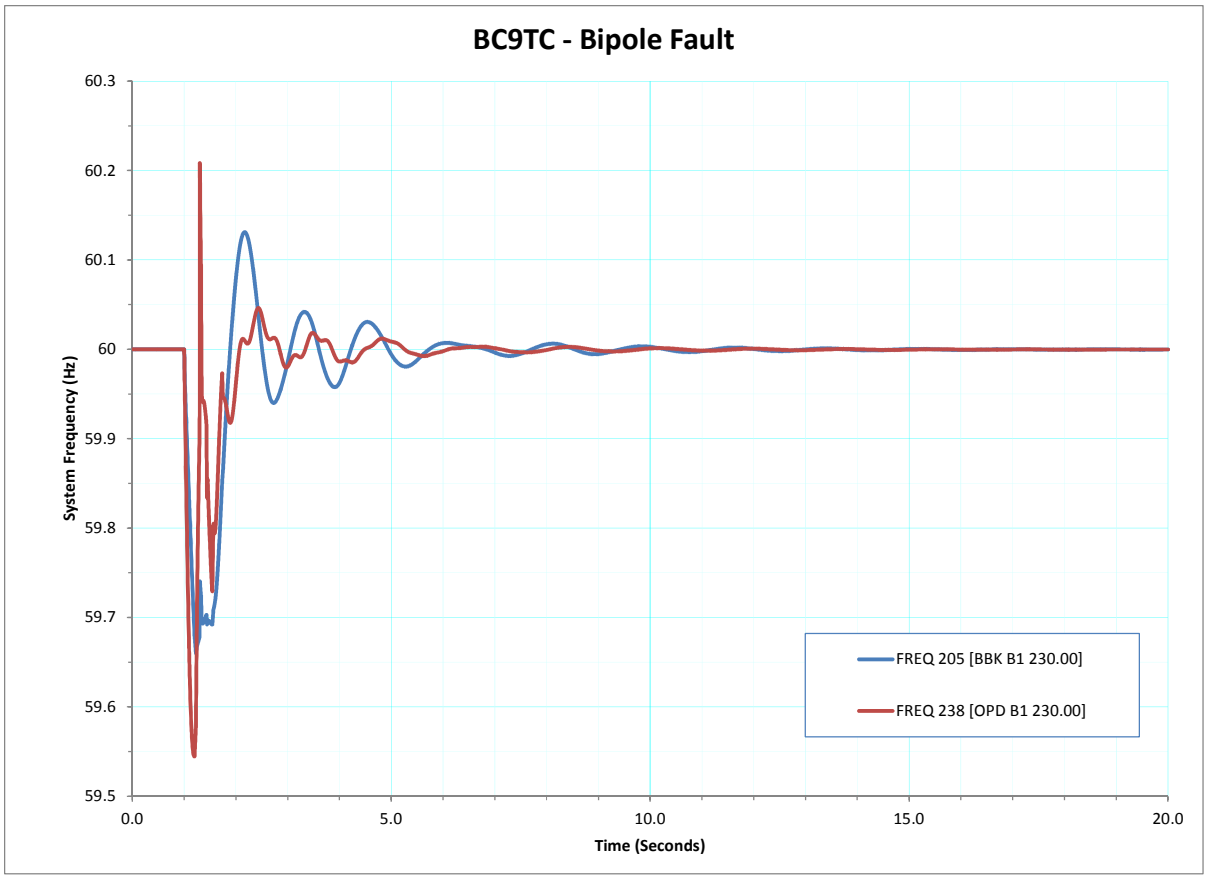


Figure 242 - BC9TC - Bipole Fault - System Frequency (Hz)

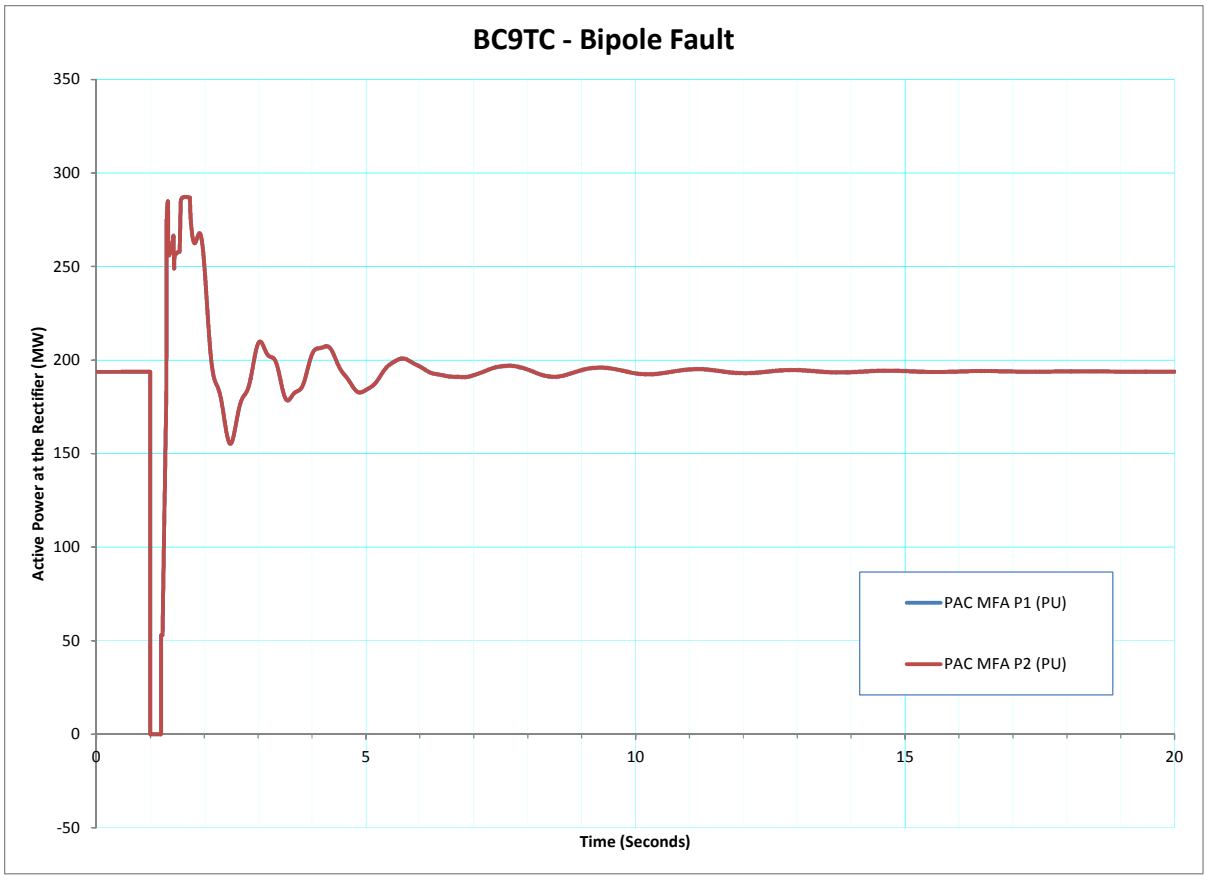


Figure 243 - BC9TC - Bipole Fault - Active Power at the Rectifier (MW)

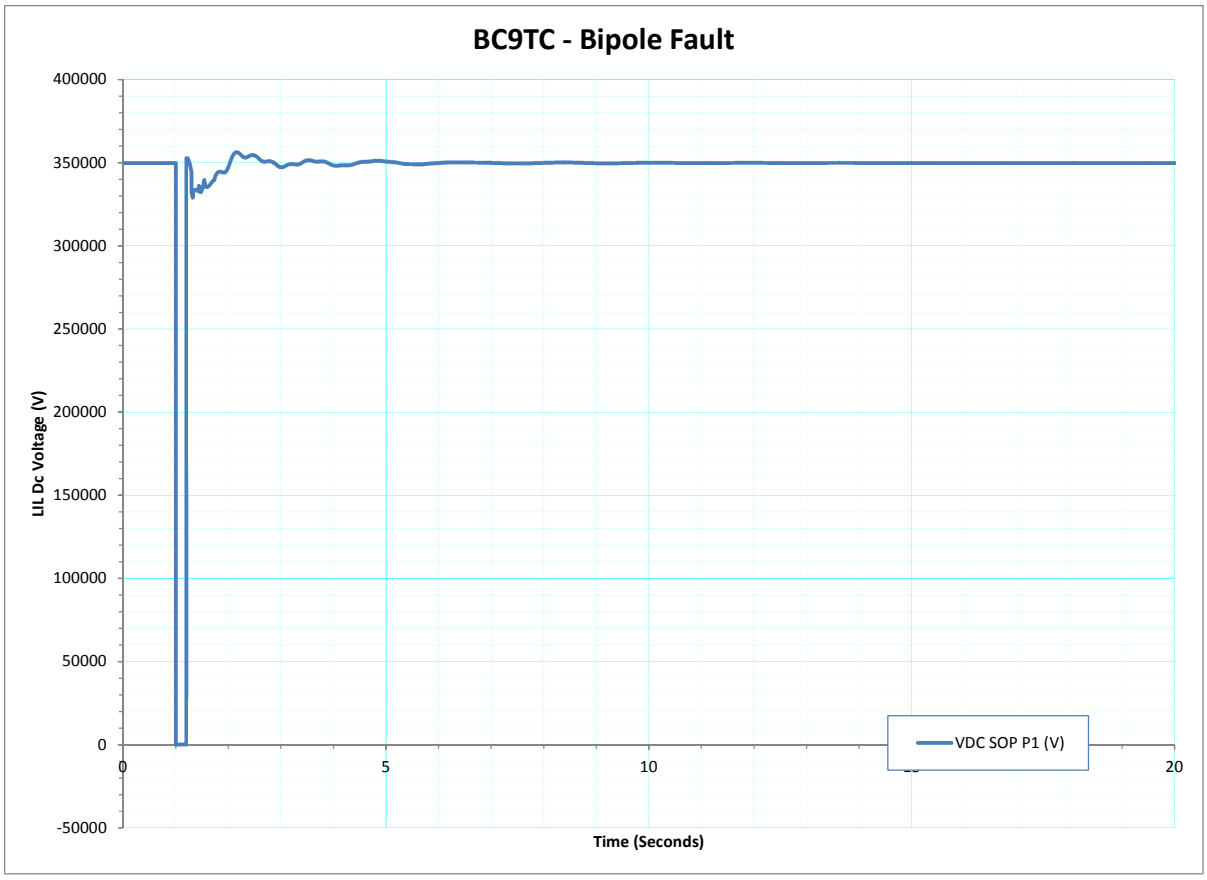


Figure 244 - BC9TC - Bipole Fault - LIL Dc Voltage (V)

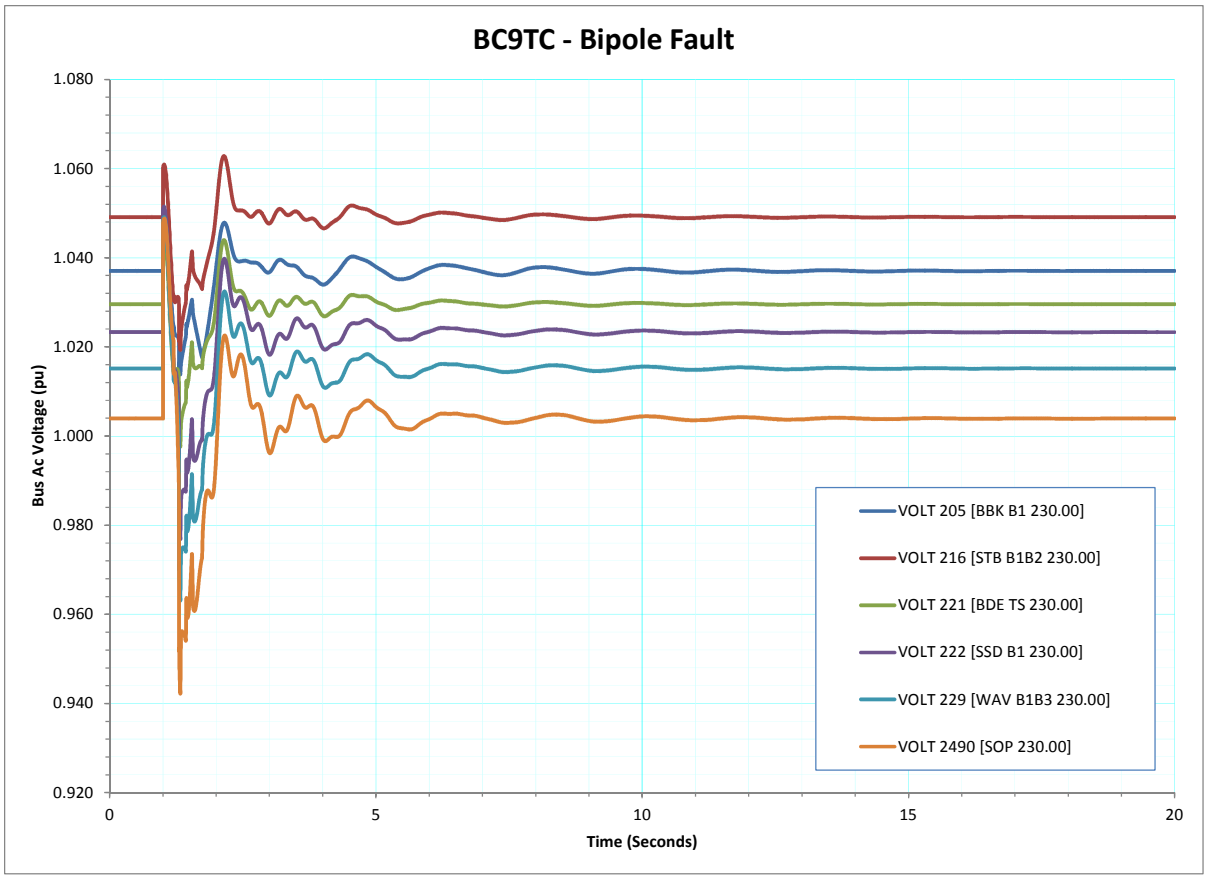


Figure 245 - BC9TC - Bipole Fault - Bus Ac Voltage (pu)

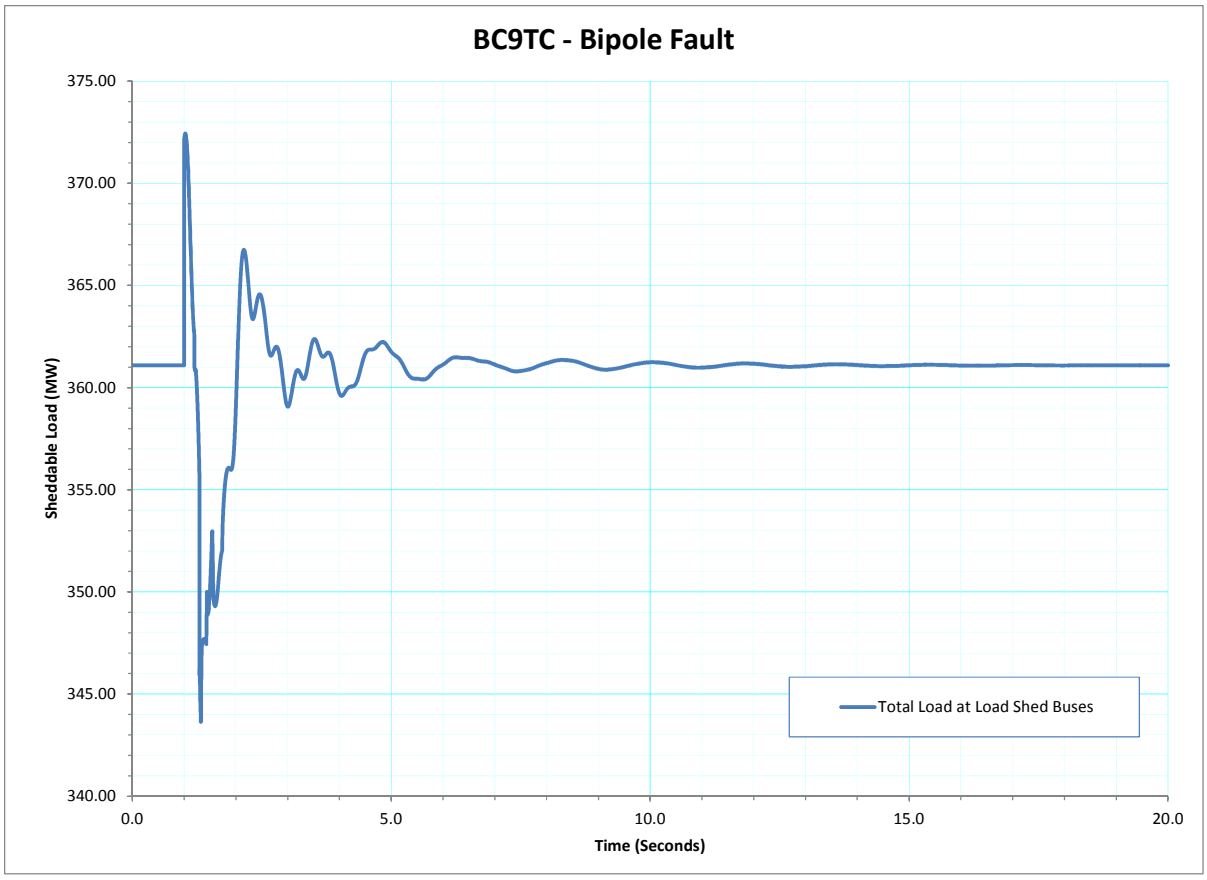


Figure 246 - BC9TC - Bipole Fault - Sheddable Load (MW)

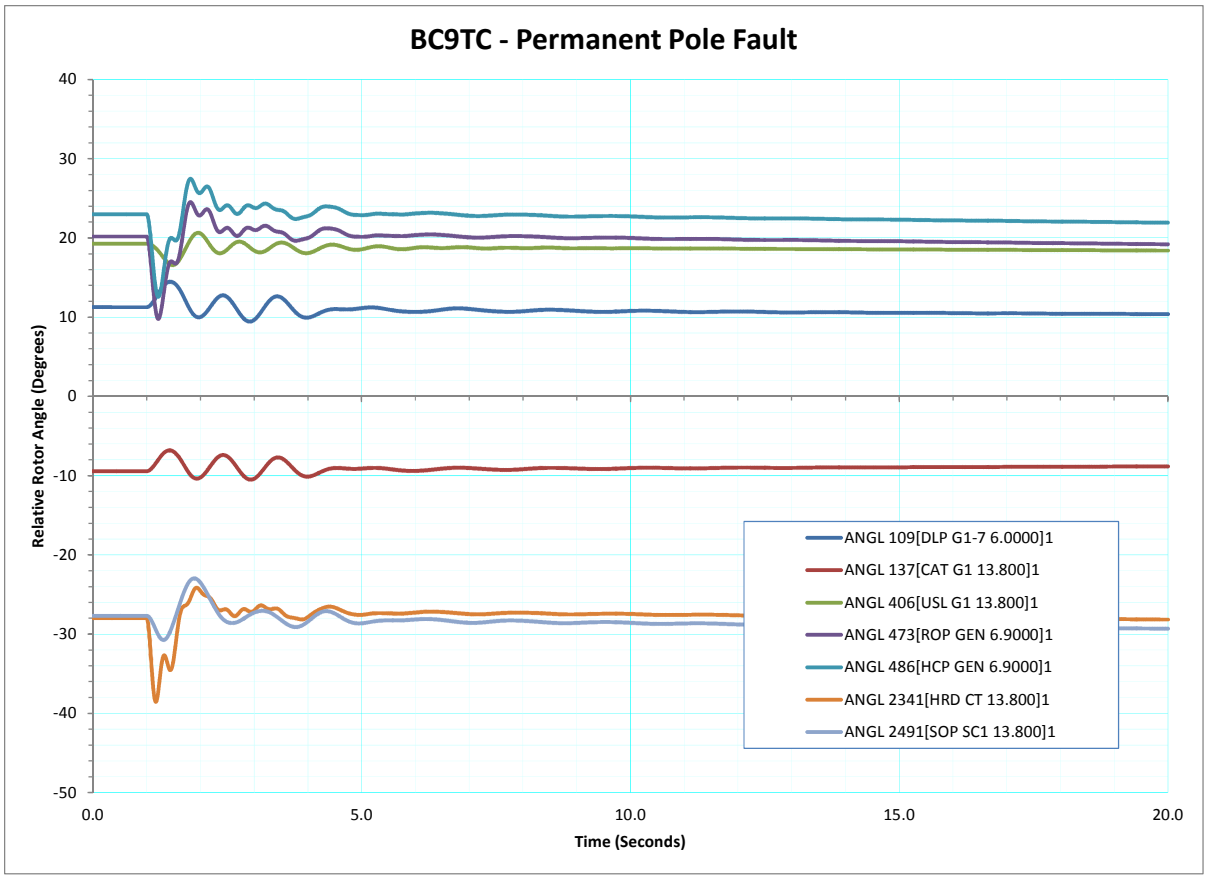


Figure 247 - BC9TC - Permanent Pole Fault - Relative Rotor Angle (Degrees)

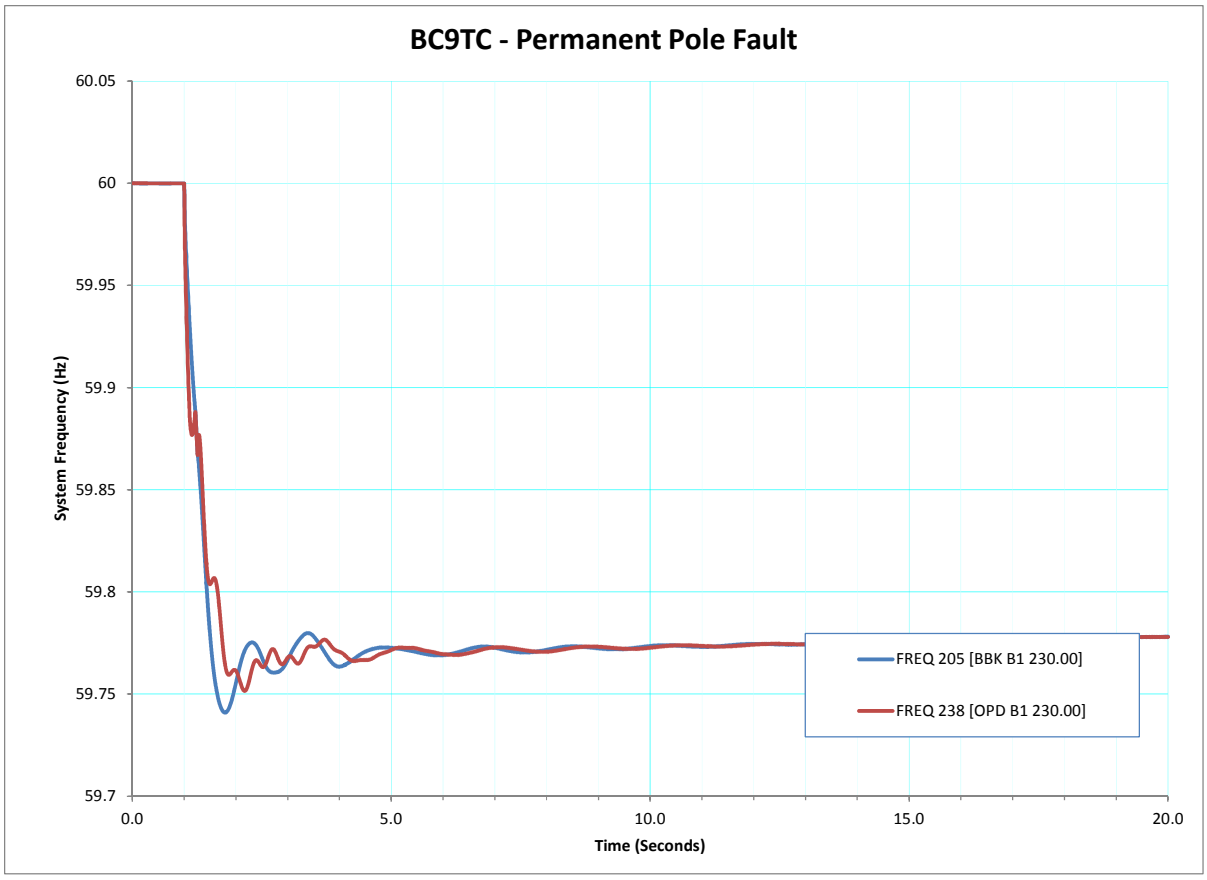


Figure 248 - BC9TC - Permanent Pole Fault - System Frequency (Hz)

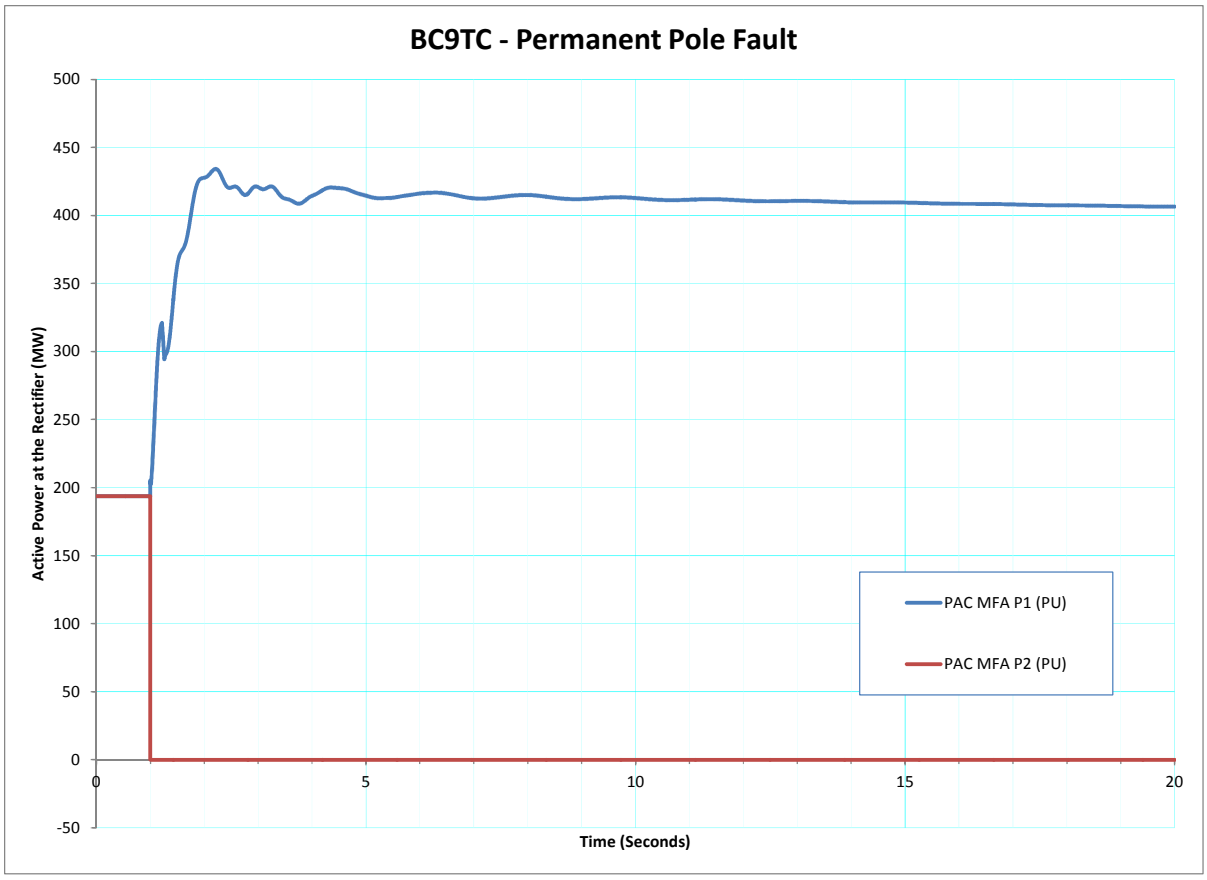


Figure 249 - BC9TC - Permanent Pole Fault - Active Power at the Rectifier (MW)

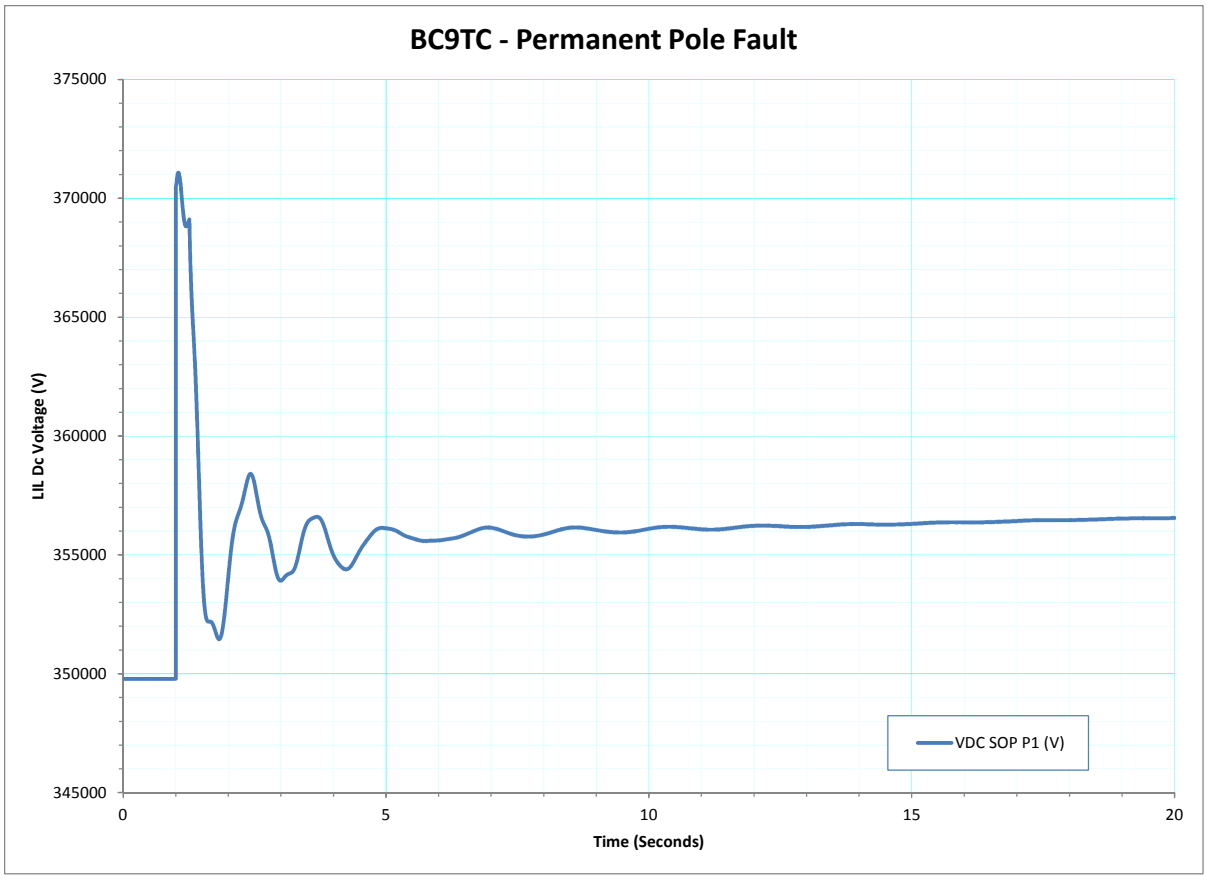


Figure 250 - BC9TC - Permanent Pole Fault - LIL Dc Voltage (V)

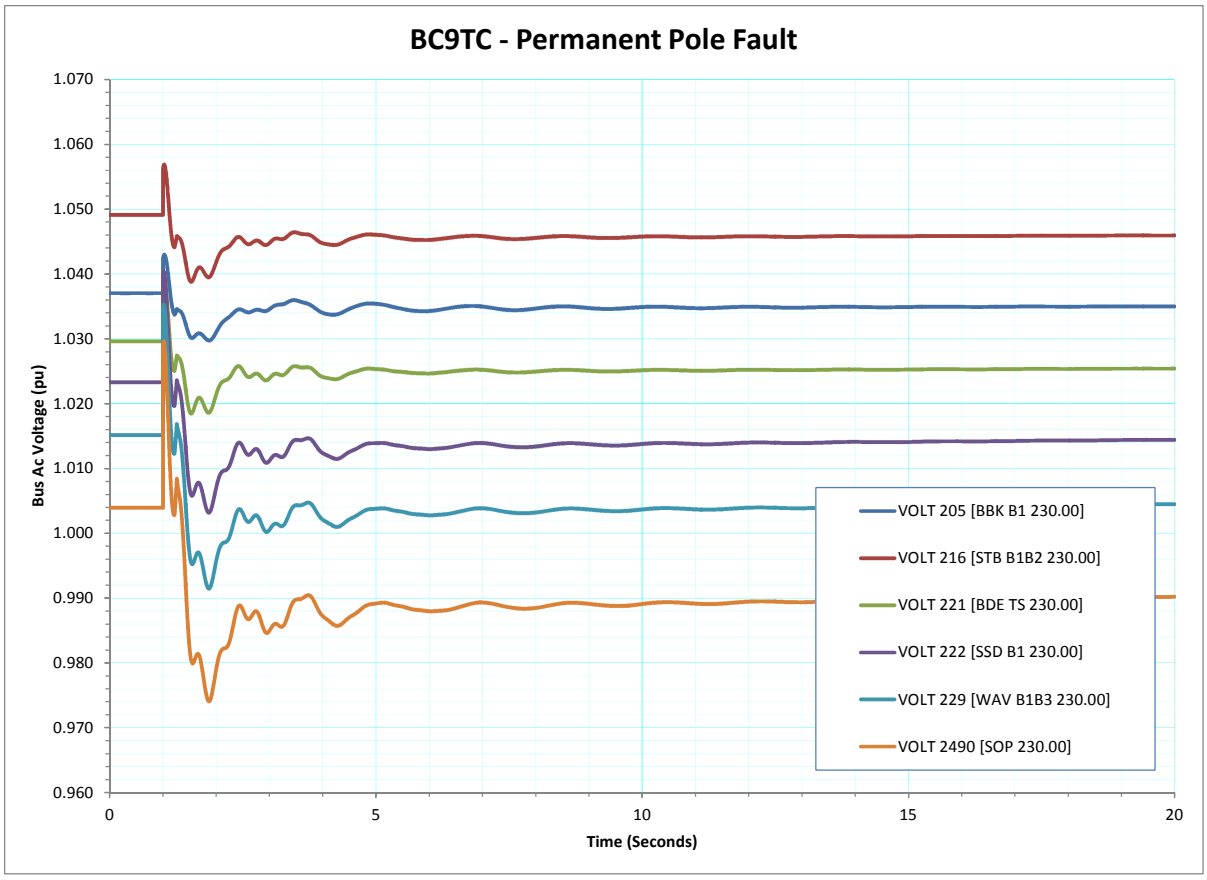


Figure 251 - BC9TC - Permanent Pole Fault - Bus Ac Voltage (pu)

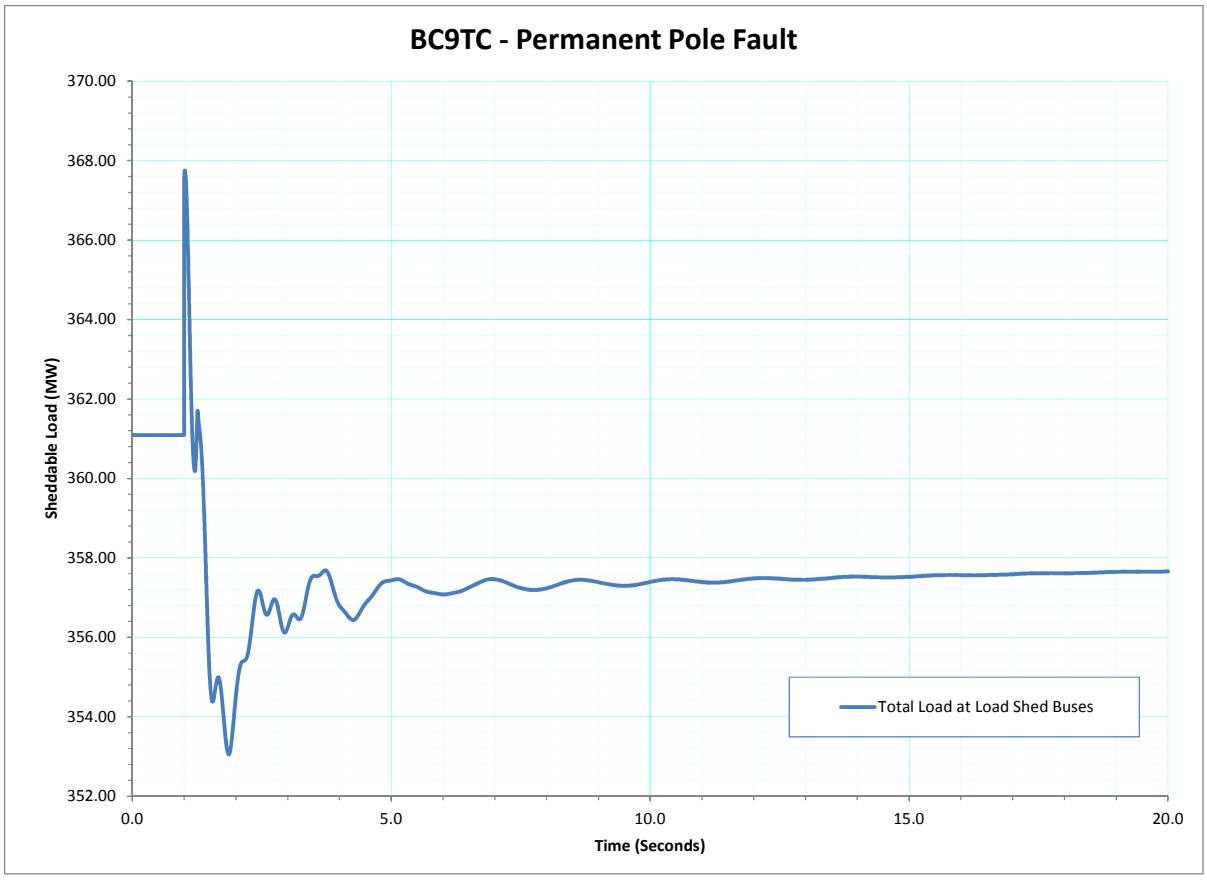


Figure 252 - BC9TC - Permanent Pole Fault - Sheddable Load (MW)

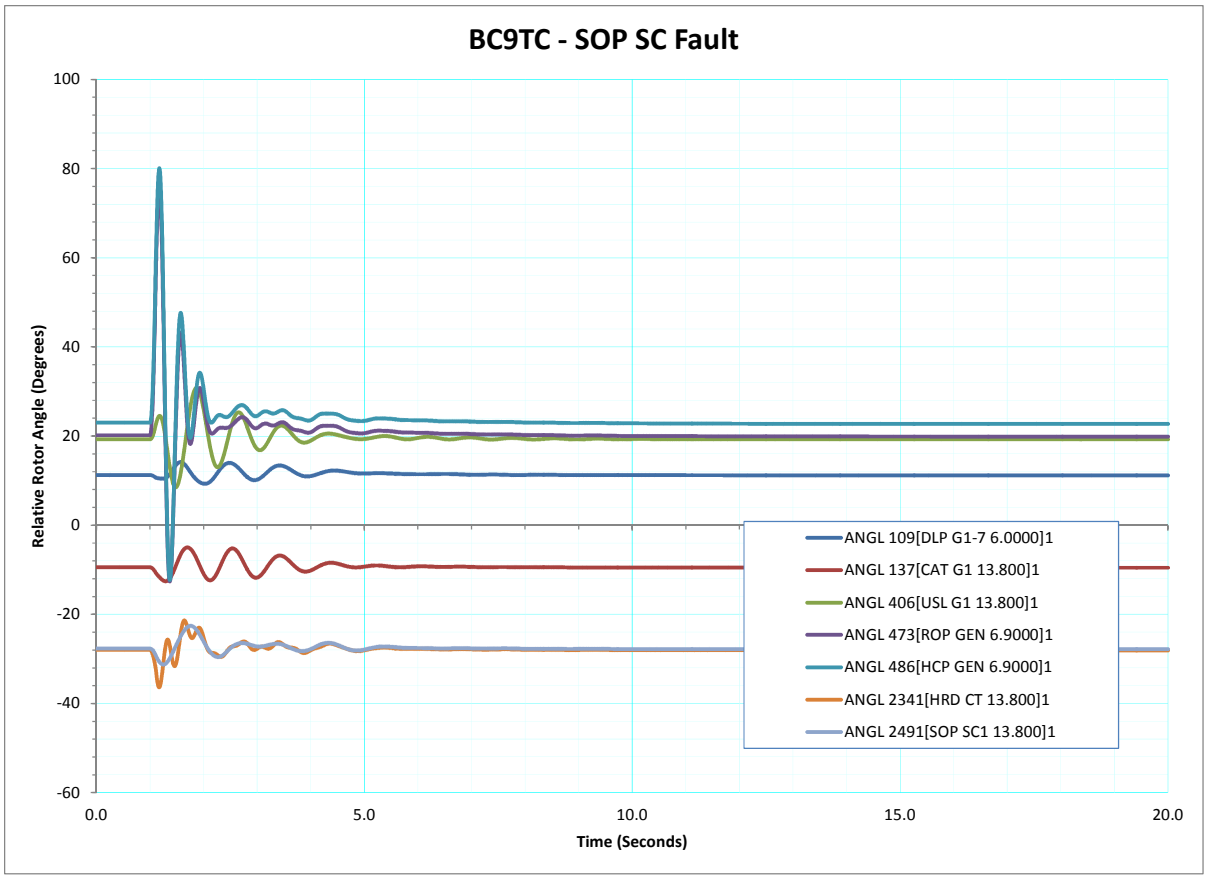


Figure 253 - BC9TC - SOP SC Fault - Relative Rotor Angle (Degrees)

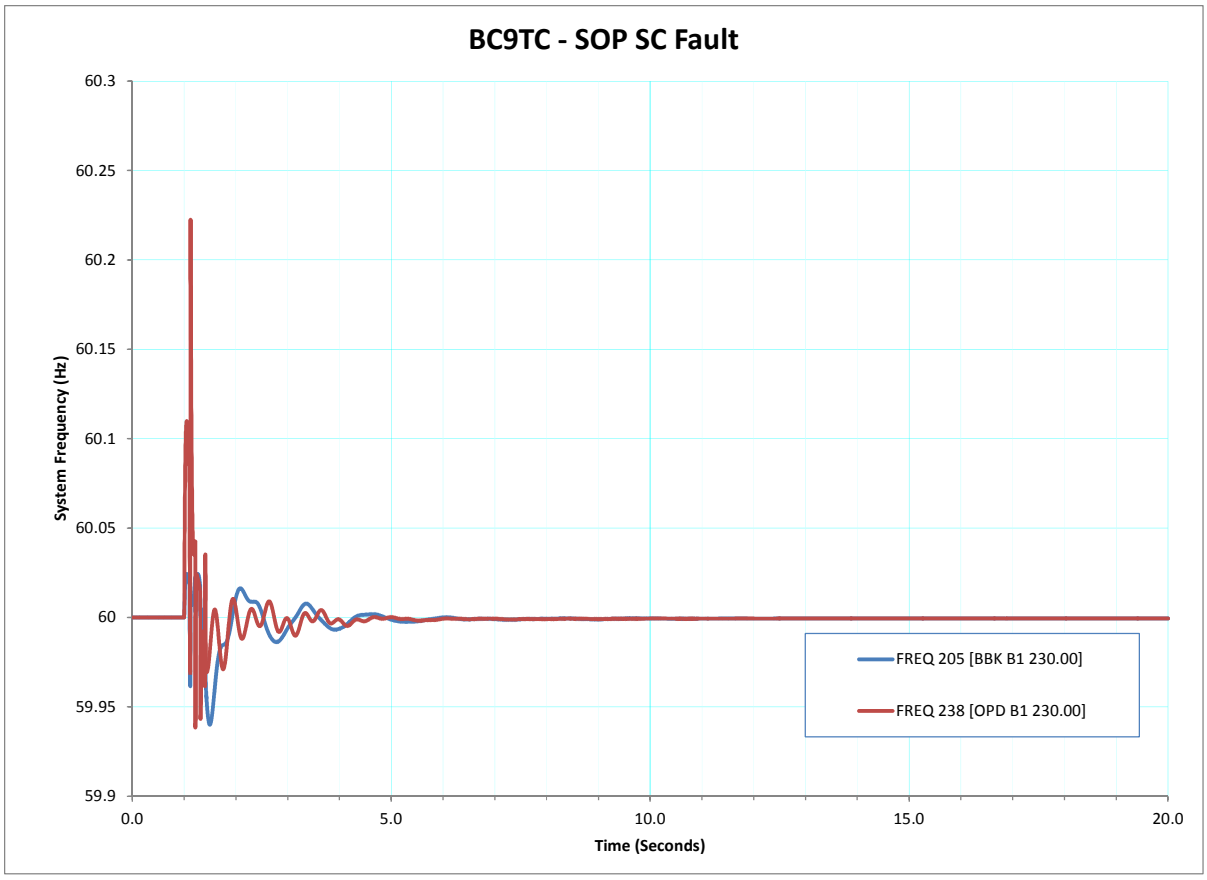


Figure 254 - BC9TC - SOP SC Fault - System Frequency (Hz)

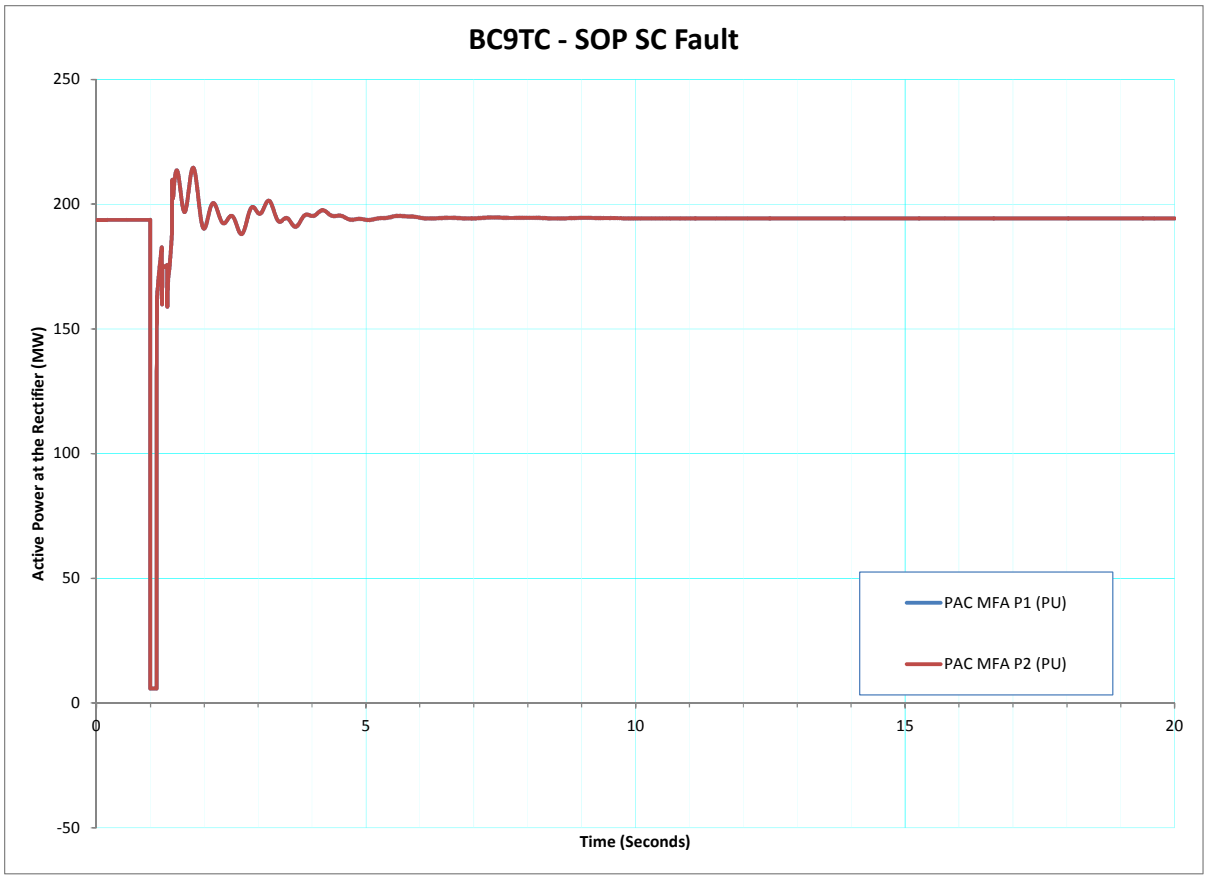


Figure 255 - BC9TC - SOP SC Fault - Active Power at the Rectifier (MW)

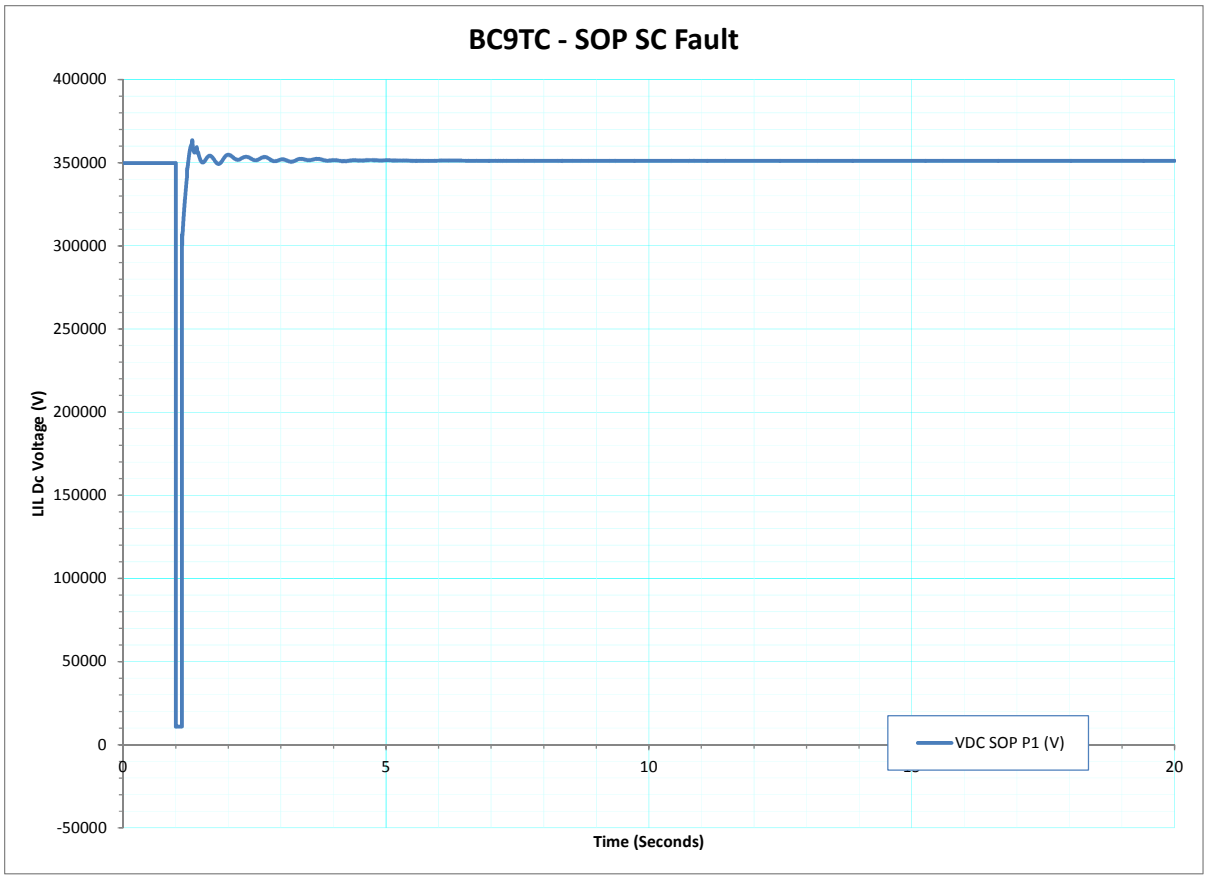


Figure 256 - BC9TC - SOP SC Fault - LIL Dc Voltage (V)

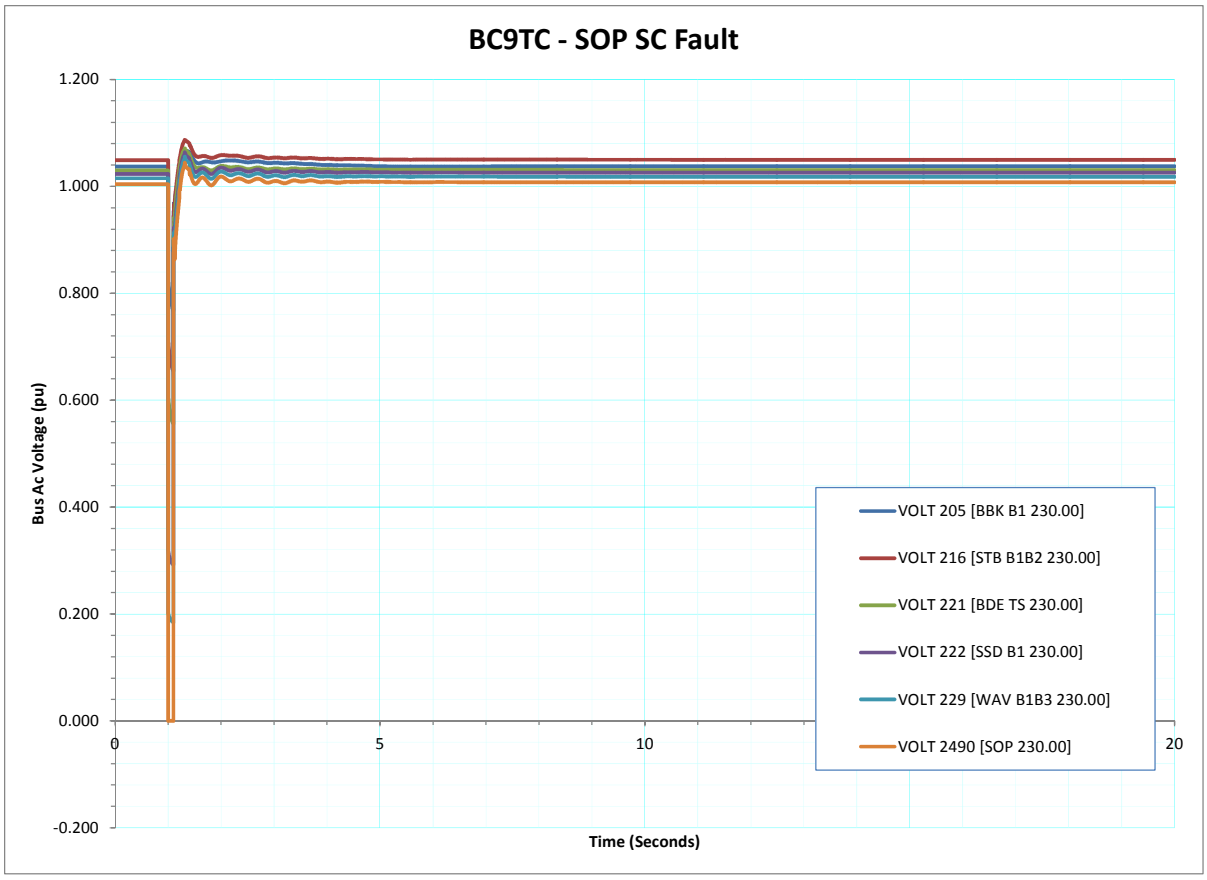


Figure 257 - BC9TC - SOP SC Fault - Bus Ac Voltage (pu)

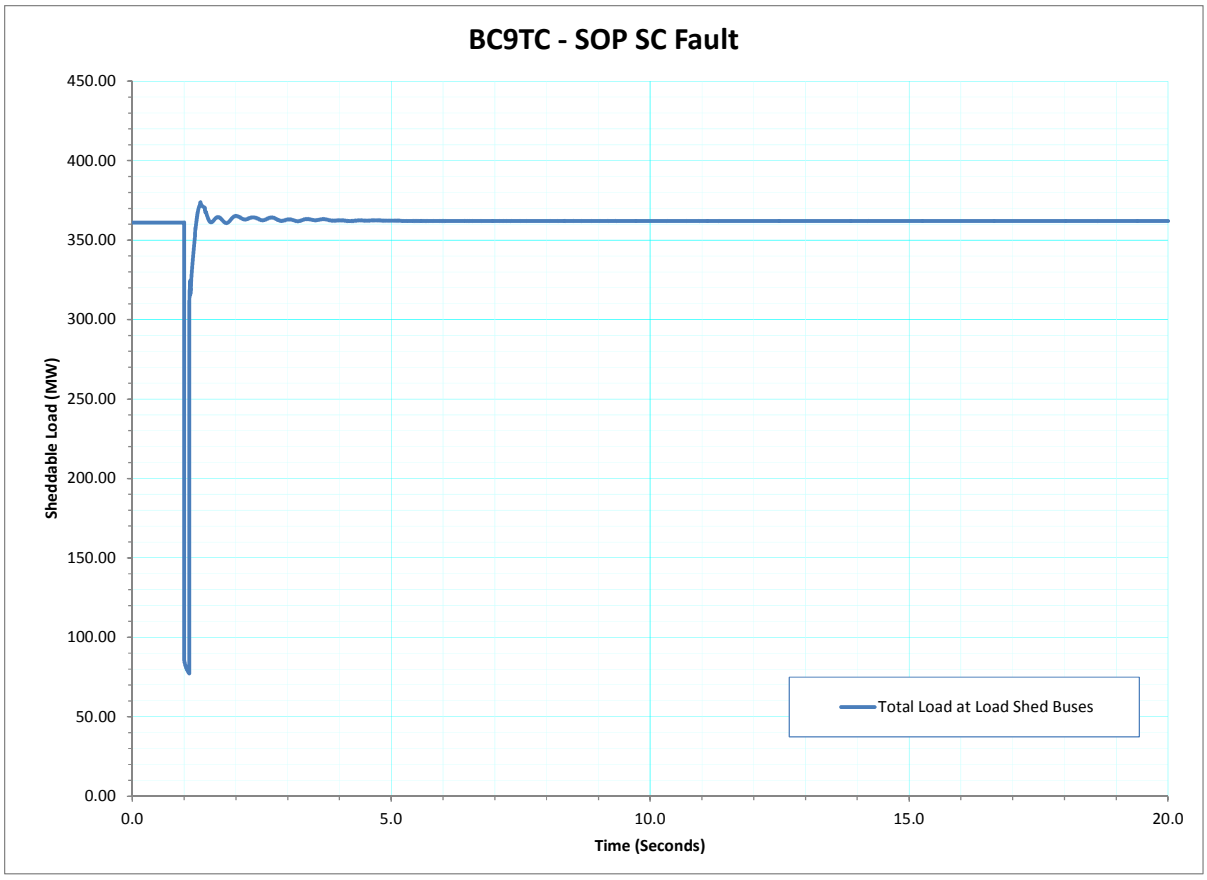


Figure 258 - BC9TC - SOP SC Fault - Sheddable Load (MW)

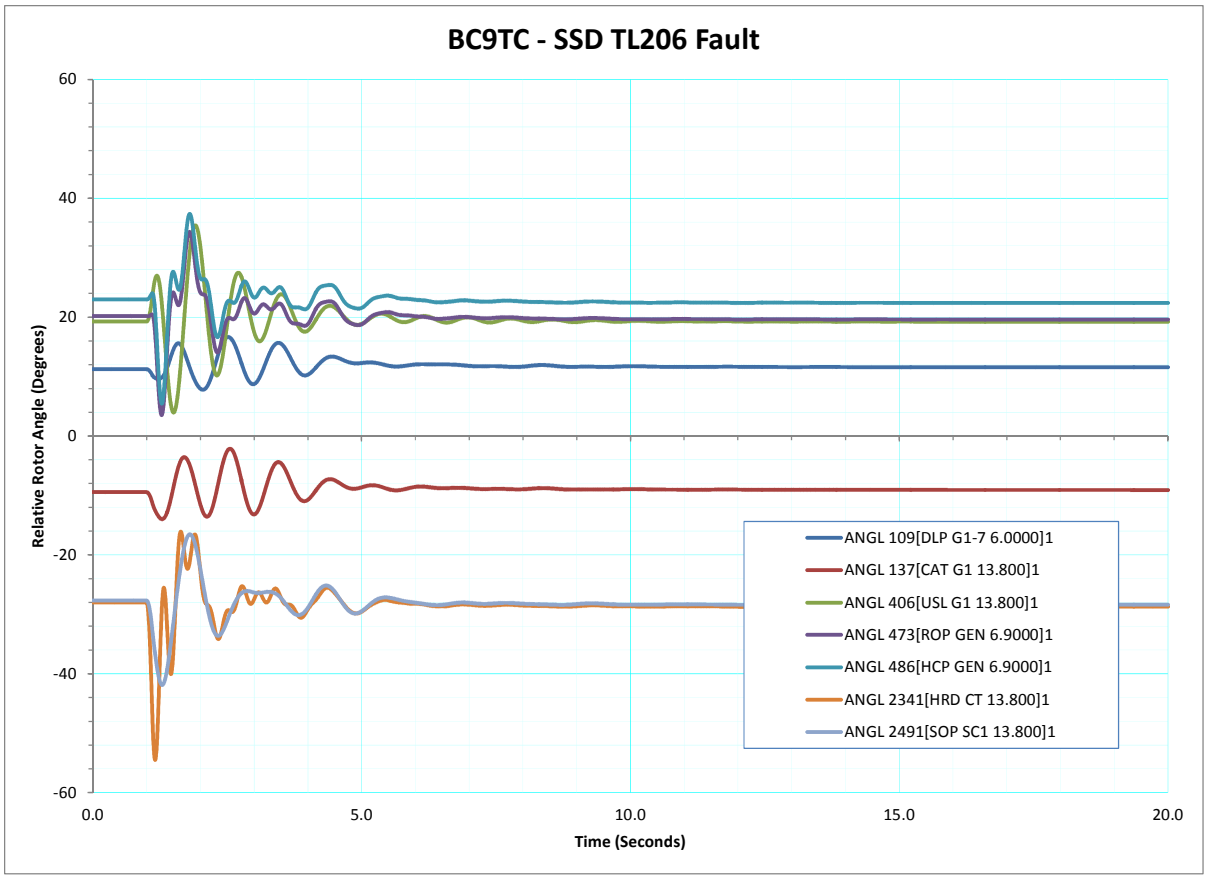


Figure 259 - BC9TC - SSD TL206 Fault - Relative Rotor Angle (Degrees)

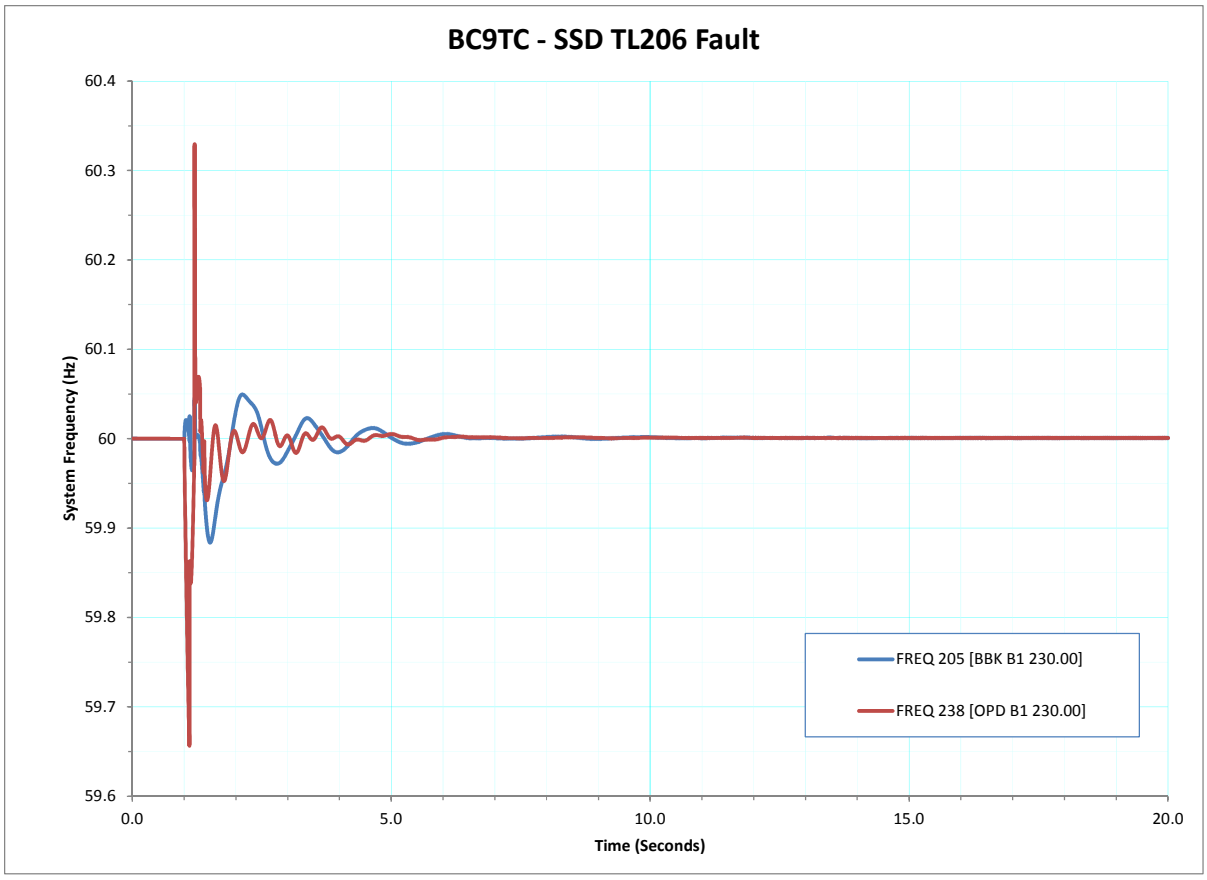


Figure 260 - BC9TC - SSD TL206 Fault - System Frequency (Hz)

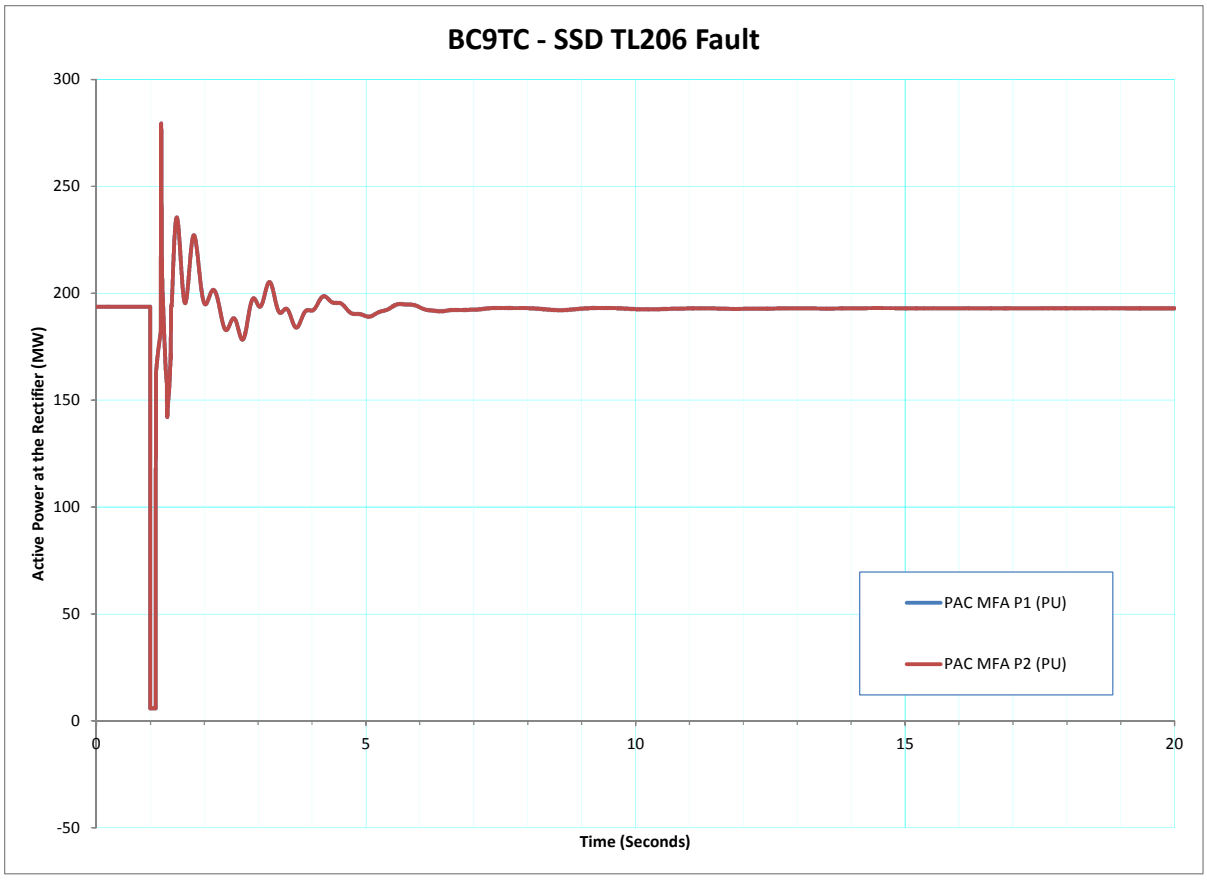


Figure 261 - BC9TC - SSD TL206 Fault - Active Power at the Rectifier (MW)

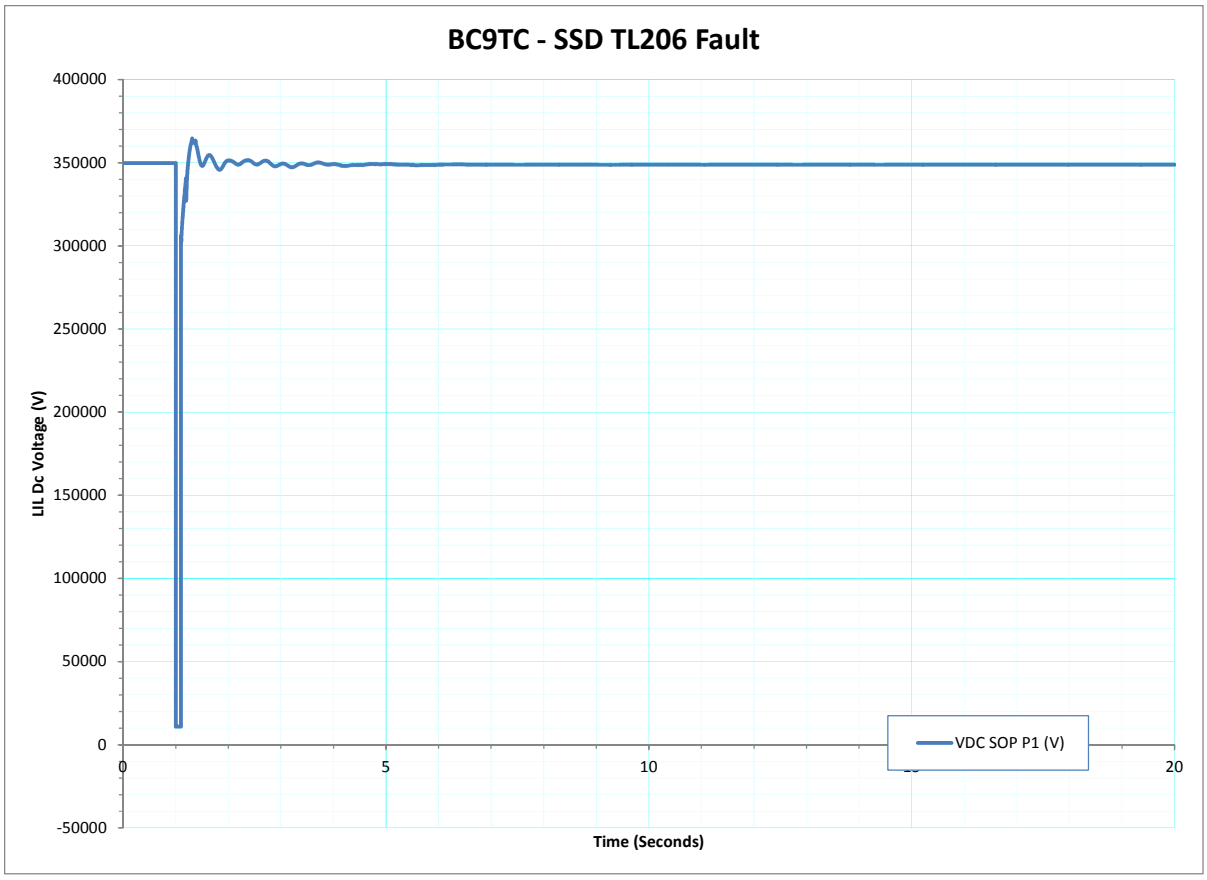


Figure 262 - BC9TC - SSD TL206 Fault - LIL Dc Voltage (V)

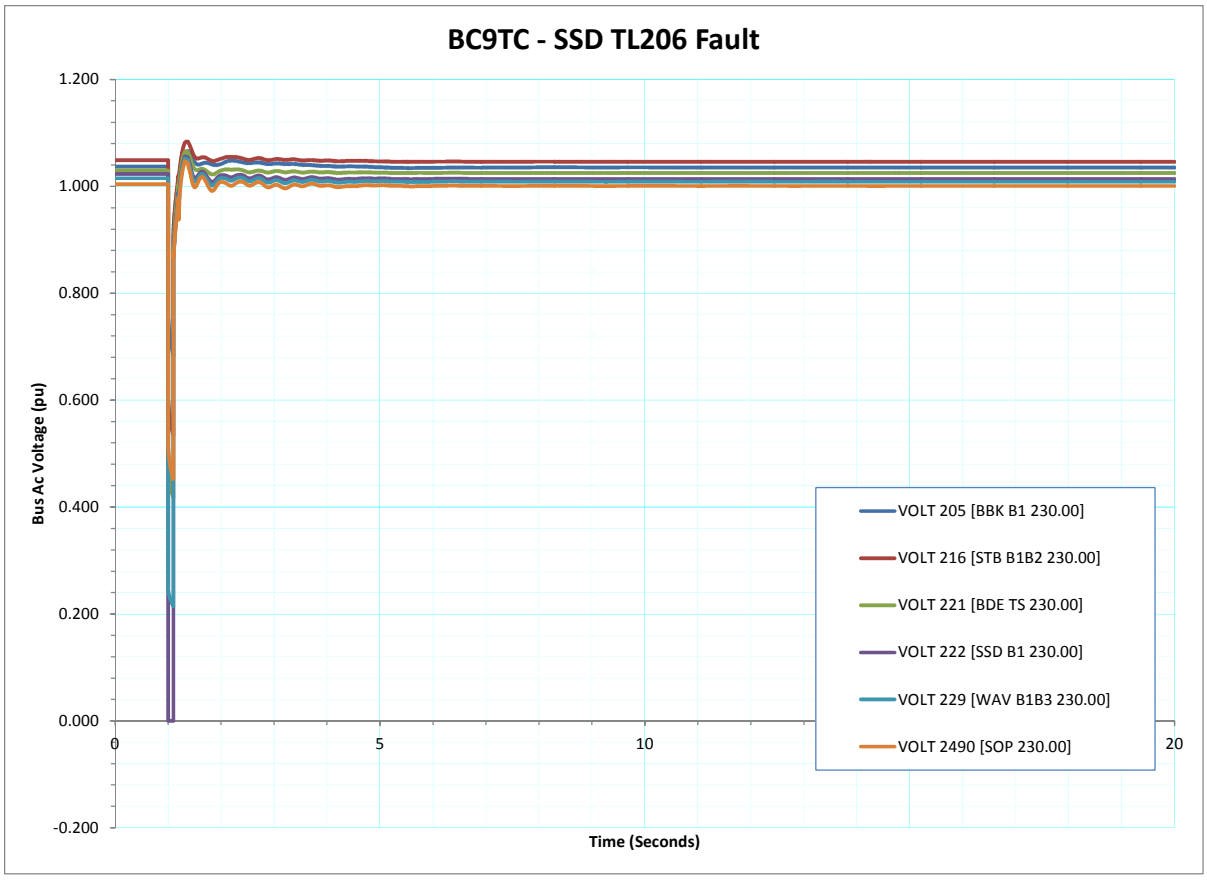


Figure 263 - BC9TC - SSD TL206 Fault - Bus Ac Voltage (pu)

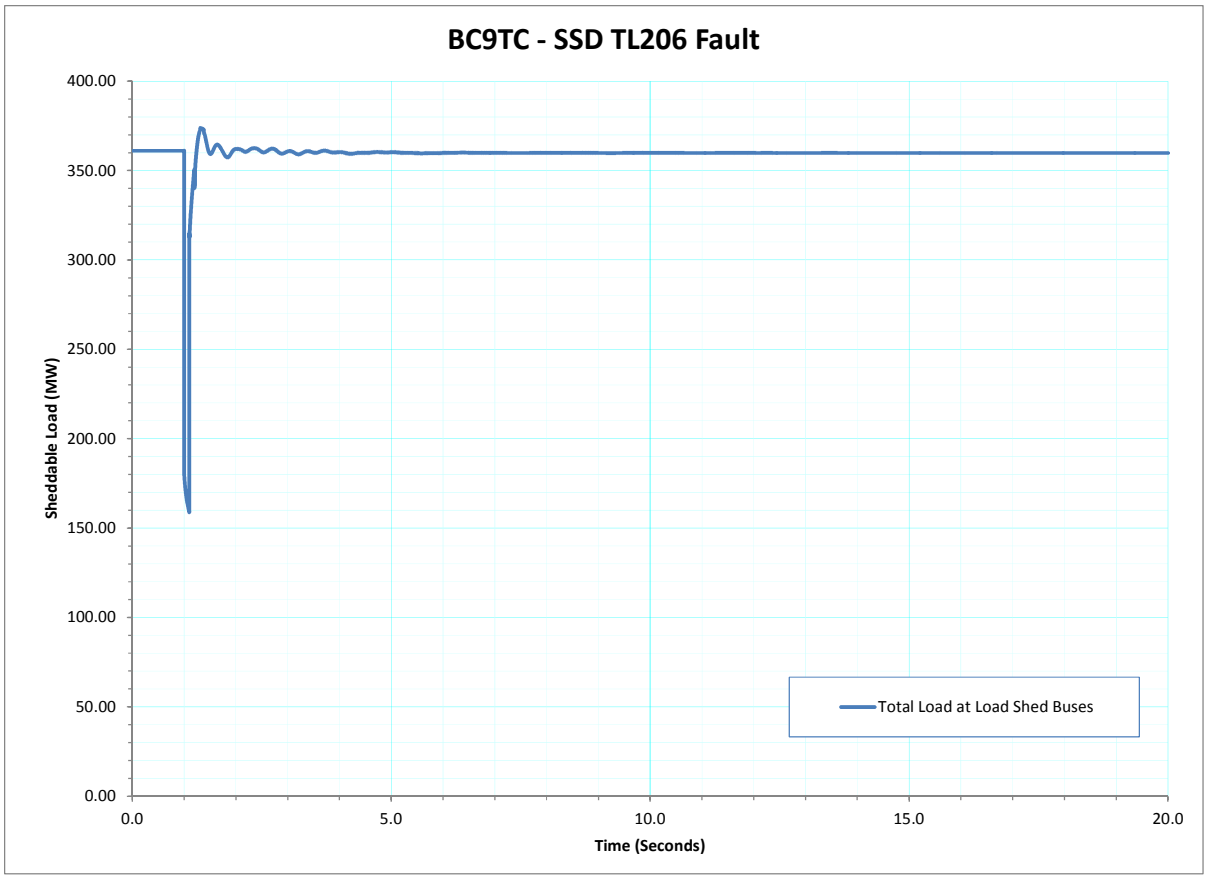


Figure 264 - BC9TC - SSD TL206 Fault - Sheddable Load (MW)

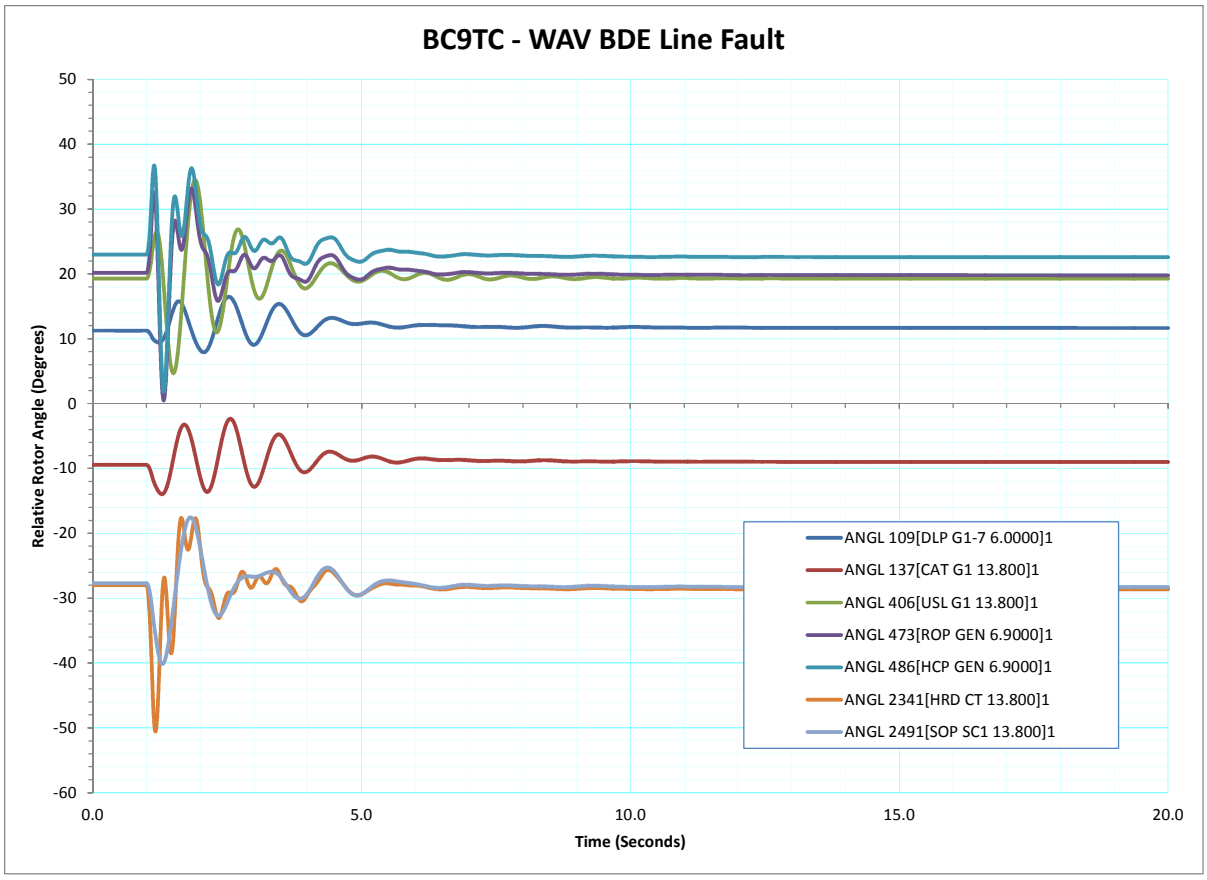


Figure 265 - BC9TC - WAV BDE Line Fault - Relative Rotor Angle (Degrees)

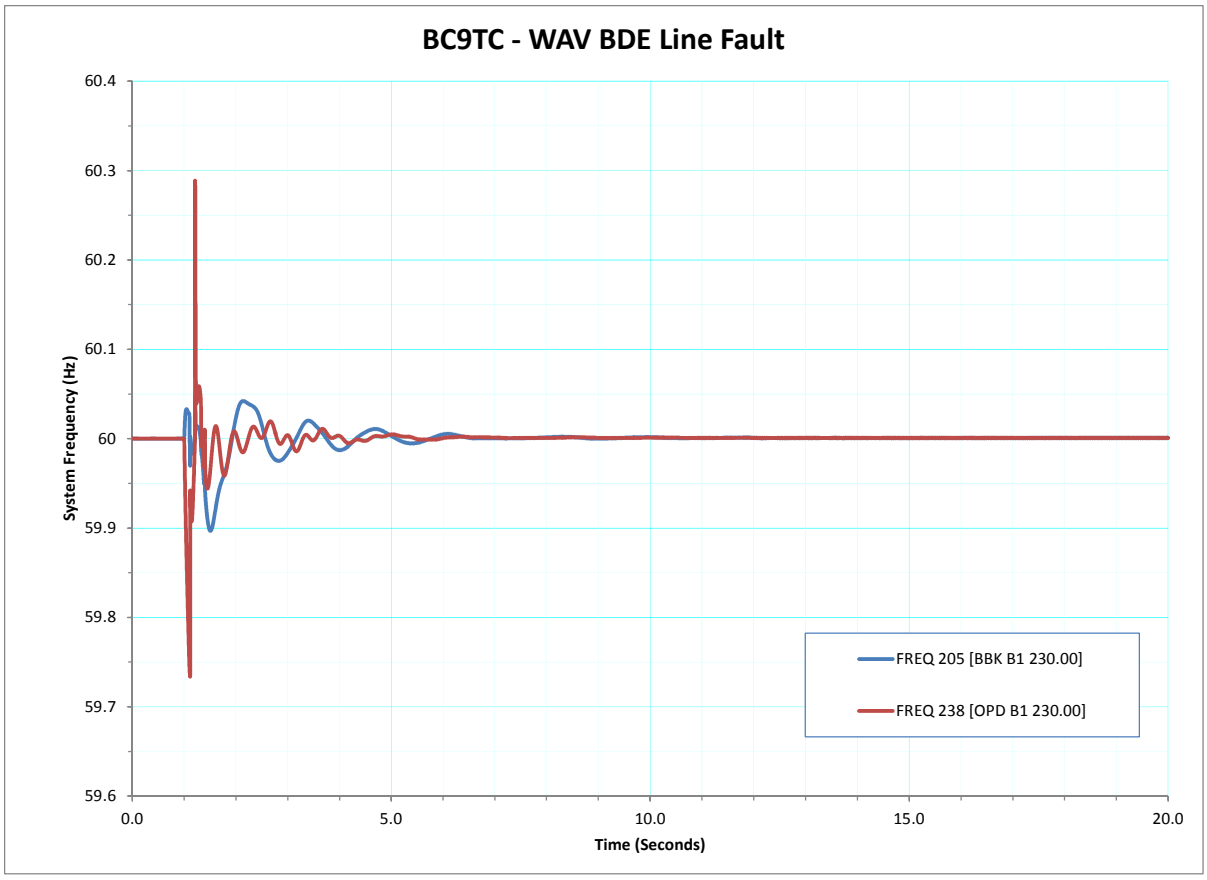


Figure 266 - BC9TC - WAV BDE Line Fault - System Frequency (Hz)

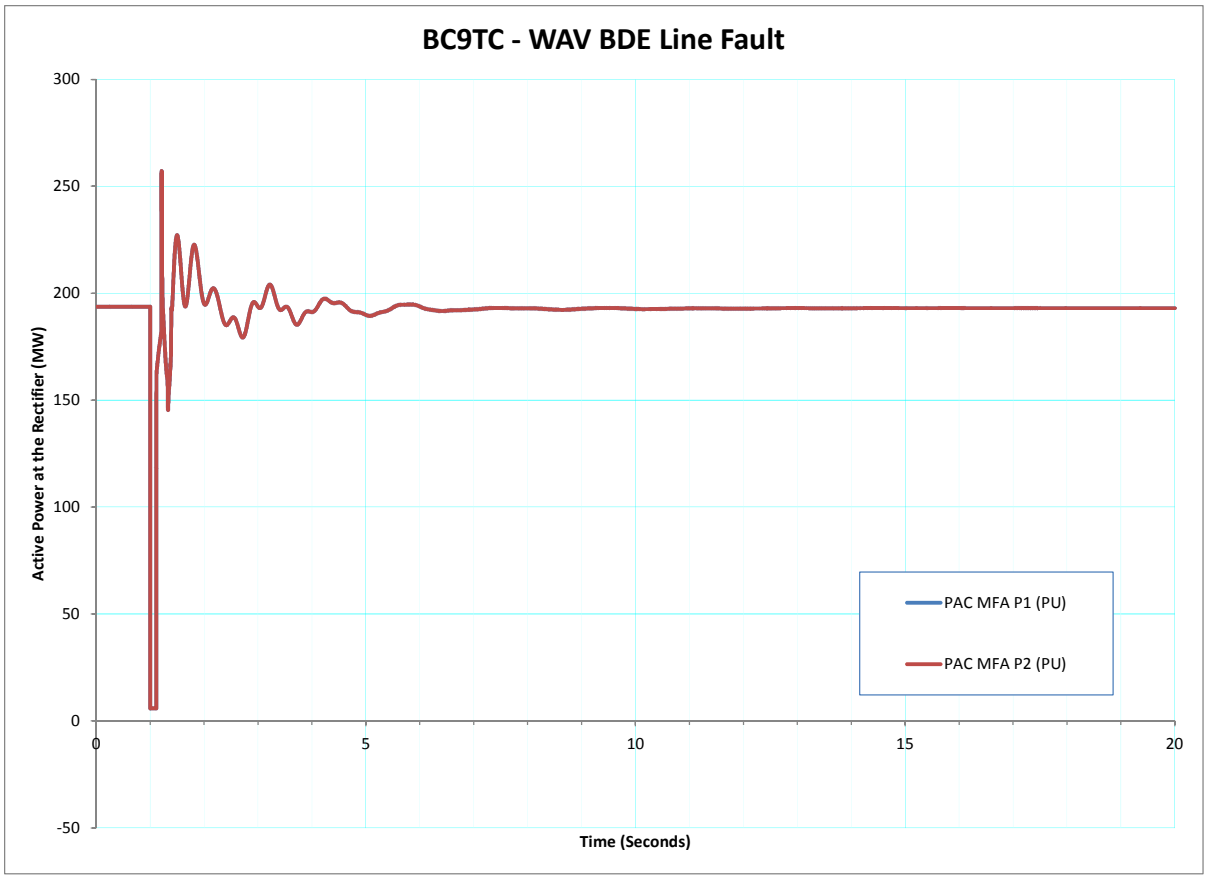


Figure 267 - BC9TC - WAV BDE Line Fault - Active Power at the Rectifier (MW)

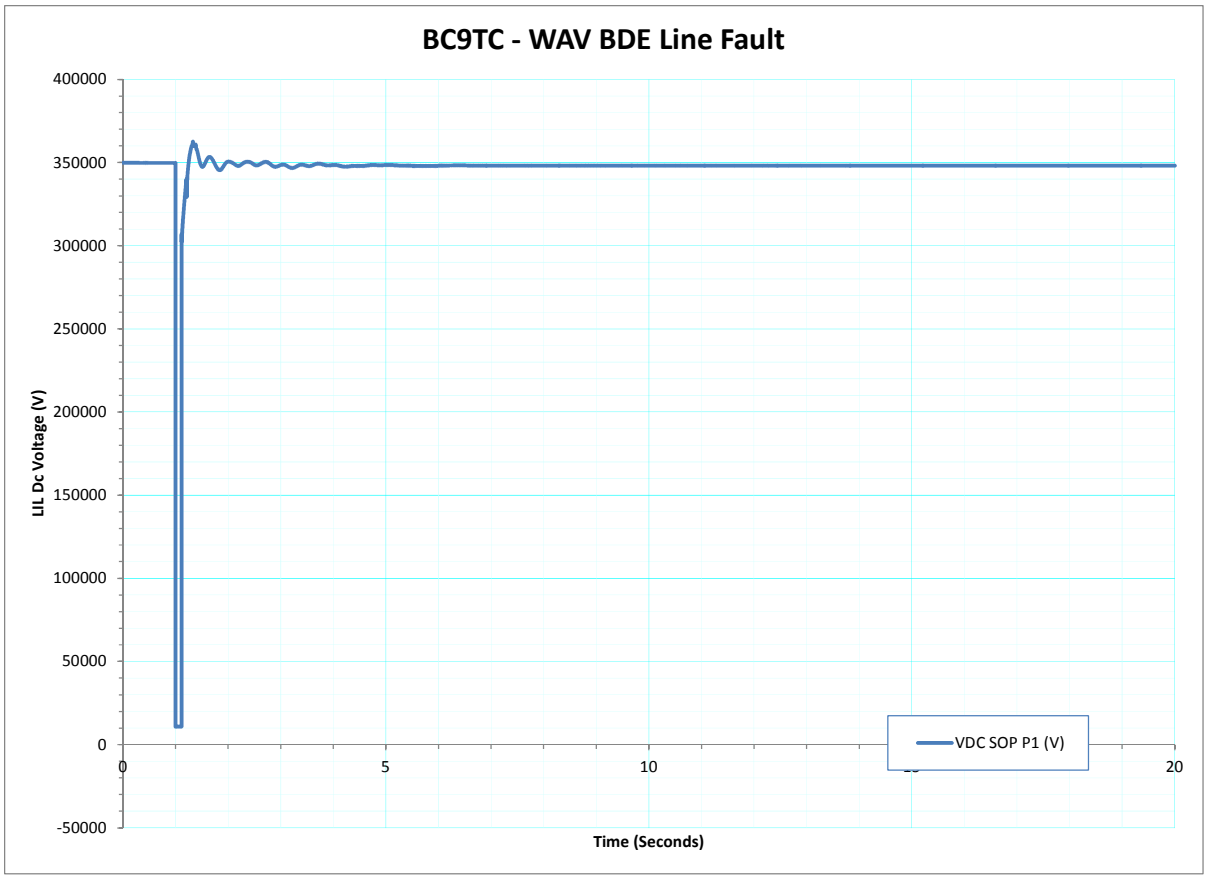


Figure 268 - BC9TC - WAV BDE Line Fault - LIL Dc Voltage (V)

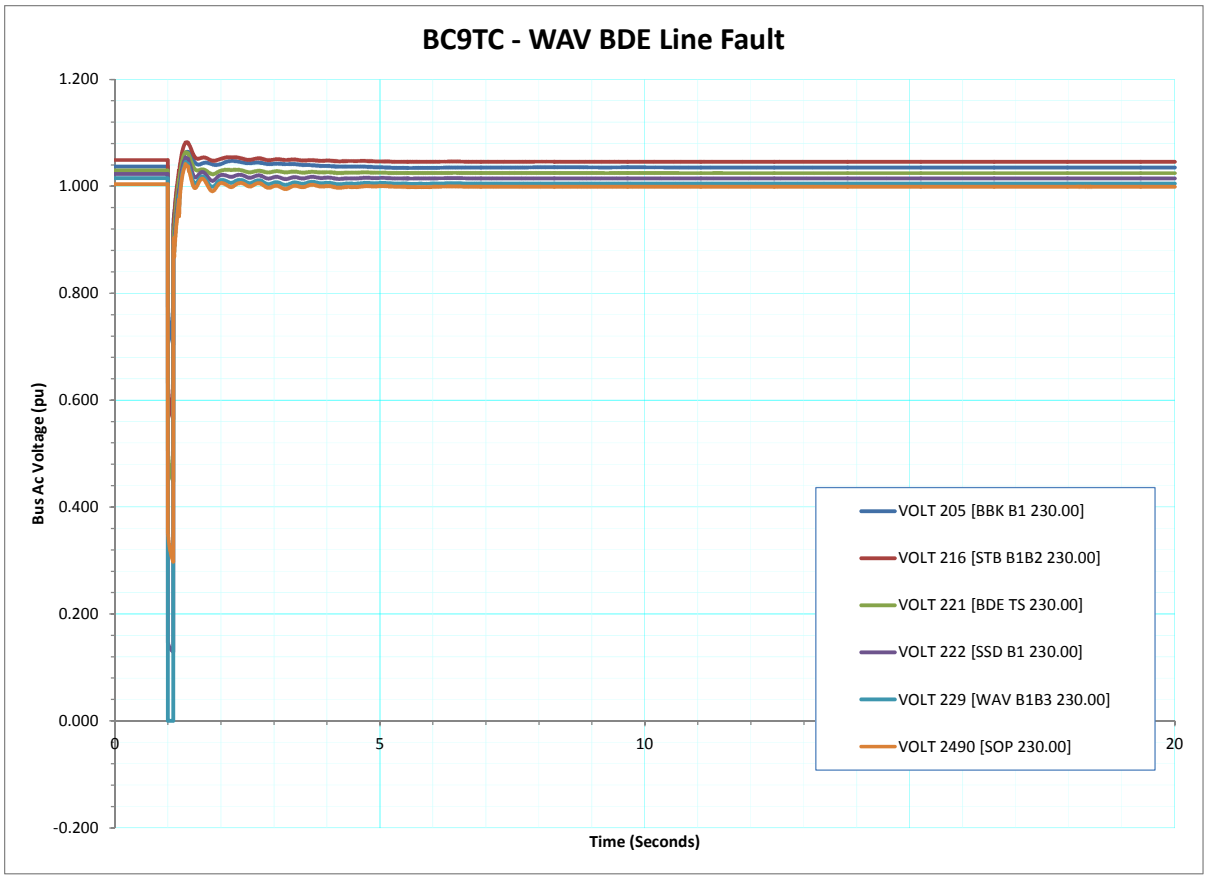


Figure 269 - BC9TC - WAV BDE Line Fault - Bus Ac Voltage (pu)

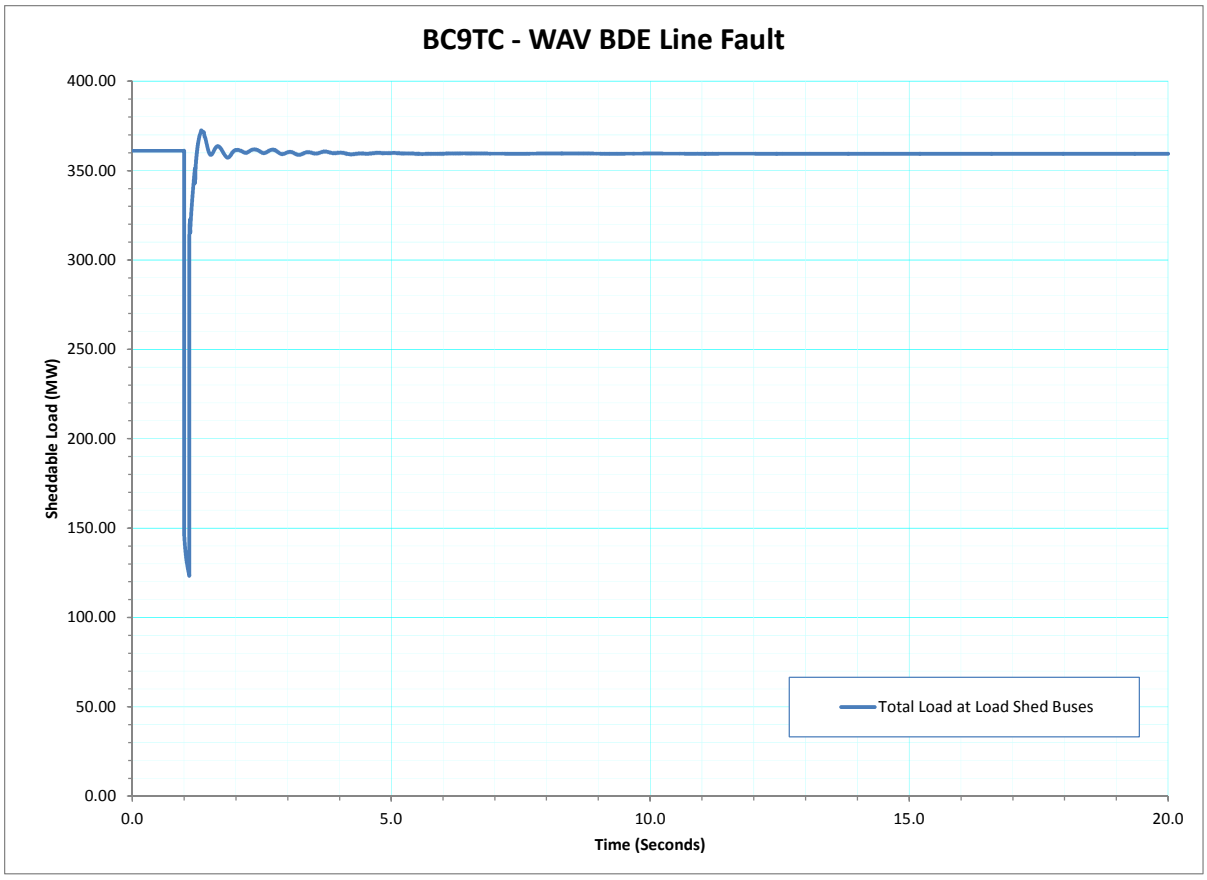


Figure 270 - BC9TC - WAV BDE Line Fault - Sheddable Load (MW)

1.10. BASE CASE 10 TRANSIENT STABILITY PLOTS

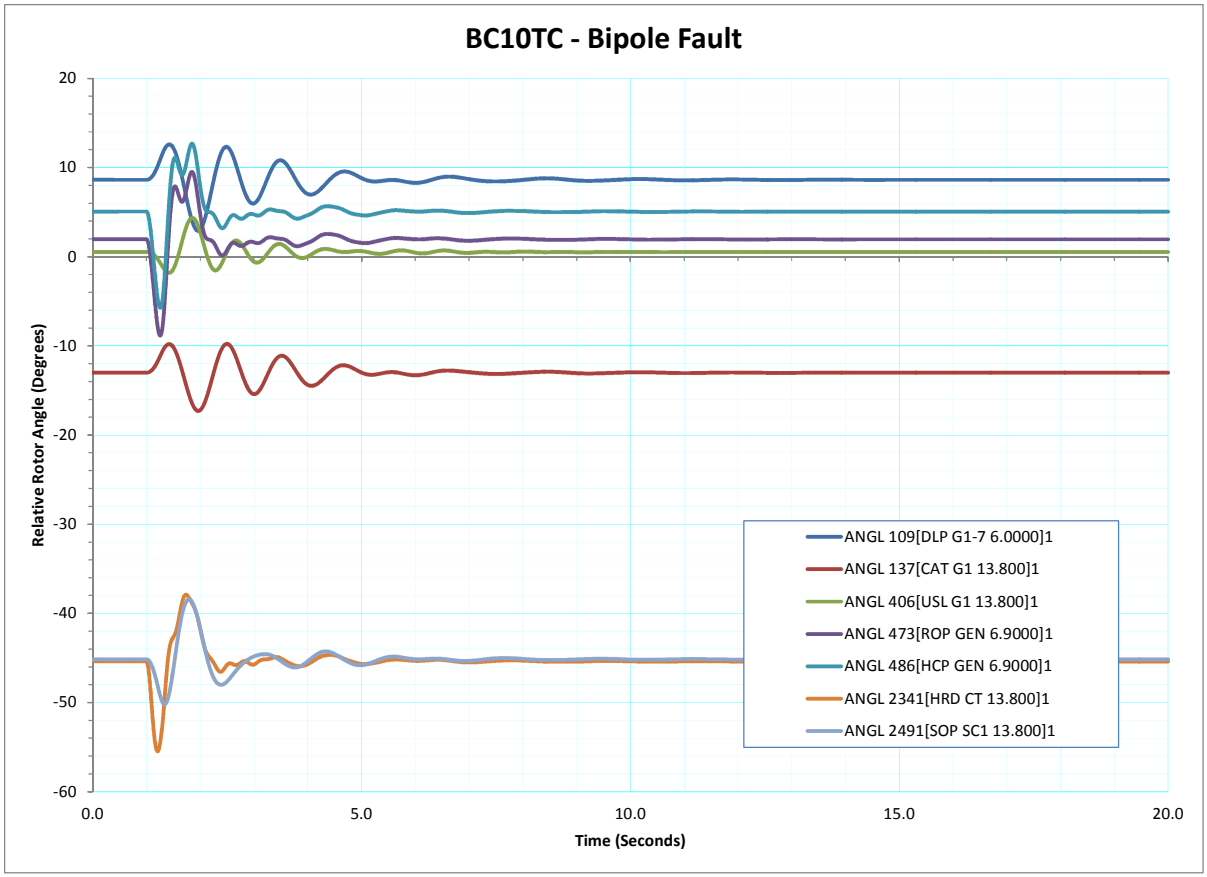


Figure 271 - BC10TC - Bipole Fault - Relative Rotor Angle (Degrees)

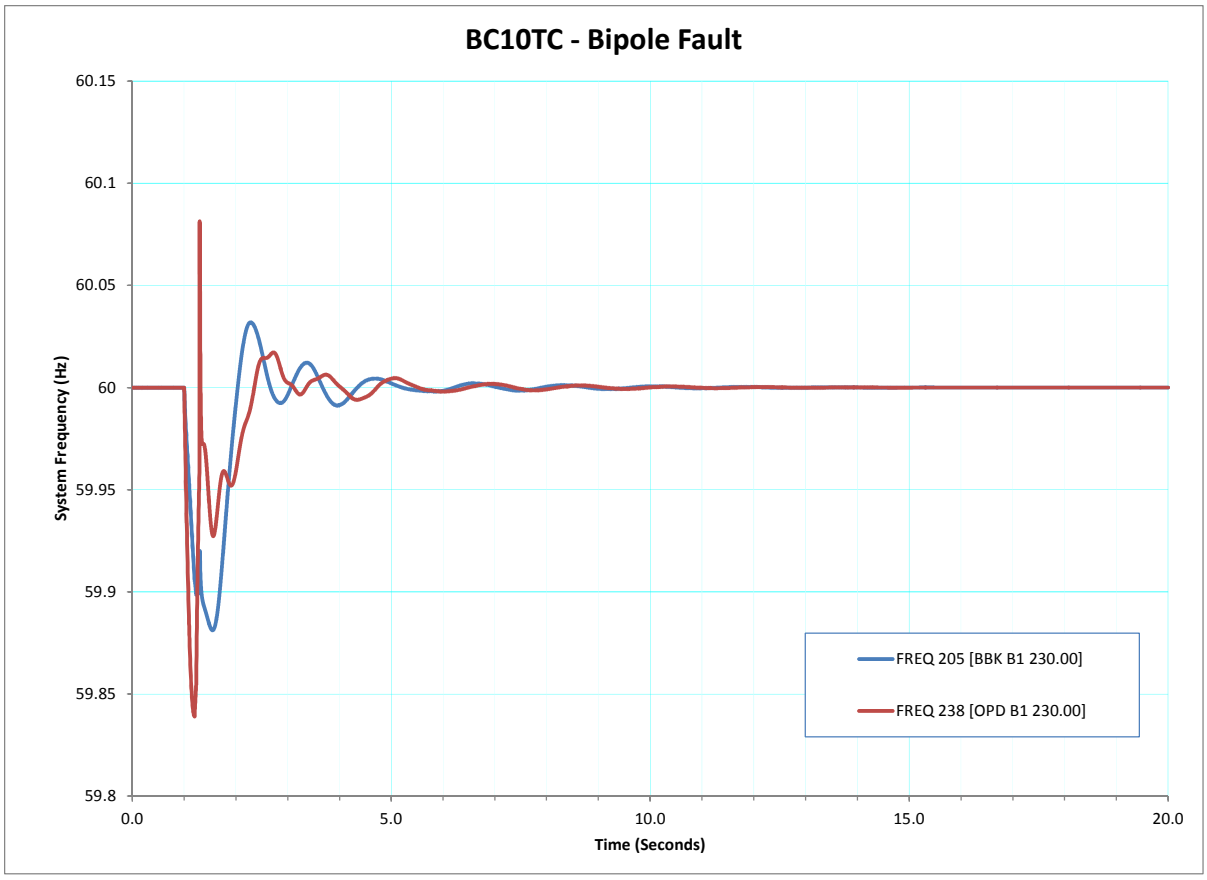


Figure 272 - BC10TC - Bipole Fault - System Frequency (Hz)

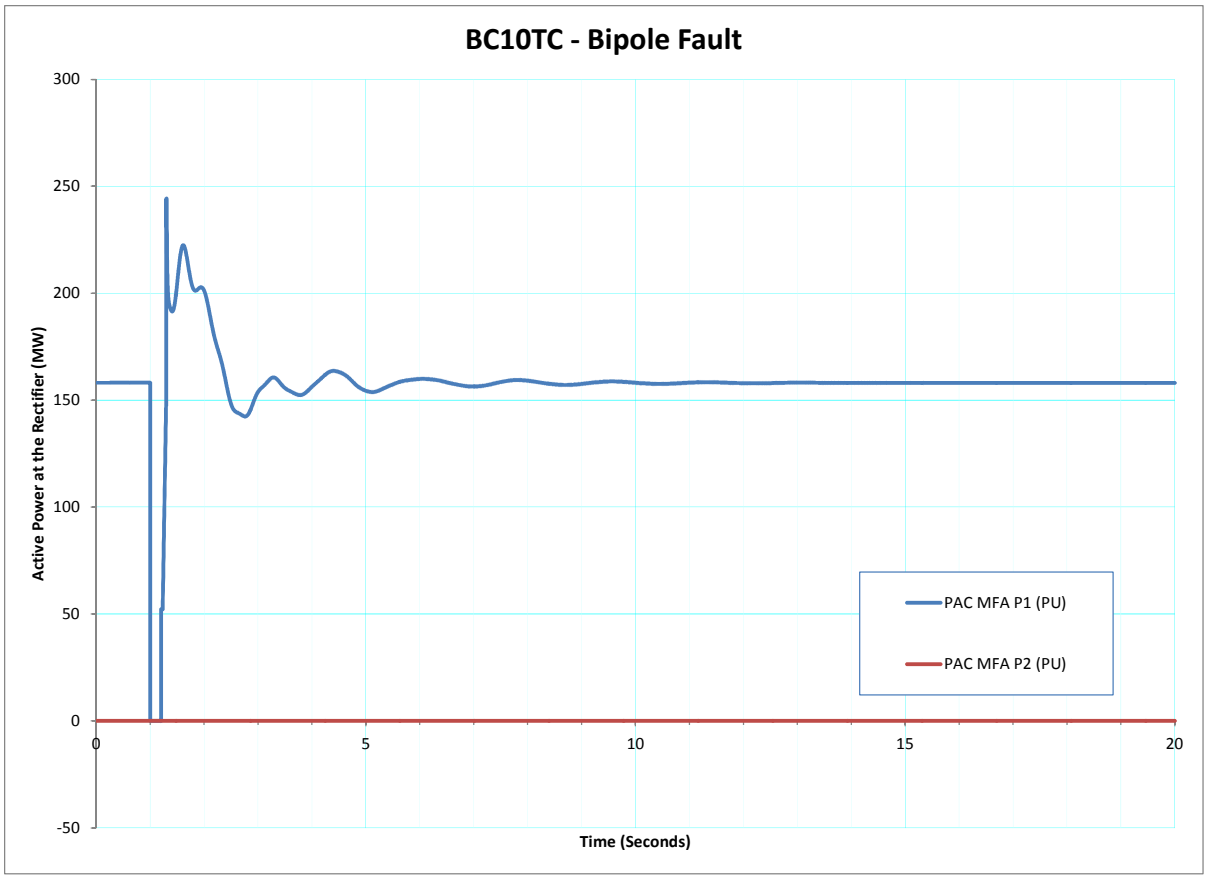


Figure 273 - BC10TC - Bipole Fault - Active Power at the Rectifier (MW)

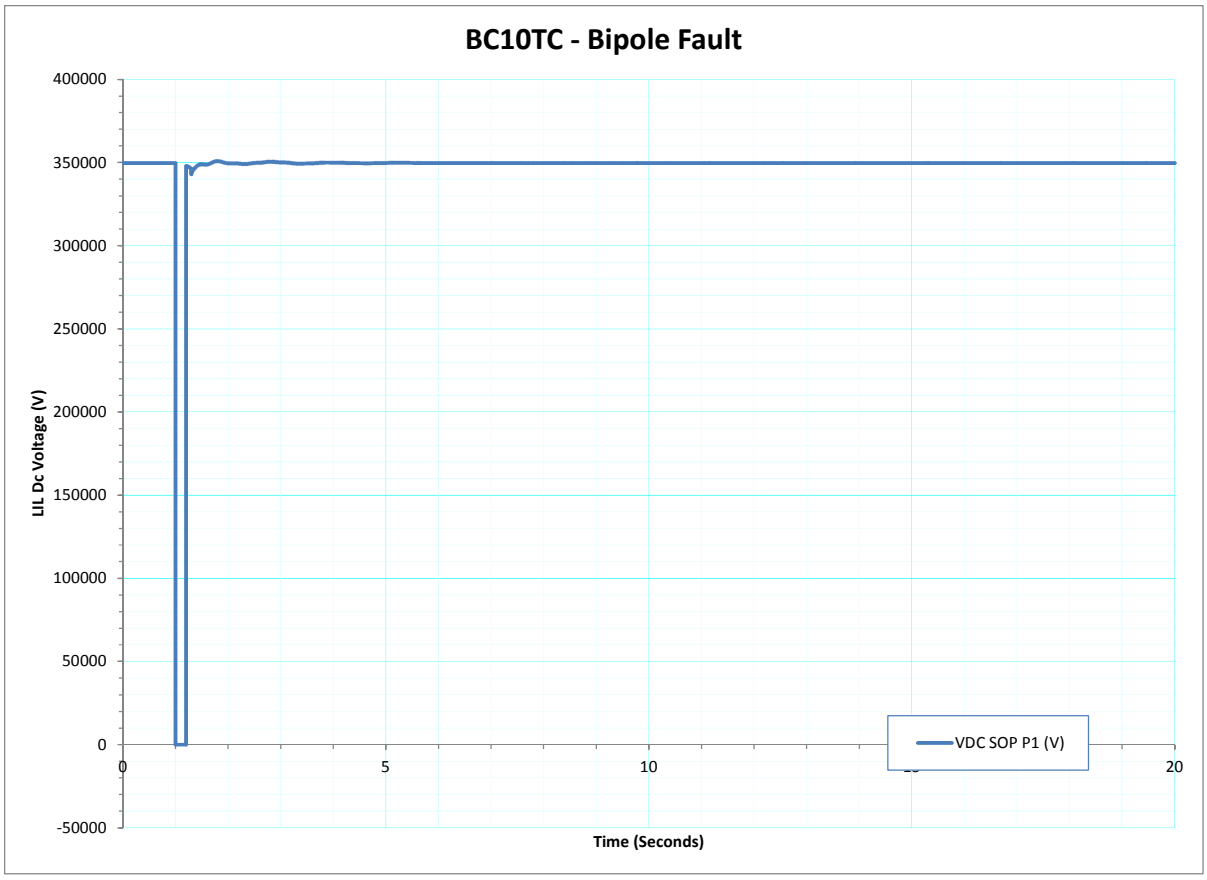


Figure 274 - BC10TC - Bipole Fault - LIL Dc Voltage (V)

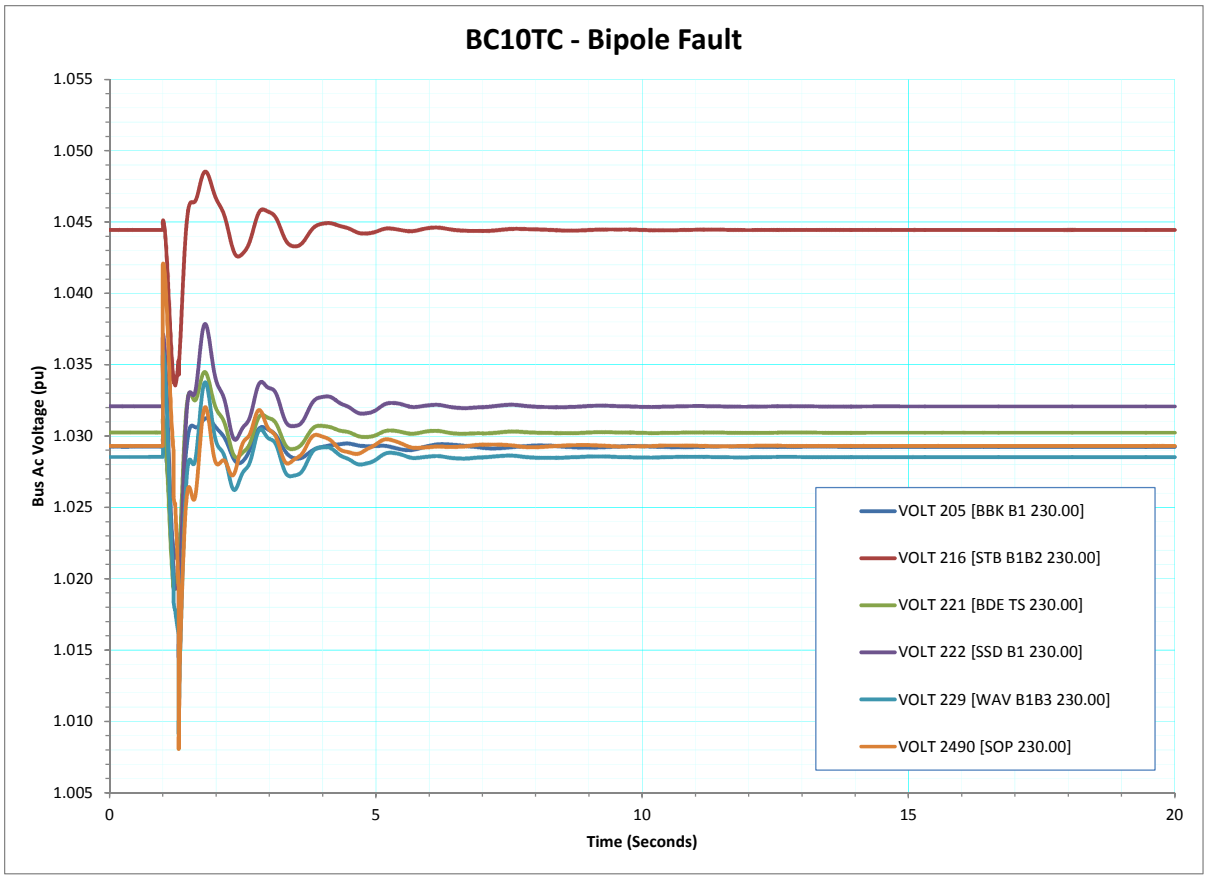


Figure 275 - BC10TC - Bipole Fault - Bus Ac Voltage (pu)

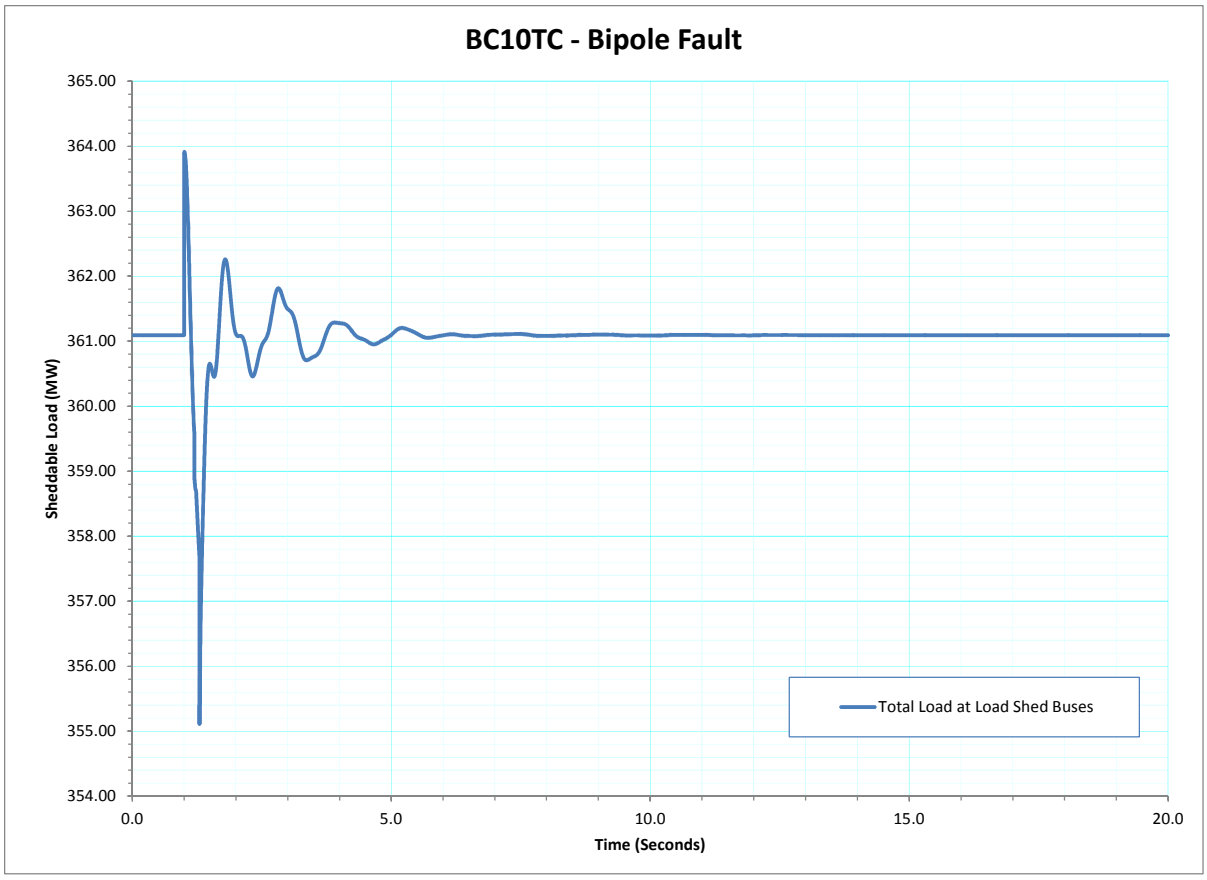


Figure 276 - BC10TC - Bipole Fault - Sheddable Load (MW)

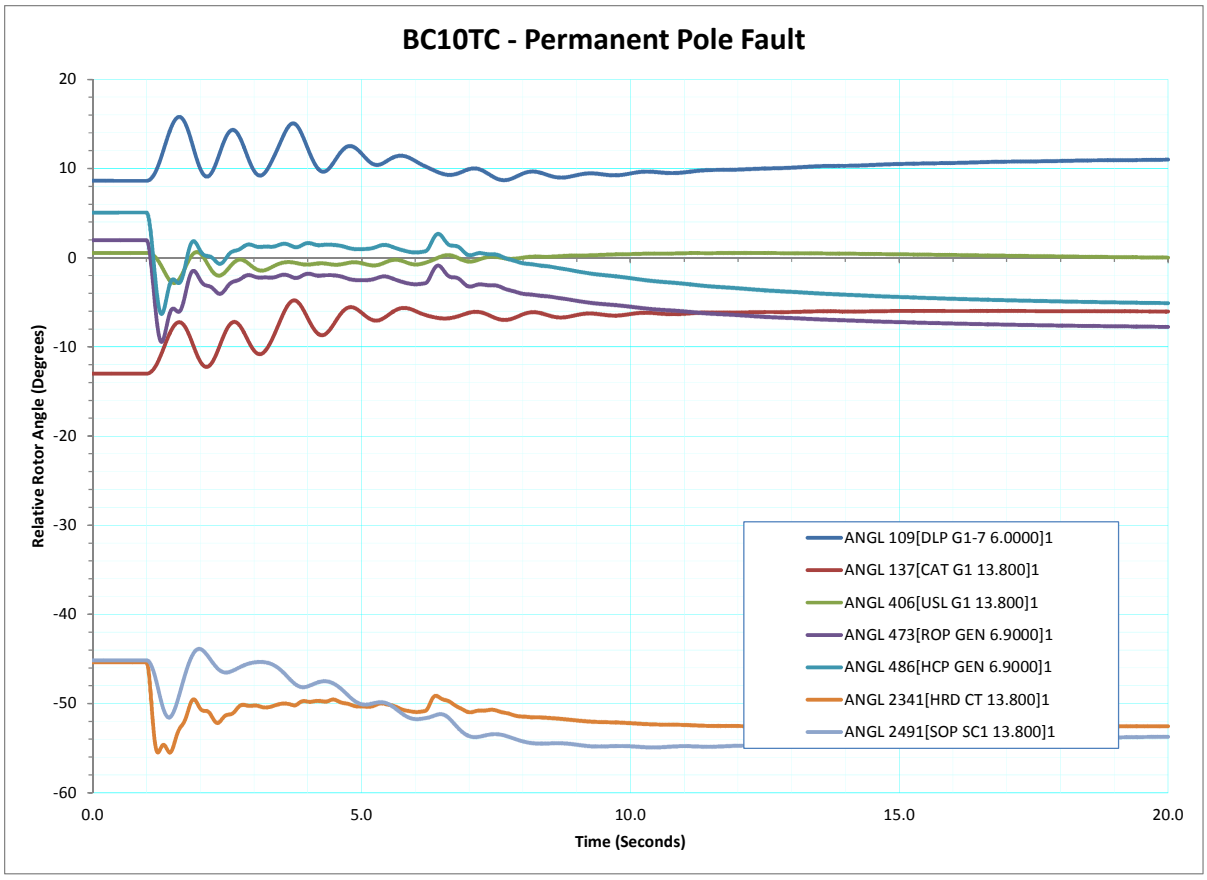


Figure 277 - BC10TC - Permanent Pole Fault - Relative Rotor Angle (Degrees)

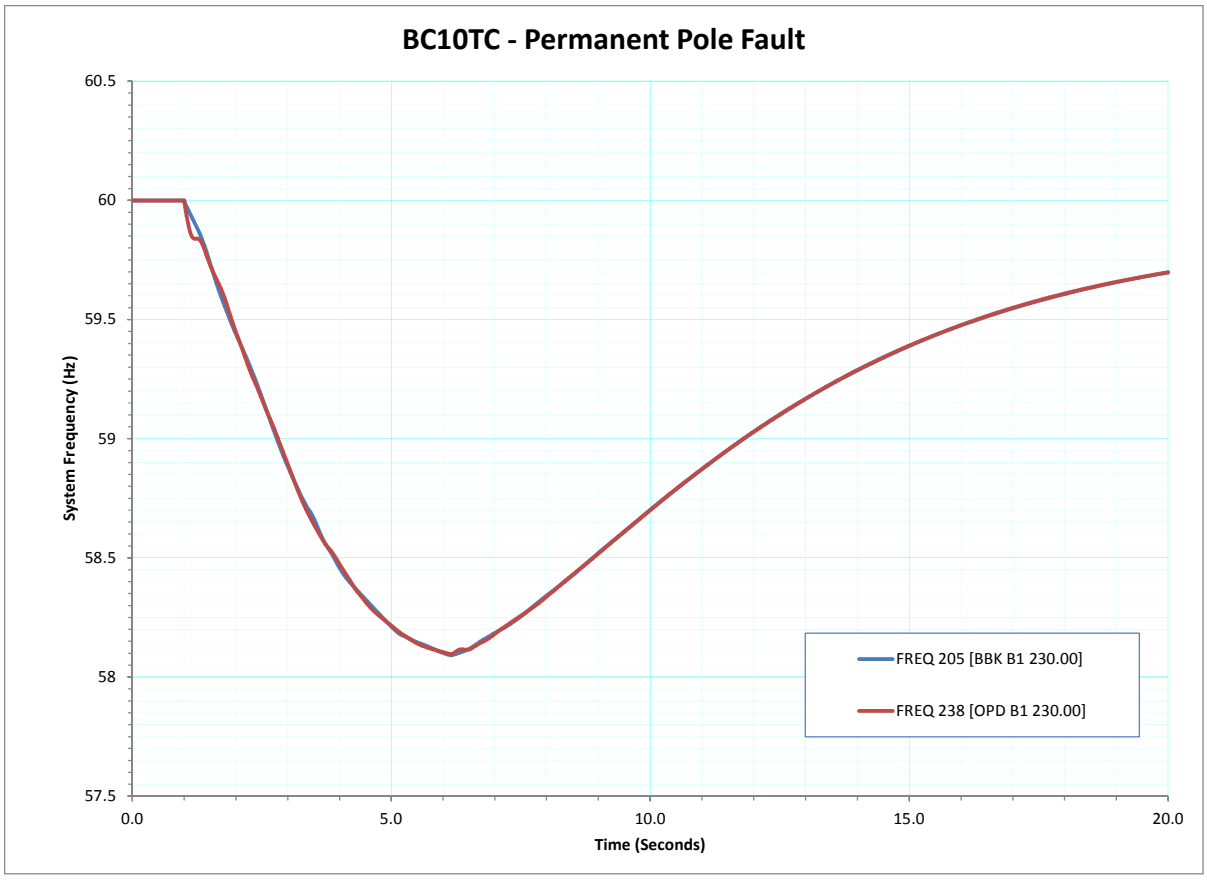


Figure 278 - BC10TC - Permanent Pole Fault - System Frequency (Hz)

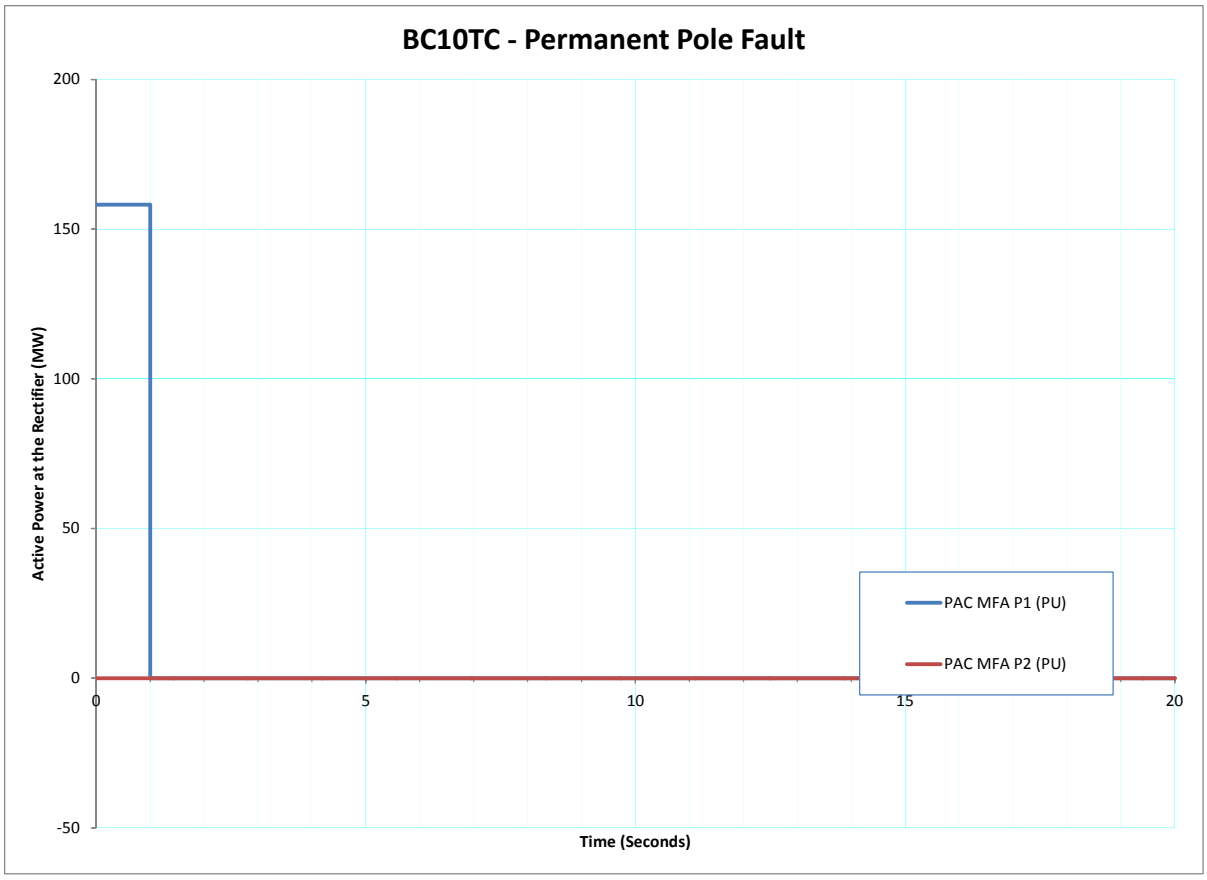


Figure 279 - BC10TC - Permanent Pole Fault - Active Power at the Rectifier (MW)

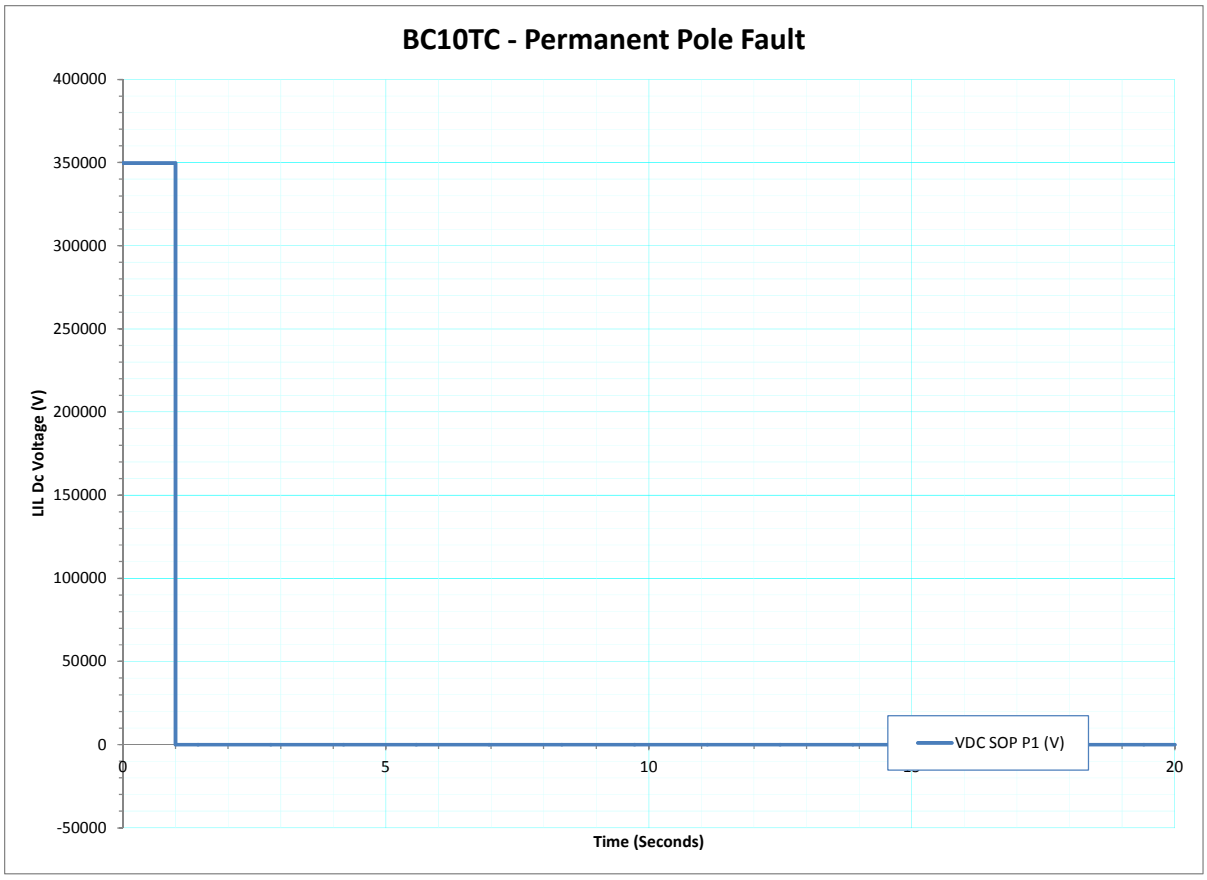


Figure 280 - BC10TC - Permanent Pole Fault - LIL Dc Voltage (V)

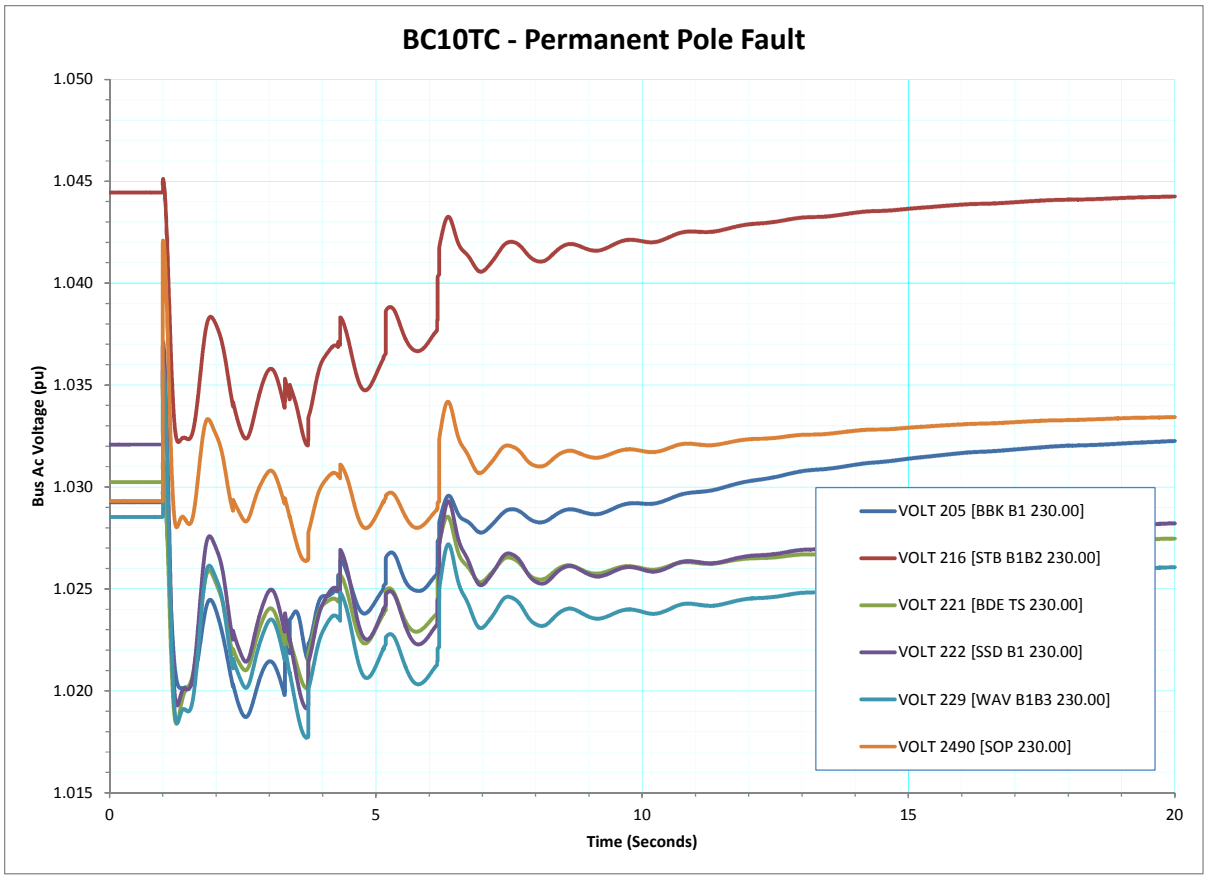


Figure 281 - BC10TC - Permanent Pole Fault - Bus Ac Voltage (pu)

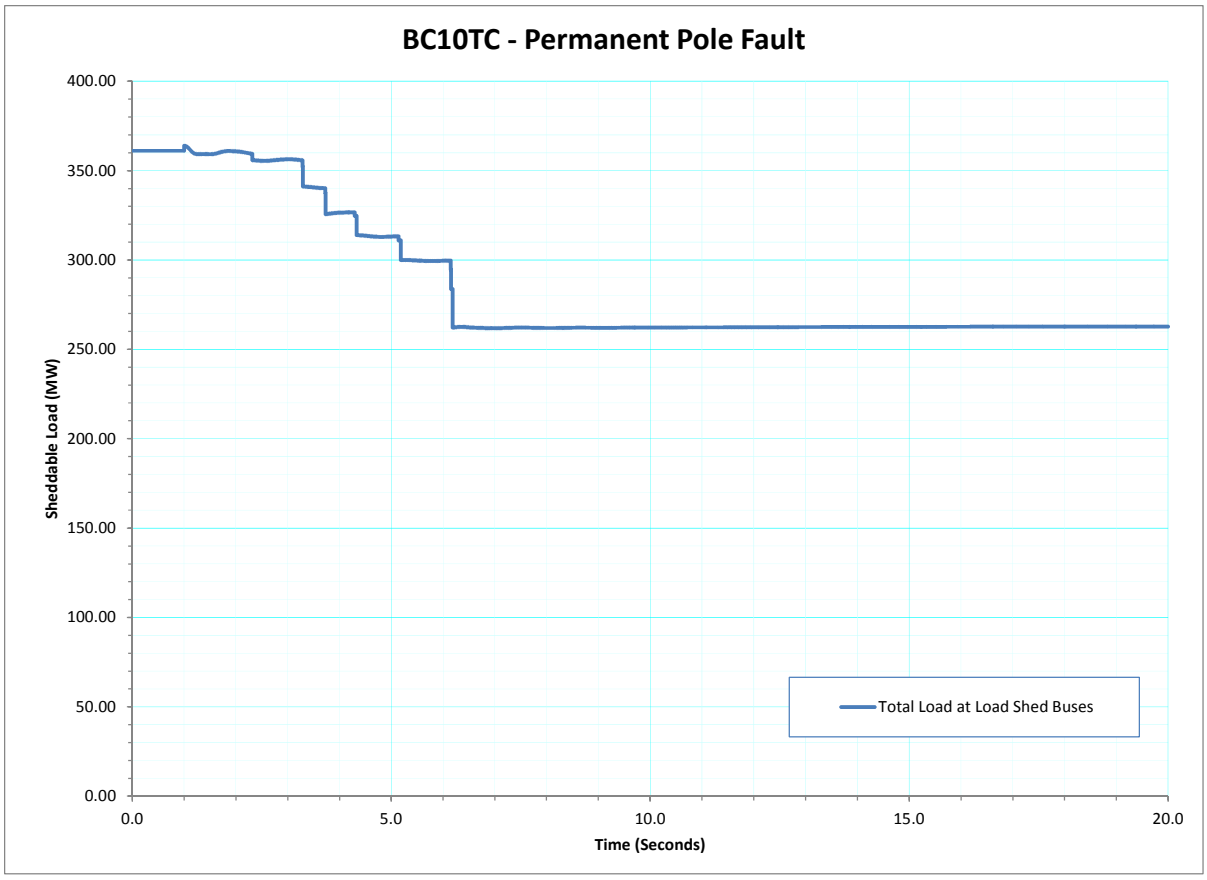


Figure 282 - BC10TC - Permanent Pole Fault - Sheddable Load (MW)

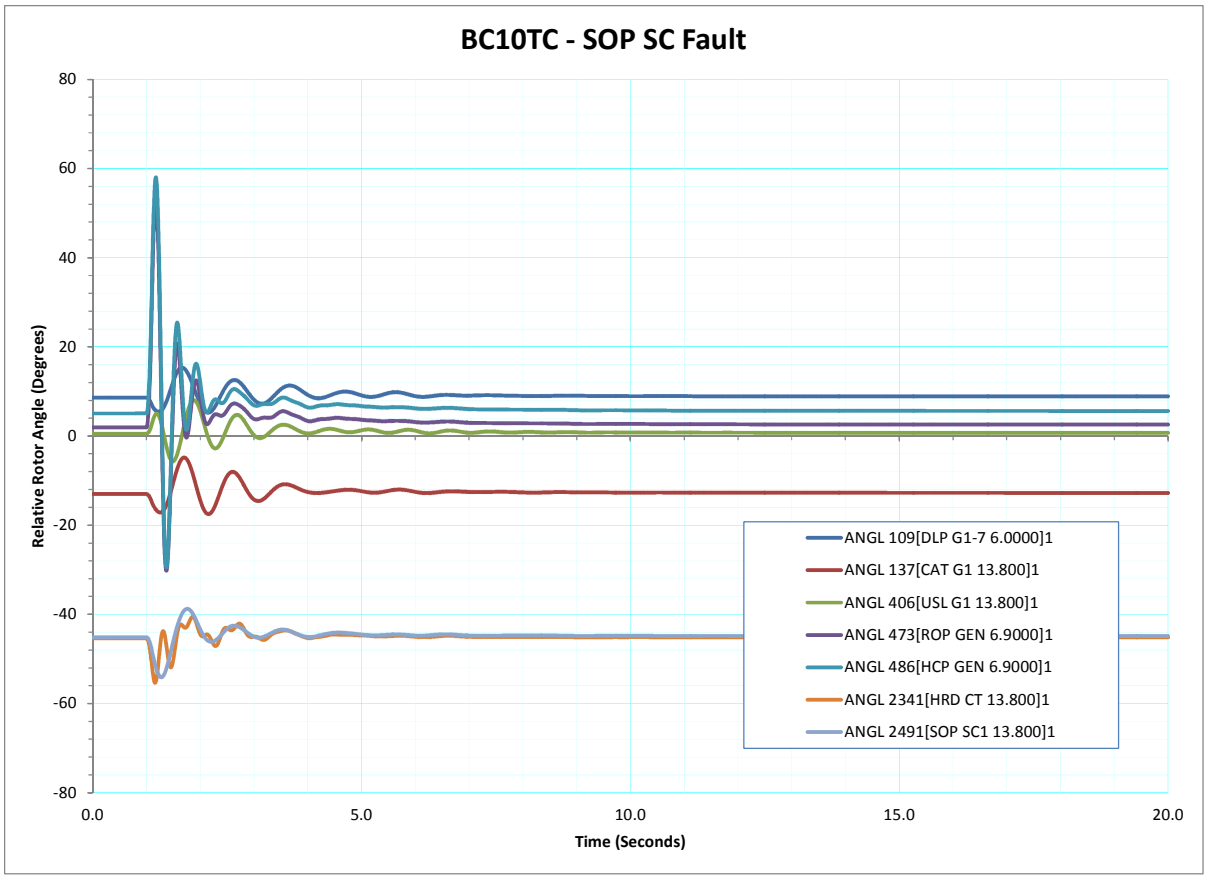


Figure 283 - BC10TC - SOP SC Fault - Relative Rotor Angle (Degrees)

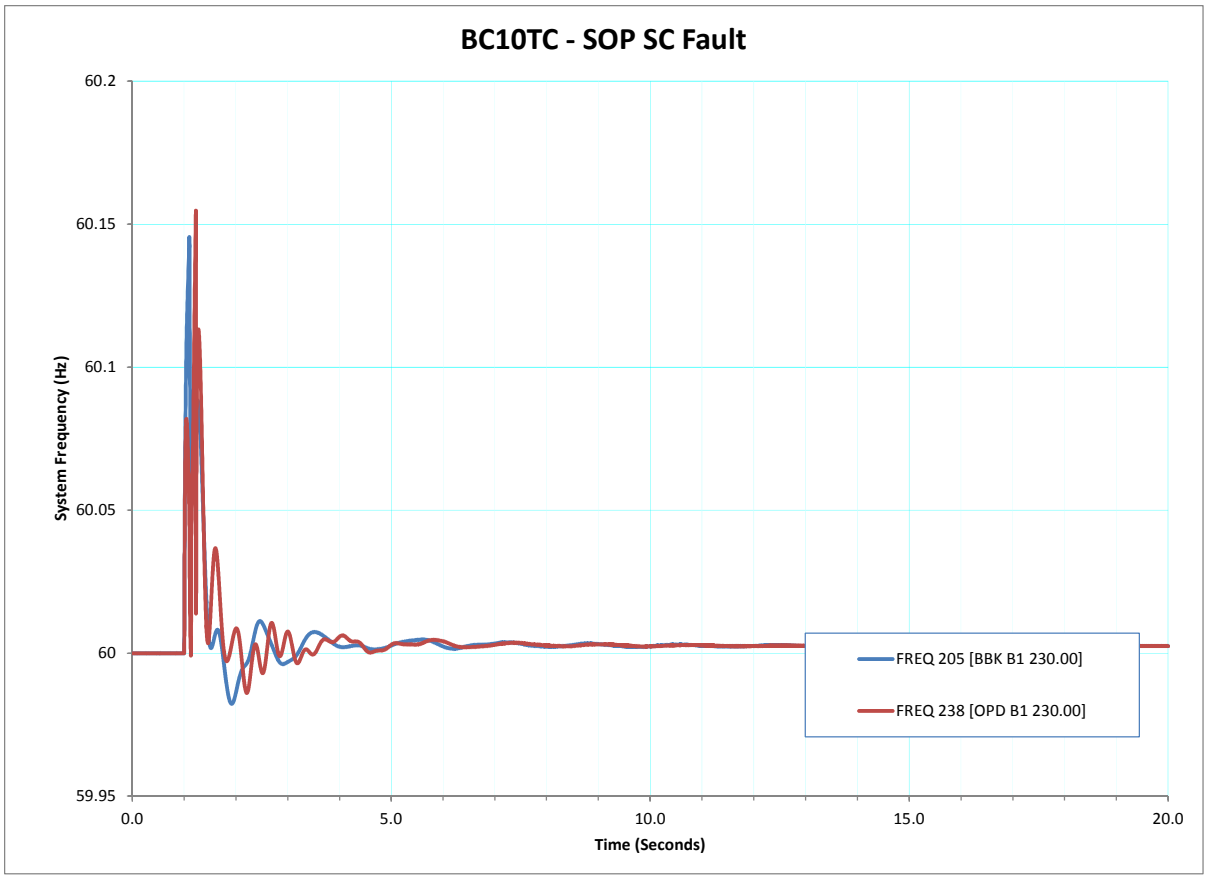


Figure 284 - BC10TC - SOP SC Fault - System Frequency (Hz)

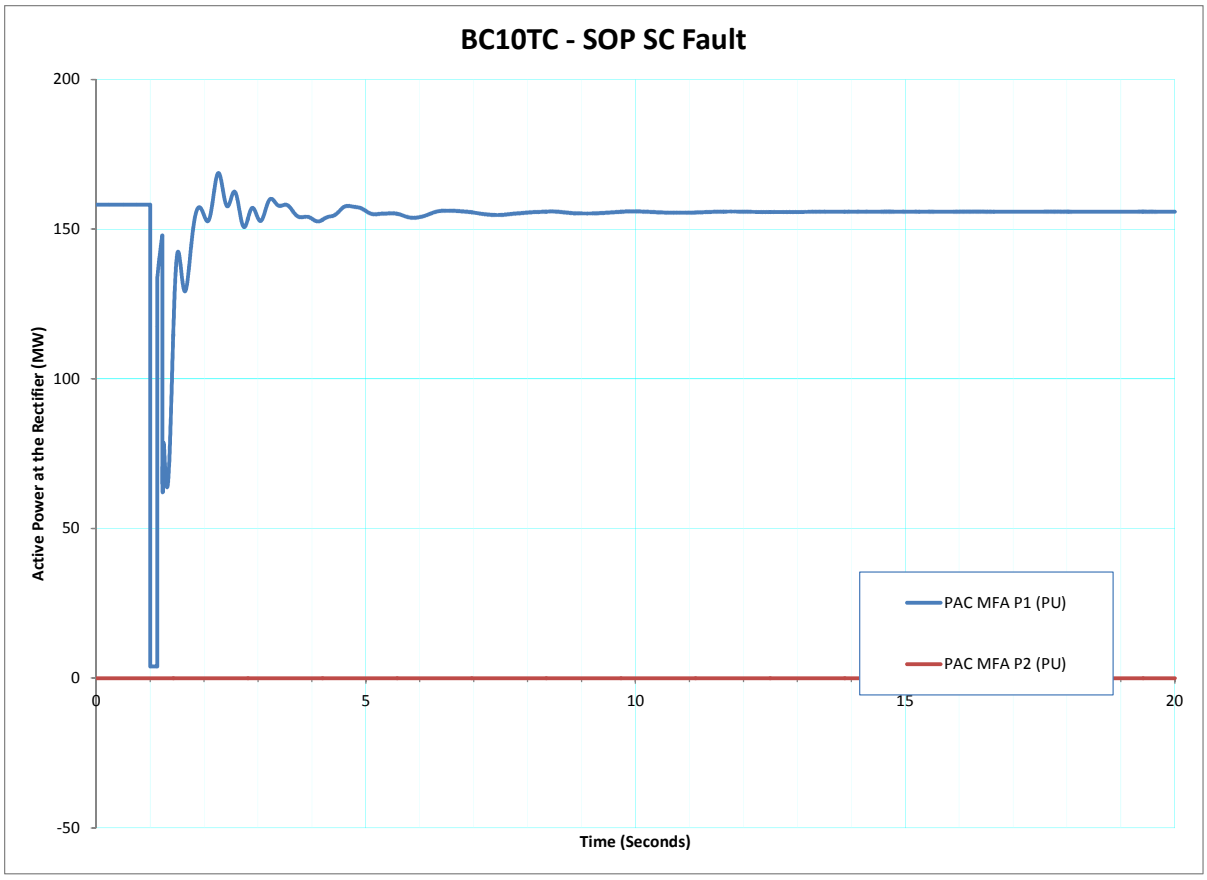


Figure 285 - BC10TC - SOP SC Fault - Active Power at the Rectifier (MW)

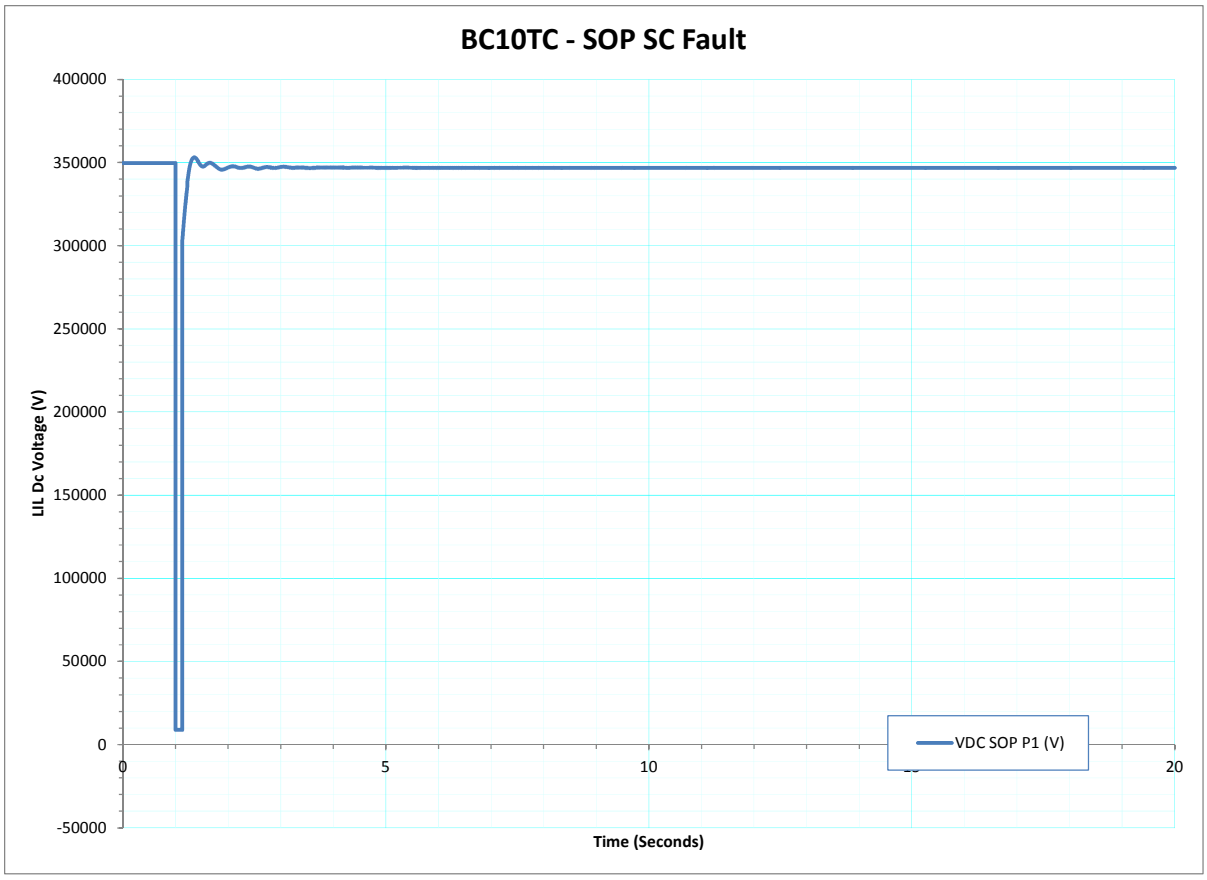


Figure 286 - BC10TC - SOP SC Fault - LIL Dc Voltage (V)

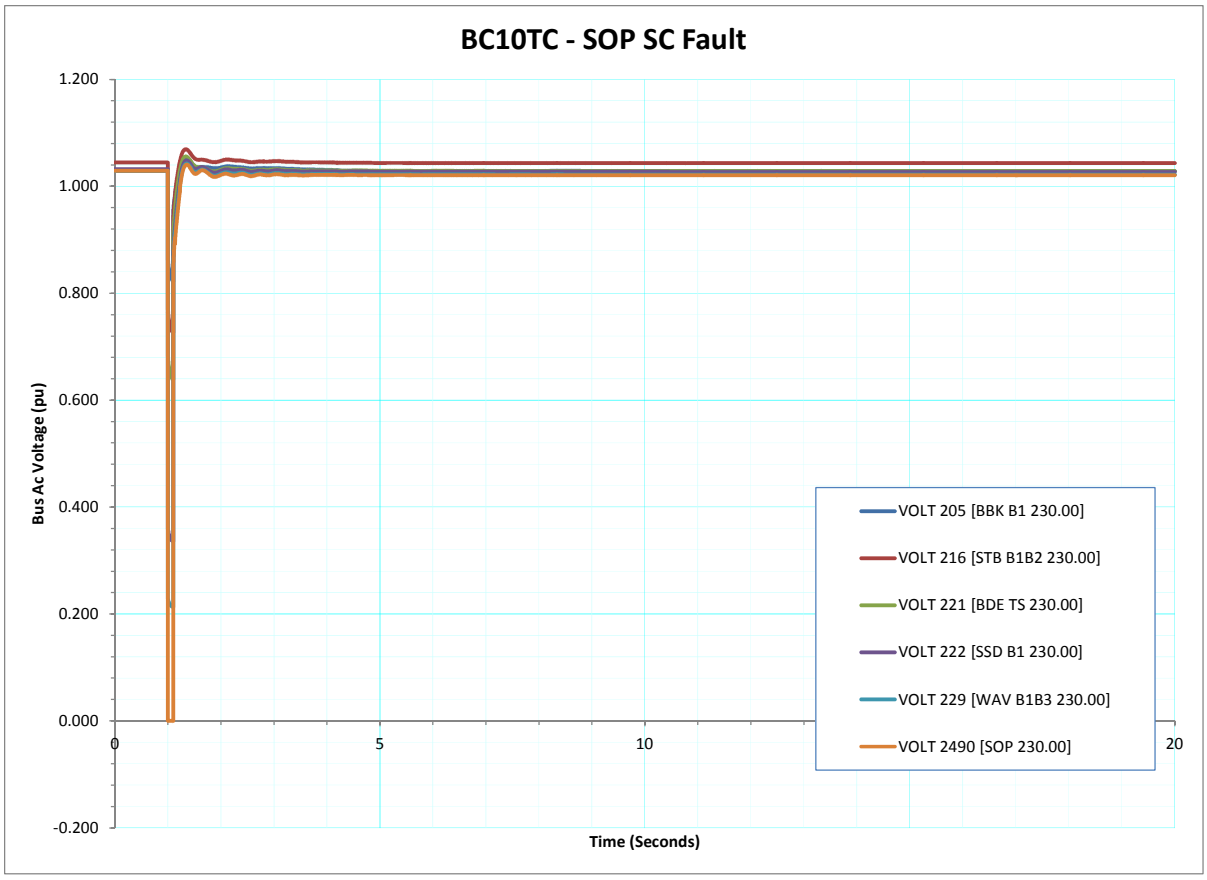


Figure 287 - BC10TC - SOP SC Fault - Bus Ac Voltage (pu)

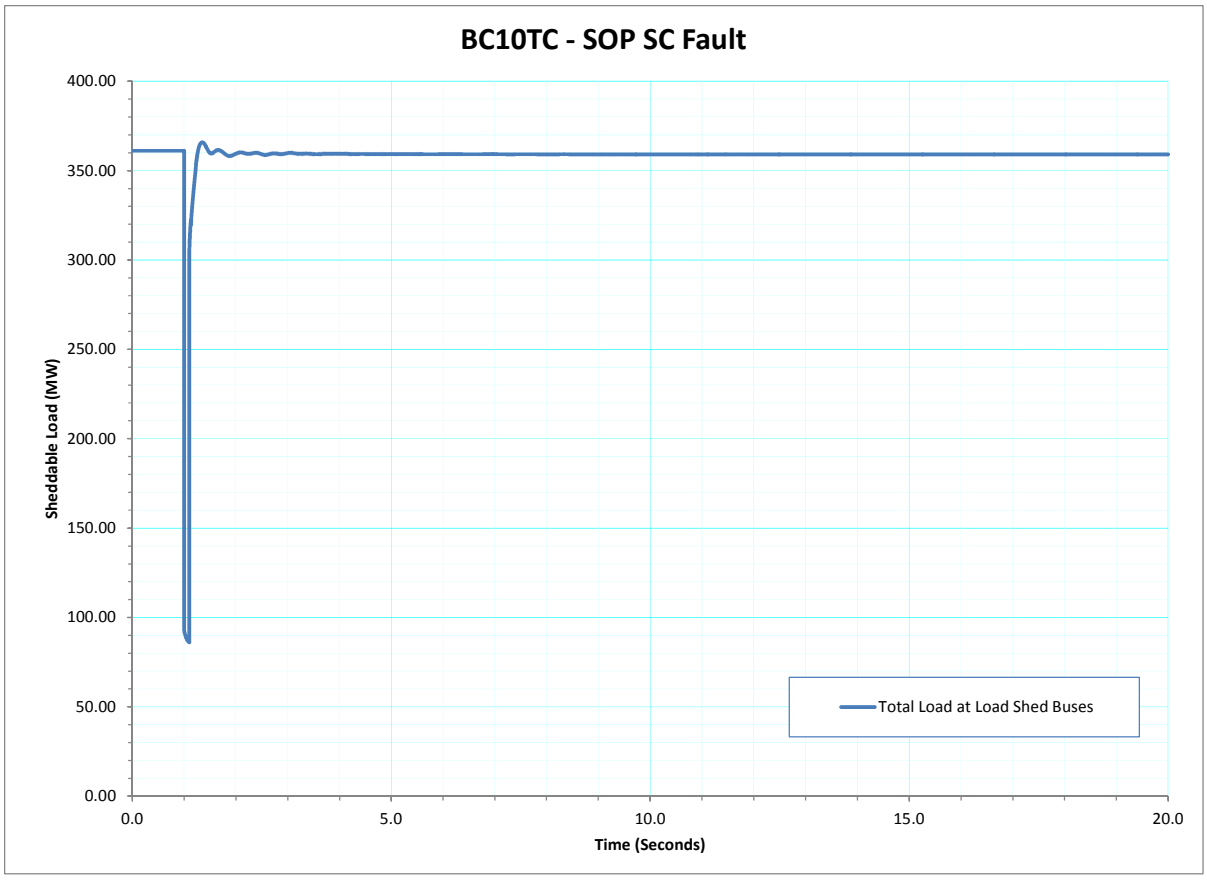


Figure 288 - BC10TC - SOP SC Fault - Sheddable Load (MW)

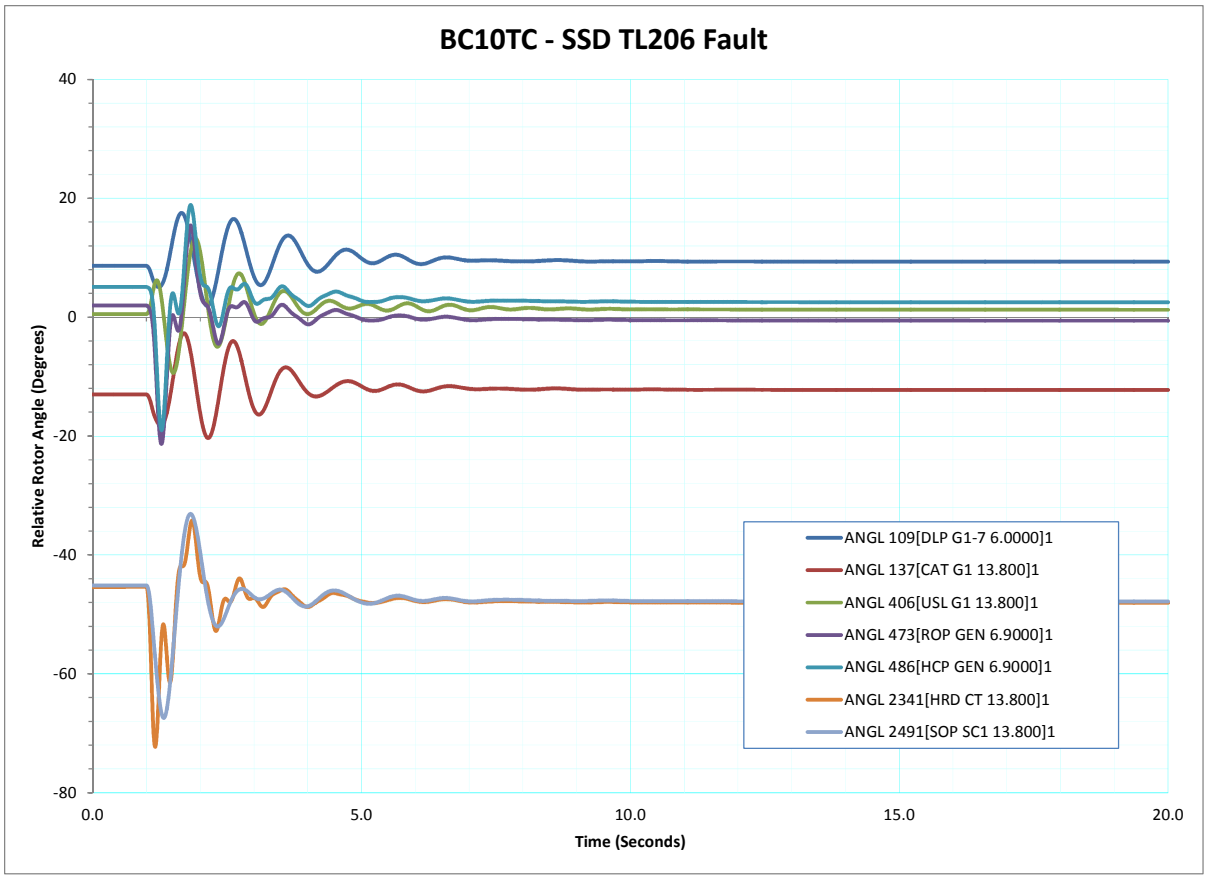


Figure 289 - BC10TC - SSD TL206 Fault - Relative Rotor Angle (Degrees)

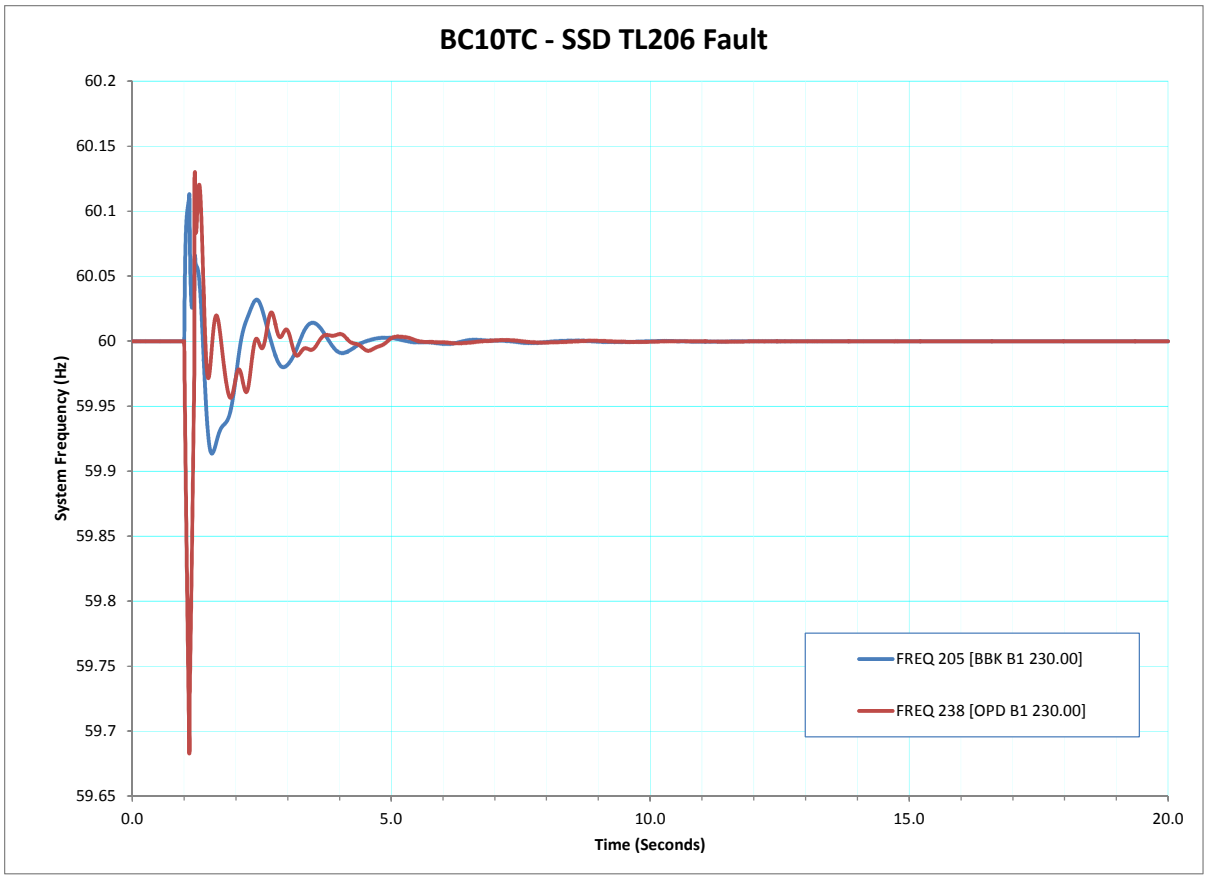


Figure 290 - BC10TC - SSD TL206 Fault - System Frequency (Hz)

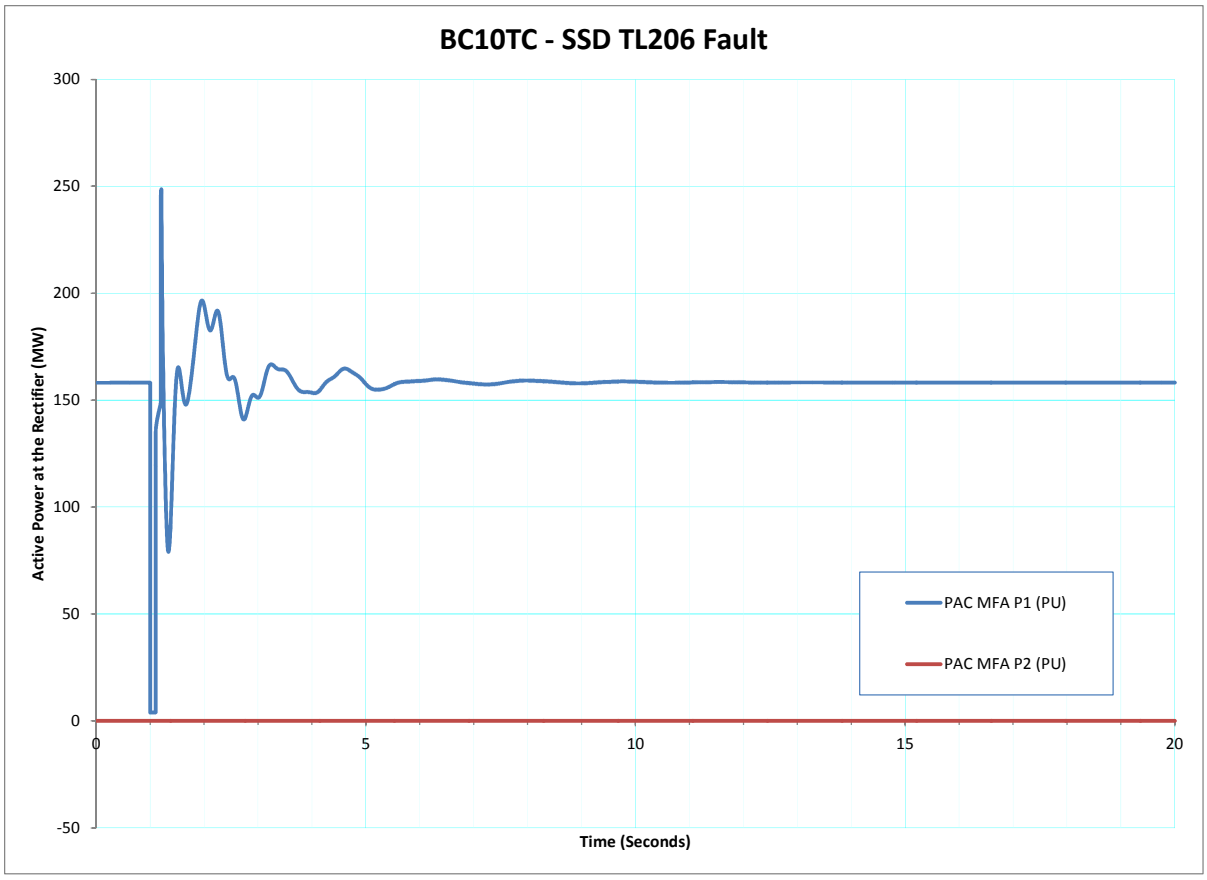


Figure 291 - BC10TC - SSD TL206 Fault - Active Power at the Rectifier (MW)

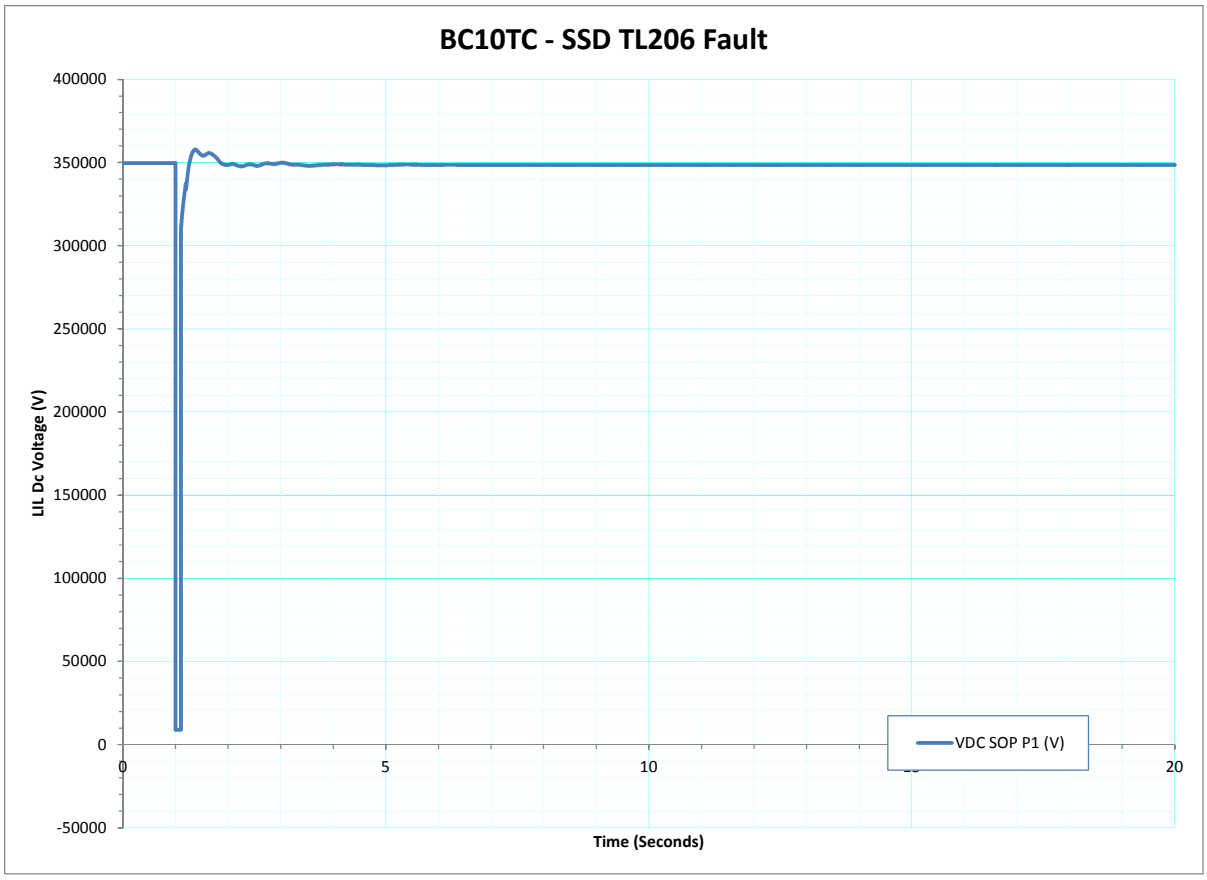


Figure 292 - BC10TC - SSD TL206 Fault - LIL Dc Voltage (V)

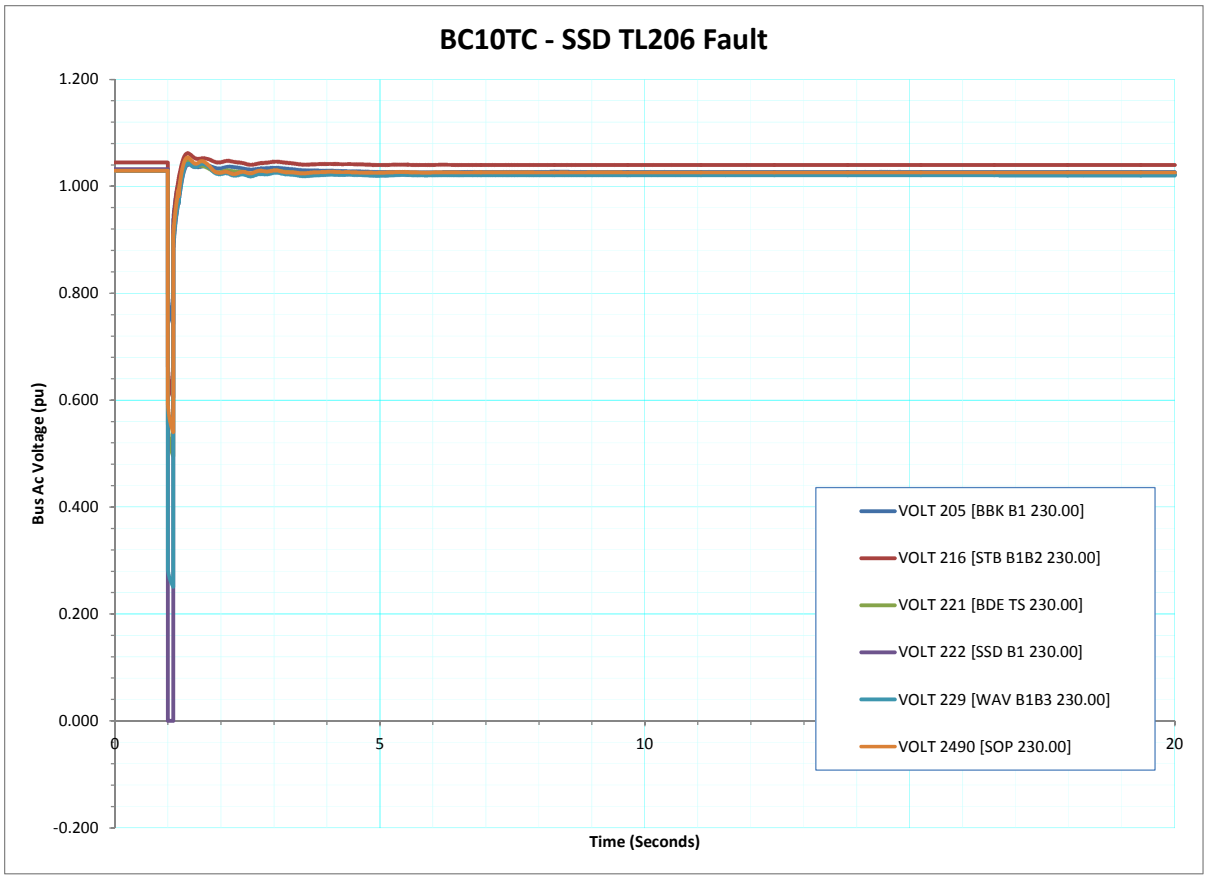


Figure 293 - BC10TC - SSD TL206 Fault - Bus Ac Voltage (pu)

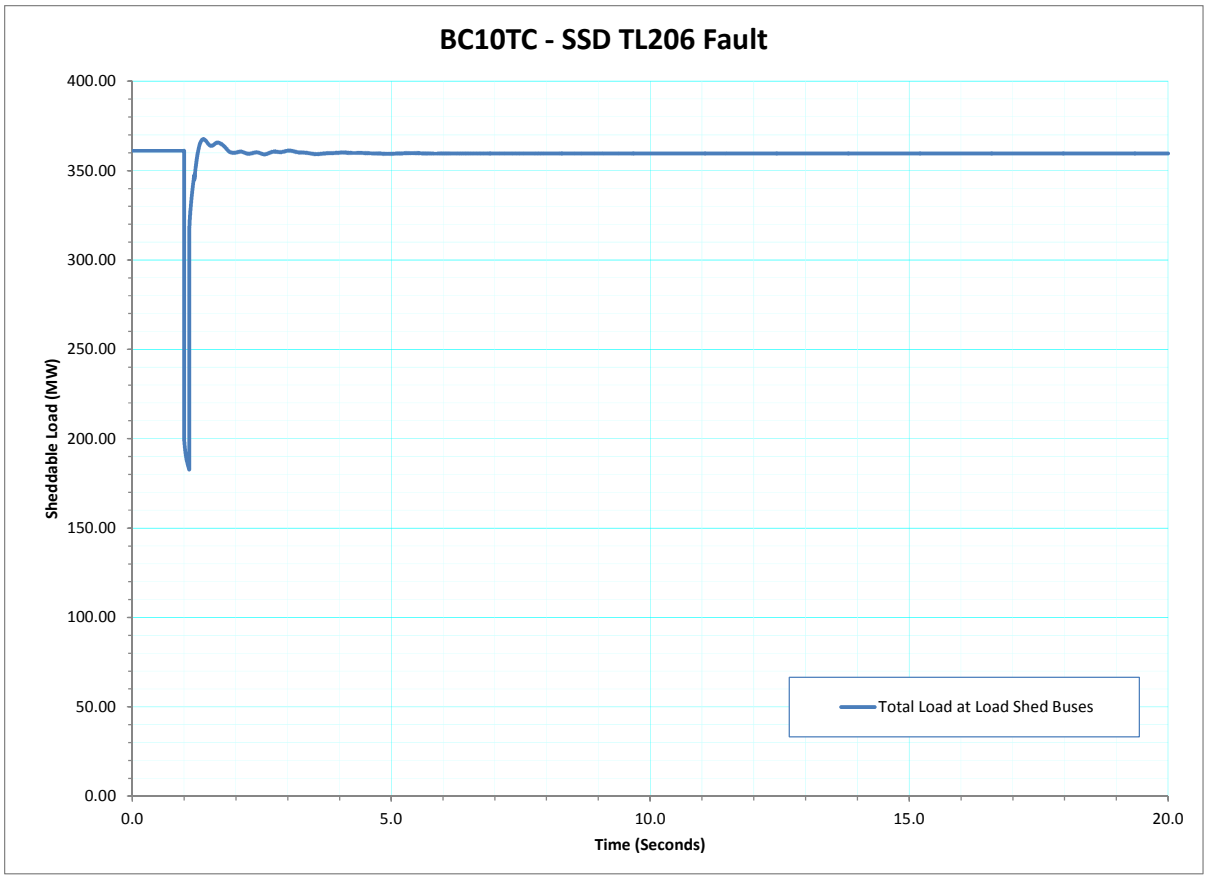


Figure 294 - BC10TC - SSD TL206 Fault - Sheddable Load (MW)

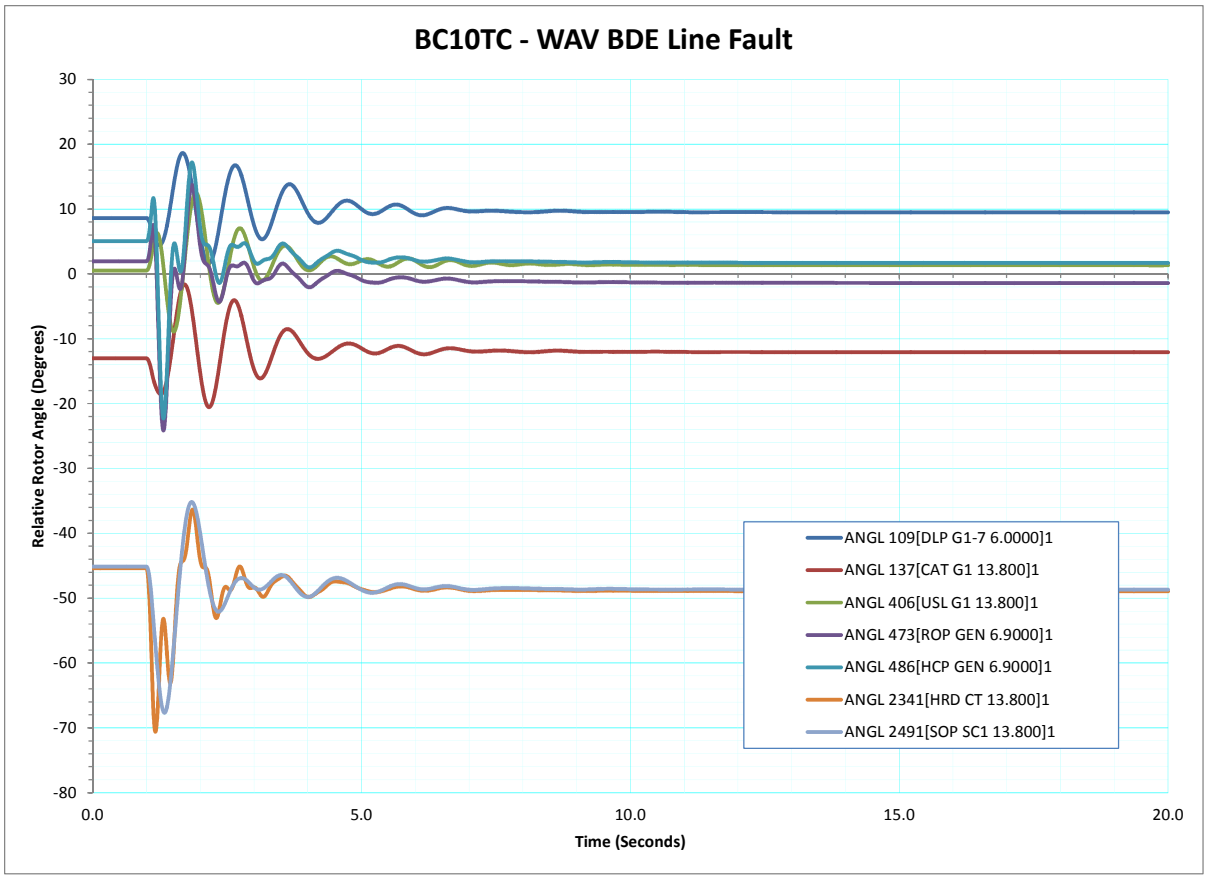


Figure 295 - BC10TC - WAV BDE Line Fault - Relative Rotor Angle (Degrees)

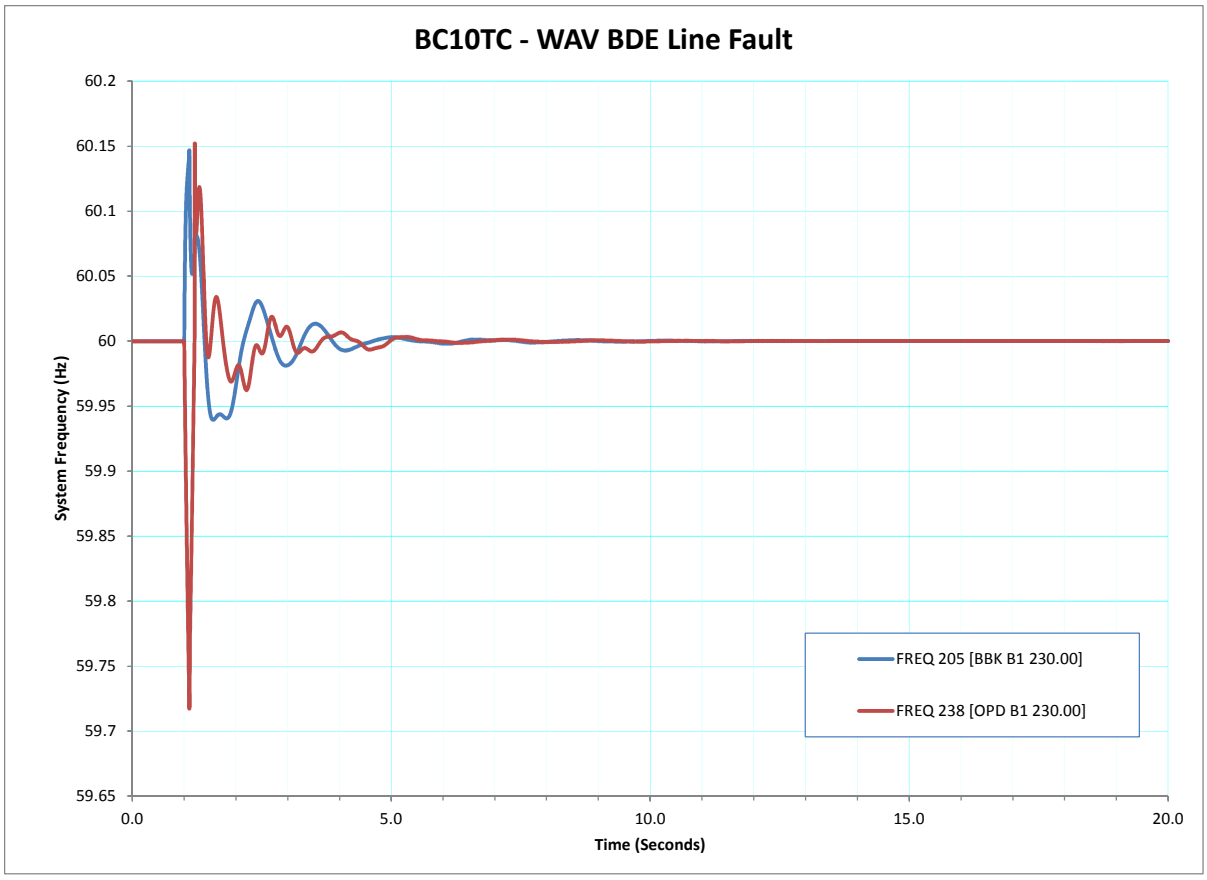


Figure 296 - BC10TC - WAV BDE Line Fault - System Frequency (Hz)

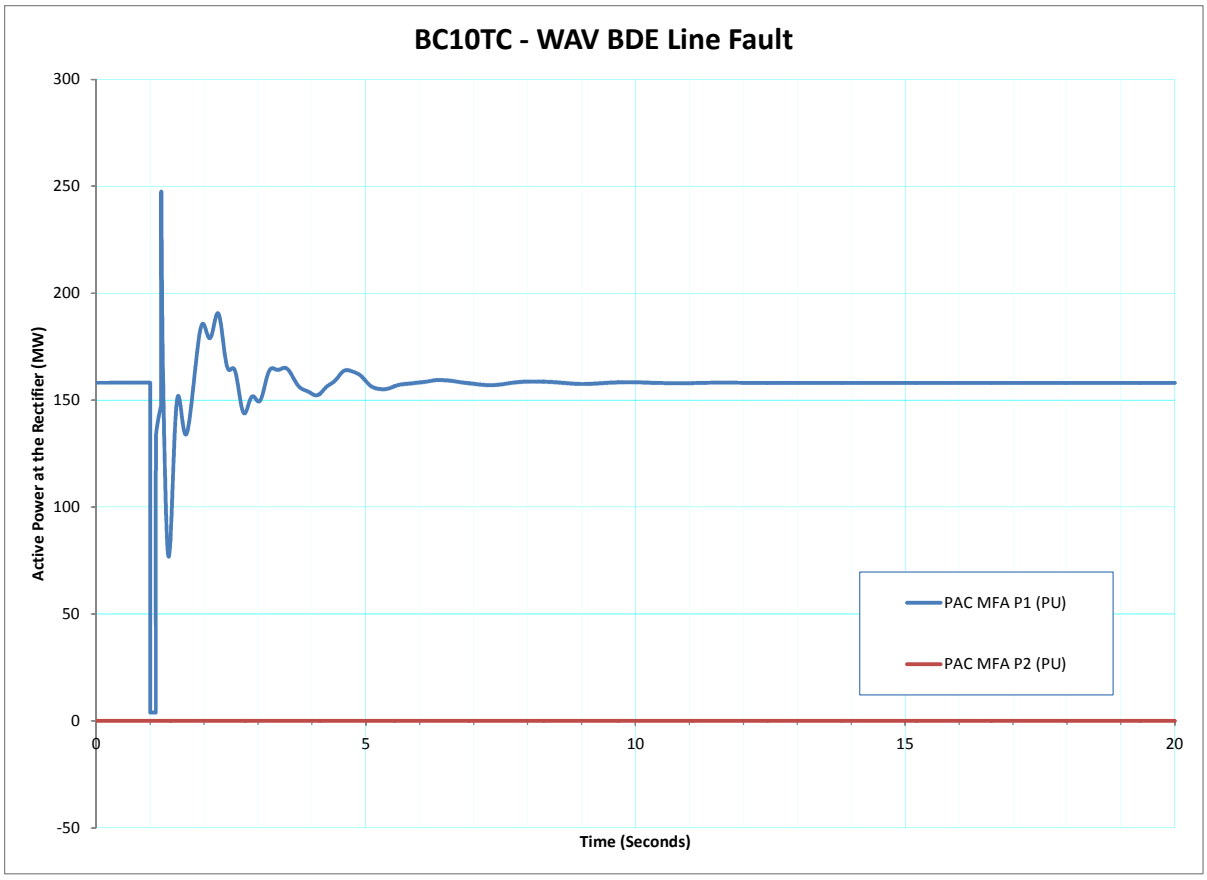


Figure 297 - BC10TC - WAV BDE Line Fault - Active Power at the Rectifier (MW)

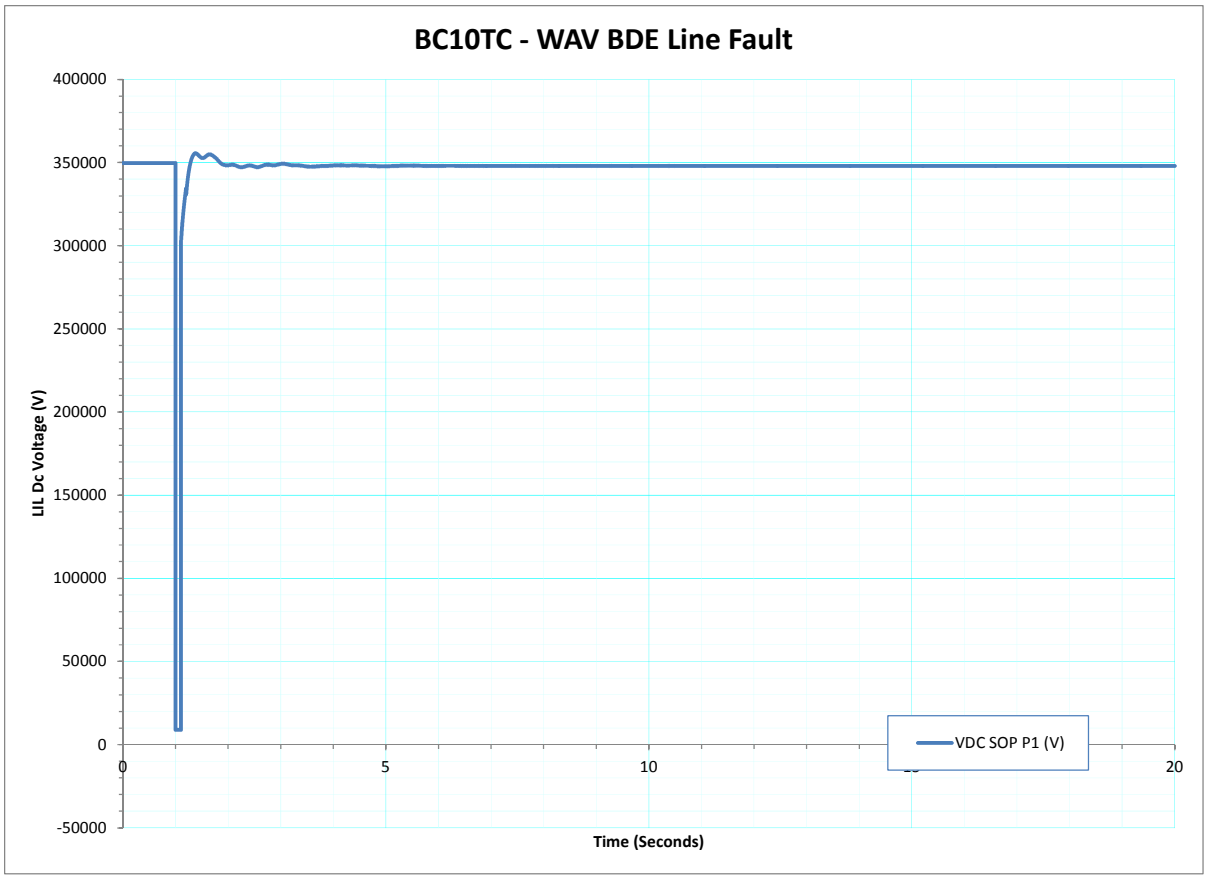


Figure 298 - BC10TC - WAV BDE Line Fault - LIL Dc Voltage (V)

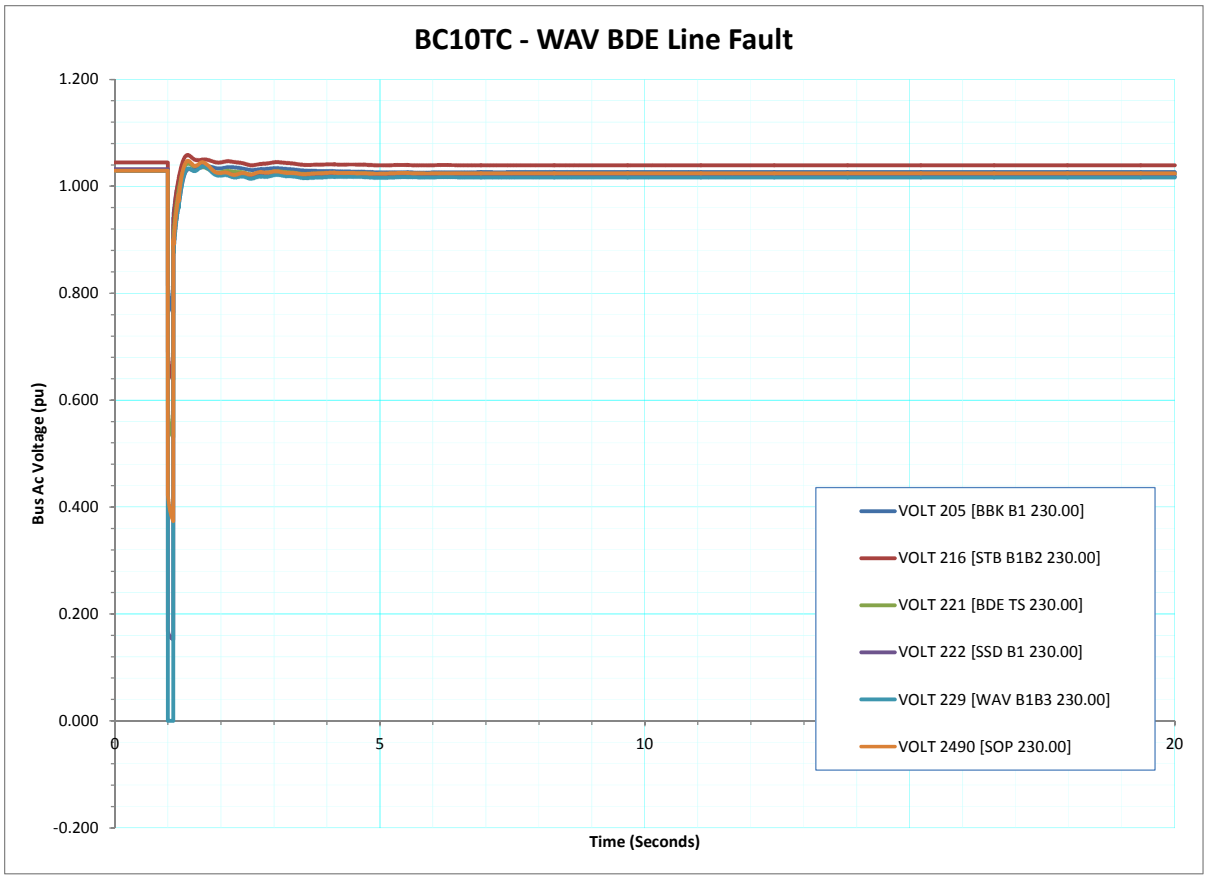


Figure 299 - BC10TC - WAV BDE Line Fault - Bus Ac Voltage (pu)

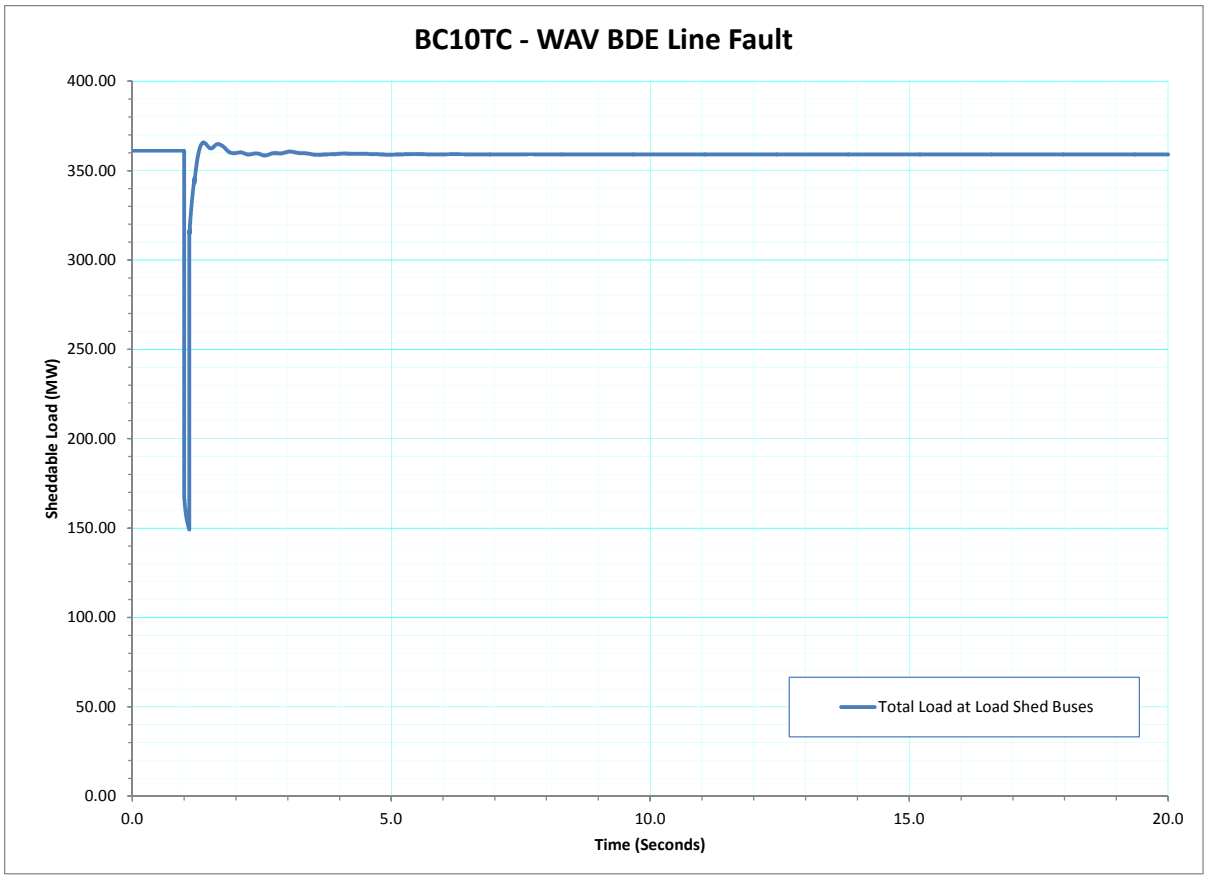


Figure 300 - BC10TC - WAV BDE Line Fault - Sheddable Load (MW)

1.11. BASE CASE 11 TRANSIENT STABILITY PLOTS

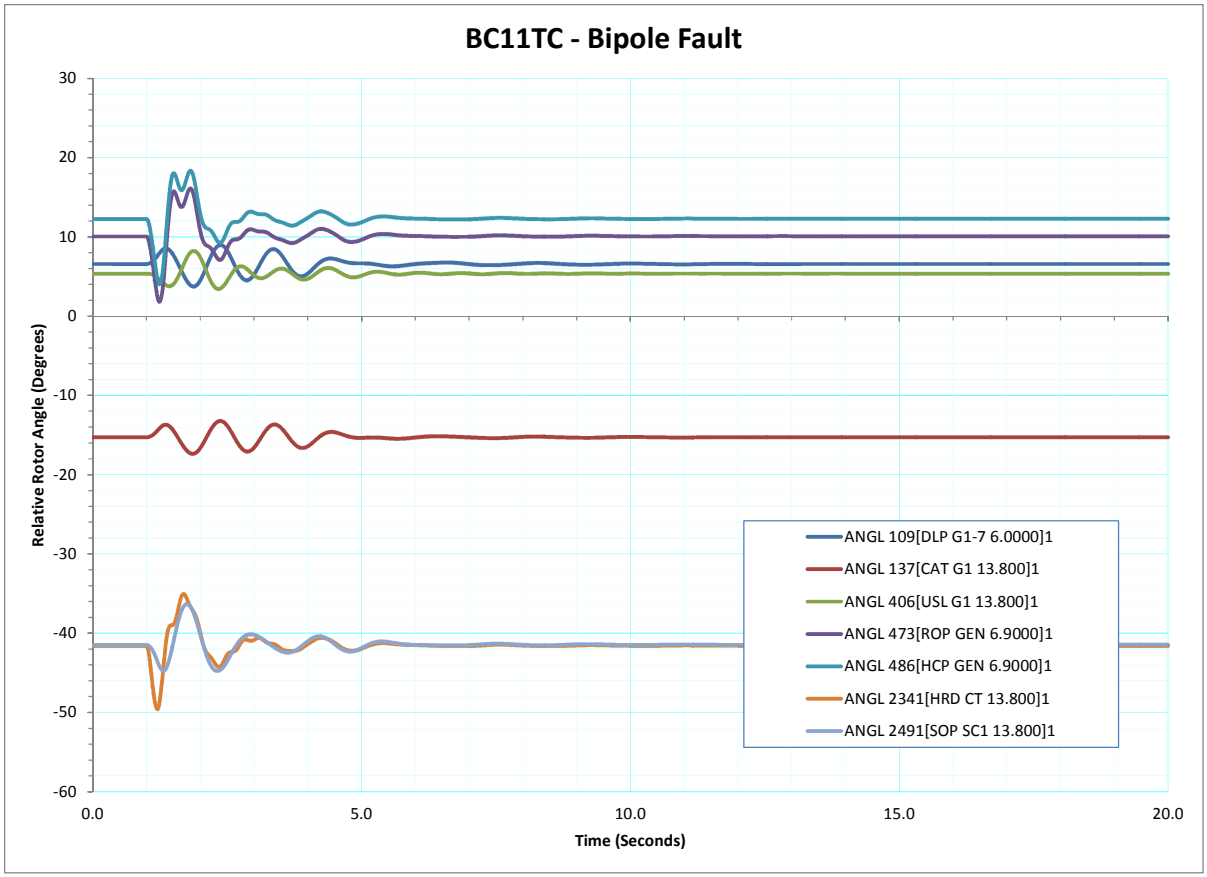


Figure 301 - BC11TC - Bipole Fault - Relative Rotor Angle (Degrees)

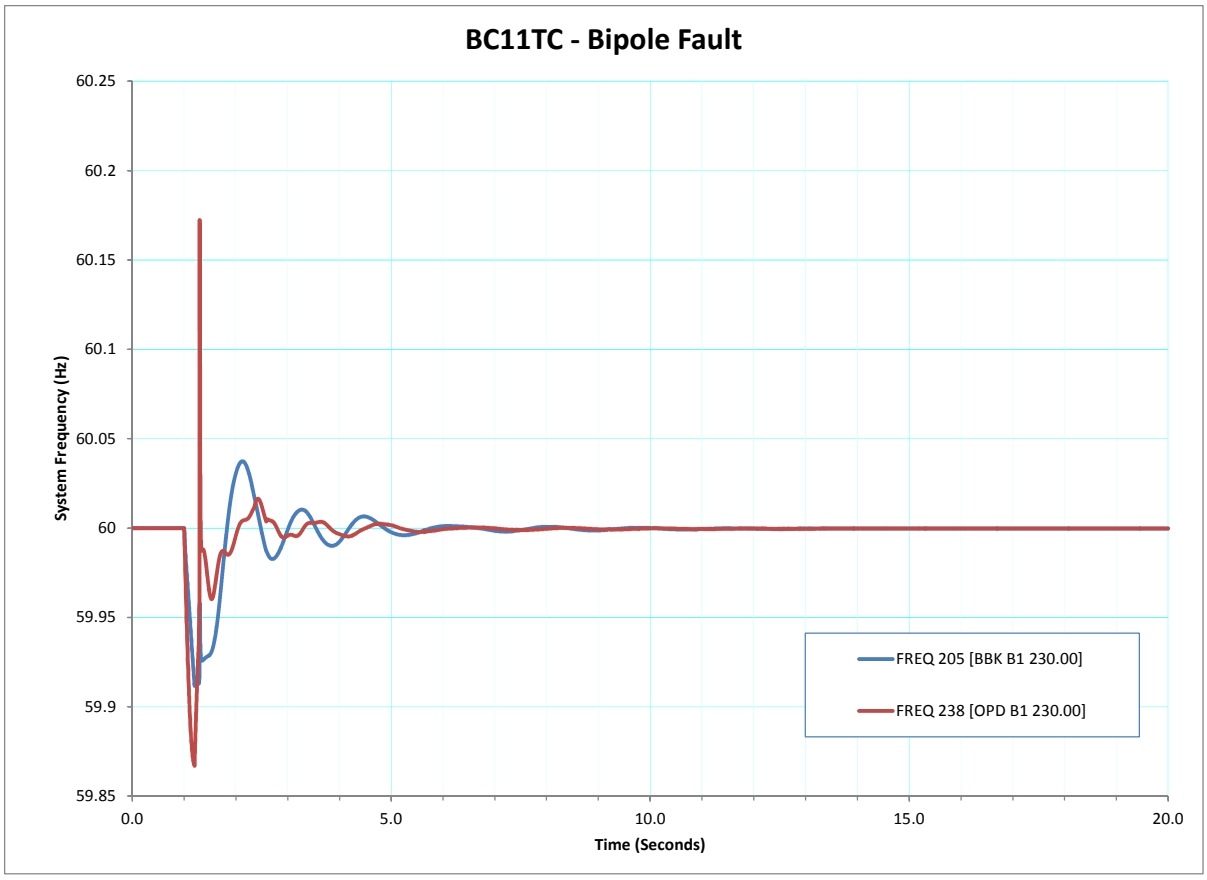


Figure 302 - BC11TC - Bipole Fault - System Frequency (Hz)

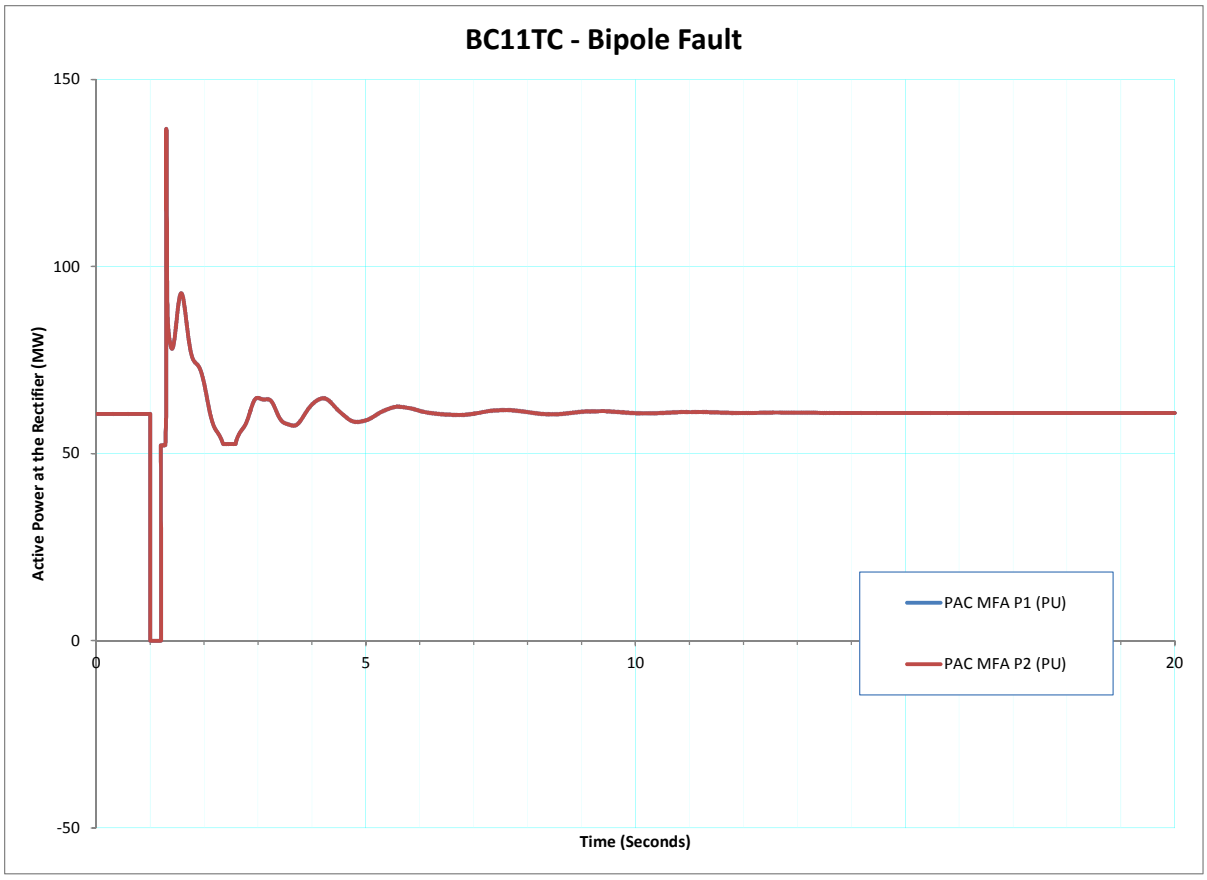


Figure 303 - BC11TC - Bipole Fault - Active Power at the Rectifier (MW)

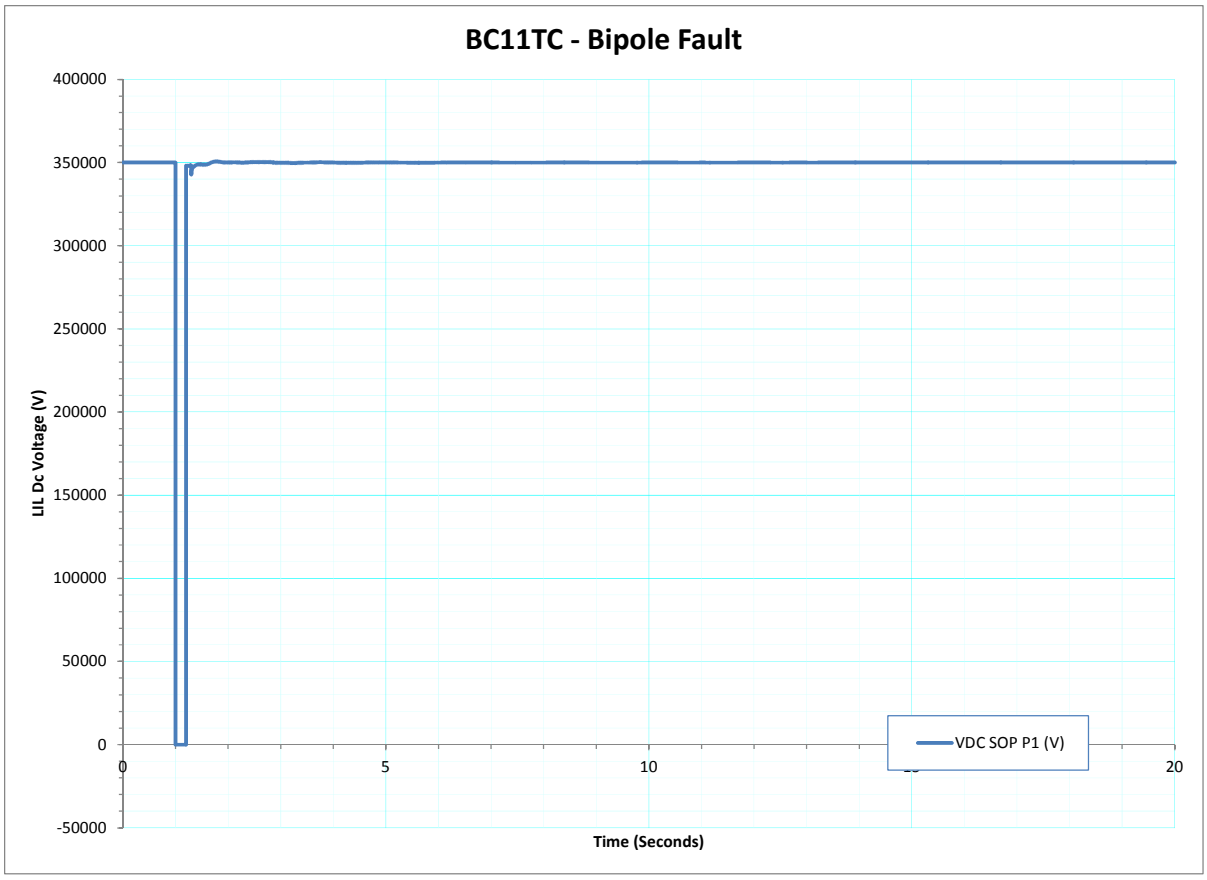


Figure 304 - BC11TC - Bipole Fault - LIL Dc Voltage (V)

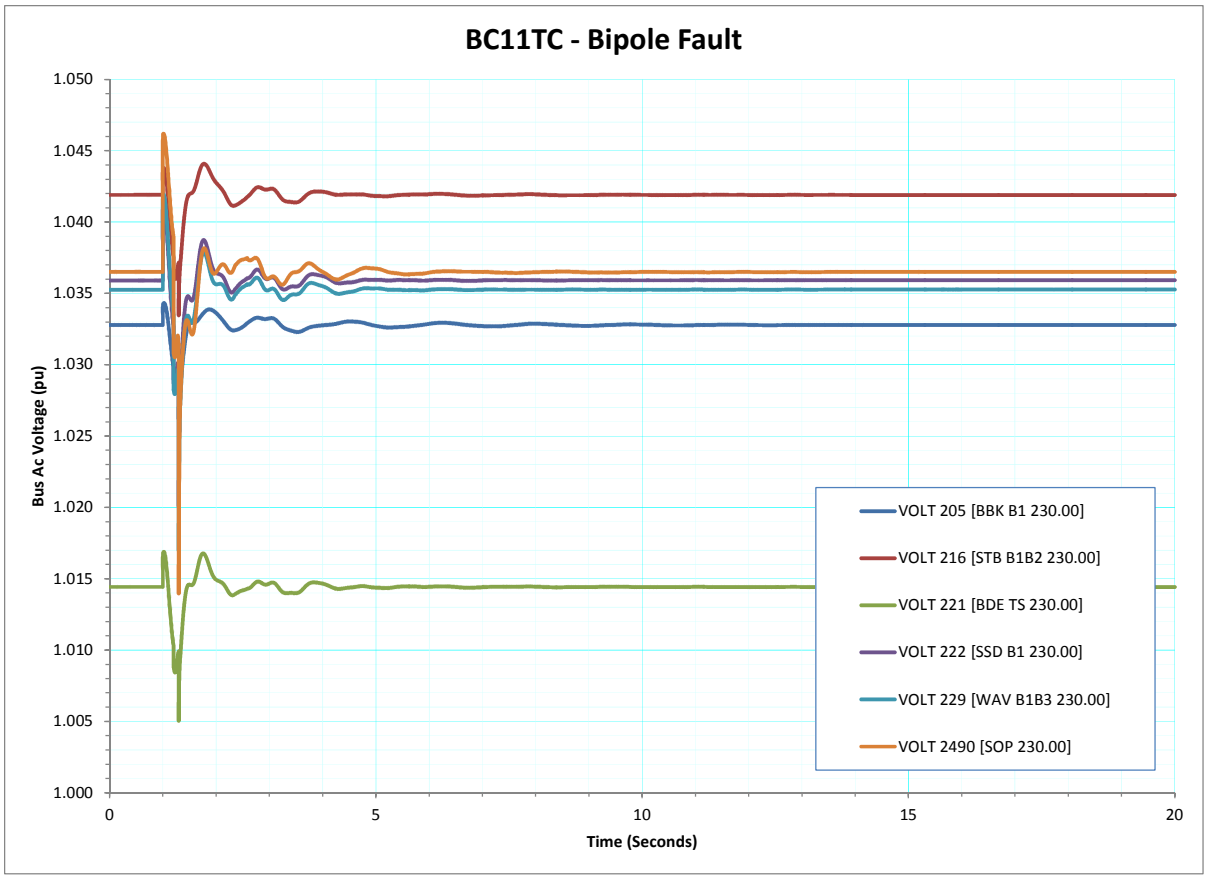


Figure 305 - BC11TC - Bipole Fault - Bus Ac Voltage (pu)

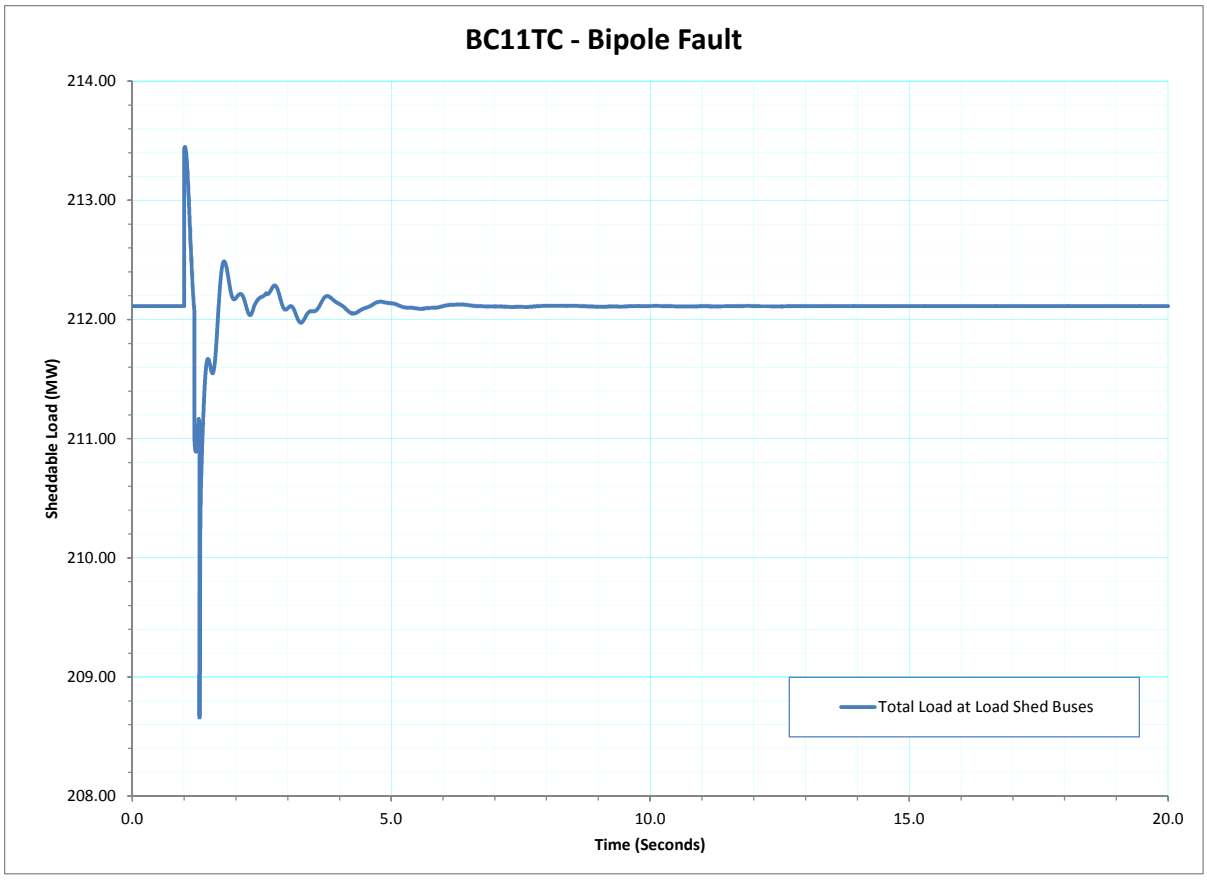


Figure 306 - BC11TC - Bipole Fault - Sheddable Load (MW)

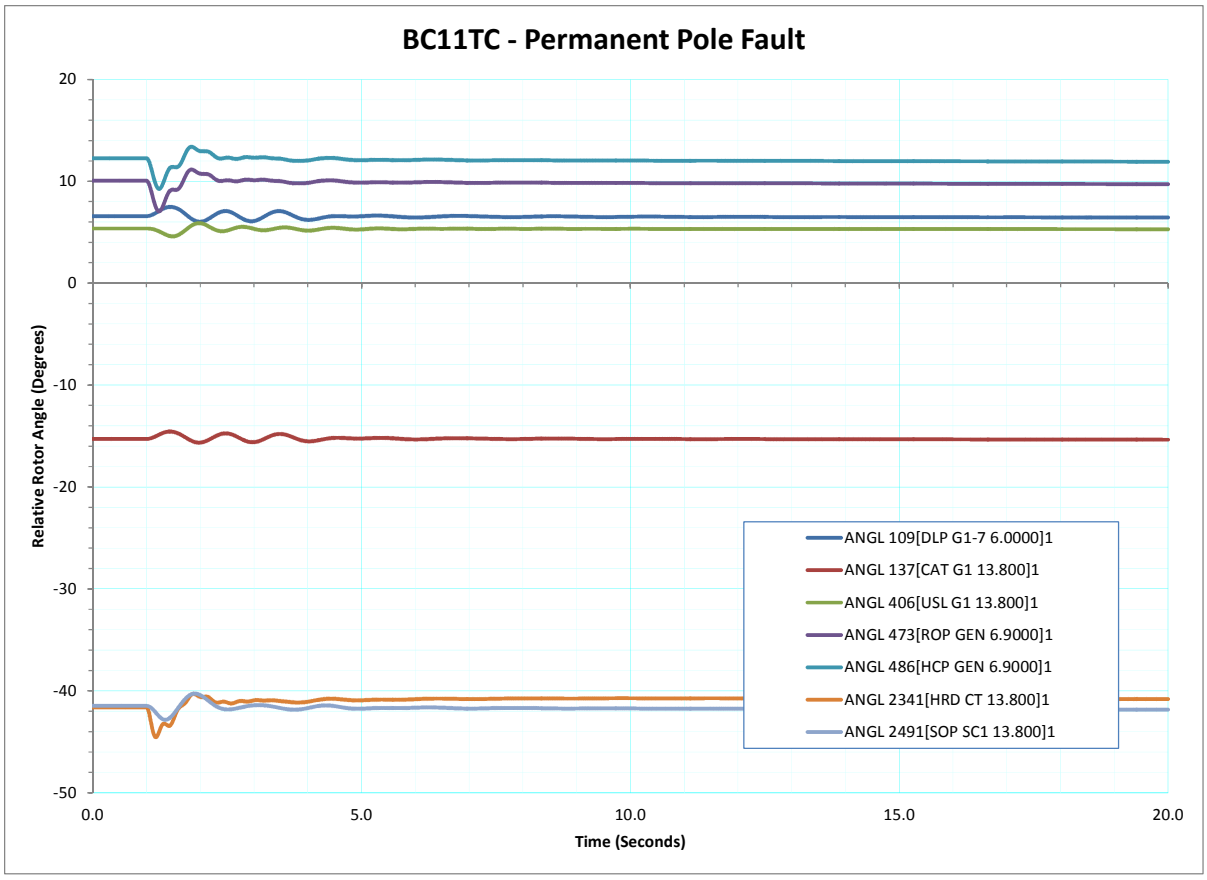


Figure 307 - BC11TC - Permanent Pole Fault - Relative Rotor Angle (Degrees)

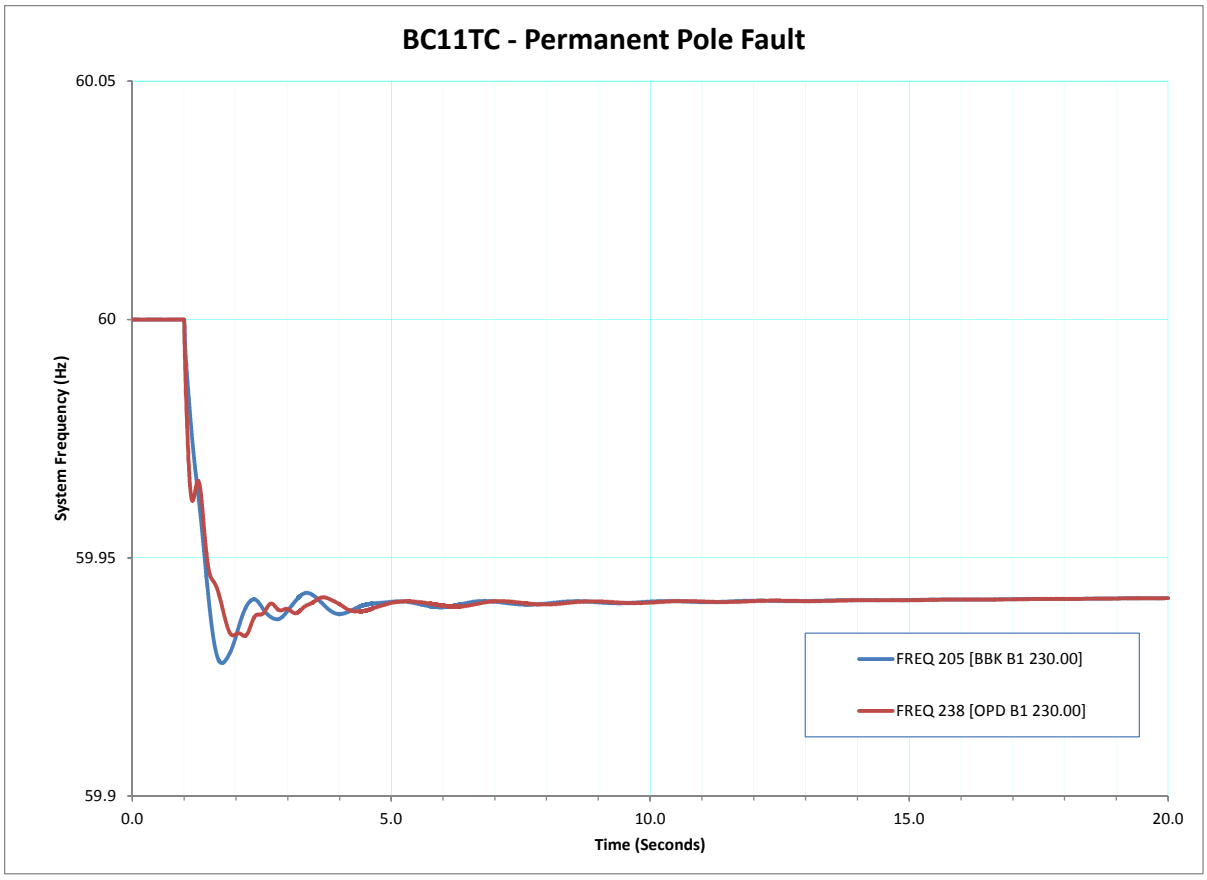


Figure 308 - BC11TC - Permanent Pole Fault - System Frequency (Hz)

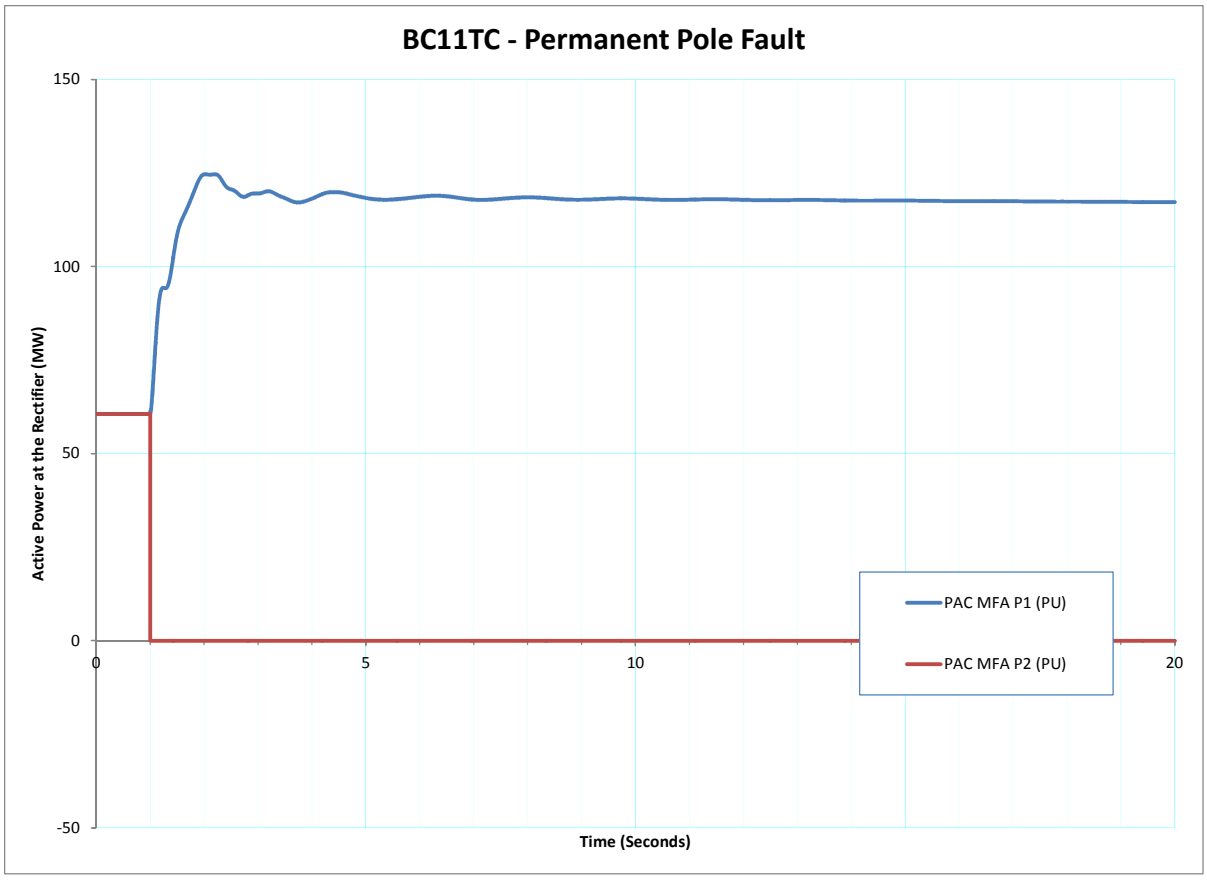


Figure 309 - BC11TC - Permanent Pole Fault - Active Power at the Rectifier (MW)

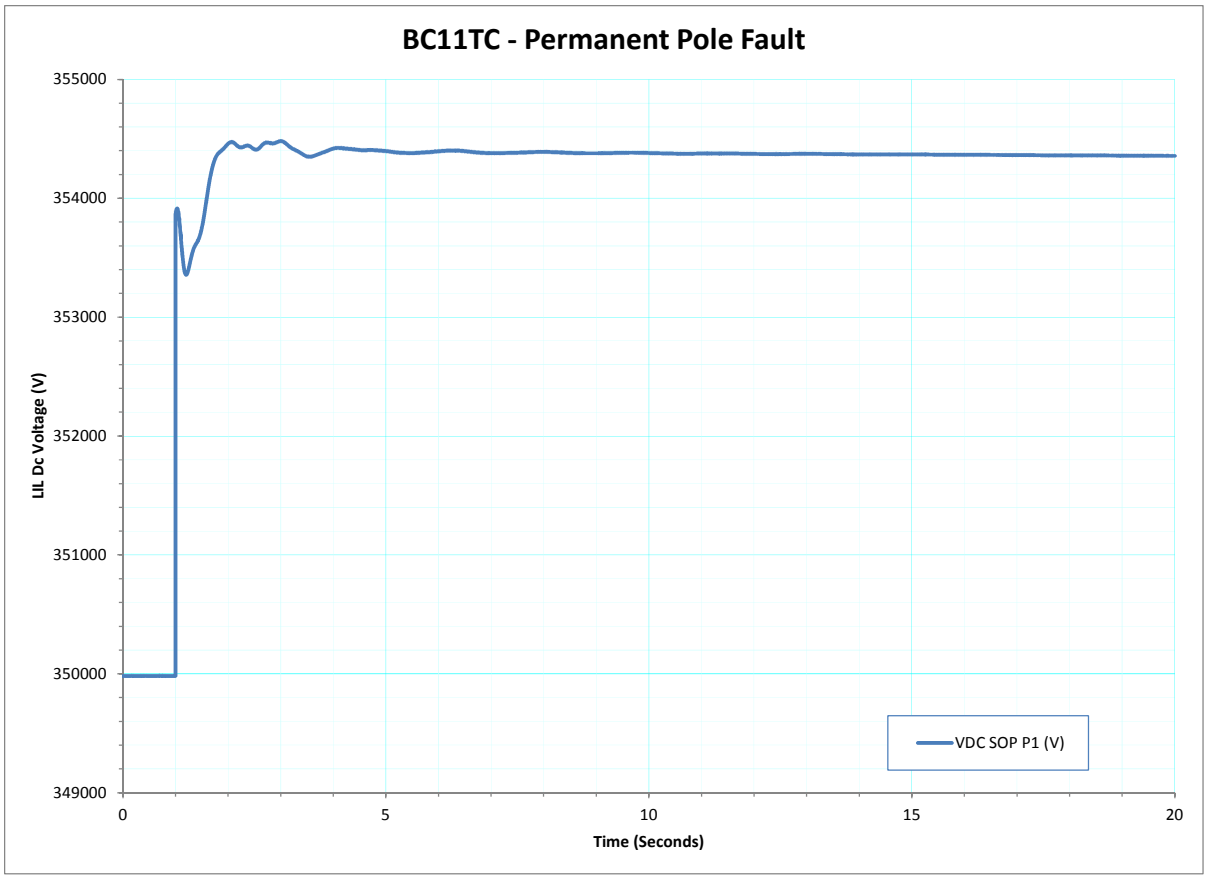


Figure 310 - BC11TC - Permanent Pole Fault - LIL Dc Voltage (V)

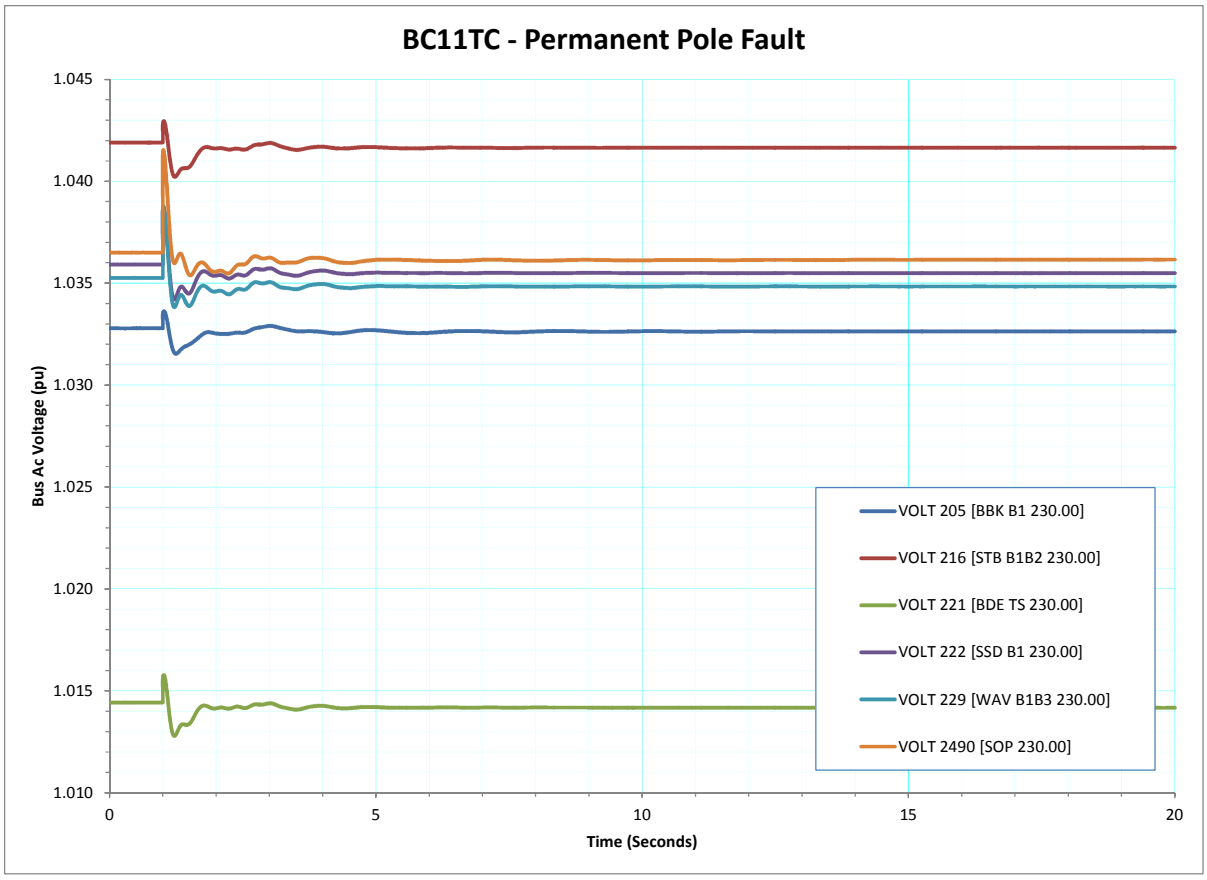


Figure 311 - BC11TC - Permanent Pole Fault - Bus Ac Voltage (pu)

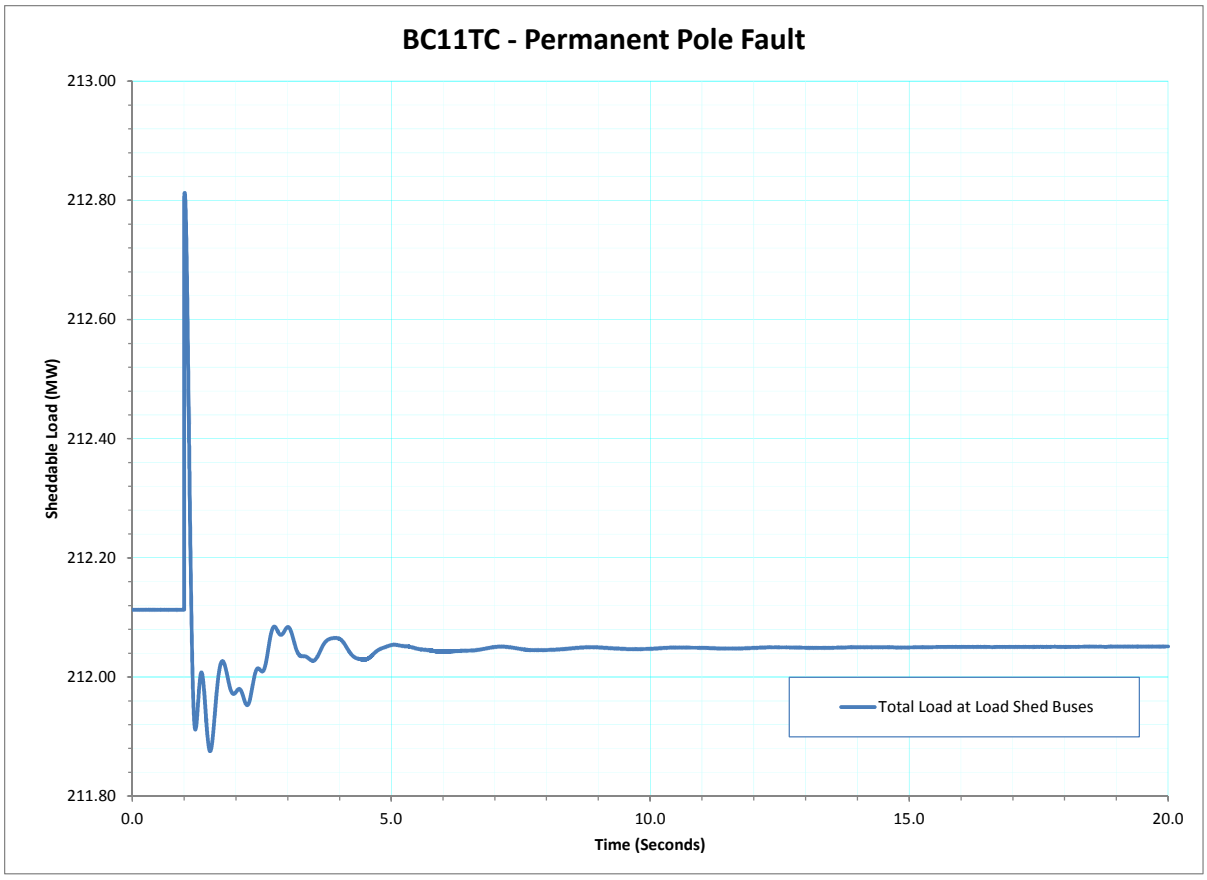


Figure 312 - BC11TC - Permanent Pole Fault - Sheddable Load (MW)

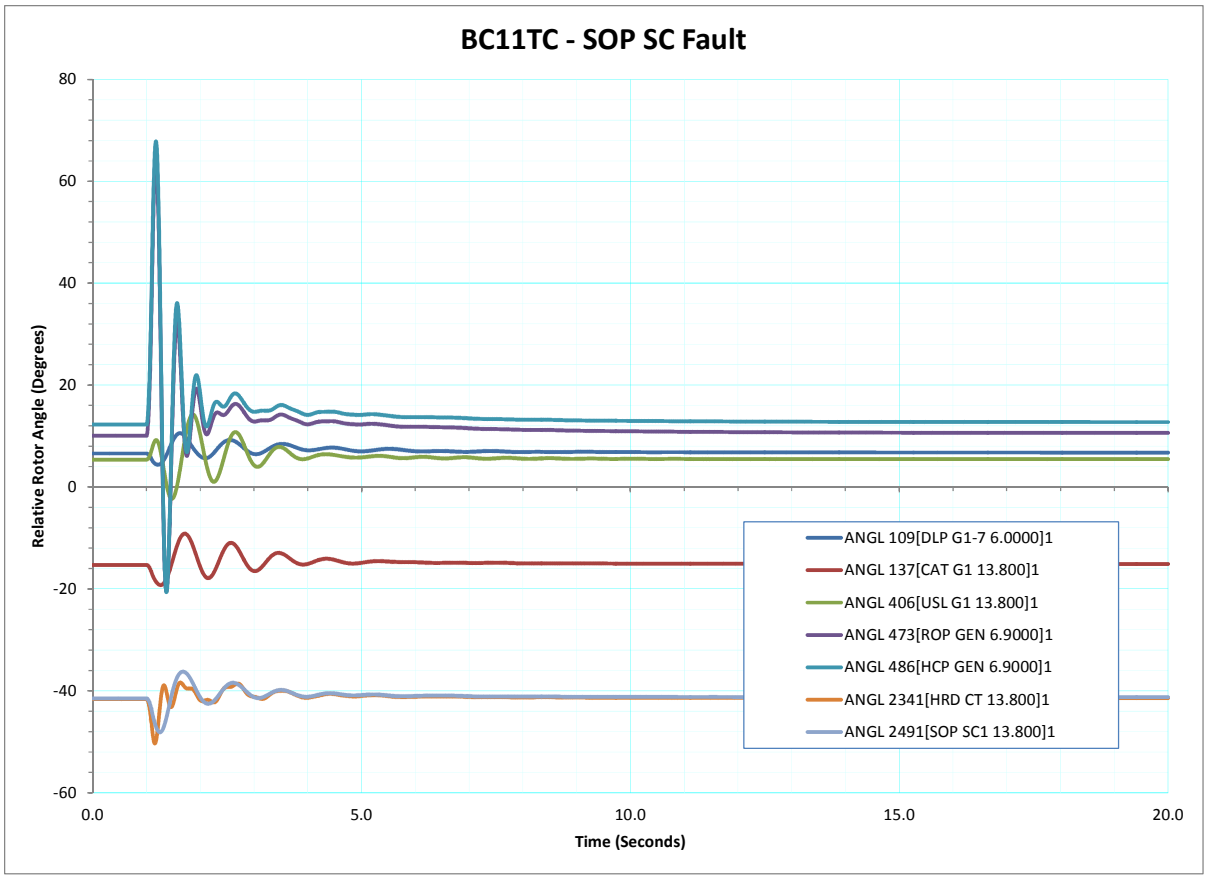


Figure 313 - BC11TC - SOP SC Fault - Relative Rotor Angle (Degrees)

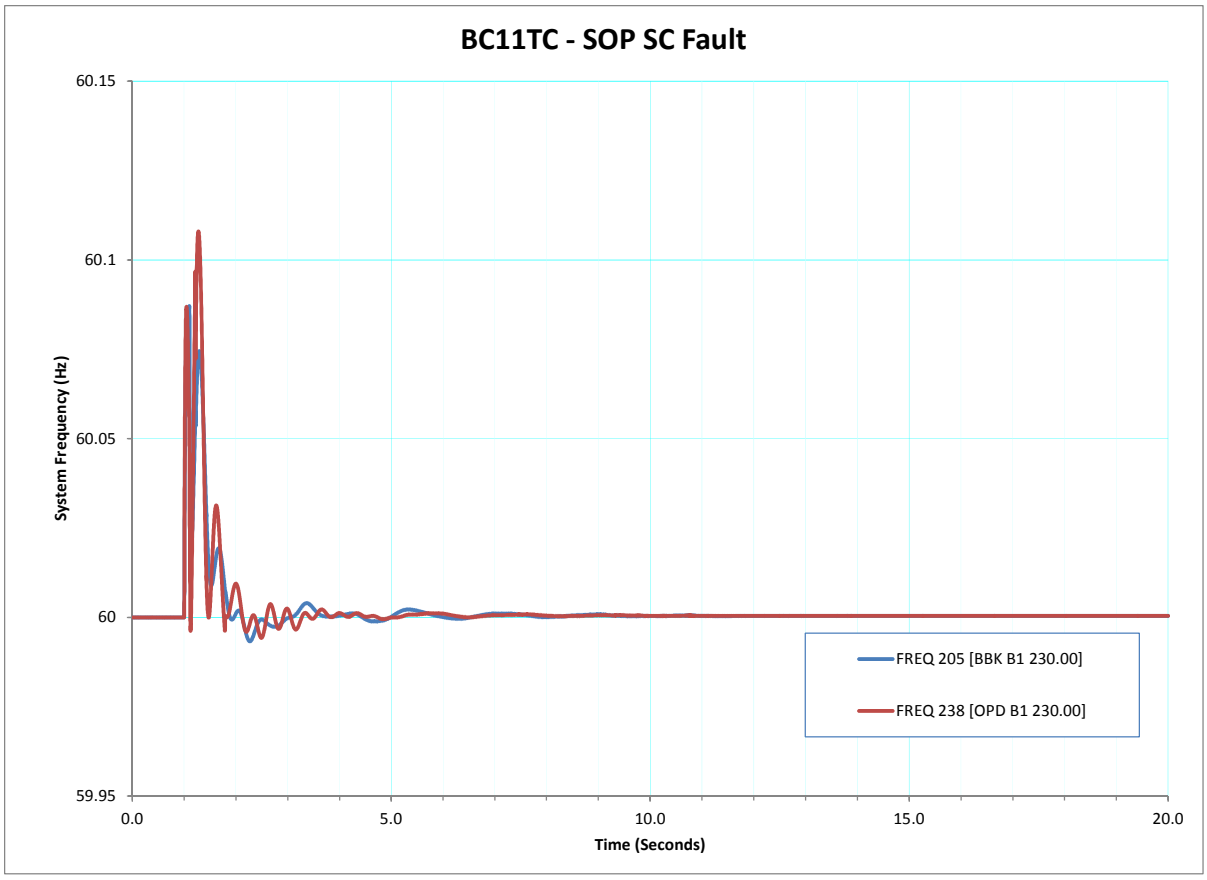


Figure 314 - BC11TC - SOP SC Fault - System Frequency (Hz)

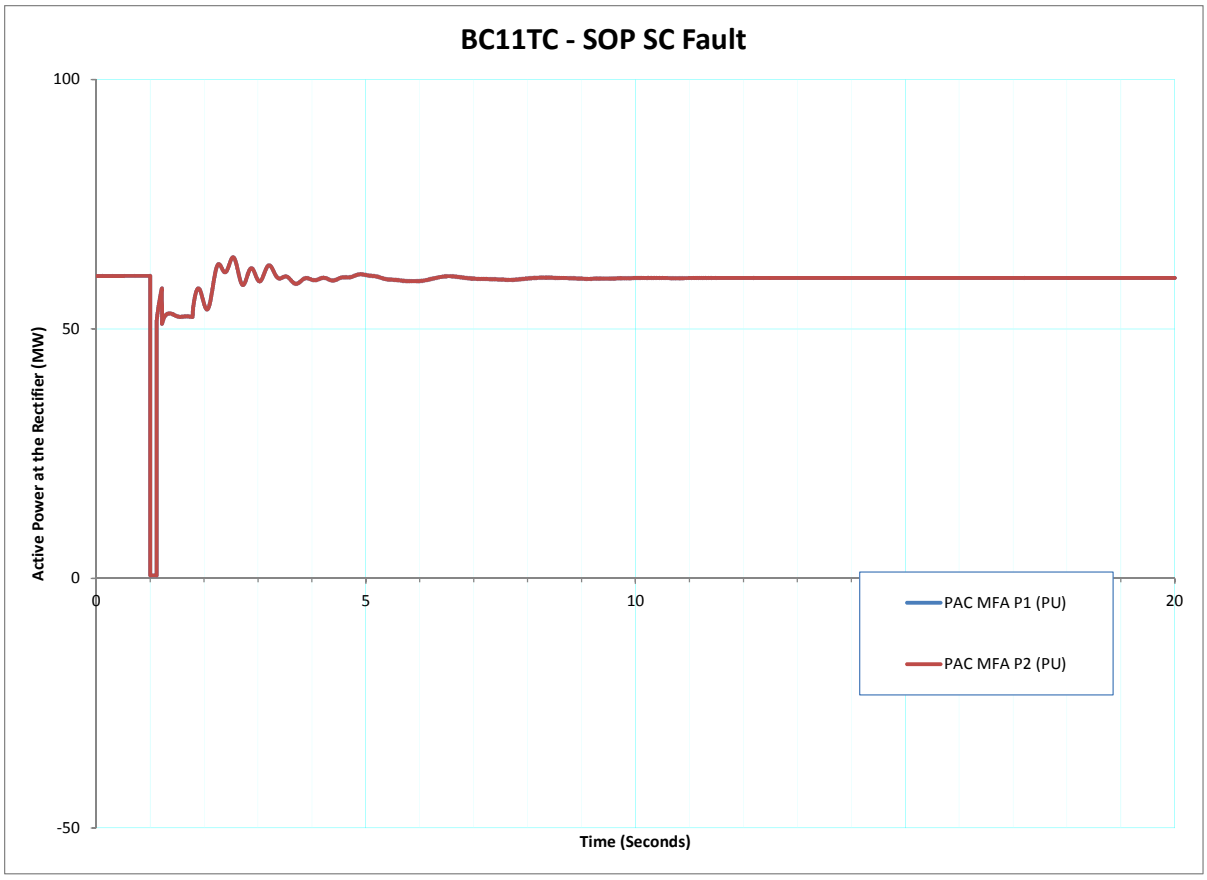


Figure 315 - BC11TC - SOP SC Fault - Active Power at the Rectifier (MW)

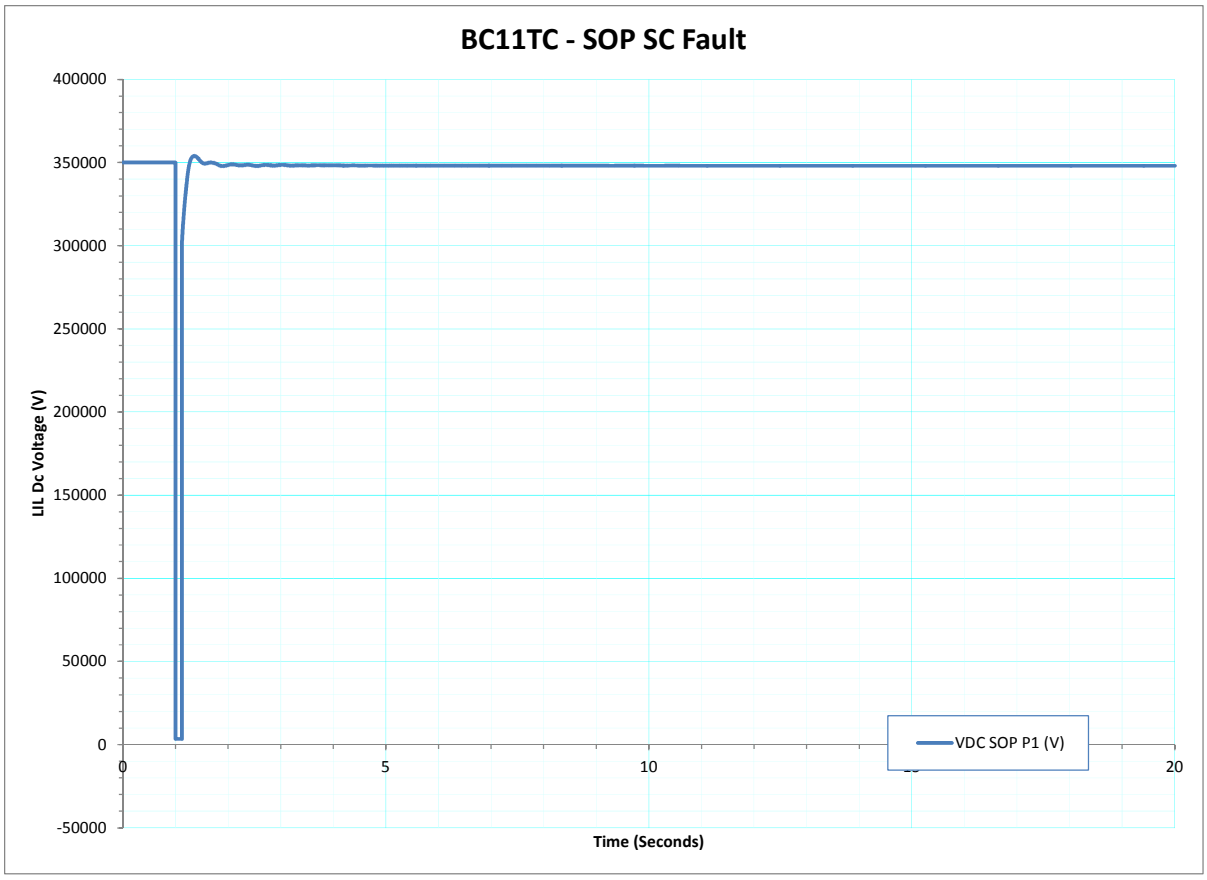


Figure 316 - BC11TC - SOP SC Fault - LIL Dc Voltage (V)

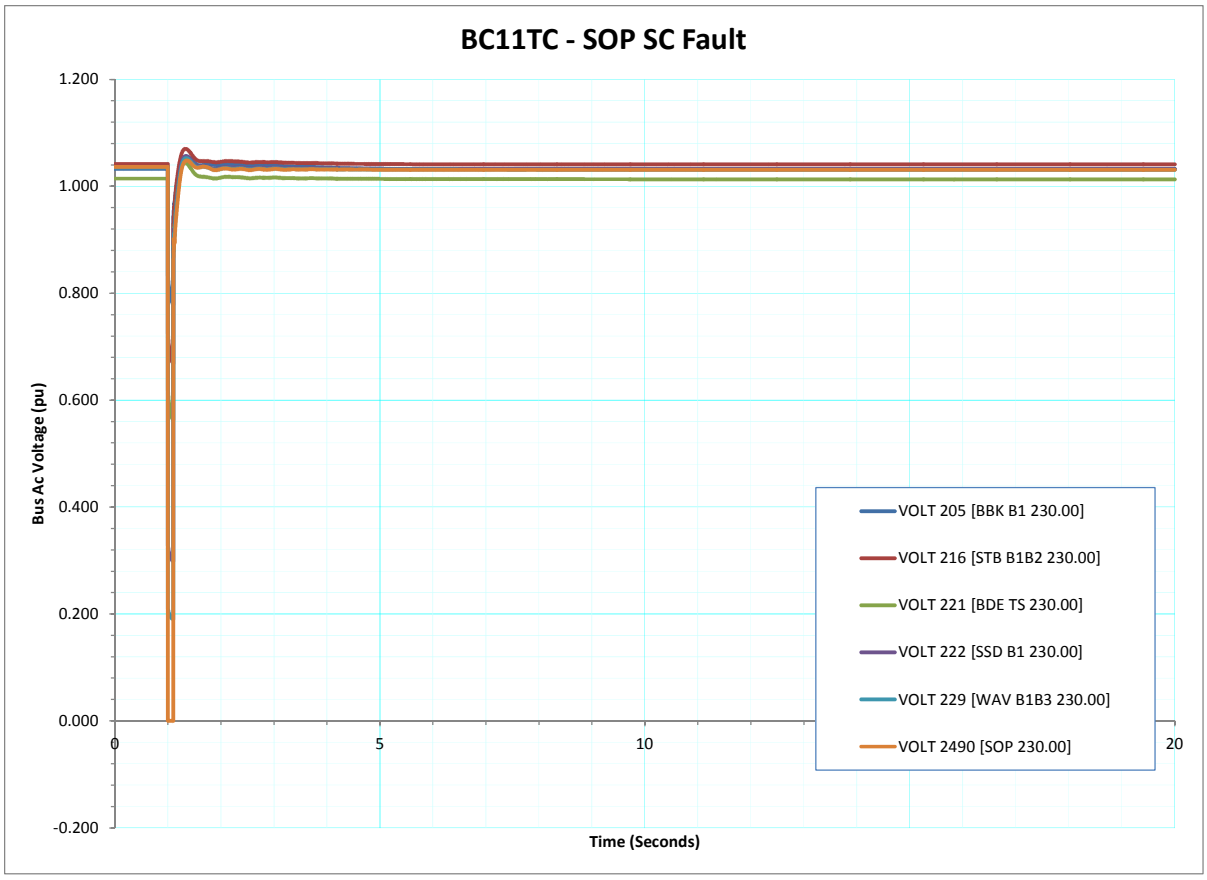


Figure 317 - BC11TC - SOP SC Fault - Bus Ac Voltage (pu)

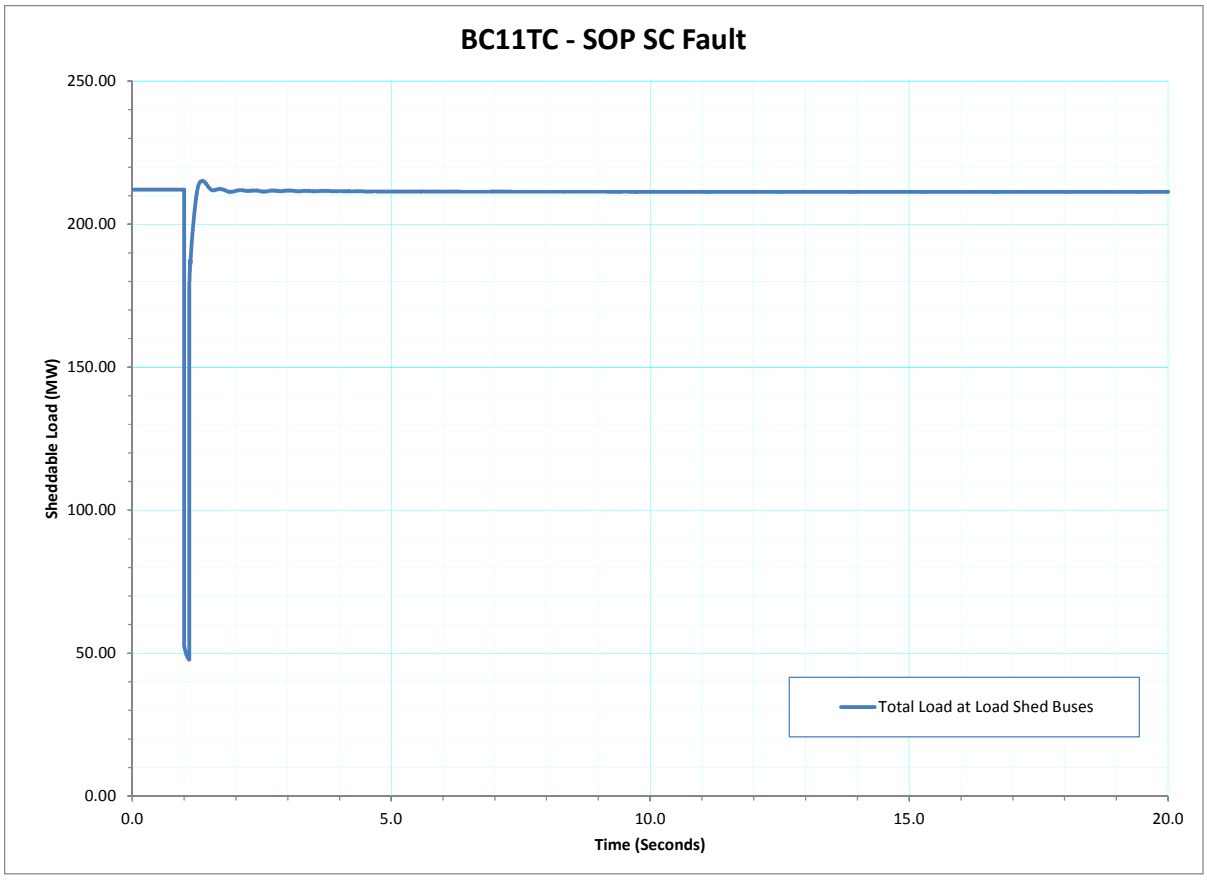


Figure 318 - BC11TC - SOP SC Fault - Sheddable Load (MW)

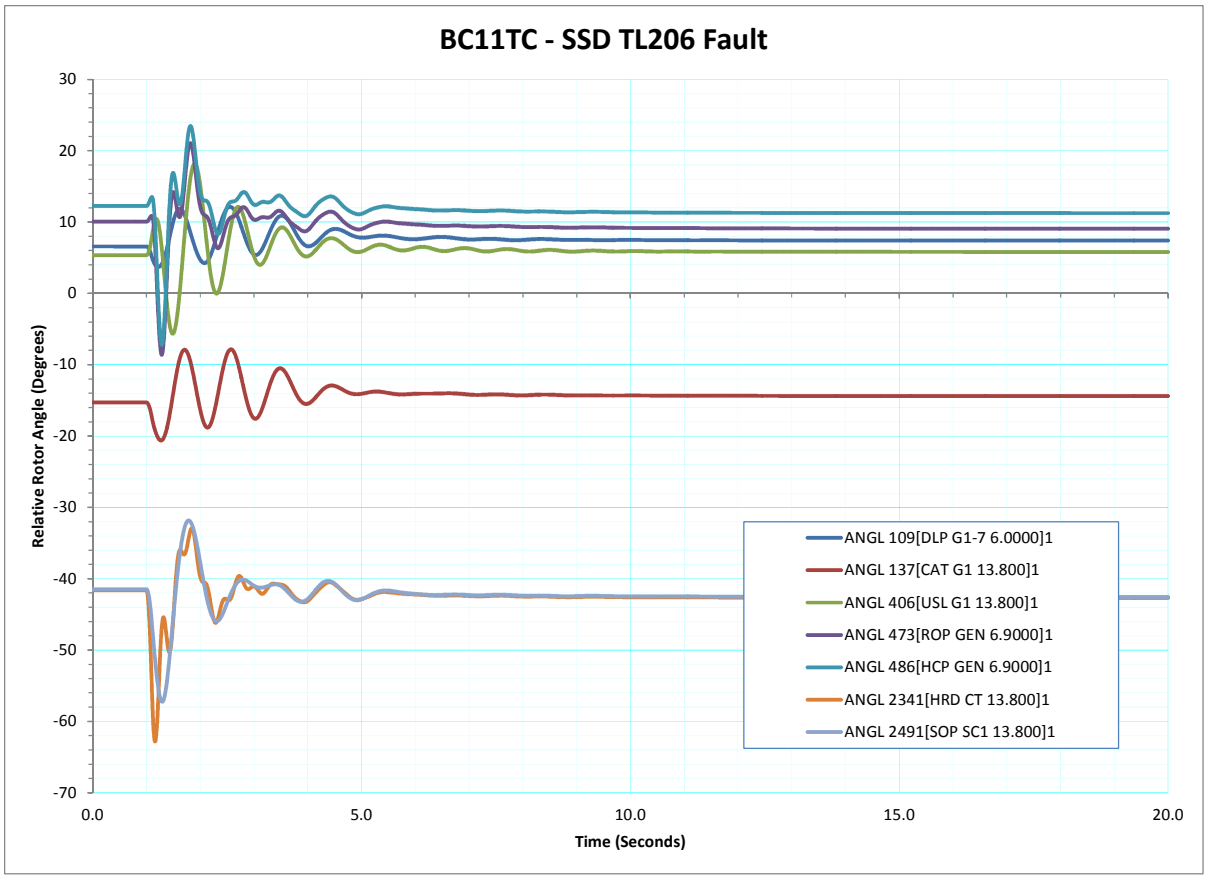


Figure 319 - BC11TC - SSD TL206 Fault - Relative Rotor Angle (Degrees)

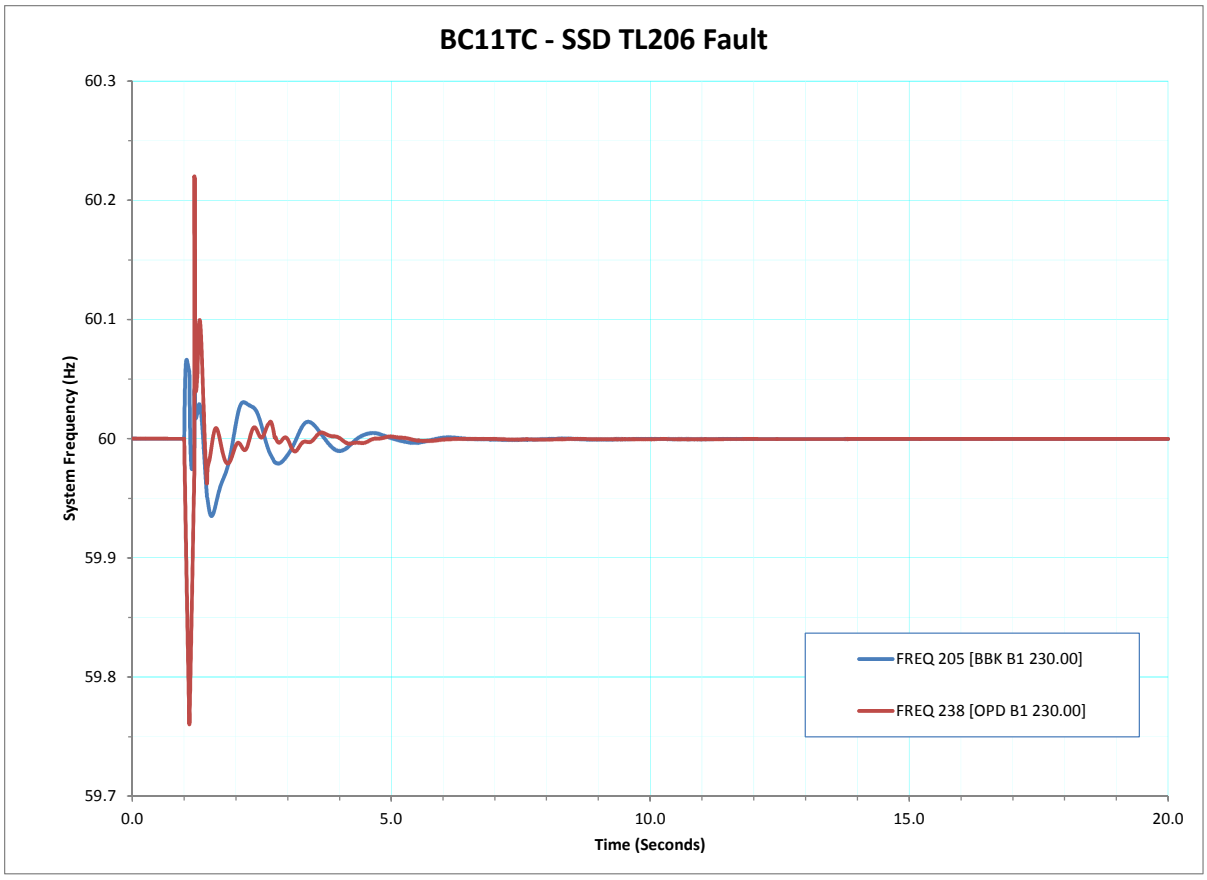


Figure 320 - BC11TC - SSD TL206 Fault - System Frequency (Hz)

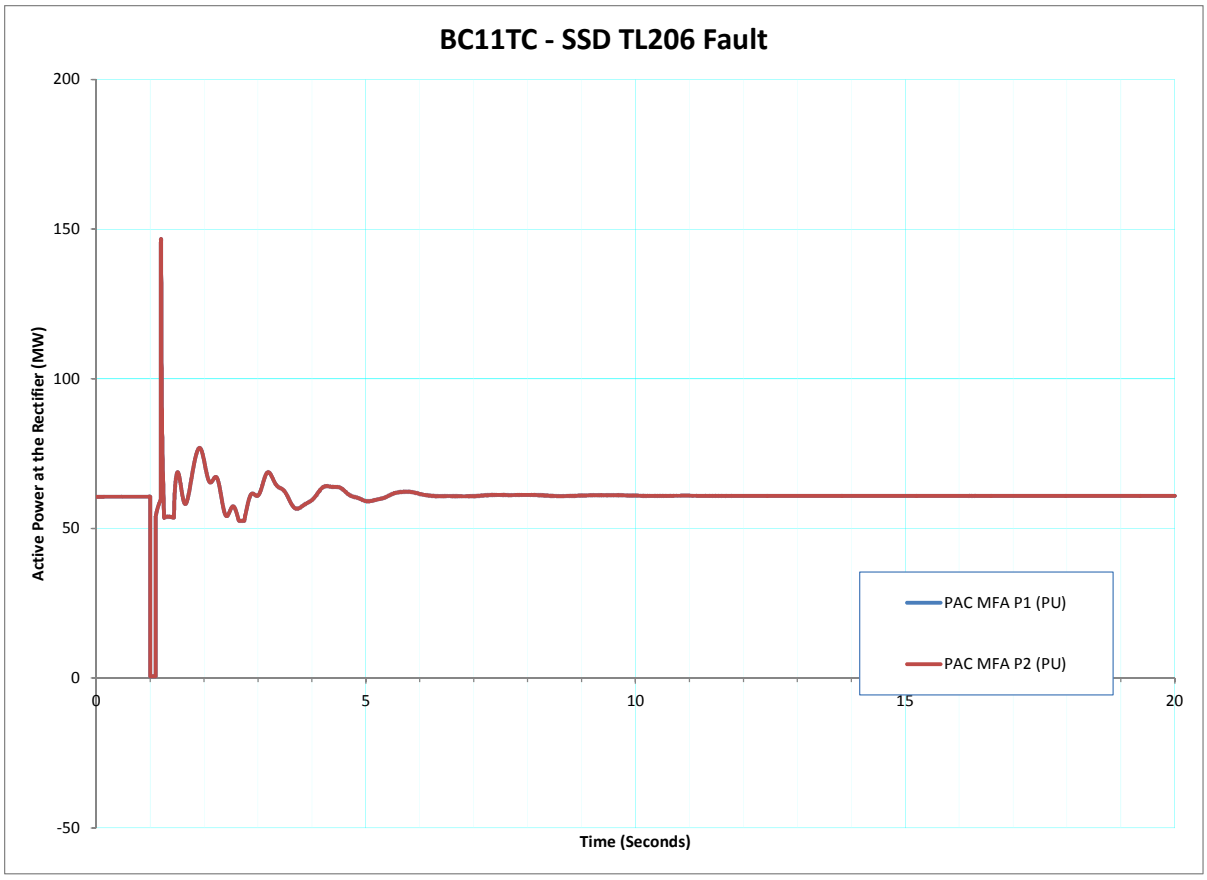


Figure 321 - BC11TC - SSD TL206 Fault - Active Power at the Rectifier (MW)

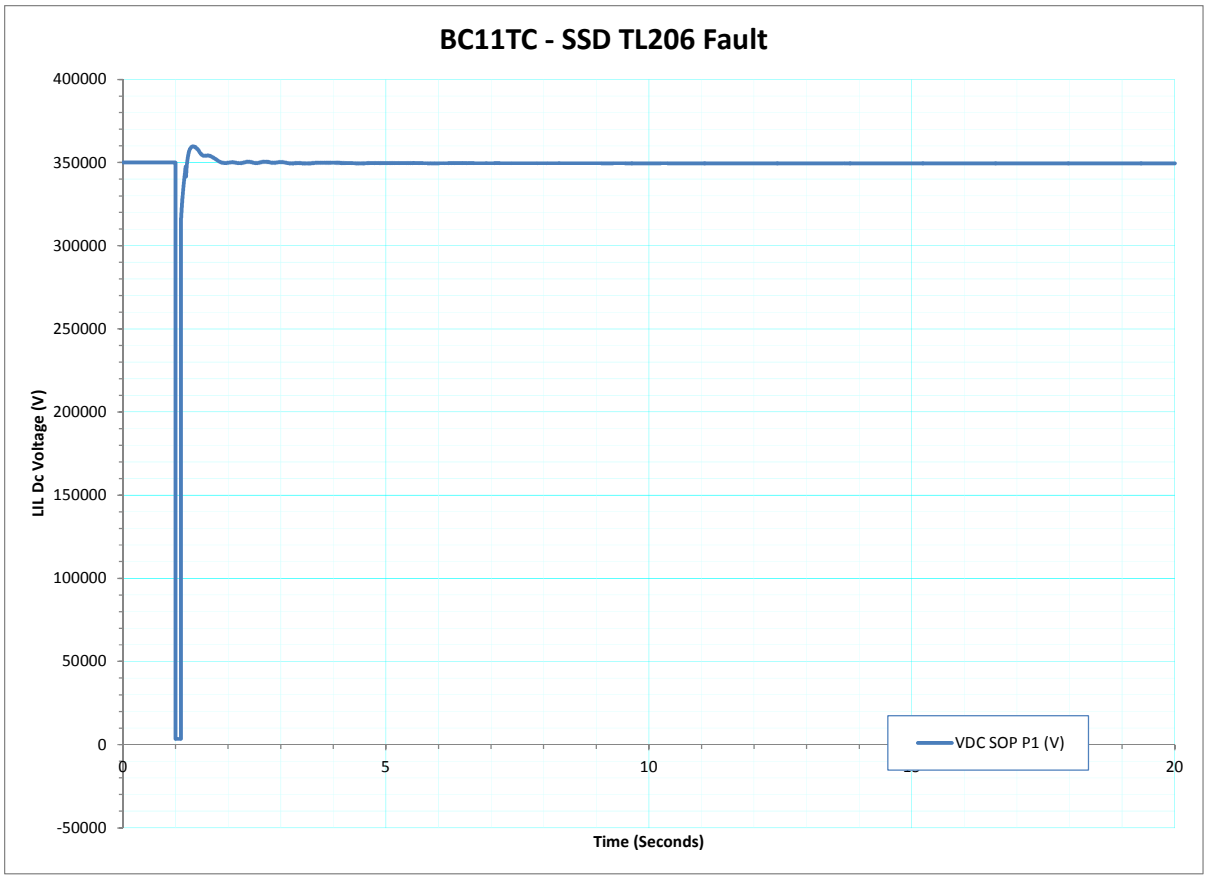


Figure 322 - BC11TC - SSD TL206 Fault - LIL Dc Voltage (V)

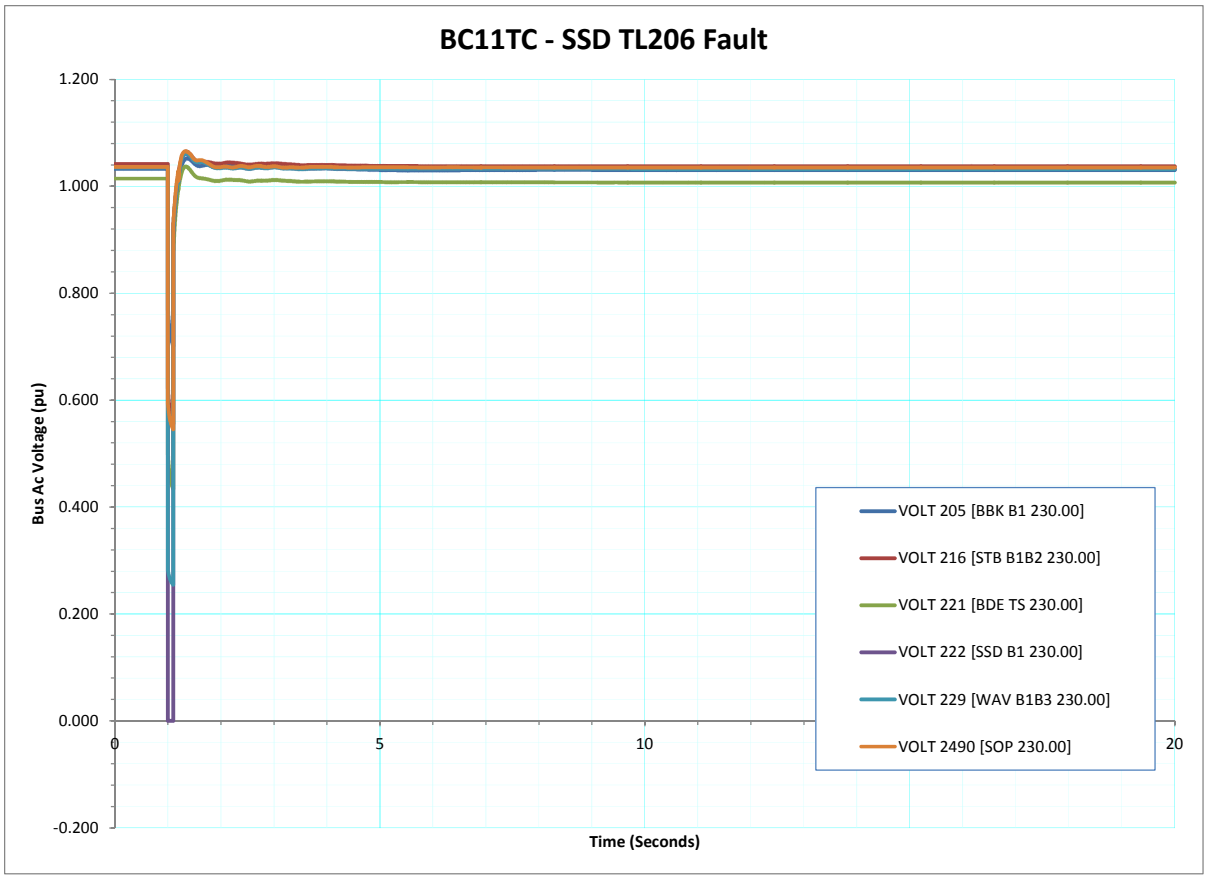


Figure 323 - BC11TC - SSD TL206 Fault - Bus Ac Voltage (pu)

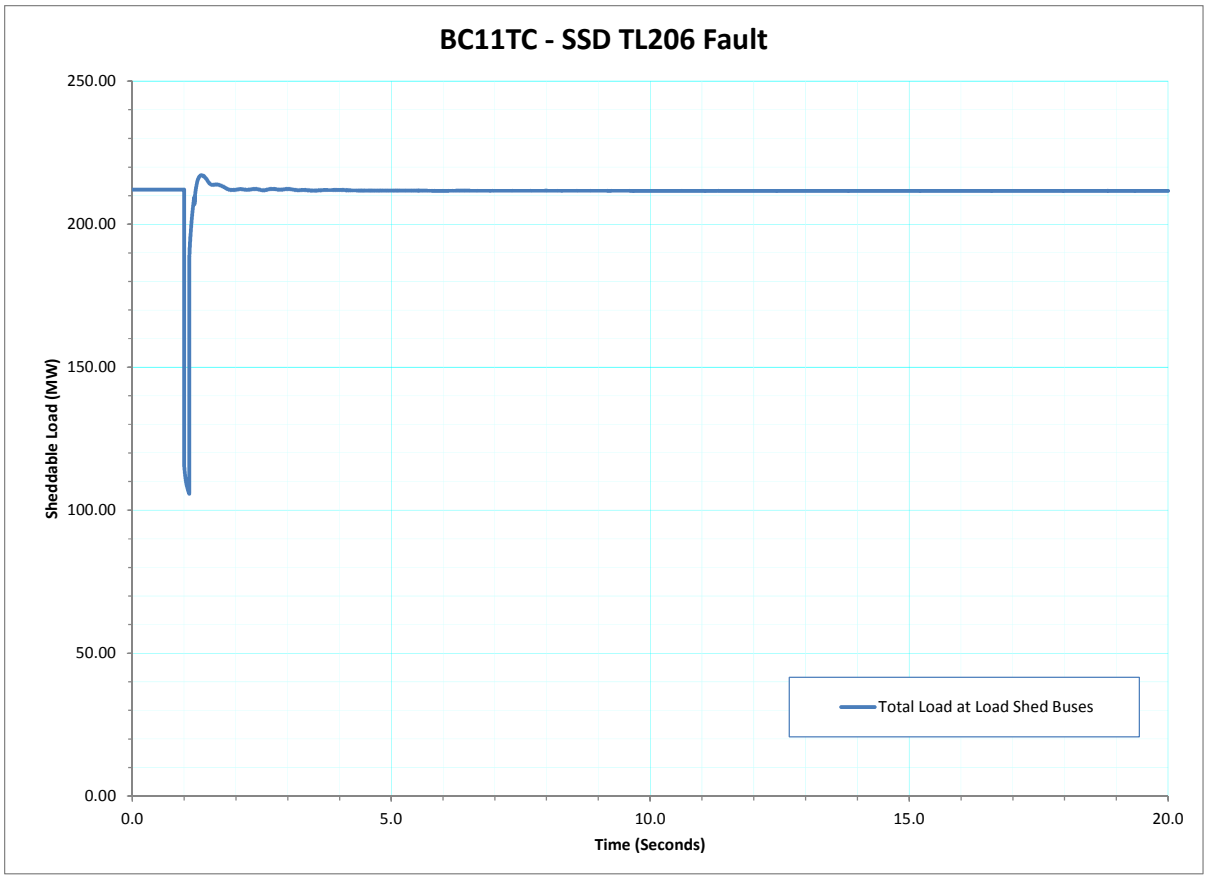


Figure 324 - BC11TC - SSD TL206 Fault - Sheddable Load (MW)

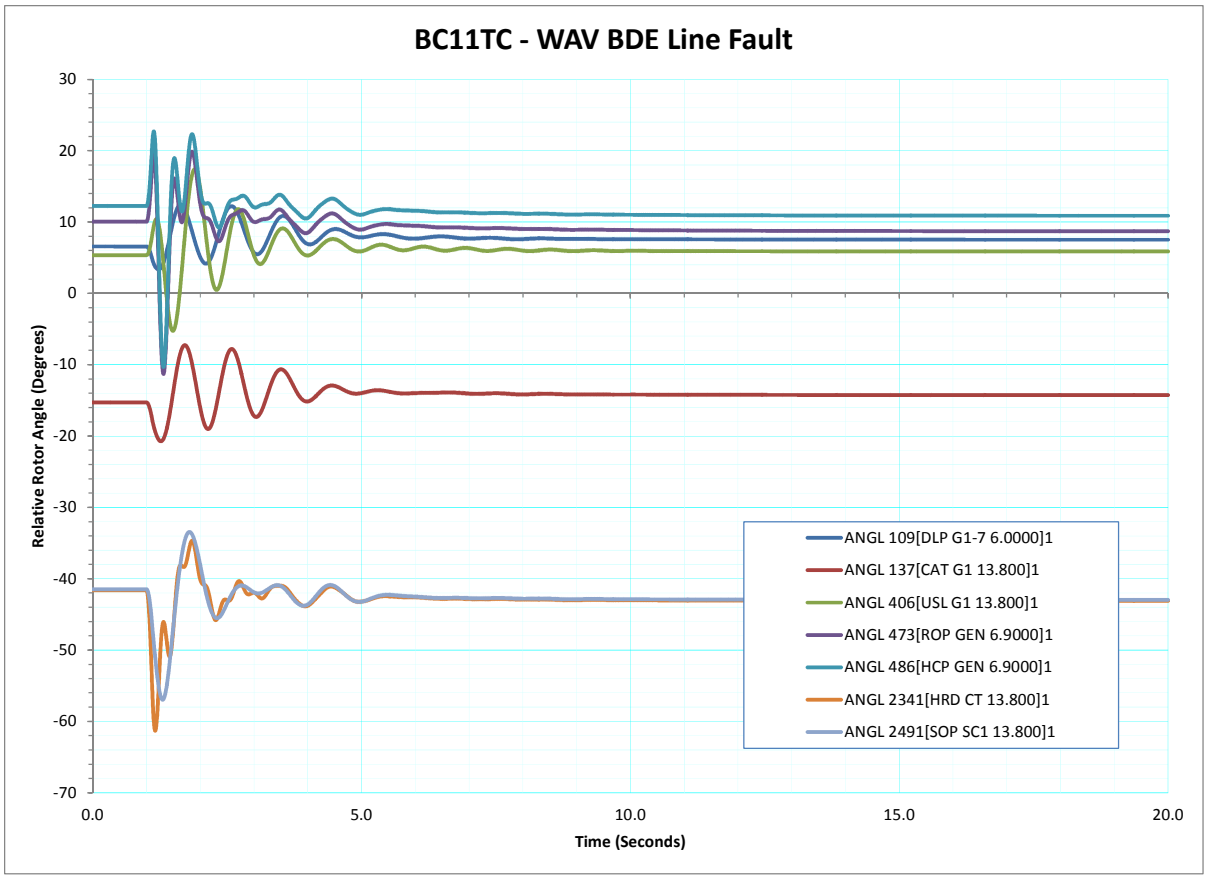


Figure 325 - BC11TC - WAV BDE Line Fault - Relative Rotor Angle (Degrees)

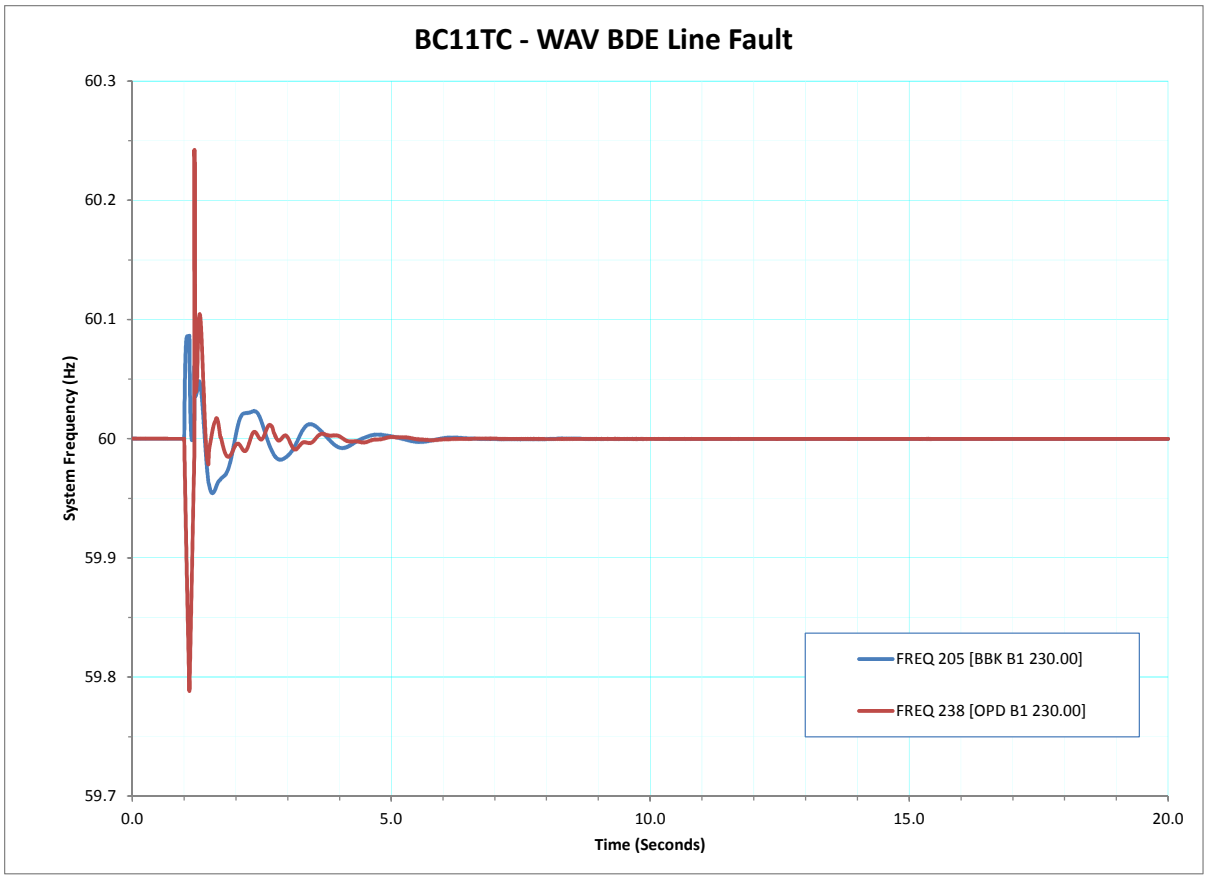


Figure 326 - BC11TC - WAV BDE Line Fault - System Frequency (Hz)

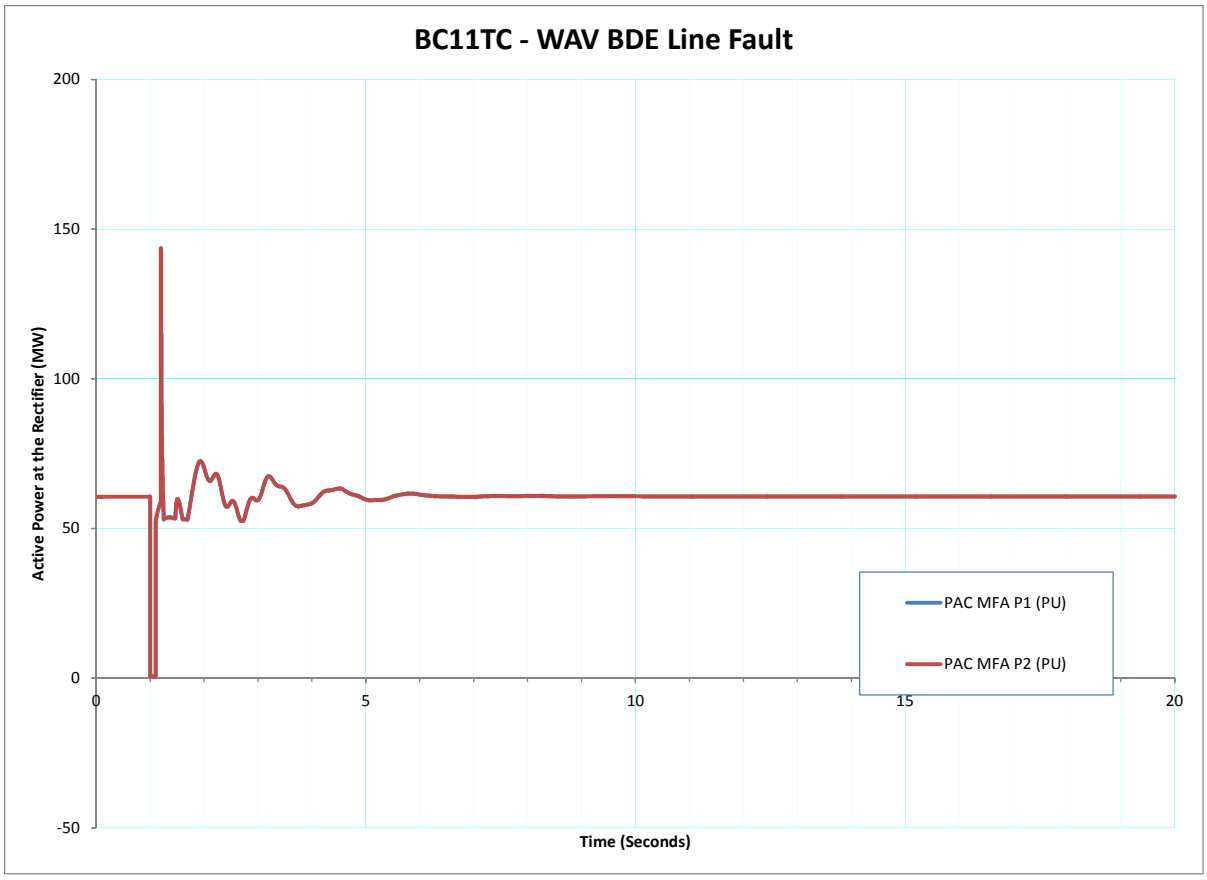


Figure 327 - BC11TC - WAV BDE Line Fault - Active Power at the Rectifier (MW)

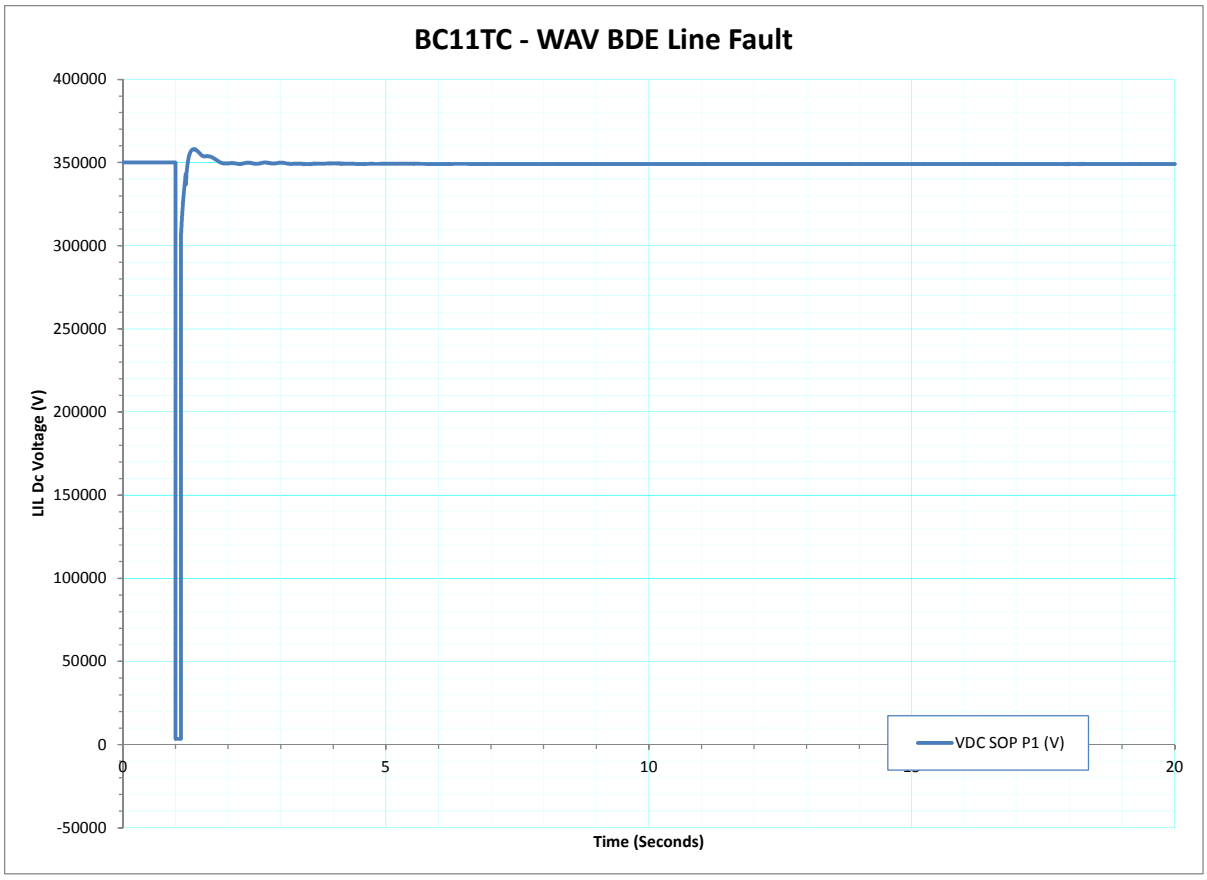


Figure 328 - BC11TC - WAV BDE Line Fault - LIL Dc Voltage (V)

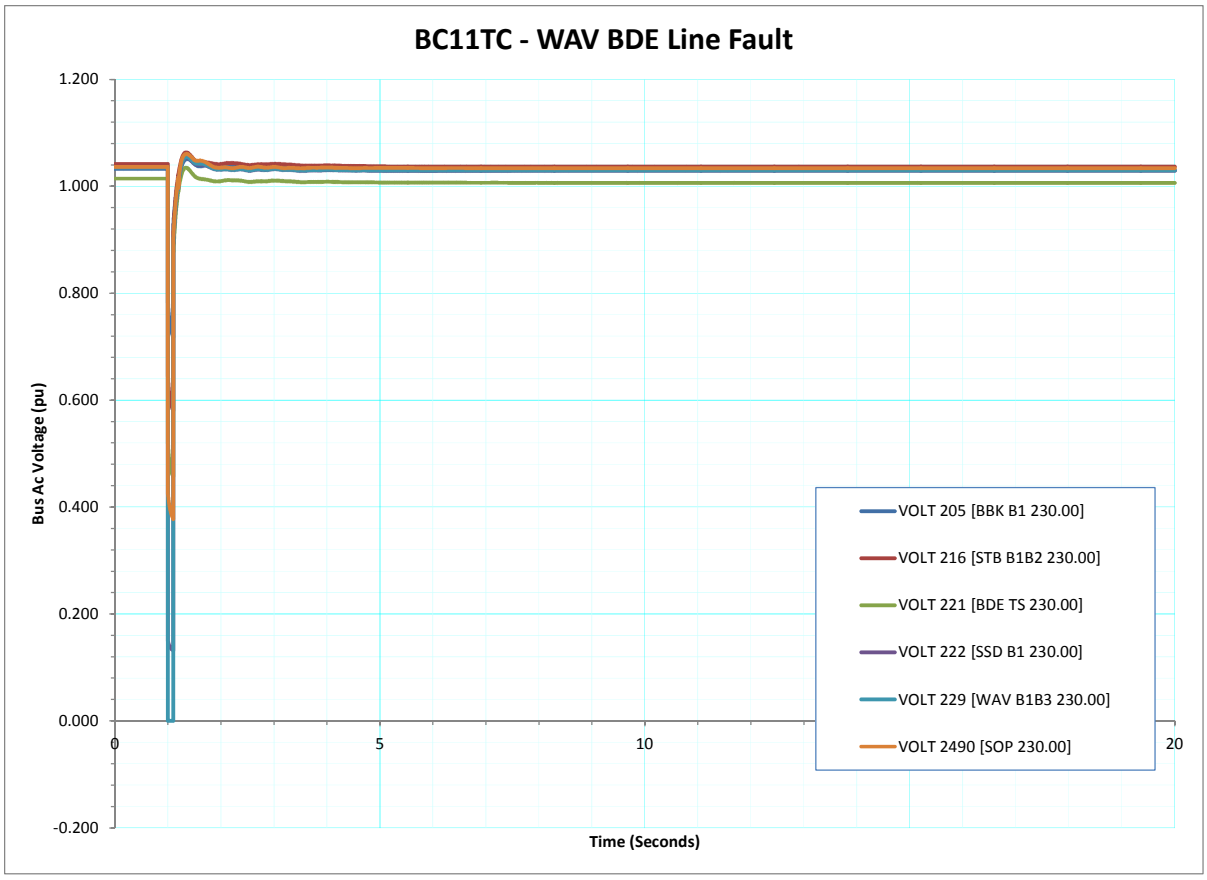


Figure 329 - BC11TC - WAV BDE Line Fault - Bus Ac Voltage (pu)

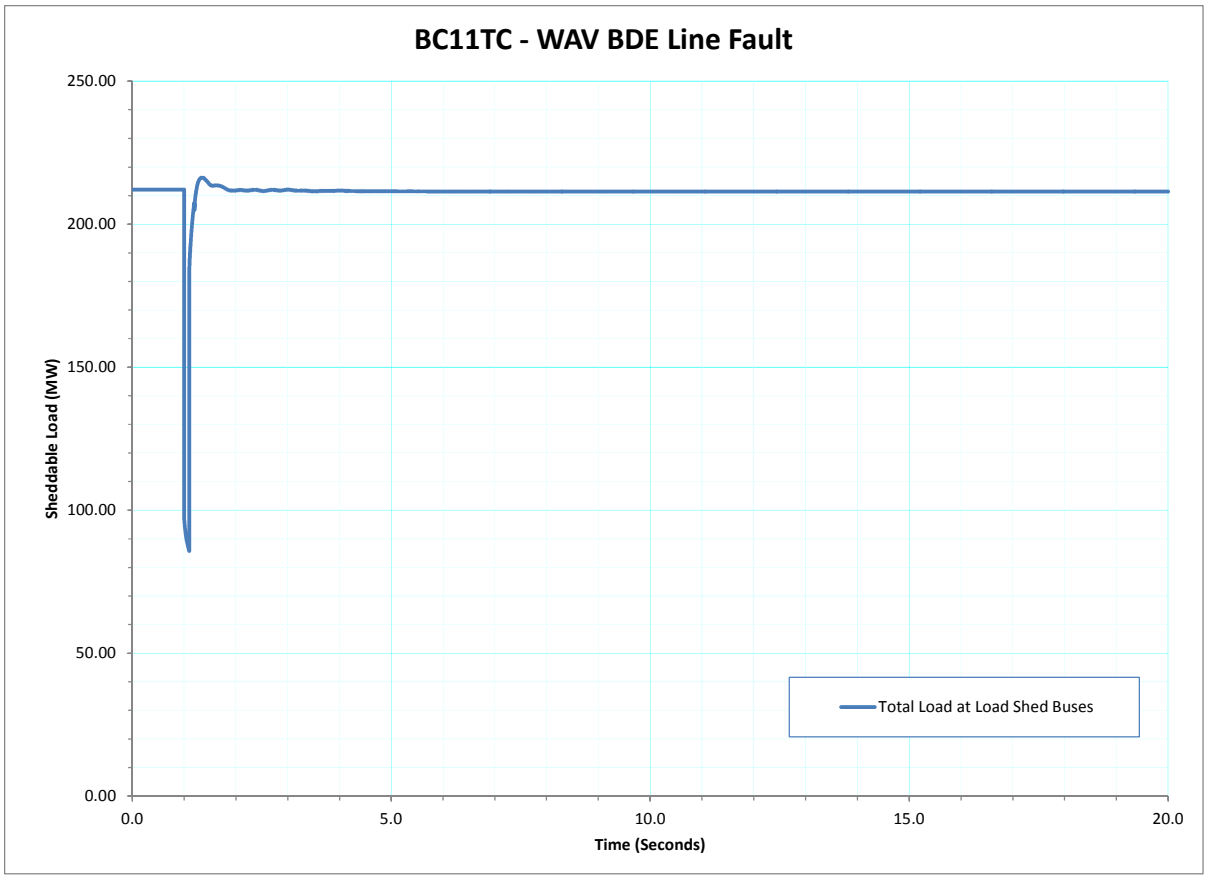


Figure 330 - BC11TC - WAV BDE Line Fault - Sheddable Load (MW)

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APPENDIX C1 – UPGRADE TRANSMISSION LINE CORRIDOR BAY D'ESPOIR – WESTERN AVALON – SEPTEMBER 2011

newfoundland labrador hydro
a nalcor energy company

Hydro Place. 500 Columbus Drive.
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 f. 709.737.1800
www.nlh.nl.ca

September 22, 2011

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

ATTENTION: Ms. Cheryl Blundon
Director of Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro – 2012 Capital Budget Application

Please find enclosed ten copies of the following with regard to the above-noted Application:

- Volume II, Tab 10: Upgrade Transmission Line Corridor Bay d'Espoir to Western Avalon Report; and

- Section B, pg B-27 Revision 1 – necessary due to revisions to the components of the budget. For ease of reference, the revisions are highlighted in yellow.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young

Senior Legal Counsel
GPY/jc

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Thomas Johnson – Consumer Advocate
Dean Porter – Poole Althouse

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES



Electrical
Mechanical
Civil
Protection & Control
Transmission & Distribution
Telecontrol
System Planning

UPGRADE TRANSMISSION LINE CORRIDOR

Bay d'Espoir to Western Avalon

September 2011

newfoundland labrador hydro
a nalcor energy company

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1 INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) owns and operates eleven 230 kV lines totaling 627 km in length connecting the Bay d'Espoir Generating Station to the major load centers and generation in the eastern portion of the province. Figure 1 provides a diagram of the Bay d'Espoir East 230 kV transmission system.

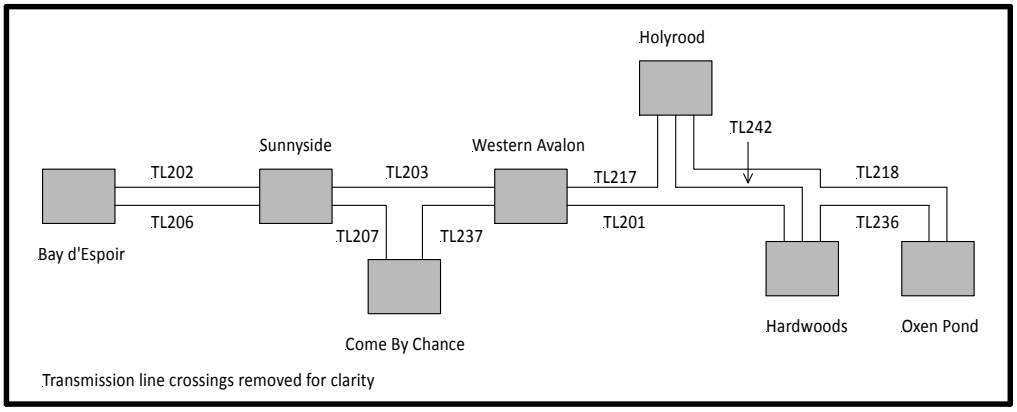


Figure 1 – Bay d'Espoir East 230 kV Transmission System

The Bay d'Espoir East 230 kV transmission system is characterized as being a heavily loaded system. Conversely, the 230 kV transmission system west of Bay d'Espoir is characterized as being a more lightly loaded system. Table 1 provides a summary of east and west loads at the time of system peaks for the period 2006 – 2010. By comparison the 230 kV transmission system east of Bay d'Espoir is loaded to approximately twice the loading of the 230 kV transmission system west of Bay d'Espoir. The heavy loading on the eastern portion of the system is coupled with the incentive to provide least-cost power to customers by minimizing Holyrood production and maximizing production from hydroelectric resources located in Bay d'Espoir and west. Constant monitoring of the load on the eastern portion of the system is therefore required. Thermal load limits on the lines must be strictly enforced to avoid unacceptable line sag and/or potential conductor damage. Further loading pressures will be placed upon the Bay d'Espoir East system with the addition of the Vale processing plant at Long Harbour and has already occurred due to the loss of load and net hydroelectric generation increase attributed to the closure of the Abitibi Bowater paper mill

in Grand Falls – Windsor.

Table 1 - Bay d'Espoir East and West 230 kV Transmission System Peak Loads 2006 to 2010

Year	Bay d'Espoir – East[1]	Bay d'Espoir – West[2]
2006	836	431
2007	848	450
2008	827	436
2009	858	428
2010	833	378

Notes
1- Bay d'Espoir – East load equal to TL202 and TL206 flow plus Paradise River, Holyrood and Hardwoods generation at time of peak.
2- Bay d'Espoir – West load equal to TL204 and TL231 flow plus Cat Arm, Hinds Lake, Stephenville, Hawke's Bay, St. Anthony Diesel Plant generation and Non-Utility Generation purchases at time of peak.
3- Connaigre Peninsula loads not included
4- Values based on the Hydro Energy Management System (EMS) hourly data and not weather adjusted

Lower Churchill Impacts

Given that the Lower Churchill Project has yet to receive final project sanction, analysis of the Bay d'Espoir East 230 kV transmission system must consider both the continued Isolated Island Scenario and the Labrador Infeed Scenario. In effect, the proposed project must be appropriate to either an Isolated Island or Labrador-Interconnected future.

To accomplish this, the Bay d'Espoir East 230 kV transmission system was split into two sections – Bay d'Espoir to Western Avalon and Western Avalon to St. John's. This project considers only the upgrade requirements for the Bay d'Espoir to Western Avalon section of the Bay d'Espoir East 230 kV transmission system. The Western Avalon to St. John's section can only be considered once the decision on the Lower Churchill Project and subsequent need for the Soldiers Pond Terminal Station is made. With the final decision on the Lower Churchill Project scheduled for late 2011 or early 2012, Hydro intends to submit any necessary upgrade projects for the Western Avalon to St. John's section of the Bay d'Espoir East 230 kV transmission system associated with the proposed Lower Churchill Project to The Board as part of its 2013 capital budget application.

2 PROJECT DESCRIPTION

The Upgrade Transmission Line Corridor – Bay d'Espoir to Western Avalon project will consist of a new 230 kV transmission line, 188 km in length connecting Bay d'Espoir and Western Avalon Terminal Stations. This includes construction of a 230 kV steel tower transmission line complete with overhead ground wire over its entire length. A minimum conductor size of 795 kcmil, 26/7 ACSR "DRAKE" with a 75 ˚C conductor temperature rating or 804 kcmil 54/19 AACSR/TW with an 80 ˚C conductor temperature is required to provide the necessary thermal rating for the new circuit. At Bay d'Espoir Terminal Station, three 230 kV circuit breakers, six 230 kV motor operated disconnect switches and associated control panels will be added to complete the breaker-and-one-half arrangement on the first two legs of the station layout and accommodate the new 230 kV transmission line termination on a third leg. Figure 2 provides a single line diagram with the proposed additions in red.

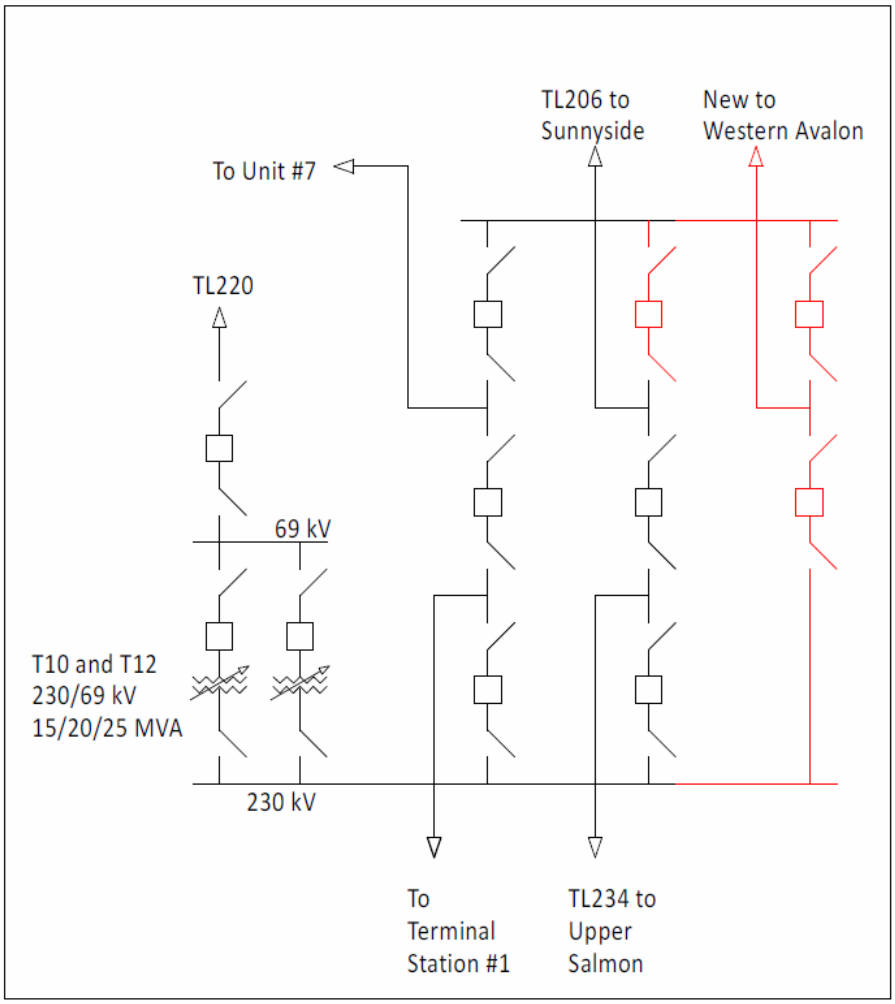


Figure 2 – Bay d'Espoir Terminal Station #2 Additions for New 230 kV Transmission Line

At Western Avalon Terminal Station a new 230 kV ring bus consisting of four 230 kV circuit breakers is proposed for the southern end of the terminal station. Rather than construct the new ring bus using traditional gas filled, air insulated circuit breakers and motor operated disconnect switches, Hydro is proposing to use a compact gas insulated switchgear (GIS) ring bus configuration. The rationale for the use of the GIS equipment is to limit the civil works for the ring bus addition. The Western Avalon Terminal Station is situated on the side of a hill near Chapel Arm. The land to the west of the terminal station consists of an upward sloping steep embankment which has had drainage issues in the past. Excavation to the west would to be extremely costly as it would require additional slope

stability and drainage work along with relocation of the existing access road. The land to the east consists of a downward sloping steep embankment to Route 201. Expansion in this direction would require extensive amounts of fill. If acquisition of building lots for private homes in the area of the Western Avalon Terminal Station were to be pursued, a minimal extension to the south side of the station can be accommodated to permit installation of the compact GIS and access road realignment. As part of the GIS ring bus addition, TL208 will be re-terminated in the new ring along with the new 230 kV transmission line to Bay d'Espoir. This will improve the reliability of the TL208 supply as it will no longer be tripped due to an outage to 230 kV bus B1 or 230/66 kV transformers T1 or T2. Figure 3 provides a single line diagram of the Western Avalon Terminal Station with the proposed additions shown in red. The GIS ring bus addition will contain one spare line termination for a future 230 kV transmission line to the east, if/when it may be required. Hydro has secured the land in the area to permit the future line termination.

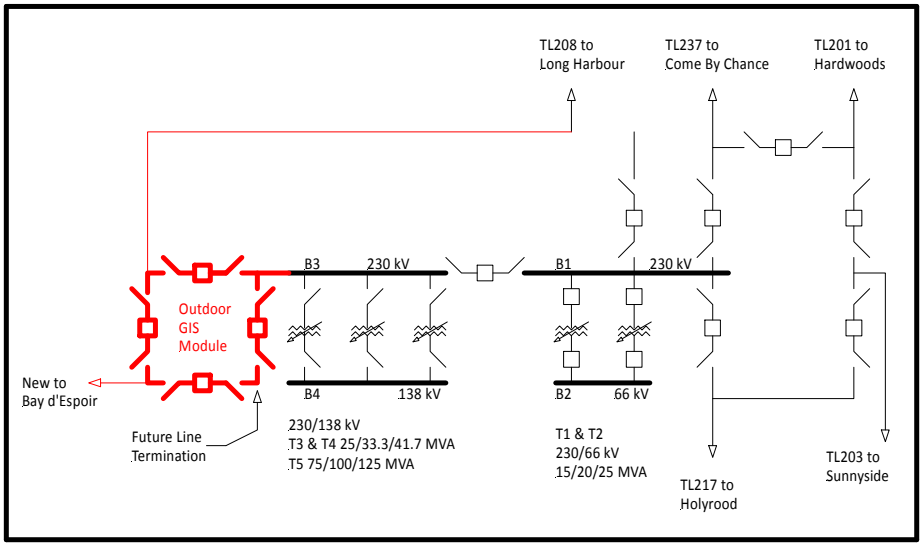


Figure 3 – Western Avalon Terminal Station Additions for New 230 kV Transmission Line

It should also be noted that this project also includes a study to investigate suspension insulators on TL206 (Bay d'Espoir to Sunnyside). These are original insulators manufactured by NEMA and are of the same vintage as the Canadian Porcelain/Canadian Ohio Brass

insulators that have experienced significant cement growth and mechanical failure over time. However, there is little industry information on the long term mechanical and electrical performance of the NEMA insulators. It is suspected that the NEMA insulators on TL206 do not meet Hydro's existing suspension insulator specification. To confirm the residual mechanical strength of the NEMA insulators following 43 years in service, Hydro is proposing to remove sample strings from service and complete laboratory testing. Cost of this component is estimated at $50,000. Following testing Hydro will be in a better position to report the condition of the TL206 insulators to the Board with a recommendation on a replacement program for the NEMA insulators.

As discussed in the Justification Section below, analysis indicates that this new 230 kV transmission line is required to increase firm system capacity in both the continued Isolated Island Scenario and the Labrador Interconnected Scenario.

3 EXISTING SYSTEM

The existing Bay d'Espoir to Western Avalon transmission corridor consists of five 230 kV transmission lines including:

- TL202 – Bay d'Espoir to Western Avalon;
- TL203 – Sunnyside to Western Avalon;
- TL206 - Bay d'Espoir to Western Avalon;
- TL207 – Sunnyside to Come By Chance; and
- TL237 – Come By Chance to Western Avalon.

Table 2 provides the rating of each transmission line for varying ambient temperature.

Table 2 - Bay d'Espoir to Western Avalon Transmission Corridor Line Ratings

TL #	MVA Rating for an Ambient Temperature of			
	30 ˚C	**25 ˚C**	**15 ˚C**	**0 ˚C**
TL202	199.3	236.9	297.7	369.5
TL203	261.7	278.0	307.8	347.0
TL206	199.3	236.9	297.7	369.5
TL207	355.8	375.5	411.5	459.6
TL237	355.8	375.5	411.5	459.6

Of these transmission lines, TL202 and TL206 are the most heavily loaded lines during the late spring to early fall time period when the Holyrood Thermal Generating Station is shut down or operating at minimal levels. This is due to the fact that they carry the loads of both the Burin and Avalon Peninsulas along with a portion of the load on the 138 kV transmission loop between Stony Brook and Sunnyside. Load relief to TL202 and TL206 is provided by the Paradise River Hydroelectric Generating Station and the St. Lawrence and Fermeuse wind farms when in operation. Under a line-outage contingency Hydro will start its combustion

turbines at Holyrood (10 MW) and Hardwoods (46 MW) to reduce the loading on the transmission corridor. Given a thermal rating of 297.7 MVA on a 15 ˚C day (i.e. spring/fall) Hydro must limit the loading on TL202 and TL206 to approximately 353 MW (297.7 + 10 + 46 = 353.7) to ensure that TL202 or TL206 does not become overloaded should TL206 or TL202 trip. Consequently for Bay d'Espoir East loads in excess of 353 MW on a 15 ˚C day, Hydro must operate generation at its Holyrood Thermal Generating Station.

This inefficiency is further illustrated in Table 3, which includes the triggers used by System Operations to determine when generators at Holyrood Thermal Generating Station are to be brought online. In an optimal situation, the generators at Holyrood would only be dispatched after all hydroelectric generators on the island are brought online (while maintaining sufficient reserve to withstand the loss of the largest unit). These optimal thresholds are indicated in Table 3.

Due to the existing thermal limitations, generators at Holyrood must be brought online at load levels that are much lower than the optimal values. The Holyrood units are therefore required to operate much earlier in the fall and later in the spring than would otherwise be required. This problem is compounded as the generators are often dispatched to produce a minimal output power (approximately 70 MW), resulting in a highly inefficient use of fuel.

Table 3 - Thresholds for Bringing Generators Online at Holyrood Thermal Generating Station

Number of Holyrood Generators In Service	Optimal Threshold to Bring an Additional Holyrood Generator Online (MW of System Generation)	Threshold to Bring an Additional Holyrood Generator Online (MW of System Generation)	Threshold/ Optimal Threshold
0*	994	635	69.2%
1*	1137	835	78.8%
2	1319	960	77.3%

* Holyrood Unit Three online as a Synchronous Condenser

While these factors demonstrate significant restrictions in the operational flexibility of the existing transmission system east of Bay d'Espoir, there is a much greater concern relating to transfer capacity. In the event of the loss of a unit at Holyrood, the existing transmission system would be unable to supply system loads above 1280 MW. While this analysis is described in detail in Section 4, it may be noted that the peak load for 2012 is forecasted to exceed 1350 MW. The loss of a unit at Holyrood would therefore result in a significant exposure for unsupplied load.

3.1 Age of Equipment or System

The 230 kV transmission lines in the Bay d'Espoir to Western Avalon corridor were built between 1965 and 1968. The original in service dates of the transmission lines are as follows:

- TL202 – Bay d'Espoir to Sunnyside – 1966
- TL203 – Sunnyside to Western Avalon – 1965
- TL206 – Bay d'Espoir to Sunnyside – 1968
- TL207 – Sunnyside to Come By Chance – 1968
- TL237 – Sunnyside to Come By Chance – 1968

3.2 Major Work and/or Upgrades

The following upgrades have occurred along the Bay d'Espoir to Western Avalon transmission corridor since installation:

Table 4 - Major Work or Upgrades

Year	Major Work/Upgrade	Comments
2003	TL203 Thermal Uprate	The thermal rating of TL203 was increased to meet system loading requirements
2002	TL237 Rebuild	Following 1994 ice storm TL237 was rebuilt for a 3 in ice load as part of the Avalon Transmission Upgrade Project
2002	TL207 Rebuild	Following 1994 ice storm TL207 was rebuilt for a 3 in ice load as part of the Avalon Transmission Upgrade Project
2001	TL206 Lightning arrester additions	Poor lightning performance of TL202 and TL206 resulted in a significant number of simultaneous outages and loss of supply to Avalon Peninsula
1993 to 1996	TL202 insulator replacements	Canadian Ohio Brass insulators replaced
1984	TL203 line upgraded with high strength 562.5 kcmil conductor	Ice storms resulted in failure of TL203 structures and outages to customers. A high strength 562.5 kcmil conductor was added to 22 km along the two-inch ice zones

3.3 Anticipated Useful life

The proposed 230 kV transmission line has an estimated service life of 50 years.

3.4 Maintenance History

As the proposed 230 kV transmission line between Bay d'Espoir and Western Avalon is a new asset, there is no maintenance history.

3.5 Outage Statistics

As the proposed 230 kV transmission line between Bay d'Espoir and Western Avalon is a new asset, there are no available outage statistics. Given the application of an overhead ground wire along its entire length, it is anticipated that the lightning performance of the new line will be very similar to that of TL206 which is equipped with lightning arresters. The mechanical and structural performance of the proposed line will be very similar to that of TL202, TL206, TL207 and TL237 as it will be designed withstand comparable meteorological loading.

Outage statistics for existing 230 kV transmission lines in the Bay d'Espoir to Western Avalon corridor are as follows:

Table 5 – Listing of Transmission Line Terminal Equipment Performance Bay d'Espoir to Western Avalon Corridor

Transmission Line	Frequency (per terminal year)	Unavailability (%)
TL202 (2006 – 2010)	0.40	0.0176
TL203 (2006 – 2010)	0.20	0.0006
TL206 (2006 – 2010)	0.00	0.0000
TL207 (2006 – 2010)	0.00	0.0000
TL237 (2006 – 2010)	0.10	0.0000
Hydro 230 kV (2006 – 2010)	0.99	0.0127
CEA 230 kV (2005 – 2009)	0.16	0.0370
Frequency (per terminal year) is the number of line outages per line terminal. Unavailability is amount of time the line is not available for terminal related causes.		

3.6 Industry Experience

As discussed in Section 4, when the load or power transfer requirements of a portion of the transmission system exceed the original rating of the transmission lines, several alternatives are considered in the industry. One alternative is to investigate the potential to increase the rating of the existing transmission lines either through re-conductoring or a combination of conductor changes (replacement or re-tensioning) and structure modifications (increases in structure height or mid span structures). The second alternative is to consider the addition of new transmission lines at the same or higher voltage to the corridor. A third alternative is to increase the voltage rating of the existing lines.

When power system stability becomes an issue along a portion of the transmission system due to changes in the system topology, generation dispatch or load patterns, the two prominent alternatives used in industry include series compensation and the construction of new transmission lines.

Series compensation involves the addition of a capacitor bank in series with the transmission line to effectively reduce its impedance. This reduction allows for the "stiffening" of the transmission network and improves stability. This technique is used extensively by Hydro-Québec TransÉnergie to increase the transmission capacity of their 735 kV network. Series compensation on the 735 kV network ranges from 16% to 50%.

The other alternative to improve power system stability is to increase the number of transmission lines and/or voltage levels in a corridor. Like series compensation, the construction of parallel lines allow reduces the overall transmission corridor impedance and thereby "stiffens" the transmission network so that it is no longer susceptible to instability.

When both transmission line ratings and power system stability issues occur along the same transmission corridor, series compensation, in and of itself, is not an effective solution on its own.

3.7 Maintenance or Support Arrangements

Normal routine maintenance work for the proposed 230 kV transmission line and associated terminal station equipment will be performed by Hydro personnel.

3.8 Vendor Recommendations

This project includes the purchase and installation of new terminal station equipment and the design and construction of a new 230 kV transmission line. Therefore vendor recommendation with respect to repair or replacement is not pertinent.

3.9 Availability of Replacement Parts

Required spare parts for terminal station equipment and transmission structure

components will be purchased at the time of the equipment purchases.

3.11 Retirements

There will be no retirements as part of this project.

3.12 Safety Performance

This project is not required to comply with any specific safety regulation.

3.13 Environmental Performance

This project is not required to address any non-compliance issues pertaining to environmental regulations.

3.14 Operating Regime

The proposed 230 kV transmission line and associated terminal station equipment will be placed in service on a continuous basis, being removed only for regularly scheduled maintenance.

4 JUSTIFICATION

As indicated in Section 1, significant development east of Bay d'Espoir, particularly on the Avalon Peninsula has resulted in a shift in the province's load distribution. As a result of this shift, the limited transmission capacity east of Bay d'Espoir has become the governing factor for determining the total firm capacity of the Newfoundland and Labrador Hydro Transmission System. This limitation is demonstrated in a contingency scenario involving the loss of a unit at Holyrood over peak. As indicated in the load flow analyses below, this worst-case scenario would put a significant strain on the Bay d'Espoir East transmission system. It should also be noted that the duration of the contingency could be quite extensive if a unit at Holyrood were to be damaged or otherwise out of service.

Existing System

For the existing system, the contingency involving the loss of a unit a Holyrood is illustrated in Figure 4 where a limit of approximately 854 MW is delivered to loads east of Bay d'Espoir. As indicated in the figure, the absolute limit of the transmission system is reached in this case with gas turbines at Holyrood, Hardwoods, and the Newfoundland Power unit at Greenhill brought online for support.

It should be noted that the loss of the Holyrood unit does not result in the overloading of transmission lines in this case. Rather, the loss of the unit results in a lack of reactive power support on the Avalon Peninsula. As illustrated, Holyrood Units 2 and 3 are generating 94.8 Mvar and 103.8 Mvar, respectively, which equals their reactive power limits. If system load were to increase, these units would no longer be able to meet the reactive power consumption of the load, and the system would experience a voltage collapse.

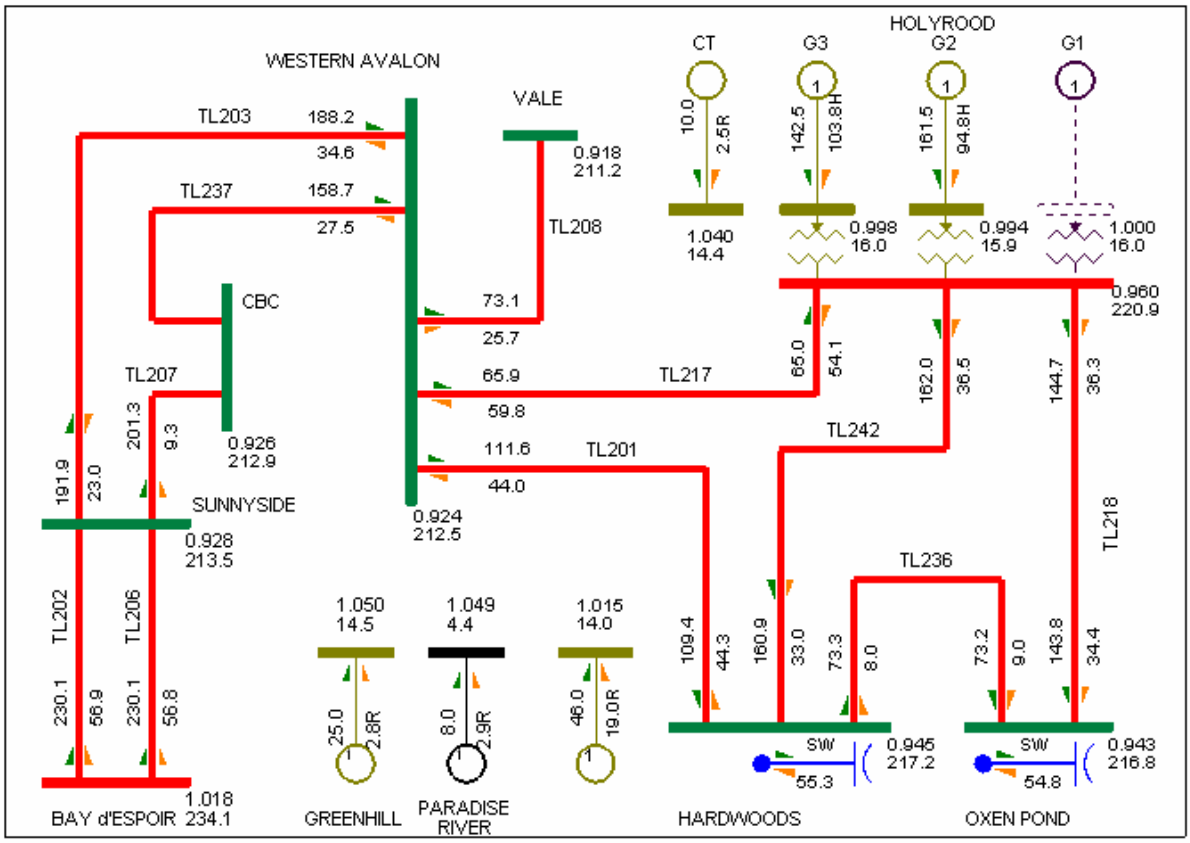


Figure 4 – Existing Transmission System – Loss of Unit 1 at Holyrood

As a result, the transmission system would only have a firm capacity of 1280 MW. As the forecasted system peak for 2012 is 1353 MW (as indicated in Section 4.6), this would result in a significant exposure for unsupplied load. This result would indicate that there is an immediate need for enhancements to the transmission system east of Bay d'Espoir.

By comparison, analysis performed in 2009-2010 indicated that this violation in the firm system capacity of the transmission system east of Bay d'Espoir would not occur until the end of the five year planning horizon. A summary of this analysis is provided in Table 6.

The next available load forecast from Newfoundland Power for use in the 2010-2011 planning and capital budget cycle revealed actual system peaks for 2010. As indicated in Table 6, these figures are higher than previously forecasted. Given the near-term violation

of the firm transmission capacity criterion, a detailed investigation was performed to identify acceptable transmission system alternatives that will meet all technical requirements.

Table 6 – Forecasted Load for the Bay d'Espoir-East Transmission System

Forecast Year		2009	2010	2011	2012	2013	2014
2009-2010	Load (MW)	820	834	846	854	868	-
	Percent Loading* (%)	96%	98%	99%	100%	102%	-
2010-2011	Load (MW)	-	872	880	903	923	971
	Percent Loading* (%)	-	102%	103%	106%	108%	114%

*Percent Loading is based on an existing system capacity of 854 MW east of Bay d'Espoir.

As indicated in the following sections, the required transmission upgrades have been identified for both proposed generation expansion scenarios including a continued Isolated Island and a Labrador Infeed. These upgrades have been reviewed from a technical standpoint to ensure that the proposed solution would ensure sufficient system capacity for both scenarios.

Continued Isolated Island

Under a continued Isolated Island generation expansion scenario, the least cost hydroelectric generation sources include:

- Island Pond – 36 MW
- Round Pond – 18 MW
- Portland Creek – 23 MW

These sources are all located west of Bay d'Espoir and a continued Isolated Island scenario would therefore result in increased loading on the Bay d'Espoir to Western Avalon transmission corridor. In such a scenario, the system's existing transfer limits would not be acceptable.

No additional generation would be installed east of Bay d'Espoir in a continued Isolated

Island scenario until the 2022 timeframe when a 170 MW combined-cycle combustion turbine (CCCT) would be installed on the Avalon Peninsula. Transmission upgrades are therefore required. Alternatives for the transmission system East of Bay d'Espoir include:

(1) Performing thermal upgrades on TL202, TL206 and TL203;
(2) Installing series compensation on TL202 and TL206;
(3) Constructing a new 230 kV transmission line from Bay d'Espoir to Western Avalon Terminal Station;
(4) Installing shunt capacitor banks;
(5) Performing thermal upgrades on TL202, TL206 and TL203, installing series compensation on TL202 and TL206, and installing shunt capacitor banks;
(6) Constructing a new 230 kV transmission line from Bay d'Espoir to Western Avalon Terminal Station and installing shunt capacitor banks;
(7) Adding a 315 kV transmission line; or
(8) Adding a 315 kV transmission line and installing shunt capacitor banks.

A proposal involving only thermal upgrades on TL202, TL206 and TL203 would not improve system capacity. As demonstrated in Figure 4, system limitations for the contingency involving the loss of Holyrood Unit 1 relate primarily to reactive support on the Avalon Peninsula. Solutions involving thermal upgrades alone are only applicable after sufficient reactive power compensation has been added to the system and transmission lines become overloaded at higher system loads.

The installation of series compensation on TL202 and TL206 would help to improve transmission capacity east of Bay d'Espoir by reducing the amount of reactive power absorbed by the lines. Using the Hydro-Québec TransÉnergie system as a benchmark (as discussed in Section 3.6), an upper limit of 50% series compensation was added to each line. This level of compensation maximizes the transfer capability of the transmission system.

Figure 5 illustrates the result with 50% series compensation on TL202 and TL206. In this scenario 940 MW is transferred to loads east of Bay d'Espoir before the limits of the reactive power support on the Avalon Peninsula are reached. Loads in this case are representative of a scenario where total system generation is approximately 1410 MW. At this increased loading level, analysis indicates that no transmission line overloading would occur under any contingency. Series compensation therefore provides an increase of 130 MW in the capacity of the Island transmission system.

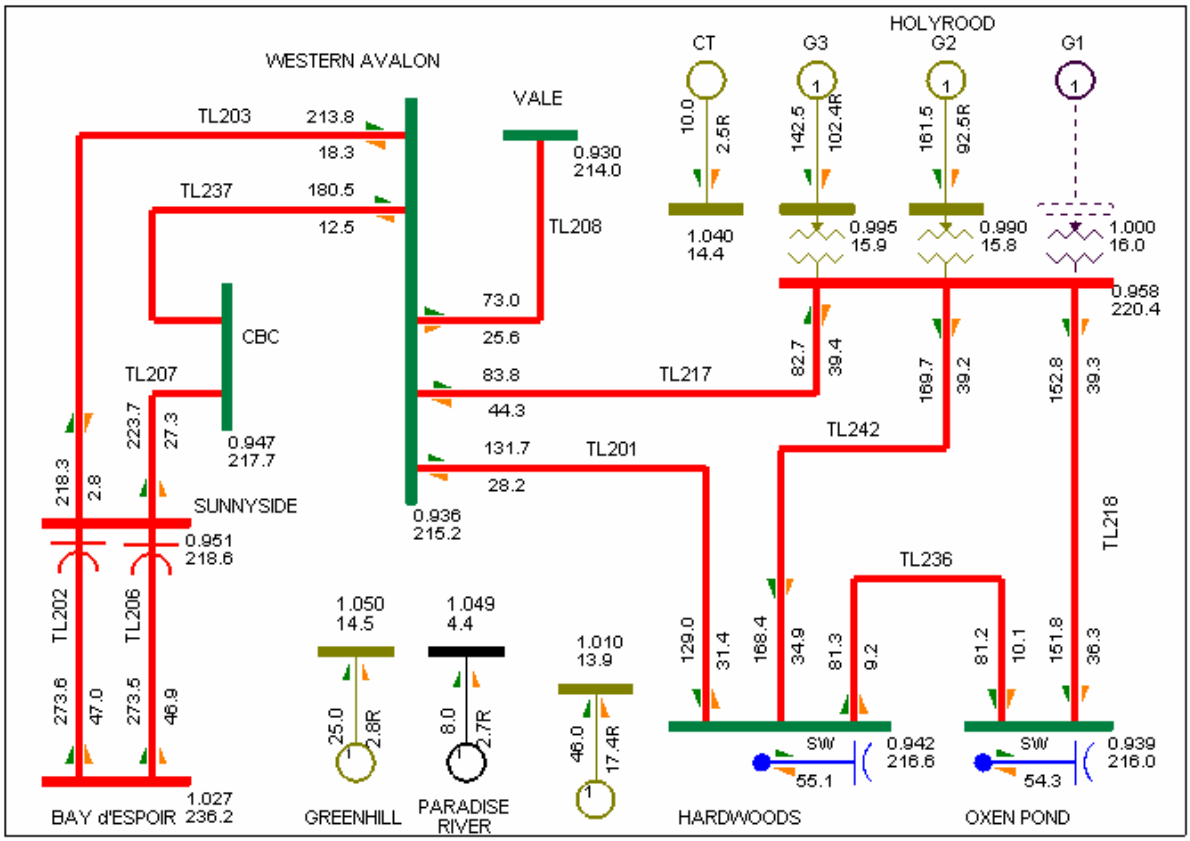


Figure 5 – Series Compensation – Loss of Unit 1 at Holyrood

Another alternative to improve the transfer capability of the existing system would involve the construction of a new 230 kV transmission line from Bay d'Espoir to Western Avalon. As illustrated in Figure 6, the Bay d'Espoir East Transmission System would be able to transfer approximately 950 MW to loads in the contingency case involving the loss of a unit at

Holyrood. This scenario is representative of a loading condition where total system generation is in the order of 1440 MW. The new transmission line would therefore increase the capacity of the existing system by approximately 140 MW.

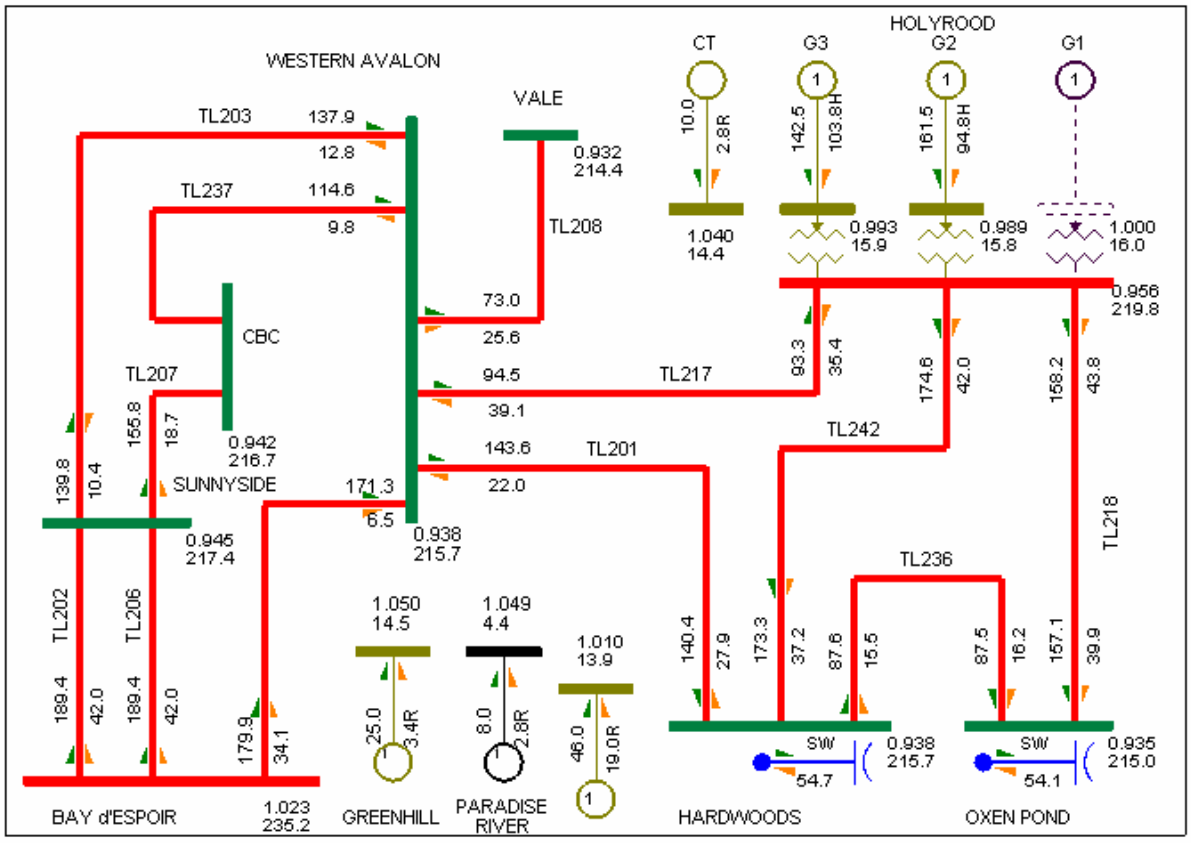


Figure 6 – New 230 kV BDE-WAV Transmission Line – Loss of Unit 1 at Holyrood

In each of the cases defined above, it is noted that the capacity of the Bay d'Espoir East Transmission System is limited primarily due to a lack of reactive power support on the Avalon Peninsula. A logical proposed would be to investigate the addition of capacitor banks as a means of avoiding voltage collapse.

The application of capacitors is illustrated in Figure 7 where a 153 Mvar bank is installed at Come by Chance Terminal Station. This site was selected at it represents one of the lowest points in the system's voltage profile and also due to the stringent undervoltage limitations

required for the operation of the North Atlantic Refinery. As illustrated, this system would able to transfer 950 MW to loads east of Bay d'Espoir. It should also be noted that at this increased loading level, no transmission lines would be overloaded under contingency. From a voltage stability and thermal overload perspective, the firm capacity of the transmission system in this case would reach 1420 MW.

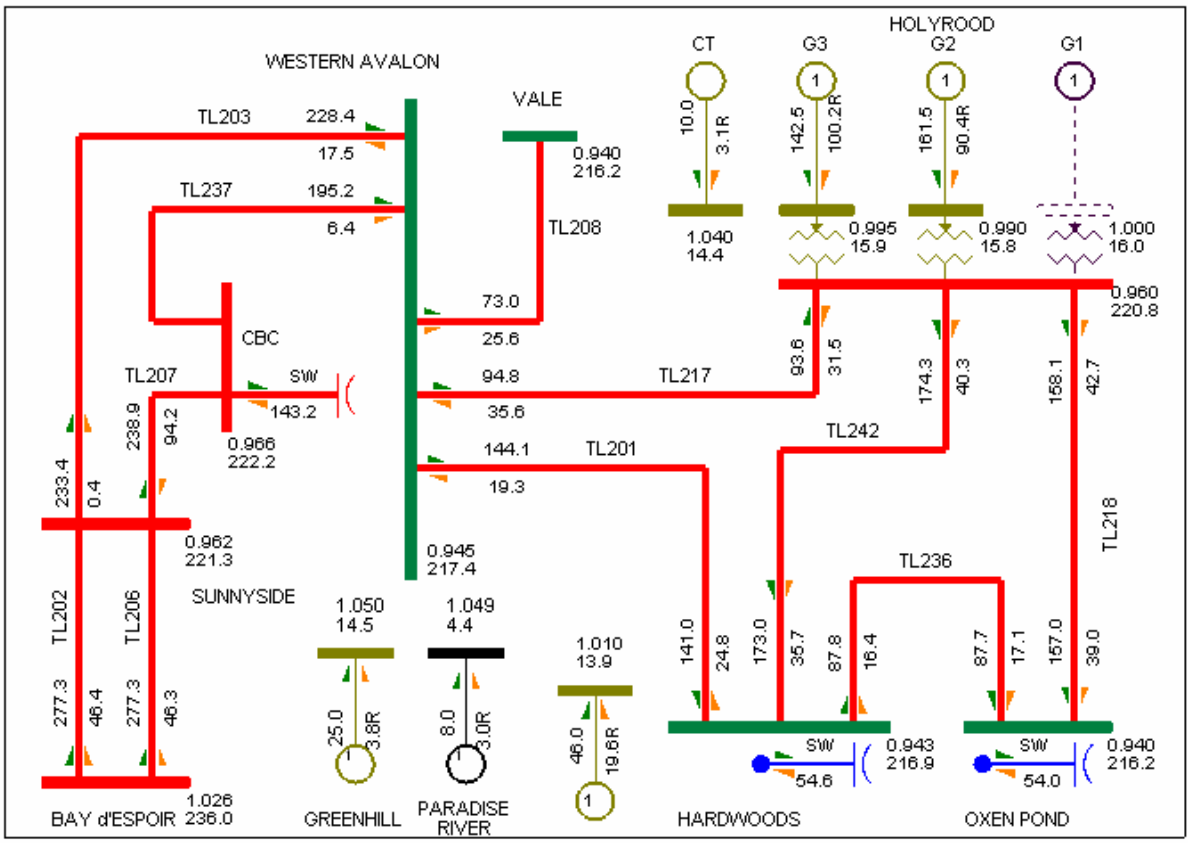


Figure 7 – Capacitor Bank Installation – Loss of Unit 1 at Holyrood

While the addition of the capacitor banks on the Avalon Peninsula would increase the voltage stability of the system by providing significant reactive power support, the system must also be designed to have an adequate angular stability. This type of stability refers to the ability of the generators within the transmission system to maintain synchronism following a disturbance. In an ac transmission system, the only way to increase the angular stability is to add transmission lines or to provide series compensation for existing lines.

A solution involving the addition of shunt capacitor banks alone would therefore not improve the angular stability of the power system. Figure 8 demonstrates the angular stability of a generator at Holyrood following a contingency involving an unsuccessful reclose for a single-line-to-ground fault event on transmission line TL202.

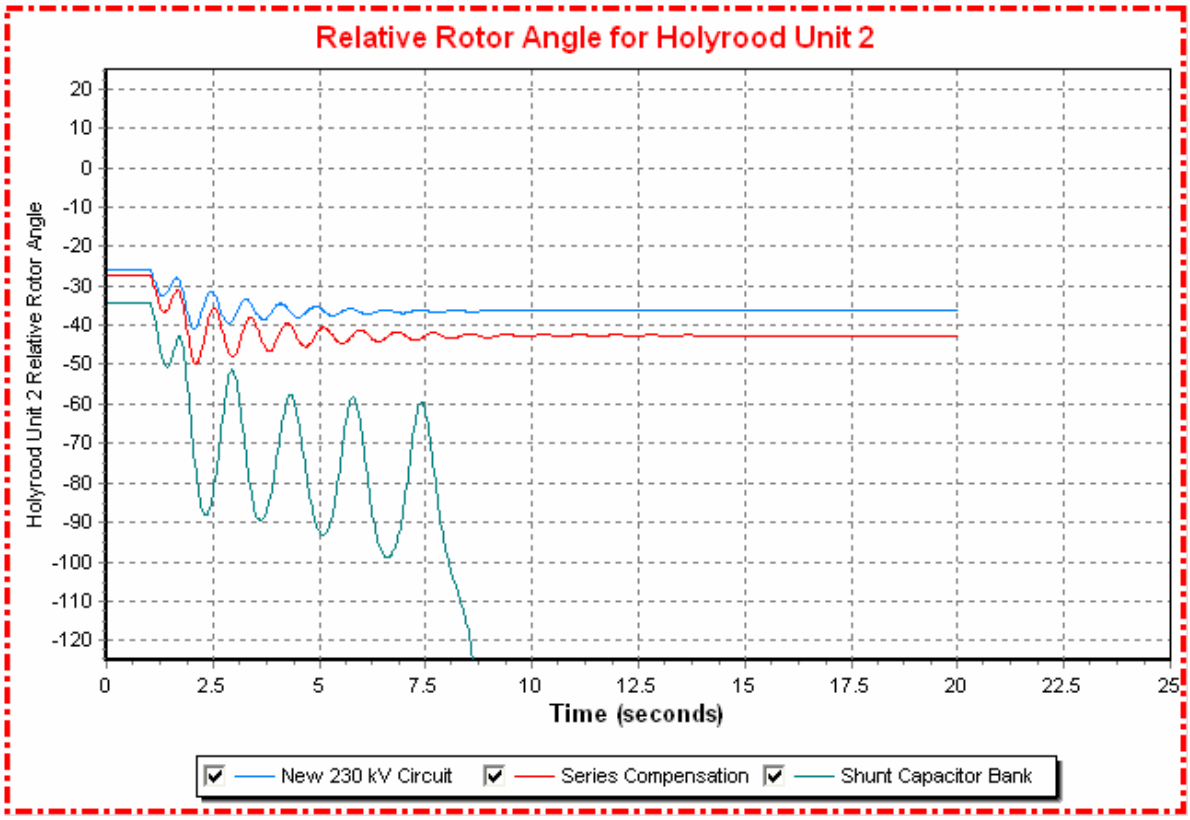


Figure 8 – Angular Stability following SLG Fault on TL202

The blue line in Figure 8 illustrates the post-fault behaviour of the Holyrood unit for the scenario where the transmission system is reinforced with the new 230 kV circuit from Bay d'Espoir to Western Avalon. As indicated, the system demonstrates angular stability as the unit quickly settles to a constant relative rotor angle. A similar result is illustrated by the red line, which demonstrates the angular stability of the system when reinforced with series compensation on TL202 and TL206.

The green line in Figure 8 indicates that the system is highly unstable in a scenario where only shunt capacitor banks are added to the transmission system. Following the fault, the unit at Holyrood would begin to oscillate uncontrollably and would have to be tripped to avoid damage. This situation would then require underfrequency load shedding in an attempt to prevent the collapse of the Island Transmission System. Due to the poor angular stability of this system, a solution involving the addition of a shunt capacitor bank alone would not be an acceptable solution.

Based on the analysis, it is evident that in order to increase the capacity of the Bay d'Espoir East Transmission System, both voltage stability and the angular stability must be improved. As noted, a combination of transmission line reinforcement and reactive support in the form of capacitor banks would provide an optimal solution.

Figure 9 illustrates a scenario involving series compensation on TL202 and TL206 and a new capacitor bank at Come by Chance. As indicated, this system allows for the transfer of 1017 MW to loads east of Bay d'Espoir. It should be noted that at this increased load level, contingencies on TL202, TL206, or TL207 would result in thermal overloading on TL206, TL202, and TL203, respectively. Thermal uprating of these lines are therefore required in this case. For TL202 and TL206, thermal uprating would require the installation of mid-span structures and the modification of terrain in the transmission line right of way. For TL203, uprating would require that the full line (44 km) be re-conductored with 795 kcmil, 26/7 ACSR "DRAKE" with additional mid-span structures or 804 kcmil 54/19 AACSR/TW with additional mid-span structures and modifications to dead-end structures. With the 795 conductor, TL202, TL206, and TL203 will each be rated for a conductor temperature of 75˚C. The 804 conductor option will allow for TL203 to be rated for a conductor temperature of 80˚C.

Total system generation in this case would be in the order of 1485 MW. While this would represent an increase of 235 MW in firm transmission system capacity over the existing

system, this solution would not be adequate to meet capacity requirements beyond 2017. As additional generating capacity would not be added east of Bay d'Espoir until 2022, this solution would not provide an acceptable technical alternative.

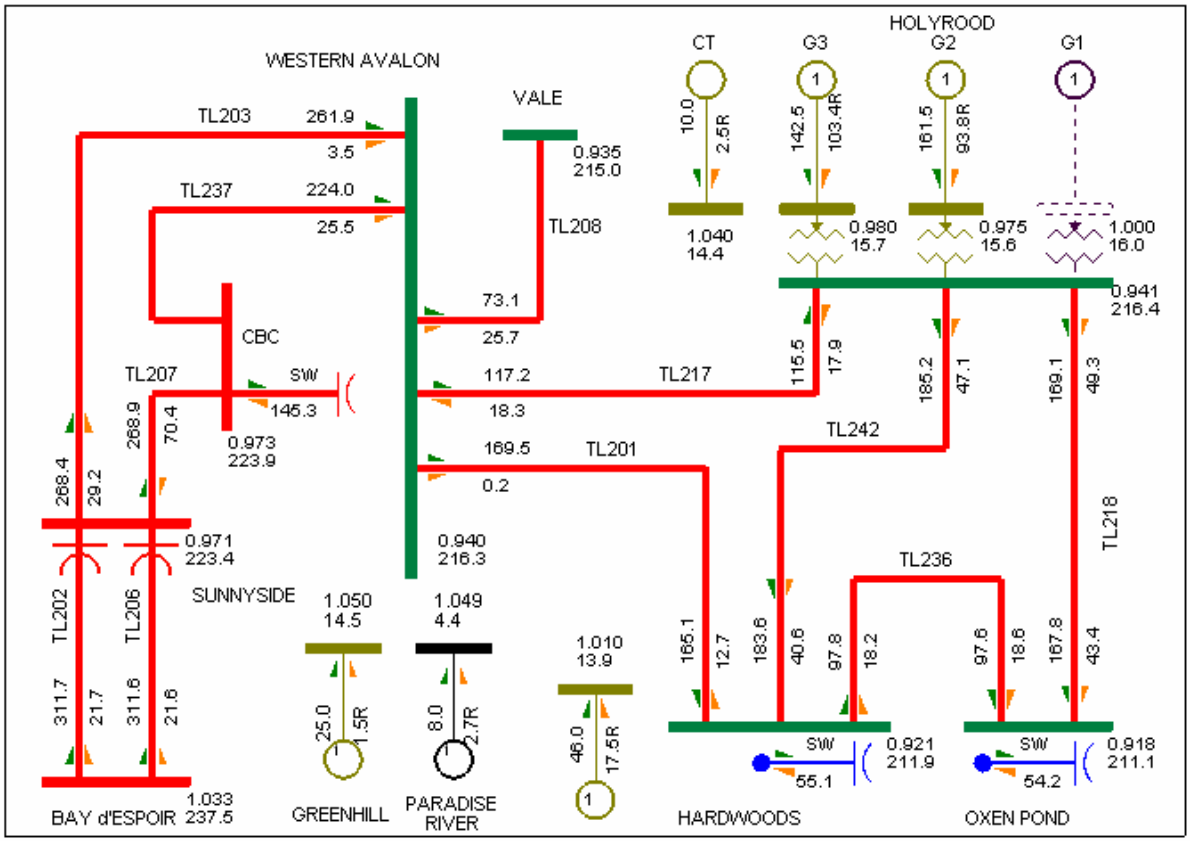


Figure 9 – Series Compensation, Thermal Upgrades, and Capacitor Bank

Loss of Unit 1 at Holyrood

The scenario involving the addition of a new 230 kV transmission line from Bay d'Espoir to Western Avalon and a capacitor bank at Come by Chance is illustrated in Figure 10. In this case, the transmission system is capable of providing firm supply of approximately 1045 MW to loads east of Bay d'Espoir. System generation in the case would be in the order of 1555 MW, which would indicate that these upgrades would increase the firm capacity of the transmission system by 275 MW. The addition of the third line would also allow for the thermal uprating of transmission lines TL202, TL206, and TL203 to be avoided. The alternative also ensures sufficient transmission capacity until 2022, at which point and 170

MW of generation would be available on the Avalon Peninsula following the construction of a new 170 MW CCCT.

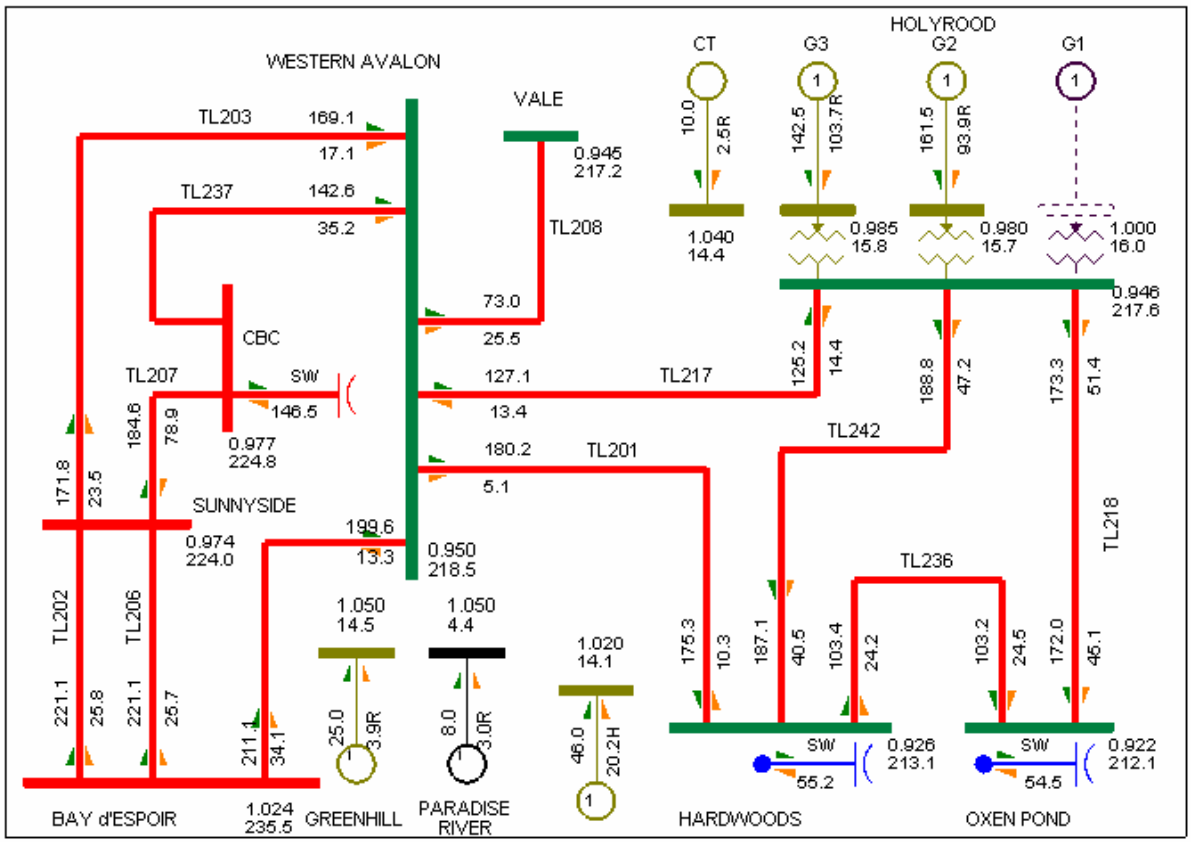


Figure 10 – New 230 kV TL and Capacitor Bank – Loss of Unit 1 at Holyrood

As part of the investigation, solutions involving the increase of the system voltage in the Bay d'Espoir to Western Avalon transmission corridor were also considered. Specifically, analysis was performed involving a new 315 kV line from Bay d'Espoir to Western Avalon.

Results of this analysis indicate that the addition of a transmission line at this voltage would increase in the transfer capacity of the system only slightly beyond the thresholds reached in the previous example. As illustrated in Figure 11, the addition of the 315 kV transmission line would not allow for an appreciable increase in transfer capacity over the case involving a new 230 kV transmission line. Due to reactive power limitations of the system, the

transfer limit of the Bay d'Espoir East Transmission System is limited to 950 MW. Firm total system capacity is therefore limited to approximately 1440 in this case.

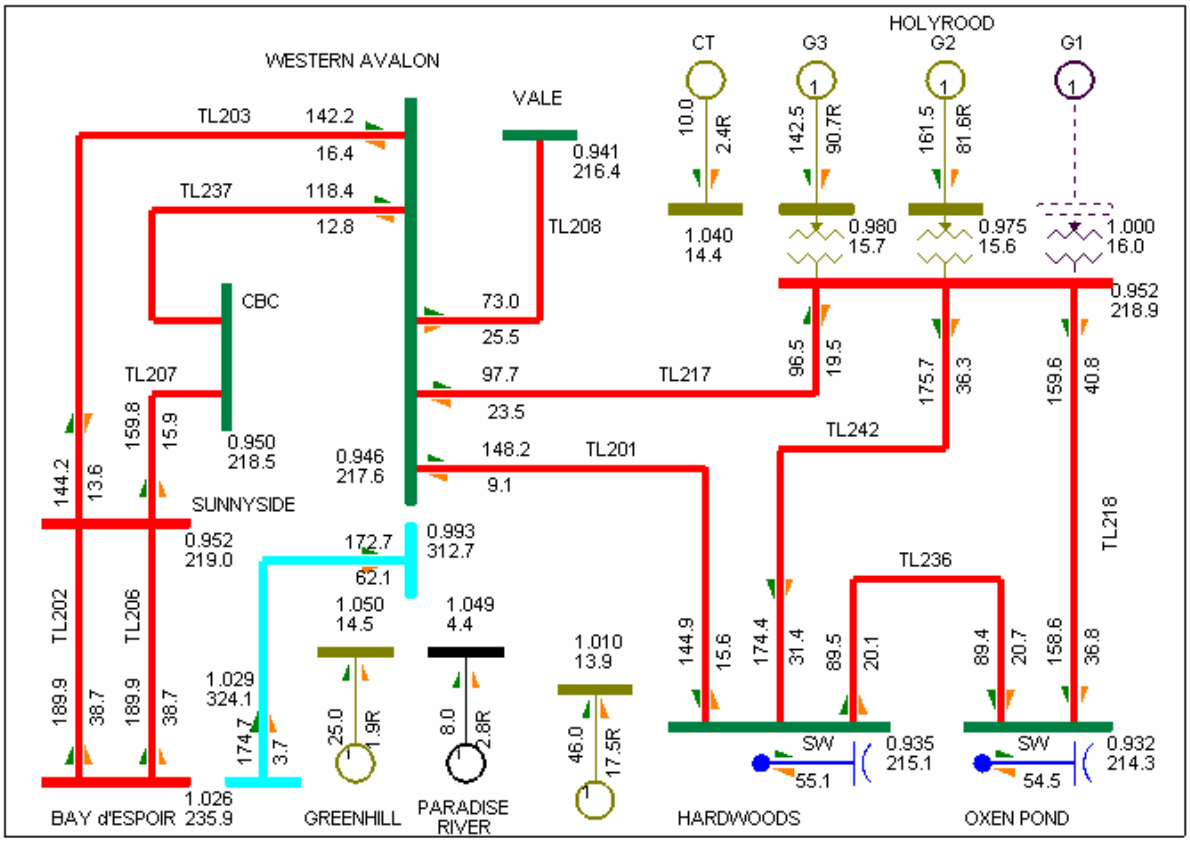


Figure 12 – New 315 kV Transmission Line – Loss of Unit 1 at Holyrood

If a new 315 kV circuit were to be supplemented with a capacitor bank at Come By Chance, approximately 1065 MW to be transferred to loads east of Bay d'Espoir, as illustrated in Figure 12. This would be representation of a loading condition where system generation has reached approximately 1583 MW.

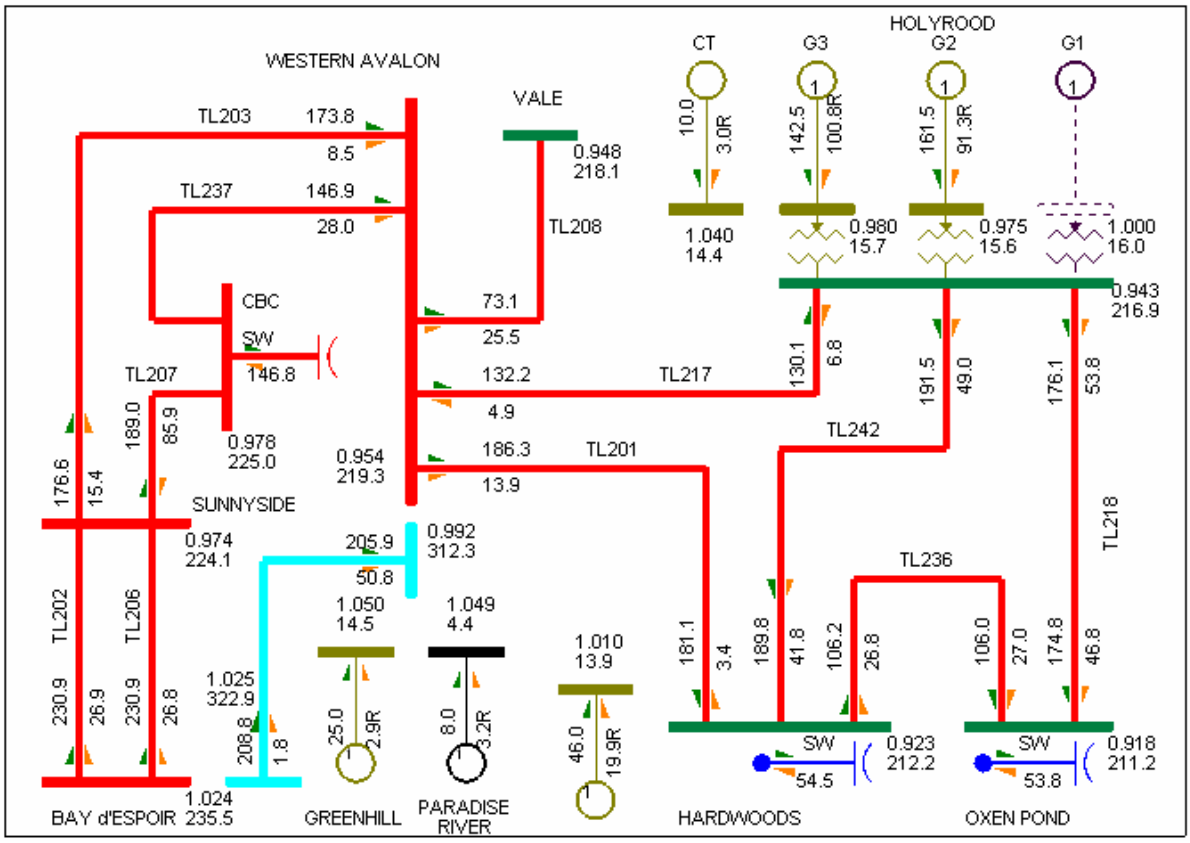


Figure 12 – New 315 kV TL and Capacitor Bank – Loss of Unit 1 at Holyrood

It should also be noted that the establishment of the 315 kV transmission voltage would require fully redundant 230/315 kV transformation at both Bay d'Espoir Terminal Station #2 and Western Avalon Terminal Station, complete with 315 kV circuit breakers and disconnect switches. Such an addition would also require the complete set of terminal station additions described above in Section 2 to permit the interconnection of 315 kV infrastructure to the existing stations. In combining this extensive listing of terminal station upgrades to the increased construction cost of a 315 kV transmission line, this solution would involve an increased capital expenditure without providing a substantial improvement in system capacity beyond those provided by the 230 kV alternatives discussed above.

Based on the results presented, it is concluded that an optimal solution for improving transmission system capacity would involve a combination of transmission line

reinforcement and reactive support. A solution involving only reactive support would not be acceptable due to poor angular stability, while a solution involving only thermal upgrades would not improve system capacity. Reinforcements in the form of series compensation or a new transmission line would therefore be required.

Solutions involving the series compensation do not provide sufficient system capacity beyond 2017 and are not acceptable given that no generation will be added east of Bay d'Espoir until 2022. Therefore, a new transmission line should be constructed from Bay d'Espoir to Western Avalon to meet the 2022 transfer requirement. Both the 230 kV and 315 kV transmission line alternatives were considered. It has been determined that solutions involving 315 kV transmission lines require a significant number of additional system upgrades while only provided marginal improvements in system capacity. Given this result, the construction of a new 230 kV transmission line is found to be the optimal solution for a generation expansion scenario involving the continued Isolated Operation of the Island System.

Labrador Infeed

Under the Labrador Infeed generation expansion scenario the concept includes a 900 MW HVdc transmission system between Muskrat Falls in Labrador and Soldiers Pond on the Avalon Peninsula and a second 500 MW HVdc transmission system between western Newfoundland (Bottom Brook Terminal Station) and Cape Breton, Nova Scotia. The power and energy delivered to the Island from Labrador will displace that generated at the Holyrood Thermal Generating Station. Up to 816 MW will be delivered to the Island over peak. The HVdc system to the Maritimes will operate as an export line under normal operation with power and energy in excess of the Province's needs being sold to the Maritime and New England markets. For loss of the HVdc system between Labrador and the Island, the HVdc link to the Maritimes will be capable of delivering up to 475 MW to the Island in the post contingency period.

As part of the preliminary technical feasibility analysis performed for the Lower Churchill Project, a series of integration studies have included investigations of the upgrades required within the Island Transmission System to ensure reliability and security of supply for the Project. In these studies, many contingencies were investigated. A benchmark case was chosen to assess transient system stability in the event of a three-phase fault near the 230 kV bus at Sunnyside Terminal Station. This three-phase fault was identified as being particularly severe as it would (1) suppress ac system voltages to a point where the HVdc link from Labrador would experience a commutation failure (effectively causing it to shut down during the fault), while (2) impacting the transmission of power from hydroelectric sources to the significant loads in the eastern portion of the province.

Results of the transient stability studies indicate that the system would be able to withstand the three-phase fault at Sunnyside Terminal Station with appropriate system upgrades. The upgrades include the installation of high-inertia synchronous condensers and either:

(1) series compensation on TL202 and TL206; or
(2) a new 230 kV transmission line from Bay d'Espoir to Western Avalon Terminal Station.

Stability plots for the above cases are provide in Figures 13 and 14, respectively.

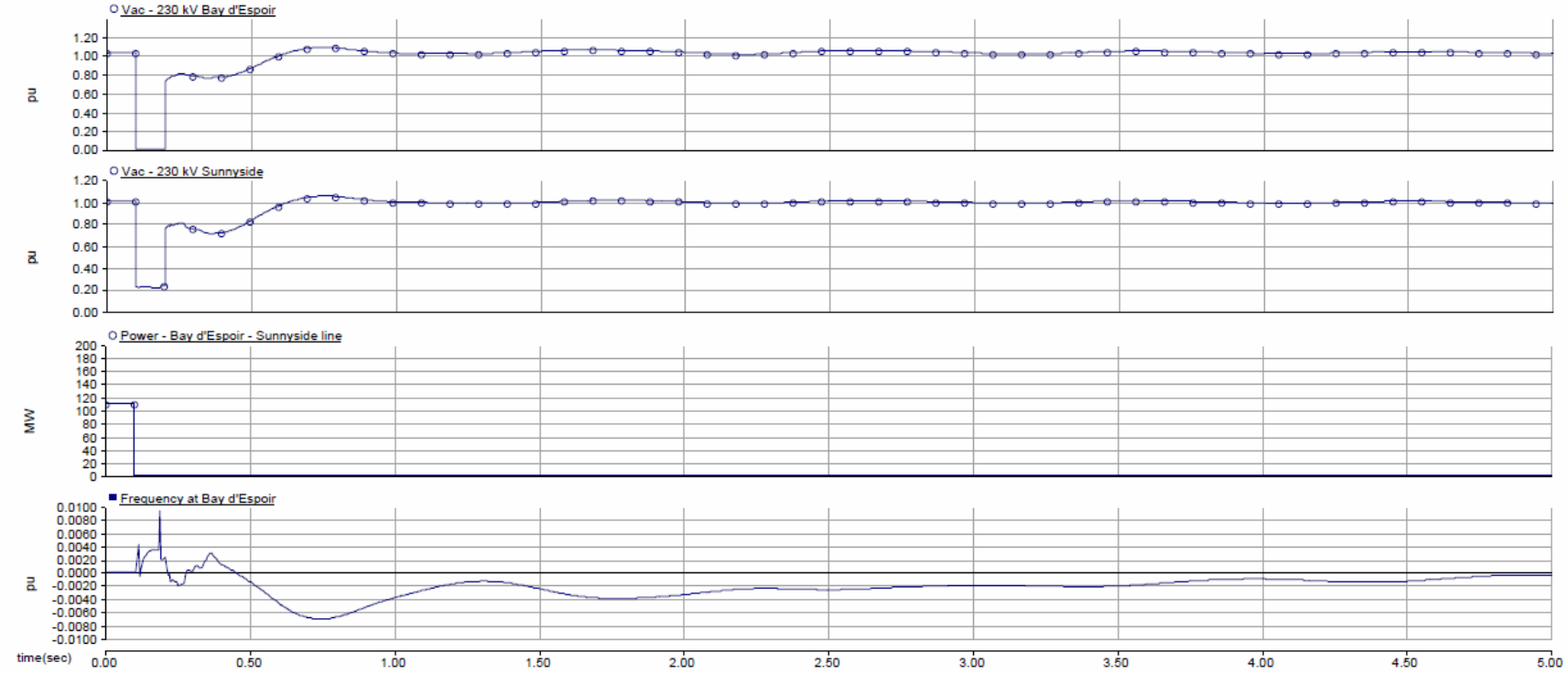


Figure 13 – Stability Plot from DC1210 - HVdc System Sensitivity Analysis
Three-Phase Fault on TL202 – Series Compensation on TL202 and TL206

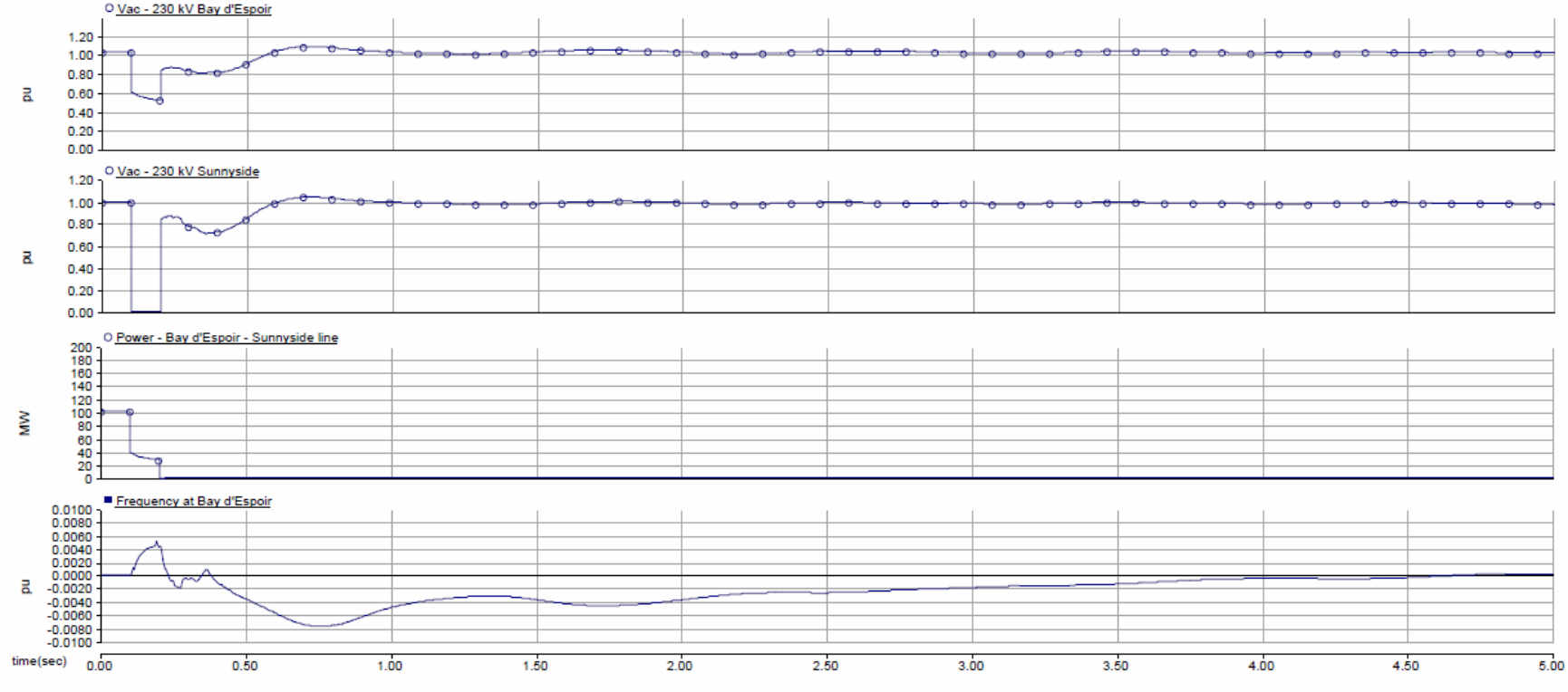


Figure 14 – Stability Plot from DC1210 - HVdc System Sensitivity Analysis
Three-Phase Fault on TL202 – New 230 kV Transmission Line from BDE-WAV

While each of these alternatives ensures transient stability for specified 230 kV system contingencies, the transmission capacity of the Bay d'Espoir to Western Avalon corridor also has a significant impact in a scenario involving the loss of the HVdc link between Labrador and the Island. For this contingency, power will be imported from the Maritimes to supplement the startup of standby generation on the Island.

As in the continued Isolated Operation, Island System upgrades consisting of series compensation for transmission lines TL202 and TL206 will increase the angular stability of the power system, as illustrated in Figure 13. However, unlike the continued Isolated Operation scenario, the Holyrood Thermal Generating Station is not available to provide active power (MW) to the Bay d'Espoir East Transmission System in the Labrador Infeed Scenario. As a result, contingencies involving the loss of the Labrador Infeed would result significant overloading on the transmission lines, and therefore require the thermal uprating of TL202, TL206, and TL203.

Despite these thermal upgrades, analysis has indicated that thermal overloading will occur on TL202 and TL206 following the loss of the HVdc link from Labrador. Figure 15 illustrates the case where all generation on the island is brought online and a full import of 475 MW is received from the Maritimes following the loss of the HVdc link from Labrador. In this case, 1060 MW is being supplied to loads east of Bay d'Espoir. As illustrated, the uprated TL202 and TL206 will be loaded to 107% of their rated limits. This will result in the sagging of the transmission lines beyond Newfoundland and Labrador Hydro's clearance requirements. Such violations are unacceptable as they could lead to potential safety concerns. Analysis indicates that thermal overloads will be experienced on TL202 and TL206 if the import from the Maritimes were to exceed 440 MW.

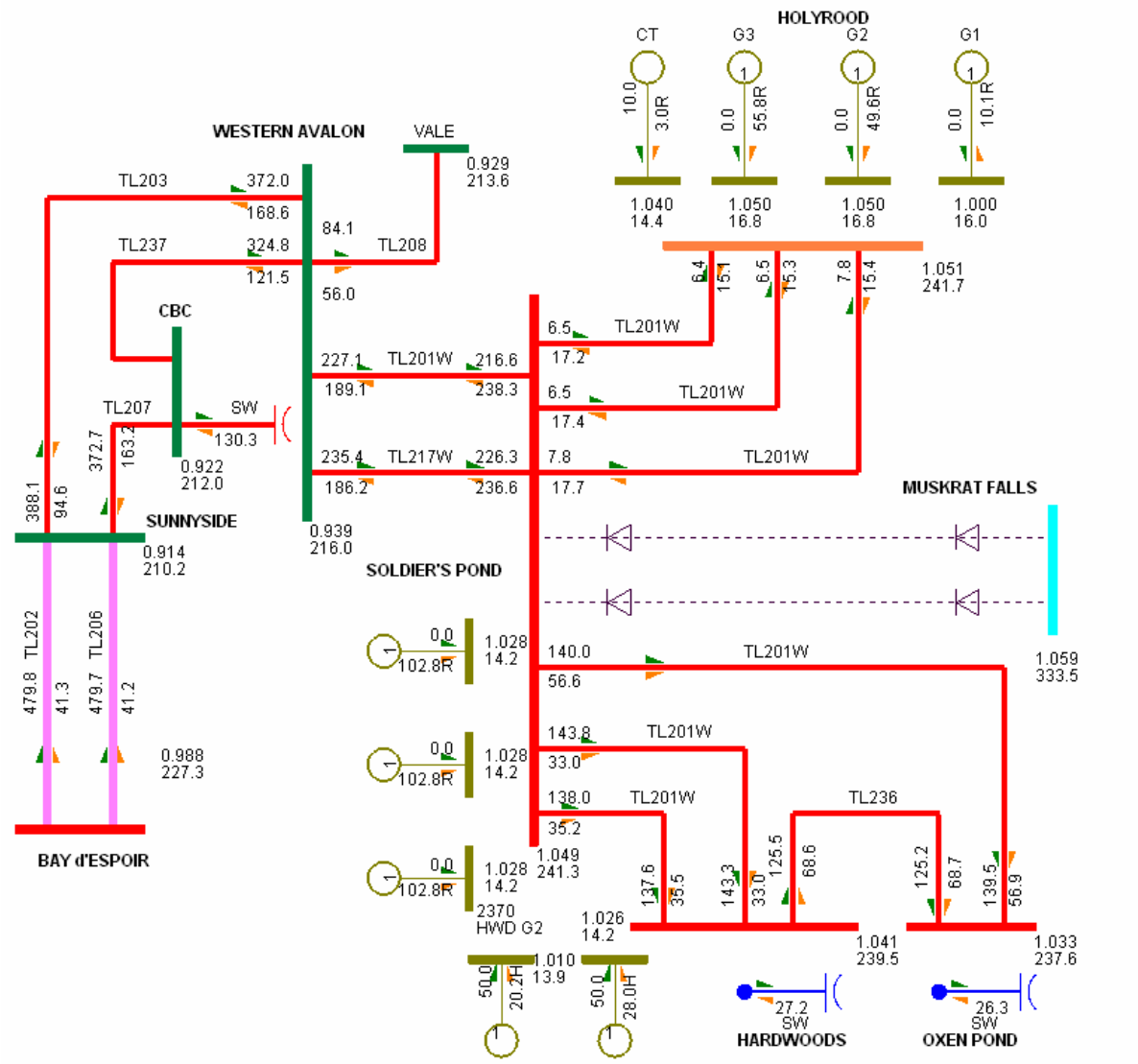


Figure 15 – Thermal Upgrades and Series Compensation – Loss of HVdc Infeed

Figure 16 demonstrates how the addition of the new 230 kV transmission line between Bay d'Espoir and Western Avalon results in the elimination of all transmission line overloads. This solution will allow for firm transmission system capacity in excess of 1600 MW in the event of the loss of the Labrador Infeed without any thermal upgrades to TL202, TL206, or TL203.

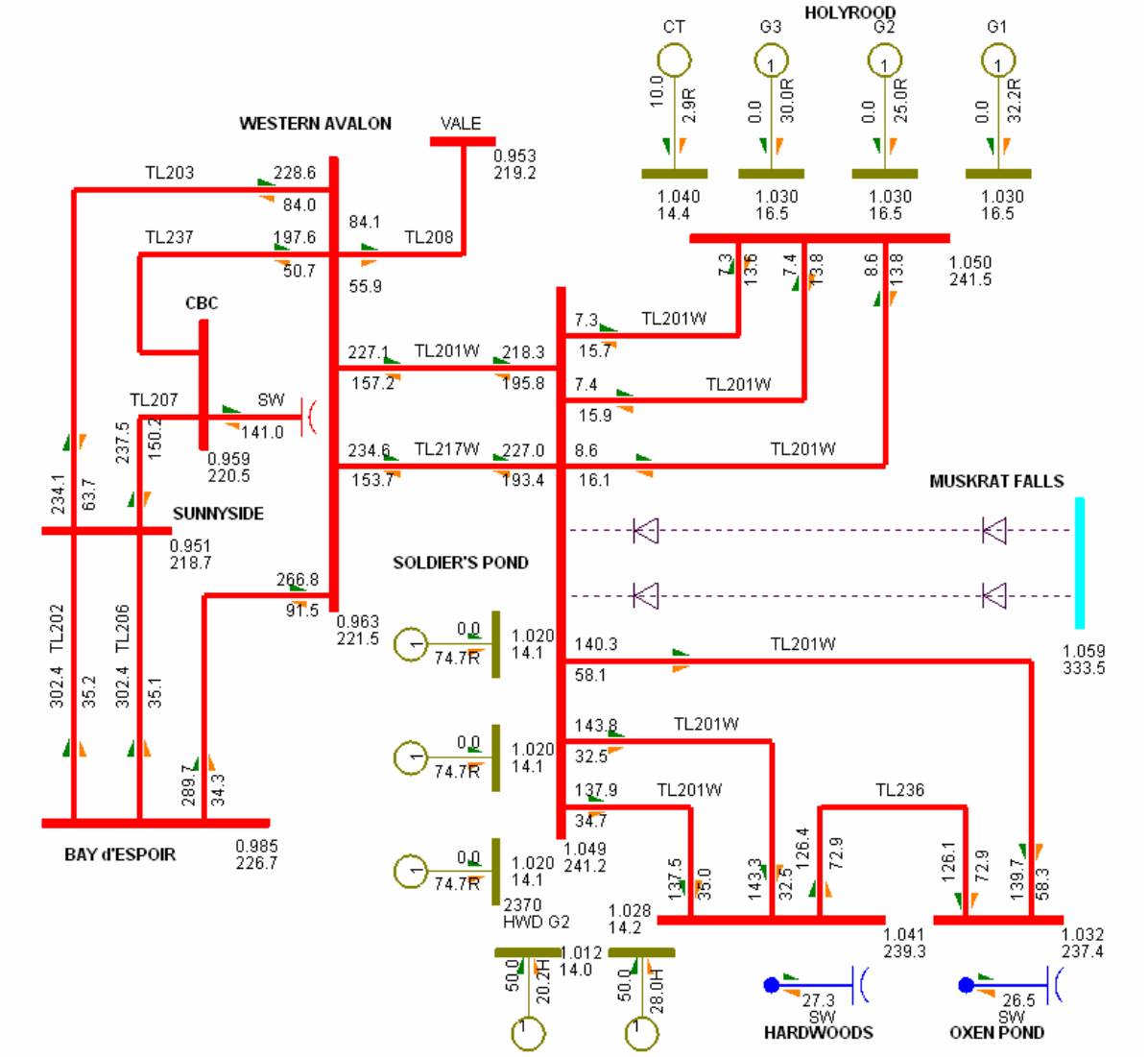


Figure 16 – New 230 kV Transmission Line – Loss of HVdc Infeed

It should be noted that reactive compensation in the form of a 153 Mvar capacitor bank at Come by Chance was included in both of the cases described above. Without this capacitor bank, the system would suffer from low voltage violations in the event of the loss of the Labrador Infeed. This capacitor bank can be considered part of the overall reactive power requirements of the HVdc converter station in this scenario.

Based on the analysis, it is concluded that a new 230 kV circuit from Bay d'Espoir to Western Avalon meets all of the technical requirements for the Labrador Infeed Scenario.

This new circuit ensures transient stability during severe ac contingencies and security of supply in the event of the failure of the HVdc link from Labrador. In order for this transmission line to be in service prior to the proposed HVdc interconnection in 2017, line construction must begin in 2012 as per the five-year project schedule provided in Section 5.2.

Analysis of the thermal upgrades plus 50% series compensation on TL202 and TL206 indicate that the option cannot provide the transfer capacity required to supply the loads east of Bay d'Espoir in the event of the failure of the HVdc link from Labrador.

4.1 Net Present Value

The construction of a new 230 kV transmission line from Bay d'Espoir to Western Avalon Terminal Station is a technical requirement needed to meet the forecasted system loads east of Bay d'Espoir. A complete net present value analysis was not performed as the project is required in both the Labrador Infeed and continued Isolated Operation generation expansion alternatives. As a result of being common to both alternatives, the cost of the project has no relevant impact on overall cumulative present worth.

4.2 Levelized Cost of Energy

The levelized cost of energy is a high level means to compare costs of developing two or more alternative generating sources. Therefore, the levelized cost of energy is not applicable for the project.

4.3 Cost Benefit Analysis

The new 230 kV transmission line from Bay d'Espoir to Western Avalon Terminal Station is a technical requirement needed to meet the forecasted system loads east of Bay d'Espoir. A complete cost benefit analysis was not performed as the project is common to both the

Labrador Infeed and continued Isolated Operation generation expansion scenarios.

4.4 Legislative or Regulatory Requirements

This project is not required to comply with legislation or regulations. The project is required to ensure reliable operation of the power system and to supply forecasted loads east of Bay d'Espoir while adhering to all system planning criteria.

4.5 Historical Information

The proposed project is not routine and is a technical requirement to meet load growth east of Bay d'Espoir for the Labrador Infeed and continued Isolated Operation generation expansion scenarios.

4.6 Forecast Customer Growth

The 2010 Peak Load Forecast for the Newfoundland and Labrador Hydro System is provided in Table 7. This forecast is equal to the 2010 Peak Load Forecast for the Interconnected Island System minus generation from Newfoundland Power and Deer Lake Power.

Based upon the peak system load data presented in Table 1, it is estimated that loads east of Bay d'Espoir will account for approximately 67% of the total system load. These values have been corrected to account for additional load associated with the Vale facility in Long Harbour and also for the reduced system losses in cases involving the construction of a new transmission line from Bay d'Espoir to Western Avalon. This reduction in losses would effectively decrease the required transfer capacity east of Bay d'Espoir.

Table 7 – 2010 Newfoundland and Labrador Hydro System Peak Load Forecast

Year	NLH System Generation (MW)	Required BDE-East Transmission System Capacity (MW)	Required BDE-East Transmission System Capacity (With New TL) (MW)
2011	1320	880	865
2012	1353	903	888
2013	1383	923	908
2014	1448	971	956
2015	1465	998	983
2016	1477	1009	994
2017	1486	1015	1000
2018	1496	1022	1007
2019	1511	1032	1017
2020	1526	1042	1027
2021	1539	1050	1035
2022	1558	1063	1048

4.7 Energy Efficiency Benefits

The new 230 kV circuit significantly increases the transmission capacity east of Bay d'Espoir to and allows for improved efficiency in the operation of generators at Holyrood. This results in reduced fuel consumption and, in turn, may reduce the potential for spill at hydroelectric facilities in a continued Isolated Operation generation expansion scenario. These values require extensive hydrological modeling to be quantified.

4.8 Losses During Construction

There are no anticipated losses during construction.

4.9 Status Quo

A solution involving the status quo would not be acceptable for generation expansion scenarios involving a Labrador Infeed or continued Isolated Operation.

In a generation expansion scenario involving the Labrador Infeed, the existing transmission system must be reinforced to maintain stability in the event of contingencies on the 230 kV system. Upgrades to the Bay d'Espoir East Transmission System are also required to ensure security of supply in the event of contingencies involving the loss of the Labrador Infeed via import from the Maritimes.

For a generation expansion scenario involving continued Isolated Operation, the limitations of the existing transmission system result in an inadequate transfer capacity for loads east of Bay d'Espoir. This is of particular concern as all proposed hydroelectric developments in this scenario are west of Bay d'Espoir.

4.10 Alternatives

Alternatives considered for this project include:

(1) Performing thermal upgrades on TL202, TL206 and TL203;
(2) Installing series compensation on TL202 and TL206;
(3) Constructing a new 230 kV transmission line from Bay d'Espoir to Western Avalon Terminal Station;
(4) Installing shunt capacitor banks;
(5) Performing thermal upgrades on TL202, TL206 and TL203, installing series compensation on TL202 and TL206, and installing shunt capacitor banks;
(6) Constructing a new 230 kV transmission line from Bay d'Espoir to Western Avalon Terminal Station and installing shunt capacitor banks;
(7) Adding a 315 kV transmission line ; or

(8) Adding a 315 kV transmission line and installing shunt capacitor banks.

Based upon the analysis in Section 4, a new 230 kV transmission line from Bay d'Espoir to Western Avalon Terminal Station (supplemented with reactive support in the form of shunt capacitor banks) is the preferred alternative for generation expansion scenarios involving both the Labrador Infeed and continued Isolated Operation.

5 CONCLUSION

It is recommended that a new 230 kV transmission line be constructed from Bay d'Espoir to Western Avalon Terminal Station. This upgrade is required to ensure the security of supply for loads east of Bay d'Espoir in generation expansion scenarios involving both a Labrador Infeed and a continued Isolated Operation. Budget Estimate

Table 8 - Budget Estimate

Project Cost: *($ x1,000)*	**2012**	**2013**	**2014**	**2015**	**2016**	**TOTAL**
Material Supply	0.0	14,288.8	13,645.0	18,465.5	1,677.5	48,076.8
Labour	2,042.0	2,330.0	2,288.0	2,502.0	2,973.1	12,135.1
Consultant	242.6	247.8	0.0	0.0	0.0	490.4
Contract Work	0.0	10,409.0	22,615.6	24,700.0	21,674.5	79,399.1
Other Direct Costs	165.1	181.2	205.0	273.0	340.1	1,164.4
Interest and Escalation	182.2	2,738.6	7,771.4	17,258.4	26,033.4	53,984.0
Contingency	0.0	0.0	0.0	0.0	14,126.5	14,126.5
	2,631.9	**30,195.4**	**46,525.0**	**63,198.9**	**66,825.1**	**209,376.3**

5.2 Project Schedule

Table 9 - Project Schedule: Year 1 - 2012

Activity		Start Date	End Date
Insulator Testing	• Perform Testing of NEMA insulators	Apr. 2012	Aug. 2012
Planning	• Determine Outage Schedule (as Required) • Survey TL Corridor and Terminal Stations	Jan. 2012 Jun. 2012	Mar. 2012 Aug. 2012
Design	• Preliminary Design, Structure Layouts	Apr. 2012	Aug. 2012
Procurement	• Tendering and Award	Apr. 2012	Nov. 2012
Construction	• Environmental Assessment and Draft Results	Jun. 2012	Aug. 2012
Commissioning	• Environmental Assessment Final Report	Nov. 2012	Nov. 2012
Closeout	• Update Design Data	Dec. 2012	Dec. 2012

Table 9 (Continued) - Project Schedule: Year 2 - 2013

Activity		Start Date	End Date
Planning	• Determine Outage Schedule as Required	Jan. 2013	Mar. 2013
Design	• Electrical/Civil/T&D Design for BDE TS	Feb. 2013	Jul. 2013
Procurement	• Tender and Award • Electrical Equipment Delivery	Feb. 2013 Mar. 2013	Oct. 2013 Dec. 2013
Construction	• Civil Earthworks • Transmission Line Construction	Apr. 2013 June 2013	Oct. 2013 Dec. 2013
Commissioning	• Review Civil/Transmission Earthworks	Nov. 2013	Nov. 2013
Closeout	• Update Design Data	Dec. 2013	Dec. 2013

Table 9 (Continued) - Project Schedule: Year 3 - 2014

Activity		Start Date	End Date
Planning	• Determine Outage Schedule as Required	Jan. 2014	Mar. 2014
Design	• Electrical Design	Feb. 2014	Jun. 2014
Procurement	• Electrical Equipment Delivery	Jan. 2014	Dec. 2014
	• Structure Steel Delivery	Jan. 2014	Apr. 2014
	• Electrical Construction Tender and Award	Apr. 2014	Sep. 2014
Construction	• Electrical Construction	Apr. 2014	Oct. 2014
	• Civil Transmission Line Construction	Apr. 2014	Nov. 2014
Commissioning	• Review Civil/Transmission Earthworks	Nov. 2014	Nov. 2014
	• Electrical Equipment		
Closeout	• Update Design Data and Documents	Dec. 2014	Dec. 2014

Table 9 (Continued) - Project Schedule: Year 4 - 2015

Activity		Start Date	End Date
Planning	• Determine Outage Schedule as Required	Jan. 2015	Mar. 2015
Design	• Design Modifications	Apr. 2015	Nov. 2015
Procurement	• Electrical Equipment Delivery	Jan. 2015	Sep. 2015
Construction	• Electrical Construction • Transmission Line Construction	Apr. 2015 Apr. 2015	Oct. 2015 Nov. 2015
Commissioning	• Review TL Construction • Electrical Equipment	Nov. 2015	Nov. 2015
Closeout	• Update Design Data and Documents	Dec. 2015	Dec. 2015

Table 9 (Continued): Project Schedule: Year 5 - 2016

Activity		Start Date	End Date
Planning	• Determine Outage Schedule as Required	Jan. 2016	Mar. 2016
Design	• Design Modifications	Apr. 2016	Nov. 2016
Procurement	• P&C/Telecontrol Equipment	Jan. 2016	Mar. 2016
Construction	• Transmission Line Completion • P&C/Telecontrol Installation	Apr. 2016 Apr. 2016	Sept. 2016 Oct. 2016
Commissioning	• System Commissioning	Nov. 2016	Nov. 2016
Closeout	• Update Design Data and Documents	Dec. 2016	Dec. 2016

Project Title: Upgrade Transmission Line Corridor

Location: Bay d'Espoir to Western Avalon

Category: Transmission and Rural Operations - Transmission

Definition: Other

Classification: Normal

Project Description:

This proposal describes the upgrade to the transmission line corridor from Bay d'Espoir to Western Avalon Terminal Station. These upgrades will consist of a testing program on insulators for TL206, as well as the construction of a new 230 kV transmission line. These upgrades are requirements to ensure the security of supply to growing loads east of Bay d'Espoir. These upgrades will be required for generation expansion scenarios involving either a Labrador Infeed or continued Isolated Island operation. The new transmission line will be 188 km in length from Bay d'Espoir to Western Avalon and will require terminal station modifications at each end.

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2012**	**2013**	**Beyond**	**Total**
Material Supply	0.0	14,288.8	33,788.0	48,076.8
Labour	2,042.0	2,330.0	7,763.1	12,135.1
Consultant	242.6	247.8	0.0	490.4
Contract Work	0.0	10,409.0	68,990.1	79,399.1
Other Direct Costs	165.1	181.2	818.1	1,164.4
Interest and Escalation	182.2	2,738.6	51,063.2	53,984.0
Contingency	0.0	0.0	14,126.5	14,126.5
TOTAL	**2,631.9**	**30,195.4**	**176,549.0**	**209,376.3**

Operating Experience:

Hydro identified that the transfer of power to load centres east of Bay d'Espoir is constrained as a result of the thermal limitations of the transmission lines and the voltage stability of the power system. As a result, Newfoundland and Labrador Hydro must operate units at the Holyrood Thermal Generating Station in an inefficient manner, resulting in increased fuel consumption and increased spill at hydroelectric facilities.

APPENDIX C2 – DC1020 VOLUME 1 - HVDC SYSTEM INTEGRATION STUDY – MAY 2009

HYDRO
THE POWER OF COMMITMENT

THE Lower Churchill PROJECT

May 2008

DC1020 - HVdc System Integration Study
Volume 1 - Summary Report

prepared by

HATCH™

in association with

RSW inc.

Statnett

TGS TransGrid Solutions

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PETER KUFFEL
SIGNATURE
May 27/08
DATE
NEWFOUNDLAND & LABRADOR

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Executive Summary

Introduction

Newfoundland and Labrador Hydro (Hydro) is planning to install a three-terminal HVdc system linking Labrador, Newfoundland, and New Brunswick. The proposed HVdc system will be bipolar, with each converter station having the ability to run as either rectifier or inverter. It will involve cable and overhead line, with about 40 km of cable between Labrador and Newfoundland and about 480 km between Newfoundland and New Brunswick. The proposed HVdc system is conceptually shown in Figure 1.

This report presents a summary of all work undertaken as part of the WTO DC1020 HVdc System Integration Study. It provides a summary of the individual study tasks completed followed by an overall discussion of results and conclusions.

The principal objectives of the HVdc System Integration Study were to:

- Demonstrate the feasibility of a multi-terminal HVdc link connecting Labrador, Newfoundland, and New Brunswick given the requirements of the Newfoundland system.
- Determine the system additions required for integrating the proposed three-terminal HVdc system into the Labrador and Newfoundland systems. Although basic consideration was given to integration into the New Brunswick system, the study concentrated on the Labrador and Newfoundland systems. A separate system impact study will be performed by the New Brunswick system operator to assess the requirements in New Brunswick.
- Determine the limitations of the proposed HVdc system.
- Determine feasible mitigation steps to ensure that the integrated system performs in an acceptable manner.
- Ensure that the integrated system design minimizes the need for load shedding in Newfoundland.

The major study tasks conducted as part of the overall WTO DC 1020 HVdc System Integration Study included:

- Power flow and short circuit analysis.
- Comparison of the performance of conventional and Capacitor Commutated Converter (CCC) HVdc technologies.
- Transient stability analysis.
- Cursory evaluation of alternate HVdc configurations.
- Development of a multi-terminal HVdc model for future PSSE studies.

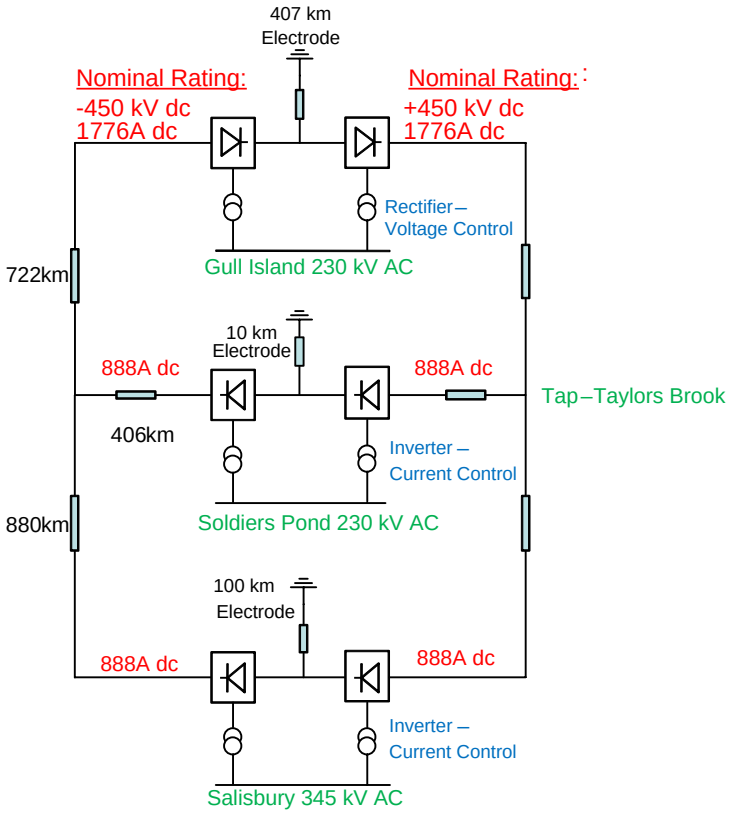
In order to complete the work and provide Hydro with results in a timely and efficient manner, a series of interim reports were submitted to Hydro for review and approval upon completion of the major study tasks identified within the WTO. The following interim reports have been previously submitted to Newfoundland and Labrador Hydro for review and approval.

- DC1020 HVdc System Integration Study – Power Flow and Short Circuit Analysis Interim Report
- DC1020 HVdc System Integration Study - Comparison of Conventional and CCC HVdc Technology Interim Report
- DC1020 HVdc System Integration Study – Transient Stability Analysis Interim Report
- DC1020 HVdc System Integration Study – Cursory Evaluation of Alternate HVdc Configurations Interim Report
- DC1020 HVdc System Integration Study – Multi-Terminal HVdc Link PSSE Stability Model Interim Report

These reports are submitted as separate volumes to this summary report.

Proposed Multi-Terminal HVdc System Description

The basic configuration of the proposed multi-terminal HVdc system is shown in the figure below.



Basic Configuration of the HVdc Transmission System

Salient points of the proposed multi-terminal HVdc system include:

- Nominal converter ratings:
  - ♦ Gull Island (Labrador) 1600 MW
  - ♦ Soldiers Pond (Newfoundland) 800 MW
  - ♦ Salisbury (New Brunswick) 800 MW
- The converters at Soldiers Pond and Gull Island have special overload requirements when operating in monopolar as follows:
  - ♦ Gull Island 1.5 pu for 10 minutes and 1.25 pu continuous on a per pole basis
  - ♦ Soldiers Pond 2.0 pu for 10 minutes and 1.5 pu continuous on a per pole basis

  The Soldiers Pond converter overload capability is meant to allow for the startup of generation on the Island of Newfoundland to avoid load shedding in case of pole loss when operating as an inverter.

  The converter at Salisbury has a typical overload requirement of 10% continuous.
- The HVdc operating voltage is 450 kV (defined at the rectifier).
- The selected route includes two cable sections as follows:
  - ♦ 40 km across Strait of Belle Isle
  - ♦ 480 km across Cabot Strait
- Although the normal operating configuration would have Gull Island operating as a rectifier and Soldiers Pond and Salisbury operating as inverters, all converters must be capable of operating both as a rectifier and as an inverter.
- The HVdc system must be able to operate with any two of the three converters in operation.
- The HVdc in-feed into Soldiers Pond will provide frequency control for the Newfoundland Island ac system. Frequency control is provided with Soldiers Pond operating as an inverter or as a rectifier.

As the HVdc conductor optimization and route selection was not finalized prior to carrying out the HVdc system integration study, the conductor type, geometry and line lengths used in the studies were based on the preliminary data available at the time. Although final transmission line and cable parameters may differ from those used in this study, the overall impact on results should be minimal, therefore the results obtained in this study will be valid.

The HVdc parameters used in this study are preliminary values based on typical industry practice and are subject to change during later phases of more detailed design such as the pre-specification studies. Current normal industry practice is to supply a single twelve pulse valve group per pole at each station for HVdc transmission systems with power ratings similar to that being considered. Each twelve pulse valve group is connected to the ac system either through two three phase, two winding, converter transformers or three, single phase, three winding converter transformers to provide the necessary wye:wye and wye:delta connections.

The proposed multi-terminal HVdc system included a number of key technical challenges related to the HVdc system, including:

- Multi-terminal configuration – Although multi-terminal HVdc has been used in the past, detailed information on actual control systems in service is not readily available; therefore, considerable effort was required to develop and implement the overall control-system concepts.
- Long HVdc cable – Although two-terminal HVdc systems with undersea cables are in operation, the length of the cable section across the Cabot Strait is considerably longer than any systems currently in operation. (Note that there are currently a number of HVdc links under design or construction with cable lengths similar to that of the LCP.) The length of the undersea cable (and hence the cable capacitance) has a dramatic impact on the overall performance of the HVdc link and must be accounted for in the design of the control system. Furthermore, the length of cable, coupled with the multi-terminal configuration, added yet another dimension to the requirements of the control system.
- Significance of the HVdc infeed to the Newfoundland ac system – Since the HVdc infeed represents a significant portion of the generation on the Island of Newfoundland, performance of the HVdc system is key to the overall stability of the Newfoundland ac system. This requirement puts added complexity on the control system.
- The requirement to operate each station in rectifier or inverter mode adds complexity to the overall control system.

Newfoundland AC System

All ac system conditions considered in the study were based on year 2016. The year 2016 and future peak Newfoundland Island power flow cases considered have several significant modifications when compared to the system existing today.

1. A new large refinery load (175 MW, 85 MVAr) is planned to be in service near Pipers Hole, between Bay d'Espoir and Sunnyside. As well, a nickel smelter load (83 MW, 40 MVAr) is planned for the Long Harbour area. The internal Hydro studies for the additions of these loads have not yet been completed; therefore it is expected that system impacts due to the loads will be observed in this HVdc feasibility study.
2. Hydro is planning to convert units #1 to #3 at Holyrood to synchronous condensers as part of the Lower Churchill Project for voltage control and in support of the system short circuit level with the following ratings:
    i) Unit #1 – 142/-72 MVAr
    ii) Unit #2 – 142/-72 MVAr
    iii) Unit #3 – 150/-69 MVAr
3. Hydro is planning to install five 50 MW combustion turbines (CT) to meet load requirements between 2010 and the HVdc 2015 in-service date. These CTs will be specified with the capability to operate in synchronous condenser mode. Initial indications were that these CTs would be located at the Holyrood station.

The major Hydro Island load centre is located east of Bay d'Espoir on the Avalon Peninsula, while the majority of the generation is located west of Bay d'Espoir. This can result in heavy west to east power flow on the 230 kV transmission system, in particular between Bay d'Espoir, Sunnyside, Western Avalon and Soldiers Pond. In addition, approximately 255 MW of new industrial load (refinery and smelter) is planned to be installed along this heavily loaded west to east corridor, which serves to increase the loading on these 230 kV lines. As a general result this can cause voltage depression and thermal overloading in the area. The HVdc infeed into Soldiers Pond will normally be operated as an inverter and generally has a positive impact on the Island transmission system as it off-loads this west to east power flow by injecting power closer to the load centre.

Many of the issues observed are not necessarily due to the HVdc infeed but are due to the lack of transmission linking the generation in the west to the load in the east.

Effective Short Circuit Ratio (ESCR) Considerations

Beyond the basic consideration of power transfer, there are a number of ways which the dc and associated ac systems interact at the converter stations. As the strength of the ac system reduces, both in normal operation and as a result of contingencies, certain interactions tend to become more pronounced. These interactions include:

- Recovery from ac and dc Faults: For acceptable performance it is required that the dc system should recover from ac or dc faults without subsequent commutation failures. As a general guide, recovery to 90% of pre-disturbance power transfer within 100 to 300ms is desirable. As the Short Circuit Level (SCL) of the ac systems decreases, the effects of magnetizing inrush currents can become more pronounced, resulting in a slower recovery. Attempting to increase the speed of recovery can sometimes lead to the dc system drawing excessive reactive power from the ac network, resulting in a prolonged depression of the ac network voltage, particularly as the Short Circuit Ratio (SCR) of the ac systems decreases.
- Temporary Overvoltages: Temporary ac system overvoltages can occur at the dc terminals due to converter blocking, ac fault inception and clearing, dc faults, and other disturbances. The severity of these overvoltages increases as the SCR of the ac systems decreases.

  While it may be an issue for ac systems with higher SCRs also, the capacitive shunt compensation at the converter bus and the relatively high system inductance for low SCR ac systems typically results in a parallel resonance at second harmonic. Such a resonance can result in harmonic voltages which are substantial relative to the magnitude of the fundamental during disturbances.
- Commutation Failures: It is a general requirement that the converter does not experience commutation failures for frequently occurring changes in the associated ac systems such as small voltage and phase deviations. As the SCR decreases the likelihood of commutation failures occurring increases.
- Converter Reactive Power Element Switching: As the SCR decreases the voltage sensitivity to changes in the reactive power increases and creates the potential for voltage changes within the ac network in the vicinity of the converter station when reactive power elements are switched.
- System Inertia: In addition to characterizing the ac system as having sufficient SCR, it is also necessary to consider the overall inertia of the system. In cases where overall system inertia is low, synchronous compensators can be used to increase the system SCR and help maintain ac system voltage and frequency.

Effective short circuit ratio (ESCR) is defined as follows:

ESCR = (Short circuit MVA at AC bus – MVA rating of filters)/Rated DC power

The CIGRE Guide for Planning DC Links Terminating at AC System Locations Having Low Short Circuit Capacities identifies the following categories of ESCR:

High	ESCR > 2.5
Low	2.5 > = ESCR > = 1.5
Very Low	ESCR < 1.5

Based on industry experience it can be stated that low or very low SCR in itself is not a technical limitation in the evaluation of an HVdc transmission option, but it must be recognized that decreasing SCR (and ESCR) results in overall decreased performance of the interconnected ac/dc systems. The effects of reducing ESCR on overall performance becomes even more pronounced for long HVdc cables. As such, it was recommended that a minimum ESCR of 2.5 for the inverter ac systems be maintained.

Power Flow and Short Circuit Analysis

This study task included the steady state analysis portion of the WTO DC1020 HVdc System Integration Study including the power flow and short circuit studies. The purpose of the steady state analysis was to determine new facilities including steady state reactive power requirements and upgrades to existing facilities that are required within the Hydro transmission system in order to interconnect the 800 MW HVdc link while ensuring that the Hydro criteria for acceptable power system operation is maintained.

At the time of this study, it was assumed that the nominal HVdc operating voltage would be 500 kV. Subsequent to the completion of the study it was recommended in WTO 1010 that the nominal HVdc operating voltage should be 450 kV and not 500 kV. Although this change in HVdc voltage will affect the losses of the HVdc system it will not have a significant impact on the overall findings of the Power Flow and Short Circuit Analysis and therefore the results obtained in this study are still valid.

Comparison of Conventional and Capacitor Commutated Converter (CCC) HVDC Technology

Following completion of the Power Flow and Short Circuit Analysis, transient stability analysis to determine the dynamic performance of the interconnected ac/dc systems was undertaken. Initial findings of the transient stability analysis showed that for the 1600 MW load base-case, with the HVdc operating in bipolar mode with 800 MW in-feed into Newfoundland, performance of the interconnected ac/dc system was worse than expected.

Based on the initial results obtained and discussions with Hydro, it was recommended to, and approved by Hydro, that a more comprehensive comparison of the performance of conventional and Capacitor Commutated Converter (CCC) HVdc technology should be undertaken in order to evaluate the potential benefits. This comparison would form the basis for a recommendation of which configuration should be used for the transient stability studies.

Conventional HVdc technology offers efficient, reliable and economical operation, however it has a number of notable drawbacks as follows:

- If the commutation of current in an inverter from one valve to the next is not completed before the line to line voltage driving the commutation changes sign, a commutation failure occurs. In practise, the thyristors require a finite time following the end of the conduction period in order to re-gain the ability to block forward voltages, therefore the valves must be fired sufficiently early ahead of the line to line voltage zero crossings. Successful commutation therefore depends on the ac system voltage, and disturbances in the ac system voltage can result in commutation failures. Disturbances in ac system voltage become more pronounced when the inverter is operated in a weak ac system, hence there is an increased susceptibility to commutation failures in inverters operating with weak ac systems.
- The conventional arrangement presents a special problem with long HVDC cables since any reduction of the inverter bus voltage causes a corresponding decrease in dc voltage and thus an increase in dc current because of the cable capacitance discharge. The sudden increase in dc current in turn causes the extinction angle gamma to decrease, which increases the probability of commutation failures.
- The demand for reactive power, which is typically about 0.5 pu of the rated active power must be supplied by shunt reactive power elements at the converter or from the ac system itself.

The capacitive commutated converter has the potential to mitigate these drawbacks.

This study task therefore included a preliminary transient stability study to evaluate the dynamic performance of the Newfoundland system with the application of conventional and CCC HVdc technology for the Lower Churchill Project. New Island ac system facilities, upgrades to the existing Island ac system, and potential special protection systems such as cross-tripping of loads required to maintain system stability and provide acceptable system voltage recovery following normal-clearing three-phase faults and slow-clearing single line-to-ground faults were identified for both technologies.

Upgrades within the Newfoundland ac system identified and recommended in the Power Flow and Short Circuit Analysis task formed the basis of the Newfoundland ac system used in the comparison of conventional and CCC HVdc technology study.

While PSSE is an industry standard for transient stability analysis, some aspects of the multi-terminal HVdc models that are associated with the software were incompatible with the requirements of this study. The power flow model is restricted in the control modes available, and the stability model requires extensive response data that can be obtained only from other sources, such as detailed simulation. Therefore, the primary tool used for this study was the PSCAD electromagnetic transients simulation software.

Transient Stability Study

Following completion of the Comparison of Conventional and CCC HVdc Technology, the full transient stability study for the proposed Lower Churchill multi-terminal HVdc project was completed in order to demonstrate the feasibility of the interconnection given the ac systems in Labrador, Newfoundland, and New Brunswick and the requirements of the Newfoundland ac system. Potential stability issues were investigated along with system upgrades required in the Newfoundland ac system to support the HVdc in-feed. A number of ac system configurations, HVdc system configurations, and contingencies were investigated in order to determine the performance of the overall interconnected ac/dc systems, with the primary focus of the study being the performance of the Newfoundland ac system and the impact of the HVdc in-feed. Consideration was also given

to limitations of the proposed HVdc system and feasible mitigation steps to ensure that the integrated systems perform in an acceptable manner.

Upgrades to the Newfoundland ac system recommended in the Comparison of Conventional and CCC HVdc Technology Study formed the basis of the ac system model for this study.

Similar to the Comparison of Conventional and CCC HVdc Technology Study, the Transient Stability Study was conducted using the PSCAD electromagnetic transients software.

Cursory Evaluation of Alternate HVdc Configurations

The HVdc system configuration considered in the WTO DC1020 HVdc System Integration Study is a three-terminal, bipolar HVdc system linking Labrador, Newfoundland, and New Brunswick. All studies conducted within the WTO DC1020 HVdc System Integration Study considered this proposed multi-terminal HVdc system configuration. A cursory evaluation of alternate HVdc configurations was performed as a separate task within the overall WTO DC 1020 HVdc System Integration Study.

The configurations considered were as follows:

- Base case: A three-terminal HVdc link connecting Gull Island, Soldiers Pond and Salisbury. This alternative was the main focus of the system integration studies.
- Alternative 1: A two-terminal HVdc link connecting Gull Island to Soldiers Pond and another two-terminal HVdc link connecting Soldiers Pond to Salisbury.
- Alternative 2: A two-terminal HVdc link connecting Gull Island to Soldiers Pond and another two-terminal HVdc link connecting Gull Island to Salisbury.
- Alternative 3: A two-terminal HVdc link connecting Gull Island to Taylors Brook and another two-terminal HVdc link connecting Taylors Brook to Salisbury, in conjunction with new ac transmission from Taylors Brook to Soldiers Pond.
- Alternative 4: A two-terminal HVdc link connecting Gull Island to Soldiers Pond and another two-terminal HVdc link connecting Taylor Brook to Salisbury, in conjunction with new ac transmission from Taylors Brook to Soldiers Pond.
- Alternative 5: Three two-terminal HVdc links; one connecting Gull Island to Taylors Brook, one connecting Taylors Brook to Salisbury and one connecting Taylors Brook to Soldiers Pond.

The alternatives were compared in terms of the cost of the converter terminals, length of the overhead lines and cables, requirement for synchronous condensers, and advantages and disadvantages as compared to the base case multi-terminal HVdc configuration.

PSSE Model Development for Future Studies

The existing multi-terminal HVdc PSSE stability models which are available from the standard library provided with the PSSE software are “response” models. They require the user to provide voltage and current recovery characteristics to model recovery from converter blocks. These characteristics are very system dependant and must be obtained from the response of a good detailed electromagnetic transients model or from the response of

the actual system. Detailed models will capture the interaction of the HVdc and ac systems, an important factor with weak ac systems, and will also capture the critical response of the dc line and cable network.

TransGrid Solutions has developed a user written HVdc model for PSSE that allows the representation of the closed-loop HVdc controls as well as the HVdc line L/R dynamics. This custom developed model uses a two time-step approach in which the HVdc model is run at a smaller time-step than the rest of the PSSE solution, thereby allowing the dynamics of the fast HVdc controls and of the HVdc line to be modeled. This model has been shown to provide far superior results when compared to the standard library HVdc models available in PSSE and other transient stability software packages.

The purpose of this task within the WTO DC1020 HVdc System Integration Study was to develop a more accurate PSSE stability model for multi-terminal HVdc as compared with the PSS/E library model. The transient stability study portion of the HVdc System Integration Study was performed using PSCAD, therefore the PSCAD model and its results provided all of the information necessary to develop and benchmark an appropriate and more accurate PSSE stability model for multi-terminal HVdc. This model uses the two time-step technique to model the dynamics of the HVdc overhead line and cable and the HVdc controls in order to provide a more accurate representation of the multi-terminal HVdc link for PSSE.

Results

The results of the overall WTO DC1020 HVdc System Integration Study include the following:

- During nominal bipolar operation, the Gull Island converter supplies a rated current of 1600 A (1.0 pu). The total power injected at Soldiers Pond is 769.6 MW and at Salisbury is 762.6 MW, resulting in losses of 30.4 MW and 37.4 MW at Soldiers Pond and Salisbury respectively.

  The losses increase when operating in monopolar mode, requiring up to 2850 A (1.60 pu current) at Gull Island to supply the 10-minute 100% overload requirement at Soldiers Pond (2.11 pu current) and the continuous 10% overload at Salisbury (1.1 pu current), and up to 2367 A (1.33 pu) at Gull Island to supply the continuous 50% and 10% overloads at Soldiers Pond (1.57 pu current) and Salisbury (1.1 pu current) respectively.

- The major Hydro Island load centre is located east of Bay d'Espoir on the Avalon Peninsula, while the majority of the generation is located west of Bay d'Espoir. This can result in heavy west to east power flow on the 230 kV transmission system, in particular between Bay d'Espoir, Sunnyside, Western Avalon and Soldiers Pond. In addition, approximately 255 MW of new industrial load (refinery and smelter) is planned to be installed along this heavily loaded west to east corridor, which serves to increase the loading on these 230 kV lines. As a general result this can cause voltage depression and thermal overloading in the area.
- The HVdc infeed into Soldiers Pond will normally be operated as an inverter and generally has a positive impact on the Island transmission system from the power flow point of view as it off-loads this west to east power flow by injecting power closer to the load centre.
- The following system upgrades were required within the Newfoundland ac system in order to support the HVdc in-feed:
  - Synchronous condensers:
    - Conversion of all three units at Holyrood to synchronous condenser operation.

- Installation of five (5) combustion turbines that can operate as synchronous condensers at the Pipers Hole 230 kV bus.
- One 300 MVAr high inertia synchronous condenser is in-service at the Soldiers Pond 230 kV bus at all times.
- One 300 MVAr high inertia synchronous condenser is in-service at the Pipers Hole 230 kV bus at all times.

The results indicated that the worst case contingencies (TL202/206 faults) can result in voltage collapse around Sunnyside due to the heavy west to east power transfers between Bay d'Espoir and Soldiers Pond. These already heavy west to east power transfers are further increased by the proposed refinery and smelter loads which are also located along this transmission corridor. The synchronous condensers at Holyrood control their own bus voltage and are not VAR-limited during these worst contingencies because the voltage problems occur too far west of Holyrood for the reactive power support at Holyrood to be significantly useful in these voltage collapse scenarios. Since reactive power support is best provided locally as it cannot be transmitted over long distances, when considering the need to provide additional synchronous condensers to support the HVdc in-feed, consideration was also given to providing the necessary dynamic voltage support required near Sunnyside to avoid the possible voltage collapse scenarios.

It was found that the addition of one 300MVAR synchronous condenser at each of the Soldiers Pond and Pipers Hole buses provided the necessary support for the HVdc in-feed and avoided the voltage collapse for the worst case contingencies.

High-inertia synchronous condensers are required in order to avoid excessive frequency decay which can occur for faults that cause a commutation failure of the Soldiers Pond converter while simultaneously disturbing the generation at Bay d'Espoir. The study shows the need to have one high-inertia synchronous condenser on at all times at each of the Soldiers Pond and Pipers Hole buses. The final number of synchronous condensers installed will have to take into account the need for maintenance outages.

- 50% series compensation of both 230 kV lines from Bay d'Espoir to Sunnyside. Note that a detailed study is required to fully assess the impact of the proposed 50% series compensation on the Island ac system.
- Upgrades to avoid overloads on a number of 230 kV lines on the Island as identified in the power flow study as follows:
  - Upgraded to 75 degrees C:
    - TL202 and TL206 from Bay d'Espoir to Pipers Hole and Pipers Hole to Sunnyside
  - Rebuild:
    - TL203 from Sunnyside to Western Avalon
    - TL201 from Western Avalon to Soldiers Pond and Soldiers Pond to Hardwoods

NLH should verify the adequacy of TL207 from Sunnyside to Come By Chance and TL237 from Come By Chance to Western Avalon in order to determine if upgrades are required as information provided indicates that the ratings on the circuits are higher than what exists in the PSSE models used.

Note that potential impacts of the proposed 50% series compensation must be investigated in order to determine if other line upgrades in addition to those identified here are required as a result of the series compensation.

- Circuit breaker replacement as identified in the short circuit study. Note that during the course of the transient stability study the number and rating of synchronous condensers required to dynamically support the HVdc in-feed was increased as compared to that used in the short circuit study. A cursory review of short circuit currents was conducted as part of the transient stability study, however short circuit levels should be verified once the final configuration of synchronous condensers is determined. The following is a list of substations where the existing circuit breakers would require replacement as identified in this study:
  - Stony Brook 138kV
  - Bay d'Espoir 230kV
  - Holyrood 230kV

  Once the final configuration is determined, further fault level investigation should be carried out to identify the individual breakers that should be replaced.
- Protection and fault clearing times, particularly for faults at Bay d'Espoir and Pipers Hole should be optimized in order to prevent voltage sags of long duration.
- The 50 MVAr shunt capacitor located at Western Avalon was assumed to be out of service for the transient stability studies as the synchronous condensers added to the Island system should provide sufficient voltage regulation to allow the shunt capacitor to be removed. This assumption should be verified using power flow analysis.

- The following special protection and control systems were required within the Newfoundland and Labrador ac systems in order to support the HVdc in-feed:
  - Cross tripping of the proposed 175 MW refinery load at Pipers Hole. The transient stability study determined that cross tripping of the refinery load was required in order to maintain system stability for faults which result in the tripping of one of the 230 kV lines between Bay d'Espoir and Pipers Hole. The study considered only tripping of the entire refinery load. Additional studies should be undertaken to determine if it would be possible to trip only a portion of the load while maintaining system stability.
  - The existing under-frequency load shed scheme on the Island should be re-examined and modified in order to avoid unnecessary load shed under conditions where the HVdc in-feed can stabilize the Island frequency. The under-frequency load shed scheme should be configured to act as a back up to the HVdc in-feed and should only operate in circumstances where the HVdc in-feed cannot control the Island frequency. Additional studies are required in order to coordinate the under-frequency load shed scheme with the HVdc system during detailed design studies.
  - Any existing special protection systems on the Island required to reduce generation in the case of over-frequency should be re-examined and modified in order to avoid unnecessary generator tripping under

conditions where the HVdc in-feed can stabilize the Island frequency. The scheme should be configured to act as a back up to the HVdc in-feed and should only operate in circumstances where the HVdc in-feed cannot control the Island frequency. Additional studies are required in order to coordinate the generation reduction scheme with the HVdc system during detailed design studies.

- A special protection scheme is required in Labrador in order to reduce generation in the case of a load rejection due to the outage of the last 735 kV line from Gull Island.
- The effectiveness of power system stabilizers within the Newfoundland system should be investigated. This includes a review of the design and tuning of existing stabilizers and the identification of potential new stabilizers which can provide benefit to the overall stability of the system.
- The application of correctly designed and tuned stabilizers on the Gull Island generators is essential to maintaining steady power flow through the 735 kV lines.
- HVdc run up and run back schemes should be implemented in order to aid in overall system stability.

- Conventional HVdc technology provides good overall system performance given the ac system upgrades identified above. Salient points of the performance of the proposed multi-terminal HVdc system include:
  - Performance of the proposed multi-terminal HVdc system in bipolar, monopolar, three-terminal, and two terminal operation was seen to be good.
  - No conditions (ac system configurations or contingencies) were observed under which the interconnected HVdc and Newfoundland ac systems could not successfully recover. The system was transiently stable with adequate post-disturbance recovery. Recovery of the HVdc power transfer is dictated, to a large extent, by the time required to charge the large cable capacitance; therefore, significant improvement in the speed of recovery beyond that obtained in these feasibility studies is not likely.
  - The need for under-frequency load shedding in the Newfoundland ac system is minimized. The HVdc system, due to its inherent controllability, provides an effective means of fast and efficient frequency control within the Newfoundland ac system by modulation of the HVdc power transfer to overcome capacity deficit or surplus situations. There are however a number of conditions where the HVdc system will not be able to provide the necessary frequency control due to operational limits or converter capacities. Therefore the existing under-frequency load shedding scheme in the Newfoundland system should be modified in order to operate only when the HVdc frequency controller is not able to provide the necessary control for under-frequency conditions.
  - The 2.0 pu, 10-minute overload rating of the Soldiers Pond converter and corresponding overload rating of the Gull Island converter provides suitable mitigation for the loss of a pole, even under conditions of high HVdc power in-feed.
  - When operating in three terminal mode with Gull Island as the only rectifier, the complete loss of the Gull Island converters can be successfully mitigated by reversal of the Salisbury converter from inverter to rectifier operation. This has been demonstrated from the point of view of the Newfoundland system only; additional studies are required to determine the impact on the New Brunswick ac system.
  - When the HVdc link is operating in two terminal mode with Salisbury as the rectifier and Soldiers Pond as the inverter, a number of situations can arise where the HVdc in-feed to Soldiers Pond is limited due

to the overload capability of the Salisbury converters, resulting in the need for under-frequency load shedding in the Newfoundland ac system.

- Operating the Soldiers Pond converter as a rectifier was successfully demonstrated. The maximum power export from Soldiers Pond when operating as a rectifier was limited to approximately 165 MW due to the Newfoundland ac system configuration given. With additional ac system upgrades, an increased export level should be attainable.

- Many of the issues observed are not necessarily due to the HVdc infeed but are due to the lack of transmission linking the generation in the west to the load in the east and the impacts of the approximately 255 MW of new industrial load (refinery and smelter) which is planned to be installed along this heavily loaded west to east corridor. Additional system impact studies involving the proposed loads are required to define more exact requirements of connecting the new loads separate from the impacts of the HVdc infeed into Soldiers Pond.

- A cursory evaluation of alternate HVdc configurations as mentioned above was undertaken. The alternatives were compared in terms of the cost of the converter terminals, length of the overhead lines and cables, requirement for synchronous condensers, and advantages and disadvantages as compared to the base case multi-terminal HVdc configuration.

  Salient points of the comparison of alternative HVdc configurations include:

  - For all alternatives except alternative 2, the total cost of converters is greater than that of the base case multi-terminal HVdc configuration. Converter costs for alternative 2 were found to be lower than the multi-terminal HVdc configuration however this was due to the simplified converter cost calculation method applied. It is expected that the actual cost of converters for alternative 2 would be at least equivalent to or greater than that of the multi-terminal HVdc configuration.

  - For all alternatives except alternative 3, the total length of HVdc overhead line and cable is equal to or greater than that of the base case multi-terminal HVdc configuration. In the case of alternatives 3 and 4 an additional 800 km of 230 kV as transmission lines are required on the Island of Newfoundland.

  - For all alternatives, synchronous condenser requirements within the Newfoundland ac system are equal to or greater than those of the base case multi-terminal HVdc configuration.

  - None of the alternatives considered provided any significant advantages as compared to the base case multi-terminal HVdc configuration.

  In summary it was determined that none of the alternative configurations considered was found to be a preferable solution to the base case multi-terminal HVdc configuration.

- A user written multi-terminal HVdc model for PSSE suitable for future studies was developed and validated against the PSCAD model used for the transient stability study. Results of validation testing show very good correlation between the PSSE and PSCAD models providing a high degree of confidence in the PSSE model. The PSSE model allows the use of the PSSE transient stability software for future studies with a high degree of confidence in the representation of the multi-terminal HVdc system.

Conclusions

Based on the results of this study it is concluded that:

1. The feasibility of the proposed multi-terminal HVdc system was successfully demonstrated. Performance of the proposed multi-terminal HVdc system was seen to be good; bipolar, monopolar, multi-terminal and two terminal operations were successfully demonstrated. Conventional HVdc technology provides good overall system performance given the ac system upgrades identified.
2. Key upgrades and additions required in the Newfoundland ac system to support the HVdc in-feed include:
    a. Conversion of all three units at Holyrood to synchronous condenser operation.
    b. Installation of five (5) combustion turbines that can operate as synchronous condensers at the Pipers Hole 230 kV bus.
    c. One 300 MVAr high inertia synchronous condenser in-service at the Soldiers Pond 230 kV bus at all times.
    d. One 300 MVAr high inertia synchronous condenser in-service at the Pipers Hole 230 kV bus at all times.
    e. 50% series compensation of both 230 kV lines from Bay d'Espoir to Sunnyside.
    f. Upgrades to a number of 230 kV lines to avoid potential overloads.
    g. Replacement of a number of circuit breakers at three stations as follows:
        - Stony Brook 138 kV
        - Bay d'Espoir 230 kV
        - Holyrood 230 kV
    h. Modification of the existing under-frequency load shedding scheme to avoid unnecessary load shedding.
    i. Implementation of a special protection system to cross trip the proposed refinery load at Pipers Hole in the event of a fault which results in the clearing of one of the 230 kV lines between Bay d'Espoir and Sunnyside.
3. The need for high inertia synchronous condensers is due to the low inertia of the Newfoundland system and the rapid frequency decline which can result from a fault that causes a commutation failure of the HVdc in-feed and simultaneous disruption of the generators at Bay d'Espoir.
4. Many of the issues observed are not necessarily due to the HVdc in-feed but are due to the lack of transmission linking the generation in the west to the load in the east and the impacts of the approximately 255 MW of new industrial load (refinery and smelter) which is planned to be installed along this heavily loaded west to east corridor. Additional system impact studies involving the proposed loads are required to define more exact requirements of connecting the new loads separate from the impacts of the HVdc in-feed into Soldiers Pond.
5. No conditions (ac system configurations or contingencies) were observed under which the interconnected HVdc and Newfoundland ac systems could not successfully recover. Recovery of the HVdc power transfer is dictated, to a large extent, by the time required to charge the large cable

capacitance; therefore, significant improvement in the speed of recovery beyond that obtained in these feasibility studies is not likely.

6. The need for under-frequency load shedding in the Newfoundland ac system is minimized. The HVdc system, due to its inherent controllability, provides an effective means of fast and efficient frequency control within the Newfoundland ac system by modulation of the HVdc power transfer to overcome capacity deficit or surplus situations. There are however a number of conditions where the HVdc system will not be able to provide the necessary frequency control due to operational limits or converter capacities. Therefore the existing under-frequency load shedding scheme in the Newfoundland system should be modified in order to operate only when the HVdc frequency controller is not able to provide the necessary control for under-frequency conditions.

7. The 2.0 pu, 10-minute overload rating of the Soldiers Pond converter and corresponding overload rating of the Gull Island converter provides suitable mitigation for the loss of a pole, even under conditions of high HVdc power in-feed.

8. When operating in three terminal mode with Gull Island as the only rectifier, the complete loss of the Gull Island converters can be successfully mitigated by reversal of the Salisbury converter from inverter to rectifier operation. This has been demonstrated form the point of view of the Newfoundland system only; additional studies are required to determine the impact on the New Brunswick ac system.

9. When the HVdc link is operating in two terminal mode with Salisbury as the rectifier and Soldiers Pond as the inverter, a number of situations can arise where the HVdc in-feed to Soldiers Pond is limited due to the overload capability of the Salisbury converters, resulting in the need for under-frequency load shedding in the Newfoundland ac system.

10. Operation with the Soldiers Pond converter operating as a rectifier was successfully demonstrated. The maximum power export from Soldiers Pond when operating as a rectifier was limited to approximately 165 MW due to the Newfoundland ac system configuration given. With additional ac system upgrades, an increased export level should be attainable.

11. A cursory evaluation of alternate HVdc configurations was undertaken. The alternatives were compared in terms of the cost of the converter terminals, length of the overhead lines and cables, requirement for synchronous condensers, and advantages and disadvantages as compared to the base case multi-terminal HVdc configuration. It was determined that none of the alternative configurations considered was found to be a preferable solution to the base case multi-terminal HVdc configuration.

12. A user written multi-terminal HVdc model for PSSE suitable for future studies was developed and validated against the PSCAD model used for the transient stability study. Results of validation testing show very good correlation between the PSSE and PSCAD models providing a high degree of confidence in the PSSE model. The PSSE model developed allows the use of the PSSE transient stability software for future studies with a high degree of confidence in the representation of the multi-terminal HVdc system.

Recommendations

This study has successfully demonstrated the feasibility of the proposed multi-terminal HVdc system and it is therefore recommended that the design of the multi-terminal HVdc system can be further refined to advance the implementation of the overall project.

Additional studies recommended for refinement of the functional design include:

1. System impact study of the proposed 175 MW refinery load at Pipers Hole.
2. A study to determine the impact of the 50% series compensation recommended for the 230 kV lines between Bay d'Espoir and Sunnyside. Items to be addressed should include, but not be limited to;
    a. Insulation Co-ordination
    b. Switching Studies
    c. Series resonance studies
3. System integration study to evaluate the impact of the proposed HVdc system on the New Brunswick ac system.
4. Investigation into the impact of a bipole block on the Newfoundland System.
5. Reactive power study to optimize the ratings, location and number of synchronous condensers and ac filters required within the Newfoundland ac system.
6. Resonance studies to ensure that the HVdc system does not adversely interact with potential resonances in the Labrador, Newfoundland and New Brunswick ac systems. This should include:
    a. Harmonic resonance investigations
    b. Resonance study of the proposed dc line/cable
7. A study to identify and mitigate any potential sub-synchronous resonance issues.
8. Facilities studies to develop detailed implementation schemes and cost estimates for the identified transmission and control system facilities.

Potential Further Work

In addition to the studies identified in the recommendations, it is noted that the HVdc system considered for this study consisted entirely of line commutated converters; the application of voltage source converters was not considered. Given the rapid development of voltage source converter technology, it is suggested that some consideration be given to the application of voltage source converters. Due to the necessary power ratings, it is likely that voltage source converters could only be used at the Soldiers Pond and Salisbury terminals, the Gull Island terminal would likely remain a line commutated converter. Such a hybrid scheme has never been studied, designed or placed into service however it may present some benefits and preliminary feasibility studies may be warranted to determine if such a configuration is possible.

One other option which may provide some benefits is a configuration using a two terminal line commutated HVdc system between Gull Island and Soldiers Pond and a separate two terminal voltage source converter HVdc system between Soldiers Pond and Salisbury. (The location of the voltage source converter in Newfoundland could be changed if it would provide added benefit.)

1. Introduction

Newfoundland and Labrador Hydro (Hydro) is planning to install a three-terminal HVdc system linking Labrador, Newfoundland, and New Brunswick. The proposed HVdc system will be bipolar, with each converter station having the ability to run as either rectifier or inverter. It will involve cable and overhead line, with about 40 km of cable between Labrador and Newfoundland and about 480 km between Newfoundland and New Brunswick. The proposed HVdc system is conceptually shown in Figure 1.

The Labrador (Gull Island) converters will be nominally rated at 1600 MW; whereas, the Newfoundland (Soldiers Pond) and New Brunswick (Salisbury) stations will each be rated at 800 MW. The converters at Soldiers Pond require an overload capability of 2.0 pu for 10 minutes and 1.5 pu continuously. This would allow for the startup of generation to avoid load shedding in the event of the loss of one pole of the HVdc system. The converters at Salisbury do not require any special overload capability and will have an overload rating which is typical of HVdc systems (10-15%).

This report presents a summary of all work undertaken as part of the WTO DC1020 HVdc System Integration Study. It provides a summary of the individual study tasks completed followed by an overall discussion of results and conclusions.

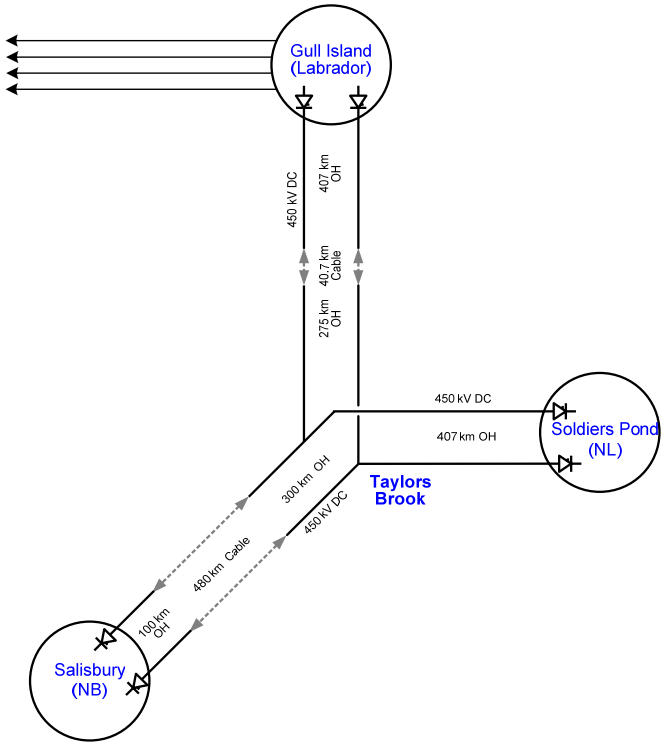


Figure 1 - Proposed Lower Churchill Multi-Terminal HVdc System

1.1 Scope and Objectives of the HVdc System Integration Study

The principal objectives of the HVdc System Integration Study were to:

- Demonstrate the feasibility of a multi-terminal HVdc link connecting Labrador, Newfoundland, and New Brunswick given the requirements of the Newfoundland system.
- Determine the system additions required for integrating the proposed three-terminal HVdc system into the Labrador and Newfoundland systems. Although basic consideration was given to integration into the New Brunswick system, the study concentrated on the Labrador and Newfoundland systems.
- Determine the limitations of the proposed HVdc system.
- Determine feasible mitigation steps to ensure that the integrated system performs in an acceptable manner.
- Ensure that the integrated system design minimizes the need for load shedding in Newfoundland.

The following tasks were identified as part of the overall WTO DC1020 HVdc System Integration Study:

- Data gathering and model development
- Power flow analysis
- Transient stability analysis
- Short circuit analysis
- Model development
- Qualitative issues
- Reporting and deliverables

The major study tasks conducted as part of the overall HVdc System Integration Study included:

- Power flow and short circuit analysis.
- Comparison of the performance of conventional and Capacitor Commutated Converter (CCC) HVdc technologies.
- Transient stability analysis.
- Cursory evaluation of alternate HVdc configurations.
- Development of a multi-terminal HVdc model for future PSSE studies.

In order to complete the work and provide Hydro with results in a timely and efficient manner, a series of interim reports were submitted to Hydro for review and approval upon completion of the major study tasks identified within the WTO. The following interim reports have been previously submitted to Hydro for review and approval.

- DC1020 HVdc System Integration Study – Power Flow and Short Circuit Analysis Interim Report [1]
- DC1020 HVdc System Integration Study - Comparison of Conventional and CCC HVdc Technology Interim Report [2]
- DC1020 HVdc System Integration Study – Transient Stability Analysis Interim Report [3]
- DC1020 HVdc System Integration Study – Cursory Evaluation of Alternate HVdc Configurations Interim Report [4]
- DC1020 HVdc System Integration Study – Multi-Terminal HVdc Link PSSE Stability Model Interim Report [5]

The bodies of each of the interim reports submitted are included as separate volumes to this final report. Detailed results included with each of the interim reports are not included here due to the volume of results; detailed results have been included with each of the interim reports.

The purpose of this report is to summarize all the work undertaken as part of the WTO DC1020 HVdc System Integration Study which has been detailed in the interim reports previously submitted and provide overall conclusions and recommendations of the HVdc System Integration Study.

2. Proposed Multi-Terminal HVdc System

2.1 Multi-Terminal HVdc System Overview

Salient points of the proposed multi-terminal HVdc system include:

- Bipolar, three-terminal HVdc link using conventional technology configured as shown in Figure 2.

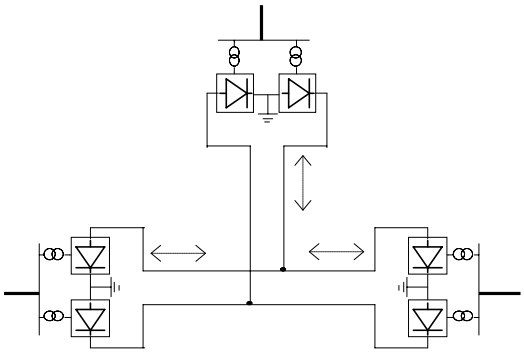


Figure 2 - Basic Configuration of the HVdc Transmission System

- Nominal converter ratings:
  - Gull Island (Labrador) 1600 MW
  - Soldiers Pond (Newfoundland) 800 MW
  - Salisbury (New Brunswick) 800 MW
- The converters at Soldiers Pond and Gull Island have special overload requirements when operating in monopolar as follows:
  - Gull Island 1.5 pu for 10 minutes and 1.25 pu continuous on a per pole basis
  - Soldiers Pond 2.0 pu for 10 minutes and 1.5 pu continuous on a per pole basis

The Soldiers Pond converter overload capability is meant to allow for the startup of generation on the Newfoundland Island to avoid load shedding in case of pole loss when operating as an inverter.

The converter at Salisbury has a typical overload requirement of 10% continuous.

- The HVdc operating voltage is 450 kV (defined at the rectifier).
- Although the normal operating configuration would have Gull Island operating as a rectifier and Soldiers Pond and Salisbury operating as inverters, all converters must be capable of operating both as a rectifier and as an inverter. Therefore high speed reversal switches are required at each station.
- The HVdc system must be able to operate with any two of the three converters in operation.

- The HVdc in-feed into Soldiers Pond will provide frequency control for the Newfoundland Island ac system. Frequency control is provided with Soldiers Pond operating as an inverter or as a rectifier.

2.2 Basic Circuit Parameters of the Proposed Multi-Terminal HVdc System

The HVdc-system electric-circuit parameters were selected based on typical industry practices. Selection of main-circuit parameters was based on the following:

- Each converter is comprised of a single twelve-pulse valve group per pole.
- Converter transformer ratings were based on the maximum continuous ratings per pole for each station.
- AC filters were rated to provide approximately 60% of rated HVdc power.
- Smoothing reactor sizes and HVdc filter ratings were selected based on industry practice.
- HVdc overhead line parameters were based on information from WTO DC1010 available at the start of the study.
- HVdc submarine cable parameters were based on industry data available at the start of the study.
- Overhead transmission and undersea cable lengths are as follows:
  - Gull Island to Strait of Belle Isle – Overhead line 407 km
  - Across Strait of Belle Isle – Undersea cable 40 km
  - Straight of Belle Isle to Taylors Brook – Overhead line 275 km
  - Taylors Brook to Soldiers Pond – Overhead line 406 km
  - Taylors Brook to Cabot Strait – Overhead line 300 km
  - Across Cabot Strait – Undersea cable 480 km
  - Cabot Strait to Salisbury – Overhead line 100 km
- Electrodes for ground/sea return for each station are located as follows:
  - Gull Island – Sea electrode at Strait of Belle Isle, 407 km from converters
  - Soldiers Pond – Sea electrode 10 km from converters
  - Salisbury – Sea electrode at Cabot Strait, 100 km from converters

  The overhead ground wires of the HVdc transmission lines from the converter stations to the sea electrodes are used as electrode lines.
- The impedance of each sea electrode was set to 0.5 Ohms.

2.3 Key Technical Challenges of the Proposed Multi-Terminal HVdc System

The proposed multi-terminal HVdc system included a number of key technical challenges related to the HVdc system, including:

- Multi-terminal configuration – Although multi-terminal HVdc has been used in the past, detailed information on actual control systems in service is not readily available; therefore, considerable effort was required to develop and implement the overall control-system concepts.
- Long HVdc cable – Although two-terminal HVdc systems with undersea cables are in operation, the length of the cable section across the Cabot Strait is considerably longer than any systems currently in operation. (Note that there are currently a number of HVdc links under design or construction with cable lengths similar to that of the LCP.) The length of the undersea cable (and hence the cable capacitance) has a dramatic impact on the overall performance of the HVdc link and must be accounted for in the design of the control system. Furthermore, the length of cable, coupled with the multi-terminal configuration, added yet another dimension to the requirements of the control system.
- Significance of the HVdc infeed to the Newfoundland ac system – Since the HVdc infeed represents a significant portion of the generation on the Island of Newfoundland, performance of the HVdc system is key to the overall stability of the Newfoundland ac system. This requirement puts added complexity on the control system.
- The requirement to operate each station in rectifier or inverter mode adds complexity to the overall control system.

2.4 Salient Points of the Multi-Terminal HVdc Control System Implemented

Salient features of the multi-terminal HVdc control system which were implemented to overcome some of the key technical challenges included the following:

- In order to improve commutation performance, the system is operated with current control at the inverter(s) and voltage control at the rectifier. This mode of operation provides better immunity to commutation failure resulting from disturbances in the inverter ac system.

  When a long HVdc cable is combined with an inverter connected to a weak ac system, the performance of the HVdc link is severely impacted by the fact that the cable can discharge quickly into the inverter when the ac system voltage drops a small amount. This increase in dc current causes a transient increase in converter reactive power consumption which further reduces the weak system bus voltage. The initial transient increase in dc current is not seen by the rectifier, since it is mainly driven by the energy stored in the large capacitance of the HVdc cable; therefore implementation of current control at the rectifier is not effective in controlling the over-current.

  By operating the inverter in current control, it can respond immediately to the transient increase in dc current to counteract the discharge into the inverter. This however requires the inverter to operate at a higher extinction angle so that it has sufficient room to provide current control while avoiding commutation failure.

- The HVdc power order is set by the station(s) operating as inverter.

- A current-balance controller was implemented to ensure that current order allocation to inverters and rectifiers was always balanced.
- A frequency controller was developed that measures the frequency of the Newfoundland ac system and modulates the HVdc power in-feed to stabilize the Newfoundland frequency. Effective frequency control of the Newfoundland system will minimize the need for under-frequency load shed in the Newfoundland system, even for large disturbances.
- A special damping feature was implemented to improve the overall performance of the long cable system. This damping function is designed to counteract sudden increases in HVdc current that can result in commutation failures.

3. Power Flow and Short Circuit Analysis

This study task included the steady state analysis portion of the WTO DC1020 HVdc System Integration Study including the power flow and short circuit studies. The purpose of the steady state analysis was to determine new facilities including steady state reactive power requirements and upgrades to existing facilities that are required within the Hydro transmission system in order to interconnect the 800 MW HVdc link while ensuring that the Hydro criteria for acceptable power system operation is maintained.

The steady state analysis was performed using the PSSE version 30.2 software package.

This study assumed that New Brunswick (NB) transmission system is able to wheel through 760 MW from Salisbury 345 kV substation to the northern Maine area. This assumption was validated as part of the work undertaken.

At the time of this study, it was assumed that the nominal HVdc operating voltage would be 500 kV. Subsequent to the completion of the study it was recommended in WTO 1010 that the nominal HVdc operating voltage should be 450 kV and not 500 kV. Although this change in HVdc voltage will affect the losses of the HVdc system it will not have a significant impact on the overall findings of the Power Flow and Short Circuit Analysis and therefore the results obtained in this study are still valid.

3.1 Objectives

The objectives of the steady state analysis were to determine:

- The total steady state reactive power supply requirements at the converter stations, including the harmonic filter requirements for the converter stations in Labrador and Newfoundland and the potential need for any synchronous condenser(s) to provide additional reactive power support and/or to increase the effective short circuit ratio at the Soldiers Pond bus.
- The requirements for any other reactive power supply elsewhere in the Hydro transmission system to meet steady state voltage criteria.
- The losses for the proposed HVdc solutions and associated configurations.
- Any other equipment requirements such as new equipment or upgrades to existing Hydro transmission system equipment required to meet thermal loading and steady state voltage criteria.
- The pre-HVdc system strengths.
- The impacts of adding the HVdc system including reactive power compensation additions on existing circuit breaker ratings to determine the need for any breaker replacements.
- The range of ESCR at the Soldiers Pond bus for the various power system configurations and the reactive power compensation of the HVdc system.
- Preliminary HVdc design parameters, including typical converter transformer impedances, ranges required for alpha and gamma at each station in each operating mode, and tap changer ranges for the converter transformers.

- The required HVdc operating modes, considering the bi-directional nature of each terminal and the need to provide frequency control in Newfoundland.

3.2 Summary of Power Flow Analysis

The purpose of the power flow analysis was to determine the total steady state reactive power requirements of the Island system such that the steady state voltage requirements are met, and to determine any network upgrades to the existing Island system that are required to relieve thermal overloading.

The full Hydro Island AC system PSSE model is used for the power flow analysis. Eleven (11) Island power flow configurations are represented, ranging from minimum generation light summer night loading to maximum generation future peak winter loading along with various ranges of infeed levels at Soldiers Pond from minimum DC power (80 MW) to maximum DC power (800 MW). One configuration is also represented in which the Island is exporting power. All power flow cases represent year 2016, with the exception of the future peak maximum load case. Table 1 below provides a brief description of the base cases.

Table 1
Power Flow Base Cases

No.	Hydro System Load	Soldiers Pond	Island Generation	Labrador (Gull)	NB
BC1	Peak (1600 MW)	Full Import (800 MW)	economic dispatch	Weak	Peak load
BC2	Peak (1600 MW)	Reduced Import (600 MW)	max economic dispatch	Weak	Peak load
BC3	Future Peak (1800 MW)	Full Import (800 MW)	max generation	Weak	Peak load
BC4	Summer Night (550 MW)	Reduced Import (255 MW)	min generation	Weak	Peak load
BC5	Summer Night (550 MW)	Minimum Import (80 MW)	economic dispatch	Weak	Peak load
BC6	Intermediate (1000 MW)	Full Import (800 MW)	economic dispatch	Weak	Peak load
BC7	Intermediate (1000 MW)	Minimum Import (80 MW)	max economic dispatch	Weak	Peak load
BC8	200 MW (550 MW)	Export	dispatch	Weak	Peak load
BC9	Peak (1600 MW)	Full Import (800 MW)	economic dispatch	Weak	Weak, Peak load
BC10	Peak (1600 MW)	Full Import (800 MW)	economic dispatch	Weak	Light load
BC11	Peak (1600 MW)	Full Import (800 MW)	economic dispatch	Weak	Strong, Light load
BC12	Summer Night (550 MW)	Minimum Import (80 MW)	economic dispatch	Normal	Peak load
BC13	Future Peak (1800 MW)	Reduced Import (600 MW)	max generation	Weak	Peak load

Note that base cases BC9 and BC11 are greyed out because they were not studied. Originally it was thought that these cases would test variations of strong and weak New Brunswick systems with light and

peak loads, however only two New Brunswick power flow cases were available – a strong case with peak load and a weak case with light load, therefore cases BC9 and BC11 were dropped from the original scope. However, two cases were added, BC12 to test the Labrador system for overvoltages when operating at minimum power, and BC13 to test the future peak maximum load case when operating with a 600 MW monopolar infeed at Soldiers Pond.

The year 2016 and future peak Island power flow cases have several significant modifications when compared to the existing system today:

1. A new large refinery load (175 MW, 85 MVAr) is planned to be in-service near Piper's Hole, between Bay D'Espoir and Sunnyside. As well, a nickel smelter load (83 MW, 40 MVAr) is planned for the Long Harbour area. The internal Hydro studies for the additions of these loads have not yet been completed, therefore it was expected that system impacts due the loads will be observed in this HVdc feasibility study.

2. Hydro is planning to convert units #1 to #3 at Holyrood to synchronous condensers as part of the Lower Churchill Project to meet ESCR requirements. In addition Hydro is planning to install five 50 MW combustion turbines (CT) at Holyrood to meet load requirements between 2010 and the HVdc 2015 in-service date. These CTs will be specified with the capability to operate in synchronous condenser mode. The Holyrood station will have a total of eight (8) synchronous condensers available for voltage control and in support of ESCR with the following ratings:

   a. Unit #1 – 142/-72 MVAr
   b. Unit #2 – 142/-72 MVAr
   c. Unit #3 – 150/-69 MVAr
   d. CT Units #1-5: 63.5 MVA at 0.85 power factor leading per CT

   For all cases considered, it was assumed that one large synchronous condenser (unit #3 - 150 MVA) at Holyrood and one small synchronous condenser (50 MW CT running as synchronous condenser) are out of service for maintenance.

3. A 54 MW CT at Hardwoods is capable of operation as a synchronous condenser with a +28/-25 MVAr rating.

The major Hydro load centre is located on the Avalon Peninsula (east side of the Island) while the majority of the generation is located in the west. The Island terminal of the HVdc link will be located at Soldiers Pond which, electrically, is between Holyrood, Hardwoods and Oxen Pond stations. The HVdc terminal will normally be operated as an inverter, with a nominal rated infeed of 765.8 MW (800 MW minus losses). One power flow case is setup with Soldiers Pond in rectifier operation to test the Island's export capability. The HVdc infeed is located nearer to the load centre (i.e. more to the east) than the majority of the other Island generation and should help to off-load heavy west to east flows.

For all power flow cases, the Labrador system is represented by a weak system configuration. This weak configuration is achieved by removing the Muskrat Falls generating station, a 230 kV line from Gull Island to Muskrat Falls and a 735 kV line from Churchill Falls to Gull Island Generating Station. There is one power flow case in which the Labrador system is represented with the 230 kV Gull Island-Muskrat Falls and the 735 kV Churchill Falls-Gull Island lines in-service. This case is used to determine the worst case steady state overvoltages in the Labrador System when operating at minimum power.

For all power flow cases, the New Brunswick system power flow conditions represent the winter peak load case, with the exception of one case that represents summer light load conditions. The New Brunswick system is contained in a reduced system model of approximately 1000 buses.

The Gull Island terminal will normally be operated as the rectifier with the Island and New Brunswick terminals operating as inverters, although the DC link will be designed such that any terminal could be a rectifier or inverter. In addition, the link will normally run as a bipole however situations may occur in which an entire pole or any section of a pole could be out of service (i.e. forced outage or scheduled maintenance). Taking this information into consideration, various DC configurations are studied as listed in Table 2.

Table 2
HVdc Configurations

No.	Gull Island	Soldiers Pond	Salisbury	Description
DC1	REC - BP	INV - BP	INV - BP	Normal
DC2	REC - MP	INV – MP (overload)	INV - MP	Loss of 1 pole at Gull Island
DC3	REC - MP	INV – MP(continuous)	INV - MP	Loss of 1 pole at Gull Island
DC4	REC - BP	INV – MP (overload)	INV - BP	Loss of 1 pole at Soldiers Pond
DC5	REC - BP	INV – MP (continuous)	INV - BP	Loss of 1 pole at Soldiers Pond
DC6	REC - BP	INV - BP	INV - MP	Loss of 1 pole at Salisbury
DC7	OFF	INV - BP	REC - BP	2-terminal
DC8	OFF	REC - BP	INV - BP	2-terminal
DC9	INV - BP	REC - BP	OFF	2-terminal
DC10	REC – BP	REC – BP	OFF	2-terminal

A total of nineteen (19) power flow cases representing various combinations of Island, Labrador, New Brunswick and HVdc configurations were created as listed below in Table 3. Unless otherwise stated, Gull Island is operating as the rectifier and Soldiers Pond and Salisbury are operating as inverters. BP stands for bipole, MP stands for monopole.

Table 3
Complete Set of Power Flow Cases for Steady State Analysis

Base Case	DC	Soldiers Pond	Salisbury	Gull Island
BC1	DC1	800 BP	800 BP	1600 BP
	DC6	800 BP	400 MP	1200 BP
	DC7[1]	800 BP	800 BP–REC	OFF
BC2	DC1	600 BP	800 BP	1400 BP
	DC3	600 MP	400 MP	1000 MP
	DC5	600 MP	800 BP	1400 BP
BC3	DC1	800 BP	800 BP	1600 BP
	DC4	800 MP	400 MP	1000 MP
BC4	DC1	255 BP	800 BP	1055 BP
	DC3	255 MP	400 MP	655 MP
BC5	DC1	80 BP	800 BP	880 BP
BC6	DC1	800 BP	800 BP	1600 BP
BC7	DC1	80 BP	800 BP	880 BP
BC8[2]	DC8	200 BP–REC	800 BP–INV	OFF
	DC9	200 BP–REC	OFF	800 BP–INV
BC9[3]	DC1	800 BP	800 BP	1600 BP
	DC6	800 BP	400 MP	1200 BP
BC10[4]	DC1	800 BP	800 BP	1600 BP
	DC6	800 BP	400 MP	1200 BP
	DC7	800 BP	800 BP–REC	OFF
BC11[3]	DC1	800 BP	800 BP	1600 BP
	DC6	800 BP	400 MP	1200 BP
BC12	DC10	80 BP	OFF	80 BP
BC13	DC3	600 MP	400 MP	1000 MP

For all power flow cases considered, it was assumed that one large synchronous condenser (unit #3 - 150 MVA) at Holyrood and one small synchronous condenser (50 MW CT running as synchronous condenser) are out of service for maintenance.

Table 4 lists the Island contingencies which were studied.

[1] Cannot solve this power flow when NB system is at peak load. Instead case BC10-DC7 was created in which the NB system is at light load.
[2] Can only get approximately 200 MW out of Island system base case, further export would require Island system upgrades.
[3]These base cases were not created as TGS did not have a stong/weak peak/light load for NB system; only a peak and light load case were available.
[4] Represents NB light load system, all other base cases represent NB peak load system.

Table 4
Contingencies for Steady State Analysis

Contingency	Description
C1	Soldiers Pond to Holyrood 230 kV line
C2	Soldiers Pond to Hardwoods 230 kV line
C3	Soldiers Pond to Oxen Pond 230 kV line
C4	Soldiers Pond to Western Avalon 230 kV line
C5	Western Avalon to Come By Chance 230 kV line
C6	Come By Chance to Sunnyside 230 kV line
C7	Western Avalon to Sunnyside 230 kV line
C8	Sunnyside to Piper's Hole 230 kV line
C9	Piper's Hole to Bay d'Espoir 230 kV line
C10	Hardwoods gas turbine in synchronous condenser mode
C11	150 MVAr synchronous condenser

Steady state AC contingency analysis (PSSE activity ACCC) was used to assess the impact of the HVdc link on the Hydro Island system. It tests the adequacy of the Island transmission system to transfer the additional 800 MW of power from the HVdc infeed and determines the worst-case contingencies.

Buses and branches in the Hydro system were monitored and a number of contingencies applied for all power flow cases considered. The purpose was to find any contingencies that resulted in a thermal overload of a transmission line or transformer or that resulted in a steady state voltage violation or voltage collapse scenario. If a problem was discovered, mitigation in the form of extra reactive power support, transmission line upgrades or generation re-dispatch was evaluated.

The following steady state Hydro system criteria were used to determine the steady state transmission solution:

1) Steady state voltages should be within the following ranges:
    a. 0.95 pu – 1.05 pu – System Intact
    b. 0.90 pu – 1.10 pu – Contingency (N-1)

2) Thermal loading on a transmission line or transformer should not exceed 100% of:
    a. Rate A – Summer season (30 degrees C ambient) – light load
    b. Rate B – Spring/Fall season (15 degrees C ambient) – intermediate load
    c. Rate C – Winter season (0 degrees C ambient) – peak load

Within the Hydro Island system, if during a contingency the thermal loading of a transmission line or transformer was found to exceed 100% of its rating, it was deemed acceptable mitigation practice to use a generation re-dispatch to correct the issue as long as there is sufficient Island generation available and if the re-dispatch reduces the loading on all transmission lines and transformers to at or below 100% of their thermal ratings.

Beyond the basic consideration of power transfer, there are a number of ways which the dc and associated ac systems interact at the converter stations. As the strength of the ac system reduces, both in normal operation and as a result of contingencies, certain interactions tend to become more pronounced. These interactions include:

- Recovery from ac and dc Faults: For acceptable performance it is required that the dc system should recover from ac or dc faults without subsequent commutation failures. As a general guide, recovery to 90% of pre-disturbance power transfer within 100 to 300ms is desirable. As the Short Circuit Level (SCL) of the ac systems decreases, the effects of magnetizing inrush currents can become more pronounced, resulting in a slower recovery. Attempting to increase the speed of recovery can sometimes lead to the dc system drawing excessive reactive power from the ac network, resulting in a prolonged depression of the ac network voltage, particularly as the Short Circuit Ratio (SCR) of the ac systems decreases.

- Temporary Overvoltages: Temporary ac system overvoltages can occur at the dc terminals due to converter blocking, ac fault inception and clearing, dc faults, and other disturbances. The severity of these overvoltages increases as the SCR of the ac systems decreases.

  While it may be an issue for ac systems with higher SCRs also, the capacitive shunt compensation at the converter bus and the relatively high system inductance for low SCR ac systems typically results in a parallel resonance at second harmonic. Such a resonance can result in harmonic voltages which are substantial relative to the magnitude of the fundamental during disturbances.

- Commutation Failures: It is a general requirement that the converter does not experience commutation failures for frequently occurring changes in the associated ac systems such as small voltage and phase deviations. As the SCR decreases the likelihood of commutation failures occurring increases.

- Converter Reactive Power Element Switching: As the SCR decreases the voltage sensitivity to changes in the reactive power increases and creates the potential for voltage changes within the ac network in the vicinity of the converter station when reactive power elements are switched.

- System Inertia: In addition to characterizing the ac system as having sufficient SCR, it is also necessary to consider the overall inertia of the system. In cases where overall system inertia is low, synchronous compensators can be used to increase the system SCR and help maintain ac system voltage and frequency.

Effective short circuit ratio (ESCR) is defined as follows:

ESCR = (Short circuit MVA at AC bus – MVA rating of filters)/Rated DC power

The CIGRE Guide for Planning DC Links Terminating at AC System Locations Having Low Short Circuit Capacities[5] identifies the following categories of ESCR:

High	ESCR > 2.5
Low	2.5 > = ESCR > = 1.5
Very Low	ESCR < 1.5

Based on industry experience it can be stated that low or very low SCR in itself is not a technical limitation in the evaluation of an HVdc transmission option, but it must be recognized that decreasing

[5] Guide for Planning DC Links Terminating at AC system Locations Having Low Short-Circuit Capacities, Part II: Planning Guidelines. CIGRE Working Group 14.07, IEEE Working Group 15.05.05, December 1997.

SCR (and ESCR) results in overall decreased performance of the interconnected ac/dc systems. The effects of reducing ESCR on overall performance becomes even more pronounced for long HVdc cables.

As such, it is recommended that a minimum ESCR of 2.5 for the inverter ac systems be maintained. Dynamic performance studies will further validate this minimum ESCR value, however for the purposes of the power flow analysis the goal is to design the reactive power requirements such that the ESCR at the Soldiers Pond bus is at least 2.5.

3.3 Summary of Short Circuit Analysis

The purpose of the short circuit analysis was to quantify impacts to existing maximum fault levels particularly near to the HVdc system bus and to identify any circuit breakers whose ratings are exceeded due to increased fault levels. Another purpose of the short circuit analysis was to quantify the minimum short circuit level at the Soldiers Pond bus and identify the need for synchronous condenser(s) to maintain a minimum ESCR of 2.5.

The HVdc system itself does not contribute to the short circuit strength of the system, however a synchronous condenser installed to support the HVdc system will increase the short circuit strength.

Fault application (PSSE activity ASCC) was used to determine the three-phase and line-to-ground fault levels at a particular bus. All Hydro power flow cases provided contained sequence data, therefore the same cases as used for the power flow analysis were used in the short circuit analysis.

Power flow cases representing the minimum short circuit levels were used to determine the short circuit MVA level and the corresponding ESCR at the Soldiers Pond bus. The short circuit cases used to determine minimum system strengths used the base assumption similar to that used in the power flow study in which one 150 MVAr synchronous condenser and one Holyrood CT synchronous condenser are out of service for maintenance. Then the ESCRs were determined for system intact and contingency conditions.

Power flow cases representing the maximum short circuit levels were used to determine the fault levels at key buses, particularly near to the Soldiers Pond and Gull Island buses. These power flow cases represent system intact conditions with maximum generation and all available synchronous condensers in service. The fault levels at each bus were then compared with the existing fault level and nearby breaker ratings to determine if any breaker ratings will be exceeded. If so, mitigation such as breaker replacement is required.

3.4 Results of Power Flow and Short Circuit Analysis

The multi-terminal HVdc system consists of a three-terminal link connecting Labrador, Newfoundland and New Brunswick. The proposed HVdc system is bipolar with normal operation having Labrador as rectifier and Newfoundland and New Brunswick as inverters, however each converter station is capable of operating as either rectifier or inverter.

At the time of the power flow analysis, it was assumed that the HVdc system will operate at a rated dc voltage of +/-500 kV. The Labrador terminal is connected to the Gull Island 230 kV bus and has a

nominal rating of 1600 MW, or 1600 A. The Newfoundland terminal is connected to the Soldiers Pond 230 kV bus and has a nominal rating of 800 MW, or 800 A. The New Brunswick terminal is connected to the Salisbury 345 kV bus and has a nominal rating of 800 MW, or 800 A.

In determining preliminary parameters for the HVdc system, typical industry practice was followed. DC line lengths and corresponding resistances were as shown in Table 5. The nominal operating points as determined during the power flow analysis are given in Table 6. The HVdc parameters used in the power flow study were preliminary values and are subject to change during later phases of more detailed design such as the pre-specification studies.

Table 5
DC Line Lengths and Resistances for the Power Flow Analysis

DC Line Section	Length (km)	DC Resistance per pole (ohms)
Gull Island - Tap	648.7	9.17
Tap - Soldiers Pond	480.0	6.94
Tap - Salisbury	725.0	8.77
Gull Island Electrode	407.0	6.39 (includes 0.5 ohm sea resistance)
Salisbury Electrode	100.0	1.94 (includes 0.5 ohm sea resistance)

Table 6
Nominal Operating Points Determined in the Power Flow Anslysis

Converter	Per Pole Parameters	Nominal Bipolar	10-min Overload Monopolar	Continuous Monopolar
Gull Island	Vdc (kV)	500	481.7	485
	Pdc (MW)	1600	1258	1042
	Idc (A)	1600 (1.0 pu)	2611 (1.66 pu)	2149 (1.34 pu)
	Qdc (MVAr)	823.8	693.6	532.8
	Alpha (deg)	19.1	14.6	14.9
Soldiers Pond	Vdc (kV)	478.7	444.2	455.2
	Pdc (MW)	765.8	765.8	574.4
	Idc (A)	800 (1.0 pu)	1724 (2.16 pu)	1262 (1.58 pu)
	Qdc (MVAr)	456.2	558.6	380.4
	Gamma (deg)	25.0	25.0	25.0
Salisbury	Vdc (kV)	477.1	448.6	456.3
	Pdc (MW)	763.4	394.8	401.6
	Idc (A)	800 (1.0 pu)	880 (1.1 pu)	880 (1.1 pu)
	Qdc (MVAr)	492.8	263.5	271.4
	Gamma (deg)	25.0	25.0	25.0

During nominal bipolar operation, the Gull Island converter supplies a rated current of 1600 A (1.0 pu). The total power injected at Soldiers Pond is 765.8 MW and at Salisbury is 763.4 MW, resulting in losses of 34.2 MW and 36.6 MW at Soldiers Pond and Salisbury respectively.

The losses increase when operating in monopolar mode, requiring up to 2611 A (1.66 pu current) at Gull Island to supply the 10-minute 100% overload requirement at Soldiers Pond (2.16 pu current) and the continuous 10% overload at Salisbury (1.1 pu current), and up to 2149 A (1.34 pu) at Gull Island to supply the continuous 50% and 10% overloads at Soldiers Pond (1.58 pu current) and Salisbury (1.1 pu current) respectively.

HVdc converters typically consume reactive power in the approximate amount of 55% of their real power output. The exact amount of reactive power consumed depends on the commutating reactance of the converter transformers, the tap position of the converter transformers and the firing angle of the converter. For the purposes of this study, the commutating reactances of the converter transformers were held constant throughout the tap changer ranges. The power flow studies assumed a minimum reactive power compensation of 450 MVAr at Soldiers Pond and Salisbury and 900 MVAr at Gull Island.

As a starting point for the power flow study, the HVdc converter at Soldiers Pond was assumed to provide its full reactive power compensation in the form of 450 MVAr of filters and shunt capacitors. It was quickly discovered that if the HVdc infeed was operating in its 2.0 pu monopolar configuration, a voltage collapse would occur even without any outages in the Island system. The heavy west-east flow and the new refinery load at Piper's Hole, combined with the increased reactive power consumption of the HVdc inverter at Soldiers Pond (559 MVAr monopolar compared to 462 MVAr bipolar), depressed the system voltage enough to cause system wide voltage collapse that begins around the Sunnyside and Piper's Hole area, very near to the new refinery load. Significant improvement in voltage is achieved with the addition of local area reactive power supply at the Sunnyside 230 kV bus.

In terms of maintaining acceptable steady state voltages on the Island, the worst case power flows were found to be the future peak load cases, in particular:

- 1800 MW future peak Island loading, 800 MW bipolar infeed at Soldiers Pond (Case BC3-DC1)
- 1800 MW future peak Island loading, 600 MW monopolar infeed at Soldiers Pond (case BC3-DC3)
- 1800 MW future peak Island loading, 800 MW 10-minute overload monopolar infeed at Soldiers Pond (Case BC3-DC4)

The worst case corresponding contingencies were found to be:

- Loss of 230 kV line from Bay d'Espoir to Piper's Hole (Contingency C9)
- Loss of synchronous condenser unit #3 at Holyrood (Contingency C11)

These two contingencies were the determining cases for total reactive power requirements for the Island. Again, the absolute worst power flow case was the 10-minute 2 pu overload scenario in which the HVdc inverter at Soldiers Pond is in monopolar operation (BC3-DC4). This is due to the fact that the HVdc converter's reactive power absorption is highest in this case at 559 MVAr compared to 462 MVAr in the bipolar case.

The result of losing either the Bay d'Espoir-Piper's Hole line or the Holyrood unit #3 synchronous condenser with insufficient reactive power support in the system is voltage collapse. Combinations of reactive power supply at Holyrood, Soldiers Pond and Sunnyside were tested. As additional reactive power supply, a 150 MVAr synchronous condenser at Soldiers Pond was tested as one of the alternatives. For the purposes of power flow analysis, a single 150 MVAr synchronous condenser at Soldiers Pond was assumed because of the close proximity to Holyrood unit #3, an outage of either of these two units could likely be considered a similar outage and would require a similar reactive power

requirement at Sunnyside. Several scenarios of reactive power sources required to avoid voltage collapse are summarized in Table 7.

Table 7
Reactive Power Solutions to Avoid Voltage Collapse in the Power Flow Study

Scenario	Contingency	Holyrood #3 (150 MVAr)	Soldiers Pond Synchronous Condenser (150 MVAr)	Soldiers Pond Filters (MVAr)	Sunnyside (MVAr)
0	C9	Out	None	450	300
1	C11	In (but lose)	Out	450	200
1	C9	In	Out	450	150
2	C9	Out	In	450	165

Scenario 0 assumes no additional reactive power support (aside from 450 MVAr filters) is installed at Soldiers Pond. This would require at least 300 MVAr of steady state reactive power supply at Sunnyside, which is a substantial amount of reactive power support and could not all be supplied in the form of shunt capacitors.

Scenarios 1 and 2 assume a 150 MVAr synchronous condenser is installed at Soldiers Pond in addition to the 450 MVAr filters. As a base case assumption it is assumed that either one of these 150 MVAr units at Holyrood or Soldiers Pond could be out of service for maintenance. The defining case for the total reactive power requirement at Sunnyside then becomes loss of the in-service 150 MVAr synchronous condenser, which requires a minimum of 200 MVAr of steady state reactive power support at Sunnyside to avoid system voltage collapse.

The preferred solution for the total Island reactive power supply as found from the Power Flow study is as follows:

- 450 MVAr filters at Soldiers Pond
- 150 MVAr synchronous condenser at Soldiers Pond
- 200 MVAr capacitive reactive power support at Sunnyside

The entire contingency analysis was performed on all power flow cases with the above reactive power solution modeled, taking into account a base case maintenance outage of one of the CT units at Holyrood plus a base case maintenance outage of either of the 150 MVAr synchronous condensers at Holyrood or Soldiers Pond. With this reactive power solution, no further voltage violations or voltage collapse scenarios were observed, with the exception of contingency C9, loss of 230 kV line from Bay d'Espoir to Piper's Hole during BC7 when the HVdc infeed at Soldiers Pond is at minimum power or during BC8 when the HVdc converter is exporting power. These scenarios will require a fast DC run-up (when importing) and run-down (when exporting) to prevent system voltage collapse. A corresponding transfer trip of generation in the west would be required to offset the increase in HVdc infeed. The voltage collapse seems to occur if there is more than approximately 225-250 MW flowing from west to east on both of the Bay d'Espoir to Piper's Hole lines. If it would not be desired to perform a fast dc power run-up or run-down, then it would likely be possible to develop an operating guideline to limit steady state power flow on the circuits between Bay d'Espoir and Piper's Hole by re-dispatching

generation to avoid the voltage collapse scenario in the first place. This would require further study to determine if this is in fact possible and what the power flow limit would be.

The Gull Island station is connected to a strong network with a minimum short circuit strength of 5851 MVA, corresponding to an ESCR of 3.1. The steady state reactive power requirement can be fulfilled by the use of filters and shunt capacitors, no synchronous condensers are required. A total of 900 MVAr of reactive power support is modeled at the 1600 MW Gull Island converter.

A minimum power case at Gull Island was checked to ensure that overvoltages in the Labrador system would not be too high. This power flow case included all transmission lines in-service which were previously taken out-of-service for the weak representation in other power flow cases. Muskrat Falls generating station was kept out-of-service. In order to find the worst condition for high voltages, one of the two 735 kV 165 MVAr reactors at Gull Island was taken out-of-service as were generating units #2 to #4 at Gull Island. The Gull Island rectifier was supplying 80 MW of power to Soldiers Pond with 250 MVAr of filters connected. The steady state 230 kV voltage observed on the Gull Island bus was 1.047 pu. The single Gull Island generating unit still had approximately 65 MVAr room left for further reactive power absorption. Overvoltages are therefore not expected to be a problem.

The heavily loaded 230 kV transmission corridor between Bay d'Espoir and Soldiers Pond not only results in voltage problems but also results in thermal overloading on several 230 kV lines in the area.

Generally the worst overloading occurs when the Soldiers Pond DC infeed is operating at lower power levels, or even worse if it is exporting power. This results in the need for more Island generation in the west to serve the major load centre in the east, in addition to the new refinery load at Piper's Hole, causing several 230 kV transmission lines to be significantly overloaded under certain power flow conditions. Hydro currently operates their Island system with a guideline to re-dispatch generation to mitigate overloaded lines.

Table 8 lists the thermal overloads for all power flow cases without network upgrades and the post-contingency generation re-dispatch that would be required to eliminate the listed overload.

Table 8
Thermal Overloads Before any Upgrades are Implemented

Overloaded Line	Contingency	Rate	Power Flow	Overload (%)	Pre-Contingency HVdc Infeed (MW)	Post-Contingency Redispatch (MW)
Piper's Hole-Bay d'Espoir TL202, TL206	C9	C	BC2-DC1	117.8	600 BP	+60 DC infeed
		C	BC2-DC3	122.2	600 MP	+70 Holyrood
		C	BC2-DC5	123.3	600 MP	+75 Holyrood
		C	BC3-DC1	107.4	800 BP	+25 Holyrood
		C	BC3-DC4	110.9	800 MP	+35 Holyrood
		A	BC5-DC1	169.8	80 BP	+175 DC infeed
		A	BC12-DC10	174.0	80 BP	+160 DC infeed
		C	BC13-DC3	106.9	600 MP	+50 Holyrood
	Base, all	A	BC8	162.1-169.9	-200 BP	0 DC export +225 Holyrood
Sunnyside-Western Avalon TL203	C5	B	BC6-DC1	118.4	800 BP	-50 DC infeed
	C6	B	BC7-DC1	126.7	80 BP	+100 DC infeed
	C4,C5,C6	A	BC8	202.6	-200 BP	0 DC export +50 Holyrood
Piper's Hole-Sunnyside TL202	C8	A	BC5-DC1	113.3	80 BP	+25 DC infeed
		B	BC7-DC1	147.6	80 BP	+150 DC infeed
		A	BC12-DC10	117.1	80 BP	+35 DC infeed
		A	BC8	128.6	-200 BP	0 DC export +120 Holyrood
Western Avalon-Soldiers Pond TL201	C4	B	BC6-DC1	146.5	800 BP	-175 DC infeed
		A	BC8	197.8	-200 BP	0 DC export
Hardwoods-Soldiers Pond TL201	C2	C	BC3-DC1	108.1	800 BP	+54 Hardwoods
		C	BC3-DC4	108.0	800 MP	+54 Hardwoods
		C	BC13-DC3	107.3	600 MP	+54 Hardwoods
Piper's Hole-Sunnyside TL206	Base, all	A	BC8	128.6-133.6	-200 BP	+250 Holyrood in base case
Sunnyside-Come By Chance TL207	C7	A	BC8	150.5	-200 BP	+35 DC import
Come By Chance-Western Avalon TL237	C7	A	BC8	142.9	-200 BP	-130 DC export
Western Avalon-Soldiers Pond TL217	C5,C6,C7	A	BC8	103.2	-200 BP	-110 DC export

As an alternative to relying on generator re-dispatch to relieve overloads, especially because some of the overloads are extremely high, the overloaded lines were considered to be upgraded as detailed below and the contingency analysis was re-run.

1) **TL202 and TL206 – Bay d'Espoir to Piper's Hole and Piper's Hole to Sunnyside**
These lines could be upgraded to 75 degrees C with the addition of a few mid span structures.

	Current Rating (MVA)	Upgraded Rating (MVA)	Rating Increase (%)
Rate A	199.3	341.8	71.5 %
Rate B	297.7	402.4	35.2 %
Rate C	369.5	453.8	22.8 %

2) **TL203 – Sunnyside to Western Avalon**
This line is an H-frame wood pole design with multiple conductor types. Upgrading this line is not considered at viable option but instead the circuit would need to be replaced. The Hydro standard would be to rebuild TL203 using steel structures and the 804 MCM AACSR/TW conductor.

	Current Rating (MVA)	Upgraded Rating (MVA)	Rating Increase (%)
Rate A	261.7	355.8	35.9 %
Rate B	307.8	411.5	33.7 %
Rate C	347.0	459.6	32.4 %

3) **TL207 – Sunnyside to Come By Chance**
This line was upgraded to use the 804 MCM AACSR/TW conductor. The maximum conductor temperature was set at 80 deg C to match the hot conductor sag to the maximum ice load sag. This line would require further review by Hydro transmission design. For the purposes of this study the current thermal ratings will be assumed.

	Current Rating (MVA)	Upgraded Rating (MVA)	Rating Increase (%)
Rate A	355.8	n/a	n/a
Rate B	411.5	n/a	n/a
Rate C	459.6	n/a	n/a

4) **TL237 – Come by Chance to Western Avalon**
Same comments as for line TL207.

5) **TL217 – Western Avalon to Soldiers Pond**
This line was upgraded using the 804 MCM AACSR/TW conductor except for two 5km sections that had been rebuilt following a previous ice storm. The two 5km sections consist of 795 MCM ACSR DRAKE conductor. A recent review by Hydro Transmission Design has indicated that this section can be operated at a 75 deg C conductor temperature without violating ground clearance requirements. Therefore the ratings on this circuit are higher than what exists in the original PSSE model.

	Current Rating (MVA)	Upgraded Rating (MVA)	Rating Increase (%)
Rate A	199.3	341.8	71.5 %
Rate B	297.7	402.4	35.2 %
Rate C	369.5	453.8	22.8 %

6) TL201 – Western Avalon to Soldiers Pond and Soldiers Pond to Hardwoods

This line is an H-frame wood pole construction and consists of multiple conductor types. Uprating of the existing line is not viewed as a viable option. Instead the line would need to be rebuilt using the 804 AACSR/TW conductor type.

	Current Rating (MVA)	Upgraded Rating (MVA)	Rating Increase (%)
Rate A	175.5	355.8	102.7 %
Rate B	260.2	411.5	58.1 %
Rate C	322.2	459.6	42.6 %

With the line upgrades in place, most of the overloads are mitigated. The remaining overloads are summarized below in Table 9. They can all be mitigated by re-dispatching generation following the contingency.

Table 9
Thermal Overloads After Line Upgrades are Implemented

Overloaded Line	Contingency	Rate	Power Flow	Overload (%)	Pre-Contingency HVdc Infeed (MW)	Post-Contingency Redispatch (MW)
Piper's Hole-Bay d'Espoir TL202, TL206	C9	A	BC12-DC10	101.4	80 BP	+10 DC import
		B	BC7*		80 BP	+175 DC import
		A	BC8*		-200 BP	0 DC export +75 Holyrood
		C	BC2-DC5	100.3	600 MP	n/a
Sunnyside-Western Avalon TL203	C5,C6	A	BC8	146.7	-200 BP	-125 DC export
Piper's Hole-Sunnyside TL202	C8	A	BC8	148.6	-200 BP	-160 DC export
		B	BC7-DC1	108.9	80 BP	+35 DC import
Sunnyside-Come By Chance TL207	C7	A	BC8	150.3	-200 BP	-130 DC export
Come By Chance-Western Avalon TL237	C7	A	BC8	142.7	-200 BP	-110 DC export

** These contingencies require fast dc run-up (if importing into Soldiers Pond) or fast dc run-down (if exporting from Soldiers Pond).*

Power flow analysis determined the total reactive power requirement to be 600 MVAr at Soldiers Pond (450 MVAr filters and 150 MVAr synchronous condenser was assumed) and 200 MVAr at Sunnyside in addition to the eight synchronous condensers at Holyrood.

As a starting point for the short circuit analysis, in order to verify that a synchronous condenser is actually required at Soldiers Pond, the minimum ESCR was found assuming no synchronous condenser is installed at Soldiers Pond. This results in a minimum ESCR of 1.9 (1967 MVA) during minimum generation power flow case BC4 for contingency C11, loss of Holyrood unit #3. This ESCR is below the desired minimum of 2.5. With the single 150 MVAr synchronous condenser at Soldiers Pond, the minimum ESCR is increased to 2.5 (2545 MVA) for this worst case contingency.

Therefore, the short circuit analysis verified the fact that Soldiers Pond will require one 150 MVAr synchronous condenser to maintain the desired minimum ESCR. Dynamic performance studies will verify this requirement based on dynamic performance results. For a complete listing of ESCR results for all power flows and all contingencies, please refer to the DC1020 HVdc System Integration Study – Power Flow and Short Circuit Analysis Interim Report [1].

Maximum fault levels were tested with power flow cases BC1, BC2, BC3, BC7 and BC8 which represent the power flow cases with most Island generation in-service. In addition, all synchronous condensers at Holyrood and Soldiers Pond were placed in-service. Power flow cases BC1 and BC3 were found to produce very similar results and represented the highest fault levels.

Stations near Soldiers Pond and Holyrood saw the largest increase in fault levels. This is due to the addition of a synchronous condenser at Soldiers Pond and the five CTs at Holyrood. Table 10 below summarizes all stations in which the fault level is increased by more than 10%. Please note that existing fault level data and breaker ratings were not available for all buses, only buses for which this data was available were compared to the new increased fault levels in Table 10. For a complete listing of fault levels with the new facilities in service please refer to the DC1020 HVdc System Integration Study – Power Flow and Short Circuit Analysis Interim Report [1].

Table 10
Stations with Fault Levels Increases Greater than 10%

Station	Existing Fault Level (MVA)		New Fault Level (MVA)				Breaker Ratings
	3P	LG	3P	Increase	LG	Increase	
Come By Chance 230	2019	1831	2520	24.8%	2520	37.6%	7960
Come By Chance 13.8	301	317	335	11.3%	349	10.1%	Customer-owned
Western Avalon 230	2152	2349	2954	37.3%	3182	35.5%	4980, 5600
Western Avalon 138	1281	1531	1600	24.9%	1882	22.9%	4780
Western Avalon 66	465	324	540	16.1%	363	12.0%	1430, 1500
Long Harbour 230	1653	1439	2151	30.1%	1777	23.5%	None
Long Harbour 46	423	464	807	90.8%	918	97.8%	1590
Sunnyside 230	2164	2084	2701	24.8%	3055	46.6%	5600
Sunnyside 138	1386	1630	1569	13.2%	1933	18.6%	2510
Oxen Pond 230	2396	3335	3387	41.4%	3577	7.3%	5600
Oxen Pond 66	1441	1337	2017	40.0%	1696	26.9%	2380
Hardwoods 230	2223	2605	3758	69.1%	4149	59.3%	5430, 7560, 13360
Hardwoods 66	1628	1625	2285	40.4%	2060	26.8%	2380, 2360, 2850, 3600
Holyrood 230	2657	3307	4629	74.2%	**5754**	74.0%	**5100**, **5430**,7570,12550
Holyrood 138	1377	1690	1839	33.6%	2212	30.9%	5020
Holyrood 66	542	501	629	16.1%	564	12.6%	4570
Holyrood 16	1827	0	2200	20.4%	0	-	None
Holyrood 16	1773	0	2099	18.4%	0	-	None
Holyrood 16	1598	0	1928	20.7%	0	-	None

Despite the increase in fault levels, the only station in which breaker ratings were exceeded was Holyrood. The maximum fault level seen at Holyrood station was 4629 MVA three-phase and 5754 MVA line-to-ground. Nine breakers at Holyrood rated for 5100 MVA (B12B15, B3L18, B12L42, B3B13) and 5430 MVA (B2L42, B12L17, B1L17, B1B11, B2B11) would require replacement.

3.5 Conclusions of Power Flow and Short Circuit Analysis

Based on the results of the steady state analysis of the Lower Churchill multi-terminal HVdc the following conclusions were made:

1) **Steady State Reactive Power Requirements**: The steady state reactive power requirements are as follows:

   - Soldiers Pond 230 kV bus – 450 MVAr filters, 150 MVAr synchronous condenser
   - Sunnyside 230 kV – 200 MVAr capacitance

   The reactive power support is required to compensate the HVdc converter reactive power absorption, to prevent voltage collapse under heavily loaded Island conditions particularly on 230 kV lines between Bay d'Espoir and Soldiers Pond, and to maintain the minimum effective short circuit ratio (ESCR) at the Soldiers Pond bus to 2.5.

   The determining contingencies for the steady state reactive power requirements were C9, loss of one of the Bay d'Espoir to Piper's Hole lines, and C11, loss of Holyrood unit #3, during the future peak Island load (1800 MW) BC3-DC4 power flow case in which the HVdc inverter at Soldiers Pond was operating in the 10-minute 2.0 pu monopolar mode. In this case the inverter at Soldiers Pond is absorbing 559 MVA compared to the 462 MVAr during bipolar operation. Without the additional reactive power support of the synchronous condenser at Soldiers Pond and the 200 MVAr at Sunnyside, the result of either of these contingencies would be system wide voltage collapse.

   The synchronous condensers at Holyrood control their own bus voltage and are not VAR-limited during these worst contingencies because the voltage problems occur too far west of Holyrood for the reactive power support at Holyrood to be significantly useful in these voltage collapse scenarios. Therefore the synchronous condenser required for Soldiers Pond should be located right at the converter and not at Holyrood as local support will be required at Soldiers Pond. It is unlikely that fewer than 450 MVAr of filters will be required at Soldiers Pond because of the voltage depression occurring west of Soldiers Pond. If filters were removed at Soldiers Pond then a similar amount of reactive power support as was removed would be required at Sunnyside. It comes down to determining a reasonable split and location of total system reactive power requirements. With Sunnyside already requiring 200 MVAr, it would be undesirable to move some of the filter requirements from Soldiers Pond to Sunnyside. It would more likely be possible to lower the filter requirements at Soldiers Pond if the Holyrood synchronous condensers were located directly at Soldiers Pond.

   Even with the above described reactive power support, it should be noted that for power flow cases BC7 with the HVdc infeed at minimum power of 80 MW and for case BC8 when the DC is exporting 200 MW, a fast HVdc run-up (minimum 50 MW when importing) and run-down

(minimum 100 MW when exporting) is required to prevent system voltage collapse for contingency C9, loss of a Bay d'Espoir to Piper's Hole. A corresponding transfer trip of generation in the west would be required to offset the increase in generation in the east. The voltage collapse seems to occur if there is more than approximately 225-250 MW flowing from west to east on both of the Bay d'Espoir to Piper's Hole lines. If it would not be desired to perform a fast dc power run-up or run-down, then it would likely be possible to develop an operating guideline to limit steady state power flow on the circuits between Bay d'Espoir and Piper's Hole by re-dispatching generation to avoid the voltage collapse scenario in the first place. This would require further study to determine if this is in fact possible and what the exact power flow limit would be. Dynamic performance studies could investigate this issue further.

Dynamic performance studies will verify these requirements, whether one synchronous condenser at Soldiers Pond is sufficient, and whether there are any dynamic reactive power requirements at the Sunnyside 230 kV station.

2) **Newfoundland Network Upgrades**: All but one of the thermal overloads on the Island occur on the heavily loaded west to east 230 kV transmission corridor between Bay d'Espoir and Soldiers Pond.

The exception to this corridor is 230 kV line TL201 from Soldiers Pond to Hardwoods. This line becomes overloaded only during the future peak Island load (1800 MW) power flow case due to load serving requirements on the radial 66 kV system underlying Hardwoods and Oxen Pond stations. The overload is worse, up to 115%, if the two 25 MW wind farms are not in-service. This line will need to be upgraded and will require a rebuild with 804 MCM AACSR/TW conductor as stated in Table 11.

For the remaining 230 kV lines between Bay d'Espoir and Soldiers Pond, the highest overloads occur when the HVdc system is exporting power from the Island, and the next worst situation is when the HVdc system is importing low power. However, some overloads still occur even when the HVdc system is importing its maximum rated power. It is possible to mitigate all of these overloads by re-dispatching Island generation, first by increasing the HVdc import if there is room available (or lowering the HVdc export) and then by turning on generation from the CTs at Holyrood when there is no more room left on the HVdc. This effectively reduces the west to east power flow and reduces loading on the affected 230 kV lines.

Many of these overloads are quite high however and instead of relying on generator redispatch to mitigate the overloads, Table 11 describes line upgrades that could be implemented.

Table 11
230 kV Transmission Line Upgrades

Line		Current Rating (MVA)	New Rating (MVA)	Upgrade
TL202	Bay d'Espoir-Piper's Hole	199.3/297.7/369.5	341.8/402.4/453.8	Thermal uprating to 75 degrees C.
TL206	Piper's Hole – Sunnyside	199.3/297.7/369.5	341.8/402.4/453.8	Thermal uprating to 75 degrees C.
TL203	Sunnyside – Western Avalon	261.7/307.8/347.0	355.8/411.5/459.6	Rebuild with 804 MCM AACSR/TW conductor.
TL217	Western Avalon-Soldiers Pond	199.3/297.7/369.5	341.8/402.4/453.8	Recent review indicates can operate at 75 degrees C as is.
TL201	Western Avalon-Soldiers Pond	175.5/260.2/322.2	355.8/411.5/459.6	Rebuild with 804 MCM AACSR/TW conductor.
TL201	Soldiers Pond-Hardwoods	175.5/260.2/322.2	355.8/411.5/459.6	Rebuild with 804 MCM AACSR/TW conductor.

Lines TL207 from Sunnyside to Come By Chance and TL237 from Come By Chance to Western Avalon have already been upgraded to use 804 MCM AACSR/TW conductor. These lines would require further review by Hydro Transmission Design if the ratings were to be increased.

If the line upgrades listed in Table 11 are implemented, a few overloads still remain but only during cases with very low HVdc infeed power or when the HVdc is exporting power from the Island. These cases are summarized below in Table 12. These overloads can be mitigated by increasing HVdc imports or decreasing HVdc exports post-contingency.

Table 12
Overloads After Line Upgrades are Implemented

Overloaded Line	Contingency	Rate	Power Flow	Overload (%)	Pre-Contingency HVdc Infeed (MW)	Post-Contingency Redispatch (MW)
Piper's Hole-Bay d'Espoir TL202, TL206	C9	A	BC12-DC10	101.4	80 BP	+10 HVdc import
		B	BC7*		80 BP	+175 HVdc import
		A	BC8*		-200 BP	0 HVdc export +75 Holyrood
		C	BC2-DC5	100.3	600 MP	-
Sunnyside-Western Avalon TL203	C5, C6	A	BC8	146.7	-200 BP	-125 HVdc export
Piper's Hole-Sunnyside TL202	C8	A	BC8	148.6	-200 BP	-160 HVdc export
		B	BC7-DC1	108.9	80 BP	+35 HVdc import
Sunnyside-Come By Chance TL207	C7	A	BC8	150.3	-200 BP	-130 HVCD export
Come By Chance-Western Avalon TL237	C7	A	BC8	142.7	-200 BP	-110 HVdc export

**These scenarios require a fast HVdc run-up or run-down.*

3) **HVdc System Losses**: HVdc losses in bipolar operation at nominal rating - Operating at a dc voltage of 500 kV per pole with Gull Island producing nominal rated 1600 A per pole current, a total power of 765.8 MW is injected at Soldiers Pond and a total power of 763.4 MW is injected at Salisbury, resulting in losses of 34.2 MW and 36.6 MW at Soldiers Pond and Salisbury respectively.

   The losses increase when operating in monopolar mode, requiring up to 2611 A (1.66 pu current) at Gull Island to simultaneously supply the 10-minute 100% overload requirement at Soldiers Pond (2.16 pu current) and the continuous 10% overload at Salisbury (1.1 pu current), and up to 2149 A (1.34 pu) at Gull Island to supply the continuous 50% and 10% overloads at Soldiers Pond (1.58 pu current) and Salisbury (1.1 pu current) respectively.

4) **Minimum ESCR at Soldiers Pond**: The minimum ESCR at the Soldiers Pond bus occurs during the minimum Island generation case for loss of Holyrood unit #3 resulting in the following ESCRs:

   - ESCR = 1.9 (1967 MVA) without a synchronous condenser at Soldiers Pond
   - ESCR = 2.5 (2545 MVA) with 150 MVAr synchronous condenser at Soldiers Pond

   Therefore a synchronous condenser is required at Soldiers Pond to meet the minimum desired ESCR of 2.5. The base case assumes maintenance outages of the Soldiers Pond synchronous condenser and one Holyrood CT synchronous condenser.

5) **Impacts to Maximum Fault Levels**: Maximum fault levels at the following stations are increased by the listed percentages with the addition of a synchronous condenser at Soldiers Pond and the five new CTs at Holyrood:

   - Come by Chance – 10.1 – 37.6%
   - Western Avalon – 12.0 – 37.3%
   - Long Harbour – 23.5 – 97.8 %
   - Sunnyside – 13.2 – 46.6%
   - Oxen Pond – 7.3 – 41.4%
   - Hardwoods – 8.1 – 69.1%
   - Holyrood – 12.6 – 74.2%

   At the Holyrood 230 kV station, nine breakers rated for 5100 MVA (B12B15, B3L18, B12L42, B3B13) and 5430 MVA (B2L42, B12L17, B1L17, B1B11, B2B11) would require replacement as their ratings are exceeded. No other breaker ratings are exceeded at other stations despite the increase in fault levels.

3.6 Key Findings of Power Flow and Short Circuit Analysis

The power flow and short circuit analysis found that from a power flow point of view, the 800 MW HVdc infeed into Soldiers Pond is feasible with the following Island system upgrades.

- 230 kV line upgrades between Bay d'Espoir and Soldiers Pond and Hardwoods to relieve thermal overloading.
- Minimum of 200 MVAR capacitive reactive power support at Sunnyside to mitigate low ac system voltages.
- The addition of a minimum of one 150 MVAR synchronous condenser at Soldiers Pond to ensure a minimum ESCR of 2.5 at the Soldiers Pond bus.
- Breaker replacements at Holyrood due to increased short circuit levels resulting from new synchronous condenser installations.
- Initial powerflow findings indicated that during minimum Island load conditions approximately 200 MW could be exported via the HVdc link from Soldiers Pond, but this would likely require a fast HVdc run-back scheme to be in place for worst-case contingencies during this operating mode.

It should be noted that a portion of the Island system upgrades identified in this study, in particular the need for reactive power support at Sunnyside and the extensive thermal upgrades required on 230 kV transmission between Bay d'Espoir and Soldiers Pond, are largely due to approximately 255 MW of new industrial load (refinery and smelter) which is planned to be installed along the heavily loaded transmission corridor. The major Hydro Island load centre is located east of Bay d'Espoir on the Avalon Peninsula, while the majority of the generation is located west of Bay d'Espoir. This can result in heavy west to east power flow on the 230 kV transmission system, in particular between Bay d'Espoir, Sunnyside, Western Avalon and Soldiers Pond, with further increased loading due to the new industrial loads. As a general result this can cause voltage depression and thermal overloading in the area.

The HVdc infeed into Soldiers Pond generally has a positive impact on the Island transmission system as it off-loads this west to east power flow by injecting power closer to the load centre. Many of the issues observed are not necessarily due to the HVdc infeed but are due to the lack of transmission linking the generation in the west to the load in the east. For example, without the new refinery load, the reactive power requirement at Sunnyside reduced to approximately 50 MVAr from 200 MVAr. It is therefore important that further system impact studies be undertaken to more clearly identify system upgrades which are required as a result of connecting the new loads separate from upgrades required to support the HVdc in-feed into Soldiers Pond.

4. Comparison of Conventional and Capacitor Commutated Converter (CCC) HVdc Technology

Following completion of the Power Flow and Short Circuit Analysis, transient stability analysis to determine the dynamic performance of the interconnected ac/dc systems was undertaken. Initial findings of the transient stability analysis showed that for the 1600 MW load base-case, with the HVdc operating in bipolar mode with 800 MW infeed into Newfoundland, performance of the interconnected ac/dc system was worse than expected.

Based on the initial results obtained and discussions with Hydro, it was recommended to, and approved by Hydro, that a more comprehensive comparison of the performance of conventional and Capacitor Commutated Converter (CCC) HVdc technology should be undertaken in order to evaluate the potential benefits. This comparison would form the basis for a recommendation of which configuration should be used for the transient stability studies.

Conventional HVdc technology offers efficient, reliable and economical operation, however it has a number of notable drawbacks as follows:

1. The converter relies on the line voltage for the commutation process, therefore at the inverter the valve must be triggered sufficiently early of the line voltage zero crossing to provide it with enough commutation margin. Because of this dependence, the converter is susceptible to commutation failures in the event of ac system voltage depressions and when operated in weak ac systems.
2. The conventional arrangement presents a special problem with long HVDC cables since any reduction of the inverter bus voltage causes a corresponding decrease in dc voltage and thus an increase in dc current because of the cable capacitance discharge. The sudden increase in dc current in turn causes the extinction angle gamma to decrease, which increases the probability of commutation failures.
3. The demand for reactive power, which is typically about 0.5 pu of the rated active power must be supplied by shunt reactive power elements at the converter or from the ac system itself.

The capacitive commutated converter has the potential to mitigate these drawbacks.

In principle the addition of the series capacitors between the valve side of the converter transformer and the valves themselves results in an additional commutating voltage. As a result of this additional commutating voltage, an increased firing angle range is obtained for both rectifier and inverter operation. This increased commutation voltage also results in a reduction of the overlap angle (commutation interval), leading to lower reactive power consumption.

Because of the presence of the capacitors, the commutation circuit includes both inductance and capacitance; therefore the basic equations of the conventional converter are no longer valid. The capacitors are charged with a polarity that aids in the commutation process. The size of the capacitors can be selected so that, in theory, the firing angle (alpha) can be increased well beyond 90 degrees. The commutation voltage also now has a phase lag and a higher amplitude when compared to the real bus

voltage. This results in an additional commutation margin provided by the capacitors, consequently a smaller extinction angle is possible.

The capacitors also provide an additional commutation margin proportional to the dc current. For example, as the dc current increases, the voltage on the capacitors increases, resulting in an increase of the extinction angle. This is contrary to the situation in a conventional converter where the extinction angle decreases with increasing dc current. This certainly improves the commutation failure performance. This characteristic is very beneficial for an HVdc system with a long cable. It also has better performance in the event of remote ac system faults.

One major advantage of a capacitive commutated converter as compared to a conventional inverter is that for minimum commutation margin control it has a positive impedance while the conventional inverter has a negative impedance. This positive impedance characteristic will improve the inverter performance in long dc cable transmission.

Although there is currently a back-to-back CCC HVdc system in operation, CCC technology has not yet been applied to a long distance HVdc transmission system. The application of a CCC to the Lower Churchill Project has the potential of improving performance due to the basic nature of CCC, however it also adds another degree of complexity to the interconnected ac/dc system and should be used only if it is demonstrated that there is a substantial performance benefit.

This study task therefore included a preliminary transient stability study to evaluate the dynamic performance of the Newfoundland system with the application of conventional and CCC HVdc technology for the Lower Churchill Project. New Island ac system facilities, existing Island ac system upgrades and potential special protection systems such as cross-tripping of loads required to maintain system stability and provide acceptable system voltage recovery following normal-clearing three-phase faults and slow-clearing single line-to-ground faults were identified for both technologies.

Upgrades within the Newfoundland ac system identified and recommended in the Power Flow and Short Circuit Analysis task formed the basis of the Newfoundland ac system used in the comparison of conventional and CCC HVdc technology study.

While PSSE is an industry standard for transient stability analysis, some aspects of the multi-terminal HVdc models that are associated with the software are incompatible with the requirements of this study. The power flow model is restricted in the control modes available, and the stability model requires extensive response data that can be obtained only from other sources, such as detailed simulation. Therefore, the primary tool used for this study was the PSCAD electromagnetic transients simulation software.

4.1 Objectives

The objectives of the comparison of conventional and CCC HVdc technology study were to:

- Determine Newfoundland ac system upgrades required to maintain acceptable dynamic system performance of the ac and dc systems for the application of conventional HVdc technology.

- Determine Newfoundland ac system upgrades required to maintain acceptable dynamic system performance of the ac and dc systems for the application of CCC HVdc technology.
- Compare the overall performance of the Newfoundland ac system for the application of conventional and CCC HVdc technology for the LCP.
- Develop recommendations on the HVdc technology and corresponding ac system reinforcements to be used for the remainder of the WTO DC1020 transient stability analysis.

4.2 Summary of the Comparison of Conventional and CCC HVdc Technology

Initial transient stability analysis findings showed that for the 1600 MW load base-case, with the HVdc operating in bipolar mode with 800 MW infeed, performance of the interconnected ac/dc system was worse than expected when compared to results of earlier studies. A summary of the initial findings is given below:

- Various faults within the island ac network result in unacceptable voltage depressions and even voltage collapse. These are most pronounced in the Bay d'Espoir and Sunnyside regions of the network.
- Various faults within the island ac network result in unacceptable frequency decay.
- Results were worse for faults which cause a large disruption of the generators at Bay d'Espoir and simultaneous commutation failure of the HVdc infeed.
- Fast recovery of the HVdc power infeed following fault removal provides some benefit. The rate at which the HVdc power recovers must be balanced off against the risk of a secondary commutation failure if it is too fast.
- The addition of more and larger rating synchronous condensers within the Newfoundland system provided some improvement in voltage performance, however the overall improvement was marginal.
- The use of high-inertia synchronous condensers within the Newfoundland system provided some improvement in frequency performance.
- The addition of a third 230 kV ac circuit between Bay d'Espoir and the Sunnyside region provides substantial improvement to the overall system recovery.
- Cases with the HVdc operating monopolar with 600 MW infeed appear to be worse that the 800 MW bipolar configuration.

The degraded performance which was observed when compared to the results from the earlier study was attributed to the following:

- Impact of long cable on commutation performance and HVdc recovery at Soldiers Pond following faults.
- The system load used in the two studies is considerably different; in particular the current study includes a 175 MW refinery load at Pipers Hole.

- In the current study the loads are modeled as constant current for the real portion and constant impedance for the reactive portion, whereas in the earlier study both the real and reactive portion of loads were modeled as constant impedance loads. The use of constant current for real power loads provides more realistic results and is much more onerous on the transient performance of the network.
- Results of the earlier study indicate that the system was unstable for a fault on the Bay d'Espoir to Sunnyside line. Mitigation of this was not provided in the study.
- Load shedding was used in the earlier study whereas in the present study one of the main goals is to avoid load shedding.

Overall, the initial results indicated the need to improve the response of the HVdc system, increase the inertia of the Newfoundland system, provide more dynamic voltage support in the Sunnyside area, and reinforce the existing west to east transmission.

A number of optional configurations were investigated as discussed below:

- Additional synchronous condensers were provided in order to improve overall performance. Results showed that this was only marginally effective.
- The location of the five 50MVA combustion turbines was varied to determine its effect on overall system performance. The location was seen to have little impact.
- A two terminal Gull Island to Soldiers Pond HVdc link was investigated in order to determine the impact of the long cable section from Cape Ray to Salisbury on the performance of the Soldiers Pond converter. As expected, removal of the long cable section resulted in improved commutation performance and the ability to recover the HVdc infeed faster. Overall system performance was improved; however, a fault on the Bay d'Espoir to Sunnyside ac line still resulted in voltage collapse.
- A damping function was developed and added to the multi-terminal HVdc controls in order to allow faster recovery from commutation failures. The addition of the new damping function provided recovery from commutation failures at Soldiers Pond for the multi-terminal HVdc which were comparable to that obtained for the two-terminal HVdc.
- A two-terminal Capacitor Commutated Converter (CCC) HVdc link was examined. As expected the CCC provided improved commutation performance and provided some immunity to commutation failures. In particular, a fault at Bay d'Espoir no longer resulted in a commutation failure; hence, the overall system performance for this fault was very good and the voltage collapse was avoided.

Based on the initial results and following discussions with Hydro, the following conclusions and recommendations on how to proceed were agreed upon:

- Since performance of the multi-terminal HVdc with the damping function included in the controls was nearing that of the two terminal HVdc (Gull Island to Soldiers Pond only) it was decided that a two terminal option should not be considered at this time.
- Since the preliminary look at CCC provided some immunity from commutation failures, a three terminal CCC model should be developed and used to better evaluate the potential performance benefits.

- A more comprehensive comparison of the performance of CCC versus conventional HVdc should be conducted at this stage of the study. This comparison will form the basis for recommending which configuration should be used in the transient stability studies.
- Continued work on the transient stability studies should wait until a recommendation has been put forward regarding the HVdc configuration and approval has been received from Hydro.
- In order to better identify ac system upgrades which are associated with the new refinery load, cases which consider the refinery load out of service need to be studied. Under this configuration, the Bay d'Espoir units should be re-dispatched such that one is running in synchronous condenser mode and the five 50 MVA combustion turbines should be located at Holyrood.
- Both 800 MW bipolar and 600 MW monopolar HVdc operating configurations should be considered. The 1600 MW base case load should be used for the 800 MW bipolar case, and a modified case with the refinery load out of service and the Bay d'Espoir units re-dispatched should be used for the 600 MW monopolar configuration.

As a result, a preliminary transient stability analysis of the Lower Churchill multi-terminal HVdc project was undertaken in order to compare the performance of conventional HVdc technology with the performance of capacitor commutated converter (CCC) HVdc technology. The analysis was performed on the year 2016 Island system peak load (1600 MW) case with 800 MW bipolar infeed (base case BC1-DC1). The purpose of the HVdc technology comparison was to provide a recommendation and justification for the direction of the remainder of the transient stability studies, i.e. whether conventional or CCC HVdc technology should be pursued.

Sensitivity to the new refinery load (175 MW) planned to be installed at Pipers Hole was included in the analysis. In addition an evaluation of the benefits of adding series compensation to the 230 kV lines between Bay d'Espoir and Pipers Hole was performed.

In order to conduct the comparison of conventional and CCC HVdc technology study a PSCAD model of the Hydro system based on power flow analysis case BC1-DC1 was developed. Models for both the conventional and CCC multiterminal HVdc technologies were created. Transient stability studies were performed by applying normal-clearing (100ms) three-phase faults and slow-clearing (250ms) single line to ground faults at the expected worst-case locations in the Newfoundland system to ensure that the transient stability criteria, including rotor angle stability and transient under-voltage criteria is met.

The following assumptions were made:

- All large synchronous condensers (units 1-3) at Holyrood are in-service.
- If the new refinery load at Pipers Hole is in-service then the five new CTs currently planned for installation as synchronous condensers at Holyrood are relocated to Pipers Hole. If the new refinery load at Pipers Hole is out-of-service then the five new CTs are left as synchronous condensers at Holyrood. In all cases, one of these five CTs is assumed to be out-of-service for maintenance.
- In the case testing sensitivity to the new refinery load out-of-service, the generation at Bay d'Espoir is re-dispatched to maintain approximately 60 MW on each of units 1-6 with unit7 operating as a synchronous condenser.

- One 300 MVAR synchronous condenser (high inertia of 2.2) is in-service at both Pipers Hole 230 kV bus and Soldiers Pond 230 kV bus in all cases. Data for the high-inertia synchronous condensers used was based on identical machines located at Manitoba Hydro's Dorsey Converter Station.

The following dynamic performance criteria were used to determine the Island AC transmission solution:

- Transient under-voltages following fault clearing should not drop below 0.7 pu.
- The system should be stable and reasonably well damped following fault clearing.
- Under-frequency load shedding should be avoided if at all possible.

Results of the power flow analysis provide indication as to which fault cases are expected to cause worst-case dynamic performances. Table 13 lists the contingencies that were studied in this preliminary transient stability analysis.

Table 13
Contingencies for Preliminary Transient Stability Analysis

Contingency	Description
1	100 ms 3PF at Bay d'Espoir, clear Bay d'Espoir to Pipers Hole 230 kV line
2	100 ms 3PF at mid-point, clear Bay d'Espoir to Pipers Hole 230 kV line
3	100 ms 3PF at Pipers Hole, clear Bay d'Espoir to Pipers Hole 230 kV line
4	100 ms 3PF at Sunnyside, clear Sunnyside to Western Avalon 230 kV line
5	100 ms 3PF at Soldiers Pond, clear Soldiers Pond to Western Avalon 230 kV line
6	250 ms LGF at Soldiers Pond, clear Soldiers Pond to Western Avalon 230 kV line

When transient stability criteria was not met or when poor HVdc dynamic performance was observed the following mitigation measures were investigated:

- HVdc control parameter optimization.
- Reactive power compensation.
- Trip of the 175 MW new refinery load at Pipers Hole.
- 50% series compensation on both 230 kV lines between Bay d'Espoir and Pipers Hole

The dynamic performance results and impact of load cross-tripping and series compensation for the conventional HVdc technology and the CCC HVdc technology was then compared and recommendations made as to which technology should be considered for the remainder of the transient stability studies.

4.3 Results of the Comparison of Conventional and CCC HVdc Technology

The following results were obtained:

- General Fault Performance:

Among all cases, the worst-case disturbance in terms of maintaining system stability and 0.7 pu transient under-voltage criteria was found to be a three-phase fault on one of the Bay d'Espoir to Pipers Hole lines.

Also in all cases, a slow-clearing single line-to-ground fault at Soldiers Pond causes a commutation failure for the length of the fault, however the DC is able to recover and the AC system dynamic performance criteria is met. Minimum frequency dips to 0.978 pu on the second swing, but this is expected to be improved with frequency controller tuning on the HVdc.

A three-phase fault at Soldiers Pond on a Soldiers Pond-Western Avalon line and a three-phase fault at Sunnyside on the Sunnyside-Western Avalon line both cause commutation failure but the fault recoveries are within acceptable dynamic performance criteria.

The mitigation option looking at 50% series compensation on the Bay d'Espoir to Piper's Hole lines changes the original power flow case by lowering the impedance of the lines and drawing more power through them. The system intact case with 50% series compensation has 194 MVA flow on each Bay d'Espoir-Pipers Hole line and during an outage of one of the two parallel lines the line flow is increased to 368 MVA for the case being studied.

- Newfoundland AC System Reactive Power Support:

It was found that more reactive power support and inertia within the Newfoundland ac system than first identified in the power flow analysis would be necessary to dynamically support the HVdc infeed. Power flow analysis indicated the need for 200 MVAR at Sunnyside and one 150 MVAR synchronous condenser at Soldiers Pond. Initial stability analysis indicates that one 300 MVAR high inertia synchronous condenser is required to be in-service at both Pipers Hole 230 kV bus and Soldiers Pond 230 kV bus at all times.

In addition, it was found that if the new refinery load at Pipers Hole is in-service then relocating the five new CTs currently planned for installation as synchronous condensers at Holyrood to Pipers Hole was beneficial.

- Conventional HVdc Technology:

With the new refinery load in- or out-of-service, the system becomes unstable for a three-phase-to-ground fault at Bay d'Espoir on one of the Pipers Hole 230 kV lines. This is due to the fact that the Bay d'Espoir generators are faulted and simultaneously the HVdc experiences a commutation failure which results in a momentary loss of the 800 MW DC infeed. Cross-tripping the new refinery load if it is in service does not mitigate the instability.

With the new refinery load in-service a three-phase-to-ground fault at Pipers Hole on a Bay d'Espoir line would require the 175 MW new refinery load to be cross-tripped in order to maintain system stability.

With the addition of 50% series compensation on both 230 kV lines between Bay d'Espoir and Pipers Hole, recovery from a three-phase-to-ground fault at Bay d'Espoir on one of the Pipers Hole 230 kV lines is possible if the 175 MW new refinery load is cross-tripped. However voltage criteria is violated at the Bay d'Espoir and Sunnyside buses during recovery. In addition, with series compensation, a fault at Pipers Hole on a Bay d'Espoir line no longer requires the 175 MW new refinery load to be cross-tripped.

- CCC HVdc Technology:

The main benefit of CCC HVdc technology in this system is the ability of the HVdc to avoid commutation failure for a three-phase-to-ground fault at Bay d'Espoir. By avoiding the commutation failure for a Bay d'Espoir fault, the severity of this fault on the overall system is greatly reduced. This is true for both the operating scenarios with and without the new 175 MW refinery load in-service.

With CCC HVdc technology a three-phase-to-ground fault at Pipers Hole on a Bay d'Espoir line would require the 175 MW new refinery load to cross-tripped. The load cross-tripping can be avoided if 50% series compensation is installed on both 230 kV lines between Bay d'Espoir and Pipers Hole.

The complete results of the study are summarized in Table 14.

Table 14
Summary of Preliminary Transient Stability Study Results

HVDC Configuration	Fault Location	Refinery Status	Refinery Crosstrip	Series Compensation	Stable?	Voltage Violations?
Conventional	BDE	IN	0 MW	No	NO	-
	Midpoint	IN	0 MW	No	NO	-
	PH	IN	0 MW	No	NO	-
	BDE	IN	175 MW	No	NO	-
	Midpoint	IN	175 MW	No	YES	none
	PH	IN	175 MW	No	YES	none
CCC	BDE	IN	0 MW	No	YES	none
	Midpoint	IN	0 MW	No	YES	none
	PH	IN	0 MW	No	NO	-
	PH	IN	175 MW	No	YES	none
Conventional	BDE	OUT	-	No	NO	-
	Midpoint	OUT	-	No	YES	none
	PH	OUT	-	No	YES	none
CCC	BDE	OUT	-	No	YES	none
	Midpoint	OUT	-	No	YES	none
	PH	OUT	-	No	YES	none
Conventional	BDE	IN	0 MW	Yes	NO	-
	Midpoint	IN	0 MW	Yes	NO	-
	PH	IN	0 MW	Yes	YES	none
	Midpoint	IN	175 MW	Yes	YES	BDE-0.65 pu, SSD-0.64 pu
	BDE	IN	175 MW	Yes	YES	BDE-0.60 pu, SSD-0.67 pu
CCC	BDE	IN	0 MW	Yes	YES	none
	Midpoint	IN	0 MW	Yes	YES	none
	PH	IN	0 MW	Yes	YES	none
Conventional	BDE	OUT	-	Yes	YES	none
	Midpoint	OUT	-	Yes	YES	none
	PH	OUT	-	Yes	YES	none
CCC	BDE	OUT	-	Yes	YES	none
	Midpoint	OUT	-	Yes	YES	none
	PH	OUT	-	Yes	YES	none

The following salient points are noted from the table above:

- Application of conventional HVdc technology results in system collapse for a number of contingencies with and without the 175 MW new refinery load in service. Also, cross-tripping the new refinery load, if it were in-service, does not avoid system collapse.
- Application of conventional HVdc technology in conjunction with the addition of 50% series compensation to both of the 230 kV Bay d'Espoir - Pipers Hole lines will result in stable recovery from all contingencies considered. For cases with the 175 MW new refinery load in-service, cross-trip of the new load is required for certain contingencies to maintain system stability.
- Application of CCC HVdc technology results in system recovery for all contingencies with and without the 175 MW new refinery load in service. For cases with the 175 MW new refinery load in-service, cross-trip of the new load is required for certain contingencies to maintain system stability.
- Application of CCC HVdc technology in conjunction with the addition of 50% series compensation to both of the 230 kV Bay d'Espoir - Pipers Hole lines will result in stable recovery from all contingencies considered. For cases with the 175 MW new refinery load in-service, cross-trip of the new load is not required for any of the contingencies considered to maintain system stability.

4.4 Conclusions of the Comparison of Conventional and CCC HVdc Technology

Based on the results of the comparison of conventional and CCC HVdc technology, the following conclusions were made:

1. More reactive power support and inertia within the Newfoundland ac system than first identified in the power flow analysis would be necessary to dynamically support the HVdc infeed. Power flow analysis indicated the need for 200 MVAR at Sunnyside and one 150 MVAR synchronous condenser at Soldiers Pond. Initial stability analysis indicates that one 300 MVAR high inertia synchronous condenser is required to be in-service at both Pipers Hole 230 kV bus and Soldiers Pond 230 kV bus at all times.
2. If the new refinery load at Pipers Hole is put into service then relocating the five new CTs currently planned for installation as synchronous condensers at Holyrood to Pipers Hole was beneficial.
3. The use of conventional HVdc technology without the addition of 50% series compensation on both 230 kV lines between Bay d'Espoir and Pipers Hole can result in system instability for some of the contingencies considered.
4. The use of conventional HVdc technology with the addition of 50% series compensation on both 230 kV lines between Bay d'Espoir and Pipers Hole is technically feasible if cross-tripping of the 175 MW new refinery load for specific contingencies is acceptable.
5. The use of CCC HVdc technology without the addition of 50% series compensation on both 230 kV lines between Bay d'Espoir and Pipers Hole is technically feasible if cross-tripping of the 175 MW new refinery load for specific contingencies is acceptable.

6. The use of CCC HVdc technology with the addition of 50% series compensation on both 230 kV lines between Bay d'Espoir and Pipers Hole is also technically feasible and it avoids cross-tripping of the 175 MW new refinery load.

It should be noted that the base power flow case being studied (1600 MW load, 800 MW bipolar infeed, BC1-DC1) in this preliminary transient stability analysis is not necessarily the most stressed case. The 600 MW monopolar infeed case as well as the future peak 1800 MW Island load cases are expected to provide slightly worse results as less spinning reserve is available. It is likely that the need for series compensation will be even more apparent in these cases in order to provide an interconnected ac/dc system solution with improved dynamic performance and increased robustness.

The study results show that system stability can be maintained using conventional HVdc with the application of the series compensation on the 230 kV lines between Bay d'Espoir and Pipers Hole if crosstrip of the 175 MW new refinery load is permitted. The CCC HVdc technology does provide some added benefit in that the 175 MW refinery load does not require cross-tripping if series compensation on the 230 kV lines between Bay d'Espoir and Pipers Hole are installed. This benefit, however, is fairly limited. On the other hand, there is some uncertainty associated with the application of the CCC to a long distance multiterminal HVdc link.

4.5 Key Findings of the Comparison of Conventional and CCC HVdc Technology

Based on the results of this study the following recommendations were made:

- Install 50% series compensation on the 230 kV lines between Bay d'Espoir and Pipers Hole to improve dynamic performance of the system.
- Conventional HVdc technology with the above mentioned series compensation is recommended. The dynamic performance of the system with the conventional HVdc is acceptable with the exception of voltage criteria violations under certain disturbances. These violations attributed to inherent system problems and not the HVdc in-feed itself and should therefore be dealt with separately.
- There is a marginal benefit of the application of CCC HVdc technology, but due to uncertainties with its application this technology is not recommended.
- One 300 MVAr high-inertia synchronous condenser must be in service at Pipers Hole. This replaces the 200 MVAr SVC at Sunnyside that was identified in the Power Flow Analysis.
- One 300 MVAr high-inertia synchronous condenser must be in service at Soldiers Pond. This replaces the 150 MVAr synchronous condenser at Soldiers Pond that was identified in the Power Flow Analysis.
- If the new refinery load at Pipers Hole is put into service then the five new CTs currently planned for installation as synchronous condensers at Holyrood should be relocated to Pipers Hole.

It was therefore recommended that conventional HVdc technology be used for the remainder of the transient stability studies. This recommendation was accepted by Newfoundland and Labrador Hydro.

5. Transient Stability Study

Following completion of the Comparison of Conventional and CCC HVdc Technology, the full transient stability study for the proposed Lower Churchill multi-terminal HVdc project was completed in order to demonstrate the feasibility of the interconnection given the ac systems in Labrador, Newfoundland, and New Brunswick and the requirements of the Newfoundland ac system. Potential stability issues were investigated along with system upgrades required in the Newfoundland ac system to support the HVdc in-feed. A number of ac system configurations, HVdc system configurations, and contingencies were investigated in order to determine the performance of the overall interconnected ac/dc systems, with the primary focus of the study being the performance of the Newfoundland ac system and the impact of the HVdc in-feed on its performance. Consideration was also given to limitations of the proposed HVdc system and feasible mitigation steps to ensure that the integrated systems perform in an acceptable manner.

Upgrades to the Newfoundland ac system recommended in the Comparison of Conventional and CCC HVdc Technology Study formed the basis of the ac system model for this study.

While PSSE is an industry standard for transient stability analysis, some aspects of the multi-terminal HVdc models that are associated with the software are incompatible with the requirements of this study. The power flow model is restricted in the control modes available, and the stability model requires extensive response data that can be obtained only from other sources, such as detailed simulation. Therefore, the primary tool used for the Transient Stability Study was the PSCAD electromagnetic transients simulation software.

5.1 Objectives

The objectives of the transient stability study were as follows:

- To demonstrate the feasibility of the multi-terminal HVdc system given the configurations of the respective ac systems in Labrador, Newfoundland, and New Brunswick and the requirements of the Newfoundland ac system.
- To determine any potential stability issues given the proposed ac system configurations, maximum power levels, and proposed HVdc multi-terminal system by looking at the following contingencies:
    - ♦ AC system faults within each of the three ac networks that may affect HVdc commutation or ac system strength;
    - ♦ HVdc system faults and outages including converter (pole) blocking and converter commutation failure;
    - ♦ Events that will require the HVdc system to provide dynamic frequency control of the Newfoundland ac system, such as loss of generation in Newfoundland; and
    - ♦ Loss of generation in Labrador.

- To determine preliminary HVdc equipment and HVdc control system requirements to minimize the impact of loss of a pole and to provide the necessary dynamic response of the HVdc system, including overload capability.
- To identify preliminary transient and dynamic voltage-control issues.
- To determine system-mitigation steps required for HVdc disturbances resulting in transient or permanent loss of HVdc transmission capability.
- To determine Newfoundland Island system upgrades required to maintain acceptable dynamic system performance of the ac and dc systems for conventional HVdc technology.

5.2 Summary of the Transient Stability Study

As part of the WTO DC1020 HVdc System Integration Study, transient stability analysis for the proposed Lower Churchill multi-terminal HVdc project was completed in order to demonstrate the feasibility of the interconnection given the ac systems in Labrador, Newfoundland, and New Brunswick and the requirements of the Newfoundland ac system. Potential stability issues were investigated along with system upgrades required in the Newfoundland ac system to support the HVdc in-feed.

A number of ac system configurations, HVdc system configurations, and contingencies were investigated in order to determine the performance of the overall interconnected ac/dc systems, with the primary focus of the study being the performance of the Newfoundland ac system and the impact of the HVdc in-feed on its performance. Consideration was also given to limitations of the proposed HVdc system and feasible mitigation steps to ensure that the integrated systems perform in an acceptable manner.

Key issues identified in the study included:

- Determination of preliminary HVdc equipment and HVdc control system requirements to minimize the impact of loss of a pole and to provide the necessary dynamic response of the HVdc system, including overload capability.
- Determination of system-mitigation steps required for HVdc disturbances resulting in transient or permanent loss of HVdc transmission capability.
- Evaluation of the effectiveness of the HVdc system to provide control of the Newfoundland ac system frequency and the resultant need for under-frequency load shedding.
- Determination of Newfoundland Island system upgrades required to maintain acceptable dynamic system performance of the ac and dc systems.
- Determination of potential stability issues given the proposed ac system configurations, maximum power levels, and proposed HVdc multi-terminal system.
- Identification of transient and dynamic voltage-control issues.

Criteria and guidelines applied in the study included the following:

- Load shedding should not occur for loss of a pole or of the largest generator in the Newfoundland system.
- The system response following disturbances should be stable and reasonably well damped.
- Transient under-voltages following fault clearing should not drop below 0.7 pu.
- Under-frequency load-shedding should be avoided to the greatest extent possible.

With regards to the voltage criteria, the primary focus was to optimize the controls such that the voltage dip during a disturbance should not drop below 0.7 pu. However, the duration of voltage below 0.8 pu was also noted, keeping in view that a voltage dip below 20% for a duration of 20-cycles is acceptable.

While PSSE is an industry standard for transient stability analysis, some aspects of the multi-terminal HVdc models that are associated with the software are incompatible with the requirements of this study. The power flow model is restricted in the control modes available, and the stability model requires extensive response data that can be obtained only from other sources, such as detailed simulation. Therefore, the primary tool used for the Transient Stability Study was the PSCAD electromagnetic transients simulation software.

AC system data used for the transient stability analysis was based on that used in the DC 1020 HVdc System Integration Study – Power Flow and Short Circuit Analysis. Due to the length of computation time required to perform simulations in electromagnetic transients software, direct implementation of the PSSE ac system models used in the power flow analysis is not practical within PSCAD; therefore some reduction of the ac system representations was required.

Results of the DC 1020 HVdc System Integration Study – Power Flow and Short Circuit Analysis indicated that additional voltage support would be required in the form of one 150 MVAr synchronous condenser at Soldiers Pond and one 200 MVAr Static Var Compensator (SVC) at Sunnyside.

The DC 1020 HVdc System Integration Study - Comparison of Conventional and Capacitor Commutated Converter (CCC) HVdc Technology study indicated that the system upgrades recommended in the DC 1020 HVdc System Integration Study – Power Flow and Short Circuit Analysis were not sufficient to dynamically support the HVdc in-feed.

Based on the results of the DC 1020 HVdc System Integration Study - Comparison of Conventional and CCC HVdc Technology, the following ac system upgrades were included in the remainder of the transient stability studies:

- Application of 50% series compensation to both 230 kV lines from Bay d'Espoir to Pipers Hole.
- One 300 MVAr high-inertia synchronous condenser must be in service at Pipers Hole. This replaces the 200 MVAr SVC at Sunnyside that was identified in the Power Flow Analysis. The machine and excitation parameters for the 300 MVAr high-inertia synchronous condenser used are the same as those of identical machines currently in service at Manitoba Hydro's Dorsey converter station.

- One 300 MVAr high-inertia synchronous condenser must be in service at Soldiers Pond. This replaces the 150 MVAr synchronous condenser at Soldiers Pond that was identified in the Power Flow Analysis. The machine and excitation parameters for the 300 MVAr high-inertia synchronous condenser used are the same as those of identical machines currently in service at Manitoba Hydro's Dorsey converter station.
- The proposed five new CTs are relocated from Holyrood to Pipers Hole.

Furthermore, only conventional HVdc technology was considered for the transient stability study.

The original PSSE full-system model provided by Hydro of the Newfoundland system for the power flow analysis represented all the high-voltage networks as well as the low-voltage distribution networks down to 600 V. Most of these low-voltage distribution networks can be suitably replaced with equivalent loads for transient stability studies without impacting the accuracy of the simulation results. Reduced ac system models were developed and their performance benchmarked against the full system model.

In order to validate the system reduction, the short-circuit levels at key buses within the full- and reduced-system models were compared, and the results indicated a good agreement. As a result of this comparison, a PSCAD model for the Newfoundland ac system was developed based on the reduced PSSE model. In this initial PSCAD model, the HVdc converter at Soldiers Pond was represented by an ac source whose magnitude and phase angle were controlled to result in a real-power injection and reactive-power absorption equivalent to that of the operating HVdc link.

The ac transmission lines were modeled in PSCAD using a distributed parameters (Bergeron) model based on the data within the PSSE models. Key 230 kV lines were modeled using the more accurate frequency-dependent models based on the physical line parameters and geometry provided by Hydro. Similarly, generator step-up transformer winding connections and the nominal ratings of all the transformers were updated based on the transformer data provided by Hydro. Constant-current and constant-impedance load models were used to model the active and reactive component of each load respectively.

Validation of the ac system implemented within PSCAD included the following:

- Comparison of the active and reactive power flows within the PSCAD and reduced PSSE models - Results showed excellent comparison of the real and reactive power flows, with the greatest difference being 2 MVAr, which can be attributed to inherent differences in modeling techniques used by the two softwares.
- Comparison of the equivalent Thevenin Impedances at various buses within the PSCAD and reduced PSSE models - For this comparison, all generators are replaced with their sub-transient reactance, and all the loads are modeled as constant impedance.

  In PSCAD the representation of a transmission network and loads is valid for a wide range of frequencies from 0 Hz to several kHz. However, the transmission network and load model used in PSSE represents a phasor-based model valid only at 60 Hz. Therefore, in order to perform the comparison, the Thevenin impedance for the PSCAD model must be calculated at 60 Hz. Table 15

shows the comparison of equivalent impedance between the PSSE model and the PSCAD model at several buses within the Newfoundland system. The results indicate good agreement and, hence, validate the model of the transmission network within PSCAD.

- Comparison of the dynamic response of the PSCAD model and reduced PSSE models for several critical contingencies - The results indicated a good agreement between PSCAD and the PSSE reduced model.

Table 15
Comparison of Thevenin Impedances within the Newfoundland System

Bus/Station Name	Bus Number	Base KV	Z_{PSSE}		Z_{PSCAD}	
			Mag(Ω)	Ang(deg.)	Mag(Ω)	Ang(deg.)
Soldiers Pond	2490	230	18.45	71.96	18.43	71.92
Sunnyside	222	230	22.81	69.60	22.76	69.59
Bay d'Espoir	221	230	15.00	81.26	14.97	81.47
Stony Brook	216	230	29.38	75.34	29.27	75.20
Massey Drive	208	230	45.06	72.24	44.97	72.08

Overall, the validation showed a good comparison between PSCAD and the reduced PSSE, thereby providing confidence in the implementation of the Newfoundland ac network model in PSCAD.

Additional cursory checks were carried out involving a wide range of faults to validate the PSCAD model against the PSSE Full System Model, and it was found that for certain faults the dynamic response between the PSCAD model and the PSSE Full System Model were different. However, dynamic response between PSCAD and the reduced PSSE models showed good agreement for these faults. These results indicated a difference between the PSSE full- and reduced-system models that was not seen earlier. It should be noted that dynamic performance comparison of the full- and reduced-system models in PSSE was not carried out earlier.

Further investigations found that a suitable dynamic comparison can be obtained only if equivalent loads at Hardwoods (bus 335) and Chamberlains (bus 349) were replaced with original sub-systems used in the full-system model. These changes were implemented in the PSCAD and reduced PSSE models. After implementing these changes, good comparison of the dynamic performance was obtained.

The completion of the above procedure and resultant good comparison between PSSE and PSCAD results provided a high degree of confidence for the PSCAD model of the Newfoundland ac system.

The original PSSE full-system model provided by Hydro included a reduced-equivalent representation of the Labrador ac system in a weak configuration. The only additional reduction implemented prior to development of the model in PSCAD was the combination of identical individual generators into aggregate machines at Churchill Falls and Gull Island. The Labrador ac system model included the following:

- Gull Island Generation (2222 MVA) including excitation and governor systems.
- Churchill Falls Generation (5500 MVA) including excitation and governor systems.

- Muskrat Falls Generation was not included.
- One 230 kV line from Gull Island to Muskrat Falls and on to Happy Valley/Goose Bay.
- Generation (26.57 MVA) at Happy Valley/Goose Bay including excitation and governor systems.
- One 735 kV line from Gull Island to Romaine.
- Three 735 kV ac lines from Churchill Falls to Montagnais.
- One 735 kV ac line from Romaine to Montagnais.
- The AC system beyond Montagnais was represented by a source behind a complex equivalent with a short-circuit strength of 8023 MVA at a damping angle of 88.39 degrees.
- Two 230 kV lines from Churchill Falls to Wabush.
- Two synchronous condensers (60 MVA each) at Wabush including excitation systems.
- Loads and shunt reactors.
- The above represented a weak configuration for the Labrador ac system. For a strong configuration, the following modifications were made:
    - A 735 kV line from Gull Island to Churchill Falls was added;
    - A second 230 kV line from Gull Island to Muskrat Falls was added; and
    - A 165 MVAR shunt reactor at Gull Island was switched off.

Similar to the implementation of the Newfoundland ac system in PSCAD, transmission lines were represented using a distributed parameters (Bergeron) model based on the data included in the PSSE model. Validation of the PSCAD model included a comparison of short-circuit levels and Thevenin impedances at various impedances. As no simplifications were made to the generators or excitation and governor systems, no comparison of dynamic performance was undertaken. Table 16 shows the results of the comparison of Thevenin impedances. The results show good comparison and provide a high degree of confidence in the PSCAD model of the Labrador ac system.

Table 16
Comparison of Thevenin Impedances within the Labrador System

Bus/Station Name	Bus Number	Base KV	Z_{PSSE}		Z_{PSCAD}	
			Mag(Ω)	Ang(deg.)	Mag(Ω)	Ang(deg.)
Gull Island	2308	230	6.79	87.68	6.79	87.64
Montagnais	2800	735	24.96	72.23	24.96	72.20
Churchill Falls	2700	735	24.24	79.34	24.23	79.29
Wabush	2307	230	27.22	76.57	27.20	76.53
Muskrat Falls	2309	230	26.65	85.82	26.64	85.78

The New Brunswick ac system was represented with an equivalent, consisting of a voltage source behind a complex impedance based on the weak-system configuration. This simplification was deemed acceptable as it allowed for reasonable representation of the commutation performance of the HVdc converters at Salisbury. The New Brunswick system was therefore represented by a source behind a

complex equivalent impedance with a short-circuit strength of 3585 MVA at a damping angle of 76 degrees.

A PSCAD model of the multi-terminal HVdc system was developed which included a detailed representation of the HVdc control system. The proposed Lower Churchill Project (LCP) multi-terminal HVdc system included a number of key technical challenges that had to be overcome during the development of the control system, including:

- Multi-terminal configuration – Although multi-terminal HVdc has been used in the past, detailed information on actual control systems in service is not readily available; therefore, considerable effort was required to develop and implement the overall control-system concepts.
- Long HVdc cable – Although two-terminal HVdc systems with undersea cables are in operation, the length of the cable section across the Cabot Strait is considerably longer than those of any systems currently in operation. (Note that there are currently a number of HVdc links under design or construction with cable lengths longer than that of the LCP.) The length of the undersea cable (and hence the cable capacitance) has a dramatic impact on the overall performance of the HVdc link and must be accounted for in the design of the control system. Furthermore, the length of cable, coupled with the multi-terminal configuration, added yet another dimension to the requirements of the control system.
- Significance of the HVdc in-feed to the Newfoundland ac system – Since the HVdc in-feed represents a significant portion of the generation on the Island of Newfoundland, performance of the HVdc system is key to the overall stability of the Newfoundland ac system. This requirement puts added complexity on the control system.

Salient features of the HVdc control system adopted include the following:

- In order to improve commutation performance, the system is operated with current control at the inverter(s) and voltage control at the rectifier. This mode of operation provides better immunity to commutation failure resulting from disturbances in the inverter ac system.

  When a long HVdc cable is combined with an inverter connected to a weak ac system, the performance of the HVdc link is severely impacted by the fact that the cable can discharge quickly into the inverter when the ac system voltage drops a small amount. This increase in dc current causes a transient increase in converter reactive power consumption which further reduces the weak system bus voltage. The initial transient increase in dc current is not seen by the rectifier, since it is mainly driven by the energy stored in the large capacitance of the HVdc cable; therefore implementation of current control at the rectifier is not effective in controlling the over-current.

  By operating the inverter in current control, it can respond immediately to the transient increase in dc current to counteract the discharge into the inverter. This however requires the inverter to operate at a higher extinction angle so that it has sufficient room to provide current control while avoiding commutation failure.
- The HVdc power order is set by the station(s) operating as inverter.

- A current-balance controller was implemented to ensure that current order allocation to inverters and rectifiers was always balanced.
- A frequency controller was developed that measures the frequency of the Newfoundland ac system and modulates the HVdc power in-feed to stabilize the Newfoundland frequency. Effective frequency control of the Newfoundland system will minimize the need for under-frequency load shed in the Newfoundland system, even for large disturbances.
- A special damping feature was implemented to improve the overall performance of the long cable system. This damping function is designed to counteract sudden increases in HVdc current that can result in commutation failures.
- The control system uses digital sampling throughout in order to provide a realistic representation of the modern HVdc control system that would be used in the actual plant. Furthermore, the implementation of the overall control system is based on practical experience and reflects a control system that could be supplied for the actual plant by any of the current HVdc suppliers.

Following development of the basic control system in PSCAD, an extensive program of parameter tuning was undertaken. Initial tuning was performed using simple ac system equivalents at each of the three converters chosen to represent expected weak ac system conditions. The goal of the initial tuning was to provide recovery of HVdc power to 90% of the pre-fault level within 300 ms of fault clearing for faults within each of the three ac systems.

Following initial tuning, the HVdc system model was integrated into the PSCAD model of the three ac systems, which was developed independently and controller parameters were retuned as required. Following extensive testing and parameter optimization, acceptable system performance was obtained. The final control-system configuration and parameters selected represent a reasonable HVdc control system that could be implemented in the field and provide a high degree of confidence in the study results.

A total of 11 system scenarios were developed based on a combination of the final ac system base cases (BC1 to BC11) and HVdc configurations identified which represented a wide range of operating conditions as shown in Table 17. As seen in Table 17, the only difference between base cases 1, 9, 10, and 11 is the representation of the New Brunswick ac system. As the New Brunswick system was not the focus of the study, it was decided that cases 9, 10, and 11 would not be considered in the study. Base case 1 was retained, as it represented the worst-case configuration of the New Brunswick system (weak, peak-load configuration).

Two additional base cases (12 and 13), as shown in Table 17, were added to the study.

Detailed generation dispatch within the Newfoundland system for each of the base cases considered in the study is shown in Table 18.

Table 17
System Configurations

No.	Hydro System Load	Soldiers Pond	Newfoundland Generation	Labrador (Gull)	NB
BC1	Peak (1600 MW)	Full Import (800 MW)	economic dispatch	Weak	Weak, peak load
BC2	Peak (1600 MW)	Reduced Import (600 MW)	maximum economic dispatch	Weak	Weak, peak load
BC3	Future Peak (1800 MW)	Full Import (800 MW)	Maximum generation	Weak	Weak, peak load
BC4	Summer Night (550 MW)	Reduced Import (250 MW)	Minimum generation	Weak	Weak, peak load
BC5	Summer Night (550 MW)	Minimum Import (80 MW)	economic dispatch	Weak	Weak, peak load
BC6	Intermediate (1000 MW)	Full Import (800 MW)	economic dispatch	Weak	Weak, peak load
BC7	Intermediate (1000 MW)	Minimum Import (80 MW)	maximum economic dispatch	Weak	Weak, peak load
BC8	625 MW	Export (175 MW)	maximum economic dispatch	Weak	Weak, peak load
BC9	Peak (1600 MW)	Full Import (800 MW)	economic dispatch	Weak	Strong, peak load
BC10	Peak (1600 MW)	Full Import (800 MW)	economic dispatch	Weak	Weak, light load
BC11	Peak (1600 MW)	Full Import (800 MW)	economic dispatch	Weak	Strong, light load
BC12	Summer Night (550 MW)	Import (80 MW)	economic dispatch	Strong	Weak, peak load
BC13	Future Peak (1800 MW)	Reduced Import (600 MW)	maximum generation	Weak	Weak, peak load

Table 18
Newfoundland Generation Dispatch for Retained Base Case Scenarios

Base Cases	BC1	BC2	BC3	BC4	BC5	BC6	BC7	BC8	BC12	BC13
Hydro System Load (MW)	**1584.5**	**1584.5**	**1750.5**	**625.0**	**625.0**	**990.1**	**990.1**	**625.0**	**625.0**	**1750.5**
Generation Dispatch										
HVdc at Soldiers Pond	765.9	578.4	765.9	248.8	78.5	765.9	78.5	-175.0	79.8	574.2
Hydro										
Bay d'Espoir Unit 1	57.8	67.8	69.0	61.6	60.6	58.5	71.2	59.1	59.2	67.6
Bay d'Espoir Unit 2	58.2	68.3	69.5	off	off	off	69.7	58.0	off	68.1
Bay d'Espoir Unit 3	58.2	68.3	69.5	off	60.8	off	69.7	58.0	60.8	68.1
Bay d'Espoir Unit 4	58.2	68.3	69.5	off	off	off	69.7	58.0	off	68.1
Bay d'Espoir Unit 5	58.2	68.3	69.5	off	60.8	off	69.7	58.0	60.8	68.1
Bay d'Espoir Unit 6	58.2	68.3	69.5	off	off	off	69.7	58.0	off	68.1
Bay d'Espoir Unit 7	135.0	154.0	154.0	135.0	135.0	sc	154.0	154.0	135.0	154.0
Cat Arm Unit 1	35.0	65.0	65.0	35.0	35.0	sc	60.0	65.0	35.0	65.0
Cat Arm Unit 2	35.0	65.0	65.0	sc	35.0	sc	60.0	65.0	35.0	65.0
Upper Salmon	75.0	84.0	84.0	64.0	75.0	70.0	75.0	84.0	75.0	84.0
Hinds Lake	67.0	75.0	75.0	off	off	off	67.0	75.0	off	75.0
Granite Canal	25.0	40.0	40.0	22.0	30.0	25.0	35.0	40.0	30.0	40.0
Paradise River	8.0	8.0	8.0	off	8.0	off	8.0	8.0	8.0	8.0
Hydro – Thermal										
Hardwoods	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc
Stephenville	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc
Holyrood CT1	sc	30.0	sc	sc	sc	sc	sc	sc	sc	50.0
Holyrood CT2	sc	sc	sc	sc	sc	sc	sc	sc	sc	50.0
Holyrood CT3	sc	sc	sc	sc	sc	sc	sc	sc	sc	50.0
Holyrood CT4	sc	sc	sc	sc	sc	sc	sc	sc	sc	50.0
Holyrood CT5	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc
NUGS										
Star Lake	17.9	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4
Rattle Brook	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
CBP&P	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Exploits	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0
Wind										
St. Lawrence	25.0	25.0	25.0	0.0	0.0	12.0	12.0	0.0	0.0	25.0
Fermuse	25.0	25.0	25.0	0.0	0.0	12.0	12.0	0.0	0.0	25.0
Goulds	25.0	25.0	25.0	0.0	0.0	12.0	12.0	0.0	0.0	25.0
Total Generation	872.3	1073.3	1050.5	385.6	568.2	257.5	982.7	908.1	566.8	1242.1
HVdc Participation, %	48.3%	36.5%	43.8%	39.8%	12.6%	77.4%	7.9%	-32.0%	12.8%	32.8%

A total of nine different HVdc system configurations were originally proposed for the study, as shown in Table 19 below. Configurations DC4, DC5, and DC6 represent a mixed-mode operation where the rectifier and one inverter are operating in bipolar mode and the other inverter is operating in monopolar mode. Although such mixed-mode operation will be required in the actual system, the inclusion of these

configurations in this study would not provide any additional insight into the feasibility of the proposed HVdc interconnection. In addition, considerable time would have been required to implement mixed-mode operation within the PSCAD model; therefore it was decided that mixed-mode operation (configurations DC4, DC5, and DC6) would not be included in the study.

Table 19
HVdc System Configurations

Configuration	Gull Island	Soldiers Pond	Salisbury	Description
DC1	REC – BP	INV – BP	INV - BP	Normal
DC2	REC – MP	INV - MP[1]	INV - MP	Loss of 1 pole at Gull Island
DC3	REC – MP	INV - MP[2]	INV - MP	Loss of 1 pole at Gull Island
DC4	REC – BP	INV - MP[1]	INV - BP	Loss of 1 pole at Soldiers Pond
DC5	REC – BP	INV - MP[2]	INV - BP	Loss of 1 pole at Soldiers Pond
DC6	REC – BP	INV – BP	INV - MP	Loss of 1 pole at Salisbury
DC7	OFF	INV – BP	REC - BP	2-terminal
DC8	OFF	REC – BP	INV - BP	2-terminal
DC9	INV - BP	REC – BP	OFF	2-terminal

Notes: 1) Overload - monopolar at 2.0 p.u.
2) Continuous monopolar at 1.5 p.u.

A total of 13 system scenarios were developed based on a combination of the final base cases and HVdc configurations identified as shown in Table 20.

Table 20
Final System Configurations Considered

Base Case	DC	Soldiers Pond	Salisbury	Gull Island
BC1	DC1	800 BP	800 BP	1600 BP
	DC7	800 BP	800 BP–REC	OFF
BC2	DC3	600 MP	400 MP	1000 MP
BC3	DC1	800 BP	800 BP	1600 BP
	DC4	800 MP	400 MP	1000 MP
BC4	DC1	255 BP	800 BP	1055 BP
	DC3	255 MP	400 MP	655 MP
BC5	DC1	80 BP	800 BP	880 BP
BC6	DC1	800 BP	800 BP	1600 BP
BC7	DC1	80 BP	800 BP	880 BP
BC8	DC8	165 BP–REC	165 BP–INV	OFF
BC12	DC10	80 BP	OFF	80 BP
BC13	DC3	600 MP	400 MP	1000 MP

A total of 72 disturbances were identified for transient stability analysis. The full set of contingencies were simulated for the following scenarios;

- BC1-DC1 - HVdc in normal bipolar operation with peak Newfoundland load, economic generation dispatch, and full HVdc import at Soldiers Pond (800 MW).
- BC2-DC3 - HVdc in monopolar operation with peak Newfoundland load, maximum economic dispatch, and reduced HVdc import at Soldiers Pond (600 MW).
- BC6-DC1 - HVdc in normal bipolar operation with the weakest Newfoundland system with 1000 MW load, minimum generation dispatch, and full HVdc import at Soldiers Pond (800 MW).

From the above three full contingency analyses, the ten worst contingencies were identified and simulated for the remaining 10 of 13 system scenarios.

As a result of the need to modify the reactive power compensation within the Newfoundland ac system as compared to that used of the initial Short Circuit Analysis, a cursory review of fault levels within the Newfoundland system was undertaken.

5.3 Results of the Transient Stability Study

Good performance of the multi-terminal HVdc system was observed for all ac system and HVdc configurations considered.

Faults within the Newfoundland Island ac system can result in temporary commutation failure of the Soldiers Pond converter, depending on fault location and severity. The likelihood of commutation failure is increased due to the long undersea cable across the Cabot Strait. The large capacitance of this undersea cable tends to discharge through the Soldiers Pond inverter, whose dc voltage was transiently reduced due to the ac system fault. The cable discharge further increases the dc current, thus increasing the likelihood of commutation failure. However, following fault clearing, recovery of the HVdc infeed was seen to be good, with the HVdc power typically recovering to 90% of pre-disturbance power within 300 ms of fault clearing.

Faults within the Labrador and New Brunswick systems with the corresponding converters operating as inverters were not considered in detail; however, the same conditions will apply to these as to the Newfoundland system regarding likelihood of commutation failure and the impact of the long undersea cable.

- When operating in three terminal mode with two stations operating as inverters, commutation failure of one inverter causes a loss of HVdc power in the other inverter while the commutation failure persists; however, HVdc power recovery is good following removal of the commutation failure.
- Under some fault conditions within the Newfoundland ac system, the Soldiers Pond converter is able to continue commutation during the fault, resulting in a reduced HVdc power in-feed during the fault. Upon clearing of the fault, HVdc power recovery to the pre-disturbance level is good.
- No conditions (ac system configurations or contingencies) were observed under which the HVdc system could not successfully recover. Recovery of the HVdc power transfer is dictated, to a large extent, by the time required to charge the large cable capacitance; therefore, significant improvements in the speed of recovery beyond that obtained in these feasibility studies is not likely.

Performance in two-terminal mode with Soldiers Pond operating as an inverter or a rectifier was also seen to be good. Although the maximum power export from Soldiers Pond when operating as a rectifier was limited to approximately 165 MW due to the Newfoundland ac system configuration given, the results demonstrate that export from Newfoundland is feasible. With additional ac system upgrades, an increased export level should be attainable.

The system is transiently stable with adequate post-disturbance recovery. The majority of contingencies studied result in voltage dips with acceptable duration (20-cycle); however, some disturbances resulted in voltage dips beyond the criteria limits. Additional improvements in the Newfoundland ac system will be required to improve the voltage-sag problems if these are deemed excessive.

The need for under-frequency load shedding in the Newfoundland ac system is minimized. The HVdc system, due to its inherent controllability, provides an effective means of fast and efficient frequency control within the Newfoundland ac system by modulation of the HVdc power transfer to overcome capacity deficit or surplus situations. A number of simulations were carried out to show the effectiveness of such a control to maintain system stability.

Figure 3 shows the effectiveness of the HVdc frequency control at maintaining the Island frequency for the loss of the single largest generator on the Island of Newfoundland (Bay d'Espoir Unit #7). As seen in Figure 3 the Island frequency recovers to 1.0 pu following loss of the largest single generator on the Island when the frequency control is active; whereas, without the frequency control, the frequency decays, and under-frequency load shed would be required on the Island to avoid eventual frequency collapse.

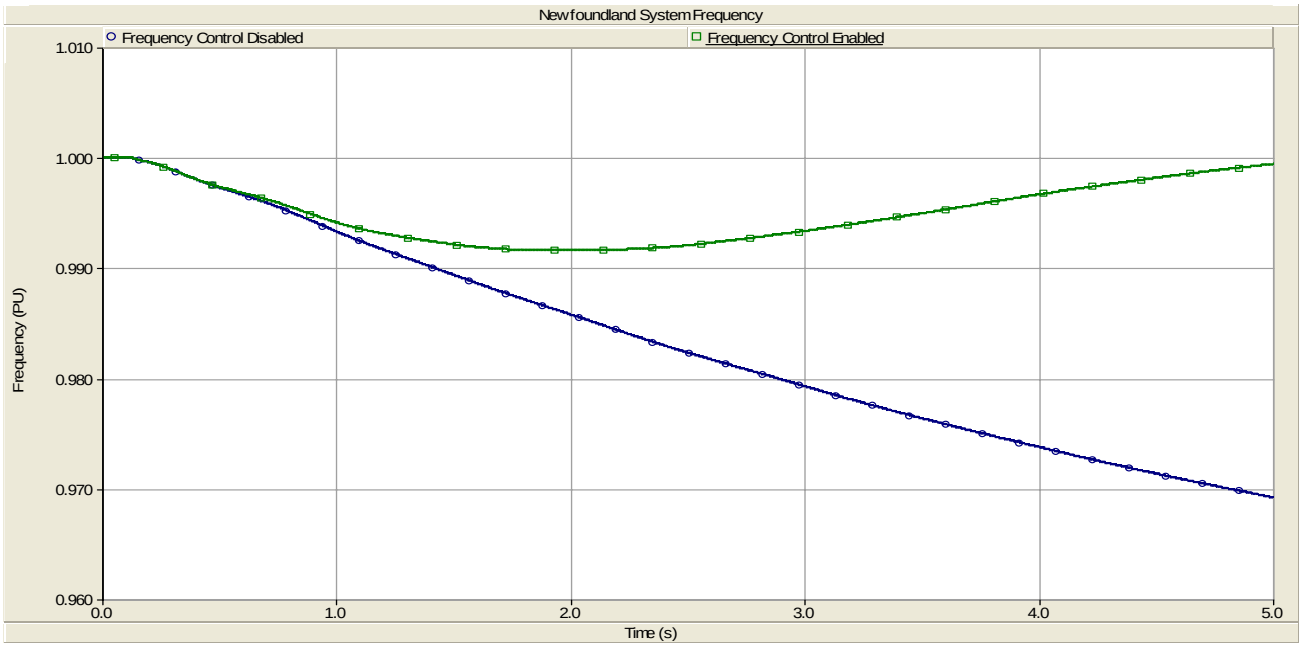


Figure 3 - Effect of HVdc Frequency Control on Newfoundland Island Frequency (Base-Case: BC1-DC1, Trip Unit #7 at Bay d'Espoir)

Effective frequency regulation can be provided by the HVdc link as long as the frequency controller does not reach its output limit or the dc current order does not reach its maximum or minimum limits. Selection of the limits on the output of the frequency controller itself should be done to provide sufficient range to modulate the HVdc power transfer to overcome the worst case expected capacity deficit or surplus situations. The limits should be selected considering both rectifier and inverter operation of the Soldiers Pond converter.

As previously mentioned, the HVdc frequency control feature modulates the dc power at Soldiers Pond to correct for under or over frequency conditions within the Newfoundland ac system. When Soldiers Pond operates as an inverter, an under-frequency condition on the Newfoundland ac system will cause the frequency controller to increase in HVdc power infeed to counteract the under frequency, while an over-frequency will result in a decrease in HVdc power infeed. Conversely when Soldiers Pond is operating as a rectifier, an under-frequency condition on the Newfoundland ac system will cause the frequency controller to decrease the HVdc power export to counteract the under frequency, while an over-frequency will result in a increase in HVdc power export.

The output of the frequency controller is a “delta power order” which is then used to calculate a dc current order modulation signal which is summed to the main dc current order prior to the application of current order limits. Therefore, if the output of the frequency controller attempts to modulate the current order beyond its upper or lower limits it cannot do so. In such a situation, the frequency controller would not be able to provide effective frequency control. Consideration must be given to what operating conditions can result in the effectiveness of the HVdc frequency controller being limited by reaching current order limits, resulting in the need for alternative measures to stabilize the Newfoundland ac system frequency.

Under conditions where the Soldiers Pond converter is operating at a low HVdc power level, the ability of the HVdc link to mitigate over-frequencies on the Newfoundland system when Soldiers Pond is an inverter, or under-frequencies when Soldiers Pond is a rectifier, will be limited by the minimum dc power transfer capability of the Soldiers Pond converter, which would typically be in the range of 10%. In the event that sufficient room does not exist between the pre-disturbance operating point and the minimum power level to provide the necessary frequency control, it may be possible to reverse the operation of the Soldiers Pond converter from inverter to rectifier operation (or vice-versa). This however would result in a “step change” of HVdc power from minimum import to minimum export (or vice-versa) which may be more than is required to overcome the frequency deviation. Additional studies are required to determine if this is feasible.

Under normal bipolar operating conditions with Gull Island operating as the rectifier and Soldiers Pond as an inverter, the 1.5pu continuous overload rating should provide adequate range for mitigation of under frequency conditions on the Newfoundland ac system.

Under monopolar operation with Gull Island operating as a rectifier and Soldiers Pond as an inverter, mitigation of under-frequencies on the Newfoundland ac system will not be possible if the HVdc in-feed at Soldiers Pond is operating at its 2.0 pu, ten minute overload rating. If the Soldiers Pond converter is operating at its 1.5pu continuous overload rating, mitigation of under-frequencies will be possible only if the HVdc in-feed can be transiently increased into the 10 minute overload region. This will depend on

the allowed frequency of operation within the 1.5 pu to 2.0 pu range and the time since the last operation within this range.

Under two-terminal bipolar or monopolar operation with Salisbury operating as the rectifier and Soldiers Pond as the inverter, mitigation of under-frequencies on the Newfoundland ac system will be limited by the maximum overload rating of the Salisbury converter. Therefore some consideration should be given to increasing the overload of the Salisbury converter to provide adequate range for frequency control of the Newfoundland system when in two terminal operation.

With Soldiers Pond operating as a rectifier, the studies indicate that the maximum HVdc export from the Newfoundland system is approximately 165 MW due to limitations of the ac system. Under such conditions, mitigation of over-frequency conditions on the Newfoundland ac system should be possible. If the export level is increased due to ac system enhancements, then consideration must be given to the ability to mitigate over-frequencies by reaching the maximum rating of the Salisbury converter.

In summary the results show that the HVdc frequency control feature can effectively mitigate frequency variations within the Newfoundland ac system, however some conditions do exist where its ability can be limited. Therefore the existing under-frequency load shedding scheme should be modified in order to operate only when the HVdc frequency controller is not able to provide the necessary control for under-frequency conditions. Likewise, a generation rejection scheme should also be considered for the Newfoundland system in order to operate only when the HVdc frequency controller is not able to provide the necessary control for over-frequency conditions.

Most contingencies were simulated with the HVdc frequency control disabled in order to identify critical cases with maximum frequency deviations. A number of contingencies were repeated with the HVdc frequency control enabled to demonstrate its effectiveness at stabilizing the Newfoundland ac frequency.

The 2.0 pu overload rating of the Soldiers Pond converter provides effective mitigation for loss of one pole at Soldiers Pond. In such an event, the remaining pole automatically increases its power transfer to compensate for the lost HVdc in-feed. This is possible as long as the rectifier station has sufficient capability to supply the required HVdc power on the remaining pole, which is always the case if Gull Island is operating as a rectifier. In the event that Salisbury is operating as the only rectifier and a pole is lost, the HVdc infeed into the Newfoundland system will be limited to the overload rating of one pole of the Salisbury converter; hence, some under-frequency load shedding may be necessary in the Newfoundland system. This situation again indicates the need to consider the potential benefits of increased overload capability of the Salisbury converter.

When Gull Island is operating as a rectifier and Soldiers Pond and Salisbury are operating as inverters, the impact of the complete loss of Gull Island on the Newfoundland system can be effectively mitigated by reversing the operation of Salisbury from inverter to rectifier operation. This is true assuming bipolar operation. In the case of monopolar operation, if the in-feed to Soldiers Pond is greater than 1.0 pu prior to the loss of the Gull Island converter, then reversal of the Salisbury converter from inverter to rectifier operation will not provide sufficient HVdc in-feed to the Newfoundland system (due to the overload capability of the Salisbury converter) and hence some under-frequency load shedding will be necessary in the Newfoundland system.

These studies have demonstrated that reversal of the Salisbury converter from inverter to rectifier operation upon loss of the Gull Island converter is possible from the Newfoundland ac system point of view; additional studies are required to verify that this is acceptable to the New Brunswick ac system. Reversal of any one converter station from rectifier to inverter operation (or vice versa) requires the use of high-speed reversing switches at the given converter station. Isolation of line sections from Taylors Brook to each of the converter stations will require high-speed switches at Taylors Brook.

When Soldiers Pond is operating as a rectifier, power runbacks can be applied to the Soldiers Pond converter following faults within the Newfoundland ac system. A power runback is a decrease in HVdc power order which is initiated through the HVdc controls and in this case is done to provide improved recovery of the ac system. The runbacks effectively delay the recovery of the HVdc system while there is a power deficit in the Newfoundland ac system; improving overall recovery. The runbacks are released following system recovery and the HVdc link returned to its pre-fault power level. Such power runbacks are commonly used in HVdc schemes to assist in the ac system recovery and should be considered.

The worst-case disturbance within the Newfoundland ac system is a three-phase fault at Bay d'Espoir on one of the 230 kV lines to Pipers Hole requiring tripping of the line to clear the fault. This fault causes the HVdc to fail commutation, which collapses the HVdc power momentarily. At the same time, it also causes a large disturbance of the Bay d'Espoir generators. Recovery from this fault is possible only with the cross tripping of the 175 MW refinery load at Pipers Hole. It should be noted that this study only considered tripping the entire refinery load at Pipers Hole, additional studies should be conducted to determine if tripping of a smaller block of load would be sufficient to maintain system stability.

A three-phase fault at the Pipers Hole end of one of the 230 kV lines to Bay d'Espoir followed by tripping of the 230 kV line to clear the fault also required cross tripping of the 175 MW refinery load to maintain overall system stability; however, this was not necessary for all system configurations considered.

The protection and fault-clearing times for faults at Bay d'Espoir and Pipers Hole should be optimized to prevent voltage sags of long duration.

Prolonged voltage dips can occur on various buses due to delayed fault clearing, which can extend to buses other than the affected ones. It is essential that protection philosophy and clearing time for delayed tripping be reviewed and optimized to minimize spreading of voltage dips.

A special protection and remedial action scheme is needed to reduce Gull Island generation in case of load rejection due to the outage of the last 735 kV line from Gull Island.

The model for the Transient Stability Study was developed based on the base cases and information made available by Hydro. The parameters of individual components were not reviewed and/or optimized. For the purpose of this study, the aggregate behavior of machines within the Newfoundland network was taken into consideration and individual machine swings were ignored. Furthermore, different load levels were studied without any system reinforcements. These studies have shown the technical feasibility of HVdc to act as the main source of power into the Newfoundland system. However, it is important that adequacy and modeling accuracy of the existing system be assessed in order to resolve any outstanding problems with the ac system.

5.4 Conclusions of the Transient Stability Study

Based on the results of this study it was concluded that:

1. Performance of the proposed multi-terminal HVdc system was seen to be good, successfully demonstrating the feasibility of the proposed multi-terminal HVdc interconnection. Bipolar, monopolar, multi-terminal and two terminal operations were studied and the performance was found to be good.

2. The following system upgrades were required within the Newfoundland ac system in order to support the HVdc in-feed:

   a. Conversion of all three units at Holyrood to synchronous condenser operation.

   b. Installation of five (5) combustion turbines that can operate as synchronous condensers at the Pipers Hole 230 kV bus.

   c. 50% series compensation of both 230 kV lines from Bay d'Espoir to Pipers Hole.

   d. One 300 MVAr high inertia synchronous condenser in-service at the Pipers Hole 230 kV bus at all times.

   e. One 300 MVAr high inertia synchronous condenser in-service at the Soldiers Pond 230 kV bus at all times.

   The above upgrades are in addition to upgrades as identified in the power flow study to avoid overloads on a number of 230 kV lines on the Island as follows:

   - Upgraded to 75 degrees C:
     - TL202 and TL206 from Bay d'Espoir to Pipers Hole and Pipers Hole to Sunnyside
   - Rebuild:
     - TL203 from Sunnyside to Western Avalon
     - TL201 from Western Avalon to Soldiers Pond and Soldiers Pond to Hardwoods

   NLH should verify the adequacy of TL207 from Sunnyside to Come By Chance and TL237 from Come By Chance to Western Avalon in order to determine if upgrades are required as information provided indicates that the ratings on the circuits are higher than what exists in the PSSE models used.

   Note that potential impacts of the proposed 50% series compensation must be investigated in order to determine if other line upgrades in addition to those identified here are required as a result of the series compensation.

3. Faults within the Newfoundland Island ac system can result in temporary commutation failure of the Soldiers Pond converter, depending on fault location and severity. The likelihood of commutation failure is increased due to the long undersea cable across the Cabot Strait. The large capacitance of this undersea cable tends to discharge through the Soldiers Pond inverter, whose dc voltage was transiently reduced due to the ac system fault. The cable discharge further increases the dc current, thus increasing the likelihood of commutation failure. However, following fault clearing, recovery of the HVdc infeed was seen to be good, with the HVdc power typically recovering to 90% of pre-disturbance power within 300 ms of fault clearing.

4. No conditions (ac system configurations or contingencies) were observed under which the HVdc system could not successfully recover. Recovery of the HVdc power transfer is dictated, to a large extent, by the time required to charge the large cable capacitance; therefore, significant improvement in the speed of recovery beyond that obtained in these feasibility studies is not likely.

5. Performance with Soldiers Pond operating as a rectifier was successfully demonstrated. The maximum power export from Soldiers Pond when operating as a rectifier was limited to approximately 165 MW due to the Newfoundland ac system configuration given. With additional ac system upgrades, an increased export level should be attainable.

6. The system is transiently stable with adequate post-disturbance recovery. The majority of contingencies studied result in voltage dips with acceptable duration (20-cycle); however, some disturbances resulted in voltage dips beyond the criteria limits. Additional improvements in the Newfoundland ac system will be required to improve the voltage-sag problems if these are deemed excessive.

7. The need for under-frequency load shedding in the Newfoundland ac system is minimized. The HVdc system, due to its inherent controllability, provides an effective means of fast and efficient frequency control within the Newfoundland ac system by modulation of the HVdc power transfer to overcome capacity deficit or surplus situations. There are however a number of conditions where the HVdc system will not be able to provide the necessary frequency control due to operational limits or converter capacities. Therefore the existing under-frequency load shedding scheme in the Newfoundland system should be modified in order to operate only when the HVdc frequency controller is not able to provide the necessary control for under-frequency conditions. Likewise, a generation rejection scheme should also be considered for the Newfoundland system in order to operate only when the HVdc frequency controller is not able to provide the necessary control for over-frequency conditions.

8. The 2.0 pu, 10-minute overload rating of the Soldiers Pond converter and corresponding overload rating of the Gull Island converter provides suitable mitigation for the loss of a pole, even under conditions of high HVdc power in-feed.

9. When operating in three terminal mode with Gull Island as the only rectifier, the complete loss of the Gull Island converters can be successfully mitigated by reversal of the Salisbury converter from inverter to rectifier operation. The studies have shown that this is possible from the Newfoundland ac system point of view, additional studies are required to determine the impact on the New Brunswick ac system.

10. When the HVdc link is operating in two terminal mode with Salisbury as the rectifier and Soldiers Pond as the inverter, a number of situations arose where the HVdc in-feed to Soldiers Pond was limited due to the overload capability of the Salisbury converters, resulting in the need for under-frequency load shedding in the Newfoundland ac system. Consideration should be given to the potential benefits of providing additional overload capability within the Salisbury converter and the resultant improvements in the performance of the Newfoundland ac system when Salisbury is operating as the only rectifier. Increasing the overload rating of Salisbury will be limited by the current carrying capacity of the cable across Cabot Strait.

11. The worst-case disturbance within the Newfoundland ac system is a three-phase fault at Bay d'Espoir on one of the 230 kV lines to Pipers Hole requiring tripping of the line to clear the fault. This fault causes the HVdc to fail commutation, which collapses the HVdc power momentarily. At the same time, it also causes a large disturbance of the Bay d'Espoir generators. Recovery from this fault is possible only with the cross tripping of the proposed 175 MW refinery load at Pipers Hole. It should be noted that this study only considered tripping of the entire refinery load at Pipers Hole, additional studies should be conducted to determine if tripping of a smaller block of load would be sufficient to maintain system stability.
12. The protection and fault-clearing times for faults at Bay d'Espoir and Pipers Hole should be optimized to prevent voltage sags of long duration.
13. A special protection and remedial action scheme is needed to reduce Gull Island generation in case of load rejection due to the outage of the last 735 kV line from Gull Island.
14. Correctly designed/tuned stabilizers on the Gull Island generators are essential to maintain steady power flow through the 735 kV lines. Also, the performance of the Newfoundland ac system should be reviewed to evaluate requirements for stabilizers in other parts of the network.

5.5 Key Findings of the Transient Stability Study

The transient stability study successfully demonstrated the feasibility of the proposed HVdc multi-terminal system and in particular, demonstrated acceptable dynamic performance of the Newfoundland ac system with the proposed HVdc infeed given the following upgrades to the Newfoundland system:

- Conversion of all three units at Holyrood to synchronous condenser operation.
- Installation of five (5) combustion turbines that can operate as synchronous condensers at the Pipers Hole 230 kV bus.
- 50% series compensation of both 230 kV lines from Bay d'Espoir to Sunnyside.
- One 300 MVAr high inertia synchronous condenser is in-service at the Pipers Hole 230 kV bus at all times.
- One 300 MVAr high inertia synchronous condenser is in-service at the Soldiers Pond 230 kV bus at all times.

The above upgrades are in addition to upgrades as identified in the power flow study to avoid overloads on a number of 230 kV lines on the Island as follows:

- Upgraded to 75 degrees C:
  - TL202 and TL206 from Bay d'Espoir to Pipers Hole and Pipers Hole to Sunnyside
- Rebuild:
  - TL203 from Sunnyside to Western Avalon
  - TL201 from Western Avalon to Soldiers Pond and Soldiers Pond to Hardwoods

NLH should verify the adequacy of TL207 from Sunnyside to Come By Chance and TL237 from Come By Chance to Western Avalon in order to determine if upgrades are required as information provided indicates that the ratings on the circuits are higher than what exists in the PSSE models used.

Note that potential impacts of the proposed 50% series compensation must be investigated in order to determine if other line upgrades in addition to those identified here are required as a result of the series compensation.

Key findings of the transient stability study included the following:

- Performance of the proposed multi-terminal HVdc system in bipoar, monopolar, three-terminal, and two terminal operation was seen to be good.
- No conditions (ac system configurations or contingencies) were observed under which the interconnected HVdc and Newfoundland ac systems could not successfully recover. The system was transiently stable with adequate post-disturbance recovery. Recovery of the HVdc power transfer is dictated, to a large extent, by the time required to charge the large cable capacitance; therefore, significant improvement in the speed of recovery beyond that obtained in these feasibility studies is not likely.
- The need for under-frequency load shedding in the Newfoundland ac system is minimized. The HVdc system, due to its inherent controllability, provides an effective means of fast and efficient frequency control within the Newfoundland ac system by modulation of the HVdc power transfer to overcome capacity deficit or surplus situations. There are however a number of conditions where the HVdc system will not be able to provide the necessary frequency control due to operational limits or converter capacities. Therefore the existing under-frequency load shedding scheme in the Newfoundland system should be modified in order to operate only when the HVdc frequency controller is not able to provide the necessary control for under-frequency conditions.
- The 2.0 pu, 10-minute overload rating of the Soldiers Pond converter and corresponding overload rating of the Gull Island converter provides suitable mitigation for the loss of a pole, even under conditions of high HVdc power in-feed.
- When operating in three terminal mode with Gull Island as the only rectifier, the complete loss of the Gull Island converters can be successfully mitigated by reversal of the Salisbury converter from inverter to rectifier operation.
- Operation with the Soldiers Pond converter operating as a rectifier was successfully demonstrated. The maximum power export from Soldiers Pond when operating as a rectifier was limited to approximately 165 MW due to the Newfoundland ac system configuration given. With additional ac system upgrades, an increased export level should be attainable.

6. Cursory Evaluation of Alternate HVdc Configurations

The HVdc system configuration considered in the WTO DC1020 HVdc System Integration Study is a three-terminal HVdc system linking Labrador, Newfoundland, and New Brunswick. The proposed HVdc system is bipolar, with each converter station having the ability to run as either rectifier or inverter. It uses both cable and overhead line, with about 40 km of cable between Labrador and Newfoundland and about 480 km between Newfoundland and New Brunswick.

The Labrador (Gull Island) converters are nominally rated at 1600 MW; whereas, the Newfoundland (Soldiers Pond) and New Brunswick (Salisbury) stations are rated at 800 MW each. The converters at Soldiers Pond require an overload capability of 2.0 pu for 10 minutes and 1.5 pu continuously. This would allow for the startup of generation to avoid load shedding in the event of the loss of one pole of the HVdc system. The converters at Salisbury do not require any special overload capability and will have an overload rating which is typical of HVdc systems (10-15%).

All studies conducted within the WTO DC1020 HVdc System Integration Study considered this proposed multi-terminal HVdc system configuration. A cursory evaluation of alternate HVdc configurations was performed as a separate task within the overall WTO DC 1020 HVdc System Integration Study. This cursory evaluation compared a number of alternative HVdc configurations considering cost, expected performance and impacts on the reliability of the overall transmission system.

6.1 Objectives

The objective of this study was to compare a number of alternative HVdc configurations considering cost, expected performance and impacts on the reliability of the overall transmission system to the proposed base case multi-terminal HVdc system.

6.2 Summary of the Cursory Evaluation of Alternate HVdc Configuration Study

A cursory evaluation of alternate HVdc configurations was performed as a separate task within the overall WTO DC 1020 HVdc System Integration Study. This cursory evaluation compared a number of alternative HVdc configurations considering cost, expected performance and impacts on the reliability of the overall transmission system.

The configurations considered are as follows:

Base case: A three-terminal HVdc link connecting Gull Island, Soldiers Pond and Salisbury. This alternative was the main focus of the system integration studies.

Alternative 1: A two-terminal HVdc link connecting Gull Island to Soldiers Pond and another two-terminal HVdc link connecting Soldiers Pond to Salisbury.

Alternative 2: A two-terminal HVdc link connecting Gull Island to Soldiers Pond and another two-terminal HVdc link connecting Gull Island to Salisbury.

Alternative 3: A two-terminal HVdc link connecting Gull Island to Taylors Brook and another two-terminal HVdc link connecting Taylors Brook to Salisbury, in conjunction with new ac transmission from Taylors Brook to Soldiers Pond.

Alternative 4: A two-terminal HVdc link connecting Gull Island to Soldiers Pond and another two-terminal HVdc link connecting Taylors Brook to Salisbury, in conjunction with new ac transmission from Taylors Brook to Soldiers Pond.

Alternative 5: Three two-terminal HVdc links; one connecting Gull Island to Taylors Brook, one connecting Taylors Brook to Salisbury and one connecting Taylors Brook to Soldiers Pond.

The alternatives were compared in terms of the cost of the converter terminals, length of the overhead lines and cables, requirement for synchronous condensers, and advantages and disadvantages as compared to the base case multi-terminal HVdc configuration.

Converter cost calculations were made based on the assumption of 1pu$/MW for each converter of a two-terminal HVdc link.

One recent 2500 MW bipolar, two terminal HVdc project has been awarded at a price of 350 million USD, which equates to a cost of 140,000 USD/MW for both converter stations or 70,000 USD/MW for each of the two converters. Based on the CIGRE report of WG 14.20 the estimated cost of one converter terminal of a 450 kV, bipolar, two terminal HVdc system is 78,750 USD/MW. Based on these values it seems that the actual cost of a converter terminal is in the range of 75,000 USD /MW to 80,000 USD/MW.

This cost can be broken down into the following items:

Table 21
Approximate Cost Breakdown for an HVdc Terminal

Engineering and Overhead	20.00%
Other Equipment	10.00%
Controls	7.00%
ac Filters	10.00%
Civil Works	13.00%
Valves	20.00%
Transformers	20.00%
Total	100.00%

Converter costs for the base case multi-terminal HVdc configuration were increased by 10% to account additional costs associated with the multi-terminal option. The overload requirements for each alternative were determined and the corresponding converter costs calculated.

The total length of the HVdc overhead transmission line and undersea cable, along with any ac lines required for the given alternative were also determined. It should be noted that costs of the associated transmission lines and cables were not calculated; only the relative lengths were compared.

Synchronous condenser requirements on the Island of Newfoundland for the given alternative were considered based on the need to provide adequate Equivalent Short Circuit Ratio (ESCR) in the case of a single HVdc link, and the Multi-infeed Interactive Effective Short Circuit Ratio (MIESCR) in the case where two or more HVdc links terminate electrically close to one another. The MIESCR is a generalization of the ESCR index that can be used for multi-infeed systems to indicate the effect of one HVdc system on the other.

6.3 Results of the Cursory Evaluation of Alternate HVdc Configuration Study

The cost of converter terminals, length of overhead lines and cables and relative amount of synchronous condensers required for the base case multi-terminal HVdc configuration and the five alternatives considered are summarized in Table 22.

Table 22
Summary of Converter Costs, Line Lengths, and Synchronous Condenser Requirements

Case	Converter Cost		DC OH Line		DC cable km	ac OH Line km	Need for Synchronous Condenser
	pu$	Relative to base case	km	Relative to base case			
Base	4306	1	1488	1	520	0	Low
Alt. 1	6144	1.43	1894	1.27	520	0	High
Alt. 2	3864	0.83*	2170	1.46	561	0	Low
Alt. 3	6144	1.43	1082	0.73	520	800	Very High
Alt. 4	6144	1.43	1488	1	520	800	Fairly High
Alt. 5	8408	1.95	1488	1	520	0	Extremely High

* *No provision has been included to account for the fact that the total installed converter capacity at Gull Island is installed in two separate converter stations which should be expected to increase the cost as compared to installation of the entire capacity within a single converter.*

Salient points of the overall comparison of the alternatives includes:

- For all alternatives except alternative 2, the total cost of converters is greater than that of the base case multi-terminal HVdc configuration.
- For all alternatives except alternative 3, the total length of HVdc overhead line and cable is equal to or greater than that of the base case multi-terminal HVdc configuration. In the case of alternatives 3 and 4 an additional 800km of 230 kV ac transmission lines are required on the Island of Newfoundland.
- For all alternatives, synchronous condenser requirements within the Newfoundland ac system are equal to or greater than those of the base case multi-terminal HVdc configuration.
- None of the alternatives considered provided any significant advantages as compared to the base case multi-terminal HVdc configuration while providing some disadvantages.

6.4 Conclusions of the Cursory Evaluation of Alternate HVdc Configuration Study

Based on the results of this cursory evaluation it is concluded that the base case multi-terminal HVdc configuration offers the lowest overall cost when considering the cost of converters, HVdc overhead lines and undersea cables, ac transmission lines, and synchronous condenser requirements. Furthermore, none of the alternatives considered offered any significant advantages over the base case multi-terminal HVdc configuration. Therefore it is concluded than none of the alternative configurations should be considered as a preferable option to the base case multi-terminal HVdc configuration.

6.5 Key Findings of the Cursory Evaluation of Alternate HVdc Configuration Study

Key findings of the Cursory Evaluation of Alternate HVdc Configurations include:

- The base case multi-terminal HVdc configuration offers the lowest overall cost when considering the cost of converters, HVdc overhead lines and undersea cables, ac transmission lines, and synchronous condenser requirements.

- None of the alternatives considered offered any significant advantages over the base case multi-terminal HVdc configuration.
- Therefore it is recommended than none of the alternative configurations be considered as a preferable option to the base case multi-terminal HVdc configuration.

7. PSSE Model Development for Future Studies

The existing multi-terminal HVdc PSSE stability models which are available from the standard library provided with the PSSE software are "response" models. They require the user to provide voltage and current recovery characteristics to model recovery from converter blocks. These characteristics are very system dependant and must be obtained from the response of a good detailed electromagnetic transients model or from the response of the actual system. Detailed models will capture the interaction of the HVdc and ac systems, an important factor with weak ac systems, and will also capture the critical response of the dc line and cable network.

TransGrid Solutions has developed a user written HVdc model for PSSE that allows the representation of the closed-loop HVdc controls as well as the HVdc line L/R dynamics. This custom developed model uses a two time-step approach in which the HVdc model is run at a smaller time-step than the rest of the PSSE solution, thereby allowing the dynamics of the fast HVdc controls and of the HVdc line to be modeled. This model has been shown to provide far superior results when compared to the standard library HVdc models available in PSSE and other transient stability software packages.

The purpose of this task was to develop a more accurate PSSE stability model for multi-terminal HVdc. The transient stability study portion of the HVdc System Integration Study was performed using PSCAD, therefore the PSCAD model and its results provided all of the information necessary to develop and benchmark an appropriate and more accurate PSSE stability model for multi-terminal HVdc. This model uses the two time-step technique to model the dynamics of the HVdc overhead line and cable and the HVdc controls in order to provide a more accurate representation of the multi-terminal HVdc link for PSSE.

7.1 Objectives

The objectives of the PSSE multi-terminal HVdc stability model development are to:

- Develop a custom PSSE stability model of the multi-terminal HVdc link using simplified controls that are based on the PSCAD model used in the transient stability studies of WTO DC1020.
- Develop a PSSE IPLAN program to provide a simple method for the end user to set up a desired powerflow on the HVdc link in the PSSE loadflow program so that the model will initialize properly for use with the custom PSSE stability model.
- Validate the PSSE stability model against the PSCAD model for various loadflows and contingencies.

7.2 Summary of PSSE Model Development for Future Studies

The standard PSSE library contains only a response-type model for a multi-terminal HVdc link. This response-type model does not include any of the DC line/cable dynamics, nor does it model any of the HVdc closed-loop controls. Such a model also requires that one of the inverters be operated in voltage-control mode, which is not consistent with the control scheme used by the PSCAD model in the transient stability analysis.

Therefore, a custom model of the multi-terminal HVdc link was developed for use in future PSSE studies to represent the response of the multi-terminal HVdc system more accurately. This custom model is based on a two-timestep algorithm developed by TransGrid Solutions that allows for detailed controls and for HVdc overhead line and cable dynamics to be represented, while still ensuring numerical stability.

The PSSE multi-terminal HVdc model was programmed to be capable of operating in bipolar or monopolar modes for the following HVdc configurations:

1. 3-terminal: Gull Island – rectifier, Soldiers Pond – inverter, Salisbury – inverter
2. 2-terminal: Soldiers Pond – rectifier, Salisbury – inverter
3. 2-terminal: Salisbury – rectifier, Soldiers Pond – inverter

PSSE model validation was performed against the same PSCAD model as was used in the WTO DC1020 transient stability studies.

The PSSE transient stability solution is a fundamental frequency phasor-based solution, and does not represent switching harmonics or individual phase quantities. A typical timestep used in PSSE simulation is a half-cycle, or 8.33 ms, which is large relative to that used in PSCAD simulations. Accordingly, the user-written model alone is run at a smaller internal timestep in order to maintain numerical stability due to the small integration timesteps of the HVdc current, voltage, and gamma controllers, and to the differential equations associated with the line and cable capacitances and inductances. Since the PSSE model is a phasor-based solution and does not represent individual thyristors, commutation failures cannot be modeled accurately. In order to represent the response to a commutation failure of the HVdc link, the inverter is forced into “bypass” mode if the inverter extinction angle gamma falls below a certain internal model setpoint. This setpoint represents the minimum extinction angle below which the converter is assumed to fail commutation.

The PSCAD model is the actual project model used in the transient stability studies for WTO DC1020. It represents the details of all of the converter controls, including the DC converter current, voltage, and gamma controllers along with low level valve firing controls to produce firing pulses used to turn individual thyristors on and off. Filtering functions for signal measurement and conditioning are used to remove the harmonics generated by the converter. This model is the more accurate of the two, since it represents all parts of the control system and does not make any approximations. In electromagnetic transient simulation, network equations are solved at a series of discrete intervals (timesteps). A typical timestep used in a PSCAD simulation is 50 μs.

More accurate than the PSSE Transient Stability model, the PSCAD model includes all of the low-level firing controls, as well as the non-linear aspects of the electrical grid (such as transformer saturation). The application and removal of the fault are also point-on-wave dependent in the PSCAD solution (i.e. the fault can be applied at a peak voltage or at a zero point), which can affect the initial control response. The controls in the PSCAD model also respond to certain events, such as the detection of commutation failures and the sensing of individual phase voltages, which cannot be represented in the PSSE model. As

such, more accurate results are expected with the PSCAD model. Transient stability programs, such as PSSE, produce only positive-sequence voltages.

Initial validation of the PSSE model was performed using an equivalent test system consisting of ac equivalents representing short-circuit levels of 8694 MVA at Gull Island (Station A), 2994 MVA at Soldiers Pond (Station B) and 3585 MVA at Salisbury (Station C). The Gull Island terminal was operated in a bipolar configuration as the rectifier, supplying rated power to the Soldiers Pond and Salisbury terminals, both operating as inverters.

For all dynamic simulations, loads were modeled with the real power portion as constant current loads and with the reactive power portion as constant impedance loads.

The frequency controller at Soldiers Pond was enabled for all simulations.

The next step in the validation process was performed using the reduced Newfoundland Island and Labrador ac systems PSSE model, the same model representation as was used to perform the transient stability studies in PSCAD. The New Brunswick ac system remained as an equivalent voltage source.

In each of the three possible HVdc configurations that can be simulated with the PSSE it is possible to run any of them in bipolar or monopolar operation, resulting in a total of six possible HVdc configurations. Monopolar operation was only tested on the three-terminal HVdc configuration as it can be assumed that this validation testing can be extended to both of the two-terminal configurations.

The two two-terminal HVdc configurations, one in which Soldiers Pond is the rectifier and the other in which Salisbury is the rectifier, were tested in bipolar operation using powerflow cases BC8-DC8 and BC1-DC7 respectively.

In order to test the four HVDC configurations described above, the following powerflows were used for validation testing :

BC1-DC1 – Rated bipolar operation with Gull Island as rectifier and Soldiers Pond and Salisbury as inverters (3-terminal)

BC2-DC3 - Monopolar operation with Gull Island as rectifier and Soldiers Pond at 1.5 pu and Salisbury at 1.1 pu overload as inverters (3-terminal)

BC8-DC8 - Bipolar operation with Soldiers Pond as rectifier supplying 175 MW to Salisbury (2-terminal)

BC1-DC7 - Bipolar operation with Salisbury as rectifier supplying rated power to Soldiers Pond (2-terminal)

The test cases that were simulated are listed in Table 23.

Table 23
PSSE Model Validation Test Cases

Test No.	Contingency No. [2]	Power Flow Case	Power Flow Description	Test Description
T1.1	n/a	EQUIV	Equivalent Voltage Source System representing BC1-DC1.	**DC Voltage Reference Step at Station A.** 1.0 pu -> 0.95 pu -> 1.0 pu
T1.2	n/a	EQUIV		**DC Current Reference Step at Station B.** 1.0 pu -> 0.95 pu -> 1.0 pu
T1.3	n/a	EQUIV		**DC Current Reference Step at Station C.** 1.0 pu -> 0.95 pu -> 1.0 pu
T1.4	n/a	EQUIV		**3PF at Station A to 0% voltage for 100 ms.** No equipment tripping.
T1.5	n/a	EQUIV		**3PF at Station B to 0% voltage for 100 ms.** No equipment tripping.
T1.6	n/a	EQUIV		**3PF at Station C to 0% voltage for 100 ms.** No equipment tripping.
T1.7	n/a	EQUIV		**3PF at Station A to 50% voltage for 100 ms.** No equipment tripping.
T1.8	n/a	EQUIV		**3PF at Station B to 50% voltage for 100 ms.** No equipment tripping.
T1.9	n/a	EQUIV		**3PF at Station C to 50% voltage for 100 ms.** No equipment tripping.
T1.10	n/a	EQUIV		**3PF at Station A to 90% voltage for 100 ms.** No equipment tripping.
T1.11	n/a	EQUIV		**3PF at Station B to 90% voltage for 100 ms.** No equipment tripping.
T1.12	n/a	EQUIV		**3PF at Station C to 90% voltage for 100 ms.** No equipment tripping.
T2.1	C15	BC1-DC1	Bipolar three-terminal operation. Gull Island rectifier Soldiers Pond inverter – 1.0 pu Salisbury inverter – 1.0 pu 2016 winter peak Newfoundland Island load (1600 MW)	**3PF at Station B to 0% voltage for 100 ms.** No equipment tripping.
T2.2	C60	BC1-DC1		**3PF at Station A to 0% voltage for 100 ms.** No equipment tripping.
T2.3	C70	BC1-DC1		**3PF at Station C to 0% voltage for 100 ms.** No equipment tripping.
T2.4	C17	BC1-DC1		**3PF at Bay d'Espoir 230 kV bus.** Trip Bay d'Espoir – Pipers Hole line and refinery load.
T2.5	C18	BC1-DC1		**3PF at Pipers Hole 230 kV bus.** Trip Pipers Hole – Sunnyside line.
T2.6	C19	BC1-DC1		**3PF at Sunnyside 230 kV bus.** Trip Sunnyside – Western Avalon line.
T2.7	C20	BC1-DC1		**3PF at Western Avalon 230 kV bus.** Trip Western Avalon – Soldiers Pond line.
T2.8	C21	BC1-DC1		**3PF at Soldiers Pond 230 kV bus.** Trip Soldiers Pond – Hardwoods line.
T2.9	C22	BC1-DC1		**3PF at Oxen Pond 230 kV bus.** Trip Oxen Pond – Soldiers Pond line.
T2.10	C23	BC1-DC1		**3PF at Holyrood 230 kV bus.** Trip Holyrood – Soldiers Pond line.
T2.11	C72	BC1-DC1		**3PF at Pipers Hole 230 kV bus.** Trip Pipers Hole – Bay d'Espoir line.
T2.12	C26	BC1-DC1		**3PF at Pipers Hole 230 kV bus.** Trip Pipers Hole synchronous condenser.
T2.13	C28	BC1-DC1		**3PF at Soldiers Pond converter transformer 230 kV** Trip converter transformer and Pole 2.

Test No.	Contingency No. [2]	Power Flow Case	Power Flow Description	Test Description
T3.1	C15	BC2-DC3	Monopolar 3-terminal operation. Gull Island rectifier Soldiers Pond inverter – 1.5 pu overload Salisbury inverter – 1.1 pu overload Future winter peak Newfoundland Island load (1800 MW)	**3PF at Station B to 0% voltage for 100 ms.** No equipment tripping.
T3.2	C60	BC2-DC3		**3PF at Station A to 0% voltage for 100 ms.** No equipment tripping.
T3.3	C70	BC2-DC3		**3PF at Station C to 0% voltage for 100 ms.** No equipment tripping.
T3.4	C17	BC2-DC3		**3PF at Bay d'Espoir 230 kV bus.** Trip Bay d'Espoir – Pipers Hole line and refinery load.
T3.5	C19	BC2-DC3		**3PF at Sunnyside 230 kV bus.** Trip Sunnyside – Western Avalon line.
T4.1	C15	BC8-DC8	Bipolar 2-terminal operation. Gull Island OFF Soldiers Pond rectifier Salisbury inverter – 175 MW Summer night Newfoundland Island load (625 MW)	**3PF at Station B to 0% voltage for 100 ms.** No equipment tripping.
T4.2	C70	BC8-DC8		**3PF at Station C to 0% voltage for 100 ms.** No equipment tripping.
T4.3	C17	BC8-DC8		**3PF at Bay d'Espoir 230 kV bus.** Trip Bay d'Espoir – Pipers Hole line and refinery load.
T4.4	C19	BC8-DC8		**3PF at Sunnyside 230 kV bus.** Trip Sunnyside – Western Avalon line.
T5.1	C15	BC1-DC7	Bipolar 2-terminal operation. Gull Island OFF Soldiers Pond inverter – 1.0 pu Salisbury rectifier 2016 winter peak Newfoundland Island load (1600 MW)	**3PF at Station B to 0% voltage for 100 ms.** No equipment tripping.
T5.2	C70	BC1-DC7		**3PF at Station C to 0% voltage for 100 ms.** No equipment tripping.
T5.3	C26	BC1-DC7		**3PF at Pipers Hole 230 kV bus.** Trip Pipers Hole synchronous condenser.

The validation testing was performed using the PSCAD version 4.2.1 software package and the PSSE version 30.2 software package. The PSSE model validation tests were run with the default PSSE timestep of 8.33 ms.

Instructions on how to use the model were presented in the last section of the interim report.

7.3 Results of PSSE Model Development for Future Studies

The steady-state and dynamic performance of the PSSE model compares very well to the PSCAD model. Despite inherent differences between the models the comparability of results between the two models is excellent, and correlations are within the degree of accuracy possible given that PSCAD and PSSE use different main program solution methods.

The PSSE Transient Stability model compares very well to the PSCAD model; however, there are some slight differences evident in some cases. The controls for the converter are not represented in full detail in the PSSE model, and a simplified control system has been assumed to be sufficiently accurate and practical for the purposes of transient stability modeling.

Since the PSSE model is a phasor-based solution and does not represent individual thyristors, commutation failures cannot be modeled accurately. In order to represent the response of the HVdc link to a commutation failure, the inverter is forced into "bypass" mode if the inverter firing angle gamma

falls below a certain internal model setpoint. Therefore, disturbances that result in a commutation failure in PSCAD may look slightly different in PSSE.

Another inherent difference between the PSCAD and PSSE models is the measurement of the voltages and real and reactive powerflows in these models. The PSCAD method of determining an RMS quantity uses instantaneous three-phase inputs; whereas in PSSE the RMS value is calculated directly.

PSSE results for the validation testing performed on the equivalent test system provide a good comparison with PSCAD.

Some differences are notable in a few cases, particularly the 50% faults in which the HVdc system is on the verge of switching control modes on fault recovery (i.e. switching from voltage to current control at the rectifier). Control mode switchover occurs automatically and is driven by the error signals to the individual controllers (voltage, current, extinction angle). When a control mode switchover takes place a pronounced change in the response of the HVdc system can be observed. Therefore a very small difference in error signals to the controller can result in a noticeable difference in the overall system response if control mode switching occurs in one case and not in another. In some of the cases control mode switching occurred in the PSCAD model; whereas the PSSE model did not switch control modes. Again this was due to extremely small differences in inputs to the controllers which in the case of the PSCAD model were enough to initiate the control mode switchover and in the case of the PSSE model were just below the threshold of control mode switchover. Under these circumstances it is expected that the response of the two models looks slightly different.

In addition, some slight differences can be seen in current reference responses during fault cases. This is due to the fact that these current references are non-linear functions that are very dependent on the DC-voltage responses (due to voltage-dependent current limits). Any slight difference in DC-voltage response will cause a difference in DC current order.

Despite slight differences as described above, the overall trend of the responses between PSCAD and PSSE are very similar, and become nearly identical by several hundred milliseconds after fault clearing.

It should be noted that the PSCAD AC voltages are RMS measurements that have a smoothing time constant of 20ms, whereas the PSSE ac voltages are not smoothed, with the exception of the ac voltage measurements on the commutating buses that are coming from measurements inside the custom PSSE HVdc model; these three PSSE AC commutating bus voltages have a smoothing time constant of 8ms which is still not the same as PSCAD. Therefore the ac voltages look slightly different especially on fault application and clearing.

Results for the validation testing performed on the reduced PSSE model test systems provide a good comparison with PSCAD as well. The same comments can be made for these cases as was described for the equivalent test system above.

In addition to these comments, it should be noted that the 300 MVAR synchronous condensers modeled at Pipers Hole and Soldiers Pond do not model the same exciters in PSSE and PSCAD. The PSCAD model includes a more detailed and better exciter model, which was not available in the PSSE library.

Therefore, the differences in responses of the synchronous condensers in PSCAD and PSSE are sometimes cause for slight differences in voltage and reactive power quantities in the Newfoundland Island ac system, particularly for faults near to the synchronous condensers.

Please note that for the BC8-DC8 cases in which the Soldiers Pond terminal is exporting to the Salisbury terminal, the transient stability studies determined that the worst case Bay d'Espoir-Pipers Hole fault (contingency 17) requires a fast runback of the HVdc in order to maintain ac system stability on the Newfound Island. The custom PSSE model does not include this runback scheme and so this contingency is not shown in the validation testing.

7.4 Conclusions of PSSE Model Development for Future Studies

PSSE model validation was performed against the same PSCAD model as was used in the WTO DC1020 transient stability studies. Validation testing showed excellent correlation between the PSSE and PSCAD dynamic performance for most faults during various powerflow and HVdc configurations. Any differences in results can be attributed to inherent differences between the three-phase switching solution used in an electromagnetic transient program, such as PSCAD, and the positive-sequence phasor-based solution of transient stability software, such as PSSE. Validation testing provided excellent comparability within the degree possible between two such different types of models.

To summarize, the most important issue is that the PSSE model injects the correct currents such that the real and reactive powers at the AC buses – and especially the AC bus voltages – look as close to those of the PSCAD model as possible. The AC bus voltage responses between PSCAD to PSSE compare very well.

7.5 Key Findings of PSSE Model Development for Future Studies

Key findings of the PSSE Model Development for Future studies include:

- A user written multi-terminal HVdc model for PSSE suitable for future studies was developed and validated against the PSCAD model used for the transient stability study.
- Results of validation testing show very good correlation between the PSSE and PSCAD models providing a high degree of confidence in the PSSE model.
- The PSSE model allows the use of the PSSE transient stability software for future studies with a high degree of confidence in the representation of the multi-terminal HVdc system.

8. Discussion of Overall WTO DC102 HVdc System Integration Study Results

All ac system conditions considered in the HVdc System Integration Study were based on year 2016 and beyond. The year 2016 and future peak Newfoundland Island power flow cases considered have several significant modifications when compared to the system existing today:

- A new large refinery load (175 MW, 85 MVAr) is planned to be in service near Pipers Hole, between Bay d'Espoir and Sunnyside. As well, a nickel smelter load (83 MW, 40 MVAr) is planned for the Long Harbour area. The internal Hydro studies for the additions of these loads have not yet been completed; therefore it is expected that system impacts due to the loads will be observed in this HVdc feasibility study.
- Hydro is planning to convert units #1 to #3 at Holyrood to synchronous condensers as part of the Lower Churchill Project for voltage control and in support of the system short circuit level with the following ratings:
  - Unit #1 – 142/-72 MVAr
  - Unit #2 – 142/-72 MVAr
  - Unit #3 – 150/-69 MVAr
- Hydro is planning to install five 50 MW combustion turbines (CT) to meet load requirements between 2010 and the HVdc 2015 in-service date. These CTs will be specified with the capability to operate in synchronous condenser mode. Initial indications were that these CTs would be located at the Holyrood station.

The results of the overall WTO DC1020 HVdc System Integration Study include the following:

- The basic bipolar multi-terminal HVdc link is shown in Fig.4.

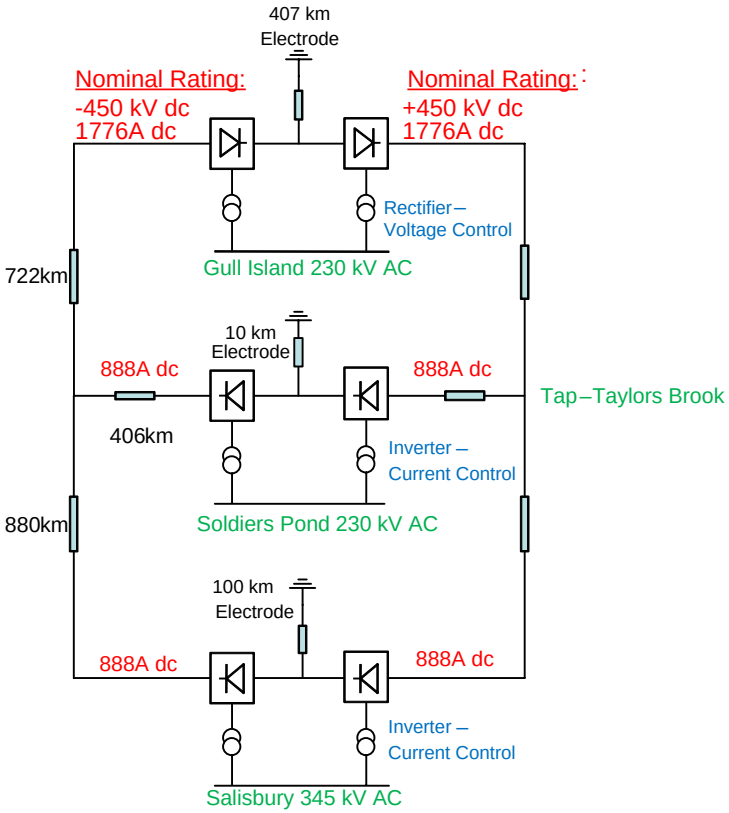


Figure 4 - Proposed Multi-Terminal HVdc System and Line Lengths

- Nominal operating points for the proposed multi-terminal HVdc system are shown in Table 24.

  During nominal bipolar operation, the Gull Island converter supplies a rated current of 1600 A (1.0 pu). The total power injected at Soldiers Pond is 769.6 MW and at Salisbury is 762.6 MW, resulting in losses of 30.4 MW and 37.4 MW at Soldiers Pond and Salisbury respectively.

  The losses increase when operating in monopolar mode, requiring up to 2850 A (1.60 pu current) at Gull Island to supply the 10-minute 100% overload requirement at Soldiers Pond (2.11 pu current) and the continuous 10% overload at Salisbury (1.1 pu current), and up to 2367 A (1.33 pu) at Gull Island to supply the continuous 50% and 10% overloads at Soldiers Pond (1.57 pu current) and Salisbury (1.1 pu current) respectively.

Table 24
Nominal Operating Points

Converter	Per Pole Parameters	Nominal Bipolar	10-min Overload Monopolar	Continuous Monopolar
Gull Island	Vdc (kV)	450	437	439
	Pdc (MW)	1600	1245	1067
	Idc (A)	1776 (1.0 pu)	2850 (1.6 pu)	2367 (1.33 pu)
	Qdc (MVAr)	738	646.9	514.3
	Alpha (deg)	15.8	13.3	13.7
Soldiers Pond	Vdc (kV)	433.3	408.3	416.0
	Pdc (MW)	769.6	764.8	578.2
	Idc (A)	888 (1.0 pu)	1873 (2.11 pu)	1390 (1.57 pu)
	Qdc (MVAr)	446.6	537.8	367.5
	Gamma (deg)	24.4	24.0	23.6
Salisbury	Vdc (kV)	429.4	407.7	413.3
	Pdc (MW)	762.6	398.3	403.4
	Idc (A)	888 (1.0 pu)	976.8 (1.1 pu)	976.8 (1.1 pu)
	Qdc (MVAr)	486.2	259.0	264.2
	Gamma (deg)	24.4	23.7	24.1

- The major Hydro Island load centre is located east of Bay d'Espoir on the Avalon Peninsula, while the majority of the generation is located west of Bay d'Espoir. This can result in heavy west to east power flow on the 230 kV transmission system, in particular between Bay d'Espoir, Sunnyside, Western Avalon and Soldiers Pond. In addition, approximately 255 MW of new industrial load (refinery and smelter) is planned to be installed along this heavily loaded west to east corridor, which serves to increase the loading on these 230 kV lines. As a general result this can cause voltage depression and thermal overloading in the area.

  The HVdc infeed into Soldiers Pond will normally be operated as an inverter and generally has a positive impact on the Island transmission system from the power flow point of view as it off-loads this west to east power flow by injecting power closer to the load centre.

- The following system upgrades were required within the Newfoundland ac system in order to support the HVdc in-feed:

  - Synchronous condensers:
    - Conversion of all three units at Holyrood to synchronous condenser operation.
    - Installation of five (5) combustion turbines that can operate as synchronous condensers at the Pipers Hole 230 kV bus.
    - One 300 MVAr high inertia synchronous condenser in-service at the Soldiers Pond 230 kV bus at all times.
    - One 300 MVAr high inertia synchronous condenser in-service at the Pipers Hole 230 kV bus at all times.

  The results indicated that the worst case contingencies (TL202/206 faults) can result in voltage collapse around Sunnyside due to the heavy west to east power transfers between Bay d'Espoir and Soldiers Pond. These already heavy west to east power transfers are further increased by the

proposed refinery and smelter loads which are also located along this transmission corridor. The synchronous condensers at Holyrood control their own bus voltage and are not VAR-limited during these worst contingencies because the voltage problems occur too far west of Holyrood for the reactive power support at Holyrood to be significantly useful in these voltage collapse scenarios. Since reactive power support is best provided locally as it cannot be transmitted over long distances, when considering the need to provide additional synchronous condensers to support the HVdc in-feed, consideration was also given to providing the necessary dynamic voltage support required near Sunnyside to avoid the possible voltage collapse scenarios.

It was found that the addition of one 300MVAR synchronous condenser at each of the Soldiers Pond and Pipers Hole buses provided the necessary support for the HVdc in-feed and avoided the voltage collapse for the worst case contingencies

High-inertia synchronous condensers are required in order to avoid excessive frequency decay which can occur for faults which cause a commutation failure of the Soldiers Pond converter while simultaneously disturbing the generation at Bay d'Espoir. The study shows the need to have one high-inertia synchronous condenser on at all times at each of the Soldiers Pond and Pipers Hole buses. The final number of synchronous condensers installed will have to take into account the need for maintenance outages.

- 50% series compensation of both 230 kV lines from Bay d'Espoir to Pipers Hole. Note that a detailed study is required to fully assess the impact of the proposed 50% series compensation on the Island ac system.
- Upgrades to avoid overloads on a number of 230 kV lines on the Island as identified in the power flow study as follows:
  - Upgraded to 75 degrees C:
    - TL202 and TL206 from Bay d'Espoir to Pipers Hole and Pipers Hole to Sunnyside
  - Rebuild:
    - TL203 from Sunnyside to Western Avalon
    - TL201 from Western Avalon to Soldiers Pond and Soldiers Pond to Hardwoods

  NLH should verify the adequacy of TL207 from Sunnyside to Come By Chance and TL237 from Come By Chance to Western Avalon in order to determine if upgrades are required as information provided indicates that the ratings on the circuits are higher than what exists in the PSSE models used.

  Note that potential impacts of the proposed 50% series compensation must be investigated in order to determine if other line upgrades in addition to those identified here are required as a result of the series compensation.
- Circuit breaker replacement as identified in the short circuit study. Note that during the course of the transient stability study the number and rating of synchronous condensers required to dynamically support the HVdc in-feed was increased as compared to that used in the short

circuit study. A cursory review of short circuit currents was conducted as part of the transient stability study, however short circuit levels should be verified once the final configuration of synchronous condensers is determined. The following is a list of substations where the existing circuit breakers would require replacement as identified in this study:

- Stony Brook 138kV
- Bay d'Espoir 230kV
- Holyrood 230kV

Once the final configuration is determined, further fault level investigation should be carried out to identify the individual breakers that should be replaced.

- Protection and fault clearing times, particularly for faults at Bay d'Espoir and Pipers Hole should be optimized in order to prevent voltage sages of long duration.
- The 50 MVAr shunt capacitor located at Western Avalon was assumed to be out of service for the transient stability studies as the synchronous condensers added to the Island system should provide sufficient voltage regulation to allow the shunt capacitor to be removed. This assumption should be verified using power flow analysis.

- The following special protection and control systems were required within the Newfoundland and Labrador ac systems in order to support the HVdc in-feed:
  - Cross tripping of the proposed 175 MW refinery load at Pipers Hole. The transient stability study determined that cross tripping of the refinery load was required in order to maintain system stability for faults which result in the tripping of one of the 230 kV lines between Bay d'Espoir and Pipers Hole. The study only considered tripping of the entire refinery load. Additional studies should be undertaken to determine if it would be possible to trip only a portion of the load while maintaining system stability.
  - The existing under-frequency load shed scheme on the Island should be re-examined and modified in order to avoid unnecessary load shed under conditions where the HVdc in-feed can stabilize the Island frequency. The under-frequency load shed scheme should be configured to act as a back up to the HVdc in-feed and should only operate in circumstances where the HVdc in-feed cannot control the Island frequency. Additional studies are required in order to coordinate the under-frequency load shed scheme with the HVdc system during detailed design studies.
  - Any existing special protection systems on the Island required to reduce generation in the case of over-frequency should be re-examined and modified in order to avoid unnecessary generator tripping under conditions where the HVdc in-feed can stabilize the Island frequency. The scheme should be configured to act as a back up to the HVdc in-feed and should only operate in circumstances where the HVdc in-feed cannot control the Island frequency. Additional studies are required in order to coordinate the generation reduction scheme with the HVdc system during detailed design studies.
  - A special protection scheme is required in Labrador in order to reduce generation in the case of a load rejection due to the outage of the last 735 kV line from Gull Island.

- The effectiveness of power system stabilizers within the Newfoundland system should be investigated. This includes a review of the design and tuning of existing stabilizers and the identification of potential new stabilizers which can provide benefit to the overall stability of the system.
- The application of correctly designed and tuned stabilizers on the Gull Island generators is essential to maintaining steady power flow through the 735 kV lines.
- HVdc run up and run back schemes should be implemented in order to aid in overall system stability.

- Conventional HVdc technology provides good overall system performance given the ac system upgrades identified above. Salient points of the performance of the proposed multi-terminal HVdc system include:
  - Performance of the proposed multi-terminal HVdc system in bipolar, monopolar, three-terminal, and two terminal operation was seen to be good.
  - No conditions (ac system configurations or contingencies) were observed under which the interconnected HVdc and Newfoundland ac systems could not successfully recover. The system was transiently stable with adequate post-disturbance recovery. Recovery of the HVdc power transfer is dictated, to a large extent, by the time required to charge the large cable capacitance; therefore, significant improvement in the speed of recovery beyond that obtained in these feasibility studies is not likely.
  - The need for under-frequency load shedding in the Newfoundland ac system is minimized. The HVdc system, due to its inherent controllability, provides an effective means of fast and efficient frequency control within the Newfoundland ac system by modulation of the HVdc power transfer to overcome capacity deficit or surplus situations. There are however a number of conditions where the HVdc system will not be able to provide the necessary frequency control due to operational limits or converter capacities. Therefore the existing under-frequency load shedding scheme in the Newfoundland system should be modified in order to operate only when the HVdc frequency controller is not able to provide the necessary control for under-frequency conditions.
  - The 2.0 pu, 10-minute overload rating of the Soldiers Pond converter and corresponding overload rating of the Gull Island converter provides suitable mitigation for the loss of a pole, even under conditions of high HVdc power in-feed.
  - When operating in three terminal mode with Gull Island as the only rectifier, the complete loss of the Gull Island converters can be successfully mitigated by reversal of the Salisbury converter from inverter to rectifier operation. This has been demonstrated form the point of view of the Newfoundland system only; additional studies are required to determine the impact on the New Brunswick ac system.
  - When the HVdc link is operating in two terminal mode with Salisbury as the rectifier and Soldiers Pond as the inverter, a number of situations can arise where the HVdc in-feed to Soldiers Pond is limited due to the overload capability of the Salisbury converters, resulting in the need for under-frequency load shedding in the Newfoundland ac system.

- Operating the Soldiers Pond converter as a rectifier was successfully demonstrated. The maximum power export from Soldiers Pond when operating as a rectifier was limited to approximately 165 MW due to the Newfoundland ac system configuration given. With additional ac system upgrades, an increased export level should be attainable.

- Many of the issues observed are not necessarily due to the HVdc infeed but are due to the lack of transmission linking the generation in the west to the load in the east and the impacts of the approximately 255 MW of new industrial load (refinery and smelter) which is planned to be installed along this heavily loaded west to east corridor. Additional system impact studies involving the proposed loads are required to define more exact requirements of connecting the new loads separate from the impacts of the HVdc infeed into Soldiers Pond.

- A cursory evaluation of alternate HVdc configurations was undertaken. The alternatives were compared in terms of the cost of the converter terminals, length of the overhead lines and cables, requirement for synchronous condensers, and advantages and disadvantages as compared to the base case multi-terminal HVdc configuration. The following alternative configurations were considered:

  - Base case: A three-terminal HVdc link connecting Gull Island, Soldiers Pond and Salisbury. This alternative was the main focus of the system integration studies.

  - Alternative 1: A two-terminal HVdc link connecting Gull Island to Soldiers Pond and another two-terminal HVdc link connecting Soldiers Pond to Salisbury.

  - Alternative 2: A two-terminal HVdc link connecting Gull Island to Soldiers Pond and another two-terminal HVdc link connecting Gull Island to Salisbury.

  - Alternative 3: A two-terminal HVdc link connecting Gull Island to Taylors Brook and another two-terminal HVdc link connecting Taylors Brook to Salisbury, in conjunction with new ac transmission from Taylors Brook to Soldiers Pond.

  - Alternative 4: A two-terminal HVdc link connecting Gull Island to Soldiers Pond and another two-terminal HVdc link connecting Taylor Brook to Salisbury, in conjunction with new ac transmission from Taylors Brook to Soldiers Pond.

  - Alternative 5: Three two-terminal HVdc links; one connecting Gull Island to Taylors Brook, one connecting Taylors Brook to Salisbury and one connecting Taylors Brook to Soldiers Pond .

- Salient points of the comparison of alternative HVdc configurations include:

  - For all alternatives except alternative 2, the total cost of converters is greater than that of the base case multi-terminal HVdc configuration. Converter costs for alternative 2 were found to be lower than the multi-terminal HVdc configuration however this was due to the simplified converter cost calculation method applied. It is expected that the actual cost of converters for alternative 2 would be at least equivalent to or greater than that of the multi-terminal HVdc configuration.

  - For all alternatives except alternative 3, the total length of HVdc overhead line and cable is equal to or greater than that of the base case multi-terminal HVdc configuration. In the case of alternatives 3 and 4 an additional 800km of 230 kV ac transmission lines are required on the Island of Newfoundland.

- For all alternatives, synchronous condenser requirements within the Newfoundland ac system are equal to or greater than those of the base case multi-terminal HVdc configuration.
- None of the alternatives considered provided any significant advantages as compared to the base case multi-terminal HVdc configuration.

In summary it was determined that none of the alternative configurations considered was found to be a preferable solution to the base case multi-terminal HVdc configuration.

- A user written multi-terminal HVdc model for PSSE suitable for future studies was developed and validated against the PSCAD model used for the transient stability study. Results of validation testing show very good correlation between the PSSE and PSCAD models providing a high degree of confidence in the PSSE model.The PSSE model allows the use of the PSSE transient stability software for future studies with a high degree of confidence in the representation of the multi-terminal HVdc system.

9. Conclusions

Based on the results of this study it is concluded that:

1. The feasibility of the proposed multi-terminal HVdc system was successfully demonstrated. Performance of the proposed multi-terminal HVdc system was seen to be good; bipolar, monopolar, multi-terminal and two terminal operations were successfully demonstrated. Conventional HVdc technology provides good overall system performance given the ac system upgrades identified.
2. Key upgrades and additions required in the Newfoundland ac system required to support the HVdc in-feed include:
   a. Conversion of all three units at Holyrood to synchronous condenser operation.
   b. Installation of five (5) combustion turbines that can operate as synchronous condensers at the Pipers Hole 230 kV bus.
   c. One 300 MVAr high inertia synchronous condenser is in-service at the Soldiers Pond 230 kV bus at all times.
   d. One 300 MVAr high inertia synchronous condenser is in-service at the Pipers Hole 230 kV bus at all times.
   e. 50% series compensation of both 230 kV lines from Bay d'Espoir to Sunnyside.
   f. Upgrades to a number of 230 kV lines to avoid potential overloads as follows:
      - Upgraded to 75 degrees C:
        - ♦ TL202 and TL206 from Bay d'Espoir to Pipers Hole and Pipers Hole to Sunnyside
      - Rebuild:
        - ♦ TL203 from Sunnyside to Western Avalon
        - ♦ TL201 from Western Avalon to Soldiers Pond and Soldiers Pond to Hardwoods

      NLH should verify the adequacy of TL207 from Sunnyside to Come By Chance and TL237 from Come By Chance to Western Avalon in order to determine if upgrades are required as information provided indicates that the ratings on the circuits are higher than what exists in the PSSE models used.

      Note that potential impacts of the proposed 50% series compensation must be investigated in order to determine if other line upgrades in addition to those identified here are required as a result of the series compensation.
   g. Replacement of a number of circuit breakers at the following substations:
      - Stony Brook 138 kV
      - Bay d'Espoir 230 kV
      - Holyrood 230 kV

      During the course of the transient stability study the number and rating of synchronous condensers required to dynamically support the HVdc in-feed was increased as compared to that

used in the short circuit study. A cursory review of short circuit currents was conducted as part of the transient stability study, however short circuit levels should be verified once the final configuration of synchronous condensers is determined. Once the final configuration is determined, further fault level investigation should be carried out to identify the individual breakers that should be replaced.

h. Modification of the existing under-frequency load shedding scheme to avoid unnecessary load shedding.

i. Implementation of a special protection system to cross trip the proposed refinery load at Pipers Hole in the event of a fault which results in the clearing of one of the 230 kV lines between Bay d'Espoir and Sunnyside.

3. The need for high inertia synchronous condensers is due to the low inertia of the Newfoundland system and the rapid frequency decline which can result from a fault that causes a commutation failure of the HVdc in-feed and simultaneous disruption of the generators at Bay d'Espoir.

4. Many of the issues observed are not necessarily due to the HVdc in-feed but are due to the lack of transmission linking the generation in the west to the load in the east and the impacts of the approximately 255 MW of new industrial load (refinery and smelter) which is planned to be installed along this heavily loaded west to east corridor. Additional system impact studies involving the proposed loads are required to define more exact requirements of connecting the new loads separate from the impacts of the HVdc in-feed into Soldiers Pond.

5. No conditions (ac system configurations or contingencies) were observed under which the interconnected HVdc and Newfoundland ac systems could not successfully recover. Recovery of the HVdc power transfer is dictated, to a large extent, by the time required to charge the large cable capacitance; therefore, significant improvement in the speed of recovery beyond that obtained in these feasibility studies is not likely.

6. The need for under-frequency load shedding in the Newfoundland ac system is minimized. The HVdc system, due to its inherent controllability, provides an effective means of fast and efficient frequency control within the Newfoundland ac system by modulation of the HVdc power transfer to overcome capacity deficit or surplus situations. There are however a number of conditions where the HVdc system will not be able to provide the necessary frequency control due to operational limits or converter capacities. Therefore the existing under-frequency load shedding scheme in the Newfoundland system should be modified in order to operate only when the HVdc frequency controller is not able to provide the necessary control for under-frequency conditions.

7. The 2.0 pu, 10-minute overload rating of the Soldiers Pond converter and corresponding overload rating of the Gull Island converter provides suitable mitigation for the loss of a pole, even under conditions of high HVdc power in-feed.

8. When operating in three terminal mode with Gull Island as the only rectifier, the complete loss of the Gull Island converters can be successfully mitigated by reversal of the Salisbury converter from inverter to rectifier operation. This has been demonstrated from the point of view of the Newfoundland system only; additional studies are required to determine the impact on the New Brunswick ac system.

9. When the HVdc link is operating in two terminal mode with Salisbury as the rectifier and Soldiers Pond as the inverter, a number of situations can arise where the HVdc in-feed to Soldiers Pond is

limited due to the overload capability of the Salisbury converters, resulting in the need for under-frequency load shedding in the Newfoundland ac system.

10. Operation with the Soldiers Pond converter operating as a rectifier was successfully demonstrated. The maximum power export from Soldiers Pond when operating as a rectifier was limited to approximately 165 MW due to the Newfoundland ac system configuration given. With additional ac system upgrades, an increased export level should be attainable.

11. A cursory evaluation of alternate HVdc configurations was undertaken. The alternatives were compared in terms of the cost of the converter terminals, length of the overhead lines and cables, requirement for synchronous condensers, and advantages and disadvantages as compared to the base case multi-terminal HVdc configuration. It was determined that none of the alternative configurations considered was found to be a preferable solution to the base case multi-terminal HVdc configuration.

12. A user written multi-terminal HVdc model for PSSE suitable for future studies was developed and validated against the PSCAD model used for the transient stability study. Results of validation testing show very good correlation between the PSSE and PSCAD models providing a high degree of confidence in the PSSE model. The PSSE model developed allows the use of the PSSE transient stability software for future studies with a high degree of confidence in the representation of the multi-terminal HVdc system.

10. Recommendations

This study has successfully demonstrated the feasibility of the proposed multi-terminal HVdc system and it is therefore recommended that the design of the multi-terminal HVdc system can be further refined to advance the implementation of the overall project.

Additional studies recommended for refinement of the functional design include:

1. System impact study of the proposed 175 MW refinery load at Pipers Hole.
2. A study to determine the impact of the 50% series compensation recommended for the 230 kV lines between Bay d'Espoir and Pipers Hole. Items to be addressed should include, but not be limited to;
    a. Insulation Co-ordination
    b. Switching Studies
    c. Series resonance studies
3. System integration study to evaluate the impact of the proposed HVdc system on the New Brunswick ac system.
4. Investigation into the impact of a bipole block on the Newfoundland ac system.
5. Reactive power study to optimize the ratings, location and number of synchronous condensers and ac filters required within the Newfoundland ac system.
6. Resonance studies to ensure that the HVdc system does not adversely interact with potential resonances in the Labrador, Newfoundland and New Brunswick ac systems. This should include:
    a. Harmonic resonance investigations
    b. Resonance study of the proposed dc line/cable.
7. A study to identify and mitigate any potential sub-synchronous resonance issues.
8. Facilities studies to develop detailed implementation schemes and cost estimates for the identified transmission and control system facilities.

11. Potential Further Work

In addition to the studies identified in the recommendations, it is noted that the HVdc system considered for this study consisted entirely of line commutated converters; the application of voltage source converters was not considered. Given the rapid development of voltage source converter technology, it is suggested that some consideration be given to the application of voltage source converters. Due to the necessary power ratings, it is likely that voltage source converters could only be used at the Soldiers Pond and Salisbury terminals, the Gull Island terminal would likely remain a line commutated converter. Such a hybrid scheme has never been studied, designed or placed into service however it may present some benefits and preliminary feasibility studies may be warranted to determine if such a configuration is possible.

One other option which may provide some benefits is a configuration using a two terminal line commutated HVdc system between Gull Island and Soldiers Pond and a separate two terminal voltage source converter HVdc system between Soldiers Pond and Salisbury. (The location of the voltage source converter in Newfoundland could be changed if it would provide added benefit).

References

1. DC1020 HVdc System Integration Study – Power Flow and Short Circuit Analysis Interim Report.
2. DC1020 HVdc System Integration Study - Comparison of Conventional and CCC HVdc Technology Interim Report.
3. DC1020 HVdc System Integration Study – Transient Stability Analysis Interim Report.
4. DC1020 HVdc System Integration Study – Cursory Evaluation of Alternate HVdc Configurations Interim Report.
5. DC 1020 HVdc System Integration Study – Multi-Terminal HVdc Link PSSE Stability Model Interim Report

APPENDIX C3 – DC1020 VOLUME 2 - HVDC SYSTEM INTEGRATION STUDY - POWER FLOW AND SHORT CIRCUIT ANALYSIS – MAY 2008

HYDRO
THE POWER OF COMMITMENT

THE Lower Churchill PROJECT

May 2008

DC1020 - HVdc System Integration Study

Volume 2 - Power Flow and Short Circuit Analysis

prepared by

HATCH™

in association with

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PETER KUFFEL
SIGNATURE
May 27/08
DATE
NEWFOUNDLAND & LABRADOR

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Appendices

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Appendix F - New Brunswick Power Injection Assessment
(Please refer to Attachment 1 for the corresponding set of plots.)

Attachment 1 - Set of Plots Corresponding to Appendix F

Executive Summary

Steady state analysis of the Lower Churchill multi-terminal HVdc project has been completed. The following conclusions can be made:

1. The steady state reactive power requirements are as follows:
    - Soldiers Pond 230 kV bus – 450 MVAr filters, 150 MVAr synchronous condenser
    - Sunnyside 230 kV – 200 MVAr capacitance

The reactive power support is required to compensate the HVdc converter reactive power absorption, to prevent voltage collapse under heavily loaded Island conditions particularly on 230 kV lines between Bay d'Espoir and Soldiers Pond, and to maintain the minimum effective short circuit ratio (ESCR) at the Soldiers Pond bus to 2.5.

2. HVdc losses in bipolar operation at nominal rating:
    - Operating at a dc voltage of 500 kV per pole with Gull Island producing nominal rated 1600 A per pole current, a total power of 765.8 MW is injected at Soldiers Pond and a total power of 763.4 MW is injected at Salisbury, resulting in losses of 34.2 MW and 36.6 MW at Soldiers Pond and Salisbury respectively.
3. HVdc losses in monopolar operation:
    - The losses increase when operating in monopolar mode, requiring up to 2611 A (1.66 pu current) at Gull Island to simultaneously supply the 10-minute 100% overload requirement at Soldiers Pond (2.16 pu current) and the continuous 10% overload at Salisbury (1.1 pu current), and up to 2149 A (1.34 pu) at Gull Island to supply the continuous 50% and 10% overloads at Soldiers Pond (1.58 pu current) and Salisbury (1.1 pu current) respectively.
4. Maximum fault levels at the following stations are increased by the listed percentages with the addition of a synchronous condenser at Soldiers Pond and the five new combustion turbines (CTs) at Holyrood:
    - Come by Chance - 10.1 – 37.6%
      Western Avalon – 12.0 – 37.3%
      Long Harbour – 23.5 – 97.8 %
      Sunnyside – 13.2 – 46.6%
      Oxen Pond – 7.3 – 41.4%
      Hardwoods – 8.1 – 69.1%
      Holyrood – 12.6-74.2%
    - At the Holyrood 230 kV station, nine breakers rated for 5100 MVA (B12B15, B3L18, B12L42, B3B13) and 5430 MVA (B2L42, B12L17, B1L17, B1B11, B2B11) would require replacement as their ratings are exceeded. No other breaker ratings are exceeded at other stations despite the increase in fault levels.
5. The minimum ESCR at the Soldiers Pond bus occurs during the minimum Island generation case for loss of Holyrood unit #3 resulting in the following ESCRs:

- ESCR = 1.9 (1967 MVA) without a synchronous condenser at Soldiers Pond
- ESCR = 2.5 (2545 MVA) with 150 MVAr synchronous condenser at Soldiers Pond

Therefore a synchronous condenser is required at Soldiers Pond to meet the minimum desired ESCR of 2.5.

6. Due to very heavy west to east power flow along the 230 kV transmission corridor between Bay d'Espoir and Soldiers Pond, made worse by a proposed new refinery load near Piper's Hole, several 230 kV lines were observed to be overloaded particularly for loss of one of the 230 kV lines in that corridor. The overloads are worst during cases of low DC infeed at Soldiers Pond and especially when exporting from Soldiers Pond, but can also occur to a lesser degree for the maximum DC infeed cases. The following line upgrades could be implemented to significantly reduce the amount of overloads observed:

Line		**Current Rating (MVA)**	**New Rating (MVA)**	**Upgrade**
TL202	Bay d'Espoir-Piper's Hole	199.3/297.7/369.5	341.8/402.4/453.8	Thermal uprate to 75 degrees C.
TL206	Piper's Hole – Sunnyside	199.3/297.7/369.5	341.8/402.4/453.8	Thermal uprate to 75 degrees C.
TL203	Sunnyside – Western Avalon	261.7/307.8/347.0	355.8/411.5/459.6	Rebuild with 804 MCM AACSR/TW conductor.
TL217	Western Avalon-Soldiers Pond	199.3/297.7/369.5	341.8/402.4/453.8	Recent review indicates can operate at 75 degrees C
TL201	Western Avalon-Soldiers Pond	175.5/260.2/322.2	355.8/411.5/459.6	Rebuild with 804 MCM AACSR/TW conductor.
TL201	Soldiers Pond-Hardwoods	175.5/260.2/322.2	355.8/411.5/459.6	Rebuild with 804 MCM AACSR/TW conductor.
TL207	Sunnyside – Come by Chance	355.8/411.5/459.6	-	Requires detailed review by Transmission Design.
TL237	Come By Chance-Western Avalon	355.8/411.5/459.6	-	Requires detailed review by Transmission Design.

Several overloads still exist after the line upgrades listed above are implemented, however the overloads only occur during cases of minimum DC infeed or during DC export. Generation re-dispatch in which the DC infeed power is increased and generation in the west is decreased can be used to relieve the remaining overloaded lines.

7. The need for a fast HVdc power run-up and run-down has been identified as follows:

   - Depending on whether the Soldiers Pond converter is importing or exporting power, a fast HVdc power run-up or run-down will be required to either increase the power being imported into Soldiers Pond or to decrease the power being exported in order to off-load the 230 kV transmission corridor between Bay d'Espoir and Soldiers Pond to prevent a voltage collapse scenario for loss of one of the parallel 230 kV lines between Bay d'Espoir and Piper's Hole. Power flow cases in which the DC infeed is operating at minimum power of 80 MW and cases in which the DC is exporting can result in pre-contingency power flows of greater than 300 MW on both of the Bay d'Espoir to Piper's Hole lines. It appears that if this pre-contingency power flow is greater than approximately 225-250 MW a fast DC run-up (when importing) and run-down (when exporting) is required to prevent system voltage collapse for loss of one of the 230 kV lines between Bay d'Espoir to Piper's Hole. Corresponding generation in the west would require transfer tripping.

8. It should be noted that a portion of the Island system upgrades identified in this report, in particular the need for reactive power support at Sunnyside and the extensive thermal upgrades required on 230 kV transmission between Bay d'Espoir and Soldiers Pond, are largely due to approximately 255 MW of new industrial load (refinery and smelter) which is planned to be installed along the heavily loaded transmission corridor. The major NLH Island load centre is located east of Bay d'Espoir on the Avalon Peninsula, while the majority of the generation is located west of Bay d'Espoir. This can result in heavy west to east power flow on the 230 kV transmission system, in particular between Bay d'Espoir, Sunnyside, Western Avalon and Soldiers Pond, with further increased loading due to the new industrial loads. As a general result this can cause voltage depression and thermal overloading in the area. The HVdc infeed into Soldiers Pond generally has a positive impact on the Island transmission system as it off-loads this west to east power flow by injecting power closer to the load centre. Many of the issues discussed are not necessarily due to the HVdc infeed but are due to the lack of transmission linking the generation in the west to the load in the east. For example, without the new refinery load, the reactive power requirement at Sunnyside reduces to approximately 50 MVAr from 200 MVAr. It will be important for further system impact studies involving the loads to define more exact requirements of connecting the new loads separate from the impacts of the HVdc infeed into Soldiers Pond.

1. Introduction

This report describes the steady state analysis portion of the WTO DC1020, the DC system integration studies for the Lower Churchill Project (LCP), including the power flow and short circuit studies. The purpose of the steady state analysis is to determine new facilities including steady state reactive power requirements and upgrades to existing facilities that are required within the Newfoundland and Labrador Hydro (NLH) transmission system in order to interconnect the 800 MW HVdc link while ensuring that the NLH criteria for acceptable power system operation is maintained.

The steady state analysis is performed using the PSS/E version 30.2 software package.

Also, this study assumes that New Brunswick (NB) transmission system is able to wheel through 760 MW from Salisbury 345 kV substation to the northern Maine area. This assumption has been validated in a separate study and the summary results are included in Appendix 6 – New Brunswick Power Injection Assessment. The load flow and transient stability study was carried out using PSS/E version 29.4 since the dynamic model was available in this format."

1.1 Objectives

The objectives of the steady state analysis are to determine:

1. The total steady state reactive power supply requirements at the converter stations, including the harmonic filter requirements for the converter stations in Labrador and Newfoundland and the potential need for any synchronous condenser(s) to provide additional reactive power support and/or to increase the effective short circuit ratio at the Soldiers Pond bus.
2. The requirements for any other reactive power supply elsewhere in the NLH transmission system to meet steady state voltage criteria.
3. The losses for the proposed HVdc solutions and associated configurations.
4. Any other equipment requirements such as new equipment or upgrades to existing NLH transmission system equipment required to meet thermal loading and steady state voltage criteria.
5. The pre-HVdc system strengths.
6. The impacts of adding the HVdc system including reactive power compensation additions on existing circuit breaker ratings to determine the need for any breaker replacements.
7. The range of ESCR at the Soldiers Pond bus for the various power system configurations and the reactive power compensation of the HVdc system.
8. Preliminary HVdc design parameters, including typical converter transformer impedances, ranges required for alpha and gamma at each station in each operating mode, and tap changer ranges for the converter transformers.
9. The required HVdc operating modes, considering the bi-directional nature of each terminal and the need to provide frequency control in Newfoundland.

1.2 Procedure

The steady state analysis is carried out using the following procedure:

1. Create power flow cases for the various NLH generation and load dispatches and for the various multi-terminal HVdc configurations and operating points. This involves merging the NLH power flow cases with the New Brunswick area power flow cases via a multi-terminal HVdc model.
2. Perform power flow studies by performing steady state contingency analysis on the NLH power system using the various power flow cases to determine the steady state reactive power requirements of the converters and to ensure that the steady state criteria, including voltage and thermal loading, is met for all operating conditions in the NLH system.
3. Perform short circuit studies by applying faults at key NLH system buses to determine the maximum short circuit levels and impacts to existing circuit breakers and to determine the range of minimum ESCRs at the Soldiers Pond bus using the reactive power supply requirements as determined from the power flow analysis.

2. Multi-terminal HVdc Information

2.1 Ratings, Losses and Equipment Data

The multi-terminal HVdc system consists of a three-terminal link connecting Labrador, Newfoundland and New Brunswick. The proposed HVdc system is bipolar with normal operation having Labrador as rectifier and Newfoundland and New Brunswick as inverters; however, each converter station is capable of operating as either rectifier or inverter.

The HVdc system will operate at a rated dc voltage of +/-500 kV. The Labrador terminal is connected to the Gull Island 230 kV bus and has a nominal rating of 1600 MW, or 1600 A. The Newfoundland terminal is connected to the Soldiers Pond 230 kV bus and has a nominal rating of 800 MW, or 800 A. The New Brunswick terminal is connected to the Salisbury 345 kV bus and has a nominal rating of 800 MW, or 800 A.

The HVdc infeed into Soldiers Pond will be a major source of power to the NLH Island and will provide frequency control. The converters at Soldiers Pond will require a 10-minute 2.0 pu and a continuous 1.5 pu overload capability in order to maintain supply to the Island during loss of an HVdc pole. The 10-minute overload capability will provide NLH operators time to turn on other Island generation in the event of a HVdc pole outage. The converters at Salisbury are assumed to have a typical 10% current overload capability. The 1.5 pu and 2.0 pu overload ratings at Soldiers Pond refer to nominal power (not current) injected at Soldiers Pond after losses when Gull Island is supplying rated 800 MW to the Island. The special overload capabilities at Soldiers Pond will require each pole at Gull Island to have a 1.66 pu current rating and at Soldiers Pond to have a 2.16 pu current rating.

The rectifier and inverter control modes used in a multi-terminal HVdc link are different than in a typical two-terminal HVdc link. In a multi-terminal link, the inverters will operate in current control mode and the rectifier will operate in voltage control mode. This is because stable current sharing between the two inverters is best achieved if both inverters are operating in current control. An additional reason to operate the inverters in current control is because a long section of the HVdc line from the tap at Taylors Brook to New Brunswick is an HVdc cable. The large capacitance and discharge current associated with a long HVdc cable can cause significant transient overcurrents into an inverter during even remote AC inverter faults. The operation of an inverter at the end of a long HVdc cable is most stable in current control mode. In order for the inverters to be able to control their current, they need to be able to adjust their dc voltage in order to maintain the ordered current. This requires the inverters to operate somewhere above minimum gamma, which is typically 16 to 18 degrees in a two-terminal link, in order that the current controller has enough dynamic range in its firing angle to be able to adjust its dc voltage and subsequently control its dc current. The gamma range at the inverters in this multi-terminal HVdc link will be approximately 22 to 24 degrees. The impact of operating at a higher gamma is that the converter consumes slightly more reactive power. The rectifier is then left to control the dc voltage.

The bipolar multi-terminal HVdc link is represented by the configuration shown below in Figure 1. The DC line extends from Gull Island to a tap at Taylors Brook, at which point the line splits to terminate at Soldiers Pond on the NLH Island system and at Salisbury in the New Brunswick system. The Gull Island

terminal is grounded through a 407 km electrode line and the Salisbury terminal is grounded through a 100 km electrode line.

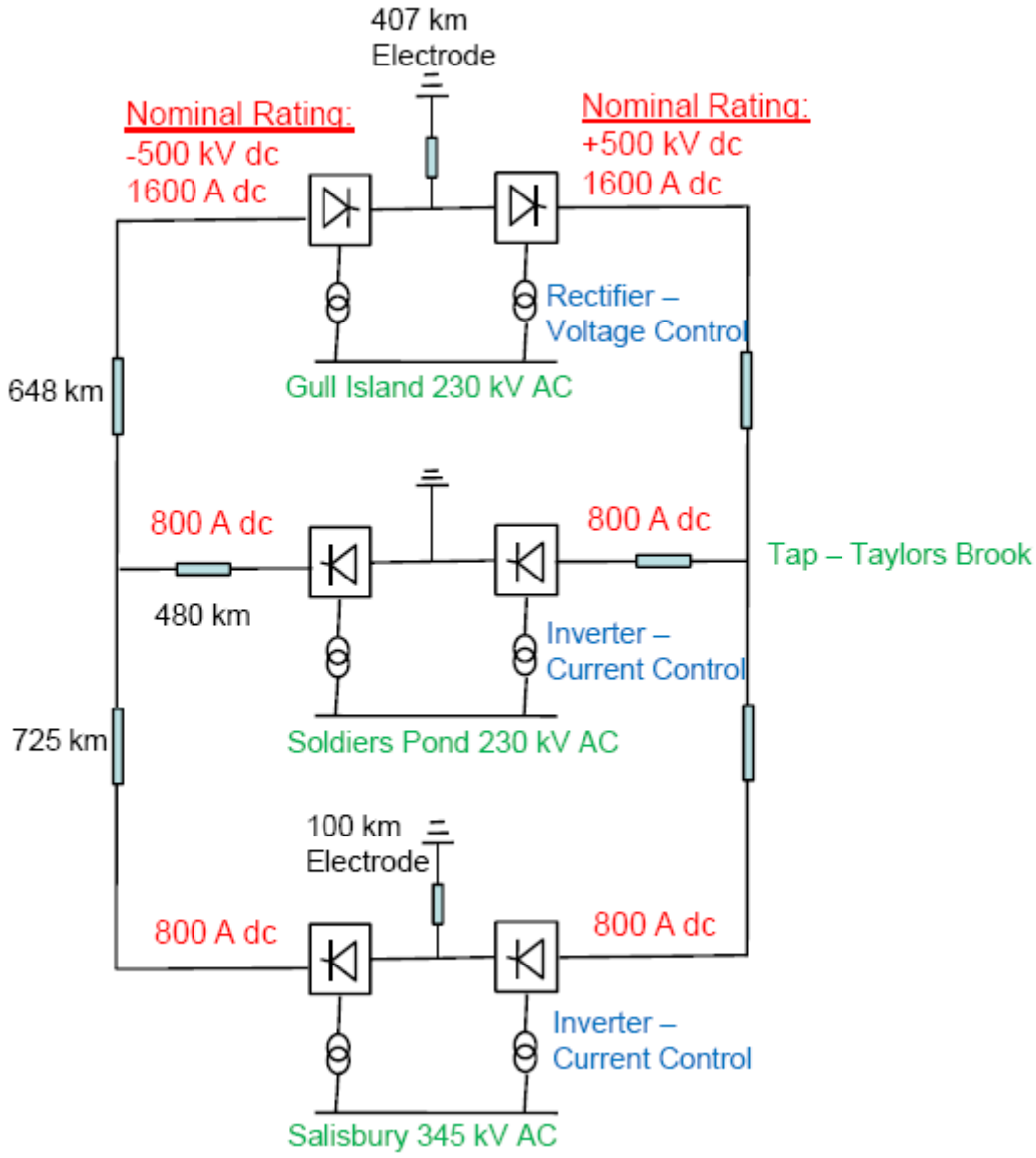


Figure 1 – Multi-terminal HVdc link and line lengths

Table 1 summarizes the DC line lengths and resistances used in the steady state analysis. As the DC conductor optimization and route selection was not finalized prior to carrying out the power flow and short circuit analysis, the conductor type, geometry and line lengths used in the studies were based on the preliminary data available at the time. Although final transmission line and cable parameters may differ from those used in this study, the overall impact on results should be minimal. Please refer to Appendix 2 for further information on the DC line conductor assumptions.

Table 1
DC Line Lengths and Resistances

DC Line Section	Length (km)	DC Resistance per pole (ohms)
Gull Island - Tap	648.7	9.17
Tap - Soldiers Pond	480.0	6.94
Tap - Salisbury	725.0	8.77
Gull Island Electrode	407.0	6.39 (includes 0.5 ohm sea resistance)
Salisbury Electrode	100.0	1.94 (includes 0.5 ohm sea resistance)

In determining preliminary parameters for the HVdc system, typical industry practice was followed by assuming a commutating reactance of 0.14 pu for the converter transformers. The commutating reactance would not usually be higher than this value, and if it is lower then it will absorb less reactive power. Therefore the assumption of 0.14 pu for the commutating reactance will provide a reasonable estimate for the steady state reactive power requirements.

The power flow studies assumed an initial converter transformer tap changer range of 0.9 to 1.1. An alpha firing angle range of 12 to 20 degrees was assumed at the rectifier. Gamma was set to be 25 degrees for the purposes of power flow studies although its range will likely be closer to 22 to 24 degrees. The assumption of operating at a higher gamma draws slightly more reactive power into the converter, also providing a conservative estimate when determining the steady state reactive power requirements for the HVdc system.

The HVdc parameters used in this study are preliminary values and are subject to change during later phases of more detailed design such as the pre-specification studies.

The nominal operating points of the HVdc system in bipolar and monopolar operating modes along with the HVdc system parameters used in the power flow analysis are summarized below in Tables 2 and 3. Current normal industry practice is to supply a single twelve pulse valve group per pole at each station for HVdc transmission systems with power ratings similar to that being considered. Each twelve pulse valve group is connected to the ac system either through two three phase, two winding, converter transformers or three, single phase, three winding converter transformers to provide the necessary wye:wye and wye:delta connections. Please refer to Appendix 2 for further information related to the converter transformers.

Table 2
Converter Transformer Data

Converter	Rating (MVA)	Voltage (kV)	Tap Changer Range	Commutating Reactance (pu)
Gull Island	2 x 585 per pole	230–208.6	0.9-1.1	0.14 pu
Soldiers Pond	2 x 351 per pole	230–208.6	0.9-1.1	0.14 pu
Salisbury	2 x 234 per pole	345–208.6	0.9-1.1	0.14 pu

Table 3
Nominal Operating Points

Converter	Per Pole Parameters	Nominal Bipolar	10-min Overload Monopolar	Continuous Monopolar
Gull Island	Vdc (kV)	500	481.7	485
	Pdc (MW)	1600	1258	1042
	Idc (A)	1600 (1.0 pu)	2611 (1.66 pu)	2149 (1.34 pu)
	Qdc (MVAr)	823.8	693.6	532.8
	Alpha (deg)	19.1	14.6	14.9
Soldiers Pond	Vdc (kV)	478.7	444.2	455.2
	Pdc (MW)	765.8	765.8	574.4
	Idc (A)	800 (1.0 pu)	1724 (2.16 pu)	1262 (1.58 pu)
	Qdc (MVAr)	456.2	558.6	380.4
	Gamma (deg)	25.0	25.0	25.0
Salisbury	Vdc (kV)	477.1	448.6	456.3
	Pdc (MW)	763.4	394.8	401.6
	Idc (A)	800 (1.0 pu)	880 (1.1 pu)	880 (1.1 pu)
	Qdc (MVAr)	492.8	263.5	271.4
	Gamma (deg)	25.0	25.0	25.0

During nominal bipolar operation, the Gull Island converter supplies a rated current of 1600 A (1.0 pu). The total power injected at Soldiers Pond is 765.8 MW and at Salisbury is 763.4 MW, resulting in losses of 34.2 MW and 36.6 MW at Soldiers Pond and Salisbury respectively.

The losses increase when operating in monopolar mode, requiring up to 2611 A (1.66 pu current) at Gull Island to supply the 10-minute 100% overload requirement at Soldiers Pond (2.16 pu current) and the continuous 10% overload at Salisbury (1.1 pu current), and up to 2149 A (1.34 pu) at Gull Island to supply the continuous 50% and 10% overloads at Soldiers Pond (1.58 pu current) and Salisbury (1.1 pu current) respectively.

2.2 Reactive Power Requirements

HVdc converters typically consume reactive power in the approximate amount of 55% of their real power output. The exact amount of reactive power consumed depends on the commutating reactance of the converter transformers, the tap position of the converter transformers and the firing angle of the converter. For the purposes of this study, the commutating reactances of the converter transformers were held constant throughout the tap changer ranges. The power flow studies assumed a minimum reactive power compensation of 450 MVAr at Soldiers Pond and Salisbury and 900 MVAr at Gull Island.

As a first assumption and start to the power flow analysis, the reactive power compensation at each station is assumed to be supplied by a combination of filters and shunt capacitors. Power flow analysis is used to determine the total reactive power requirements based on NLH system voltages during contingency analysis. Short circuit analysis is then used to determine if a portion of that total reactive power requirement should be in the form of a synchronous condenser to increase the short circuit strength at the Soldiers Pond bus. At rated power output, minimum filter requirements would be approximately 250 MVAr at Soldiers Pond and Salisbury and 500 MVAr at Gull Island in order to meet harmonic performance requirements.

2.3 ESCR Requirements

Beyond the basic consideration of power transfer, there are a number of ways which the dc and associated ac systems interact at the converter stations. As the strength of the ac system reduces, both in normal operation and as a result of contingencies, certain interactions tend to become more pronounced.[1] These interactions include:

- Recovery from ac and dc Faults: For acceptable performance it is required that the dc system should recover from ac or dc faults without subsequent commutation failures. As a general guide, recovery to 90% of pre-disturbance power transfer within 100 to 300ms is desirable. As the Short Circuit Level (SCL) of the ac systems decreases, the effects of magnetizing inrush currents can become more pronounced, resulting in a slower recovery. Attempting to increase the speed of recovery can sometimes lead to the dc system drawing excessive reactive power from the ac network, resulting in a prolonged depression of the ac network voltage, particularly as the Short Circuit Ratio (SCR) of the ac systems decreases.
- Temporary Overvoltages: Temporary ac system overvoltages can occur at the dc terminals due to converter blocking, ac fault inception and clearing, dc faults, and other disturbances. The severity of these overvoltages increases as the SCR of the ac systems decreases.
- While it may be an issue for ac systems with higher SCRs also, the capacitive shunt compensation at the converter bus and the relatively high system inductance for low SCR ac systems typically results in a parallel resonance at second harmonic. Such a resonance can result in harmonic voltages which are substantial relative to the magnitude of the fundamental during disturbances.
- Commutation Failures: It is a general requirement that the converter does not experience commutation failures for frequently occurring changes in the associated ac systems such as small voltage and phase deviations. As the SCR decreases, the likelihood of commutation failures occurring increases.
- Converter Reactive Power Element Switching: As the SCR decreases the voltage sensitivity to changes in the reactive power increases and creates the potential for voltage changes within the ac network in the vicinity of the converter station when reactive power elements are switched.
- System Inertia: In addition to characterizing the ac system as having sufficient SCR, it is also necessary to consider the overall inertia of the system. In cases where overall system inertia is low,

[1] Guide for Planning DC Links Terminating at AC system Locations Having Low Short-Circuit Capacities, Part II: Planning Guidelines. CIGRE Working Group 14.07, IEEE Working Group 15.05.05, December 1997.

synchronous compensators can be used to increase the system SCR and help maintain ac system voltage and frequency.

Effective short circuit ratio (ESCR) is defined as follows:

ESCR = (Short circuit MVA at AC bus – MVA rating of filters)/Rated DC power

The CIGRE Guide for Planning DC Links Terminating at AC System Locations Having Low Short Circuit Capacities identifies the following categories of ESCR:

High	ESCR > 2.5
Low	2.5 > = ESCR > = 1.5
Very Low	ESCR < 1.5

Based on industry experience it can be stated that low or very low SCR in itself is not a technical limitation in the evaluation of an HVdc transmission option, but it must be recognized that decreasing SCR (and ESCR) results in overall decreased performance of the interconnected ac/dc systems. The effects of reducing ESCR on overall performance becomes even more pronounced for long HVdc cables.

As such, it is recommended that a minimum ESCR of 2.5 for the inverter ac systems be maintained. Dynamic performance studies will further validate this minimum ESCR value, however for the purposes of the power flow analysis the goal is to design the reactive power requirements such that the ESCR at the Soldiers Pond bus is at least 2.5.

The HVdc system itself does not contribute to the short circuit strength of the system, however a synchronous condenser installed with the HVdc system will increase the short circuit strength if deemed necessary by the short circuit studies.

3. Study Power Flow Models

Steady state analysis is performed using a range of power flow cases that represent various generation and load dispatches in the NLH Island system for various years, seasons and times of day. For each of these power flows, various HVdc infeed amounts are considered for several combinations of HVdc monopolar and bipolar configurations. The power flow cases represent a range of weak to strong system conditions in the NLH Island system. Although the power flow models include the New Brunswick and large surrounding area system connected via the multi-terminal HVdc link, the focus of the steady state analysis is solely on the NLH system, with particular attention to the Island system.

3.1 AC System Representations

3.1.1 NLH Island System

The full NLH Island AC system PSSE model is used for the power flow analysis. Eleven (11) Island power flow configurations are represented, ranging from minimum generation light summer night loading to maximum generation future peak winter loading along with various ranges of infeed levels at Soldiers Pond from minimum DC power (80 MW) to maximum DC power (800 MW). One configuration is also represented in which the Island is exporting power. All power flow cases represent year 2016, with the exception of the future peak maximum load case. Table 4 below provides a brief description of the base cases. For more detailed information on the Island dispatch please refer to Appendix 1.

Table 4
Power Flow Base Cases

NO.	NLH System Load	Soldiers Pond	Island Generation	Labrador (Gull)	NB
BC1	Peak (1600 MW)	Full Import (800 MW)	economic dispatch	Weak	Peak load
BC2	Peak (1600 MW)	Reduced Import (600 MW)	max economic dispatch	Weak	Peak load
BC3	Future Peak (1800 MW)	Full Import (800 MW)	max generation	Weak	Peak load
BC4	Summer Night (550 MW)	Reduced Import (255 MW)	min generation	Weak	Peak load
BC5	Summer Night (550 MW)	Minimum Import (80 MW)	economic dispatch	Weak	Peak load
BC6	Intermediate (1000 MW)	Full Import (800 MW)	economic dispatch	Weak	Peak load
BC7	Intermediate (1000 MW)	Minimum Import (80 MW)	max economic dispatch	Weak	Peak load
BC8	200 MW (550 MW)	Export	dispatch	Weak	Peak load
BC9	Peak (1600 MW)	Full Import (800 MW)	economic dispatch	Weak	Weak, Peak load
BC10	Peak (1600 MW)	Full Import (800 MW)	economic dispatch	Weak	Light load
BC11	Peak (1600 MW)	Full Import (800 MW)	economic dispatch	Weak	Strong, Light load
BC12	Summer Night (550 MW)	Minimum Import (80 MW)	economic dispatch	Normal	Peak load
BC13	Future Peak (1800 MW)	Reduced Import (600 MW)	max generation	Weak	Peak load

Note that base cases BC9 and BC11 are greyed out because they were not studied. Originally it was thought that these cases would test variations of strong and weak New Brunswick systems with light and peak loads, however only two New Brunswick power flow cases were available – a strong case with peak load and a weak case with light load, therefore cases BC9 and BC11 were dropped from the original scope. However, two cases were added, BC12 to test the Labrador system for overvoltages when operating at minimum power, and BC13 to test the future peak maximum load case when operating with a 600 MW monopolar infeed at Soldiers Pond.

The year 2016 and future peak Island power flow cases have several significant modifications when compared to the existing system today:

1. A new large refinery load (175 MW, 85 MVAr) is planned to be in-service near Piper's Hole, between Bay D'Espoir and Sunnyside. As well, a nickel smelter load (83 MW, 40 MVAr) is planned for the Long Harbour area. The internal NLH studies for the additions of these loads have not yet been completed, therefore it is expected that system impacts due the loads will be observed in this HVdc feasibility study.

2. NLH is planning to convert units #1 to #3 at Holyrood to synchronous condensers as part of the Lower Churchill Project to meet ESCR requirements. In addition NLH is planning to install five 50 MW combustion turbines (CT) at Holyrood to meet load requirements between 2010 and the HVdc 2015 in-service date. These CTs will be specified with the capability to operate in synchronous condenser mode. The Holyrood station will have a total of eight (8) synchronous condensers available for voltage control and in support of ESCR with the following ratings:

   a. Unit #1 – 142/-72 MVAr
   b. Unit #2 – 142/-72 MVAr
   c. Unit #3 – 150/-69 MVAr
   d. CT Units #1-5: 63.5 MVA at 0.85 power factor leading

   In addition, a 54 MW CT at Hardwoods is capable of operation as a synchronous condenser with a +28/-25 MVAr rating.

3. The 24 MVAr capacitor bank at Long Harbour is removed.

4. The 50 MVAr capacitor bank at Western Avalon is in-service.

The major NLH load centre is located on the Avalon Peninsula (east side of the Island) while the majority of the generation is located in the west. The Island terminal of the HVdc link will be located at Soldiers Pond which is between Holyrood, Hardwoods and Oxen Pond stations. The HVdc terminal will normally be operated as an inverter, with a nominal rated infeed of 765.8 MW (800 MW minus losses). One power flow case is setup with Soldiers Pond in rectifier operation to test the Island's export capability. The HVdc infeed is located nearer to the load centre (i.e. more to the east) than the majority of the other Island generation and should help to off-load heavy west to east flows.

3.1.2 Labrador System

For all power flow cases, the Labrador system is represented by a weak system configuration. As shown in Figure 2, this weak configuration is achieved by removing the Muskrat Falls generating station, a 230 kV line from Gull Island to Muskrat Falls and a 735 kV line from Churchill Falls to Gull Island Generating Station.

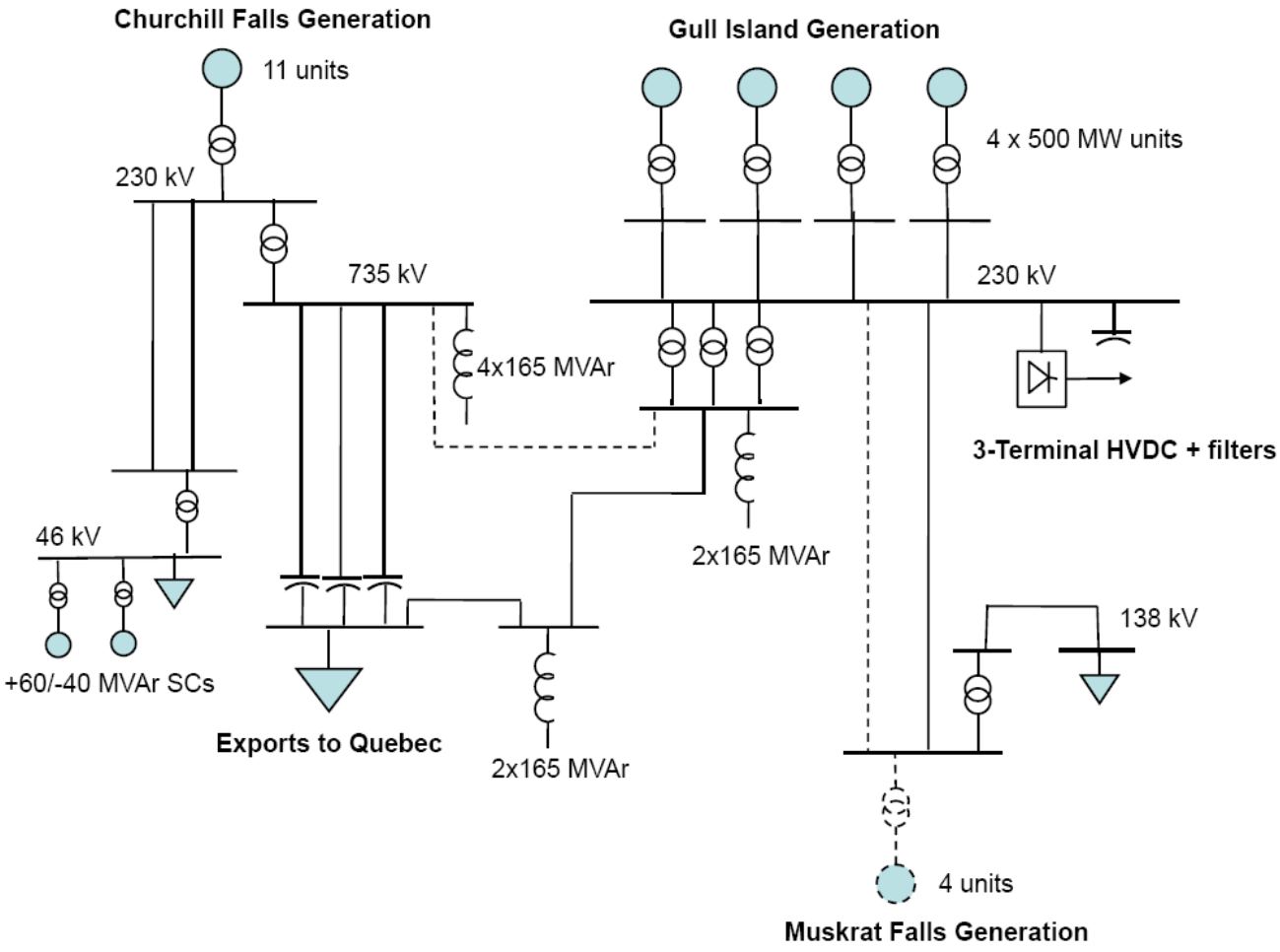


Figure 2 – Labrador System in Weak Configuration

There is one power flow case in which the Labrador system is represented with the 230 kV Gull Island-Muskrat Falls and the 735 kV Churchill Falls-Gull Island lines in-service. This case is used to determine the worst case steady state overvoltages in the Labrador System when operating at minimum power.

The Labrador terminal of the HVdc system will normally operate as the rectifier, supplying power to Newfoundland Island and to New Brunswick, although a few power flow cases represent the terminal as an inverter. When the power level into the HVdc link is adjusted at Gull Island for the various power flow cases, the offsetting power adjustment is made to the equivalent load which represents power exports to Quebec. This Quebec equivalent load is adjusted to maintain the Churchill Falls generation at 5428 MW.

3.1.3 New Brunswick System

For all power flow cases, the New Brunswick system power flow conditions represent the winter peak load case, with the exception of one case that represents summer light load conditions.

The New Brunswick system is contained in a reduced system model of approximately 1000 buses.

The New Brunswick terminal of the HVdc system will normally operate as an inverter, although one power flow case represents the system operating as a rectifier. The offsetting power adjustments from the HVdc infeed are scheduled to a bus at Orrington which is the first 345 kV bus south of the Maine-New Brunswick border.

3.2 Multi-terminal HVdc Link Representation

The Gull Island terminal will normally be operated as the rectifier with the Island and New Brunswick terminals operating as inverters, although the DC link will be designed such that any terminal could be a rectifier or inverter. In addition, the link will normally run as a bipole however situations may occur in which an entire pole or any section of a pole could be out of service (i.e. forced outage or scheduled maintenance). Taking this information into consideration, various DC configurations are studied as listed in Table 5.

Table 5
HVdc Configurations

NO.	Gull Island	Soldiers Pond	Salisbury	Description
DC1	REC - BP	INV - BP	INV - BP	Normal
DC2	REC - MP	INV – MP (overload)	INV - MP	Loss of 1 pole at Gull Island
DC3	REC - MP	INV – MP(continuous)	INV - MP	Loss of 1 pole at Gull Island
DC4	REC - BP	INV – MP (overload)	INV - BP	Loss of 1 pole at Soldiers Pond
DC5	REC - BP	INV – MP (continuous)	INV - BP	Loss of 1 pole at Soldiers Pond
DC6	REC - BP	INV - BP	INV - MP	Loss of 1 pole at Salisbury
DC7	OFF	INV - BP	REC - BP	2-terminal
DC8	OFF	REC - BP	INV - BP	2-terminal
DC9	INV - BP	REC - BP	OFF	2-terminal
DC10	REC – BP	REC – BP	OFF	2-terminal

3.3 PSSE Multi-terminal DC Line Power Flow Model

The HVdc link is modeled in PSSE using two separate multi-terminal DC line models, one line to represent each pole of the bipole. The HVdc link could have been represented as one bipole line containing both poles however it was found that this setup did not provide adequate flexibility when configuring the model in certain monopolar configurations.

The PSSE model requires that one of the inverters be in voltage control mode, although this is likely not consistent with how the actual HVdc link will operate. In order to populate the data for the PSSE multi-terminal DC line models, the operating points of the HVdc link for both poles were calculated for each

of the HVdc configurations listed in Table 5 for appropriate base case power flows listed in Table 4. The combinations of HVdc configurations and base case power flows that were studied are listed in Table 6 of upcoming section 4.3. The detailed set of HVdc operating points for each of these power flow cases containing the DC voltages, currents and powers for both poles at all three terminals can be found in Appendix 2. These operating points including a positive current or power order at the rectifier, a positive voltage at the voltage-controlling inverter and a negative current or power order at the other inverter. These values are entered into the SETVAL field of the converter data for both poles of the HVdc link in order to change the operating point of the HVdc system. The remainder of the data that populate the model, including parameters such as DC line resistances, converter transformer data, firing angle ranges and such remain the same when changing operating points, unless a mode change from rectifier to inverter is made, then the firing angle limits must be modified appropriately.

For further detailed information regarding multi-terminal DC models in PSSE, please refer to PSSE Application Guide Volume II section 6.4.9.

3.4 Set of Final Power Flow Models

A total of nineteen (19) power flow cases representing various combinations of Island, Labrador, New Brunswick and HVdc configurations were created as listed below in Table 6. Unless otherwise stated, Gull Island is operating as the rectifier and Soldiers Pond and Salisbury are operating as inverters. BP stands for bipole, MP stands for monopole. Appendix 5 contains a set of power flow diagrams for each of these cases listed in Table 6.

Table 6
Complete set of power flow cases for steady state analysis

Base Case	DC	Soldiers Pond	Salisbury	Gull Island
BC1	DC1	800 BP	800 BP	1600 BP
	DC6	800 BP	400 MP	1200 BP
	DC7[2]	800 BP	800 BP–REC	OFF
BC2	DC1	600 BP	800 BP	1400 BP
	DC3	600 MP	400 MP	1000 MP
	DC5	600 MP	800 BP	1400 BP
BC3	DC1	800 BP	800 BP	1600 BP
	DC4	800 MP	400 MP	1000 MP
BC4	DC1	255 BP	800 BP	1055 BP
	DC3	255 MP	400 MP	655 MP
BC5	DC1	80 BP	800 BP	880 BP
BC6	DC1	800 BP	800 BP	1600 BP
BC7	DC1	80 BP	800 BP	880 BP
BC8[3]	DC8	200 BP–REC	800 BP–INV	OFF
	DC9	200 BP–REC	OFF	800 BP–INV
BC9[4]	DC1	800 BP	800 BP	1600 BP
	DC6	800 BP	400 MP	1200 BP

[2] Cannot solve this power flow when NB system is at peak load. Instead case BC10-DC7 was created in which the NB system is at light load.
[3] Can only get approximately 200 MW out of Island system base case, further export would require Island system upgrades.
[4]These base cases were not created as TGS did not have a strong/weak peak/light load for NB system; only a peak and light load case were available.

Base Case	DC	Soldiers Pond	Salisbury	Gull Island
BC10[5]	DC1	800 BP	800 BP	1600 BP
	DC6	800 BP	400 MP	1200 BP
	DC7	800 BP	800 BP–REC	OFF
BC11[3]	DC1	800 BP	800 BP	1600 BP
	DC6	800 BP	400 MP	1200 BP
BC12	DC10	80 BP	OFF	80 BP
BC13	DC3	600 MP	400 MP	1000 MP

3.5 Assumptions

The following assumptions were made for each of the power flow cases:

1. One large synchronous condenser (unit #3 - 150 MVA) at Holyrood and one small synchronous condenser (50 MW CT running as synchronous condenser) are out of service for maintenance.

3.6 Contingencies

Table 7 lists the Island contingencies that are studied.

Table 7
Contingencies for Steady State Analysis

Contingency	Description
C1	Soldiers Pond to Holyrood 230 kV line
C2	Soldiers Pond to Hardwoods 230 kV line
C3	Soldiers Pond to Oxen Pond 230 kV line
C4	Soldiers Pond to Western Avalon 230 kV line
C5	Western Avalon to Come By Chance 230 kV line
C6	Come By Chance to Sunnyside 230 kV line
C7	Western Avalon to Sunnyside 230 kV line
C8	Sunnyside to Piper's Hole 230 kV line
C9	Piper's Hole to Bay d'Espoir 230 kV line
C10	Hardwoods gas turbine in synchronous condenser mode
C11	150 MVAr synchronous condenser

[5] Represents NB light load system, all other base cases represent NB peak load system.

4. Power Flow Analysis

The purpose of the power flow analysis is to determine the total steady state reactive power requirements of the Island system such that the steady state voltage requirements are met, and to determine any network upgrades to the existing Island system that are required to relieve thermal overloading.

4.1 Study Procedure

Steady state AC contingency analysis (PSS/E activity ACCC) is used to assess the impact of the HVdc link on the NLH Island system. It tests the adequacy of the Island transmission system to transfer the additional 800 MW of power from the HVdc infeed and determines the worst-case contingencies.

Buses and branches in the NLH system are monitored. Contingencies, as defined in Table 7, are applied for all power flow cases described in Table 6. The purpose is to find any contingencies that result in a thermal overload of a transmission line or transformer or that result in a steady state voltage violation or voltage collapse scenario. If a problem is discovered, mitigation in the form of extra reactive power support, transmission line upgrades or generation re-dispatch are evaluated.

4.2 Criteria

The following steady state NLH system criteria are used to determine the steady state transmission solution:

1. Steady state voltages should be within the following ranges:
    a. 0.95 pu – 1.05 pu – System Intact
    b. 0.90 pu – 1.10 pu – Contingency (N-1)

2. Thermal loading on a transmission line or transformer should not exceed 100% of:
    a. Rate A – Summer season (30 degrees C ambient) – light load
    b. Rate B – Spring/Fall season (15 degrees C ambient) – intermediate load
    c. Rate C – Winter season (0 degrees C ambient) – peak load

Within the NLH Island system, if during a contingency the thermal loading of a transmission line or transformer is found to exceed 100% of its rating, it is deemed acceptable mitigation practice to use a generation re-dispatch to correct the issue as long as there is sufficient Island generation available and if the re-dispatch reduces the loading on all transmission lines and transformers to at or below 100% of their thermal ratings.

4.3 Study Results

The major NLH Island load centre is located east of Bay d'Espoir on the Avalon Peninsula, while the majority of the generation is located west of Bay d'Espoir. This can result in heavy west to east power flow on the 230 kV transmission system, in particular between Bay d'Espoir, Sunnyside, Western Avalon and Soldiers Pond. In addition, approximately 255 MW of new industrial load (refinery and smelter) is planned to be installed along this heavily loaded west to east corridor, which serves to increase the

loading on these 230 kV lines. As a general result this can cause voltage depression and thermal overloading in the area. The HVdc infeed into Soldiers Pond generally has a positive impact on the Island transmission system as it off-loads this west to east power flow by injecting power closer to the load centre. Many of the issues that will be discussed are not necessarily due to the HVdc infeed but are due to the lack of transmission linking the generation in the west to the load in the east. The results discuss solutions that use the HVdc infeed to assist in mitigating the problems.

The discussion of the power flow results is split into three sections – the first section defines the total reactive power requirements of the NLH system and is based on the steady state voltage criteria; the second section discusses any potential for overvoltages on the Labrador system when operating at minimum power; and the third section defines the transmission line overloads on the Island and possible mitigation measures.

4.3.1 Island - Total Steady State Reactive Power Requirements

As a starting point, the HVdc converter at Soldiers Pond was assumed to provide its full reactive power compensation in the form of 450 MVAr of filters and shunt capacitors. It was quickly discovered that if the HVdc infeed was operating in its 2.0 pu monopolar configuration, a voltage collapse would occur even without any outages in the Island system. The heavy west-east flow and the new refinery load at Piper's Hole, combined with the increased reactive power consumption of the HVdc inverter at Soldiers Pond (559 MVAr monopolar compared to 462 MVAr bipolar), depressed the system voltage enough to cause system wide voltage collapse that begins around the Sunnyside and Piper's Hole area, very near to the new refinery load. Significant improvement in voltage is achieved with the addition of local area reactive power supply at the Sunnyside 230 kV bus.

In terms of maintaining acceptable steady state voltages on the Island, the worst case power flows were found to be the future peak load cases, in particular:

- BC3-DC1 – 1800 MW future peak Island loading, 800 MW bipolar infeed at Soldiers Pond
- BC3-DC3 – 1800 MW future peak Island loading, 600 MW monopolar infeed at Soldiers Pond
- BC3-DC4 – 1800 MW future peak Island loading, 800 MW 10-minute overload monopolar infeed at Soldiers Pond

The worst case corresponding contingencies were found to be:

- C9 – Loss of 230 kV line from Bay d'Espoir to Piper's Hole
- C11 – Loss of synchronous condenser unit #3 at Holyrood

These two contingencies were the determining cases for total reactive power requirements for the Island. Again, the absolute worst power flow case was the 10-minute 2 pu overload scenario in which the HVdc inverter at Soldiers Pond is in monopolar operation (BC3-DC4). This is due to the fact that the HVdc converter's reactive power absorption is highest in this case at 559 MVAr compared to 462 MVAr in the bipolar case.

The result of losing either the Bay d'Espoir-Piper's Hole line or the Holyrood unit #3 synchronous condenser with insufficient reactive power support in the system is voltage collapse. Combinations of reactive power supply at Holyrood, Soldiers Pond and Sunnyside were tested. As additional reactive power supply, a 150 MVAr synchronous condenser at Soldiers Pond is tested as one of the alternatives. For the purposes of power flow analysis, a single 150 MVAr synchronous condenser at Soldiers Pond was assumed because of the close proximity to Holyrood unit #3, an outage of either of these two units could likely be considered a similar outage and would require a similar reactive power requirement at Sunnyside. Several scenarios of reactive power sources required to avoid voltage collapse are summarized in Table 8 below.

Table 8
Reactive Power Solutions to Avoid Voltage Collapse

Scenario	Contingency	Holyrood #3 (150 MVAr)	Soldiers Pond Synchronous Condenser (150 MVAr)	Soldiers Pond Filters (MVAr)	Sunnyside (MVAr)
0	C9	Out	None	450	300
1	C11	In (but lose)	Out	450	200
1	C9	In	Out	450	150
2	C9	Out	In	450	165

Scenario 0 assumes no additional reactive power support (aside from 450 MVAr filters) is installed at Soldiers Pond. This would require at least 300 MVAr of steady state reactive power supply at Sunnyside, which is a substantial amount of reactive power support and could not all be supplied in the form of shunt capacitors.

Scenarios 1 and 2 assume a 150 MVAr synchronous condenser is installed at Soldiers Pond in addition to the 450 MVAr filters. As a base case assumption it is assumed that either one of these 150 MVAr units at Holyrood or Soldiers Pond could be out of service for maintenance. The defining case for the total reactive power requirement at Sunnyside then becomes loss of the in-service 150 MVAr synchronous condenser, which requires a minimum of 200 MVAr of steady state reactive power support at Sunnyside to avoid system voltage collapse.

The preferred solution for the total Island reactive power supply is as follows:

- 450 MVAr filters at Soldiers Pond
- 150 MVAr synchronous condenser at Soldiers Pond
- 200 MVAr capacitive reactive power support at Sunnyside

At this point in the steady state analysis, the split of total reactive power requirements at Soldiers Pond cannot necessarily be determined. It is not desirable to add the extra supply in the form of more filters as this could cause overvoltage problems and also would further reduce the ESCR. Please refer to the discussion of Short Circuit Analysis to see the justification for the 150 MVAr synchronous condenser at Soldiers Pond.

The entire contingency analysis was performed on all power flow cases with the above reactive power solution modeled, taking into account a base case maintenance outage of one of the CT units at Holyrood plus a base case maintenance outage of either of the 150 MVAr synchronous condensers at Holyrood or Soldiers Pond. With this reactive power solution, no further voltage violations or voltage collapse scenarios were observed, with the exception of contingency C9, loss of 230 kV line from Bay d'Espoir to Piper's Hole during BC7 when the HVdc infeed at Soldiers Pond is at minimum power or during BC8 when the HVdc converter is exporting power. These scenarios will require a fast DC run-up (when importing) and run-down (when exporting) to prevent system voltage collapse. A corresponding transfer trip of generation in the west would be required to offset the increase in HVdc infeed. The voltage collapse seems to occur if there is more than approximately 225-250 MW flowing from west to east on both of the Bay d'Espoir to Piper's Hole lines. If it would not be desired to perform a fast dc power run-up or run-down, then it would likely be possible to develop an operating guideline to limit steady state power flow on the circuits between Bay d'Espoir and Piper's Hole by re-dispatching generation to avoid the voltage collapse scenario in the first place. This would require further study to determine if this is in fact possible and what the power flow limit would be. Dynamic performance analysis could look further into this scenario.

4.3.2 Labrador – Total Steady State Reactive Power Requirements

The Gull Island station is connected to a strong network with a minimum short circuit strength of 5851 MVA, corresponding to an ESCR of 3.1. The steady state reactive power requirement can be fulfilled by the use of filters and shunt capacitors, no synchronous condensers are required. A total of 900 MVAr of reactive power support is modeled at the 1600 MW Gull Island converter.

A minimum power case at Gull Island was checked to ensure that overvoltages in the Labrador system would not be too high. This power flow case, as shown in Figure 3, modeled all transmission lines in-service which were previously taken out-of-service for the weak representation in other power flow cases. Muskrat Falls generating station was kept out-of-service. In order to find the worst condition for high voltages, one of the two 735 kV 165 MVAr reactors at Gull Island was taken out-of-service as were generating units #2 to #4 at Gull Island. The Gull Island rectifier was supplying 80 MW of power to Soldiers Pond with 250 MVAr of filters connected. The steady state 230 kV voltage observed on the Gull Island bus was 1.047 pu. The single Gull Island generating unit still had approximately 65 MVAr room left for further reactive power absorption. Overvoltages are therefore not expected to be a problem.

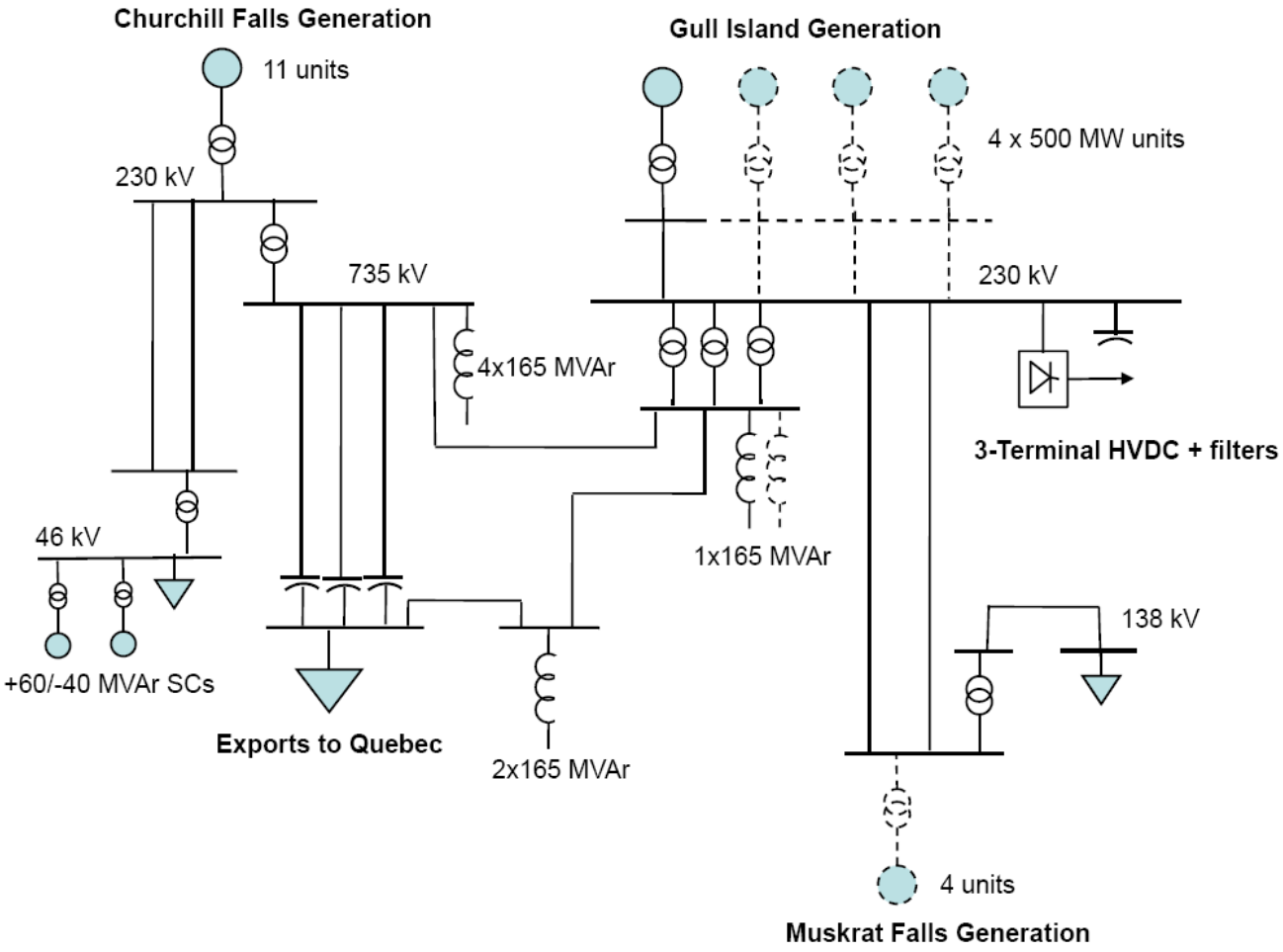


Figure 3 - Labrador system used for checking for overvoltages

4.3.3 Island - Thermal Overloads and Mitigation

The heavily loaded 230 kV transmission corridor between Bay d'Espoir and Soldiers Pond not only results in voltage problems as discussed and mitigated in section 5.5.1, but also results in thermal overloading on several 230 kV lines in the area.

Generally the worst overloading occurs when the Soldiers Pond DC infeed is operating at lower power levels, or even worse if it is exporting power. This results in the need for more Island generation in the west to serve the major load centre in the east, in addition to the new refinery load at Piper's Hole, causing several 230 kV transmission lines to be significantly overloaded under certain power flow conditions. NLH currently operates their Island system with a guideline to re-dispatch generation to mitigate overloaded lines.

Without applying any line upgrades to the Island system the export power flow case (BC8) was able to export 200 MW with the Island load at summer night light loading (550 MW). However, it was found that in order to relieve system intact base case overloads during this power flow, all 250 MW of

generation from the Holyrood CTs must be on-line. In the event of a contingency, the DC export must be reduced below 200 MW as necessary to bring loading on all lines to below 100%. However, overloads are high – in the range of 150-200%.

The import power flow cases can also use this generation re-dispatch method to mitigate all but one of the overloaded lines (the exception is line TL201 from Soldiers Pond to Hardwoods which is discussed in the next paragraph). For power flows in which the HVdc infeed was not operating at its maximum, the DC infeed power was increased and generation in the west was decreased (Bay d'Espoir generation was the swing bus for this study) to mitigate overloads. If the HVdc was already importing maximum power, then Holyrood CTs were turned on as needed to mitigate the overloads. This method was successful for mitigating all of the 230 kV line overloads between Bay d'Espoir and Soldiers Pond. Case BC13-DC3, the future peak load case (1800 MW) with the DC infeed operating as a 600 MW monopole requires the last 50 MW of generation from the Holyrood CTs to be turned on in order to relieve overloading on parallel lines from Piper's Hole-Bay d'Espoir lines TL202 and TL206 for loss of the parallel line. This case has 200 MW of generation being supplied by the Holyrood CTs pre-contingency. There is no further generation in the east that could be utilized beyond this amount for this power flow case.

Line TL201 from Soldiers Pond to Hardwoods becomes overloaded for contingency C2, loss of the parallel Soldiers Pond to Hardwoods line. This overload only occurs during the future peak load (1800 MW) case. It occurs due to high loading on the underlying 138 kV system radially connected to Hardwoods and Oxen Pond stations. The overload is worst (115%) if the two 25 MW wind farms connected to this radial system are turned off. 54 MW of generation can be turned on at Hardwoods, which reduces the overload to 103.5% (rate C) assuming the wind farms are off. Upgrading this line would require a rebuild using the 804 AACSR/TW conductor type.

Table 9 lists the thermal overloads for all power flow cases without network upgrades and the post-contingency generation re-dispatch that would be required to eliminate the listed overload.

Table 9
Thermal Overloads Before Any Upgrades are Implemented

Overloaded Line	Contingency	Rate	Power Flow	Overload (%)	Pre-Contingency HVdc Infeed (MW)	Post-Contingency Redispatch (MW)
Piper's Hole-Bay d'Espoir TL202, TL206	C9	C	BC2-DC1	117.8	600 BP	+60 DC infeed
		C	BC2-DC3	122.2	600 MP	+70 Holyrood
		C	BC2-DC5	123.3	600 MP	+75 Holyrood
		C	BC3-DC1	107.4	800 BP	+25 Holyrood
		C	BC3-DC4	110.9	800 MP	+35 Holyrood
		A	BC5-DC1	169.8	80 BP	+175 DC infeed
		A	BC12-DC10	174.0	80 BP	+160 DC infeed
		C	BC13-DC3	106.9	600 MP	+50 Holyrood
	Base, all	A	BC8	162.1-169.9	-200 BP	0 DC export +225 Holyrood
Sunnyside-Western Avalon TL203	C5	B	BC6-DC1	118.4	800 BP	-50 DC infeed
	C6	B	BC7-DC1	126.7	80 BP	+100 DC infeed
	C4,C5,C6	A	BC8	202.6	-200 BP	0 DC export +50 Holyrood
Piper's Hole-Sunnyside TL202	C8	A	BC5-DC1	113.3	80 BP	+25 DC infeed
		B	BC7-DC1	147.6	80 BP	+150 DC infeed
		A	BC12-DC10	117.1	80 BP	+35 DC infeed
		A	BC8	128.6	-200 BP	0 DC export +120 Holyrood
Western Avalon-Soldiers Pond TL201	C4	B	BC6-DC1	146.5	800 BP	-175 DC infeed
		A	BC8	197.8	-200 BP	0 DC export
Hardwoods-Soldiers Pond TL201	C2	C	BC3-DC1	108.1	800 BP	+54 Hardwoods
		C	BC3-DC4	108.0	800 MP	+54 Hardwoods
		C	BC13-DC3	107.3	600 MP	+54 Hardwoods
Piper's Hole-Sunnyside TL206	Base, all	A	BC8	128.6-133.6	-200 BP	+250 Holyrood in base case
Sunnyside-Come By Chance TL207	C7	A	BC8	150.5	-200 BP	+35 DC import
Come By Chance-Western Avalon TL237	C7	A	BC8	142.9	-200 BP	-130 DC export
Western Avalon-Soldiers Pond TL217	C5,C6,C7	A	BC8	103.2	-200 BP	-110 DC export

As an alternative to relying on generator re-dispatch to relieve overloads, especially because some of the overloads are extremely high, the overloaded lines were considered to be upgraded as detailed below and the contingency analysis was re-run.

1. **TL202 and TL206 – Bay d'Espoir to Piper's Hole and Piper's Hole to Sunnyside**
   These lines could be upgraded to 75 degrees C with the addition of a few mid span structures.

	Current Rating (MVA)	Upgraded Rating (MVA)	Rating Increase (%)
Rate A	199.3	341.8	71.5 %
Rate B	297.7	402.4	35.2 %
Rate C	369.5	453.8	22.8 %

2. **TL203 – Sunnyside to Western Avalon**
   This line is an H-frame wood pole design with multiple conductor types. Upgrading this line is not considered at viable option but instead the circuit would need to be replaced. The NLH standard would be to rebuild TL203 using steel structures and the 804 MCM AACSR/TW conductor.

	Current Rating (MVA)	Upgraded Rating (MVA)	Rating Increase (%)
Rate A	261.7	355.8	35.9 %
Rate B	307.8	411.5	33.7 %
Rate C	347.0	459.6	32.4 %

3. **TL207 – Sunnyside to Come By Chance**
   This line was upgraded to use the 804 MCM AACSR/TW conductor. The maximum conductor temperature was set at 80 deg C to match the hot conductor sag to the maximum ice load sag. This line would require further review by NLH transmission design. For the purposes of this study the current thermal ratings will be assumed.

	Current Rating (MVA)	Upgraded Rating (MVA)	Rating Increase (%)
Rate A	355.8	n/a	n/a
Rate B	411.5	n/a	n/a
Rate C	459.6	n/a	n/a

4. **TL237 – Come by Chance to Western Avalon**
   Same comments as for line TL207.

5. **TL217 – Western Avalon to Soldiers Pond**
   This line was upgraded using the 804 MCM AACSR/TW conductor except for two 5km sections that had been rebuilt following a previous ice storm. The two 5km sections consist of 795 MCM ACSR DRAKE conductor. A recent review by NLH Transmission Design has indicated that this section can be operated at a 75 deg C conductor temperature without violating ground clearance requirements. Therefore the ratings on this circuit are higher than what exists in the original PSSE model.

	Current Rating (MVA)	Upgraded Rating (MVA)	Rating Increase (%)
Rate A	199.3	341.8	71.5 %
Rate B	297.7	402.4	35.2 %
Rate C	369.5	453.8	22.8 %

6. **TL201 – Western Avalon to Soldiers Pond and Soldiers Pond to Hardwoods**

This line is an H-frame wood pole construction and consists of multiple conductor types. Uprating of the existing line is not viewed as a viable option. Instead the line would need to be rebuilt using the 804 AACSR/TW conductor type.

	Current Rating (MVA)	Upgraded Rating (MVA)	Rating Increase (%)
Rate A	175.5	355.8	102.7 %
Rate B	260.2	411.5	58.1 %
Rate C	322.2	459.6	42.6 %

With the line upgrades in place, most of the overloads are mitigated. The remaining overloads are summarized below in Table 10. They can all be mitigated by re-dispatching generation following the contingency.

Table 10
Thermal Overloads After Line Upgrades are Implemented

Overloaded Line	Contingency	Rate	Power Flow	Overload (%)	Pre-Contingency HVdc Infeed (MW)	Post-Contingency Redispatch (MW)
Piper's Hole-Bay d'Espoir TL202, TL206	C9	A	BC12-DC10	101.4	80 BP	+10 DC import
		B	BC7*		80 BP	+175 DC import
		A	BC8*		-200 BP	0 DC export +75 Holyrood
		C	BC2-DC5	100.3	600 MP	n/a
Sunnyside-Western Avalon TL203	C5,C6	A	BC8	146.7	-200 BP	-125 DC export
Piper's Hole-Sunnyside TL202	C8	A	BC8	148.6	-200 BP	-160 DC export
		B	BC7-DC1	108.9	80 BP	+35 DC import
Sunnyside-Come By Chance TL207	C7	A	BC8	150.3	-200 BP	-130 DC export
Come By Chance-Western Avalon TL237	C7	A	BC8	142.7	-200 BP	-110 DC export

**These contingencies require fast dc run-up (if importing into Soldiers Pond) or fast dc run-down (if exporting from Soldiers Pond) as described in section 5.3.1.*

4.3.4 Impacts of New Refinery Load and New 230 kV Transmission East of Bay d'Espoir

The worst cases were chosen to analyze sensitivity to the New Refinery load as well as to look at potential benefits of adding a new 230 kV line from Bay d'Espoir that would terminate at some point east of Bay d'Espoir. The two key issues noted are impacts to the amount of reactive power support required at Sunnyside and impacts to the export capability at Soldiers Pond.

New Refinery Load Not Connected

If the New Refinery load is not connected, the reactive power requirement at Sunnyside reduces to 50 MVAr from 200 MVAr. The defining case is voltage collapse following loss of a Bay d'Espoir – Piper's Hole line during the future peak load case when the DC infeed is 600 MW monopolar (BC13-DC3).

With 50 MVAr at Sunnyside and the load not connected, the export capability at Soldiers Pond increases to 300 MW, limited by 0.95 pu system intact voltages. With 75 MVAr at Sunnyside, the export capability increases to 350 MW, limited by 0.95 pu system intact voltages and thermal limits on the two circuits between Bay d'Espoir and Piper's Hole. In both of these export cases, DC run-back to 100 MW is required during loss of a Bay d'Espoir-Piper's Hole line. There is 447 MW of generation available for export if the load is not connected, and assuming Holyrood CTs are off-line because its generation would be too expensive to export.

New 230 kV Line from Bay d'Espoir East

If a new 230 kV line is built between Bay d'Espoir and Sunnyside (with New Refinery load connected), then the reactive power requirement at Sunnyside reduces to 100 MVAr from 200 MVAr. The defining case is voltage collapse following loss of Bay d'Espoir – Piper's Hole line or loss of a 150 MVAr synchronous condenser during the future peak load case when the DC infeed is 800 MW monopolar (BC3-DC4).

Extending the new line to Western Avalon or to Soldiers Pond does not have much impact on the 100 MVAr requirement at Sunnyside for this same worst case power flow and contingency.

The new 230 kV line out of Bay d'Espoir has more of an impact on export capability, in particular the closer the line termination is to Soldiers Pond the higher the export capability. Table 11 below summarizes the impact on export capability. The limiting factor is the 0.95 pu system intact voltage criteria. A fast DC run-back scheme would be required following certain contingencies. Please note that there is only 272 MW available for export in this particular case, assuming the Holyrood CTs are not producing any power.

Table 11
Export Capability with new 230 kV line out of Bay d'Espoir

Sunnyside (MVAr)	Generation Available for Export (MW)	Export Capability for Various Line Terminations (MW)		
		Sunnyside	Western Avalon	Soldiers Pond
0	272	240	265	300
100	272	325	350	375

To get a feel for the maximum possible export capability at Soldiers Pond (assuming generation is coming from west Bay d'Espoir and not from Holyrood), if the New Refinery load is not connected and a new line is built from Bay d'Espoir to Soldiers Pond, without any reactive power support at Sunnyside, the Soldiers Pond export capability is 485 MW, the limiting condition being 0.95 pu system intact voltages. This particular scenario (without the New Refinery load) has 447 MW of generation available for export, again assuming the Holyrood CTs are not producing any power.

5. Short Circuit Analysis

The purpose of the short circuit analysis is to quantify impacts to existing maximum fault levels particularly near to the HVdc system bus and to identify any circuit breakers whose ratings are exceeded due to increased fault levels. Another purpose of the short circuit analysis is to quantify the minimum short circuit level at the Soldiers Pond bus and identify the need for synchronous condenser(s) to ensure a minimum ESCR of 2.5.

5.1 ESCR Requirements of the HVdc Link

As described in Section 3.3 ESCR Requirements, it is recommended that a minimum ESCR of 2.5 be maintained at the Soldiers Pond bus. Dynamic performance studies will further validate this minimum ESCR value, however for the purposes of the power flow analysis, the goal is to design the reactive power requirements such that the ESCR at the Soldiers Pond bus is at least 2.5.

The HVdc system itself does not contribute to the short circuit strength of the system, however a synchronous condenser installed with the HVdc system will increase the short circuit strength if deemed necessary by the short circuit studies.

5.2 Study Procedure

Fault application (PSSE activity ASCC) is used to determine the three-phase and line-to-ground fault levels at a particular bus. All NLH power flow cases contain sequence data, therefore the same cases as used for the power flow analysis are used in the short circuit analysis.

Power flow cases representing the minimum short circuit levels are used to determine the short circuit MVA level and the corresponding ESCR at the Soldiers Pond bus. The power flow cases use the base assumption stated earlier which assumes that one 150 MVAr synchronous condenser and one Holyrood CT synchronous condenser are out of service for maintenance. Then the ESCRs are determined for system intact and contingency conditions.

Power flow cases representing the maximum short circuit levels are used to determine the fault levels at key buses, particularly near to the Soldiers Pond and Gull Island buses. These power flow cases represent system intact conditions with maximum generation and all available synchronous condensers in service. The fault levels at each bus are then compared with the existing fault level and nearby breaker ratings to determine if any breaker ratings will be exceeded. If so, mitigation such as breaker replacement is required.

5.3 Criteria

The following criteria must be met:

1. Fault levels at all buses must not exceed circuit breaker ratings, otherwise mitigation such as breaker replacement is required.
2. The minimum ESCR at the Soldiers Pond bus should be 2.5.

5.4 Study Results

5.4.1 Minimum Short Circuit Levels – ESCR

Power flow analysis determined the total reactive power requirement to be 600 MVAr at Soldiers Pond (450 MVAr filters and 150 MVAr synchronous condenser was assumed) and 200 MVAr at Sunnyside in addition to the eight synchronous condensers at Holyrood.

As a starting point in order to determine whether a synchronous condenser is actually required at Soldiers Pond, the minimum ESCR was found assuming no synchronous condenser is installed at Soldiers Pond. This results in a minimum ESCR of 1.9 (1967 MVA) during minimum generation power flow case BC4 for contingency C11, loss of Holyrood unit #3. This ESCR is below the desired minimum of 2.5. With the single 150 MVAr synchronous condenser at Soldiers Pond, the minimum ESCR is increased to 2.5 (2545 MVA) for this worst case contingency.

Therefore, the short circuit analysis verifies the fact that Soldiers Pond will require one 150 MVAr synchronous condenser to maintain the desired minimum ESCR. Dynamic performance studies will verify this requirement based on dynamic performance results.

For a complete listing of ESCR results for all power flows and all contingencies, please refer to Appendix 3.

5.4.2 Maximum Short Circuit Levels – Breaker Ratings

Maximum fault levels were tested with power flow cases BC1, BC2, BC3, BC7 and BC8 which represent the power flow cases with most Island generation in-service. In addition, all synchronous condensers at Holyrood and Soldiers Pond were placed in-service. Power flow cases BC1 and BC3 were found to produce very similar results and represented the highest fault levels.

Stations near Soldiers Pond and Holyrood saw the largest increase in fault levels. This is due to the addition of a synchronous condenser at Soldiers Pond and the five CTs at Holyrood. Table 11 below summarizes all stations in which the fault level is increased by more than 10%. Please note that existing fault level data and breaker ratings were not available for all buses, only buses for which this data was available were compared to the new increased fault levels in Table 12.

For a complete listing of fault levels with the new facilities in service please refer to Appendix 3.

Table 12
Stations with fault levels increases greater than 10%

Station	Existing Fault Level (MVA)		New Fault Level (MVA)				Breaker Ratings
	3P	LG	3P	Increase	LG	Increase	
Come By Chance 230	2019	1831	2520	24.8%	2520	37.6%	7960
Come By Chance 13.8	301	317	335	11.3%	349	10.1%	Customer-owned
Western Avalon 230	2152	2349	2954	37.3%	3182	35.5%	4980, 5600
Western Avalon 138	1281	1531	1600	24.9%	1882	22.9%	4780
Western Avalon 66	465	324	540	16.1%	363	12.0%	1430, 1500
Long Harbour 230	1653	1439	2151	30.1%	1777	23.5%	None
Long Harbour 46	423	464	807	90.8%	918	97.8%	1590
Sunnyside 230	2164	2084	2701	24.8%	3055	46.6%	5600
Sunnyside 138	1386	1630	1569	13.2%	1933	18.6%	2510
Oxen Pond 230	2396	3335	3387	41.4%	3577	7.3%	5600
Oxen Pond 66	1441	1337	2017	40.0%	1696	26.9%	2380
Hardwoods 230	2223	2605	3758	69.1%	4149	59.3%	5430, 7560, 13360
Hardwoods 66	1628	1625	2285	40.4%	2060	26.8%	2380, 2360, 2850, 3600
Holyrood 230	2657	3307	4629	74.2%	**5754**	74.0%	**5100**, **5430**,7570,12550
Holyrood 138	1377	1690	1839	33.6%	2212	30.9%	5020
Holyrood 66	542	501	629	16.1%	564	12.6%	4570
Holyrood 16	1827	0	2200	20.4%	0	-	None
Holyrood 16	1773	0	2099	18.4%	0	-	None
Holyrood 16	1598	0	1928	20.7%	0	-	None

Despite the increase in fault levels, the only station in which breaker ratings were exceeded was Holyrood. The maximum fault level seen at Holyrood station was 4629 MVA three-phase and 5754 MVA line-to-ground. Nine breakers at Holyrood rated for 5100 MVA (B12B15, B3L18, B12L42, B3B13) and 5430 MVA (B2L42, B12L17, B1L17, B1B11, B2B11) would require replacement.

6. Conclusions

6.1 Steady State Reactive Power Requirements

The minimum steady state reactive power support requirements are as follows:

- Soldiers Pond – 450 MVAr filters, 150 MVAr synchronous condenser
- Sunnyside 230 kV – 200 MVAr of capacitance

The determining contingencies for the steady state reactive power requirements were C9, loss of one of the Bay d'Espoir to Piper's Hole lines, and C11, loss of Holyrood unit #3, during the future peak Island load (1800 MW) BC3-DC4 power flow case in which the HVdc inverter at Soldiers Pond was operating in the 10-minute 2.0 pu monopolar mode. In this case the inverter at Soldiers Pond is absorbing 559 MVA compared to the 462 MVAr during bipolar operation. Without the additional reactive power support of the synchronous condenser at Soldiers Pond and the 200 MVAr at Sunnyside, the result of either of these contingencies would be system wide voltage collapse.

The synchronous condensers at Holyrood control their own bus voltage and are not VAR-limited during these worst contingencies because the voltage problems occur too far west of Holyrood for the reactive power support at Holyrood to be significantly useful in these voltage collapse scenarios. Therefore the synchronous condenser required for Soldiers Pond should be located right at the converter and not at Holyrood as local support will be required at Soldiers Pond. It is unlikely that fewer than 450 MVAr of filters will be required at Soldiers Pond because of the voltage depression occurring west of Soldiers Pond. If filters were removed at Soldiers Pond then a similar amount of reactive power support as was removed would be required at Sunnyside. It comes down to determining a reasonable split and location of total system reactive power requirements. With Sunnyside already requiring 200 MVAr, it would be undesirable to move some of the filter requirements from Soldiers Pond to Sunnyside. It would more likely be possible to lower the filter requirements at Soldiers Pond if the Holyrood synchronous condensers were located directly at Soldiers Pond.

Even with the above described reactive power support, it should be noted that for power flow cases BC7 with the HVdc infeed at minimum power of 80 MW and for case BC8 when the DC is exporting 200 MW, a fast HVdc run-up (minimum 50 MW when importing) and run-down (minimum 100 MW when exporting) is required to prevent system voltage collapse for contingency C9, loss of a Bay d'Espoir to Piper's Hole. A corresponding transfer trip of generation in the west would be required to offset the increase in generation in the east. The voltage collapse seems to occur if there is more than approximately 225-250 MW flowing from west to east on both of the Bay d'Espoir to Piper's Hole lines. If it would not be desired to perform a fast dc power run-up or run-down, then it would likely be possible to develop an operating guideline to limit steady state power flow on the circuits between Bay d'Espoir and Piper's Hole by re-dispatching generation to avoid the voltage collapse scenario in the first place. This would require further study to determine if this is in fact possible and what the exact power flow limit would be. Dynamic performance studies could investigate this issue further.

Dynamic performance studies will verify these requirements, whether one synchronous condenser at Soldiers Pond is sufficient, and whether there are any dynamic reactive power requirements at the Sunnyside 230 kV station.

6.2 NLH Network Upgrades

All but one of the thermal overloads on the Island occur on the heavily loaded west to east 230 kV transmission corridor between Bay d'Espoir and Soldiers Pond.

The exception to this corridor is 230 kV line TL201 from Soldiers Pond to Hardwoods. This line becomes overloaded only during the future peak Island load (1800 MW) power flow case due to load serving requirements on the radial 138 kV system underlying Hardwoods and Oxen Pond stations. The overload is worse, up to 115%, if the two 25 MW wind farms are not in-service. This line will need to be upgraded and will require a rebuild with 804 MCM AACSR/TW conductor as stated in upcoming Table 13.

For the remaining 230 kV lines between Bay d'Espoir and Soldiers Pond, the highest overloads occur when the HVdc system is exporting power from the Island, and the next worst situation is when the HVdc system is importing low power. However, some overloads still occur even when the HVdc system is importing its maximum rated power. It is possible to mitigate all of these overloads by re-dispatching Island generation, first by increasing the HVdc import if there is room available (or lowering the HVdc export) and then by turning on generation from the CTs at Holyrood when there is no more room left on the HVdc. This effectively reduces the west to east power flow and reduces loading on the affected 230 kV lines.

Many of these overloads are quite high however, and instead of relying on generator re-dispatch to mitigate the overloads, line upgrades could be implemented as described in Table 13.

Table 13
230 kV Transmission Line Upgrades

Line		Current Rating (MVA)	New Rating (MVA)	Upgrade
TL202	Bay d'Espoir-Piper's Hole	199.3/297.7/369.5	341.8/402.4/453.8	Thermal uprating to 75 degrees C.
TL206	Piper's Hole – Sunnyside	199.3/297.7/369.5	341.8/402.4/453.8	Thermal uprating to 75 degrees C.
TL203	Sunnyside – Western Avalon	261.7/307.8/347.0	355.8/411.5/459.6	Rebuild with 804 MCM AACSR/TW conductor.
TL217	Western Avalon-Soldiers Pond	199.3/297.7/369.5	341.8/402.4/453.8	Recent review indicates can operate at 75 degrees C as is.
TL201	Western Avalon-Soldiers Pond	175.5/260.2/322.2	355.8/411.5/459.6	Rebuild with 804 MCM AACSR/TW conductor.
TL201	Soldiers Pond-Hardwoods	175.5/260.2/322.2	355.8/411.5/459.6	Rebuild with 804 MCM AACSR/TW conductor.

Lines TL207 from Sunnyside to Come By Chance and TL237 from Come By Chance to Western Avalon have already been upgraded to use 804 MCM AACSR/TW conductor. These lines would require further review by NLH Transmission Design if the ratings were to be increased.

If the line upgrades listed in Table 13 are built, a few overloads still remain but only during cases with very low HVdc infeed power or when the HVdc is exporting power from the Island. These cases are summarized below in Table 14. These overloads can be mitigated by increasing HVdc imports or decreasing HVdc exports post-contingency.

Table 14
Overloads After Line Upgrades are Implemented

Overloaded Line	Contingency	Rate	Power Flow	Overload (%)	Pre-Contingency HVdc Infeed (MW)	Post-Contingency Re-dispatch (MW)
Piper's Hole-Bay d'Espoir TL202, TL206	C9	A	BC12-DC10	101.4	80 BP	+10 HVdc import
		B	BC7*		80 BP	+175 HVdc import
		A	BC8*		-200 BP	0 HVdc export +75 Holyrood
		C	BC2-DC5	100.3	600 MP	-
Sunnyside-Western Avalon TL203	C5,C6	A	BC8	146.7	-200 BP	-125 HVdc export
Piper's Hole-Sunnyside TL202	C8	A	BC8	148.6	-200 BP	-160 HVdc export
		B	BC7-DC1	108.9	80 BP	+35 HVdc import
Sunnyside-Come By Chance TL207	C7	A	BC8	150.3	-200 BP	-130 HVCD export
Come By Chance-Western Avalon TL237	C7	A	BC8	142.7	-200 BP	-110 HVdc export

**These scenarios require a fast HVdc run-up or run-down as described in section 7.1.*

6.3 HVdc System Losses

During normal bipolar operation, the Gull Island converter supplies a rated current of 1600 A. The power injected at Soldiers Pond is 765.8 MW and at Salisbury, 763.4 MW, resulting in losses of 34.2 MW and 36.6 MW respectively.

The losses increase when operating in monopolar mode, requiring up to 2611 A (1.66 pu current) at Gull Island to supply the 10-minute 100% overload requirement at Soldiers Pond (2.16 pu current) and the continuous 10% overload at Salisbury (1.1 pu current), and up to 2149 A (1.34 pu) at Gull Island to supply the continuous 50% and 10% overloads at Soldiers Pond (1.58 pu current) and Salisbury (1.1 pu current) respectively.

6.4 Minimum ESCR at Soldiers Pond

Soldiers Pond requires one 150 MVAr synchronous condenser to increase the minimum ESCR at the Soldiers Pond 230 kV bus up to 2.5 (2545 MVA) from 1.9 (1967 MVA) if no synchronous condenser is installed. The minimum ESCR occurs during the minimum Island generation base case (BC4) with contingency C11, loss of Holyrood unit #3. The base case assumes maintenance outages of the Soldiers Pond synchronous condenser and one Holyrood CT synchronous condenser.

6.5 Impacts to Maximum Fault Levels

Despite the increase in fault levels at various nearby stations, the only station with breakers whose ratings were exceeded was Holyrood. The maximum fault level seen at Holyrood station was 4629 MVA three-phase and 5754 MVA line-to-ground. Nine breakers at Holyrood rated for 5100 MVA (B12B15, B3L18, B12L42, B3B13) and 5430 MVA (B2L42, B12L17, B1L17, B1B11, B2B11) would require replacement.

6.6 Impacts of New Refinery Load

It should be noted that a portion of the Island system upgrades identified in this report, in particular the need for reactive power support at Sunnyside and the extensive thermal upgrades required on 230 kV transmission between Bay d'Espoir and Soldiers Pond, are largely due to approximately 255 MW of new industrial load (refinery and smelter) which is planned to be installed along the heavily loaded transmission corridor. The major NLH Island load centre is located east of Bay d'Espoir on the Avalon Peninsula, while the majority of the generation is located west of Bay d'Espoir. This can result in heavy west to east power flow on the 230 kV transmission system, in particular between Bay d'Espoir, Sunnyside, Western Avalon and Soldiers Pond, with further increased loading due to the new industrial loads. As a general result this can cause voltage depression and thermal overloading in the area. The HVdc infeed into Soldiers Pond generally has a positive impact on the Island transmission system as it off-loads this west-to-east power flow by injecting power closer to the load centre. Many of the issues discussed are not necessarily due to the HVdc infeed but are due to the lack of transmission linking the generation in the west to the load in the east. For example, without the new refinery load, the reactive power requirement at Sunnyside reduces to approximately 50 MVAr from 200 MVAr. It will be important for further system impact studies involving the loads to define more exact requirements of connecting the new loads separate from the impacts of the HVdc infeed into Soldiers Pond.

Appendix A

Newfoundland Island Generation Dispatch for Base Cases

WTO DC 1020
HVDC System Integration Study
Generation Dispatch for Base Case Scenarios

	Base Cases									
	BC1	BC2	BC3	BC4	BC5	BC6	BC7	BC8	BC12	BC13
NLH System Load (MW)	1584.5	1584.5	1750.5	625	625	990.1	990.1	625	625	1750.5
Generation Dispatch										
HVDC at Soldiers Pond	765.9	578.4	765.9	248.8	78.5	765.9	78.5	-200.0	79.8	574.2
NLH - Hydro										
Bay d'Espoir Unit 1	57.8	67.8	69	61.6	60.6	58.5	71.2	59.1	59.2	67.6
Bay d'Espoir Unit 2	58.2	68.3	69.5	off	off	off	69.7	58	off	68.1
Bay d'Espoir Unit 3	58.2	68.3	69.5	off	60.8	off	69.7	58	60.8	68.1
Bay d'Espoir Unit 4	58.2	68.3	69.5	off	off	off	69.7	58	off	68.1
Bay d'Espoir Unit 5	58.2	68.3	69.5	off	60.8	off	69.7	58	60.8	68.1
Bay d'Espoir Unit 6	58.2	68.3	69.5	off	off	off	69.7	58	off	68.1
Bay d'Espoir Unit 7	135	154	154	135	135	sc	154	154	135	154
Cat Arm Unit 1	35	65	65	35	35	sc	60	65	35	65
Cat Arm Unit 2	35	65	65	sc	35	sc	60	65	35	65
Upper Salmon	75	84	84	64	75	70	75	84	75	84
Hinds Lake	67	75	75	off	off	off	67	75	off	75
Granite Canal	25	40	40	22	30	25	35	40	30	40
Paradise River	8	8	8	off	8	off	8	8	8	8
NLH - Thermal										
Hardwoods	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc
Stephenville	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc
Holyrood CT1	sc	30	sc	sc	sc	sc	sc	sc	sc	50
Holyrood CT2	sc	sc	sc	sc	sc	sc	sc	sc	sc	50
Holyrood CT3	sc	sc	sc	sc	sc	sc	sc	sc	sc	50
Holyrood CT4	sc	sc	sc	sc	sc	sc	sc	sc	sc	50
Holyrood CT5	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc
NUGS										
Star Lake	17.9	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4
Rattle Brook	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
CBP&P	15	15	15	15	15	15	15	15	15	15
Exploits	32	32	32	32	32	32	32	32	32	32
Wind										
St. Lawrence	25	25	25	0	0	12	12	0	0	25
Fermuse	25	25	25	0	0	12	12	0	0	25
Goulds	25	25	25	0	0	12	12	0	0	25
Total Generation	1638.2	1651.7	1816.4	634.4	646.7	1023.4	1061.2	708.1	646.6	1816.3

Appendix B

HVdc Operating Points for all Base Cases

Portion of Appendix B removed from Public version

Includes data parameters for PSSE multi-terminal line model.

Corresponds to Table 6 of the report.

Line Conductor Details

As the dc conductor optimization and route selection were not finalized prior to carrying out the power flow and short circuit analysis, the conductor type, geometry and line lengths used in the studies were based on the preliminary data available at the time. Although final transmission line and cable parameters may differ from those used in this study, the overall impact on results should be minimal.

Overhead line portions assumed 2-conductor symmetrical bundle with a dc resistance of 0.02892 ohms/km. Cable portions assumed a single conductor. Line lengths were as follows:

Gull Island to Strait of Belle Isle	407 km overhead line
Strait of Belle Isle	40.7 km of submarine cable
Strait of Belle Isle to Taylors Brook	201 km of overhead line
Taylors Brook to Soldiers Pond	480 km of overhead line
Taylors Brook to Cape Ray	300 km of overhead line
Cape Ray to Salisbury	325 km of submarine cable
Cape Ray to Salisbury	100 km of overhead line

Converter Transformer Details

Current normal industry practice is to supply a single twelve pulse valve group per pole at each station for HVdc transmission systems with power ratings similar to that being considered. Each twelve pulse valve group is connected to the ac system either through two three phase, two winding, converter transformers or three, single phase, three winding converter transformers to provide the necessary wye:wye and wye:delta connections. For PSSE modeling purposes, the transformers connected to each pole have been lumped together into one equivalent transformer connected to a single bridge.

When calculating the values for the equivalent converter transformers, the commutating reactance value in ohms is referred to the secondary side of the transformer. Because these transformers are connected in series (one to each 6-pulse bridge) the secondary voltage for the equivalent transformer is double, as is the MVA rating. For example, at Gull Island:

Equivalent transformer rating = 2 * 585 = 1170 MVA
Equivalent transformer secondary voltage = 2*208.6 = 417.2 kV
Xc (ohms) = 0.14 pu * (417.2 kV*417.2 kV)/1170 MVA = 20.827 ohms

Converter Transformer Data

Converter	Rating (MVA)	Voltage (kV)	Tap Changer Range	Commutating Reactance Xc (pu)	Equivalent Transformer Rating (MVA)	Equivalent Transformer Voltage (kV)	Equivalent Transformer Xc (ohms)
Gull Island	2 x 585 per pole	230–208.6	0.9-1.1	0.14 pu	1170 per pole	230-417.2	20.827
Soldiers Pond	2 x 351 per pole	230–208.6	0.9-1.1	0.14 pu	702 per pole	230-417.2	34.712
Salisbury	2 x 234 per pole	345–208.6	0.9-1.1	0.14 pu	468 per pole	345-417.2	52.068

Appendix C

Effective Short Circuit Ratios at Soldiers Pond

ESCR and Short Circuit MVA at Soldiers Pond 230 kV Bus

Assuming Synchronous Condenser at Soldiers Pond does not exist

	BC1		BC2		BC3		BC4		BC5		BC6		BC7		BC8		BC10		BC12		BC13	
Contingency	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**
Base Case	3.2	2989	3.2	2989	3.2	2989	2.5	2453	2.6	2504	2.9	2807	3.1	2900	2.9	2734	3.2	2989	2.8	2689	3.2	2989
C1	3.1	2929	3.1	2929	3.1	2929	2.4	2395	2.5	2446	2.9	2748	3.0	2840	2.8	2664	3.1	2929	2.7	2619	3.1	2929
C2	3.2	2985	3.2	2985	3.2	2985	2.5	2453	2.6	2504	2.9	2804	3.1	2896	2.9	2734	3.2	2985	2.8	2689	3.2	2985
C3	3.2	2985	3.2	2985	3.2	2985	2.5	2453	2.6	2504	2.9	2804	3.1	2897	2.9	2734	3.2	2985	2.8	2689	3.2	2985
C4	3.0	2871	3.0	2871	3.0	2871	2.4	2370	2.4	2408	2.8	2718	2.9	2785	2.7	2625	3.0	2871	2.7	2592	3.0	2871
C5	3.1	2897	3.1	2897	3.1	2897	2.4	2387	2.5	2426	2.9	2736	2.9	2807	2.7	2646	3.1	2897	2.7	2611	3.1	2897
C6	3.1	2897	3.1	2897	3.1	2897	2.4	2387	2.5	2426	2.9	2736	2.9	2807	2.7	2646	3.1	2897	2.7	2611	3.1	2897
C7	3.0	2872	3.0	2872	3.0	2872	2.4	2368	2.4	2405	2.8	2716	2.9	2781	2.7	2622	3.0	2872	2.7	2589	3.0	2872
C8	3.2	2984	3.2	2984	3.2	2984	2.5	2449	2.6	2499	2.9	2803	3.1	2894	2.8	2728	3.2	2984	2.8	2684	3.2	2984
C9	3.0	2823	3.0	2823	3.0	2823	2.3	2319	2.4	2352	2.8	2677	2.9	2732	2.6	2561	3.0	2823	2.6	2536	3.0	2823
C10	2.6	2505	2.6	2505	2.6	2505	1.9	1967	2.0	2018	2.3	2322	2.5	2414	2.3	2255	2.6	2505	2.2	2209	2.6	2505

Assumptions:

1 Synchronous Condenser at Soldiers Pond does not exist
2 Holyrood unit #3 and a Holyrood CT synchronous condensers out of service (all other Holyrood SCs in service)
3 No reactive power support at Sunnyside
4 450 MVAR switched capacitors at Soldiers' Pond (does not contribute to short circuit current)

ESCR and Short Circuit MVA at Soldiers Pond 230 kV Bus

Assuming 150 MVAR Synchronous Condenser exists at Soldiers Pond

Soldiers Pond synchronous condenser out-of-service

	BC1		BC2		BC3		BC4		BC5		BC6		BC7		BC8		BC10		BC12		BC13	
Contingency	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**
Base Case	3.7	3409	3.7	3409	3.7	3409	3.0	2875	3.1	2925	3.5	3228	3.6	3320	3.4	3149	3.7	3409	3.3	3104	3.7	3409
C1	3.6	3320	3.6	3320	3.6	3320	2.9	2788	3.0	2839	3.4	3140	3.5	3232	3.2	3049	3.6	3320	3.2	3004	3.6	3320
C2	3.7	3404	3.7	3404	3.7	3404	3.0	2875	3.1	2925	3.5	3225	3.6	3316	3.4	3149	3.7	3404	3.3	3104	3.7	3404
C3	3.7	3405	3.7	3405	3.7	3405	3.0	2875	3.1	2925	3.5	3225	3.6	3317	3.4	3149	3.7	3405	3.3	3104	3.7	3405
C4	3.5	3290	3.5	3290	3.5	3290	2.9	2790	3.0	2828	3.4	3138	3.4	3205	3.2	3039	3.5	3290	3.2	3006	3.5	3290
C5	3.6	3317	3.6	3317	3.6	3317	2.9	2808	3.0	2848	3.4	3157	3.5	3227	3.3	3061	3.6	3317	3.2	3027	3.6	3317
C6	3.6	3317	3.6	3317	3.6	3317	2.9	2808	3.0	2848	3.4	3157	3.5	3227	3.3	3061	3.6	3317	3.2	3027	3.6	3317
C7	3.6	3292	3.6	3292	3.6	3292	2.9	2789	3.0	2826	3.4	3137	3.4	3202	3.2	3037	3.6	3292	3.2	3005	3.6	3292
C8	3.7	3404	3.7	3404	3.7	3404	3.0	2870	3.1	2920	3.5	3224	3.6	3314	3.4	3143	3.7	3404	3.3	3099	3.7	3404
C9	3.5	3244	3.5	3244	3.5	3244	2.9	2740	2.9	2773	3.3	3098	3.4	3153	3.2	2977	3.5	3244	3.1	2952	3.5	3244
C10	3.4	3195	3.4	3195	3.4	3195	3.0	2875	3.1	2925	3.2	3004	3.3	3096	3.4	3149	3.4	3195	3.3	3104	3.4	3195
C11	3.2	2989	3.2	2989	3.2	2989	2.5	2454	2.6	2504	2.9	2808	3.1	2900	2.9	2734	3.2	2989	2.8	2689	3.2	2989

Assumptions:

1 Synchronous Condenser at Soldiers' Pont out of service
2 A Holyrood CT synchronous condenser out of service (all other Holyrood SCs in service)
3 200 MVAR SVC at Sunnyside (does not contribute to short circuit current)
4 450 MVAR switched capacitors at Soldiers' Pond (does not contribute to short circuit current)

ESCR and Short Circuit MVA at Soldiers Pond 230 kV Bus

Assuming 150 MVAR Synchronous Condenser exists at Soldiers Pond

Holyrood unit #3 synchronous condenser out-of-service

	BC1		BC2		BC3		BC4		BC5		BC6		BC7		BC8		BC10		BC12		BC13	
Contingency	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**	**ESCR**	**MVA**
Base Case	4.0	3625	4.0	3625	4.0	3625	3.3	3098	3.4	3145	3.8	3450	3.9	3536	3.7	3372	4.0	3625	4.1	3745	4.0	3625
C1	3.9	3564	3.9	3564	3.9	3564	3.2	3039	3.3	3086	3.7	3390	3.8	3476	3.6	3301	3.9	3564	4.0	3644	3.9	3564
C2	4.0	3621	4.0	3621	4.0	3621	3.3	3098	3.4	3145	3.7	3447	3.9	3533	3.7	3372	4.0	3621	4.1	3745	4.0	3621
C3	4.0	3621	4.0	3621	4.0	3621	3.3	3098	3.4	3145	3.7	3447	3.9	3533	3.7	3372	4.0	3621	4.1	3745	4.0	3621
C4	3.8	3497	3.8	3497	3.8	3497	3.2	3003	3.2	3038	3.6	3350	3.7	3411	3.5	3252	3.8	3497	4.0	3636	3.8	3497
C5	3.8	3524	3.8	3524	3.8	3524	3.2	3021	3.3	3058	3.6	3369	3.7	3434	3.5	3274	3.8	3524	4.0	3658	3.8	3524
C6	3.8	3524	3.8	3524	3.8	3524	3.2	3021	3.3	3058	3.6	3369	3.7	3434	3.5	3274	3.8	3524	4.0	3658	3.8	3524
C7	3.8	3497	3.8	3497	3.8	3497	3.2	3000	3.2	3034	3.6	3346	3.7	3407	3.5	3248	3.8	3497	4.0	3634	3.8	3497
C8	4.0	3620	4.0	3620	4.0	3620	3.3	3094	3.4	3140	3.7	3446	3.9	3531	3.6	3366	4.0	3620	4.1	3740	4.0	3620
C9	3.8	3470	3.8	3470	3.8	3470	3.2	2972	3.2	3003	3.6	3329	3.7	3379	3.5	3210	3.8	3470	3.9	3603	3.8	3470
C10	3.7	3411	3.7	3411	3.7	3411	3.3	3098	3.4	3145	3.5	3225	3.6	3311	3.7	3372	3.7	3411	4.1	3745	3.7	3411
C11	3.2	3026	3.2	3026	3.2	3026	2.6	2498	2.6	2545	3.0	2850	3.1	2937	2.9	2773	3.2	3026	3.4	3145	3.2	3026

Assumptions:

1 Holyrood synchronous condenser unit #3 out of service
2 A Holyrood CT synchronous condenser out of service
3 200 MVAR SVC at Sunnyside (does not contribute to short circuit current)
4 450 MVAR switched capacitors at Soldiers' Pond (does not contribute to short circuit current)

Appendix D

Maximum Short Circuit Levels

Maximum NLH Fault Levels
Before and After HVDC System Addition

Area	Bus No	Bus Name	Station	Bus Volt kV	Rating MVA	Existing 3P MVA	Existing LG MVA	BC1-DC1 3P MVA	BC1-DC1 LG MVA	BC2-DC1 3P MVA	BC2-DC1 LG MVA	BC3-DC1 3P MVA	BC3-DC1 LG MVA	BC7-DC1 3P MVA	BC7-DC1 LG MVA	BC8-DC8 3P MVA	BC8-DC8 LG MVA
1	211	NLREFINERY	New Refinery	230	Proposed Station			2469	3018	2430	2972	2464	3009	2306	2835	2238	2781
1	227	CBC B1B2	Come-By-Chance	230	7960	2019	1831	2520	2520	2480	2477	2517	2507	2347	2369	2276	2328
1	228	CBC T1	Come-By-Chance	13.8	Customer-owned	301	317	335	349	328	342	330	343	321	334	320	334
1	229	WAV B1B3	Western Avalon	230	4980/5600	2152	2349	2954	3182	2908	3120	2964	3177	2711	2935	2622	2884
1	230	LHR B1	Long Harbour - VBN	230	New breakers	1653	1439	2151	1777	2112	1738	2147	1761	1993	1662	1947	1650
1	231	LHR B3B4	Long Harbour - VBM	46	1590	423	464	807	918	789	897	798	906	760	867	756	864
1	234	HRD TS	Holyrood	230	5100/5400/7570/12550	2657	3307	4537	5668	4517	5622	4629	5754	4123	5175	3843	4896
1	236	HWD B1B2	Hardwoods	230	5430/7560/13360	2223	2605	3694	4100	3664	4039	3758	4149	3335	3701	3055	3502
1	237	HWD G1	Hardwoods	13.8	720	961	0.14	1039	0	1026	0	1033	0	1013	0	360	0
1	238	OPD B1	Oxen Pond	230	5600	3104	2396	3335	3533	3301	3472	3387	3577	3005	3157	2773	3022
1	308	BLK NPT3	Blaketown	66	Customer-owned			527	493	515	482	523	490	483	458	488	465
1	309	BRB T2T3	Bay Roberts	66	Customer-owned			460	515	447	500	454	508	419	477	432	493
1	310	BLK NP	Blaketown	138	Customer-owned			1323	1134	1297	1104	1320	1123	1220	1052	1209	1062
1	311	WAV B4	Western Avalon	138	4780	1281	1531	1600	1882	1571	1843	1595	1870	1483	1751	1457	1735
1	334	OPD B2B5	Oxen Pond	66	2380	1441	1337	2004	1694	1973	1655	2017	1696	1813	1541	1647	1473
1	335	HWD B7B8	Hardwoods	66	2380/2630/2850/3600	1628	1625	2271	2058	2239	2016	2285	2060	2052	1880	1736	1705
1	336	WAV B2	Western Avalon	66	1430/1500	465	324	540	363	527	355	534	359	502	341	507	348
1	337	HRD B6B7	Holyrood	66	1500/4570	542	501	629	564	616	552	623	557	591	541	585	543
1	338	HRD B8	Holyrood	138	5020	1377	1690	1839	2212	1803	2164	1840	2207	1690	2039	1663	2023
1	340	HOL NP	Holyrood Town	138	Customer-owned			1415	1152	1384	1121	1411	1141	1303	1069	1294	1078
1	347	SCV NP	Seal Cove	66	Customer-owned			649	552	635	539	644	546	605	521	596	523
1	348	KEL NP	Kelligrews	66	Customer-owned			763	513	746	500	759	508	707	481	688	482
1	349	CHA NP	Chamberlains	66	Customer-owned			1332	886	1305	863	1331	880	1217	822	1119	801
1	352	SCV GEN	Seal Cove	2.4	Customer-owned			53	30	52	30	53	30	36	0	37	0
1	353	SPF NP	Springfield	138	Customer-owned			1176	849	1149	825	1171	839	1080	788	1077	801
1	354	COL NP	Colliers	138	Customer-owned			1211	876	1183	852	1206	866	1114	815	1111	827
1	357	BRB NP	Bay Roberts	138	Customer-owned			1170	875	1143	849	1165	864	1070	810	1066	823
1	428	CBC T2	Come-By-Chance	13.8	Customer-owned			335	349	329	342	330	343	321	334	320	334
1	434	HRP G1	Holyrood	16	No Unit Breakers	1827	0.12	2175	0	2154	0	2200	0	2025	0	2059	0
1	435	HRP G2	Holyrood	16	No Unit Breakers	1773	0.12	2077	0	2057	0	2099	0	1938	0	1974	0
1	436	HRP G3	Holyrood	16	No Unit Breakers	1598	0.12	1907	0	1886	0	1928	0	1770	0	1802	0
1	444	HRD CT1	Holyrood	13.8	Proposed Unit			873	0	859	0	880	0	817	0	838	0
1	445	HRD CT2	Holyrood	13.8	Proposed Unit			873	0	863	0	880	0	817	0	838	0
1	446	HRD CT3	Holyrood	13.8	Proposed Unit			873	0	863	0	880	0	817	0	838	0
1	447	HRD CT4	Holyrood	13.8	Proposed Unit			873	0	863	0	880	0	817	0	838	0
1	448	HRD CT5	Holyrood	13.8	Proposed Unit			873	0	863	0	880	0	817	0	838	0
1	507	ILC NP	Islington	66	Customer-owned			323	280	314	272	318	275	296	259	305	267
1	511	GOU WIND	Goulds	66	Customer-owned			735	923	723	908	733	920	644	822	518	683
1	512	GOU WIND	Goulds	13.8	Customer-owned			294	202	292	201	294	202	286	199	161	0
1	580	FER WIND	Fermuse	66	Customer-owned			229	227	228	226	229	227	193	201	112	132
1	581	FER WIND	Fermuse	34.5	Customer-owned			212	252	212	252	212	252	200	241	76	101
1	2301	CHF A1 B21	Churchill Falls	230	15000			7239	8436	7211	8400	7239	8436	7154	8329	7121	8279
1	2302	CHF A2 & A3	Churchill Falls	230	15000			8602	10374	8572	10336	8602	10374	8512	10258	8473	10201
1	2303	CHF A4 & A5	Churchill Falls	230	15000			8616	10407	8586	10369	8616	10407	8526	10291	8487	10233
1	2304	CHF A6 & A7	Churchill Falls	230	15000			8584	10357	8555	10319	8584	10357	8494	10241	8456	10184
1	2305	CHF A8& A9	Churchill Falls	230	15000			8633	10424	8603	10386	8633	10424	8543	10308	8504	10250
1	2306	CHF B23	Churchill Falls	230	15000			9059	10809	9030	10772	9059	10809	8971	10697	8937	10644
1	2490	SOL B1	Soldiers Pond	230	Proposed Station			4375	5534	4359	5492	4467	5622	3971	5043	3659	4722
1	2491	SOL SC1	Soldiers Pond	13.8	Proposed Station			2338	1676	2310	1652	2362	1686	2112	1443	2077	1440
2	112	IRV B1	Indian River	138	628	523	340	532	345	528	342	527	341	520	338	527	344
2	113	SPL B1	Springdale	138	1490	515	322	525	327	520	324	519	323	514	322	520	327
2	145	BWT L60	Bottom Waters	138	287	216	120	223	121	221	120	220	120	218	120	222	123
2	146	BWT B1	Bottom Waters	25	Reclosers			94	109	94	108	93	108	93	108	94	110
2	151	BUC B2	Buchans	66	4570			427	325	423	323	421	321	423	323	425	325
2	214	SOK T1	South Brook	25	Reclosers			63	65	63	65	63	64	63	65	63	66

Maximum NLH Fault Levels
Before and After HVDC System Addition

Area	Bus No	Bus Name	Station	Bus Volt kV	Rating MVA	Existing		BC1-DC1		BC2-DC1		BC3-DC1		BC7-DC1		BC8-DC8	
						3P MVA	LG MVA	3P MVA	LG MVA	3P MVA	LG MVA	3P MVA	LG MVA	3P MVA	LG MVA	3P MVA	LG MVA
2	215	BUC B1	Buchans	230	5430/7970	1824	1736	1773	1735	1759	1720	1759	1718	1736	1710	1729	1707
2	216	STB B1B2	Stony Brook	230	4780/9960	2444	2640	2433	2649	2411	2624	2417	2629	2379	2600	2359	2582
2	217	STB B3	Stony Brook	138	2480/2630	1508	1836	1512	1853	1495	1832	1492	1828	1471	1809	1466	1806
2	218	PIPERS_HOLE	Pipers Hole	230	Proposed Station			2680	3071	2638	3022	2677	3062	2497	2882	2416	2821
2	219	SOK L22	South Brook	138	Circuit Switcher	538	335	548	341	543	337	542	337	538	336	542	340
2	222	SSD B1	Sunnyside	230	5600	2164	2084	2701	3055	2661	3007	2701	3048	2515	2864	2431	2802
2	223	SSD B2B3	Sunnyside	138	2510	1386	1630	1569	1933	1541	1898	1558	1917	1471	1821	1396	1745
2	226	SSD T5	Sunnyside	25	Customer-owned			195	202	191	198	192	199	187	194	188	196
2	296	GWD NP	Glenwood	138	No Breaker	701	507	710	516	699	508	700	509	693	508	691	509
2	297	GWD NPT1	Glenwood	25	Customer-owned			68	70	67	68	67	68	68	70	68	70
2	300	RUS NP	Rusty Pond	66	Customer-owned			211	170	209	168	209	168	210	170	211	171
2	301	NWB NP	Northwest Brook	138	Customer-owned			1118	948	1097	929	1108	937	1057	905	1019	882
2	302	RBK NP	Rattling Brook	66	Customer-owned			164	184	162	182	162	182	163	183	165	186
2	303	RBK NP G	Rattling Brook	6.9	Customer-owned			86	0	85	0	85	0	86	0	87	0
2	304	GAN NP	Gander	138	Customer-owned			727	619	715	611	718	615	703	601	698	601
2	305	GAM NP	Gambo	138	Customer-owned			618	402	606	394	609	395	596	392	590	393
2	306	CLV NP	Clarenville	138	Customer-owned			1063	913	1043	893	1053	904	1006	873	968	828
2	312	NWB NPT1	Northwest Brook	25	Customer-owned			93	97	91	95	92	95	90	94	91	95
2	315	COB NP	Cobbs Pond	138	Customer-owned			757	619	745	610	748	614	732	603	727	603
2	316	COB NPT2	Cobbs Pond	66	Customer-owned			210	232	205	226	202	223	212	235	213	237
2	320	GLV NP	Glovertown	138	Customer-owned			621	391	609	384	612	385	597	382	591	381
2	321	TNS NP	Terra Nova	138	Customer-owned			656	415	643	406	647	408	630	403	622	400
2	323	PBD NP	Port Blandford	138	Customer-owned			676	432	662	423	667	425	648	419	638	415
2	324	SBK NP	Sandy Brook	66	Customer-owned			159	154	157	152	157	152	159	154	161	156
2	325	SBK GEN	Sandy Brook	6.9	Customer-owned			59	0	58	0	58	0	59	0	59	0
2	326	GFS NP	Grand Falls	138	Customer-owned			1192	1190	1177	1175	1177	1174	1163	1168	1159	1167
2	327	GFS NPT1	Grand Falls	66	Customer-owned			224	175	221	173	221	173	222	175	223	176
2	341	BFS NP	Bishops Falls	138	Customer-owned			1155	1116	1141	1102	1140	1101	1127	1096	1124	1095
2	342	BFS NPT1	Bishops Falls	25	Customer-owned			179	241	176	238	176	238	177	240	177	240
2	344	GAN NPT2	Gander	66	Customer-owned			190	144	187	142	188	142	187	142	188	144
2	380	GAM NPT2	Gambo	66	Customer-owned			202	230	198	226	198	225	198	227	199	228
2	381	HBS NP	Hare Bay	66	Customer-owned			137	122	134	120	134	119	135	121	137	122
2	382	TRN NP	Trinity	66	Customer-owned			104	96	102	94	101	93	103	95	104	96
2	383	GPD NP	Greens Pond	66	Customer-owned			80	89	79	87	78	86	80	88	81	89
2	384	WES NP	Wesleyville	66	Customer-owned			70	93	69	91	69	90	70	92	71	93
2	385	WES GEN	Wesleyville	13.2	Customer-owned			53	0	52	0	52	0	53	0	53	0
2	395	NDJ NP	Notre Dame Junction	66	Customer-owned			158	132	156	130	156	130	156	132	157	134
2	397	LEW NP	Lewisporte	66	Customer-owned			126	89	125	88	125	88	125	90	126	92
2	410	CLK NP	Clarks Head	66	Customer-owned			110	75	108	73	107	73	109	74	110	76
2	411	BOY NP	Boyds Cove	66	Customer-owned			84	51	83	50	83	50	84	51	85	52
2	412	FHD L54	Farewell Head	66	No Breaker			72	42	71	41	71	41	72	42	72	43
2	413	FHD T1	Farewell Head	25	n/a			51	66	50	65	50	65	50	65	51	66
3	103	DLK B2	Deer lake	66	1430/2380/2390			683	709	681	708	681	707	677	704	679	708
3	104	SCR NP	Seal Cove Road	138	Customer-owned	271	154	278	156	275	155	275	154	272	154	276	158
3	108	MMT NP	Marble Mountain	66	No Breaker			809	410	806	408	806	409	802	408	804	410
3	111	DLK B1	Deer lake	138	4300/7530	936	957	923	957	918	951	916	949	897	932	911	948
3	114	PAS B1	Pasadena	66	No Breaker			537	286	536	285	536	285	534	285	536	286
3	115	MDR B2B3	Massey Drive	66	1430/1490			758	736	752	732	750	731	740	723	741	724
3	135	DLK B3	Deer lake	230	12550	1353	1196	1311	1170	1298	1158	1297	1154	1271	1137	1274	1143
3	136	CAT L47	Cat Arm	230	9960	988	1130	971	1113	963	1103	961	1100	928	1063	931	1068
3	137	CAT G1	Cat Arm	13.8	No Unit Breaker	777	47	776	47	774	47	775	47	736	45	737	45
3	138	CAT G2	Cat Arm	13.8	No Unit Breaker	777	47	776	47	774	47	775	47	736	44	737	44
3	152	MDR B4	Massey Drive	66	Customer-owned			1357	768	1351	766	1350	766	1339	764	1342	766
3	200	PAB NP	Port Aux Basques	66	Customer-owned			108	117	108	116	108	116	89	101	88	101
3	201	DLS B1	Doyles	66	1500			138	182	137	182	137	182	119	160	119	160

Maximum NLH Fault Levels
Before and After HVDC System Addition

Area	Bus No	Bus Name	Station	Bus Volt kV	Rating MVA	Existing		BC1-DC1		BC2-DC1		BC3-DC1		BC7-DC1		BC8-DC8	
						3P MVA	LG MVA	3P MVA	LG MVA	3P MVA	LG MVA	3P MVA	LG MVA	3P MVA	LG MVA	3P MVA	LG MVA
3	202	DLS L14	Doyles	138	No Breaker			189	161	188	161	189	161	170	152	169	153
3	203	BBK B2	Bottom Brook	138	1490			364	432	362	430	362	430	343	411	342	411
3	204	SVL B2	Stephenville	66	1430			544	587	542	585	541	584	512	562	509	560
3	205	BBK B1	Bottom Brook	230	5430	1392	1473	1250	1255	1241	1248	1243	1252	1214	1236	1213	1235
3	206	SVL B1	Stephenville	230	15930	1219	1458	1063	1062	1056	1056	1056	1061	1034	1054	1035	1056
3	208	MDR B1B5	Massey Drive	230	5600/12550	1703	1693	1622	1631	1612	1622	1620	1628	1589	1605	1582	1601
3	209	SVL G1	Stephenville	13.8	650			593	0	592	0	592	0	566	0	557	0
3	210	HLY L51	Howley	69	2200			115	122	115	121	114	121	113	120	115	122
3	212	HLY B1	Howley	138	4300	863	827	868	839	864	835	863	833	843	817	863	836
3	213	HLK L43	Hinds Lake	138	No Breaker	790	972	803	992	800	988	799	987	778	961	800	989
3	250	HLK G1	Hinds Lake	13.8	1000			791	31	790	31	790	31	761	30	789	31
3	252	HDN L51	Hampden	69	No Breaker			82	68	81	68	81	68	80	67	82	69
3	253	JAM L52	Jacksons Arm	69	No Breaker			69	72	69	71	69	71	68	71	69	72
3	254	HDN B1	Hampden	12.5	Reclosers			31	35	31	35	31	35	31	35	31	36
3	255	JAM B1	Jacksons Arm	12.5	Reclosers			42	52	42	51	42	51	41	51	42	52
3	260	ACS SVL	Abitibi Consol. Stephenville	230	No Breaker	1210	1452	1054	1045	1047	1039	1047	1044	1026	1037	1026	1039
3	275	GBY NP	Grand Bay	66	2500			115	130	115	130	115	130	93	111	93	111
3	276	LGL NP	Long Lake	66	Customer-owned			94	93	93	93	93	93	80	84	79	84
3	278	CAM L53	Coney Arm	69	No Breaker			65	67	65	67	65	67	64	66	66	68
3	279	CAM B1	Coney Arm	12.5	Reclosers			29	34	29	34	29	34	29	34	30	35
3	281	RBH NP	Rose Blanche	25	Customer-owned			50	63	50	63	50	63	49	62	49	63
3	285	GBY NPT1	Grand Bay	12.5	Customer-owned			85	94	85	94	85	94	57	70	57	70
3	287	RBH GEN	Rose Blanche	6.9	Customer-owned			57	0	57	0	57	0	56	0	56	0
3	319	DLK NP	Deer Lake	66	No Breaker			714	759	712	757	712	757	707	753	709	757
3	328	STG NPT2	St. Georges	33	Customer-owned			136	132	136	131	136	132	115	118	115	118
3	329	BBK T2	Bottom Brook	66	1500			108	120	108	120	108	120	106	118	106	118
3	330	WHE NP	Wheelers	66	Customer-owned			85	74	85	73	85	74	83	72	83	73
3	331	HAR NP	Harmon	66	Customer-owned			445	402	443	401	443	401	424	391	423	391
3	332	STX NP	Stephenville Crossing	66	Customer-owned			414	356	412	355	412	355	389	344	388	344
3	333	STG NP	St. Georges	66	Customer-owned			263	221	262	221	262	221	243	212	244	212
3	343	LBK NP	Lookout Brook	33	Customer-owned			85	95	85	95	85	95	61	73	61	73
3	350	GAL NP	Gallants	66	Customer-owned			426	381	425	379	424	380	407	371	406	371
3	603	BBK B3	Bottom Brook	138	9560			338	393	336	390	335	390	333	388	334	389
3	604	GBK L50	Grandy Brook	138	No Breaker			163	111	162	110	162	110	161	111	161	111
3	605	GBK NREG	Grandy Brook	25	No Breaker			72	84	72	84	72	84	72	84	72	84
3	609	GBK REG	Grandy Brook	25	Reclosers			69	80	69	80	68	79	70	82	70	82
3	610	BUR NREG	Burgeo	25	No Breaker			35	26	35	26	35	25	35	26	35	26
3	611	BUR REG	Burgeo	25	No Breaker			34	25	34	25	33	24	35	26	35	27
3	612	BURGEO	Burgeo	25	Reclosers			30	21	30	21	30	21	31	22	31	23
3	867	RBK L53	Rattle Brook	69	4570			69	75	69	75	69	75	68	74	69	76
3	870	SLK L80	Star Lake	66	4780			184	219	183	218	183	217	184	218	185	219
3	871	SLK G1	Star Lake	13.8	Customer-owned			162	0	161	0	161	0	161	0	162	0
4	224	BLA L12	Bay L'Argent	138	No Breaker	439	375	435	375	427	368	430	370	416	363	387	351
4	225	LLK NP	Linton Lake	138	Customer-owned	440	466	423	451	416	443	419	446	402	434	363	405
4	232	MKS L12	Monkstown	138	No Breaker	542	464	558	476	548	468	552	470	533	460	510	452
4	282	MKS NPT1	Monkstown	25	No Breaker	124	168	127	171	125	168	125	169	124	168	125	169
4	283	PRV L58	Paradise River	25	Reclosers	74	88	77	92	77	91	77	92	76	91	77	92
4	284	PRV G1	Paradise River	4.2	Reclosers	67	0.01	71	0	70	0	70	0	70	0	71	0
4	359	MSY NP	Marystown	138	Customer-owned	445	481	425	461	418	453	421	456	404	442	362	411
4	360	MSY NPT1	Marystown	12.5	Customer-owned			151	191	152	191	147	185	150	190	149	190
4	361	SPT NP	Salt Pond	66	Customer-owned			277	320	272	315	271	313	271	317	220	269
4	362	LAU NP	Laurentian	66	Customer-owned			212	158	210	157	209	156	202	154	140	127
4	363	GRH NP	Greenhill	12.5	Customer-owned			87	107	86	105	86	106	84	103	76	95
4	364	GRH NP	Greenhill	66	Customer-owned			158	189	156	187	156	187	152	183	123	155
4	365	GAR NP	Garnish	66	Customer-owned			198	175	195	173	195	173	194	172	162	156

Maximum NLH Fault Levels
Before and After HVDC System Addition

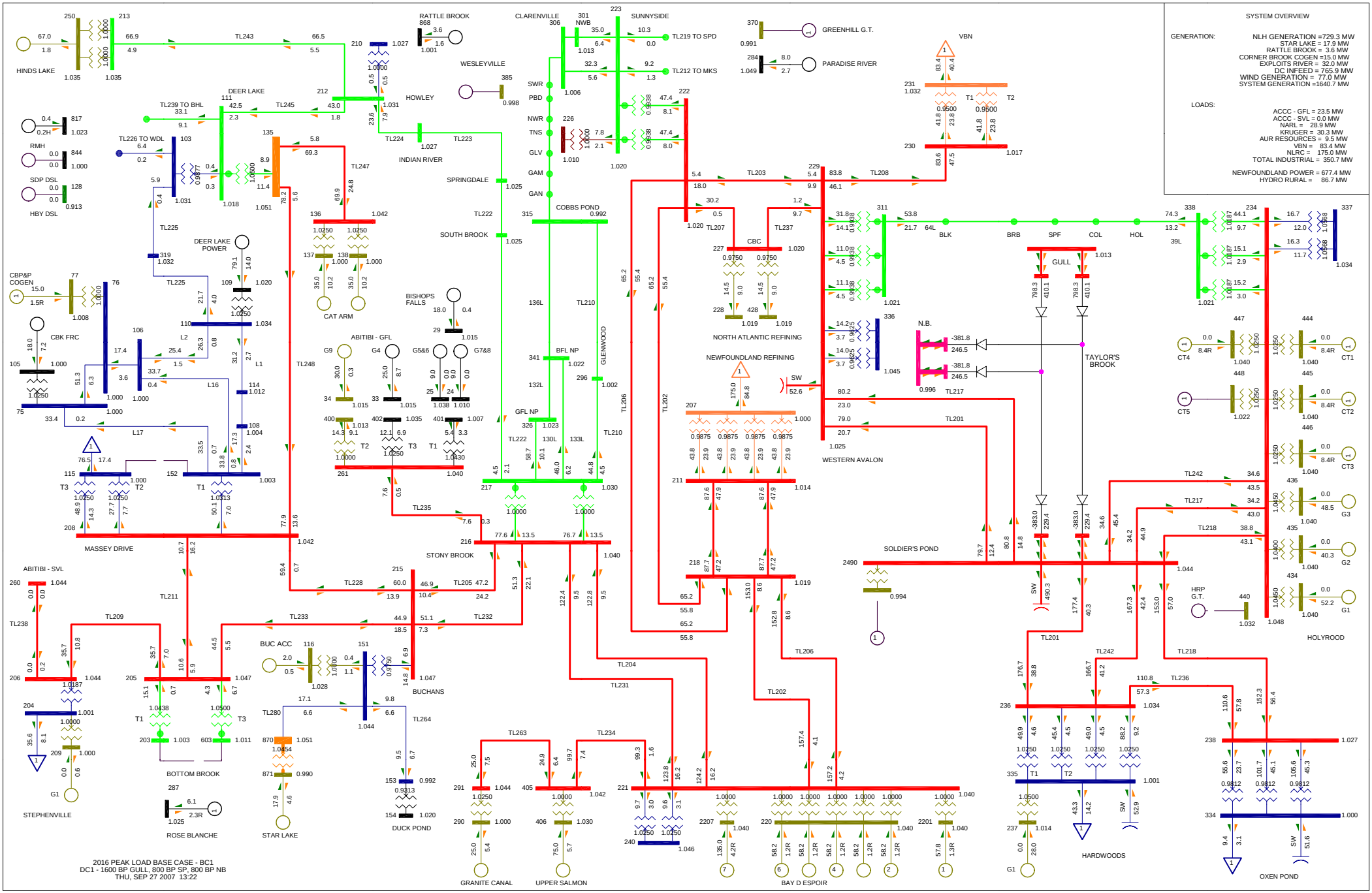
Area	Bus No	Bus Name	Station	Bus Volt kV	Rating MVA	Existing		BC1-DC1		BC2-DC1		BC3-DC1		BC7-DC1		BC8-DC8	
						3P MVA	LG MVA	3P MVA	LG MVA	3P MVA	LG MVA	3P MVA	LG MVA	3P MVA	LG MVA	3P MVA	LG MVA
4	366	WEB NP	Webbers Cove	66	Customer-owned			181	148	179	147	179	146	174	144	130	123
4	370	GRT GEN	Greenhill	13.8	Customer-owned			91	0	90	0	90	0	88	0	79	0
4	371	SPO NP	Salt Pond	138	Customer-owned	461	498	432	462	425	455	429	457	410	443	362	406
4	372	STL WIND	St. Lawrence Wind	66	Customer-owned			205	143	203	142	202	142	196	140	133	116
4	373	STL WIND	St. Lawrence Wind	25	Customer-owned			181	212	180	211	179	210	179	210	82	105
5	100	BHL B1	Berry Hill	138	5970	385	277	358	266	356	264	354	263	349	262	356	266
5	101	BHL T1	Berry Hill	66	1500			107	153	107	152	106	152	106	151	107	152
5	102	RHR B1	Rocky Harbour	12.5	Reclosers			45	53	45	53	45	53	45	53	45	53
5	107	CHD T1	Cow Head	12.5	Reclosers			36	44	36	44	36	44	36	44	36	44
5	119	CHD B1	Cow Head	66	1490			72	62	71	62	71	62	71	62	72	62
5	120	DHR B1B2	Daniels Harbour	66	1500			85	114	85	114	85	114	83	112	84	113
5	121	PBN B2	Peter's Barren	66	4570	104	149	89	128	88	127	88	127	87	125	87	126
5	124	PPD L27	Parsons Pond	66	No Breaker			68	66	67	66	68	66	67	66	67	66
5	125	HBY B1	Hawke's Bay	66	1500			59	66	59	66	59	66	58	65	58	65
5	127	HBY B2B3	Hawke's Bay	12.5	Reclosers			41	56	41	56	41	56	41	55	40	55
5	129	WDL B1	Wiltondale	66	1430			209	119	208	118	208	118	208	119	209	120
5	130	GLB L29	Glenburnie	66	No Breaker			116	60	115	60	115	60	115	60	116	61
5	132	PPT B2	Plum Point	12.5	Reclosers			61	71	60	71	60	71	60	70	60	71
5	133	PPT B1	Plum Point	138	9560			130	106	129	106	128	106	128	105	131	106
5	134	BCV B1	Bear Cove	138	9560			118	98	117	97	116	98	115	97	118	98
5	139	DHR B3B4	Daniels Harbour	12.5	Reclosers			24	27	24	27	24	27	24	27	24	27
5	140	BCV B2	Bear Cove	12.5	Reclosers			58	68	58	68	58	68	57	68	57	68
5	141	PBN B1	Peter's Barren	138	9560	232	173	200	158	199	157	197	156	195	156	199	158
5	143	PPD T1	Parsons Pond	12.5	Reclosers			15	16	14	16	15	16	14	16	14	16
5	144	WDL T1	Wiltondale	12.5	Reclosers			14	14	14	14	13	14	14	14	14	14
5	147	GLB B1	Glenburnie	12.5	Reclosers			34	38	34	38	34	38	34	38	34	39
5	148	SCV L27	Sally's Cove	66	No Breaker			89	96	89	96	89	96	89	96	89	96
5	150	RHR B1	Rocky Harbour	66	No Breaker			108	58	108	57	107	57	108	58	108	59
5	807	RWC B3	Reddickton Wood Chip	12.5	Reclosers			31	39	31	39	31	39	32	41	31	40
5	808	RWC T2	Reddickton Wood Chip	12.5	Reclosers			32	42	32	41	32	42	32	41	32	41
5	809	RWC B1	Reddickton Wood Chip	69	2630			46	59	45	58	46	59	45	58	45	58
5	815	RMH TAP	Reddickton Mini Hydro	12.5				19	21	19	20	19	20	20	21	20	21
5	816	RMH HV	Reddickton Mini Hydro	12.5	Reclosers			18	19	18	19	18	19	19	20	19	20
5	818	MBK L57	Main Brook	69	No Breakers			52	63	52	62	52	63	51	62	52	63
5	822	STA B1	St. Anthony Airport	69	2380/4570			63	92	63	92	64	93	62	90	63	92
5	846	SDP B1	St. Anthony Diesel Plant	25	Reclosers			40	59	40	58	40	59	40	59	39	58
5	848	SDP L61	St. Anthony Diesel Plant	69	No Breaker			49	59	49	59	49	59	48	58	48	58
5	850	STA L56	St. Anthony Airport	138	No Breaker			102	87	101	87	101	87	100	87	103	87
6	221	BDE TS	Bay d'Espoir	230	5130/5600/5710	3845	4576	4025	4794	3987	4747	4000	4757	3935	4696	3896	4661
6	240	BDE B9	Bay d'Espoir	69	1430	289	299	296	304	291	299	289	296	292	300	294	304
6	241	CRV L20	Conne River	69	No Breaker	201	155	207	159	205	158	204	157	205	158	206	160
6	242	EHW L20	English HR. West	69	No Breaker	113	70	118	71	117	71	117	70	117	71	117	72
6	243	BCX L20	Barachoix	69	No Breaker	100	60	105	62	104	61	103	61	104	62	104	62
6	244	CRV T1	Conne River	12.5	Reclosers			31	33	30	33	30	33	30	33	31	33
6	245	EHW T1	English HR. West	25	Reclosers	42	50	44	52	44	52	44	51	44	52	45	52
6	246	BCX T1	Barachoix	25	Reclosers	62	78	65	82	64	81	64	81	64	81	65	82
6	247	BDE B14	Bay d'Espoir	24	Reclosers			100	115	99	114	99	114	99	114	99	115
6	290	GCL G1	Granite Canal	13.8	1506	414	0.04	417	0	430	0	429	0	424	0	419	0
6	291	GCL L63	Granite Canal	230	No Breaker	861	762	887	779	888	779	887	778	882	775	877	771
6	405	USL L34	Upper Salmon	230	12550/15935	1683	1600	1741	1656	1732	1647	1732	1646	1719	1637	1709	1629
6	406	USL G1	Upper Salmon	13.8	920	861	0.2	884	0	885	0	885	0	874	0	863	0
6	407	USL T2	Upper Salmon	25	Reclosers			94	104	94	104	94	104	93	102	92	101
6	2201	BDP G1	Bay d'Espoir G1	13.8	No Unit Breaker	984	0.13	1025	0	1021	0	1021	0	1025	0	1028	0
6	2207	BDP G7	Bay d'Espoir G7	13.8	No Unit Breaker	2095	0.27	2181	0	2174	0	2176	0	2181	0	2186	0
7	27	ACG GFL	Abitibi Cons. Grand Falls	66	Customer-owned			209	242	208	240	207	239	208	241	209	242

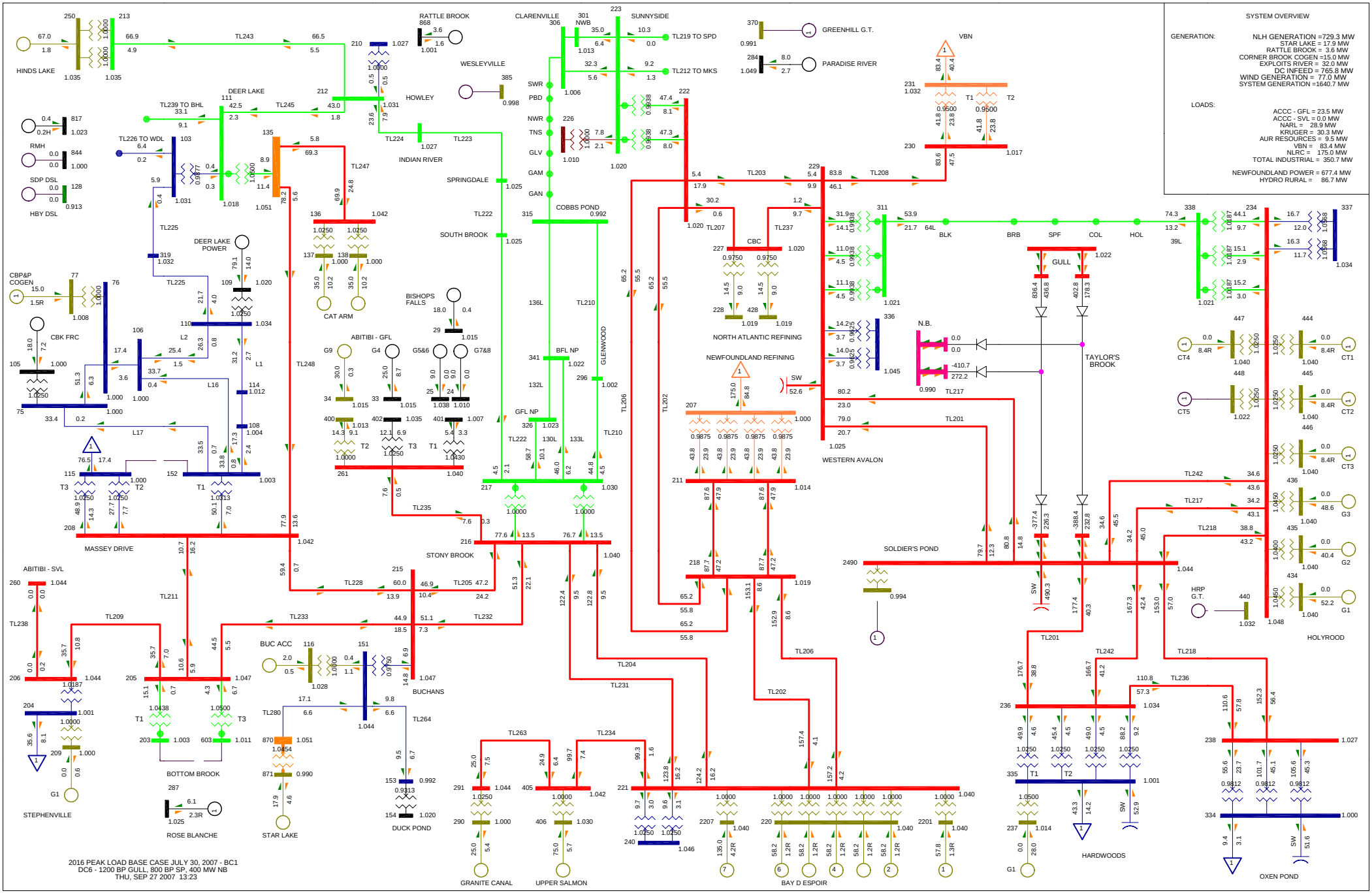
Maximum NLH Fault Levels
Before and After HVDC System Addition

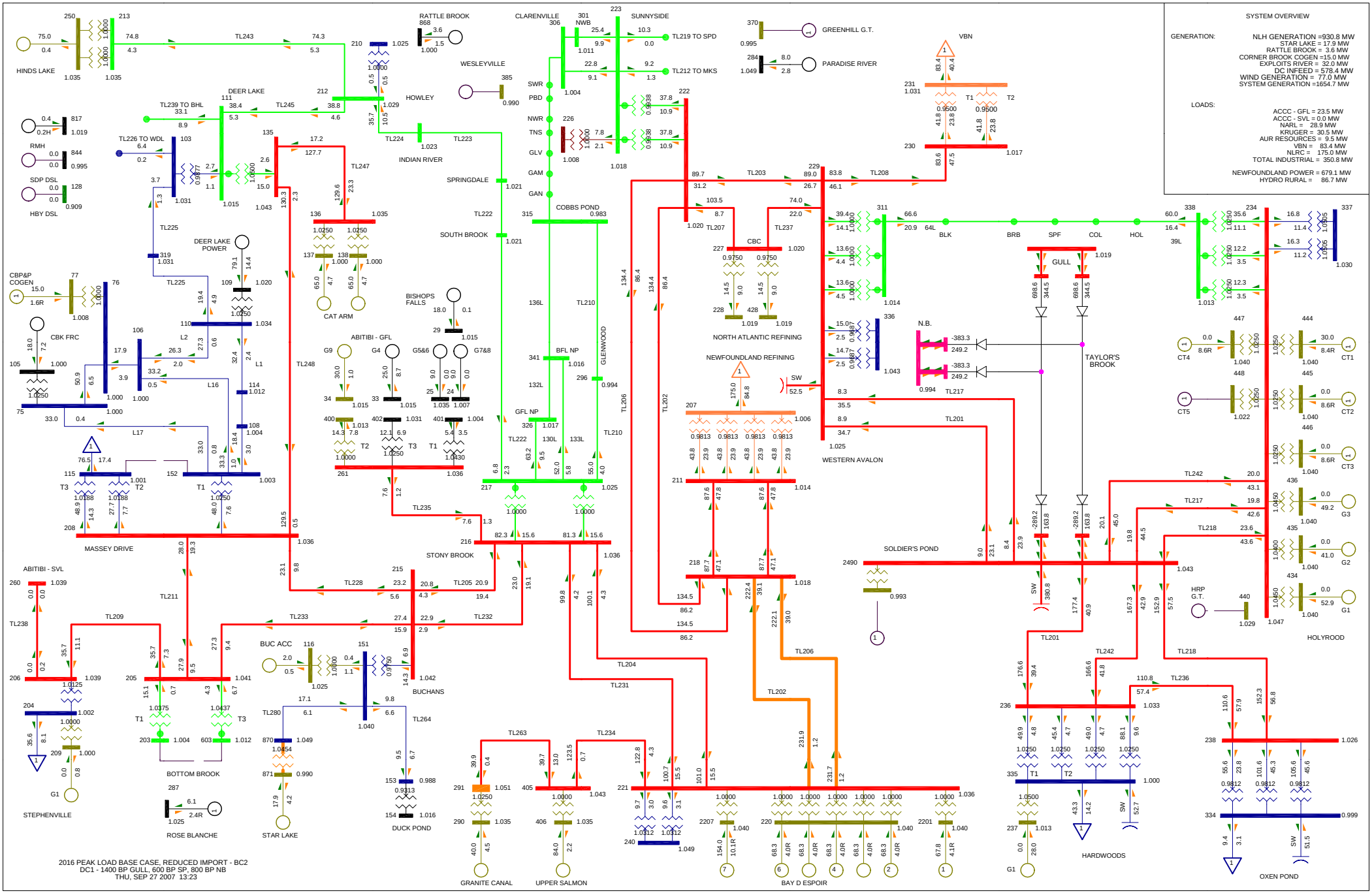
Area	Bus No	Bus Name	Station	Bus Volt kV	Rating MVA	Existing		BC1-DC1		BC2-DC1		BC3-DC1		BC7-DC1		BC8-DC8	
						3P MVA	LG MVA	3P MVA	LG MVA	3P MVA	LG MVA	3P MVA	LG MVA	3P MVA	LG MVA	3P MVA	LG MVA
7	28	ACG BFL	Abitibi Cons. Bishop Falls	66	Customer-owned			184	219	183	219	183	218	184	219	184	220
7	261	ACG GFL	Abitibi Cons. Grand Falls	230	No Breaker	2419	2614	2409	2623	2388	2599	2393	2603	2357	2576	2337	2558
7	400	ACG T2	Abitibi Cons. Grand Falls	13.8	1055			542	19	540	19	541	19	540	19	543	19
8	75	CBPP E	Corner Brook Pulp & Paper	66	Customer-owned			1442	983	1437	980	1436	980	1427	977	1429	979
8	76	CBPP B	Corner Brook Pulp & Paper	66	Customer-owned			1451	984	1446	981	1445	982	1436	979	1439	981
8	106	CBPP D	Corner Brook Pulp & Paper	66	Customer-owned			1445	959	1440	956	1439	956	1429	954	1432	956
8	109	DLP G1-7	Deer Lake Power	6	Customer-owned			686	0	685	0	686	0	683	0	683	0
8	110	DLP B1B4	Deer Lake Power	66	Customer-owned			754	865	752	863	753	863	748	858	750	861
9	153	DPD L64	Duck Pond	66	No Breaker			143	73	141	73	141	72	142	73	143	73
10	2101	CHF A1	Churchill Falls	15	No Unit Breaker			5072	0	5056	0	5072	0	5022	0	4991	0
10	2102	CHF A2	Churchill Falls	15	No Unit Breaker			5386	0	5371	0	5386	0	5338	0	5306	0
10	2103	CHF A3	Churchill Falls	15	No Unit Breaker			5386	0	5371	0	5386	0	5338	0	5306	0
10	2104	CHF A4	Churchill Falls	15	No Unit Breaker			5326	0	5311	0	5326	0	5279	0	5247	0
10	2105	CHF A5	Churchill Falls	15	No Unit Breaker			5326	0	5311	0	5326	0	5279	0	5247	0
10	2106	CHF A6	Churchill Falls	15	No Unit Breaker			5321	0	5306	0	5321	0	5274	0	5242	0
10	2107	CHF A7	Churchill Falls	15	No Unit Breaker			5383	0	5368	0	5383	0	5335	0	5303	0
10	2108	CHF A8	Churchill Falls	15	No Unit Breaker			5329	0	5314	0	5329	0	5282	0	5250	0
10	2109	CHF A9	Churchill Falls	15	No Unit Breaker			5392	0	5376	0	5392	0	5344	0	5311	0
10	2110	CHF A10	Churchill Falls	15	No Unit Breaker			5512	0	5497	0	5512	0	5466	0	5436	0
10	2111	CHF A11	Churchill Falls	15	No Unit Breaker			5448	0	5434	0	5448	0	5403	0	5373	0
10	2115	MUSK G1-4	Muskrat Falls	15	Proposed Station			1725	0	1682	0	1725	0	1586	0	1448	0
10	2121	GUL G1	Gull Island	15	Proposed Station			4784	3709	4682	3629	4784	3709	4454	3451	4395	3313
10	2122	GUL G2	Gull Island	15	Proposed Station			3325	1454	3230	1412	3325	1454	3018	1319	2937	1222
10	2123	GUL G3	Gull Island	15	Proposed Station			3325	1454	3230	1412	3325	1454	3018	1319	2937	1222
10	2124	GUL G4	Gull Island	15	Proposed Station			3325	1454	3230	1412	3325	1454	3018	1319	2937	1222
10	2131	CHF L1301	Churchill Falls	138	No Breaker			688	764	685	760	688	764	678	752	671	744
10	2133	MUSKRAT	Muskrat Falls	138	No Breaker			710	390	694	380	710	390	659	359	599	328
10	2134	MUSKRAT	Muskrat Falls	25	Reclosers			38	0	38	0	38	0	36	0	32	0
10	2135	HVY B13	Happy Valley	138	2637			545	492	534	480	545	492	510	454	467	423
10	2136	HVY B11 B12	Happy Valley	25	1448			379	495	374	488	379	495	362	471	335	438
10	2137	HVY G1	Happy Valley	13.8	n/a			342	267	339	264	342	267	332	258	320	250
10	2141	WTS SC1	Wabush	13.8	n/a			763	539	762	538	763	539	761	538	760	537
10	2142	WTS SC2	Wabush	13.8	n/a			756	544	755	543	756	544	754	542	753	542
10	2307	WABUSH TS	Wabush	230	3500			1758	481	1755	480	1758	481	1749	478	1744	477
10	2308	GUL 230	Gull Island	230	Proposed Station			6124	7829	5969	7631	6124	7829	5620	7182	5784	7196
10	2309	MFA 230	Muskrat Falls	230	Proposed Station			2140	1385	2087	1351	2140	1385	1967	1273	1815	1138
10	2341	GUL T1	Gull Island	230	Proposed Station			5784	6976	5641	6803	5784	6976	5316	6408	5392	6304
10	2342	GUL T2	Gull Island	230	Proposed Station			5542	6746	5400	6573	5542	6746	5079	6180	5140	6072
10	2343	GUL T3	Gull Island	230	Proposed Station			5542	6746	5400	6573	5542	6746	5079	6180	5140	6072
10	2344	GUL T4	Gull Island	230	Proposed Station			5542	6746	5400	6573	5542	6746	5079	6180	5140	6072
10	2461	WTS BUS 1	Wabush	46	1500/2000/2510/1992			1404	0	1402	0	1404	0	1398	0	1396	0
10	2462	WTS BUS 2	Wabush	46	1500/2000/2510/1992			1199	0	1197	0	1199	0	1193	0	1191	0
10	2700	CHF TS	Churchill Falls	735	25000			21922	24565	21879	24496	21922	24565	21831	24386	22088	24536
10	2704	GUL TS	Gull Island	735	Proposed Station			6249	7397	6100	7219	6249	7397	5759	6813	5777	6627

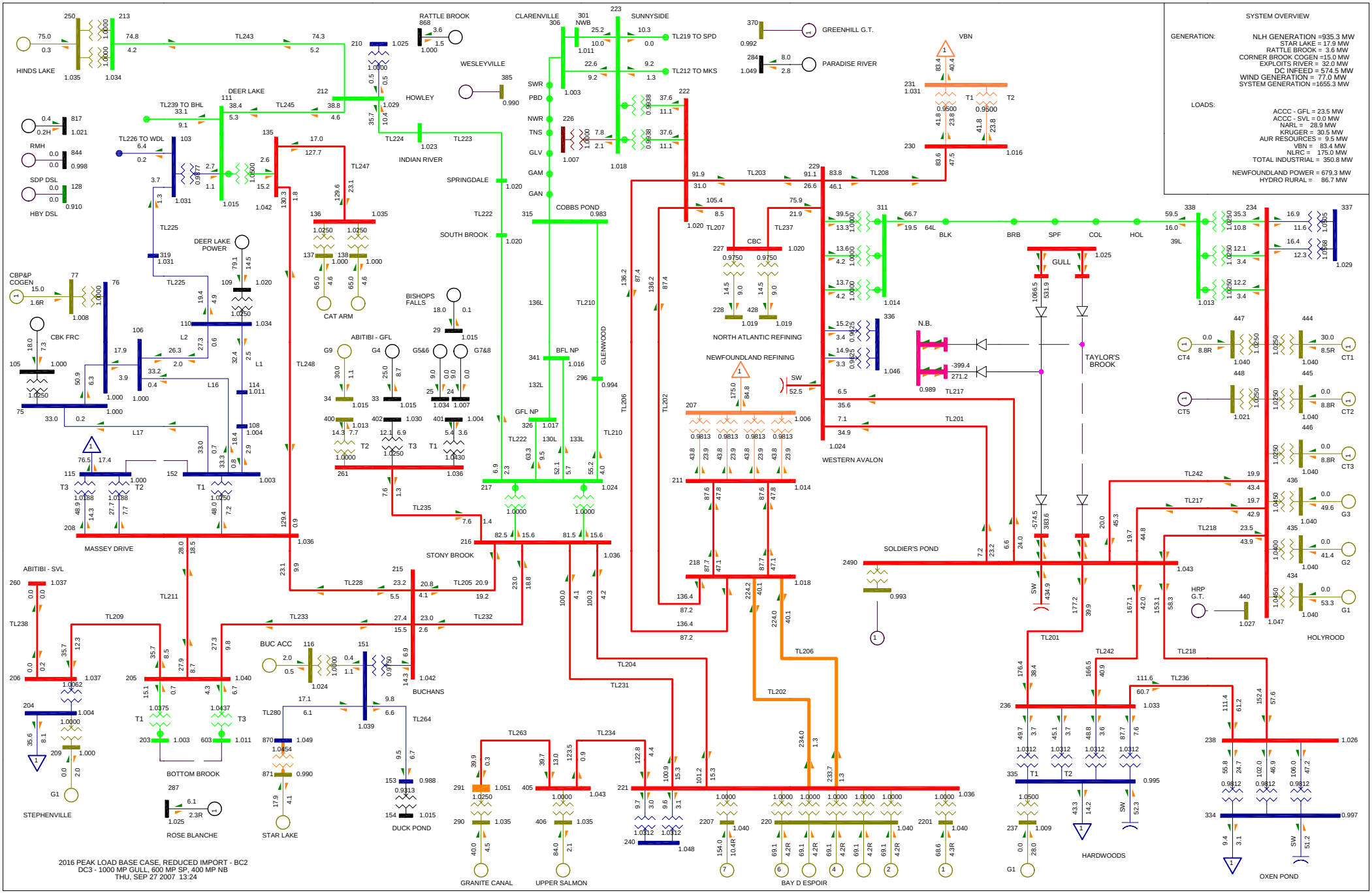
Appendix E

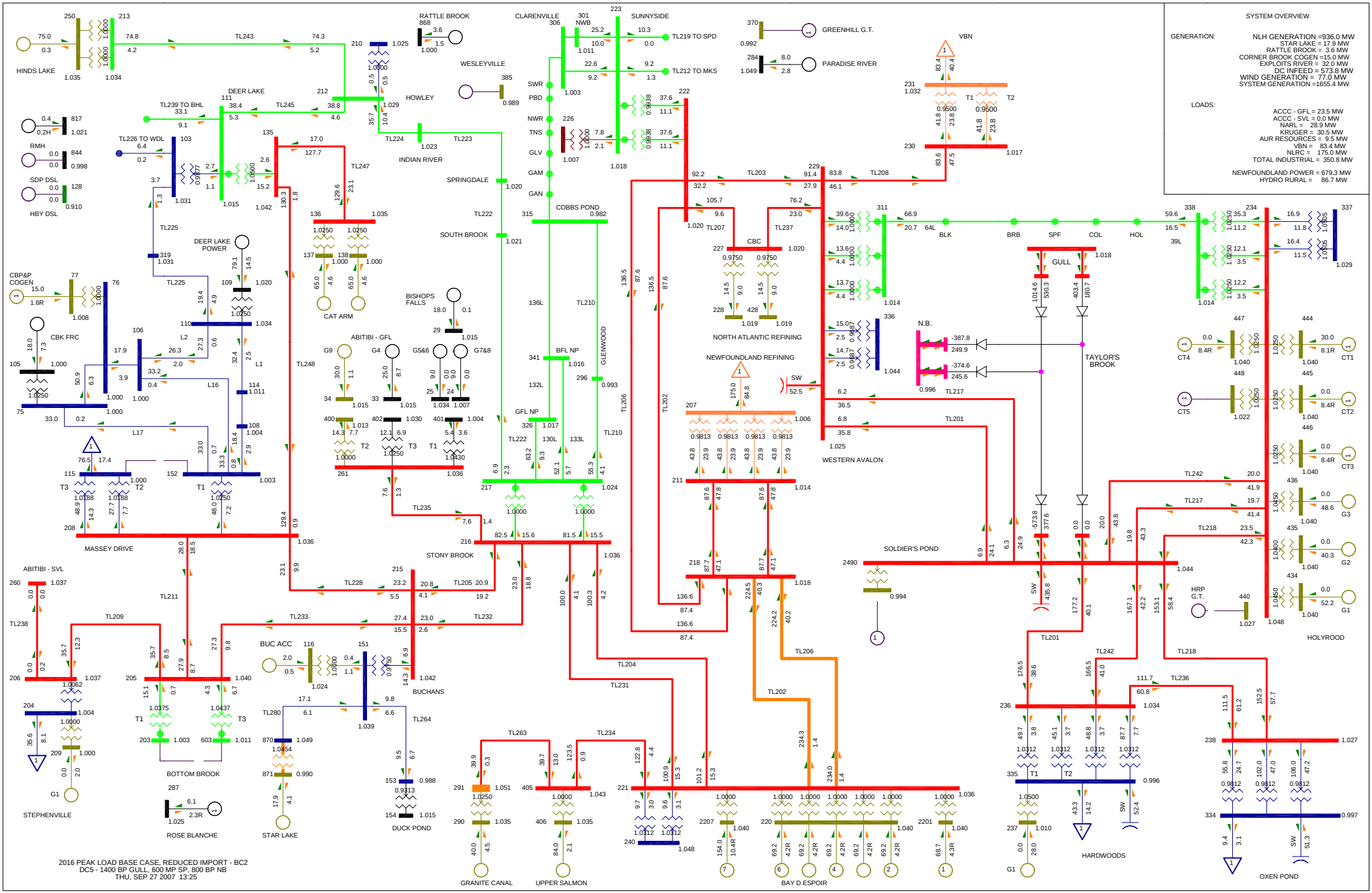
Power Flow Case Diagrams

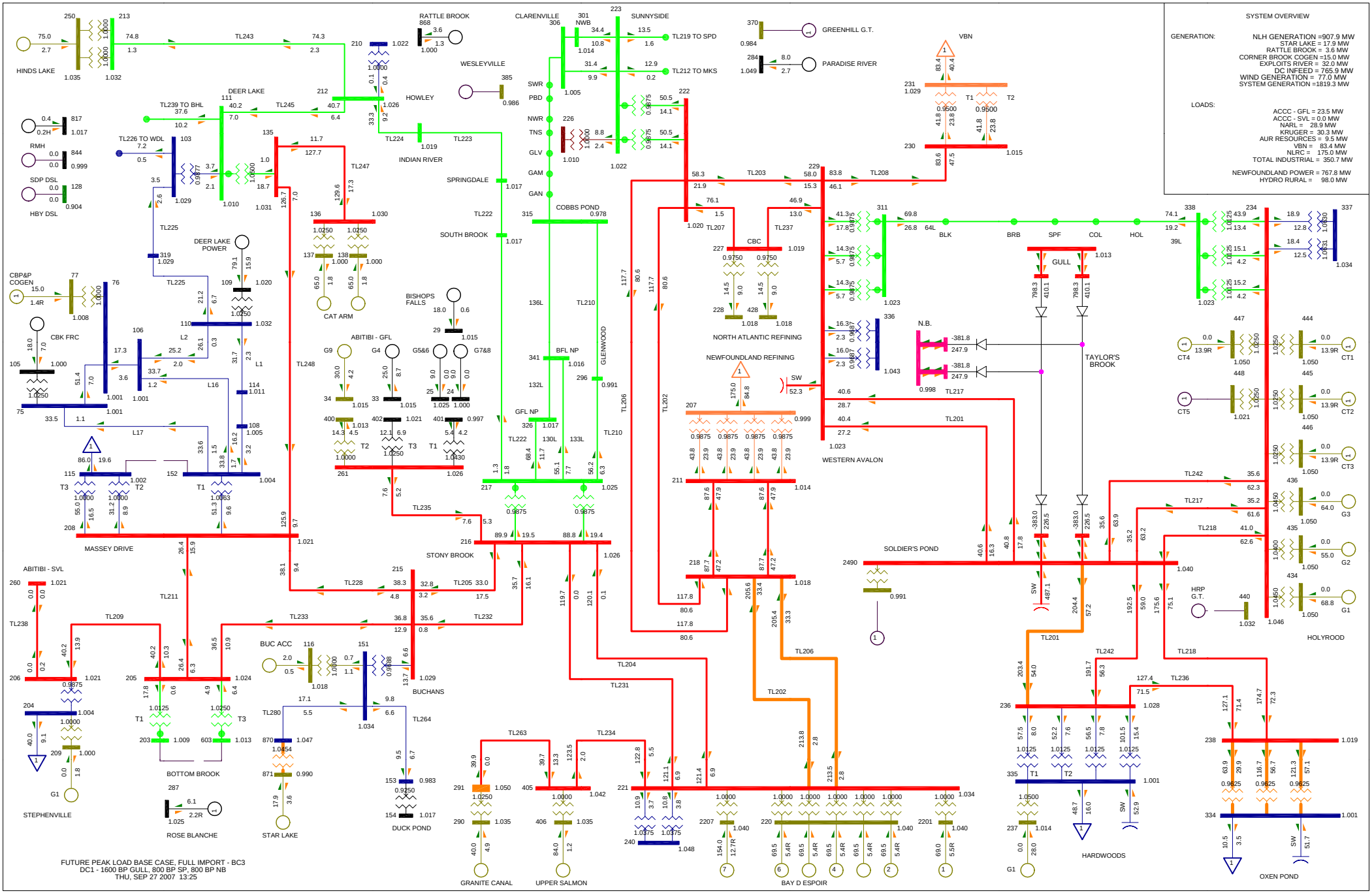

SYSTEM OVERVIEW
GENERATION:
NLH GENERATION =729.3 MW
STAR LAKE = 17.9 MW
RATTLE BROOK = 3.6 MW
CORNER BROOK COGEN =15.0 MW
EXPLOITS RIVER = 32.0 MW
DC INFEED = 765.9 MW
WIND GENERATION = 77.0 MW
SYSTEM GENERATION =1640.7 MW
LOADS:
ACCC - GFL = 23.5 MW
ACCC - SVL = 0.0 MW
NARL = 28.9 MW
KRUGER = 30.3 MW
AUR RESOURCES = 9.5 MW
VBN = 83.4 MW
NLRC = 175.0 MW
TOTAL INDUSTRIAL = 350.7 MW
NEWFOUNDLAND POWER = 677.4 MW
HYDRO RURAL = 86.7 MW
HINDS LAKE
RATTLE BROOK
WESLEYVILLE
HOWLEY
INDIAN RIVER
DEER LAKE
DEER LAKE POWER
TL239 TO BHL
TL226 TO WDL
RMH
SDP DSL
HBY DSL
TL225
TL243
TL245
TL247
TL224
TL223
CAT ARM
CBP&P COGEN
CBK FRC
MASSEY DRIVE
ABITIBI - SVL
STEPHENVILLE
ROSE BLANCHE
BOTTOM BROOK
TL211
TL238
TL209
TL228
TL233
BUC ACC
BUCHANS
TL280
TL264
STAR LAKE
DUCK POND
ABITIBI - GFL
TL248
BISHOPS FALLS
SPRINGDALE
SOUTH BROOK
TL222
CLARENVILLE
SUNNYSIDE
TL219 TO SPD
TL212 TO MKS
SWR
PBD
NWR
TNS
GLV
GAM
GAN
COBBS POND
BFL NP
GFL NP
GLENWOOD
TL210
TL206
TL235
STONY BROOK
TL263
TL234
TL231
TL204
TL205
TL232
GRANITE CANAL
UPPER SALMON
BAY D ESPOIR
GREENHILL G.T.
PARADISE RIVER
VBN
TL203
TL208
CBC
TL237
NORTH ATLANTIC REFINING
NEWFOUNDLAND REFINING
TL202
TL201
WESTERN AVALON
N.B.
TL217
TAYLOR'S BROOK
BLK
BRB
SPF
COL
HOL
GULL
SOLDIER'S POND
TL242
TL218
HRP G.T.
HOLYROOD
CT4
CT5
CT1
CT2
CT3
G3
G2
G1
TL236
HARDWOODS
OXEN POND
2016 PEAK LOAD BASE CASE - BC1
DC1 - 1600 BP GULL, 800 BP SP, 800 BP NB
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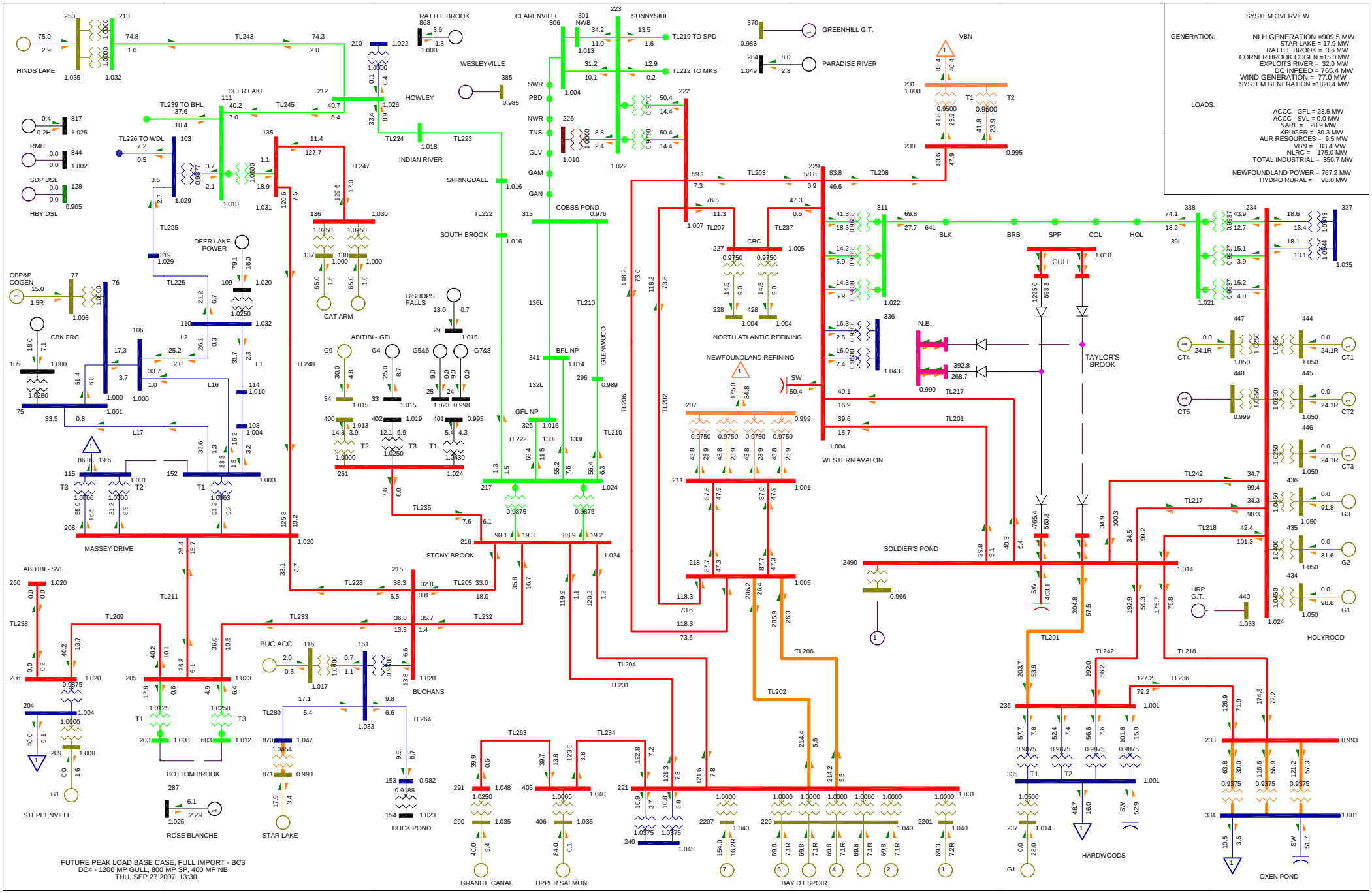

SYSTEM OVERVIEW
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SYSTEM GENERATION =1640.7 MW
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NARL = 28.9 MW
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AUR RESOURCES = 9.5 MW
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HINDS LAKE
RATTLE BROOK
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DEER LAKE
TL239 TO BHL
TL226 TO WDL
RMH
SDP DSL
HBY DSL
TL225
DEER LAKE POWER
CBP&P COGEN
CBK FRC
TL243
TL245
TL247
TL224
TL223
INDIAN RIVER
CAT ARM
SPRINGDALE
SOUTH BROOK
TL222
BISHOPS FALLS
ABITIBI - GFL
TL248
MASSEY DRIVE
ABITIBI - SVL
TL211
TL209
TL238
BOTTOM BROOK
STEPHENVILLE
ROSE BLANCHE
BUC ACC
BUCHANS
TL228
TL233
TL232
TL205
TL235
STONY BROOK
TL280
TL264
STAR LAKE
DUCK POND
CLARENVILLE
SUNNYSIDE
TL219 TO SPD
TL212 TO MKS
SWR
PBD
NWR
TNS
GLV
GAM
GAN
COBBS POND
BFL NP
GFL NP
GLENWOOD
TL210
TL206
TL204
TL231
TL263
TL234
GRANITE CANAL
UPPER SALMON
BAY D ESPOIR
GREENHILL G.T.
PARADISE RIVER
VBN
TL203
TL208
CBC
TL237
NORTH ATLANTIC REFINING
NEWFOUNDLAND REFINING
TL202
TL201
WESTERN AVALON
N.B.
TL217
SOLDIER'S POND
BLK
BRB
SPF
COL
HOL
GULL
TAYLOR'S BROOK
TL242
TL218
HRP G.T.
HOLYROOD
CT1
CT2
CT3
CT4
CT5
G1
G2
G3
HARDWOODS
OXEN POND
2016 PEAK LOAD BASE CASE JULY 30, 2007 - BC1
DC6 - 1200 BP GULL, 800 BP SP, 400 MW NB
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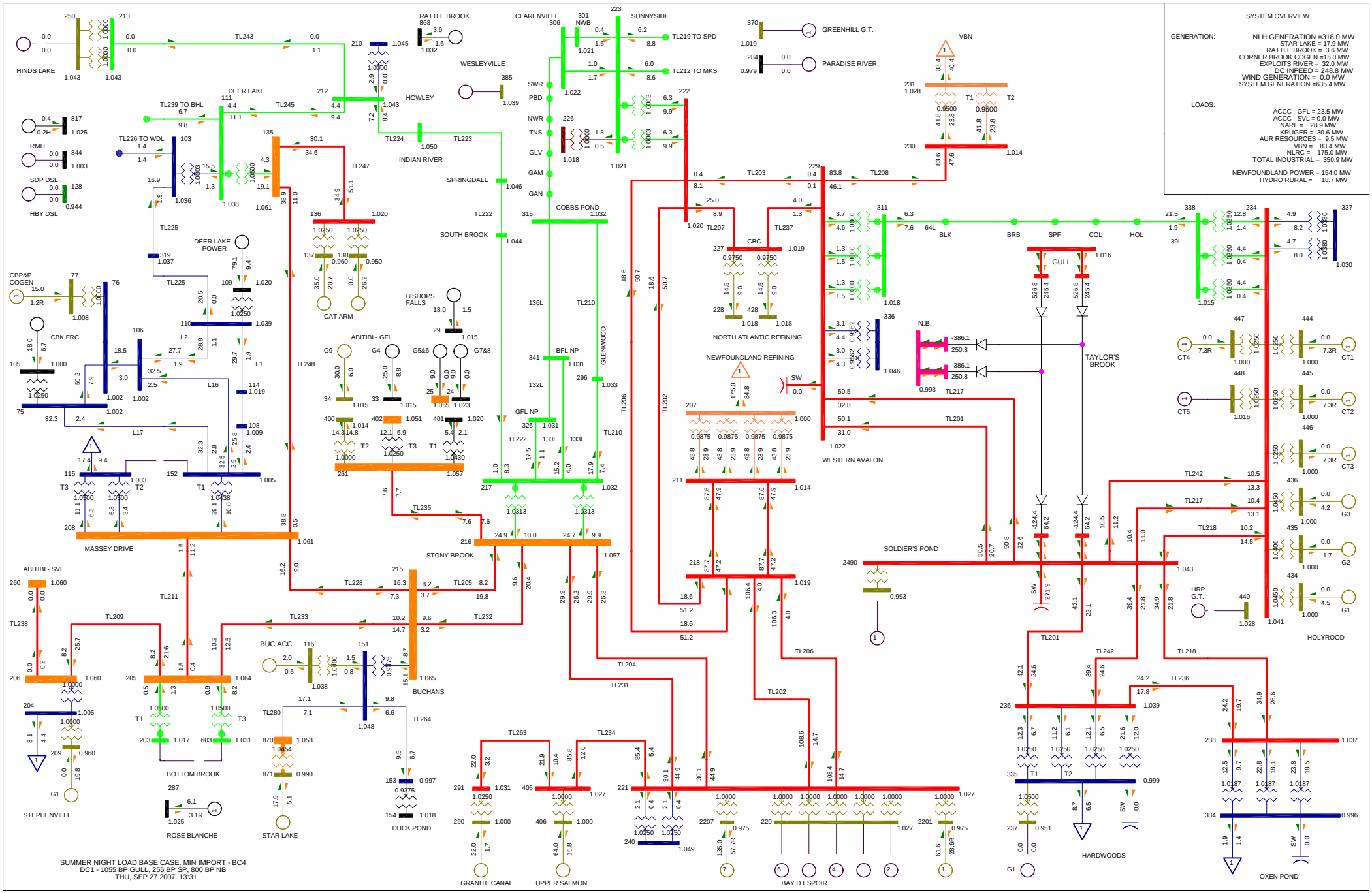

SYSTEM OVERVIEW
GENERATION:
NLH GENERATION =930.8 MW
STAR LAKE = 17.9 MW
RATTLE BROOK = 3.6 MW
CORNER BROOK COGEN =15.0 MW
EXPLOITS RIVER = 32.0 MW
DC INFEED = 578.4 MW
WIND GENERATION = 77.0 MW
SYSTEM GENERATION =1654.7 MW
LOADS:
ACCC - GFL = 23.5 MW
ACCC - SVL = 0.0 MW
NARL = 28.9 MW
KRUGER = 30.5 MW
AUR RESOURCES = 9.5 MW
VBN = 83.4 MW
NLRC = 175.0 MW
TOTAL INDUSTRIAL = 350.8 MW
NEWFOUNDLAND POWER = 679.1 MW
HYDRO RURAL = 86.7 MW
HINDS LAKE
RATTLE BROOK
WESLEYVILLE
HOWLEY
DEER LAKE
TL239 TO BHL
TL226 TO WDL
RMH
SDP DSL
HBY DSL
TL225
DEER LAKE POWER
CBP&P COGEN
CBK FRC
TL243
TL245
TL247
TL224
TL223
INDIAN RIVER
CAT ARM
SPRINGDALE
SOUTH BROOK
TL222
BISHOPS FALLS
ABITIBI - GFL
TL248
MASSEY DRIVE
ABITIBI - SVL
TL211
TL209
TL238
BOTTOM BROOK
STEPHENVILLE
ROSE BLANCHE
BUC ACC
STAR LAKE
TL228
TL233
TL232
TL205
BUCHANS
TL280
TL264
DUCK POND
TL235
STONY BROOK
CLARENVILLE
SUNNYSIDE
TL219 TO SPD
TL212 TO MKS
SWR
PBD
NWR
TNS
GLV
GAM
GAN
COBBS POND
TL210
GLENWOOD
BFL NP
GFL NP
TL222
TL263
TL234
GRANITE CANAL
UPPER SALMON
TL231
TL204
TL206
TL202
BAY D ESPOIR
GREENHILL G.T.
PARADISE RIVER
VBN
TL203
TL208
CBC
TL237
NORTH ATLANTIC REFINING
NEWFOUNDLAND REFINING
TL207
TL202
TL206
TL201
TL217
WESTERN AVALON
N.B.
TAYLOR'S BROOK
GULL
BLK
BRB
SPF
COL
HOL
SOLDIER'S POND
HRP G.T.
HARDWOODS
TL242
TL218
TL236
HOLYROOD
OXEN POND
CT1
CT2
CT3
CT4
CT5
G1
G2
G3
2016 PEAK LOAD BASE CASE, REDUCED IMPORT - BC2
DC1 - 1400 BP GULL, 600 BP SP, 800 BP NB
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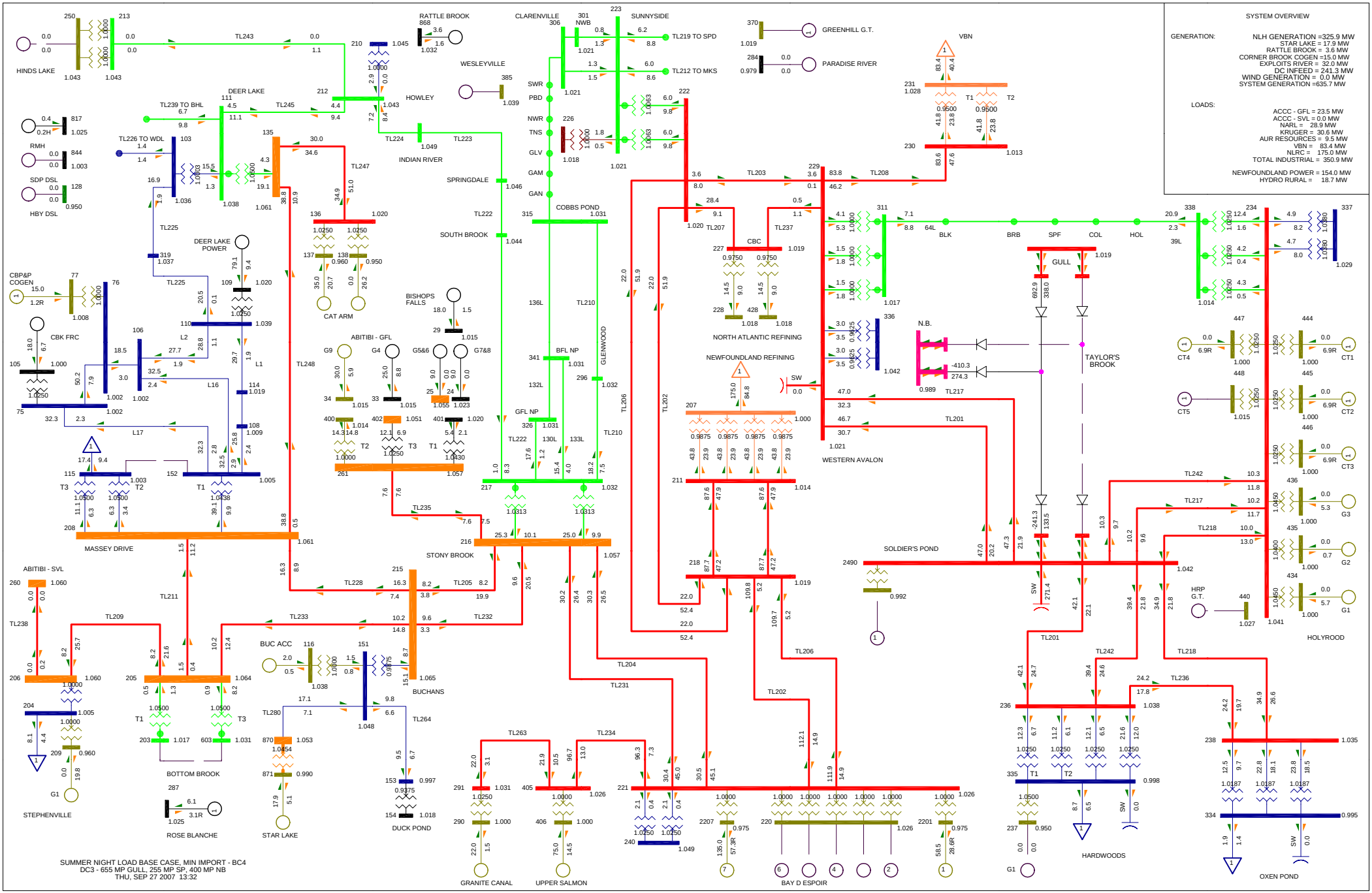

SYSTEM OVERVIEW
GENERATION:
NLH GENERATION =935.3 MW
STAR LAKE = 17.9 MW
RATTLE BROOK = 3.6 MW
CORNER BROOK COGEN =15.0 MW
EXPLOITS RIVER = 32.0 MW
DC INFEED = 574.5 MW
WIND GENERATION = 77.0 MW
SYSTEM GENERATION =1655.3 MW
LOADS:
ACCC - GFL = 23.5 MW
ACCC - SVL = 0.0 MW
NARL = 28.9 MW
KRUGER = 30.5 MW
AUR RESOURCES = 9.5 MW
VBN = 83.4 MW
NLRC = 175.0 MW
TOTAL INDUSTRIAL = 350.8 MW
NEWFOUNDLAND POWER = 679.3 MW
HYDRO RURAL = 86.7 MW
HINDS LAKE
RATTLE BROOK
CLARENVILLE
SUNNYSIDE
GREENHILL G.T.
PARADISE RIVER
VBN
WESLEYVILLE
HOWLEY
DEER LAKE
INDIAN RIVER
SPRINGDALE
COBBS POND
SOUTH BROOK
GLENWOOD
BISHOPS FALLS
CAT ARM
ABITIBI - GFL
DEER LAKE POWER
CBP&P COGEN
CBK FRC
HBY DSL
RMH
SDP DSL
MASSEY DRIVE
STONY BROOK
NORTH ATLANTIC REFINING
NEWFOUNDLAND REFINING
WESTERN AVALON
CBC
N.B.
GULL
TAYLOR'S BROOK
BLK
BRB
SPF
COL
HOL
HOLYROOD
SOLDIER'S POND
HRP G.T.
ABITIBI - SVL
BUC ACC
BUCHANS
BOTTOM BROOK
STEPHENVILLE
ROSE BLANCHE
STAR LAKE
DUCK POND
GRANITE CANAL
UPPER SALMON
BAY D ESPOIR
HARDWOODS
OXEN POND
2016 PEAK LOAD BASE CASE, REDUCED IMPORT - BC2
DC3 - 1000 MP GULL, 600 MP SP, 400 MP NB
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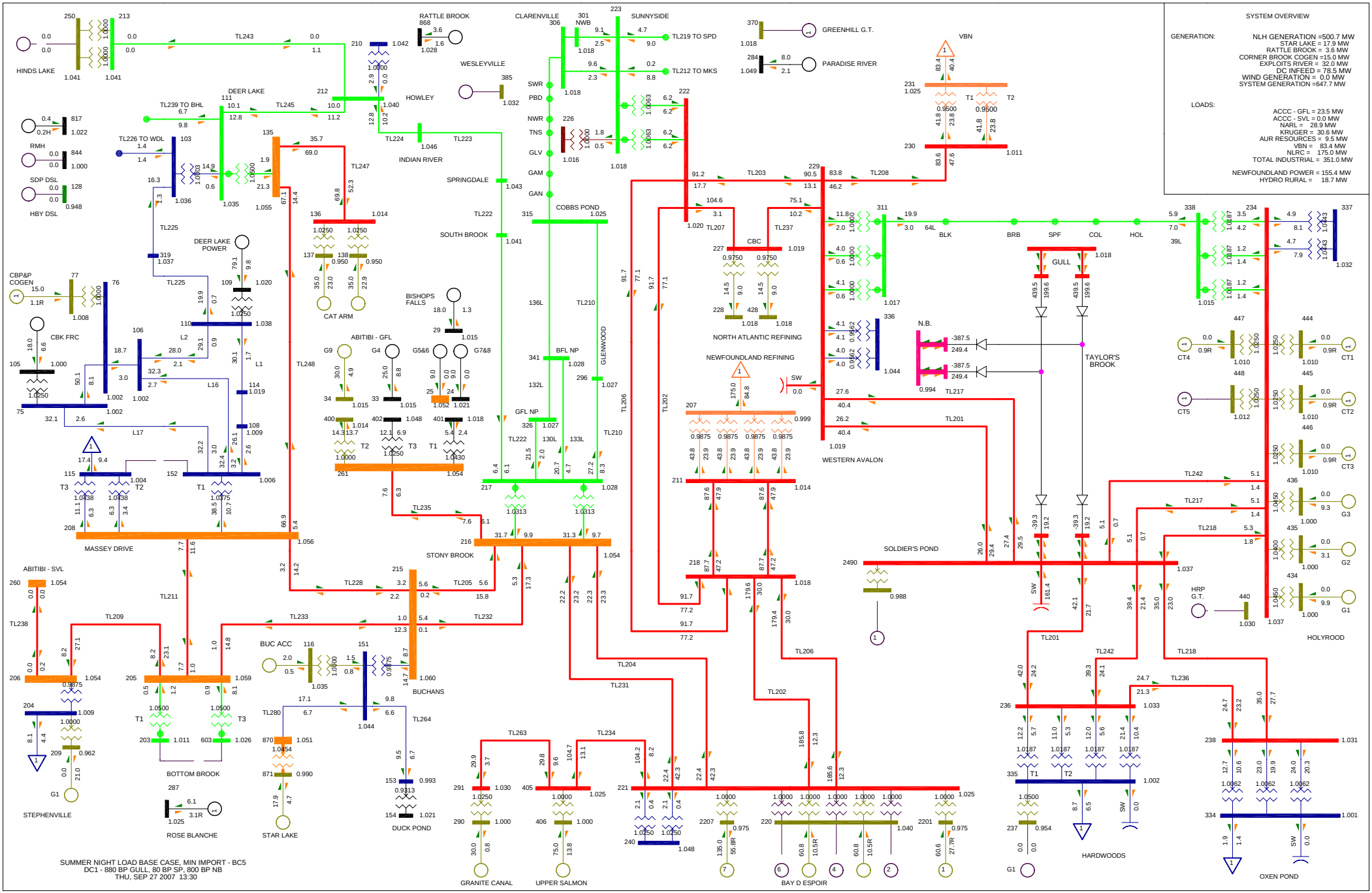

SYSTEM OVERVIEW
GENERATION:
NLH GENERATION =936.0 MW
STAR LAKE = 17.9 MW
RATTLE BROOK = 3.6 MW
CORNER BROOK COGEN =15.0 MW
EXPLOITS RIVER = 32.0 MW
DC INFEED = 573.8 MW
WIND GENERATION = 77.0 MW
SYSTEM GENERATION =1655.4 MW
LOADS:
ACCC - GFL = 23.5 MW
ACCC - SVL = 0.0 MW
NARL = 28.9 MW
KRUGER = 30.5 MW
AUR RESOURCES = 9.5 MW
VBN = 83.4 MW
NLRC = 175.0 MW
TOTAL INDUSTRIAL = 350.8 MW
NEWFOUNDLAND POWER = 679.3 MW
HYDRO RURAL = 86.7 MW
HINDS LAKE
RATTLE BROOK
WESLEYVILLE
HOWLEY
DEER LAKE
TL239 TO BHL
TL226 TO WDL
RMH
SDP DSL
HBY DSL
INDIAN RIVER
CLARENVILLE
SUNNYSIDE
TL219 TO SPD
TL212 TO MKS
GREENHILL G.T.
PARADISE RIVER
VBN
SPRINGDALE
COBBS POND
SOUTH BROOK
DEER LAKE POWER
CBP&P COGEN
CBK FRC
CAT ARM
BISHOPS FALLS
ABITIBI - GFL
GLENWOOD
BFL NP
GFL NP
CBC
NORTH ATLANTIC REFINING
NEWFOUNDLAND REFINING
N.B.
WESTERN AVALON
GULL
TAYLOR'S BROOK
BLK
BRB
SPF
COL
HOL
MASSEY DRIVE
STONY BROOK
SOLDIER'S POND
HOLYROOD
HRP G.T.
ABITIBI - SVL
BUC ACC
BUCHANS
BOTTOM BROOK
STEPHENVILLE
ROSE BLANCHE
STAR LAKE
DUCK POND
GRANITE CANAL
UPPER SALMON
BAY D ESPOIR
HARDWOODS
OXEN POND
2016 PEAK LOAD BASE CASE, REDUCED IMPORT - BC2
DC5 - 1400 BP GULL, 600 MP SP, 800 BP NB
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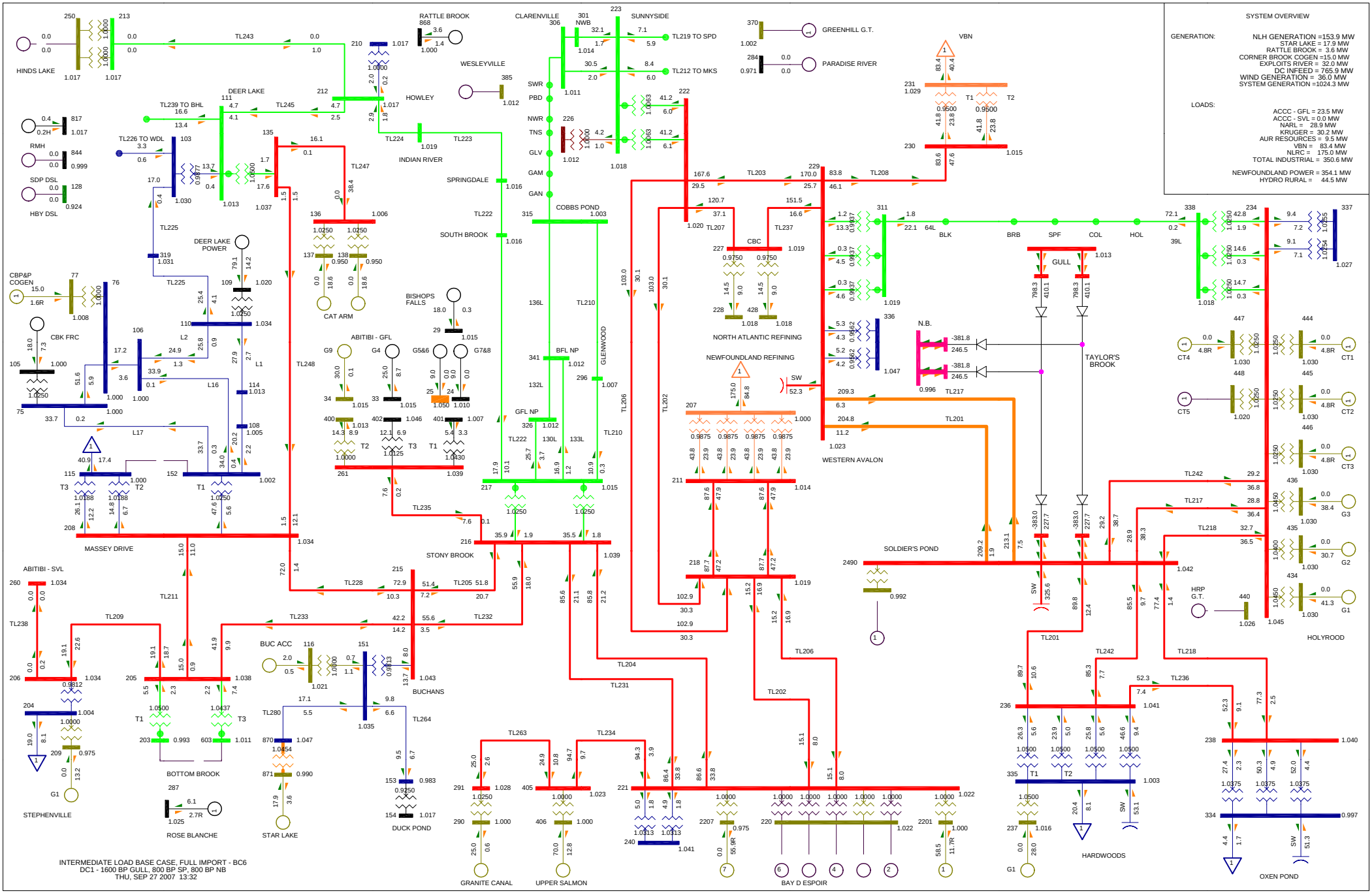

SYSTEM OVERVIEW
GENERATION:
NLH GENERATION =907.9 MW
STAR LAKE = 17.9 MW
RATTLE BROOK = 3.6 MW
CORNER BROOK COGEN =15.0 MW
EXPLOITS RIVER = 32.0 MW
DC INFEED = 765.9 MW
WIND GENERATION = 77.0 MW
SYSTEM GENERATION =1819.3 MW
LOADS:
ACCC - GFL = 23.5 MW
ACCC - SVL = 0.0 MW
NARL = 28.9 MW
KRUGER = 30.3 MW
AUR RESOURCES = 9.5 MW
VBN = 83.4 MW
NLRC = 175.0 MW
TOTAL INDUSTRIAL = 350.7 MW
NEWFOUNDLAND POWER = 767.8 MW
HYDRO RURAL = 98.0 MW
HINDS LAKE
RATTLE BROOK
WESLEYVILLE
HOWLEY
DEER LAKE
INDIAN RIVER
CLARENVILLE
SUNNYSIDE
GREENHILL G.T.
PARADISE RIVER
VBN
SPRINGDALE
SOUTH BROOK
COBBS POND
GLENWOOD
CAT ARM
BISHOPS FALLS
ABITIBI - GFL
DEER LAKE POWER
CBP&P COGEN
CBK FRC
MASSEY DRIVE
ABITIBI - SVL
STEPHENVILLE
BUC ACC
BUCHANS
BOTTOM BROOK
ROSE BLANCHE
STAR LAKE
DUCK POND
BFL NP
GFL NP
STONY BROOK
NORTH ATLANTIC REFINING
NEWFOUNDLAND REFINING
CBC
WESTERN AVALON
SOLDIER'S POND
N.B.
GULL
TAYLOR'S BROOK
BLK
BRB
SPF
COL
HOL
HRP G.T.
HOLYROOD
HARDWOODS
OXEN POND
BAY D ESPOIR
GRANITE CANAL
UPPER SALMON
CT1
CT2
CT3
CT4
CT5
G1
G2
G3
TL203
TL207
TL237
TL208
TL201
TL202
TL206
TL204
TL231
TL205
TL228
TL235
TL210
TL222
TL223
TL224
TL225
TL226 TO WDL
TL239 TO BHL
TL243
TL245
TL247
TL248
TL211
TL209
TL238
TL233
TL232
TL280
TL263
TL234
TL264
TL217
TL218
TL236
TL242
TL219 TO SPD
TL212 TO MKS
FUTURE PEAK LOAD BASE CASE, FULL IMPORT - BC3
DC1 - 1600 BP GULL, 800 BP SP, 800 BP NB
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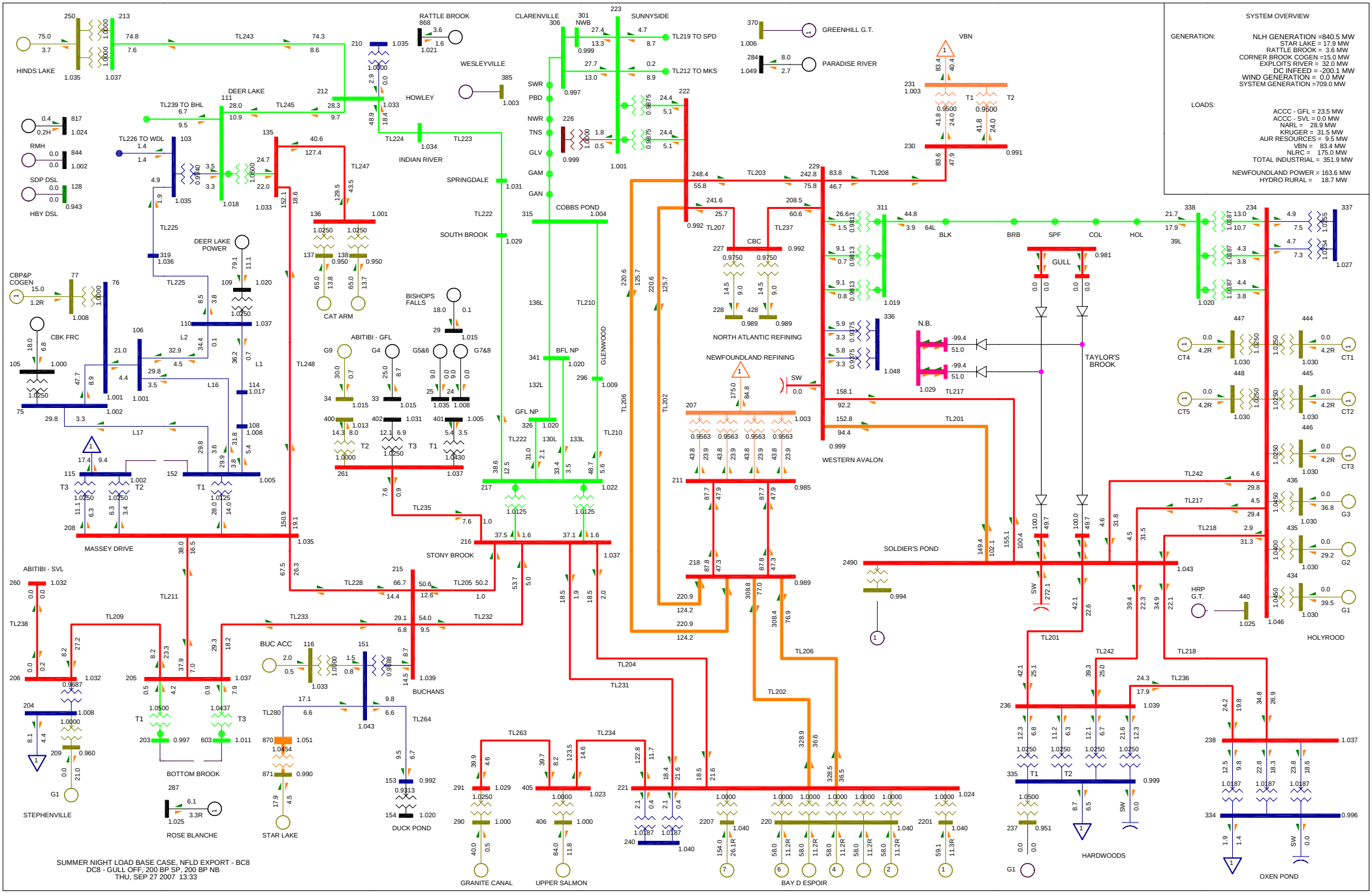

SYSTEM OVERVIEW
GENERATION:
NLH GENERATION =909.5 MW
STAR LAKE = 17.9 MW
RATTLE BROOK = 3.6 MW
CORNER BROOK COGEN =15.0 MW
EXPLOITS RIVER = 32.0 MW
DC INFEED = 765.4 MW
WIND GENERATION = 77.0 MW
SYSTEM GENERATION =1820.4 MW
LOADS:
ACCC - GFL = 23.5 MW
ACCC - SVL = 0.0 MW
NARL = 28.9 MW
KRUGER = 30.3 MW
AUR RESOURCES = 9.5 MW
VBN = 83.4 MW
NLRC = 175.0 MW
TOTAL INDUSTRIAL = 350.7 MW
NEWFOUNDLAND POWER = 767.2 MW
HYDRO RURAL = 98.0 MW
HINDS LAKE
RATTLE BROOK
CLARENVILLE
SUNNYSIDE
GREENHILL G.T.
PARADISE RIVER
VBN
WESLEYVILLE
DEER LAKE
HOWLEY
INDIAN RIVER
TL239 TO BHL
TL226 TO WDL
RMH
SDP DSL
HBY DSL
TL219 TO SPD
TL212 TO MKS
SPRINGDALE
COBBS POND
SOUTH BROOK
GLENWOOD
DEER LAKE POWER
CBP&P COGEN
CBK FRC
CAT ARM
BISHOPS FALLS
ABITIBI - GFL
CBC
NORTH ATLANTIC REFINING
NEWFOUNDLAND REFINING
BFL NP
GFL NP
WESTERN AVALON
N.B.
GULL
TAYLOR'S BROOK
BLK
BRB
SPF
COL
HOL
CT4
CT5
CT1
CT2
CT3
G3
G2
G1
HOLYROOD
MASSEY DRIVE
ABITIBI - SVL
STONY BROOK
SOLDIER'S POND
HRP G.T.
BUC ACC
BUCHANS
BOTTOM BROOK
STEPHENVILLE
ROSE BLANCHE
STAR LAKE
DUCK POND
GRANITE CANAL
UPPER SALMON
BAY D ESPOIR
HARDWOODS
OXEN POND
FUTURE PEAK LOAD BASE CASE, FULL IMPORT - BC3
DC4 - 1200 MP GULL, 800 MP SP, 400 MP NB
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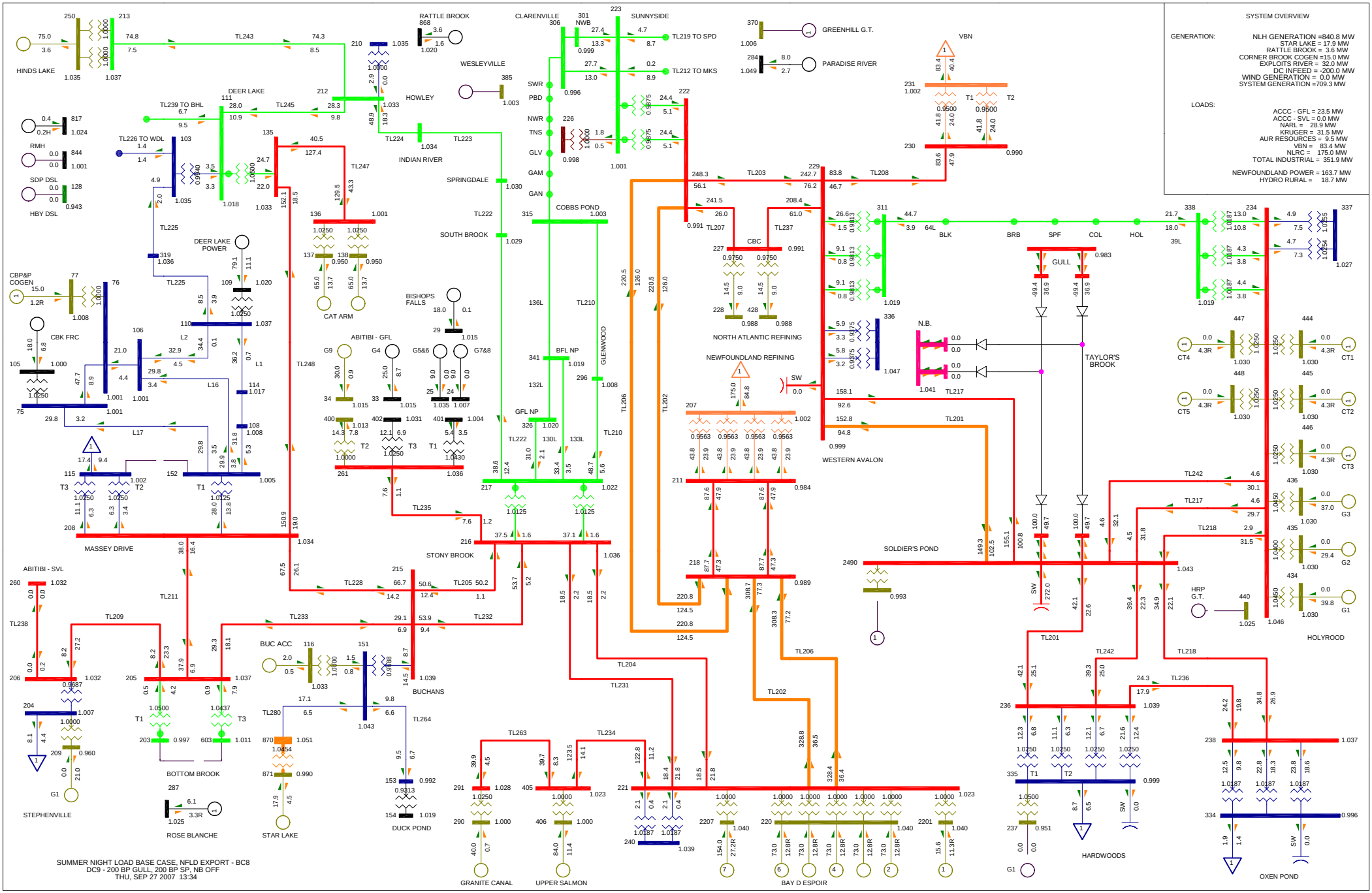

SYSTEM OVERVIEW
GENERATION:
NLH GENERATION =318.0 MW
STAR LAKE = 17.9 MW
RATTLE BROOK = 3.6 MW
CORNER BROOK COGEN =15.0 MW
EXPLOITS RIVER = 32.0 MW
DC INFEED = 248.8 MW
WIND GENERATION = 0.0 MW
SYSTEM GENERATION =635.4 MW
LOADS:
ACCC - GFL = 23.5 MW
ACCC - SVL = 0.0 MW
NARL = 28.9 MW
KRUGER = 30.6 MW
AUR RESOURCES = 9.5 MW
VBN = 83.4 MW
NLRC = 175.0 MW
TOTAL INDUSTRIAL = 350.9 MW
NEWFOUNDLAND POWER = 154.0 MW
HYDRO RURAL = 18.7 MW
HINDS LAKE
RATTLE BROOK
CLARENVILLE
SUNNYSIDE
GREENHILL G.T.
PARADISE RIVER
VBN
WESLEYVILLE
DEER LAKE
HOWLEY
INDIAN RIVER
SPRINGDALE
SOUTH BROOK
COBBS POND
GLENWOOD
BISHOPS FALLS
CAT ARM
ABITIBI - GFL
DEER LAKE POWER
CBP&P COGEN
CBK FRC
MASSEY DRIVE
ABITIBI - SVL
STEPHENVILLE
ROSE BLANCHE
BOTTOM BROOK
BUC ACC
STAR LAKE
BUCHANS
DUCK POND
STONY BROOK
GFL NP
BFL NP
GRANITE CANAL
UPPER SALMON
BAY D ESPOIR
CBC
NORTH ATLANTIC REFINING
NEWFOUNDLAND REFINING
WESTERN AVALON
N.B.
SOLDIER'S POND
GULL
TAYLOR'S BROOK
BLK
BRB
SPF
COL
HOL
HRP G.T.
HOLYROOD
HARDWOODS
OXEN POND
SUMMER NIGHT LOAD BASE CASE, MIN IMPORT - BC4
DC1 - 1055 BP GULL, 255 BP SP, 800 BP NB
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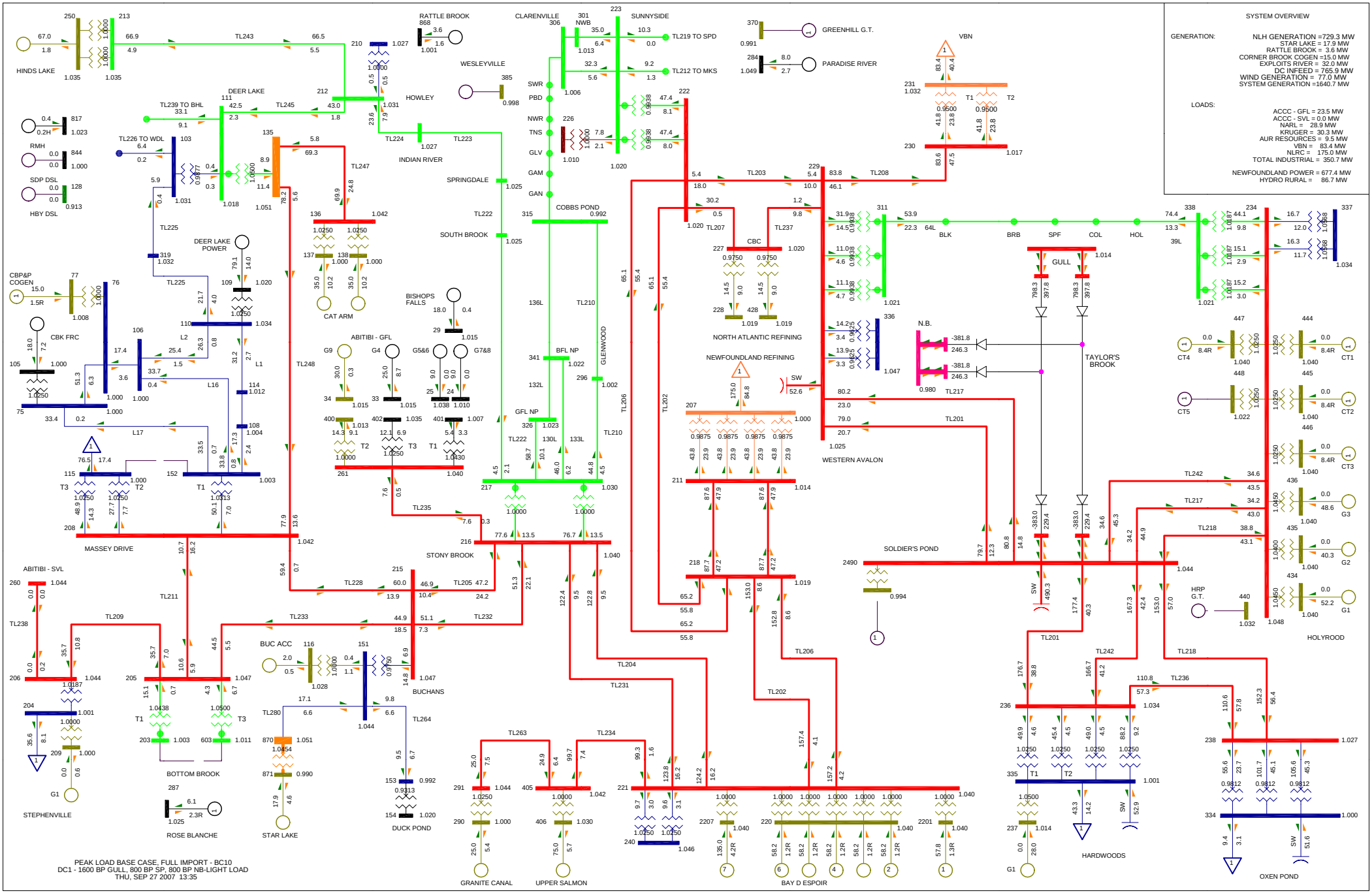

SYSTEM OVERVIEW
GENERATION:
NLH GENERATION =325.9 MW
STAR LAKE = 17.9 MW
RATTLE BROOK = 3.6 MW
CORNER BROOK COGEN =15.0 MW
EXPLOITS RIVER = 32.0 MW
DC INFEED = 241.3 MW
WIND GENERATION = 0.0 MW
SYSTEM GENERATION =635.7 MW
LOADS:
ACCC - GFL = 23.5 MW
ACCC - SVL = 0.0 MW
NARL = 28.9 MW
KRUGER = 30.6 MW
AUR RESOURCES = 9.5 MW
VBN = 83.4 MW
NLRC = 175.0 MW
TOTAL INDUSTRIAL = 350.9 MW
NEWFOUNDLAND POWER = 154.0 MW
HYDRO RURAL = 18.7 MW
HINDS LAKE
RATTLE BROOK
WESLEYVILLE
CLARENVILLE
SUNNYSIDE
GREENHILL G.T.
PARADISE RIVER
VBN
DEER LAKE
HOWLEY
INDIAN RIVER
SPRINGDALE
SOUTH BROOK
COBBS POND
GLENWOOD
CAT ARM
BISHOPS FALLS
ABITIBI - GFL
NORTH ATLANTIC REFINING
NEWFOUNDLAND REFINING
WESTERN AVALON
GULL
TAYLOR'S BROOK
BLK
BRB
SPF
COL
HOL
CBP&P COGEN
CBK FRC
DEER LAKE POWER
MASSEY DRIVE
STONY BROOK
SOLDIER'S POND
HRP G.T.
HOLYROOD
ABITIBI - SVL
BUC ACC
BUCHANS
BOTTOM BROOK
STEPHENVILLE
ROSE BLANCHE
STAR LAKE
DUCK POND
GRANITE CANAL
UPPER SALMON
BAY D ESPOIR
HARDWOODS
OXEN POND
SUMMER NIGHT LOAD BASE CASE, MIN IMPORT - BC4
DC3 - 655 MP GULL, 255 MP SP, 400 MP NB
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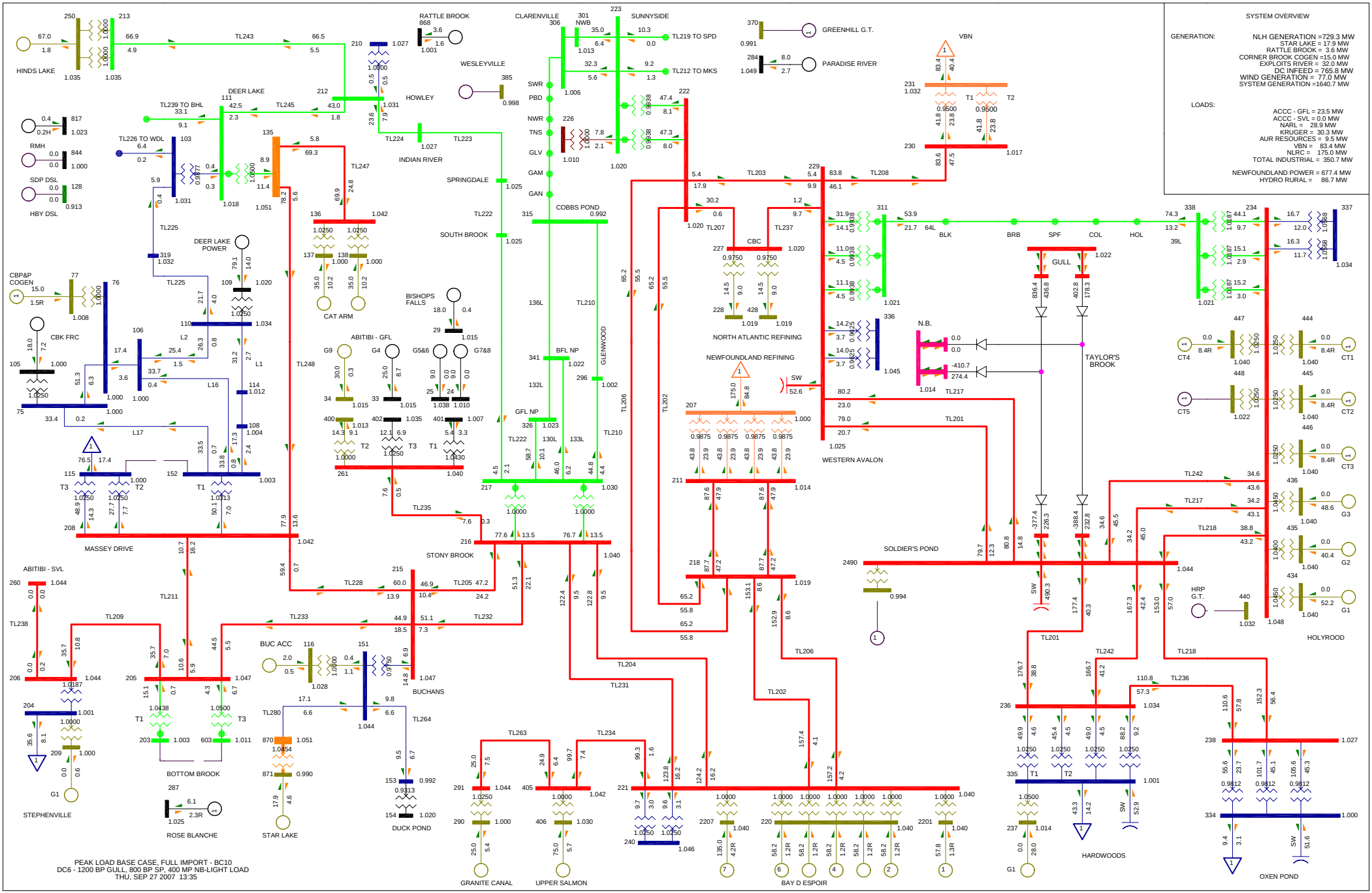

SYSTEM OVERVIEW
GENERATION:
NLH GENERATION =500.7 MW
STAR LAKE = 17.9 MW
RATTLE BROOK = 3.6 MW
CORNER BROOK COGEN =15.0 MW
EXPLOITS RIVER = 32.0 MW
DC INFEED = 78.5 MW
WIND GENERATION = 0.0 MW
SYSTEM GENERATION =647.7 MW
LOADS:
ACCC - GFL = 23.5 MW
ACCC - SVL = 0.0 MW
NARL = 28.9 MW
KRUGER = 30.6 MW
AUR RESOURCES = 9.5 MW
VBN = 83.4 MW
NLRC = 175.0 MW
TOTAL INDUSTRIAL = 351.0 MW
NEWFOUNDLAND POWER = 155.4 MW
HYDRO RURAL = 18.7 MW
HINDS LAKE
RATTLE BROOK
CLARENVILLE
SUNNYSIDE
GREENHILL G.T.
PARADISE RIVER
VBN
WESLEYVILLE
DEER LAKE
HOWLEY
TL239 TO BHL
TL226 TO WDL
RMH
SDP DSL
HBY DSL
INDIAN RIVER
SPRINGDALE
COBBS POND
SOUTH BROOK
CAT ARM
DEER LAKE POWER
CBP&P COGEN
CBK FRC
BISHOPS FALLS
ABITIBI - GFL
NORTH ATLANTIC REFINING
NEWFOUNDLAND REFINING
WESTERN AVALON
N.B.
GULL
TAYLOR'S BROOK
BLK
BRB
SPF
COL
HOL
MASSEY DRIVE
STONY BROOK
GLENWOOD
BFL NP
GFL NP
SOLDIER'S POND
HRP G.T.
HOLYROOD
ABITIBI - SVL
BUC ACC
BUCHANS
BOTTOM BROOK
STEPHENVILLE
ROSE BLANCHE
STAR LAKE
DUCK POND
GRANITE CANAL
UPPER SALMON
BAY D ESPOIR
HARDWOODS
OXEN POND
CT1
CT2
CT3
CT4
CT5
G1
G2
G3
SUMMER NIGHT LOAD BASE CASE, MIN IMPORT - BC5
DC1 - 880 BP GULL, 80 BP SP, 800 BP NB
THU, SEP 27 2007 13:30

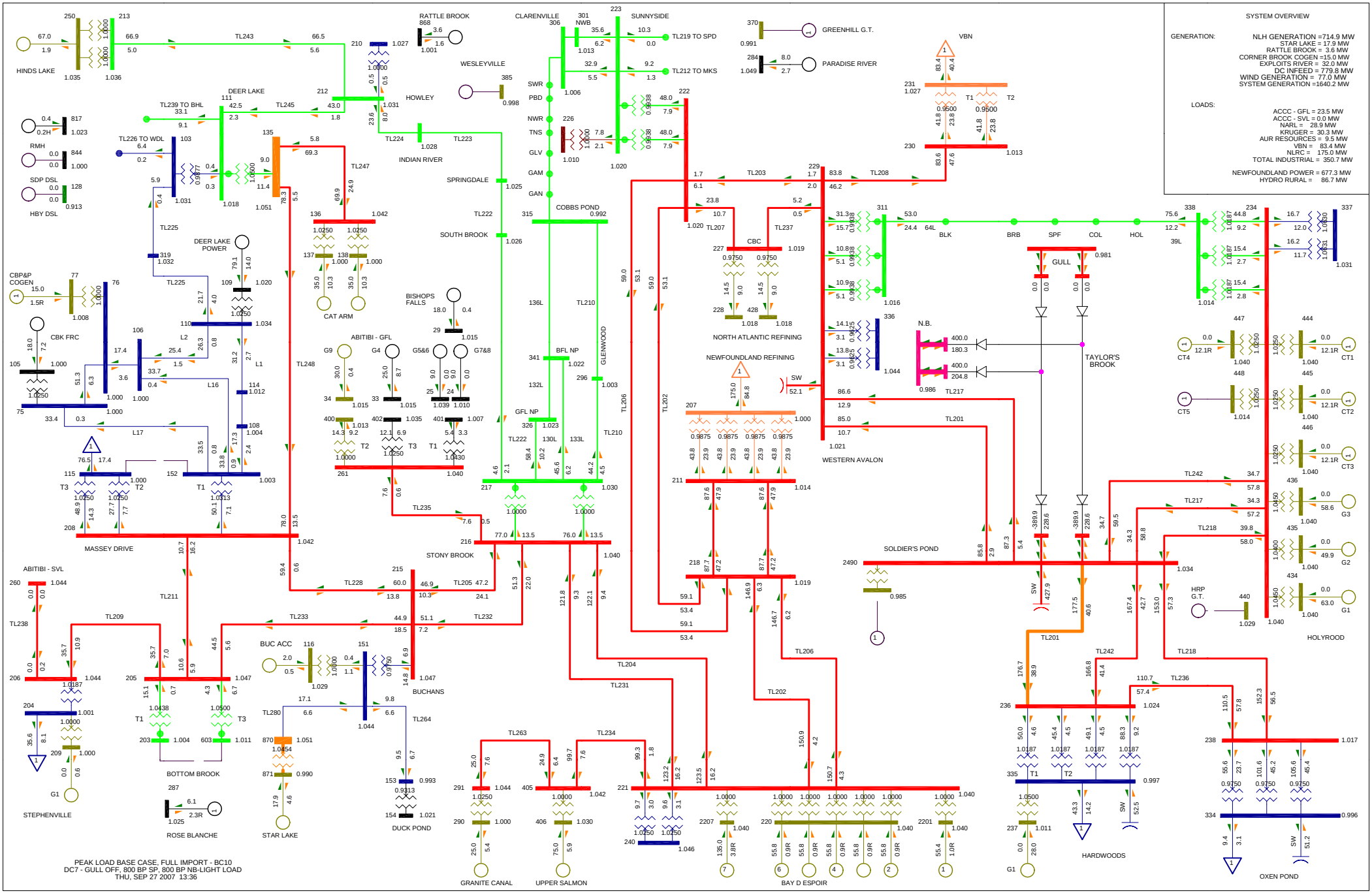

SYSTEM OVERVIEW
GENERATION:
NLH GENERATION =153.9 MW
STAR LAKE = 17.9 MW
RATTLE BROOK = 3.6 MW
CORNER BROOK COGEN =15.0 MW
EXPLOITS RIVER = 32.0 MW
DC INFEED = 765.9 MW
WIND GENERATION = 36.0 MW
SYSTEM GENERATION =1024.3 MW
LOADS:
ACCC - GFL = 23.5 MW
ACCC - SVL = 0.0 MW
NARL = 28.9 MW
KRUGER = 30.2 MW
AUR RESOURCES = 9.5 MW
VBN = 83.4 MW
NLRC = 175.0 MW
TOTAL INDUSTRIAL = 350.6 MW
NEWFOUNDLAND POWER = 354.1 MW
HYDRO RURAL = 44.5 MW
HINDS LAKE
RATTLE BROOK
WESLEYVILLE
HOWLEY
INDIAN RIVER
DEER LAKE
DEER LAKE POWER
TL239 TO BHL
TL226 TO WDL
RMH
SDP DSL
HBY DSL
TL243
TL245
TL247
TL224
TL223
TL225
CBP&P COGEN
CBK FRC
CAT ARM
BISHOPS FALLS
ABITIBI - GFL
TL248
MASSEY DRIVE
ABITIBI - SVL
TL211
TL209
TL238
STEPHENVILLE
BOTTOM BROOK
ROSE BLANCHE
TL228
TL233
TL232
BUC ACC
BUCHANS
TL280
TL264
STAR LAKE
DUCK POND
TL235
STONY BROOK
SPRINGDALE
SOUTH BROOK
TL222
CLARENVILLE
SUNNYSIDE
TL219 TO SPD
TL212 TO MKS
SWR
PBD
NWR
TNS
GLV
GAM
GAN
COBBS POND
GLENWOOD
TL210
BFL NP
GFL NP
TL205
TL231
TL263
TL234
TL204
GRANITE CANAL
UPPER SALMON
GREENHILL G.T.
PARADISE RIVER
VBN
TL203
TL208
TL207
TL237
CBC
NORTH ATLANTIC REFINING
NEWFOUNDLAND REFINING
TL202
TL206
WESTERN AVALON
N.B.
TAYLOR'S BROOK
GULL
BLK
BRB
SPF
COL
HOL
64L
39L
TL217
TL201
SOLDIER'S POND
TL242
TL218
HRP G.T.
HOLYROOD
TL236
HARDWOODS
OXEN POND
BAY D ESPOIR
INTERMEDIATE LOAD BASE CASE, FULL IMPORT - BC6
DC1 - 1600 BP GULL, 800 BP SP, 800 BP NB
THU, SEP 27 2007 13:32

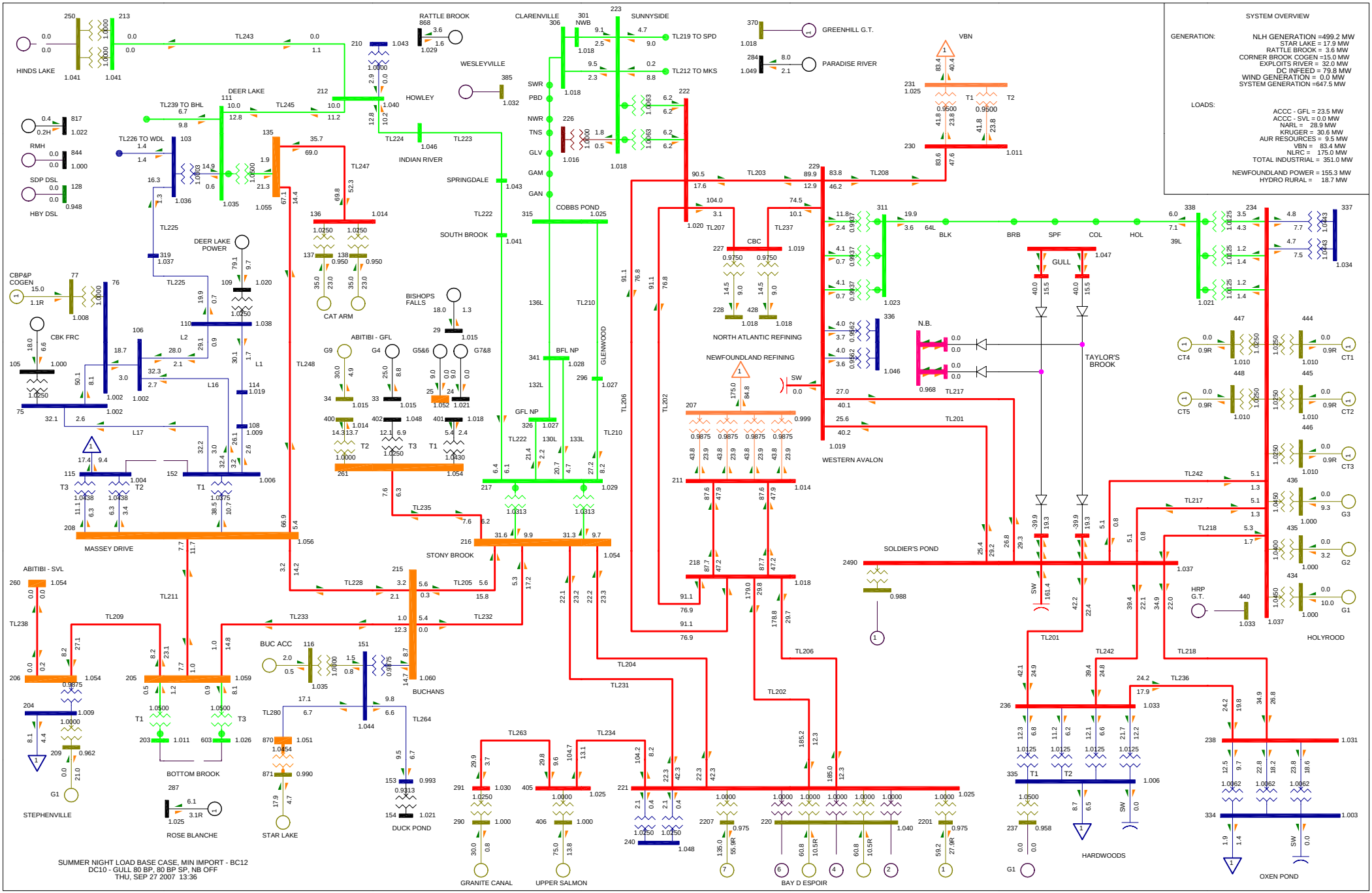

SYSTEM OVERVIEW
GENERATION:
NLH GENERATION =840.5 MW
STAR LAKE = 17.9 MW
RATTLE BROOK = 3.6 MW
CORNER BROOK COGEN =15.0 MW
EXPLOITS RIVER = 32.0 MW
DC INFEED = -200.1 MW
WIND GENERATION = 0.0 MW
SYSTEM GENERATION =709.0 MW
LOADS:
ACCC - GFL = 23.5 MW
ACCC - SVL = 0.0 MW
NARL = 28.9 MW
KRUGER = 31.5 MW
AUR RESOURCES = 9.5 MW
VBN = 83.4 MW
NLRC = 175.0 MW
TOTAL INDUSTRIAL = 351.9 MW
NEWFOUNDLAND POWER = 163.6 MW
HYDRO RURAL = 18.7 MW
HINDS LAKE
RATTLE BROOK
CLARENVILLE
SUNNYSIDE
GREENHILL G.T.
PARADISE RIVER
VBN
WESLEYVILLE
DEER LAKE
HOWLEY
INDIAN RIVER
TL219 TO SPD
TL212 TO MKS
TL239 TO BHL
TL226 TO WDL
RMH
SDP DSL
HBY DSL
SPRINGDALE
SOUTH BROOK
COBBS POND
GLENWOOD
DEER LAKE POWER
CBP&P COGEN
CBK FRC
CAT ARM
BISHOPS FALLS
ABITIBI - GFL
BFL NP
GFL NP
NORTH ATLANTIC REFINING
NEWFOUNDLAND REFINING
WESTERN AVALON
BLK
BRB
SPF
COL
HOL
GULL
TAYLOR'S BROOK
N.B.
CT1
CT2
CT3
CT4
CT5
G1
G2
G3
HRP G.T.
HOLYROOD
MASSEY DRIVE
ABITIBI - SVL
STONY BROOK
SOLDIER'S POND
BUC ACC
BUCHANS
BOTTOM BROOK
STEPHENVILLE
ROSE BLANCHE
STAR LAKE
DUCK POND
GRANITE CANAL
UPPER SALMON
BAY D ESPOIR
HARDWOODS
OXEN POND
SUMMER NIGHT LOAD BASE CASE, NFLD EXPORT - BC8
DC8 - GULL OFF, 200 BP SP, 200 BP NB
THU, SEP 27 2007 13:33

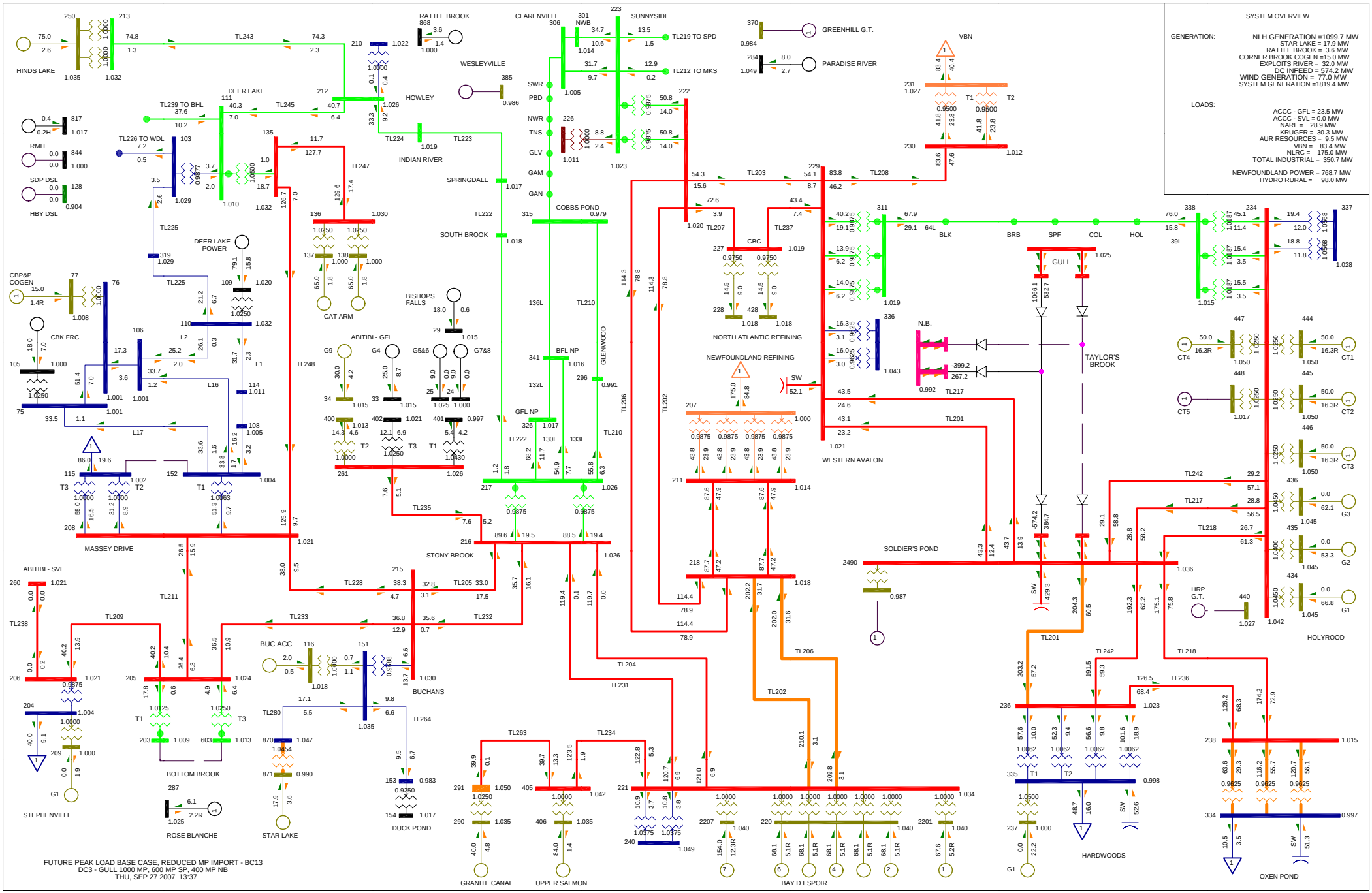

SYSTEM OVERVIEW
GENERATION:
NLH GENERATION =840.8 MW
STAR LAKE = 17.9 MW
RATTLE BROOK = 3.6 MW
CORNER BROOK COGEN =15.0 MW
EXPLOITS RIVER = 32.0 MW
DC INFEED = -200.0 MW
WIND GENERATION = 0.0 MW
SYSTEM GENERATION =709.3 MW
LOADS:
ACCC - GFL = 23.5 MW
ACCC - SVL = 0.0 MW
NARL = 28.9 MW
KRUGER = 31.5 MW
AUR RESOURCES = 9.5 MW
VBN = 83.4 MW
NLRC = 175.0 MW
TOTAL INDUSTRIAL = 351.9 MW
NEWFOUNDLAND POWER = 163.7 MW
HYDRO RURAL = 18.7 MW
HINDS LAKE
RATTLE BROOK
CLARENVILLE
SUNNYSIDE
GREENHILL G.T.
PARADISE RIVER
VBN
DEER LAKE
WESLEYVILLE
HOWLEY
INDIAN RIVER
SPRINGDALE
SOUTH BROOK
COBBS POND
GLENWOOD
BISHOPS FALLS
CAT ARM
DEER LAKE POWER
CBP&P COGEN
CBK FRC
ABITIBI - GFL
NORTH ATLANTIC REFINING
NEWFOUNDLAND REFINING
WESTERN AVALON
N.B.
GULL
TAYLOR'S BROOK
BLK
BRB
SPF
COL
HOL
MASSEY DRIVE
STONY BROOK
GFL NP
BFL NP
SOLDIER'S POND
HRP G.T.
HOLYROOD
ABITIBI - SVL
BUC ACC
BUCHANS
BOTTOM BROOK
STEPHENVILLE
ROSE BLANCHE
STAR LAKE
DUCK POND
GRANITE CANAL
UPPER SALMON
BAY D ESPOIR
HARDWOODS
OXEN POND
SUMMER NIGHT LOAD BASE CASE, NFLD EXPORT - BC8
DC9 - 200 BP GULL, 200 BP SP, NB OFF
THU, SEP 27 2007 13:34


SYSTEM OVERVIEW
GENERATION:
NLH GENERATION =729.3 MW
STAR LAKE = 17.9 MW
RATTLE BROOK = 3.6 MW
CORNER BROOK COGEN =15.0 MW
EXPLOITS RIVER = 32.0 MW
DC INFEED = 765.9 MW
WIND GENERATION = 77.0 MW
SYSTEM GENERATION =1640.7 MW
LOADS:
ACCC - GFL = 23.5 MW
ACCC - SVL = 0.0 MW
NARL = 28.9 MW
KRUGER = 30.3 MW
AUR RESOURCES = 9.5 MW
VBN = 83.4 MW
NLRC = 175.0 MW
TOTAL INDUSTRIAL = 350.7 MW
NEWFOUNDLAND POWER = 677.4 MW
HYDRO RURAL = 86.7 MW
HINDS LAKE
RATTLE BROOK
WESLEYVILLE
HOWLEY
DEER LAKE
TL239 TO BHL
TL226 TO WDL
RMH
SDP DSL
HBY DSL
TL225
DEER LAKE POWER
CBP&P COGEN
CBK FRC
TL243
TL245
TL247
TL224
TL223
INDIAN RIVER
CAT ARM
SPRINGDALE
SOUTH BROOK
TL222
BISHOPS FALLS
ABITIBI - GFL
TL248
MASSEY DRIVE
ABITIBI - SVL
TL211
TL209
TL238
BOTTOM BROOK
STEPHENVILLE
ROSE BLANCHE
BUC ACC
BUCHANS
TL228
TL233
TL232
TL205
TL280
TL264
STAR LAKE
DUCK POND
TL235
STONY BROOK
GFL NP
GLENWOOD
TL210
TL206
TL222
TL263
TL234
GRANITE CANAL
UPPER SALMON
CLARENVILLE
SUNNYSIDE
TL219 TO SPD
TL212 TO MKS
SWR
PBD
NWR
TNS
GLV
GAM
GAN
COBBS POND
BFL NP
TL247
TL203
TL208
TL237
CBC
NORTH ATLANTIC REFINING
NEWFOUNDLAND REFINING
TL207
TL202
TL201
WESTERN AVALON
GREENHILL G.T.
PARADISE RIVER
VBN
N.B.
TAYLOR'S BROOK
GULL
BLK
BRB
SPF
COL
HOL
SOLDIER'S POND
TL217
TL218
TL242
HOLYROOD
HRP G.T.
CT1
CT2
CT3
CT4
CT5
G1
G2
G3
HARDWOODS
OXEN POND
TL236
TL231
TL204
BAY D ESPOIR
PEAK LOAD BASE CASE, FULL IMPORT - BC10
DC1 - 1600 BP GULL, 800 BP SP, 800 BP NB-LIGHT LOAD
THU, SEP 27 2007 13:35


SYSTEM OVERVIEW
GENERATION:
NLH GENERATION =729.3 MW
STAR LAKE = 17.9 MW
RATTLE BROOK = 3.6 MW
CORNER BROOK COGEN =15.0 MW
EXPLOITS RIVER = 32.0 MW
DC INFEED = 765.8 MW
WIND GENERATION = 77.0 MW
SYSTEM GENERATION =1640.7 MW
LOADS:
ACCC - GFL = 23.5 MW
ACCC - SVL = 0.0 MW
NARL = 28.9 MW
KRUGER = 30.3 MW
AUR RESOURCES = 9.5 MW
VBN = 83.4 MW
NLRC = 175.0 MW
TOTAL INDUSTRIAL = 350.7 MW
NEWFOUNDLAND POWER = 677.4 MW
HYDRO RURAL = 86.7 MW
HINDS LAKE
RATTLE BROOK
WESLEYVILLE
HOWLEY
DEER LAKE
TL239 TO BHL
TL226 TO WDL
RMH
SDP DSL
HBY DSL
TL225
DEER LAKE POWER
CBP&P COGEN
CBK FRC
TL243
TL245
TL247
TL224
TL223
INDIAN RIVER
CAT ARM
SPRINGDALE
SOUTH BROOK
TL222
BISHOPS FALLS
ABITIBI - GFL
TL248
MASSEY DRIVE
ABITIBI - SVL
TL211
TL209
TL238
BOTTOM BROOK
STEPHENVILLE
ROSE BLANCHE
BUC ACC
BUCHANS
TL280
TL264
STAR LAKE
DUCK POND
TL228
TL233
TL232
TL205
TL235
STONY BROOK
GFL NP
TL210
GLENWOOD
TL206
BFL NP
COBBS POND
CLARENVILLE
SUNNYSIDE
TL219 TO SPD
TL212 TO MKS
SWR
PBD
NWR
TNS
GLV
GAM
GAN
TL263
TL234
TL231
TL204
GRANITE CANAL
UPPER SALMON
BAY D ESPOIR
TL203
TL208
TL207
TL237
CBC
NORTH ATLANTIC REFINING
NEWFOUNDLAND REFINING
TL202
TL217
TL201
WESTERN AVALON
GREENHILL G.T.
PARADISE RIVER
VBN
T1
T2
N.B.
GULL
TAYLOR'S BROOK
SOLDIER'S POND
BLK
BRB
SPF
COL
HOL
64L
39L
TL242
TL218
TL236
HRP G.T.
HOLYROOD
HARDWOODS
OXEN POND
CT4
CT1
CT5
CT2
CT3
G3
G2
G1
PEAK LOAD BASE CASE, FULL IMPORT - BC10
DC6 - 1200 BP GULL, 800 BP SP, 400 MP NB-LIGHT LOAD
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SYSTEM OVERVIEW
GENERATION:
NLH GENERATION =714.9 MW
STAR LAKE = 17.9 MW
RATTLE BROOK = 3.6 MW
CORNER BROOK COGEN =15.0 MW
EXPLOITS RIVER = 32.0 MW
DC INFEED = 779.8 MW
WIND GENERATION = 77.0 MW
SYSTEM GENERATION =1640.2 MW
LOADS:
ACCC - GFL = 23.5 MW
ACCC - SVL = 0.0 MW
NARL = 28.9 MW
KRUGER = 30.3 MW
AUR RESOURCES = 9.5 MW
VBN = 83.4 MW
NLRC = 175.0 MW
TOTAL INDUSTRIAL = 350.7 MW
NEWFOUNDLAND POWER = 677.3 MW
HYDRO RURAL = 86.7 MW
HINDS LAKE
RATTLE BROOK
WESLEYVILLE
HOWLEY
INDIAN RIVER
DEER LAKE
DEER LAKE POWER
TL239 TO BHL
TL226 TO WDL
RMH
SDP DSL
HBY DSL
CBP&P COGEN
CBK FRC
CAT ARM
BISHOPS FALLS
ABITIBI - GFL
MASSEY DRIVE
ABITIBI - SVL
STEPHENVILLE
BOTTOM BROOK
ROSE BLANCHE
BUC ACC
STAR LAKE
BUCHANS
DUCK POND
CLARENVILLE
SUNNYSIDE
TL219 TO SPD
TL212 TO MKS
SPRINGDALE
SOUTH BROOK
COBBS POND
BFL NP
GFL NP
GLENWOOD
STONY BROOK
GRANITE CANAL
UPPER SALMON
GREENHILL G.T.
PARADISE RIVER
VBN
NORTH ATLANTIC REFINING
NEWFOUNDLAND REFINING
WESTERN AVALON
CBC
N.B.
GULL
TAYLOR'S BROOK
BLK
BRB
SPF
COL
HOL
SOLDIER'S POND
HRP G.T.
HOLYROOD
HARDWOODS
OXEN POND
BAY D ESPOIR
PEAK LOAD BASE CASE, FULL IMPORT - BC10
DC7 - GULL OFF, 800 BP SP, 800 BP NB-LIGHT LOAD
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SYSTEM OVERVIEW
GENERATION:
NLH GENERATION =499.2 MW
STAR LAKE = 17.9 MW
RATTLE BROOK = 3.6 MW
CORNER BROOK COGEN =15.0 MW
EXPLOITS RIVER = 32.0 MW
DC INFEED = 79.8 MW
WIND GENERATION = 0.0 MW
SYSTEM GENERATION =647.5 MW
LOADS:
ACCC - GFL = 23.5 MW
ACCC - SVL = 0.0 MW
NARL = 28.9 MW
KRUGER = 30.6 MW
AUR RESOURCES = 9.5 MW
VBN = 83.4 MW
NLRC = 175.0 MW
TOTAL INDUSTRIAL = 351.0 MW
NEWFOUNDLAND POWER = 155.3 MW
HYDRO RURAL = 18.7 MW
HINDS LAKE
RATTLE BROOK
WESLEYVILLE
CLARENVILLE
SUNNYSIDE
GREENHILL G.T.
PARADISE RIVER
VBN
DEER LAKE
HOWLEY
INDIAN RIVER
SPRINGDALE
COBBS POND
SOUTH BROOK
GLENWOOD
CAT ARM
BISHOPS FALLS
ABITIBI - GFL
DEER LAKE POWER
CBP&P COGEN
CBK FRC
MASSEY DRIVE
ABITIBI - SVL
STEPHENVILLE
ROSE BLANCHE
BOTTOM BROOK
STAR LAKE
BUC ACC
BUCHANS
DUCK POND
STONY BROOK
GFL NP
BFL NP
GRANITE CANAL
UPPER SALMON
BAY D ESPOIR
CBC
NORTH ATLANTIC REFINING
NEWFOUNDLAND REFINING
WESTERN AVALON
N.B.
TAYLOR'S BROOK
GULL
BLK
BRB
SPF
COL
HOL
SOLDIER'S POND
HRP G.T.
HOLYROOD
HARDWOODS
OXEN POND
SUMMER NIGHT LOAD BASE CASE, MIN IMPORT - BC12
DC10 - GULL 80 BP, 80 BP SP, NB OFF
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SYSTEM OVERVIEW
GENERATION:
NLH GENERATION =1099.7 MW
STAR LAKE = 17.9 MW
RATTLE BROOK = 3.6 MW
CORNER BROOK COGEN =15.0 MW
EXPLOITS RIVER = 32.0 MW
DC INFEED = 574.2 MW
WIND GENERATION = 77.0 MW
SYSTEM GENERATION =1819.4 MW
LOADS:
ACCC - GFL = 23.5 MW
ACCC - SVL = 0.0 MW
NARL = 28.9 MW
KRUGER = 30.3 MW
AUR RESOURCES = 9.5 MW
VBN = 83.4 MW
NLRC = 175.0 MW
TOTAL INDUSTRIAL = 350.7 MW
NEWFOUNDLAND POWER = 768.7 MW
HYDRO RURAL = 98.0 MW
HINDS LAKE
RATTLE BROOK
WESLEYVILLE
CLARENVILLE
SUNNYSIDE
GREENHILL G.T.
PARADISE RIVER
VBN
DEER LAKE
HOWLEY
INDIAN RIVER
SPRINGDALE
COBBS POND
SOUTH BROOK
GLENWOOD
CAT ARM
BISHOPS FALLS
ABITIBI - GFL
CBP&P COGEN
CBK FRC
DEER LAKE POWER
MASSEY DRIVE
ABITIBI - SVL
STONY BROOK
BUC ACC
BUCHANS
BOTTOM BROOK
STEPHENVILLE
ROSE BLANCHE
STAR LAKE
DUCK POND
GRANITE CANAL
UPPER SALMON
BAY D ESPOIR
NORTH ATLANTIC REFINING
NEWFOUNDLAND REFINING
WESTERN AVALON
SOLDIER'S POND
GULL
TAYLOR'S BROOK
HRP G.T.
HOLYROOD
HARDWOODS
OXEN POND
BLK
BRB
SPF
COL
HOL
FUTURE PEAK LOAD BASE CASE, REDUCED MP IMPORT - BC13
DC3 - GULL 1000 MP, 600 MP SP, 400 MP NB
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Appendix F

New Brunswick Power Injection Assessment

(Please refer to Attachment 1 for the corresponding set of plots.)

Results on New Brunswick system not included in Public version

Attachment 1

Set of Plots Corresponding to Appendix F

APPENDIX C4 – DC1020 VOLUME 3 - HVDC SYSTEM INTEGRATION STUDY - COMPARISON OF CONVENTIONAL AND CCC HVDC TECHNOLOGY – MAY 2008

HYDRO
THE POWER OF COMMITMENT

THE Lower Churchill PROJECT

May 2008

DC1020 - HVdc System Integration Study

Volume 3 - Comparison of Conventional and CCC HVdc Technology

prepared by

HATCH™

in association with

RSW inc.

Statnett

TGS TransGrid Solutions

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PEG Newfoundland and Labrador
PERMIT HOLDER
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REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
PETER KUFFEL
SIGNATURE
May 27/08
DATE
NEWFOUNDLAND & LABRADOR

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Appendices

Appendix A – Island Single Line Diagrams of Power Flows with 50% Series Compensation

Appendix B – Summary of Dynamic Performance Results

Appendix C – Results for Conventional HVdc with 175 MW New Refinery Load In-Service

Appendix D – Results for CCC HVdc with 175 MW New Refinery Load In-Service

Appendix E – Results for Conventional HVdc with 175 MW New Refinery Load Out-of-Service

Appendix F – Results for CCC HVdc with 175 MW New Refinery Load Out-of-Service

Executive Summary

Preliminary transient stability analysis of the Lower Churchill multi-terminal HVdc project has been completed in order to compare the performance of conventional HVdc technology with the performance of capacitor-commutated converter (CCC) HVdc technology. The analysis has been performed on the year 2016 Island system peak load (1600 MW) case with 800 MW bipolar infeed (base case BC1-DC1). The purpose of the HVdc technology comparison is to provide a recommendation and justification for the direction of the remainder of the transient stability studies, i.e. whether conventional or CCC HVdc technology should be pursued.

Sensitivity to the new refinery load (175 MW) planned to be installed at Pipers Hole was included in the analysis. In addition an evaluation of the benefits of adding series compensation to the 230 kV lines between Bay d'Espoir and Pipers Hole was performed.

One 300 MVAR high inertia synchronous condenser (identical to those used by Manitoba Hydro) is required to be in-service at all times at both the 230 kV Pipers Hole bus and at the 230 kV Soldiers Pond bus. Without these synchronous condensers the dynamic performance of the system is unstable or unacceptable for various disturbances.

The following conclusions can be made:

1. Conventional HVdc Technology

With the refinery load in- or out-of-service, the system becomes unstable for a three-phase-to-ground fault at Bay d'Espoir on one of the Pipers Hole 230 kV lines. This is due to the fact that the Bay d'Espoir generators are faulted and simultaneously the HVdc experiences a commutation failure which results in a momentary loss of the 800 MW DC infeed. Cross-tripping the refinery load if it is in service does not mitigate the instability.

With the refinery load in-service a three-phase-to-ground fault at Pipers Hole on a Bay d'Espoir line would require the 175 MW new refinery load to be cross-tripped in order to maintain system stability.

With the addition of 50% series compensation on both 230 kV lines between Bay d'Espoir and Pipers Hole, recovery from a three-phase-to-ground fault at Bay d'Espoir on one of the Pipers Hole 230 kV lines is possible if the 175 MW new refinery load is cross-tripped. However voltage criteria is violated at the Bay d'Espoir and Sunnyside buses during recovery. In addition, with series compensation, a fault at Pipers Hole on a Bay d'Espoir line no longer requires the 175 MW new refinery load to be cross-tripped.

2. CCC HVdc Technology

The main benefit of CCC HVdc technology in this system is the ability of the HVdc to avoid commutation failure for a three-phase-to-ground fault at Bay d'Espoir. By avoiding the commutation failure for a Bay d'Espoir fault, the severity of this fault on the overall system is greatly reduced. This is true for both the operating scenarios with and without the new 175 MW refinery load in-service.

With CCC HVdc technology a three-phase-to-ground fault a Pipers Hole on a Bay d'Espoir line would require the 175 MW new refinery load to cross-tripped. The load cross-tripping can be avoided if 50% series compensation is installed on both 230 kV lines between Bay d'Espoir and Pipers Hole.

3. Other Load/Generation Dispatches

It should be noted that the base power flow case studied (1600 MW load, 800 MW bipolar infeed, BC1-DC1) in this preliminary transient stability analysis is not necessarily the most stressed case. The 600 MW monopolar infeed case as well as the future peak 1800 MW Island load case are expected to provide slightly worse results as less Island spinning reserve is available. It is likely that, in these cases, series compensation on the Bay d'Espoir-Pipers Hole lines will be a necessary AC system solution to improve dynamic performance and increase robustness especially for disturbances that are already on the verge of violating dynamic performance criteria. However, this is not yet known for certain at this point in time. Even if the system is considered not stressed to its maximum extent, the need and benefit of series compensation is quite evident.

A summary of findings for the potential solutions to maintain system stability are given below:

1. The use of conventional HVdc technology with the addition of 50% series compensation on both 230 kV lines between Bay d'Espoir and Pipers Hole is technically feasible if cross-tripping of the 175 MW new refinery load for specific contingencies is acceptable.
2. The use of CCC HVdc technology without the addition of 50% series compensation on both 230 kV lines between Bay d'Espoir and Pipers Hole is technically feasible if cross-tripping of the 175 MW new refinery load for specific contingencies is acceptable.
3. The use of CCC HVdc technology with the addition of 50% series compensation on both 230 kV lines between Bay d'Espoir and Pipers Hole is also technically feasible and it avoids cross-tripping of the 175 MW new refinery load.

It was noted from the study results that system stability can be maintained with the conventional HVdc with the application of the series compensation on the 230 kV lines between Bay d'Espoir and Pipers Hole if crosstrip of the 175 MW new refinery load is permitted. The CCC HVdc technology does provide some added benefit in that the 175 MW refinery load does not require cross-tripping if series compensation on the 230 kV lines between Bay d'Espoir and Pipers Hole are installed. This benefit, however, is fairly limited. On the other hand, there is some uncertainty associated with the application of the CCC to a long distance multi-terminal HVdc link.

Based on the results of this study the following recommendations are made:

1. Install 50% series compensation on the 230 kV lines between Bay d'Espoir and Pipers Hole to improve dynamic performance of the system.
2. The conventional HVdc technology with the above mentioned series compensation is recommended. The dynamic performance of the system with the conventional HVdc is acceptable with the exception of voltage criteria violations under certain disturbances. These violations are considered as attributed to system inherent problems and can be dealt with separately.

There is a marginal benefit of the application of CCC HVdc technology, but due to uncertainties with its application this technology is not recommended.

1. Introduction

This report compares the dynamic performance of NFL system with conventional HVdc technology to that with CCC HVdc technology in the Lower Churchill multi-terminal HVdc link. This report discusses the results of preliminary transient stability analysis for the WTO DC1020, the DC system integration studies for the Lower Churchill Project (LCP). New Island system facilities, existing Island system upgrades and potential special protection systems such as cross-tripping of loads are identified as required for both technologies to maintain system stability and provide acceptable system voltage recovery following normal-clearing three-phase faults and slow-clearing single line-to-ground faults.

Although there is currently a back-to-back CCC HVdc system in operation, CCC technology has not yet been applied to a long distance HVdc transmission system. The application of a CCC to the Lower Churchill Project has the potential of improving performance due to the basic nature of CCC, however it also adds another degree of complexity to the interconnected ac/dc system and should be used only if it is demonstrated that there is a substantial performance benefit.

The transient stability analysis was performed using the PSCAD version 4.2.1 software package.

All analysis for this comparison has been performed on the year 2016 Island system peak load (1600 MW) case with 800 MW bipolar infeed at Soldiers Pond (case BC1-DC1).

1.1 Objectives

The objectives of the preliminary transient stability analysis are to determine:

1. Island system upgrades required to maintain acceptable dynamic system performance of the AC and DC systems for conventional HVdc technology.
2. Island system upgrades required to maintain acceptable dynamic system performance of the AC and DC systems for CCC HVdc technology.
3. Comparison of CCC and conventional HVdc technology performances in the Island AC system.
4. Develop recommendations on the required system reinforcement and the use of HVdc technology and request for guidance from NLH as to the direction of the remainder of the WTO DC1020 transient stability analysis.

1.2 Procedure

The transient stability analysis was carried out using the following procedure:

1. Create a PSCAD model of the NLH system based on power flow analysis case BC1-DC1. Setup the model for both the conventional and CCC multi-terminal HVdc technologies.
2. Perform transient stability studies by applying normal-clearing (100 ms) three-phase faults and slow-clearing (250 ms) single line to ground faults at the expected worst-case locations in the NLH Island

system to ensure that the transient stability criteria, including rotor angle stability and transient under-voltage criteria is met.

3. When transient stability criteria is not met, determine acceptable mitigation including cross-tripping of the 175 MW new refinery load and the application of 50% series compensation on both 230 kV lines between Bay d'Espoir and Pipers Hole
4. Compare the dynamic performance results and impact of load cross-tripping and series compensation for the conventional HVdc technology and the CCC HVdc technology.
5. Provide recommendations and discussion on conventional HVdc technology versus CCC HVdc technology.

2. Background

Discussions were held between NLH and TGS on November 12 and 13 in Winnipeg regarding preliminary findings of the transient stability studies prior to the work performed for this report. Personnel involved in the meetings included Paul Humphries and Peter Thomas of NLH, and Peter Kuffel, Rebecca Brandt and Dan Kell of TGS. A summary of the discussions is provided below.

A summary of the initial findings presented by TGS is given below:

- Initial findings showed that for the 1600 MW load base-case, with the HVdc operating in bipolar mode with 800 MW infeed, performance of the interconnected ac/dc system was worse than expected when compared to results of earlier studies performed by Teshmont. A summary of the initial findings is given below:
  - Various faults within the island ac network result in unacceptable voltage depressions and even voltage collapse. These are most pronounced in the Bay d'Espoir and Sunnyside regions of the network.
  - Results were worse for faults which cause a large disruption of the generators at Bay d'Espoir and simultaneous commutation failure of the HVdc infeed.
  - The addition of more and larger rating synchronous condensers within the Island system provided some improvement, however the overall improvement was marginal.
  - Fast recovery of the HVdc power infeed following fault removal provides some benefit. The rate at which the HVdc power recovers must be balanced off against the risk of a secondary commutation failure if it is too fast.
  - The addition of a third 230 kV ac circuit between Bay d'Espoir and the Sunnyside region provides substantial improvement to the overall system recovery.
  - Cases with the HVdc operating monopolar with 600 MW infeed appear to be worse that the 800 MW bipolar configuration.
- The degraded performance when compared to results from the earlier Teshmont study were attributed to the following:
  - Impact of long cable on commutation performance and HVdc recovery at Soldiers Pond following faults.
  - The system load used in the two studies is considerably different; in particular the current study includes a 175 MW refinery load at Pipers Hole.
  - In the current study the loads are modeled as constant current for the real portion and constant impedance for the reactive portion, whereas in the earlier Teshmont study both the real and reactive portion of loads were modeled as constant impedance loads. The use of constant current for real power loads provides more realistic results and is much more onerous on the transient performance of the network.

  - Results of the earlier Teshmont study indicate that the system was unstable for a fault on the Bay d'Espoir to Sunnyside line. Mitigation of this was not provided in the study.
  - Load shedding was used in the earlier Teshmont study whereas in the present study one of the main goals is to avoid load shedding.
- Based on the initial findings a number of optional configurations were considered as discussed below:
  - Additional synchronous condensers were provided in order to improve overall performance. Results showed that this was only marginally effective.
  - The location of the five 50 MVA combustion turbines was varied to determine its effect on overall system performance. The location was seen to have little impact.
  - A two terminal Gull Island to Soldiers Pond HVdc link was investigated in order to determine the impact of the long cable section from Cape Ray to Salisbury on the performance of the Soldiers Pond converter. As expected, removal of the long cable section resulted in improved commutation performance and the ability to recover the HVdc infeed faster. Overall system performance was improved; however, a fault on the Bay d'Espoir to Sunnyside ac line still resulted in voltage collapse.
  - A damping function was developed and added to the multi-terminal HVdc controls in order to allow faster recovery from commutation failures. The addition of the new damping function provided recovery from commutation failures at Soldiers Pond for the multi-terminal HVdc which were comparable to that obtained for the two-terminal HVdc.
  - A two-terminal Capacitor Commutated Converter (CCC) HVdc link was examined. As expected the CCC provided improved commutation performance and provided some immunity to commutation failures. In particular, a fault at Bay d'Espoir no longer resulted in a commutation failure; hence, the overall system performance for this fault was very good and the voltage collapse avoided.

A discussion of general study requirements followed and is summarized below:

- Synchronous condensers which are added to support the HVdc infeed should be added at the Soldiers Pond and Pipers Hole buses due to space constraints at the Sunnyside station.
- Initial synchronous condenser parameters will be based on the machines used by Manitoba Hydro which have a heavier inertia which will improve overall system performance.
- The five 50 MVA combustion turbines should initially be located at the 230 kV bus to which the new refinery load is connected. A sensitivity to locating these at Holyrood should be undertaken.
- The need for a third 230 kV circuit should be avoided if at all possible.
- Transient post contingency voltages should remain above 70% for all buses.
- Steady state post contingency voltages must remain above 90% at all buses except Come-by-Chance where it must be above 93%.

- It is acceptable to trip the new refinery load (or portion of it) in order to avoid voltage collapse for faults between Bay d'Espoir and Pipers Hole. This should be avoided if possible.
- There is a need to identify system performance issues with and without the new refinery load in service in order to better understand ac system upgrades which are required to support the HVdc infeed and those required to support the new refinery load.

A discussion of how to proceed with the study followed and is summarized below:

- Since performance of the multi-terminal HVdc with the damping function included in the controls was nearing that of the two terminal HVdc (Gull Island to Soldiers Pond only) it was decided that a two terminal option should not be considered at this time.
- Since the preliminary look at CCC provided some immunity from commutation failures, a three terminal CCC model should be developed and used to better evaluate the potential performance benefits.
- A more comprehensive comparison of the performance of CCC versus conventional HVdc should be conducted at this stage of the study. This comparison will form the basis for recommending which configuration should be used in the transient stability studies.
- Continued work on the transient stability studies should wait until a recommendation has been put forward regarding the HVdc configuration and approval has been received from NLH.
- In order to better identify ac system upgrades which are associated with the new refinery load cases which consider the refinery load out of service need to be studied. Under this configuration, the Bay d'Espoir units should be re-dispatched such that one is running is synchronous condenser mode and the five 50 MVA combustion turbines should be located at Holyrood.
- Both 800 MW bipolar and 600 MW monopolar HVdc operating configurations should be considered. The 1600 MW base case load should be used for the 800 MW bipolar case, and a modified case with the refinery load out of service and the Bay d'Espoir units re-dispatched should be used for the 600 MW monopolar configuration.

3. Conventional and CCC HVdc Technology

The basic building block of the HVDC line commutated converter (LCC) is the six pulse Graetz bridge as shown in Figure 1 which is connected in series to result in a 12-pulse bridge as shown in Figure 2.

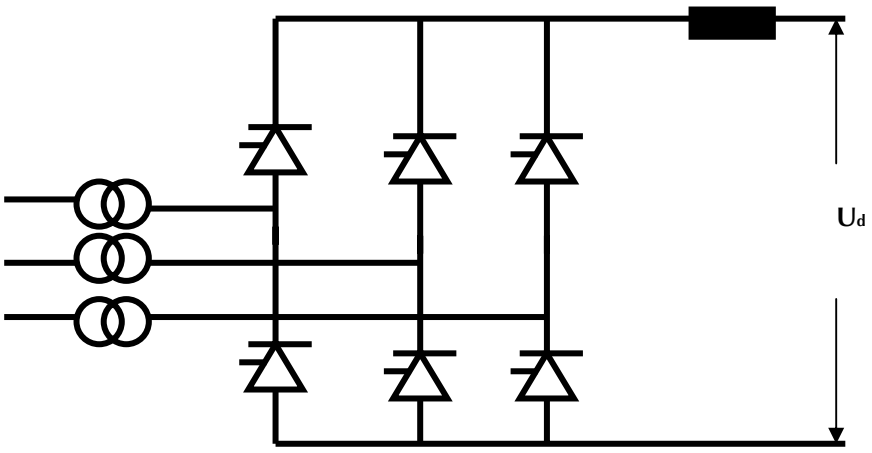


Figure 1 - Six Pulse Graetz Bridge

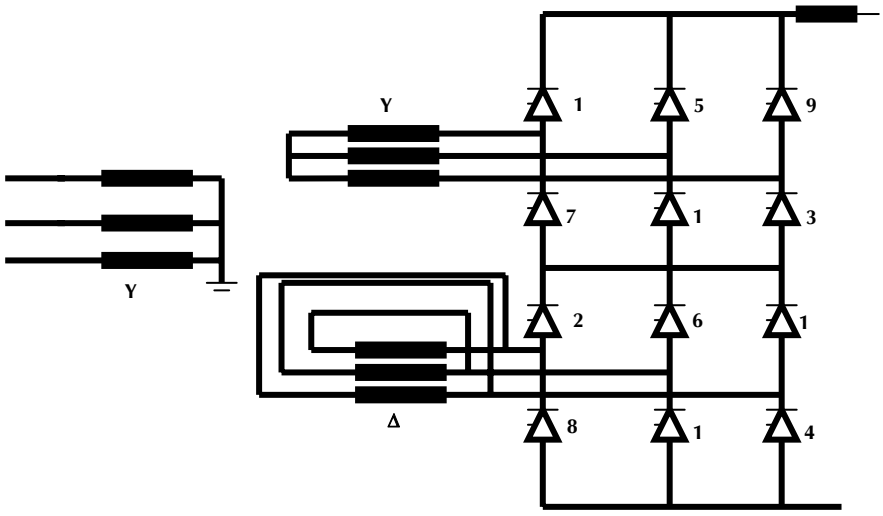


Figure 2 - Twelve Pulse Converter Bridge

Although this configuration offers efficient, reliable and economical operation, it has a number of notable drawbacks as follows:

1. The converter relies on the line voltage for the commutation process, therefore at the inverter the valve must be triggered sufficiently early of the line voltage zero crossing to provide it with enough commutation margin. Because of this dependence, the converter is susceptible to commutation failures in the event of ac system voltage depressions and when operated in weak ac systems.
2. The conventional arrangement presents a special problem with long HVDC cables since any reduction of the inverter bus voltage causes a corresponding decrease in dc voltage and thus an increase in dc current because of the cable capacitance discharge. The sudden increase in dc current in turn causes the extinction angle gamma to decrease, which increases the probability of commutation failures.
3. The demand for reactive power, which is typically about 0.5 pu of the rated active power must be supplied by shunt reactive power elements at the converter or from the ac system itself.
4. Upon sudden load rejection due to a block of the converter, an ac overvoltage occurs due to the loss of power and the fact that the capacitive shunt compensation elements (ac filters) remain connected to the ac busbar. Usually these shunt banks are removed from service to protect the equipment and to reduce the overvoltage.

The capacitive commutated converter as shown in figures 3 can mitigate these drawbacks.

In principle the addition of the series capacitors results in an additional commutating voltage. As a result of this additional commutating voltage, an increased firing angle range is obtained for both rectifier and inverter operation. This increased commutation voltage also results in a reduction of the overlap angle (commutation interval), leading to lower reactive power consumption.

Because of the presence of the capacitors, the commutation circuit includes both inductance and capacitance; therefore the basic equations of the conventional converter are no longer valid. The capacitors are charged with a polarity that aids in the commutation process. The size of the capacitors can be selected so that, in theory, the firing angle (alpha) can be increased well beyond 90 degrees. The commutation voltage also now has a phase lag and a higher amplitude when compared to the real bus voltage. This results in an additional commutation margin provided by the capacitors, consequently a smaller extinction angle is possible.

The capacitors also provide an additional commutation margin proportional to the dc current. For example, as the dc current increases, the voltage on the capacitors increases, resulting in an increase of the extinction angle. This is contrary to the situation in a conventional converter where the extinction angle decreases with increasing dc current. This certainly improves the commutation failure performance. This characteristic is very beneficial for an HVDC system with a long cable. It also has better performance in the event of remote ac system faults.

One major advantage of a capacitive commutated converter as compared to a conventional inverter is that for minimum commutation margin control it has a positive impedance while the conventional

inverter has a negative impedance. This positive impedance characteristic will improve the inverter performance in long dc cable transmission. Figure 3 shows the basic configuration of a Capacitor Commutated Converter (CCC).

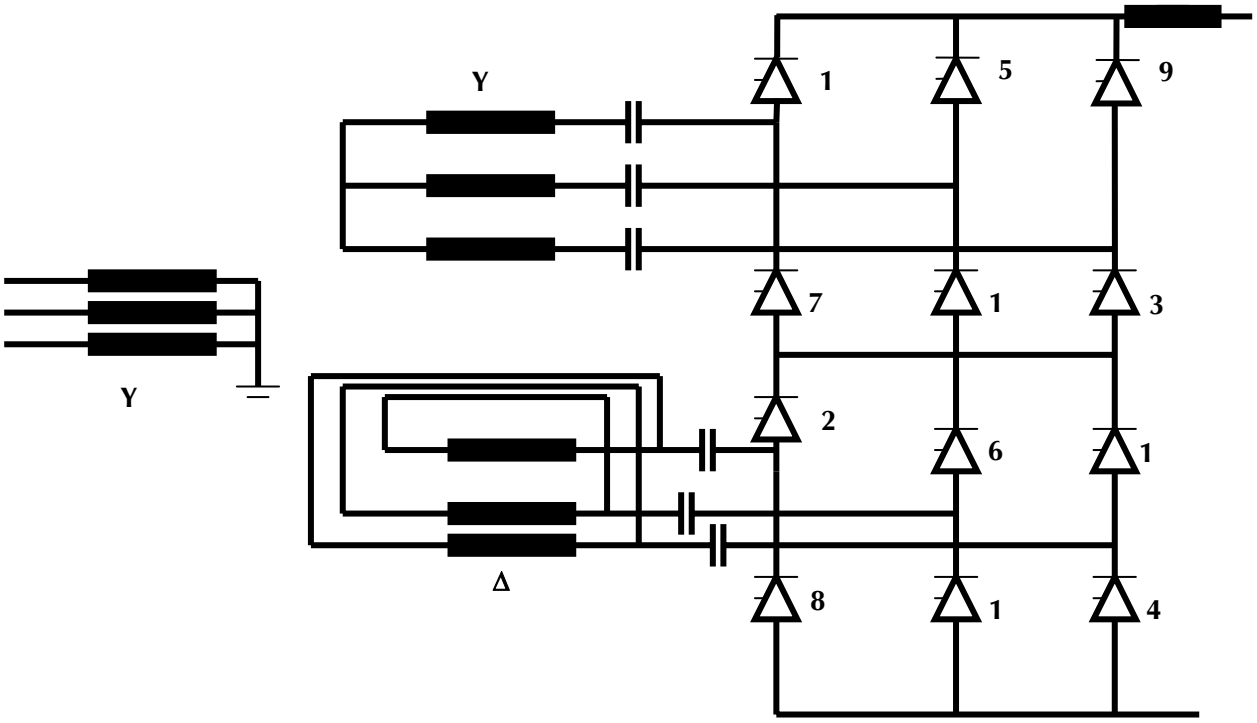


Figure 3 - CCC Converter Bridge

In this circuit the capacitors are connected between the converter and the ac bus on the valve side of the converter transformer. Because of the presence of the capacitors on the valve side, the CCC typically has a higher voltage impressed on the valves as compared to the conventional HVDC converter. This results in higher requirements for the snubber circuits and an increased voltage rating for the arrestor compared to the conventional HVDC, therefore it requires an increase in the valve insulation. The increased voltage stress is in the range of 10%. On the other hand, the short circuit current upon valve short circuit at the rectifier is lower than the conventional HVDC valve. This is due to the fast charging of the capacitors which produces a counter voltage that will limit the peak value. The typical protection during the valve short circuit fault is to block the valves with no bypass action. However it is standard in the design to assume that the blocking may fail and three or four loops of fault current will continue depending on the speed of the circuit breaker trip. The capacitor counter voltage will certainly reduce the peak of these loops. The capacitor counter voltage will also reduce the blocking voltage seen by the valve involved in the short circuit.

The phase currents of the CCC are very similar to the phase currents of a conventional HVDC. The only difference is that the currents during the overlap interval are not only part of the sine wave with fundamental frequency but also contain a component with the natural frequency of the capacitor/inductor circuit. As explained earlier, because the capacitor voltage supports the commutation of current from one valve to another, the overlap angle is reduced. The reduction will lead to a slight increase in the ac harmonics. The increase is in the range of 1% to 2%.

In a CCC the rating of the converter transformer is reduced because the reactive power flowing through the transformer is reduced. Obviously the no load losses of the converter transformer are lower due to the reduced rating of the unit. However, the load losses are increased due to the increased harmonic currents and the increased commutation jumps.

Since the CCC is self regulating in terms of reactive power consumption, the number and size of the ac filters can be reduced. Therefore, upon sudden block of the converter the resulting overvoltage on the ac bus is minimized.

Although there is currently a back-to-back CCC HVdc system in operation, CCC technology has not yet been applied to a long distance HVdc transmission system. Two specific areas of concern with the application of CCC to a long distance HVdc transmission system is the increased potential for system resonances and control system instabilities due to ac/dc system interactions. It can be assumed that the major suppliers would be able to overcome these issues; however the impact cannot be fully understood without extensive design studies. Therefore there is some uncertainty associated with the application of the CCC and its recommendation should only be justified when clear and substantial performance benefits are possible.

4. Study Models for Transient Stability Analysis

The preliminary transient stability analysis was performed using the year 2016 Island system peak load (1600 MW) case with 800 MW bipolar infeed into Soldiers Pond, corresponding to power flow case BC1-DC1 from the WTO DC1020 power flow analysis.

The real power portion of all loads are represented as constant current loads and the reactive power portion of all loads are represented as constant impedance loads.

4.1 AC System Representations

4.1.1 NLH Island System

Due to the length of computation time required to perform simulations in electromagnetic transients software, a reduced NLH Island AC system model is used to represent the AC system and its initial power flow conditions in PSCAD.

Based on the results of the previous preliminary stability analysis, it is known that more dynamic reactive power support as well as increased inertia will be required in the Island system. Preliminary analysis suggests that one 300 MVAR synchronous condenser be in-service at all times at both the Pipers Hole 230 kV bus and at Soldiers Pond 230 kV bus.

The year 2016 and future peak Island power flow cases have several significant modifications when compared to the existing system today:

1. A new large refinery load (175 MW, 85 MVAr) is planned to be in-service near Piper's Hole, between Bay D'Espoir and Sunnyside. As well, a nickel smelter load (83 MW, 40 MVAr) is planned for the Long Harbour area. The internal NLH studies for the additions of these loads have not yet been completed, therefore it is expected that system impacts due the loads will be observed in this HVdc feasibility study.

2. NLH is planning to convert units #1 to #3 at Holyrood to synchronous condensers as part of the Lower Churchill Project to meet ESCR requirements. In addition NLH is planning to install five 50 MW combustion turbines (CT) at Holyrood to meet load requirements between 2010 and the HVdc 2015 in-service date. These CTs will be specified with the capability to operate in synchronous condenser mode. The Holyrood station will have a total of eight (8) synchronous condensers available for voltage control and in support of ESCR with the following ratings:

    a. Unit #1 – 142/-72 MVAr
    b. Unit #2 – 142/-72 MVAr
    c. Unit #3 – 150/-69 MVAr
    d. CT Units #1-5: 63.5 MVA at 0.85 power factor leading

In addition, a 54 MW CT at Hardwoods is capable of operation as a synchronous condenser with a +28/-25 MVAr rating.

4.1.2 Labrador System

As described in the WTO DC1020 power flow analysis report, the Labrador system is represented by a weak system configuration. This weak configuration is achieved by removing the Muskrat Falls generating station, a 230 kV line from Gull Island to Muskrat Falls and a 735 kV line from Churchill Falls to Gull Island Generating Station.

The Labrador terminal of the HVdc system is operating as the rectifier, supplying rated power to Newfoundland Island and to New Brunswick.

In all test cases considered, the HVdc frequency control at Soldiers Pond is disabled as this function has not yet been optimized. The implementation of the frequency controller should provide improved post-contingency frequency response.

4.1.3 New Brunswick System

The New Brunswick system was represented by an equivalent voltage source with a system strength of [redacted] MVA.

4.2 Multi-terminal HVdc Link Representation

The Gull Island terminal was operated in a bipolar configuration as the rectifier, supplying rated power to the Island and New Brunswick terminals both operating as inverters.

Two different HVdc technologies were modeled, one representing conventional HVdc, the other representing CCC HVdc.

4.3 Sensitivities

The following sensitivities were studied:

1. Impact of new refinery load in- or out-of-service. The new refinery load (175 MW, 85 MVAR) at Pipers Hole is in-service in the base power flow case BC1-DC1. Sensitivity to this load being out-of-service is studied as power flow studies indicated this load has significant impact on the Island system during contingencies particularly between Bay d'Espoir and Soldiers Pond.

2. Impact of CCC HVdc technology and conventional HVdc technology.

3. Cursory impact of adding series capacitors to the 230 kV lines between Bay d'Espoir and Pipers Hole.

4.4 Assumptions

The following assumptions were made for each case:

1. All large synchronous condensers (units 1-3) at Holyrood are in-service.

2. If the new refinery load at Pipers Hole is in-service then the five new CTs currently planned for installation as synchronous condensers at Holyrood are relocated to Pipers Hole. If the new refinery load at Pipers Hole is out-of-service then the five new CTs are left as synchronous condensers at Holyrood. In all cases, one of these five CTs is assumed to be out-of-service for maintenance.

3. In the case testing sensitivity to new refinery load out-of-service, the generation at Bay d'Espoir is re-dispatched to maintain approximately 60 MW on each of units 1-6 with unit7 operating as a synchronous condenser.

4. One 300 MVAR synchronous condenser (high inertia of 2.2) is in-service at both Pipers Hole 230 kV bus and Soldiers Pond 230 kV bus in all cases.

4.5 Contingencies

Results of the power flow analysis provide indication as to which fault cases are expected to cause worst-case dynamic performances. Table 1 lists the contingencies that were studied in this preliminary transient stability analysis.

Table 1
Contingencies for Preliminary Transient Stability Analysis

Contingency	Description
1	100ms 3PF at Bay d'Espoir, clear Bay d'Espoir to Pipers Hole 230 kV line
2	100ms 3PF at mid-point, clear Bay d'Espoir to Pipers Hole 230 kV line
3	100ms 3PF at Pipers Hole, clear Bay d'Espoir to Pipers Hole 230 kV line
4	100ms 3PF at Sunnyside, clear Sunnyside to Western Avalon 230 kV line
5	100ms 3PF at Soldiers Pond, clear Soldiers Pond to Western Avalon 230 kV line
6	250ms LGF at Soldiers Pond, clear Soldiers Pond to Western Avalon 230 kV line

It is important to note that most of the line faults are of single-phase-to-ground type. Whereas, the second contingency in the above Table-1 represents a tower failure the probability of which is very remote as compared with the single-phase-to-ground faults. As noted from the study results, this contingency results in violation of the set voltage criteria. It is expected that a single-phase-to-ground fault will not result in voltage violation.

5. Transient Stability Analysis

The purpose of this preliminary transient stability analysis is to compare conventional and CCC HVdc technology and to determine the required Island AC system upgrade to dynamically support the 800 MW DC infeed at Soldiers Pond. These AC system upgrades are determined for both conventional HVdc technology and CCC HVdc technology in order that a recommendation can be made to steer the direction for the remainder of the transient stability analysis.

5.1 Study Procedure

Results of the steady state AC contingency analysis from the DC1020 load flow report were used to identify the expected worst-case contingencies. These contingencies, as described in Table 1, are applied and the simulations run for 5 seconds.

Bus voltages, system frequency, generator speeds and various transmission line power flows in the NLH system are monitored along with various HVdc parameters. The purpose is to identify any contingencies that result in a violation of system stability criteria or that result in poor HVdc dynamic performance. If a problem is discovered, mitigation in the following forms is studied:

1. HVdc control parameter optimization.

2. Trip of the 175 MW new refinery load at Pipers Hole.

3. 50% series compensation on both 230 kV lines between Bay d'Espoir and Pipers Hole.

5.2 Dynamic Performance Criteria

The following dynamic performance criteria are used to determine the Island AC transmission solution:

1. Transient undervoltages following fault clearing should not drop below 0.7 pu.

2. The system should be stable and reasonably well damped following fault clearing.

3. Under-frequency load shedding should be avoided if at all possible.

5.3 Study Results

The major NLH Island load centre is located east of Bay d'Espoir on the Avalon Peninsula, while the majority of the generation is located west of Bay d'Espoir. This can result in heavy west to east power flow on the 230 kV transmission system, in particular between Bay d'Espoir, Sunnyside, Western Avalon and Soldiers Pond. In addition, approximately 255 MW of new industrial load (refinery and smelter) is planned to be installed along this heavily loaded west to east corridor, which increases the loading on these 230 kV lines. As a general result this can cause voltage and rotor angle stability issues for the Island system along with steady state voltage depression and thermal overloading on lines in this corridor.

The HVdc infeed into Soldiers Pond generally has a positive steady state impact on the Island transmission system as it off-loads this west to east power flow by injecting power closer to the load centre. Faults within the Island ac network that cause a commutation failure at Soldiers Pond will however result in a transient loss of the entire HVdc infeed (800 MW in this case) during the commutation failure and for a short period following AC fault clearing as the HVdc power is recovering (approximately 200-300ms depending on the fault). In particular, faults causing commutation failure while simultaneously disturbing the Bay d'Espoir generators to a high enough degree (i.e. a fault very near Bay d'Espoir) can be enough to result in system instability with the existing Island AC system.

Many of the issues are not necessarily due solely to the HVdc infeed but are also due to the lack of transmission linking the generation in the west of the Island to the load in the east of the Island, and also due to the large new refinery loads that are planned to be installed in the area. Issues as presented are also due simply to the fact that the HVdc infeed represents approximately half of the Island's total generation in this case while the Island has very little spinning reserve. Transient loss of this infeed at the same time as disturbing the Bay d'Espoir generators results in a huge disturbance to the system and an immediate momentarily large energy mismatch.

It was quickly discovered that in order to survive faults between Bay d'Espoir and Soldiers Pond, more reactive power support than first identified in the power flow analysis would be necessary. Power flow analysis indicated the need for 200 MVAR at Sunnyside and one 150 MVAR synchronous condenser at Soldiers Pond. Initial stability analysis indicates that one 300 MVAR high inertia synchronous condenser is required to be in-service at both Pipers Hole 230 kV bus and Soldiers Pond 230 kV bus at all times. This indicates the need for two 300 MVAR synchronous condensers to be installed at both Pipers Hole and Soldiers Pond to account for maintenance outages.

The discussion of the worst-case transient stability results is split into two major sections – the first section discusses dynamic performance results with the new refinery load at Pipers Hole in-service; the second section discusses worst-case dynamic performance results with the new refinery load out-of-service. Within each of these sections the performance of conventional HVdc technology is compared with CCC HVdc technology. In addition, a brief discussion regarding the benefits of adding 50% series compensation to the 230 kV lines between Bay d'Espoir and Pipers Hole is included for the worst-case faults.

Among all cases, the worst-case disturbance in terms of maintaining system stability and 0.7 pu transient under-voltage criteria was found to be a three-phase fault on one of the Bay d'Espoir to Pipers Hole lines.

Also in all cases, a slow-clearing single line-to-ground fault at Soldiers Pond causes a commutation failure for the length of the fault, however the DC is able to recover and the AC system dynamic performance criteria is met. Minimum frequency dips to 0.978 pu on the second swing, but this is expected to be improved with frequency controller tuning on the HVdc.

A three-phase fault at Soldiers Pond on a Soldiers Pond-Western Avalon line and a three-phase fault at Sunnyside on the Sunnyside-Western Avalon line both cause commutation failure but the fault recoveries are within acceptable dynamic performance criteria.

The mitigation option looking at 50% series compensation on the Bay d'Espoir to Pipers Hole lines changes the original power flow case by lowering the impedance of the lines and drawing more power through them. The system intact case with 50% series compensation has 194 MVA flow on each Bay d'Espoir-Pipers Hole line and during an outage of one of the two parallel lines the line flow is increased to 368 MVA for the case being studied (BC1-DC1). Appendix A contains single line diagrams showing the Island system power flow for both the system intact and Bay d'Espoir – Pipers Hole line out scenarios.

For a complete summary of results please refer to Appendix B. For a set of plots showing dynamic performance results please refer to Appendix C-F.

5.3.1 New Refinery Load In-Service

With the new refinery load at Pipers Hole in-service, the five new CTs (synchronous condensers) that are planned to be installed at Holyrood are re-located to Pipers Hole.

5.3.1.1 Conventional HVdc Technology

The worst-case disturbance is a three-phase fault at Bay d'Espoir on one of the 230 kV lines to Pipers Hole. This fault causes the HVdc to fail commutation which collapses the HVdc power momentarily. At the same time it also causes a large disturbance of the Bay d'Espoir generators. The system cannot survive this disturbance and becomes unstable.

Tripping the 175 MW new refinery load at Pipers Hole during the fault was tested to see if system stability could be maintained, but dropping this load is not enough.

A fault at Pipers Hole on one of the Bay d'Espoir lines also causes system instability but can be mitigated by cross-tripping the 175 MW new refinery load.

With the addition of 50% series compensation on both 230 kV lines between Bay d'Espoir and Pipers Hole recovery from a fault at Bay d'Espoir on one of the Pipers Hole 230 kV lines is possible with tripping of the 175 MW new refinery load. It should be noted that although the system was stable and did recover, some voltage criteria violations were observed at the Bay d'Espoir and Sunnyside buses. Furthermore, with the addition of the series compensation, recovery from a fault at Pipers Hole on one of the Bay d'Espoir lines no longer requires cross-trip of the refinery load.

In summary, the use of conventional HVdc technology (without any system reinforcement) results in system collapse for a fault at Bay d'Espoir. However, addition of 50% series compensation on both 230 kV lines between Bay d'Espoir and Pipers Hole in combination with crosstripping of the 175 MW new refinery load (when necessary) provides suitable mitigation for all contingencies.

A complete set of results is contained in Appendix C.

5.3.1.2 CCC HVdc Technology

With CCC technology the previously worst-case Bay d'Espoir fault now does not cause the HVdc to fail commutation. By avoiding commutation failure the system response to the fault is well within the accepted dynamic performance criteria. Faults on the Bay d'Espoir to Pipers Hole line were tested at the midpoint of the line and also at Pipers Hole. The midpoint fault location also did not cause a commutation failure and had acceptable dynamic performance.

For CCC HVdc technology the worst-case disturbance is a fault at Pipers Hole on one of the Bay d'Espoir to Pipers Hole lines. This disturbance causes the HVdc to fail commutation and again causes system instability. This fault however, because it is further from the Bay d'Espoir generators, is not as severe as the Bay d'Espoir location for the conventional HVdc technology, and in this case cross-tripping the new 175 MW refinery load is sufficient to maintain system stability and meet dynamic performance criteria.

The results obtained indicate the development of neutral stable oscillations in the dc current approximately 500 ms following recovery from the fault. The oscillations appear to be due to an ac/dc system interaction which results in a imbalance across the capacitors located between the converter transformers and valve groups in the CCC. Due to time limitations, significant effort was not spent on determining suitable mitigation for these oscillations during this study. It is important to note that such oscillations are a real phenomenon and will need to be addressed if the CCC technology is pursued.

With the addition of 50% series compensation on both 230 kV lines between Bay d'Espoir and Pipers Hole cross-tripping of the 175 MW new refinery load is no longer required for the fault at Pipers Hole on one of the Bay d'Espoir to Pipers Hole lines.

In summary, the use of CCC HVdc technology in combination with cross-tripping of the 175 MW new refinery load (when necessary) provides stable response for all contingencies considered. The addition of 50% series compensation on both 230 kV lines between Bay d'Espoir and Pipers Hole eliminates the need to cross-trip the 175 MW new refinery load for all contingencies.

A complete set of results is contained in Appendix D.

5.3.2 New Refinery Load Out-of-Service

If the planned refinery load at Pipers Hole does not go ahead, the five new CTs (synchronous condensers) that are planned to be installed at Holyrood are left at Holyrood and not relocated to Pipers Hole. Bay d'Espoir generation is redispatched to operate unit 7 as a synchronous condenser and maintain approximately 60 MW on each of units 1-6.

The cases without the refinery load are far less stressed and generally see improved overall dynamic performance.

5.3.2.1 Conventional HVdc Technology

The worst-case disturbance is still a three-phase fault at Bay d'Espoir on one of the 230 kV lines to Pipers Hole. This fault causes the HVdc to fail commutation which collapses the HVdc power momentarily. At

the same time it also causes a large disturbance of the Bay d'Espoir generators. The system cannot survive this disturbance and becomes unstable.

With the addition of 50% series compensation on both 230 kV lines between Bay d'Espoir and Pipers Hole recovery from a fault at Bay d'Espoir on one of the Pipers Hole 230 kV lines is possible.

In summary, the use of conventional HVdc technology without any system reinforcement results in system collapse for a fault at Bay d'Espoir. The addition of 50% series compensation on both 230 kV lines between Bay d'Espoir and Pipers Hole provides suitable mitigation for all contingencies considered.

A complete set of results is contained in Appendix E.

5.3.2.2 CCC HVdc Technology

Similar to Section 6.3.1, the CCC technology provides the HVdc with better immunity to commutation failure and avoids commutation failure for faults midway down the Bay d'Espoir- Pipers Hole line to Bay d'Espoir. Faults at Pipers Hole still cause the HVdc to fail commutation however the dynamic performance of the fault recovery in this case is within acceptable criteria.

With the addition of 50% series compensation on both 230kV lines between Bay d'Espoir and Pipers Hole system recovery was improved.

In summary, the use of CCC technology provides stable response for all contingencies considered. The addition of 50% series compensation on both 230 kV lines between Bay d'Espoir and Pipers Hole resulted in improved recovery for all contingencies considered.

A complete set of results is contained in Appendix F.

5.3.3 Summary of Results – Conventional HVdc versus CCC HVdc

The complete results are summarized in the table below.

HVDC Configuration	Fault Location	Refinery Status	Refinery Crosstrip	Series Compensation	Stable?	Voltage Violations?
Conventional	BDE	IN	0 MW	No	NO	-
	Midpoint	IN	0 MW	No	NO	-
	PH	IN	0 MW	No	NO	-
	BDE	IN	175 MW	No	NO	-
	Midpoint	IN	175 MW	No	YES	none
	PH	IN	175 MW	No	YES	none
CCC	BDE	IN	0 MW	No	YES	none
	Midpoint	IN	0 MW	No	YES	none
	PH	IN	0 MW	No	NO	-
	PH	IN	175 MW	No	YES	none
Conventional	BDE	OUT	-	No	NO	-
	Midpoint	OUT	-	No	YES	none
	PH	OUT	-	No	YES	none
CCC	BDE	OUT	-	No	YES	none
	Midpoint	OUT	-	No	YES	none
	PH	OUT	-	No	YES	none
Conventional	BDE	IN	0 MW	Yes	NO	-
	Midpoint	IN	0 MW	Yes	NO	-
	PH	IN	0 MW	Yes	YES	none
	Midpoint	IN	175 MW	Yes	YES	BDE-0.65 pu, SSD-0.64 pu
	BDE	IN	175 MW	Yes	YES	BDE-0.60 pu, SSD-0.67 pu
CCC	BDE	IN	0 MW	Yes	YES	none
	Midpoint	IN	0 MW	Yes	YES	none
	PH	IN	0 MW	Yes	YES	none
Conventional	BDE	OUT	-	Yes	YES	none
	Midpoint	OUT	-	Yes	YES	none
	PH	OUT	-	Yes	YES	none
CCC	BDE	OUT	-	Yes	YES	none
	Midpoint	OUT	-	Yes	YES	none
	PH	OUT	-	Yes	YES	none

The following salient points are noted from the table above:

- Application of conventional HVdc technology results in system collapse for a number of contingencies with and without the 175 MW new refinery load in service. Also, cross-tripping the new refinery load, if it were in-service, does not avoid system collapse.
- Application of conventional HVdc technology in conjunction with the addition of 50% series compensation to both of the 230 kV Bay d'Espoir - Pipers Hole lines will result in stable recovery from all contingencies considered. For cases with the 175 MW new refinery load in-service, cross-trip of the new load is required for certain contingencies to maintain system stability.

- Application of CCC HVdc technology results in system recovery for all contingencies with and without the 175 MW new refinery load in service. For cases with the 175 MW new refinery load in-service, cross-trip of the new load is required for certain contingencies to maintain system stability.
- Application of CCC HVdc technology in conjunction with the addition of 50% series compensation to both of the 230 kV Bay d'Espoir - Pipers Hole lines will result in stable recovery from all contingencies considered. For cases with the 175 MW new refinery load in-service, cross-trip of the new load is not required for any of the contingencies considered to maintain system stability.

The main benefit of CCC HVdc technology in this system is the ability to avoid commutation failure for a three-phase fault at Bay d'Espoir. By avoiding the commutation failure for a Bay d'Espoir fault, the need for a third 230 kV circuit between Bay d'Espoir and Pipers Hole is eliminated. This fact is true for both the system with and without the new 175 MW refinery load in-service.

In order to maintain system stability, conventional HVdc technology would require the addition of 50% series compensation to both of the 230 kV Bay d'Espoir - Pipers Hole lines and cross-trip of the 175 MW new refinery load at Pipers Hole (for certain contingencies) in order to maintain system stability for all contingencies considered.

It should be noted that the base power flow case being studied (1600 MW load, 800 MW bipolar infeed, BC1-DC1) in this preliminary transient stability analysis is not necessarily the most stressed case. The 600 MW monopolar infeed case as well as the future peak 1800 MW Island load cases are expected to provide slightly worse results as less spinning reserve is available. It is likely that the need for series compensation will be even more apparent in these cases in order to provide an interconnected ac/dc system solution with improved dynamic performance and increased robustness.

6. Conclusions and Recommendations

The following conclusions can be made as a result of the preliminary transient stability analysis:

1. Conventional HVdc Technology

With the refinery load in- or out-of-service, the system becomes unstable for a fault at Bay d'Espoir on one of the Pipers Hole 230 kV lines. This is due to the fact that the Bay d'Espoir generators are faulted and simultaneously the HVdc experiences a commutation failure which results in a momentary loss of the 800 MW DC infeed. Cross-tripping the refinery load if it is in service does not mitigate the instability.

With the refinery load in-service a fault at Pipers Hole on a Bay d'Espoir line would require the 175 MW new refinery load to be cross-tripped in order to maintain system stability.

With the addition of 50% series compensation on both 230kV lines between Bay d'Espoir and Pipers Hole, recovery from a fault at Bay d'Espoir on one of the Pipers Hole 230 kV lines is possible if the 175 MW new refinery load is cross-tripped, however voltage criteria is violated at the Bay d'Espoir and Sunnyside buses during recovery. In addition, with series compensation, a fault at Pipers Hole on a Bay d'Espoir line no longer requires the 175 MW new refinery load to be cross-tripped in order to maintain system stability.

2. CCC HVdc Technology

The main benefit of CCC HVdc technology in this system is the ability of the HVdc to avoid commutation failure for a three-phase fault at Bay d'Espoir. By avoiding the commutation failure for a Bay d'Espoir fault, the severity of this fault on the overall system is greatly reduced. This fact is true for both the system with and without the new 175 MW refinery load in-service.

With CCC HVdc technology a fault a Pipers Hole on a Bay d'Espoir line would require the 175 MW new refinery load to cross-tripped. The load cross-tripping can be avoided if 50% series compensation is installed on both 230 kV lines between Bay d'Espoir and Pipers Hole.

3. Other Power Flow Cases

It should be noted that the base power flow case being studied (1600 MW load, 800 MW bipolar infeed, BC1-DC1) in this preliminary transient stability analysis is not necessarily the most stressed case. The 600 MW monopolar infeed case as well as the future peak 1800 MW Island load cases are expected to provide slightly worse results as less spinning reserve is available. It is likely that the series compensation will either be necessary in these cases or at the least may offer an AC system solution with improved dynamic performance and increased robustness.

The results of this study show that with the application of the series compensation on the 230 kV lines between Bay d'Espoir and Pipers Hole system stability is maintained for all contingencies considered with conventional HVdc technology if crosstrip of the 175 MW new refinery load is permitted. Although the application of CCC HVdc technology does provide some added benefit in that the 175 MW refinery load does not require crosstripping, this benefit is fairly limited, whereas there is some uncertainty associated with the application of the CCC to a long distance multi-terminal HVdc link.

Based on the results of this study the following recommendations are made:

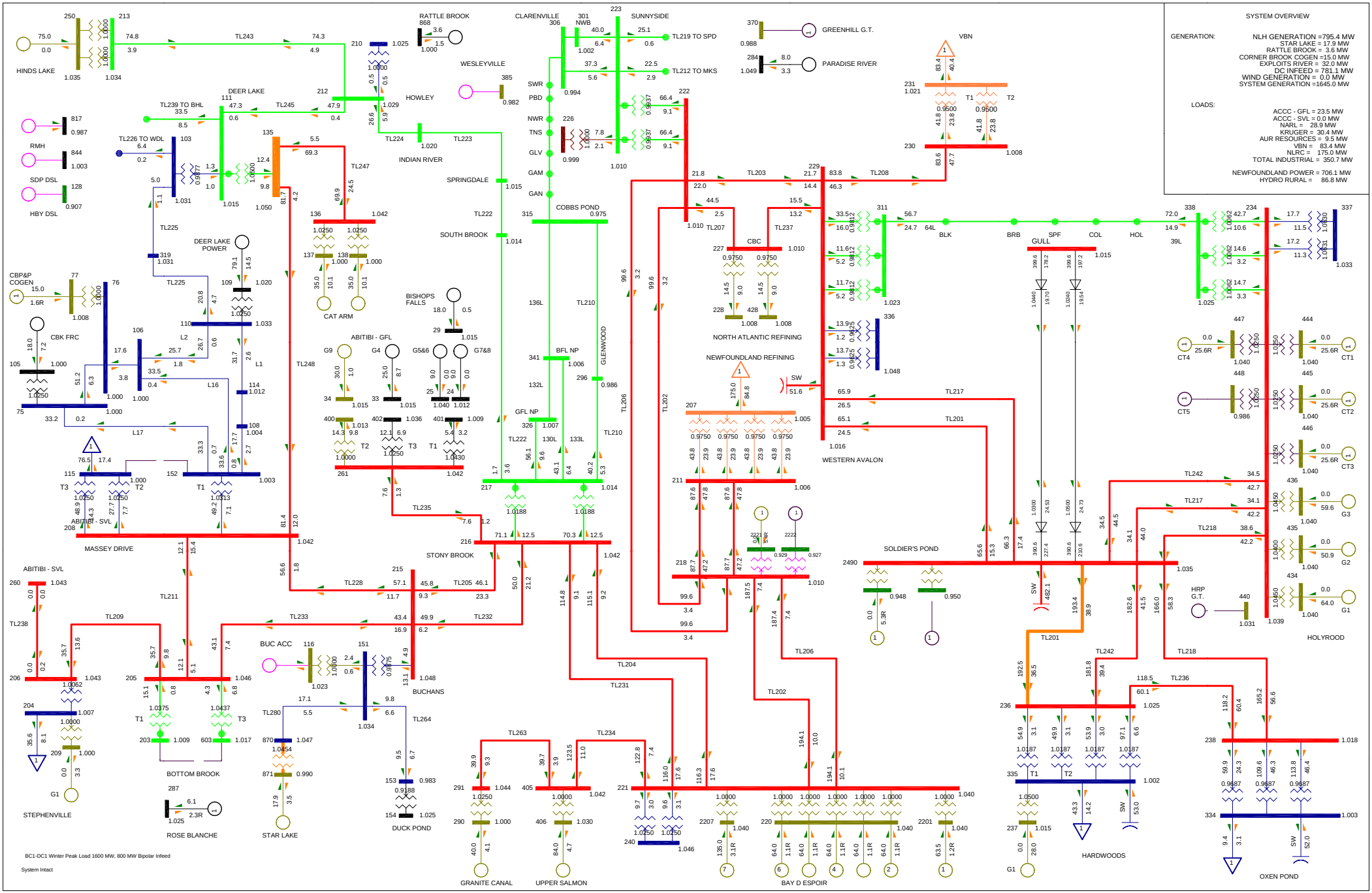
1. Install 50% series compensation on the 230 kV lines between Bay d'Espoir and Pipers Hole to improve dynamic performance of the system.

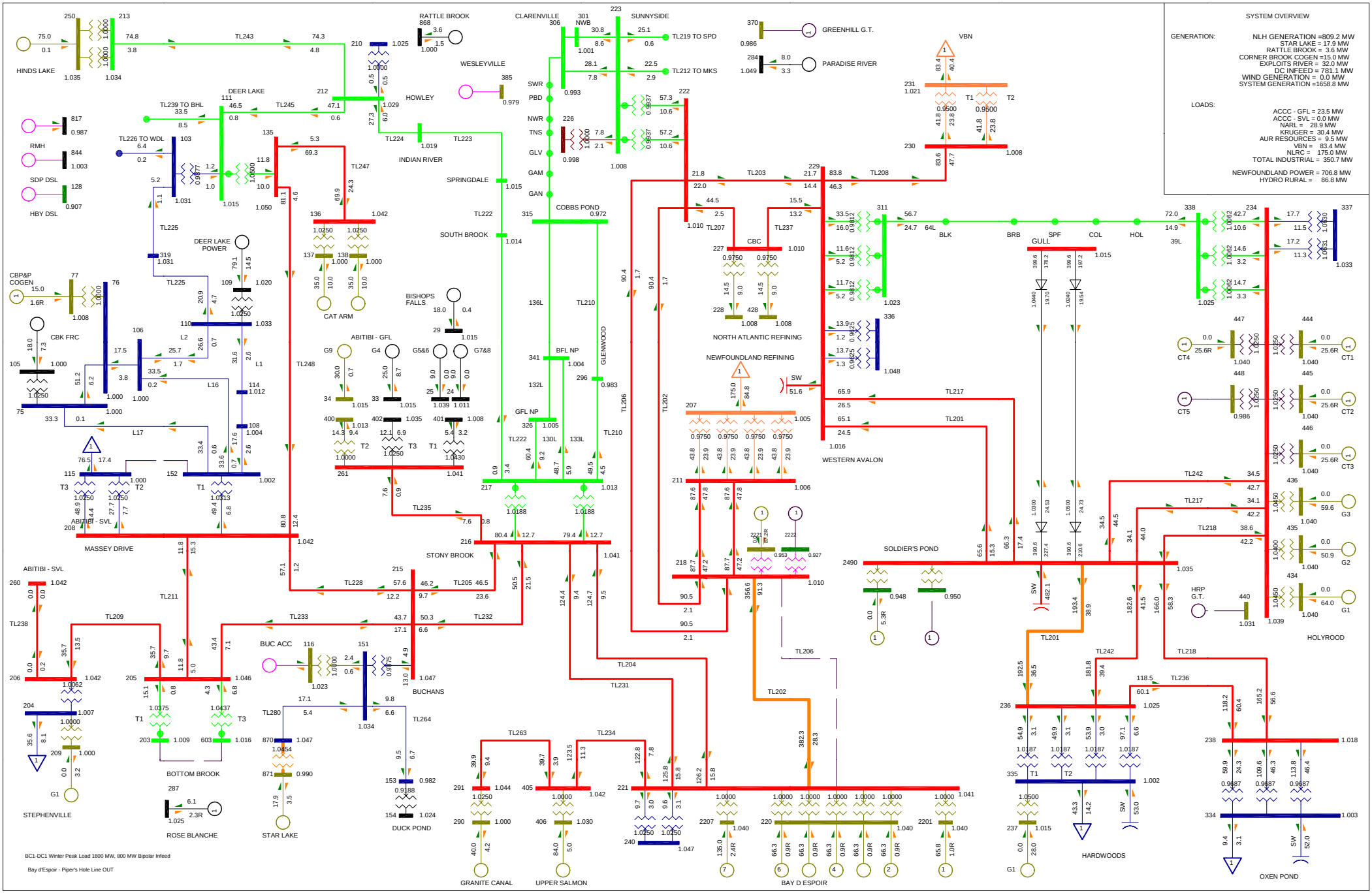
2. The conventional HVdc technology with the above mentioned series compensation is recommended. The dynamic performance of the system with the conventional HVdc is acceptable with the exception of voltage criteria violations under certain disturbances. These violations are considered as attributed to system inherent problems and can be dealt with separately.

3. There is a marginal benefit of the application of CCC HVdc technology, but due to uncertainties with its application this technology is not recommended.

Appendix A

Island Single Line Diagrams of Power Flows with 50% Series Compensation


SYSTEM OVERVIEW
GENERATION:
NLH GENERATION =795.4 MW
STAR LAKE = 17.9 MW
RATTLE BROOK = 3.6 MW
CORNER BROOK COGEN =15.0 MW
EXPLOITS RIVER = 32.0 MW
DC INFEED = 781.1 MW
WIND GENERATION = 0.0 MW
SYSTEM GENERATION =1645.0 MW
LOADS:
ACCC - GFL = 23.5 MW
ACCC - SVL = 0.0 MW
NARL = 28.9 MW
KRUGER = 30.4 MW
AUR RESOURCES = 9.5 MW
VBN = 83.4 MW
NLRC = 175.0 MW
TOTAL INDUSTRIAL = 350.7 MW
NEWFOUNDLAND POWER = 706.1 MW
HYDRO RURAL = 86.8 MW
HINDS LAKE
RATTLE BROOK
WESLEYVILLE
HOWLEY
INDIAN RIVER
DEER LAKE
DEER LAKE POWER
RMH
SDP DSL
HBY DSL
CBP&P COGEN
CBK FRC
CAT ARM
BISHOPS FALLS
ABITIBI - GFL
ABITIBI - SVL
MASSEY DRIVE
CLARENVILLE
SUNNYSIDE
GREENHILL G.T.
PARADISE RIVER
VBN
SPRINGDALE
SOUTH BROOK
COBBS POND
BFL NP
GFL NP
GLENWOOD
STONY BROOK
CBC
NORTH ATLANTIC REFINING
NEWFOUNDLAND REFINING
WESTERN AVALON
SOLDIER'S POND
GULL
BLK
BRB
SPF
COL
HOL
HRP G.T.
HOLYROOD
CT1
CT2
CT3
CT4
CT5
G1
G2
G3
ABITIBI - SVL
BUC ACC
BUCHANS
BOTTOM BROOK
STEPHENVILLE
ROSE BLANCHE
STAR LAKE
DUCK POND
GRANITE CANAL
UPPER SALMON
BAY D ESPOIR
HARDWOODS
OXEN POND
BC1-DC1 Winter Peak Load 1600 MW, 800 MW Bipolar Infeed
System Intact


SYSTEM OVERVIEW
GENERATION:
NLH GENERATION =809.2 MW
STAR LAKE = 17.9 MW
RATTLE BROOK = 3.6 MW
CORNER BROOK COGEN =15.0 MW
EXPLOITS RIVER = 32.0 MW
DC INFEED = 781.1 MW
WIND GENERATION = 0.0 MW
SYSTEM GENERATION =1658.8 MW
LOADS:
ACCC - GFL = 23.5 MW
ACCC - SVL = 0.0 MW
NARL = 28.9 MW
KRUGER = 30.4 MW
AUR RESOURCES = 9.5 MW
VBN = 83.4 MW
NLRC = 175.0 MW
TOTAL INDUSTRIAL = 350.7 MW
NEWFOUNDLAND POWER = 706.8 MW
HYDRO RURAL = 86.8 MW
HINDS LAKE
RATTLE BROOK
CLARENVILLE
SUNNYSIDE
GREENHILL G.T.
PARADISE RIVER
VBN
WESLEYVILLE
HOWLEY
DEER LAKE
TL239 TO BHL
TL226 TO WDL
RMH
SDP DSL
HBY DSL
INDIAN RIVER
SPRINGDALE
SOUTH BROOK
COBBS POND
BISHOPS FALLS
CAT ARM
DEER LAKE POWER
CBP&P COGEN
CBK FRC
ABITIBI - GFL
ABITIBI - SVL
MASSEY DRIVE
STONY BROOK
BUC ACC
BUCHANS
BOTTOM BROOK
STEPHENVILLE
ROSE BLANCHE
STAR LAKE
DUCK POND
GRANITE CANAL
UPPER SALMON
BAY D ESPOIR
CBC
NORTH ATLANTIC REFINING
NEWFOUNDLAND REFINING
WESTERN AVALON
SOLDIER'S POND
HRP G.T.
HOLYROOD
HARDWOODS
OXEN POND
BLK
BRB
SPF
COL
HOL
GULL
BC1-DC1 Winter Peak Load 1600 MW, 800 MW Bipolar Infeed
Bay d'Espoir - Piper's Hole Line OUT

Appendix B

Summary of Dynamic Performance Results

Case		Synchronous Condensers				Fault	Load Tripped	Min Transient Voltage After Fault clears (pu)			Min Frequency Deviation (pu)	Comm Fail ?	Stable ?	Notes
		Sunnyside SYNCS	SP SYNCHS	Holyrood SYNCHS	Holyrood CT-SYNCHS			Sunnyside	Soldiers Pond	Bay d'Espoir				
REFINERY LOAD IN - No Series Compensation on Bay d'Espoir Piper's Hole Lines - CONVENTIONAL DC														
NC1	1	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF BDE-PH (BDE)							NO	see case NC1.1a
	2	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF BDE-PH (mid)							NO	see case NC1.2a
	3	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF BDE-PH (PH)							NO	see case NC1.3a
	4	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF SSD-WAV		0.75	0.90	0.82	0.983	YES	YES	
	5	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF SP-WAV		0.86	0.94	0.87	0.978	YES	YES	
	6	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	BF LGF SP-WAV		0.70	0.92	0.70	0.973	YES	YES	
	1a	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF BDE-PH (BDE)	175 MW refinery						NO	
	2a	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF BDE-PH (mid)	175 MW refinery	0.81	0.90	0.74	0.987	YES	YES	
	3a	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF BDE-PH (PH)	175 MW refinery	0.80	0.91	0.79	0.989	YES	YES	
REFINERY LOAD IN - Series Compensation on Bay d'Espoir Piper's Hole Lines - CONVENTIONAL DC														
SC1	1	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF BDE-PH (BDE)							NO	see case SC1.1a
	2	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF BDE-PH (mid)							NO	see case SC1.2a
	3	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF BDE-PH (PH)		0.75	0.90	0.82	0.983	YES	YES	
	4	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF SSD-WAV		0.81	0.90	0.89	0.983	YES	YES	
	5	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF SP-WAV		0.93	0.95	0.98	0.979	YES	YES	
	6	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	BF LGF SP-WAV		0.92	0.97	0.94	0.974	YES	YES	
	1a	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF BDE-PH (BDE)	175 MW refinery	0.67	0.87	0.60	0.986	YES	YES	
	2a	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF BDE-PH (mid)	175 MW refinery	0.64	0.86	0.65	0.981	YES	YES	
	3a	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF BDE-PH (PH)	175 MW refinery	0.82	0.92	0.90	0.990	YES	YES	
REFINERY LOAD IN - No Series Compensation on Bay d'Espoir Piper's Hole Lines - CCC														
NC2	1	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF BDE-PH (BDE)		0.969	1.006	0.992	N/A	NO	YES	
	2	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF PH-BDE (mid)		0.97	1.01	1.04	N/A	NO	YES	
	3	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF PH-BDE (PH)							NO	see case NC2.3a
	4	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF SSD-WAV		0.82	0.86	0.90	0.981	YES	YES	
	5	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF SP-WAV		0.90	0.92	0.93	0.981	YES	YES	
	6	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	BF LGF SP-WAV		0.87	0.80	0.82	0.978	YES	YES	
	3a	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF PH-BDE (PH)	175 MW refinery	0.82	0.88	0.80	0.986	YES	YES	
REFINERY LOAD IN - Series Compensation on Bay d'Espoir Piper's Hole Lines - CCC														
SC2	1	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF BDE-PH (BDE)		1.00	1.02	1.04		NO	YES	
	2	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF PH-BDE (mid)		1.00	1.02	1.04		NO	YES	
	3	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF PH-BDE (PH)		0.79	0.87	0.88	0.98	YES	YES	
	4	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF SSD-WAV		0.88	0.86	0.97	0.981	YES	YES	
	5	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	3PF SP-WAV		0.94	0.93	1.00	0.982	YES	YES	
	6	1-300 MIL	1-300 MIL	3	4 @ Pipers Hole	BF LGF SP-WAV		0.90	0.89	0.97	0.98	YES	YES	

Summary of Dynamic Performance Results with New 175 MW Refinery Load In-Service

Case		Synchronous Condensers				Fault	Load Tripped	Min Transient Voltage After Fault clears (pu)			Min Frequency Deviation (pu)	Comm Fail ?	Stable ?	Notes
		Sunnyside SYNCS	SP SYNCHS	Holyrood SYNCHS	Holyrood CT-SYNCHS			Sunnyside	Soldiers Pond	Bay d'Espoir				
REFINERY LOAD OUT - No Series Compensation on Bay d'Espoir Piper's Hole Lines - CONVENTIONAL DC														
NC3	1	1-300 MIL	1-300 MIL	3	4 @ Holyrood	3PF BDE-PH (BDE)							NO	see case SC3.1
	2	1-300 MIL	1-300 MIL	3	4 @ Holyrood	3PF BDE-PH (mid)		0.87	0.94	0.86	0.980	YES	YES	
	3	1-300 MIL	1-300 MIL	3	4 @ Holyrood	3PF BDE-PH (PH)		0.82	0.94	0.85	0.981	YES	YES	
	4	1-300 MIL	1-300 MIL	3	4 @ Holyrood	3PF SSD-WAV		0.84	0.94	0.93	0.982	YES	YES	
	5	1-300 MIL	1-300 MIL	3	4 @ Holyrood	3PF SP-WAV		0.94	0.96	0.95	0.977	YES	YES	
	6	1-300 MIL	1-300 MIL	3	4 @ Holyrood	BF LGF SP-WAV		0.83	0.95	0.86	0.971	YES	YES	
REFINERY LOAD OUT - Series Compensation on Bay d'Espoir Piper's Hole Lines - CONVENTIONAL DC														
SC3	1	1-300 MIL	1-300 MIL	3	4 @ Holyrood	3PF BDE-PH (BDE)		0.78	0.92	0.80	0.979	YES	YES	
	2	1-300 MIL	1-300 MIL	3	4 @ Holyrood	3PF BDE-PH (mid)		0.78	0.91	0.85	0.975	YES	YES	
	3	1-300 MIL	1-300 MIL	3	4 @ Holyrood	3PF BDE-PH (PH)		0.86	0.95	0.94	0.982	YES	YES	
	4	1-300 MIL	1-300 MIL	3	4 @ Holyrood	3PF SSD-WAV		0.88	0.94	0.95	0.983	YES	YES	
	5	1-300 MIL	1-300 MIL	3	4 @ Holyrood	3PF SP-WAV		0.97	0.97	1.01	0.979	YES	YES	
	6	1-300 MIL	1-300 MIL	3	4 @ Holyrood	BF LGF SP-WAV		0.94	0.99	0.99	0.973	YES	YES	
REFINERY LOAD OUT - No Series Compensation on Bay d'Espoir Piper's Hole Lines - CCC														
NC4	1	1-300 MIL	1-300 MIL	3	4 @ Holyrood	3PF BDE-PH (BDE)		0.98	1.005	1.001	N/A	NO	YES	
	2	1-300 MIL	1-300 MIL	3	4 @ Holyrood	3PF BDE-PH (mid)		0.98	1.005	1.04	N/A	NO	YES	
	3	1-300 MIL	1-300 MIL	3	4 @ Holyrood	3PF BDE-PH (PH)		0.85	0.93	0.84	0.978	YES	YES	
	4	1-300 MIL	1-300 MIL	3	4 @ Holyrood	3PF SSD-WAV		0.91	0.92	0.97	0.98	YES	YES	
	5	1-300 MIL	1-300 MIL	3	4 @ Holyrood	3PF SP-WAV		0.96	0.95	1.01	0.981	YES	YES	
	6	1-300 MIL	1-300 MIL	3	4 @ Holyrood	BF LGF SP-WAV		0.86	0.85	0.94	0.977	YES	YES	
REFINERY LOAD OUT - Series Compensation on Bay d'Espoir Piper's Hole Lines - CCC														
SC4	1	1-300 MIL	1-300 MIL	3	4 @ Holyrood	3PF BDE-PH (BDE)		0.95	0.98	0.92		NO	YES	
	2	1-300 MIL	1-300 MIL	3	4 @ Holyrood	3PF BDE-PH (mid)		0.85	0.86	0.8	0.996	NO	YES	
	3	1-300 MIL	1-300 MIL	3	4 @ Holyrood	3PF BDE-PH (PH)		0.89	0.85	0.98	0.98	YES	YES	
	4	1-300 MIL	1-300 MIL	3	4 @ Holyrood	3PF SSD-WAV		0.95	0.93	1.01	0.981	YES	YES	
	5	1-300 MIL	1-300 MIL	3	4 @ Holyrood	3PF SP-WAV		0.99	0.95	1.02	0.983	YES	YES	
	6	1-300 MIL	1-300 MIL	3	4 @ Holyrood	BF LGF SP-WAV		0.95	0.93	0.98	0.979	YES	YES	

Summary of Dynamic Performance Results with New 175 MW Refinery Load Out-of-Service

Appendix C

Results for Conventional HVdc with 175 MW New Refinery Load In-Service

Appendices C through F not filed

APPENDIX C5 – DC1020 VOLUME 4 HVDC SYSTEM INTEGRATION STUDY - MULTI-TERMINAL HVDC LINK PSSE STABILITY MODEL – MAY 2008

HYDRO
THE POWER OF COMMITMENT

THE Lower Churchill PROJECT

May 2008

DC1020 - HVdc System Integration Study

Volume 4 - Multi-Terminal HVdc Link PSSE Stability Model

prepared by

HATCH™

in association with

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SIGNATURE
May 27/08
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Executive Summary

A custom user-written two-timestep PSSE transient stability model representing the Lower Churchill multi-terminal HVdc link has been developed for use in future PSSE studies. The model represents the dynamics of the HVdc overhead lines and cables, and includes simplified fast HVdc closed-loop controls that are directly based on the controls used in the PSCAD electromagnetic transients model.

PSSE model validation was performed against the same PSCAD model as was used in the WTO DC1020 transient stability studies. Validation testing showed excellent correlation between the PSSE and PSCAD dynamic performance for most faults during various powerflow and HVdc configurations. Any differences in results can be attributed to inherent differences between the three-phase switching solution used in an electromagnetic transient program, such as PSCAD, and the positive-sequence phasor-based solution of transient stability software, such as PSSE. Validation testing provided excellent comparability within the degree possible between two such different types of models.

The PSSE multi-terminal HVdc model was programmed to be capable of operating in bipolar or monopolar modes for the following HVdc configurations:

1. 3-terminal: Gull Island – rectifier, Soldiers Pond – inverter, Salisbury – inverter
2. 2-terminal: Soldiers Pond – rectifier, Salisbury – inverter
3. 2-terminal: Salisbury – rectifier, Soldiers Pond – inverter

Validation testing was performed on various powerflows to demonstrate the PSSE model performance of all three of the HVdc configurations listed above.

The validation testing was performed using the PSCAD version 4.2.1 software package and the PSSE version 30.2 software package.

Instructions on how to use the model are contained in the last section of this report.

1. Introduction

This report provides end-user instructions and validates the custom PSSE transient stability model of the multi-terminal high voltage direct current ("HVdc") link that was developed specifically for the Lower Churchill Project for work task order ("WTO") DC1020. This report discusses the results of the validation testing that was performed against the same PSCAD model that was developed and used for the transient-stability studies portion of WTO DC1020.

The multi-terminal HVdc PSSE stability model represents the three-terminal HVdc bipole connecting Gull Island (Station A) in Labrador, Soldiers Pond (Station B) in Newfoundland Island and Salisbury (Station C) in New Brunswick.

The standard PSSE library contains only a response-type model for a multi-terminal HVdc link. This response-type model does not include any of the DC line/cable dynamics, nor does it model any of the HVdc closed-loop controls. Such a model also requires that one of the inverters be operated in voltage-control mode, which is not consistent with the control scheme used by the PSCAD model in the transient stability analysis. Therefore, a custom model of the multi-terminal HVdc link was developed for use in future PSSE studies to represent the response of the multi-terminal HVdc system more accurately. This custom model is based on a two-timestep algorithm that allows for detailed controls and for HVdc overhead line and cable dynamics to be represented while still ensuring numerical stability. For more detailed information on response-type models compared to the two-timestep model, please refer to [1].

Validation testing was performed using the PSCAD version 4.2.1 software package and the PSSE version 30.2 software package.

1.1 Objectives

The objectives of the PSSE multi-terminal HVdc stability model development are to:

1. Develop a custom PSSE stability model of the multi-terminal HVdc link using simplified controls that are based on the PSCAD model used in the transient stability studies of WTO DC1020.
2. Develop a PSSE IPLAN program to provide a simple method for the end user to set up a desired powerflow on the HVdc link in the PSSE loadflow program so that the model will initialize properly for use with the custom PSSE stability model.
3. Validate the PSSE stability model against the PSCAD model for various loadflows and contingencies.

1.2 Procedure

The PSSE model was developed using the following procedure:

1. Create simplified controls based on the detailed PSCAD model for inclusion with the PSSE model.
2. Write the Fortran code to represent the multi-terminal HVdc overhead lines and cables and the DC controls for use in PSSE.

3. Validate the PSSE model by comparing dynamic performance of the PSSE model to the PSCAD model for various contingencies during various powerflow scenarios.
4. Provide instructions for the end user to implement and use the custom PSSE model.

2. PSSE Model – HVdc Configurations

The loadflow portion of the Lower Churchill multi-terminal HVdc model is set up using two PSSE multi-terminal DC line models (one for each pole of the bipole) and a series of filter shunt branches connected to the three existing system buses that will become the commutating buses of the HVdc link, namely Gull Island 230 kV bus, Soldiers Pond 230 kV bus, and Salisbury 345 kV bus. Appendix A shows this setup in an equivalent voltage-source test system, along with the PSSE bus numbers used in this test system.

As the electrode lines and ground resistances are of no impact in bipolar mode, ground resistances of each electrode and each electrode line are modeled only if the HVdc link is operating in monopolar mode. A provided IPLAN program (LCPDC.irf, as described in Section 6 herein) can be used to set up the desired HVdc configuration and powerflow, and will automatically insert the appropriate ground resistance and electrode line parameter values into the HVdc model if the user chooses to operate in monopolar mode.

The IPLAN program takes the zero impedance branches that connect each filter to the commutating bus in or out of service as needed.

The PSSE multi-terminal HVdc dynamic model was programmed to be capable of operating in bipolar or monopolar modes for the following HVdc configurations:

1. 3-terminal: Gull Island – rectifier, Soldiers Pond – inverter, Salisbury – inverter
2. 2-terminal: Soldiers Pond – rectifier, Salisbury – inverter
3. 2-terminal: Salisbury – rectifier, Soldiers Pond – inverter

Please note that the PSSE model has been programmed only to model monopolar operation in which all three terminals are operating in monopolar mode, i.e. an entire pole is out-of-service. Mixed mode operation where two terminals operate bipolar and the third terminal operates monopolar is not currently supported within the model.

While in reality it will be possible to operate any of the three terminals as rectifier or inverter, it was not possible to include all of the combinations of configurations in the PSSE model due to time constraints. The three HVdc configurations that are included in the PSSE model were chosen because they demonstrate the feasibility and worst case configurations of the multi-terminal link. Gull Island as inverter was not included as it is assumed this would be the least likely mode of operation of the Lower Churchill HVdc link.

3. PSCAD and PSSE Model Descriptions

This report compares results from two different models:

- PSSE Transient Stability Lower Churchill HVdc Model
- PSCAD (Electromagnetic Transient) Lower Churchill HVdc Model

PSSE Transient Stability is the main focus of this report. The PSSE transient stability solution is a fundamental frequency phasor-based solution, and does not represent switching harmonics or individual phase quantities. A typical timestep used in PSSE simulation is a half-cycle, or 8.33 ms, which is large relative to that used in PSCAD simulations. Accordingly, the user-written model alone is run at a smaller internal timestep in order to maintain numerical stability due to the small integration timesteps of the HVdc current, voltage, and gamma controllers, and to the differential equations associated with the line and cable capacitances and inductances. Since the PSSE model is a phasor-based solution and does not represent individual thyristors, commutation failures cannot be modeled accurately. In order to represent the response to a commutation failure of the HVdc link, the inverter is forced into "bypass" mode if the inverter extinction angle gamma falls below a certain internal model setpoint. This setpoint represents the minimum extinction angle below which the converter is assumed to fail commutation.

The PSCAD model is the actual project model used in the transient stability studies for WTO DC1020. It represents the details of all of the converter controls, including the DC converter current, voltage, and gamma controllers along with low level valve firing controls to produce firing pulses used to turn individual thyristors on and off. Filtering functions for signal measurement and conditioning are used to remove the harmonics generated by the converter. This model is the more accurate of the two, since it represents all parts of the control system and does not make any approximations. In electromagnetic transient simulation, network equations are solved at a series of discrete intervals (timesteps). A typical timestep used in a PSCAD simulation is 50 μs.

More accurate than the PSSE Transient Stability model, the PSCAD model includes all of the low-level firing controls, as well as the non-linear aspects of the electrical grid (such as transformer saturation). The application and removal of the fault are also point-on-wave dependent in the PSCAD solution (i.e. the fault can be applied at a peak voltage or at a zero point), which can affect the initial control response. The controls in the PSCAD model also respond to certain events, such as the detection of commutation failures and the sensing of individual phase voltages, which cannot be represented in the PSSE model. As such, more accurate results are expected with the PSCAD model. Transient stability programs, such as PSSE, produce only positive-sequence voltages.

4. Validation Testing – Description of Test Systems and Contingencies

4.1 Equivalent Test System

Validation of the PSSE model was first performed using an equivalent test system as shown in Appendix A. A test system with simple ac equivalents representing short-circuit levels of 8694 MVA at Gull Island (Station A), 2994 MVA at Soldiers Pond (Station B) and [redacted] MVA at Salisbury (Station C) were used. The Gull Island terminal was operated in a bipolar configuration as the rectifier, supplying rated power to the Soldiers Pond and Salisbury terminals, both operating as inverters.

For all dynamic simulations, loads were modeled with the real power portion as constant current loads and with the reactive power portion as constant impedance loads.

The frequency controller at Soldiers Pond was enabled for all simulations.

4.2 Reduced PSSE Model Test System

Validation testing was then performed using the reduced Newfoundland Island and Labrador ac systems PSSE model, the same model representation as was used to perform the transient stability studies in PSCAD. The New Brunswick ac system remained as an equivalent voltage source.

In each of the three possible HVdc configurations that can be simulated with the PSSE model (as described in Section 3) it is possible to run any of them in bipolar or monopolar operation, resulting in a total of six possible HVdc configurations. Monopolar operation was only tested on the three-terminal HVdc configuration as it can be assumed that this validation testing can be extended to both of the two-terminal configurations.

The two two-terminal HVdc configurations, one in which Soldiers Pond is the rectifier and the other in which Salisbury is the rectifier, were tested in bipolar operation using powerflow cases BC8-DC8 and BC1-DC7 respectively.

In order to test the four HVDC configurations described above, the following powerflows were used for validation testing (please refer to the report for the Transient Stability Studies of WTO DC1020 [2] for detailed descriptions of the powerflow cases):

BC1-DC1 - Rated bipolar operation with Gull Island as rectifier and Soldiers Pond and Salisbury as inverters (3-terminal)

BC2-DC3 - Monopolar operation with Gull Island as rectifier and Soldiers Pond at 1.5 pu and Salisbury at 1.1 pu overload as inverters (3-terminal)

BC8-DC8 - Bipolar operation with Soldiers Pond as rectifier supplying 175 MW to Salisbury (2-terminal)

BC1-DC7 - Bipolar operation with Salisbury as rectifier supplying rated power to Soldiers Pond (2-terminal)

4.3 Contingencies

The test cases that were simulated are listed in Table 1. Results for all cases comparing the PSCAD model and PSSE model are provided in Appendices 3-7. The PSSE model validation tests were run with the default PSSE timestep of 8.33 ms.

Table 1
Test Case Descriptions

Test No.	Contingency No. [2]	Power Flow Case	Power Flow Description	Test Description
T1.1	n/a	EQUIV	Equivalent Voltage Source System representing BC1-DC1. [See Appendix C]	**DC Voltage Reference Step at Station A.** 1.0 pu -> 0.95 pu -> 1.0 pu
T1.2	n/a	EQUIV		**DC Current Reference Step at Station B.** 1.0 pu -> 0.95 pu -> 1.0 pu
T1.3	n/a	EQUIV		**DC Current Reference Step at Station C.** 1.0 pu -> 0.95 pu -> 1.0 pu
T1.4	n/a	EQUIV		**3PF at Station A to 0% voltage for 100 ms.** No equipment tripping.
T1.5	n/a	EQUIV		**3PF at Station B to 0% voltage for 100 ms.** No equipment tripping.
T1.6	n/a	EQUIV		**3PF at Station C to 0% voltage for 100 ms.** No equipment tripping.
T1.7	n/a	EQUIV		**3PF at Station A to 50% voltage for 100 ms.** No equipment tripping.
T1.8	n/a	EQUIV		**3PF at Station B to 50% voltage for 100 ms.** No equipment tripping.
T1.9	n/a	EQUIV		**3PF at Station C to 50% voltage for 100 ms.** No equipment tripping.
T1.10	n/a	EQUIV		**3PF at Station A to 90% voltage for 100 ms.** No equipment tripping.
T1.11	n/a	EQUIV		**3PF at Station B to 90% voltage for 100 ms.** No equipment tripping.
T1.12	n/a	EQUIV		**3PF at Station C to 90% voltage for 100 ms.** No equipment tripping.
T2.1	C15	BC1-DC1	Bipolar three-terminal operation. Gull Island rectifier Soldiers Pond inverter – 1.0 pu Salisbury inverter – 1.0 pu 2016 winter peak Newfoundland Island load (1600 MW) [See Appendix D]	**3PF at Station B to 0% voltage for 100 ms.** No equipment tripping.
T2.2	C60	BC1-DC1		**3PF at Station A to 0% voltage for 100 ms.** No equipment tripping.
T2.3	C70	BC1-DC1		**3PF at Station C to 0% voltage for 100 ms.** No equipment tripping.
T2.4	C17	BC1-DC1		**3PF at Bay d'Espoir 230 kV bus.** Trip Bay d'Espoir – Pipers Hole line and refinery load.
T2.5	C18	BC1-DC1		**3PF at Pipers Hole 230 kV bus.** Trip Pipers Hole – Sunnyside line.
T2.6	C19	BC1-DC1		**3PF at Sunnyside 230 kV bus.** Trip Sunnyside – Western Avalon line.
T2.7	C20	BC1-DC1		**3PF at Western Avalon 230 kV bus.** Trip Western Avalon – Soldiers Pond line.
T2.8	C21	BC1-DC1		**3PF at Soldiers Pond 230 kV bus.** Trip Soldiers Pond – Hardwoods line.
T2.9	C22	BC1-DC1		**3PF at Oxen Pond 230 kV bus.** Trip Oxen Pond – Soldiers Pond line.

Test No.	Contingency No. [2]	Power Flow Case	Power Flow Description	Test Description
T2.10	C23	BC1-DC1		**3PF at Holyrood 230 kV bus.** Trip Holyrood – Soldiers Pond line.
T2.11	C72	BC1-DC1		**3PF at Pipers Hole 230 kV bus.** Trip Pipers Hole – Bay d'Espoir line.
T2.12	C26	BC1-DC1		**3PF at Pipers Hole 230 kV bus.** Trip Pipers Hole synchronous condenser.
T2.13	C28	BC1-DC1		**3PF at Soldiers Pond converter transformer 230 kV** Trip converter transformer and Pole 2.
T3.1	C15	BC2-DC3	Monopolar 3-terminal operation. Gull Island rectifier Soldiers Pond inverter – 1.5 pu overload Salisbury inverter – 1.1 pu overload Future winter peak Newfoundland Island load (1800MW) [See Appendix E]	**3PF at Station B to 0% voltage for 100 ms.** No equipment tripping.
T3.2	C60	BC2-DC3		**3PF at Station A to 0% voltage for 100 ms.** No equipment tripping.
T3.3	C70	BC2-DC3		**3PF at Station C to 0% voltage for 100 ms.** No equipment tripping.
T3.4	C17	BC2-DC3		**3PF at Bay d'Espoir 230 kV bus.** Trip Bay d'Espoir – Pipers Hole line and refinery load.
T3.5	C19	BC2-DC3		**3PF at Sunnyside 230 kV bus.** Trip Sunnyside – Western Avalon line.
T4.1	C15	BC8-DC8	Bipolar 2-terminal operation. Gull Island OFF Soldiers Pond rectifier Salisbury inverter – 175 MW Summer night Newfoundland Island load (625 MW) [See Appendix F]	**3PF at Station B to 0% voltage for 100 ms.** No equipment tripping.
T4.2	C70	BC8-DC8		**3PF at Station C to 0% voltage for 100 ms.** No equipment tripping.
T4.3	C17	BC8-DC8		**3PF at Bay d'Espoir 230 kV bus.** Trip Bay d'Espoir – Pipers Hole line and refinery load.
T4.4	C19	BC8-DC8		**3PF at Sunnyside 230 kV bus.** Trip Sunnyside – Western Avalon line.
T5.1	C15	BC1-DC7	Bipolar 2-terminal operation. Gull Island OFF Soldiers Pond inverter – 1.0 pu Salisbury rectifier 2016 winter peak Newfoundland Island load (1600 MW) [See Appendix G]	**3PF at Station B to 0% voltage for 100 ms.** No equipment tripping.
T5.2	C70	BC1-DC7		**3PF at Station C to 0% voltage for 100 ms.** No equipment tripping.
T5.3	C26	BC1-DC7		**3PF at Pipers Hole 230 kV bus.** Trip Pipers Hole synchronous condenser.

5. Validation Testing – Comparison of PSSE and PSCAD Models

The steady-state and dynamic performance of the PSSE model compares very well to the PSCAD model. Despite inherent differences between the models the comparability of results between the two models is excellent, and correlations are within the degree of accuracy possible given that PSCAD and PSSE use different main program solution methods.

The PSSE Transient Stability model compares very well to the PSCAD model; however, there are some slight differences evident in some cases. The controls for the converter are not represented in full detail in the PSSE model, and a simplified control system has been assumed to be sufficiently accurate and practical for the purposes of transient stability modeling.

Since the PSSE model is a phasor-based solution and does not represent individual thyristors, commutation failures cannot be modeled accurately. In order to represent the response of the HVdc link to a commutation failure, the inverter is forced into "bypass" mode if the inverter firing angle gamma falls below a certain internal model setpoint. Therefore, disturbances that result in a commutation failure in PSCAD may look slightly different in PSSE.

Another inherent difference between the PSCAD and PSSE models is the measurement of the voltages and real and reactive powerflows in these models. The PSCAD method of determining an RMS quantity uses instantaneous three-phase inputs; whereas in PSSE the RMS value is calculated directly.

The measurement of frequency is also different between the PSCAD and PSSE models. In the PSCAD model, the frequency measurement is based on a real-world algorithm in which instantaneous bus voltages are processed via an industry-accepted method used for measuring frequency. In the PSSE model, the frequency measurement is simply taken as the derivative of the bus angle. Due to fast changes in the current injected from the PSSE model, it was seen for certain faults in PSSE that numerical spikes in frequency were possible depending on the fault location. In order to remove or lessen these spikes in frequency, the time constant for the frequency filter used in PSSE was set to 100ms instead of the default 33.3ms. For the two-terminal mode of operation in which Salisbury is operating as the rectifier sending power to Soldiers Pond, frequency spikes at Salisbury that were caused by disturbances in the Newfoundland Island system that resulted in a commutation failure at Soldiers Pond require the frequency filter time constant to be set even higher, up to 200ms. The frequency filter is used to remove numerical issues associated with the PSSE frequency measurement. The time constant for this filter can be modified using the ALTR -> Solution Parameters command in the PSSE dynamics program.

To summarize, the most important issue is that the PSSE model injects the correct currents such that the real and reactive powers at the AC buses – and especially the AC bus voltages – look as close to those of the PSCAD model as possible. The AC bus voltage responses between PSCAD to PSSE compare very well. The upcoming section discusses the test results in more detail.

5.1 Results – Equivalent Test System

PSSE results for the validation testing performed on the equivalent test system provide a good comparison with PSCAD.

Some differences are notable in a few cases, particularly the 50% faults in which the HVdc system is on the verge of switching control modes on fault recovery. In some of the PSCAD cases this control mode switching occurs; whereas the PSSE model does not quite switch control modes. It is important to note that control mode switchover can have a noticeable impact on the overall response of the converter. Therefore, responses of the two models look slightly different.

In addition, some slight differences can be seen in current reference responses during fault cases. This is due to the fact that these current references are non-linear functions that are very dependent on the DC-voltage responses (due to voltage-dependent current limits). Any slight difference in DC-voltage response will cause a difference in DC current order.

Despite slight differences as described above, the overall trend of the responses between PSCAD and PSSE are very similar, and become nearly identical by several hundred milliseconds after fault clearing.

Please note that the PSCAD AC voltages are RMS measurements that have a smoothing time constant of 20ms, whereas the PSSE AC voltages are not smoothed, with the exception of the ac voltage measurements on the commutating buses that are coming from measurements inside the custom PSSE HVdc model; these three PSSE AC commutating bus voltages have a smoothing time constant of 8ms which is still not the same as PSCAD. Therefore the ac voltages look slightly different especially on fault application and clearing.

Results for the equivalent test system are provided in Appendix C.

5.2 Results – Reduced PSSE Model Test Systems

Results for the validation testing performed on the reduced PSSE model test systems provide a good comparison with PSCAD as well.

The same comments can be made for these cases as was described for the equivalent test system in Section 5.1.

In addition to these comments, it should be noted that the 300 MVAR synchronous condensers modeled at Pipers Hole and Soldiers Pond do not model the same exciters in PSSE and PSCAD. The PSCAD model includes a more detailed and better exciter model, which was not available in the PSSE library. Therefore, the differences in responses of the synchronous condensers in PSCAD and PSSE are sometimes cause for slight differences in voltage and reactive power quantities in the Newfoundland Island ac system, particularly for faults near to the synchronous condensers.

Also is should be noted that good correlation was seen between the frequency responses of the PSSE and PSCAD models, except during faults. This is because the PSCAD frequency measurement stops

measuring during a fault whereas the PSSE model does not, therefore the frequency response during a fault cannot be fairly compared between the two models.

Results for the reduced PSSE model test systems are provided in Appendices D-G.

Please note that for the BC8-DC8 cases in which the Soldiers Pond terminal is exporting to the Salisbury terminal, the transient stability studies determined that the worst case Bay d'Espoir-Pipers Hole fault (contingency 17) requires a fast runback of the HVdc in order to maintain ac system stability on the Newfoundland Island. The custom PSSE model does not include this runback scheme and so this contingency is not shown in the validation testing.

6. Model Use Instructions for End User

6.1 Model Files Delivered

The following files were delivered in electronic format. All testing was performed on Windows XP platform, PSSE Version 30.2.

CLCPDC.obj	Lower Churchill HVdc dynamic controls and line/cable model compiled code
LCP_HVDC.dyr	HVdc model dynamic data input file
LCP_HVDC.raw	Powerflow raw data file corresponding to BC1-DC1 powerflow case, 1600 MW Gull Island rectifier, 800 MW Soldiers Pond Inverter, 800 MW Salisbury inverter (rated)
LCPDC.ipl	IPLAN program code for user to set up a valid powerflow operating point for the Lower Churchill HVdc link
LCPDC.irf	Compiled IPLAN program
LCP_input.dat	Input text file containing commutating bus and filter bus numbers, required by IPLAN program.
Test-System.raw*	Equivalent test system powerflow data file corresponding to powerflow BC1-DC1
Test-System.dyr	Equivalent test system dynamic data file corresponding to powerflow BC1-DC1

*If other test systems representing different HVdc powerflows are required, the provided IPLAN program can be used on the test system powerflow case provided to move to a different operation point. Please see Section 6.3 herein, describing the IPLAN program.

6.2 Notes for First Time Model Use

Prior to performing a dynamic simulation with the Lower Churchill HVdc link in PSSE, the following steps must be taken:

1. The HVdc link and associated equipment must be added to the existing large system loadflow SAV case, as shown in the provided LCP_HVdc.raw file. PLEASE NOTE: The bus numbers associated with the rectifier and inverter commutating buses, the filter buses, and the DC line numbers associated with both HVdc poles can be changed to whatever new bus/line numbers are desired; however, the DYR file must then be changed to match the loadflow configuration (step 3, below). The filters are connected to the ac commutating buses through zero impedance branches and are represented as bus shunts. All circuit IDs for these zero impedance branches should be "1".

2. The provided HVdc controls and line/cable dynamics model file, titled "CLCPDC.obj", must be placed with other model object files.

3. The contents of the provided dynamic data file, titled "LCP_HVDC.dyr", must be added into the existing large system SNP snapshot file. PLEASE NOTE: The bus numbers associated with the rectifier and inverter commutating buses as well as the filter buses must be changed to match the loadflow configuration.

6.3 IPLAN Program to Move to a New HVdc Loadflow Operating Point

Once the model has been added to a powerflow case (as described in Section 7.2), the provided IPLAN program, LCPDC.irf, should be used to automatically set up the desired operating point of the HVdc link in the powerflow case.

The IPLAN program contains all of the filter-switching logic. It also ensures that a minimum number of filters are in service for harmonic performance requirements. The PSSE network solution will automatically determine the converter transformer tap-changer setpoints based on the firing angle limits as set in the provided loadflow HVdc data.

Before running the IPLAN program the user must ensure the text file titled "LCP_input.dat" contains the PSSE bus numbers of the commutating buses and the filter buses. An example text file has been included in the model files with bus numbers matching those used in the test system. These numbers should be modified to match the actual loadflow case being used.

The user will be asked to provide the following inputs to the IPLAN program:

```
------------------------
```

1. Whether the HVdc link is to be operated in bipolar or monopolar mode.

```
-------------------------

SELECT THE NUMBER OF POLES IN OPERATION (NORMAL MODE IS BIPOLAR OPERATION):
1 = MONOPOLAR OPERATION
2 = BIPOLAR OPERATION
(IF MONOPOLAR OPERATION IS SELECTED, THEN THE NEGATIVE POLE WILL BE BLOCKED)
```

2. The user is allowed to select from the following HVdc configurations. The PSSE model is programmed to operate in one of only three configurations.

```
-------------------------
SELECT FROM THE FOLLOWING THREE HVdc CONFIGURATIONS (NORMAL CONFIGURATION IS NO 1):
 CONFIG NO   GULL ISLAND   SOLDIERS POND     SALISBURY
     1        RECTIFIER     INVERTER          INVERTER
     2        BLOCKED       RECTIFIER         INVERTER
     3        BLOCKED       INVERTER          RECTIFIER

 ENTER CONFIG NO?(1,2,3)
```

3. Depending on the HVdc configuration selected in Step 2 above, the user will be asked first if they would like to change the inverter power order, and, if so, what the desired power order is on a per-pole basis. The rated power at both Soldiers Pond and Salisbury during bipolar operation is 400 MW per pole. During monopolar operation the continuous overload rating at Soldier Pond is 1.5 pu and at Salisbury is 1.1 pu. Soldiers Pond can also operate at 2 pu overload for 10 minutes.

```
_____________________

  CURRENT SOLDIERS POND POWER ORDER (PER POLE)                     =   399.6(MW)
  CURRENT SOLDIERS POND INVERTER DC CURRENT MAGNITUDE              =   888.0(A)
  CURRENT MAGNITUDE OF DC POWER INFEED AT SOLDIERS POND (PER POLE) =   384.8(MW)
  CHANGE IT?(y/n)
  y
  ENTER SOLDIERS POND INVERTER OUTPUT POWER
  (MAGNITUDE OF SCHEDULED POWER IN MW, PER POLE)
    300.0 MW
 -------------------------
  CURRENT SALISBURY POWER ORDER (PER POLE)                       =   399.6(MW)
  CURRENT SALISBURY INVERTER DC CURRENT MAGNITUDE                =   888.0(A)
  CURRENT MAGNITUDE OF DC POWER INFEED AT SALISBURY (PER POLE)   =   381.3(MW)
  CHANGE IT?(y/n)
  n
 -------------------------
```

4. Then the IPLAN will solve the powerflow using the PSSE activity FDNS (fast decoupled Newton solution) with input from the user as to the options for the solution.

```
-------------------------
  SETTING INITIAL FILTER STATUS
  ENTER OPTIONS FOR FDNS POWERFLOW SOLUTION

  TAP CODE IS 0 TO LOCK, 1 FOR STEPPING, 2 FOR DIRECT
  AREA INT CODE IS 0 TO DISABLE, 1 FOR TIE LINES ONLY, 2 FOR TIE LINES AND LOADS

  ENTER:
  [TAP] , [AREA INT] , [1 FOR PHASE] , [1 TO FLAT] , [1 TO LOCK] , [1 TO LOCK ]
  [CODE]   [ CODE ]    [ SHIFTERS  ]   [  START  ]   [D.C. TAPS]   [SWCH SHNTS]
   1   ,            ,     1         ,             ,             ,
```

5. Then the IPLAN will output a powerflow summary of the HVdc operating point and filter statues, and indicate whether or not the powerflow solution reached convergence.

```
 POWERFLOW SOLUTION REACHED CONVERGENCE TOLERANCE
  -------------------------
  GULL ISLAND FILTER ADJUSTMENT

  REACTIVE POWERFLOW ABSORBED BY CONVERTER          =   723.4 (MVAR)
  REACTIVE POWERFLOW SUPPLIED BY FILTERS            =   820.2 (MVAR)
  REACTIVE POWER EXCHANGE WITH THE AC SYSTEM        =    96.8 (MVAR)
  NO CHANGE FOR FILTER STATUS

  -------------------------
  SOLDIERS POND FILTER ADJUSTMENT

  REACTIVE POWERFLOW ABSORBED BY CONVERTER          =   445.7 (MVAR)
  REACTIVE POWERFLOW SUPPLIED BY FILTERS            =   423.0 (MVAR)
  REACTIVE POWER EXCHANGE WITH THE AC SYSTEM        =   -22.6 (MVAR)
```

```
        NO CHANGE FOR FILTER STATUS

        -------------------------
        SALISBURY FILTER ADJUSTMENT

        REACTIVE POWERFLOW ABSORBED BY CONVERTER          =   451.0 (MVAR)
        REACTIVE POWERFLOW SUPPLIED BY FILTERS            =   394.3 (MVAR)
        REACTIVE POWER EXCHANGE WITH THE AC SYSTEM        =   -56.7 (MVAR)
        NO CHANGE FOR FILTER STATUS

-------------------------

         ------------------------------------------------------------
         |              FINAL FILTER STATUS:                         |
         ------------------------------------------------------------
         |FILTER NO      | GULL ISLAND | SOLDIERS POND | SALISBURY   |
         ------------------------------------------------------------
         |      0        |      1      |       1       |      1      |
         |      1        |      1      |       1       |      1      |
         |      2        |      1      |       1       |      1      |
         |      3        |      1      |       1       |      1      |
         |      4        |      1      |       1       |      1      |
         |      5        |      1      |       1       |      1      |
         |      6        |      1      |       1       |      1      |
         |      7        |      1      |       1       |      1      |
         |      8        |      0      |       0       |      0      |
         |      9        |      0      |       0       |      0      |
         ------------------------------------------------------------

         ------------------------------------------------------------
         |              POWERFLOW SUMMARY:                           |
         ------------------------------------------------------------
         |ACTIVE POWER   |  779.6(MW)  |  385.0(MW)    |  363.2(MW)  |
         |REACTIVE POWER*|   96.8(MVAR)|  -22.6(MVAR)  |  -56.7(MVAR)|
         |  DC CURRENT   | 1732.4(A)   |  888.0(A)     |  844.4(A)   |
         |  DC VOLTAGE   |  450.0(kV)  |  433.6(kV)    |  430.1(kV)  |
         ------------------------------------------------------------
         * EXCHANGE WITH AC SYSTEM
         -------------------------
```

6.4 Dynamic Model User – Settable Parameters – CONs and ICONs

The model data sheet is contained in Appendix B. The CONs (real constants) and ICONs (integer constants) are described below.

6.4.1 CONs

PREFDC_A (J): Power reference at Gull Island (Station A) (pu). The dynamic model will automatically initialize this CON to match the steady-state conditions of the loadflow case. This CON can be used dynamically to change the DC power reference, but should be changed only if Station A is operating as the inverter. However the PSSE model is not programmed to model Gull Island as an inverter in any of the HVdc configurations included in the PSSE model, therefore this CON should not be changed. The filter-switching logic is included in the dynamic model; however, tap-changer control is not included (due to the very slow action of tap-changer control). Therefore, the simulation should be accurate to

approximately 10 seconds, at which time tap changers would begin to act. The dynamic model should therefore not be used to move to a new steady-state operating point.

PREFDC_B (J+1): Power reference at Soldiers Pond (Station B) (pu). The dynamic model will automatically initialize this CON to match the steady-state conditions of the loadflow case. This CON can be used dynamically to change the DC power reference but should be changed only if Station B is operating as an inverter, i.e. only in HVdc configurations 1 and 3 [see Section 6.3 (2)]. The filter-switching logic is included in the dynamic model; however, tap-changer control is not included (due to the very slow action of tap-changer control). Therefore, the simulation should be accurate to approximately 10 seconds, at which time tap changers would begin to act. The dynamic model should therefore not be used to move to a new steady-state operating point.

PREFDC_C (J+2): Power reference at Salisbury (Station C) (pu). The dynamic model will automatically initialize this CON to match the steady-state conditions of the loadflow case. This CON can be used dynamically to change the DC power reference but should be changed only if Station C is operating as an inverter, i.e. only in HVdc configurations 1 and 2 [see Section 6.3 (2)]. The filter-switching logic is included in the dynamic model; however, tap-changer control is not included (due to the very slow action of tap-changer control). Therefore, the simulation should be accurate to approximately 10 seconds, at which time tap changers would begin to act. The dynamic model should therefore not be used to move to a new steady-state operating point.

Frequency Controller at B (J+3): 1 enables the frequency controller at Soldiers Pond (Station B); 0 disables it. Default 1.

Filter Switching (J+4): 1 enables the filter switching; 0 disables it. Default 0.
Filter switching was only enabled during validation testing when performing the power order ramping tests. Filter switching was disabled during fault testing.

HVdc Configuration (J+5): Default 1.
1. 3-terminal: Gull Island – rectifier, Soldiers Pond – inverter, Salisbury – inverter
2. 2-terminal: Soldiers Pond – rectifier, Salisbury – inverter
3. 2-terminal: Salisbury – rectifier, Soldiers Pond – inverter

6.4.2 ICONs

Please fill in the bus numbers as appropriate as described in the model data sheet contained in Appendix C.

*Please note the user is responsible to ensure the CONs and ICONs of the dynamic model match the loadflow setup [see Section 6.2].

6.5 Simulating a Power Ramp

In order to simulate a change in power reference at one or both inverters (depending on the HVdc configuration being studied), during the dynamic simulation the user must change the appropriate CON

to the desired per unit value: CON (J + 1) for Soldiers Pond as inverter, and CON (J + 2) for Salisbury as inverter. The CON associated with the rectifier power reference should not be changed; the CON should be changed only at the inverter ends.

It is also important to note that the inverter power references should be changed for both DC lines (poles) to be the same value. The custom model has not been programmed to operate with unbalanced bipolar operation. The ground currents, and hence HVdc losses, will be incorrect if the user attempts to operate the HVdc link in this manner.

6.6 Simulating a Permanent Block of One Pole

In order to simulate a permanent block of one of the HVdc poles, the user must change the control mode of the **SECOND*** multi-terminal DC line loadflow model to "blocked" or "0" during a dynamic simulation. The dynamic model will then automatically perform a permanent DC block of this line. Please note that the PSSE model is not intended for simulating a restart from a DC block. If the DC line is blocked, the model assumes it is a permanent block. If Soldiers Pond is an inverter, the model will automatically go to the 2 pu monopolar operation; if Salisbury is an inverter, the model will automatically go to the 1.1 pu monopolar operation.

*It is very important that it is the second of the two multi-terminal DC lines that is blocked, as the custom PSSE dynamic model requires this to be so.

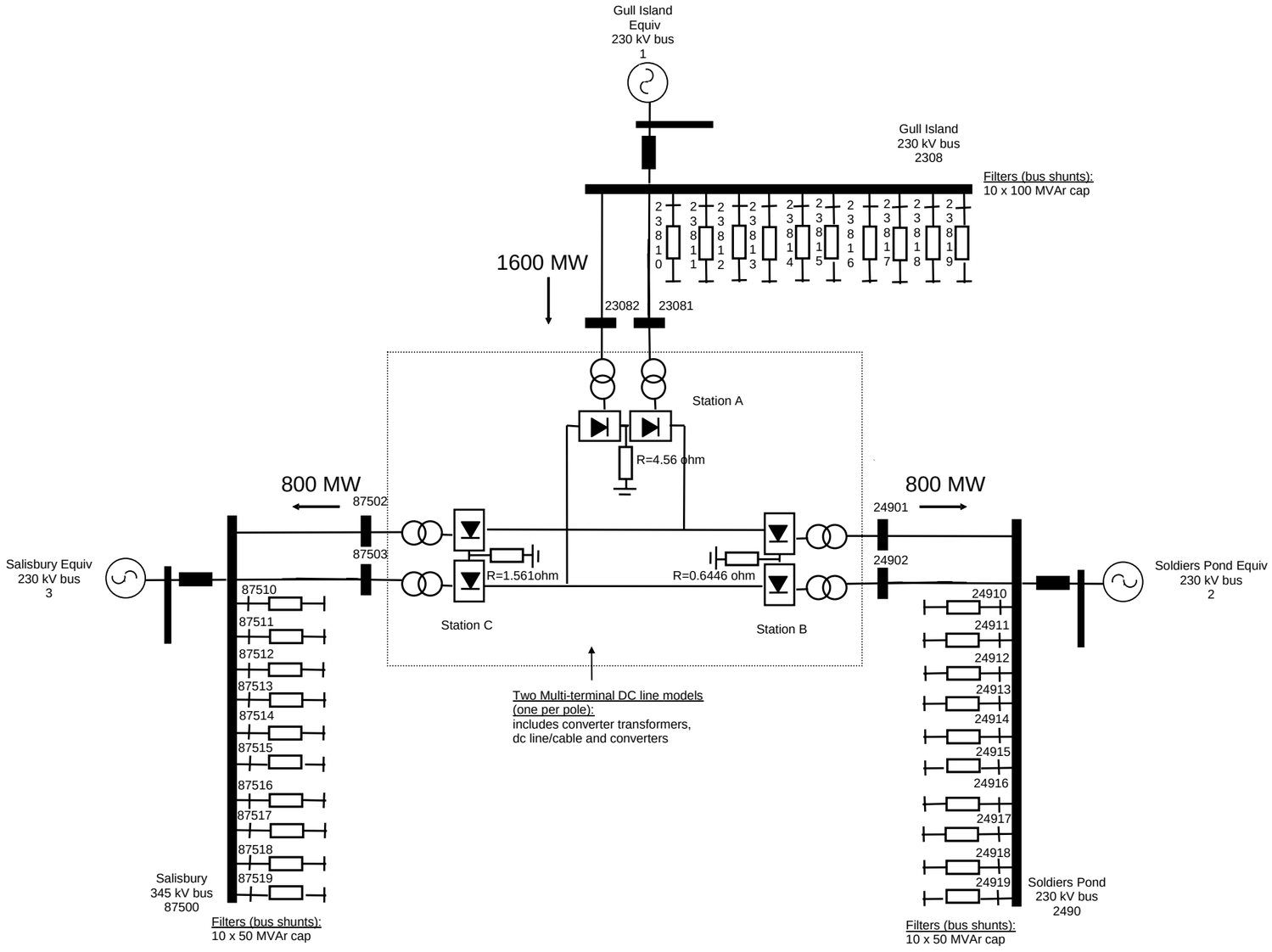
References

1. R.M. Brandt, U.D. Annakkage, D.P. Brandt, N. Kshatriya, "Validation of a Two-Time Step HVDC Transient Stability Model including Detailed HVDC Controls and DC Line L/R Dynamics," *Conference Proceedings,* IEEE Power Engineering Society General Meeting, Montreal, Canada, June 2006.

2. Newfoundland and Labrador Hydo Lower Churchill Project, "DC1020 – HVDC System Integration Study – Transient Stability Studies Report".

Appendix A

Diagram of Equivalent Test System


Gull Island
Equiv
230 kV bus
1
Gull Island
230 kV bus
2308
Filters (bus shunts):
10 x 100 MVAr cap
2381 0
2381 1
2381 2
2381 3
2381 4
2381 5
2381 6
2381 7
2381 8
2381 9
1600 MW
23082
23081
Station A
R=4.56 ohm
800 MW
87502
87503
R=1.561ohm
Station C
R=0.6446 ohm
Station B
800 MW
24901
24902
Salisbury Equiv
230 kV bus
3
87510
87511
87512
87513
87514
87515
87516
87517
87518
87519
Salisbury
345 kV bus
87500
Filters (bus shunts):
10 x 50 MVAr cap
Two Multi-terminal DC line models
(one per pole):
includes converter transformers,
dc line/cable and converters
24910
24911
24912
24913
24914
24915
24916
24917
24918
24919
Soldiers Pond
230 kV bus
2490
Filters (bus shunts):
10 x 50 MVAr cap
Soldiers Pond Equiv
230 kV bus
2

Appendix B

Lower Churchill HVdc PSSE Model Datasheet

TransGrid Solutions, Inc.

User Model Data Sheet
CLCPDC

LOWER CHURCHILL PROJECT HVDC INTERCONNECTOR MODEL

DC Line #_____I
This model uses CONs starting with #_____J
and STATEs starting with #_____K
and VARs starting with #_____L
and ICONs starting with #_____M

CONs *	#	Value	Description
J		1.0	PREFDC_A, Operator power reference at A (pu)
J+1		1.0	PREFDC_B, Operator power reference at B (pu)
J+2		1.0	PREFDC_C, Operator power reference at C (pu)
J+3		1	Frequency Controller at B Enable : 1, Disable : 0
J+4		0	Filter Switching Enable : 1, Disable : 0
J+5		1	HVDC Configuration 1 : A-Rec, B-Inv, C-Inv 2 : A-OFF, B-Rec, C-Inv 3 : A-OFF, B-Inv, C-Rec

STATEs	#	Description
K		IDC_A
K+1		IDC_B
K+2		VD
K+3		IDC_C
K+4		Not used
K+5		X_PI_A
K+6		X_PI_B
K+7		X_PI_C
K+8		KP_A
K+9		KP_B
K+10		KP_C
K+11		UREF_ADD1_A
K+12		UREF_ADD1_B
K+13		UREF_ADD1_C
K+14		UDMEAS_A
K+15		UDMEAS_B
K+16		UDMEAS_C
K+17		UDMEAS1_A
K+18		UDMEAS1_B
K+19		UDMEAS1_C
K+20		AMIN1_A
K+21		AMIN1_B
K+22		AMIN1_C
K+23		AMAX1_A
K+24		AMAX1_B
K+25		AMAX1_C
K+26		IMARG2_A
K+27		IMARG2_B
K+28		IMARG2_C
K+29		IMARG5_A
K+30		IMARG5_B
K+31		IMARG5_C
K+32		UVDCLI_A
K+33		UVDCLI_B
K+34		UVDCLI_C
K+35		UVDCLR_A
K+36		UVDCLR_B
K+37		UVDCLR_C
K+38		IREFCC2_A
K+39		IREFCC2_B
K+40		IREFCC2_C
K+41		UDAVG_A
K+42		UDAVG_B
K+43		UDAVG_C
K+44		IDCM_A
K+45		IDCM_B
K+46		IDCM_C
K+47		GMEAS_A
K+48		GMEAS_B
K+49		GMEAS_C
K+50		VACM_A
K+51		VACM_B
K+52		VACM_C
K+53		IAD
K+54		IDB
K+55		IDC
K+56		VA
K+57		VB
K+58		VC
K+59		IDAMP3_A
K+60		IDAMP3_B
K+61		IDAMP3_C
K+62		IDAMP1_A
K+63		IDAMP1_B
K+64		IDAMP1_C
K+65		X_UFC_B
K+66		X_LFC_B
K+67		IDREF_A
K+68		IDREF_B
K+69		IDREF_C
K+70		QACM_A
K+71		QACM_B
K+72		QACM_C
K+73		PCONVM_A
K+74		PCONVM_B
K+75		PCONVM_C
K+76		QCONVM_A
K+77		QCONVM_B
K+78		QCONVM_C

K+79		Not used

VARs	#	Description
L		PAC_A
L+1		PAC_B
L+2		PAC_C
L+3		QAC_A
L+4		QAC_B
L+5		QAC_C
L+6		IDC_A
L+7		IDC_B
L+8		IDC_C
L+9		VDC_A
L+10		VDC_B
L+11		VDC_C
L+12		ALFA_A
L+13		ALFA_B
L+14		ALFA_C
L+15		FA_A
L+16		FA_B
L+17		FA_C
L+18		VAC_A
L+19		VAC_B
L+20		VAC_C
L+21		PI_INPUT_A
L+22		PI_INPUT_B
L+23		PI_INPUT_C
L+24		PI_OUT_A
L+25		PI_OUT_B
L+26		PI_OUT_C
L+27		TN_A
L+28		TN_B
L+29		TN_C
L+30		PI_MAX_A
L+31		PI_MAX_B
L+32		PI_MAX_C
L+33		PI_MIN_A
L+34		PI_MIN_B
L+35		PI_MIN_C
L+36		KP1_A
L+37		KP1_B
L+38		KP1_C
L+39		AMIN_A
L+40		AMIN_B
L+41		AMIN_C
L+42		AMAX_A
L+43		AMAX_B
L+44		AMAX_C
L+45		ACUV_TIMER_A
L+46		ACUV_TIMER_B
L+47		ACUV_TIMER_C
L+48		AMAX_SWITCH_A
L+49		AMAX_SWITCH_B
L+50		AMAX_SWITCH_C
L+51		ID0_TIMER_A
L+52		ID0_TIMER_B
L+53		ID0_TIMER_C
L+54		ID0_TIMER1_A
L+55		ID0_TIMER1_B
L+56		ID0_TIMER1_C
L+57		HIGH_ALFA_A
L+58		HIGH_ALFA_B
L+59		HIGH_ALFA_C
L+60		ALFA_TIMER_A
L+61		ALFA_TIMER_B
L+62		ALFA_TIMER_C
L+63		UDMEAS_TIMER_A
L+64		UDMEAS_TIMER_B
L+65		UDMEAS_TIMER_C
L+66		TNSWITCH_A
L+67		TNSWITCH_B
L+68		TNSWITCH_C
L+69		UDR_ERR_A
L+70		UDR_ERR_B
L+71		UDR_ERR_C
L+72		UREF_ADD2_A
L+73		UREF_ADD2_B
L+74		UREF_ADD2_C
L+75		ID01_TIMER_A
L+76		ID01_TIMER_B
L+77		ID01_TIMER_C
L+78		UDI_ERR_A
L+79		UDI_ERR_B
L+80		UDI_ERR_C
L+81		GERR_A
L+82		GERR_B
L+83		GERR_C
L+84		ID_ERR_A
L+85		ID_ERR_B
L+86		ID_ERR_C
L+87		PI_CMODE_A
L+88		PI_CMODE_B
L+89		PI_CMODE_C
L+90		IREFCC_A
L+91		IREFCC_B
L+92		IREFCC_C
L+93		UVDCL_A
L+94		UVDCL_B
L+95		UVDCL_C
L+96		UVDCLR7_A
L+97		UVDCLR7_B
L+98		UVDCLR7_C
L+99		UVDCLR7_PREV_A
L+100		UVDCLR7_PREV_B
L+101		UVDCLR7_PREV_C
L+102		UVDCLR8_TIMER_A
L+103		UVDCLR8_TIMER_B
L+104		UVDCLR8_TIMER_C

L+105		UVDCLR7_TIMER_A
L+106		UVDCLR7_TIMER_B
L+107		UVDCLR7_TIMER_C
L+108		UVDCLR10_TIMER_A
L+109		UVDCLR10_TIMER_B
L+110		UVDCLR10_TIMER_C
L+111		UVDCLR10_A
L+112		UVDCLR10_B
L+113		UVDCLR10_C
L+114		IREF_TC4_A
L+115		IREF_TC4_B
L+116		IREF_TC4_C
L+117		IREF_TC4_TIMER_A
L+118		IREF_TC4_TIMER_B
L+119		IREF_TC4_TIMER_C
L+120		IREF_TC7_TIMER_A
L+121		IREF_TC7_TIMER_B
L+122		IREF_TC7_TIMER_C
L+123		IREF_A
L+124		IREF_B
L+125		IREF_C
L+126		UREF_A
L+127		UREF_B
L+128		UREF_C
L+129		IMARG_A
L+130		IMARG_B
L+131		IMARG_C
L+132		IMARG1_A
L+133		IMARG1_B
L+134		IMARG1_C
L+135		IMARG4_A
L+136		IMARG4_B
L+137		IMARG4_C
L+138		IREFDC_A
L+139		IREFDC_B
L+140		IREFDC_C
L+141		UDREF_A
L+142		UDREF_B
L+143		UDREF_C
L+144		ACUV_A
L+145		ACUV_B
L+146		ACUV_C
L+147		ID0_A
L+148		ID0_B
L+149		ID0_C
L+150		UDREC_A
L+151		UDREC_B
L+152		UDREC_C
L+153		IREF_TC8_A
L+154		IREF_TC8_B
L+155		IREF_TC8_C
L+156		IREF_CC1_A
L+157		IREF_CC1_B
L+158		IREF_CC1_C

L+159		GAMMA_A
L+160		GAMMA_B
L+161		GAMMA_C
L+162		ACUV_TIMER1_A
L+163		ACUV_TIMER1_B
L+164		ACUV_TIMER1_C
L+165		UDMEAS_HIGH_A
L+166		UDMEAS_HIGH_B
L+167		UDMEAS_HIGH_C
L+168		REAL IA_INJ
L+169		REAL IB_INJ
L+170		REAL IC_INJ
L+171		IMAG IA_INJ
L+172		IMAG IB_INJ
L+173		IMAG IC_INJ
L+174		CHECK_A
L+175		CHECK_B
L+176		CHECK_C
L+177		Not used
L+178		DCMODE_PREV
L+179		INV_RECOV_C
L+180		INV_TIMER_A
L+181		INV_TIMER_B
L+182		INV_TIMER_C
L+183		INVBYP_A
L+184		INVBYP_B
L+185		INVBYP_C
L+186		Not used
L+187		Not used
L+188		Not used
L+189		IDAMP2_A
L+190		IDAMP2_B
L+191		IDAMP2_C
L+192		IDAMP_A
L+193		IDAMP_B
L+194		IDAMP_C
L+195		LFC_OUT_B
L+196		UFC_IN_B
L+197		UFC_OUT_B
L+198		SEVERE_FAULT_C
L+199		SEVERE_FAULT_B
L+200		UDRECBP_A
L+201		UDRECBP_B
L+202		UDRECBP_C
L+203		PREF_A
L+204		PREF_B
L+205		PREF_C
L+206		ACUV_TIMER2_A
L+207		ACUV_TIMER2_B
L+208		ACUV_TIMER2_C
L+209		QACUP_A
L+210		QACUP_B
L+211		QACUP_C
L+212		QACUP_PREV_A

L+213		QACUP_PREV_B
L+214		QACUP_PREV_C
L+215		QACUP_TIMER_A
L+216		QACUP_TIMER_B
L+217		QACUP_TIMER_C
L+218		QACDOWN_A
L+219		QACDOWN_B
L+220		QACDOWN_C
L+221		QACDOWN_PREV_A
L+222		QACDOWN_PREV_B
L+223		QACDOWN_PREV_C
L+224		QACDOWN_TIMER_A
L+225		QACDOWN_TIMER_B
L+226		QACDOWN_TIMER_C
L+227		CTR_A
L+228		CTR_B
L+229		CTR_C
L+230		LFC_OUT_B
L+231		QEXCH_A
L+232		QEXCH_B
L+233		QEXCH_C
L+234		IREFAA_B
L+235		FCONT2_B
L+236		UFC_OUT_B
L+237		LFC_OUT_B
L+238		IREFPU_A
L+239		IREFPU_B
L+240		IREFPU_C
L+241		QAC_PREV_C
L+242		HOLD_QAC_B
L+243		QAC_PREV_B
L+244		HOLD_QAC_A
L+245		QAC_PREV_A
L+246		HOLD_QAC_C
L+247		QACDOWN_TIMER1_A
L+248		QACDOWN_TIMER1_B
L+249		QACDOWN_TIMER1_C
L+250		250 to 299 – 20ms TIME DELAY A
L+299		250 to 299 – 20ms TIME DELAY A
L+300		300 to 349 – 20ms TIME DELAY B
L+349		300 to 349 – 20ms TIME DELAY B
L+350		350 to 399 – 20ms TIME DELAY C
L+400		350 to 399 – 20ms TIME DELAY C

ICONs **	**#**	**Value**	**Description**
M		1	DC line number of Pole 1
M+1		2	DC line number of Pole 2
M+2		2308	230 kV bus number station A
M+3		23010	Station A filter 1
M+4		1	Ckt Id branch connecting A filter 1
M+5		2308	230 kV bus number station A
M+6		23011	Station A filter 2
M+7		1	Ckt Id branch connecting A filter 2
M+8		2308	230 kV bus number station A
M+9		23012	Station A filter 3
M+10		1	Ckt Id branch connecting A filter 3
M+11		2308	230 kV bus number station A
M+12		23013	Station A filter 4
M+13		1	Ckt Id branch connecting A filter 4
M+14		2308	230 kV bus number station A
M+15		23014	Station A filter 5
M+16		1	Ckt Id branch connecting A filter 5
M+17		2308	230 kV bus number station A
M+18		23015	Station A filter 6
M+19		1	Ckt Id branch connecting A filter 6
M+20		2308	230 kV bus number station A
M+21		23016	Station A filter 7
M+22		1	Ckt Id branch connecting A filter 7
M+23		2308	230 kV bus number station A
M+24		23017	Station A filter 8
M+25		1	Ckt Id branch connecting A filter 8
M+26		2308	230 kV bus number station A
M+27		23018	Station A filter 9
M+28		1	Ckt Id branch connecting A filter 9
M+29		2308	230 kV bus number station A
M+30		23019	Station A filter 10
M+31		1	Ckt Id branch connecting A filter 10
M+32		2490	230 kV bus number station B
M+33		24910	Station B filter 1
M+34		1	Ckt Id branch connecting B filter 1
M+35		2490	230 kV bus number station B
M+36		24911	Station B filter 2
M+37		1	Ckt Id branch connecting B filter 2
M+38		2490	230 kV bus number station B
M+39		24912	Station B filter 3
M+40		1	Ckt Id branch connecting B filter 3
M+41		2490	230 kV bus number station B
M+42		24913	Station B filter 4
M+43		1	Ckt Id branch connecting B filter 4
M+44		2490	230 kV bus number station B
M+45		24914	Station B filter 5
M+46		1	Ckt Id branch connecting B filter 5
M+47		2490	230 kV bus number station B

M+48		24915	Station B filter 6
M+49		1	Ckt Id branch connecting B filter 6
M+50		2490	230 kV bus number station B
M+51		24916	Station B filter 7
M+52		1	Ckt Id branch connecting B filter 7
M+53		2490	230 kV bus number station B
M+54		24917	Station B filter 8
M+55		1	Ckt Id branch connecting B filter 8
M+56		2490	230 kV bus number station B
M+57		24918	Station B filter 9
M+58		1	Ckt Id branch connecting B filter 9
M+59		2490	230 kV bus number station B
M+60		24919	Station B filter 10
M+61		1	Ckt Id branch connecting B filter 10
M+62		87501	230 kV bus number station C
M+63		87510	Station C filter 1
M+64		1	Ckt Id branch connecting C filter 1
M+65		87501	230 kV bus number station C
M+66		87511	Station C filter 2
M+67		1	Ckt Id branch connecting C filter 2
M+68		87501	230 kV bus number station C
M+69		87512	Station C filter 3
M+70		1	Ckt Id branch connecting C filter 3
M+71		87501	230 kV bus number station C
M+72		87513	Station C filter 4
M+73		1	Ckt Id branch connecting C filter 4
M+74		87501	230 kV bus number station C
M+75		87514	Station C filter 5
M+76		1	Ckt Id branch connecting C filter 5
M+77		87501	230 kV bus number station C
M+78		87515	Station C filter 6
M+79		1	Ckt Id branch connecting C filter 6
M+80		87501	230 kV bus number station C
M+81		87516	Station C filter 7
M+82		1	Ckt Id branch connecting C filter 7
M+83		87501	230 kV bus number station C
M+84		87517	Station C filter 8
M+85		1	Ckt Id branch connecting C filter 8
M+86		87501	230 kV bus number station C
M+87		87518	Station C filter 9
M+88		1	Ckt Id branch connecting C filter 9
M+89		87501	230 kV bus number station C
M+90		87519	Station C filter 10
M+91		1	Ckt Id branch connecting C filter 10

****The user must fill in the ICONs with the appropriate bus numbers.**

```
1 'USRMDL' 0 'CLCPDC' 7 1 92 6 80 400
      1     2
   2308 23010  1
   2308 23011  1
   2308 23012  1
   2308 23013  1
   2308 23014  1
   2308 23015  1
   2308 23016  1
   2308 23017  1
   2308 23018  1
   2308 23019  1
   2490 24910  1
   2490 24911  1
   2490 24912  1
   2490 24913  1
   2490 24914  1
   2490 24915  1
   2490 24916  1
   2490 24917  1
   2490 24918  1
   2490 24919  1
  87501 87510  1
  87501 87511  1
  87501 87512  1
  87501 87513  1
  87501 87514  1
  87501 87515  1
  87501 87516  1
  87501 87517  1
  87501 87518  1
  87501 87519  1
  0 0 0 0 0 0 0 0
       1.00000      1.00000      1.00000      1.00000      0.00000
       0.00000      1.00000      0.00000      0.00000      0.00000/
```

*CON(J), CON(J+1) and CON(J+2) are automatically initialized by the model to match the loadflow conditions. The other CONs should be set by the user. Please see Section 7.4 for more details.

Appendix C

Validation Test Results – Equivalent Source Model

Appendices C through G not filed

APPENDIX C6 – DC1020 VOLUME 5 HVDC SYSTEM INTEGRATION STUDY – TRANSIENT STABILITY STUDY – MAY 2008

HYDRO
THE POWER OF COMMITMENT

THE Lower Churchill PROJECT

May 2008

DC1020 - HVdc System Integration Study

Volume 5 - Transient Stability Study

prepared by

HATCH™

in association with

RSW inc.

Statnett

TGS TransGrid Solutions

PROVINCE OF NEWFOUNDLAND AND LABRADOR
PEG Newfoundland and Labrador
PERMIT HOLDER
This Permit Allows
HATCH LTD.
To practice Professional Engineering
in Newfoundland and Labrador.
Permit No. as issued by PEG Y0188
which is valid for the year 2008

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
PETER KUFFEL
SIGNATURE
May 27/08
DATE
NEWFOUNDLAND & LABRADOR

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Appendices

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Appendix B – NLH System Fault Levels

Nomenclature

BP	- Bipole
CCC	- Capacitor Commutated Converter
CT	- Combustion Turbine
HVdc	- High Voltage Direct Current
INV	- Inverter
LCP	- Lower Churchill Project
MP	- Monopole
NLH	- Newfoundland and Labrador Hydro
NBP	- New Brunswick Power
REC	- Rectifier
SLG	- Single Line to Ground
SVC	- Static Var Compensator
Newfoundland System	- Interconnected ac transmission system on the island of Newfoundland
Labrador System	- Interconnected ac transmission system in Labrador including Churchill Falls, Gull Island, Muskrat Falls and the 735kV transmission ties to the Hydro Quebec Trans Energie System

Executive Summary

Introduction

Newfoundland and Labrador Hydro (NLH) is planning to install a three-terminal HVdc system linking Labrador, Newfoundland, and New Brunswick. The proposed HVdc system will be bipolar, with each converter station having the ability to run as either a rectifier or inverter. It will involve cable and overhead line, with about 40 km of cable between Labrador and Newfoundland and about 480 km between Newfoundland and New Brunswick.

The Labrador (Gull Island) converters will be nominally rated at 1600 MW; whereas, the Newfoundland (Soldiers Pond) and New Brunswick (Salisbury) stations will each be rated at 800 MW. The converters at Soldiers Pond require an overload capability of 2.0 pu for 10 minutes and 1.5 pu continuously. This would allow for the startup of generation to avoid load shedding in the event of the loss of one pole of the HVdc system. The converters at Salisbury do not require any special overload capability and will have an overload rating which is typical of HVdc systems (10-15%).

As part of the WTO DC1020 HVdc System Integration Study, transient stability analysis for the proposed Lower Churchill multi-terminal HVdc project has been completed in order to demonstrate the feasibility of the HVDC interconnection among the ac systems in Labrador, Newfoundland, and New Brunswick and identify the requirements of the Newfoundland ac system. Potential stability issues were investigated along with system upgrades required in the Newfoundland ac system to support the HVdc in-feed. A number of ac system configurations, HVdc system configurations, and contingencies were investigated in order to determine the performance of the overall interconnected ac/dc systems, with the primary focus of the study being the performance of the Newfoundland ac system and the impact of the HVdc in-feed on its performance. Consideration was also given to limitations of the proposed HVdc system and feasible mitigation steps to ensure that the integrated systems performs in an acceptable manner.

Key issues identified in the study included:

- Determination of preliminary HVdc equipment and HVdc control system requirements to minimize the impact of loss of a pole and to provide the necessary dynamic response of the HVdc system, including overload capability.
- Determination of system-mitigation steps required for HVdc disturbances resulting in transient or permanent loss of HVdc transmission capability.
- Evaluation of the effectiveness of the HVdc system to provide control of the Newfoundland ac system frequency and the resultant need for under-frequency load shedding.
- Determination of Newfoundland Island system upgrades required to maintain acceptable dynamic system performance of the ac and dc systems.
- Determination of potential stability issues given the proposed ac system configurations, maximum power levels, and proposed HVdc multi-terminal system.
- Identification of transient and dynamic voltage-control issues.

Study Methodology

Criteria and guidelines applied in the study included the following:

1) Load shedding should not occur for loss of a pole or of the largest generator in the Newfoundland system.

2) The system response following disturbances should be stable and reasonably well damped.

3) Transient under-voltages following fault clearing should not drop below 0.7 pu.

4) Under-frequency load-shedding should be avoided to the greatest extent possible.

With regards to the voltage criteria, the primary focus was to optimize the controls such that the voltage dip during a disturbance should not drop below 0.7 pu. However, the duration of voltage below 0.8 pu was also noted, keeping in view that a voltage dip below 20% for a duration of 20-cycles is acceptable.

While PSS/E is an industry standard for transient stability analysis, some aspects of the multi-terminal HVdc models that are associated with the software are incompatible with the requirements of this study. The power flow model is restricted in the control modes available, and the stability model requires extensive response data that can be obtained only from other sources, such as detailed simulation. Therefore, the primary tool used for the Transient Stability Study was the PSCAD electromagnetic transients simulation software.

AC system data used for the transient stability analysis was based on that used in the DC 1020 HVdc System Integration Study – Power Flow and Short Circuit Analysis. Due to the length of computation time required to perform simulations in electromagnetic transients software, direct implementation of the PSS/E ac system models used in the power flow analysis is not practical within PSCAD; therefore some reduction of the ac system representations was required.

The year 2016 and future peak Island of Newfoundland power flow cases considered in the Transient Stability Study have several significant modifications when compared to the system existing today:

1. A new large refinery load (175 MW, 85 MVAr) is planned to be in service near Pipers Hole, between Bay d'Espoir and Sunnyside. As well, a nickel smelter load (83 MW, 40 MVAr) is planned for the Long Harbour area. The internal NLH studies for the additions of these loads have not yet been completed; therefore it is expected that system impacts due to the loads will be observed in this HVdc feasibility study.

2. NLH is planning to convert units #1 to #3 at Holyrood to synchronous condensers as part of the Lower Churchill Project for voltage control and in support of the system short circuit level with the following ratings:

    - Unit #1 – 142/-72 MVAr
    - Unit #2 – 142/-72 MVAr
    - Unit #3 – 150/-69 MVAr

3. NLH is planning to install five 50 MW combustion turbines (CT) to meet load requirements between 2010 and the HVdc 2015 in-service date. These CTs will be specified with the capability to operate in

synchronous condenser mode. Initial indications were that these CTs would be located at the Holyrood station.

Results of the DC 1020 HVdc System Integration Study – Power Flow and Short Circuit Analysis indicated that additional voltage support would be required in the form of one 150 MVAr synchronous condenser at Soldiers Pond and one 200 MVAr Static Var Compensator (SVC) at Sunnyside.

The DC 1020 HVdc System Integration Study - Comparison of Conventional and Capacitor Commutated Converter (CCC) HVdc Technology study indicated that the system upgrades recommended in the DC 1020 HVdc System Integration Study – Power Flow and Short Circuit Analysis were not sufficient to dynamically support the HVdc in-feed.

Based on the results of the DC 1020 HVdc System Integration Study - Comparison of Conventional and CCC HVdc Technology the following ac system upgrades were identified and included in the remainder of the transient stability studies:

1. Application of 50% series compensation to both 230 kV lines from Bay d'Espoir to Pipers Hole.
2. One 300 MVAr high-inertia synchronous condenser must be in service at Pipers Hole. This replaces the 200 MVAr SVC at Sunnyside that was identified in the Power Flow Analysis. The machine and excitation parameters for the 300 MVAr high-inertia synchronous condenser used are the same as those of identical machines currently in service at Manitoba Hydro's Dorsey converter station.
3. One 300 MVAr high-inertia synchronous condenser must be in service at Soldiers Pond. This replaces the 150 MVAr synchronous condenser at Soldiers Pond that was identified in the Power Flow Analysis. The machine and excitation parameters for the 300 MVAr high-inertia synchronous condenser used are the same as those of identical machines currently in service at Manitoba Hydro's Dorsey converter station.
4. The proposed five new CTs are relocated from Holyrood to Pipers Hole.

The Labrador system was represented by a reduced equivalent weak-system configuration. This weak configuration was achieved by removing the Muskrat Falls generating station, a 230 kV line from Gull Island to Muskrat Falls, and a 735 kV line from Churchill Falls to Gull Island Generating Station.

The New Brunswick ac system was represented with an equivalent, consisting of a voltage source behind a complex impedance based on the weak-system configuration. This simplification was deemed acceptable as it allowed for reasonable representation of the commutation performance of the HVdc converters at Salisbury. The New Brunswick system was therefore represented by a source behind a complex equivalent impedance with a short-circuit strength of [redacted] MVA at a damping angle of [redacted] degrees.

Reduced ac system representations were developed in PSS/E and then models were developed in PSCAD. Performance benchmarking of the PSS/E and PSCAD models was performed in order to validate the ac system models in PSCAD. A PSCAD model of the multiterminal HVdc system was developed which included a detailed representation of the HVdc control system. The proposed Lower Churchill Project (LCP) multi-terminal HVdc system included a number of key technical challenges that had to be overcome during the development of the control system, including:

- Multi-terminal configuration – Although multi-terminal HVdc has been used in the past, detailed information on actual control systems in service is not readily available; therefore, considerable effort was required to develop and implement the overall control-system concepts.
- Long HVdc cable – Although two-terminal HVdc systems with undersea cables are in operation, the length of the cable section across the Cabot Strait is considerably longer than those of any systems currently in operation. (Note that there are currently a number of HVdc links under design or construction with cable lengths longer than that of the LCP.) The length of the undersea cable (and hence the cable capacitance) has a dramatic impact on the overall performance of the HVdc link and must be accounted for in the design of the control system. Furthermore, the length of cable, coupled with the multi-terminal configuration, added yet another dimension to the requirements of the control system.
- Significance of the HVdc infeed to the Newfoundland ac system – Since the HVdc infeed represents a significant portion of the generation on the Island of Newfoundland, performance of the HVdc system is key to the overall stability of the Newfoundland ac system. This requirement puts added complexity on the control system.

Following extensive testing and parameter optimization, acceptable system performance was obtained. The final control-system configuration and parameters selected represent a reasonable HVdc control system that could be implemented in the field and provide a high degree of confidence in the study results.

A total of 13 system scenarios were developed based on a combination of the final ac system base cases and HVdc configurations identified which represented a wide range of operating conditions. A total of 72 disturbances were identified for transient stability analysis.

The full set of contingencies were simulated for the following scenarios;

BC1-DC1 - HVdc in normal bipolar operation with peak (1600 MW) Newfoundland load, economic generation dispatch, and full HVdc import at Soldiers Pond (800MW).

BC2-DC3 - HVdc in monopolar operation with peak (1600 MW) Newfoundland load, maximum economic dispatch, and reduced HVdc import at Soldiers Pond (600MW).

BC6-DC1 - HVdc in normal bipolar operation with the weakest Newfoundland system with 1000 MW load, minimum generation dispatch, and full HVdc import at Soldiers Pond (800 MW).

From the above three full contingency analyses, the ten worst contingencies were identified and simulated for the remaining 10 of 13 system scenarios.

Discussion of Results

The results of the study show that:

- Good performance of the multi-terminal HVdc system was observed for all ac system and HVdc configurations considered.
- Faults within the Newfoundland Island ac system can result in temporary commutation failure of the Soldiers Pond converter, depending on fault location and severity. However, following fault clearing,

recovery of the HVdc infeed was seen to be good, with the HVdc power typically recovering to 90% of pre-disturbance power within 300 ms of fault clearing.

- When operating in three terminal mode with two stations operating as inverters, commutation failure of one inverter causes a loss of HVdc power in the other inverter while the commutation failure persists; however, HVdc power recovery is good following removal of the commutation failure.
- No conditions (ac system configurations or contingencies) were observed under which the HVdc system could not successfully recover.
- Performance in two-terminal mode with Soldiers Pond operating as an inverter or as a rectifier was also seen to be good. The maximum power export from Soldiers Pond when operating as a rectifier was limited to approximately 165 MW due to the Newfoundland ac system configuration given.
- The system is transiently stable with adequate post-disturbance recovery. The majority of contingencies studied result in voltage dips with acceptable duration (20-cycle); however, some disturbances resulted in voltage dips beyond the criteria limits. Additional improvements in the Newfoundland ac system will be required to improve the voltage-sag problems if these are deemed excessive.
- The need for under-frequency load shedding in the Newfoundland ac system is minimized. The HVdc system, due to its inherent controllability, provides an effective means of fast and efficient frequency control within the Newfoundland ac system by modulation of the HVdc power transfer to overcome capacity deficit or surplus situations. There are however a number of conditions in which the HVdc system will not be able to provide the necessary frequency control due to operational limits or converter capacities. Therefore the existing under-frequency load shedding scheme in the Newfoundland system should be modified in order to operate only when the HVdc frequency controller is not able to provide the necessary control for under-frequency conditions. Likewise, a generation rejection scheme should also be considered for the Newfoundland system in order to operate only when the HVdc frequency controller is not able to provide the necessary control for over-frequency conditions.
- The 2.0 pu, 10-minute overload rating of the Soldiers Pond converter and the corresponding overload rating of the Gull Island converter provides suitable mitigation for the loss of a pole, even under conditions of high HVdc power in-feed.
- When operating in three terminal mode with Gull Island as the only rectifier, the complete loss of the Gull Island converters can be successfully mitigated by reversal of the Salisbury converter from inverter to rectifier operation.
- When the HVdc link is operating in two terminal mode with Salisbury as the rectifier and Soldiers Pond as the inverter, a number of situations arose where the HVdc in-feed to Soldiers Pond was limited due to the overload capability of the Salisbury converters, resulting in the need for under-frequency load shedding in the Newfoundland ac system.
- The worst-case disturbance within the Newfoundland ac system is a three-phase fault at Bay d'Espoir on one of the 230 kV lines to Pipers Hole requiring tripping of the line to clear the fault. This fault causes the HVdc to fail commutation, which collapses the HVdc power momentarily. At the same time, it also causes a large disturbance of the Bay d'Espoir generators. Recovery from this fault is possible only with the cross tripping of the proposed 175 MW refinery load at Pipers Hole.

- The protection and fault-clearing times for faults at Bay d'Espoir and Pipers Hole should be optimized to prevent voltage sags of long duration.
- A special protection and remedial action scheme is needed to reduce Gull Island generation in case of load rejection due to the outage of the last 735 kV line from Gull Island.

Conclusions

Based on the results of this study it is concluded that:

1. Performance of the proposed multi-terminal HVdc system was seen to be good, successfully demonstrating the feasibility of the proposed multi-terminal HVdc interconnection. Bipolar, monopolar, multi-terminal and two terminal operations were studied and the performance found to be good.
2. The following system upgrades were required within the Newfoundland ac system in order to support the HVdc in-feed:
    a. Conversion of all three units at Hollyrood to synchronous condenser operation.
    b. Installation of five (5) combustion turbines that can operate as synchronous condensers at the Pipers Hole 230kV bus.
    c. 50% series compensation of both 230 kV lines from Bay d'Espoir to Sunnyside.
    d. One 300 MVAr high inertia synchronous condenser is in-service at the Pipers Hole 230 kV bus at all times.
    e. One 300MVAr high inertia synchronous condenser is in-service at the Soldiers Pond 230 kV bus at all times.
3. Faults within the Newfoundland Island ac system can result in temporary commutation failure of the Soldiers Pond converter, depending on fault location and severity. The likelihood of commutation failure is increased due to the long undersea cable across the Cabot Strait. The large capacitance of this undersea cable tends to discharge through the Soldiers Pond inverter, whose dc voltage was transiently reduced due to the ac system fault. The cable discharge further increases the dc current, thus increasing the likelihood of commutation failure. However, following fault clearing, recovery of the HVdc infeed was seen to be good, with the HVdc power typically recovering to 90% of pre-disturbance power within 300 ms of fault clearing.
4. No conditions (ac system configurations or contingencies) were observed under which the HVdc system could not successfully recover. Recovery of the HVdc power transfer is dictated, to a large extent, by the time required to charge the large cable capacitance; therefore, significant improvement in the speed of recovery beyond that obtained in these feasibility studies is not likely.
5. Performance with Soldiers Pond operating as a rectifier was successfully demonstrated. The maximum power export from Soldiers Pond when operating as a rectifier was limited to approximately 165 MW due to the Newfoundland ac system configuration given. With additional ac system upgrades, an increased export level should be attainable.

6. The system is transiently stable with adequate post-disturbance recovery. The majority of contingencies studied result in voltage dips with acceptable duration (20-cycle); however, some disturbances resulted in voltage dips beyond the criteria limits. Additional improvements in the Newfoundland ac system will be required to improve the voltage-sag problems if these are deemed excessive.

7. The need for under-frequency load shedding in the Newfoundland ac system is minimized. The HVdc system, due to its inherent controllability, provides an effective means of fast and efficient frequency control within the Newfoundland ac system by modulation of the HVdc power transfer to overcome capacity deficit or surplus situations. There are however a number of conditions where the HVdc system will not be able to provide the necessary frequency control due to operational limits or converter capacities. Therefore the existing under-frequency load shedding scheme in the Newfoundland system should be modified in order to operate only when the HVdc frequency controller is not able to provide the necessary control for under-frequency conditions. Likewise, a generation rejection scheme should also be considered for the Newfoundland system in order to operate only when the HVdc frequency controller is not able to provide the necessary control for over-frequency conditions.

8. The 2.0 pu, 10-minute overload rating of the Soldiers Pond converter and corresponding overload rating of the Gull Island converter provides suitable mitigation for the loss of a pole, even under conditions of high HVdc power in-feed.

9. When operating in three terminal mode with Gull Island as the only rectifier, the complete loss of the Gull Island converters can be successfully mitigated by reversal of the Salisbury converter from inverter to rectifier operation. The studies have shown that this is possible from the Newfoundland ac system point of view, additional studies are required to determine the impact on the New Brunswick ac system.

10. When the HVdc link is operating in two terminal mode with Salisbury as the rectifier and Soldiers Pond as the inverter, a number of situations arose where the HVdc in-feed to Soldiers Pond was limited due to the overload capability of the Salisbury converters, resulting in the need for under-frequency load shedding in the Newfoundland ac system. Consideration should be given to the potential benefits of providing additional overload capability within the Salisbury converter and the resultant improvements in the performance of the Newfoundland ac system when Salisbury is operating as the only rectifier. Increasing the overload rating of Salisbury will be limited by the current carrying capacity of the cable across Cabot Strait.

11. The worst-case disturbance within the Newfoundland ac system is a three-phase fault at Bay d'Espoir on one of the 230 kV lines to Pipers Hole requiring tripping of the line to clear the fault. This fault causes the HVdc to fail commutation, which collapses the HVdc power momentarily. At the same time, it also causes a large disturbance of the Bay d'Espoir generators. Recovery from this fault is possible only with the cross tripping of the proposed 175 MW refinery load at Pipers Hole. It should be noted that this study considered only the trip of the entire refinery load at Pipers Hole, additional studies should be conducted to determine if tripping of a smaller block of load would be sufficient to maintain system stability.

12. The protection and fault-clearing times for faults at Bay d'Espoir and Pipers Hole should be optimized to prevent voltage sags of long duration.

13. A special protection and remedial action scheme is needed to reduce Gull Island generation in case of load rejection due to the outage of the last 735 kV line from Gull Island.

14. Correctly designed/tuned stabilizers on the Gull Island generators are essential to maintain steady power flow through the 735 kV lines. Also, the performance of the Newfoundland ac system should be reviewed to evaluate requirements for stabilizers in other parts of the network.

Recommendations

This study has successfully demonstrated the feasibility of the proposed multiterminal HVdc system. It is therefore recommended that the design of the multi-terminal HVdc system can be further refined to advance the implementation of the overall project. Additional studies recommended for refinement of the detailed design include:

1. System impact study of the proposed 175MW refinery load at Pipers Hole.
2. Studies to look at the 50% Series compensation recommended for the lines TL202 and TL206. These studies should include;
    a. Insulation Co-ordination
    b. Switching Studies
    c. Series resonance studies
3. Study to look at the impact of a bi-pole block on the Newfoundland System.
4. System integration study to evaluate the impact of the proposed HVdc system on the New Brunswick ac system.
5. Reactive power study to optimize the ratings, location and number of synchronous condensers and ac filters required within the Newfoundland ac system.
6. A study to identify and mitigate any potential sub-synchronous resonance issue should be performed.
7. Facilities studies to develop detailed implementation schemes and cost estimates for the identified transmission and control system facilities.
8. Resonance studies to ensure that the HVdc system does not adversely interact with potential resonances in the Labrador, Newfoundland and New Brunswick ac systems. This should include:
    a. Harmonic resonance investigations
    b. Resonance study of the proposed dc line/cable.

1. Introduction

Newfoundland and Labrador Hydro (NLH) is planning to install a three-terminal HVdc system linking Labrador, Newfoundland, and New Brunswick. The proposed HVdc system will be bipolar, with each converter station having the ability to run as either a rectifier or inverter. It will involve cable and overhead line, with about 40 km of cable between Labrador and Newfoundland and about 480 km between Newfoundland and New Brunswick. The proposed HVdc system is conceptually shown in Figure 1.1.

The Labrador (Gull Island) converters will be nominally rated at 1600 MW; whereas, the Newfoundland (Soldiers Pond) and New Brunswick (Salisbury) stations will each be rated at 800 MW. The converters at Soldiers Pond require an overload capability of 2.0 pu for 10 minutes and 1.5 pu continuously. This would allow for the startup of generation in Newfoundland to avoid load shedding in the event of the loss of one pole of the HVdc system. The converters at Salisbury do not require any special overload capability and will have an overload rating which is typical of HVdc systems (10-15%).

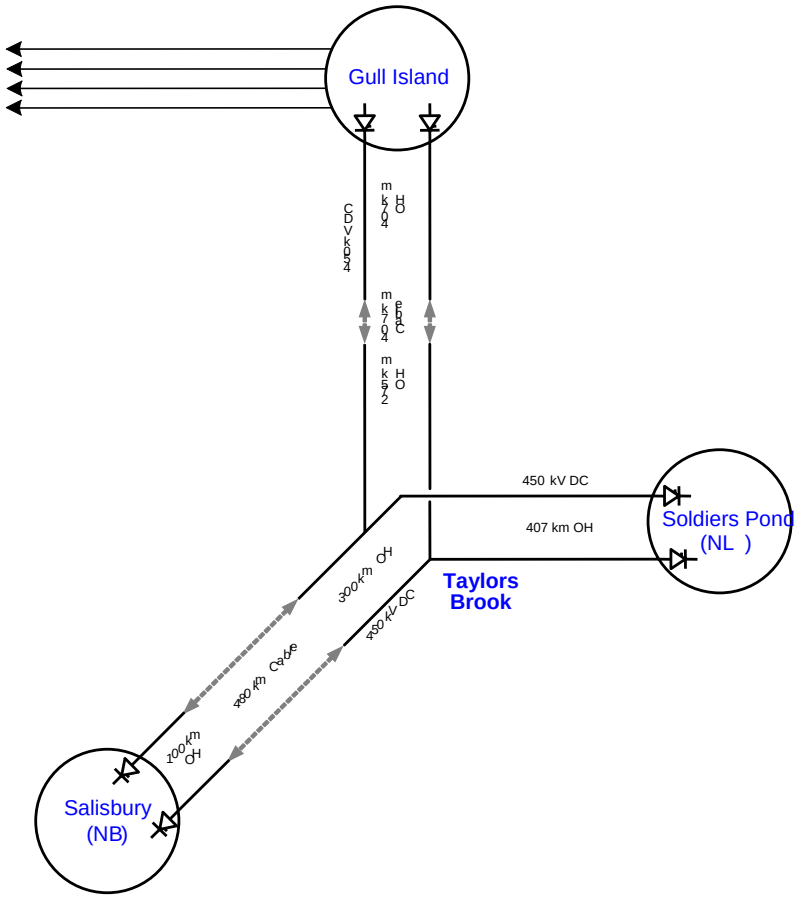


Figure 1.1 - Overview of Proposed Three-Terminal HVdc System

The HVdc system will be a major source of power to Newfoundland, and it will provide frequency control. An important feature of the proposed HVdc system is the overload capability and frequency control during forced outage of the largest generator within the Newfoundland system.

This report presents the results of the Transient Stability Analysis task identified as part of WTO DC1020 HVdc System Integration Study.

1.1 Background

The objectives of the System Integration Study were to:

- Demonstrate the feasibility of a multi-terminal HVdc link connecting Labrador, Newfoundland, and New Brunswick given the requirements of the Newfoundland system.
- Determine the system additions required for integrating the proposed three-terminal HVdc system into the Labrador and Newfoundland systems. Although basic consideration was given to integration into the New Brunswick system, the study concentrated on the Labrador and Newfoundland systems.
- Determine the limitations of the proposed HVdc system.
- Determine feasible mitigation steps to ensure that the integrated system performs in an acceptable manner.

The following tasks were identified as part of the WTO DC1020 HVdc System Integration Study:

- Data gathering and model development
- Power flow analysis
- Transient stability analysis
- Short circuit analysis
- Model development
- Qualitative issues
- Reporting and deliverables

Reports on the results of the Power Flow and Short Circuit Analysis [1] have been submitted to NLH for review and approval. In addition, a report detailing the results of a preliminary transient stability analysis comparing the performance of conventional and capacitor commutated converter (CCC) HVdc technology [2] has also been submitted to NLH. That report recommended the application of conventional HVdc technology over the CCC, and identified ac system upgrades required to dynamically support the HVdc in-feed. The recommendation was approved by NLH and, therefore, the transient stability studies detailed in this report were based only on the application of conventional HVdc technology. As the ac system upgrades recommended in the Comparison of Conventional and CCC HVdc Technology Interim Report [2] were different from those originally identified in the Power Flow and Short Circuit Analysis Report [1], a cursory review of fault levels within the Newfoundland system was performed, the results of which are presented in Appendix B of this report.

While PSS/E is an industry standard for transient stability analysis, some aspects of the multi-terminal HVdc models that are associated with the software are incompatible with the requirements of this study. The power flow model is restricted in the control modes available, and the stability model requires extensive response data that can be obtained only from other sources, such as detailed simulation. Therefore, the primary tool used for the Transient Stability Study was the PSCAD electromagnetic transients simulation software.

1.2 Scope and Objectives of Transient Stability Study

The objectives of the Transient Stability Study were as follows:

1) To demonstrate the feasibility of the multi-terminal HVdc system given the configurations of the respective ac systems in Labrador, Newfoundland, and New Brunswick and the requirements of the Newfoundland ac system.
2) To determine any potential stability issues given the proposed ac system configurations, maximum power levels, and proposed HVdc multi-terminal system by looking at the following contingencies:
    a) AC system faults within each of the three ac networks that may affect HVdc commutation or ac system strength,
    b) HVdc system faults and outages including converter (pole) blocking and converter commutation failure,
    c) Events that will require the HVdc system to provide dynamic frequency control of the Newfoundland ac system, such as loss of generation in Newfoundland,
    d) Loss of generation in Labrador.
3) To determine preliminary HVdc equipment and HVdc control system requirements to minimize the impact of loss of a pole and to provide the necessary dynamic response of the HVdc system, including overload capability,
4) To identify preliminary transient and dynamic voltage-control issues,
5) To determine system-mitigation steps required for HVdc disturbances resulting in transient or permanent loss of HVdc transmission capability.
6) To determine Newfoundland Island system upgrades required to maintain acceptable dynamic system performance of the ac and dc systems for conventional HVdc technology.

2. Criteria and Assumptions

2.1 Criteria

The following criteria and guidelines were used in the study:

1) Load shedding should not occur for loss of a pole or of the largest generator in the Newfoundland system.
2) The system response following disturbances should be stable and reasonably well damped.
3) Transient under-voltages following fault clearing should not drop below 0.7 pu.
4) Under-frequency load-shedding should be avoided to the greatest extent possible.

With regards to the voltage criteria, the primary focus was to optimize the controls such that the voltage dip during a disturbance should not drop below 0.7 pu. However, the duration of voltage below 0.8 pu was also noted, keeping in view that a voltage dip below 20% for a duration of 20-cycles is acceptable.

2.2 Assumptions

The following assumptions were made for each case:

1) Conventional HVdc technology is used.
2) All existing units at Holyrood are operating as synchronous condensers and are in service in all cases.
3) The proposed new 175 MW refinery load at Pipers Hole is in service in all cases. The refinery load may be tripped in case of a fault at Bay d'Espoir or Pipers Hole, if necessary, to maintain system stability and to avoid extensive load shedding.
4) The proposed five new combustion turbines (CTs) are located at Pipers Hole. These CTs can operate as synchronous condensers or as generators, depending on the particular power flow being considered. Only four of the five proposed CTs are in service in all cases.
5) One 300 MVAr synchronous condenser (high inertia of 2.2) is in service at both Pipers Hole 230 kV bus and Soldiers Pond 230 kV bus in all cases.
6) 50% series compensation is applied to both 230 kV lines between Bay d'Espoir and Pipers Hole.
7) No mitigation measures are to be investigated to reduce voltage dip (at other than the affected buses) during back-up fault clearing.
8) A three-cycle tripping time was used for disturbance cases with unsuccessful single pole reclosing. If a breaker is closed onto a fault and then tripped, the remote end line breaker will also trip instead of reclosing into the fault.
9) The network topology would remain the same for all the base cases with different system-load levels. Essentially this means that no additional system reinforcements were included while studying the future peak load conditions.

3. Study Models for Transient Stability Analysis

AC system data used for the transient stability analysis was based on that used in the Power Flow and Short Circuit Analysis [1]. Due to the length of computation time required to perform simulations in electromagnetic transients software, direct implementation of the PSS/E ac system models used in the power flow analysis is not practical within PSCAD; therefore some reduction of the ac system representations was required. A description of the ac system reductions and the PSCAD model validation procedure is provided in Section 4.

A detailed description of each power flow case and HVdc system configuration that was studied is provided in Section 4.

3.1 AC-System Representations

3.1.1 Newfoundland AC System

The year 2016 and future peak Newfoundland Island power flow cases considered in the Transient Stability Study have several significant modifications when compared to the system existing today:

1. A new large refinery load (175 MW, 85 MVAr) is planned to be in service near Pipers Hole, between Bay d'Espoir and Sunnyside. As well, a nickel smelter load (83 MW, 40 MVAr) is planned for the Long Harbour area. The internal NLH studies for the additions of these loads have not yet been completed; therefore it is expected that system impacts due to the loads will be observed in this HVdc feasibility study.
2. NLH is planning to convert units #1 to #3 at Holyrood to synchronous condensers as part of the Lower Churchill Project for voltage control and in support of the system short circuit level with the following ratings:
    i. Unit #1 – 142/-72 MVAr
    ii. Unit #2 – 142/-72 MVAr
    iii. Unit #3 – 150/-69 MVAr
3. NLH is planning to install five 50 MW combustion turbines (CTs) to meet load requirements between 2010 and the HVdc 2015 in-service date. These CTs will be specified with the capability to operate in synchronous condenser mode. Initial indications were that these CTs would be located at the Holyrood station.

Results of the Power Flow Analysis [1] indicated that additional voltage support would be required in the form of one 150 MVAR synchronous condenser at Soldiers Pond and one 200 MVAr Static Var Compensator (SVC) at Sunnyside.

The transient stability study 'Comparison of Conventional and CCC HVdc Technology Report' [2] indicated that the system upgrades recommended in the Power Flow Analysis [1] were not sufficient to dynamically support the HVdc in-feed. Based on the results of the Comparison of Conventional and CCC

HVdc [2], the following ac system upgrades were identified and included in the remainder of the transient stability studies:

1. Application of 50% series compensation to both 230 kV lines from Bay d'Espoir to Pipers Hole.

2. One 300 MVAr high-inertia synchronous condenser must be in service at Pipers Hole. This replaces the 200 MVAr SVC at Sunnyside that was identified in the Power Flow Analysis. The machine and excitation parameters for the 300 MVAr high-inertia synchronous condenser used are the same as those of identical machines currently in service at Manitoba Hydro's Dorsey converter station.

3. One 300 MVAr high-inertia synchronous condenser must be in service at Soldiers Pond. This replaces the 150 MVAr synchronous condenser at Soldiers Pond that was identified in the Power Flow Analysis. The machine and excitation parameters for the 300 MVAr high-inertia synchronous condenser used are the same as those of identical machines currently in service at Manitoba Hydro's Dorsey converter station.

4. The proposed five new CTs are relocated from Holyrood to Pipers Hole.

3.1.2 Labrador AC System

As described in the Power Flow Analysis Report [1], the Labrador system is represented by a reduced equivalent weak-system configuration. This weak configuration is achieved by removing the Muskrat Falls generating station, a 230 kV line from Gull Island to Muskrat Falls, and a 735 kV line from Churchill Falls to Gull Island Generating Station.

For cases requiring a strong ac system representation, the second 230 kV line from Gull Island to Muskrat Falls and the 735 kV line from Churchill Falls to Gull Island Generating Station are included. Note that Muskrat Falls generation is not included, even in the strong-system configuration.

3.1.3 New Brunswick AC System

The New Brunswick ac system was not included in the Power Flow Analysis. Separate PSS/E data representing weak- and strong-system configurations were provided. As the main focus of the System Integration Study was the performance of the Newfoundland and Labrador systems, it was decided to represent the New Brunswick AC system with an equivalent, consisting of a voltage source behind a complex impedance based on the weak-system configuration. This simplification was deemed acceptable as it allows for reasonable representation of the commutation performance of the HVdc converters at Salisbury.

The New Brunswick system was therefore represented by a source behind a complex equivalent impedance with a short-circuit strength of [redacted] MVA at a damping angle of [redacted] degrees.

3.2 HVdc System Representation

Salient points of the HVdc system include:

- Bipolar, three-terminal HVdc link using conventional technology configured as shown in Figure 3-1.

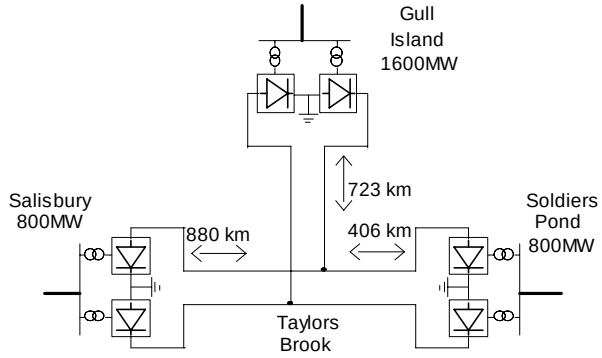


Figure 3-1 - Basic Configuration of the HVdc Transmission System

- Nominal converter ratings:
  - Gull Island (Labrador) 1600 MW
  - Soldiers Pond (Newfoundland) 800 MW
  - Salisbury (New Brunswick) 800 MW
- The converters at Soldiers Pond and Gull Island have special overload requirements when operating in monopolar as follows:
  - Gull Island 1.5 pu for 10 minutes and 1.25 pu continuous on a per pole basis
  - Soldiers Pond 2.0 pu for 10 minutes and 1.5 pu continuous on a per pole basis

  The Soldiers Pond converter overload capability is meant to allow for the startup of generation on the Island of Newfoundland to avoid load shedding in case of pole loss when operating as an inverter.

  The converter at Salisbury has a typical overload requirement of 10% continuous.
- The HVdc operating voltage is 450 kV (defined at the rectifier).
- Overhead transmission and undersea cable lengths are as follows:
  - Gull Island to Strait of Belle Isle – Overhead line 407 km
  - Across Strait of Belle Isle – Undersea cable 40 km
  - Straight of Belle Isle to Taylors Brook – Overhead line 275 km
  - Taylors Brook to Soldiers Pond – Overhead line 406 km
  - Taylors Brook to Cabot Strait – Overhead line 300 km
  - Across Cabot Strait – Undersea cable 480 km
  - Cabot Strait to Salisbury – Overhead line 100 km
- Electrodes for ground/sea return for each station are located as follows:

- Gull Island – Sea electrode at Strait of Belle Isle, 407 km from converters
- Soldiers Pond – Sea electrode 10 km from converters
- Salisbury – Sea electrode at Cabot Strait, 100 km from converters

  The overhead ground wires of the HVdc transmission lines from the converter stations to the sea electrodes are used as electrode lines.

- Although the normal operating configuration would have Gull Island operating as a rectifier and Soldiers Pond and Salisbury operating as inverters, all converters must be capable of operating both as a rectifier and as an inverter. Therefore high speed reversal switches are required at each station.
- The HVdc system must be able to operate with any two of the three converters in operation.
- The HVdc in-feed into Soldiers Pond will provide frequency control for the Newfoundland ac system. Frequency control is provided with Soldiers Pond operating as an inverter or as a rectifier.

4. Study Tools, Model Development, and Validation

4.1 Study Tools

While PSS/E is an industry standard for transient stability analysis, some aspects of the multi-terminal HVdc models that are associated with the software are incompatible with the requirements of this study. The power-flow model is restricted in the control modes available, and the stability model requires extensive response data that can be obtained only from other sources, such as detailed simulation. Therefore, the primary tool used for the Transient Stability Study was version 4.2 of the PSCAD electromagnetic transients simulation software, which has a powerful three-phase time-domain solution with excellent HVdc modeling capabilities.

Development and validation of the PSCAD model used for the Transient Stability Study was separated into the development of the ac system models and the HVdc system model as described below.

4.2 AC Systems

AC-system data used for the transient stability analysis was based on that used in the Power Flow and Short Circuit Analysis [1]. Due to the length of computation time required to perform simulations in electromagnetic transients software, direct implementation of the PSS/E ac system models used in the Power Flow Analysis is not practical within PSCAD; therefore, some reduction of the ac system representations was required.

The full PSS/E power-system model provided by NLH included a detailed representation of the Newfoundland ac system and a reduced representation of the Labrador ac system. In this model, the Newfoundland and Labrador ac systems were asynchronously connected using a two-terminal bipolar HVdc system. A separate model of the New Brunswick ac system was provided. Since the main focus of the System Integration Study was the performance of the Newfoundland system, the Newfoundland system was represented in the greatest detail.

The real power portions of all loads were represented as constant-current loads and the reactive power portions of all loads were represented as constant-impedance loads.

4.2.1 Newfoundland AC System

The original PSS/E full-system model provided by NLH represented all the high-voltage networks as well as the low-voltage distribution networks down to 600 V. Most of these low-voltage distribution networks can be suitably replaced with equivalent loads for transient stability studies without impacting the accuracy of the simulation results. Therefore, NLH also provided a reduced-system model (Reduced Model 1) with most of the low-voltage sub-systems replaced by their equivalents. Table 4-1 shows a comparison between these two models in terms of the number of system components, such as number of bus bars, transmission lines, and generators.

Table 4-1
Comparison of Original Full and Reduced Model 1 Components

	Original Full Model	Reduced Model 1
Bus bars	557	167
Loads	132	68
Switching shunts	21	11
Transmission lines	664	233
Transformers	335	106
Plants	86	46
Generators	110	57

Although the 'Reduced Model 1' represents a significant reduction in the size of the ac system compared to the full system model, it was found that further simplifications were possible; hence, the following simplifications were recommended to the NLH.

- The 138 kV sub-system between Sunnyside (bus 223) and Stony Brook (bus 217) can be replaced with two equivalent loads at each bus bar and an equivalent transmission line between bus 217 and 223.
- The 138 kV sub-system, consisting of all loads and generators connected to Grand Falls and the transmission line (TL235) connecting Grand Falls Terminal Station (bus 261) and Stony Brook terminal station (bus 216), can be replaced with an equivalent load.
- All the generators and loads connected to Corner Brook Pulp and Paper Company (bus 106), except for the generator connected to bus 105, can be replaced with an equivalent load.

NLH provided a further reduced model, 'Reduced Model 2', with the above simplifications implemented.

In order to validate the system reduction, the short-circuit levels at key buses within the full- and reduced-system models were compared, and the results indicated a good agreement. As a result of this comparison, a PSCAD model for the Newfoundland ac system was developed based on the 'Reduced Model 2' PSS/E model. In this initial PSCAD model, the HVdc converter at Soldiers Pond was represented by an ac source whose magnitude and phase angle were controlled to result in a real-power injection and reactive-power absorption equivalent to that of the operating HVdc link.

The ac transmission lines were modeled using a distributed parameters (Bergeron) model based on the data within the PSS/E models. Key 230 kV lines were modeled using the more accurate frequency-dependent models based on the physical line parameters and geometry provided by NLH. Similarly, generator step-up transformer winding connections and the nominal ratings of all the transformers were updated based on the transformer data provided by NLH. Constant-current and constant-impedance load models were used to model the active and reactive component of each load respectively.

Validation of the ac system implemented within PSCAD included the following:

- Comparison of the active and reactive power flows within the PSCAD and Reduced Model 2 PSS/E models - Results showed excellent comparison of the real and reactive power flows, with the greatest difference being 2 MVAr, which can be attributed to inherent differences in modeling techniques used by the two softwares.

- Comparison of the equivalent Thevenin Impedances at various buses within the PSCAD and Reduced Model 2 PSS/E models - For this comparison, all generators are replaced with their sub-transient reactance, and all the loads are modeled as constant impedance.

  In PSCAD the representation of a transmission network and loads is valid for a wide range of frequencies from 0 Hz to several kHz. However, the transmission network and load model used in PSS/E represents a phasor-based model valid only at 60 Hz. Therefore, in order to perform the comparison, the Thevenin impedance for the PSCAD model must be calculated at 60 Hz. Table 4-2 shows the comparison of equivalent impedance between the PSS/E model and the PSCAD model at several buses within the Newfoundland system. The results indicate good agreement and, hence, validate the model of the transmission network within PSCAD.

Table 4-2
Comparison of Thevenin Impedances within the Newfoundland System

Bus/Station Name	Bus Number	Base KV	Z_{PSSE}		Z_{PSCAD}	
			Mag(Ω)	Ang(deg.)	Mag(Ω)	Ang(deg.)
Soldiers Pond	2490	230	18.45	71.96	18.43	71.92
Sunnyside	222	230	22.81	69.60	22.76	69.59
Bay d'Espoir	221	230	15.00	81.26	14.97	81.47
Stony Brook	216	230	29.38	75.34	29.27	75.20
Massey Drive	208	230	45.06	72.24	44.97	72.08

- Comparison of the dynamic response of the PSCAD model and PSS/E Reduced Model 2 for several critical contingencies - Figure 4-1 to Figure 4-3 show the response of the system for a 100ms, zero impedance, three-phase fault at the Sunnyside bus (bus 222). PSS/E results are marked with circles and PSCAD results are marked with squares. The results indicate a good agreement between PSCAD and PSS/E Reduced Model 2.

Overall, the validation showed a good comparison between PSCAD and PSS/E Reduced Model 2, thereby providing confidence in the implementation of the Newfoundland ac network model in PSCAD.

Additional cursory checks were carried out involving a wide range of faults to validate the PSCAD model against the PSS/E Full System Model, and it was found that for certain faults the dynamic response between the PSCAD model and the PSS/E Full System Model were different. However, dynamic response between PSCAD and PSS/E Reduced Models 1 and 2 showed good agreement for these faults.

These results indicated a difference between the PSS/E full- and reduced-system models that was not seen earlier. It should be noted that dynamic performance comparison of the full- and reduced-system models in PSS/E was not carried out earlier.

Further investigations found that a suitable dynamic comparison can be obtained only if equivalent loads at Hardwoods (bus 335) and Chamberlains (bus 349) were replaced with original sub-systems used in the full-system model. These changes were implemented in PSS/E Reduced Model 2, and the resultant model was renamed 'Reduced Model 3'. The changes were also implemented in the PSCAD model. After implementing these changes, good comparison of the dynamic performance was obtained.

The completion of the above procedure and resultant good comparison between PSS/E and PSCAD results provided a high degree of confidence for the PSCAD model of the Newfoundland ac system.

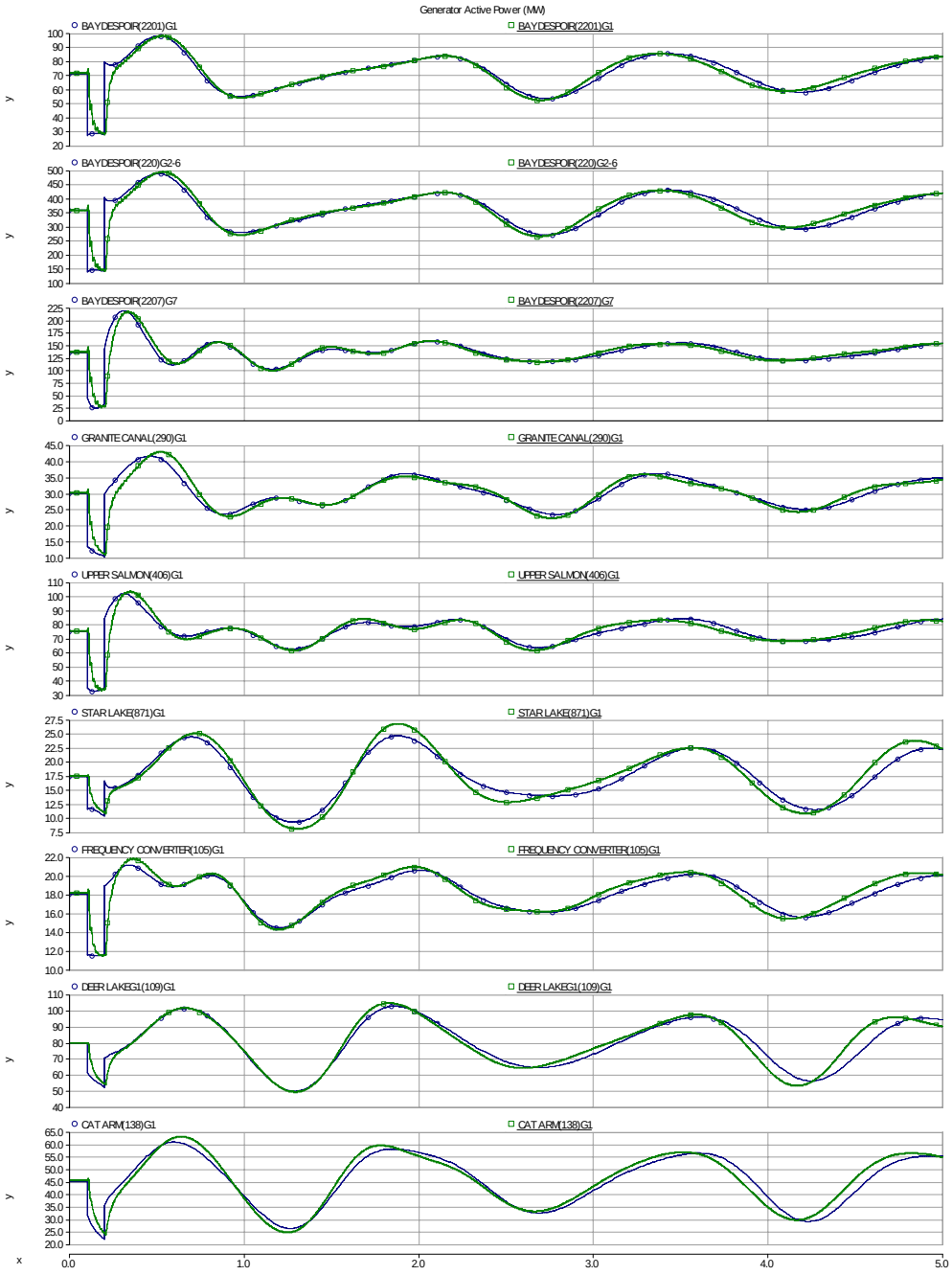


Figure 4-1 Comparison of PSS/E (o) and PSCAD ()Generator Real Power 100 ms, 0%, 3 Phase Fault at Sunnyside

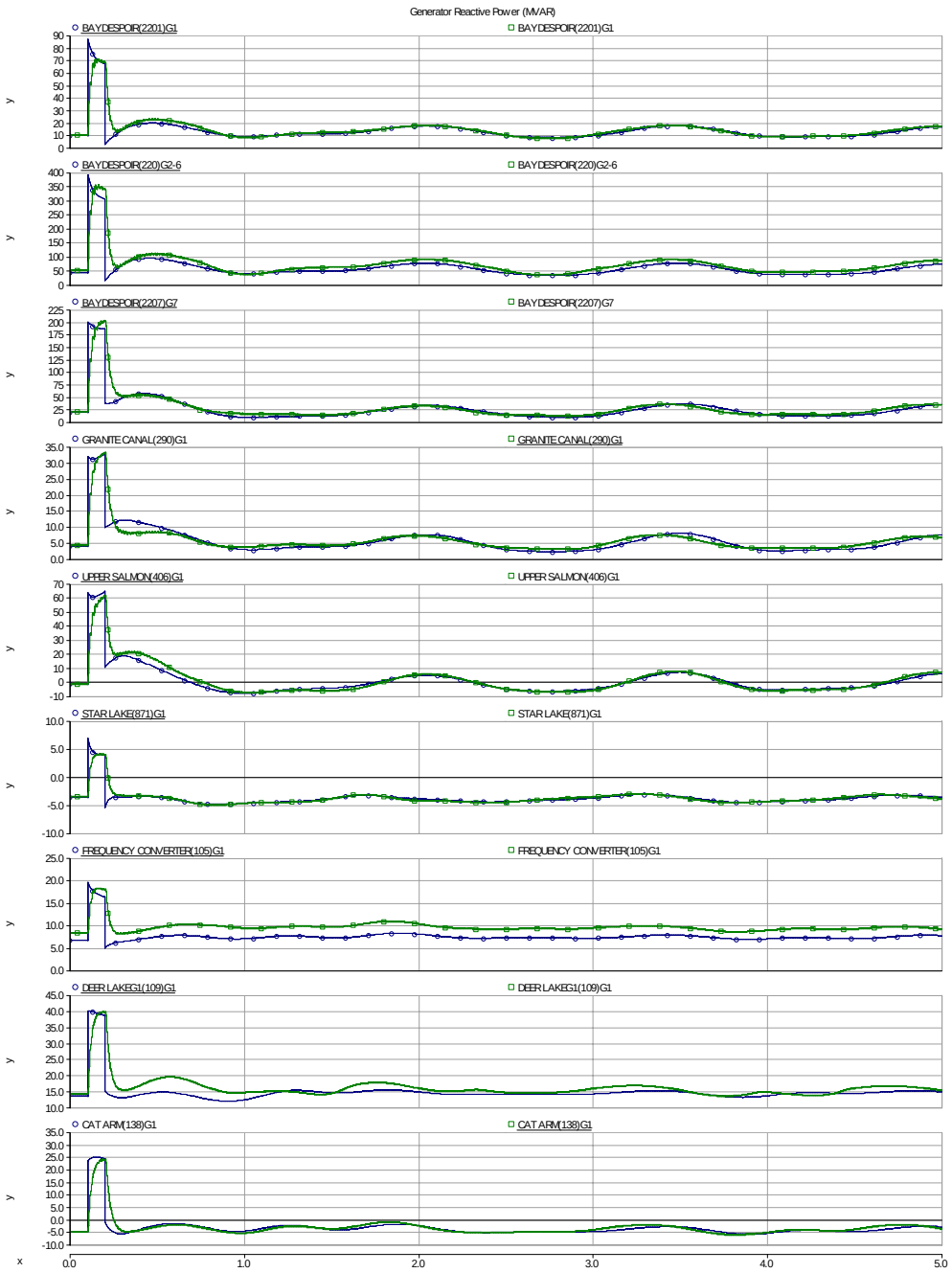


Figure 4-2 Comparison of PSS/E (o) and PSCAD ()Generator Reactive Power 100 ms, 0%, 3 Phase Fault at Sunnyside

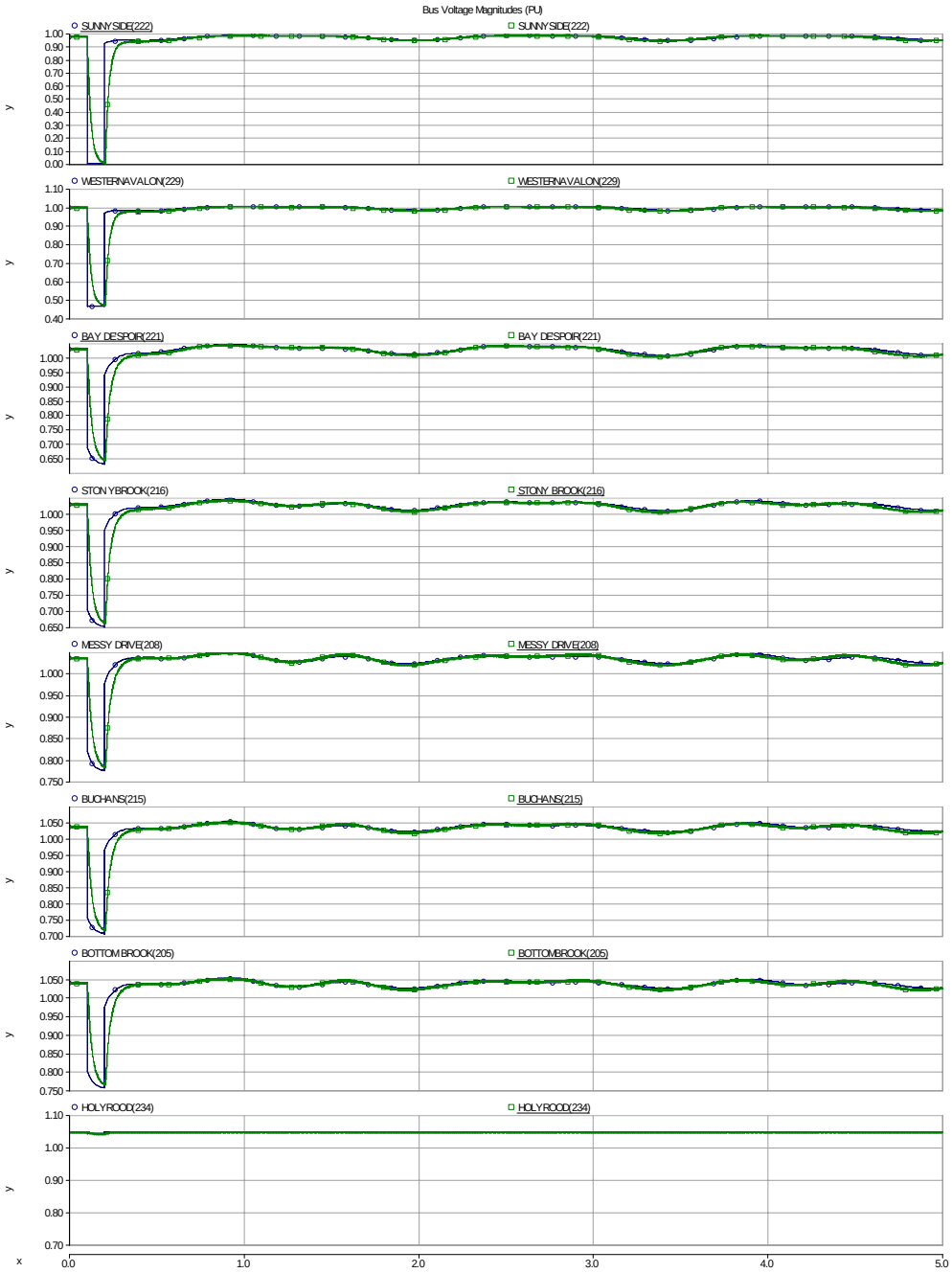


Figure 4-3 Comparison of PSS/E (o) and PSCAD ()Bus Voltage Magnitudes 100 ms, 0%, 3 Phase Fault at Sunnyside

4.2.2 Labrador AC System

The original PSS/E full-system model provided by NLH included a reduced-equivalent representation of the Labrador ac system in a weak configuration. The only additional reduction implemented prior to development of the model in PSCAD was the combination of identical individual generators into aggregate machines at Churchill Falls and Gull Island. The Labrador ac system model included the following:

- Gull Island Generation (2222 MVA) including excitation and governor systems.
- Churchill Falls Generation (5500 MVA) including excitation and governor systems.
- Muskrat Falls Generation was not included.
- One 230 kV line from Gull Island to Muskrat Falls and on to Happy Valley/Goose Bay.
- Generation (26.57 MVA) at Happy Valley/Goose Bay including excitation and governor systems
- One 735 kV line from Gull Island to Romaine.
- Three 735 kV ac lines from Churchill Falls to Montagnais.
- One 735 kV ac line from Romaine to Montagnais.
- The AC system beyond Montagnais was represented by a source behind a complex equivalent with a short-circuit strength of [redacted] MVA at a damping angle of [redacted] degrees.
- Two 230 kV lines from Churchill Falls to Wabush.
- Two synchronous condensers (60 MVA each) at Wabush including excitation systems.
- Loads and shunt reactors.

The above represented a weak configuration for the Labrador AC system. For a strong configuration, the following modifications were made:

- A 735 kV line from Gull Island to Churchill Falls was added,
- A second 230 kV line from Gull Island to Muskrat Falls was added,
- A 165 MVAR shunt reactor at Gull Island was switched off.

Similar to the implementation of the Newfoundland ac system in PSCAD, transmission lines were represented using a distributed parameters (Bergeron) model based on the data included in the PSS/E model. Validation of the PSCAD model included a comparison of short-circuit levels and Thevenin impedances at various impedances. As no simplifications were made to the generators or excitation and governor systems, no comparison of dynamic performance was undertaken. Table 4-3 shows the results of the comparison of Thevenin impedances. The results show good comparison and provide a high degree of confidence in the PSCAD model of the Labrador ac system.

Table 4-3
Comparison of Thevenin Impedances within the Labrador System

Bus/Station Name	Bus Number	Base KV	Z_{PSSE}		Z_{PSCAD}	
			Mag(Ω)	Ang(deg.)	Mag(Ω)	Ang(deg.)
Gull Island	2308	230	6.79	87.68	6.79	87.64
Montagnais	2800	735	[redacted]	[redacted]	[redacted]	[redacted]
Churchill Falls	2700	735	24.24	79.34	24.23	79.29
Wabush	2307	230	27.22	76.57	27.20	76.53
Muskrat Falls	2309	230	26.65	85.82	26.64	85.78

4.2.3 New Brunswick AC System

The New Brunswick AC system was represented by a source behind a complex equivalent with a short-circuit strength of [redacted] MVA at a damping angle of [redacted] degrees. This simplification was deemed acceptable, as it allows for reasonable representation of the commutation performance of the HVdc converters at Salisbury.

4.3 HVdc Model Development

Based on the results of the Comparison of Conventional and CCC HVdc Technology [2], the Transient Stability Study considered only the use of conventional HVdc technology.

The HVdc system model developed for the Transient Stability Study can be separated into three parts: the HVdc electric-circuit configuration, the HVdc control system, and the synchronous condenser requirements necessary to support the HVdc infeed on the Island of Newfoundland.

4.3.1 HVdc Electric Circuit Model

The HVdc-system electric-circuit parameters were selected based on typical industry practices. Selection of main-circuit parameters was based on the following:

- Each converter is comprised of a single twelve-pulse valve group per pole.
- Converter transformer ratings were based on the maximum continuous ratings per pole for each station.
- AC filters were rated to provide approximately 60% of rated HVdc power.
- Smoothing reactor sizes and HVdc filter ratings were selected based on industry practice.
- HVdc overhead line parameters were based on information from WTO DC1010 available at the start of the Transient Stability Study.
- HVdc submarine cable parameters were based on industry data available at the start of the Transient Stability Study.
- Overhead-line and undersea-cable lengths were based on information provided by NLH.
- The sea electrodes for each station were located as follows:

- ♦ Gull Island – 407 km from the converter station in the Strait of Belle Isles
- ♦ Soldiers Pond – 10 km from the converter station in Conception Bay
- ♦ Salisbury – 100 km from the converter station on the coast of New Brunswick

- The impedance of each sea electrode was set to 0.5 Ohms

Key HVdc electric-circuit parameters are summarized in Table 4-4.

Table 4-4
Key HVdc Electric Circuit Parameters

Parameter	Gull Island	Soldiers Pond	Salisbury
Station Identifier	A	B	C
Nominal Rating (MW)	1600	800	800
Nominal HVdc Voltage (kV)	450	450	450
Commutating Bus Voltage (kV)	230	230	345
Number of 12-Pulse Valve Groups per Pole	1	1	1
Converter Transformer Rating (MVA)	1170	702	468
Converter Transformer Voltage Valve Side (kV)	187.74	187.74	187.74
Converter Transformer Leakage Reactance (pu)	0.14	0.14	0.14
Smoothing Reactor (H)	0.5	0.5	0.5
AC Filters Total Installed	10x100MVAR	10x50MVAR	10x50MVAR
AC Filters Configuration	11,13,23,25,HP	11,13,23,25,HP	11,13,23,25,HP
Minimum AC Filter Requirements	3x100MVAR (11,13,23)	3x50MVAR (11,13,23)	3x50MVAR (11,13,23)

Key HVdc overhead line and undersea cable parameters are summarized below:

- Gull Island to Strait of Bell Isle:
  - ♦ Overhead line
  - ♦ Type of Model : Frequency Dependant Phase Model
  - ♦ Segment length: 407 km
  - ♦ Number of conductors per pole: 2
  - ♦ Conductor diameter: 5.14 cm
  - ♦ Conductor DC resistance: 0.02 Ohms/km
  - ♦ Bundle spacing: 4.572 cm

- Number of overhead ground Wires: 2
- Overhead ground wire diameter: 5.14cm
- Overhead ground wire resistance: 0.02 Ohms/km
- Tower geometry was based on typical geometries used for HVdc systems of similar rating.
- Note that the overhead ground wires are used as an electrode line from the converter to the sea electrode located in the Strait of Belle Isle.

- Across Strait of Belle Isle:
  - Undersea cable
  - Type of Model : Bergeron Model
  - Segment length: 40.7km
  - Number of conductors per pole: 1
  - Conductor + sequence resistance: 0.00919e-3 ohms/m
  - Conductor + sequence travel time: 8.93e-9 sec/m
  - Conductor + sequence surge impedance: 21.27 ohm
- Strait of Belle Isle to Long Range Mountains:
  - Overhead line
  - Type of Model : Frequency Dependant Phase Model
  - Segment length: 100 km
  - Number of conductors per pole: 2
  - Conductor diameter: 5.14 cm
  - Conductor DC resistance: 0.02 Ohms/km
  - Bundle spacing: 45.72cm
  - Number of overhead ground Wires: 1
  - Overhead ground wire diameter: 1.14 cm
  - Overhead ground wire resistance: 2.64 Ohms/km
  - Tower geometry was based on typical geometries used for HVdc systems of similar rating.
- Over Long Range Mountains:
  - Overhead line
  - Type of Model : Frequency Dependant Phase Model
  - Segment length: 45 km

- Number of conductors per pole: 1
- Conductor diameter: 6.0 cm
- Conductor DC resistance: 0.013 Ohms/km
- Number of overhead ground Wires: 1
- Overhead ground wire diameter: 1.14 cm
- Overhead ground wire resistance: 2.64 Ohms/km
- Tower geometry was based on typical geometries used for HVdc systems of similar rating.

- Long Range Mountains to Taylors Brook:
  - Overhead line
  - Type of Model : Frequency Dependant Phase Model
  - Segment length: 130 km
  - Number of conductors per pole: 2
  - Conductor diameter: 5.14 cm
  - Conductor DC resistance: 0.02 Ohms/km
  - Bundle spacing: 45.72cm
  - Number of overhead ground Wires: 1
  - Overhead ground wire diameter: 1.14 cm
  - Overhead ground wire resistance: 2.64 Ohms/km
  - Tower geometry was based on typical geometries used for HVdc systems of similar rating.
- Taylors Brook to Soldiers Pond:
  - Overhead line
  - Type of Model : Frequency Dependant Phase Model
  - Segment length: 406 km
  - Number of conductors per pole: 2
  - Conductor diameter: 5.14 cm
  - Conductor DC resistance: 0.02 Ohms/km
  - Bundle spacing: 45.72cm
  - Number of overhead ground Wires: 1
  - Overhead ground wire diameter: 1.14 cm
  - Overhead ground wire resistance: 2.64 Ohms/km

- Tower geometry was based on typical geometries used for HVdc systems of similar rating.

- Taylors Brook to Cape Ray:
  - Overhead line
  - Type of Model : Frequency Dependant Phase Model
  - Segment length: 300 km
  - Number of conductors per pole: 2
  - Conductor diameter: 5.14 cm
  - Conductor DC resistance: 0.02 Ohms/km
  - Bundle spacing: 45.72cm
  - Number of overhead ground Wires: 1
  - Overhead ground wire diameter: 1.14 cm
  - Overhead ground wire resistance: 2.64 Ohms/km
  - Tower geometry was based on typical geometries used for HVdc systems of similar rating.
- Across Cabot Strait:
  - Undersea cable
  - Type of Model : Bergeron Model
  - Segment length: 480 km
  - Number of conductors per pole: 1
  - Conductor + sequence resistance: 0.00919e-3 ohms/m
  - Conductor + sequence travel time: 8.93e-9 sec/m
  - Conductor + sequence surge impedance: 21.27 ohm
- Coast of New Brunswick to Salisbury:
  - Overhead lineType of Model: Frequency Dependant Phase Model
  - Segment length: 100 km
  - Number of conductors per pole: 2
  - Conductor diameter: 5.14 cm
  - Conductor DC resistance: 0.02 Ohms/km
  - Bundle spacing: 45.72cm
  - Number of overhead ground Wires: 2
  - Overhead ground wire diameter: 5.14 cm

- Overhead ground wire resistance: 0.02 Ohms/km
- Tower geometry was based on typical geometries used for HVdc systems of similar rating.
- Note that the overhead ground wires are used as an electrode line from the converter to the sea electrode located in the Cabot Strait.

4.3.2 HVdc Control System Model

One of the significant benefits of PSCAD is the ability to develop custom, user-defined models of electric circuit elements and control systems. TransGrid Solutions has developed an extensive library of custom control building blocks, which were used in the development of the overall HVdc control system for this study. These control blocks have been developed to mimic the performance of actual HVdc control systems including the effects of digital sampling, as such they provide a very accurate representation of the HVdc control system.

The Lower Churchill Project (LCP) multi-terminal HVdc system proposed included a number of key technical challenges that had to be overcome during the development of the control system, including:

- Multi-terminal configuration – Although multi-terminal HVdc has been used in the past, detailed information on actual control systems in service is not readily available; therefore, considerable effort was required to develop and implement the overall control-system concepts.
- Long HVdc cable – Although two-terminal HVdc systems with undersea cables are in operation, the length of the cable section across the Cabot Strait is considerably longer than any systems currently in operation. (Note that there are currently a number of HVdc links under design or construction with cable lengths similar to that of the LCP.) The length of the undersea cable (and hence the cable capacitance) has a dramatic impact on the overall performance of the HVdc link and must be accounted for in the design of the control system. Furthermore, the length of cable, coupled with the multi-terminal configuration, added yet another dimension to the requirements of the control system.
- Significance of the HVdc infeed to the Newfoundland ac system – Since the HVdc infeed represents a significant portion of the generation on the Island of Newfoundland, performance of the HVdc system is key to the overall stability of the Newfoundland ac system. This requirement puts added complexity on the control system.
- The requirement to operate each station in rectifier or inverter mode adds complexity to the overall control system.

4.3.2.1 Salient Features of the HVdc Control System Model

Salient features of the control system adopted include the following:

- In order to improve commutation performance, the system is operated with current control at the inverter(s) and voltage control at the rectifier. This mode of operation provides better immunity to commutation failure resulting from disturbances in the inverter ac system.

  When a long HVdc cable is combined with an inverter connected to a weak ac system, the performance of the HVdc link is severely impacted by the fact that the cable can discharge quickly

into the inverter when the ac system voltage drops a small amount. This increase in dc current causes a transient increase in converter reactive power consumption which further reduces the weak system bus voltage. The initial transient increase in dc current is not seen by the rectifier, since it is mainly driven by the energy stored in the large capacitance of the HVdc cable; therefore implementation of current control at the rectifier is not effective in controlling the over-current.

By operating the inverter in current control, it can respond immediately to the transient increase in dc current to counteract the discharge into the inverter. This however requires the inverter to operate at a higher extinction angle so that it has sufficient room to provide current control while avoiding commutations failure.

- The HVdc power order is set by the station(s) operating as inverter.
- A current-balance controller was implemented to ensure that current order allocation to inverters and rectifiers was always balanced.
- A frequency controller was developed that measures the frequency of the Newfoundland ac system and modulates the HVdc power in-feed to stabilize the Newfoundland frequency. Effective frequency control of the Newfoundland system will minimize the need for under-frequency load shed in the Newfoundland system, even for large disturbances.
- A special damping feature was implemented to improve the overall performance of the long cable system. This damping function is designed to counteract sudden increases in HVdc current that can result in commutation failures.
- The control system uses digital sampling throughout in order to provide a realistic representation of the modern HVdc control system that would be used in the actual plant. Furthermore, the implementation of the overall control system is based on practical experience and reflects a control system that could be supplied for the actual plant by any of the current HVdc suppliers.

4.3.2.2 Basic Functions Implemented within the HVdc Control System Model

The following features were implemented within the overall HVdc control system hierarchy:

- HVdc and ac system signal measurement and conditioning
  - ♦ Measurement and conditioning of all signals
  - ♦ Calculation of control signals
- Power reference controls
  - ♦ Power-order reference setting
- Power direction controls
  - ♦ Converter operating mode (rectifier/inverter) selection
- Frequency controls
  - ♦ Newfoundland ac frequency-limit control

- Current-order reference controls
  - Calculation of current order based on power order and dc voltage
  - Calculation of current-order modulation based on frequency control
- Current Balance Control
  - Allocation and balance of all current orders
- Pole controls
  - Implementation of current order limits
  - Current margin allocation
- Voltage Dependant Current Limits (VDCL)
  - Application of VDCLs
- Converter Controls
  - Implementation of extinction angle control, dc current control, and dc voltage control
  - Selection of control mode
  - Implementation of special dc current damping function
- Converter Sequence Controls
  - Implementation of converter block/deblock sequences
- Low-Level Converter Controls
  - Implementation of firing controls including phase lock loop, application of force retard, valve bypass logic
  - Implementation of extinction angle measurement.
  - These controls are implemented within the valve group model itself.
- Tap-Changer Controls
  - Automatic adjustment of converter transformer tap changer
  - The tap-changer controls implemented are intended for initial configuration of a given power flow only and do not represent the operation of the transformer tap changer in response to system events.
- Reactive Power Controls
  - Automatic configuration of ac filters based on a steady-state balance of reactive power exchange with the ac system.
  - The reactive power controls implemented are intended for initial configuration of a given power flow only and do not represent the operation of the reactive power controller in response to system events.

4.3.2.3 HVdc Control System Development and Parameter Tuning

As no multi-terminal HVdc control system model was available prior to the start of the Study, the multi-terminal HVdc control system was developed based on concepts and implementations used for two-terminal HVdc links. Following development of the basic control system in PSCAD, an extensive program of parameter tuning was undertaken. Initial tuning was performed using simple ac system equivalents at each of the three converters chosen to represent expected weak ac system conditions. The goal of the initial tuning was to provide recovery of HVdc power to 90% of the pre-fault level within 300 ms of fault clearing for faults within each of the three ac systems.

Following initial tuning, the HVdc system model was integrated into the PSCAD model of the three ac systems, which was developed independently. Preliminary testing on the combined AC/DC model showed unacceptable performance of the integrated systems; in particular, stability issues were observed within the Newfoundland system. Modifications were implemented within the HVdc control model, including the development of the dc current damping controller, and changes were made to the ac system, including the addition of series compensation and high-inertia synchronous condensers in order to improve overall system performance.

Following extensive testing and parameter optimization, acceptable system performance was obtained. The final control-system configuration and parameters selected represent a reasonable HVdc control system that could be implemented in the field and provide a high degree of confidence in the study results.

4.3.3 Synchronous Condenser Requirements to Support the HVdc In-Feed

As determined in the study on the comparison of conventional and CCC HVdc technology [2], one 300 MVAR high inertia synchronous condenser is required to be in-service at all times at both the 230 kV Pipers Hole bus and at the 230 kV Soldiers Pond bus. Without these synchronous condensers the earlier study [2] found that the dynamic performance of the system is unstable or unacceptable for various disturbances.

A model for these synchronous condensers was developed in PSCAD, based on the 300 MVAR synchronous condensers installed by Manitoba Hydro for compensation of the Bipoles 1 and 2 HVdc systems. The duty of these machines is similar to that required for the proposed Lower Churchill Project, providing both system strength and system inertia, therefore the machine parameters were adopted for this study.

4.3.4 Limitations of the PSCAD HVdc Model

The PSCAD HVdc model developed and used for this Study has the following limitations, which should be noted:

- The model cannot currently be used to simulate mixed-mode operation where two terminals are operating bipolar and the third terminal is operating monopolar. Although this is a valid operating

configuration for the real system, implementation of features required to support this within the PSCAD model would require significant time and effort, and operation in mixed-mode would not provide any additional insights into the overall feasibility of the proposed multi-terminal HVdc system.

- The model cannot be used to simulate operation where two stations are operating as rectifiers at the same time. Although each station can be operated as a rectifier or as an inverter, operation with more than one station configured as a rectifier concurrently is not possible at this time. Significant time and effort would be required to implement this mode of operation in the PSCAD model.

The above limitations have no impact on this study or the results produced. Implementation of the above features in the model is possible and can be pursued by NLH in the future, if so desired.

5. Study Methodology

The following general procedure was followed for the performance of studies:

1. Configure the integrated ac/dc PSCAD model to represent the power flow base cases provided by NLH with the given generation dispatch of the Newfoundland island ac system and HVdc configurations.
2. Perform transient simulations for the full set of 72 contingencies for three scenarios identified in Section 5.4.
3. Based on the results of the above simulations, identify the worst disturbance cases.
4. Simulate ten worst disturbances for the remaining generation dispatch and HVdc configurations.
5. Perform additional sensitivity cases to improve performance of the HVdc system.
6. Document study results and analysis, and prepare recommendations.
7. Prepare study report.

5.1 Load Flow Base Cases

A total of 11 base cases were originally proposed, representing different ac system configurations and HVdc system configurations and loadings as shown in Table 5-1.

As seen in Table 5-1, the only difference between base cases 1, 9, 10, and 11 is the representation of the New Brunswick ac system. As the New Brunswick system was not the focus of the study, it was decided that cases 9, 10, and 11 would not be considered in the study. Base case 1 was retained, as it represented the worst-case configuration of the New Brunswick system (weak, peak-load configuration).

Two additional base cases (12 and 13), as shown in Table 5-2, were added to the study.

Detailed generation dispatch within the Newfoundland system for each of the base cases considered in the study is shown in Table 5-3.

Table 5-1
Originally Identified Base Case Configurations
Base Cases

NO.	NLH System Load	Soldiers Pond	Newfoundland Generation	Labrador (Gull)	NB
BC1	Peak (1600 MW)	Full Import (800 MW)	economic dispatch	Weak	Weak, peak load
BC2	Peak (1600 MW)	Reduced Import (600 MW)	maximum economic dispatch	Weak	Weak, peak load
BC3	Future Peak (1800 MW)	Full Import (800 MW)	Maximum generation	Weak	Weak, peak load
BC4	Summer Night (625 MW)	Reduced Import (250 MW)	Minimum generation	Weak	Weak, peak load
BC5	Summer Night (625 MW)	Minimum Import (80 MW)	economic dispatch	Weak	Weak, peak load
BC6	Intermediate (1000 MW)	Full Import (800 MW)	economic dispatch	Weak	Weak, peak load
BC7	Intermediate (1000 MW)	Minimum Import (80 MW)	maximum economic dispatch	Weak	Weak, peak load
BC8	625 MW	Export (175 MW)	maximum economic dispatch	Weak	Weak, peak load
BC9	Peak (1600 MW)	Full Import (800 MW)	economic dispatch	Weak	Strong, peak load
BC10	Peak (1600 MW)	Full Import (800 MW)	economic dispatch	Weak	Weak, light load
BC11	Peak (1600 MW)	Full Import (800 MW)	economic dispatch	Weak	Strong, light load

Table 5-2
Additional Base Case Configurations Added to the Study
Base Cases

NO.	NLH System Load	Soldiers Pond	Newfoundland Generation	Labrador (Gull)	NB
BC12	Summer Night (625 MW)	Import (80 MW)	economic dispatch	Strong	Weak, peak load
BC13	Future Peak (1800 MW)	Reduced Import (600 MW)	maximum generation	Weak	Weak, peak load

Table 5-3
WTO DC 1020: HVdc System Integration Study
Generation Dispatch for Base Case Scenarios

Base Cases	BC1	BC2	BC3	BC4	BC5	BC6	BC7	BC8	BC12	BC13
NLH System Load (MW)	1584.5	1584.5	1750.5	625.0	625.0	990.1	990.1	625.0	625.0	1750.5
Generation Dispatch										
HVdc at Soldiers Pond	765.9	578.4	765.9	248.8	78.5	765.9	78.5	-175.0	79.8	574.2
NLH – Hydro										
Bay d'Espoir Unit 1	57.8	67.8	69.0	61.6	60.6	58.5	71.2	59.1	59.2	67.6
Bay d'Espoir Unit 2	58.2	68.3	69.5	off	off	off	69.7	58.0	off	68.1
Bay d'Espoir Unit 3	58.2	68.3	69.5	off	60.8	off	69.7	58.0	60.8	68.1
Bay d'Espoir Unit 4	58.2	68.3	69.5	off	off	off	69.7	58.0	off	68.1
Bay d'Espoir Unit 5	58.2	68.3	69.5	off	60.8	off	69.7	58.0	60.8	68.1
Bay d'Espoir Unit 6	58.2	68.3	69.5	off	off	off	69.7	58.0	off	68.1
Bay d'Espoir Unit 7	135.0	154.0	154.0	135.0	135.0	sc	154.0	154.0	135.0	154.0
Cat Arm Unit 1	35.0	65.0	65.0	35.0	35.0	sc	60.0	65.0	35.0	65.0
Cat Arm Unit 2	35.0	65.0	65.0	sc	35.0	sc	60.0	65.0	35.0	65.0
Upper Salmon	75.0	84.0	84.0	64.0	75.0	70.0	75.0	84.0	75.0	84.0
Hinds Lake	67.0	75.0	75.0	off	off	off	67.0	75.0	off	75.0
Granite Canal	25.0	40.0	40.0	22.0	30.0	25.0	35.0	40.0	30.0	40.0
Paradise River	8.0	8.0	8.0	off	8.0	off	8.0	8.0	8.0	8.0
NLH – Thermal										
Hardwoods	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc
Stephenville	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc
Holyrood CT1	sc	30.0	sc	sc	sc	sc	sc	sc	sc	50.0
Holyrood CT2	sc	sc	sc	sc	sc	sc	sc	sc	sc	50.0
Holyrood CT3	sc	sc	sc	sc	sc	sc	sc	sc	sc	50.0
Holyrood CT4	sc	sc	sc	sc	sc	sc	sc	sc	sc	50.0
Holyrood CT5	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc
NUGS										
Star Lake	17.9	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4
Rattle Brook	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
CBP&P	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Exploits	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0
Wind										
St. Lawrence	25.0	25.0	25.0	0.0	0.0	12.0	12.0	0.0	0.0	25.0
Fermuse	25.0	25.0	25.0	0.0	0.0	12.0	12.0	0.0	0.0	25.0
Goulds	25.0	25.0	25.0	0.0	0.0	12.0	12.0	0.0	0.0	25.0
Total Generation	872.3	1073.3	1050.5	385.6	568.2	257.5	982.7	908.1	566.8	1242.1
HVdc Participation, %	48.3%	36.5%	43.8%	39.8%	12.6%	77.4%	7.9%	-32.0%	12.8%	32.8%

5.2 HVdc Configurations

A total of nine different HVdc system configurations were originally proposed for the study, as shown in Table 5-4 below. Configurations DC4, DC5, and DC6 represent a mixed-mode operation where the rectifier and one inverter are operating in bipolar mode and the other inverter is operating in monopolar mode. Although such mixed-mode operation will be required in the actual system, the inclusion of these configurations in this study would not provide any additional insight into the feasibility of the proposed HVdc interconnection. In addition, considerable time would have been required to implement mixed-mode operation within the PSCAD model; therefore it was decided that mixed-mode operation (configurations DC4, DC5, and DC6) would not be included in the study.

Table 5-4
HVdc Configurations

Configuration	Gull Island	Soldiers Pond	Salisbury	Description
DC1	REC – BP	INV – BP	INV - BP	Normal
DC2	REC – MP	INV - MP[1]	INV - MP	Loss of 1 pole at Gull Island
DC3	REC – MP	INV - MP[2]	INV - MP	Loss of 1 pole at Gull Island
DC4	REC – BP	INV - MP[1]	INV - BP	Loss of 1 pole at Soldiers Pond
DC5	REC – BP	INV - MP[2]	INV - BP	Loss of 1 pole at Soldiers Pond
DC6	REC – BP	INV – BP	INV - MP	Loss of 1 pole at Salisbury
DC7	OFF	INV – BP	REC - BP	2-terminal
DC8	OFF	REC – BP	INV - BP	2-terminal
DC9	INV - BP	REC – BP	OFF	2-terminal

Notes:

1) Overload - monopolar at 2.0 p.u.
2) Continuous monopolar at 1.5 p.u.

5.3 Study Cases

A total of 13 system scenarios were developed based on a combination of the final base cases and HVdc configurations identified as shown in Table 5-5.

Table 5-5
Final System Configurations Considered

Base Case	DC	Soldiers Pond	Salisbury	Gull Island
BC1	DC1	800 BP	800 BP	1600 BP
	DC7	800 BP	800 BP–REC	OFF
BC2	DC3	600 MP	400 MP	1000 MP
BC3	DC1	800 BP	800 BP	1600 BP
	DC4	800 MP	400 MP	1200 MP
BC4	DC1	255 BP	800 BP	1055 BP
	DC3	255 MP	400 MP	655 MP
BC5	DC1	80 BP	800 BP	880 BP
BC6	DC1	800 BP	800 BP	1600 BP
BC7	DC1	80 BP	800 BP	880 BP
BC8	DC8	165 BP–REC	165 BP–INV	OFF
BC12	DC10	80 BP	OFF	80 BP
BC13	DC3	600 MP	400 MP	1000 MP

A total of 72 disturbances were identified for transient stability analysis as given in Table 5-6.

The full set of contingencies were simulated for the following scenarios;

BC1-DC1 - Normal system operation with all HVdc facilities in bipolar operation at full power, peak ac load scenarios, and economic generation dispatch.

BC2-DC3 - HVdc in monopolar operation at Soldiers Pond with peak Newfoundland load, maximum economic dispatch, and reduced import.

BC6-DC1 - The weakest Newfoundland system with 1000 MW load, minimum generation dispatch and HVdc at Soldiers Pond in bipolar operation with full import (800 MW).

From the above three full contingency analyses, the ten worst contingencies were identified and simulated for the remaining 10 of 13 system scenarios. The worst contingencies are shown as highlighted in Table 5-6.

5.4 Contingency List

Table 5-6
WTO DC 1020 HVdc System Integration Study- Transient Stability Analysis
List of Contingencies

No.			Description	PSS/E Identifier	Fault Location	Clearing Time (cy)		Reclose Time (cy)	
						Near End	Far End		
NL1	**Equipment Tripping without Faults**								
	NL1.1	*230 kV Transmission Lines*			-	-	-	-	-
		NL1.1.1	Bay d'Espoir to Pipers Hole - TL206	221 to 218 cct 2	-	-	-	-	-
		NL1.1.2	Pipers Hole to Sunnyside - TL206	218 to 222 cct 2	-	-	-	-	-
		NL1.1.3	Sunnyside to Western Avalon -TL203	222 to 229 cct 1	-	-	-	-	-
		NL1.1.4	Western Avalon to Soldiers Pond - TL201	229 to 2490 cct 2	-	-	-	-	-
		NL1.1.5	Soldiers Pond to Hardwoods - TL201	2490 to 236 cct 1	-	-	-	-	-
		NL1.1.6	Soldiers Pond to Oxen Pond - TL218	2490 to 238 cct 1	-	-	-	-	-
		NL1.1.7	Soldiers Pond to Holyrood - TL242	2490 to 234 cct 1	-	-	-	-	-
	NL1.2	*Shunt Capacitor or Filter Bank*							
		NL1.2.1	Largest Soldiers Pond AC Filter Bank	Bus 2490	-	-	-	-	-
	NL1.3	*Synchronous Condensers*							
		NL1.3.1	Soldiers Pond 300 MVAR Condenser	Bus 2494 m/c 1	-	-	-	-	-
		NL1.3.2	Pipers Hole 300 MVAR Condenser	Bus 2221 m/c 1	-	-	-	-	-
	NL1.4	*Largest on-line Generator*							
		NL1.4.1	Bay d'Espoir Unit 7*	Bus 2207 m/c 7	-	-	-	-	-
	NL1.5	*HVdc Pole*							
		NL1.5.1	HVdc intermittent pole outage					-	-
		NL1.5.2	HVdc permanent pole outage					-	-
	NL1.6	*HVdc Bipole*							
		NL1.6.1	Islanding of Newfoundland with assist from NB HVdc						
NL2	**Bus Faults without Equipment Tripping**								
	NL2.1	230 kV three-phase fault at Soldiers Pond		Bus 2490	Bus 2490	-	-	-	-

Table 5-6
WTO DC 1020 HVdc System Integration Study- Transient Stability Analysis
List of Contingencies

No.			Description	PSS/E Identifier	Fault Location	Clearing Time (cy)		Reclose Time (cy)	
						Near End	Far End		
	NL2.2	230 kV line-to-ground fault at Soldiers Pond		Bus 2490	Bus 2490	-	-	-	-
NL3	**NL AC-System 3-Phase Fault with Equipment Tripping**								
	NL3.1	*230 kV Transmission Lines*							
		NL3.1.1	Bay d'Espoir to Piper's Hole - TL206	221 to 218 cct 2	BDE - 220	5	6	-	-
		NL3.1.2	Pipers Hole to Sunnyside - TL206	218 to 222 cct 2	PHL - 218	5	6	-	-
		NL3.1.3	Sunnyside to Western Avalon -TL203	222 to 229 cct 1	SSD - 222	5	6	-	-
		NL3.1.4	Western Avalon to Soldier's Pond - TL201	229 to 2490 cct 2	WAV - 229	5	6	-	-
		NL3.1.5	Soldiers Pond to Hardwoods - TL201	2490 to 236 cct 1	SOL - 2490	5	6	-	-
		NL3.1.6	Soldiers Pond to Oxen Pond - TL218	2490 to 238 cct 1	OPD - 238	5	6	-	-
		NL3.1.7	Soldiers Pond to Holyrood - TL242	2490 to 234 cct 1	HRD - 234	5	6	-	-
		NL3.1.8	Bay d'Espoir to Pipers Hole - TL206	218 to 221 cct 2	PHL - 218	5	6	-	-
	NL3.2	*Shunt Capacitor or Filter Bank*							
		NL3.2.1	Largest Soldiers Pond AC Filter Bank	Bus 2490	Bus 2490	6	-	-	-
	NL3.3	*Synchronous Condensers*							
		NL3.3.1	Soldiers Pond 300 MVAR Condenser	Bus 2494 m/c 1	Bus 2490	6	-	-	-
		NL3.3.2	Piper's Hole 300 MVAR Condenser	Bus 2221 m/c 1	Bus 218	6	-	-	-
	NL3.4	*Largest on-line Generator*							
		NL3.4.1	Bay d'Espoir Unit 7*	Bus 2207 m/c 7	Bus 220	6	-	-	-
	NL3.5	*HVdc Pole*							
		NL3.5.1	HVdc Pole	Converter Transf.	Bus 2490	6	-	-	-
NL4	**NL AC-System Single Line-to-Ground Fault with Equipment Tripping**								
	NL4.1	*230 kV Transmission Lines - Successful Reclose*							
		NL4.1.1	Bay d'Espoir to Pipers Hole - TL206	221 to 218 cct 2	BDE - 220	5	6	BDE-30	PHL-45
		NL4.1.2	Pipers Hole to Sunnyside - TL206	218 to 222 cct 2	PHL - 218	5	6	PHL-30	SSD-45
		NL4.1.3	Sunnyside to Western Avalon -TL203	222 to 229 cct 1	SSD - 222	5	6	SSD-30	WAV-40
		NL4.1.4	Western Avalon to Soldiers Pond - TL201	229 to 2490 cct 2	WAV - 229	5	6	WAV-30	SOL-50

Table 5-6
WTO DC 1020 HVdc System Integration Study- Transient Stability Analysis
List of Contingencies

No.			Description	PSS/E Identifier	Fault Location	Clearing Time (cy)		Reclose Time (cy)	
						Near End	Far End		
		NL4.1.5	Soldiers Pond to Hardwoods - TL201	2490 to 236 cct 1	SOL - 2490	5	6	SOL-30	HWD-50
		NL4.1.6	Soldiers Pond to Oxen Pond - TL218	2490 to 238 cct 1	OPD - 238	5	6	SOL-45	OPD-30
		NL4.1.7	Soldiers Pond to Holyrood - TL242	2490 to 234 cct 1	HRD - 234	5	6	SOL-30	HRD-45
	NL4.2	*Shunt Capacitor or Filter Bank*							
		NL4.2.1	Largest Soldiers Pond AC Filter Bank	Bus 2490	Bus 2490	6	-	-	-
	NL4.3	*Synchronous Condensers*							
		NL4.3.1	Soldiers Pond 300 MVAR Condenser	Bus 2494 m/c 1	Bus 2490	6	-	-	-
		NL4.3.2	Pipers Hole 300 MVAR Condenser	Bus 2221 m/c 1	Bus 218	6	-	-	-
	NL4.4	*Largest on-line Generator*							
		NL4.4.1	Bay d'Espoir Unit 7*	Bus 2207 m/c 7	Bus 220	6	-	-	-
	NL4.5	*HVdc Pole*							
		NL4.5.1	HVdc Pole	Converter Transf.	Bus 2490	6	-	-	-
NL5	**NL AC-System Faults with Delayed Tripping**								
	NL5.1	*230 kV Transmission Lines LG Fault with Unsuccessful Reclose*							
		NL5.1.1	Bay d'Espoir to Pipers Hole - TL206	221 to 218 cct 2	BDE - 220	5	6	BDE-30	PHL-45
		NL5.1.2	Pipers Hole to Sunnyside - TL206	218 to 222 cct 2	PHL - 218	5	6	PHL-30	SSD-45
		NL5.1.3	Sunnyside to Western Avalon -TL203	222 to 229 cct 1	SSD - 222	5	6	SSD-30	WAV-40
		NL5.1.4	Western Avalon to Soldiers Pond - TL201	229 to 2490 cct 2	WAV - 229	5	6	WAV-30	SOL-50
		NL5.1.5	Soldiers Pond to Hardwoods - TL201	2490 to 236 cct 1	SOL - 2490	5	6	SOL-30	HWD-50
		NL5.1.6	Soldiers Pond to Oxen Pond - TL218	2490 to 238 cct 1	OPD - 238	5	6	SOL-45	OPD-30
		NL5.1.7	Soldiers Pond to Holyrood - TL242	2490 to 234 cct 1	HRD - 234	5	6	SOL-30	HRD-45
	NL5.2	*138 kV Transmission Line 3-Phase Fault with Back-up Clearing*							
		NL5.2.1	Holyrood to Bay Roberts - 39L	338 to 357	HRD - 338	6	30	-	-
		NL5.2.2	Western Avalon to Blaketwon 64L	311 to 310 cct 1	WAV - 311	6	24	-	-
		NL5.2.3	Sunnyside to Salt Pond - TL219	223 to 371 cct 1	SSD - 223	5	33	-	-
	NL5.3	*138 kV Transmission Line LG Fault with Back-up Clearing*							
		NL5.3.1	Holyrood to Bay Roberts - 39L	338 to 357	HRD - 338	28	28	-	-

Table 5-6
WTO DC 1020 HVdc System Integration Study- Transient Stability Analysis
List of Contingencies

No.			Description	PSS/E Identifier	Fault Location	Clearing Time (cy)		Reclose Time (cy)	
						Near End	Far End		
		NL5.3.2	Western Avalon to Blaketwon 64L	311 to 310 cct 1	WAV - 311	38	23	-	-
		NL5.3.3	Sunnyside to Salt Pond - TL219	223 to 371 cct 1	SSD - 223	5	77	-	-
	NL5.4	*66 kV Transmission Line 3-Phase Fault with Back-up Clearing*							
		NL5.4.1	Hardwoods to Goulds - 72L	335 to 445 cct 1	HWD - 335	10	66	-	-
		NL5.4.2	Hardwoods to Chamberlains - 49L	335 to 349 cct 1	CHA - 349	10	25	-	-
		NL5.4.3	Western Analon to Blaketown - 86L	336 to 308 cct 1	WAV - 336	10	36	-	-
	NL5.5	*66 kV Transmission Line SLG Fault with Back-up Clearing*							
		NL5.5.1	Hardwoods to Goulds - 72L	335 to 445 cct 1	HWD - 335	25	25	-	-
		NL5.5.2	Hardwoods to Chamberlains - 49L	335 to 349 cct 1	CHA - 349	25	40	-	-
		NL5.5.3	Western Avalon to Blaketown - 86L	336 to 308 cct 1	WAV - 336	25	40	-	-
L2	**Labrador AC-System Faults Without Equipment Tripping**								
	L2.1	230 kV three-phase fault at Gull Island		Bus 2308	Bus 2308	6	-	-	-
	L2.2	230 kV line-to-ground fault at Gull Island		Bus 2308	Bus 2308	6	-	-	-
L3	**Labrador AC-System 3-Phase Faults with Normal Tripping**								
	L3.1	*230 kV Transmission Line*							
		L3.1.1	Gull Island to Muskrat Falls-Trip Happy Valley	2308 to 2309 cct 1	Bus 2308	6	6	-	-
	L3.2	*Shunt Capacitor or Filter Bank*							
		L3.2.1	Largest Gull Island AC Filter Bank	Bus 2308	Bus 2308	6	-	-	-
	L3.3	*Largest on-line Generator*							
		L3.3.1	Gull Island 500 MW Generator Bus 2121 m/c 1	2308 to 2341 cct 1	Bus 2308	6	6	-	-
L4	**Labrador AC-System LG Faults with Normal Tripping**								
	L4.1	*230 kV Transmission Line*							
		L4.1.1	Gull Island to Muskrat Falls-Trip Happy Valley	2308 to 2309 cct 1	Bus 2308	6	6	-	-
	L4.2	*Shunt Capacitor or Filter Bank*							
		L4.2.1	Largest Gull Island AC Filter Bank	Bus 2308	Bus 2308	6	-	-	-
	L4.3	*Largest on-line Generator*							

Table 5-6
WTO DC 1020 HVdc System Integration Study- Transient Stability Analysis
List of Contingencies

No.			Description	PSS/E Identifier	Fault Location	Clearing Time (cy)		Reclose Time (cy)	
						Near End	Far End		
		L4.3.1	Gull Island 500 MW Generator Bus 2121 m/c 1	2308 to 2341 cct 1	Bus 2308	6	6	-	-
L6	**735 kV Faults with Line Tripping**								
	L6.1		735 kV 3-Phase Fault at Gull Island	2704 to 2801 cct 1	Bus 2704	6	6	-	-
	L6.2		735 kV LG Fault at Gull Island	2704 to 2801 cct 1	Bus 2704	6	6	-	-
NB2	**NB AC-System Faults**								
	NB2.1		345 kV 3-Phase Fault at Salisbury						
	NB2.2		345 kV LG Fault at Salisbury						

6. Analysis of Results and Discussion

The major Newfoundland load centre is located east of Bay d'Espoir on the Avalon Peninsula, while the majority of the generation is located west of Bay d'Espoir. This can result in heavy west-to-east power flow on the 230 kV transmission system, in particular between Bay d'Espoir, Sunnyside, Western Avalon, and Soldiers Pond. In addition, approximately 255 MW of new industrial load (refinery and smelter) is planned to be installed along this heavily loaded west-to-east corridor, which increases the loading on these 230 kV lines. As a general result, this can cause voltage and rotor-angle stability issues for the Newfoundland system along with steady-state voltage depression and thermal overloading on lines in this corridor.

The HVdc in-feed into Soldiers Pond generally has a positive steady-state impact on the Island transmission system as it off-loads this west-to-east power flow by injecting power closer to the load centre. Faults within the Newfoundland ac network that cause a commutation failure at Soldiers Pond will, however, result in a transient loss of the entire HVdc in-feed during the commutation failure and for a short period following ac fault clearing while the HVdc power is recovering (approximately 300 ms, depending on the fault). In particular, faults causing a commutation failure while simultaneously disturbing the Bay d'Espoir generators to a high enough degree (i.e. a fault very near Bay d'Espoir) pose the greatest risk to stability of the Newfoundland ac system.

Many of the issues observed in the Newfoundland system are not necessarily due solely to the HVdc in-feed but are more related to the operation of the integrated Newfoundland ac system and the HVdc in-feed. Major contributing factors other than the HVdc in-feed itself are the lack of transmission linking the generation in the west to the load centre in the east of the Island, and the large new refinery load that is planned to be installed at Pipers Hole.

Initial stability analysis performed in the comparison of conventional and CCC HVdc technology [2] indicated that one 300 MVAr high-inertia synchronous condenser is required to be in service at both Pipers Hole 230 kV bus and Soldiers Pond 230 kV bus at all times. In addition, 50% series compensation of both 230 kV lines from Bay d'Espoir to Pipers Hole was also required. The discussion of results and observations presented below are based on both the series compensation and synchronous condenser requirements previously identified [2] being in service.

6.1 General Trends and Observations

Good performance of the multi-terminal HVdc system was observed for all ac system and HVdc configurations considered.

Faults within the Newfoundland ac system can result in temporary commutation failure of the Soldiers Pond converter, depending on fault location and severity. The likelihood of commutation failure is increased due to the long undersea cable across the Cabot Strait. The large capacitance of this undersea cable tends to discharge through the Soldiers Pond inverter, whose dc voltage was transiently reduced due to the ac system fault. The cable discharge further increases the dc current, thus increasing the likelihood of commutation failure. However, following fault clearing, recovery of the HVdc infeed was

seen to be good, with the HVdc power typically recovering to 90% of pre-disturbance power within 300 ms of fault clearing.

Faults within the Labrador and New Brunswick systems with the corresponding converters operating as inverters were not considered in detail; however, the same conditions will apply to these as to the Newfoundland system regarding likelihood of commutation failure and the impact of the long undersea cable.

When operating in three terminal mode with two stations operating as inverters, commutation failure of one inverter causes a loss of HVdc power in the other inverter while the commutation failure persists; however, HVdc power recovery is good following removal of the commutation failure.

Under some fault conditions within the Newfoundland ac system, the Soldiers Pond converter is able to continue commutation during the fault, resulting in a reduced HVdc power in-feed during the fault. Upon clearing of the fault, HVdc power recovery to the pre-disturbance level is good.

No conditions (ac system configurations or contingencies) were observed under which the HVdc system could not successfully recover. Recovery of the HVdc power transfer is dictated, to a large extent, by the time required to charge the large cable capacitance; therefore, significant improvements in the speed of recovery beyond that obtained in these feasibility studies is not likely.

Performance in two-terminal mode with Soldiers Pond operating as an inverter or a rectifier was also seen to be good. Although the maximum power export from Soldiers Pond when operating as a rectifier was limited to approximately 165 MW due to the Newfoundland ac system configuration given, the results demonstrate that export from Newfoundland is feasible. With additional ac system upgrades, an increased export level should be attainable.

The system is transiently stable with adequate post-disturbance recovery. The majority of contingencies studied result in voltage dips with acceptable duration (20-cycle); however, some disturbances resulted in voltage dips beyond the criteria limits. Additional improvements in the Newfoundland ac system will be required to improve the voltage-sag problems if these are deemed excessive.

The need for under-frequency load shedding in the Newfoundland ac system is minimized. The HVdc system, due to its inherent controllability, provides an effective means of fast and efficient frequency control within the Newfoundland ac system by modulation of the HVdc power transfer to overcome capacity deficit or surplus situations. A number of simulations were carried out to show the effectiveness of such a control to maintain system stability.

Figure 6-1 shows the effectiveness of the HVdc frequency control at maintaining the Island frequency for the loss of the single largest generator on the Island of Newfoundland (Bay d'Espoir Unit #7). As seen in Figure 6-1 the Island frequency recovers to 1.0 pu following loss of the largest single generator on the Island when the frequency control is active; whereas, without the frequency control, the frequency decays, and under-frequency load shed would be required on the Island to avoid eventual frequency collapse.

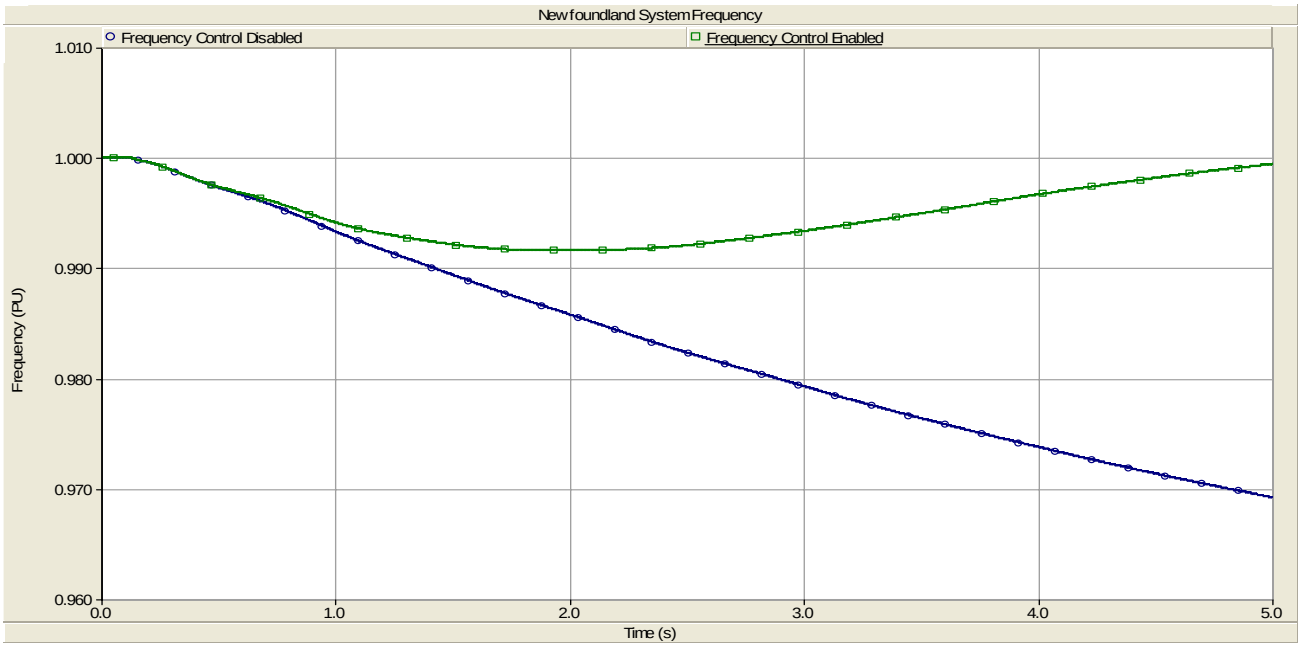


Figure 6-1
Effect of HVdc Frequency Control on Newfoundland Island Frequency
(Base-Case: BC1-DC1, Trip Unit #7 at Bay d'Espoir)

Effective frequency regulation can be provided by the HVdc link as long as the frequency controller does not reach its output limit or the dc current order does not reach its maximum or minimum limits. Selection of the limits on the output of the frequency controller itself should be done to provide sufficient range to modulate the HVdc power transfer to overcome the worst case expected capacity deficit or surplus situations. The limits should be selected considering both rectifier and inverter operation of the Soldiers Pond converter.

As previously mentioned, the HVdc frequency control feature modulates the dc power at Soldiers Pond to correct for under or over frequency conditions within the Newfoundland ac system. When Soldiers Pond operates as an inverter, an under-frequency condition on the Newfoundland ac system will cause the frequency controller to increase in HVdc power infeed to counteract the under frequency, while an over-frequency will result in a decrease in HVdc power infeed. Conversely when Soldiers Pond is operating as a rectifier, an under-frequency condition on the Newfoundland ac system will cause the frequency controller to decrease in HVdc power export to counteract the under frequency, while an over-frequency will result in a increase in HVdc power export.

The output of the frequency controller is a "delta power order" which is then used to calculate a dc current order modulation signal which is summed to the main dc current order prior to the application of current order limits. Therefore, if the output of the frequency controller attempts to modulate the current order beyond its upper or lower limits it cannot do so. In such a situation, the frequency controller

would not be able to provide effective frequency control. Consideration must be given to what operating conditions can result in the effectiveness of the HVdc frequency controller being limited by reaching current order limits, resulting in the need for alternative measures to stabilize the Newfoundland ac system frequency.

Under conditions where the Soldiers Pond converter is operating at a low HVdc power level, the ability of the HVdc link to mitigate over-frequencies on the Newfoundland system when Soldiers Pond is an inverter, or under-frequencies when Soldiers Pond is a rectifier, will be limited by the minimum dc power transfer capability of the Soldiers Pond converter, which would typically be in the range of 10%. In the event that sufficient room does not exist between the pre-disturbance operating point and the minimum power level to provide the necessary frequency control, it may be possible to reverse the operation of the Soldiers Pond converter from inverter to rectifier operation (or vice-versa). This however would result in a "step change" of HVdc power from minimum import to minimum export (or vice-versa) which may be more than is required to overcome the frequency deviation. Additional studies are required to determine if this is feasible.

Under normal bipolar operating conditions with Gull Island operating as the rectifier, and Soldiers Pond as an inverter, the 1.5pu continuous overload rating should provide adequate range for mitigation of under frequency conditions on the Newfoundland ac system.

Under monopolar operation with Gull Island operating as a rectifier and Soldiers Pond as an inverter, mitigation of under-frequencies on the Newfoundland ac system will not be possible if the HVdc in-feed at Soldiers Pond is operating at its 2.0 pu, ten minute overload rating. If the Soldiers Pond converter is operating at its 1.5pu continuous overload rating, mitigation of under-frequencies will be possible only if the HVdc in-feed can be transiently increased into the 10 minute overload region. This will depend on the allowed frequency of operation within the 1.5 pu to 2.0 pu range and the time since the last operation within this range.

Under two-terminal bipolar or monopolar operation with Salisbury operating as the rectifier and Soldiers Pond as the inverter, mitigation of under-frequencies on the Newfoundland ac system will be limited by the maximum overload rating of the Salisbury converter. Therefore some consideration should be given to increasing the overload of the Salisbury converter to provide adequate range for frequency control of the Newfoundland system when in two terminal operation.

With Soldiers Pond operating as a rectifier, the studies indicate that the maximum HVdc export from the Newfoundland system is approximately 165MW due to limitations of the ac system. Under such conditions, mitigation of over-frequency conditions on the Newfoundland ac system should be possible. If the export level is increased due to ac system enhancements, then consideration must be given to the ability to mitigate over-frequencies by reaching the maximum rating of the Salisbury converter.

In summary the results show that the HVdc frequency control feature can effectively mitigate frequency variations within the Newfoundland ac system, however some conditions do exist where its ability can be limited. Therefore the existing under-frequency load shedding scheme should be modified in order to operate only when the HVdc frequency controller is not able to provide the necessary control for under-frequency conditions. Likewise, a generation rejection scheme should also be considered for the Newfoundland system in order to operate only when the HVdc frequency controller is not able to provide the necessary control for over-frequency conditions.

Most contingencies were simulated with the HVdc frequency control disabled in order to identify critical cases with maximum frequency deviations. A number of contingencies were repeated with the HVdc frequency control enabled to demonstrate its effectiveness at stabilizing the Newfoundland ac frequency.

The 2.0 pu overload rating of the Soldiers Pond converter provides effective mitigation for loss of one pole at Soldiers Pond. In such an event, the remaining pole automatically increases its power transfer to compensate for the lost HVdc in-feed. This is possible as long as the rectifier station has sufficient capability to supply the required HVdc power on the remaining pole, which is always the case if Gull Island is operating as a rectifier. In the event that Salisbury is operating as the only rectifier and a pole is lost, the HVdc infeed into the Newfoundland system will be limited to the overload rating of one pole of the Salisbury converter; hence, some under-frequency load shedding may be necessary in the Newfoundland system. This situation again indicates the need to consider the potential benefits of increased overload capability of the Salisbury converter.

When Gull Island is operating as a rectifier and Soldiers Pond and Salisbury are operating as inverters, the impact of the complete loss of Gull Island on the Newfoundland system can be effectively mitigated by reversing the operation of Salisbury from inverter to rectifier operation. This is true assuming bipolar operation. In the case of monopolar operation, if the in-feed to Soldiers Pond is greater than 1.0 pu prior to the loss of the Gull Island converter, then reversal of the Salisbury converter from inverter to rectifier operation will not provide sufficient HVdc in-feed to the Newfoundland system (due to the overload capability of the Salisbury converter) and hence some under-frequency load shedding will be necessary in the Newfoundland system.

These studies have demonstrated that reversal of the Salisbury converter from inverter to rectifier operation upon loss of the Gull Island converter is possible from the Newfoundland ac system point of view; additional studies are required to verify that this is acceptable to the New Brunswick ac system. Reversal of any one converter station from rectifier to inverter operation (or vice versa) requires the use of high-speed reversing switches at the given converter station. Isolation of line sections from Taylors Brook to each of the converter stations will require high-speed switches at Taylors Brook.

When Soldiers Pond is operating as a rectifier, power runbacks can be applied to the Soldiers Pond converter following faults within the Newfoundland ac system. The runbacks effectively delay the recovery of the HVdc system while there is a power deficit in the Newfoundland ac system; improving overall recovery. The runbacks are released following system recovery and the HVdc link returned to its pre-fault power level. Such power runbacks are commonly used in HVdc schemes to assist in the ac system recovery and should be considered.

The worst-case disturbance within the Newfoundland ac system is a three-phase fault at Bay d'Espoir on one of the 230 kV lines to Pipers Hole requiring tripping of the line to clear the fault. This fault causes the HVdc to fail commutation, which collapses the HVdc power momentarily. At the same time, it also causes a large disturbance of the Bay d'Espoir generators. Recovery from this fault is possible only with the cross tripping of the 175 MW refinery load at Pipers Hole. It should be noted that this study considered only the trip of the entire refinery load at Pipers Hole, additional studies should be conducted to determine if tripping of a smaller block of load would be sufficient to maintain system stability.

A three-phase fault at the Pipers Hole end of one of the 230 kV lines to Bay d'Espoir followed by tripping of the 230 kV line to clear the fault also required cross tripping of the 175 MW refinery load to maintain overall system stability; however, this was not necessary for all system configurations considered.

The protection and fault-clearing times for faults at Bay d'Espoir and Pipers Hole should be optimized to prevent voltage sags of long duration.

Prolonged voltage dips can occur on various buses due to delayed fault clearing on the 138kV and 66kV networks (contingencies NL5.2-NL5.4), which can extend to buses other than the affected ones. It is essential that protection philosophy and clearing time for delayed tripping be reviewed and optimized to minimize spreading of voltage dips.

A special protection and remedial action scheme is needed to reduce Gull Island generation in case of load rejection due to the outage of the last 735 kV line from Gull Island.

The model for the Transient Stability Study was developed based on the base cases and information made available by NLH. The parameters of individual components were not reviewed and/or optimized. For the purpose of this study, the aggregate behavior of machines within the Newfoundland network was taken into consideration and individual machine swings were ignored. Furthermore, different load levels were studied without any system reinforcements. These studies have shown the technical feasibility of HVdc to act as the main source of power into the Newfoundland system. However, it is important that adequacy and modeling accuracy of the existing system be assessed in order to resolve any outstanding problems with the AC system.

6.2 Detailed Analysis of Results

6.2.1 BC1-DC1: 800 MW BP, 1600 MW Peak Load

This base case represents the peak load Newfoundland ac system (1600 MW) with economic generation dispatch and full 800 MW import through HVdc in a bipolar configuration. The Labrador and New Brunswick systems were represented as weak.

It is noted that in this case the economic generation dispatch provides a reserve margin of 3.4% in the NLH system. Outage of the largest unit (#7 at Bay d'Espoir) would lead to a generation capacity deficit of 5%, and the frequency control feature of HVdc appears to be an appropriate and logical means to overcome this deficit.

For this case, all 72 system contingencies (CN001 – CN072) were run.

The results of these simulations are summarized below.

6.2.1.1 AC System Response

- There are, in general, no voltage or frequency violations resulting from equipment tripping without any fault in the system. The exception is tripping of Bay d'Espoir Unit #7 (NL1.4.1), which results in a frequency dip at Soldiers Pond to 0.97 pu. If the frequency control feature of HVdc is enabled, the frequency declines to a minimum of 0.992 pu and is then controlled back

to 1 pu by the HVdc frequency control function. The system is, however, stable in both situations.

- The variation in machine speeds due to equipment tripping without any fault is marginal.
- The system is, in general, transiently stable for the simulated disturbance conditions. The post-fault voltage recovery is adequate. The only exception is the application of a three-phase fault at Bay d'Espoir, as described below.
- A three-phase normally cleared fault at Bay d'Espoir followed by tripping of Bay d'Espoir-Pipers Hole 230 kV line (TL206) results in voltage collapse, which can be avoided only by tripping the refinery load (NL3.1.1). With refinery load-tripping, the system voltages recover to acceptable values. The worst voltage dip occurs at Salt Pond (Bus #371), where the voltage remains below 0.8 pu for 320 ms. This voltage dip at Salt Pond should be treated as exceptional, since the system beyond this bus is represented by an equivalent without generators. Nevertheless, the duration of the voltage dip is acceptable.
- A single line-to-ground fault (SLG) and subsequent successful line reclosing does not result in voltage violation. Unsuccessful line reclosing into SLG faults results in large voltage excursions (NL5.1.3) of +/- 11% on buses 234, 236, 238 and 2490. The post-disturbance system is, however, stable.
- A number of delayed fault-clearing cases result in a prolonged voltage dip at various buses during fault-clearing times. The post-fault voltage recovery is, however, acceptable.
- Faults in the Labrador and New Brunswick systems do not result in voltage violations during post-fault recovery.
- 735 kV faults followed by tripping of a 735 kV line (L6.1 & L6.2) when this is the last 735kV line in service result in an excessive increase in the frequency measured at the converter bus. The machines at Gull Island and at Bus #2137 seem to swing out. This is owing to the interruption of the large amount of power flowing through the 735 kV line being tripped. Thus, a special protection and remedial scheme should be implemented in order to maintain system stability. Although quite important, this is related to performance of the ac system and not to HVdc. The system performance is considered adequate, assuming that such a scheme will be in place to overcome the problem.

6.2.1.2 HVdc System Response

- In general, response of the multi-terminal HVdc system is good.
- For most cases, the dc power recovered to 90% of pre-fault levels within approximately 300 ms.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.13 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The maximum overvoltage observed at Gull Island was 1.09 pu, and was limited by the strength of the system and by the action of the local generators. The maximum overvoltage at Soldiers Pond observed was 1.1 pu

and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.

- For all cases, the Newfoundland ac system frequency is maintained above approximately 0.98 pu with the assistance of the frequency controller of the HVdc link. The results demonstrate the effectiveness of the HVdc frequency control function and suggest the need to re-examine the existing under-frequency load-shedding scheme on the Island to ensure that under-frequency load shedding is minimized and is utilized only when the HVdc link is not able to control Island frequency.
- For the contingencies NL1.1.1 to NL1.3.2 that consider only equipment tripping the dc link experienced only a slight shift in operating point, which did not change the operating mode of the HVdc link.
- For contingency NL1.4.1 (loss of Bay d'Espoir Unit #7), the Newfoundland Island ac system experiences a frequency decline. When the HVdc frequency controller is disabled, the Island frequency continues to decline to approximately 0.98 pu (58.8 Hz) approximately 3 seconds after loss of the machine, and under-frequency load shedding would be required to stop the continued frequency decline. When the HVdc frequency controller is enabled, it responds to the initial under frequency, and automatically increases the HVdc power in-feed, which limits the under frequency to approximately 0.99 pu, followed by a return to nominal frequency, thus avoiding the need for under frequency load shedding.
- Contingency NL1.6.1 demonstrates that reversal of the Salisbury converter from inverter to rectifier operation to supply the Soldiers Pond inverter in case of total loss of the Gull Island converters is possible. The results show that reversal of the Salisbury converter requires approximately 400 ms to complete. During that time, the Newfoundland ac frequency dips to approximately 0.98 pu at which time the re-establishment of the HVdc in-feed into the Newfoundland system (now fed from Salisbury operating as a rectifier) is able to bring the frequency back 1 pu.
- For contingency NL1.5.1, which simulates a commutation failure in one pole due to a missing valve-firing pulse, the results indicate that the healthy pole suffers a sympathetic commutation failure. Recovery of both poles is good.
- For contingency NL3.1.1, which required a cross-trip of the refinery load, the Newfoundland ac system experiences an over frequency following cross-trip of the refinery load. The HVdc frequency control responds to the over frequency, reducing the HVdc power in-feed from 769 MW to 572 MW to successfully counteract the over frequency.
- For contingency NL3.5.1, which simulates the loss of one pole, the HVdc power in-feed into Soldiers Pond on the remaining pole is doubled, resulting in minimal impact on the Newfoundland ac system. The firing angle at Gull Island, and the extinction angle at Salisbury on the remaining pole, settle out at higher values due to the reduced reactive power consumption resulting from the loss of the pole and the reduction of HVdc power transfer at those stations. In the actual plant, this would result in eventual tap- changer operation to establish a more optimal operating point.

- For contingencies NL5.1.1 to NL5.1.7 and NL5.3.2, which simulate single line-to-ground faults with an unsuccessful reclose, a subsequent commutation failure is observed when the ac line recloses back onto the fault. This is expected, and the system recovers following the clearing of the line.
- For contingencies L6.1 and L6.2, which simulate loss of the last 735kV line from Gull Island, an over frequency is observed at the Gull Island converter bus following the tripping of the 735kV line. As the HVdc system does not contain a frequency control function for the ac system connected to Gull Island, it cannot be use to mitigate the over frequency; therefore, a special protection system that results in generator tripping is required.

6.2.1.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a multi-terminal, bipolar configuration with all converters at nominal rated power and peak load (1600MW) conditions of the Newfoundland ac system.
- The post-disturbance system is transiently stable with adequate voltage recovery.
- Performance of the HVdc system is good.
- The frequency control feature implemented within the HVdc controls provides effective control of the Island frequency, minimizing the need for under frequency load shedding within the Newfoundland ac system.
- The 2.0 pu overload rating of the Soldiers Pond converters provides effective mitigation of the loss of a pole on the Newfoundland ac system.
- The impact of the complete loss of the Gull Island converters on the Newfoundland ac system can be effectively mitigated by reversing operation of the Salisbury converter from inverter to rectifier operation.
- Faults with delayed clearing can result in prolonged voltage dips at various buses. The voltage dip may extend to buses other than the affected ones.
- A special protection and remedial action scheme is needed to reduce Gull Island generation in case of load rejection due to the outage of the last 735 kV line.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good. There are some issues related to the ac system that need to be addressed separately.

6.2.2 BC1-DC7: 800 MW BP, 1600 MW Peak Load, Salisbury 800 MW BP-Rectifier

This base case represents the peak load Newfoundland ac system (1600 MW) with economic generation dispatch and full 800 MW import from Salisbury through HVdc in a bipolar configuration. The HVdc at Gull Island is assumed off. The Labrador and New Brunswick ac systems were represented as weak.

It is noted that economic generation dispatch in this case provides a reserve margin of 3.4% in the NLH system. Outage of the largest unit (#7 at Bay d'Espoir) would lead to a generation capacity deficit of 5%, and the frequency control feature of the HVdc link appears, to an appropriate and logical means, to overcome this deficit. However, the capability of the HVdc frequency controller to mitigate under-frequency conditions in the Newfoundland system will be limited by the overload rating of the Salisbury converter, which is operating as a rectifier. The frequency control feature of HVdc was on, and only the selected ten contingencies were simulated for this base case.

The results of these simulations are summarized below.

6.2.2.1 AC System Response

- There are no voltage violations in general, except in the case of a three-phase fault at Pipers Hole (NL3.3.2) followed by the normal clearing and tripping of the 300 MVA synchronous condenser.
- The duration of the voltage dip below 0.8 pu under other contingencies does not exceed 300 ms.
- Outage of Bay d'Espoir Unit #7 followed by the normal clearing of a three-phase fault (Contingency NL3.4.1) requires tripping of the refinery load to maintain system stability. With the tripping of the refinery load, there are no voltage and/or frequency violations.
- The line flows following the disturbances are adequately damped by the end of simulations.

6.2.2.2 HVdc System Response

- In general, response of the HVdc link is good.
- Recovery of the HVdc in-feed at Soldiers Pond is slightly slower with Salisbury as the rectifier compared to corresponding cases where Gull Island is the rectifier. This is mainly due to the fact that the Salisbury rectifier, which is rated for 800 MW, requires more time to charge the long dc cable than does the Gull Island rectifier, which is rated at 1600MW.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.17 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The maximum overvoltage at Soldiers Pond observed was 1.08 pu and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.
- The ability of the HVdc frequency controller to regulate the Newfoundland system frequency is limited due the overload rating of the Salisbury converter. Contingencies that result in an under frequency on the Newfoundland system may require load shedding.
- For contingency NL3.5.1, which consists of the loss of the largest generator on the Newfoundland system , the HVdc in-feed is not capable of providing adequate frequency control since the Salisbury rectifier does not have a sufficient overload rating. The pre-

disturbance HVdc power transfer was 800MW, with an overload rating of 880MW. The Salisbury rectifier is not capable of transmitting sufficient HVdc power to satisfy the generation shortfall on the Newfoundland system following the tripping of the largest generator on the Island. In this situation, under frequency load shedding would be required on the Newfoundland system. If this is not acceptable, then consideration should be given to increasing the overload rating of the Salisbury converter when it operates in rectifier mode. Increasing the overload rating to approximately 1.2 pu would provide sufficient capability to avoid under-frequency load shedding on the Newfoundland system for loss of the largest single generator on the Island.

- For contingency NL3.5.2, the loss of one pole results in the HVdc in-feed into Soldiers Pond being limited to the overload capability of the Salisbury converter (1.1 pu).When operating with Salisbury as the rectifier, loss of a pole will result in the need for under frequency load shedding on the Newfoundland system.

6.2.2.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a two-terminal, bipolar configuration with the Soldiers Pond (inverter) and Salisbury (rectifier) converters at nominal power in the event that the Gull Island converters are not available under peak load (1600MW) conditions of the Newfoundland ac system.
- The system is transiently stable with adequate recovery.
- Performance of the HVdc system is good.
- When Salisbury is operating as a rectifier, the ability of the HVdc frequency controller to regulate the Newfoundland system frequency is limited by the overload rating of the Salisbury converter. Under certain fault conditions, under-frequency load shedding will be required on the Island.
- When Salisbury is operating as a rectifier, the loss of one pole may result in a net shortfall of HVdc into Soldiers Pond due to the overload rating of the Salisbury converter. The HVdc shortfall results in a frequency decline in the Newfoundland ac system, which will require under frequency load shedding.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good. This configuration demonstrates the ability to operate in two-terminal mode with Salisbury operating as a rectifier.

6.2.3 BC2-DC3: 600 MW Monopole, 1600 MW Peak Load

This base case represents the peak load Newfoundland ac system (1600 MW) with maximum economic generation dispatch and a reduced (600 MW) import from Gull Island through HVdc in a monopolar

configuration, representing monopolar operation. The Labrador and New Brunswick ac systems were represented as weak.

It is noted that generation dispatch in this case provides a reserve margin of 4.2% in the NLH system. Outage of the largest unit (#7 at Bay d'Espoir) would lead to a generation capacity deficit of 5.5%. Therefore, the frequency control feature of the HVdc link was enabled whenever appropriate in a total of 72 disturbances simulated for this base case.

The results of these simulations are summarized below.

6.2.3.1 AC System Response

- There are no voltage violations resulting from equipment tripping without any fault or from faults without tripping any equipment.
- Except for a three-phase fault at Bay d'Espoir, the system is transiently stable for the simulated disturbance conditions. The maximum voltage dip occurs in the case of a three-phase fault at Pipers Hole followed by the normal clearing and tripping of the 300 MVA synchronous condenser (NL3.3.2). The voltages at various buses remain below 0.8 pu for about 300 ms. The post-fault voltage recovery is adequate.
- A three-phase normally cleared fault at Bay d'Espoir, followed by tripping of Bay d'Espoir-Pipers Hole 230 kV line (NL3.1.1), results in voltage collapse, which can be avoided only by tripping the refinery load. With refinery load tripping, the system voltages recover to acceptable values. Even with tripping the refinery load, the voltage at Sunnyside dips to 71% which is the worst case for all contingencies. The voltage at Salt Pond (Bus #371) remains below 0.8 pu for a duration of 270 ms.
- A single line-to-ground fault and subsequent line reclosing does not result in voltage violation.
- A number of delayed fault-clearing cases result in a prolonged voltage dip at various buses during fault-clearing times. An important observation is the effect of back-up fault clearing on buses other than the adjacent ones. For example, a three-phase fault at Holyrood 138 kV bus (N338) with a 30-cycle back-up clearing at Bay Roberts (N357) results in a prolonged voltage dip at Western Avalon (N336 and N311), as shown in Figure 6-2. This long duration voltage dip is a direct consequence of the time duration in back-up tripping. Although the post-fault voltage recovery is acceptable in this particular disturbance, it is always desirable to confine the effect of a disturbance due to a fault by minimizing the back-up clearing time.
- Faults in the Labrador and New Brunswick systems do not result in voltage violations during post-fault recovery.
- The variation in machine speeds due to equipment tripping without any faults is marginal.
- As previously mentioned, outage of Bay d'Espoir Unit #7, whether due to fault clearing or without any fault, results in maximum deviation in machine speeds. However, machine speeds recover if the frequency control feature of the HVdc link is on.

- 735 kV faults followed by the tripping of the last 735 kV line (L6.1 and L6.2) result in excessive increase in the frequency measured at the Gull Island converter bus. The machines at Gull Island and at Bus #2137 seem to swing out. This is owing to the interruption of a large amount of power flowing through the 735 kV line being tripped. Thus, a special protection and remedial scheme should be implemented in order to maintain system stability. Although quite important, this is related to performance of the ac system and not to HVdc. The system performance is considered adequate, assuming that such a scheme will be in place to overcome the problem.

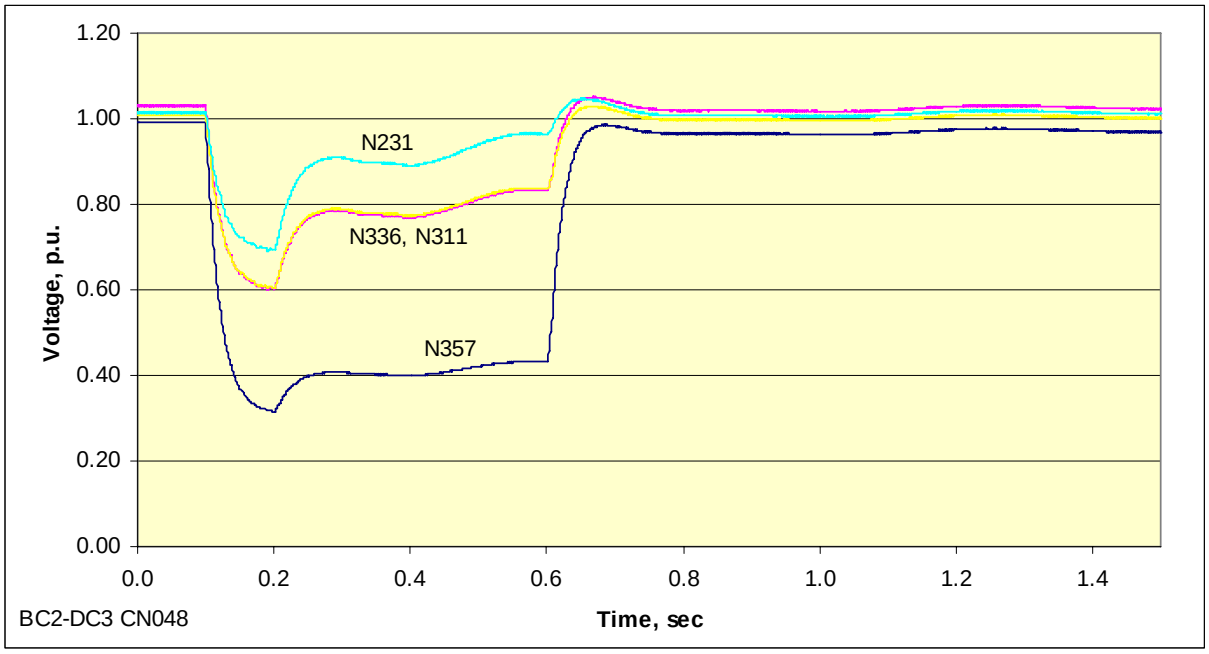


Figure 6-2
Voltage Dip During Fault Due to Delayed Fault Clearing
(Base Case: BC2-DC3, Three-phase Fault at Holyrood)

6.2.3.2 HVdc System Response

- In general, response of the multi-terminal HVdc system is good.
- For most cases, the dc power recovered to 90% of pre-fault levels within approximately 300 ms.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.08 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The maximum overvoltage observed at Gull Island was 1.05 pu, and was limited by the strength of the system and by the action of the local generators. The maximum overvoltage at Soldiers Pond observed was 1.1 pu and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.

- For all cases, the Newfoundland ac system frequency is maintained above approximately 0.98 pu with the assistance of the frequency controller of the HVdc link. Use of the HVdc frequency controller to stabilize the Newfoundland ac system frequency while in monopolar operation requires the ability to transiently increase the HVdc in-feed into Soldiers Pond beyond the 1.5 pu maximum continuous rating into the 10-minute overload region. Utilization of the 10-minute overload capability for frequency regulation is possible only if sufficient time has elapsed since the last operation in this region and if no equipment stress occurs.
- The results demonstrate the effectiveness of the HVdc frequency control function and suggest the need to re-examine the existing under frequency load-shedding scheme on the Newfoundland system to ensure that under frequency load shedding is minimized and is utilized only when the HVdc link is not able to control Island frequency.
- For the contingencies NL1.1.1 to NL1.3.2 which consider only equipment tripping, the dc link experienced only a slight shift in operating point, which did not change the operating mode of the dc link.
- For contingency NL1.4.1 (loss of Bay d'Espoir Unit #7), the Newfoundland ac system experiences a frequency decline. The HVdc frequency controller responds to the initial under frequency and automatically increases the HVdc power in-feed. Since the HVdc is operating in monopolar mode at 1.5pu prior to the disturbance, use of the HVdc frequency controller to stabilize the Newfoundland system frequency assumes that the HVdc can transiently operate above the 1.5 pu continuous monopolar steady-state limit. If this is not the case, then under-frequency load shedding would be required.
- Contingency NL1.6.1 demonstrates that the reversal of the Salisbury converter from inverter to rectifier operation--to supply the Soldiers Pond inverter in case of total loss of the Gull Island converters--is possible. The results show that approximately 400 ms is required to complete the reversal of the Salisbury converter. The results also show that, following reversal of the Salisbury converter, the HVdc in-feed to Soldiers Pond is limited to the overload rating of the Salisbury converter (1.1 pu); therefore, some under-frequency load shedding will be required on the Newfoundland ac system in order to maintain the system frequency. Alternatively, the import level from Salisbury could be limited to cover off any generation loss.
- For contingency NL3.1.1, which required a cross-trip of the proposed refinery load, the Newfoundland ac system experiences an over frequency following the cross-tripping of the refinery load. The HVdc frequency control responds to the over frequency, reducing the HVdc power in-feed from 769 MW to 572 MW in order to successfully counteract the over frequency.
- For contingencies NL5.1.1 to NL5.2.1, which simulate single line-to-ground faults with an unsuccessful reclose, a subsequent commutation failure is observed when the ac line recloses back onto the fault. This is as expected, and the system recovers following the clearing of the line.
- For contingencies NL5.3.1, NL5.3.2, and NL5.5, a second commutation failure is observed during recovery of the HVdc link. With the HVdc link running in bipolar mode, these same faults recover without a second commutation failure. The second commutation failure observed when operating in monopolar mode is due to the fact that the HVdc link must recover to its 1.5

pu overload rating, which corresponds to a much higher dc current than that of the bipolar cases. This higher current causes a higher var consumption, which further depresses the ac voltage under this type of prolonged ac system fault. Some HVdc schemes employ an ac undervoltage detection circuit that will limit the dc current under prolonged ac system under-voltages. This type of special control was beyond the scope of this study, but should be considered for future studies to improve performance under such conditions. It should be noted that all cases recovered with no stability issues.

6.2.3.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a multi-terminal, monopolar configuration with the Soldiers Pond converter operating at its continuous rating of 1.5 pu under peak load (1600 MW) conditions of the Newfoundland ac system.
- The post-disturbance system is transiently stable with adequate voltage recovery.
- Use of the HVdc frequency controller to stabilize the Newfoundland ac system frequency while in monopolar operation requires the ability to transiently increase the HVdc in-feed into Soldiers Pond beyond the 1.5 pu maximum continuous rating into the 10-minute overload region. Utilization of the 10-minute overload capability for frequency regulation is possible only if sufficient time has elapsed since the last operation in this region and if no equipment stress occurs. The existing under frequency load-shedding scheme on the Newfoundland system should be re-examined to ensure that under frequency load shedding is minimized and is utilized only when the HVdc link is not able to control Island frequency.
- Loss of the largest single generator on the Newfoundland system, whether due to fault clearing or without any fault, results in maximum deviation in machine speeds, which can be overcome by the frequency control feature of the HVdc link, assuming it has the capability to transiently increase the HVdc in-feed to Soldiers Pond above the 1.5 pu continuous overload rating.
- The effect of the loss of the Gull Island rectifier on the Newfoundland system can be partially mitigated by reversing the Salisbury converter from inverter to rectifier operation. Following reversal of the Salisbury converter, the HVdc in-feed to Soldiers Pond will be limited to the overload capability of the Salisbury converter.
- Faults with delayed clearing can result in prolonged voltage dips at various buses.
- A special protection and remedial action scheme is needed to reduce Gull Island generation in case of load rejection due to the outage of the last 735 kV line.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good. There are some issues related to the ac system that need to be addressed separately.

6.2.4 BC3-DC1: 800 MW BP, 1800 MW Future Peak Load

This base case represents the future peak load Newfoundland ac system (1800 MW) with maximum generation dispatch and full 800 MW import from Gull Island through HVdc in a bipolar configuration. The Labrador and New Brunswick ac systems were represented as weak.

It is noted that future Newfoundland load is represented in the system model without any system reinforcement. The generation dispatch is such that the reserve margin is not sufficient to account for the forced outage of the largest unit. However, because of the frequency control feature of the HVdc system, this is not considered an issue.

The results of the ten selected contingencies simulated for this base case are summarized below.

6.2.4.1 AC System Response

- There are no voltage violations observed during recovery following a disturbance. The maximum voltage dip was observed at Salt Pond (Bus #371), which remains below 0.8 pu for about 340 ms (NL3.1.1). The voltage deviation at this particular bus should be ignored, as the rest of the system connected to this bus was modeled as an equivalent without any machines.
- The frequency measured at the converter bus, along with the machine speeds, does not show major deviations in most of the contingencies. The worst dip in machine speeds occurs in the event of an outage of Bay d'Espoir Unit #7 following the normal clearing of a three-phase fault (NL3.4.1). The machine speeds in general decline to 0.96 pu. The system stability, however, is exhibited by excellent voltage recovery and adequate damping on line flows. The decline in machine speeds is expected to be effectively mitigated by the frequency control feature of the HVdc link.
- Slow damping on 735 kV line flows is noted during a few contingencies. This is due to the absence of stabilizers on the Gull Island generators.

6.2.4.2 HVdc System Response

- In general, response of the HVdc link is good.
- For most cases, the dc power recovered to 90% of pre-fault levels within approximately 300 ms.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.12 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The maximum overvoltage observed at Gull Island was 1.08 pu, and was limited by the strength of the system and by the action of the local generators. The maximum overvoltage at Soldiers Pond observed was 1.13 pu and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.
- For most cases, the Newfoundland ac system frequency is maintained above approximately 0.98 pu. In some cases with the HVdc frequency control disabled, the results show a decrease in

system frequency below 0.98pu, however this decrease is expected to be effectively mitigated by the HVdc frequency control. The results demonstrate the effectiveness of the HVdc frequency control function and suggest the need to re-examine the existing under frequency load-shedding scheme on the Newfoundland system to ensure that under-frequency load shedding is minimized and is utilized only when the HVdc link is not able to control Island frequency.

- For contingencies NL5.1.1 to NL5.2.1, which simulate single line-to-ground faults with an unsuccessful reclose, a subsequent commutation failure is observed when the ac line recloses back onto the fault. This is expected, and the system recovers following the clearing of the line.

6.2.4.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a multi-terminal, bipolar configuration with all converters at nominal rated power under future peak load (1800 MW) conditions of the Newfoundland ac system.
- The post-disturbance system is transiently stable with adequate voltage recovery.
- Performance of the HVdc system is good.
- The frequency control feature implemented within the HVdc controls provides effective control of the Island frequency, minimizing the need for under frequency load shedding within the Newfoundland ac system.
- Faults with delayed clearing can result in prolonged voltage dips at various buses. The voltage dip may extend to buses other than the affected ones.
- A special protection and remedial action scheme is needed to reduce Gull Island generation in case of load rejection due to the outage of the last 735 kV line.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good. There are some issues related to the ac system that need to be addressed separately.

6.2.5 BC3-DC4: 800 MW MP, 1800 MW Future Peak Load

This base case represents the future peak load Newfoundland ac system (1800 MW) with maximum generation dispatch and full 800 MW import from Gull Island through HVdc in a monopolar configuration, representing the 10-minute overloading capability. The Labrador and New Brunswick ac systems were represented as weak.

It is noted that future NLH load is represented in the system model without any system reinforcement. The generation dispatch is such that the reserve margin is not sufficient to compensate for the forced outage of the largest unit. Since the HVdc is operating in monopolar mode at its maximum 10-minute

overload rating of 2.0 pu, the HVdc frequency control feature will not be able to mitigate under frequency conditions on the NLH system.

The results of the nine selected contingencies simulated for this base case are summarized below.

6.2.5.1 AC System Response

- A three-phase normally cleared fault at Bay d'Espoir (NL3.1.1) followed by the tripping of the Bay d'Espoir-Pipers Hole 230 kV line (TL206) requires the refinery load be tripped to maintain system stability. With refinery load tripping, the post-fault voltage recovery is acceptable. However, the voltage dip during recovery is the worst for all contingencies considered. The voltage remains below 0.8 pu for a duration of 300 ms or more at various buses. The voltage at Salt Pond (Bus #371) remains below 0.8 pu for about 370 ms, which is an exceptional case and should be treated separately while evaluating the performance of the ac system independently.
- A three-phase normally cleared fault at Pipers Hole (NL3.1.8 and NL3.3.2) also results in severe voltage dips at various buses. However, the duration of the voltage dip is reduced to within 300 ms if the refinery load is tripped.
- The voltage dip at Salt Pond (Bus #371) is the worst of all. However, as previously noted, the system beyond this bus has been equivalenced, and no generator has been modeled at this bus. Therefore, a voltage dip at this bus should be ignored while evaluating the voltage performance of the ac system and should be evaluated separately as the system is transiently stable.
- The frequency measured at Soldiers Pond (and various machines) declines to 0.965 pu in the event of an outage of Bay d'Espoir Unit #7 following a three-phase fault clearing (NL3.4.1). The voltage performance in this case is excellent.
- Slow damping on 735 kV line flows is noted in a few contingencies (e.g. NL3.3.2 and NB2.1.), which is due to the absence of stabilizers on the Gull Island units. The system is, however, stable.

6.2.5.2 HVdc System Response

- In general, response of the HVdc link is good.
- For most cases, the dc power recovered to 90% of pre-fault levels within approximately 300 ms.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.08 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The maximum overvoltage observed at Gull Island was 1.08 pu, and was limited by the strength of the system and by the action of the local generators. The maximum overvoltage at Soldiers Pond observed was 1.13 pu and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.

- The HVdc frequency control is not able to mitigate under frequencies within the Newfoundland ac system since the HVdc in-feed to Soldiers Pond is operating at its maximum 2.0 pu 10-minute overload rating. Under such operating conditions, under frequency load shedding will be required on the Newfoundland system.
- For contingencies NL5.1.1 to NL5.2.1 which simulate single line-to-ground faults with an unsuccessful reclose, a subsequent commutation failure is observed when the ac line recloses back onto the fault. This is expected, and the system recovers following the clearing of the line.
- For contingency L2.1, an overvoltage of 1.16 pu was observed on the Soldiers Pond bus. The observed overvoltage, which is greater than that of the corresponding case in bipolar operation, is due to the extra reactive power support required for the 2.0 pu monopolar operation.
- For contingency NB2.1, HVdc recovery is slightly longer than that of the corresponding case in bipolar operation due to the fact that, in monopolar operation, the HVdc must recover to a higher dc current, which will inherently slow down recovery.

6.2.5.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a multi-terminal, monopolar configuration with the Soldiers Pond converter operating at its 2.0 pu 10-minute overload rating under peak future load (1800 MW) conditions of the Newfoundland ac system.
- The post-disturbance system is transiently stable with adequate voltage recovery.
- Performance of the HVdc system is good.
- The HVdc frequency control is not able to mitigate under frequencies within the Newfoundland ac system since the HVdc in-feed to Soldiers Pond is operating at its maximum 2.0 pu 10-minute overload rating. Under such operating conditions, under frequency load shedding will be required on the Newfoundland system.
- Faults with delayed clearing can result in prolonged voltage dips at various buses. The voltage dip may extend to buses other than the affected ones.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good. There are some issues related to the ac system that need to be addressed separately.

6.2.6 BC4-DC1: 250 MW BP, 625 MW Summer Night Load

This base case represents the summer night load Newfoundland ac system (625 MW) with minimum generation dispatch and a reduced 250 MW import from Gull Island through HVdc in a bipolar configuration. The Labrador and New Brunswick ac systems were represented as weak.

The results of the ten contingencies simulated for this base case are summarized below.

6.2.6.1 AC System Response

- There are no voltage violations or severe voltage dips during post-fault recovery.
- A three-phase fault at Bay d'Espoir, followed by the normal clearing and tripping of Bay d'Espoir Unit #7 (NL3.4.1), results in a frequency decline at Soldiers Pond to 0.94 pu when the HVdc frequency control is disabled. If the frequency control feature is enabled, a change of only 1% in the frequency is observed, and frequency recovers.
- The line flows are fairly damped, except that slow damping on 735 kV line flows are noted in some contingencies, which is due to the absence of stabilizers on the Gull Island generators.

6.2.6.2 HVdc System Response

- In general, response of HVdc link is good.
- For all cases, the dc power recovered to 90% of pre-fault levels within approximately 300 ms.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.1 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The maximum overvoltage observed at Gull Island was 1.06 pu, and was limited by the strength of the system and by the action of the local generators. The maximum overvoltage at Soldiers Pond observed was 1.05 pu and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.
- For most cases, the Newfoundland ac system frequency is maintained above approximately 0.98 pu. In some cases with the HVdc frequency control disabled, the results show a decrease in system frequency below 0.98pu, however this decrease is expected to be effectively mitigated by the HVdc frequency control. The results demonstrate the effectiveness of the HVdc frequency control function and suggest the need to re-examine the existing under frequency load-shedding scheme on the Newfoundland system to ensure that under frequency load shedding is minimized and is utilized only when the HVdc link is not able to control Island frequency.
- Contingency NL3.4.1 shows an example of the effectiveness of the HVdc frequency controller in maintaining the Newfoundland system frequency. Pre-fault power transfer was 250MW; upon loss of the Bay d'Espoir Unit #7, which was outputting 135 MW, the HVdc frequency control increases the HVdc in-feed to Soldiers Pond, limiting the frequency deviation to 0.989 pu and avoiding the need for under frequency load shedding on the Island.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.1 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The overvoltages at Gull Island were limited by the strength of the system and by the action of the local generators; while the

overvoltages at Soldiers Pond are largely limited by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.

- For contingencies NL5.1.1 to NL5.1.7 which simulate single line-to-ground faults with an unsuccessful reclose, a subsequent commutation failure is observed when the ac line recloses back onto the fault. This is expected, and the system recovers following the clearing of the line.

6.2.6.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a multi-terminal, bipolar configuration with the Soldiers Pond converter operating at a reduced level (250 MW) under summer night load (625 MW) conditions of the Newfoundland ac system.
- The post-disturbance system is transiently stable with adequate voltage recovery.
- Performance of the HVdc system is good.
- The frequency control feature implemented within the HVdc controls provides effective control of the Island frequency, minimizing the need for under frequency load shedding within the Newfoundland ac system.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good. There are some issues related to the ac system that need to be addressed separately.

6.2.7 BC4-DC3: 250 MW MP, 625 MW Summer Night Load

This base case represents the summer night load Newfoundland ac system (625 MW) with minimum generation dispatch and a reduced 250 MW import from Gull Island through HVdc in a monopolar configuration. The Labrador and New Brunswick ac systems were represented as weak.

The results of the nine selected contingencies simulated for this base-case are summarized below.

6.2.7.1 AC System Response

- There are no voltage violations or severe voltage dips during post-fault recovery.
- Outage of Bay d'Espoir Unit #7, followed by a normally cleared three-phase fault (NL3.4.1), results in a frequency decline at Soldiers Pond to 0.94 pu with the HVdc frequency control feature disabled. It is expected that collapse of the frequency will be avoided if the frequency control feature of the HVdc link is enabled, as demonstrated in case BC4-DC1.
- The line flows are fairly damped, except that slow damping on 735 kV line flows are noted in some contingencies, which is due to the absence of stabilizers on the Gull Island generators.

6.2.7.2 HVdc System Response

- In general, response of the HVdc link is good.
- For all cases, the dc power recovered to 90% of pre-fault levels within approximately 300 ms.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.1 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The maximum overvoltage observed at Gull Island was 1.06 pu, and was limited by the strength of the system and by the action of the local generators. The maximum overvoltage at Soldiers Pond observed was 1.05 pu and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.
- For most cases, the Newfoundland ac system frequency is maintained above approximately 0.98 pu. In some cases with the HVdc frequency control disabled, the results show a decrease in system frequency below 0.98pu, however this decrease is expected to be effectively mitigated by the HVdc frequency control. The results demonstrate the effectiveness of the HVdc frequency control function and suggest the need to re-examine the existing under frequency load-shedding scheme on the Newfoundland system to ensure that under frequency load shedding is minimized and is utilized only when the HVdc link is not able to control Island frequency.
- For contingencies NL5.1.1 to NL5.2.1 , which simulate single line-to-ground faults with an unsuccessful reclose, a subsequent commutation failure is observed when the ac line recloses back onto the fault. This is expected, and the system recovers following the clearing of the line.

6.2.7.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a multi-terminal, monopolar configuration with the Soldiers Pond converter operating at a reduced level (250MW) under summer night load (625MW) conditions of the Newfoundland ac system.
- The post-disturbance system is transiently stable with adequate voltage recovery.
- Performance of the HVdc system is good.
- The frequency control feature implemented within the HVdc controls provides effective control of the Island frequency, minimizing the need for under frequency load shedding within the Newfoundland ac system.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good. There are some issues related to the ac system that need to be addressed separately.

6.2.8 BC5-DC1: 80 MW BP, Summer Night (625 MW) Load

This base case represents the summer night load Newfoundland ac system (625 MW) with economic generation dispatch and minimum (80 MW) import from Gull Island through HVdc in a bipolar configuration, representing minimum power transfer through HVdc. The Labrador and New Brunswick ac systems were represented as weak.

The results of the ten selected contingencies simulated for this base case are summarized below.

6.2.8.1 AC System Response

- There are no voltage violations or severe voltage dips during post-fault recovery.
- Outage of Bay d'Espoir Unit #7, followed by a normally cleared three-phase fault (NL3.4.1), was simulated with the frequency control of the HVdc link enabled, which results in marginal frequency deviation and adequate voltage recovery and damping on line flows.
- The line flows are fairly damped, except that slow damping on 735 kV line flows is noted in some contingencies, which is due to the absence of stabilizers on the Gull Island generators.

6.2.8.2 HVdc System Response

- In general, response of the HVdc link is good.
- For all cases, the dc power recovered to 90% of pre-fault levels within approximately 300 ms.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.12 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The maximum overvoltage observed at Gull Island was 1.03 pu, and was limited by the strength of the system and by the action of the local generators. The maximum overvoltage at Soldiers Pond observed was 1.04 pu and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.
- This power level of HVdc has very little impact on the ac system, as it accounts for only 12.6% of total generation.
- For all cases, the Newfoundland ac system frequency is maintained above approximately 0.98 pu with the assistance of the frequency controller of the HVdc link. The results demonstrate the effectiveness of the HVdc frequency control function and suggest the need to re-examine the existing under frequency load-shedding scheme on the Island to ensure that under frequency load shedding is minimized and is utilized only when the HVdc link is not able to control Island frequency.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.06 pu at the Salisbury bus. The over voltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The overvoltages at Gull Island

were limited by the strength of the system and by the action of the local generators, while the overvoltages at Soldiers Pond are largely limited by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.

- For contingencies NL5.1.1 to NL5.2.1 which simulate single line-to-ground faults with an unsuccessful reclose, a subsequent commutation failure is observed when the ac line recloses back onto the fault. This is expected, and the system recovers following the clearing of the line.

6.2.8.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a multi-terminal, bipolar configuration with all the converters operating at their minimum limits (10%) under summer night load (625MW) conditions of the Newfoundland ac system.
- The post-disturbance system is transiently stable with adequate voltage recovery.
- Performance of the HVdc system is good.
- The frequency control feature implemented within the HVdc controls provides effective mitigation of under frequencies within the Island frequency, minimizing the need for under frequency load shedding within the Newfoundland ac system. It should be noted that since the HVdc in-feed to Soldiers Pond is operating at its minimum limit, the HVdc frequency controller will not be able to mitigate conditions of over frequency within the Newfoundland ac system.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good. There are some issues related to the ac system that need to be addressed separately.

6.2.9 BC6-DC1: 800 MW BP, 1000 MW Intermediate Load

This base case represents the Newfoundland ac system with intermediate (1000MW) load with economic generation dispatch and maximum (800 MW) import from Gull Island through HVdc in a bipolar configuration. The Labrador and New Brunswick ac systems were represented as weak.

In this case, the largest generating unit (#7 at Bay d'Espoir) is dispatched as a synchronous condenser. hence outage of this unit is not expected to have a severe impact on the system. Therefore contingency NL3.4.1 which considered trip of the largest generator in the Newfoundland system considered the trip of DLP units 1 to 7 for this base case.

In this case, the dc supplies approximately 80% of the Newfoundland load, with a large amount of Island generation taken off line, with a corresponding reduction in the overall Island system inertia. It is therefore expected that faults resulting in the transient loss of HVdc in-feed to Soldiers Pond will cause significant frequency deviations, even with the HVdc frequency control enabled. This type of dispatch would not be recommended.

All the 72 disturbances were simulated for this base case. A summary of the simulation results is given below.

6.2.9.1 AC System Response

- The system exhibits adequate post-contingency voltage recovery in all the disturbances.
- Momentary voltage dips are noted on unsuccessful reclose/open operations.
- Prolonged voltage dips are noted during back-up clearing. The voltage dip extends from the affected buses to others as well, and may remain below 0.8 pu during fault clearing.
- Slow damping on 735 kV line flows is noted. This slow damping is due to the absence of stabilizers on the Gull Island generators.
- 735 kV faults, followed by the tripping of the last 735 kV line (L6.1 & L6.2), result in excessive increase in the frequency measured at the converter bus. The machines at Gull Island and at Bus #2137 seem to swing out. The reason for this is the interruption of a large amount of power flowing through the 735 kV line being tripped. Thus, a special protection and remedial scheme should be implemented in order to maintain system stability. Although quite important, this is related to performance of the ac system and, as such, not related to HVdc. The system performance is considered adequate, assuming that such a scheme will be in place to overcome the problem.

6.2.9.2 HVdc System Response

- In general, response of the HVdc link is good.
- For most cases, the dc power recovered to 90% of pre-fault levels within approximately 300 ms..
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.12 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The maximum overvoltage observed at Gull Island was 1.07 pu, and was limited by the strength of the system and by the action of the local generators. The maximum overvoltage at Soldiers Pond observed was 1.13 pu and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.
- Faults that cause the transient loss of the HVdc in-feed to Soldiers Pond result in more severe under frequencies than those observed for other system configurations, in some cases exceeding the 0.98 pu limit. This is due to the fact that, in this operating configuration, the HVdc supplies approximately 80% of the Newfoundland load, with a large amount of Island generation taken off line; there is a corresponding reduction in the overall Island system inertia. Therefore, loss of HVdc in-feed has a more prevalent impact on the Island frequency. However, it was seen that the HVdc frequency controller was able to mitigate the under frequency conditions observed.
- For contingencies where the HVdc in-feed is transiently interrupted (NL1.5.1, NL1.5.2, NL3.5.1, NL4.51), excursions in the Newfoundland system frequency are observed as described above.

The HVdc frequency controller is able to stabilize the Island frequency; however, the frequency swings are more pronounced than those observed for other system configurations. This is directly attributable to lack of inertia in the Newfoundland ac system.

- For the contingencies that consider only equipment tripping (NL1.1.1 to NL1.3.2), the dc link experienced only a slight shift in operating point, which did not change the operating mode of the dc link.
- Contingency NL1.6.1 demonstrates that reversal of the Salisbury converter from inverter to rectifier operation--to supply the Soldiers Pond inverter in case of total loss of the Gull Island converters--is possible. The results show that reversal of the Salisbury converter requires approximately 400 ms to complete. During that time, the Island ac frequency dips to approximately 0.98 pu, at which time the re-establishment of the HVdc in-feed into the Island system (now fed from Salisbury operating as a rectifier) is able to bring the frequency back 1 pu.
- For contingency NL1.5.1, which simulates a commutation failure in one pole due to a missing valve-firing pulse, the results indicate that the healthy pole suffers a sympathetic commutation failure. Recovery of both poles is good.
- For contingency NL3.5.1, which simulates the loss of one pole, the HVdc power in-feed into the Island system on the remaining pole is doubled, resulting in minimal impact on the Newfoundland ac system. The firing angle at Gull Island and the extinction angle at Salisbury on the remaining pole settle out at higher values due to the reduced reactive power consumption resulting from the loss of the pole and to the reduction of HVdc power transfer at those stations. This would result in eventual tap-changer operation in the actual plant to establish a more optimal operating point.
- For contingencies NL5.1.1 to NL5.1.7, which simulate single line-to-ground faults with an unsuccessful reclose, a subsequent commutation failure is observed when the ac line recloses back onto the fault. This is expected, and the system recovers following the clearing of the line.
- For contingencies NL5.3.1, NL5.3.2, and NL5.5.1 a second commutation failure is observed during recovery of the HVdc link. This second commutation failure occurs when the building dc current causes the ac bus voltage to depress, which, in this case, is compounded by the lack of system inertia and the reduced short-circuit level. Some HVdc schemes employ an ac under voltage detection circuit that will limit the dc current under prolonged ac system under voltages. This type of special control was beyond the scope of this study, but should be considered for future studies to improve performance under such conditions. It should be noted that all cases recovered with no stability issues.

6.2.9.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a multi-terminal, bipolar configuration with all converters at nominal rated power and intermediate load (1000 MW) conditions of the Newfoundland ac system.

- The post-disturbance system is transiently stable with adequate voltage recovery.
- Performance of the HVdc system is good.
- Faults that cause the transient loss of the HVdc in-feed to Soldiers Pond result in more severe under frequencies than those observed for other system configurations, in some cases exceeding the 0.98 pu limit. This is due to the fact that, in this operating configuration, the HVdc supplies approximately 80% of the Newfoundland load, with a large amount of Island generation taken off line and a corresponding reduction in the overall Island system inertia. Therefore, loss of the HVdc in-feed has a more prevalent impact on the Island frequency. However, it was seen that the HVdc frequency controller was able to mitigate the under-frequency conditions observed.
- The 2.0 pu overload rating of the Soldiers Pond converters provides effective mitigation of the loss of a pole on the Newfoundland ac system.
- The impact of the complete loss of the Gull Island converters on the Newfoundland ac system can be effectively mitigated by reversing operation of the Salisbury converter from inverter to rectifier operation.
- Faults with delayed clearing can result in prolonged voltage dips at various buses. The voltage dip may extend to buses other than the affected ones.
- A special protection and remedial action scheme is needed to reduce Gull Island generation in case of load rejection due to the outage of the last 735 kV line.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good. There are some issues related to the ac system that need to be addressed separately. Although the results show acceptable overall system performance, operation with this type of dispatch is not recommended.

6.2.10 BC7-DC1: 80 MW BP, 1000 MW Intermediate Load

This base case represents the intermediate Newfoundland ac system load with maximum economic generation dispatch and minimum import (80 MW) from Gull Island through HVdc in a bipolar configuration, representing minimum HVdc transfer. The Labrador and New Brunswick ac systems were represented as weak.

The frequency control of HVdc was enabled for simulations. The results of ten selected contingencies are summarized below.

6.2.10.1 AC System Response

- Adequate post-disturbance voltage recovery is observed in all the cases. The worst voltage dip occurs at Salt Pond (Bus #371) and Sunnyside (Bus #223) when a three-phase fault is applied at Pipers Hole followed by the normal clearing and tripping of the Bay d'Espoir-Pipers Hole line (NL3.1.8). Following fault clearing, the voltage at these buses remains below 0.8 pu for 300 ms.

- The refinery load was tripped to maintain stability in case of a three-phase fault at Bay d'Espoir with normal clearing and tripping of the Bay d'Espoir-Pipers Hole line (NL3.1.1).
- The machine speed measured at the converter bus remains within close limits of 1.0 pu during all the contingencies, except in the event of a three-phase fault at Bay d'Espoir (NL3.1.1) with normal clearing and subsequent tripping of the Bay d'Espoir-Pipers Hole 230 kV line. In this case, the frequency (and hence the machine speeds) increases to 1.04 pu, which is due to the tripping of the refinery load. Since the HVdc is operating at its minimum limit, it cannot provide any mitigation for the over frequency condition. Under such conditions, it may be necessary to consider tripping of the appropriate amount of generation on the Island, which was outside the scope of this study.
- Slow damping on 735 kV line flows is noted. This slow damping is due to the absence of stabilizers on the Gull Island generators. The other line flows in all the contingencies are adequately damped.

6.2.10.2 HVdc System Response

- In general, response of the multi-terminal HVdc system is good.
- For all cases, the dc power recovered to 90% of pre-fault levels within approximately 300 ms.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.13 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The maximum overvoltage observed at Gull Island was 1.02 pu, and was limited by the strength of the system and by the action of the local generators. The maximum overvoltage at Soldiers Pond observed was 1.045 pu and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.
- Contingency NL3.1.1, which resulted in the need to cross trip the refinery load at Pipers Hole, causes the Island system to experience an over frequency. Since the HVdc in-feed to Soldiers Pond is at its minimum limit of 80MW, the HVdc cannot provide mitigation for the over frequency condition. One option that could be investigated is to allow the HVdc converter at Soldiers Pond to reverse from inverter to rectifier operation. The investigation of this option was outside the scope of this study.

6.2.10.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a multi-terminal, bipolar configuration with all converters at minimum rated power (10%) and intermediate load (1000MW) conditions of the Newfoundland ac system.
- The post-disturbance system is transiently stable with adequate voltage recovery.

- Performance of the HVdc system is good.
- The frequency control feature implemented within the HVdc controls cannot provide mitigation of over frequency conditions within the Newfoundland ac system, since the HVdc in-feed at Soldiers Pond is operating at its minimum limit. Over frequency mitigation would require the implementation of generator tripping or the reversal of the Soldiers Pond converter from inverter to rectifier operations, the investigation of which is outside the scope of this study.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good. Consideration should be given as how to provide mitigation for over frequency conditions when the HVdc in-feed at Soldiers Pond is operating at its minimum limit.

6.2.11 BC8-DC8: 165 MW BP-REC, 625 MW Load

This base case represents the minimum Newfoundland ac system load (625 MW) with 900 MW generation dispatch and HVdc at Soldiers Pond as rectifier with export to the New Brunswick system in a bipolar configuration. The HVdc at Gull Island is off. The Labrador and New Brunswick ac systems were represented as weak.

Due to ac system constraints, the maximum HVdc power that was available for export was 165 MW.

The results of the nine selected contingencies simulated for this base case are summarized below.

6.2.11.1 AC System Response

- Adequate post-disturbance voltage recovery was observed in all the cases. The worst voltage dip occurs at N221 (Refinery 230 kV) during normal clearing of a three-phase fault at Pipers Hole (NL3.1.8) followed by tripping of Bay d'Espoir-Pipers Hole line (TL206). Following fault clearing, the voltage at the Refinery 230 kV bus remains below 0.8 pu for 290ms.
- The frequency measured at the converter bus increases to a maximum of 1.03 pu (NL3.1.1) and a minimum of 0.96 pu (NL3.4.1) with the HVdc frequency control feature disabled. Based on the earlier results obtained it is expected that enabling of the HVdc frequency control will successfully mitigate these frequency excursions.
- Adequate damping on the line flows is observed during all the contingencies.

6.2.11.2 HVdc System Response

- In general, response of the HVdc link is good.
- For all cases, the dc power recovered to 90% of pre-fault levels within approximately 300 ms.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.13 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to

the simplified representation of the New Brunswick ac system. The maximum overvoltage at Soldiers Pond observed was 1.02 pu and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.

- The HVdc frequency control feature should provide suitable mitigation of over- and under-frequency conditions within the Newfoundland ac system. Since the Soldiers Pond converter is operating as a rectifier, the ability to mitigate under-frequencies will be impacted by the Soldiers Pond rectifier reaching its minimum power limit.
- For contingency NL3.5.1, in addition to the cross-tripping of the proposed refinery load, a power runback was applied to the HVdc link to delay recovery while there was still a power deficit on the system. The runback was released following system recovery, and the HVdc link returned to its pre-fault power level. Such power runbacks are commonly used in HVdc schemes to assist in the ac system recovery.
- For contingencies NL5.1.5 and NL5.1.6 the dc voltage at Soldiers Pond collapses due to the application of the fault within the Newfoundland system. The collapse in dc voltage causes the interruption of the dc current since Soldiers Pond is operating as a rectifier; this results in the temporary loss of HVdc power transmission. HVdc power transmission is re-established following the clearing of the ac system fault.

6.2.11.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a two-terminal, bipolar configuration with the Soldiers Pond (rectifier) and Salisbury (inverter) exporting power from Newfoundland. The maximum HVdc export power level was seen to be 165 MW, which was due to constraints within the Newfoundland ac system.
- The post-disturbance system is transiently stable with adequate voltage recovery.
- Performance of the HVdc system is good.
- An HVdc power runback was implemented to further improve the recovery of the Newfoundland ac system from faults. Such runbacks are common in HVdc schemes and are used to improve the recovery performance of the ac systems.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good.

6.2.12 BC12-DC10: 80 MW BP, 625 MW Minimum Peak Load

This base case represents the minimum peak Newfoundland ac system load (625 MW) with economic generation dispatch and minimum import from Gull Island (80 MW) through a bipolar two-terminal HVdc between Gull Island and Soldiers Pond. The HVdc at Salisbury is off. The Gull Island ac system was represented as normal.

The results of the nine selected contingencies simulated for this base case are summarized below.

6.2.12.1 AC System Response

- Adequate post-disturbance voltage recovery is observed during all the disturbances.
- Since the frequency control feature of the HVdc was disabled the frequency measured at the converter bus was seen to decline to a minimum of 0.97 pu (NL3.4.1). Enabling the frequency control feature of the HVdc is expected to successfully mitigate the frequency variation as has been demonstrated in numerous other cases.
- Adequate damping on line flows is noted during all the disturbances.

6.2.12.2 HVdc System Response

- In general, response of the HVdc link is good.
- For all cases, the dc power recovered to 90% of pre-fault levels within approximately 300 ms.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The maximum overvoltage observed at Gull Island was 1.04 pu, and was limited by the strength of the system and by the action of the local generators. The maximum overvoltage at Soldiers Pond observed was 1.04 pu and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.
- For all cases, the Newfoundland ac system frequency is maintained above approximately 0.98 pu with the assistance of the frequency controller of the HVdc link. Since the HVdc in-feed to Soldiers Pond is at its minim limit, the HVdc frequency controller cannot be used to mitigate over-frequency conditions.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.06 pu.
- For contingencies NL5.1.1 to NL5.2.1 (CN041-CN048) which simulate single line-to-ground faults with an unsuccessful reclose, a subsequent commutation failure is observed when the ac line recloses back onto the fault. This is expected, and the system recovers following the clearing of the line.

6.2.12.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a two-terminal, bipolar configuration with Soldiers Pond (inverter) and Gull Island (rectifier) operating at minimum rated power (10%) and minimum load (625 MW) conditions of the Newfoundland ac system.
- Consideration should be given as how to provide mitigation for over-frequency conditions when the HVdc in-feed at Soldiers Pond is operating at its minimum limit.

- The post-disturbance system is transiently stable with adequate voltage recovery.
- Performance of the HVdc system is good.
- The frequency control feature implemented within the HVdc controls cannot provide mitigation of over-frequency conditions within the Newfoundland ac system since the HVdc in-feed at Soldiers Pond is operating at its minimum limit. Over-frequency mitigation would require the implementation of generator tripping or the reversal of the Soldiers Pond converter from inverter to rectifier operation, the investigation of which is outside the scope of this study.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good.

6.2.13 BC13-DC3: 600 MW MP, 1800 MW Future Peak Load

This base case represents the future peak Newfoundland ac system load (1800 MW) with maximum generation dispatch and 600 MW import from Gull Island through HVdc in a monopolar configuration running in steady-state overload conditions. The Labrador and New Brunswick ac systems were represented as weak.

The results of the nine selected contingencies simulated for this base case are summarized below.

6.2.13.1 AC System Response

- Severe voltage dips are observed in the case of a three-phase fault at Bay d'Espoir with normal clearing and tripping of the Bay d'Espoir-Pipers Hole 230 kV line (NL3.1.1). The voltages at various buses remain below 0.8 pu for a duration of 390 ms to 500 ms. Reduction in fault-clearing time by one cycle has a drastic effect on the voltage dip, which leaves the minimum voltage dip to 270 ms at N371.
- Severe voltages dips are also observed in the case of a three-phase fault at Pipers Hole with normal clearing and tripping of the 300 MVA synchronous condenser (NL3.3.2). The voltages at various buses remain low for a duration of 300 ms or more. The maximum duration of voltage dip is observed at Salt Pond (Bus #371) which is ignored as previously discussed. Reducing the clearing time by one cycle has the same effect as mentioned above.
- Severe voltages dips are also observed in the case of a three-phase fault at Pipers Hole with normal clearing and tripping of the Bay d'Espoir-Pipers Hole 230 kV line (NL3.1.8). The voltages at various buses remain below 0.8 pu for a maximum duration of 320 ms. The voltage at Salt Pond (Bus #471) remains below 0.8 pu for 360 ms, which is ignored as previously discussed in the results of BC3-DC4.
- With the HVdc frequency control feature disabled, the maximum decline in frequency is noted in the case of a three-phase fault at Bay d'Espoir followed by normal clearing and tripping on Unit #7 (NL3.4.1). The frequency measured at the converter bus declines to 0.95 pu by the end

of simulation and seems to continue. Enabling of the HVdc frequency control is expected to effectively control the NLH system frequency in this case as was seen in numerous other cases.

- Slow damping on all line flows is noted in certain cases. The slow damping on 735 kV line flows is due to the absence of stabilizers on the Gull Island generators.

6.2.13.2 HVdc System Response

- In general, response of the HVdc system is good.
- For all cases, the dc power recovered to 90% of pre-fault levels within approximately 300 ms.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.06 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The maximum overvoltage observed at Gull Island was 1.06 pu, and was limited by the strength of the system and by the action of the local generators. The maximum overvoltage at Soldiers Pond observed was 1.1 pu and was limited largely by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.
- The Newfoundland ac system experiences a frequency decline resulting from loss of the largest single generator on the Island, whether due to fault clearing or without any fault. With the HVdc frequency controller disabled, under-frequency load shedding is required to avoid a collapse of system frequency. If the HVdc frequency control feature is enabled, it is expected that modulation of the HVdc in-feed to Soldiers Pond will provide effective mitigation of the under frequency, avoiding the need for under-frequency load shedding. Since the HVdc is operating in monopolar mode at 1.5 pu prior to the disturbance, use of the HVdc frequency controller to stabilize the Island frequency assumes that the HVdc can transiently operate above the 1.5 pu continuous monopolar steady-state limit. If this is not the case, then under-frequency load shedding would be required.
- For all cases, overvoltages observed at the commutating buses during faults or during fault recovery were acceptable. The highest overvoltage observed was approximately 1.13 pu at the Salisbury bus. The overvoltages observed at the Salisbury bus were somewhat pessimistic due to the simplified representation of the New Brunswick ac system. The overvoltages at Gull Island were limited by the strength of the system and by the action of the local generators, while the overvoltages at Soldiers Pond are largely limited by the 300 MVA synchronous condenser connected to the Soldiers Pond bus.
- For contingencies NL5.1.1 to NL5.2.1, which simulate single line-to-ground faults with an unsuccessful reclose, a subsequent commutation failure is observed when the ac line recloses back onto the fault. This is expected, and the system recovers following the clearing of the line.

6.2.13.3 Summary

Salient points of the simulation results are summarized below:

- The results demonstrate the capability to successfully operate the HVdc system in a multi-terminal, monopolar configuration with the Soldiers Pond converter operating at its 1.5pu continuous overload rating under peak future load (1800 MW) conditions of the Newfoundland ac system.
- Some consideration must be given to mitigation of under-frequency conditions on the Island if operation above the 1.5 pu maximum limit is not possible
- The post-disturbance system is transiently stable with adequate voltage recovery.
- Use of the HVdc frequency control feature to mitigate under frequencies within the Newfoundland ac system when in monopolar operation at the 1.5 pu maximum continuous limit requires the ability to increase the HVdc in-feed to Soldiers Pond into the 10-minute overload region. This will depend on the length of time since the previous operation above the 1.5 pu continuous limit. If this capability is not available, then under-frequency load shedding will be required.

In summary, the system is transiently stable with adequate recovery, and performance of the HVdc system is good.

7. Conclusions and Recommendations

7.1 Conclusions

Based on the results of this study, the following conclusions are made:

1. Performance of the proposed multi-terminal HVdc system was seen to be good, successfully demonstrating the feasibility of the proposed multi-terminal HVdc interconnection. Bipolar, monopolar, multi-terminal and two terminal operation was studied and the performance found to be good.
2. The following system upgrades were required within the Newfoundland ac network in order to support the HVdc in-feed:
    a. Conversion of all three units at Hollyrood to synchronous condenser operation.
    b. Installation of five (5) combustion turbines which can operate as synchronous condensers at the Pipers Hole 230kV bus.
    c. 50% series compensation of both 230 kV lines from Bay d'Espoir to Sunnyside.
    d. One 300 MVAr high inertia synchronous condenser is in-service at the Pipers Hole 230 kV bus at all times.
    e. One 300MVAr high inertia synchronous condenser is in-service at the Soldiers Pond 230 kV bus at all times.
3. No conditions (ac system configurations or contingencies) were observed under which the HVdc system could not successfully recover. Recovery of the HVdc power transfer is dictated, to a large extent, by the time required to charge the large cable capacitance associated with the cable across the Cabot Strait; therefore, significant improvements in the speed of recovery beyond that obtained in this study is not likely. Recovery of the HVdc infeed was seen to be good, with the HVdc power typically recovering to 90% of pre-disturbance power within 300 ms of fault clearing.
4. The system is transiently stable with adequate post-disturbance recovery. The majority of contingencies studied result in voltage dips with acceptable duration (20-cycle); however, some disturbances resulted in voltage dips beyond the criteria limits. Additional improvements in the Newfoundland ac system will be required to improve the voltage-sag problems if these are deemed excessive.
5. The need for under-frequency load shedding in the Newfoundland ac system is minimized. The HVdc system, due to its inherent controllability, provides an effective means of fast and efficient frequency control within the Newfoundland ac system by modulation of the HVdc power transfer to overcome capacity deficit or surplus situations. There are however a number of conditions where the HVdc system will not be able to provide the necessary frequency control due to operational limits or converter capacities. Therefore the existing under-frequency load shedding scheme in the Newfoundland system should be modified in order to operate only when the HVdc frequency controller is not able to provide the necessary control for under-frequency conditions. Likewise, a generation rejection scheme should also be considered for the Newfoundland system in order to

operate only when the HVdc frequency controller is not able to provide the necessary control for over-frequency conditions.

6. The 2.0 pu, ten minute overload rating of the Soldiers Pond converter and corresponding overload rating of the Gull Island converter provides suitable mitigation for the loss of a pole, even under conditions of high HVdc power in-feed.

7. When operating in three terminal mode with Gull Island as the only rectifier, the complete loss of the Gull Island converters can be successfully mitigated by reversal of the Salisbury converter from inverter to rectifier operation. The studies have shown that this is possible from the Newfoundland ac system point of view, additional studies are required to determine the impact on the New Brunswick ac system.

8. When the HVdc link is operating in two terminal mode with Salisbury as the rectifier and Soldiers Pond as the inverter, a number of situations arose where the HVdc in-feed to Soldiers Pond was limited due to the overload capability of the Salisbury converters, resulting in the need for under-frequency load shedding in the Newfoundland ac system. Consideration should be given to the potential benefits of providing additional overload capability within the Salisbury converter and the resultant improvements in the performance of the Newfoundland ac system when Salisbury is operating as the only rectifier.

9. Operation with Soldiers Pond as a rectifier is possible. The maximum HVdc export level out of the Newfoundland system was found to be 165 MW due to limitations within the Newfoundland ac system. It is expected that this level could be increased with suitable upgrades to the Newfoundland ac system.

10. The worst-case disturbance within the Newfoundland ac system is a three-phase fault at Bay d'Espoir on one of the 230 kV lines to Pipers Hole requiring tripping of the line to clear the fault. This fault causes the HVdc to fail commutation, which collapses the HVdc power momentarily. At the same time, it also causes a large disturbance of the Bay d'Espoir generators. Recovery from this fault is possible only with the cross tripping of the 175 MW refinery load at Pipers Hole. It should be noted that this study considered only the trip of the entire refinery load at Pipers Hole, additional studies should be conducted to determine if tripping of a smaller block of load would be sufficient to maintain system stability.

11. The protection and fault-clearing times for faults at Bay d'Espoir and Pipers Hole should be optimized to prevent voltage sags of long duration.

12. A special protection and remedial action scheme is needed to reduce Gull Island generation in case of load rejection due to the outage of the last 735 kV line from Gull Island.

13. Correctly designed/tuned stabilizers on the Gull Island generators are essential to maintain steady power flow through the 735 kV lines. Also, the performance of the Newfoundland ac system should be reviewed to evaluate requirements for stabilizers in other parts of the network.

7.2 Recommendations

This study has successfully demonstrated the feasibility of the proposed multiterminal HVdc system and it is therefore recommended that the design of the multi-terminal HVdc system can be further refined to advance the implementation of the overall project. Additional studies recommended for refinement of the detailed design include:

1. System impact study of the proposed 175MW refinery load at Pipers Hole.
2. Studies to look at the 50% Series compensation recommended for the lines TL202 and TL206. These studies should include;
    a. Insulation Co-ordination
    b. Switching Studies
    c. Series resonance studies
3. Study to look at the impact of a bi-pole block on the Newfoundland System.
4. System integration study to evaluate the impact of the proposed HVdc system on the New Brunswick ac system.
5. Reactive power study to optimize the ratings, location and number of synchronous condensers and ac filters required within the Newfoundland ac system.
6. A study to identify and mitigate any potential sub-synchronous resonance issue should be performed.
7. Facilities studies to develop detailed implementation schemes and cost estimates for the identified transmission and control system facilities.
8. Resonance studies to ensure that the HVdc system does not adversely interact with potential resonances in the Labrador, Newfoundland and New Brunswick ac systems. This should include:
    a. Harmonic resonance investigations
    b. Resonance study of the proposed dc line/cable.

References

1. DC1020 HVdc System Integration Study – Power Flow and Short Circuit Analysis Interim Report.
2. DC1020 HVdc System Integration Study – Comparison of Conventional & CCC HVdc Technology Interim Report.

Appendix A

Stability Simulations Results

(attached DVD's)

Appendix A is not included in Public version

Appendix B

NLH System Fault Levels

Table-B.1
Maximum NLH Fault Levels
Before and After HVdc System Addition and
Series Compensation on Bay D'Espoir-Pipers Hole 230 kV Lines

Station	Existing Fault Level (MVA)		New Fault Level (MVA)				Breaker Ratings
	3P	LG	3P	Increase	LG	Increase	
NL Refinery 230 kV	2019	1831	4674	132%	5334	191%	New Station
Buchans 230 kV	1824	1736	1890	4%	1801	4%	5430/7970
Stony Brook 230 kV	2444	2640	2650	8%	2836	7%	4780/9960
Stony Brook 138 kV(959)	1508	1836	2250	49%	2689	20%	2480/2630
Pipers Hole 230 kV	n/a	n/a	5554	n/a	6623	n/a	New Station
Pipers Hole SCo LV	n/a	n/a	2502	n/a	1757	n/a	New Station
Soldiers Pond SCo LV	n/a	n/a	2430	n/a	1733	n/a	New Station
BDP G2-6	984	0.13	4179	325%	1	408%	No Unit Breaker
Bay d'Espoir 230 kV	3845	4576	5076	32%	5698	25%	5130/5600/5710
Sunnyside 230 kV	2164	2084	5355	147%	5845	180%	5600
Come-By-Chance 230 kV	2019	1831	4370	116%	3894	113%	7960
Western Avalon 230 kV	2152	2349	3960	84%	3818	63%	4980/5600
Western Avalon 138 kV	1281	1531	4360	240%	4340	183%	4780
Long Harbour 230 kV	1653	1439	2588	57%	1929	34%	New Breakers
Holyrood 230 kV	2657	3307	4620	74%	5360	62%	5100/5400/7570/12550
Bay d'Espoir 69 kV	289	299	309	7%	317	6%	1430
Abitibi Cons, Grand Falls 230 kV	2419	2614	2622	8%	2808	7%	No Breaker
Abitibi Cons T2 13.8 kV	*	*	554		20		1055
Abitibi Cons T1&T3 6.9kV	*	*	572		368		*
Granite Canal 230 kV	861	762	931	8%	813	7%	No Breaker
Granite Canal 13.8 kV	414	0.04	437	6%	0	0%	1506
Upper Salmon 230 kV	1683	1600	1891	12%	1752	10%	12550/15935
Upper Salmon 13.8 kV	861	0	915	6%	0	0%	920
Pipers Hole CT1-5	n/a	n/a	857	n/a	0	n/a	NA
Bay d'Espoir 13.8 kV	984	0.13	1051	7%	0.13	0%	No Unit Breaker
Bay d'Espoir *7 13.8 kV	2095	0.27	2265	8%	0.27	0%	No Unit Breaker

*Information not available.

APPENDIX C7 – DC1020 VOLUME 6 – HVDC SYSTEM INTEGRATION STUDY – CURSORY EVALUATION OF ALTERNATIVE HVDC CONFIGURATIONS – MAY 2008

HYDRO
THE POWER OF COMMITMENT

THE Lower Churchill PROJECT

May 2008

DC1020 - HVdc System Integration Study

Volume 6 - Cursory Evaluation of Alternate HVdc Configurations

prepared by

HATCH™

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PETER KUFFEL
SIGNATURE
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Executive Summary

Newfoundland and Labrador Hydro (Hydro) is planning to install a three-terminal HVdc system linking Labrador, Newfoundland, and New Brunswick. The proposed HVdc system will be bipolar, with each converter station having the ability to run as either rectifier or inverter. It will use both cable and overhead line, with about 40 km of cable between Labrador and Newfoundland and about 480 km between Newfoundland and New Brunswick.

The Labrador (Gull Island) converters will be nominally rated at 1600 MW; whereas, the Newfoundland (Soldiers Pond) and New Brunswick (Salisbury) stations will each be rated at 800 MW. The converters at Soldiers Pond require an overload capability of 2.0 pu for 10 minutes and 1.5 pu continuously. This would allow for the start-up of generation to avoid load shedding in the event of the loss of one pole of the HVdc system. The converters at Salisbury do not require any special overload capability and will have an overload rating which is typical of HVdc systems (10-15%).

The report "DC 1020 HVdc System Integration Study- Transient Stability Analysis" [1] presented the results of the detailed transient stability analysis of the proposed multi-terminal HVdc system. This report presents the results of a cursory evaluation of alternate HVdc configurations performed as a separate task within the overall WTO DC1020 HVdc System Integration Study. This cursory evaluation compared a number of alternative HVdc configurations considering cost, expected performance and impacts on the reliability of the overall transmission system.

The configurations considered are as follows:

a) Base case: A three-terminal HVdc link connecting Gull Island, Soldiers Pond and Salisbury. This alternative was the main focus of the system integration studies.

b) Alternative 1: A two-terminal HVdc link connecting Gull Island to Soldiers Pond and another two-terminal HVdc link connecting Soldiers Point to Salisbury.

c) Alternative 2: A two-terminal HVdc link connecting Gull Island to Soldiers Pond and another two-terminal HVdc link connecting Gull Island to Salisbury.

d) Alternative 3: A two-terminal HVdc link connecting Gull Island to Taylors Brook and another two-terminal HVdc link connecting Taylors Brook to Salisbury, in conjunction with new ac transmission from Taylors Brook to Soldiers Pond.

e) Alternative 4: A two-terminal HVdc link connecting Gull Island to Soldiers Pond and another two-terminal HVdc link connecting Taylor Brook to Salisbury, in conjunction with new ac transmission from Taylors Brook to Soldiers Pond.

f) Alternative 5: Three two-terminal HVdc links; one connecting Gull Island to Taylors Brook, one connecting Taylors Brook to Salisbury and one connecting Taylors Brook to Soldiers Pond.

The alternatives were compared in terms of the cost of the converter terminals, length of the overhead lines and cables, requirement for synchronous condensers, and advantages and disadvantages as compared to the base case multi-terminal HVdc configuration.

Converter cost calculations were made based on the assumption of 1pu$/MW for each converter of a two-terminal HVdc link. Converter costs for the base case multi-terminal HVdc configuration were increased by 10% to account additional costs associated with the multi-terminal option. The overload requirements for each alternative were determined and the corresponding converter costs calculated.

The total length of the HVdc overhead transmission line and undersea cable, along with any ac lines required for the given alternative were also determined. It should be noted that costs of the associated transmission lines and cables were not calculated; only the relative lengths were compared.

Synchronous condensers requirements on the Island of Newfoundland for the given alternative were considered based on the need to provide adequate Equivalent Short Circuit Ratio (ESCR) in the case of a single HVdc link, and the Multi-infeed Interactive Effective Short Circuit Ratio (MIESCR) in the case where two or more HVdc links terminate electrically close to one another. The MIESCR is a generalization of the ESCR index that can be used for multi-infeed systems to indicate the effect of one HVdc system on the other.

The cost of converter terminals, length of overhead lines and cables and relative amount of synchronous condensers required for the base case multi-terminal HVdc configuration and the five alternatives considered are summarized in Table 1.

Table 1
Summary of Results

Case	Converter Cost		DC OH Line		DC Cable km	ac OH Line km	Need for Synchronous Condenser
	pu$	Relative to base case	km	Relative to base case			
Base	4306	1	1488	1	520	0	Low
Alt. 1	6144	1.43	1894	1.27	520	0	High
Alt. 2	3864	0.83[1]	2170	1.46	561	0	Low
Alt. 3	6144	1.43	1082	0.73	520	800	Very High
Alt. 4	6144	1.43	1488	1	520	800	Fairly High
Alt. 5	8408	1.95	1488	1	520	0	Extremely High

[1] *No provision has been included to account for the fact that the total installed converter capacity at Gull Island is installed in two separate converter stations which should be expected to increase the cost as compared to installation of the entire capacity within a single converter.*

Salient point of the overall comparison of the alternatives includes:

- For all alternatives except alternative 2, the total cost of converters is greater than that of the base case multi-terminal HVdc configuration.
- For all alternatives except alternative 3, the total length of HVdc overhead line and cable is equal to or greater than that of the base case multi-terminal HVdc configuration. In the case of alternatives 3 and 4 an additional 800km of 230kV as transmission lines are required on the Island of Newfoundland.
- For all alternatives, synchronous condenser requirements within the Newfoundland ac system are equal to greater than those of the base case multi-terminal HVdc configuration.
- None of the alternatives considered provided any significant advantages as compared to the base case multi-terminal HVdc configurations while providing some disadvantages.

Based on the results of this cursory evaluation it is concluded that the base case multi-terminal HVdc configuration offers the lowest overall cost when considering the cost of converters, HVdc overhead lines and undersea cables, ac transmission lines, and synchronous condenser requirements. Furthermore, none of the alternatives considered offered any significant advantages over the base case multi-terminal HVdc configuration. Therefore it is recommended that none of the alternative configurations be considered as a preferable option to the base case multi-terminal HVdc configuration.

1. Introduction

Newfoundland and Labrador Hydro (Hydro) is planning to install a three-terminal HVdc system linking Labrador, Newfoundland, and New Brunswick. The proposed HVdc system will be bipolar, with each converter station having the ability to run as either rectifier or inverter. It will use both cable and overhead line, with about 40 km of cable between Labrador and Newfoundland and about 480 km between Newfoundland and New Brunswick.

The Labrador (Gull Island) converters will be nominally rated at 1600 MW; whereas, the Newfoundland (Soldiers Pond) and New Brunswick (Salisbury) stations will each be rated at 800 MW. The converters at Soldiers Pond require an overload capability of 2.0 pu for 10 minutes and 1.5 pu continuously. This would allow for the start-up of generation to avoid load shedding in the event of the loss of one pole of the HVdc system. The converters at Salisbury do not require any special overload capability and will have an overload rating which is typical of HVdc systems (10-15%).

The report "DC 1020 HVdc System Integration Study- Transient Stability Analysis" [1] presented the results of the detailed transient stability analysis of the proposed multi-terminal HVdc system. This report presents the results of a cursory evaluation of alternate HVdc configurations performed as a separate task within the overall WTO DC 1020 HVdc System Integration Study. This cursory evaluation compared a number of alternative HVdc configurations considering cost, expected performance and impacts on the reliability of the overall transmission system.

2. Evaluation of Alternate HVdc Configurations

In the following sections the budget price for a bipolar, two terminal HVdc link (two converters only, cost of transmission line is extra) is considered to be 2 per units $/MW. The cost of each converter is therefore assumed to be 1 per unit $/MW

One recent 2500MW bipolar, two terminal HVdc project has been awarded at a price of 350 million USD, which equates to a cost of 140,000 USD/MW for both converter stations or 70,000 USD/MW for each of the two converters. Based on the CIGRE report of WG 14.20 the estimated cost of one converter terminal of a 450 kV, bipolar, two terminal HVdc system is 78,750 USD/MW. Based on these values it seems that the actual cost of a converter terminal is in the range of 75,000 USD /MW to 80,000 USD/MW.

This cost can be broken down into the following items:

Table 2
Approximate Cost Breakdown for an HVdc Terminal

Engineering and Overhead	
Other Equipment	
Controls	
ac Filters	
Civil Works	
Valves	
Transformers	
Total	**100.00%**

2.1 Base Case – Multi-Terminal HVdc System

This alternative is the three-terminal HVdc system connecting Gull Island, Soldiers Pond and Salisbury as shown in Figure 1and was the main focus of the HVdc System Integration Study.

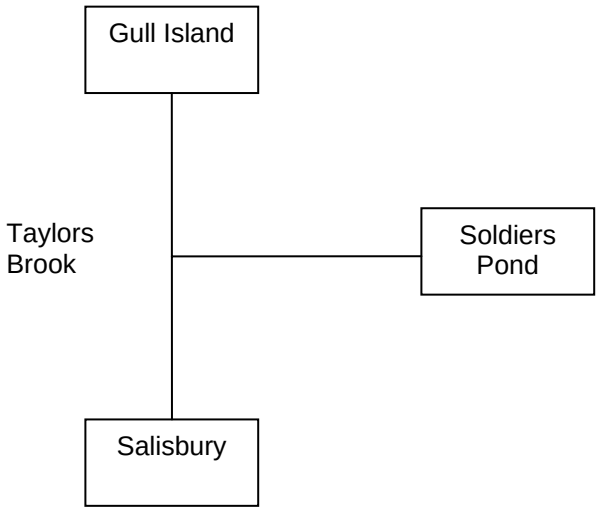


Figure 1 Base Case – Multi-Terminal HVdc System

The feasibility study has shown that this option is technically viable and is capable of delivering reliable power to Newfoundland. Based on the previous studies, the rating of the HVdc terminals are as shown in Table 3 below. The short term (10-minute) overload capacities are only needed in mono-polar operation mode.

Table 3
Converter Ratings for Base Case Three-Terminal HVdc Configuration (per Pole)

		Overload rating (MW)	
Location	**Nominal rating (MW)**	**10 Minute**	**Steady State**
Gull Island	800	1240 (1.55 pu)	1040 (1.3 pu)
Soldiers Pond	400	800 (2.0 pu)	600 (1.5 pu)
Salisbury	400	4400 (1.1 pu)	4400 (1.1 pu)
Total (per pole)	**1600**	**2480**	**2080**
Total (Bipole)	**3200**	**4960**	**4160**

2.1.1 Converter Terminal Costs

The estimated costs of each of the three terminals with this option are given in Tables 4 to 6 below. It should be mentioned that HVdc converters are generally designed with an inherent overload capability of 10%. The Gull Island and Soldiers Pond terminals in this option require larger overload capacities which will affect their costs; however the large overload capacity is required only in mono-polar operation. Upon loss of a pole, the healthy pole at Soldiers Pond must be capable of delivering the full bipolar power (800 MW) for at least 10 minutes. The healthy pole at Gull Island must be able to deliver the 800 MW required at Soldiers Pond as well as the 440 MW demanded by the healthy pole at Salisbury.

The cost of a converter station for a multi-terminal HVdc is assumed to be 10% more than a comparable converter station for a two-terminal HVdc link. This is due to the extra engineering cost and the extra equipment required for power reversal capability. Therefore in Table 4 to Table 6 the cost of converter terminals without the extra overload capacity is considered 1.1pu$/MW.

The fourth columns in Table 4 to Table 6 show the estimated effect of the large overload capacity on each item of the cost. The increased overload capacity will have minimal effect on the cost of engineering and controls and therefore these items of cost remain unchanged.

Operation in overload conditions normally requires increased capacity of the ac filters. However in this case the overload capacity is needed only when one pole is not in service. Consequently the ac filters from this pole can be used to provide the necessary reactive power support for overload operation. As a result the increased overload capacity does not affect the cost of ac filters.

HVdc thyristor valves have very short thermal time constants and therefore any increase in overload capacity of each pole (even for short term) requires similar increase in valve ratings. The cost of valves is therefore estimated to be increased in proportion to the 10-minute overload capacity. Transformers on the other hand have large thermal time constant and can handle short term overloads. Transformer MVA ratings are therefore affected only by the steady state overload capacity. Assuming that the cost of transformers is proportional to their MVA ratings, this item of cost is then increased in proportion to the steady state overload capacity of each terminal.

Increased overload capacity also affects the cost of civil work. Increased transformer, busbars, switch gear, cooling system sizes etc., means more civil work and hence higher cost. Most parts of the civil work cost increase in proportion to the steady state overload capacity. The size of ac filters and their associated civil work is not increased here; however there are items that are increased in proportion to the short term overload capacity. Therefore it seems reasonable to assume this item of cost is increased in proportion to the steady state overload capacity.

The costs of various other equipments are affected differently by the overload capacity. While certain items like Potential Transformers may remain unchanged, other items such as the ac breakers should be selected according to the short term overload capacity. On average the cost of other equipment is estimated to be increased in proportion to the steady state overload capacity.

Table 4
Estimated Cost of Gull Island Terminal for Base Case Multi-Terminal HVdc Configuration

Gull Island			
	% of total cost	**Total Cost without OL rating**	**Total Cost with OL rating**
Engineering and OH			
Other Equip			
Controls			
ac Filters			
Civil Works			
Valves			
Transformers			
Total (per pole)	**100.00%**	**1760 pu$**	**2181 pu$**

Table 5
Estimated Cost of Soldiers Pond Terminal for Base Case Multi-Terminal HVdc Configuration

Soldiers Pond			
	% of total cost	**Total Cost without OL rating**	**Total Cost with OL rating**
Engineering and OH			
Other Equip			
Controls			
ac Filters			
Civil Works			
Valves			
Transformers			
Total	**100%**	**880 pu$**	**1245 pu$**

Table 6
Estimated Cost of Salisbury Terminal for Base Case Multi-Terminal HVdc Configuration

Salisbury			
	% of total cost	**Total Cost without OL rating**	**Total Cost with OL rating**
Engineering and OH			
Other Equip			
Controls			
ac Filters			
Civil Works			
Valves			
Transformers			
Total	**100%**	**880 pu$**	**880 pu$**

The estimated total cost of the three terminals is given in Table 7 below.

Table 7
Total Estimated Converter Costs for Base Case Multi-Terminal HVdc Configuration

Location	**Estimated Cost**
Gull Island	2181 pu$
Soldiers Pond	1245 pu$
Salisbury	880 pu$
Total	**4306 pu$**

2.1.2 Transmission Lines and Cables

The required overhead transmission lines and cables for this option are summarized in Table 8. Note that in the discussion of cable lengths no consideration is given to the need for multiple cables in parallel to support the required dc current. The lengths given correspond only to the estimated length of cable and do not consider the need for cables in parallel.

Table 8
Overhead Line and Cable Lengths for Base Case Multi-Terminal HVdc Configuration

Section	OHL (km)	Cable (km)
Gull Island to Strait of Belle Isles	407	
Across Strait of Belle Isles		40.7 (two poles)
Strait of Belle Isle to Taylors Brook	275	
Taylors Brook to Soldiers Pond	406	
Taylors Brook to Cape Ray	300	
Across Cabot Strait		480 (two poles)
Coast of New Brunswick to Salisbury	100	
Total	**1488**	**520.7**

2.1.3 Effective Short Circuit Ratio

Effective short circuit ratio (ESCR) is defined as follows:

ESCR = (Short circuit MVA at AC bus – MVA rating of filters)/Rated DC power

Based on industry experience it can be stated that low or very low SCR in itself is not a technical limitation in the evaluation of an HVdc transmission option, but it must be recognized that decreasing short circuit ratio (and therefore the ESCR) results in overall decreased performance of the interconnected ac/dc systems. The effects of reducing ESCR on overall performance becomes even more pronounced for HVdc system which utilize long cables.

Based on the system data provided for the Power Flow and Transient Stability study portions of WTO DC 1020 and results of the Transient Stability study [1] which found that one 300MVAr synchronous condenser must be in-service at both the Pipers Hole and Soldiers Pond 230kV ac buses, the Effective Short Circuit Ratios (ESCRs) at the three terminals are as follows:

Gull Island ESCR = 4.81
Soldiers Pond ESCR = 3.12
Salisbury ESCR =

The results of the transient Stability Study [1] have shown good performance of the multi-terminal HVdc system and indicate that the ESCRs at each of the three terminals are sufficient.

It should be noted that the Transient Stability Study [1] found the need for having one 300MVAr synchronous condenser in service at Pipers Hole and Soldiers Pond was based on increasing the ESCR and providing system inertia.

2.2 Alternative 1 – Two Two-Terminal HVdc Links – Option 1

This alternative includes two separate Two-terminal HVdc systems, one connecting Gull Island to Soldiers Pond and another connecting Soldiers Point to Salisbury as shown in Figure 2.

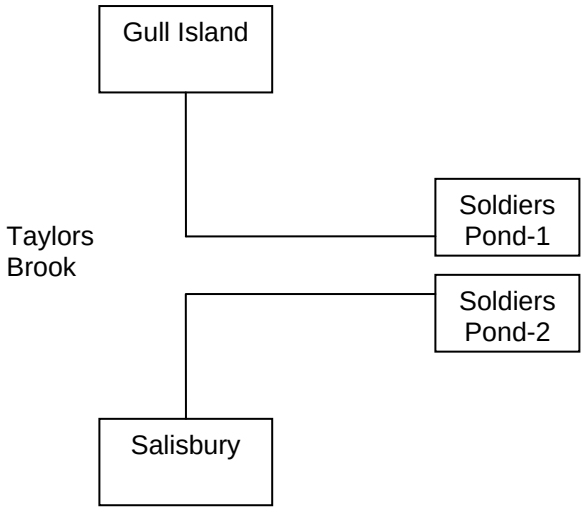


Figure 2 Alternative 1 - Two Two-Terminal HVdc Systems - Option 1

Nominal and overload ratings of the required terminals for this alternative are as shown in Table 9.

Table 9
Nominal and Overload Ratings for Alternative 1 (per Pole)

		Overload rating (MW)	
Location	**Nominal rating (MW)**	**10 Minute**	**Steady State**
Gull Island	800	1600 (2.0 pu)	1200 (1.5 pu)
Soldiers Pond 1	800	1600 (2.0 pu)	1200 (1.5 pu)
Soldiers Pond 2	400	440 (1.1 pu)	440 (1.1 pu)
Salisbury	400	440 (1.1 pu)	440 (1.1 pu)
Total (per pole)	**2400**	**4080**	**3280**
Total (Bipole)	**4800**	**8160**	**6560**

In this alternative, under the worst case scenario where 1600MW flows from Gull Island to Soldiers Pond 1 and 800 MW flows from Soldiers Pond 2 to Salisbury; if one pole in the Gull Island to Soldiers Pond 1 system trips the healthy pole must be able to transmit the whole 1600MW to maintain the net power delivered to the Newfoundland system at 800MW and also maintain the 800MW power flow in the Soldiers Pond 2 to Salisbury HVdc system. Therefore in this alternative, the Gull Island and Soldiers Pond 1 terminals must have 100% short term and 50% steady state overload capacities. The Soldiers Pond 2 to Salisbury HVdc link however does not need an increased overload capacity. In case of a pole loss in Soldiers Pond 2 to Salisbury link the New Brunswick system should be able to absorb the power shortage.

When comparing to the base case multi-terminal configuration, alternative 1 requires a total installed converter capacity with 1.5 times the nominal rating, 1.65 times the 10-minute overload rating, and 1.58 times the steady state overload rating.

2.2.1 Converter Terminal Costs

Repeating the analysis of Table 5 to Table 7, cost estimates for the converter terminals for alternative 1 are given in Table 10.

Table 10
Estimated cost of converter terminals for Alternative 1

Location	Nominal rating (MW)	10 Min. OL (MW)	Steady State OL (MW)	Cost
Gull Island (per pole)	800	1600 (2.0 pu)	1200 (1.5 pu)	1(pu$/MW) x 800(MW) x 1.42 = 1136 pu$
Soldiers Pond 1 (per pole)	800	1600 (2.0 pu)	1200 (1.5 pu)	1(pu$/MW) x 800(MW) x 1.42 = 1136 pu$
Soldiers Pond 2 (per pole)	400	440 (1.1 pu)	440 (1.1 pu)	1(pu$/MW) x 400(MW) = 400 pu$
Salisbury (per pole)	400	440 (1.1 pu)	440 (1.1 pu)	1(pu$/MW) x 400(MW) = 400 pu$
Total (per Pole)	**2400**	**4080**	**3280**	**3072 pu$**
Total (Bipole)	**4800**	**8160**	**6560**	**6144 pu$**

Due to the increased overload capacity, it is seen that the cost of the Gull Island and Soldiers Pond 1 terminals has increased by approximately 43% as compared to the base case multi-terminal HVdc configuration. The cost of the Salisbury terminal has been reduced by 10% due to the fact that this is now a two terminal (not a multi-terminal) converter; however a new Soldiers Pond 2 converter with a rating equal to that of the Salisbury converter is required.

When comparing the converter costs for alternative 1 to the base case multi-terminal HVdc configuration it is seen that the overall converter costs have increased by approximately 43%.

2.2.2 Transmission Lines and Cables

The approximate lengths of the overhead lines and cables required in this alternative are given in Table 11.

Table 11
Approximate length of the required OH lines and cables for Alternative-1

Section	OHL (km)	Cable (km)
Gull Island to Strait of Belle Isle	407	
Across Strait of Belle Isles		40.7 (two poles)
Strait of Belle Isle to Taylors Brook	275	
Taylors Brook to Soldiers Pond 1	406	
Bipole 1 Subtotal	**1088**	**40.7**
Soldiers Pond 2 to Taylors Brook	406	
Taylors Brook to Cape Ray	300	
Across Cabot Strait		480 (two poles)
Coast of New Brunswick to Salisbury	100	
Bipole 2 Subtotal	**806**	**480**
Total	**1894**	**520.7**

Here it is assumed that the transmission line from Gull Island to Soldiers Pond follows the same route as the base case multi-terminal HVdc system. It is also assumed that a second overhead line is built between Soldiers Pond and Taylors Brook which is then extended to Cape Ray on the same route as the base case multi-terminal HVdc system. The submarine cable and the overhead line within New Brunswick are identical to the multi-terminal option.

Comparing the lengths of overhead lines and cables required for Alternative 1 to those required in the Base Case it is seen that Alternative 1 requires 27% more overhead line and the same length of undersea cable as the base case.

2.2.3 Effective Short Circuit Ratio

The effective short circuit ratios at Gull Island and Salisbury in this option are identical to those of the base case multi-terminal configuration.

At Soldiers Pond there are two HVdc terminals in this case, making a multi-infeed system. Because of the interactions between the two nearby HVdc terminals the conventional definition of the ESCR cannot be used in a multi-infeed system. The Multi-infeed Interactive Effective Short Circuit Ratio (MIESCR) is a generalization of the ESCR index that can be used for multi-infeed systems to indicate the effect of one HVdc system on the other.

For converter 'i' the MIESCR index is defined as:

$$\mathrm{MIESCR}_i = \frac{(\mathrm{SCC}_i - \mathrm{Qf}_i)}{\mathrm{Pdc}_i + \sum_j (\mathrm{MIIF}_{j,i} \times \mathrm{Pdc}_j)}$$

Where:

- SCCi is the short circuit MVA available at the converter bus
- Qfi is the bus filter and capacitor MVA of the converter 'i'
- Pdci is the rated dc power of the converter 'i'
- Pdcj is the rated dc power of the adjacent converter 'j'
- MIIFj,I is the Multi Infeed Interaction Factor between converters j and i.

MIIF is an index describing the proximity of the converters that varies between one for converters connected to the same ac bus, and zero for converters infinitely far apart.

At Soldiers Pond the two converters will be electrically close and therefore the MIFF will be close to one. Assuming the Newfoundland ac system is identical to that used in the base case multi-terminal configuration the MIESCR index for the two converters (Soldiers Pond 1 and 2) can be calculated as:

Soldiers Pond 1 (1600 MW Converter) MIESCR = 0.833

Soldiers Pond 2 (800 MW Converter) MIIESCR = 1.039

The MIISCR for both converters is very low, indicating that more synchronous condensers would need to be installed at Soldiers Pond to increase the system short circuit capacity.

When comparing to the base case multi-terminal HVdc configuration it is concluded that additional synchronous condensers would be required in the Newfoundland system to support the HVdc transmission proposed in Alternative 1.

2.2.4 Advantages

The following is a list of advantages of this alternative as compared to the base case multi-terminal configuration:

- The two HVdc links could be built in stages, with the Gull Island to Soldiers Pond 1 link built prior to the Soldiers Pond 2 to Salisbury link. However, it is most likely that the Gull Island to Soldiers Pond 1 HVdc link would have to be built initially to its final capacity since staging of this two terminal link would not present substantial economic benefits.

- Only conventional two-terminal HVdc links are used therefore some of the challenges associated with the multi-terminal option are avoided. HVdc controls are less complicated compared to the base case multi-terminal HVdc system.
- The effect of the long dc cable is removed from the circuit between Gull Island and Soldiers Pond and its performance will improve.
- If the Soldiers Pond 1 converters are unavailable then power can still be supplied to the Newfoundland system by operating Salisbury as a rectifier and Soldiers Pond 2 as an inverter.
- There is the potential for sharing of spare transformers between the Soldiers Pond 1 and 2 converters depending on the design, physical locations, and configurations of the transformers in the two converter stations.

2.2.5 Disadvantages

The following is a list of disadvantages of this alternative as compared to the base case multi-terminal configuration:

- This alternative requires 1600 MW more of installed converters, adding more than 2000pu$ (49%) to the converter station costs.
- This alternative requires approximately 406km (27%) more overhead line.
- The two separate HVdc links which terminate electrically close to one another at Soldiers Pond would results in a multi-infeed HVdc scenario. Although the two HVdc links are effectively independent of one another, the performance of one will greatly impact the performance of the other due to the close coupling at Soldiers Pond.
- The Multi-Infeed ESCR (MIESCR) in Newfoundland is very low, requiring to the need to install more synchronous condensers.
- Potential for increased overvoltages at Soldiers Pond due to increased ac filter requirements.
- Increased operating losses due to the additional filters and need to convert 800MW from dc to ac and again from ac to dc in Soldiers Pond.
- Increased maintenance due to the fact that there are now two converter stations at Soldiers Pond.
- Increased size and complexity of the overall converter station at Soldiers Pond.
- Potential for increased spares requirements due to different equipment ratings within the Soldiers Pond 1 and 2 converter stations.

2.2.6 Summary

Based on the results of this cursory evaluation it is seen that when compared to the base case multi-terminal HVdc configuration the alternative of two HVdc links, one from Gull Island to Soldiers Pond 1 and the second from Soldiers Pond 2 to Salisbury will result in:

- increased converter costs;
- increased HVdc overhead line lengths;
- additional synchronous condensers within the Newfoundland system and their associated costs.

In addition the alternative does not provide any substantial technical advantages over the base case multi-terminal HVdc while having some technical disadvantages.

It is therefore concluded that the alternative of providing two two-terminal HVdc systems, one from Gull Island to Soldiers Pond 1 and the second from Soldiers Pond 2 to Salisbury is not recommended above the base case multi-terminal HVdc configuration.

2.3 Alternative 2 – Two Two-Terminal HVdc Links – Option 2

This alternative includes two, two-terminal HVdc systems, one connecting Gull Island to Soldiers Pond and another connecting Gull Island to Salisbury as shown in Figure 3.

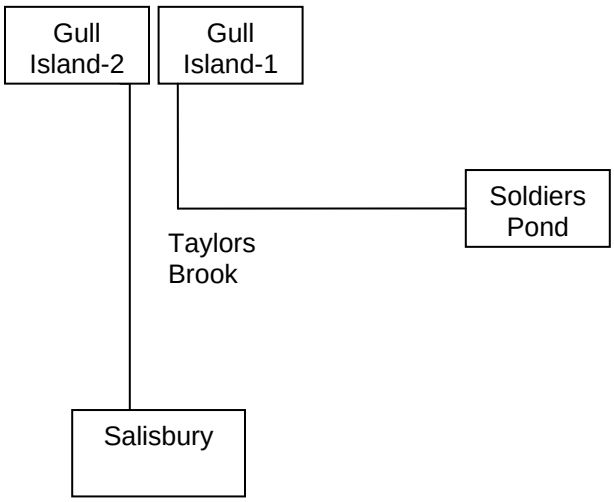


Figure 3 Two Two-Terminal HVdc Links- Option 2 (Alternative-2)

Nominal and overload ratings of the required terminals for this alternative are as shown in Table 12 below.

Table 12
Nominal and Overload Ratings for Alternative 2 (per pole)

		Overload rating (MW)	
Location	**Nominal rating (MW)**	**10 Minute**	**Steady State**
Gull Island 1	400	800 (2.0 pu)	600 (1.5 pu)
Gull Island 2	400	440 (1.1 pu)	440 (1.1 pu)
Soldiers Pond	400	800 (2.0 pu)	600 (1.5 pu)
Salisbury	400	440 (1.1 pu)	440 (1.1 pu)
Total (per pole)	**1600**	**2480**	**2080**
Total (per pole)	**3200**	**4960**	**4160**

In this alternative the first two terminal HVdc link connecting Gull Island 1 and Soldiers Pond must have 100% overload capacity for at least 10 minutes. This is required to avoid a power shortage in Newfoundland in the case of the loss of a pole. The second HVdc link between Gull Island 2 and Salisbury does not require an increased overload capacity.

When comparing to the base case multi-terminal configuration, alternative 2 requires installed converter capacity with the same nominal rating, 10-minute overload rating, and steady state overload rating.

2.3.1 Converter Terminal Costs

Repeating the analysis of Table 5 to Table 7, cost estimates for the converter terminals for alternative 2 are given in Table 13.

Table 13
Estimated Cost of Converter Terminals for Alternative 2

		Overload rating (MW)		
Location	**Nominal rating (MW)**	**10 Minute**	**Steady State**	**Estimated Cost**
Gull Island 1 (per pole)	400	800 (2.0 pu)	600 (1.5 pu)	566 pu$
Gull Island 2 (per pole)	400	440 (1.1 pu)	440 (1.1 pu)	400 pu$
Soldiers Pond (per pole)	400	800 (2.0 pu)	600 (1.5 pu)	566 pu$
Salisbury (per pole)	400	440 (1.1 pu)	440 (1.1 pu)	400 pu$
Total (per pole)	**1600**	**2480**	**2080**	**1932 pu$**
Total (per pole)	**3200**	**4960**	**4160**	**3864 pu$**

Following the same approach taken for the base case, effect of the increased overload capacity on the cost of the Gull Island 1 and Soldiers Pond terminals can be calculated. Gull Island 2 and Salisbury terminals are standard two-terminal converters and their costs are strictly 1pu$/MW.

In this alternative it is seen that the combined installed converter capacity is the same as that for the base case multi-terminal configuration, however two-terminal HVdc links are used, therefore given the analysis used, the cost is reduced. It should be noted that in the analysis used there is no cost adjustment to reflect the fact that the total installed converter capacity at Gull Island for alternative 2 is located within two separate converter stations as compared to the base case multi-terminal configuration which requires only a single converter station at Gull Island.

2.3.2 Transmission Lines and Cables

The approximate lengths of the overhead lines and cables required in this alternative are given in Table 14.

Table 14
Approximate length of OH lines and cables for Alternative-2

Section	OHL (km)	Cable (km)
Gull Island 1 to Strait of Belle Isle	407	
Across Strait of Belle Isle		40.7 (two poles)
Strait of Belle Isle to Taylors Brook	270	
Taylors Brook to Soldiers Pond	406	
Bipole 1 Subtotal	**1088**	**40.7**
Gull Island 2 to Strait of Belle Isle	407	
Across Strait of Belle Isle		40.7 (two poles)
Strait of Belle Isle to Taylors Brook	270	
Taylors Brook to Cape Ray	300	
Across Cabot Strait		480 (two poles)
Coast of New Brunswick to Salisbury	100	
Bipole 2 Subtotal	**1082**	**520.7**
Total	**2170**	**561.4**

In this alternative two independent transmission lines connect Gull Island to Soldiers Pond and Gull Island to Salisbury. The first line from Gull Island 1 to Soldiers Pond is assumed to follow the same route as the base case multi-terminal configuration and include a total of 1088km of overhead line and 40.7km of submarine cable. The second line from Gull Island 2 to Salisbury is also assumed to follow the same route as base case multi-terminal configuration and include a total of 2170km of overhead line and 520.7km of cable.

Comparing the lengths of overhead lines and cables required for Alternative 2 to those required in the Base Case it is seen that Alternative 2 requires 46% more overhead line and 8% more undersea cable as the base case.

2.3.3 Effective Short Circuit Ratio

In this alternative there are two HVdc terminals at Gull Island. The MIESCR for these terminals are shown below and are seen to be reasonably high.

Gull Island 1 MIESCR = 5.12

Gull Island 2 MIESCR = 5.12

The effective short circuit ratios for the Soldiers Pond and Salisbury terminals are unchanged from the base case multi-terminal HVdc configuration.

When comparing to the base case multi-terminal HVdc configuration it is seen that no additional synchronous condensers would be required.

2.3.4 Advantages

The following is a list of advantages of this alternative as compared to the base case multi-terminal configuration:

- The analysis indicates a potential reduction in the converter costs of approximately 10%. It should be noted that the analysis does not account for the fact that the total converter capacity at Gull Island would now be split between two converters in separate HVdc links which would tend to increase the cost as compared to installing the same capacity within a single converter.
- The two HVdc links could be built in stages, with the Gull Island 1 to Soldiers Pond link built prior to the Gull Island 2 to Salisbury link. It is most likely that the transmission lines and cables across the Strait of Belle Isle for both HVdc links would be installed at the same time due to construction costs. Staggering construction of the converter stations at Gull Island would also incur some additional costs.
- The two DC links are more independent, therefore power delivery to the Newfoundland system is more reliable and less affected by the events in New Brunswick system and the Gull Island 2 to Salisbury HVdc link.
- Only conventional two-terminal HVdc links are used therefore some of the challenges associated with the multi-terminal option are avoided. HVdc controls are less complicated compared to the base case multi-terminal HVdc system.
- The effect of the long dc cable is removed from the circuit between Gull Island 1 and Soldiers Pond and its performance.

If one converter is unavailable at Gull Island, there is no impact on the converters of the other HVdc link.

2.3.5 Disadvantages

- This alternative requires approximately 680km (46%) more overhead line and 40km (8%) more undersea cable.
- Loss of transmission capacity from Labrador to Soldiers Pond cannot be offset by importing power from New Brunswick to Newfoundland.
- Direct import of power from New Brunswick to Newfoundland and vice versa is not possible. Importing power from New Brunswick to Newfoundland via Labrador would result in increased losses.
- Increased maintenance due to the fact that there are now two converter stations at Gull Island.
- Increased size and complexity of the overall converter station at Gull Island.
- Potential for increased spares requirements due to different equipment ratings within the Gull Island 1 and 2 converter stations.

2.3.6 Summary

Based on the results of this cursory evaluation it is seen that when compared to the base case multi-terminal HVdc configuration the alternative of two HVdc links, one from Gull Island 1 to Soldiers Pond and the second from Gull Island 2 to Salisbury will result in:

- decrease in converter costs (potentially); and
- greatly increased HVdc overhead line and cable lengths.

In addition the alternative does not provide any substantial technical advantages over the base case multi-terminal HVdc while having some technical disadvantages.

It is therefore concluded that the alternative of providing two, two-terminal HVdc systems, one from Gull Island 1 to Soldiers Pond and the second from Gull Island 2 to Salisbury is not recommended above the base case multi-terminal HVdc configuration.

2.4 Alternative 3 – Two Two-Terminal HVdc Links and ac – Option 1

This alternative includes two, two-terminal HVdc systems, one connecting Gull Island to Taylors Brook and the other connecting Taylors Brook to Salisbury plus the addition of ac transmission connecting Taylors Brook to Soldiers Pond. New ac transmission between Taylors Brook and Soldiers Pond is assumed to be required as the existing east-west lines in Newfoundland are heavily loaded.

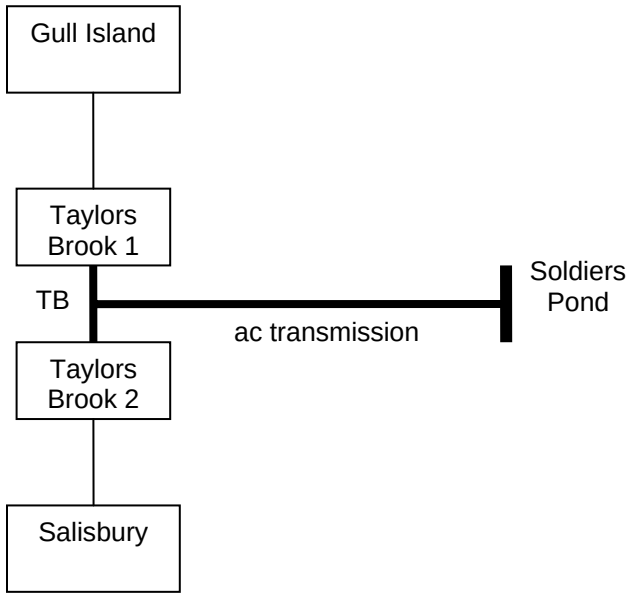


Figure 4 Two Two-Terminal HVdc Links and ac – Option 1 (Alternative 3)

Nominal and overload ratings of the required terminals for this alternative are as shown in Table 15.

Table 15
Nominal and Overload Ratings for Alternative 3 (per pole)

		Overload rating (MW)	
Location	**Nominal rating (MW)**	**10 Minute**	**Steady State**
Gull Island	800	1600 (2.0 pu)	1200 (1.5 pu)
Taylors Brook 1	800	1600 (2.0 pu)	1200 (1.5 pu)
Taylors Brook 2	400	440 (1.1 pu)	440 (1.1 pu)
Salisbury	400	440 (1.1 pu)	440 (1.1 pu)
Total (per pole)	**2400**	**4080**	**3280**
Total (Bipole)	**4800**	**8160**	**6560**

These requirements are exactly the same as alternative 1. Similar to that case, if one pole in Gull Island to Taylors Brook 1 system trips the healthy pole must be able to transmit the full power to maintain the net power delivered to the Newfoundland system at 800MW. The power flow in Taylors Brook 2 to Salisbury system should not be affected by this event. The Taylors Brook 2 to Salisbury link however does not need an increased overload capacity; in the case of loss of a pole in the Taylors Brook 2 to Salisbury link the New Brunswick system should be able to absorb the power shortage.

When comparing to the base case multi-terminal configuration, alternative 3 requires a total installed converter capacity with 1.5 times the nominal rating, 1.65 times the 10-minute overload rating, and 1.58 times the steady state overload rating.

2.4.1 Converter Terminal Costs

Repeating the analysis of Table 5 to Table 7, cost estimates for the converter terminals for alternative 3 are given in Table 16.

Table 16
Converter terminal cost estimate for Alternative-3

Location	Nominal rating (MW)	10 Min. OL (MW)	Steady State OL (MW)	Cost
Gull Island (per pole)	800	1600 (2.0 pu)	1200 (1.5 pu)	1136 pu$
Taylors Brook 1 (per pole)	800	1600 (2.0 pu)	1200 (1.5 pu)	1136 pu$
Taylors Brook 2 (per pole)	400	440 (1.1 pu)	440 (1.1 pu)	400 pu$
Salisbury (per pole)	400	440 (1.1 pu)	440 (1.1 pu)	400 pu$
Total (per pole)	**2400**	**4080**	**3280**	**3072 pu$**
Total (Bipole)	**4800**	**8160**	**6560**	**6144 pu$**

Due to the increased overload capacity, it is seen that the cost of the Gull Island terminal has increased by approximately 5% as compared to the base case multi-terminal HVdc configuration. The cost of the two terminals at Taylors Brook combined is approximately 2.47 times the cost of the Soldiers Pond converter in the base case multi-terminal HVdc configuration. The cost of the Salisbury terminal has been reduced by 10% due to the fact that this is now a two terminal (not a multi-terminal) converter.

When comparing the converter costs for alternative 3 to the base case multi-terminal HVdc configuration it is seen that the overall converter costs have increased by approximately 43%. (Note that costs of the new ac transmission required to connect Taylors Brook to Soldiers Pond has not been factored into the above converter costs.)

2.4.2 Transmission Lines and Cables

The approximate lengths of the overhead lines and cables required in this alternative are given in Table 17.

Table 17
Approximate length of the required OH lines and cables for Alternative-3

Section	OHL (km)	Cable (km)	ac OHL (km)
Gull Island to Strait of Belle Isle	407		
Across Strait of Belle Isle		40.7 (two poles)	
Strait of Belle Isle to Taylors Brook	275		
Bipole1 Subtotal	**682**	**40.7**	
Taylors Brook to Cape Ray	300		
Across Cabot Strait		480 (two poles)	
Coast of New Brunswick to Salisbury	100		
Bipole2 Subtotal	**400**	**480**	
Taylors Brook to Soldiers Pond			**2 x 400**
Total	**1082**	**520.7**	**800**

Here it is assumed that the HVdc transmission line and cable from Gull Island to Taylors Brook follows the same route as the base case multi-terminal HVdc system. It is also assumed that the second HVdc line and cable between Taylors Brook and Salisbury follows the same route as the base case multi-terminal HVdc system. In addition to the HVdc lines, the combined length of the ac transmission required to interconnect Taylors Brook and Soldiers Pond is included. It is assumed that at least two 230kV lines would be required and the route would be the same as that for the HVdc line in the original multi-terminal configuration between Taylors Brook and Soldiers Pond.

Comparing the lengths of overhead lines and cables required for Alternative 3 to those required in the Base Case it is seen that Alternative 3 requires 27% less overhead line and the same undersea cable as the base case; however alternative 3 also requires 800km of 230kV ac transmission lines on the Island of Newfoundland.

2.4.3 Effective Short Circuit Ratio

The effective short circuit ratios at Gull Island and Salisbury in this option are identical to the three-terminal option.

At Taylors Brook however there are two HVdc systems terminating next to each other and hence MIESCR must be calculated for both converters. The Short Circuit Capacity at this bus depends on the parameters of the planed ac line(s) as well as its terminating bus. Due to the weakness of the existing system at this area it is anticipated that MIESCR at Taylors Brook will be very low (particularly for the 1600MW converter). As a result large amount of synchronous condensers will be required to raise MIESCR to an acceptable level.

When comparing to the base case multi-terminal HVdc configuration it is concluded that a large number of additional synchronous condensers would be required in the Newfoundland system to support the HVdc transmission at Taylors Brook proposed in Alternative 3.

2.4.4 Advantages

The following is a list of advantages of this alternative as compared to the base case multi-terminal configuration:

- The total length of HVdc overhead line is reduced.
- The two HVdc links could be built in stages, with the Gull Island to Taylors Brook 1 link built prior to the Taylors Brook 2 to Salisbury link. However, it is most likely that the Gull Island to Taylors Brook 1 HVdc link would have to be built initially to its final capacity since staging of this two terminal link would not present substantial economic benefits.
- Only conventional two-terminal HVdc links are used therefore some of the challenges associated with the multi-terminal option are avoided. HVdc controls are less complicated compared to the base case multi-terminal HVdc system.
- The effect of the long dc cable is removed from the circuit between Gull Island and Taylors Brook and its performance.
- If the Gull Island to Taylors Brook 1 link is unavailable then power can still be supplied to the Newfoundland system by operating Salisbury as a rectifier and Taylors Brook 2 as an inverter.

This option has all advantages of alternative-1, however compared to that case the total length of DC transmission lines is reduced here. Transmission line losses are also expected to be reduced as the maximum power transfer between TB and SP is now 800MW, while in alternative-1 BiPole1 and 2 in total transfer 1800MW on this part of the route.

2.4.5 Disadvantages

The following is a list of disadvantages of this alternative as compared to the base case multi-terminal configuration:

- This alternative requires 1600 MW more of installed converters, adding more than 2000 pu$ (49%) to the converter station costs.
- This alternative requires new ac transmission lines to interconnect Taylors Brook to Soldiers Pond. It is anticipated that at least two 230kV lines will be required with a total installed length of approximately 800 km.
- The two separate HVdc links which terminate at Taylors Brook would results in a multi-infeed HVdc scenario. Although the two HVdc links are effectively independent of one another, the performance of one will greatly impact the performance of the other due to the close coupling at Taylors Brook.
- The Multi-Infeed ESCR (MIESCR) in Newfoundland is very low, requiring to the need to install a large number of synchronous condensers.

- A large sub-station would have to be established at Taylors Brook.
- Potential for increased overvoltages at Taylors Brook due to increased ac filter requirements.
- Increased operating losses due to the additional filters and need to convert 800 MW from dc to ac and again from ac to dc at Taylors Brook.
- Increased maintenance due to the fact that there are now two converter stations at Taylors Brook.
- Potential for increased spares requirements due to different equipment ratings within the Taylors Brook 1 and 2 converter stations.

2.4.6 Summary

Based on the results of this cursory evaluation it is seen that when compared to the base case multi-terminal HVdc configuration the alternative of two HVdc links, one from Gull Island to Taylors Brook 1 and the second from Taylors Brook 2 to Salisbury, in conjunction with new ac transmission interconnecting Taylors Brook to Soldiers Pond will result in:

- increased converter costs;
- reduced HVdc overhead line lengths;
- new ac transmission line requirements within the Newfoundland system; and
- large number of additional synchronous condensers within the Newfoundland system and their associated costs.

In addition the alternative does not provide any substantial technical advantages over the base case multi-terminal HVdc while having some technical disadvantages.

It is therefore concluded that the alternative of providing two, two-terminal HVdc systems, one from Gull Island to Taylors Brook 1 and the second from Taylors Brook 2 to Salisbury combined with new ac transmission facilities to interconnect Taylors Brook to Solders Pond is not recommended above the base case multi-terminal HVdc configuration.

2.5 Alternative 4 – Two Two-Terminal HVdc Links and ac – Option 2

This alternative includes two, two-terminal HVdc systems, one connecting Gull Island to Soldiers Pond and the other connecting Taylors Brook to Salisbury plus the addition of ac transmission connecting Taylors Brook to Soldiers Pond. New ac transmission between Taylors Brook and Soldiers Pond is assumed to be required as the existing east-west lines in Newfoundland are heavily loaded. The basic configuration is shown in Figure 5.

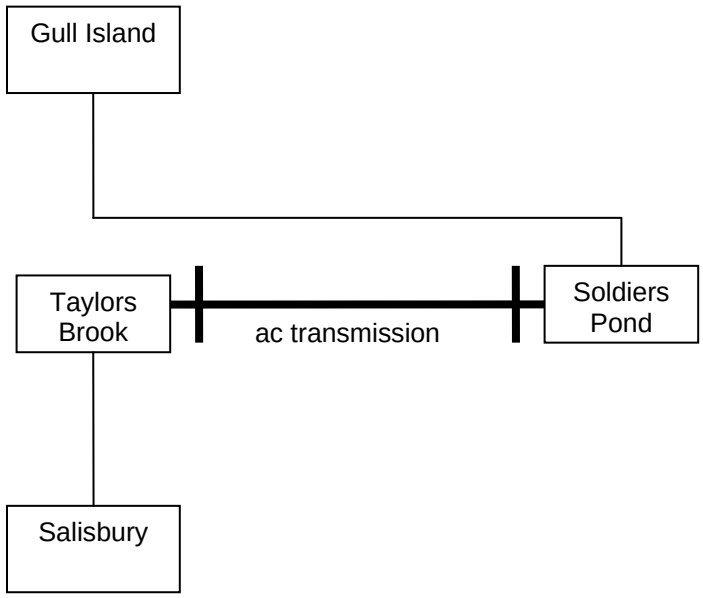


Figure 5 Two Two-Terminal HVdc Links and ac – Option 2 (Alternative-4)

Nominal and overload ratings of the required terminals for this alternative are as shown in Table 18.

Table 18
Nominal and Overload Ratings for Alternative 4 (per pole)

		Overload rating (MW)	
Location	**Nominal rating (MW)**	**10 Minute**	**Steady State**
Gull Island	800	1600 (2.0 pu)	1200 (1.5 pu)
Soldiers Pond	800	1600 (2.0 pu)	1200 (1.5 pu)
Taylors Brook	400	440 (1.1 pu)	440 (1.1 pu)
Salisbury	400	440 (1.1 pu)	440 (1.1 pu)
Total (per pole)	**2400**	**4080**	**3280**
Total (Bipole)	**4800**	**8160**	**6560**

These requirements are exactly the same as alternative 1. Similar to that case, if one pole in Gull Island to Soldiers Pond system trips the healthy pole must be able to transmit the full power to maintain the net power delivered to the Newfoundland system at 800MW. The power flow in Taylors Brook to Salisbury system should not be affected by this event. The Taylors Brook to Salisbury link however does not need

an increased overload capacity; in the case of loss of a pole in the Taylors Brook to Salisbury link the New Brunswick system should be able to absorb the power shortage.

When comparing to the base case multi-terminal configuration, alternative 4 requires a total installed converter capacity with 1.5 times the nominal rating, 1.65 times the 10-minute overload rating, and 1.58 times the steady state overload rating.

2.5.1 Converter Terminal Costs

Repeating the analysis of Table 5 to Table 7, cost estimates for the converter terminals for alternative 4 are given in Table 19.

Table 19
Converter terminal cost estimate for Alternative 4

Location	Nominal rating (MW)	10 Min. OL (MW)	Steady State OL (MW)	Cost
Gull Island (per pole)	800	1600 (2.0 pu)	1200 (1.5 pu)	1136 pu$
Soldiers Pond (per pole)	800	1600 (2.0 pu)	1200 (1.5 pu)	1136 pu$
Taylors Brook (per pole)	400	440 (1.1 pu)	440 (1.1 pu)	400 pu$
Salisbury (per pole)	400	440 (1.1 pu)	440 (1.1 pu)	400 pu$
Total (per pole)	**2400**	**4080**	**3280**	**3072 pu$**
Total (per pole)	**4800**	**8160**	**6560**	**6144 pu$**

Due to the increased overload capacity, it is seen that the cost of the Gull Island terminal has increased by approximately 5% as compared to the base case multi-terminal HVdc configuration. The combined cost of the two terminals at Soldiers Pond and Taylors Brook is approximately 2.47 times the cost of the Soldiers Pond converter in the base case multi-terminal HVdc configuration. The cost of the Salisbury terminal has been reduced by 10% due to the fact that this is now a two terminal (not a multi-terminal) converter.

When comparing the converter costs for alternative 4 to the base case multi-terminal HVdc configuration it is seen that the overall converter costs have increased by approximately 43%. (Note that costs of the new ac transmission required to connect Taylors Brook to Soldiers Pond has not been factored into the above converter costs.)

2.5.2 Transmission Lines and Cables

The approximate lengths of the required overhead lines and cables in this case are given in Table 20.

Table 20
Approximate length of the required OH lines and cables for Alternative-4

Section	OHL (km)	Cable (km)	ac OHL (km)
Gull Island to Strait of Belle Isle	407		
Across Strait of Belle Isle		40.7 (two poles)	
Strait of Belle Isles to Taylors Brook	275		
Taylors Brook to Soldiers Pond	406		
Bipole1 Subtotal	**1088**	**40.7**	
Taylors Brook to Cape Ray	300		
Across Cabot Strait		480 (two poles)	
Coat of New Brunswick to Salisbury	100		
Bipole2 Subtotal	**400**	**480**	
Taylors Brook to Soldiers Pond			**2 x 400**
Total	**1488**	**520.7**	**800**

Here it is assumed that the HVdc transmission line and cable from Gull Island to Soldiers Pond follows the same route as the base case multi-terminal HVdc system. It is also assumed that the second HVdc line and cable between Taylors Brook and Salisbury follows the same route as the base case multi-terminal HVdc system. In addition to the HVdc lines, the combined length of the ac transmission required to interconnect Taylors Brook and Soldiers Pond is included. It is assumed that at least two 230kV lines would be required and the route would be the same as that for the HVdc line between Taylors Brook and Soldiers Pond.

Comparing the lengths of overhead lines and cables required for Alternative 4 to those required in the Base Case it is seen that Alternative 4 requires the same length of HVdc overhead line and the same undersea cable as the base case; however alternative 4 also requires 800km of 230kV ac transmission lines on the Island of Newfoundland.

2.5.3 Effective Short Circuit Ratio

The effective short circuit ratios at Gull Island and Salisbury in this option are identical to the three-terminal option.

With the new ac lines connecting Taylors Brook and Soldiers Pond, the two HVdc terminals at these buses will electrically become close to each other and hence MIESCR must be calculated for both converters. The Multi Infeed Interaction Factor between the two terminals depends on the parameters of the new ac lines and cannot be estimated at this point. However, large amount of synchronous condensers are expected to be required at Taylors Brook to achieve reasonably high MIESCR. Compared to the three-terminal case, MIESCR at Soldiers Pond will be much lower. This is because of the larger rating of the converter (1600MW vs. 800MW) and also the proximity of the Taylors Brook terminal. As a result more synchronous condensers are likely to be required at this bus as well.

When comparing to the base case multi-terminal HVdc configuration it is concluded that a large number of additional synchronous condensers would be required in the Newfoundland system to support the HVdc transmission at Soldiers Pond and Taylors Brook proposed in Alternative 4.

2.5.4 Advantages

The following is a list of advantages of this alternative as compared to the base case multi-terminal configuration:

- The total length of HVdc overhead line is reduced.
- The two HVdc links could be built in stages, with the Gull Island to Soldiers Pond link built prior to the Taylors Brook to Salisbury link. However, it is most likely that the Gull Island to Soldiers Pond HVdc link would have to be built initially to its final capacity since staging of this two terminal link would not present substantial economic benefits.
- Only conventional two-terminal HVdc links are used therefore some of the challenges associated with the multi-terminal option are avoided. HVdc controls are less complicated compared to the base case multi-terminal HVdc system.
- The effect of the long dc cable is removed from the circuit between Gull Island and Soldiers Pond and its performance.
- If the Gull Island to Soldiers Pond link is unavailable then power can still be supplied to the Newfoundland system by operating Salisbury as a rectifier and Taylors Brook as an inverter.

2.5.5 Disadvantages

The following is a list of disadvantages of this alternative as compared to the base case multi-terminal configuration:

- This alternative requires 1600 MW more of installed converters, adding close to 2000pu$ (43%) to the converter station costs.
- This alternative requires new ac transmission lines to interconnect Taylors Brook to Soldiers Pond. It is anticipated that at least two 230kV lines will be required with a total installed length of approximately 800 km.
- The two separate HVdc links which terminate at Soldiers Pond and Taylors Brook would results in a multi-infeed HVdc scenario. Although the two HVdc links are effectively independent of one another, the performance of one will greatly impact the performance of the other.
- The Multi-Infeed ESCR (MIESCR) in Newfoundland is very low, requiring to the need to install a large number of synchronous condensers.
- A large sub-station would have to be established at Taylors Brook.
- Increased operating losses due to the additional filters and need to convert 800MW from dc to ac and again from ac to dc at Soldiers Pond.

- Increased maintenance due to the fact that there are now two converter stations on the island, one at Solders Pond and one at Taylors Brook.
- Increased spares requirements due to the physical separation of the Soldiers Pond and Taylors Brook converter stations.

2.5.6 Summary

Based on the results of this cursory evaluation it is seen that when compared to the base case multi-terminal HVdc configuration the alternative of two HVdc links, one from Gull Island to Soldiers Pond and the second from Taylors Brook 2 to Salisbury, in conjunction with new ac transmission interconnecting Taylors Brook to Soldiers Pond will result in:

- increased converter costs;
- reduced HVdc overhead line lengths;
- new ac transmission line requirements within the Newfoundland system; and
- large number of additional synchronous condensers within the Newfoundland system and their associated costs.

In addition the alternative does not provide any substantial technical advantages over the base case multi-terminal HVdc while having some technical disadvantages.

It is therefore concluded that the alternative of providing two, two-terminal HVdc systems, one from Gull Island to Soldiers Pond and the second from Taylors Brook to Salisbury combined with new ac transmission facilities to interconnect Taylors Brook to Solders Pond is not recommended above the base case multi-terminal HVdc configuration.

2.6 Alternative 5 - Three, Two-Terminal HVdc Links

This alternative includes three, two terminal HVdc systems, one from Gull Island to Taylors Brook 1, one from Taylors Brook 2 to Soldiers Pond, and the third from Taylors Brook 3 to Salisbury. In addition to the converter stations located at Taylors Brook, an extensive ac system would have to be established there in order to interconnect the converters. The basic configuration is shown in Figure 6.

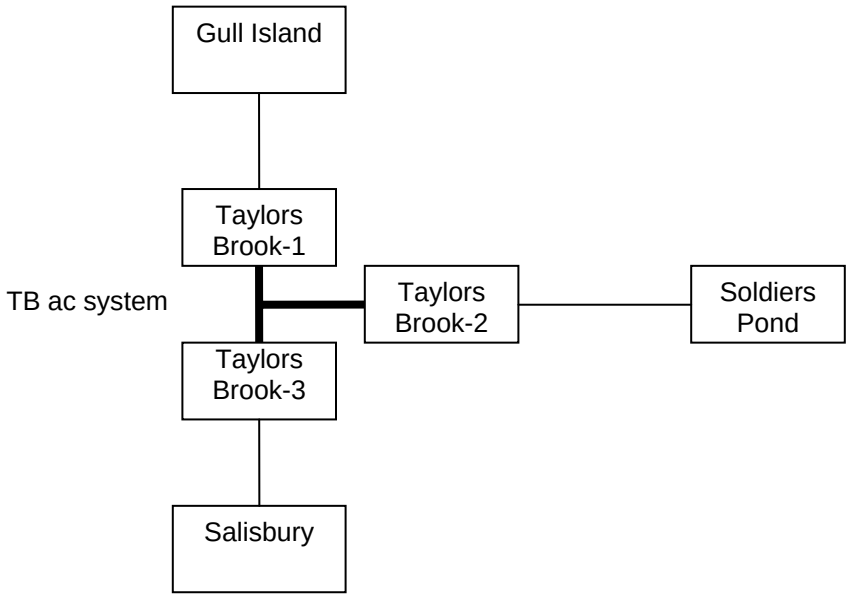


Figure 6 Alternative 5 - Three Two-Terminal HVdc Links

Nominal and overload ratings of the required terminals for this alternative are as shown in Table 21.

Table 21
Nominal and Overload Ratings for Alternative 5 (per Pole)

		Overload rating (MW)	
Location	**Nominal rating (MW)**	**10 Minute**	**Steady State**
Gull Island	800	1600 (2 pu)	1200 (1.5 pu)
Taylors Brook 1	800	1600 (2 pu)	1200 (1.5 pu)
Taylors Brook 2	400	800 (2.0 pu)	600 (1.5 pu)
Soldiers Pond	400	800 (2.0 pu)	600 (1.5 pu)
Taylors Brook 3	400	440 (1.1 pu)	440 (1.1 pu)
Salisbury	400	440 (1.1 pu)	440 (1.1 pu)
Total (per pole)	**3200**	**5680**	**4480**
Total (Bipole)	**6400**	**11360**	**8960**

These requirements represent the largest amount of installed converter capacity for all alternatives considered.

When comparing to the base case multi-terminal configuration, alternative 5 requires a total installed converter capacity with 2.0 times the nominal rating, 2.29 times the 10-minute overload rating, and 2.15 times the steady state overload rating.

2.6.1 Converter Terminal Costs

Repeating the analysis of Table 5 to Table 7, cost estimates for the converter terminals for alternative 5 are given in Table 22.

Table 22
Estimated cost of converter terminals for Alternative-5

Location	Nominal rating (MW)	10 Min. OL (MW)	Steady State OL (MW)	Cost
Gull Island (per pole)	800	1600 (2.0 pu)	1200 (1.5 pu)	1136 pu$
Taylors Brook 1 (per pole)	800	1600 (2.0 pu)	1200 (1.5 pu)	1136 pu$
Taylors Brook 2 (per pole)	400	800 (2.0 pu)	600 (1.5 pu)	566 pu$
Soldiers Pond (per pole)	400	800 (2.0 pu)	600 (1.5 pu)	566 pu$
Taylors Brook 3 (per pole)	400	480 (1.1 pu)	440 (1.1 pu)	400 pu$
Salisbury (per pole)	400	480 (1.1 pu)	440 (1.1 pu)	400 pu$
Total (per pole)	**3200**	**5680**	**4480**	**4204 pu$**
Total (Bipole)	**6400**	**11360**	**8960**	**8408 pu$**

When comparing the converter costs for alternative 5 to the base case multi-terminal HVdc configuration it is seen that the overall converter costs have increased by approximately 95%. This is due to the fact that there are now three separate two-terminal HVdc links with a total of six converter stations. (Note that costs of the new ac transmission required to interconnect the three HVdc links at Taylors Brook has not been factored into the above converter costs.)

2.6.2 Transmission Lines and Cables

The approximate lengths of the required overhead lines and cables in this case are given in Table 23.

Table 23
Overhead line and cable lengths for Alternative-5

Section	OHL (km)	Cable (km)
Gull Island to Strait of Belle Isle	407	
Across Strait of Belle Isle		40.7 (two poles)
Strait of Belle Isle to Taylors Brook	275	
Taylors Brook to Soldiers Pond	406	
Taylors Brook to Cape Ray	300	
Across Cabot Strait		480 (two poles)
Cost of New Brunswick to Salisbury	100	
Total	**1488**	**520.7**

Comparing the lengths of overhead lines and cables required for Alternative 5 to those required in the Base Case it is seen that Alternative 4 requires the same length of HVdc overhead line and undersea cable as the base case.

2.6.3 Effective Short Circuit Ratio

The effective short circuit ratios at Gull Island and Salisbury terminals are similar to the three-terminal case.

Since there are now multiple HVdc links terminating within the Newfoundland system, the MIESCR should be calculated instead of the ESCR for the converter at Soldiers Pond. However due to the weakness of the existing ac connection the MIIF factor will be small and the MIESCR is expected to be slightly less than the ESCR value calculated for the three-terminal case. Therefore no additional synchronous condensers will be required to support the HVdc converter at Soldiers Pond.

At Taylors Brook the three HVdc terminals are connected to the same bus, causing a substantial reduction in MIESCR. Even to achieve MIESCR = 1 (very low) the ac system short circuit capacity (SCC) must be more than 4160MVA. Given the low strength of the existing system at this bus majority of this capacity must come from new synchronous condensers. Therefore a very large number of additional synchronous condensers will be required to support the three HVdc terminals at Taylors Brook.

2.6.4 Advantages

The following is a list of advantages of this alternative as compared to the base case multi-terminal configuration:

- The three HVdc links could be built in stages, with the Gull Island to Taylors Brook and The Taylors Brook to Soldiers Pond links built prior to the Taylors Brook to Salisbury link. However, it is most likely that the Gull Island to Taylors Brook HVdc link would have to be built initially

to its final capacity since staging of this two terminal link would not present substantial economic benefits.

- Only conventional two-terminal HVdc links are used therefore some of the challenges associated with the multi-terminal option are avoided. HVdc controls are less complicated compared to the base case multi-terminal HVdc system.
- The effect of the long dc cable is removed from the circuit between Gull Island and Soldiers Pond and its performance.
- If the Gull Island to Soldiers Pond link is unavailable then power can still be supplied to the Newfoundland system by operating Salisbury as a rectifier and Taylors Brook as an inverter.

2.6.5 Disadvantages

The following is a list of disadvantages of this alternative as compared to the base case multi-terminal configuration:

- This alternative requires a total of 8960MW of installed converter capacity which is unreasonably high, increasing the cost of the converter station costs by 95%.
- The three separate HVdc links which terminate at Taylors Brook would results in a multi-infeed HVdc scenario.
- Although the three HVdc links are effectively independent of one another, the performance of one will greatly impact the performance of the others.
- The Multi-Infeed ESCR (MIESCR) at Taylors Brook is very low, requiring to the need to install a very large number of synchronous condensers.
- A large sub-station and ac system would have to be established at Taylors Brook.
- Increased operating losses due to the additional filters and need to convert dc to ac and again from ac to dc at Taylors Brook.
- Increased maintenance due to the fact that there are now three new converter stations at Taylors Brook.
- Increased spares requirements due to the different ratings of converter equipment at the three terminals in Taylors Brook.

2.6.6 Summary

Based on the results of this cursory evaluation it is seen that when compared to the base case multi-terminal HVdc configuration the alternative of three, two terminal HVdc links, one from Gull Island to Taylors Brook, one from Taylors Brook to Soldiers Pond, and the third from Taylors Brook to Salisbury will result in:

- drastically increased converter costs;

- no reduction in HVdc overhead line or cable lengths;
- new ac transmission facilities at Taylors Brook to interconnect the three HVdc terminals located there; and
- a very large number of additional synchronous condensers within the Newfoundland system and their associated costs.

In addition the alternative does not provide any substantial technical advantages over the base case multi-terminal HVdc while having some technical disadvantages.

It is therefore concluded that the alternative of providing three, two terminal HVdc links, one from Gull Island to Taylors Brook, one from Taylors Brook to Soldiers Pond, and the third from Taylors Brook to Salisbury is not recommended above the base case multi-terminal HVdc configuration.

3. Summary of Results

The cost of converter terminals, length of overhead lines and cables and relative amount of required synchronous condensers for the base case and the five alternatives are summarized in Table 24.

Table 24
Summary of Results

Case	Converter Cost		DC OH Line		DC Cable km	ac OH Line km	Need for Synchronous Condenser
	pu$	Relative to base case	km	Relative to base case			
Base	4306	1	1488	1	520	0	Low
Alt. 1	6144	1.43	1894	1.27	520	0	High
Alt. 2	3864	0.83[1]	2170	1.46	561	0	Low
Alt. 3	6144	1.43	1082	0.73	520	800	Very High
Alt. 4	6144	1.43	1488	1	520	800	Fairly High
Alt. 5	8408	1.95	1488	1	520	0	Extremely High

[1] *No provision has been included to account for the fact that the total installed converter capacity at Gull Island is installed in two separate converter stations which should be expected to increase the cost as compared to installation of the entire capacity within a single converter.*

Salient point of the overall comparison of the alternatives includes:

- For all alternatives except alternative 2, the total cost of converters is greater than that of the base case multi-terminal HVdc configuration.
- For all alternatives except alternative 3, the total length of HVdc overhead line and cable is equal to or greater than that of the base case multi-terminal HVdc configuration. In the case of alternatives 3 and 4, an additional 800 km of 230 kV as transmission lines are required on the island of Newfoundland.
- For all alternatives, synchronous condenser requirements within the Newfoundland ac system are equal to greater than those of the base case multi-terminal HVdc configuration.
- None of the alternatives considered provided any significant advantages as compared to the base case multi-terminal HVdc configurations while providing some disadvantages.

4. Conclusions

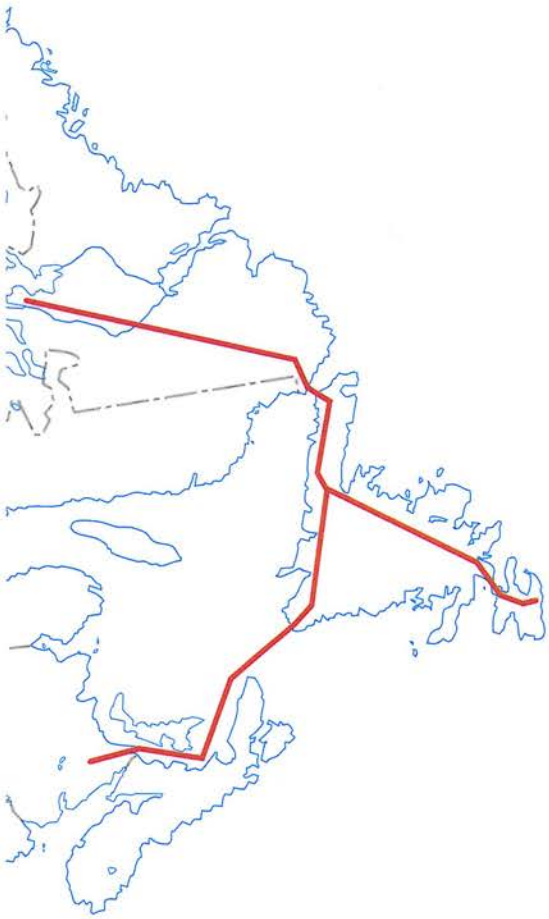
Based on the results of this cursory evaluation it is concluded that the base case multi-terminal HVdc configuration offers the lowest overall cost when considering the cost of converters, HVdc overhead lines and undersea cables, ac transmission lines, and synchronous condenser requirements. Furthermore, none of the alternatives considered offered any significant advantages over the base case multi-terminal HVdc configuration. Therefore it is recommended than none of the alternative configurations be considered as a preferable option to the base case multi-terminal HVdc configuration.

References

1. DC1020 HVdc System Integration Study - Transient Stability Analysis – Interim Report

APPENDIX C8 – DC1210 HVDC SENSITIVITY STUDIES – FINAL SUMMARY REPORT – JULY 2010

nalcor energy









THE Lower Churchill PROJECT

July 2010

DC1210 - HVdc Sensitivity Studies

Final Summary Report

prepared by

HATCH™

nalcor energy

THE Lower Churchill PROJECT

July 2010

DC1210 - HVdc Sensitivity Studies

Final Summary Report

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Executive Summary

The HVdc System Integration Study completed under WTO DC1020 confirmed the technical feasibility of a multi-terminal HVdc transmission system between Labrador, the Island of Newfoundland and New Brunswick. Further, this study identified the transmission system additions required on the Island to ensure satisfactory performance of the HVdc system for a set of predefined transmission planning criteria.

The purpose of WTO DC1210 – HVdc Sensitivity Studies was to conduct additional work identified following the completion of WTO DC1020 – HVdc System Integration Study. The principle objectives and scope of WTO DC1210 included the following:

1. HVdc Sensitivity Studies - Sensitivity studies to investigate whether system reconfiguration, relaxation of the planning criteria, special protection schemes or some combination thereof will enable the removal of the Pipers Hole synchronous condensers while facilitating acceptable system performance.

2. PSSE Model Modification - Modification of the multi-terminal PSSE model developed as part of WTO DC1020 to reflect a potential alternate cable route through Cabot Strait and overhead line in the Maritime provinces.

3. VSC Risk Assessment - A high level risk assessment of VSC technology for both a multi-terminal hybrid HVdc scheme and a Labrador to Island point-to-point HVdc scheme.

4. AC/DC Line Proximity Issues - A high level identification of potential interaction issues resulting from the location of ac and dc lines in close proximity.

5. Bipole Block Impacts - Investigation of the impact of a bipole block on the Island ac system.

HVDC Sensitivity Studies

The original DC1020 transient stability analysis found the need for a large number of synchronous condensers to be installed on the system in order to account for the worst case fault, which is a solid three-phase fault at Bay d'Espoir on one of the Bay d'Espoir-Pipers Hole 230 kV lines (TL202 or TL206). Specifically it was found that 2x300 MVAR synchronous condensers are required to be in service at all times at both the Pipers Hole and Soldiers Pond buses in order to save the system from collapse due to fast frequency decay. This translates to 3x300 MVAR synchronous condensers installed at each station in order to account for maintenance outages. In addition, it was found that 50% series compensation was required on both of the 230 kV lines between Bay d'Espoir and Pipers Hole. The Pipers Hole bus was included in the system to connect a potential new refinery load (175 MW) to the Island system.

The system additions proposed by DC1020 ensured that the Island system with the HVdc converter station at Soldiers Pond remained stable for all 230 kV bus faults without loss of load. To compare the system performance of the two alternatives (HVdc interconnection versus isolated) on a common basis, system additions in the HVdc case were identified in the HVdc case assuming that the system does not recover from the worst case fault (i.e. Bay d'Espoir 230 kV three-phase fault).

Between completion of DC1020 and this report, the certainty of the new 175 MW oil refinery became questionable. As a result, planning associated with the integration of an HVdc interconnection for the Island system has removed the new oil refinery from the base case.

The HVdc Sensitivity Study analysis is based on the assumption that the new refinery will not be going ahead, and therefore the Pipers Hole bus would not exist. It is also based on the assumption that the three-phase Bay d'Espoir fault will not be considered when determining the synchronous condenser requirements and system upgrades. This fault is not considered in this sensitivity analysis as the intent is to determine the system additions for the HVdc integration with system performance comparable to that of the existing system.

The principle objective of the HVdc sensitivity studies was to perform additional studies to investigate required system additions to ensure acceptable system performance for all contingencies except the three-phase fault at Bay d'Espoir 230 kV bus. The following points are assessed:

- The impact of splitting the 230 kV Bay d'Espoir bus such that one 230 kV circuit to Stony Brook and Sunnyside and approximately one half the Bay d'Espoir generation is connected to each 230 kV bus with the tie line between each station out of service.
- The impact of blocking recovery of the HVdc during the three-phase Bay d'Espoir fault with isolation of the Avalon Peninsula load centre.
- Application of SVC technology at Sunnyside (in lieu of synchronous condensers at Pipers Hole).
- Installation of a third 230 kV circuit between Bay d'Espoir and Western Avalon.
- Application of two different synchronous condenser designs; one, using the original synchronous condensers as per Manitoba Hydro's Dorsey station (inertia constant 2.2); and two, using new high inertia [redacted] synchronous condensers based on a vertical-shaft hydro generator design (inertia constant 7.84).

Results of the study include:

- If the intent is to design the HVdc infeed system such that its performance is similar to the existing system performance (i.e. does not survive the worst case fault), the requirements for synchronous condensers on the Island system are reduced.
- The use of high inertia synchronous condensers showed significant improvement in system performance over the synchronous condenser models with a lower inertia constant (2.2) used in the original DC1020 studies.
- The use of high inertia synchronous condensers would significantly reduce the size or number of synchronous condensers that are required to be installed at Soldiers Pond. In order to meet criteria, a single 300 MVAR high inertia synchronous condenser is sufficient, along with a 300 MVAR SVC at Sunnyside or a new 230 kV circuit between Bay d'Espoir and Western Avalon. The results are highly dependent on the type of synchronous condenser that is modeled. However, because loss of the Soldiers Pond synchronous condenser becomes the worst case contingency if only a single 300 MVAR unit is

installed, it is recommended to have 2x150 MVAR high inertia synchronous condensers in service at all times, which would translate to 3x150 MVAR installed to account for maintenance outages.

- A preliminary evaluation was performed to assess the impact of relocating a portion of the inertia from Soldiers Pond to Bay d'Espoir by changing out the rotor on Bay d'Espoir Unit 7 and by installing a high inertia 150 MVAR synchronous condenser as Bay d'Espoir Unit 8. Despite the fact that the total system inertia is very similar between the two cases, the results indicate poorer performance of the Island system when the synchronous condensers are moved away from Soldiers Pond due to poorer performance of the HVdc infeed.

Therefore from a technical system performance point of view, the best solution would be to have 2x150 MVAR high inertia synchronous condensers in service at Soldiers Pond at all times, hence installing 3x150 MVAR in order to account for maintenance outages. In addition to these 150 MVAR synchronous condensers, one of the following mitigation options is also required:

- 200 MVAR SVC at Sunnyside and 50% series compensation on the two Bay d'Espoir-Sunnyside lines; or
- 230 kV line Bay d'Espoir – Western Avalon, no series compensation on this new line or on the existing two Bay d'Espoir-Sunnyside lines.

Both of these solutions provide sufficient steady state VAR support to maintain system steady state voltages during the 800 MW monopolar 10-minute 2.0 pu overload condition.

PSSE Model Modifications

The PSSE stability model of the three-terminal HVdc link for the Lower Churchill Project developed as part of WTO DC1020 was modified to represent a shorter DC cable section and longer DC overhead line section between the tap at Taylor's Brook and the terminal at Salisbury. Specifically, the cable section between Newfoundland and Lingan, Nova Scotia was estimated at 180 km, and the new overhead line section from Lingan, Nova Scotia to Salisbury, New Brunswick was estimated at 475 km. The overhead line sections in Newfoundland from Taylor's Brook to the Gulf of St. Lawrence crossing to Nova Scotia remain unchanged.

In order to allow validation testing, the PSCAD model originally developed as part of WTO DC1020 was first updated and the DC controls were re-tuned. These changes were implemented inside the PSSE model. Validation testing was performed by comparing the results of the PSCAD and PSSE models for a solid and remote three-phase fault at each of the DC terminals for the 3-terminal case, and for solid faults only for the 2-terminal cases.

Validation testing results show that the PSSE model compares well with the PSCAD model results.

VSC Risk Assessment

A high level evaluation of the use of Voltage Source Converter (VSC) technology for the LCP HVdc system was undertaken. The objectives of the VSC Risk Assessment were to conduct a qualitative review of the characteristics of the VSC, along with the current status and expected future developments of VSC technology and to compare this with the technical requirements of the LCP to determine the potential suitability of VSC

technology to the project. The qualitative review was followed by preliminary investigations of the performance of a VSC converter in the Island ac system.

Factors considered when performing the risk assessment included:

- State of the art of VSC technology mainly as it applies to HVdc transmission.
- Characteristics of VSC.
- Future developments in VSC.

The review involved obtaining the most up-to-date data from the suppliers regarding the ratings and availability of these ratings for commercial use. This was followed by comparing this information with the technical requirements of the HVdc project. Finally, preliminary investigations using PSSE and a vendor supplied VSC-based HVdc model were undertaken to provide some insight into the potential performance benefits.

Key findings of the review included:

- A VSC-based system can be designed in a bipolar configuration.
- For the converters and the overhead lines, implementation of VSC at the proposed HVdc operating voltage of 450kV, however for the XLPE cables this is not possible.
- The latest VSC technology has a current rating of 1718 amperes, which at +/-450 kV, results in a power rating of 1547 MW per station, or 773 MW per pole. These figures are marginally less than the design ratings at Gull Island (1600 MW for the station and 800 MW per pole). One solution is to apply two VSC blocks in parallel per pole, however this may be an unnecessary complication. This limitation may lend itself to make the terminal at Gull Island a conventional line commutated converter.
- The station at Soldiers Pond is rated for 800 MW which is not a problem for the current state of the art of VSC. However, the issue here is the overload capability required at 2.0 pu even for 10 minutes and 1.5 pu continuously. This means that each pole will be rated for 800 MW for 10 minutes and 600 MW continuously. VSC converters do not have an overload capability, therefore the station at Soldiers Pond would have to be rated at 800 MW per pole continuously to account for the loss of a pole. With a current rating of 1718 amperes, the pole rating at Soldiers Pond shall be 773 MW which is close to the 800 MW. The converters are the main pieces of equipment affected by such an upgraded power rating. In principle, the normal and overload ratings are achievable at Soldiers Pond.
- The Salisbury station is rated at 800 MW and has very moderate overload requirements. Therefore this is a straight forward application for a VSC station.
- Power reversal in a VSC station is easier than power reversal in a conventional LCC station as there is no need for reversing switches.
- Because a VSC converter does not fail commutation during an ac fault, it is possible that the synchronous condenser requirements of the Island system due to an ac fault would be reduced if the Soldiers Pond terminal used VSC technology.

- Due to the required HVdc operating voltage, the HVdc cables will most likely have to be mass impregnated cables, the use of XPLE cables is not a likely possibility.
- An inherent weakness of a VSC HVdc link is a dc line fault. During the time it takes to clear a dc line fault, it is fed from all the ac systems connected to the dc line through the VSC diodes. As a result large fault currents will be drawn from the ac system, however the effect will be less than a normal ac fault as the converter transformer, phase reactors, dc smoothing reactors (if present) and any line impedance between the location of the fault and the VSC introduce an impedance which limits the current drawn from the ac side as well as limiting the rate of growth of the fault current. For the length of time it takes to clear the dc line fault, the ac voltage in all connected systems will be considerably reduced. Power infeed from the VSC is also significantly reduced while the fault is present as the power transfer in the faulty pole is stopped and power transfer in the healthy pole is reduced due to the drop in ac voltage. Depending on how long it takes to clear the dc line fault, the system frequency decay may or may not be as severe as seen during the worst three-phase ac fault in the line commutated converter studies.

Based on the review, it was concluded that:

- The rating at Gull Island can be better realized using a conventional LCC technology.
- The rating at Soldiers Pond can be achieved using a VSC technology.
- The rating at Salisbury can be achieved using a VSC technology.
- The HVdc cable will most likely have to be a mass impregnated cable, even with VSC technology.

Preliminary simulations were performed using PSSE and a vendor supplied VSC model to investigate the impact of a VSC HVdc terminal on the Island system. Results of preliminary transient stability simulations showed an overall improvement in system performance for all ac and dc faults that were studied with fewer synchronous condensers than required for the LCC technology.

Based on the above it was recommended that a more complete study to evaluate the use of VSC technology for the Soldiers Pond terminal be undertaken.

AC/DC Line Proximity Issues

A qualitative review of issues related to the application of HVdc and ac transmission lines within a common right-of-way was prepared. Use of the existing right-of-way would require that the HVdc line run in close proximity to the ac lines on separate structures, use a common structure, or require the direct burial of the ac lines with the HVdc line running on top on its own structure.

A number of articles are available on the subject of the interactions of HVdc and ac transmission lines located in close proximity to each other. Some papers consider the interactions between lines located within a common right-of-way but installed on separate towers while others consider hybrid configurations (HVdc and ac lines on a common tower).

Very few hybrid lines (HVdc and ac conductors on the same tower) have been built. One example is the National HVdc project in India which was an experimental project where one circuit of an existing double

circuit 220 kV ac line was converted to an HVdc line. The HVdc line initially operated as a monopole with a dc voltage of 100 kV and a power transfer capability of 100 MW.

HVdc and ac lines on separate structures in close proximity within the same right-of-way is more common. Examples of this include the Hydro Quebec – New England HVdc line, the Nelson River HVdc lines in Manitoba, and the Tian-Guang HVdc line in China. In these cases the HVdc lines run in close proximity to HVac lines on separate structures for a portion of the overall HVdc line length.

When considering locating HVdc and ac lines in close proximity it is necessary to consider the effects of the ac circuit on the dc circuit and vice versa; under both steady state and transient conditions. In addition, consideration must be given to the physical implementation of such a system.

Key findings of the review included:

- When an HVdc transmission line is situated in close proximity to a parallel ac transmission line, steady-state induction effects lead to a power frequency current flowing in the HVdc line. The coupling of an ac fundamental component onto the HVdc system can have the following impacts:
  - Converter transformer saturation and harmonic generation;
  - Increased ac and dc filter component ratings;
  - Converter transformer loss of life due to increased heating;
  - Increased audible noise;
  - Potential impacts on HVdc control and protection;
  - Potential impacts on transformer protection; and
  - Increase in neutral point voltage.

Possible mitigation includes the application of fundamental frequency blocking filters in order to reduce the magnitude of the fundamental frequency component current flowing within the dc system and the application of modulation functions to the HVdc controls.

- The proximity between conductors energized with ac and HVdc voltages causes changes in conductor surface gradients and the electrical environment in the vicinity of the lines. Corona and both the ac and dc electric field effects may be impacted. Calculation of conductor surface gradients is more complex than for individual ac or HVdc lines.
- Transient events include both ac and dc faults and controlled changes of the HVdc operating point and can have the following impacts:
  - Overvoltages on the HVdc line due to ac and dc faults;
  - Fundamental frequency coupling from the ac line to the HVdc line can interfere with the clearing of dc line faults and result in longer clearing times;

- HVdc pole to ground faults can have an appreciable impact on ac current; ac system protections may need to be reviewed in order to avoid false operation;
- Operation in ground return mode has the potential to cause large zero sequence transients in ac lines due to transients in the HVdc ground return circuit such as the switch from metallic return to ground return operation. The transition of the HVdc system from normal to ground return operation can result in the incorrect operation of ac ground current detection relays; and
- A fault between a conductor in the HVdc and ac line can result in a severe stress on the ac system which must be mitigated. Clearing of the fault will require the operation of the ac circuit breakers and operation of the HVdc line fault detection.

Based on the available literature and current industry experience it was concluded that:

- The use of a hybrid line with the HVdc and ac conductors on a common tower may not be suitable for the proposed line route, mainly due to the potential for a high level of interaction between the lines and the potential for HVdc to ac conductor faults. In situations where the use of common towers would be for very short distances, the risk of an HVdc to ac conductor fault may be acceptable; however in the case of the proposed line route, the distance is great enough that the risk of such a fault may be a determining factor.
- The use of HVdc and ac lines in close proximity on separate towers may be suitable if an acceptable separation can be maintained. The suitability of this option would require detailed studies in order to determine candidate line configurations and any required mitigation measures to ensure acceptable performance of the integrated HVdc and ac systems. Current industry experience can be used as a starting point for determining a potential minimum separation distance between the HVdc and ac lines. Once this is identified the suitability of the existing right-of-way can be better assessed.
- The use of a direct buried ac cable with the HVdc on towers on the same right-of-way may be suitable however studies would be required to determine the potential effects of HVdc ground faults on the buried ac cable.

Bipole Block Impacts

Bipole block impact assessment study was carried out using reduced system PSS/E load flow base case with assumptions mutually agreed with Nalcor planning staff. The objective was to investigate the impact of a bipole block on the island ac system. In the case of a permanent bipole block, underfrequency load shedding (UFLS) was expected to be required and the objective of the study exercise was to ensure that a portion of the island system remains intact and stable. In this context, the existing underfrequency load shedding scheme was reviewed and discussions with Nalcor staff were held to gain some insights for prioritizing load to shed. Accordingly, simulations were carried out with seven different UFLS settings. Based on these simulation results, it was concluded that:

- The NLH power system sustains the outage of HVdc bipole and the remaining islanded system stays stable provided the existing UFLS scheme is modified to trip about 750 MW of load with appropriate UFLS settings since the existing UFLS scheme with a provision to trip 530 MW load will not be adequate.

Most of the load shedding occurs in the St. John's area where load is lumped in the reduced system load flow model.

- A large amount of load needs to be shed quickly at the first UFLS step at 59.5 Hz, which could be achieved in multiple ways. For instance, employing rate of change of frequency underfrequency relay with pick up time of 0.08 seconds and set at 1.0 Hz/sec. In addition, Special Protection System may also be utilized for immediate tripping of load after the outage of HVdc bipole.
- The proposed preliminary settings of the UFLS scheme(s), which are based on the reduced system model analysis, should be further reviewed and optimized with full representation of the NLH power network.
- Voltage control study should be performed in conjunction with the detailed design of the UFLS scheme to devise appropriate voltage control measures for avoiding voltage violations after the operation of UFLS scheme.

1. Introduction

The HVdc System Integration Study completed under WTO DC1020 confirmed the technical feasibility of a multi-terminal HVdc transmission system between Labrador, the Island of Newfoundland and New Brunswick. Further, this study identified the transmission system additions required on the Island to ensure satisfactory performance of the HVdc system for a set of predefined transmission planning criteria. These system additions include:

- Thermal uprating of 230 kV transmission lines TL202 and TL206 (Bay d'Espoir to Sunnyside).
- Rebuild of 230 kV H-frame wood transmission lines TL201 (Western Avalon to Hardwoods) and TL203 (Sunnyside to Western Avalon).
- 50% series compensation of 230 kV transmission lines TL202 and TL206.
- Conversion of Holyrood Units 1 to 3 to synchronous condenser operation.
- Installation of three 300 MVAR high inertia synchronous condensers at the Soldier's Pond Converter Station.
- Installation of three 300 MVAR high inertia synchronous condensers at the proposed Pipers Hole Terminal Station near Sunnyside.
- Replacement of a number of high voltage circuit breakers at Bay d'Espoir, Sunnyside, Western Avalon and Holyrood Terminal Stations.

The study identified that the most severe contingency would be a three-phase fault on the 230 kV bus at Bay d'Espoir. To ensure system recovery following fault clearing it was necessary to add series compensation to 230 kV transmission lines TL202 and TL206 and to install three 300 MVAR high inertia synchronous condensers (two in service at all times) to the Pipers Hole Terminal Station.

The purpose of WTO DC1210 – HVdc Sensitivity Studies was to conduct additional work identified following the completion of WTO DC1020 – HVdc System Integration Study.

In order to make results available in a timely manner, a number of preliminary reports and technical briefs have been submitted to Nalcor Energy – Lower Churchill Project (NE-LCP) during the course of the work. Each of the preliminary reports submitted (complete with results) are included as appendices to this final report.

The purpose of this report is to summarize all the work undertaken as part of WTO DC1210 which has been detailed in the preliminary reports previously submitted and provide overall conclusions and recommendations.

1.1 Principle Objectives and Scope of WTO DC1210

The principle objectives and scope of WTO DC1210 included the following:

1. HVdc Sensitivity Studies - Sensitivity studies to investigate whether system reconfiguration, relaxation of the planning criteria, special protection schemes or some combination thereof will enable the removal of the Pipers Hole synchronous condensers while facilitating acceptable system performance.

2. PSSE Model Modification - Modification of the multi-terminal PSSE model developed as part of WTO DC1020 to reflect a potential alternate cable route through Cabot Strait and overhead line in the Maritime provinces.

3. VSC Risk Assessment - A high level risk assessment of VSC technology for both a multi-terminal hybrid HVdc scheme and a Labrador to Island point-to-point HVdc scheme.

4. AC/DC Line Proximity Issues - A high level identification of potential interaction issues resulting from the location of ac and dc lines in close proximity.

5. Bipole Block Impacts - Investigation of the impact of a bipole block on the Island ac system.

2. HVdc Sensitivity Studies

The original DC1020 transient stability analysis found the need for a large number of synchronous condensers to be installed on the system in order to account for the worst case fault, which is a solid three-phase fault at Bay d'Espoir on one of the Bay d'Espoir-Pipers Hole 230 kV lines (TL202 or TL206). Specifically it was found that 2x300 MVAR synchronous condensers are required to be in service at all times at both the Pipers Hole and Soldiers Pond buses in order to save the system from collapse due to fast frequency decay. This translates to 3x300 MVAR synchronous condensers installed at each station in order to account for maintenance outages. In addition, it was found that 50% series compensation was required on both of the 230 kV lines between Bay d'Espoir and Pipers Hole. The Pipers Hole bus was included in the system to connect a potential new refinery load (175 MW) to the Island system.

The worst case three-phase fault on the existing isolated Island system is a three-phase fault on the 230 kV bus at Holyrood. At best, assuming the boilers at Holyrood thermal generating station survive the upset caused by the fault, the system would see approximately 250 MW of load shed as a result of the fault. At worst, complete loss of Holyrood plant due to the fault would result in up to 500 MW of load shed – in essence, the entire Avalon Peninsula. Dual primary protection on the 230 kV system ensures all faults are cleared in 6 cycles (maximum). As a result, faults at the 230 kV level are cleared as quickly as possible given the existing equipment to ensure angular stability is maintained. It is understood that given the fault location on the 230 kV system, there may be some loss of local load due to voltage sag and post fault recovery voltages. Beyond the issues associated with the loss of Holyrood, loss of paper machines due to voltage dip and loss of refiner motors due to angular instability can be expected. By comparison, the system additions proposed by DC1020 ensured that the Island system with the HVdc converter station at Soldiers Pond remained stable for all 230 kV bus faults without loss of load. To compare the system performance of the two alternatives (HVdc interconnection versus isolated) on a common basis, system additions in the HVdc case were identified in the HVdc case assuming that the system does not recover from the worst case fault (i.e. Bay d'Espoir 230 kV three-phase fault).

Between completion of DC1020 and this report, the certainty of the new 175 MW oil refinery became questionable. As a result, planning associated with the integration of an HVdc interconnection for the Island system has removed the new oil refinery from the base case.

The HVdc Sensitivity Study analysis is based on the assumption that the new refinery will not be going ahead, and therefore the Pipers Hole bus would not exist. It is also based on the assumption that the three-phase Bay d'Espoir fault will not be considered when determining the synchronous condenser requirements and system upgrades. This fault is not considered in this sensitivity analysis as the intent is to determine the system additions for the HVdc integration with system performance comparable to that of the existing system.

2.1 Objectives of the HVdc Sensitivity Studies

The principle objective of the HVdc sensitivity studies was to perform additional studies to investigate required system additions to ensure acceptable system performance for all contingencies except the three-phase fault at Bay d'Espoir 230 kV bus. The following points are assessed:

- The impact of splitting the 230 kV Bay d'Espoir bus such that one 230 kV circuit to Stony Brook and Sunnyside and approximately one half the Bay d'Espoir generation is connected to each 230 kV bus with the tie line between each station out of service.
- The impact of blocking recovery of the HVdc during the three-phase Bay d'Espoir fault with isolation of the Avalon Peninsula load centre.
- Application of SVC technology at Sunnyside (in lieu of synchronous condensers at Pipers Hole).
- Installation of a third 230 kV circuit between Bay d'Espoir and Western Avalon.
- Application of two different synchronous condenser designs; one, using the original synchronous condensers as per Manitoba Hydro's Dorsey station (inertia constant 2.2); and two, using new high inertia synchronous condensers based on a vertical-shaft hydro generator design (inertia constant 7.84).

The study was to assess system performance assuming:

- The three-phase fault at Bay d'Espoir was not considered.
- The new refinery load and Pipers Hole station did not exist.
- No synchronous condensers would be installed at Pipers Hole as the station will not exist.

2.2 Power Flow Cases and Procedures for the HVdc Sensitivity Studies

Several of the worst faults were simulated for the scenario in which the refinery load and the Pipers Hole synchronous condensers as well as the Holyrood combustion turbines (CTs) were all removed from service. The transient stability analysis was performed on the future peak load flow case (approximately 1625 MW Island load without the refinery). The following power flow variations were tested:

- 800 MW bipolar infeed at Soldiers Pond, economic dispatch at Bay d'Espoir.
- 800 MW bipolar infeed at Soldiers Pond, maximum generation dispatch at Bay d'Espoir.
- 600 MW monopolar infeed at Soldiers Pond, maximum generation dispatch at Bay d'Espoir.

Two main system topologies were tested to determine the Soldiers Pond synchronous condenser requirements:

- Additional VAR support at Sunnyside in the form of an SVC.
- A third 230 kV circuit between Bay d'Espoir and Western Avalon.

The number of synchronous condensers and other system upgrades as determined from the findings of the transient stability analysis were verified for the 800 MW monopolar future peak power flow case to ensure that the steady state system VAR requirements and steady state voltages are still within criteria for the 10-minute 2.0 pu HVdc overload case.

The above analysis was performed for two types of synchronous condensers:

- 300 MVAR, inertia constant of 2.2 (Manitoba Hydro, MIL type).
- 300 MVAR, inertia constant of 7.84 (vertical shaft hydro generator type).

2.3 Synchronous Condenser Types for the HVdc Sensitivity Studies

The original transient stability analysis was performed using the machine models for the 300 MVAR MIL synchronous condensers at Manitoba Hydro's Dorsey station. These machines have an inertia constant of 2.2

NE-LCP discovered that makes a very high inertia synchronous condenser based on vertical shaft hydro generator design. These machines have an inertia constant of 7.84 which is more than three times that of the Manitoba Hydro machines.

Since inertia is the major system issue driving the need for the large synchronous condenser requirement, a sensitivity analysis was performed using these very high inertia machines to observe improvements in system performance.

2.4 Results of the HVdc Sensitivity Studies

It was found that the system performance of the 800 MW bipolar case was worse than the 600 MW monopolar case, and the maximum Bay d'Espoir dispatch scenario was worse than the economic Bay d'Espoir dispatch scenario. This makes sense as the issue is one of lost power, therefore the more power that is lost during the fault (i.e. from Bay d'Espoir generating station and from the HVdc infeed), the worse the impact to system frequency. The results presented in this report correspond to these worst case conditions, i.e. 800 MW bipolar infeed, maximum Bay d'Espoir dispatch.

Ignoring the three-phase fault at Bay d'Espoir, the next worst case fault is a three-phase fault at Sunnyside on one of the Sunnyside-Bay d'Espoir lines. Also, depending on the number of synchronous condensers in service at Soldiers Pond, a three-phase fault at Soldiers Pond followed by tripping of a Soldiers Pond synchronous condenser can be a determining case if only one synchronous condenser is in service prior to the fault.

A significant improvement in system performance was obtained with the high inertia synchronous condensers. The results indicate that the main issue with system performance is one of inertia. To demonstrate this point, the inertia value of the synchronous condensers was changed in the dynamics model from 7.84 to 2.0. The results with the lower inertia value indicate poorer system performance than the high inertia case and were similar to results provided by the

Manitoba Hydro synchronous condensers. Therefore, it can be concluded that it is in fact the large inertia of the [redacted] machines that is improving system performance.

2.4.1 Sunnyside SVC

Without the installation of synchronous condensers at Pipers Hole, the Sunnyside bus requires dynamic voltage support in the form of an SVC. The rating of this SVC depends on the system configuration and the type of Soldiers Pond synchronous condenser being studied.

Using the original 2.2 inertia machines at Soldiers Pond, it was found that 2x300 MVAR are required to be in service at all times. In addition to this, a 400 MVAR SVC plus a 100 MVAR capacitor is required to meet the 0.7 pu transient undervoltage criteria at Sunnyside for a fault at Sunnyside on one of the Sunnyside-Bay d'Espoir lines for the maximum Bay d'Espoir dispatch case.

Using the high inertia [redacted] machines at Soldiers Pond, it was found that only 1x300 MVAR machine was needed, along with a 200 MVAR SVC at Sunnyside. However if there is only one synchronous condenser at Soldiers Pond, a fault at Soldiers Pond that would trip this machine becomes the limiting case. Either a larger SVC is required at Sunnyside (300 MVAR), or 2x150 MVAR synchronous condensers need to be in service in order to leave at least 1x150 MVAR connected if the fault trips a synchronous condenser.

The Bay d'Espoir fault is still unstable for both synchronous condenser/SVC solutions.

The 800 MW monopolar 10-minute 2.0 pu overload case was verified to ensure sufficient steady state VAR support to maintain system steady state voltages.

2.4.2 New 230 kV Circuit: Bay d'Espoir-Western Avalon

Without the installation of synchronous condensers at Pipers Hole and without the addition of an SVC at Sunnyside, a new 230 kV circuit between Bay d'Espoir and Western Avalon was tested. The system response and the need for series compensation on this line and on the two existing 230 kV lines between Bay d'Espoir and Sunnyside depended on the system configuration and the type of Soldiers Pond synchronous condensers being studied.

Using 2x300 MVAR of the original 2.2 inertia machines at Soldiers Pond, without series compensation on the new line, the Sunnyside transient undervoltage dips to 0.66 pu following a fault at Sunnyside on one of the Sunnyside-Bay d'Espoir lines. If the new 230 kV line is built with 50% series compensation, this Sunnyside voltage dip improves to 0.73 pu.

Using the high inertia [redacted] machines with only 1x300 MVAR in service at Soldiers Pond, the system is stable and meets criteria even without any series compensation on the Bay d'Espoir-Sunnyside lines or on the new Bay d'Espoir-Western Avalon line. However, the Sunnyside voltage begins to dip slightly below 0.7 pu. If the 50% series compensation is installed on the two existing Bay d'Espoir-Sunnyside lines there is an improvement in the system response. However in this case because there is only one synchronous condenser at Soldiers Pond, a fault at Soldiers Pond that

would trip this machine becomes the limiting case. Instead, 2x150 MVAR synchronous condensers need to be in service in order to leave at least 1x150 MVAR on-line if a fault trips the other synchronous condenser.

The Bay d'Espoir fault is still unstable for both synchronous condenser options. However, because such good performance was obtained with the high inertia synchronous condensers, the three-phase Bay d'Espoir fault was re-visited using the high inertia synchronous condensers. It was found that in order to design the system to survive a three-phase fault at Bay d'Espoir, the only option that recovered within criteria was a case with the new 230 kV circuit between Bay d'Espoir and Western Avalon. If this new circuit plus the two circuits between Bay d'Espoir and Sunnyside are 50% series compensated, AND if 2x300 MVAR high inertia synchronous condensers are in service at Soldiers Pond (which means 3x300 MVAR would be installed to account for maintenance outages), the system is able to recover from a three-phase fault at Bay d'Espoir.

The 800 MW monopolar 10-minute 2.0 pu overload case was verified to ensure sufficient steady state VAR support to maintain system steady state voltages with 1x300 MVAR synchronous condenser at Soldiers Pond.

2.4.3 Bay d'Espoir Three-Phase Fault

In an attempt to lessen the impact of a three-phase fault at Bay d'Espoir on overall system performance, the 230 kV Bay d'Espoir bus was split such that one 230 kV circuit to Stony Brook and Sunnyside and approximately one half the Bay d'Espoir generation is connected to each 230 kV bus with the tie line between each station out of service. A three-phase fault on one of the Bay d'Espoir-Sunnyside lines was applied. The system response was not substantially improved. The Sunnyside transient voltage improved slightly but the Bay d'Espoir voltage degraded slightly and no reduction in equipment requirements was observed.

Next, a special protection system was tested which blocked the recovery of the HVdc and isolated the Avalon Peninsula load centre. Based on the analysis it appears that remaining generation on the Western portion of the Island cannot control the island frequency; at 5 seconds into the simulation the frequency of the islanded system is up to near 65 Hz. Without some careful generation crosstripping and/or staged overfrequency protection, it does not appear that Island system will settle to a frequency that is within criteria.

However, if the new 230 kV circuit between Bay d'Espoir and Western Avalon is built and if this new circuit plus the two circuits between Bay d'Espoir and Sunnyside are 50% series compensated, AND if 2x300 MVAR high inertia synchronous condensers are in service at Soldiers Pond (which means 3x300 MVAR installed to account for maintenance outages), the system is able to recover from a three-phase fault at Bay d'Espoir within criteria.

2.4.4 Impact of Inertia Relocation

Having determined that the requirement for additional system inertia could be met by continuously operating 2x150 MVAR high inertia synchronous condensers at Soldiers Pond, a preliminary

evaluation of relocating a portion of the required inertia addition was completed. Unit 7 at Bay d'Espoir is a 172 MVA machine with a relatively low inertia due to the rotor's floating rim design.

Change out of the Unit 7 rotor would result in an increase in unit inertia. Further, basic provisions were completed for the addition of a Unit 8 at Bay d'Espoir during the construction of Unit 7. As a result, the Bay d'Espoir site offers a potential location for the required system inertia increase. To investigate the impact of relocating inertia away from Soldiers Pond, it was assumed that the Bay d'Espoir Unit 7 rotor was changed out resulting in an increase in the unit's inertia from 3.883 to 7.766 (doubled), and that a high inertia generator was installed as Bay d'Espoir Unit 8 operating at 150 MW. Given that there is no additional water available at Bay d'Espoir generating station for increased energy production, Units 1 and 2 were shutdown. In addition, Unit 2 was also tested as a synchronous condenser. The analysis assumed that only 1x150 MVAR high inertia synchronous condenser was operating at all times at Soldiers Pond.

Results of the analysis indicate somewhat worse performance with a portion of the inertia moved away from Soldiers Pond. This is likely due to the fact that the performance of the HVdc is not as good with fewer synchronous condensers nearby. It was found that in order for this system configuration to be stable for all faults, 50% series compensation is required on the two existing 230 kV Bay d'Espoir-Sunnyside lines (TL202 and TL206) as well as on the new 230 kV Bay d'Espoir-Western Avalon line. If the series compensation is removed from the Bay d'Espoir-Western Avalon line the system becomes unstable for a fault at Sunnyside on one of the Bay d'Espoir-Sunnyside lines (TL202 or TL206) and is very near a second commutation failure for a three-phase fault at Soldiers Pond on the 150 MVAR synchronous condenser.

The original Bay d'Espoir system configuration with 2x150 MVAR high inertia synchronous condensers operating at Soldiers Pond did not require series compensation on any of these three lines.

The 800 MW monopolar 10-minute 2.0 pu overload case was verified to ensure sufficient VAR support to maintain the steady state system voltages with only 1x150 MVAR synchronous condenser operating at Soldiers Pond. The Soldiers Pond synchronous condenser is producing maximum reactive power of 150 MVAR during the 10 minute 2.0 pu overload condition. It is unable to hold the voltage setpoint of 1.0284 pu as was used in all of the studies, however the voltage at Soldiers Pond is still maintained at 1.018 pu, with voltages at Sunnyside dropping to 1.005 pu and Bay d'Espoir to 1.0264 pu. All system voltages are within criteria, however, despite being slightly lower than in the normal system intact 800 MW bipolar case.

2.5 Conclusions of the HVdc Sensitivity Studies

If the intent is to design the HVdc infeed system such that its performance is similar to the existing system performance (i.e. does not survive the worst case fault), the requirements for synchronous condensers on the Island system are reduced. It must be noted that failure of the HVdc infeed system for the worst case fault is expected to result in system wide collapse as opposed to loss of

approximately 500 MW in the existing system. The main issue in the Island system with the HVdc infeed is lack of inertia and resulting frequency decay due to faults which cause the HVdc infeed to fail commutation; the nearer the fault location to Bay d'Espoir generating station, the more power temporarily lost and the more severe the system frequency decay.

A new synchronous condenser model with a very high inertia constant (7.84) was tested. The high inertia machine showed significant improvement in system performance over the synchronous condenser models with a lower inertia constant (2.2) used in the original DC1020 studies.

It was found that without synchronous condensers at Pipers Hole, either an SVC at Sunnyside or a new 230 kV circuit between Bay d'Espoir and Western Avalon will provide acceptable system performance for all contingencies except the three-phase fault at Bay d'Espoir. The results are highly dependent on the type of synchronous condenser that is modeled.

The high inertia synchronous condensers would significantly reduce the size or number of synchronous condenser that are required to be installed at Soldiers Pond. In order to meet criteria for a fault at Sunnyside on one of the Bay d'Espoir-Sunnyside lines, a single 300 MVAR high inertia synchronous condenser is sufficient, along with a 300 MVAR SVC at Sunnyside or a new 230 kV circuit between Bay d'Espoir and Western Avalon.

However, because loss of the Soldiers Pond synchronous condenser becomes the worst case contingency if only a single 300 MVAR unit is installed, it is recommended to have 2x150 MVAR high inertia synchronous condensers in service at all times, which would translate to 3x150 MVAR installed to account for maintenance outages. The added benefit to a synchronous condenser rating of 150 MVAR is that it would match the Holyrood synchronous condenser ratings and their spare transformer.

Therefore from a technical system performance point of view, the best solution would be to have 2x150 MVAR high inertia synchronous condensers in service at Soldiers Pond at all times, therefore installing 3x150 MVAR in order to account for maintenance outages. In addition to these 150 MVAR synchronous condensers, one of the following mitigation options is also required:

- 200 MVAR SVC at Sunnyside and 50% series compensation on the two Bay d'Espoir-Sunnyside lines; or
- 230 kV line Bay d'Espoir – Western Avalon, no series compensation on this new line or on the existing two Bay d'Espoir-Sunnyside lines.

Both of these solutions provide sufficient steady state VAR support to maintain system steady state voltages during the 800 MW monopolar 10-minute 2.0 pu overload condition. Approximately 200 MVAR is required in steady state from the Soldiers Pond synchronous condensers to maintain the 1.0284 pu voltage setpoint that was used in the studies.

Because such good performance was obtained with the high inertia synchronous condensers, the three-phase Bay d'Espoir fault was re-visited. It was found that in order to design the system to survive a three-phase fault at Bay d'Espoir, the only option that recovered within criteria was a case with the new 230 kV circuit between Bay d'Espoir and Western Avalon. If this new circuit plus the two circuits between Bay d'Espoir and Sunnyside are 50% series compensated, AND if 2x300 MVAR high inertia synchronous condensers are in service at Soldiers Pond (which means 3x300 MVAR installed to account for maintenance outages), the system is able to recover within criteria from a three-phase fault at Bay d'Espoir.

A preliminary evaluation was performed to look at the impact of relocating a portion of the inertia from Soldiers Pond to Bay d'Espoir by changing out the rotor on Bay d'Espoir Unit 7 and by installing a high inertia 150 MVAR synchronous condenser as Bay d'Espoir Unit 8. The analysis was performed with only 1x150 MVAR high inertia synchronous condenser operating at Soldiers Pond instead of 2x150 MVAR. Despite the fact that the total system inertia is very similar in both cases, the results indicate poorer performance of the Island system when the synchronous condensers are moved away from Soldiers Pond due to poorer performance of the HVdc infeed. This system configuration as studied would require the addition of the 230 kV circuit between Bay d'Espoir and Western Avalon with 50% series compensation, as well as 50% series compensation on the two Bay d'Espoir – Sunnyside 230 kV lines. If even the series compensation from the new Bay d'Espoir – Western Avalon line is removed the system becomes unstable for a fault at Sunnyside on one of the Bay d'Espoir lines (TL202 or TL206), and in addition the HVdc infeed is on the verge of a second commutation failure for a three-phase fault on the Soldiers Pond synchronous condenser.

3. PSSE Model Modification

The original DC1020 transient The original WTO DC1020 transient stability analysis assumed a multi-terminal HVdc system with a 480 km cable connection between Newfoundland and New Brunswick across the Cabot Strait. A major task of the WTO was the development of a multi-terminal HVdc model for future PSSE studies. As part of WTO DC1210, NE-LCP requested that the PSSE model developed as part of DC1020 be modified to include a shorter cable between Newfoundland and Nova Scotia along with a new HVdc overhead transmission line from Nova Scotia to New Brunswick.

The PSSE stability model of the three-terminal HVdc link for the Lower Churchill Project has been modified to represent a shorter dc cable section and longer dc overhead line section between the tap at Taylor's Brook and the terminal at Salisbury. Specifically, the cable section between Newfoundland and Lingan, Nova Scotia is estimated at 180 km, and the new overhead line section from Lingan, Nova Scotia to Salisbury, New Brunswick is estimated at 475 km. The overhead line sections in Newfoundland from Taylor's Brook to the Gulf of St. Lawrence crossing to Nova Scotia remain unchanged.

3.1 Objectives of the PSSE Model Modification

The objectives of the PSSE Model Modification was to modify the PSSE stability model of the three-terminal HVdc link for the Lower Churchill Project to represent a shorter dc cable section and longer DC overhead line section between the tap at Taylor's Brook and the terminal at Salisbury. Specifically, the cable section between Newfoundland and Lingan, Nova Scotia is estimated at 180 km, and the new overhead line section from Lingan, Nova Scotia to Salisbury, New Brunswick is estimated at 475 km. The overhead line sections in Newfoundland from Taylor's Brook to the Gulf of St. Lawrence crossing to Nova Scotia remain unchanged.

The PSSE multi-terminal HVdc model was modified and validated to be capable of operating in bipolar or monopolar modes for the following HVdc configurations:

- 3-terminal: Gull Island – rectifier, Soldiers Pond – inverter, Salisbury – inverter
- 2-terminal: Soldiers Pond – rectifier, Salisbury – inverter
- 2-terminal: Salisbury – rectifier, Soldiers Pond – inverter

The validation testing for the monopolar configuration was performed using the 3-terminal HVdc configuration.

3.2 Power Flow Test Case

For the 3-terminal HVdc configuration, the PSSE model validation was performed using an equivalent test system representing power flow case BC1-DC1: rated bipolar operation with Gull Island as rectifier and Soldiers Pond and Salisbury as inverters (3-terminal).

The validation testing case was performed in an equivalent test system using the following system strengths:

- Gull Island – 4654 MVA ∠87 deg
- Soldiers Pond – 3305 MVA ∠74.1 deg
- Salisbury – 3949 MVA ∠76 deg

The above systems strengths represent a weak configuration at Gull Island, one 150 MVAR synchronous condenser in service at Soldiers Pond (Xd'' = 0.165 pu) and one 125 MVAR synchronous condenser in service at Salisbury (Xd'' = 0.165 pu) based on information from previously completed studies.

For the 2-terminal HVdc configurations, the PSCAD model had previously been set up using equivalent test systems, however the PSSE models that were readily available for these power flow configurations had been set up to use an equivalent source at the Salisbury terminal and the reduced version of the Newfoundland system PSSE model for the Soldiers Pond terminal. This difference in test systems results in slightly different ac voltage response for the 2-terminal test cases, however the response (especially of the HVdc quantities) very closely matches the PSCAD model and therefore still provides validation of the PSSE model.

3.3 Procedure and Results

The PSCAD model was first updated and the dc controls were re-tuned. These changes were implemented inside the PSSE model. Validation testing was performed by comparing the results of the PSCAD and PSSE models for a solid and remote three-phase fault at each of the dc terminals for the 3-terminal case, and for solid faults only for the 2-terminal cases.

Validation testing results show that the PSSE model compares well with the PSCAD model results.

4. VSC Risk Assessment

Previous studies that have been performed on the proposed Lower Churchill Project considered the application of conventional Line Commutated Converter (LCC) technology. These studies found that the main issue in the Newfoundland Island system is lack of inertia and the resulting system frequency decay due to three-phase ac faults which cause the HVdc converter to fail commutation; the nearer the ac fault location to the Bay d'Espoir generating station, the more power that is temporarily lost during the ac fault and subsequent commutation failure and the more severe the system frequency decay. This situation resulted in the need for a large number of high inertia synchronous condensers to be installed along with the HVdc infeed in order to save the Island system from frequency decay and system-wide collapse.

Because a Voltage Source Converter (VSC) does not fail commutation during an ac fault, it is possible that if the Soldiers Pond terminal used VSC technology the synchronous condenser requirements of the Island system due to an ac fault would be reduced. In order to determine the viability of VSC a high level risk assessment of VSC technology was undertaken. The risk assessment was complemented by a number of cursory evaluations of the performance of a VSC converter in the Island ac system.

4.1 Objectives of the VSC Risk Assessment

The objectives of the VSC Risk Assessment were to conduct a qualitative review of the characteristics of the VSC, along with the current status and expected future developments of VSC technology, and to compare this with the technical requirements of the LCP to determine the potential suitability of VSC technology to the project. The qualitative review was followed by preliminary investigations of the performance of a VSC converter in the Island ac system.

4.2 Methodology of the VSC Risk Assessment

The following factors were considered when performing the risk assessment:

- Review of the state of the art of VSC technology mainly as it applies to HVdc transmission.
- Review of the characteristics of VSC.
- Review of the future developments in HVdc.

The review involved obtaining the most up to date data from the suppliers regarding the ratings and availability of these ratings for commercial use. This was followed by comparing this information with the technical requirements of the HVdc project. Finally, preliminary investigations using PSSE and a vendor supplied VSC based HVdc model were undertaken to provide some insight into the potential performance benefits.

4.3 VSC Technology Review

4.3.1 Current State of the Art of VSC Technology

The VSC technology for HVdc power transmission applications is advancing quickly, from the start of a very moderate rating of 3 MW in 1997 which was demonstrated in the Hellsjőn project to the present rating of 400 MW in Transbay Cable Project to be in service in 2010. Currently HVdc using VSC technology can be at a rating of 1100 MW and +/- 320 kV with an overhead line. The current projection indicates that a full bipole at +/- 640 kV dc and 2200 MW is achievable.

Commercially the VSC technology is marketed by two of the leading suppliers of HVdc under two trade names:

- HVdc Light
- HVdc Plus

In the beginning, the application of VSC in HVdc was always tied to its connection to an HVdc cable, because during a dc fault in a VSC scheme, currents from the ac side feed through the bi-directional converter valves into the dc fault and cannot be cleared until the main ac breaker is tripped, unlike conventional LCC HVdc in which the ac side does not contribute to the dc fault due to the uni-directional valves. This means that during a dc fault on a VSC, the whole converter must be tripped in order to clear the fault, therefore automatic re-starting is not an option. Since cable applications do not usually offer a restart as a fault on the cable is almost always a permanent fault, this limitation was not an issue for the VSC.

Since a VSC converter does not control fault currents for faults occurring on the dc side it was always promoted as a complete solution with cables.

Since the VSC maintains a constant dc voltage regardless of direction, reversal of power direction in a VSC HVdc system does not require the polarity reversal of the dc voltage, and so the use of a more cost effective cross-linked polyethylene (XLPE) cable in conjunction with VSC is widespread.

Recently, for the Caprivi HVdc interconnector in Namibia, VSC technology was applied to an overhead line. This project is rated at 300 MW at 350 kV and with an in-service date in 2009. There is a provision to add a second pole to this link in the future to operate as an integrated bipole. Using high-speed HVdc circuit breakers, in the event of a dc fault, the fault can be cleared quickly on the dc side leaving the converters in service for a restart.

4.3.2 Operating Experience of VSC HVdc Stations

The current major VSC based HVdc systems are listed in the table below.

Table 4.1
VSC Based HVdc Systems Currently in Operation or Under Construction

Scheme	Rating MW	Voltage kV	VSC Converter Type
Cross Sound	330	+/- 150	3 level
Murray Link	220	+/- 150	3 level
Direct Link	180	+/- 80	2 level
Gotland	50	+/- 60	2 level
Est link	150	150	2 level
Caprivi *	300	350	2 level
Transbay	400	+/- 200	Multi-level

** First project with overhead line, it is to be expanded to a 600 MW bipole.*

The operating statistics of HVdc systems are collected and analyzed by Cigre Working Group B4-04. However, so far none of the existing VSC based HVdc systems have reported their operating experiences. But there have not been any major reliability issues with these systems and from the discussions with one of the operating companies of a VSC HVdc link, it has been running smoothly and successfully.

4.3.3 Comparison between the Features of VSC and LCC Technology

In order to draw any conclusions regarding the application of a VSC for the multi-terminal Lower Churchill HVdc transmission project, it is important to compare the VSC and the LCC converters as presented in the table below.

Table 4.2
Comparison Between VSC and LCC Technology

Comparison	LCC	VSC
Semi-conductor device	Thyristors currently 6 inch, 8.5 kV and 6000 A. No controlled turn off capability.	IGBTs with anti-parallel free-wheeling diode, with controlled turn-off capability.
DC transmission voltage with a cable	Up to 500 kV.	Up to +/- 300 kV currently limited by HVdc cable if extruded XLPE cable is used.
dc transmission voltage with an overhead line	Up to +/- 800 kV.	Up to +/- 640 kV.
DC power	Currently in the range of 6000 MW per bipolar system.	Currently up to 1100 MW and projected to increase to 2200 MW.
Reactive power requirements	Consumes up to 60% of its rating reactive power.	Does not consume any reactive power and each terminal can independently control its reactive power.
Filtering	Requires large filter banks.	Requires moderate size filter banks or no filters at all.
Black start	Limited application.	Capable of black start and feeding passive loads.
AC system short circuit level	Critical in the design.	Not critical at all.
Commutation failure performance	Fails commutation for ac disturbances.	Does not fail commutation.
Overload capability	Available if designed for up to any required design value.	Does not have any overload capability.
Application with overhead lines	Can be applied and dc line faults can be cleared by converter control.	Can be applied but dc line faults are cleared by trip of ac breaker, or the use of a dc circuit breaker. Currently one application of overhead line. It has mostly been applied with cables.
Small taps	Not economic and affects the performance.	Economic and should improve the performance.
Load rejection over voltage	Large and has to be mitigated because of the large reactive power support.	Not large because of small size of filters if required.
DC line to ground faults	Little effect on ac system with proper overload capacity.	During the time it takes to clear the fault from the ac side, reactive power will be drawn. However the impact is less than a regular ac fault.

4.3.4 Future of VSC Technology in HVdc

It is clear that VSC technology will expand over the next few years. The latest IGBT turn-off current rating of 1718 amperes will certainly increase in the future. This turn-off current rating is the major determining factor for the rating of a single converter. The dc voltage also has an impact on the rating. However, dc voltage is only a limitation for the XLPE cables and not for overhead lines or the mass impregnated cables. Currently ratings of up to 1100 MW are being quoted.

One other factor to be considered is the overload capability of the VSC which is currently non-existent.

4.3.5 Application of VSC in Multi-Terminal HVdc Systems

There are two potential applications of VSC to a multi-terminal HVdc system:

- The complete system is realized through the use of VSC. In this configuration the total power transmission capability is limited by the current rating of the VSC converters which is tied to the turn-off current rating of the IGBTs. For power reversal there is no need to reverse the voltage and therefore, unlike the LCC based system, there is no need for extra switching equipment.
- The second approach would be a hybrid configuration, where the main strong system high rating converters are realized using LCC and the weak system small tap converter using VSC. This solution achieves the high rating of the main HVdc link and a robust converter for the small tap, weak ac system. The VSC is immune to commutation failures, and hence, the overall system performance is improved.

4.4 Application of VSC to the LCP

4.4.1 Basic Requirements

Characteristics of the proposed LCP HVdc link are summarized as:

- Bipolar, three-terminal HVdc link
- Nominal voltage: +/- 450 kV (at rectifier)
- Nominal converter ratings:
  - Gull Island – 1600 MW
  - Soldiers Pond – 800 MW
  - Salisbury – 800 MW
- A high overload capability at Soldiers Pond (2.0 pu) in the event of a loss of a pole
  - Moderate overload at Salisbury (10-15%)
  - A combination of overhead line and cables

- Power reversal of all terminals

A comparison between the basic requirements and the current state of the art of VSC technology would provide a good indication whether VSC technology should be considered for the project.

4.4.1.1 Bipolar Configuration

A VSC-based system can be designed in a bipolar configuration. In fact the Caprivi project is designed as a bipolar system although for the first phase only one pole is supplied. Therefore it can operate in both bipolar and monopolar.

4.4.1.2 DC voltage of 450 kV

For the converters and the overhead lines, implementation of VSC at this voltage is posible. In fact according to the suppliers a dc voltage higher than 450 kV is possible. However, for the XLPE cable this is not possible. Therefore, a mass impregnated cable would have to be used.

4.4.1.3 Station Rating at Gull Island

The latest VSC technology has a current rating of 1718 amperes, which at +/-450 kV, results in a power rating of 1547 MW per station, or 773 MW per pole. These figures are marginally less than the design ratings at Gull Island (1600 MW for the station and 800 MW per pole).

One solution is to apply two VSC blocks in parallel per pole, however this may be an unnecessary complication.

This limitation may lend itself to make the terminal at Gull Island a conventional line commutated converter.

4.4.1.4 Station Rating at Soldiers Pond

The station at Soldiers Pond is rated for 800 MW which is not a problem for the current state of the art of VSC. However, the issue here is the overload capability required at 2.0 pu even for 10 minutes and 1.5 pu continuously. This means that each pole will be rated for 800 MW for 10 minutes and 600 MW continuously.

VSC converters do not have an overload capability, therefore the station at Soldiers Pond would have to be rated at 800 MW per pole continuously to account for the loss of a pole. With a current rating of 1718 amperes, the pole rating at Soldiers Pond shall be 773 MW which is close to the 800 MW. The converters are the main pieces of equipment affected by such an upgraded power rating.

In principle the normal and overload ratings are achievable at Soldiers Pond.

4.4.1.5 Station Rating at Salisbury

The station is rated at 800 MW and has very moderate overload requirements. Therefore this is a straight forward application for a VSC station.

4.4.1.6 Power Reversal

Power reversal in a VSC station is easier than power reversal in a conventional LCC station as there is no need for reversing switches.

4.4.2 The Requirements for Synchronous Condensers for the Project

The transient stability analysis that has been performed on the HVdc infeed using LCC technology found that the main issue in the Island system is a lack of inertia and the resulting system frequency decay due to three-phase ac faults which cause the HVdc converter to fail commutation. The nearer the ac fault location to the Bay d'Espoir generating station, the more power that is temporarily lost during the ac fault and subsequent commutation failure and the more severe the system frequency decay. This situation resulted in the need for a large number of high inertia synchronous condensers to be installed along with the HVdc infeed in order to save the Island system from frequency decay and system-wide collapse.

4.4.2.1 AC Faults

Because a VSC converter does not fail commutation during an ac fault, it is possible that if the Soldiers Pond terminal used VSC technology the synchronous condenser requirements of the Island system due to an ac fault would be reduced. Unless the three-phase ac fault is directly on the terminals of the VSC, even at reduced terminal voltage during a three-phase fault elsewhere in the Island system (e.g. during a three-phase fault at Bay d'Espoir), the VSC will still be able to feed a reduced amount of power to the Island system during the fault. In addition, the VSC will likely be able to recover faster than the LCC infeed once the ac fault is cleared. Both of these factors suggest that the frequency decay seen during the LCC stability studies due to an ac fault may not be as severe and therefore the need for synchronous condensers may be reduced.

4.4.2.2 DC Faults

An inherent weakness of a VSC HVdc link is a dc line fault. During the time it takes to clear a dc line fault, it is fed from all the ac systems connected to the dc line through the VSC diodes. As a result large fault currents will be drawn from the ac system, however the effect will be less than a normal ac fault as the converter transformer, phase reactors, dc smoothing reactors (if present), and any line impedance between the location of the fault and the VSC introduce an impedance which limits the current drawn from the ac side as well as limiting the rate of growth of the fault current. For the length of time it takes to clear the dc line fault, the ac voltage in all connected systems will be considerably reduced. Power infeed from the VSC is also significantly reduced while the fault is present as the power transfer in the faulty pole is stopped and power transfer in the healthy pole is reduced due to the drop in ac voltage. Depending on how long it takes to clear the dc line fault, the system frequency decay may or may not be as severe as seen during the worst three-phase ac fault in the line commutated converter studies.

Currently there are two VSC designs available for the application of HVdc. In both designs in a bipolar arrangement with grounded midpoint, the anti-parallel diodes conduct to feed the dc line fault as shown in the figure below. Under these circumstances, the IGBTs are bypassed and are

unable to extinguish the fault current. In earlier applications in which the VSC converters were applied in conjunction with HVdc cables, the assumption was that a fault on the cable is rare and the cable does not recover from such a fault and therefore the ac circuit breaker (S) is tripped and not automatically reclosed. However, with the application of VSC to overhead line combined with the fact that dc line faults are more frequent and are considered to be able to recover from (as opposed to cable faults), a sequence of ac and dc breaker tripping and reclosing is applied to clear the dc line fault and restart the VSC HVdc overhead line. In LCC converters, a dc line fault is cleared by applying deionization attempts without the movement of any mechanical devices.

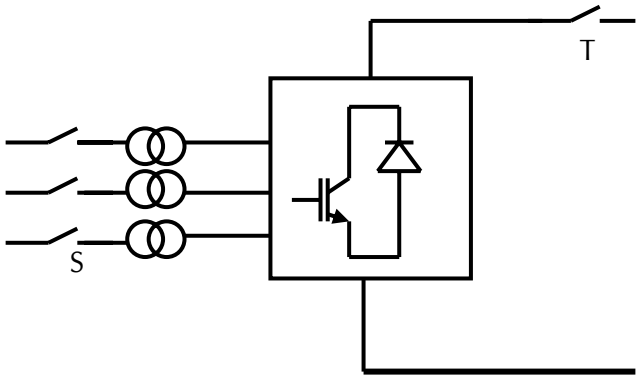


Figure 4.1 – VSC Converter with ac and dc Breakers

Based on information provided by one of the VSC suppliers, the dc line fault clearing sequence for converters connected pole-neutral operates as follows (timings are sequential, cumulative and approximate):

- dc line fault detection +10 ms (to be conservative);
- open ac and dc breakers at all stations connected to the faulted pole +50 ms after fault detection. The ac breaker clearing time of +50 ms removes the fault current source, the dc breaker clearing breaks the dc line current transient to begin the deionization time;
- dc line fault deionization time + 250 ms;
- close ac breakers with damping circuit to re-energize converters +100 ms;
- close dc breakers to re-energize dc line pole + 50 ms;
- deblock converters to restart the power flow + 30 ms;
- total time = 490 ms.

It is assumed that the VSC design of the other supplier would use a similar method to clear a dc line fault.

4.5 Preliminary Simulation Study using VSC technology

In order to evaluate the performance of the Island system and the need for synchronous condensers, further stability analysis with a VSC converter at Soldiers Pond would be required to analyze both ac and dc faults.

A preliminary transient stability evaluation of VSC technology was performed using PSSE in order to get an idea of how the Island system would perform if the Soldiers Pond HVdc infeed used a VSC converter instead of a line-commutated converter. Several of the expected worst-case faults were simulated with varying amounts of synchronous condensers operating at Soldiers Pond to see if it might be possible to reduce or eliminate the need for synchronous condensers on the Island system with a VSC infeed.

4.5.1 Power Flow Case

The transient stability analysis was performed on the future peak load flow case (approximately 1625 MW Island load without the refinery) with maximum generation dispatched at Bay d'Espoir. The 230 kV Bay d'Espoir-Sunnyside lines (TL202 and TL206) were modeled with 50% series compensation. No other system upgrades were modeled (e.g. SVCs or new lines) in the evaluation, with the exception of varying amounts of synchronous condensers at Soldiers Pond. All synchronous condensers at Holyrood were in service.

4.5.2 VSC model in PSSE

A vendor-supplied VSC model for PSSE was used in the transient stability analysis. For the sake of simplicity during this preliminary evaluation, the VSC HVdc link was modeled as a two-terminal link from Gull Island to Soldiers Pond rather than a three-terminal link. There should not be significant impact in making this simplification as far as the Island system performance is concerned.

The vendor-supplied VSC model is not yet programmed and tested to operate in the bipolar overhead line configuration. However, for the purposes of this preliminary evaluation, the VSC model as it is (i.e. intended to represent cable installations) was used with minor modifications to emulate the bipolar overhead line configuration that would be applicable in the Lower Churchill Project.

In order to account for the 2.0 pu 10-minute overload requirement of the Soldiers Pond terminal, each pole of the VSC link must be capable of carrying the full 800 MW for 10 minutes. As a VSC does not have an inherent overload capability, each pole must be rated for the full 800 MW in case of an outage of the other pole.

The closest VSC rating (bipolar overhead line configuration) to what would be required for the Lower Churchill Project that is currently available from one VSC vendor is +/- 640 kV 1518 MVA (1.186 kA). It is realized that this dc voltage is too high for the Lower Churchill Project, however this is the MVA rating closest to what is required and for purposes of preliminary evaluation it is not expected that it will have a significant impact on the dynamic performance of the system.

Of the monopolar cable configurations readily available in the vendor-supplied VSC model package, the closest is one rated for 796 MVA at +/- 320 kV dc. Therefore, the bipolar VSC link was emulated by putting two of these 796 MVA VSC models between Gull Island and Soldiers Pond for a total MVA rating of 1592 MVA.

After approximating the losses associated with the VSC link, 750 MW was injected at the Soldiers Pond bus. It must be noted however that losses will be largely impacted by dc voltage and the actual VSC converter rating that would be installed. It is assumed for this preliminary analysis that losses will not greatly impact the dynamic performance.

With each pole operating at 375 MW, or 0.5 pu, the VSC reactive power capability per pole at this operating point is approximately +374/-398 MVAR.

It should be noted that if operating closer to 1.0 pu power (i.e. when one pole is out of service), the reactive capability of the VSC is greatly reduced to approximately +60/-220 MVAR, which would affect the system performance.

4.5.3 Contingencies

The transient stability analysis of the bipolar VSC infeed was evaluated for the following fault conditions:

- 100 ms, 3Ph fault at BDE cleared by tripping one of BDE-SSD lines;
- 100 ms, 3Ph fault at SSD cleared by tripping one of BDE-SSD lines;
- 100 ms, 3Ph fault at SP cleared by tripping one of SP-WAV lines;
- 100 ms, 3Ph fault at SP cleared by tripping one of 150 MVA synchronous condensers;
- DC Pole fault.

4.5.4 Simulation Results

It was found that with the Soldiers Pond infeed modeling VSC technology, all simulations were stable and the post-fault voltages were within acceptable limits for all of the contingencies considered without any synchronous condensers operating at Soldiers Pond and without any new synchronous condensers elsewhere in the Island system (with the exception of the Holyrood machines running as synchronous condensers).

The 3-phase fault at Bay d'Espoir on one of the Bay d'Espoir (BDE) – Sunnyside lines (SSD) (TL202 or TL206) was the worst-case fault in the studies involving the line commutated converter because this fault resulted in temporary loss of the Bay d'Espoir generation, a simultaneous commutation failure at Soldiers Pond, and a subsequent temporary loss of the HVdc power infeed which resulted in a severe decay in system frequency. Using VSC technology at Soldiers Pond means that the HVdc power will still be available during this Bay d'Espoir fault because a VSC does not fail commutation and can

continue to inject power at reduced ac voltage. Therefore this fault is no longer as significant an issue with the VSC.

The dc pole-ground fault results in the total loss of one pole for 500 ms. Even without modeling any frequency control on the other pole (i.e. to pick up the slack of the faulted pole), the system response is stable and within criteria.

If the entire power were lost from both poles for 500 ms, the system would require 2x150 MVA synchronous condensers in order to recover from this fault. This would be in the very rare case of a pole-pole fault, assuming the VSC could even recover from such a fault.

4.5.5 Discussion of VSC Simulation Results

The voltage source converter (VSC) option for the Lower Churchill Project has shown good transient stability performance of the system for the expected worst contingencies that were studied. The 50% series compensation on the two Bay d'Espoir-Sunnyside lines (TL202 and TL206) has been included in the power flow case considered. In addition, all Holyrood machines were modeled in service. The following conclusions can be made based on the preliminary analysis.

- The bipolar VSC link (modeled as 2×796 MVA) has shown good performance for the expected worst contingencies that were considered without any new synchronous condensers installed in the Island system. The system has also recovered well from a dc pole fault. Further, the post-fault transient undervoltages were within the required transient undervoltage criteria. The VSC as rated in this evaluation (i.e. 2x796 MVA) provides an additional advantage that the system could be operated at full power continuously during a single-pole failure.

The ability of the VSC to continue to provide power to the Island during reduced ac voltage (because it does not fail commutation) allows the large system frequency decays to be avoided. In addition, the large reactive power capability of the VSC (especially when operating near 0.5 pu power) assists in system voltage recovery following faults. Both of these facts provide a significant advantage to the Island system performance compared to the line-commutated converter technology.

4.6 Conclusions of the VSC Risk Assessment

This high level evaluation of the VSC converters for the HVdc system showed the following:

- The rating at Gull Island can be better realized using a conventional LCC technology.
- The rating at Soldiers Pond can be achieved using a VSC technology.
- The rating at Salisbury can be achieved using a VSC technology.
- The HVdc cable will most likely have to be a mass impregnated cable, even with VSC technology.

- HVdc cable will still be a mass impregnated cable.
- Results of preliminary transient stability simulations showed an overall improvement in system performance for all ac and dc faults that were studied with fewer synchronous condensers than required for the LCC technology.

Based on the above, it is recommended that a more complete study to evaluate the use of VSC technology for the Soldiers Pond terminal be undertaken.

5. Review of AC and DC Line Proximity Issues

5.1 Background of the Review of AC and DC Line Proximity Issues

A qualitative review of issues related to the application of HVdc and ac transmission lines within a common right-of-way was prepared. Use of the existing right-of-way would require that the HVdc line run in close proximity to the ac lines on separate structures, use a common structure, or require the direct burial of the ac lines with the HVdc line running on top on its own structure.

A number of articles are available on the subject of the interactions of HVdc and ac transmission lines located in close proximity to each other. Some papers consider the interactions between lines located within a common right-of-way but installed on separate towers [1, 2, 3, 4], while others consider hybrid configurations (HVdc and ac lines on a common tower) [5, 6, 7].

Very few hybrid lines (HVdc and ac conductors on the same tower) have been built. One example is the National HVdc project in India which was an experimental project where one circuit of an existing double circuit 220 kV ac line was converted to an HVdc line [8]. The HVdc line initially operated as a monopole with a dc voltage of 100 kV and a power transfer capability of 100 MW.

HVdc and ac lines on separate structures in close proximity within the same right-of-way is more common. Examples of this include the Hydro Quebec – New England HVdc line, the Nelson River HVdc lines in Manitoba, and the Tian-Guang HVdc line in China. In these cases the HVdc lines run in close proximity to HVac lines on separate structures for a portion of the overall HVdc line length.

5.2 HVdc and AC Line Interactions

When considering locating HVdc and ac lines in close proximity it is necessary to consider the effects of the ac circuit on the dc circuit and vice versa; under both steady state and transient conditions. In addition, consideration must be given to the physical implementation of such a system.

In general it can be stated that as the HVdc line is located closer to the ac line and the coupled section length increases, the HVdc and ac line interactions are more pronounced.

5.3 Steady State Effects

5.3.1 AC/DC Coupling

When an HVdc transmission line is situated in close proximity to a parallel ac transmission line, steady-state induction effects lead to a power frequency current flowing in the HVdc line. The coupling of an ac fundamental component onto the HVdc system can have the following impacts:

- Converter Transformer Saturation and Harmonic Generation - A fundamental frequency current flowing on the dc side of the converter will be seen as a second harmonic and a dc component in the converter transformer ac system side winding. A dc component in the ac system side winding

of the converter transformer can lead to half cycle saturation which results in the generation of a broad spectrum of harmonics into both the ac and dc systems [1, 4].

- AC and DC Filter Design - The harmonics resulting from the saturation of the converter transformers pose difficulties in design of both the ac and dc filters, requiring increased filter component ratings. Additional harmonics may also lead to increased interference on telephone communication systems.
- Converter Transformer Loss of Life - Increased heating of the converter transformer must be accounted for in order to avoid loss of life.
- Increased Audible Noise - Converter transformer audible noise levels may be substantially higher than usual.
- HVdc Control and Protection – An ac component on the dc side may affect the control and protection scheme of the HVdc system including the measurement devices used.
- Transformer Protection – Transformer protection may be affected by the increased harmonics.
- Neutral Point Voltage Increase – The neutral point voltage impacts equipment insulation levels.

Possible mitigation includes the application of fundamental frequency blocking filters in order to reduce the magnitude of the fundamental frequency component current flowing within the dc system and the application of modulation functions to the HVdc controls.

5.3.2 Corona and Field Effects

The proximity between conductors energized with ac and HVdc voltages causes changes in conductor surface gradients and the electrical environment in the vicinity of the lines. Corona and both the ac and dc electric field effects may be impacted. Calculation of conductor surface gradients is more complex than for individual ac or HVdc lines. In general, when HVdc and ac lines are placed in close proximity they interact to produce levels of corona and electric field effects which depart from the simple superposition of the effects of the two lines acting separately [2].

5.4 Transient Events

Transient events include both ac and dc faults and controlled changes of the HVdc operating point. Transient events can have the following impacts:

- Overvoltages on the HVdc line due to ac and dc Faults – The voltage induced on the HVdc system as a result of a fault on the ac system can generate lightly damped fundamental frequency overvoltages, excite resonance conditions in the ac and dc systems, and cause dc currents to flow in the converter transformers. If fundamental frequency blocking filters are used in the HVdc system then faults on the converter ac system can result in a fundamental frequency oscillation in this tuned filter resulting in a significant fundamental frequency overvoltage [6]. The application of an arrestor across the blocking filter is required in order to limit the neutral point voltage.
- Delayed dc Fault Clearing – Fundamental frequency coupling from the ac line to the HVdc line interferes with the clearing of dc line faults [7]. Even though the dc current in the arc fault can be

brought to zero by the HVdc controls, fundamental frequency secondary arc current can delay the clearing of the fault.

- Impact of HVdc Faults on ac Lines – HVdc pole to ground faults can have an appreciable impact on ac current. AC system protections may need to be reviewed in order to avoid false operation.
- Controlled Changes in HVdc Operating Point – Controlled changes in HVdc operating point include both controlled power order changes and changes in operating mode such as normal bipolar operation to ground return. Controlled power order changes will result in a change in dc current which in turn will impact the ac current in a similar fashion to a dc line fault. Operation in ground return mode has the potential to cause large zero sequence transients in ac lines due to transients in the HVdc ground return circuit such as the switch from metallic return to ground return operation [9, 10]. The transition of the HVdc system from normal to ground return operation can result in the incorrect operation of ac ground current detection relays.
- Faults between the HVdc and ac Lines – A fault between a conductor in the HVdc and ac line can result in a severe stress on the ac system which must be mitigated. Clearing of the fault will require the operation of the ac circuit breakers and operation of the HVdc line fault detection. Most HVdc systems with overhead lines include an automatic restart in the event of dc line faults. In the event of a permanent fault between the HVdc conductor and the ac conductor, the ac conductor would remain charged up to the full dc voltage following the HVdc restart. This could pose a hazard to both personnel and equipment and suitable measures would have to be taken to avoid the potential for such a situation [6].

5.5 Physical Considerations

Physical considerations include the following:

- Aesthetics – Tower configuration for hybrid HVdc and ac line configuration will be determined partially by the required clearances between the HVdc conductors, ac conductors, the tower, and ground.
- Live Line Maintenance – Live line maintenance procedures will have to be modified to account for HVdc and ac conductors on a common tower.
- Impact of Tower Failure – The impact of a tower failure in the case of HVdc and ac lines on a common tower must be considered.

5.6 Identification of Issues and Mitigation

In order to clearly identify the issues which arise from the alternate line route for the Lower Churchill Project and determine suitable mitigation measures, a two part study is required.

The first part of the study should address the physical line parameters and configuration in order to ensure acceptable corona and field effects for the proposed transmission line route. It is estimated that such a study would take approximately three (3) months to complete.

The second part of the study should address the steady state and transient performance issues in order to provide sufficient information required for the design of the HVdc and its control and protection systems. It is estimated that such a study would take approximately two (2) months to complete. It should be noted that the second part of the study can only be undertaken once a likely candidate line configuration had been identified.

Additional studies would be required to ensure that existing ac system protections are adequate, or whether modifications would be required

5.7 Technical Opinion

Based on the available literature and current industry experience, the use of a hybrid line with the HVdc and ac conductors on a common tower may not be suitable for the proposed line route, mainly due to the potential for a high level of interaction between the lines and the potential for HVdc to ac conductor faults. In situations where the use of common towers would be for very short distances, the risk of an HVdc to ac conductor fault may be acceptable; however in the case of the proposed line route, the distance is great enough that the risk of such a fault may be a determining factor.

The use of HVdc and ac lines in close proximity on separate towers may be suitable if an acceptable separation can be maintained. The suitability of this option would require detailed studies in order to determine candidate line configurations and any required mitigation measures to ensure acceptable performance of the integrated HVdc and ac systems. Current industry experience can be used as a starting point for determining a potential minimum separation distance between the HVdc and ac lines. Once this is identified the suitability of the existing right-of-way can be better assessed.

The use of a direct buried ac cable with the HVdc on towers on the same right-of-way may be suitable however studies would be required to determine the potential effects of HVdc ground faults on the buried ac cable.

6. Bipole Block Impacts

6.1 Objectives of Bipole Block Study

The primary objective was to investigate the impact of a bipole block on the island ac system. It is recognised that a bipole block can be temporary or permanent. In the case of a temporary block, caused by such an event as a dc line pole to pole to ground fault, it is likely that both, or at least one pole will successfully restart and re-establish all or part of the HVdc in-feed. In the case of a permanent bipole block, underfrequency load shedding was expected to be required and the objective of the study was to ensure that a portion of the island system remains intact. The study focused on the impacts of a permanent bipole block and the goal was to identify a portion of the system which can remain intact to allow system restoration. In this context, the existing underfrequency load shedding (UFLS) scheme was reviewed and discussions with Nalcor staff were held to gain some insights for prioritizing load to shed.

6.2 Preparation of Load Flow Base Case for Bipole Block Study

Naclor advised Hatch to use one of the sensitivity study load flow base cases with some modifications for assessing Bipole Block impacts. Accordingly, a new load flow base case was prepared based on the following assumptions:

- A new 230 kV transmission line from Bay d'Espoir (BDE) - Western Avalon (WAV) is in service.
- There is no series compensation on the two Bay d'Espoir-Sunnyside lines (TL202, TL206), or the new BDE-WAV line.
- TL202 and TL206 are thermally upgraded. New thermal ratings are 341.8 MVA at 30 °C, 402.4 MVA at 15 °C, and 453.8 MVA at 0 °C.
- TL201 and TL203 are rebuilt. New thermal ratings are 355.8MVA at 30 °C, 411.5 MVA at 15 °C, and 459.6 MVA at 0 °C. It is assumed that other line parameters have not changed.
- Two (plus one spare) high-inertia, 150-MVAR synchronous condensers are in service at Soldiers Pond. The condensers are rated for +150/-83 MVAR with a Zsource of 0.165 pu. Power transformers for the syncs are rated for 150 MVA and have an impedance of 0.0012 + j0.0582 pu.
- Three Holyrood units are online as sync condensers.
- Voisey's Bay Nickel Smelter is in service. Load is 80 MW; connected to the system via two OLTC transformers.
- The Abitibi Paper Mill in Grand Falls is no longer in service. The 10 MW mill load connected to the 230 kV system at Stony Brook 230 kV bus #216 has been removed, while generating units remain online to provide 60 MW for the system. This assumes a new configuration at Grand Falls which adds a 18 MW plant at Bishop's Falls, a 25 MW G4 at Grand Falls, a 30 MW G9 at Grand Falls and four 5 MVA machines at Grand Falls. The net impact of loss of the paper mill is additional hydro generation injection into the NLH system. The four 5 MVA machines were

assumed off-line however, the other machines were considered online with a total 60 MW dispatch. The corresponding dynamic data for the Grand Falls machines were added to the dynamic data file of the reduced model.

- Grand Falls Transformer T2 has been set to Tap Position 1 as per the latest notice from NLH System Operations.
- No SVC at Sunnyside.
- 800 MW bipolar HVDC infeed.

The corresponding load flow diagram is shown in Appendix E.

6.3 Descriptions of Existing and Modified Underfrequency Load Shedding (UFLS) Schemes

Table 6.1 summarizes existing UFLS settings and corresponding load shedding levels in different load pockets/areas. Names and brief descriptions of these load pockets are also included in the table. The magnitude of loads can be correlated to the load buses in the detailed load flow base case and these loads can be tripped by implementing UFLS dynamic data as per the existing settings.

However, loads in the reduced load flow base case are lumped at a smaller set of load buses and their correlation to the existing UFLS scheme cannot be established directly, except at a few load buses that are common to both the base cases. In addition, it should be recognized that the existing UFLS scheme, as shown in Table 6-1, is designed to trip about 530 MW in all frequency step settings but this amount of load shedding will not be adequate for the loss of 800 MW infeed through HVdc bipole. Therefore a new UFLS scheme had to be devised for the purpose of this bipole block study. Accordingly, Table 6-2 below presents a modified UFLS scheme, which is loosely related to the existing UFLS scheme and it also caters to the additional amount of load shed required in the event of bipole block. The intent of this modified UFLS scheme was not to optimize the UFLS scheme at this stage but to provide a starting point for assessing the impact of bipole block on the future NLH system.

Table 6.1
Existing Underfrequency Load Shedding Scheme

Description of Loads	DFDT at 59.5 Hz	59.0 Hz (15 sec)	58.8	58.6	58.4	58.2	58.1	58.0	Total
DOMESTIC									
NP - Total Load Shedding (MW)									482
NP - Glendale 0.6 Hz/sec	29*								29*
NP - Greenhill and King's Bridge		40							40
NP - Massey Drive (Walbournes)			40						40
NP - Molloy's Lane				43					43
NP - Grand Falls and St. John's					50				50
NP - Ridge Rd, Glendale and Molloy's Lane						31 + 29*			31 + 29*
NP - Pepperrell, Pulpit Rock, Stamps Lane and Gander							90		90
NP - Massey Drive (Humber), St. John's Main, Hardwoods, Ridge Rd, Glendale, King's Bridge, Bishop's Falls								159	159
NLH - Total Load Shedding (MW)									31
NLH - St.Albans				6					6
NLH - Burgeo					6				6
NLH - Rocky Harbour						6			6
NLH - Hermitage							13		13
INDUSTRIAL									
Deer Lake Power									
Corner Brook			15						15
Total System Peak Load Shedding (MW)	29*	40	55	49	56	66	103	159	528

Table 6.2
Underfrequency Load Shedding Scheme in Base Scenario

Bus No.	Load Shed (MW)	Frequency (Hz)	Pick-up Time (s)	Load Fraction	Frequency (Hz)	Pick-up Time (s)	Fraction
335	196.44	58.8	0.1	0.2	58	0.1	0.3
334	283.00	58.4	0.1	0.18	58	0.1	0.36
349	31.86	58.2	0.1	1	0	0	0
204	41.70	58.6	0.1	1	0	0	0
603	5.00	58.4	0.1	1	0	0	0
115	89.6	58.1	0.1	1	0	0	0
111	38.2	58.2	0.1	1	0	0	0
224	6.2	59	15	1	0	0	0
225	5.00	59	15	1	0	0	0
359	13.3	59	15	1	0	0	0
371	11.00	59	15	1	0	0	0
221	21.1	58.6	0.1	0.29	58.1	0.1	0.61
223	110.4	58.8	0.1	0.6	0	0	0

6.4 Adequacy Assessment of the Modified UFLS Scheme

Seven test cases were simulated with different settings of the modified UFLS scheme for assessing adequacy of the proposed scheme(s). The objective of this analysis was to investigate effectiveness of each of the proposed UFLS schemes in maintaining stability of the NLH power system after the outage of HVdc bipole. Description of these test cases and the corresponding modifications to the UFLS schemes are noted in Table 6-3 below. The corresponding stability plots are shown in Appendix E.

The simulation results for the first four test cases show that the NLH system does not remain stable for the loss of HVdc bipole due to inadequate and slow response of the selected UFLS schemes. The results of test Case 5 show that the NLH system stays stable after the bipole block since a major portion of load is shed at 10 cycles following the loss of HVdc bipole. Table 6-4 summarizes the amount of load shed at different frequency steps, tripping times and the corresponding frequency values at which load shedding occurred. Due to heavy load shedding, voltage at OPD 66 kV bus rises above the acceptable limit and needs to be controlled by employing appropriate remedial measures; for instance, tripping the capacitors at that bus along with the tripping of load. However, the intent of this exercise was not to perform a voltage control study since the main focus was to assess the timing and the amount of load shedding required to sustain the outage of HVdc bipole.

The test Case 6 represents shedding a large amount of load at 59.2 Hz with normal pick up and tripping times involved in the typical UFLS schemes. The results show that these settings are not

adequate since the system did not sustain the bipole block contingency and the NLH power system collapsed. This is indicative of the need for immediate tripping of a large amount of load even at a higher frequency step. Subsequently, an UFLS relay (DLSHBL model) with rate of change of frequency feature was set for a pick up time of 0.08 seconds at 59.5Hz (df/dt = 1.0 Hz/sec) for tripping 90% of loads at buses 334 and 335, as shown in Case 7 of Table 6-5. The results show that the NLH power system remains stable with the proposed changes to the UFLS scheme. At the same time, voltage at certain buses rise above the acceptable limit after the operation of UFLS scheme. Correspondingly, appropriate voltage control measures need to devised during the detailed design of UFLS scheme with full representation of the NLH power network.

Based on the above mentioned simulation results, it was concluded that the NLH power system can sustain the outage of HVdc bipole and stays stable provided the existing UFLS scheme is modified to trip about 750 MW of load with appropriate UFLS settings. The first underfrequency load shedding step at 59.5 Hz has to be quick, which could be achieved by employing appropriate settings of rate of change of frequency relays and utilizing other special protection systems. It is recommended that the proposed preliminary settings of the UFLS scheme(s) should be further reviewed and optimized with detailed representation of the NLH power network. In addition, a voltage control study should also be carried out along with the detailed design of UFLS scheme to evaluate voltage control measures after the operation of UFLS scheme since large amounts of loads is rejected and voltage tend to rise under light load conditions.

Table 6.3
Description of Different Test Cases for Under-frequency Load Shedding

Case No.	Description of Test Cases	Remarks
01	UFLS scheme as per Table 6-2	System unstable
02	UFLS at Buses 334 and 335 each changed to 50% at 58.8 Hz and 50% at 58.4 Hz	
03	UFLS at Buses 334 and 335 each changed to 50% at 59.2 Hz and 50% at 58.8 Hz	
04	UFLS at Buses 334 and 335 changed to 95% and 90%, respectively, at 59.2 Hz. Pick up time for UFLS at buses 224, 225, 359 and 371 changed to 0.1 sec from 15-sec.	
05	After 10 cycles, loads at buses 334 (283 MW) and 335 (196.4 MW) dropped to 19.64 MW and 19.81 MW, respectively. Pick up time for UFLS at buses 224, 225, 359 and 371 changed to 0.1 sec from 15-sec.	System stable but appropriate voltage control measures need to be implemented at selected buses
06	UFLS at Buses 334 and 335 changed to 95% and 90%, respectively, at 59.2 Hz. Pick up time at Buses 334 and 335 set at 0.08 sec. Pick up time for UFLS at buses 224, 225, 359 and 371 set at 0.1 sec from 15-sec.	System unstable
07	DLSHBL models at Buses 334 and 335 for a DFDT setting at 0.6 Hz/sec. First pick up time 0.08 sec at 59.5 Hz. Dropped 90% load at each bus	System stable but appropriate voltage control measures need to be implemented at selected buses

Table 6.4
Load Shedding Observed in Case-5

Bus No.	Pick-up Time (s)	Frequency (Hz)	Load Shed		Operating Time (s)	Frequency (Hz)
			[%]	[MW]		
335	10-Cycle	-	-	176.59	10-cycle	58.40
334	10-Cycle	-	-	263.36	10-cycle	58.40
335	0.1	58.8	20%[4]	3.96	1.104	58.51
334	0.1	58.4	18%[4]	3.54	1.533	58.29
349	0.1	58.2	100%	31.85	1.971	58.10
204	0.1	58.6	100%	41.70	1.271	58.52
603	0.1	58.4	100%	5.00	1.608	58.26
115	0.1	58.1	100%	89.60	1.975	58.05
111	0.1	58.2	100%	38.20	1.829	58.06
224	0.1	59	100%	6.20	0.800	58.88
225	0.1	59	100%	5.00	0.800	58.88
359	0.1	59	100%	13.30	0.800	58.88
371	0.1	59	100%	11.00	0.800	58.88
221	0.1	58.6	29%	6.12	1.250	58.48
221	0.1	58.1	61%	12.87	2.104	58.09
223	0.1	58.8	60%	66.24	1.096	58.56

Notes:

1. *Block HVDC and shunt capacitors*
2. *After 10 cycles, loads at buses 334 (283 MW) and 335 (196.4 MW) dropped to 19.64 MW and 19.81 MW, respectively*
3. *Total load drop/shed = 774.53 MW*
4. *%age of remaining load (Note 2).*

Table 6-5
Load Shedding Observed in Case-7

Bus No.	Pick-up Time (s)	Frequency (Hz)	Load Shed		Operating Time (s)	Frequency (Hz)
			[%]	[MW]		
335	0.08	59.5	90%	176.80	0.300	58.52
334	0.08	59.5	90%	254.70	0.300	58.53
349	0.1	58.2	100%	31.85	1.767	58.16
204	0.1	58.6	100%	41.70	0.933	58.48
603	0.1	58.4	100%	5.00	1.617	58.24
115	0.1	58.1	100%	89.60	1.892	57.97
111	0.1	58.2	100%	38.20	1.825	57.98
224	0.1	59	100%	6.20	0.838	58.70
225	0.1	59	100%	5.00	0.838	58.70
359	0.1	59	100%	13.30	0.838	58.70
371	0.1	59	100%	11.00	0.838	58.70
221	0.1	58.6	29%	6.12	1.167	58.50
221	0.1	58.1	61%	12.87	1.908	58.06
223	0.1	58.8	60%	66.24	0.904	58.67

Notes:

1. *Block HVDC and shunt capacitors*
2. *DLSHBL models at buses 334 and 335 for DFDT setting at 0.6 Hz/sec. First pick up time 0.08 sec at 59.5 Hz.*
3. *Total under-frequency load shedding = 758.58 MW*

7. Conclusions and Recommendations

WTO DC1210 included a number of various activities – the results of which have been presented in the individual descriptions above. The following conclusions and recommendations are made.

7.1 HVdc Sensitivity Studies

If the intent is to design the HVdc infeed system such that its performance is similar to the existing system performance (i.e. does not survive the worst case fault), the requirements for synchronous condensers on the Island system are reduced.

The use of high inertia synchronous condensers showed significant improvement in system performance over the synchronous condenser models with a lower inertia constant (2.2) used in the original DC1020 studies.

The use of high inertia synchronous condensers would significantly reduce the size or number of synchronous condensers that are required to be installed at Soldiers Pond. In order to meet criteria, a single 300 MVAR high inertia synchronous condenser is sufficient, along with a 300 MVAR SVC at Sunnyside or a new 230 kV circuit between Bay d'Espoir and Western Avalon. The results are highly dependent on the type of synchronous condenser that is modeled. However, because loss of the Soldiers Pond synchronous condenser becomes the worst case contingency if only a single 300 MVAR unit is installed, it is recommended to have 2x150 MVAR high inertia synchronous condensers in service at all times, which would translate to 3x150 MVAR installed to account for maintenance outages.

Therefore from a technical system performance point of view, the best solution would be to have 2x150 MVAR high inertia synchronous condensers in service at Soldiers Pond at all times, hence installing 3x150 MVAR in order to account for maintenance outages. In addition to these 150 MVAR synchronous condensers, one of the following mitigation options is also required:

- 200 MVAR SVC at Sunnyside and 50% series compensation on the two Bay d'Espoir-Sunnyside lines; or
- 230 kV line Bay d'Espoir – Western Avalon, no series compensation on this new line or on the existing two Bay d'Espoir-Sunnyside lines.

Both of these solutions provide sufficient steady state VAR support to maintain system steady state voltages during the 800 MW monopolar 10-minute 2.0 pu overload condition.

A preliminary evaluation was performed to assess the impact of relocating a portion of the inertia from Soldiers Pond to Bay d'Espoir by changing out the rotor on Bay d'Espoir Unit 7 and by installing a high inertia 150 MVAR synchronous condenser as Bay d'Espoir Unit 8. Despite the fact that the total system inertia is very similar between the two cases, the results indicate poorer performance of the Island system when the synchronous condensers are moved away from Soldiers Pond due to poorer performance of the HVdc infeed.

7.2 PSSE Model Modification

The PSSE stability model of the three-terminal HVdc link for the Lower Churchill Project was modified to represent a shorter dc cable section and longer dc overhead line section between the tap at Taylor's Brook and the terminal at Salisbury. Specifically, the cable section between Newfoundland and Lingan, Nova Scotia was estimated at 180 km, and the new overhead line section from Lingan, Nova Scotia to Salisbury, New Brunswick was estimated at 475 km. The overhead line sections in Newfoundland from Taylor's Brook to the Gulf of St. Lawrence crossing to Nova Scotia remain unchanged.

In order to allow validation testing, the PSCAD model originally developed as part of WTO DC1020 was first updated and the dc controls were re-tuned. These changes were implemented inside the PSSE model. Validation testing was performed by comparing the results of the PSCAD and PSSE models for a solid and remote three-phase fault at each of the dc terminals for the 3-terminal case, and for solid faults only for the 2-terminal cases.

Validation testing results show that the PSSE model compares well with the PSCAD model results.

7.3 VSC Risk Assessment

A high level evaluation of the use of VSC converters for the LCP HVdc system was undertaken. Key findings of the review included:

- The rating at Gull Island can be better realized using a conventional LCC technology.
- The rating at Soldiers Pond can be achieved using a VSC technology.
- The rating at Salisbury can be achieved using a VSC technology.
- The HVdc cable will most likely have to be a mass impregnated cable even with VSC technology.

Preliminary simulations were performed using PSSE and a vendor supplied VSC model to investigate the impact of a VSC HVdc terminal on the Island system. Results of preliminary transient stability simulations showed an overall improvement in system performance for all ac and dc faults that were studied with fewer synchronous condensers than required for the LCC technology.

Based on the above it was recommended that a more complete study to evaluate the use of VSC technology for the Soldiers Pond terminal be undertaken.

7.4 AC/DC Line Proximity Issues

A qualitative review of potential impacts resulting from locating ac and dc lines in close proximity was undertaken. Based on the available literature and current industry experience it was concluded that:

- The use of a hybrid line with the HVdc and ac conductors on a common tower may not be suitable for the proposed line route, mainly due to the potential for a high level of interaction

between the lines and the potential for HVdc to ac conductor faults. In situations where the use of common towers would be for very short distances, the risk of an HVdc to ac conductor fault may be acceptable; however in the case of the proposed line route, the distance is great enough that the risk of such a fault may be a determining factor.

- The use of HVdc and ac lines in close proximity on separate towers may be suitable if an acceptable separation can be maintained. The suitability of this option would require detailed studies in order to determine candidate line configurations and any required mitigation measures to ensure acceptable performance of the integrated HVdc and ac systems. Current industry experience can be used as a starting point for determining a potential minimum separation distance between the HVdc and ac lines. Once this is identified the suitability of the existing right-of-way can be better assessed.
- The use of a direct buried ac cable with the HVdc on towers on the same right-of-way may be suitable however studies would be required to determine the potential effects of HVdc ground faults on the buried ac cable.

7.5 Bipole Block Impacts

Bipole block impact assessment study was carried out using reduced system PSS/E load flow base case with assumptions mutually agreed with Nalcor planning staff. Based on the simulation results, it was concluded that:

- The NLH power system sustains the outage of HVdc bipole and the remaining islanded system stays stable provided the existing UFLS scheme is modified to trip about 750 MW of load with appropriate UFLS settings since the existing UFLS scheme with a provision to trip 530 MW load will not be adequate. Most of the load shedding occurs in the St. John's area where load is lumped in the reduced system load flow model.
- A large amount of load needs to be shed quickly at the first UFLS step at 59.5 Hz, which could be achieved in multiple ways. For instance, employing rate of change of frequency underfrequency relay with pick up time of 0.08 seconds and set at 1.0 Hz/sec. In addition, Special Protection System may also be utilized for immediate tripping of load after the outage of HVdc bipole
- The proposed preliminary settings of the UFLS scheme(s), which are based on the reduced system model analysis, should be further reviewed and optimized with full representation of the NLH power network
- Voltage control study should be performed in conjunction with the detailed design of the UFLS scheme to devise appropriate voltage control measures for avoiding voltage violations after the operation of UFLS scheme.

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Appendix A

DC1210 HVdc Sensitivity Analysis Preliminary Final Report

Engineering Support Services for
the Lower Churchill Project
Newfoundland and Labrador Hydro

DC1210 – HVdc System Sensitivity Analysis
Preliminary Final

December 16, 2008

HATCH™

TGS TransGrid Solutions

Newfoundland and Labrador Hydro
Lower Churchill Project
DC1210 - HVdc System Sensitivity Analysis

Preliminary Final

Prepared by: Rebecca Brandt, P.Eng. — December 15, 2008 (Date)

Approvals

Hatch

Approved by: Robert Gill, P.Eng. — December 15, 2008 (Date)

Newfoundland and Labrador Hydro [Client Name, if required]

Approved by: _____ — _____ (Date)

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Executive Summary

Further analysis was performed for the Lower Churchill Project (LCP) to determine the system requirements for the HVdc infeed such that the system performance would be similar to the existing isolated system performance.

The analysis was performed under the assumption that the three-phase fault at Bay d'Espoir (BDE) on one of the Bay d'Espoir lines (TL202 or TL206) would not be used to determine the synchronous condenser requirements. The analysis was also performed on the assumption that the new refinery load at Pipers Hole would not be connected to the system.

If the intent is to design the HVdc infeed system such that its performance is similar to the existing system performance (i.e. does not survive the worst case fault), the requirements for synchronous condensers on the Island system are reduced. It must be noted that failure of the HVdc infeed system for the worst case fault is expected to result in system wide collapse as opposed to loss of approximately 500 MW in the existing isolated Island system. The main issue in the Island system with the HVdc infeed is lack of inertia and the resulting frequency decay due to faults which cause the HVdc infeed to fail commutation; the nearer the fault location to Bay d'Espoir Generating Station, the more power temporarily lost and the more severe the system frequency decay.

A new synchronous condenser model with a very high inertia constant (7.84) was tested. The high inertia machine showed significant improvement in system performance over the synchronous condenser models with a lower inertia constant (2.2) used in the original DC1020 studies.

It was found that without the synchronous condensers at Pipers Hole, either a Static Var Compensator (SVC) at Sunnyside (SSD), or a new 230 kV circuit between Bay d'Espoir and Western Avalon (WAV) will provide acceptable system performance for all contingencies except the three-phase fault at Bay d'Espoir. The results are highly dependent on the type of synchronous condenser that is modeled. Table E.1 below summarizes the possible mitigating solutions for the Island system dynamic performance.

Table E.1
Possible Solutions to Eliminate Synchronous Condensers at Pipers Hole

Synch. Cond. Type	SP Synch. Cond. In-service	Sunnyside SVC	BDE-WAV 230 kV line	50% compensation on BDE-SSD lines?
MIL- 2.2 inertia	2x300 MVAR	400 MVAR + 100 MVAR caps	-	Yes
MIL – 2.2 inertia	2x300 MVAR	-	Yes, with 50% compensation	Yes
[redacted] – 7.84 inertia	1x300 MVAR	300 MVAR	-	Yes
[redacted] – 7.84 inertia	2x150 MVAR	200 MVAR	-	Yes
[redacted] – 7.84 inertia	2x150 MVAR	-	Yes	No

The high inertia [redacted] synchronous condensers would significantly reduce the size or number of synchronous condensers that are required to be installed at Soldiers Pond. In order to meet criteria for a fault at Sunnyside on one of the Bay d'Espoir-Sunnyside lines, a single 300 MVAR high inertia synchronous

condenser is sufficient, along with a 300 not 200 MVAR SVC at Sunnyside (Table E.1 row 3) or a new 230 kV circuit between Bay d'Espoir and Western Avalon. However, because loss of the 1x300 MVAR Soldiers Pond synchronous condenser becomes the worst case contingency if only a single 300 MVAR unit is installed, it is recommended to have 2x150 MVAR high inertia synchronous condensers in-service at all times, which would translate to 3x150 MVAR installed to account for maintenance outages. The added benefit to a synchronous condenser rating of 150 MVAR is that it would match the Holyrood synchronous condenser ratings and their spare transformer.

Therefore from a technical system performance point of view, the best solution would be to have 2x150 MVAR high inertia synchronous condensers in-service at Soldiers Pond at all times, therefore installing 3x150 MVAR in order to account for maintenance outages. In addition to these 150 MVAR synchronous condensers, one of the following mitigation options is also required:

1. 200 MVAR SVC at Sunnyside and 50% series compensation on the two Bay d'Espoir-Sunnyside lines, or

2. 230 kV Bay d'Espoir – Western Avalon line, no series compensation on this new line or on the existing two Bay d'Espoir-Sunnyside lines.

Both of these solutions provide sufficient steady state VAR support to maintain system steady state voltages during the 800 MW monopolar 10-minute 2.0 pu overload condition. During the 2.0 pu overload condition, approximately 200 MVAR is drawn in steady state from the Soldiers Pond synchronous condensers to maintain the 1.0284 pu Soldiers Pond voltage setpoint that was used in the studies.

Because such good performance was obtained with the high inertia synchronous condensers, the three-phase Bay d'Espoir fault was re-visited. It was found that in order to design the system to survive a three-phase fault at Bay d'Espoir, the only option that recovered within criteria was a case with the new 230 kV circuit between Bay d'Espoir and Western Avalon. If this new circuit plus the two circuits between Bay d'Espoir and Sunnyside are 50% series compensated, AND if 2x300 MVAR of the high inertia synchronous condensers are in-service at Soldiers Pond (which means 3x300 MVAR installed to account for maintenance outages), the system is able to recover from a three-phase fault at Bay d'Espoir.

A preliminary evaluation was performed to look at the impact of relocating a portion of the inertia from Soldiers Pond to Bay d'Espoir by changing out the rotor on Bay d'Espoir Unit 7 and by installing a high inertia 150 MVAR synchronous condenser as Bay d'Espoir Unit 8. The analysis was performed with only 1x150 MVAR high inertia synchronous condenser operating at Soldiers Pond instead of 2x150 MVAR. Despite the fact that the total system inertia is very similar between the two cases, the results indicate poorer performance of the Island system when the synchronous condenser is moved away from Soldiers Pond due to poorer performance of the HVdc infeed. This system configuration would require the addition of the 230 kV circuit between Bay d'Espoir and Western Avalon with 50% series compensation as well as 50% series compensation on the two Bay d'Espoir – Sunnyside 230 kV lines. If even the series compensation from the new Bay d'Espoir – Western Avalon line is removed the system becomes unstable for a fault at Sunnyside on one of the Bay d'Espoir lines (TL202 or TL206), and in addition the HVdc infeed is on the verge of a second commutation failure for a three phase fault on the Soldiers Pond synchronous condenser.

1. Introduction

The original DC1020 transient stability analysis found the need for a large number of synchronous condensers to be installed on the system in order to account for the worst case fault, which is a solid three-phase fault at Bay d'Espoir on one of the Bay d'Espoir-Pipers Hole 230 kV lines (TL202 and/or TL206). Specifically it was found that 2x300 MVAR synchronous condensers are required to be in-service at all times at both the Pipers Hole and Soldiers Pond buses in order to save the system from collapse due to fast frequency decay. This translates to 3x300 MVAR synchronous condensers installed at each station in order to account for maintenance outages. In addition, it was found that 50% series compensation was required on both of the 230 kV lines between Bay d'Espoir and Pipers Hole. The Pipers Hole bus was included in the system to connect a potential new refinery load (175 MW) to the Island system.

The worst case three-phase fault on the existing isolated Island system is a three-phase fault on the 230 kV bus at Holyrood. At best, assuming the boilers at Holyrood Thermal Generating Station survive the upset caused by the fault, the system would see approximately 250 MW of load shed as a result of the fault. At worst, complete loss of Holyrood plant due to the fault would result in up to 500 MW of load shed, in essence, the entire Avalon Peninsula. Dual primary protection on the 230 kV system ensures all faults are cleared in 6 cycles maximum. As a result, faults at the 230 kV level are cleared as quickly as possible given the existing equipment to ensure angular stability is maintained. It is understood that given the fault location on the 230 kV system there may be some loss of local load due to voltage sag and post fault recovery voltages. Beyond the issues associated with the loss of Holyrood, loss of paper machines due to voltage dip and loss of refiner motors due to angular instability can be expected. By comparison, the system additions proposed by DC1020 ensured that the Island system with the HVdc converter station at Soldiers Pond remained stable for all 230 kV bus faults without loss of load. To compare the system performance of the two alternatives (HVdc interconnection versus isolated) on a common basis, system additions in the HVdc case are to be identified in the HVdc case assuming that the system does not recover from the worst case fault (i.e. Bay d'Espoir 230 kV three-phase fault).

Between completion of DC1020 and this report, the certainty of the new 175 MW oil refinery has become questionable. As a result, planning associated with the integration of an HVdc interconnection for the Island system has removed the new oil refinery from the base case.

The analysis in this report is based on the assumption that the new refinery load will not be going ahead, and therefore the Pipers Hole bus would not exist. It is also based on the assumption that the three-phase Bay d'Espoir fault will not be considered when determining the synchronous condenser requirements and system upgrades. This fault is not considered in this sensitivity analysis as the intent is to determine the system additions for the HVdc integration with system performance comparable to that of the existing system.

2. Terms of Reference

The scope of this study is to determine the required system additions to ensure acceptable system performance for all contingencies except the three-phase fault at Bay d'Espoir 230 kV bus. The following points are assessed:

- The impact of splitting the 230 kV Bay d'Espoir bus such that one 230 kV circuit to Stony Brook and Sunnyside and approximately one half the Bay d'Espoir generation is connected to each 230 kV bus with the tie line between each station out-of-service.
- The impact of blocking recovery of the HVdc during the three-phase Bay d'Espoir fault with isolation of the Avalon Peninsula load centre.
- Application of SVC technology at Sunnyside (in lieu of synchronous condensers at Pipers Hole).
- Installation of a third 230 kV circuit between Bay d'Espoir and Western Avalon.
- Application of two different synchronous condenser designs; one, using the original synchronous condensers as per Manitoba Hydro's Dorsey station (inertia constant 2.2); and two, using a new high inertia synchronous condensers based on a vertical-shaft hydro generator design (inertia constant 7.84).

The study was to assess system performance assuming:

- The three-phase fault at Bay d'Espoir was not considered.
- The new refinery load and Pipers Hole station did not exist.
- No synchronous condensers would be installed at Pipers Hole as the station will not exist.

3. Power Flow Cases and Procedure

Several of the worst faults were simulated for the scenario in which the refinery load and the Pipers Hole synchronous condensers as well as the Holyrood CTs were all removed from service. The transient stability analysis was performed on the future peak load flow case (approximately 1625 MW Island load without the refinery). The following power flow variations were tested:

- 800 MW bipolar infeed at Soldiers Pond, economic dispatch at Bay d'Espoir
- 800 MW bipolar infeed at Soldiers Pond, maximum generation dispatch at Bay d'Espoir
- 600 MW monopolar infeed at Soldiers Pond, maximum generation dispatch at Bay d'Espoir

Two main system topologies were tested to determine the Soldiers Pond synchronous condenser requirements:

- Additional VAR support at Sunnyside in the form of an SVC
- A third 230 kV circuit between Bay d'Espoir and Western Avalon

The number of synchronous condensers and other system upgrades as determined from the findings of the transient stability analysis were verified for the 800 MW monopolar future peak power flow case to ensure that the steady state system VAR requirements and steady state voltages are still within criteria for the 10-minute 2 per-unit HVdc overload case.

The above analysis was performed for two types of synchronous condensers:

- 300 MVAR, inertia constant of 2.2 (Manitoba Hydro, MIL type)
- 300 MVAR, inertia constant of 7.84 (vertical shaft hydro generator type)

4. Synchronous Condenser Types

The original transient stability analysis was performed using the machine models for the 300 MVAR MIL synchronous condensers at Manitoba Hydro's Dorsey station. These machines have an inertia constant of 2.2

NLH discovered that [redacted] makes a very high inertia synchronous condenser based on vertical shaft hydro generator design. These machines have an inertia constant of 7.84 which is more than three times that of the Manitoba Hydro machines.

Table 4.1 lists the stability data for the two types of synchronous condensers.

Table 4.1
Synchronous Condenser Data

Machine Data	Manitoba Hydro – MIL	[redacted]
MVAR	+300/-165 MVAR	+300/-165 MVAR
H	2.2	7.84
Xd	1.45 pu	1.24 pu
Xq	0.854 pu	0.85 pu
Xd'	0.29 pu	0.27 pu
Xq'	n/a	n/a
Xd''	0.17 pu	0.165 pu
Xq''	0.17 pu	0.177 pu
Xl	0.083 pu	0.09 pu
S(1.0)	0.123	0.04
S(1.2)	0.205	0.14
T'do	4.9 sec	11 sec
T''do	0.093 sec	0.08 sec
T''qo	0.272 sec	0.29 sec

Since inertia is the major system issue driving the need for the large synchronous condenser requirement, sensitivity analysis was performed to use these very high inertia machines to see how much the system performance would improve.

5. Results

It was found that the system performance of the 800 MW bipolar case was worse than the 600 MW monopolar case, and the maximum Bay d'Espoir dispatch scenario was worse than the economic Bay d'Espoir dispatch scenario. This makes sense as the issue is one of lost power, so the more power that is lost during the fault, i.e. from Bay d'Espoir generating station and from the HVdc infeed, the worse the impact to system frequency. The results presented in this report correspond to these worst case conditions, i.e. 800 MW bipolar infeed, maximum Bay d'Espoir dispatch.

Ignoring the three-phase fault at Bay d'Espoir, the next worst case fault is a three-phase fault at Sunnyside on one of the Sunnyside-Bay d'Espoir lines. Also, depending on the number of synchronous condensers in service at Soldiers Pond, a three-phase fault at Soldiers Pond followed by tripping of a Soldiers Pond synchronous condenser can be a determining case if only one synchronous condenser is in-service prior to the fault.

A significant improvement in system performance was obtained with the high inertia synchronous condensers. The results indicate that the main issue with system performance is one of inertia. To demonstrate this point, the inertia value of the synchronous condensers was changed in the dynamics model from 7.84 to 2.0. The results with the lower inertia value indicate poorer system performance than the high inertia case and were similar to results provided by the Manitoba Hydro synchronous condensers. Therefore, it can be concluded that it is in fact the large inertia of the machines that is improving system performance.

5.1 Sunnyside SVC

Without the installation of synchronous condensers at Pipers Hole, the Sunnyside bus requires dynamic voltage support in the form of an SVC. The rating of this SVC depends on the system configuration and the type of Soldiers Pond synchronous condenser being studied.

Using the original 2.2 inertia machines at Soldiers Pond, it was found that 2x300 MVAR are required to be in-service at all times. In addition to this, a 400 MVAR SVC plus a 100 MVAR capacitor is required to meet the 0.7 pu transient undervoltage criteria at Sunnyside for a fault at Sunnyside on one of the Sunnyside-Bay d'Espoir lines for the maximum Bay d'Espoir dispatch case. Table 5.1 summarizes these results.

Table 5.1
2x300 MVAR 2.2 inertia synchronous condenser, 400 MVAR SVC + 100 MVAR cap at Sunnyside

Fault Location	Line tripped	Minimum post fault voltage (pu)				Min post fault Gamma (Deg)	Status
		BDE	SSD	WAV	SP		
SS	SS-BDE	0.73	0.70	0.73	0.87	14	Stable
SP	SP-WAV	>0.9	>0.9	>0.9	>0.9	23	Stable
SP	SP SCo	>0.9	>0.9	>0.9	>0.9	22	Stable

Using the high inertia [redacted] machines at Soldiers Pond, it was found that only 1x300 MVAR machine was needed, along with a 200 MVAR SVC at Sunnyside. However if there is only one synchronous condenser at Soldiers Pond, a fault at Soldiers Pond that would trip this machine becomes the limiting case. Either a larger SVC is required at Sunnyside (300 MVAR), or 2x150 MVAR synchronous condensers need to be in service in order to leave at least 1x150 MVAR connected if the fault trips a synchronous condenser. These results are summarized below in Table 5.2, red text indicating where criteria is not met.

Table 5.2
1x300 MVAR High inertia synchronous condenser, 200 MVAR SVC at Sunnyside

Fault Location	Line tripped	Minimum post fault voltage (pu)				Min post fault Gamma (Deg)	Status
		BDE	SSD	WAV	SP		
SS	SS-BDE	0.801	0.694	0.726	0.816	10.4	Stable
SP	SP-WAV	0.914	0.886	0.865	0.881	19.6	Stable
SP	SP SCo	0.8	0.65	0.62	0.70	2nd comm. fail	Stable
SP	SP SCo*	0.75	0.70	0.73	0.87	17.0	Stable

**Trip one 150 MVAR synchronous condenser leaving one 150 MVAR synchronous condenser in service.*

The Bay d'Espoir fault is still unstable for both synchronous condenser/SVC solutions.

The 800 MW monopolar 10-minute 2.0 pu overload case was verified to ensure sufficient steady state VAR support to maintain system steady state voltages.

5.2 New 230 kV Circuit: Bay d'Espoir-Western Avalon

Without the installation of synchronous condensers at Pipers Hole, and without the addition of an SVC at Sunnyside, a new 230 kV circuit between Bay d'Espoir and Western Avalon was tested. The system response and the need for series compensation on this line and on the two existing 230 kV lines between Bay d'Espoir and Sunnyside depended on the system configuration and the type of Soldiers Pond synchronous condensers being studied.

Using 2x300 MVAR of the original 2.2 inertia machines at Soldiers Pond, without series compensation on the new line, the Sunnyside transient undervoltage dips to 0.66 pu following a fault at Sunnyside on one of the Sunnyside-Bay d'Espoir lines. If the new 230 kV line is built with 50% series compensation, this Sunnyside voltage dip improves to 0.73 pu. These results are summarized in Table 5.3.

Table 5.3
2x300 MVAR MIL synchronous condensers, series compensation on the new Bay d'Espoir-Western Avalon 230 kV line

Fault Location	Line tripped	Minimum post fault voltage (pu)				Min post fault Gamma (Deg)	Status
		BDE	SSD	WAV	SP		
SS	SS-BDE	0.80	0.72	0.76	0.88	20	Stable
SP	SP-WAV	>0.9	>0.9	>0.9	>0.9	22	Stable
SP	SP SCo	>0.9	>0.9	>0.9	>0.9	22	Stable

Using the high inertia [redacted] machines, with only 1x300 MVAR in service at Soldiers Pond, the system is stable and meets criteria even without any series compensation on the Bay d'Espoir-Sunnyside lines or on the new Bay d'Espoir-Western Avalon line, although the Sunnyside voltage is just starting to dip below 0.7 pu as shown in Table 5.4. If the 50% series compensation is installed on the two existing Bay d'Espoir-Sunnyside lines there is an improvement in the system response as shown in Table 5.5. However in this case because there is only one synchronous condenser at Soldiers Pond, a fault at Soldiers Pond that would trip this machine becomes the limiting case. Instead, 2x150 MVAR synchronous condensers need to be in service in order to leave at least 1x150 MVAR on-line if a fault trips the other synchronous condenser. Red text in Tables 5.4 and 5.5 indicate that criteria is not met.

Table 5.4
No series compensation on any lines. 1x300 MVAR [redacted] synchronous condenser

Fault Location	Line tripped	Minimum post fault voltage (pu)				Min post fault Gamma (Deg)	Status
		BDE	SSD	WAV	SP		
SS	SS-BDE	0.798	0.697	0.724	0.817	15	Stable
SP	SP-WAV	0.871	0.824	0.822	0.862	19.5	Stable
SP	SP SCo	-	-	-	-	-	Unstable
SP	SP SCo*	0.91	0.82	0.82	0.83	21	Stable

**Trip one 150 MVAR synchronous condenser leaving one 150 MVAR synchronous condenser in service.*

Table 5.5
No series compensation on new BDE-WAV line, 50% series compensation on BDE-SSD lines. 1x300 MVAR [redacted] synchronous condenser

Fault Location	Line tripped	Minimum post fault voltage (pu)				Min post fault Gamma (Deg)	Status
		BDE	SS	WAV	SP		
SS	SS-BDE	0.811	0.72	0.745	0.826	16.8	Stable
SP	SP-WAV	0.867	0.829	0.829	0.861	19.7	Stable
SP	SP Sco	0.80	0.70	0.70	0.78	2nd comm. fail	Stable
SP	SP SCo*	0.94	0.85	0.85	0.85	23	Stable

**Trip one 150 MVAR synchronous condenser leaving one 150 MVAR synchronous condenser in service.*

The Bay d'Espoir fault is still unstable for both synchronous condenser options. However, because such good performance was obtained with the high inertia synchronous condensers, the three-phase

Bay d'Espoir fault was re-visited using the high inertia synchronous condensers. It was found that in order to design the system to survive a three-phase fault at Bay d'Espoir, the only option that recovered within criteria was a case with the new 230 kV circuit between Bay d'Espoir and Western Avalon. If this new circuit plus the two circuits between Bay d'Espoir and Sunnyside are 50% series compensated, AND if 2x300 MVAR high inertia synchronous condensers are in service at Soldiers Pond (which means 3x300 MVAR would be installed to account for maintenance outages), the system is able to recover from a three-phase fault at Bay d'Espoir. The results are summarized in Table 5.6 below.

Table 5.6
50% series compensation on BDE-SSD lines and on new BDE-WAV line. 2x300 MVAR synchronous condensers

Fault Location	Line tripped	Minimum post fault voltage (pu)				Min post fault Gamma (Deg)	Status
		BDE	SSD	WAV	SP		
BDE	BDE-SSD	0.76	0.70	0.75	0.87	17	Stable

The 800 MW monopolar 10-minute 2.0 pu overload case was verified to ensure sufficient steady state VAR support to maintain system steady state voltages with 1x300 MVAR synchronous condenser at Soldiers Pond.

5.3 Bay d'Espoir Three-Phase Fault

In an attempt to lessen the impact of a three-phase fault at Bay d'Espoir on overall system performance, the 230 kV Bay d'Espoir bus was split such that one 230 kV circuit to Stony Brook and Sunnyside and approximately one half the Bay d'Espoir generation is connected to each 230 kV bus with the tie line between each station out-of-service. A three-phase fault on one of the Bay d'Espoir-Sunnyside lines was applied. The system response was not substantially improved. The Sunnyside transient voltage improved slightly but the Bay d'Espoir voltage degraded slightly and no reduction in equipment requirements was observed.

Next, a special protection system was tested which blocked the recovery of the HVdc and isolated the Avalon Peninsula load centre. Based upon the analysis it appears that remaining generation on the Western portion of the Island cannot control the island frequency; at 5 seconds into the simulation the frequency of the islanded system is up to near 65 Hz. Without some careful generation crosstripping and/or staged overfrequency protection it does not look like this island will settle to a frequency that is within criteria.

However as noted earlier in section 5.2, if the new 230 kV circuit between Bay d'Espoir and Western Avalon is built and if this new circuit plus the two circuits between Bay d'Espoir and Sunnyside are 50% series compensated, AND if 2x300 MVAR high inertia synchronous condensers are in service at Soldiers Pond (which means 3x300 MVAR installed to account for maintenance outages), the system is able to recover from a three-phase fault at Bay d'Espoir within criteria.

5.4 Impact of Inertia Relocation

Having determined that the requirement for additional system inertia could be met by operating of 2 x 150 MVAR high inertia synchronous condensers at Soldiers Pond at all times, a preliminary evaluation of relocating a portion of the required inertia addition was completed. Unit 7 at Bay d'Espoir is a 172 MVA machine with a relatively low inertia due to the rotor's floating rim design. Change out of the Unit 7 rotor would result in an increase in unit inertia. Further, basic provisions were completed for the addition of a Unit 8 at Bay d'Espoir during the construction of Unit 7. As a result, the Bay d'Espoir site offers a potential location for the required system inertia increase. To investigate the impact of relocating inertia away from Soldiers Pond it was assumed that the Bay d'Espoir Unit 7 rotor was changed out resulting in an increase in the unit's inertia from 3.883 to 7.766 (doubled), and that a high inertia generator was installed as Bay d'Espoir Unit 8 operating at 150 MW. Given that there is no additional water available at Bay d'Espoir Generating Station for increased energy production, Units 1 and 2 were shutdown. In addition, Unit 2 was also tested as a synchronous condenser. The analysis assumed that only 1 x 150 MVAR high inertia synchronous condenser was operating at all times at Soldiers Pond.

Results of the analysis indicate somewhat worse performance with a portion of the inertia moved away from Soldiers Pond. This is likely due to the fact that the performance of the HVdc is not as good with fewer synchronous condensers nearby. It was found that in order for this system configuration to be stable for all faults, 50% series compensation is required on the two existing 230 kV Bay d'Espoir-Sunnyside lines (TL202 and TL206) as well as on the new 230 kV Bay d'Espoir-Western Avalon line. If the series compensation is removed from the Bay d'Espoir-Western Avalon line the system becomes unstable for a fault at Sunnyside on one of the Bay d'Espoir-Sunnyside lines (TL202 or TL206) and is very near a second commutation failure for a three-phase fault at Soldiers Pond on the 150 MVAR synchronous condenser. The results are summarized in Tables 5.7 and 5.8.

The original Bay d'Espoir system configuration with 2 x 150 MVAR high inertia synchronous condensers operating at Soldiers Pond did not require series compensation on any of these three lines.

Table 5.7
50% series compensation on BDE-SSD lines and on new BDE-WAV line. Inertia relocation to BDE. 1x150 MVAR synchronous condensers at Soldiers Pond

Fault Location	Line tripped	Minimum post fault voltage (pu)				Min post fault Gamma (Deg)	Status
		BDE	SSD	WAV	SP		
SS	SS-BDE	0.80	0.72	0.73	0.79	9	Stable
SP	SP-WAV	0.93	0.86	0.85	085	23	Stable
SP	SP SCo	0.91	0.82	0.79	0.79	10	Stable

Table 5.8
No series compensation on new BDE-WAV line, 50% series compensation on BDE-SSD lines. Inertia relocation to BDE. 1x150 MVAR synchronous condensers at Soldiers Pond

Fault Location	Line tripped	Minimum post fault voltage (pu)				Min post fault Gamma (Deg)	Status
		BDE	SSD	WAV	SP		
SS	SS-BDE	-	-	-	-	-	Unstable
SP	SP-WAV	0.93	0.86	0.85	0.85	23	Stable
SP	SP SCo	0.90	0.80	0.78	0.78	7.5*	Stable

**On the verge of a second commutation failure.*

The 800 MW monopolar 10-minute 2.0 pu overload case was verified to ensure sufficient VAR support to maintain the steady state system voltages with only 1x150 MVAR synchronous condenser operating at Soldiers Pond. The Soldiers Pond synchronous condenser is producing maximum reactive power of 150 MVAR during the 10 minute 2.0 pu overload condition. It is unable to hold the voltage setpoint of 1.0284 pu as was used in all of the studies, however the voltage at Soldiers Pond is still maintained at 1.018 pu, with voltages at Sunnyside dropping to 1.005 pu and Bay d'Espoir to 1.0264 pu. All system voltages are within criteria, however, despite being slightly lower than in the normal system intact 800 MW bipolar case.

6. Conclusions

If the intent is to design the HVdc infeed system such that its performance is similar to the existing system performance (i.e. does not survive the worst case fault), the requirements for synchronous condensers on the Island system are reduced. It must be noted that failure of the HVdc infeed system for the worst case fault is expected to result in system wide collapse as opposed to loss of approximately 500 MW in the existing system. The main issue in the Island system with the HVdc infeed is lack of inertia and resulting frequency decay due to faults which cause the HVdc infeed to fail commutation; the nearer the fault location to Bay d'Espoir generating station, the more power temporarily lost and the more severe the system frequency decay.

A new synchronous condenser model with a very high inertia constant (7.84) was tested. The high inertia machine showed significant improvement in system performance over the synchronous condenser models with a lower inertia constant (2.2) used in the original DC1020 studies.

It was found that without synchronous condensers at Pipers Hole, either an SVC at Sunnyside, or a new 230 kV circuit between Bay d'Espoir and Western Avalon will provide acceptable system performance for all contingencies except the three-phase fault at Bay d'Espoir. The results are highly dependent on the type of synchronous condenser that is modeled. Table 6.1 below summarizes the possible mitigating solutions for the Island system dynamic performance, ignoring the Bay d'Espoir three-phase fault.

Table 6.1
Possible Solutions to Eliminate Synchronous Condensers at Pipers Hole

Synch. Cond. Type	SP Synch. Cond. In-service	Sunnyside SVC	BDE-WAV 230 kV line	50% compensation on BDE-SSD lines?
MIL- 2.2 inertia	2x300 MVAR	400 MVAR + 100 MVAR caps	-	Yes
MIL – 2.2 inertia	2x300 MVAR	-	Yes, with 50% compensation	Yes
[redacted] – 7.84 inertia	1x300 MVAR	300 MVAR	-	Yes
[redacted] – 7.84 inertia	2x150 MVAR	200 MVAR	-	Yes
[redacted] – 7.84 inertia	2x150 MVAR	-	Yes	No

The high inertia [redacted] synchronous condensers would significantly reduce the size or number of synchronous condenser that are required to be installed at Soldiers Pond. In order to meet criteria for a fault at Sunnyside on one of the Bay d'Espoir-Sunnyside lines, a single 300 MVAR high inertia synchronous condenser is sufficient, along with a 300 (not 200 MVAR as indicated in Table 6.1 row three) MVAR SVC at Sunnyside or a new 230 kV circuit between Bay d'Espoir and Western Avalon. However, because loss of the Soldiers Pond synchronous condenser becomes the worst case contingency if only a single 300 MVAR unit is installed, it is recommended to have 2x150 MVAR high inertia synchronous condensers in-service at all times, which would translate to 3x150 MVAR installed to account for maintenance outages. The added benefit to a synchronous condenser rating of 150 MVAR is that it would match the Holyrood synchronous condenser ratings and their spare transformer.

Therefore from a technical system performance point of view, the best solution would be to have 2x150 MVAR high inertia synchronous condensers in-service at Soldiers Pond at all times, therefore installing 3x150 MVAR in order to account for maintenance outages. In addition to these 150 MVAR synchronous condensers, one of the following mitigation options is also required:

1. 200 MVAR SVC at Sunnyside and 50% series compensation on the two Bay d'Espoir-Sunnyside lines, or
2. 230 kV line Bay d'Espoir – Western Avalon, no series compensation on this new line or on the existing two Bay d'Espoir-Sunnyside lines

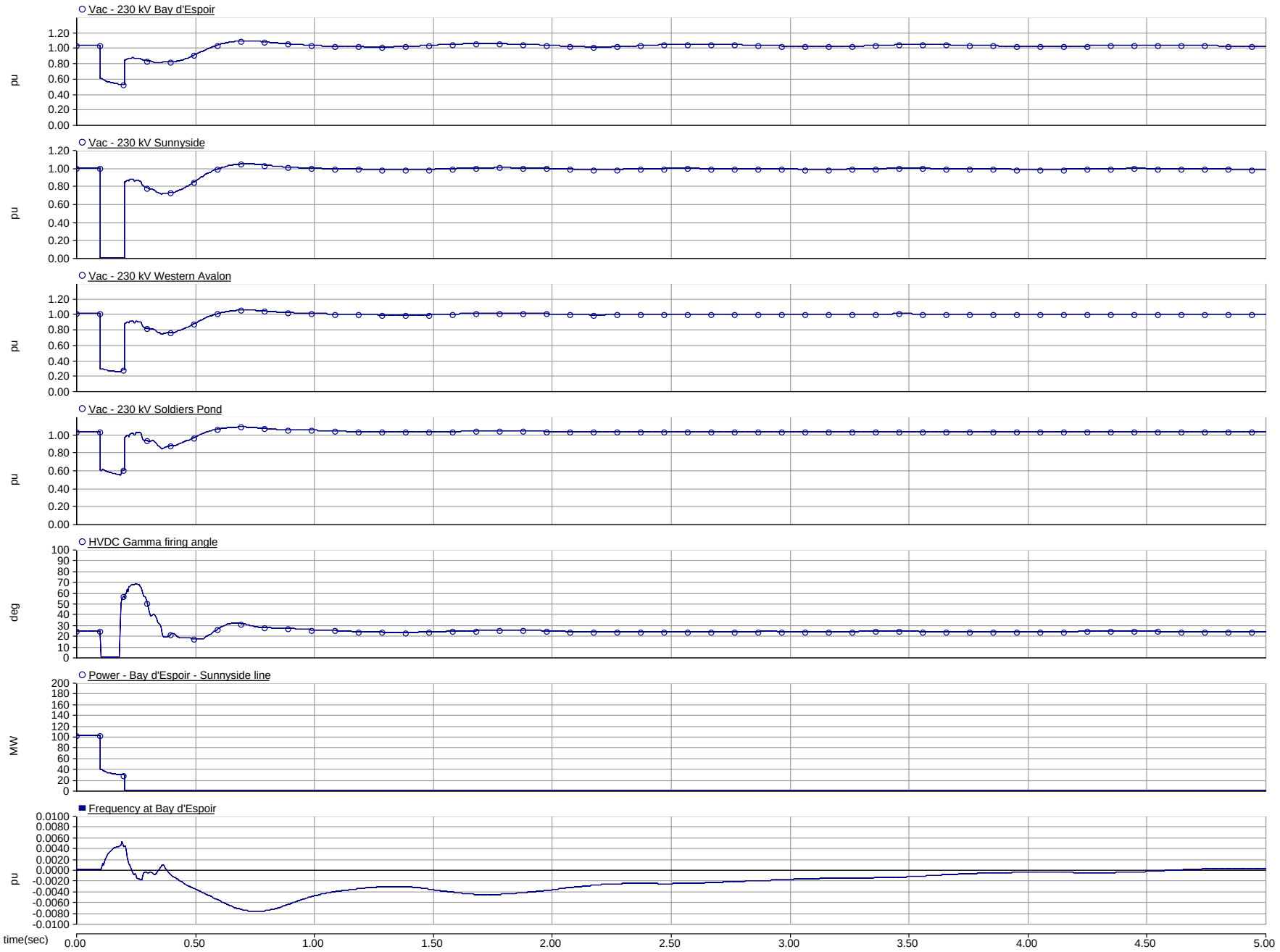
Both of these solutions provide sufficient steady state VAR support to maintain system steady state voltages during the 800 MW monopolar 10-minute 2.0 pu overload condition. Approximately 200 MVAR is required in steady state from the Soldiers Pond synchronous condensers to maintain the 1.0284 pu voltage setpoint that was used in the studies.

Because such good performance was obtained with the high inertia synchronous condensers, the three-phase Bay d'Espoir fault was re-visited. It was found that in order to design the system to survive a three-phase fault at Bay d'Espoir, the only option that recovered within criteria was a case with the new 230 kV circuit between Bay d'Espoir and Western Avalon. If this new circuit plus the two circuits between Bay d'Espoir and Sunnyside are 50% series compensated, AND if 2x300 MVAR high inertia synchronous condensers are in service at Soldiers Pond (which means 3x300 MVAR installed to account for maintenance outages), the system is able to recover within criteria from a three-phase fault at Bay d'Espoir.

A preliminary evaluation was performed to look at the impact of relocating a portion of the inertia from Soldiers Pond to Bay d'Espoir by changing out the rotor on Bay d'Espoir Unit 7 and by installing a high inertia 150 MVAR synchronous condenser as Bay d'Espoir Unit 8. The analysis was performed with only 1 x 150 MVAR high inertia synchronous condenser operating at Soldiers Pond instead of 2 x 150 MVAR. Despite the fact that the total system inertia is very similar between the two cases, the results indicate poorer performance of the Island system when the synchronous condensers are moved away from Soldiers Pond due to poorer performance of the HVdc infeed. This system configuration as studied would require the addition of the 230 kV circuit between Bay d'Espoir and Western Avalon with 50% series compensation as well as 50% series compensation on the two Bay d'Espoir – Sunnyside 230 kV lines. If even the series compensation from the new Bay d'Espoir – Western Avalon line is removed the system becomes unstable for a fault at Sunnyside on one of the Bay d'Espoir lines (TL202 or TL206), and in addition the HVdc infeed is on the verge of a second commutation failure for a three phase fault on the Soldiers Pond synchronous condenser.

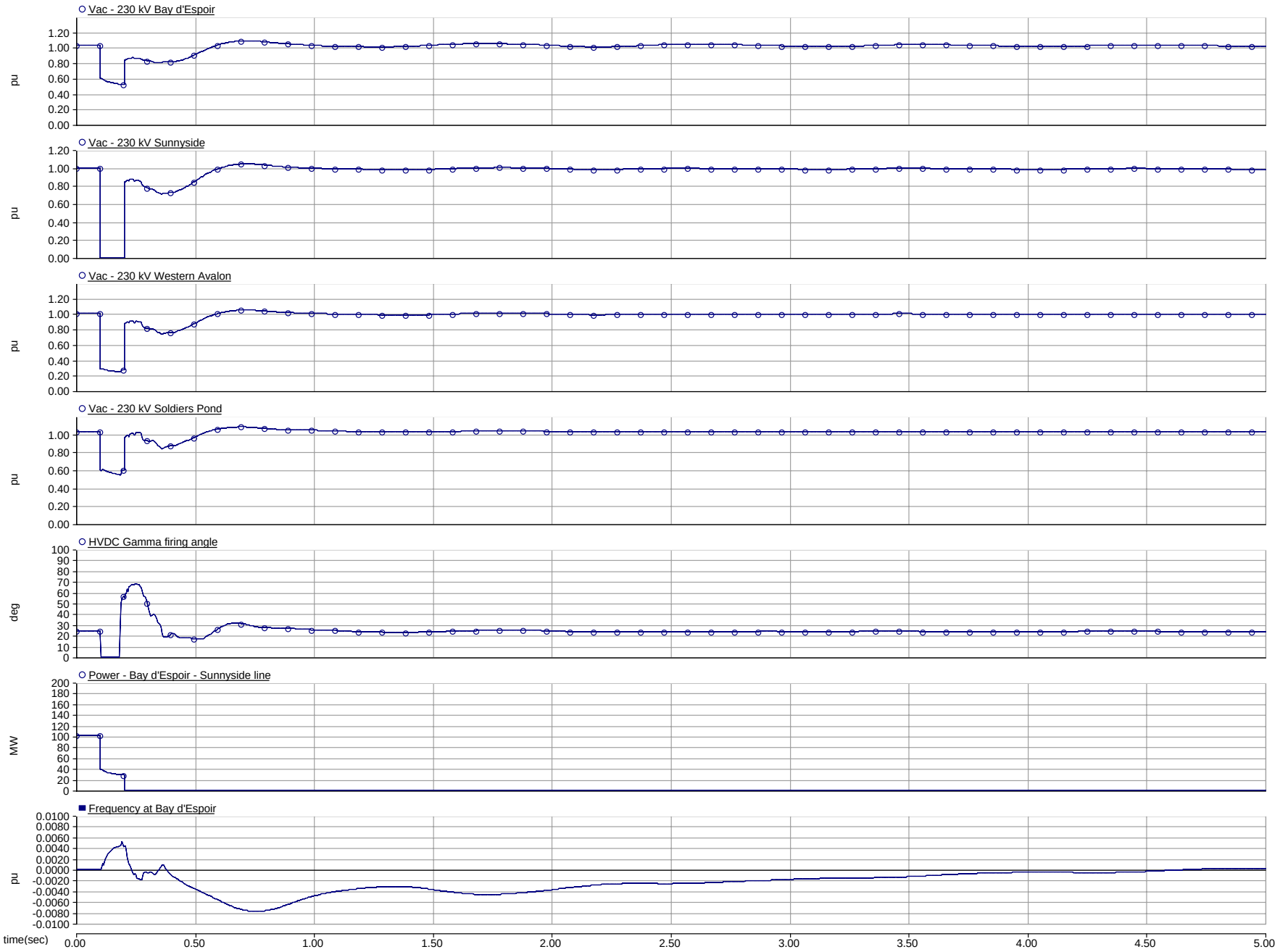
Appendix A

2x150 MVAR [redacted] SCo at SP, 200 MVAR SVC at Sunnyside, 50% series compensation on BDE-SSD lines, 3PF SSD-BDE


Vac - 230 kV Bay d'Espoir
pu
Vac - 230 kV Sunnyside
pu
Vac - 230 kV Western Avalon
pu
Vac - 230 kV Soldiers Pond
pu
HVDC Gamma firing angle
deg
Power - Bay d'Espoir - Sunnyside line
MW
Frequency at Bay d'Espoir
pu
time(sec)
0.00
0.50
1.00
1.50
2.00
2.50
3.00
3.50
4.00
4.50
5.00

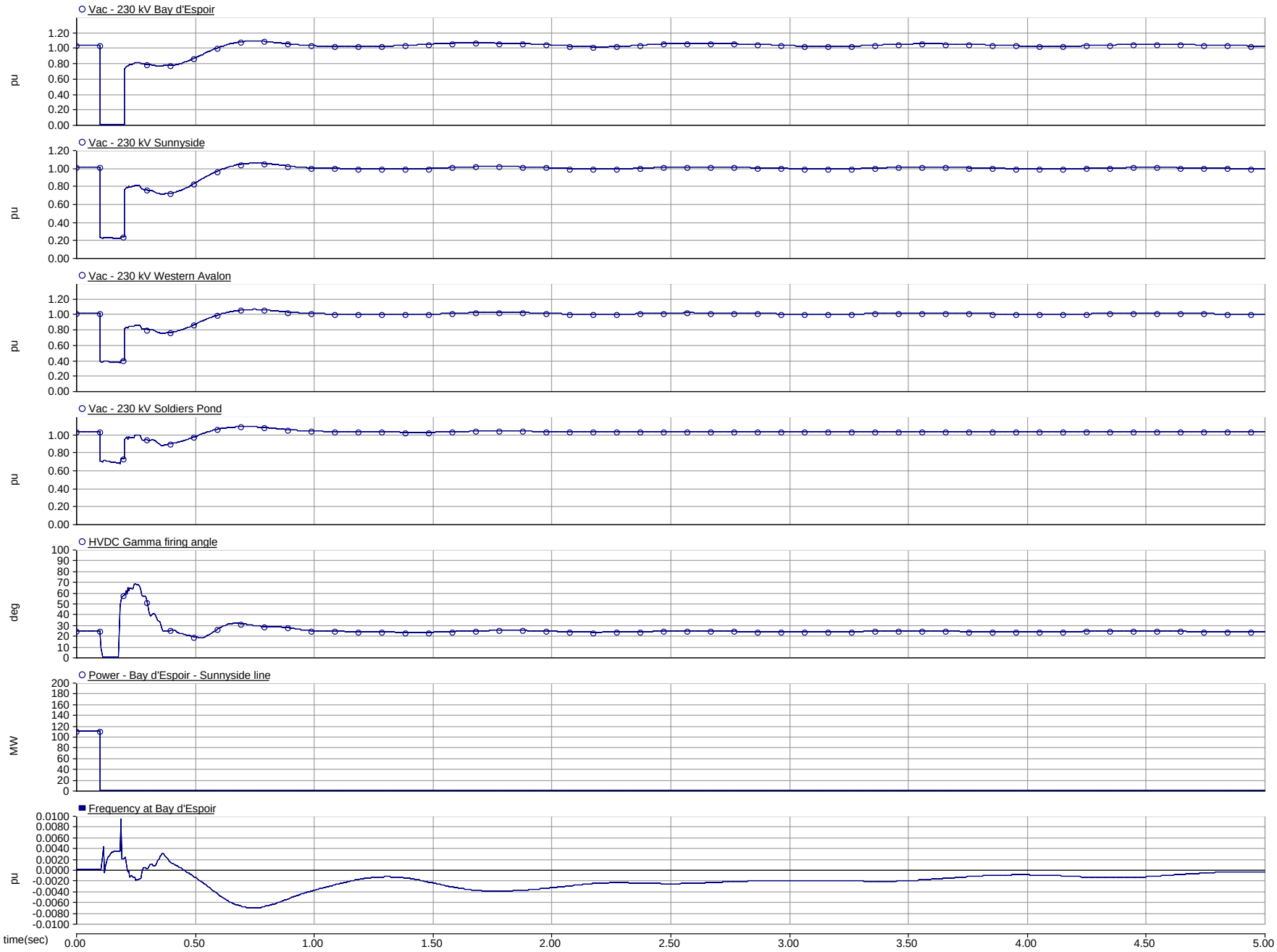
Appendix B

2x150 MVAR [redacted] SCo at SP, new BDE-WAV line, no series compensation on any lines, 3PF SSD-BDE


Vac - 230 kV Bay d'Espoir
pu
Vac - 230 kV Sunnyside
pu
Vac - 230 kV Western Avalon
pu
Vac - 230 kV Soldiers Pond
pu
HVDC Gamma firing angle
deg
Power - Bay d'Espoir - Sunnyside line
MW
Frequency at Bay d'Espoir
pu
time(sec)
0.00
0.50
1.00
1.50
2.00
2.50
3.00
3.50
4.00
4.50
5.00

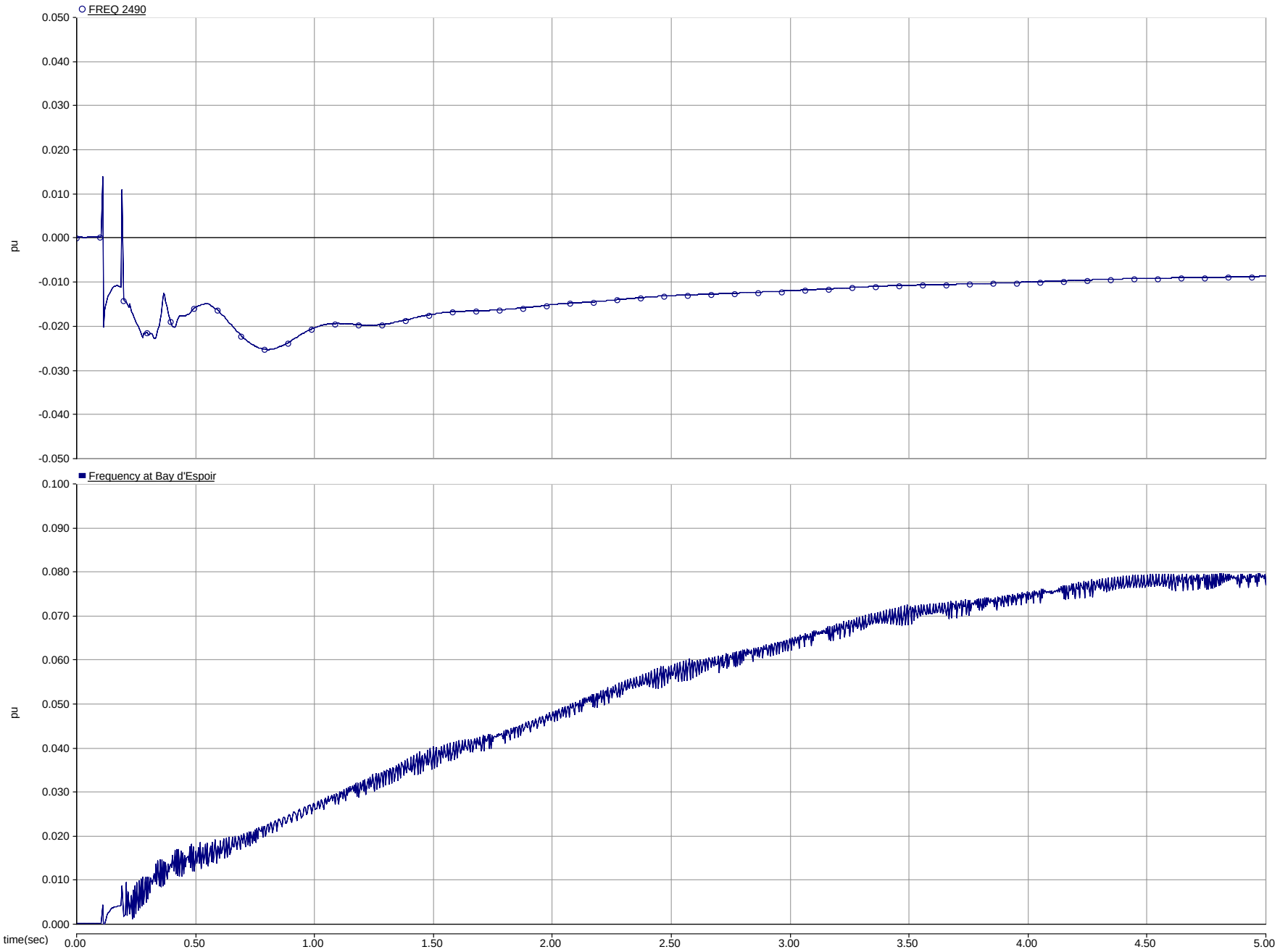
Appendix C

2x300 MVAR [redacted] SCo at SP, new BDE-WAV line, series compensation on BDE-WAV and both BDE-SSD lines, 3PF BDE-SSD


Vac - 230 kV Bay d'Espoir
Vac - 230 kV Sunnyside
Vac - 230 kV Western Avalon
Vac - 230 kV Soldiers Pond
HVDC Gamma firing angle
Power - Bay d'Espoir - Sunnyside line
Frequency at Bay d'Espoir
pu
deg
MW
time(sec)
0.00
0.50
1.00
1.50
2.00
2.50
3.00
3.50
4.00
4.50
5.00

Appendix D

Frequency plot for the case testing a special protection scheme to split Avalon Peninsula for a three-phase fault at Bay d'Espoir. 2x150 MVAR [redacted] SCo at SP, new BDE-WAV line, 3PF BDE-SSD


FREQ 2490
0.050
0.040
0.030
0.020
0.010
0.000
-0.010
-0.020
-0.030
-0.040
-0.050
pu
Frequency at Bay d'Espoir
0.100
0.090
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
pu
time(sec)
0.00
0.50
1.00
1.50
2.00
2.50
3.00
3.50
4.00
4.50
5.00

Appendix B

DC1210 PSSE Model Final Report

Engineering Support Services for

the Lower Churchill Project

Newfoundland and Labrador Hydro

DC1210 – PSSE Model
Final Report

May 21, 2009

HATCH™

TGS TransGrid Solutions

Nalcor Energy
Lower Churchill Project

DC1210 - PSSE Model

Final Report

Prepared by:		May 20, 2009
	Rebecca Brandt, P.Eng.	Date
Approvals		
Hatch		
Approved by:		May 20, 2009
	Pete Kuffel, P.Eng.	Date
Nalcor Energy		
Approved by:		
		Date

Distribution List

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4. Procedure and Results 4-1

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Appendices

Appendix A – Validation Testing Results

1. Introduction

The original WTO DC1020 transient stability analysis assumed a multi-terminal HVdc system with a 480 km cable connection between Newfoundland and New Brunswick across the Cabot Strait. A major task of the WTO was the development of a multi-terminal HVdc model for future PSSE studies. As part of WTO DC1210 Nalcor Energy – Lower Churchill Project requested that the PSSE model developed as part of DC1020 be modified to include a shorter cable between Newfoundland and Nova Scotia along with a new HVdc overhead transmission line from Nova Scotia to New Brunswick.

This report summarizes the work done to implement the requested modifications and presents the results of the validation testing performed.

2. Summary

The PSSE stability model of the three-terminal HVdc link for the Lower Churchill Project has been modified to represent a shorter DC cable section and longer DC overhead line section between the tap at Taylor's Brook and the terminal at Salisbury. Specifically, the cable section between Newfoundland and Lingan, Nova Scotia is estimated at 180 km, and the new overhead line section from Lingan, Nova Scotia to Salisbury, New Brunswick is estimated at 475 km. The overhead line sections in Newfoundland from Taylor's Brook to the Gulf of St. Lawrence crossing to Nova Scotia remain unchanged.

The PSSE multi-terminal HVdc model has been modified and validated to be capable of operating in bipolar or monopolar modes for the following HVdc configurations:

1. 3-terminal: Gull Island – rectifier, Soldiers Pond – inverter, Salisbury – inverter
2. 2-terminal: Soldiers Pond – rectifier, Salisbury – inverter
3. 2-terminal: Salisbury – rectifier, Soldiers Pond - inverter

The validation testing for the monopolar configuration was performed using the 3-terminal HVdc configuration.

3. Power Flow Test Case

For the 3-terminal HVdc configuration, the PSSE model validation was performed using an equivalent test system representing power flow case BC1-DC1: rated bipolar operation with Gull Island as rectifier and Soldiers Pond and Salisbury as inverters (3-terminal).

The validation testing case was performed in an equivalent test system using the following system strengths:

- Gull Island – 4654 MVA ∠87 deg
- Soldiers Pond – 3305 MVA ∠74.1 deg
- Salisbury – 3949 MVA ∠76 deg

The above systems strengths represent a weak configuration at Gull Island, one 150 MVAR synchronous condenser in-service at Soldiers Pond (Xd'' = 0.165 pu) and one 125 MVAR synchronous condenser in-service at Salisbury (Xd'' = 0.165 pu) based on information from previously completed studies.

For the 2-terminal HVdc configurations, the PSCAD model had previously been set up using equivalent test systems, however the PSSE models that were readily available for these power flow configurations had been set up to use an equivalent source at the Salisbury terminal and the reduced version of the Newfoundland system PSSE model for the Soldiers Pond terminal. This difference in test systems results in slightly different AC voltage response for the 2-terminal test cases, however the response (especially of the HVdc quantities) very closely matches the PSCAD model and therefore still provides validation of the PSSE model.

4. Procedure and Results

The PSCAD model was first updated and the DC controls were re-tuned. These changes were implemented inside the PSSE model. Validation testing was performed by comparing the results of the PSCAD and PSSE models for a solid and remote three-phase fault at each of the DC terminals for the 3-terminal case, and for solid faults only for the 2-terminal cases.

Validation testing results are provided in the Appendix. The PSSE model compares well with the PSCAD model results.

5. User Instructions

The user need not change any input parameters to the PSSE dynamics model, other than to ensure CON(J + 5) DC_CONFIG is set to the appropriate value:

'1' - 3-terminal: Gull Island – rectifier, Soldiers Pond – inverter, Salisbury – inverter

'2' - 2-terminal: Soldiers Pond – rectifier, Salisbury – inverter

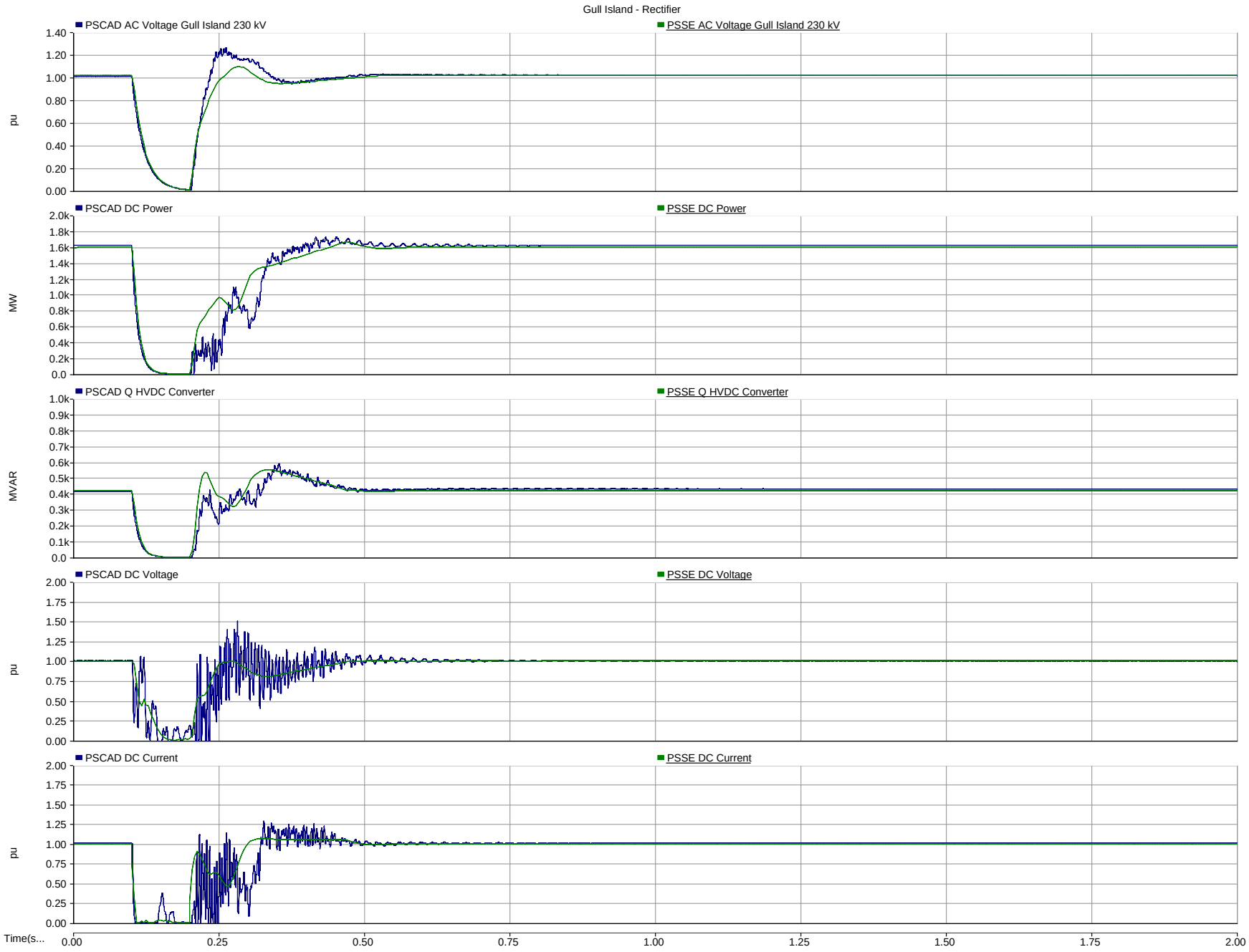
'3' - 2-terminal: Salisbury – rectifier, Soldiers Pond - inverter

Other than CON(J + 5) the original documentation for the PSSE model still applies in terms of model use instructions (Chapter 7 of DC1020 report: Multi-Terminal HVdc Link PSSE Stability Model). All dynamics model changes were internal within the PSSE model code. The updated compiled model is provided (CLCPDC-short_cable-full_version.OBJ).

The user should change the DC resistance value in the PSSE loadflow model of the DC line section from the DC tap (dc bus 2) to the NB DC terminal (dc bus 4) to be 9.451 ohms instead of 8.433 ohms (a read change raw data file is provided as an example for the 3-terminal configuration – LCP-short_cable.raw). The IPLAN program used to calculate the steady state DC operating points for the multi-terminal DC loadflow model also uses this DC resistance value and it had to be changed internally. An updated IPLAN (LCP-short_cable.ipl, LCP-short_cable.irf) is also provided.

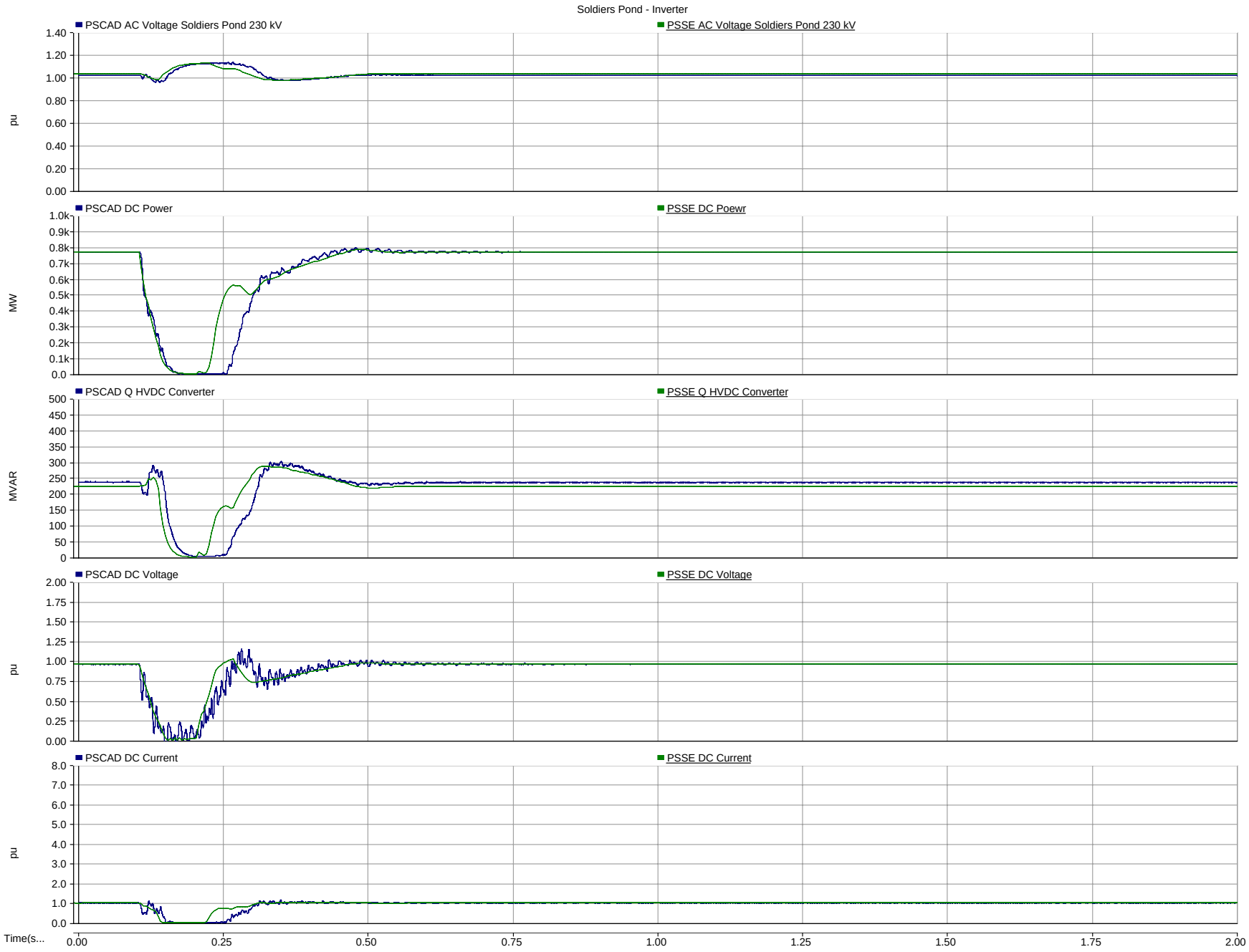
Appendix A

Validation Testing Results



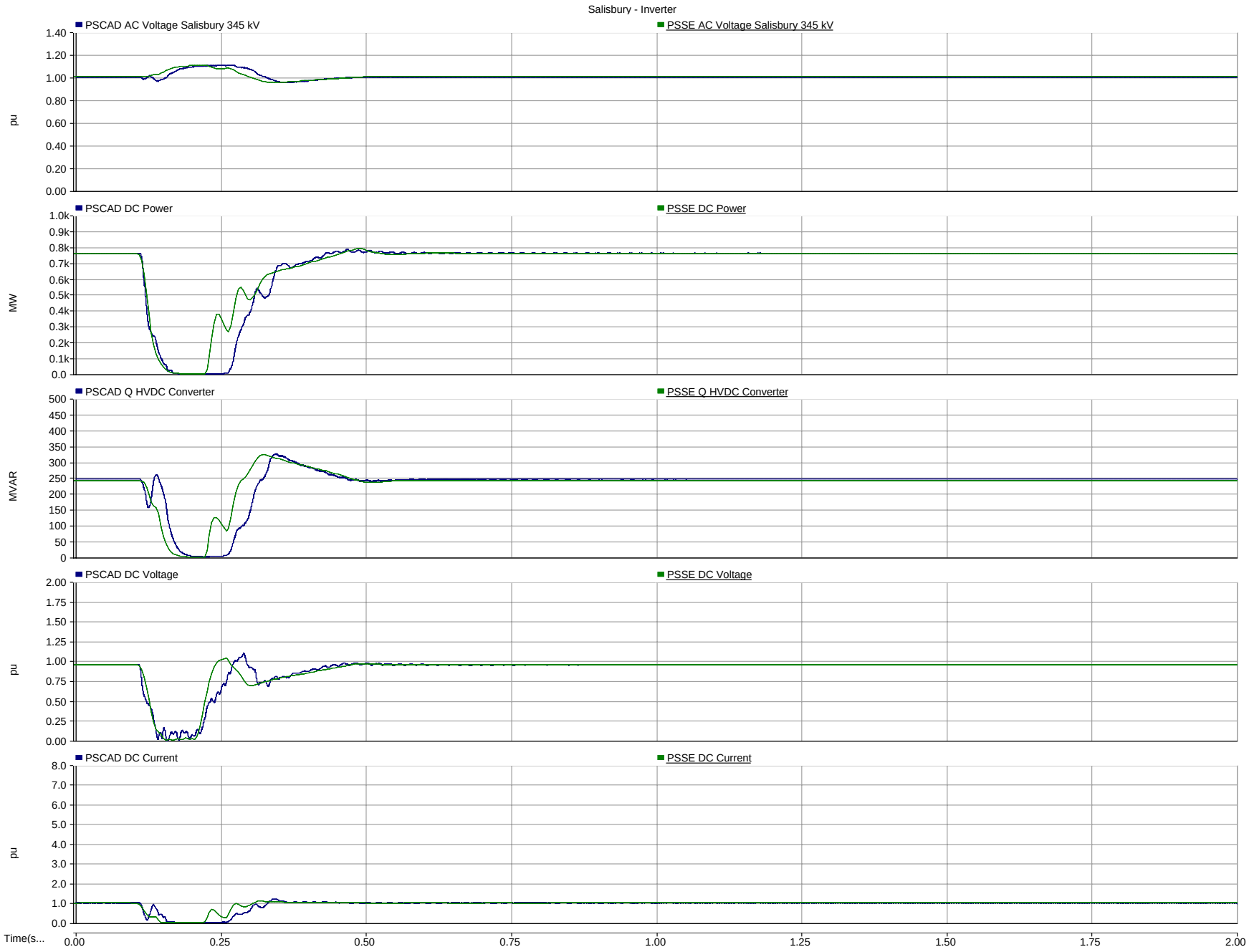
PSSE v30.3
PSCAD v4.2.1

Three-Phase Solid Fault (0%) - Gull Island 230 kV Bus
Gull Island 1600 MW Rectifier, Soldiers Pond 800 MW Inverter, Salisbury 800 MW Inverter
System Equivalent Model - Minimum Short Circuit Levels



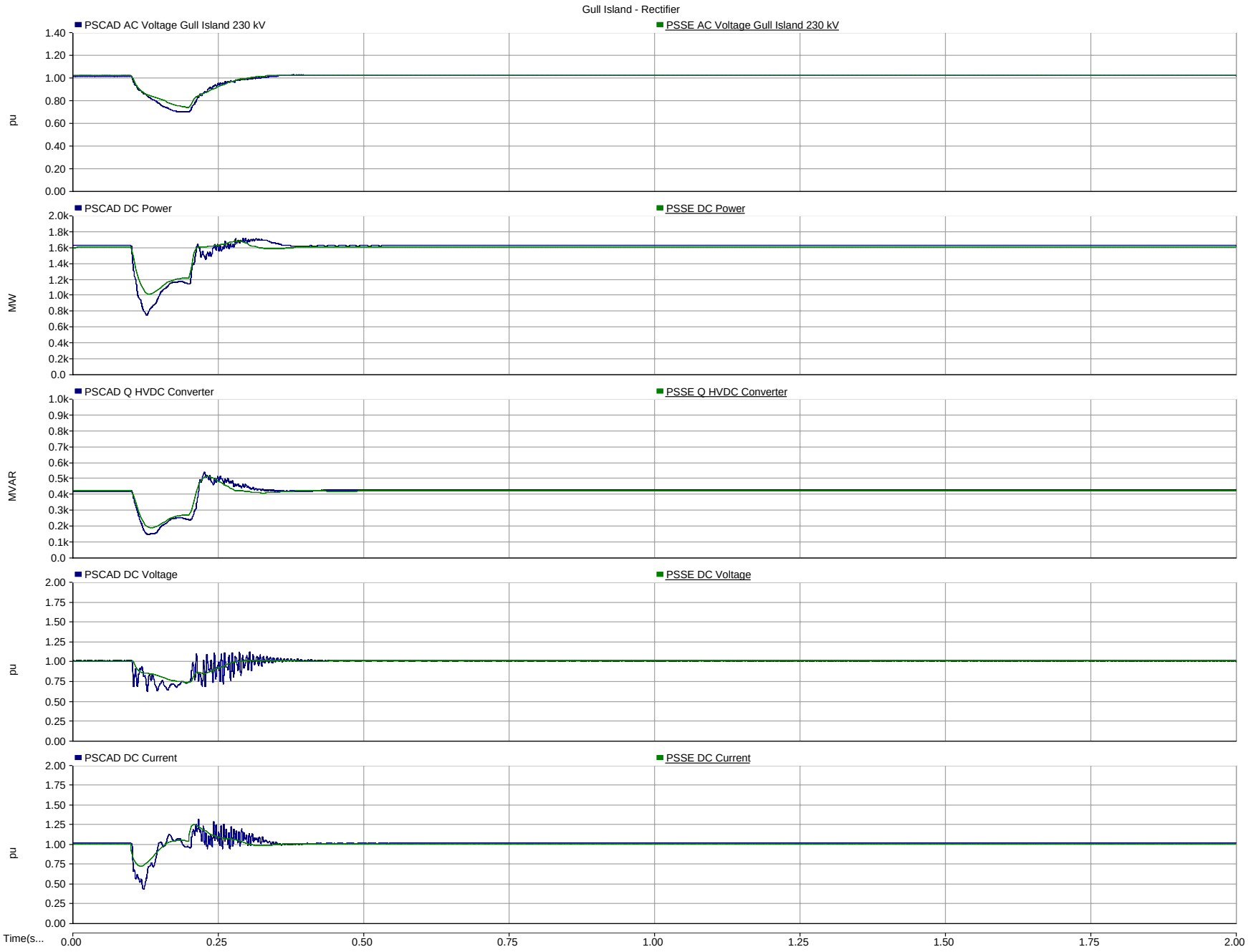
PSSE v30.3
PSCAD v4.2.1

Three-Phase Solid Fault (0%) - Gull Island 230 kV Bus
Gull Island 1600 MW Rectifier, Soldiers Pond 800 MW Inverter, Salisbury 800 MW Inverter
System Equivalent Model - Minimum Short Circuit Levels



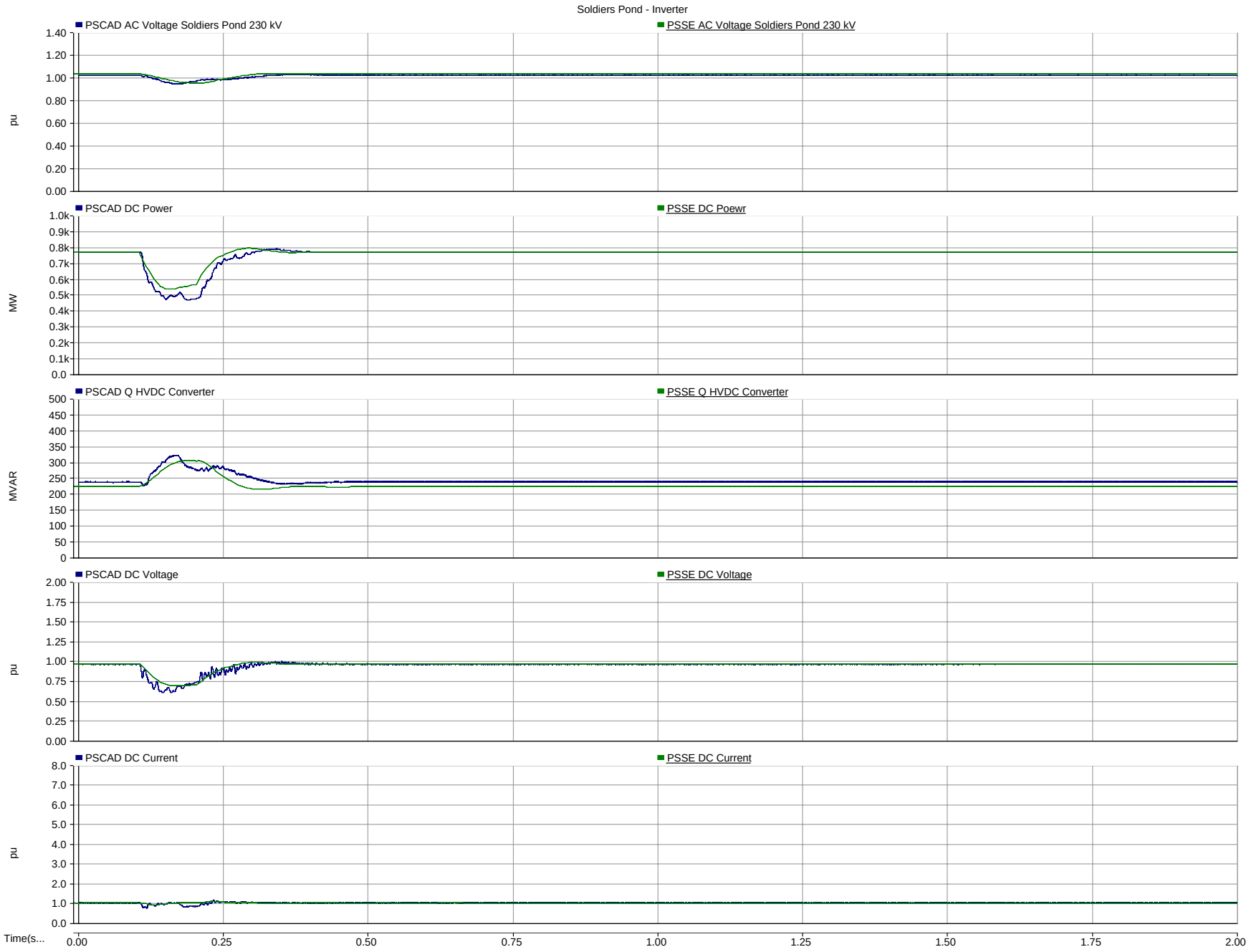
PSSE v30.3
PSCAD v4.2.1

Three-Phase Solid Fault (0%) - Gull Island 230 kV Bus
Gull Island 1600 MW Rectifier, Soldiers Pond 800 MW Inverter, Salisbury 800 MW Inverter
System Equivalent Model - Minimum Short Circuit Levels



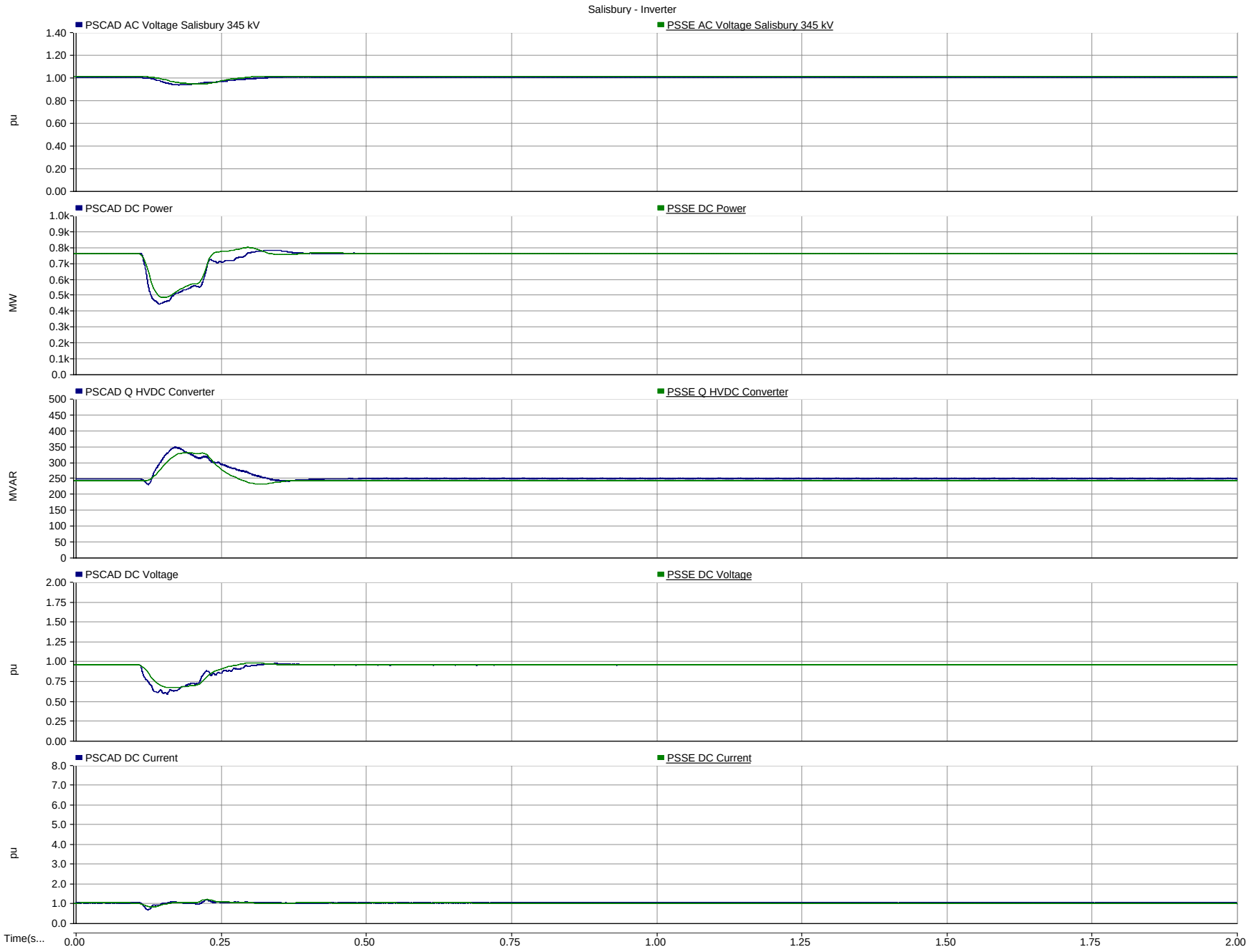
PSSE v30.3
PSCAD v4.2.1

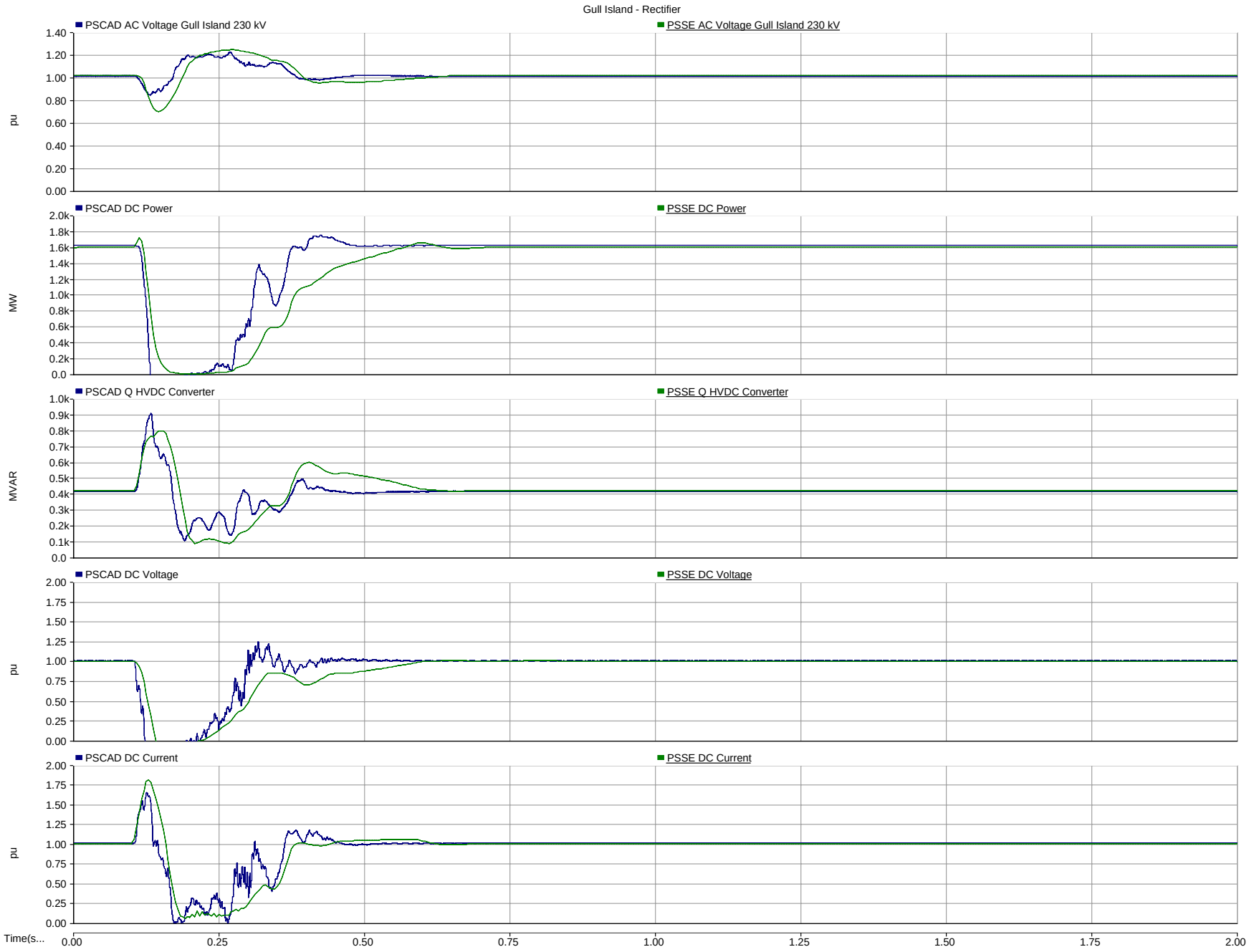
Three-Phase Remote Fault (70%) - Gull Island 230 kV Bus
Gull Island 1600 MW Rectifier, Soldiers Pond 800 MW Inverter, Salisbury 800 MW Inverter
System Equivalent Model - Minimum Short Circuit Levels



PSSE v30.3
PSCAD v4.2.1

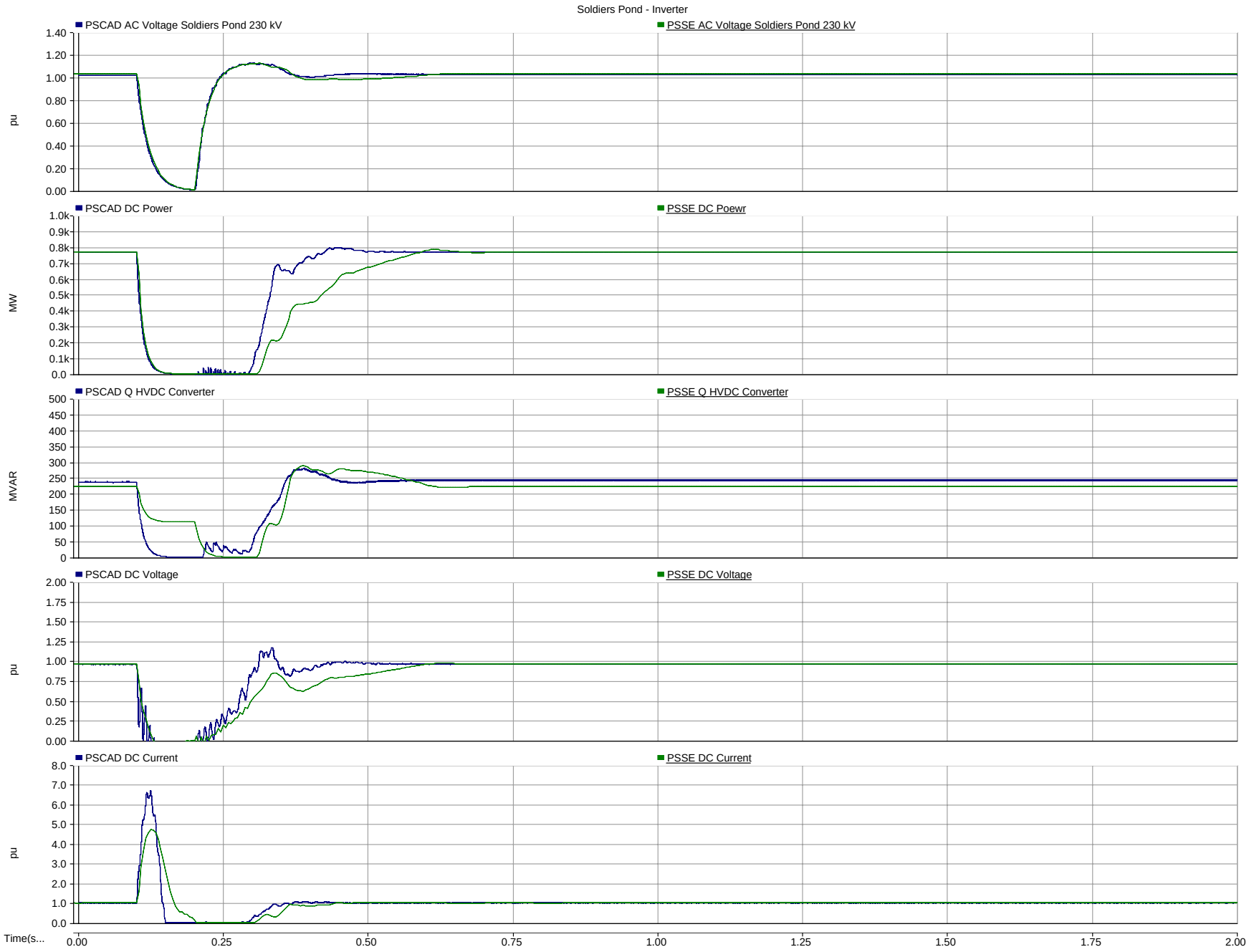
Three-Phase Remote Fault (70%) - Gull Island 230 kV Bus
Gull Island 1600 MW Rectifier, Soldiers Pond 800 MW Inverter, Salisbury 800 MW Inverter
System Equivalent Model - Minimum Short Circuit Levels


Salisbury - Inverter
PSCAD AC Voltage Salisbury 345 kV
PSSE AC Voltage Salisbury 345 kV
pu
PSCAD DC Power
PSSE DC Power
MW
PSCAD Q HVDC Converter
PSSE Q HVDC Converter
MVAR
PSCAD DC Voltage
PSSE DC Voltage
pu
PSCAD DC Current
PSSE DC Current
pu
Time(s...
0.00
0.25
0.50
0.75
1.00
1.25
1.50
1.75
2.00



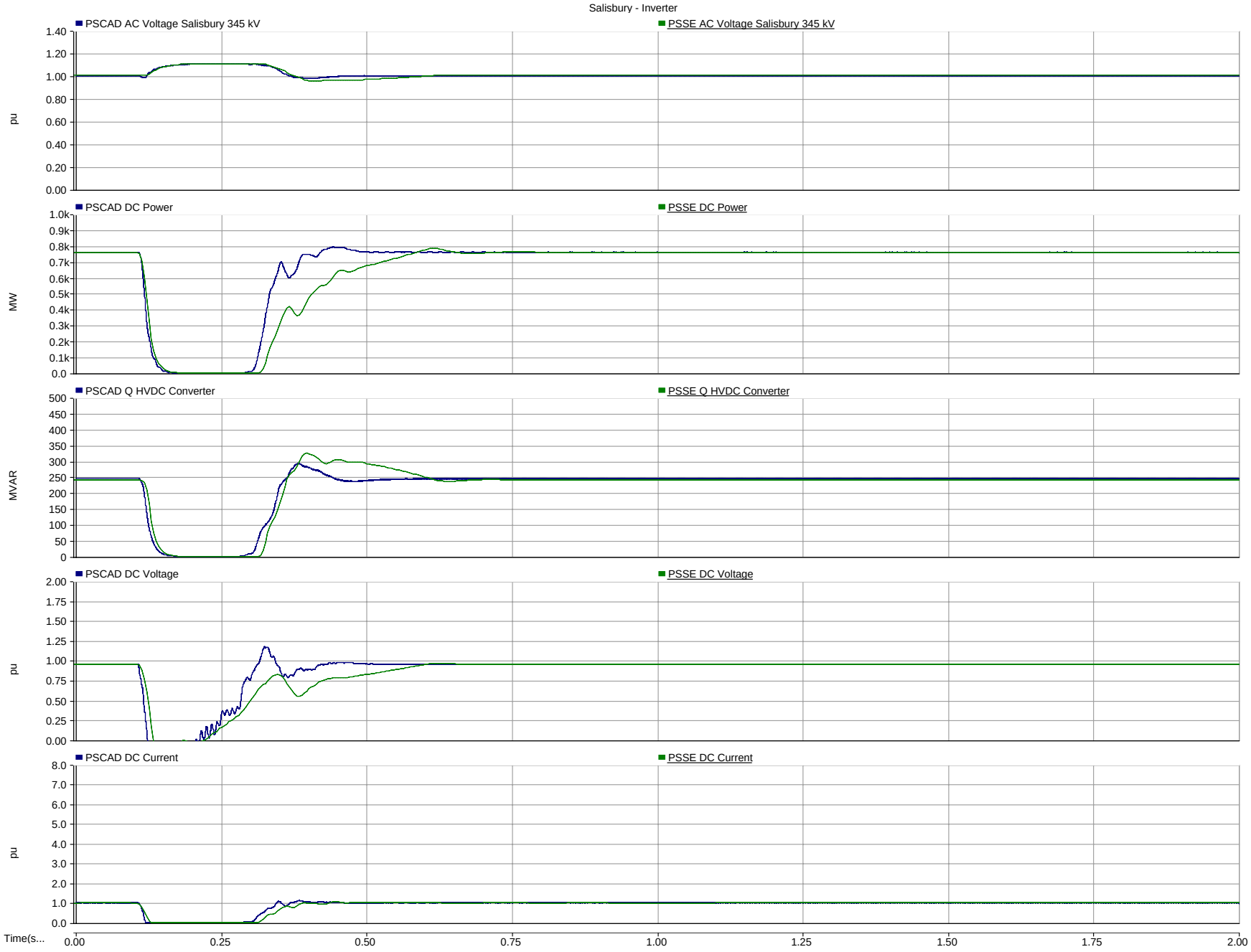
PSSE v30.3
PSCAD v4.2.1

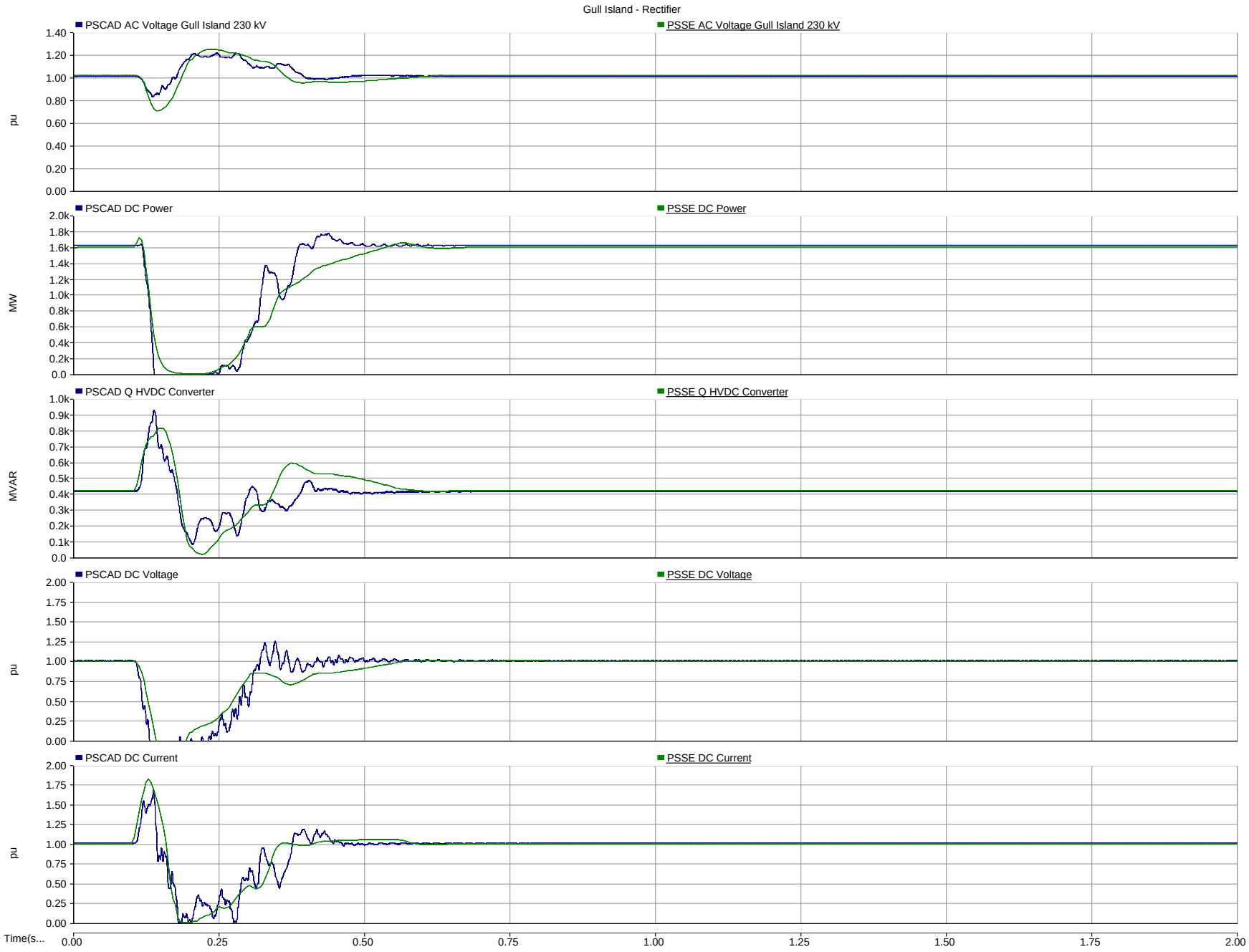
Three-Phase Solid Fault (0%) - Soldiers Pond 230 kV Bus
Gull Island 1600 MW Rectifier, Soldiers Pond 800 MW Inverter, Salisbury 800 MW Inverter
System Equivalent Model - Minimum Short Circuit Levels

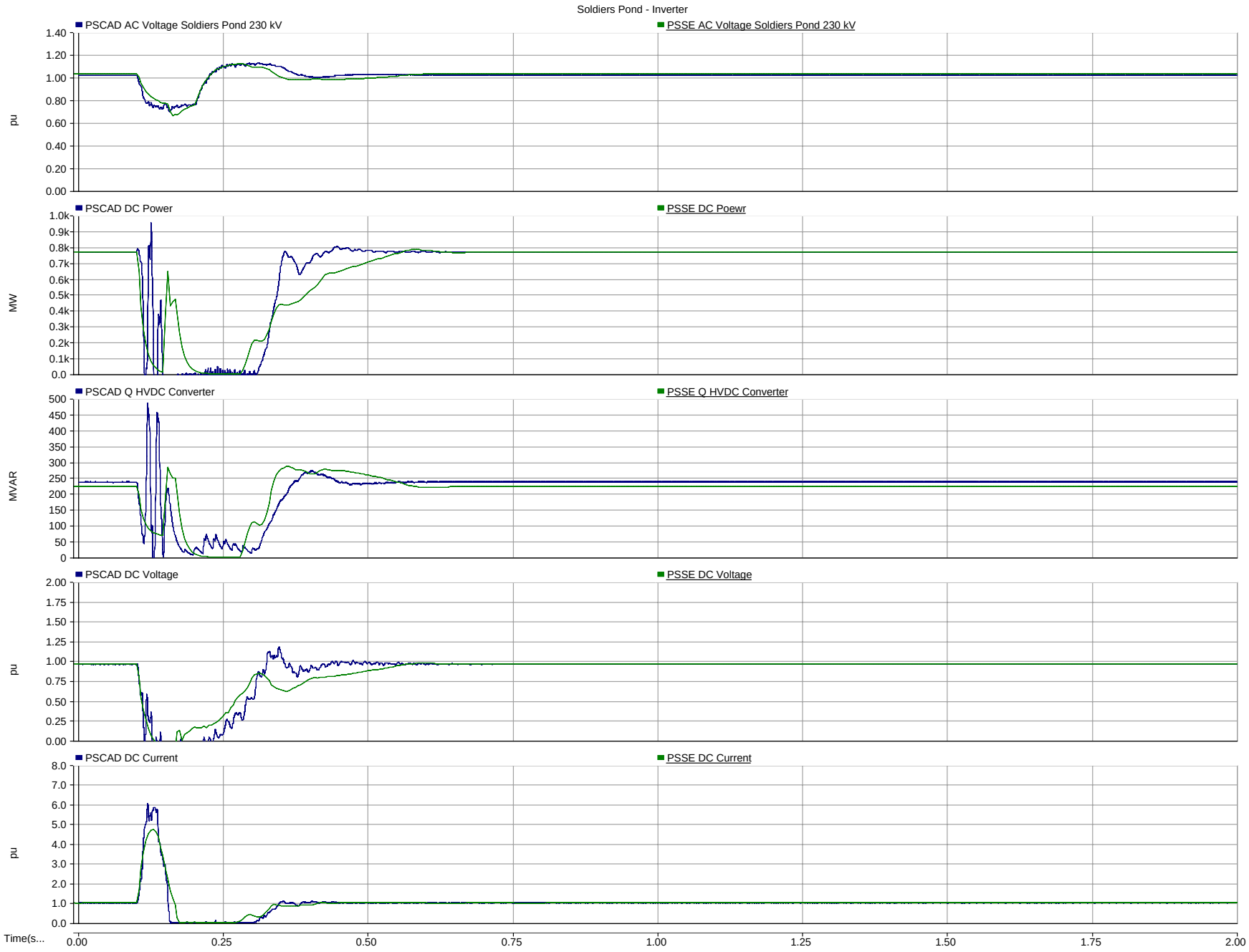


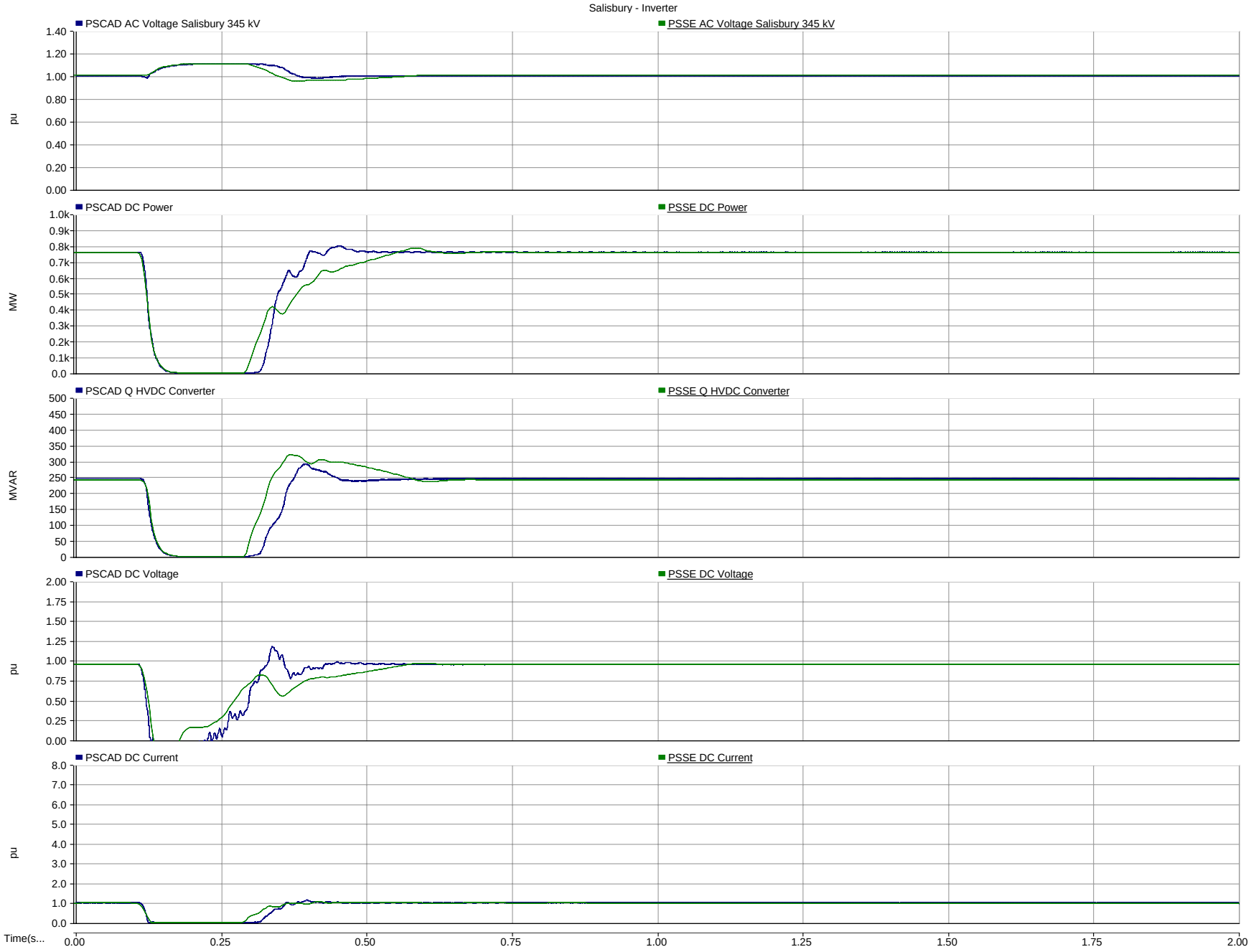
PSSE v30.3
PSCAD v4.2.1

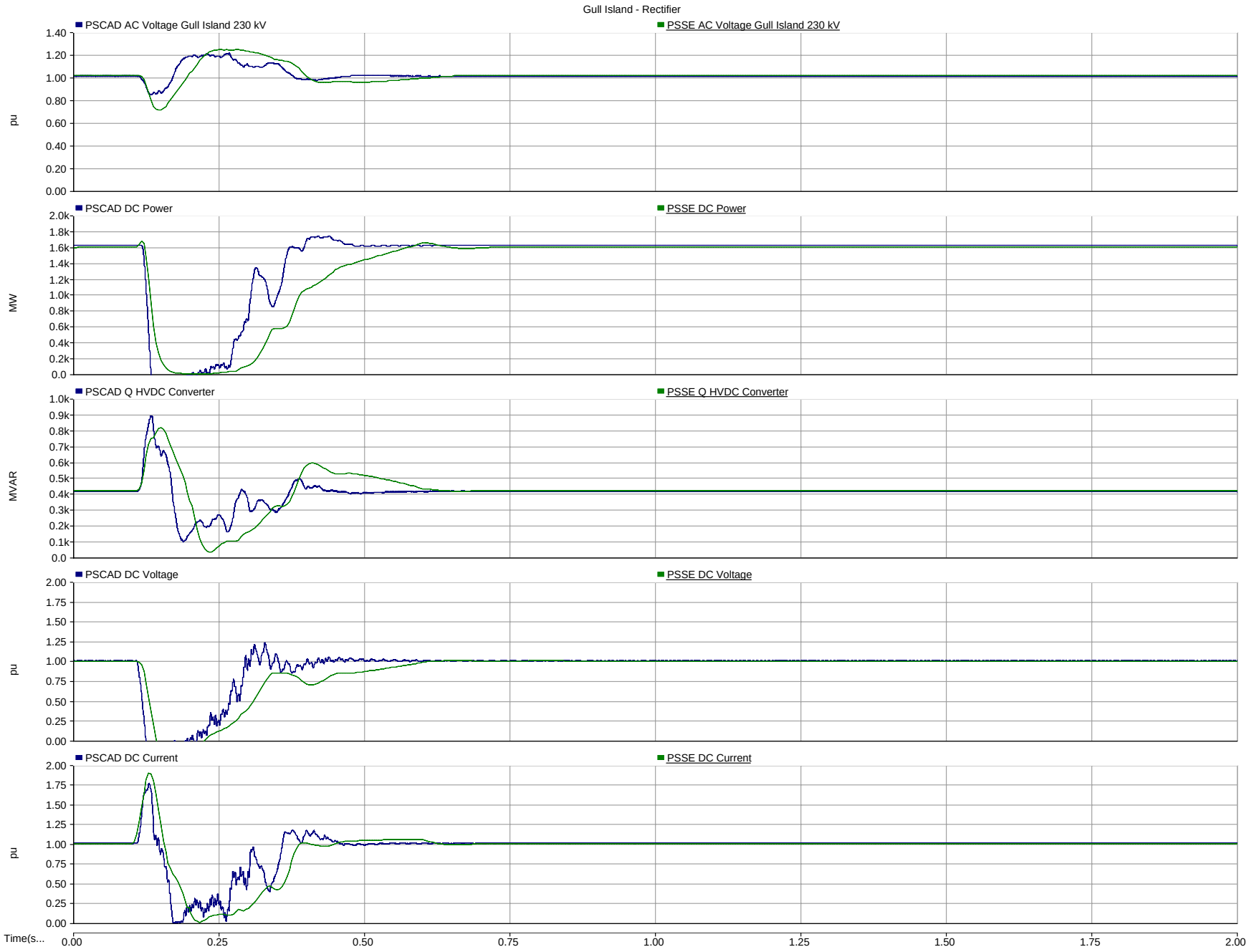
Three-Phase Solid Fault (0%) - Soldiers Pond 230 kV Bus
Gull Island 1600 MW Rectifier, Soldiers Pond 800 MW Inverter, Salisbury 800 MW Inverter
System Equivalent Model - Minimum Short Circuit Levels

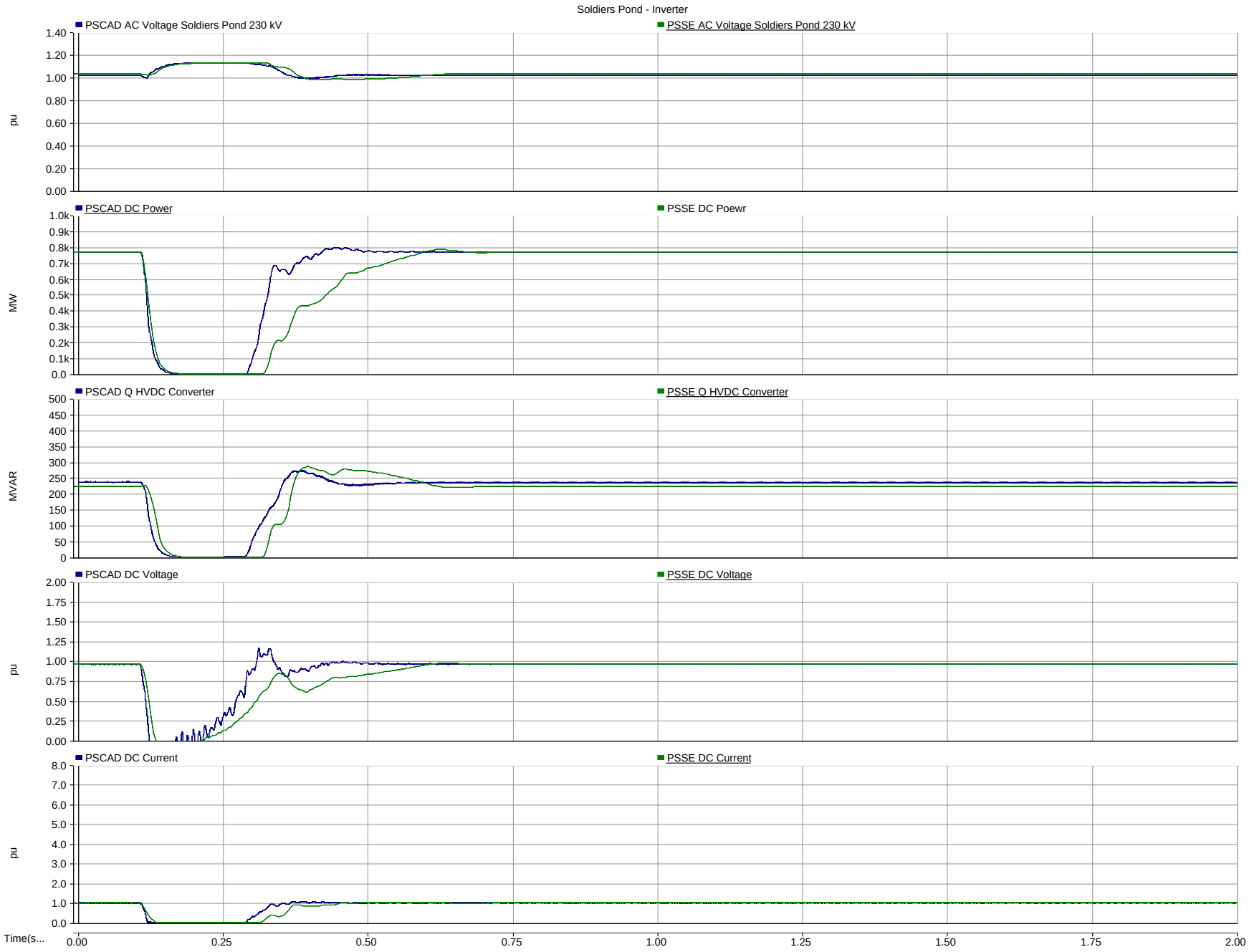

Salisbury - Inverter
PSCAD AC Voltage Salisbury 345 kV
PSSE AC Voltage Salisbury 345 kV
pu
PSCAD DC Power
PSSE DC Power
MW
PSCAD Q HVDC Converter
PSSE Q HVDC Converter
MVAR
PSCAD DC Voltage
PSSE DC Voltage
pu
PSCAD DC Current
PSSE DC Current
pu
Time(s...
0.00
0.25
0.50
0.75
1.00
1.25
1.50
1.75
2.00

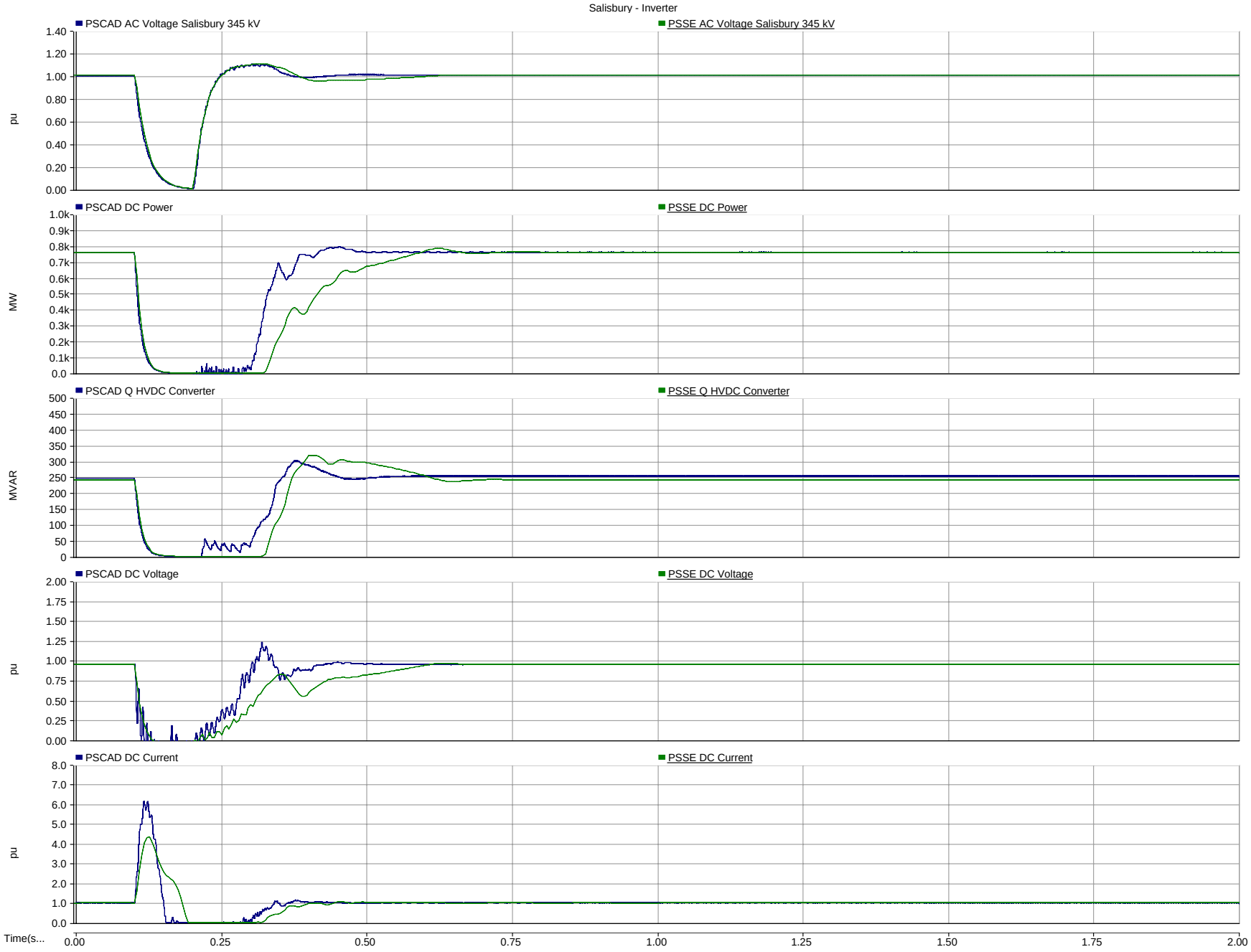

Gull Island - Rectifier
PSCAD AC Voltage Gull Island 230 kV
PSSE AC Voltage Gull Island 230 kV
pu
PSCAD DC Power
PSSE DC Power
MW
PSCAD Q HVDC Converter
PSSE Q HVDC Converter
MVAR
PSCAD DC Voltage
PSSE DC Voltage
pu
PSCAD DC Current
PSSE DC Current
pu
Time(s...
0.00
0.25
0.50
0.75
1.00
1.25
1.50
1.75
2.00


Soldiers Pond - Inverter
PSCAD AC Voltage Soldiers Pond 230 kV
PSSE AC Voltage Soldiers Pond 230 kV
pu
PSCAD DC Power
PSSE DC Poewr
MW
PSCAD Q HVDC Converter
PSSE Q HVDC Converter
MVAR
PSCAD DC Voltage
PSSE DC Voltage
pu
PSCAD DC Current
PSSE DC Current
pu
Time(s...
0.00
0.25
0.50
0.75
1.00
1.25
1.50
1.75
2.00


Salisbury - Inverter
PSCAD AC Voltage Salisbury 345 kV
PSSE AC Voltage Salisbury 345 kV
pu
PSCAD DC Power
PSSE DC Power
MW
PSCAD Q HVDC Converter
PSSE Q HVDC Converter
MVAR
PSCAD DC Voltage
PSSE DC Voltage
pu
PSCAD DC Current
PSSE DC Current
pu
Time(s...
0.00
0.25
0.50
0.75
1.00
1.25
1.50
1.75
2.00

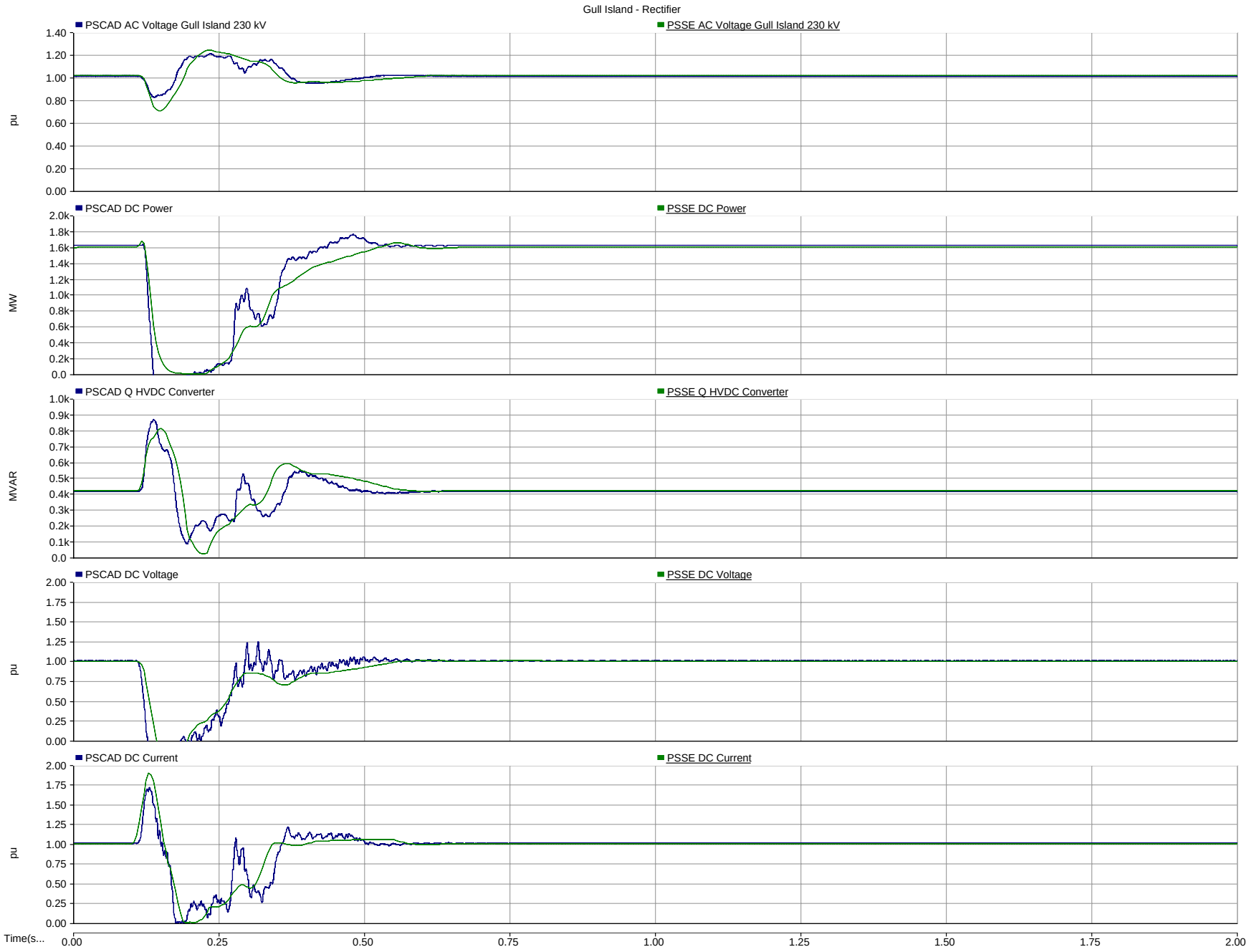

Gull Island - Rectifier
PSCAD AC Voltage Gull Island 230 kV
PSSE AC Voltage Gull Island 230 kV
pu
PSCAD DC Power
PSSE DC Power
MW
PSCAD Q HVDC Converter
PSSE Q HVDC Converter
MVAR
PSCAD DC Voltage
PSSE DC Voltage
pu
PSCAD DC Current
PSSE DC Current
pu
Time(s...
0.00
0.25
0.50
0.75
1.00
1.25
1.50
1.75
2.00

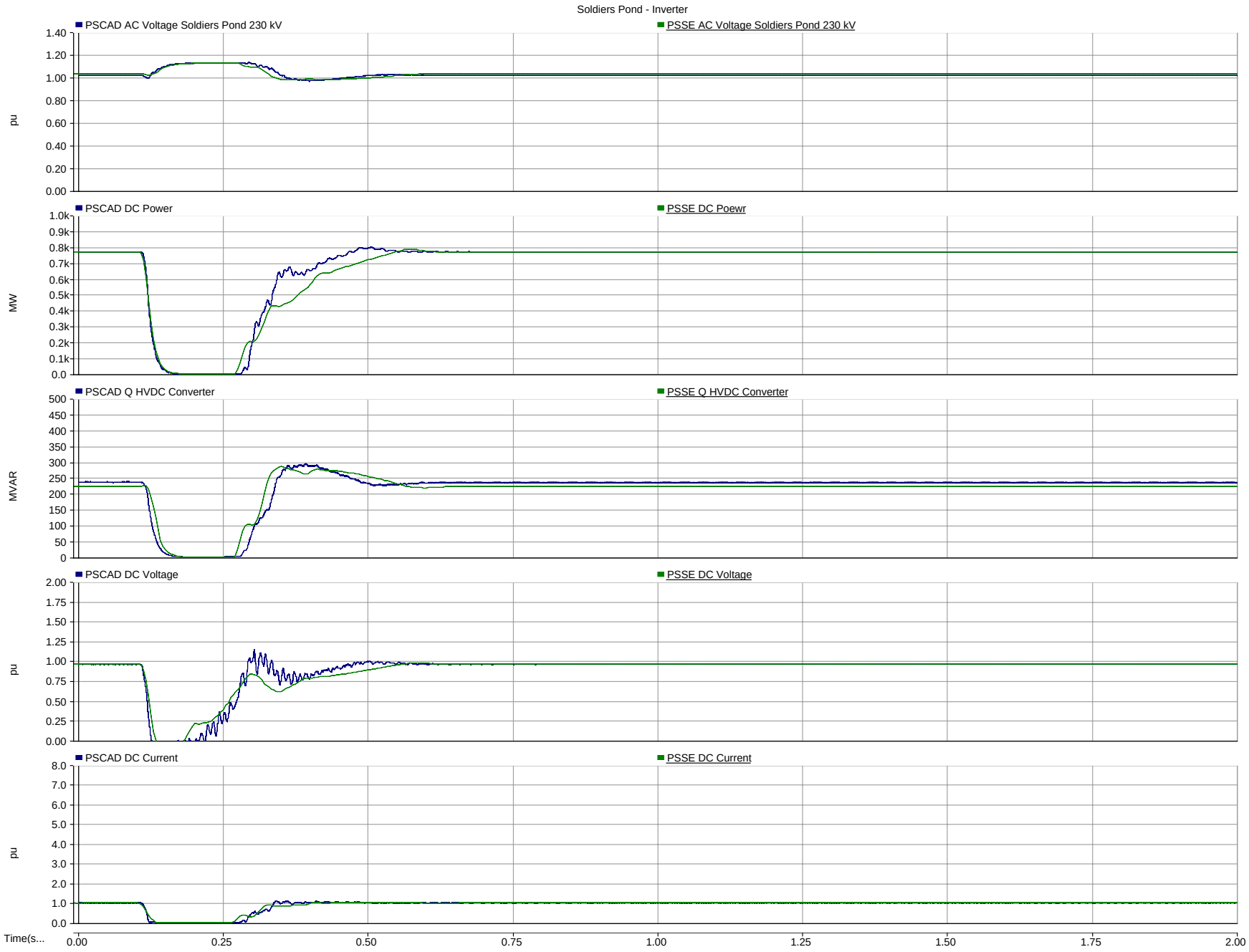

Soldiers Pond - Inverter
PSCAD AC Voltage Soldiers Pond 230 kV
PSSE AC Voltage Soldiers Pond 230 kV
pu
PSCAD DC Power
PSSE DC Poewr
MW
PSCAD Q HVDC Converter
PSSE Q HVDC Converter
MVAR
PSCAD DC Voltage
PSSE DC Voltage
pu
PSCAD DC Current
PSSE DC Current
pu
Time(s...
0.00
0.25
0.50
0.75
1.00
1.25
1.50
1.75
2.00

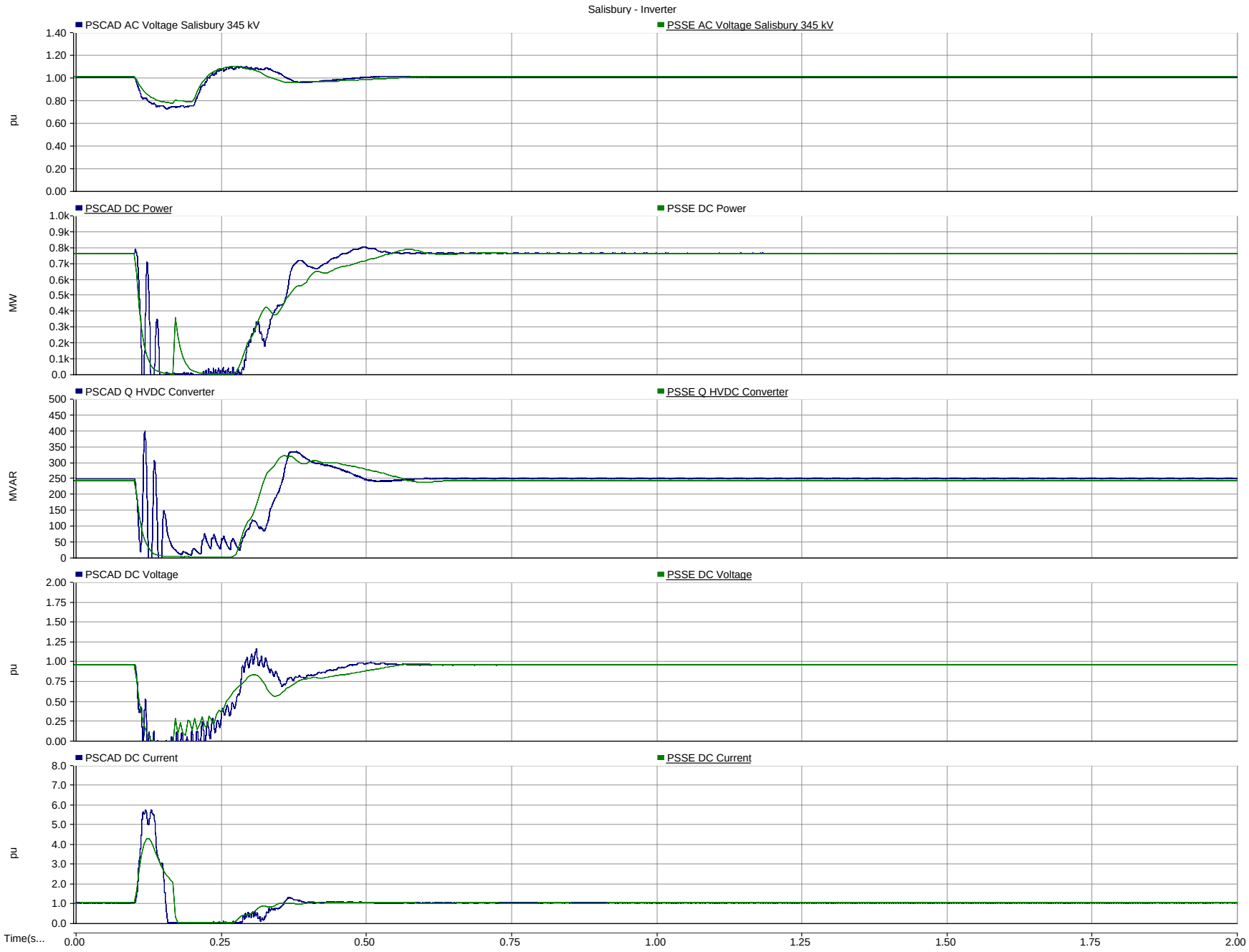


PSSE v30.3
PSCAD v4.2.1

Three-Phase Solid Fault (0%) - Salisbury 345 kV Bus
Gull Island 1600 MW Rectifier, Soldiers Pond 800 MW Inverter, Salisbury 800 MW Inverter
System Equivalent Model - Minimum Short Circuit Levels

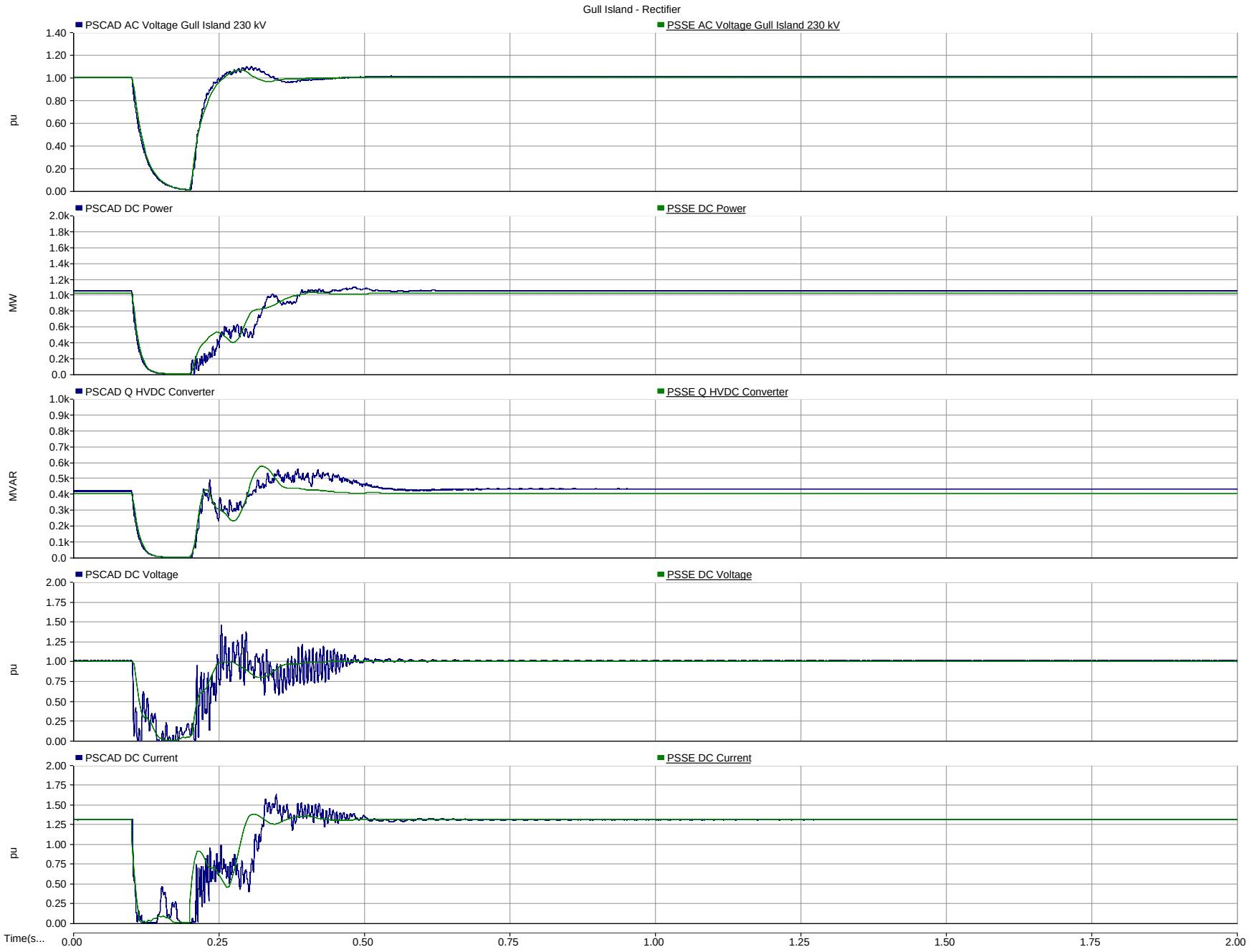

Gull Island - Rectifier
PSCAD AC Voltage Gull Island 230 kV
PSSE AC Voltage Gull Island 230 kV
pu
PSCAD DC Power
PSSE DC Power
MW
PSCAD Q HVDC Converter
PSSE Q HVDC Converter
MVAR
PSCAD DC Voltage
PSSE DC Voltage
pu
PSCAD DC Current
PSSE DC Current
pu
Time(s...
0.00
0.25
0.50
0.75
1.00
1.25
1.50
1.75
2.00


Soldiers Pond - Inverter
PSCAD AC Voltage Soldiers Pond 230 kV
PSSE AC Voltage Soldiers Pond 230 kV
pu
PSCAD DC Power
PSSE DC Poewr
MW
PSCAD Q HVDC Converter
PSSE Q HVDC Converter
MVAR
PSCAD DC Voltage
PSSE DC Voltage
pu
PSCAD DC Current
PSSE DC Current
pu
Time(s...
0.00
0.25
0.50
0.75
1.00
1.25
1.50
1.75
2.00



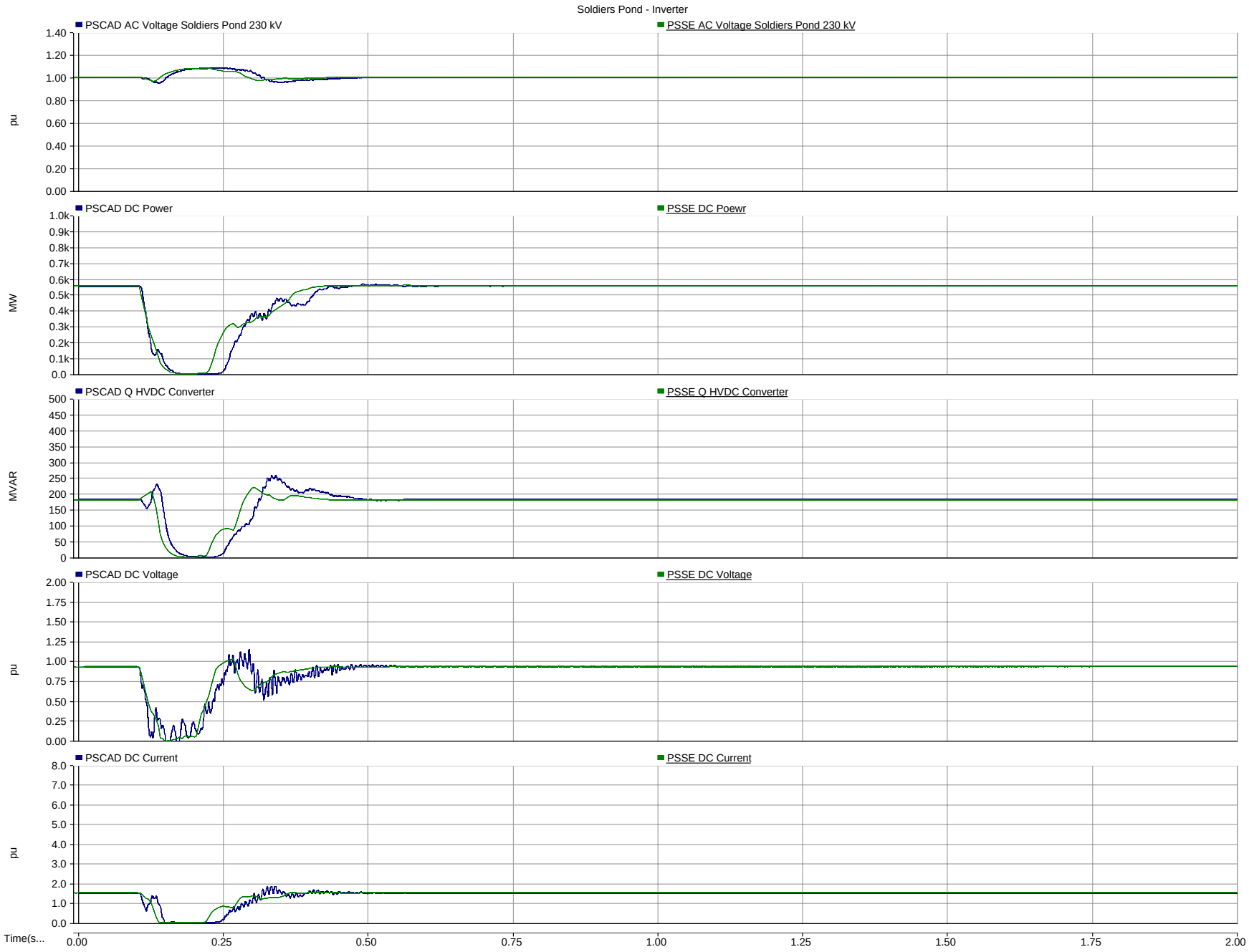
PSSE v30.3
PSCAD v4.2.1

Three-Phase Remote Fault (70%) - Salisbury 345 kV Bus
Gull Island 1600 MW Rectifier, Soldiers Pond 800 MW Inverter, Salisbury 800 MW Inverter
System Equivalent Model - Minimum Short Circuit Levels



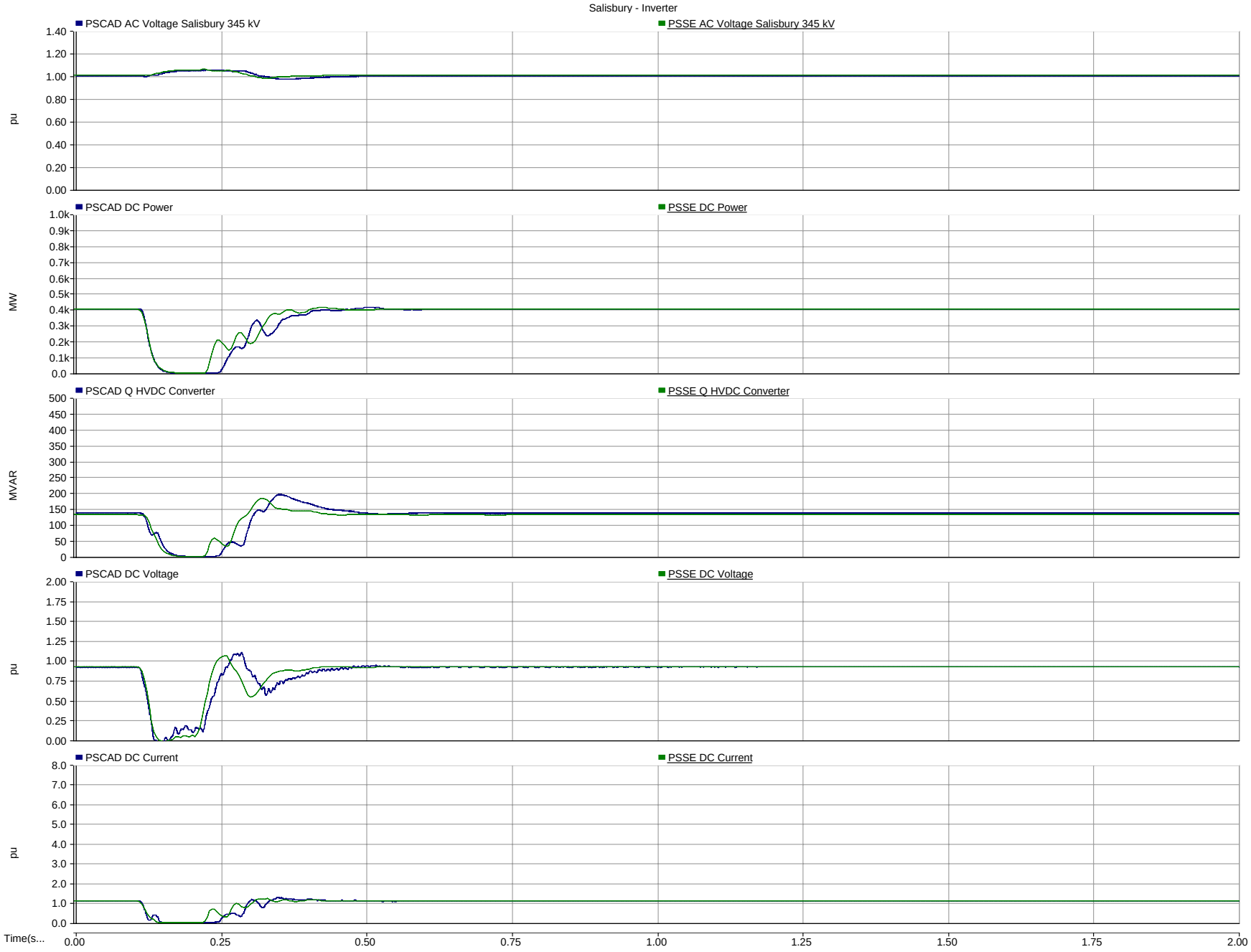
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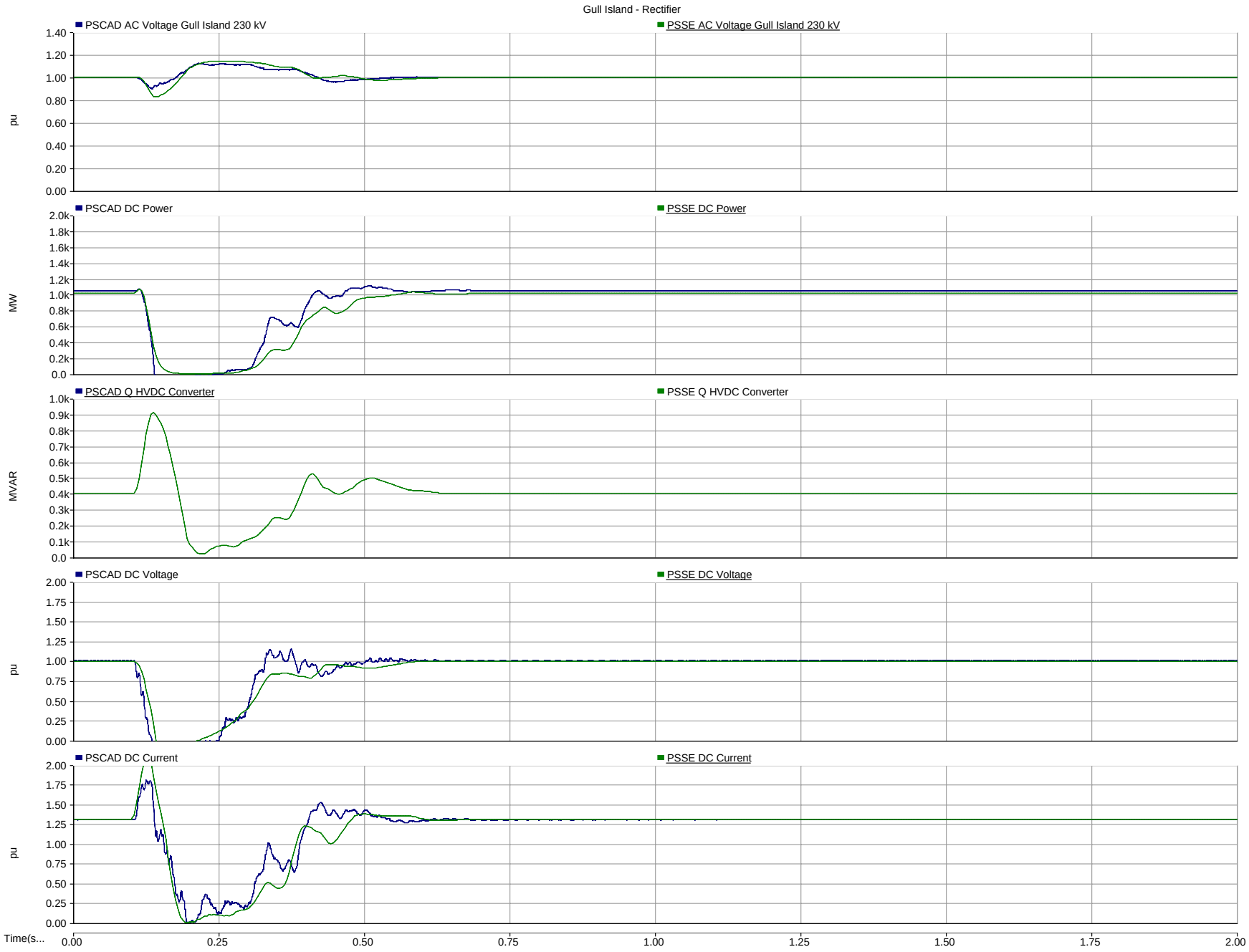
Three-Phase Solid Fault (0%) - Gull Island 230 kV Bus
Monopolar: Gull Island 1046 MW Rectifier, Soldiers Pond 572 MW Inverter, Salisbury 400 MW Inverter
System Equivalent Model - Minimum Short Circuit Levels



PSSE v30.3
PSCAD v4.2.1

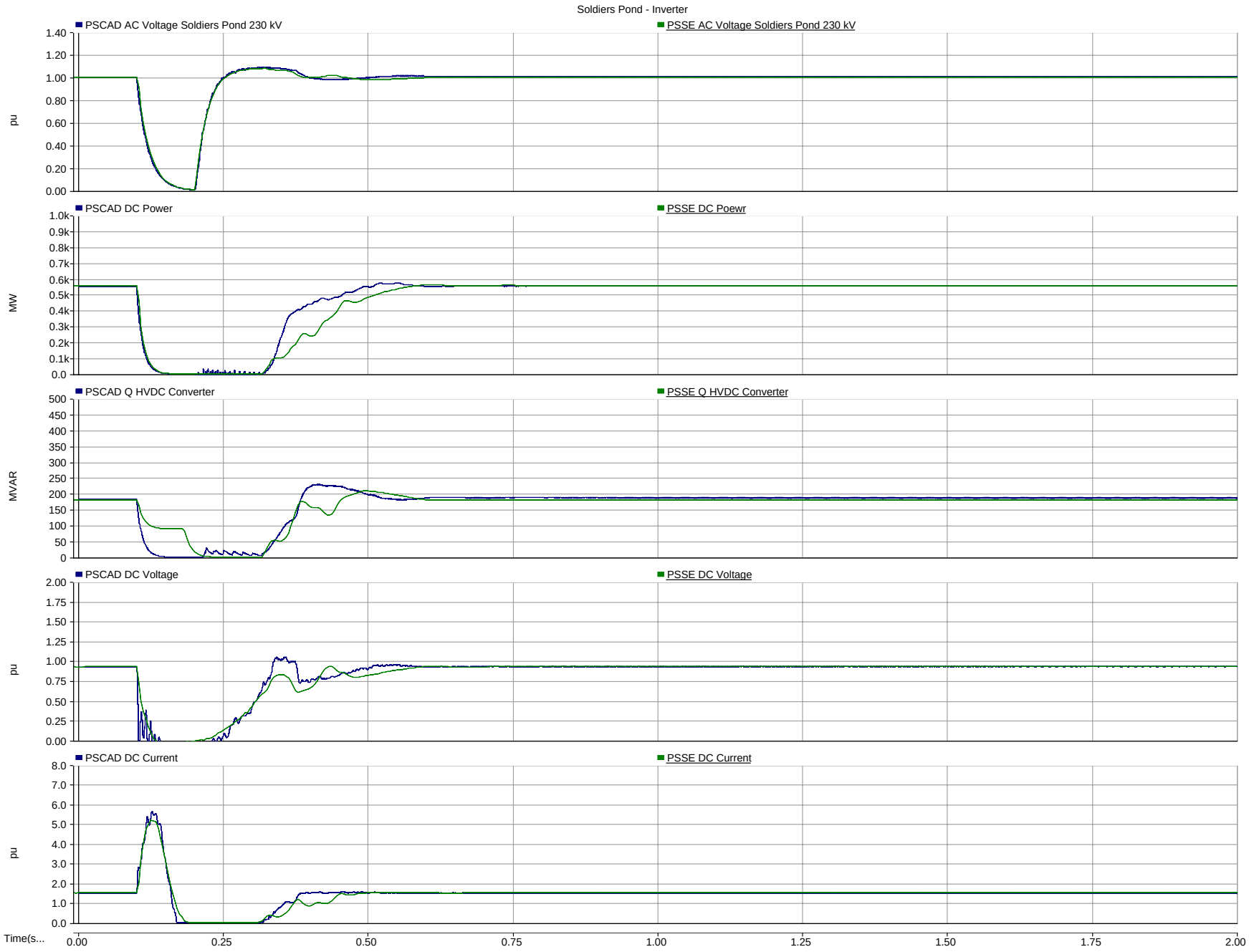
Three-Phase Solid Fault (0%) - Gull Island 230 kV Bus
Monopolar: Gull Island 1046 MW Rectifier, Soldiers Pond 572 MW Inverter, Salisbury 400 MW Inverter
System Equivalent Model - Minimum Short Circuit Levels


Salisbury - Inverter
PSCAD AC Voltage Salisbury 345 kV
PSSE AC Voltage Salisbury 345 kV
pu
PSCAD DC Power
PSSE DC Power
MW
PSCAD Q HVDC Converter
PSSE Q HVDC Converter
MVAR
PSCAD DC Voltage
PSSE DC Voltage
pu
PSCAD DC Current
PSSE DC Current
pu
Time(s...
0.00
0.25
0.50
0.75
1.00
1.25
1.50
1.75
2.00



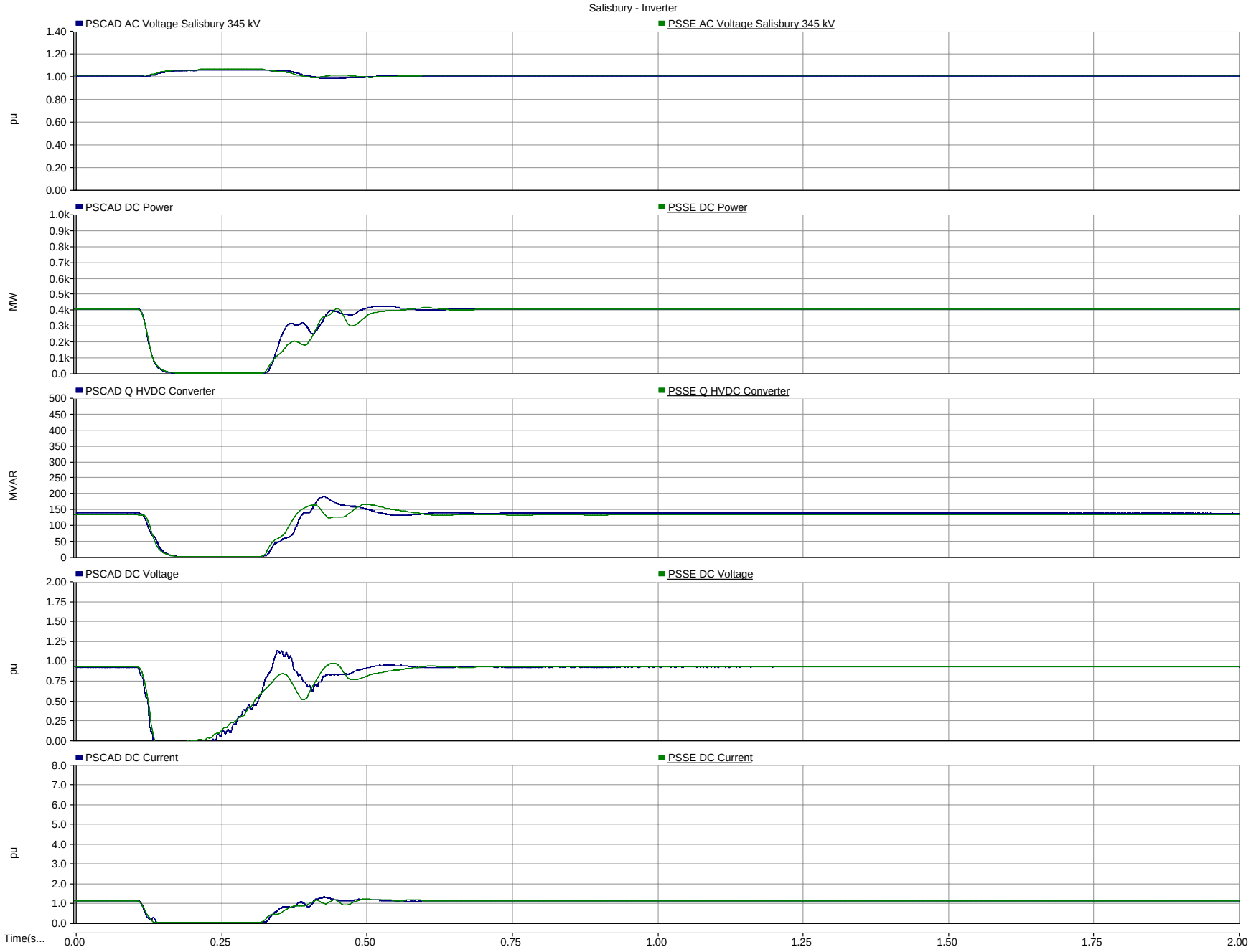
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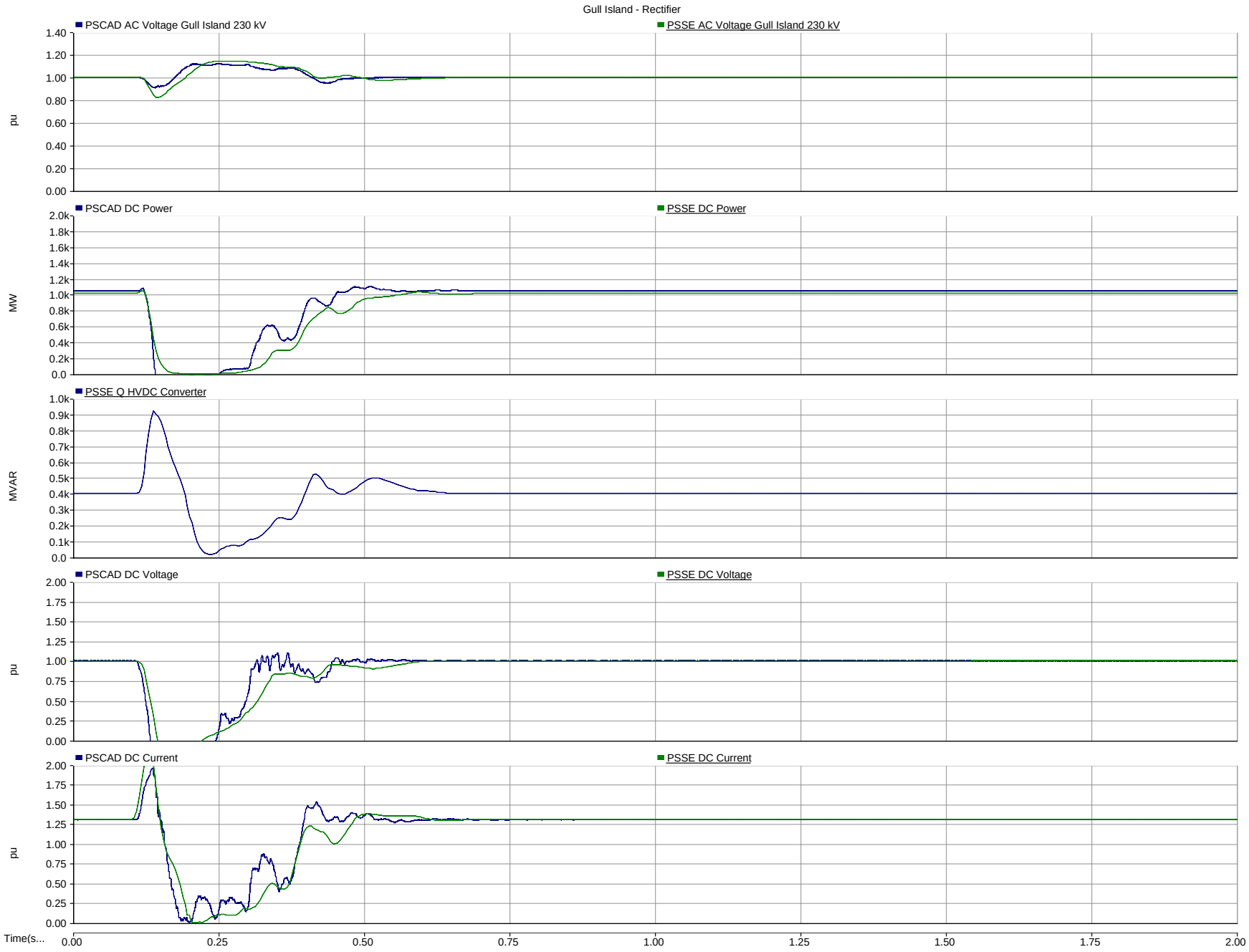
Three-Phase Solid Fault (0%) - Soldiers Pond 230 kV Bus
Monopolar: Gull Island 1046 MW Rectifier, Soldiers Pond 572 MW Inverter, Salisbury 400 MW Inverter
System Equivalent Model - Minimum Short Circuit Levels



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PSCAD v4.2.1

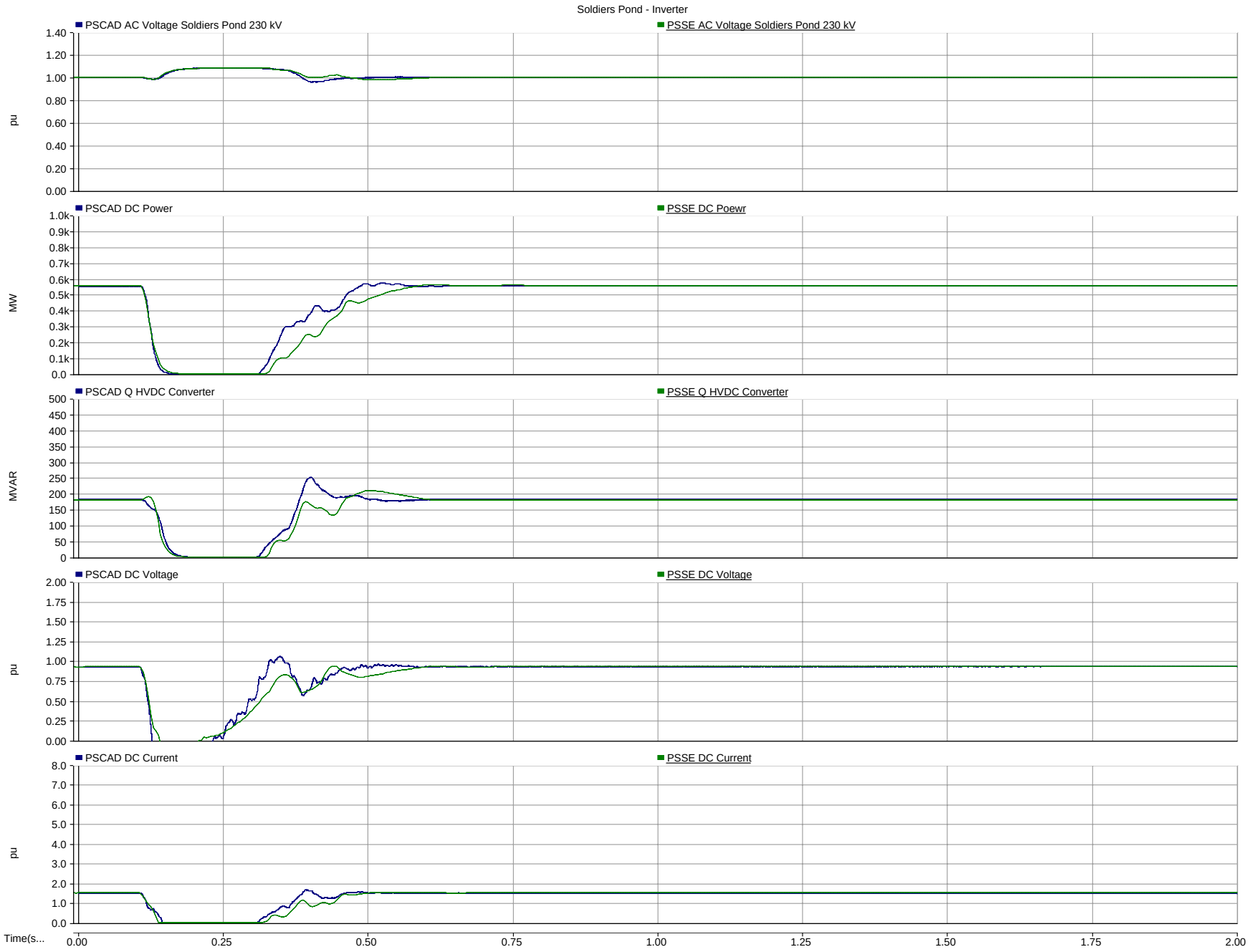
Three-Phase Solid Fault (0%) - Soldiers Pond 230 kV Bus
Monopolar: Gull Island 1046 MW Rectifier, Soldiers Pond 572 MW Inverter, Salisbury 400 MW Inverter
System Equivalent Model - Minimum Short Circuit Levels

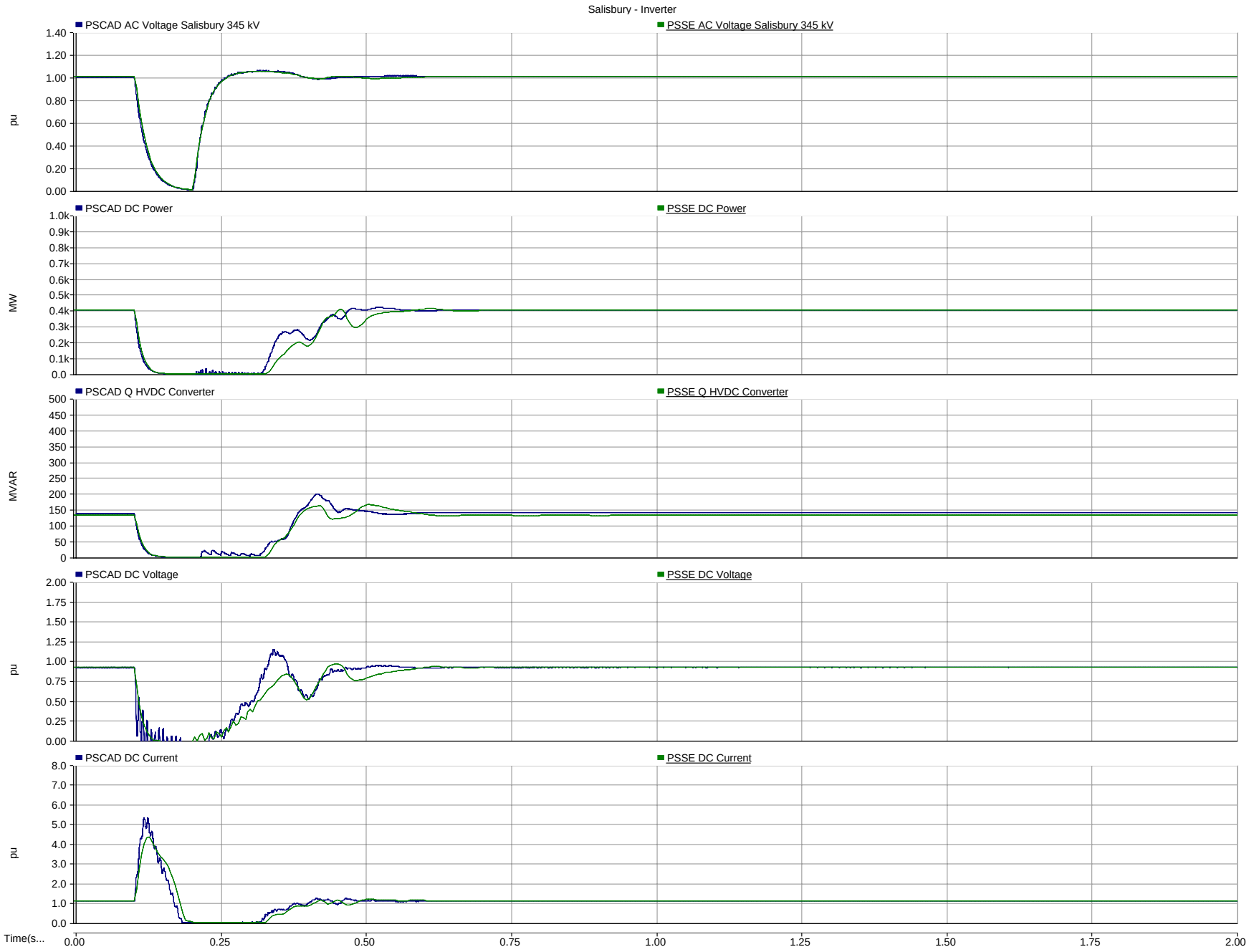

Salisbury - Inverter
PSCAD AC Voltage Salisbury 345 kV
PSSE AC Voltage Salisbury 345 kV
pu
PSCAD DC Power
PSSE DC Power
MW
PSCAD Q HVDC Converter
PSSE Q HVDC Converter
MVAR
PSCAD DC Voltage
PSSE DC Voltage
pu
PSCAD DC Current
PSSE DC Current
pu
Time(s...
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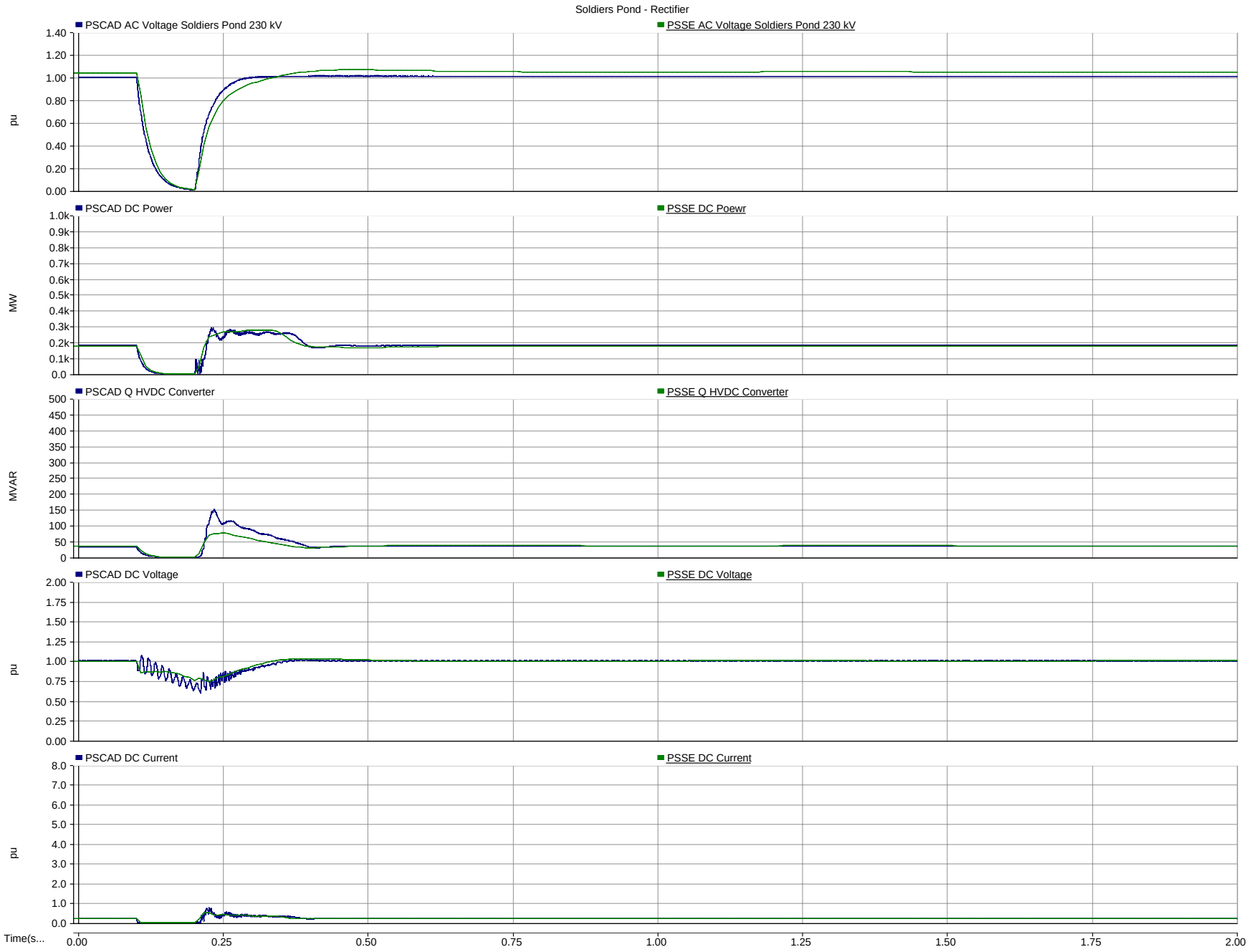


PSSE v30.3
PSCAD v4.2.1

Three-Phase Solid Fault (0%) - Salisbury 345 kV Bus
Monopolar: Gull Island 1046 MW Rectifier, Soldiers Pond 572 MW Inverter, Salisbury 400 MW Inverter
System Equivalent Model - Minimum Short Circuit Levels

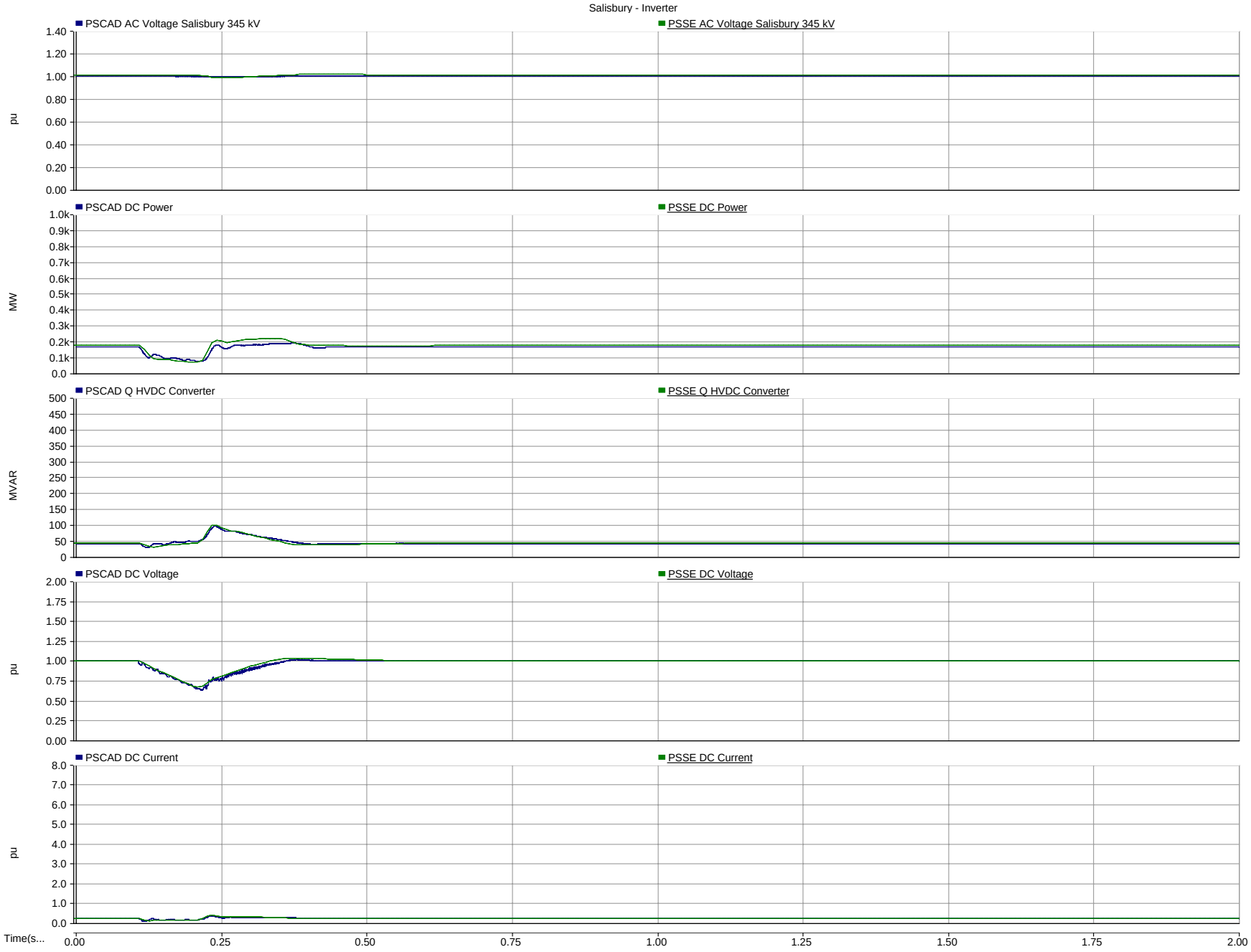

Soldiers Pond - Inverter
PSCAD AC Voltage Soldiers Pond 230 kV
PSSE AC Voltage Soldiers Pond 230 kV
pu
PSCAD DC Power
PSSE DC Poewr
MW
PSCAD Q HVDC Converter
PSSE Q HVDC Converter
MVAR
PSCAD DC Voltage
PSSE DC Voltage
pu
PSCAD DC Current
PSSE DC Current
pu
Time(s...
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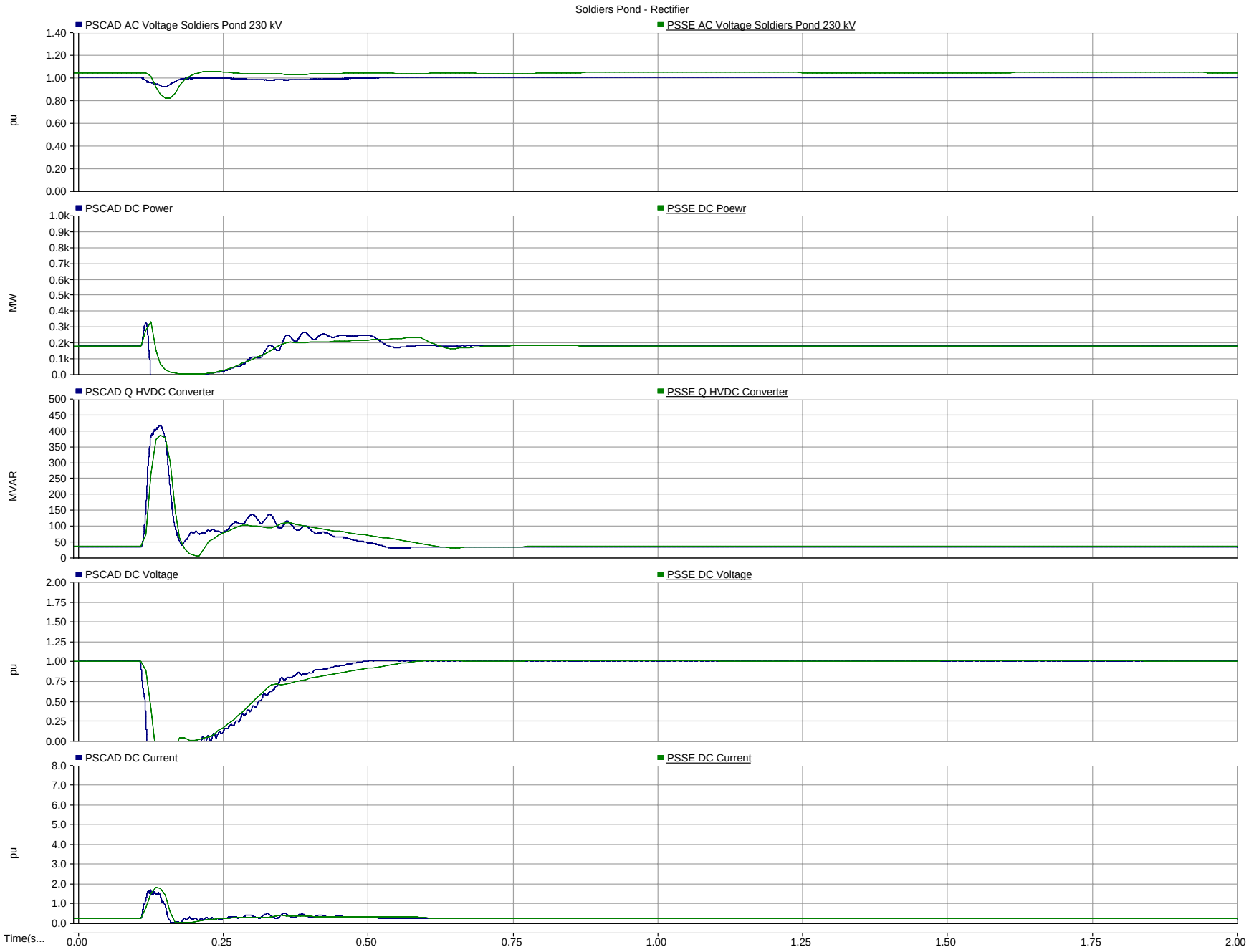

Salisbury - Inverter
PSCAD AC Voltage Salisbury 345 kV
PSSE AC Voltage Salisbury 345 kV
pu
PSCAD DC Power
PSSE DC Power
MW
PSCAD Q HVDC Converter
PSSE Q HVDC Converter
MVAR
PSCAD DC Voltage
PSSE DC Voltage
pu
PSCAD DC Current
PSSE DC Current
pu
Time(s...
0.00
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PSSE v30.3
PSCAD v4.2.1

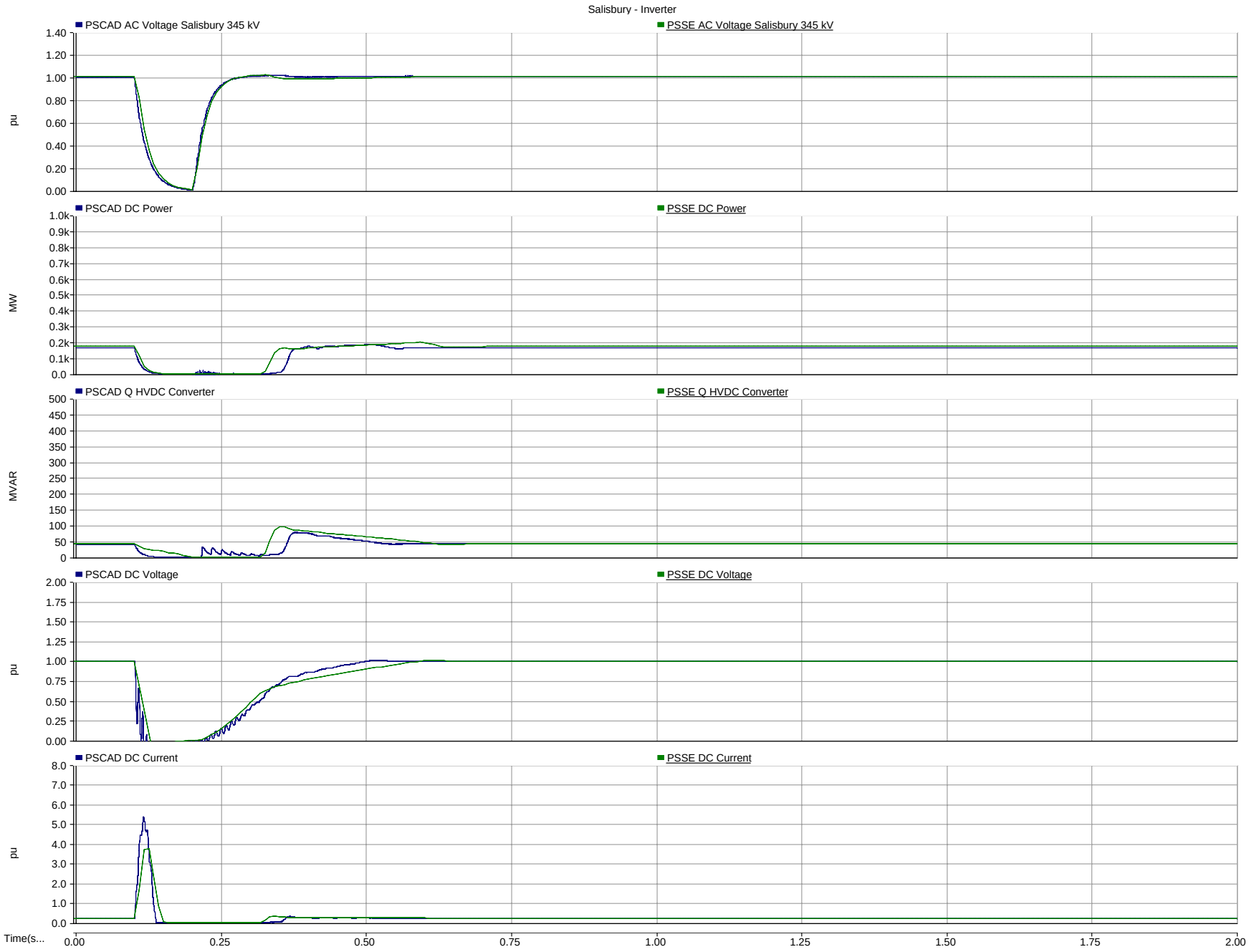
Three-Phase Solid Fault (0%) - Soldiers Pond 230 kV Bus
Two-Terminal: Gull Island OFF, Soldiers Pond 175 MW Rectifier, Salisbury 175 MW Inverter
System Equivalent Model PSCAD - Reduced System Model PSSE


Salisbury - Inverter
PSCAD AC Voltage Salisbury 345 kV
PSSE AC Voltage Salisbury 345 kV
pu
PSCAD DC Power
PSSE DC Power
MW
PSCAD Q HVDC Converter
PSSE Q HVDC Converter
MVAR
PSCAD DC Voltage
PSSE DC Voltage
pu
PSCAD DC Current
PSSE DC Current
pu
Time(s...
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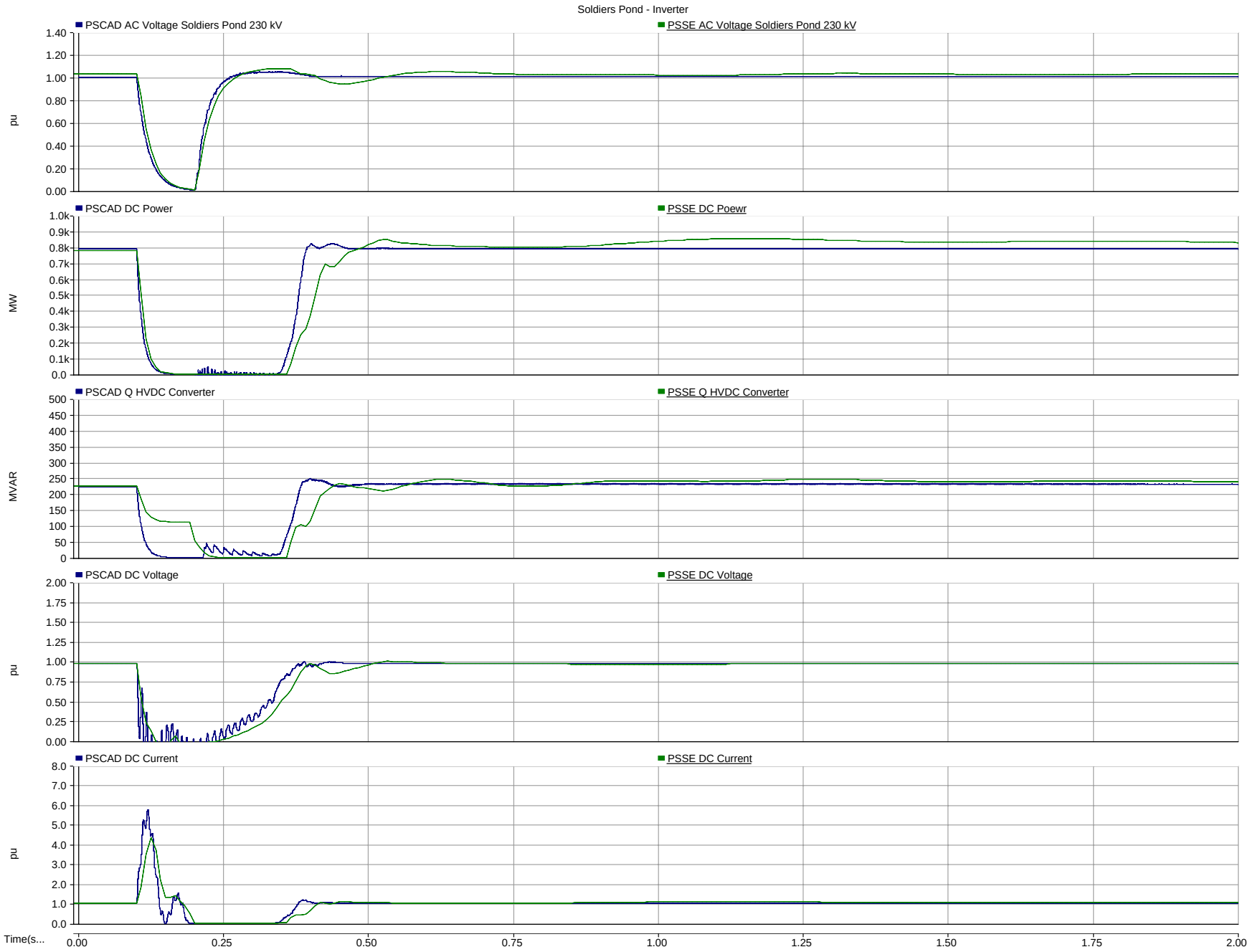
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PSCAD v4.2.1

Three-Phase Solid Fault (0%) - Salisbury 345 kV Bus
Two-Terminal: Gull Island OFF, Soldiers Pond 175 MW Rectifier, Salisbury 175 MW Inverter
System Equivalent Model PSCAD - Reduced System Model PSSE



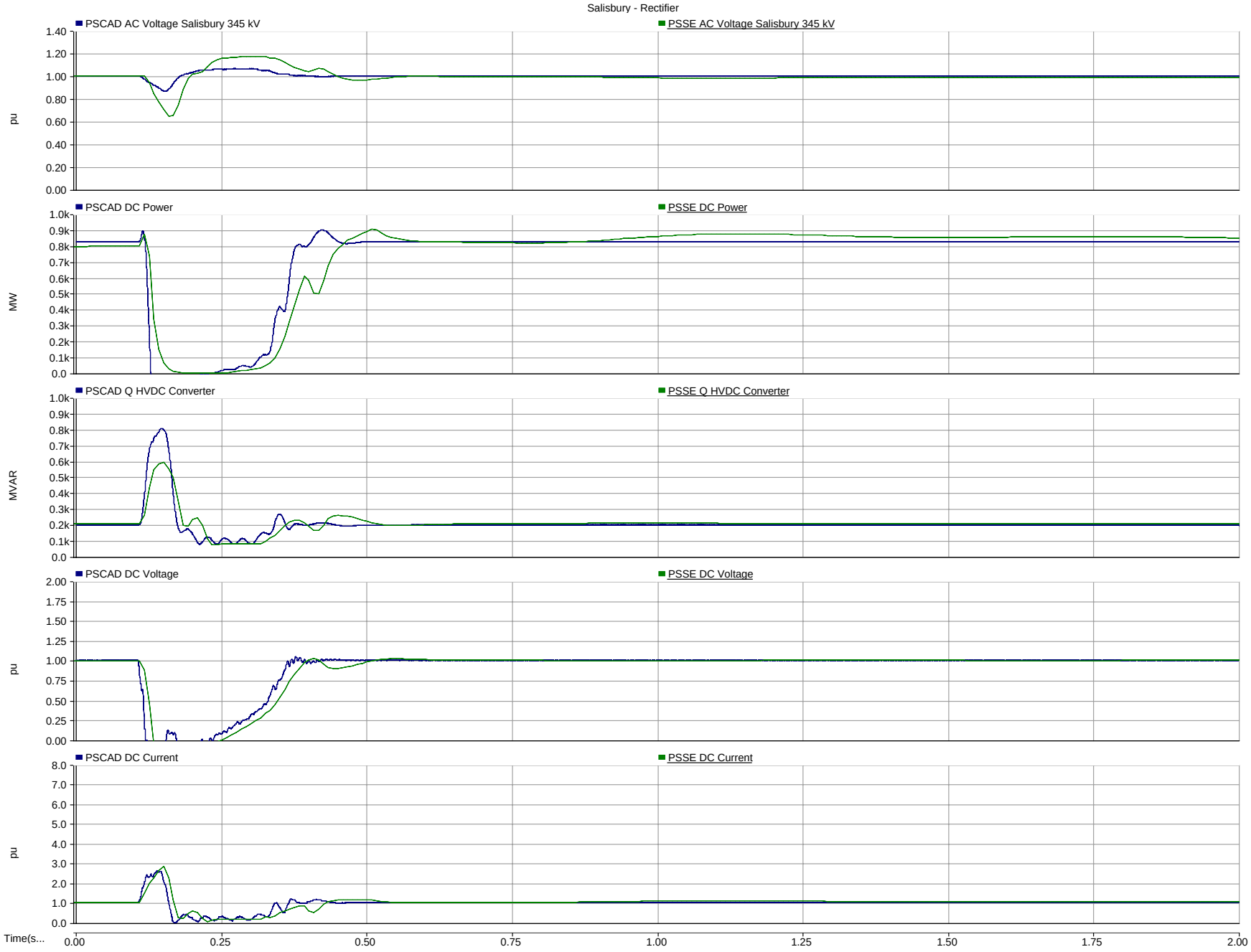
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PSCAD v4.2.1

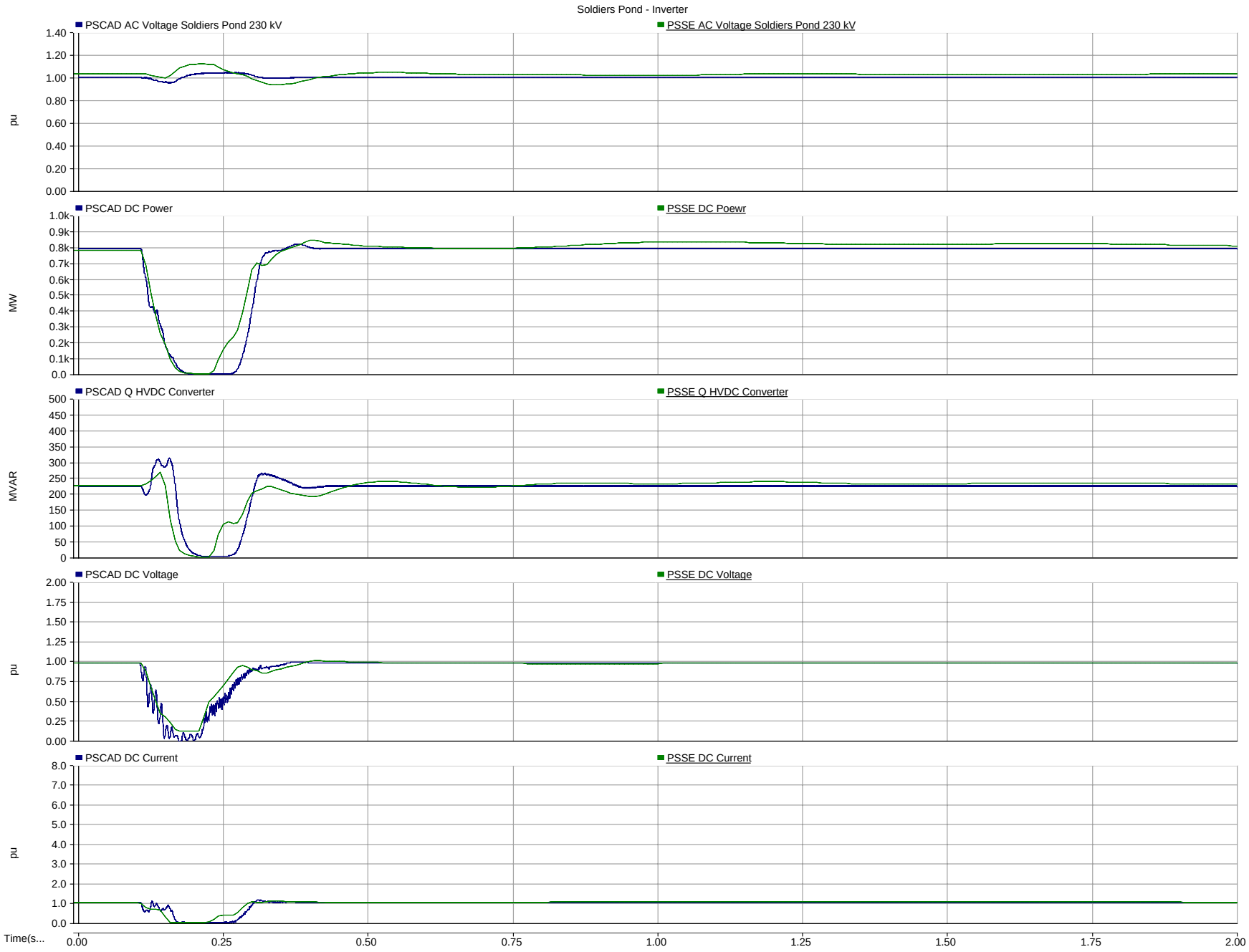
Three-Phase Solid Fault (0%) - Salisbury 345 kV Bus
Two-Terminal: Gull Island OFF, Soldiers Pond 175 MW Rectifier, Salisbury 175 MW Inverter
System Equivalent Model PSCAD - Reduced System Model PSSE



PSSE v30.3
PSCAD v4.2.1

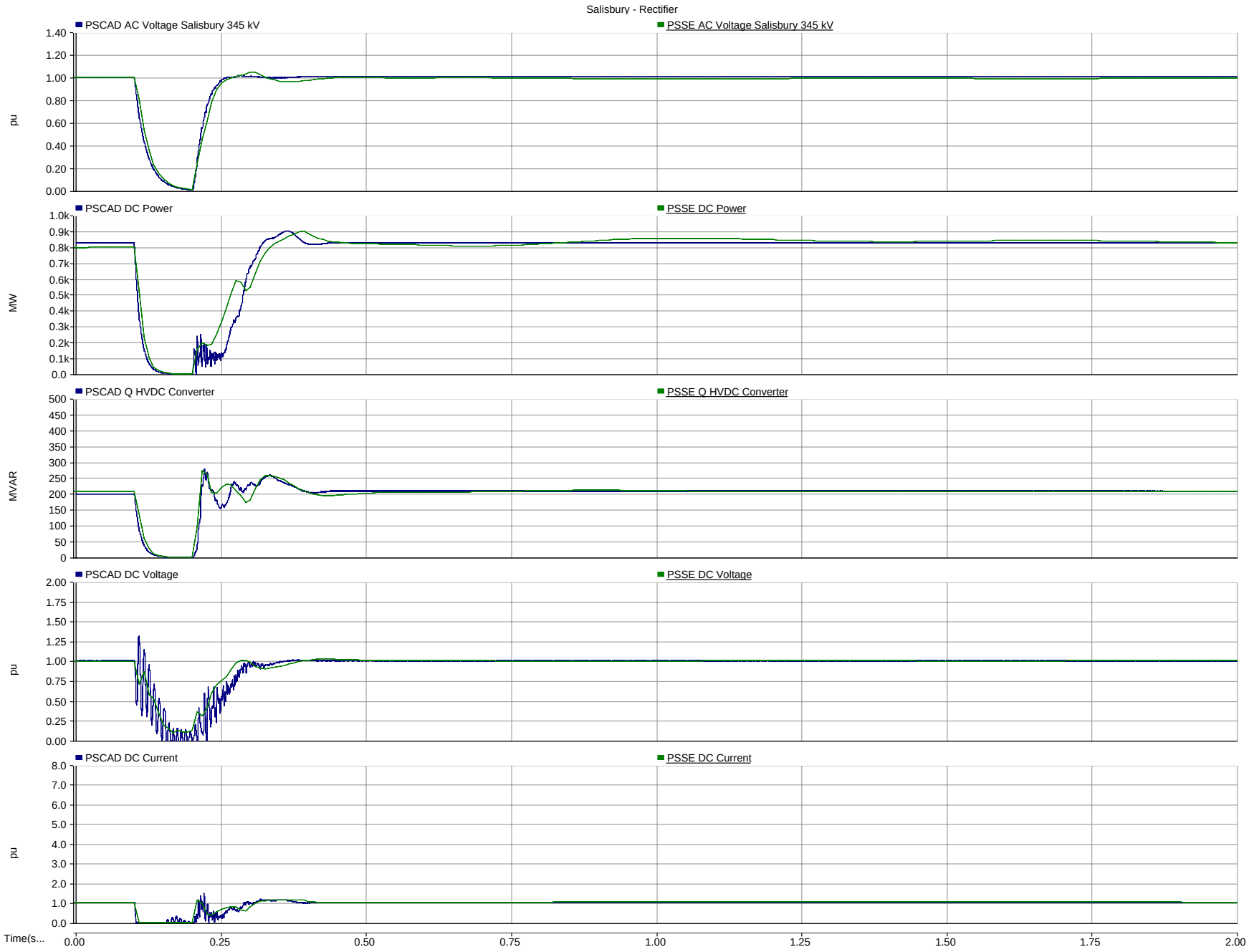
Three-Phase Solid Fault (0%) - Soldiers Pond 230 kV Bus
Two-Terminal: Gull Island OFF, Soldiers Pond 800 MW Inverter, Salisbury 800 MW Rectifier
System Equivalent Model PSCAD - Reduced System Model PSSE


Salisbury - Rectifier
PSCAD AC Voltage Salisbury 345 kV
PSSE AC Voltage Salisbury 345 kV
pu
PSCAD DC Power
PSSE DC Power
MW
PSCAD Q HVDC Converter
PSSE Q HVDC Converter
MVAR
PSCAD DC Voltage
PSSE DC Voltage
pu
PSCAD DC Current
PSSE DC Current
pu
Time(s...
0.00
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0.50
0.75
1.00
1.25
1.50
1.75
2.00



PSSE v30.3
PSCAD v4.2.1

Three-Phase Solid Fault (0%) - Salisbury 345 kV Bus
Two-Terminal: Gull Island OFF, Soldiers Pond 800 MW Inverter, Salisbury 800 MW Rectifier
System Equivalent Model PSCAD - Reduced System Model PSSE



PSSE v30.3
PSCAD v4.2.1

Three-Phase Solid Fault (0%) - Salisbury 345 kV Bus
Two-Terminal: Gull Island OFF, Soldiers Pond 800 MW Inverter, Salisbury 800 MW Rectifier
System Equivalent Model PSCAD - Reduced System Model PSSE

Appendix C

DC1210 VSC Risk Assessment Final Report

HYDRO
THE POWER OF COMMITMENT

THE Lower Churchill PROJECT

January 2009

DC1210 - VSC Risk Assessment

prepared by

HATCH™

in association with

RSW Inc.

Statnett

TGS

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Executive Summary

The purpose of this technical note is to present a high level evaluation of the application of a Voltage Source Converter (VSC) for the Lower Churchill HVdc transmission project.

In order to perform such an evaluation it is important to:

- Examine the status of the art of the VSC technology mainly as it applies to HVdc transmission.
- Examine the characteristics of the VSC.
- Examine the future developments in HVdc.

The evaluation involved obtaining the most up to date data from the suppliers regarding the ratings and availability of these ratings for commercial use. This was followed by comparing this information with the technical requirements of the HVdc project.

This high level evaluation concluded the following:

- The rating at Gull Island can be better realized using a conventional line commutated converter (LCC).
- The rating at Soldiers Pond can be achieved using a VSC converter.
- The rating at Salisbury can be achieved using a VSC converter.
- The HVdc cable will still require a mass impregnated cable.
- Results of preliminary transient stability simulations showed an overall improvement in system performance for all ac and dc faults that were studied with fewer synchronous condensers than required for the LCC technology.

The following recommendations are made:

- The application of VSC technology for the Lower Churchill Project should be considered; however, a performance study should be performed.
- Based on promising results seen from preliminary transient stability simulations, it is recommended to perform a more complete performance evaluation of VSC technology for the Soldiers Pond terminal.

1. Introduction

The purpose of this technical note is to present a high level evaluation of the application of a Voltage Source Converter (VSC) for the Lower Churchill HVdc transmission project. In order to perform such an evaluation it is important to:

- Examine the state-of-the-art of the VSC technology mainly as it applies to HVdc transmission.
- Examine the characteristics of the VSC.
- Examine the future developments in HVdc.

1.1 The Current State-of-the-Art of the VSC Technology

The VSC technology for HVdc power transmission applications is advancing quickly, from the start of a very moderate rating of 3 MW in 1997 which was demonstrated in the Hellsjőn project to the present rating of 400 MW in Transbay Cable Project to be in service in 2010. Currently HVdc using VSC technology can be at a rating of 1100 MW and +/- 320 kV with an overhead line. The current projection indicates that a full bipole at +/- 640 kV dc and 2200 MW is achievable.

Commercially the VSC technology is marketed by two of the leading suppliers of HVdc under two trade names:

- HVdc Light.
- HVdc Plus.

In the beginning, the application of VSC in HVdc was always tied to its connection to a HVdc cable, because in a VSC converter, during a dc fault, currents from the ac side feed through the bi-directional converter valves into the dc fault and cannot be cleared until the main ac breaker is tripped, unlike conventional LCC HVdc in which the ac side does not contribute to the dc fault due to the uni-directional valves. This means that during a dc fault on a VSC, the whole converter must be tripped in order to clear the fault, which means that automatic re-starting is not an option. Since cable applications do not usually offer a restart, as a fault on the cable is almost always a permanent fault, this limitation was not an issue for the VSC.

The idea here is that because a VSC does not control fault currents for faults occurring on the dc side it was always promoted as a complete solution with cables.

Since the VSC maintains a constant dc voltage, regardless of direction, reversal of power direction in a VSC HVdc system does not require the polarity reversal of the dc voltage, and so the use of a cheaper, cost effective Cross Linked Polyethylene (XLPE) cable in conjunction with VSC is wide spread.

Recently, for the Caprivi HVdc interconnector in Namibia, the VSC technology was applied to an overhead line. This project is rated at 300 MW at 350 kV and will go in to service in 2009. There is a provision to add a second pole to this link in the future to operate as an integrated bipole. By using high-speed HVdc circuit breakers, in the event of a dc fault, the fault can be cleared quickly allowing the converters to restart in about 500 ms.

1.2 Operating Experience of VSC HVdc Stations

The current major VSC based HVdc systems are listed in Table 1.1.

Table 1.1
VSC Based HVdc Systems Currently in Operation or Under Construction

Scheme	Rating MW	Voltage kV	VSC converter type **
Cross Sound	330	+/- 150	3 level converter
Murray Link	220	+/- 150	3 level converter
Direct Link	180	+/- 80	2 level converter
Gotland	50	+/- 60	2 level converter
Est link	150	150	2 level converter
Caprivi *	300	350	2 level converter
Transbay	400	+/- 200	Multi level

** First project with overhead line, it is to be expanded to a 600 MW bipole.*

*** The type of converters is described in Section 2.2.*

The operating statistics of HVdc systems are collected and analyzed by Cigre Working Group B4-04. However, so far none of the existing VSC based HVdc systems have reported their operating experiences. But there have not been any major reliability issues with these systems and from the discussions we have had with one of the operating companies of a VSC HVdc link, it has been running smoothly and successfully.

1.3 Characteristics of VSC Converters

It is important to define the types of VSCs that have been used in HVdc applications so far.

1.3.1 Two-Level Converter

A two-level converter is a converter in which the voltage of the ac terminals is switched between two discrete dc voltage levels.

1.3.2 Three-Level Converter

A three-level converter is a converter in which the voltage of the ac terminals is switched between three discrete dc voltage levels.

1.3.3 Multi-Module Converter

A multi-module converter is a converter in which the voltage of the ac terminals is switched between more than three discrete dc voltage levels using many converter modules.

Currently from the two suppliers that are offering VSC technology for HVdc, one offers the two and three-level converters with pulse width modulation control, and the other offers the multi-module converter as shown in Figures 1.1 and 1.2.

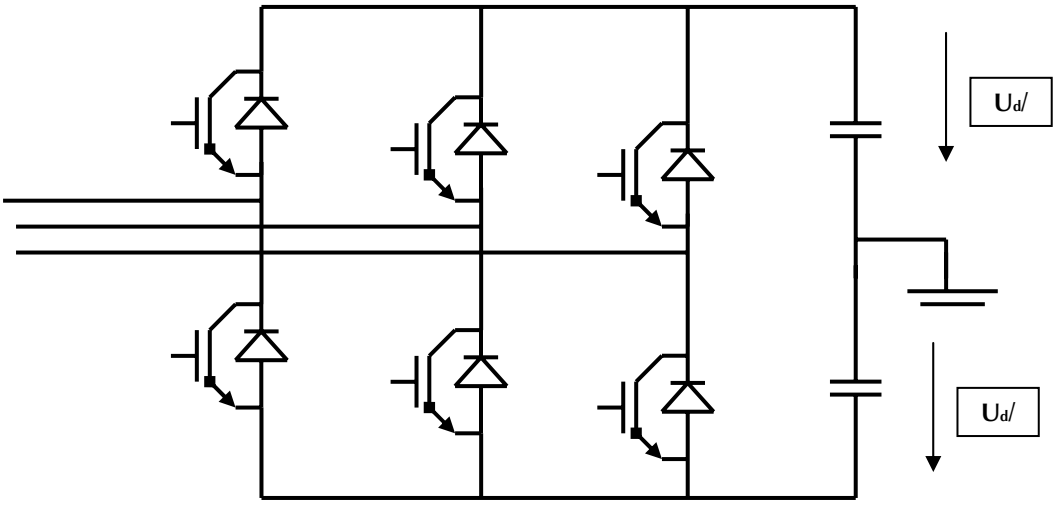


Figure 1.1 Two-Level Converter

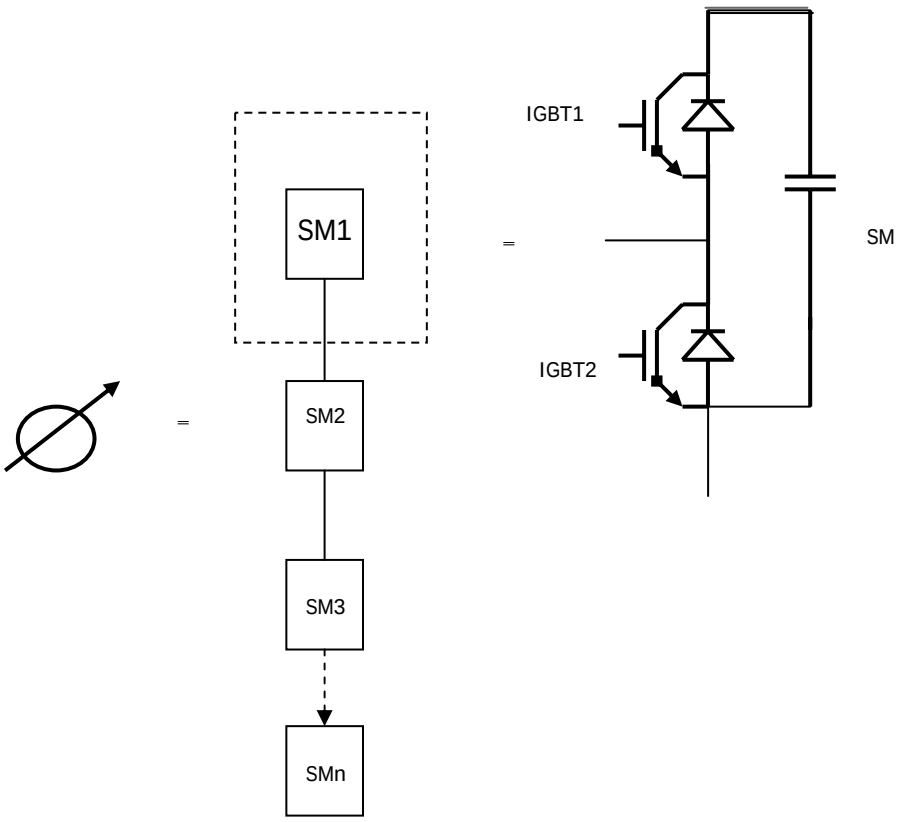


Figure 1.2 Multi-Module Converter

1.4 Comparison Between the Features of the VSC and the LCC

In order to draw any conclusions regarding the application of a VSC for the multi-terminal Lower Churchill HVdc transmission project, it is important to compare the VSC and the LCC converters as presented in Table 1.2.

Table 1.2
Comparison between LCC based and VSC based HVdc Systems

Comparison	LCC	VSC
Semi-Conductor Device	Thyristors currently 6 inch, 8.5 kV and 6000 Amps. No controlled turn- off capability	IGBTs with anti-parallel free wheeling diode, with controlled turn-off capability.
dc transmission voltage with a cable	Up to 500 kV	Up to +/- 300 kV currently limited by HVdc cable if extruded XLPE cable is used.
dc transmission voltage with an overhead line	Up to +/- 800 kV	Up to +/- 640 kV
dc power	Currently in the range of 6000 MW per bipolar system	Currently up to 1100 MW and projected to increase to 2200 MW
Reactive power requirements	Consumes up to 60% of its rating reactive power	Does not consume any reactive power and each terminal can independently control its reactive power.
Filtering	Requires large filter banks	Requires moderate size filter banks or no filters at all.
Black start	Limited application	Capable of black start and feeding passive loads
ac system short circuit level	Critical in the design	Not critical at all
Commutation failure performance	Fails commutation for ac disturbances	Does not fail commutation
Over load capability	Available if designed for up to any required design value	Does not have any overload capability
Application with overhead lines	Can be applied and dc line faults can be cleared by converter control	Can be applied but dc line faults are cleared by trip of ac breaker, or the use of a dc circuit breaker. Currently one application of overhead line. It has mostly been applied with cables.
Small taps	Not economic and affects the performance	Economic and should improve the performance
Load rejection over voltage	Large and has to be mitigated because of the large reactive power support	Not large because of small size of filters if required.
dc line to ground faults	Little effect on ac system with proper overload capacity	During the time it takes to clear the fault from the ac side, reactive power will be drawn. However the impact is less than a regular ac fault.

1.5 Semiconductor Devices for VSC Applications

Currently the semi-conductor device of choice is the Insulated Gate Bipolar Transistor (IGBT). The following section discusses the state of the art of the IGBT.

The N-channel IGBT is an N-channel MOSFET constructed on a p-type substrate thus forming a cascade connection of a vertical bipolar junction transistor with a surface MOSFET. Therefore the operation of an IGBT is similar to a power MOSFET. With the combination of a MOS gate and the continuous improvement of conduction losses, IGBTs are gaining a wider acceptance in the power transmission area. IGBTs now have a balance between the switching speeds, conduction losses and robustness.

IGBTs for the VSC applications can be press-pack or wire bonded. In the press-pack IGBT there are no solder or wire bond joints. The press-pack has the advantage of being in similar physical shape as other semi conductor devices such as thyristors and GTO thyristors. The electromechanical performance of the pressure contact IGBT is equal to the performance of other conventional devices such as thyristors.

The press-pack IGBT allows converter designs that are very similar in the mechanical structure as the present day HVdc technology. It also allows double sided cooling.

Currently both the press-pack and the wire bonded IGBTs are being applied in the high voltage and high power VSC technology.

1.6 Future of VSC Technology in HVdc

It is clear that the VSC technology will expand over the next few years. The current rating of the IGBT turn-off current of 1718 amperes will certainly increase in the future. This turn-off current rating is the major determining factor for the rating of a single converter. Obviously the dc voltage also has an impact on the rating. However, dc voltage is only a limitation for the XLPE cables and not for overhead lines or the mass impregnated cables. Currently, ratings of up to 1100 MW are being quoted.

One other factor to be considered is the overload capability of the VSC which is currently non-existent.

2. Application of VSC in Multi-Terminal HVdc Systems

Multi-terminal HVdc systems have been realized in a number of HVdc schemes that are in operation. Although it has not been a widely used application in HVdc, there has not been any unusual technical reason against applying them.

The questions being asked are related to the reliability of a multi-terminal HVdc system, i.e. how reliable is a multi-terminal HVdc system?

In principle, multi-terminal HVdc using line commutated converters (LCC) is reliable and the reliability is dependent upon:

- Reliable control and protection.
- Reliable communication system between the terminals.

Most components in the HVdc stations within a multi-terminal system are not unique and should not be a factor in determining the reliability of the scheme.

Two existing HVdc schemes have been designed as multi-terminal from the start:

- Sacoi HVdc system (Sardinia to main land Italy with a parallel tap in Corsica).
- Hydro Quebec HVdc system to New England.

Two systems operate in a multi-terminal configuration in an emergency mode:

- Nelson River bipoles 1 and 2 parallel operation.
- Itaipu bipoles 1 and 2 parallel operation.

One unique case is the Pacific Inter-Tie where currently one end of the transmission is a single converter per pole and the other end consists of two terminals in parallel.

2.1 Multi-terminal configurations

Figure 2.1 shows a typical application of parallel taps in a three terminal configuration.

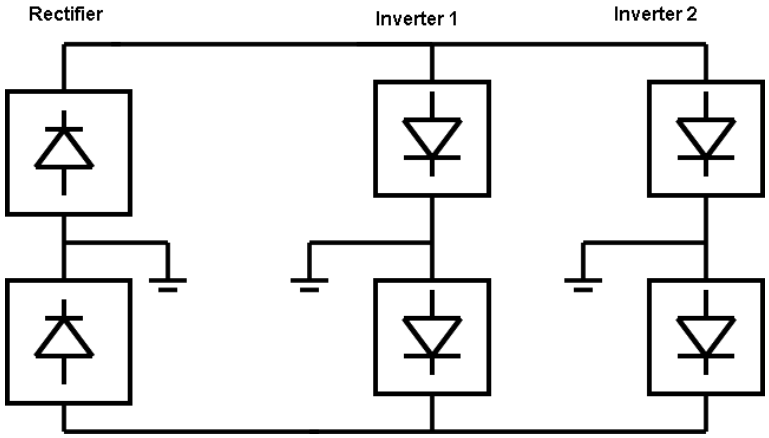


Figure 2.1 A Three-Terminal HVdc Configuration

In this case one rectifier station is connected to two inverter stations; however, any of the three stations can be connected to the multi-terminal HVdc system as a rectifier or an inverter using the appropriate reversing switches.

The performance of the complete HVdc system is certainly a function of the performance of the individual terminals.

Theoretically any number of terminals or taps can exist; however, the complexity of the control and protection systems as well as the amount of signal exchange required between terminals via the communication system will grow as the number of terminals increase. Currently three terminals are in commercial operation and four terminals are being seriously considered for two HVdc systems.

The performance of the multi-terminal system is dependent on the performance of each of the terminals. Therefore if all of the stations are comparable in rating, size, and strength of the ac system to which the stations are connected, there should not be any performance concerns. The problem arises when one of the parallel terminals operating as an inverter is relatively small in rating, and this inverter will typically be feeding a weak ac system. Dealing with this small tap is not easy and certainly affects the performance of the complete HVdc system. For example, if a parallel tap is rated for 10-20 percent of the total power, such a tap upon failing commutation due to an ac disturbance in its ac system will lead to the tap taking the full dc link current, affecting its recovery as well as the recovery of the complete system, unless some protective action is taken by the large terminals which again affects the power delivery of the complete system.

Such performance issues made many shy away from such multi-terminal configurations with a small tap. In fact the typical solution is to build the HVdc link for its main intended purpose and to feed the small load by other alternatives.

The question then becomes what a VSC can do in a multi-terminal HVdc system. There are two approaches:

- The complete system is realized through the use of VSC as shown in Figure 2-2. However, in this configuration the total power transmission capability is limited by the current rating of the VSC converters which is tied to the turn-off current rating of the IGBTs. For power reversal, there is no need to reverse the voltage and therefore, unlike the LCC based system, there is no need for extra switching equipment.
- The second approach would be a hybrid configuration in which the main strong system high rating converters are realized using LCC and the weak system small tap converter using VSC as shown in Figure 2-3. This certainly is a workable solution. It achieves the high rating of the main HVdc link and a robust converter for the small tap, weak ac system. The VSC is immune to commutation failures, and hence, the overall system performance is improved.

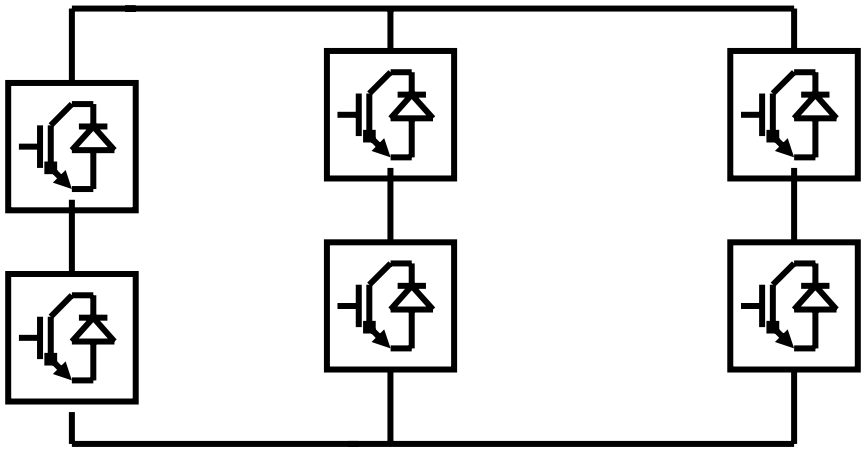


Figure 2.2 A VSC Based Multi-Terminal HVdc System

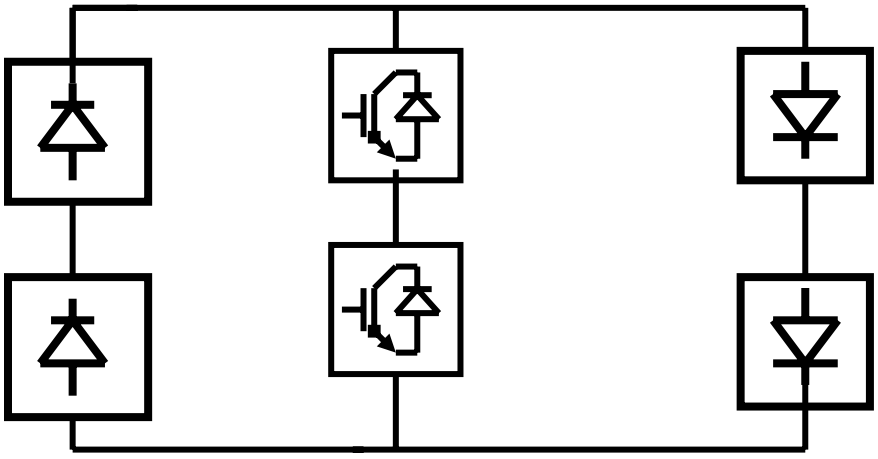


Figure 2.3 Hybrid Multi-Terminal Configuration

3. Description of the Lower Churchill HVdc Link

Newfoundland and Labrador Hydro (Hydro) is planning to install a three-terminal HVdc system linking Labrador, Newfoundland, and New Brunswick. The proposed HVdc system will be bipolar, with each converter station having the ability to run as either rectifier or inverter. It will involve cable and overhead lines, with about 40 km of cable between Labrador and Newfoundland and about 480 km between Newfoundland and New Brunswick. The proposed HVdc system is conceptually shown in Figure 3-1 below.

The Labrador (Gull Island) converters will be nominally rated at 1600 MW; whereas, the Newfoundland (Soldiers Pond) and New Brunswick (Salisbury) stations will each be rated at 800 MW. The converters at Soldiers Pond require an overload capability of 2.0 pu for 10 minutes and 1.5 pu continuously. This would allow for the startup of generation to avoid load shedding in the event of the loss of one pole of the HVdc system. The converters at Salisbury do not require any special overload capability and will have an overload rating which is typical of HVdc systems (10-15%). Gull Island converters should have enough overload capacity to accommodate the overload requirements at Soldiers Pond.

Characteristics of the HVdc link are summarized as:

- Bipolar, three-terminal HVdc link.
- Nominal voltage: +/- 450 kV (at rectifier).
- Nominal converter ratings:
  - Gull Island – 1600 MW.
  - Soldiers Pond – 800 MW.
  - Salisbury – 800 MW.

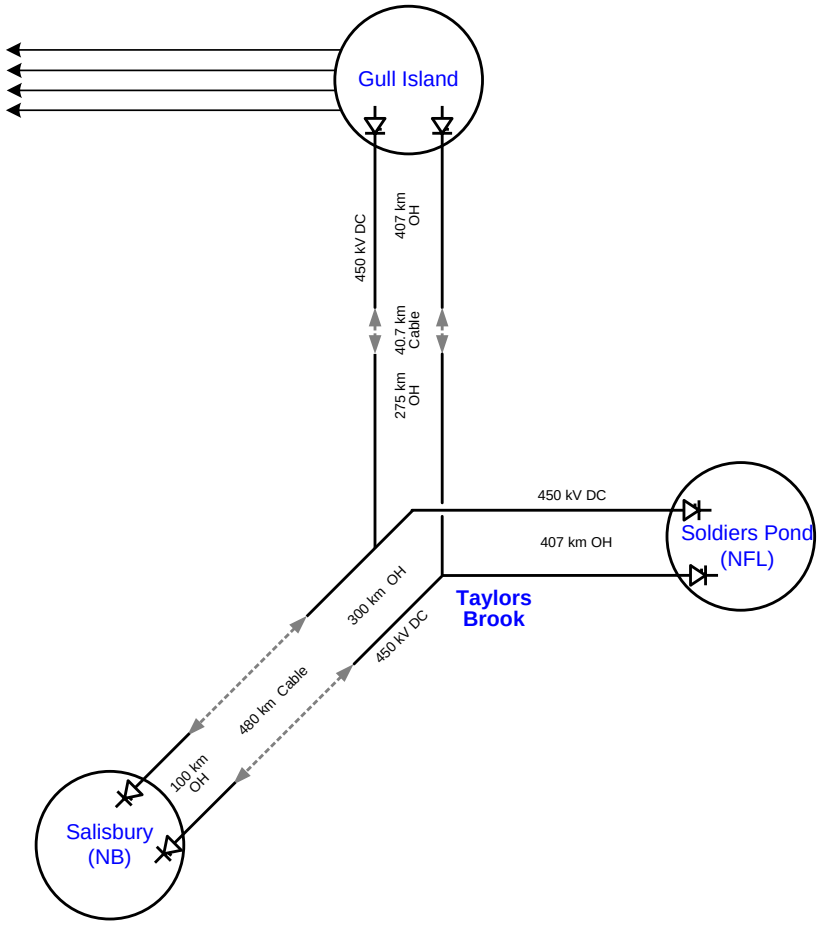


Figure 3.1 Lower Churchill HVdc System Terminal Locations

4. Application of VSC in the Lower Churchill Project

4.1 Basic Requirements

Basic requirements include:

- Bipolar configuration.
- dc voltage of +/- 450 kV.
- A combination of overhead line and cables.
- A 1600 MW converter station at Gull Island.
- A high overload capability at Soldiers Pond (2 pu) in the event of a loss of a pole.
- Moderate overload at Salisbury (10-15%).
- Power reversal of all terminals.

A comparison between the basic requirements and the current state-of-the-art of the VSC technology would provide a good indication as to whether the VSC technology should be considered for the project.

As mentioned in Section 2.1, a VSC based multi-terminal HVdc link can be:

- A hybrid of LCC and VSC.
- A complete VSC HVdc system.

4.2 Comparison with the Basic Requirements

4.2.1 Bipolar Configuration

A VSC based system can be designed in a bipolar configuration. In fact the Caprivi project is designed as a bipolar system although for the first phase only one pole is supplied. So obviously it can operate in both bipolar and monopolar.

4.2.2 DC Voltage of 450 kV

For the converters and the overhead lines, there are no show stoppers at this voltage. In fact according to the suppliers, a dc voltage higher than 450 kV is possible. However, for the XLPE cable this is not possible. Therefore, a Mass Impregnated cable would have to be used.

4.2.3 The Station Rating at Gull Island

The Gull Island rating is 1600 MW, and if we consider that the present current rating is in the range of 1718 amperes, then at +/- 450 kV we can obtain a power rating of 1547 MW for the station or 773 MW per pole. These figures are a little short of the 1600 MW rating and short of the pole rating of 800 MW plus the short time overload for the loss of a pole.

One solution is to apply two VSC blocks in parallel per pole; however, this may be an unnecessary complication.

This may lend itself to make the terminal at Gull Island a conventional line commutated converter.

4.2.4 The Station Rating at Soldiers Pond

The station at Soldiers Pond is rated for 800 MW which is not a problem for the current state of the art of VSC. However, the issue here is the overload capability required at 2 pu even for 10 minutes and 1.5 pu continuously. This means that each pole will be rated for 800 MW for 10 minutes and 600 MW continuously.

VSC converters do not have an overload capability; therefore, the station at Soldiers Pond would have to be rated at 800 MW per pole continuously to account for the loss of a pole. With a current rating of 1718 amperes, the pole rating at Soldiers Pond will be 773 MW which is close to the 800 MW. The converters are the main pieces of equipment affected by such an upgraded power rating.

In principle, the rating and overload are achievable at Soldiers Pond.

4.2.5 The Station Rating at Salisbury

The station is rated at 800 MW and has very moderate overload requirements. Therefore this is a straight-forward application for a VSC station.

4.2.6 Power Reversal

Power reversal in a VSC station is easier than power reversal in a conventional LCC station as there is no need for reversing switches.

4.2.7 The Requirements for Synchronous Condensers for the Project

The transient stability analysis that has been performed on the HVdc infeed using LCC technology found that the main issue in the Newfoundland Island system is lack of inertia and the resulting system frequency decay due to three-phase ac faults which cause the HVdc converter to fail commutation; the nearer the ac fault location to the Bay d'Espoir generating station, the more power that is temporarily lost during the ac fault and subsequent commutation failure and the more severe the system frequency decay. This situation resulted in the need for a large number of high inertia synchronous condensers to be installed along with the HVdc infeed in order to save the Island system from frequency decay and system-wide collapse.

4.2.7.1 AC Faults

Because a VSC converter does not fail commutation during an ac fault, it is possible that if the Soldiers Pond terminal used VSC technology the synchronous condenser requirements of the Island system due to an ac fault would be reduced. Unless the three-phase ac fault is directly on the terminals of the VSC, even at reduced terminal voltage during a three-phase fault elsewhere in the Island system, for example during a three-phase fault at Bay d'Espoir, the VSC will still be able to feed a reduced amount of power to the Island system during the fault. In addition, the VSC will likely

be able to recover faster than the LCC infeed once the ac fault is cleared. Both of these factors suggest that the frequency decay seen during the LCC stability studies due to an ac fault may not be as severe and therefore the need for synchronous condensers may be reduced.

4.2.7.2 DC Faults

An inherent weakness of a VSC HVdc link is a dc line fault. During the time it takes to clear a dc line fault, it is fed from all the ac systems connected to the dc line through the VSC diodes. As a result large fault currents will be drawn from the ac system, however the effect will be less than a normal ac fault as the converter transformer, phase reactors, dc smoothing reactors (if present) and any line impedance between the location of the fault and the VSC introduce an impedance which limits the current drawn from the ac side as well as limiting the rate of growth of the fault current. However, for the length of time it takes to clear the dc line fault, the ac voltage in all connected systems will be considerably reduced. Power infeed from the VSC is also significantly reduced while the fault is present as the power transfer in the faulty pole is stopped and power transfer in the healthy pole is reduced due to the drop in ac voltage, Depending on how long it takes to clear the dc line fault, the system frequency decay may or may not be as severe as seen during the worst three-phase ac fault in the line-commutated converter studies.

Currently there are two VSC designs available for the application of HVdc. In both designs in a bipolar arrangement with grounded midpoint the anti-parallel diodes conduct to feed the dc line fault as shown in Figure 4-1. Under these circumstances the IGBTs are by-passed and are unable to extinguish the fault current. In earlier applications in which the VSC converters were applied in conjunction with HVdc cables, the assumption is that a fault on the cable is rare and the cable does not recover from such a fault and therefore the ac circuit breaker (S) is tripped and not automatically reclosed. However, with the application of VSC to overhead line, combined with the fact that dc line faults are more frequent and are considered to be able to recover from (as opposed to cable faults), a sequence of ac and dc breaker tripping and reclosing is applied to clear the dc line fault and restart the VSC HVdc overhead line. In LCC converters, a dc line fault is cleared by applying de-ionization attempts without the movement of any mechanical devices.

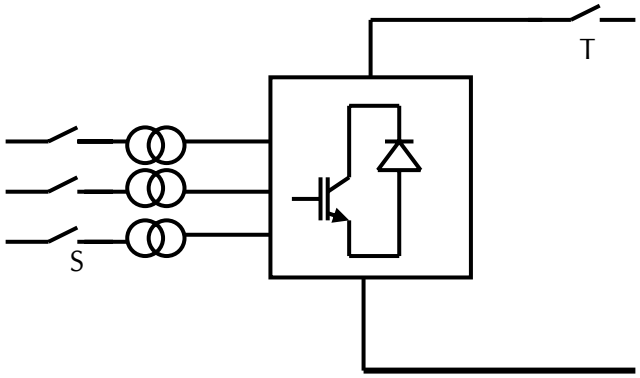


Figure 4.1 VSC converter with ac and dc breakers

Based on information provided by one of the VSC suppliers, the DC line fault clearing sequence for converters connected pole-neutral operates as follows (timings are sequential and cumulative, but approximate):

- dc line fault detection +10 ms (to be conservative)
- open ac and dc breakers at all stations connected to the faulted pole +50 ms after fault detection. The ac breaker clearing time of +50 ms removes the fault current source, the dc breaker clearing breaks the dc line current transient to begin the deionization time
- dc line fault deionization time + 250 ms
- close ac breakers with damping circuit to re-energize converters +100 ms
- close dc breakers to re-energize dc line pole + 50 ms
- deblock converters to restart the power flow + 30 ms
- total time = 490 ms

It is assumed that the VSC design of the other supplier would use a similar method to clear a DC line fault.

4.3 Preliminary Simulation Study using VSC technology

In order to evaluate the performance of the Island system and the need for synchronous condensers, further stability analysis with a VSC converter at Soldiers Pond would be required to analyze both ac and dc faults.

A preliminary transient stability evaluation of VSC technology was performed using PSSE in order to get an idea of how the Island system would perform if the Soldiers Pond HVdc infeed used a VSC converter instead of a line-commutated converter. Several of the expected worst-case faults were simulated with varying amounts of synchronous condensers operating at Soldiers Pond to see if it might be possible to reduce or eliminate the need for synchronous condensers on the Island system with a VSC infeed.

4.3.1 Power Flow Case

The transient stability analysis was performed on the future peak load flow case (approximately 1625 MW Island load without the refinery) with maximum generation dispatched at Bay d'Espoir. The 230kV Bay d'Espoir-Sunnyside lines (TL202 and TL206) were modeled with 50% series compensation. No other system upgrades were modeled (e.g. SVCs or new lines) in the evaluation, with the exception of varying amounts of synchronous condensers at Soldiers Pond. All synchronous condensers at Holyrood were in-service.

4.3.2 VSC model in PSSE

A vendor-supplied VSC model for PSSE was used in the transient stability analysis. For the sake of simplicity during this preliminary evaluation, the VSC HVDC link was modeled as a two-terminal

link from Gull Island to Soldiers Pond rather than a three-terminal link. There should not be significant impact in making this simplification as far as the Island system performance is concerned.

The vendor-supplied VSC model is not yet programmed and tested to operate in the bipolar overhead line configuration. However, for the purposes of this preliminary evaluation, the VSC model as it is (i.e. intended to represent cable installations) was used with minor modifications to emulate the bipolar overhead line configuration that would be applicable in the Lower Churchill Project.

In order to account for the 2.0 pu 10-minute overload requirement of the Soldiers Pond terminal, each pole of the VSC link must be capable of carrying the full 800 MW for 10 minutes. As a VSC does not have an inherent overload capability, each pole must be rated for the full 800 MW in case of an outage of the other pole.

The closest VSC rating (bipolar overhead line configuration) to what would be required for the Lower Churchill Project that is currently available from one VSC vendor is +/- 640 kV 1518 MVA (1.186 kA). It is realized that this dc voltage is too high for the Lower Churchill Project, however this is the MVA rating closest to what is required and for purposes of preliminary evaluation it is not expected that it will have a significant impact on the dynamic performance of the system.

Of the monopolar cable configurations readily available in the vendor-supplied VSC model package, the closest is one rated for 796 MVA at +/- 320 kV dc. Therefore, the bipolar VSC link was emulated by putting two of these 796 MVA VSC models between Gull Island and Soldiers Pond for a total MVA rating of 1592 MVA.

After approximating the losses associated with the VSC link, 750 MW was injected at the Soldiers Pond bus. Please note however that losses will be largely impacted by dc voltage and the actual VSC converter rating that would be installed. It is assumed for this preliminary analysis that losses will not greatly impact the dynamic performance.

With each pole operating at 375 MW, or 0.5 pu, the VSC reactive power capability per pole at this operating point is approximately +374/-398 MVAR.

It should be noted that if operating closer to 1.0 pu power (i.e. when one pole is out of service), the reactive capability of the VSC is greatly reduced to approximately +60/-220 MVAR, which would affect the system performance.

4.3.3 Contingencies

The transient stability analysis of the bipolar VSC infeed was evaluated for the fault conditions described in Table 4.1 below.

Table 4.1
Contingencies

Fault	Description
BDE-SSD	100ms, 3Ph fault at BDE cleared by tripping one of BDE-SSD lines
SSD-BDE	100ms, 3Ph fault at SSD cleared by tripping one of BDE-SSD lines
SP-WAV	100ms, 3Ph fault at SP cleared by tripping one of SP-WAV lines
SP_Sync	100ms, 3Ph fault at SP cleared by tripping one of 150MVA synchronous condensers
DC Pole fault	To emulate a VSC DC pole fault, a 60ms fault is applied on the ac filter bus of one of the VSC poles (i.e. on the VSC side of one of the converter transformers) through an impedance equal to the ac phase reactors. To emulate the restart of the DC pole, the faulted VSC pole is kept blocked (i.e. zero power) for 500ms from fault inception and then released.

4.3.4 Simulation Results

It was found that with the Soldiers Pond infeed modeling VSC technology, all simulations were stable and the post-fault voltages were within acceptable limits for all of the contingencies described in Table 4.1 without any synchronous condensers operating at Soldiers Pond and without any new synchronous condensers elsewhere in the Island system (with the exception of the Holyrood machines running as synchronous condensers).

The minimum transient undervoltages for the contingencies described in Table 4.1 are summarized in Table 4.2.

Table 4.2
Minimum Transient Undervoltages and System Stability Following Fault Clearing

Fault Location	Minimum Transient Undervoltage (pu)				System Status
	BDE	SSD	WAV	SP	
BDE-SSD	0.749	0.773	0.824	0.913	stable
SSD-BDE	0.875	0.857	0.878	0.935	stable
SP-WAV	0.898	0.847	0.839	0.885	stable
DC pole fault	0.954	0.883	0.881	0.919	stable

The 3-phase fault at Bay d'Espoir on one of the Bay d'Espoir (BDE) – Sunnyside lines (SSD) (TL202 or TL206) was the worst-case fault in the studies involving the line-commutated converter because this fault resulted in temporary loss of the Bay d'Espoir generation and a simultaneous commutation failure at Soldiers Pond and subsequent temporary loss of the HVDC power infeed which resulted in a severe decay in system frequency. Using VSC converters at Soldiers Pond means that the HVDC power will still be available during this Bay d'Espoir fault because a VSC does not fail commutation and can continue to inject power at reduced AC voltage. Therefore this fault is no longer as significant an issue with the VSC.

The DC pole-ground fault results in the total loss of one pole for 500 ms. Even without modeling any frequency control on the other pole, i.e. to pick up the slack of the faulted pole, the system response is stable and within criteria.

If the entire power were lost from both poles for 500 ms, the system would require 2x150 MVA synchronous condensers in order to recover from this fault. This would be in the very rare case of a pole-pole fault, assuming the VSC could even recover from such a fault.

4.3.5 Conclusions and Recommendations

The voltage source converter (VSC) option for the Lower Churchill Project has shown good transient stability performance of the system for the expected worst contingencies that were studied. The 50% series compensation on the two Bay d'Espoir-Sunnyside lines (TL202 and TL206) has been included in the power flow case considered. In addition, all Holyrood machines were modeled in-service. The following conclusions can be made based on the preliminary analysis.

- The bipolar VSC link (modeled as 2×796 MVA) has shown good performance for the expected worst contingencies that were considered without any new synchronous condensers installed in the Island system. The system has also recovered well from a DC pole fault. Further, the post-fault transient undervoltages were within the required transient undervoltage criteria. The VSC as rated in this evaluation (i.e. 2x796 MVA) provides an additional advantage that the system could be operated at full power continuously during a single pole failure.

The ability of the VSC to continue to provide power to the Island during reduced AC voltage (because it does not fail commutation) allows the large system frequency decays to be avoided. In addition, the large reactive power capability of the VSC (especially when operating near 0.5 pu power) assists in system voltage recovery following faults. Both of these facts provide a significant advantage to the Island system performance compared to the line-commutated converter technology.

Based on the promising results seen from these preliminary transient stability simulations, it is recommended to perform a more complete evaluation of VSC technology for the Soldiers Pond terminal.

5. Conclusions

This high level evaluation of the VSC converters for the HVdc system showed the following:

- The rating at Gull Island can be better realized using a conventional LCC converter.
- The rating at Soldiers Pond can be achieved using a VSC converter.
- The rating at Salisbury can be achieved using a VSC converter.
- The HVdc cable will still be a mass impregnated cable.
- Results of preliminary transient stability simulations showed an overall improvement in system performance for all ac and dc faults that were studied with fewer synchronous condensers than required for the LCC technology.

6. Recommendations

The application of VSC technology for the Lower Churchill Project should be considered; however, a more in-depth performance study should be undertaken.

Based on promising results seen from preliminary transient stability simulations, it is recommended to perform a more complete performance evaluation of VSC technology for the Soldiers Pond terminal.

Appendix D

HVdc and ac Transmission Lines in Close Proximity Interaction Issues Final Report

Nalcor Energy
Lower Churchill Project

DC1210 - HVdc and ac Transmission Lines in Close Proximity Interaction Issues

Final Report

Prepared by: Pete Kuffel, P.Eng. — April 1, 2009 (Date)

Approvals

Hatch

Approved by: Robert Woolgar, P.Eng. — April 1, 2009 (Date)

Nalcor Energy [Client Name, if required]

Approved by: _____ — Date

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1. Introduction

This white paper presents a high level qualitative review of issues related to the application of HVdc and ac transmission lines in close proximity. The paper was prepared in response to a request received by Hatch from Nalcor Energy related to the Lower Churchill Project. In particular, an alternate route for the HVdc transmission line is being considered which would have the HVdc transmission line located within an existing right of way on the Island of Newfoundland currently occupied by existing 138kV and 66kV ac lines. Use of the existing right of way would require that the HVdc line run in close proximity to the ac lines on separate structures, use a common structure, or require the direct burial of the ac lines with the HVdc line running on top on its own structure.

A number of articles are available on the subject of the interactions of HVdc and ac transmission lines located in close proximity to each other. Most papers consider the interactions between lines located within a common right of way but installed on separate towers [1, 2, 3, 4], while others consider hybrid configurations (HVdc and ac lines on a common tower) [5, 6, 7].

Very few hybrid lines (HVdc and ac conductors on the same tower) have been built. One example is the National HVdc project in India which was an experimental project where one circuit of an existing double circuit 220kV ac line was converted to an HVdc line [8]. The HVdc line initially operated as a monopole with a dc voltage of 100kV and a power transfer capability of 100MW.

HVdc and ac lines on separate structures in close proximity within the same right of way is more common. Examples of this include the Hydro Quebec – New England HVdc line, the Nelson River HVdc lines in Manitoba, and the Tian-Guang HVdc line in China. In these cases the HVdc lines run in close proximity to HVac lines on separate structures for a portion of the overall HVdc line length.

The purpose of this paper is to identify potential issues related to the application of HVdc and ac transmission lines in close proximity.

2. HVdc and AC Line Interactions

When considering locating HVdc and ac lines in close proximity it is necessary to consider the effects of the ac circuit on the dc circuit and vice versa; under both steady state and transient conditions. In addition, consideration must be given to the physical implementation of such a system.

In general it can be stated that as the HVdc line is located closer to the ac line and the coupled section length increases, the HVdc and ac line interactions are more pronounced.

2.1 Steady State Effects

2.1.1 AC/DC Coupling

When an HVdc transmission line is situated in close proximity to a parallel ac transmission line, steady-state induction effects lead to a power frequency current flowing in the HVdc line. The coupling of an ac fundamental component onto the HVdc system can have the following impacts:

- Converter Transformer Saturation and Harmonic Generation - A fundamental frequency current flowing on the dc side of the converter will be seen as a second harmonic and a dc component in the converter transformer ac system side winding. A dc component in the ac system side winding of the converter transformer can lead to half cycle saturation which results in the generation of a broad spectrum of harmonics into both the ac and dc systems [1, 4].
- AC and DC Filter Design - The harmonics resulting from the saturation of the converter transformers pose difficulties in design of both the ac and dc filters, requiring increased filter component ratings. Additional harmonics may also lead to increased interference on telephone communication systems.
- Converter Transformer Loss of Life - Increased heating of the converter transformer must be accounted for in order to avoid loss of life.
- Increased Audible Noise - Converter transformer audible noise levels may be substantially higher than usual.
- HVdc Control and Protection – An ac component on the dc side may adversely affect the control and protection scheme of the HVdc system including the measurement devices used.
- Transformer Protection – Transformer protection may be adversely affected by the increased harmonics.
- Neutral Point Voltage Increase – The neutral point voltage impacts equipment insulation levels.

Possible mitigation includes the application of fundamental frequency blocking filters in order to reduce the magnitude of the fundamental frequency component current flowing within the dc system and the application of modulation functions to the HVdc controls.

2.1.2 Corona and Field Effects

The proximity between conductors energized with ac and HVdc voltages causes changes in conductor surface gradients and the electrical environment in the vicinity of the lines. Corona, and both the ac and dc electric field effects may be affected. Calculation of conductor surface gradients is more complex than for individual ac or HVdc lines. In general, when HVdc and ac lines are placed in close proximity they interact to produce levels of corona and electric field effects which depart from the simple superposition of the effects of the two lines acting separately [2].

2.2 Transient Events

Transient events include both ac and dc faults and controlled changes of the HVdc operating point. Transient events can have the following impacts:

- Overvoltages on the HVdc line due to ac and dc Faults – The voltage induced on the HVdc system as a result of a fault on the ac system can generate lightly damped fundamental frequency overvoltages, excite resonance conditions in the ac and dc systems, and cause dc currents to flow in the converter transformers. If fundamental frequency blocking filters are used in the HVdc system then faults on the converter ac system can result in a fundamental frequency oscillation in this tuned filter resulting in a significant fundamental frequency overvoltage [6]. The application of an arrestor across the blocking filter is required in order to limit the neutral point voltage.
- Delayed dc Fault Clearing – Fundamental frequency coupling from the ac line to the HVdc line interferes with the clearing of dc line faults [7]. Even though the dc current in the fault arc can be brought to zero by the HVdc controls, fundamental frequency secondary arc current can delay the clearing of the fault.
- Impact of HVdc Faults on ac Lines – HVdc pole to ground faults can have an appreciable impact on ac current. ac system protections may need to be reviewed in order to avoid false operation.
- Controlled Changes in HVdc Operating Point – Controlled changes in HVdc operating point include both controlled power order changes and changes in operating mode such as normal bipolar operation to ground return. Controlled power order changes will result in a change in dc current which in turn will impact the ac current in a similar fashion to a dc line fault. Operation in ground return mode has the potential to cause large zero sequence transients in ac lines due to transients in the HVdc earth return circuit such as the switch from metallic return to ground return operation [9, 10]. The transition of the HVdc system from normal to ground return operation can result in the incorrect operation of ac ground current detection relays.
- Faults between the HVdc and ac Lines – A fault between a conductor in the HVdc and ac line can result in a severe stress on the ac system which must be mitigated. Clearing of the fault will require the operation of the ac circuit breakers and operation of the HVdc line fault detection. Most HVdc systems with overhead lines include an automatic restart in the event of dc line faults. In the event of a permanent fault between the HVdc conductor and the ac conductor, the ac conductor would remain charged up to the full dc voltage following the HVdc restart. This

could pose a hazard to both personnel and equipment and suitable measures would have to be taken to avoid the potential for such a situation [6].

2.3 Physical Considerations

Physical considerations include the following:

- Aesthetics – Tower configuration for hybrid HVdc and ac line configuration will be determined partially by the required clearances between the HVdc conductors, ac conductors, the tower, and ground.
- Live Line Maintenance – Live line maintenance procedures will have to be modified to account for HVdc and ac conductors on a common tower.
- Impact of Tower Failure – The impact of a tower failure in the case of HVdc and ac lines on a common tower must be considered.

3. Identification of Issues and Mitigation

In order to clearly identify the issues which arise from the alternate line route for the Lower Churchill Project and determine suitable mitigation measures, a two part study is required.

The first part of the study should address the physical line parameters and configuration in order to ensure acceptable corona and field effects for the proposed transmission line route. It is estimated that such a study would take approximately three (3) months to complete.

The second part of the study should address the steady state and transient performance issues in order to provide sufficient information required for the design of the HVdc and its control and protection systems. It is estimated that such a study would take approximately two (2) months to complete. It should be noted that the second part of the study can only be undertaken once a likely candidate line configuration had been identified.

Additional studies would be required to ensure that existing ac system protections are adequate, or whether modifications would be required.

4. Technical Opinion

Based on the available literature and current industry experience the use of a hybrid line with the HVdc and ac conductors on a common tower may not be suitable for the proposed line route; mainly due to the potential for a high level of interaction between the lines and the potential for HVdc to ac conductor faults. In situations where the use of common towers would be for very short distances, the risk of an HVdc to ac conductor fault may be acceptable, however in the case of the proposed line route the distance is great enough that the risk of such a fault may be a determining factor.

The use of HVdc and ac lines in close proximity on separate towers may be suitable if an acceptable separation can be maintained. The suitability of this option would require detailed studies in order to determine potential candidate line configurations and any required mitigation measures to ensure acceptable performance of the integrated HVdc and ac systems. Current industry experience can be used as a starting point for determining a potential minimum separation distance between the HVdc and ac lines. Once this is identified the suitability of the existing right of way can be better assessed.

The use of a direct buried ac cable with the HVdc on towers on the same right of way may be suitable however studies would be required to determine the potential effects of HVdc ground faults on the buried ac cable.

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Appendix E

Stability Plots for DC1210 Bipole Block Impact Study

SYSTEM INTEGRATION STUDY - REDUCED MODEL
BC1 - CT'S AT PH - NET WIND - DEC 18/07
WED, APR 28 2010 11:35

SYSTEM OVERVIEW

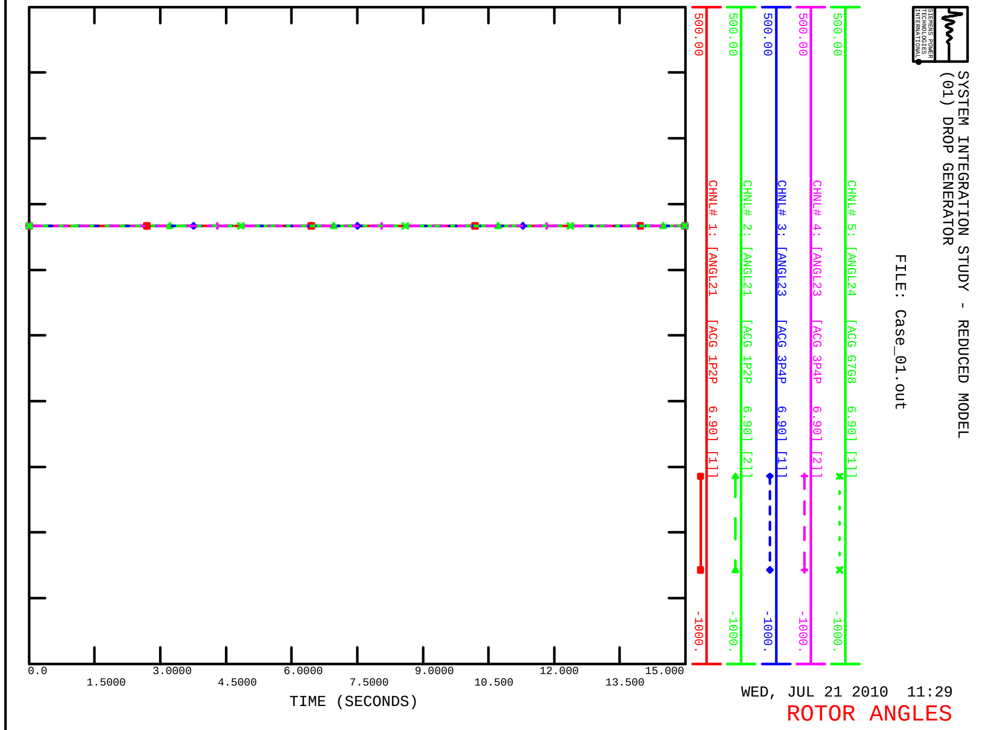
GENERATION:
NLH GENERATION =674.4 MW
STAR LAKE = 17.4 MW
RATTLE BROOK = 0.0 MW
CORNER BROOK COGEN =0.0 MW
EXPLOITS RIVER = 60.0 MW
DC INFEED = 766.0 MW
WIND GENERATION = 0.0 MW
SYSTEM GENERATION =1517.7 MW

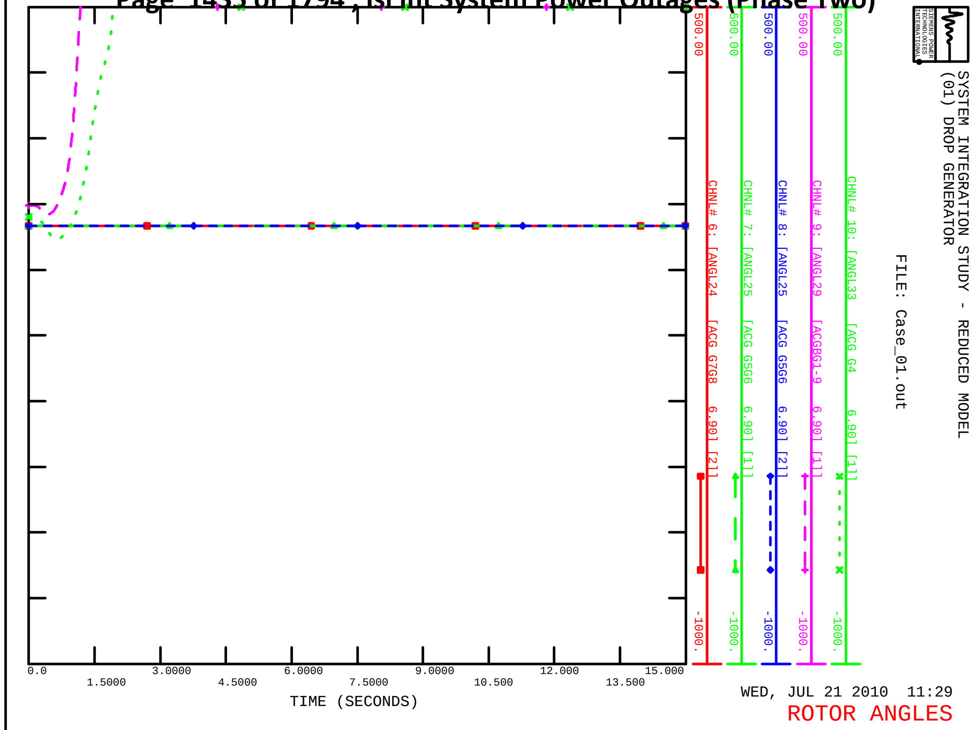
LOADS:
ACCC - GFL = 0.0 MW
ACCC - SVL = 0.0 MW
NARL = 28.9 MW
KRUGER = 15.2 MW
AUR RESOURCES = 9.5 MW
VBN = 80.0 MW
NLRC = 0.0 MW
TOTAL INDUSTRIAL = 133.6 MW

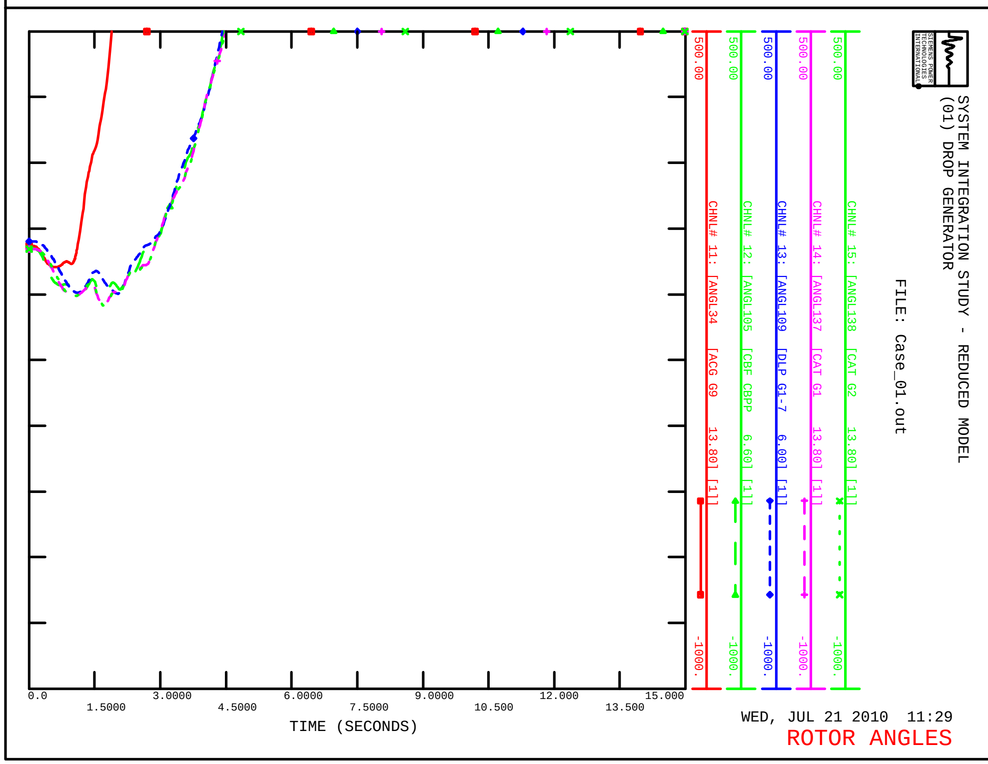
NEWFOUNDLAND POWER = 979.3 MW
HYDRO RURAL = 0.0 MW

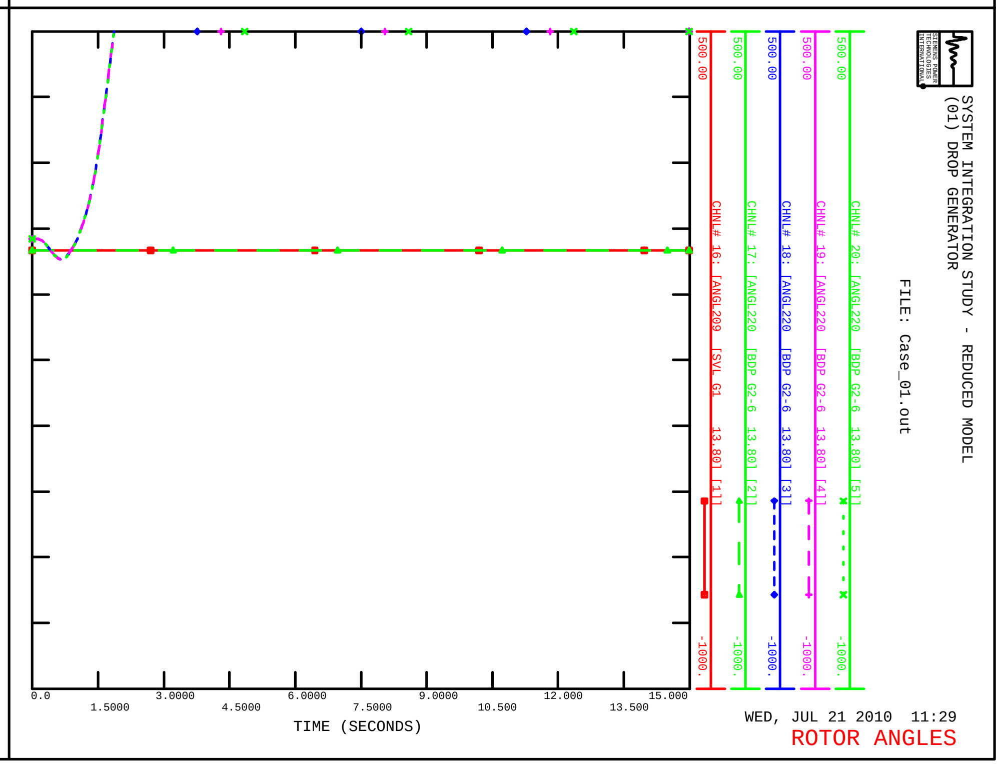
HINDS LAKE
DEER LAKE
DEER LAKE POWER
HOWLEY
INDIAN RIVER
SPRINGDALE
SOUTH BROOK
CAT ARM
BISHOPS FALLS
ABITIBI - GFL
SUNNYSIDE
TL219 TO SPD
TL212 TO MKS
PARADISE RIVER
VOISEY'S BAY NICKEL
NORTH ATLANTIC REFINING
WESTERN AVALON
CBC
BRB
BLK
GULL ISLAND
SPF
COL
HOL
SALISBURY, NB
HOLYROOD
MASSEY DRIVE
ABITIBI - SVL
STONY BROOK
PIPER'S HILL
SOLDIER'S POND
SC1
SC2
SC3
G3
G1
HRD CT2
BUCHANS
STEPHENVILLE
STAR LAKE
DUCK POND
GRANITE CANAL
UPPER SALMON
BAY D ESPOIR
HARDWOODS
OXEN POND

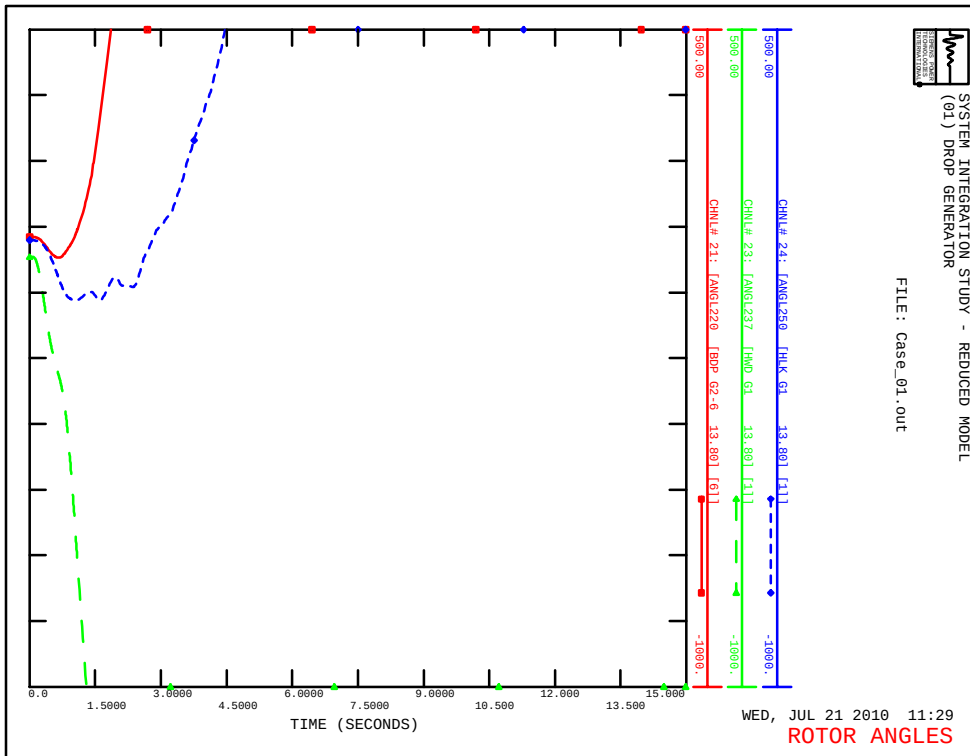
Diagram created using
'E:\Afzal\2010Works\Bipole block study\PSSE_303\Load_Flow\Bipole_Block.sav'
'E:\Afzal\2010Works\Bipole block study\PSSE_303\Load_Flow\Island Bulk - 2009-12-16.sld'

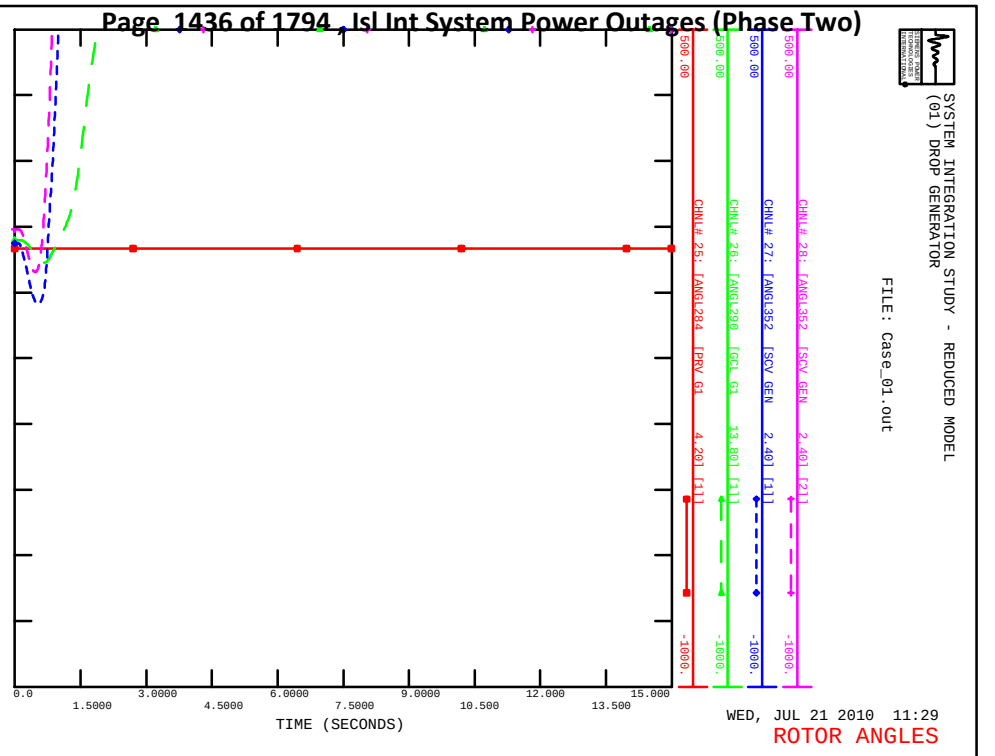

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 1: [ANGL21 [ACG 1P2P 6.90] [1]]
CHNL# 2: [ANGL21 [ACG 1P2P 6.90] [2]]
CHNL# 3: [ANGL23 [ACG 3P4P 6.90] [1]]
CHNL# 4: [ANGL23 [ACG 3P4P 6.90] [2]]
CHNL# 5: [ANGL24 [ACG G7G8 6.90] [1]]
500.00
-1000.
TIME (SECONDS)
WED, JUL 21 2010 11:29
ROTOR ANGLES

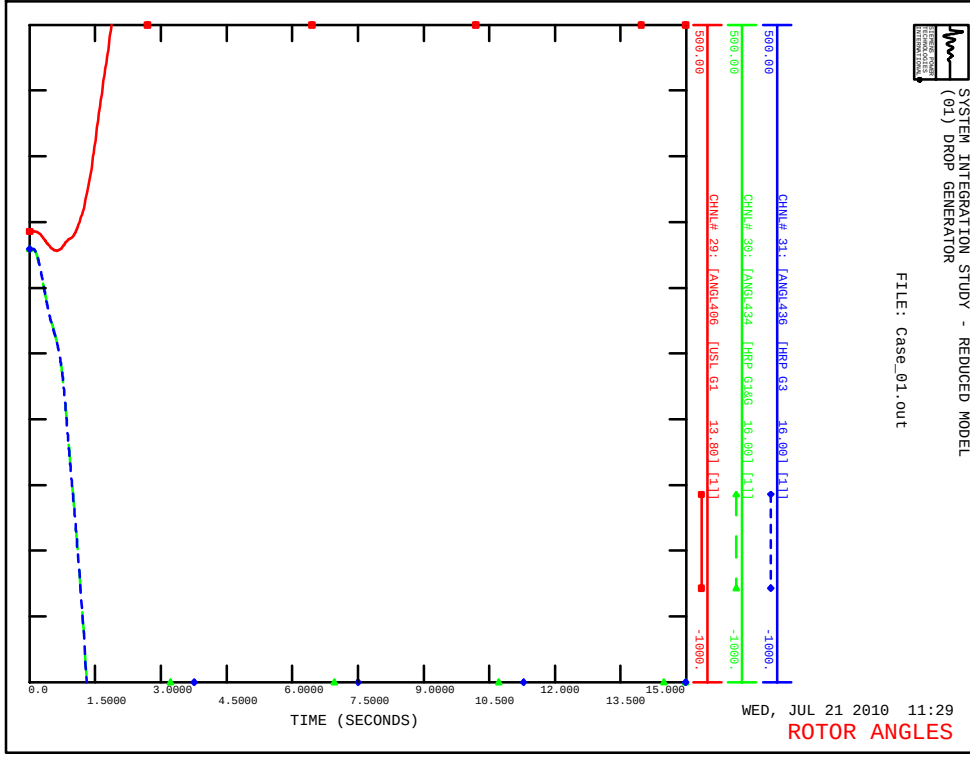

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 6: [ANGL24 [ACG G7G8 6.90] [2]]
CHNL# 7: [ANGL25 [ACG G5G6 6.90] [1]]
CHNL# 8: [ANGL25 [ACG G5G6 6.90] [2]]
CHNL# 9: [ANGL29 [ACGBG1-9 6.90] [1]]
CHNL# 10: [ANGL33 [ACG G4 6.90] [1]]
500.00
-1000.
TIME (SECONDS)
WED, JUL 21 2010 11:29
ROTOR ANGLES

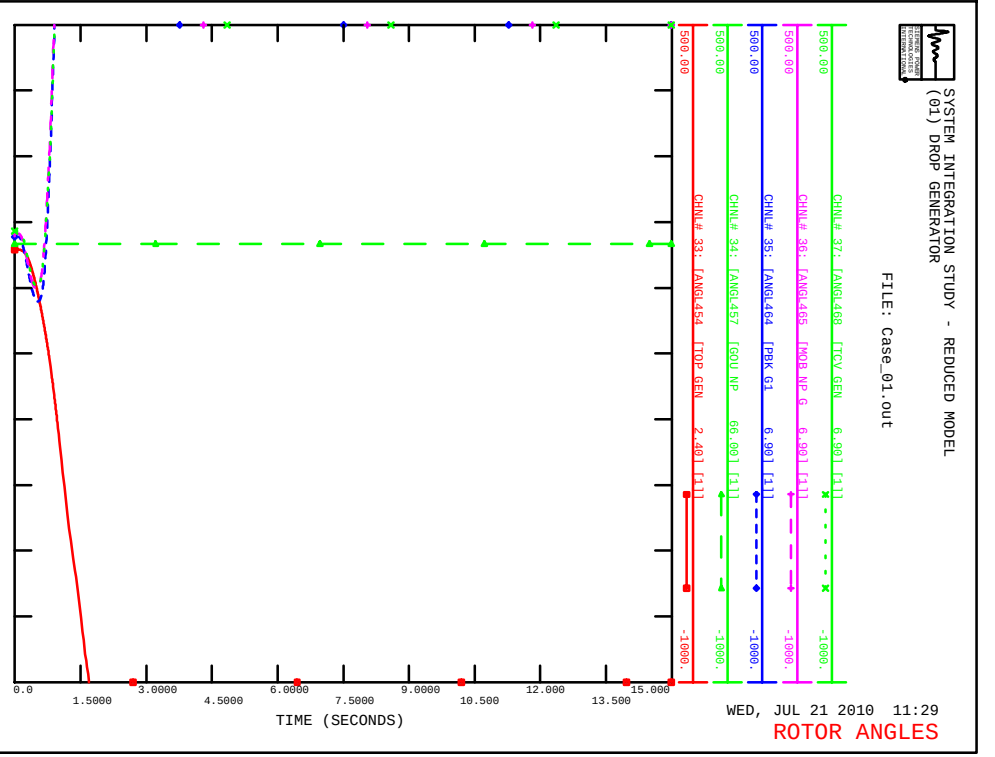

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 11: [ANGL34 [ACG G9 13.80] [1]]
CHNL# 12: [ANGL105 [CBF CBPP 6.60] [1]]
CHNL# 13: [ANGL109 [DLP G1-7 6.00] [1]]
CHNL# 14: [ANGL137 [CAT G1 13.80] [1]]
CHNL# 15: [ANGL138 [CAT G2 13.80] [1]]
500.00
-1000.
TIME (SECONDS)
WED, JUL 21 2010 11:29
ROTOR ANGLES

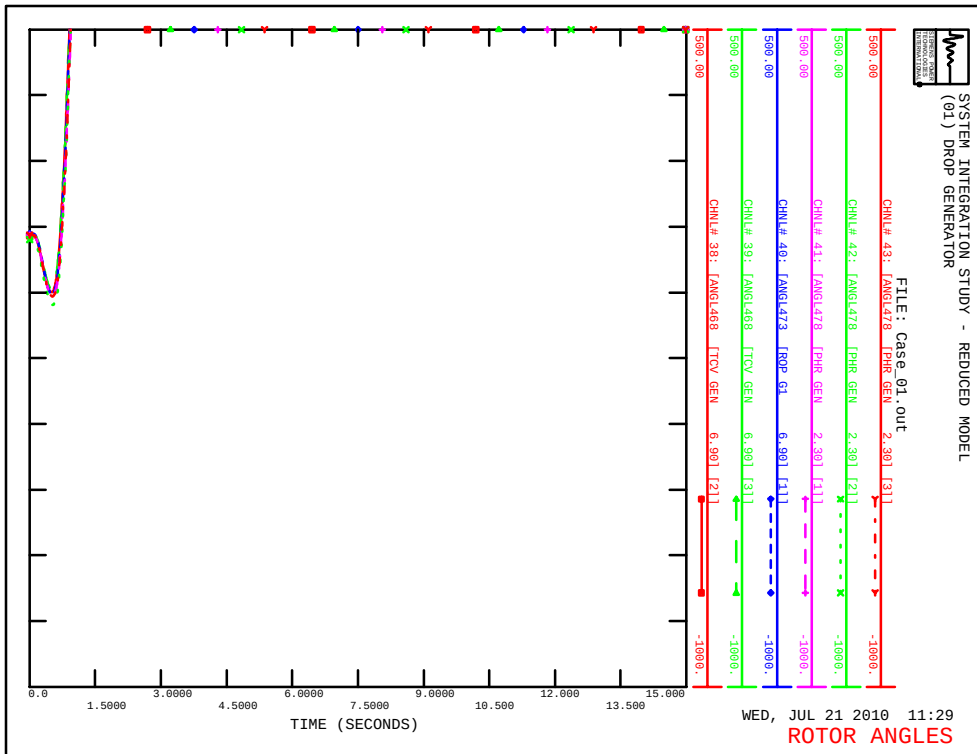

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 16: [ANGL209 [SVL G1 13.80] [1]]
CHNL# 17: [ANGL220 [BDP G2-6 13.80] [2]]
CHNL# 18: [ANGL220 [BDP G2-6 13.80] [3]]
CHNL# 19: [ANGL220 [BDP G2-6 13.80] [4]]
CHNL# 20: [ANGL220 [BDP G2-6 13.80] [5]]
500.00
-1000.
TIME (SECONDS)
WED, JUL 21 2010 11:29
ROTOR ANGLES

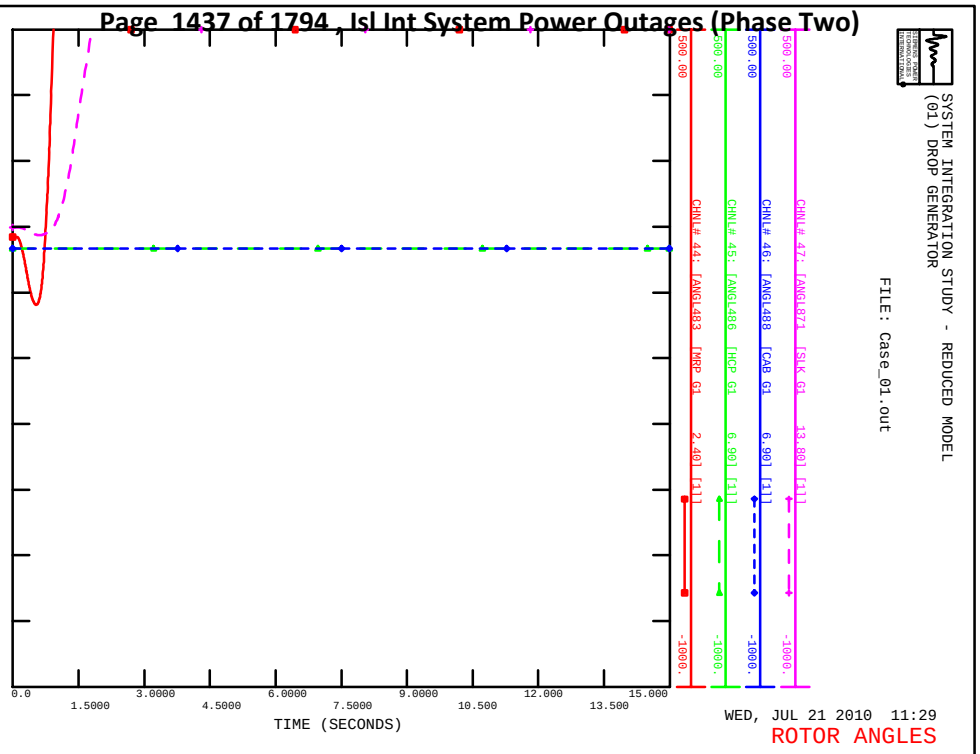

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 21: [ANGL220 [BDP G2-6 13.80] [61]
CHNL# 23: [ANGL237 [HND G1 13.80] [1]
CHNL# 24: [ANGL250 [HLK G1 13.80] [11]
TIME (SECONDS)
WED, JUL 21 2010 11:29
ROTOR ANGLES

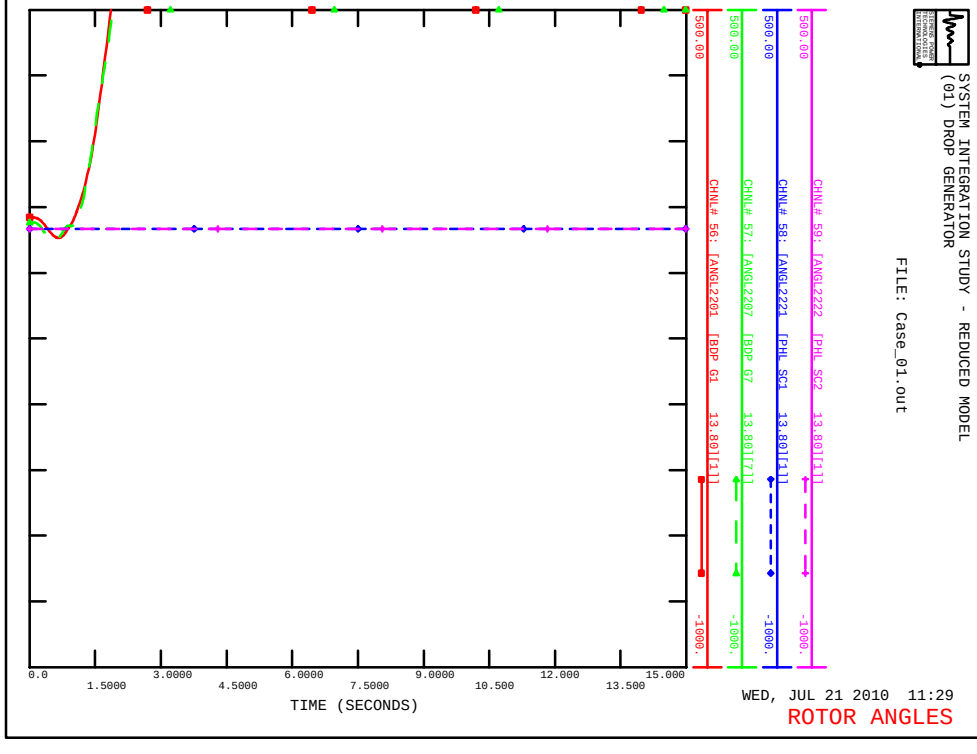

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 25: [ANGL284 [PRV G1 4.20] [11]
CHNL# 26: [ANGL290 [GCL G1 13.80] [11]
CHNL# 27: [ANGL352 [SCV GEN 2.40] [11]
CHNL# 28: [ANGL352 [SCV GEN 2.40] [21]
TIME (SECONDS)
WED, JUL 21 2010 11:29
ROTOR ANGLES

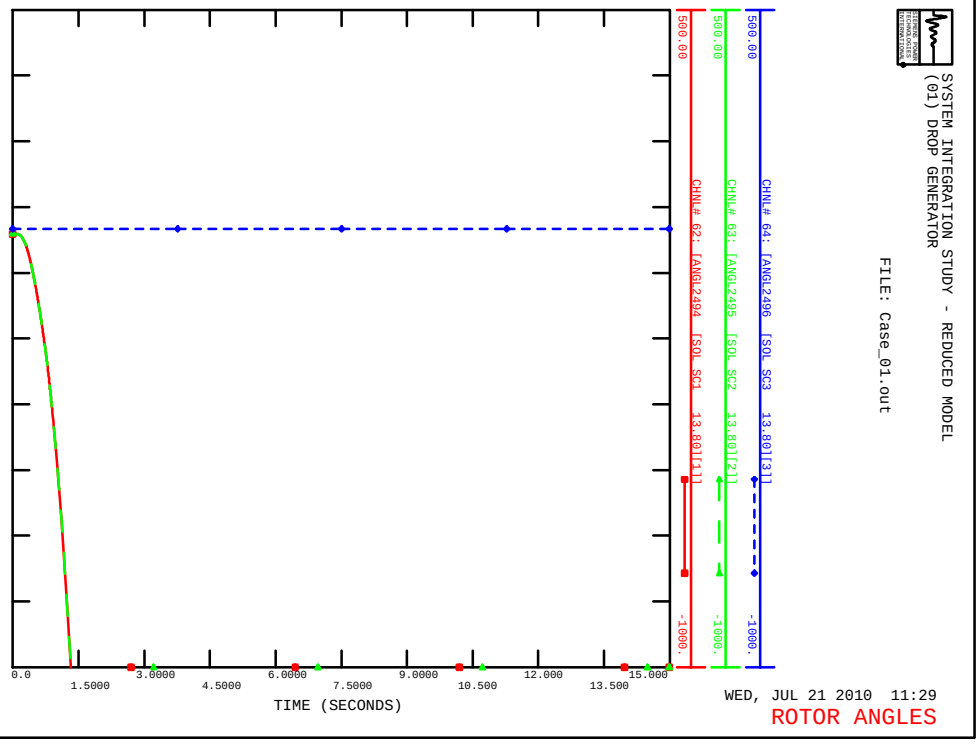

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 29: [ANGL406 [USL G1 13.80] [11]
CHNL# 30: [ANGL434 [HRP G1&G 16.00] [11]
CHNL# 31: [ANGL436 [HRP G3 16.00] [11]
TIME (SECONDS)
WED, JUL 21 2010 11:29
ROTOR ANGLES

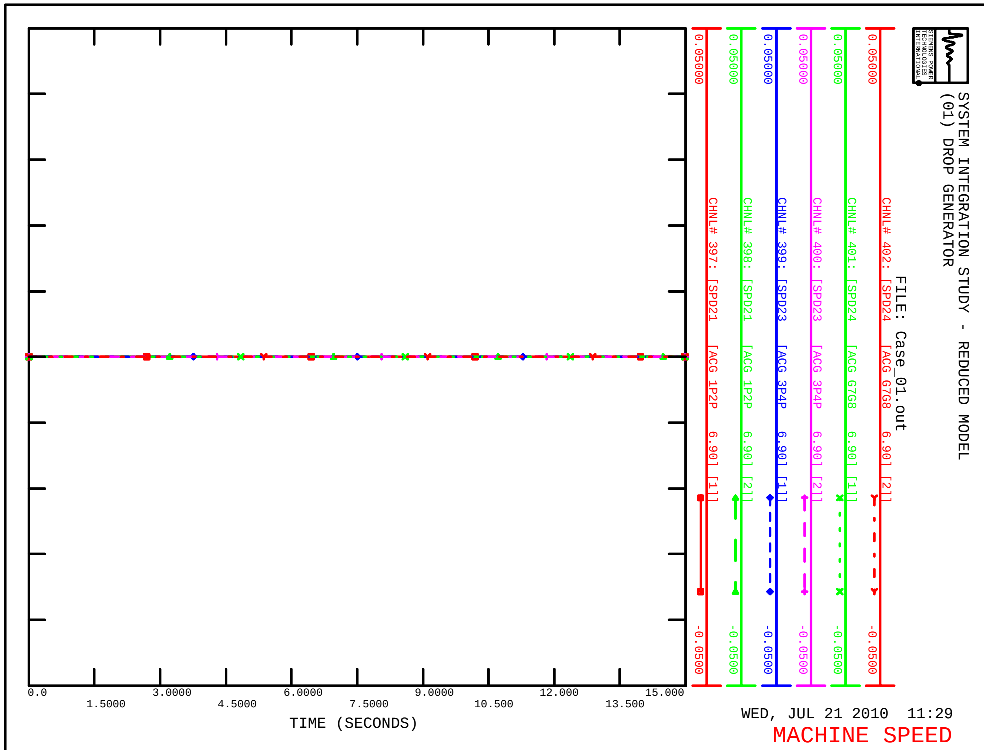

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 33: [ANGL454 [TOP GEN 2.40] [11]
CHNL# 34: [ANGL457 [CGU NP 66.00] [11]
CHNL# 35: [ANGL464 [PBK G1 6.90] [11]
CHNL# 36: [ANGL465 [MOB NP G 6.90] [11]
CHNL# 37: [ANGL468 [TCV GEN 6.90] [11]
TIME (SECONDS)
WED, JUL 21 2010 11:29
ROTOR ANGLES

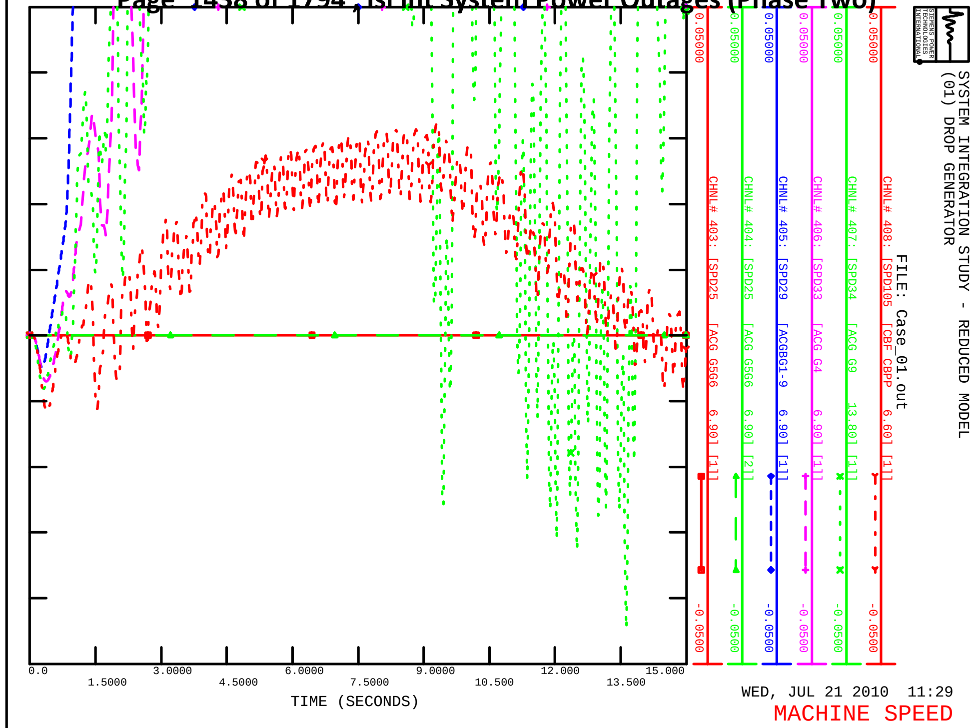

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 38: [ANGL468 [TCV GEN 6.90] [2]
CHNL# 39: [ANGL468 [TCV GEN 6.90] [3]
CHNL# 40: [ANGL473 [ROP G1 6.90] [1]
CHNL# 41: [ANGL478 [PHR GEN 2.30] [1]
CHNL# 42: [ANGL478 [PHR GEN 2.30] [2]
CHNL# 43: [ANGL478 [PHR GEN 2.30] [3]
TIME (SECONDS)
WED, JUL 21 2010 11:29
ROTOR ANGLES

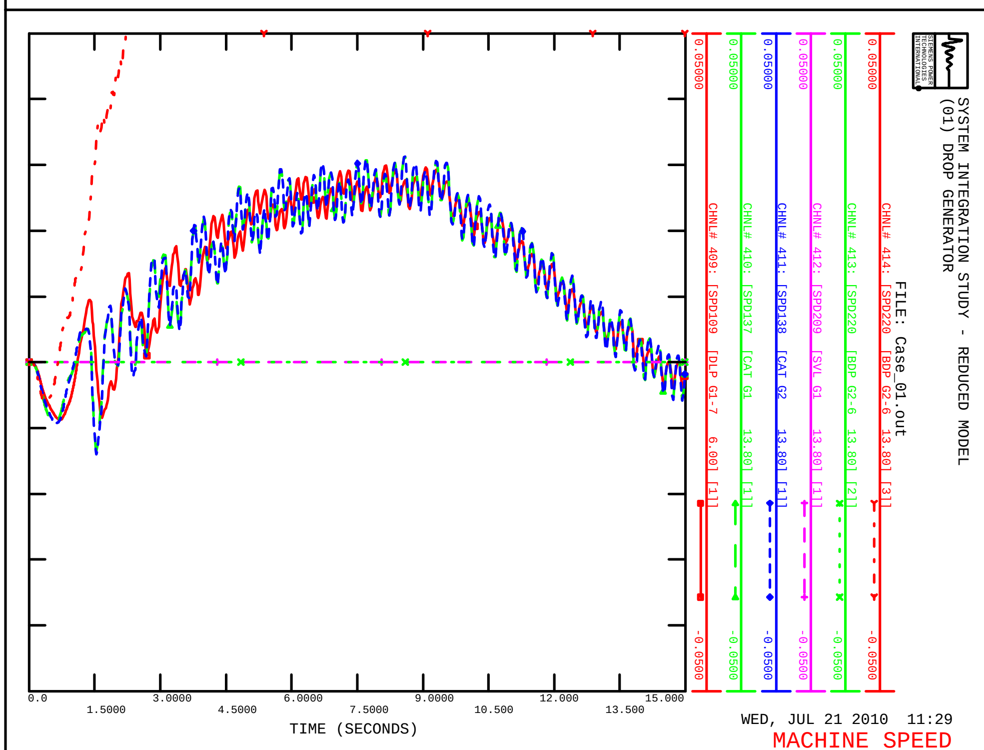

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 44: [ANGL483 [MRP G1 2.40] [1]
CHNL# 45: [ANGL486 [HCP G1 6.90] [1]
CHNL# 46: [ANGL488 [CAB G1 6.90] [1]
CHNL# 47: [ANGL871 [SLK G1 13.80] [1]
TIME (SECONDS)
WED, JUL 21 2010 11:29
ROTOR ANGLES

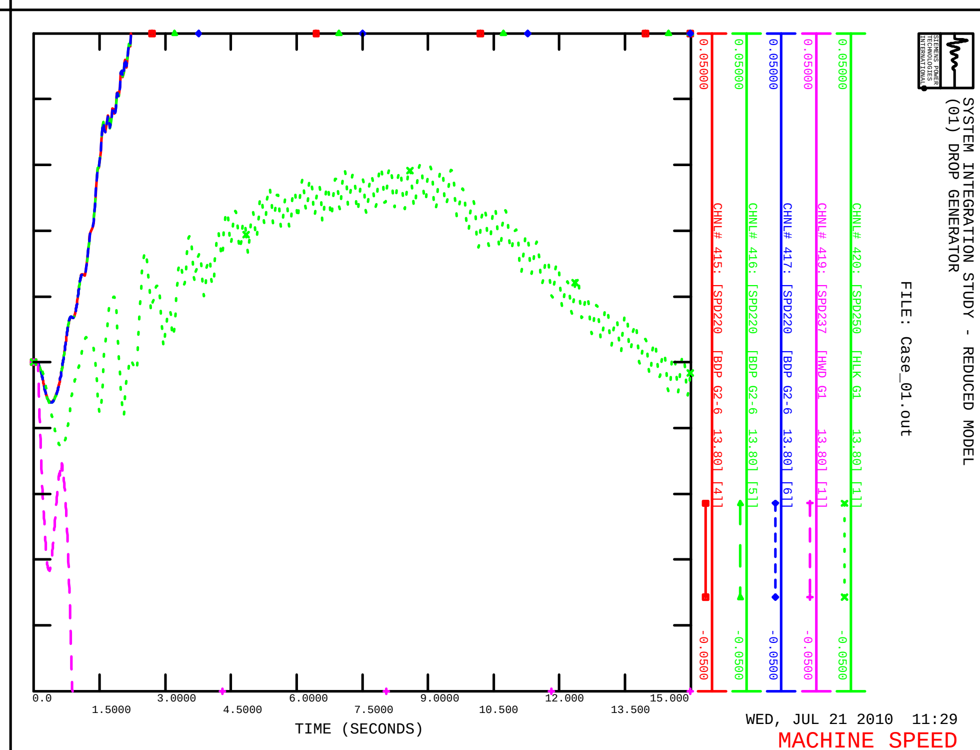

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 56: [ANGL2201 [BDP G1 13.80] [1]
CHNL# 57: [ANGL2207 [BDP G7 13.80] [7]
CHNL# 58: [ANGL2221 [PHL SC1 13.80] [1]
CHNL# 59: [ANGL2222 [PHL SC2 13.80] [1]
TIME (SECONDS)
WED, JUL 21 2010 11:29
ROTOR ANGLES

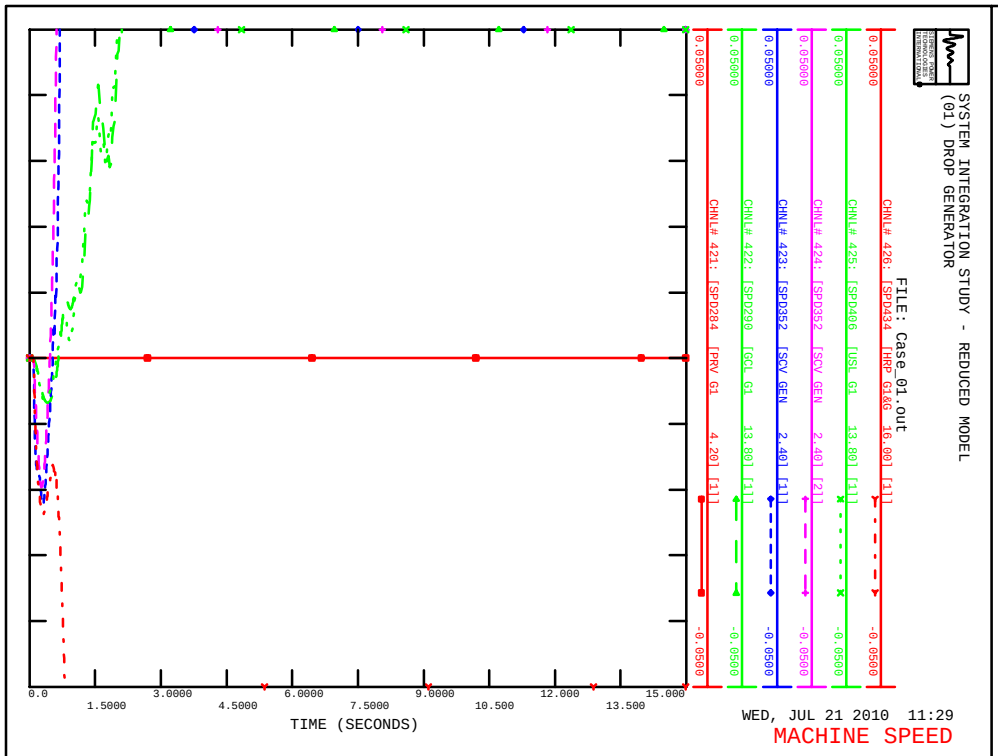

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 62: [ANGL2494 [SOL SC1 13.80] [1]
CHNL# 63: [ANGL2495 [SOL SC2 13.80] [2]
CHNL# 64: [ANGL2496 [SOL SC3 13.80] [3]
TIME (SECONDS)
WED, JUL 21 2010 11:29
ROTOR ANGLES

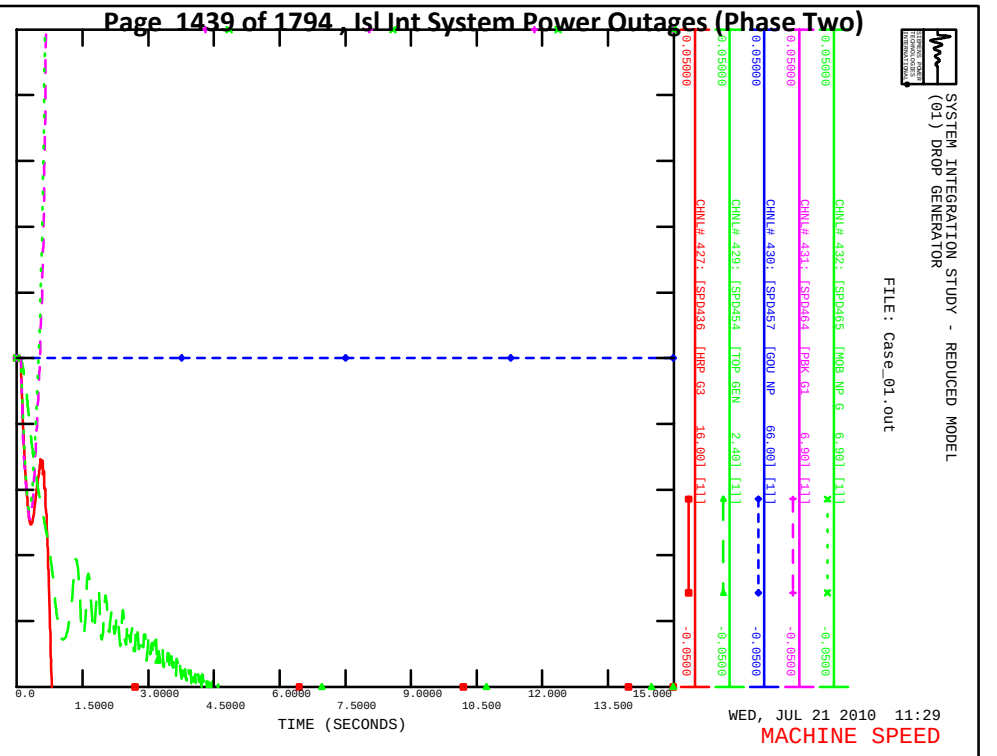

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 397: [SPD21 [ACG 1P2P 6.90] [1]
CHNL# 398: [SPD21 [ACG 1P2P 6.90] [2]
CHNL# 399: [SPD23 [ACG 3P4P 6.90] [1]
CHNL# 400: [SPD23 [ACG 3P4P 6.90] [2]
CHNL# 401: [SPD24 [ACG G7G8 6.90] [1]
CHNL# 402: [SPD24 [ACG G7G8 6.90] [2]
0.05000
-0.0500
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:29
MACHINE SPEED

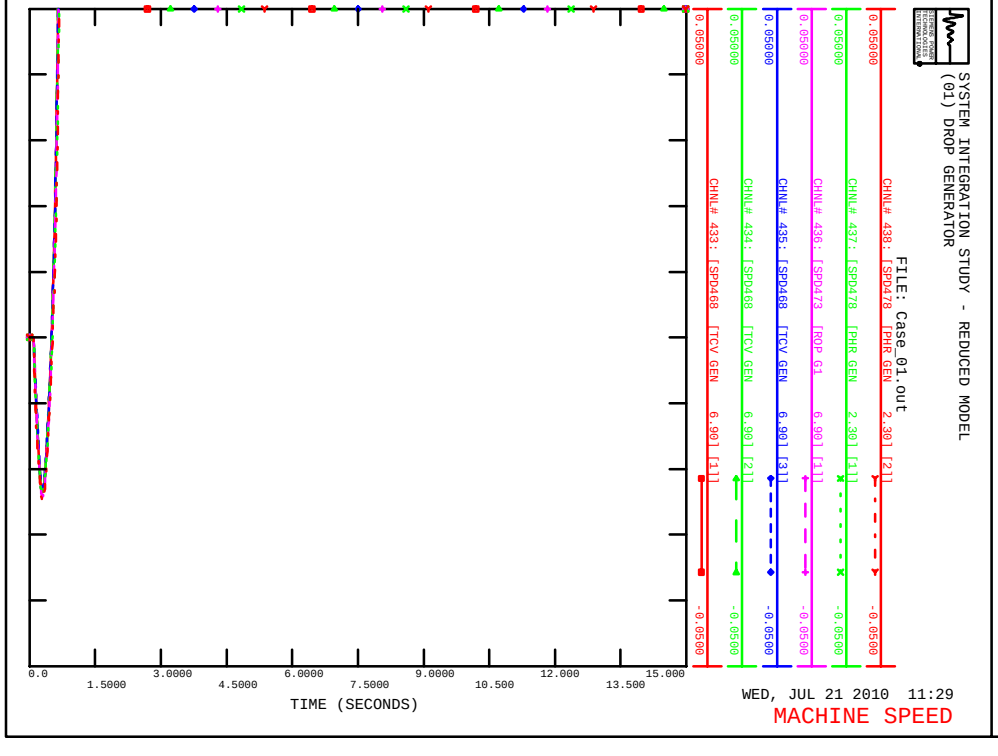

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 403: [SPD25 [ACG G5G6 6.90] [1]
CHNL# 404: [SPD25 [ACG G5G6 6.90] [2]
CHNL# 405: [SPD29 [ACGBG1-9 6.90] [1]
CHNL# 406: [SPD33 [ACG G4 6.90] [1]
CHNL# 407: [SPD34 [ACG G9 13.80] [1]
CHNL# 408: [SPD105 [CBF CBPP 6.60] [1]
0.05000
-0.0500
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:29
MACHINE SPEED

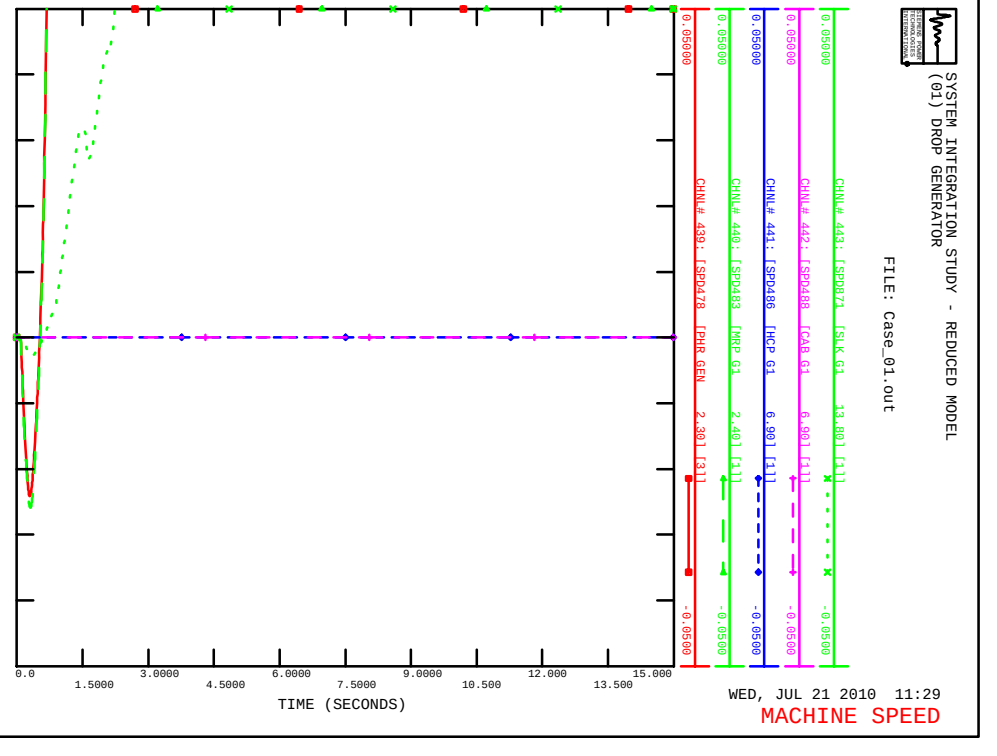

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 409: [SPD109 [DLP G1-7 6.00] [1]
CHNL# 410: [SPD137 [CAT G1 13.80] [1]
CHNL# 411: [SPD138 [CAT G2 13.80] [1]
CHNL# 412: [SPD209 [SVL G1 13.80] [1]
CHNL# 413: [SPD220 [BDP G2-6 13.80] [2]
CHNL# 414: [SPD220 [BDP G2-6 13.80] [3]
0.05000
-0.0500
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:29
MACHINE SPEED

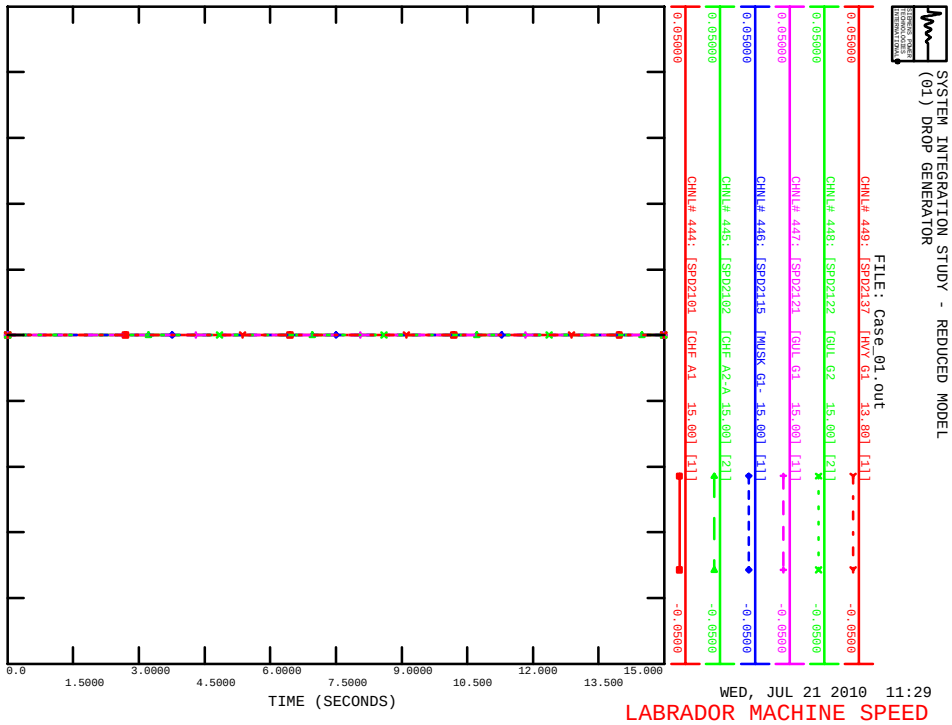

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 415: [SPD220 [BDP G2-6 13.80] [4]
CHNL# 416: [SPD220 [BDP G2-6 13.80] [5]
CHNL# 417: [SPD220 [BDP G2-6 13.80] [6]
CHNL# 419: [SPD237 [HWD G1 13.80] [1]
CHNL# 420: [SPD250 [HLK G1 13.80] [1]
0.05000
-0.0500
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:29
MACHINE SPEED

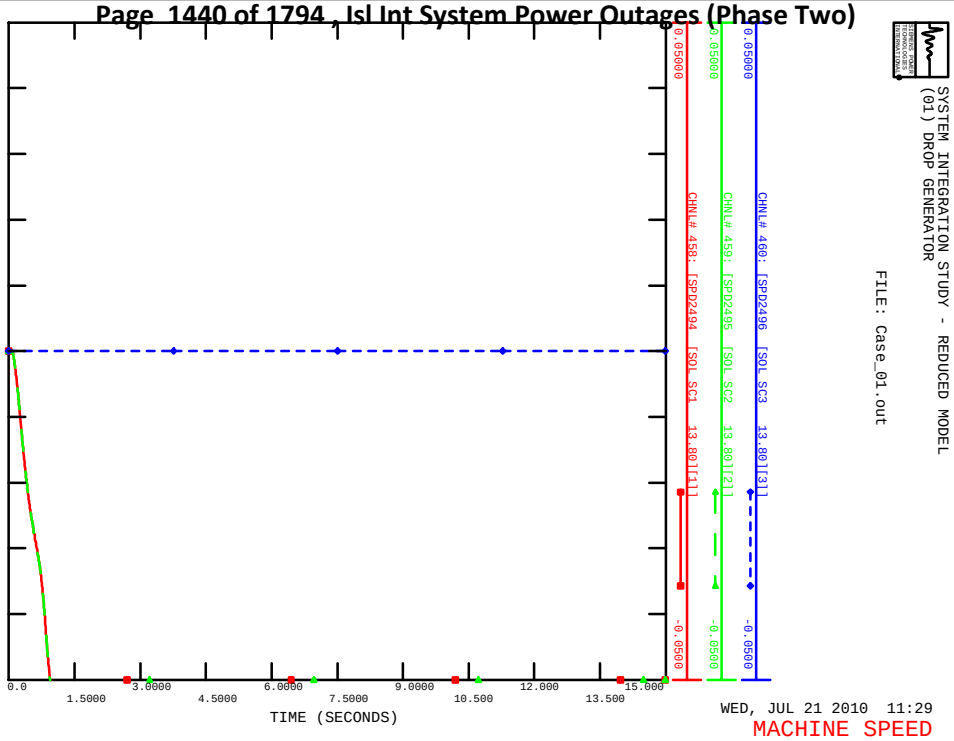

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 421: [SPD284 [PRV G1 4.20] [1]]
CHNL# 422: [SPD290 [GGL G1 13.80] [1]]
CHNL# 423: [SPD352 [SCV GEN 2.40] [1]]
CHNL# 424: [SPD352 [SCV GEN 2.40] [2]]
CHNL# 425: [SPD406 [USL G1 13.80] [1]]
CHNL# 426: [SPD434 [HRP G1&G 16.00] [1]]
TIME (SECONDS)
WED, JUL 21 2010 11:29
MACHINE SPEED

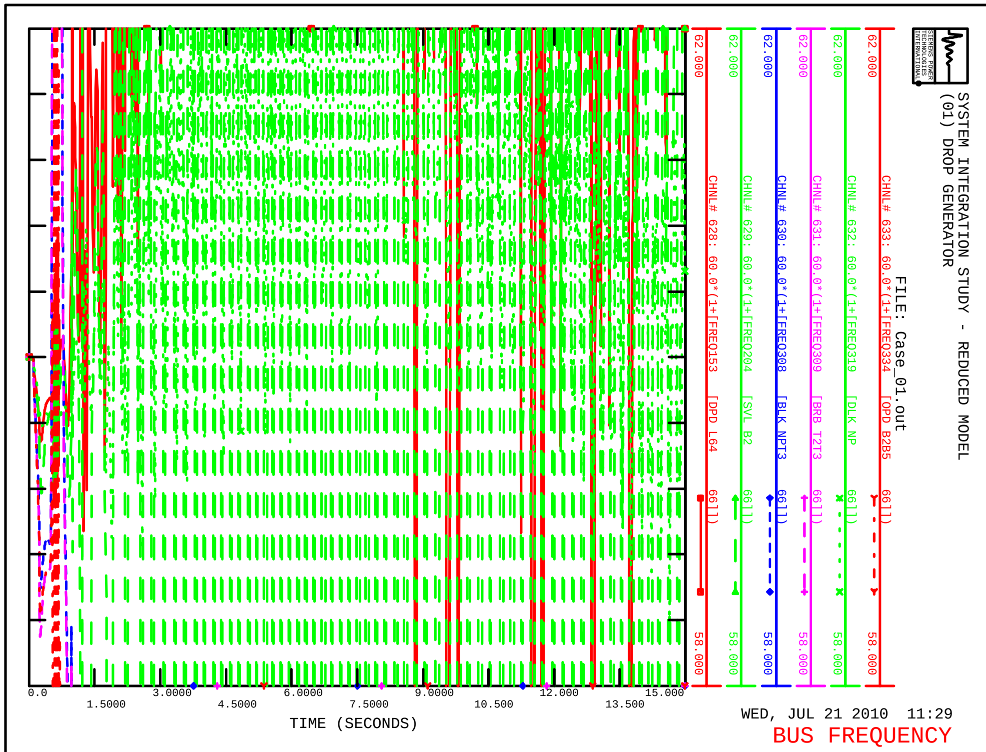

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 427: [SPD436 [HRP G3 16.00] [1]]
CHNL# 429: [SPD454 [TOP GEN 2.40] [1]]
CHNL# 430: [SPD457 [GOU NP 66.00] [1]]
CHNL# 431: [SPD464 [PBK G1 6.90] [1]]
CHNL# 432: [SPD465 [MOB NP G 6.90] [1]]
TIME (SECONDS)
WED, JUL 21 2010 11:29
MACHINE SPEED

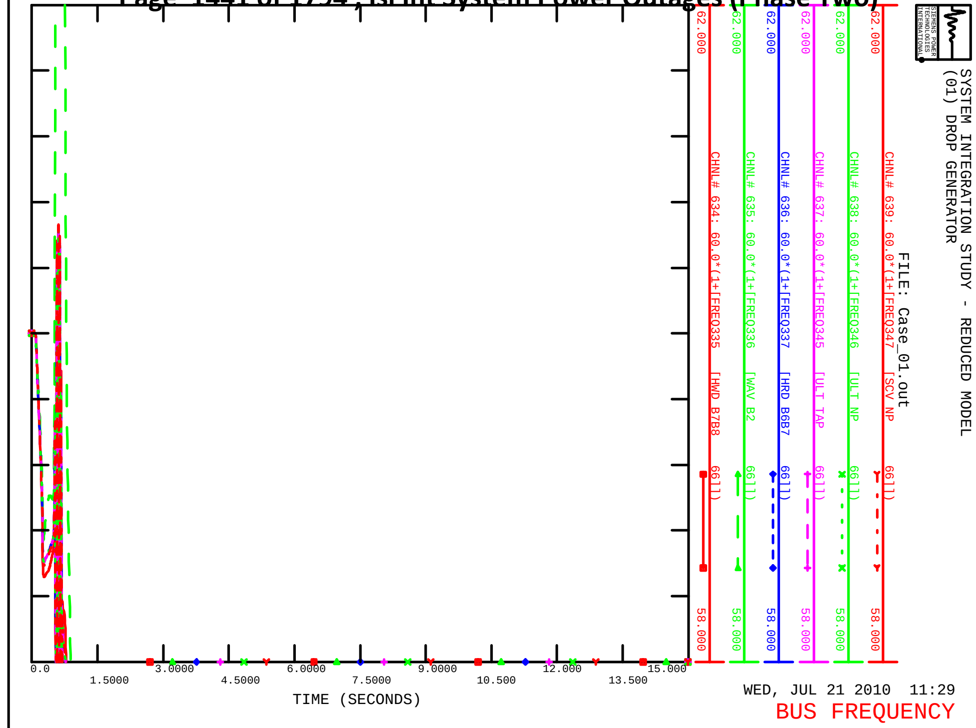

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 433: [SPD468 [TCV GEN 6.90] [1]]
CHNL# 434: [SPD468 [TCV GEN 6.90] [2]]
CHNL# 435: [SPD468 [TCV GEN 6.90] [3]]
CHNL# 436: [SPD473 [ROP G1 6.90] [1]]
CHNL# 437: [SPD478 [PHR GEN 2.30] [1]]
CHNL# 438: [SPD478 [PHR GEN 2.30] [2]]
TIME (SECONDS)
WED, JUL 21 2010 11:29
MACHINE SPEED

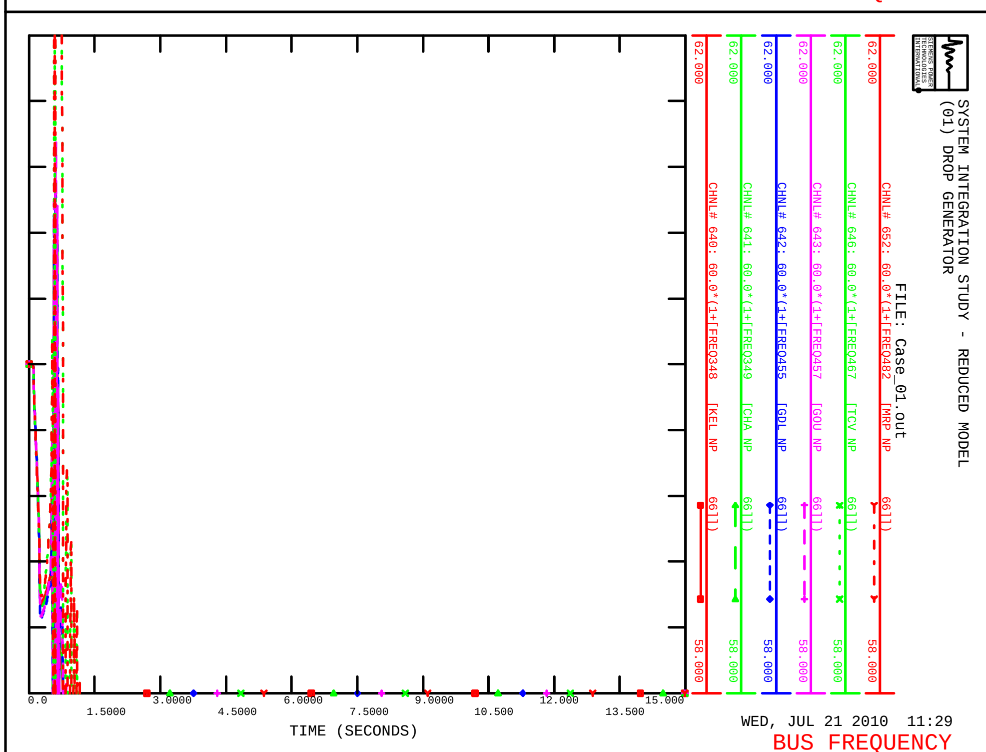

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 439: [SPD478 [PHR GEN 2.30] [3]]
CHNL# 440: [SPD483 [MRP G1 2.40] [1]]
CHNL# 441: [SPD486 [HCP G1 6.90] [1]]
CHNL# 442: [SPD488 [CAB G1 6.90] [1]]
CHNL# 443: [SPD871 [SLK G1 13.80] [1]]
TIME (SECONDS)
WED, JUL 21 2010 11:29
MACHINE SPEED

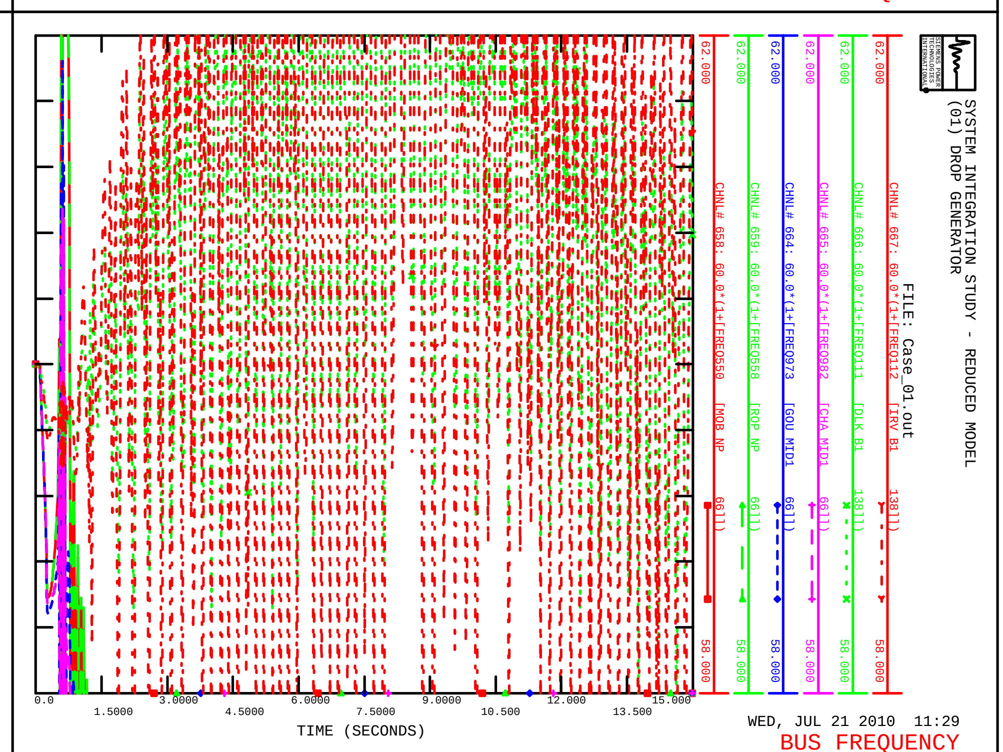

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 444: [SPD2101 [CHF A1 15.00] [1]]
CHNL# 445: [SPD2102 [CHF A2-A 15.00] [2]]
CHNL# 446: [SPD2115 [MUSK G1- 15.00] [1]]
CHNL# 447: [SPD2121 [GUL G1 15.00] [1]]
CHNL# 448: [SPD2122 [GUL G2 15.00] [2]]
CHNL# 449: [SPD2137 [HVY G1 13.80] [1]]
0.05000
-0.0500
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:29
LABRADOR MACHINE SPEED

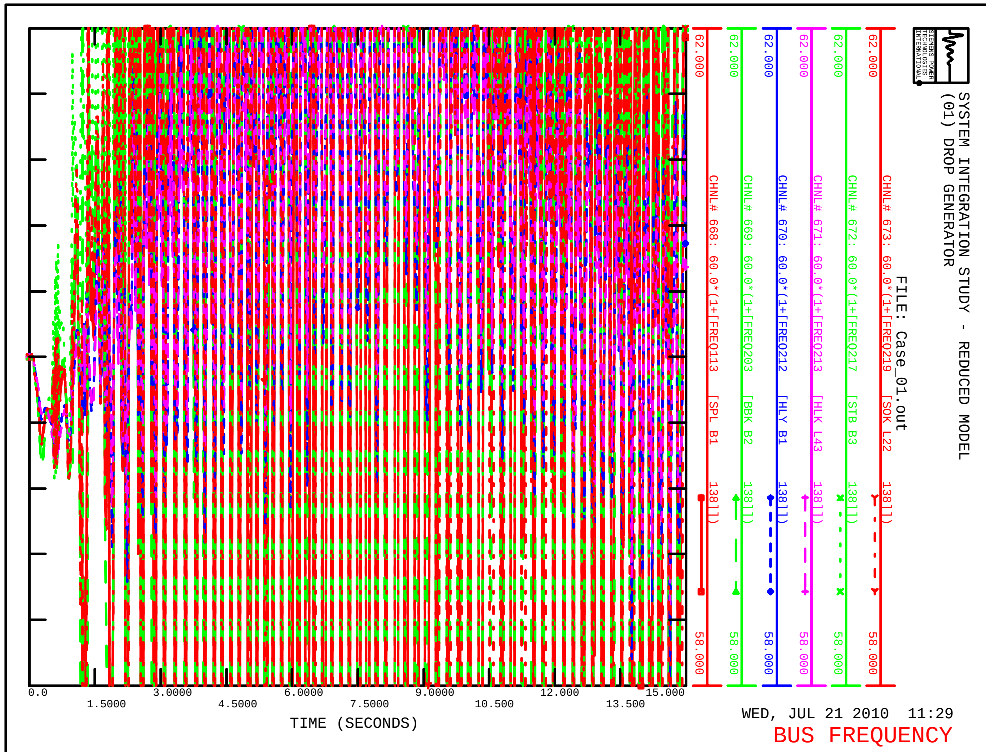

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 458: [SPD2494 [SOL SC1 13.80] [1]]
CHNL# 459: [SPD2495 [SOL SC2 13.80] [2]]
CHNL# 460: [SPD2496 [SOL SC3 13.80] [3]]
0.05000
-0.0500
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:29
MACHINE SPEED

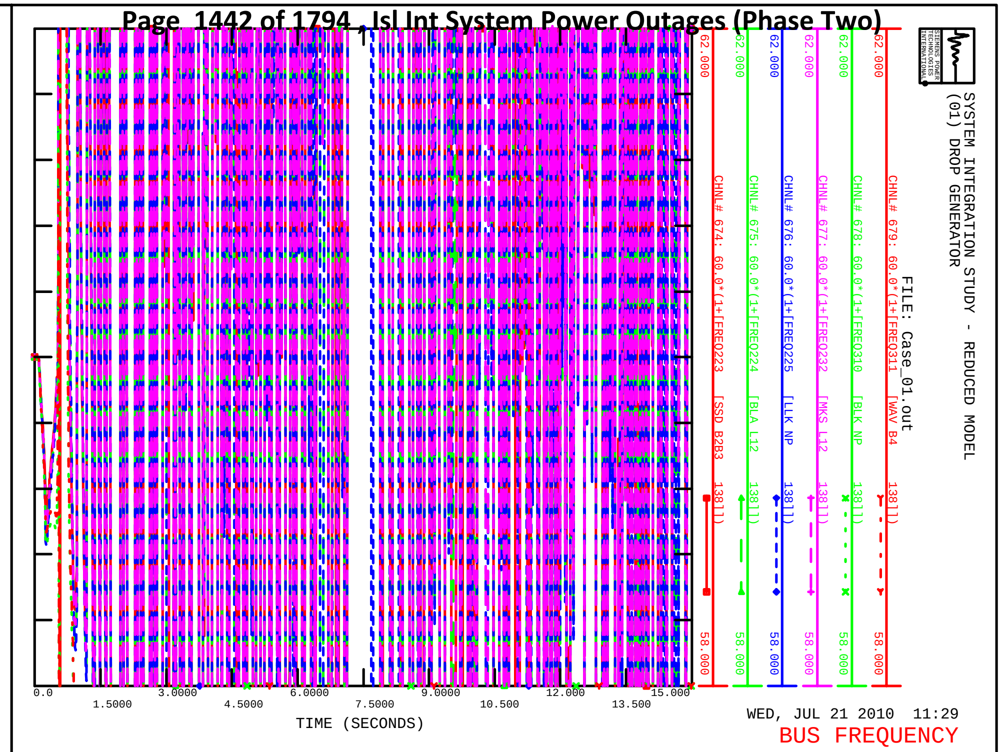

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 628: 60.0*(1+[FREQ153 [DPD L64 6611])
CHNL# 629: 60.0*(1+[FREQ204 [SVL B2 6611])
CHNL# 630: 60.0*(1+[FREQ308 [BLK NPT3 6611])
CHNL# 631: 60.0*(1+[FREQ309 [BRB T2T3 6611])
CHNL# 632: 60.0*(1+[FREQ319 [DLK NP 6611])
CHNL# 633: 60.0*(1+[FREQ334 [OPD B2B5 6611])
62.000
58.000
TIME (SECONDS)
WED, JUL 21 2010 11:29
BUS FREQUENCY

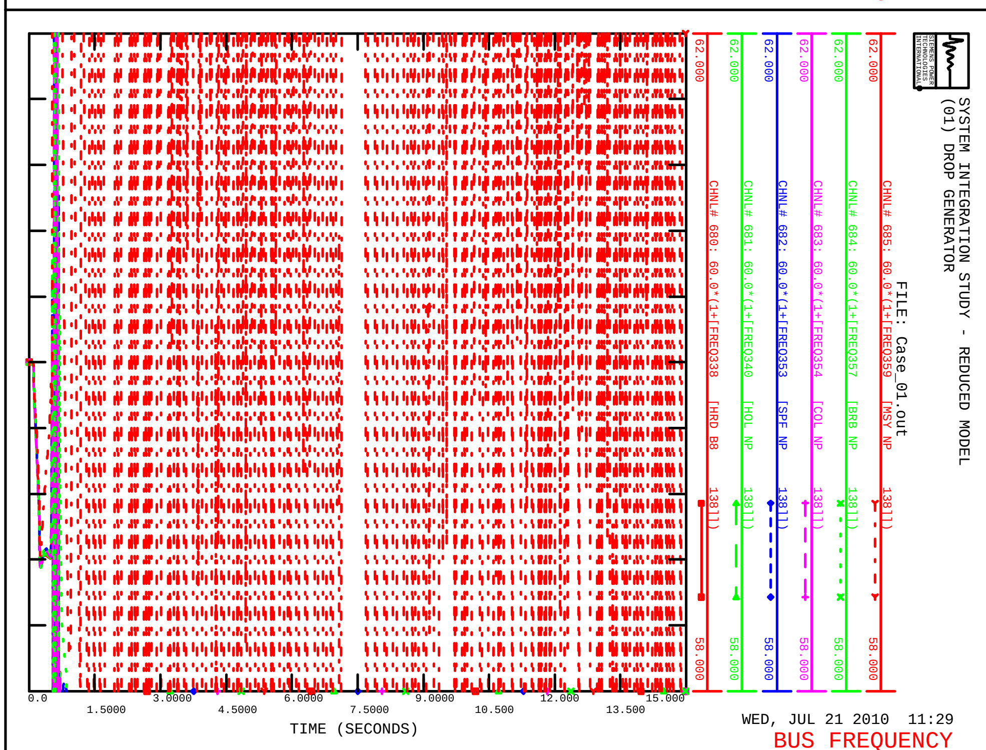

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 634: 60.0*(1+[FREQ335 [HWD B7B8 6611])
CHNL# 635: 60.0*(1+[FREQ336 [WAV B2 6611])
CHNL# 636: 60.0*(1+[FREQ337 [HRD B6B7 6611])
CHNL# 637: 60.0*(1+[FREQ345 [ULT TAP 6611])
CHNL# 638: 60.0*(1+[FREQ346 [ULT NP 6611])
CHNL# 639: 60.0*(1+[FREQ347 [SCV NP 6611])
62.000
58.000
TIME (SECONDS)
WED, JUL 21 2010 11:29
BUS FREQUENCY

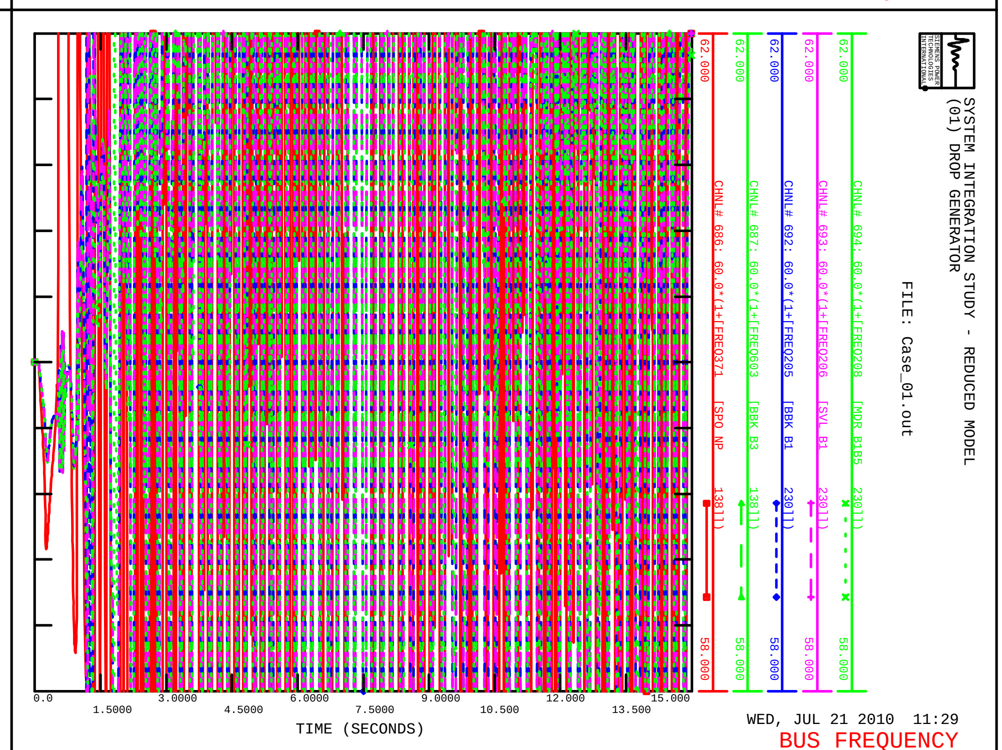

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 640: 60.0*(1+[FREQ348 [KEL NP 6611])
CHNL# 641: 60.0*(1+[FREQ349 [CHA NP 6611])
CHNL# 642: 60.0*(1+[FREQ455 [GDL NP 6611])
CHNL# 643: 60.0*(1+[FREQ457 [GOU NP 6611])
CHNL# 646: 60.0*(1+[FREQ467 [TCV NP 6611])
CHNL# 652: 60.0*(1+[FREQ482 [MRP NP 6611])
62.000
58.000
TIME (SECONDS)
WED, JUL 21 2010 11:29
BUS FREQUENCY

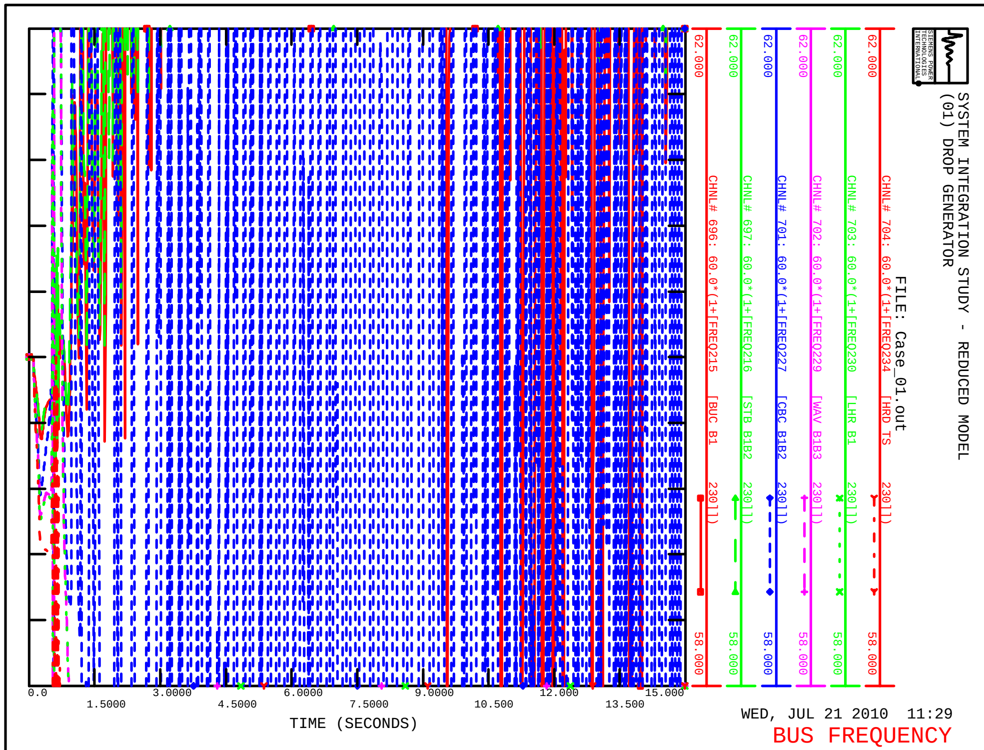

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 658: 60.0*(1+[FREQ550 [MOB NP 6611])
CHNL# 659: 60.0*(1+[FREQ558 [ROP NP 6611])
CHNL# 664: 60.0*(1+[FREQ973 [GOU MID1 6611])
CHNL# 665: 60.0*(1+[FREQ982 [CHA MID1 6611])
CHNL# 666: 60.0*(1+[FREQ111 [DLK B1 13811])
CHNL# 667: 60.0*(1+[FREQ112 [IRV B1 13811])
62.000
58.000
TIME (SECONDS)
WED, JUL 21 2010 11:29
BUS FREQUENCY

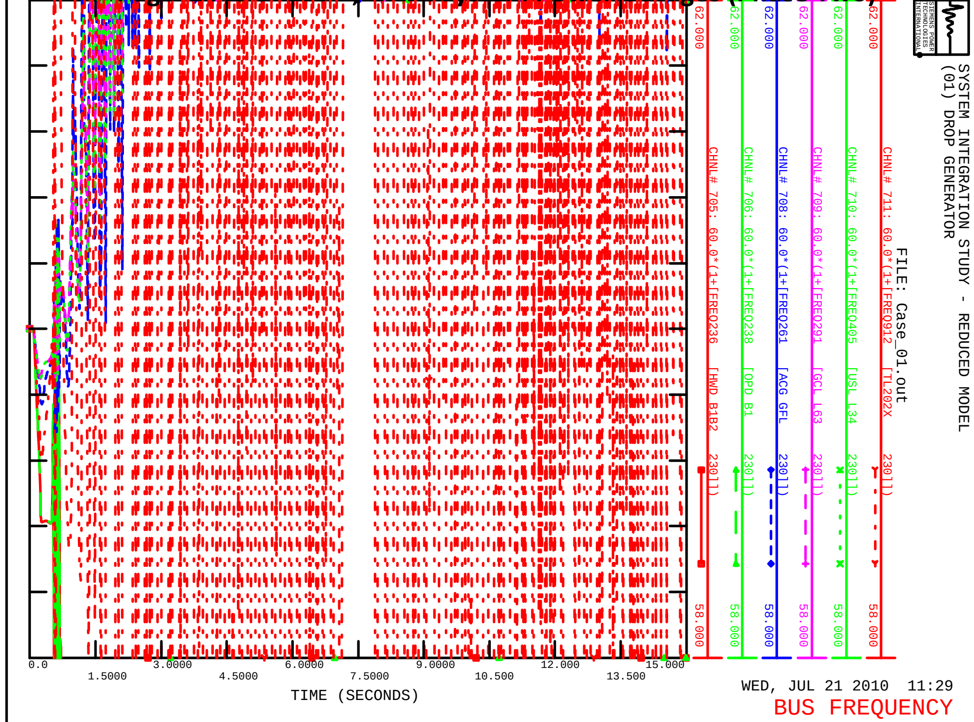

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 668: 60.0*(1+[FREQ113 [SPL B1 138]])
CHNL# 669: 60.0*(1+[FREQ203 [BBK B2 138]])
CHNL# 670: 60.0*(1+[FREQ212 [HLY B1 138]])
CHNL# 671: 60.0*(1+[FREQ213 [HLK L43 138]])
CHNL# 672: 60.0*(1+[FREQ217 [STB B3 138]])
CHNL# 673: 60.0*(1+[FREQ219 [SOK L22 138]])
62.000
58.000
TIME (SECONDS)
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
WED, JUL 21 2010 11:29
BUS FREQUENCY

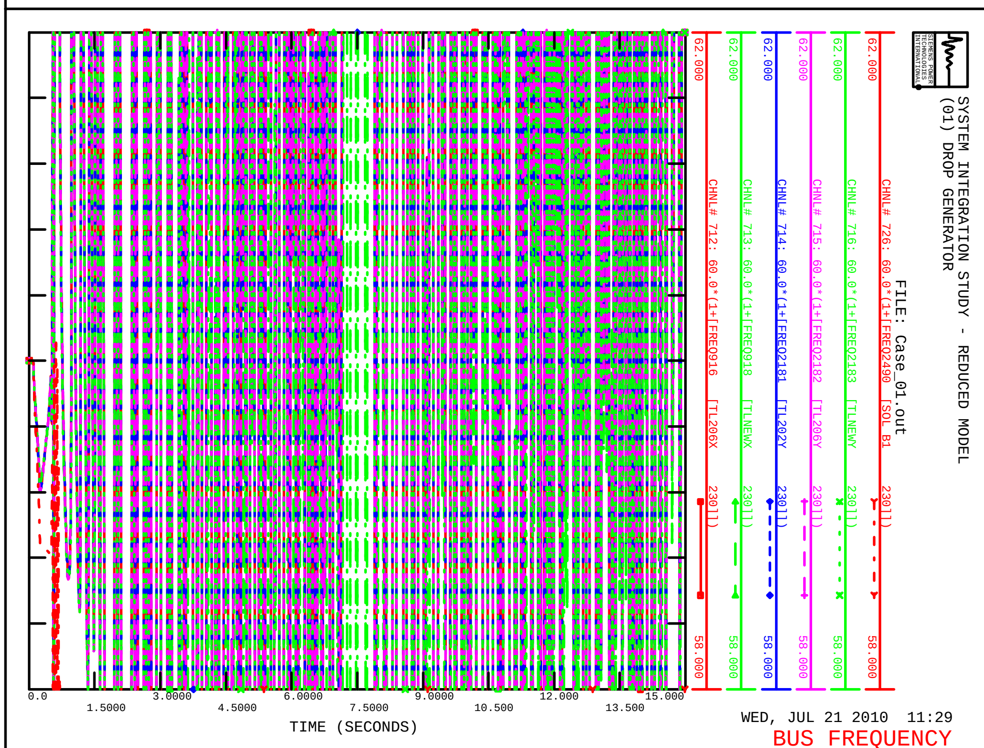

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 674: 60.0*(1+[FREQ223 [SSD B2B3 138]])
CHNL# 675: 60.0*(1+[FREQ224 [BLA L12 138]])
CHNL# 676: 60.0*(1+[FREQ225 [LLK NP 138]])
CHNL# 677: 60.0*(1+[FREQ232 [MKS L12 138]])
CHNL# 678: 60.0*(1+[FREQ310 [BLK NP 138]])
CHNL# 679: 60.0*(1+[FREQ311 [WAV B4 138]])
62.000
58.000
TIME (SECONDS)
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
WED, JUL 21 2010 11:29
BUS FREQUENCY

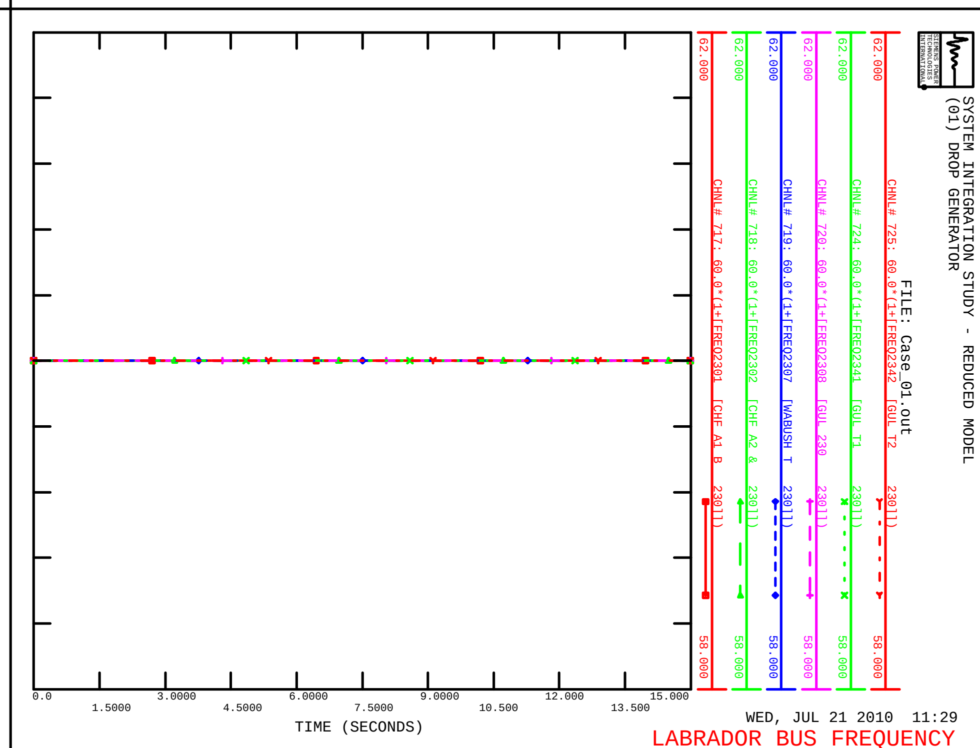

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 680: 60.0*(1+[FREQ338 [HRD B8 138]])
CHNL# 681: 60.0*(1+[FREQ340 [HOL NP 138]])
CHNL# 682: 60.0*(1+[FREQ353 [SPF NP 138]])
CHNL# 683: 60.0*(1+[FREQ354 [COL NP 138]])
CHNL# 684: 60.0*(1+[FREQ357 [BRB NP 138]])
CHNL# 685: 60.0*(1+[FREQ359 [MSY NP 138]])
62.000
58.000
TIME (SECONDS)
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1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
WED, JUL 21 2010 11:29
BUS FREQUENCY

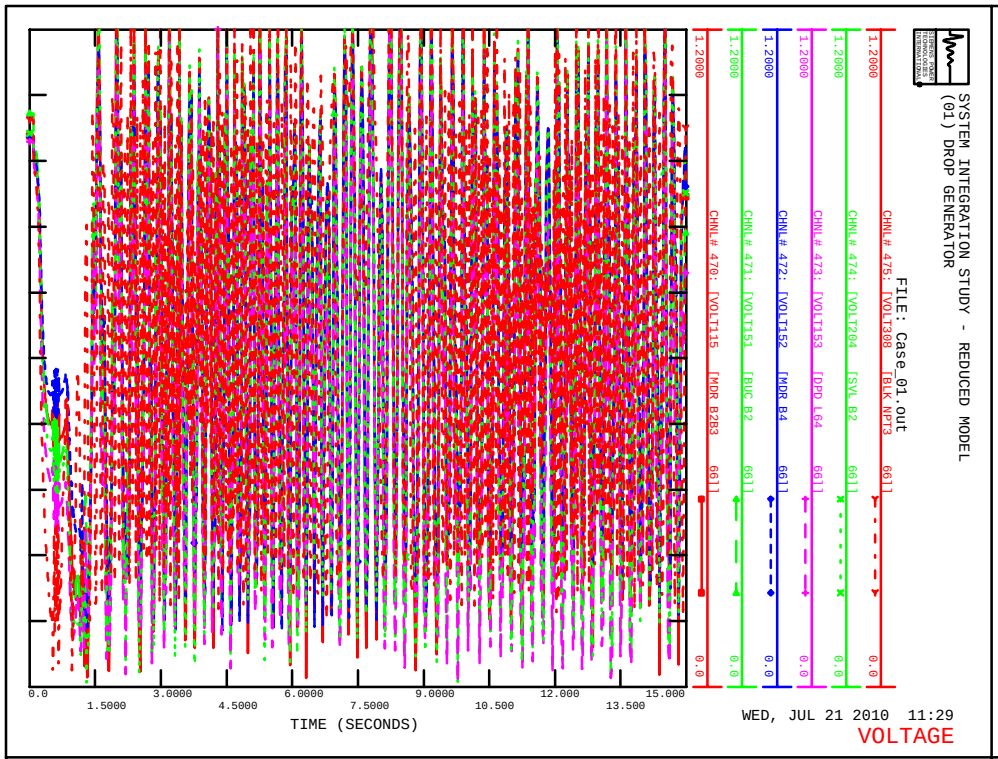

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 686: 60.0*(1+[FREQ371 [SPO NP 138]])
CHNL# 687: 60.0*(1+[FREQ603 [BBK B3 138]])
CHNL# 692: 60.0*(1+[FREQ205 [BBK B1 230]])
CHNL# 693: 60.0*(1+[FREQ206 [SVL B1 230]])
CHNL# 694: 60.0*(1+[FREQ208 [MDR B1B5 230]])
62.000
58.000
TIME (SECONDS)
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1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
WED, JUL 21 2010 11:29
BUS FREQUENCY

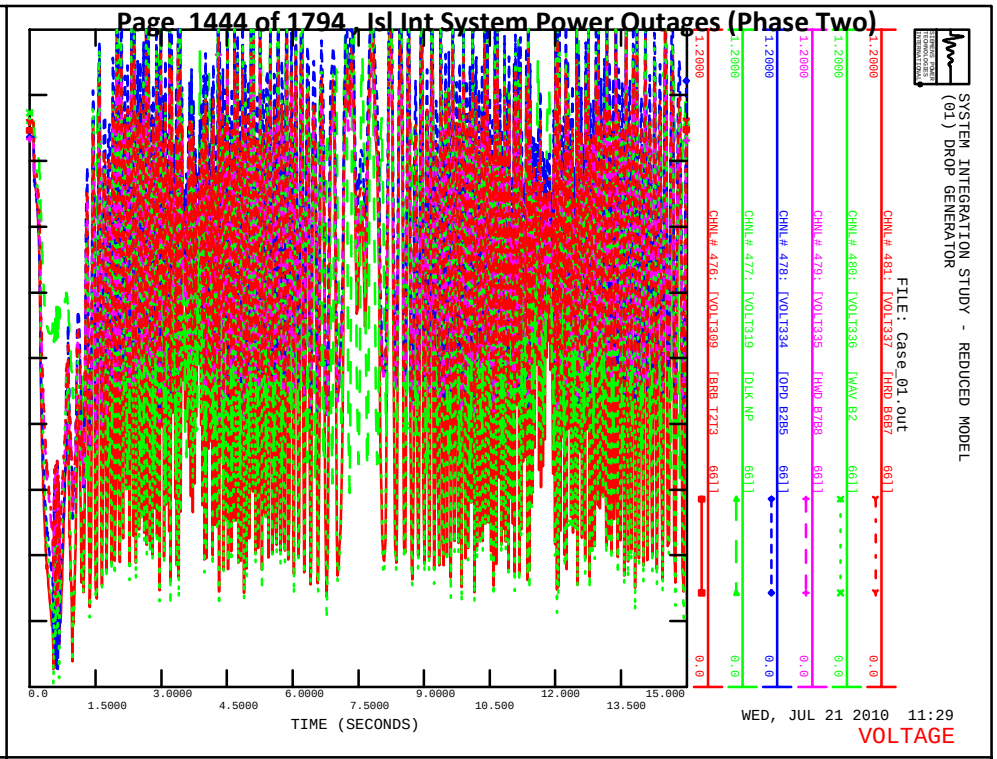

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 696: 60.0*(1+[FREQ215 [BUC B1 230]])
CHNL# 697: 60.0*(1+[FREQ216 [STB B1B2 230]])
CHNL# 701: 60.0*(1+[FREQ227 [CBC B1B2 230]])
CHNL# 702: 60.0*(1+[FREQ229 [WAV B1B3 230]])
CHNL# 703: 60.0*(1+[FREQ230 [LHR B1 230]])
CHNL# 704: 60.0*(1+[FREQ234 [HRD TS 230]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:29
BUS FREQUENCY

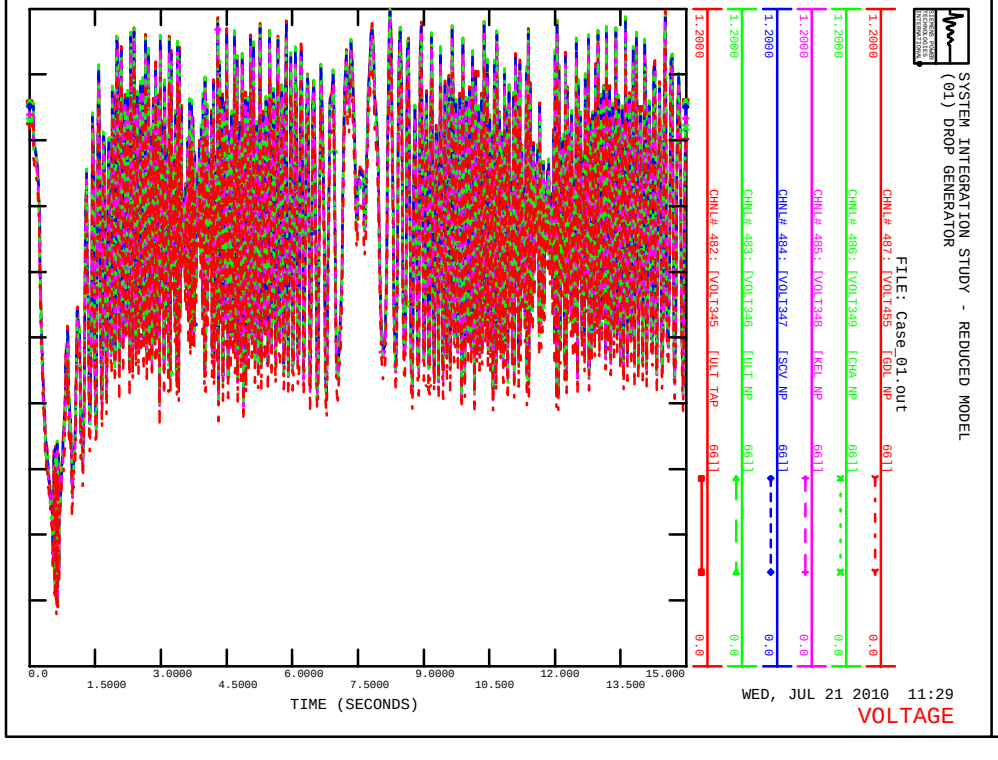

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 705: 60.0*(1+[FREQ236 [HWD B1B2 230]])
CHNL# 706: 60.0*(1+[FREQ238 [OPD B1 230]])
CHNL# 708: 60.0*(1+[FREQ261 [ACG GFL 230]])
CHNL# 709: 60.0*(1+[FREQ291 [GCL L63 230]])
CHNL# 710: 60.0*(1+[FREQ405 [USL L34 230]])
CHNL# 711: 60.0*(1+[FREQ912 [TL202X 230]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:29
BUS FREQUENCY

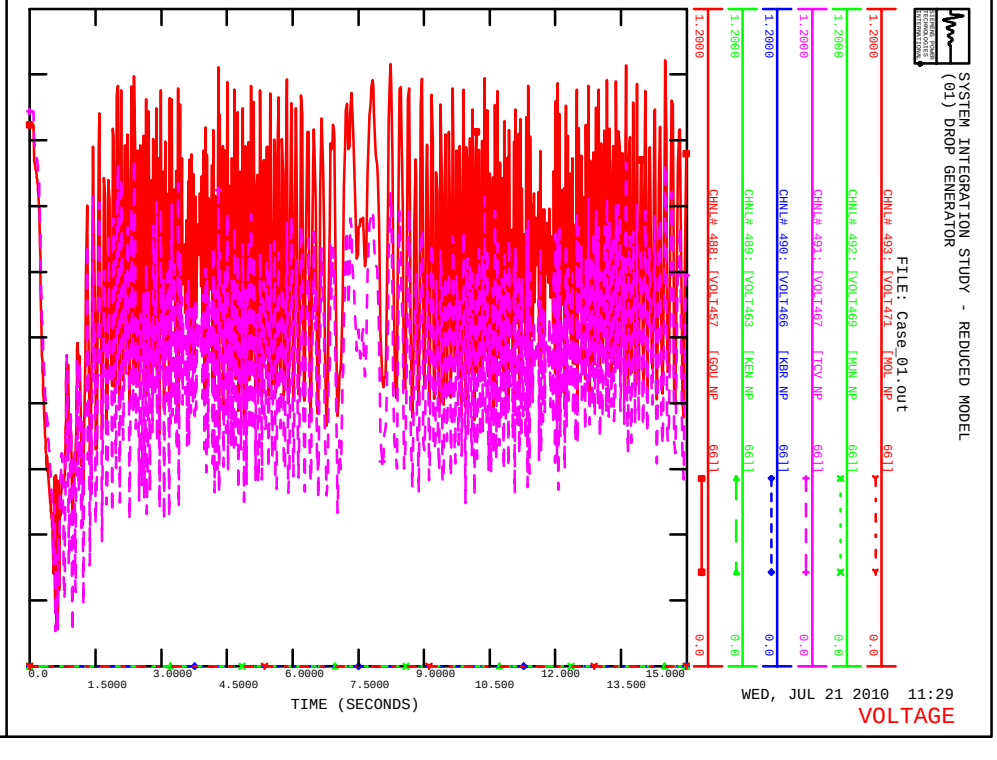

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 712: 60.0*(1+[FREQ916 [TL206X 230]])
CHNL# 713: 60.0*(1+[FREQ918 [TLNEWX 230]])
CHNL# 714: 60.0*(1+[FREQ2181 [TL202Y 230]])
CHNL# 715: 60.0*(1+[FREQ2182 [TL206Y 230]])
CHNL# 716: 60.0*(1+[FREQ2183 [TLNEWY 230]])
CHNL# 726: 60.0*(1+[FREQ2490 [SOL B1 230]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:29
BUS FREQUENCY

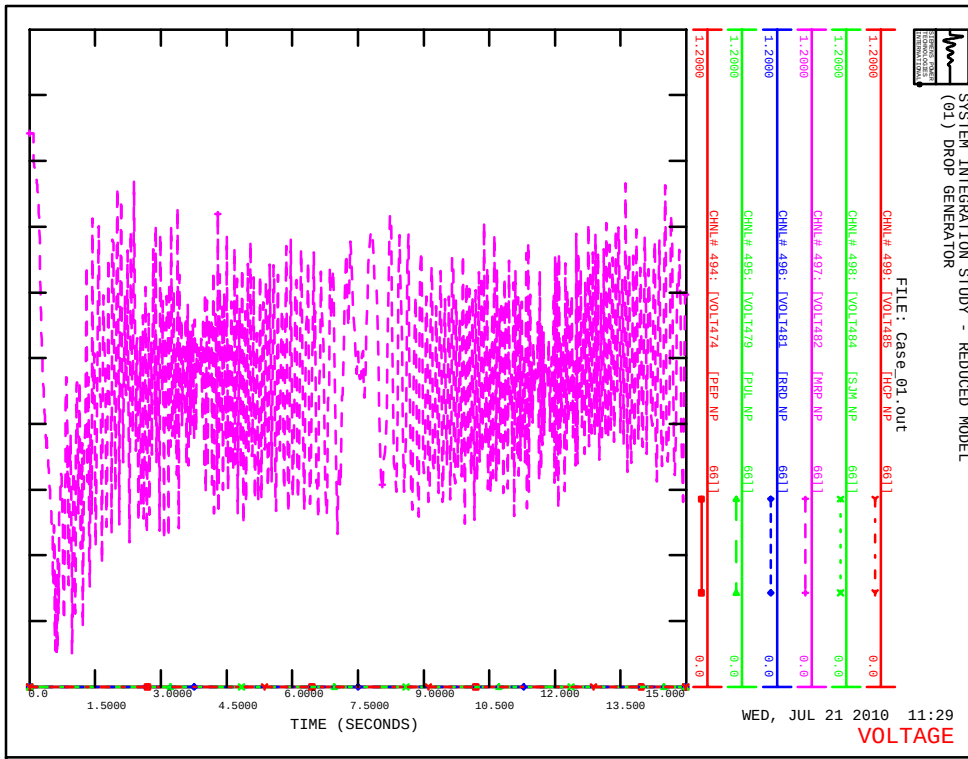

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 717: 60.0*(1+[FREQ2301 [CHF A1 B 230]])
CHNL# 718: 60.0*(1+[FREQ2302 [CHF A2 & 230]])
CHNL# 719: 60.0*(1+[FREQ2307 [WABUSH T 230]])
CHNL# 720: 60.0*(1+[FREQ2308 [GUL 230 230]])
CHNL# 724: 60.0*(1+[FREQ2341 [GUL T1 230]])
CHNL# 725: 60.0*(1+[FREQ2342 [GUL T2 230]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:29
LABRADOR BUS FREQUENCY

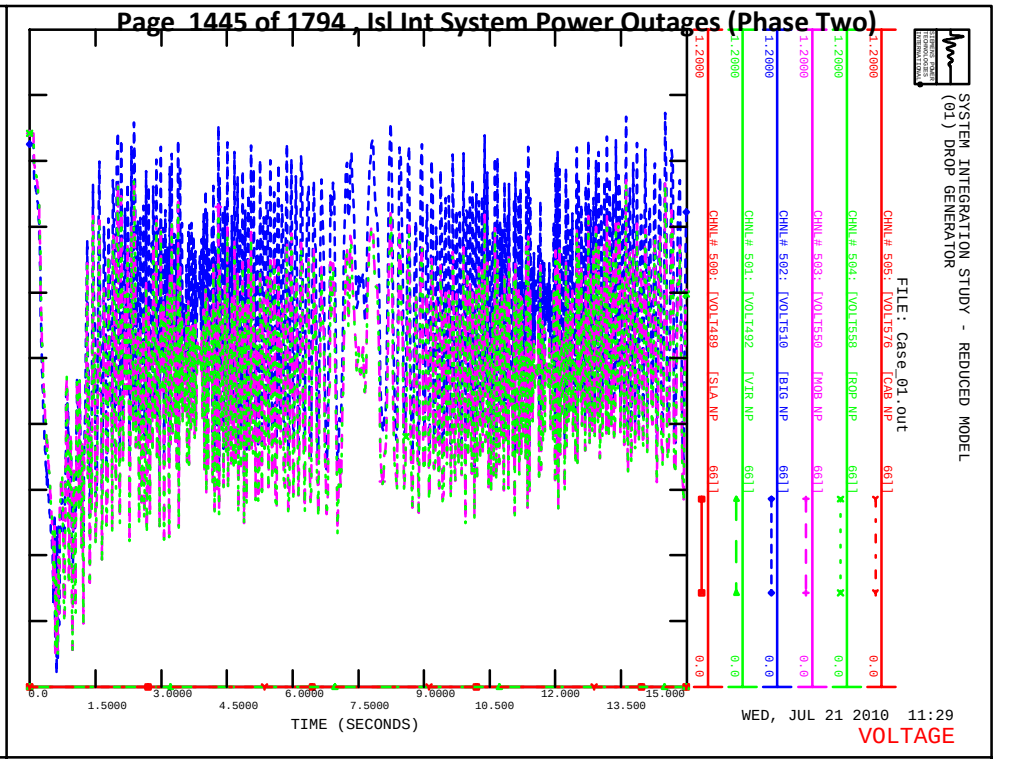

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 470: [VOLT115 [MDR B2B3 661]
CHNL# 471: [VOLT151 [BUC B2 661]
CHNL# 472: [VOLT152 [MDR B4 661]
CHNL# 473: [VOLT153 [QPD L64 661]
CHNL# 474: [VOLT204 [SVL B2 661]
CHNL# 475: [VOLT308 [BLK NPT3 661]
TIME (SECONDS)
WED, JUL 21 2010 11:29
VOLTAGE

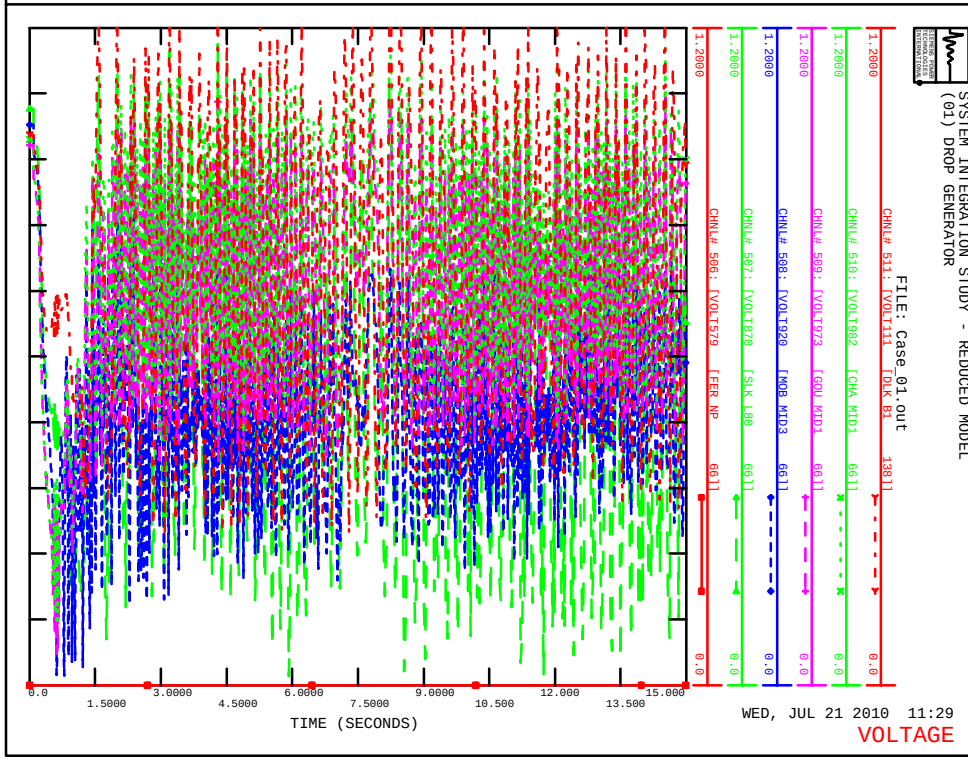

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 476: [VOLT309 [BRB T2T3 661]
CHNL# 477: [VOLT319 [DLK NP 661]
CHNL# 478: [VOLT334 [QPD B2B5 661]
CHNL# 479: [VOLT335 [HWD B7B8 661]
CHNL# 480: [VOLT336 [WAV B2 661]
CHNL# 481: [VOLT337 [HRD B6B7 661]
TIME (SECONDS)
WED, JUL 21 2010 11:29
VOLTAGE

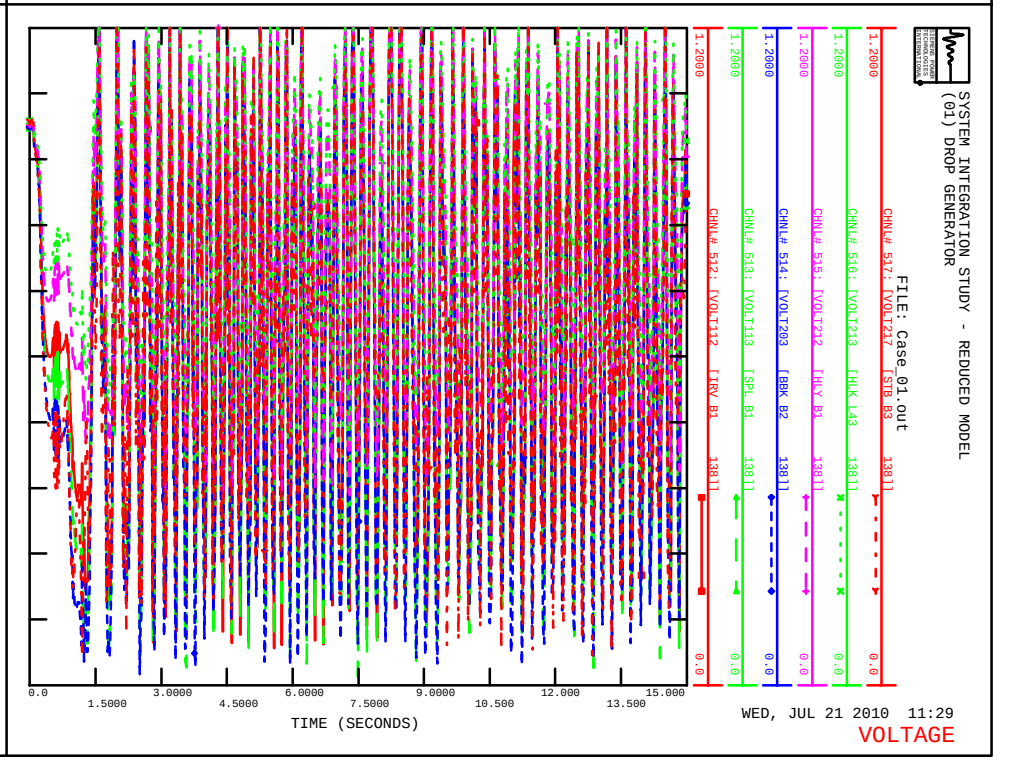

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 482: [VOLT345 [ULT TAP 661]
CHNL# 483: [VOLT346 [ULT NP 661]
CHNL# 484: [VOLT347 [SCV NP 661]
CHNL# 485: [VOLT348 [KEL NP 661]
CHNL# 486: [VOLT349 [CHA NP 661]
CHNL# 487: [VOLT455 [GDL NP 661]
TIME (SECONDS)
WED, JUL 21 2010 11:29
VOLTAGE

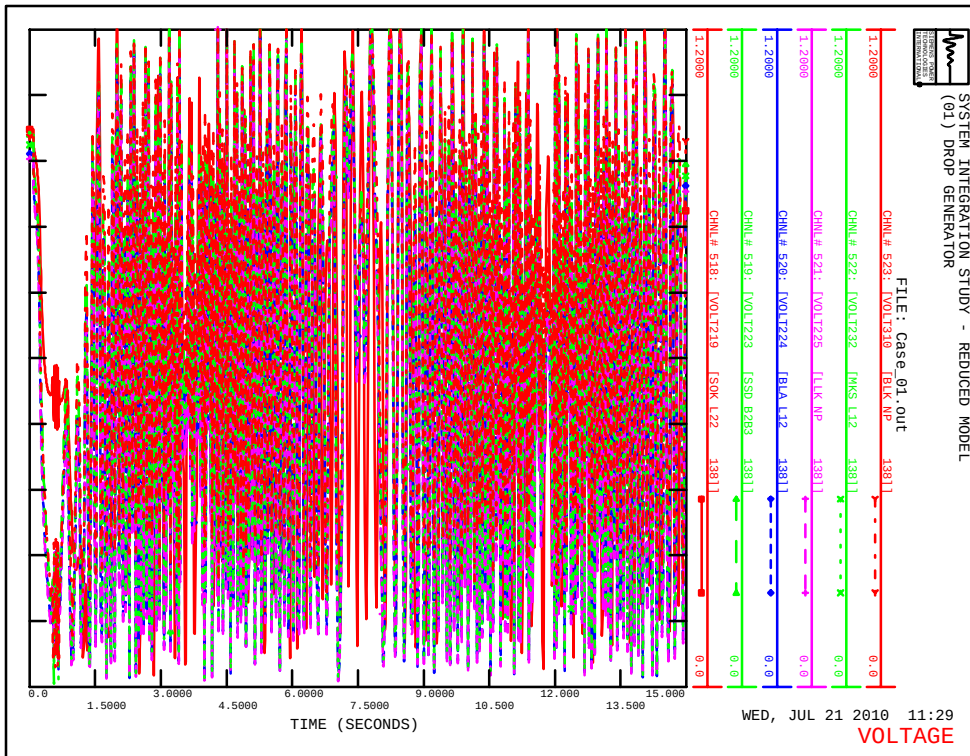

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 488: [VOLT457 [GOU NP 661]
CHNL# 489: [VOLT463 [KEN NP 661]
CHNL# 490: [VOLT466 [KBR NP 661]
CHNL# 491: [VOLT467 [TCV NP 661]
CHNL# 492: [VOLT469 [MUN NP 661]
CHNL# 493: [VOLT471 [MOL NP 661]
TIME (SECONDS)
WED, JUL 21 2010 11:29
VOLTAGE

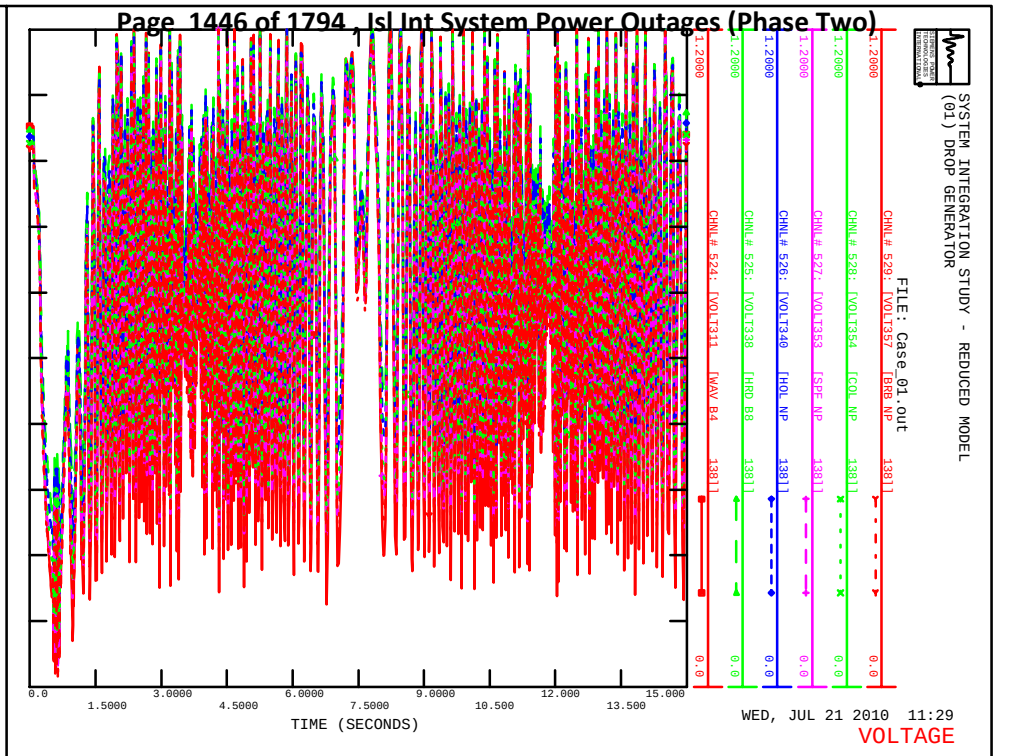

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 494: [VOLT474 [PEP NP 661]
CHNL# 495: [VOLT479 [PUL NP 661]
CHNL# 496: [VOLT481 [RRD NP 661]
CHNL# 497: [VOLT482 [MRP NP 661]
CHNL# 498: [VOLT484 [SJM NP 661]
CHNL# 499: [VOLT485 [HCP NP 661]
TIME (SECONDS)
WED, JUL 21 2010 11:29
VOLTAGE

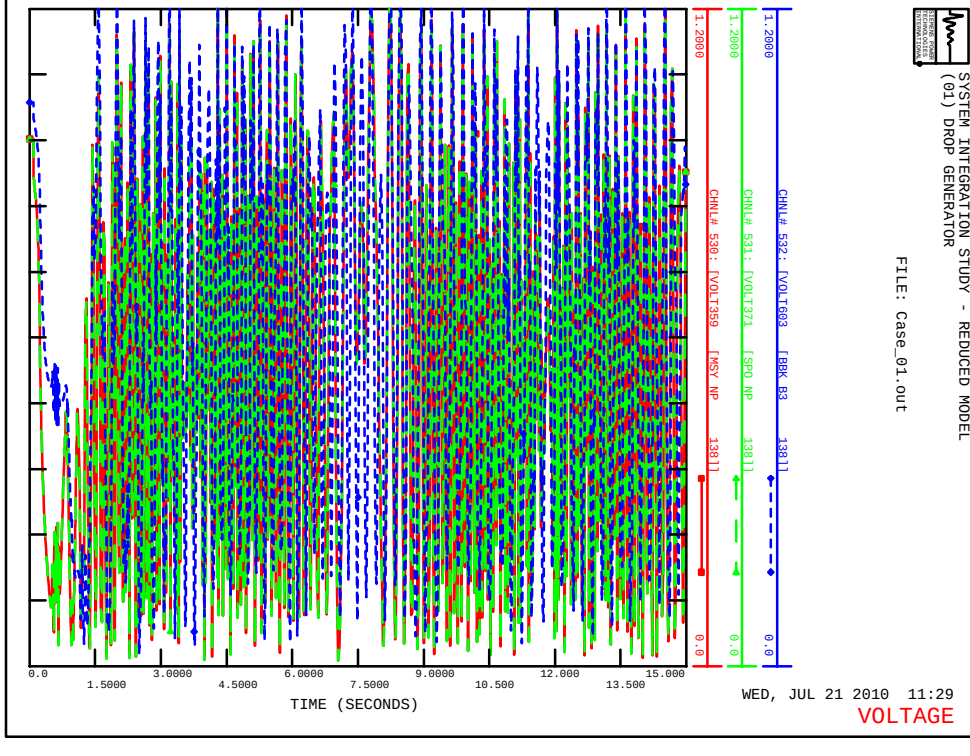

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 500: [VOLT489 [SLA NP 661]
CHNL# 501: [VOLT492 [VIR NP 661]
CHNL# 502: [VOLT510 [BIG NP 661]
CHNL# 503: [VOLT550 [MOB NP 661]
CHNL# 504: [VOLT558 [ROP NP 661]
CHNL# 505: [VOLT576 [CAB NP 661]
TIME (SECONDS)
WED, JUL 21 2010 11:29
VOLTAGE

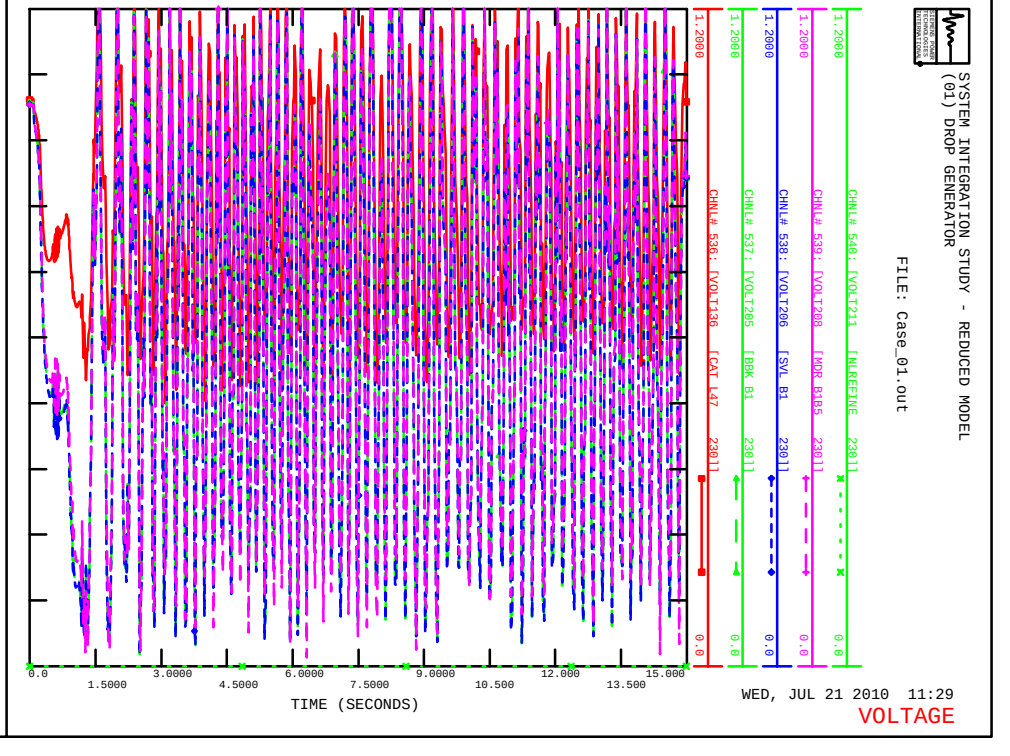

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 506: [VOLT579 [FER NP 661]
CHNL# 507: [VOLT870 [SLK L80 661]
CHNL# 508: [VOLT920 [MOB MID3 661]
CHNL# 509: [VOLT973 [GOU MID1 661]
CHNL# 510: [VOLT982 [CHA MID1 661]
CHNL# 511: [VOLT111 [DLK B1 1381]
TIME (SECONDS)
WED, JUL 21 2010 11:29
VOLTAGE

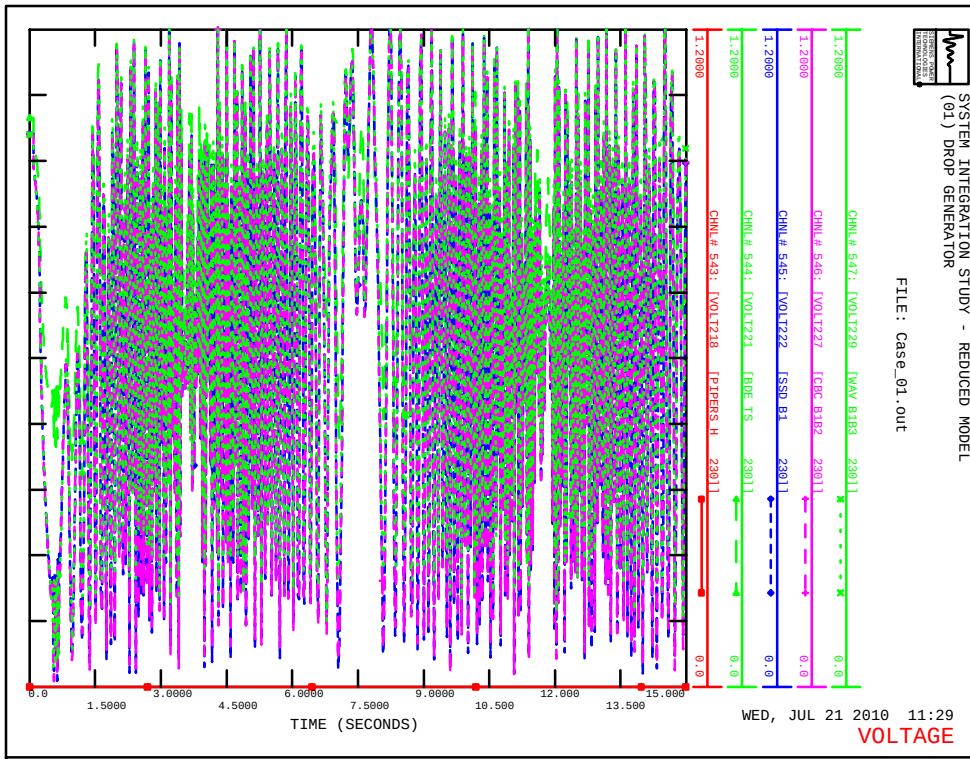

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 512: [VOLT112 [IRV B1 1381]
CHNL# 513: [VOLT113 [SPL B1 1381]
CHNL# 514: [VOLT203 [BBK B2 1381]
CHNL# 515: [VOLT232 [HLY B1 1381]
CHNL# 516: [VOLT213 [HLK L43 1381]
CHNL# 517: [VOLT237 [STB B3 1381]
TIME (SECONDS)
WED, JUL 21 2010 11:29
VOLTAGE

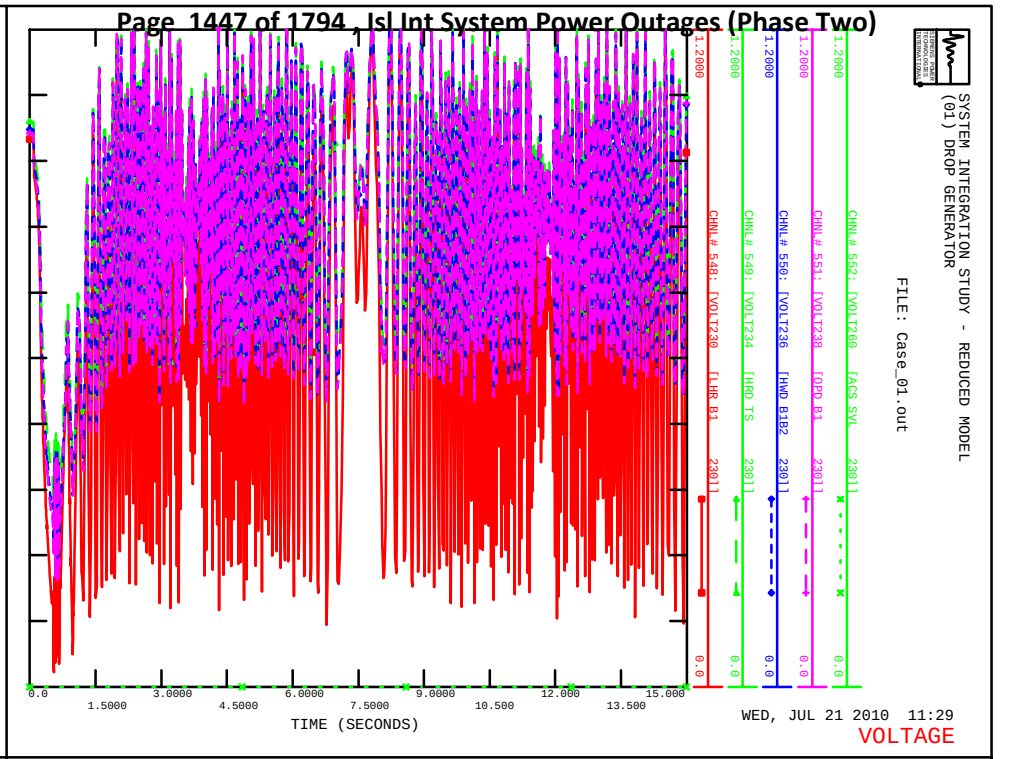

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 518: [VOLT219 [SOK L22 138]
CHNL# 519: [VOLT223 [SSD B2B3 138]
CHNL# 520: [VOLT224 [BLA L32 138]
CHNL# 521: [VOLT225 [LLK NP 138]
CHNL# 522: [VOLT232 [MKS L32 138]
CHNL# 523: [VOLT310 [BLK NP 138]
TIME (SECONDS)
WED, JUL 21 2010 11:29
VOLTAGE

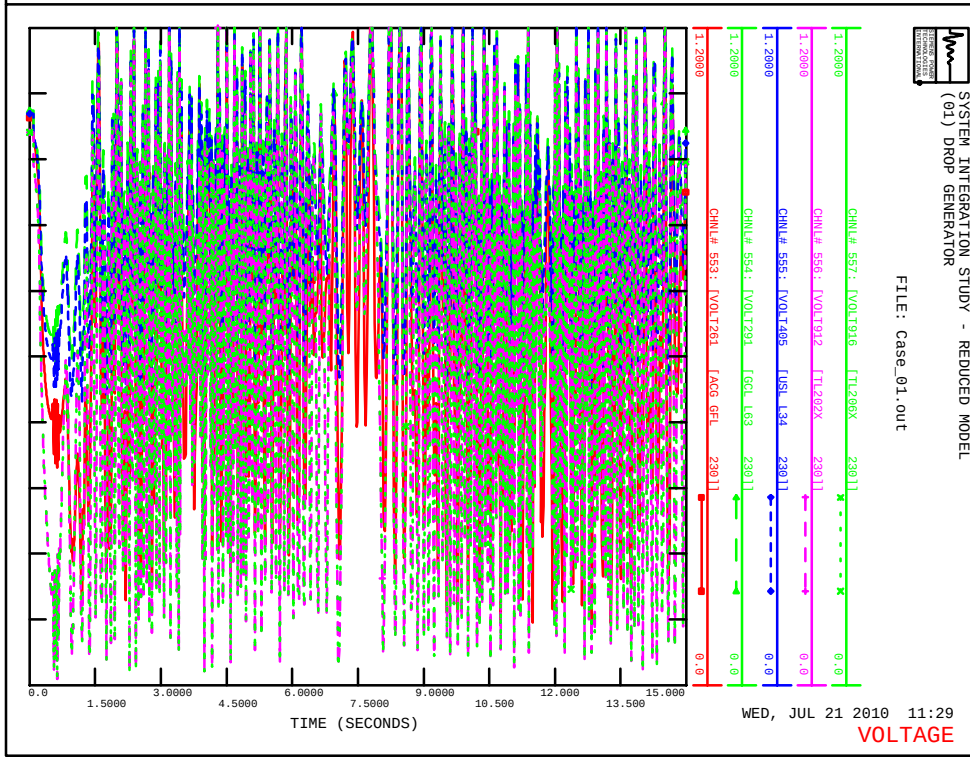

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 524: [VOLT311 [WAV B4 138]
CHNL# 525: [VOLT338 [HRD B8 138]
CHNL# 526: [VOLT340 [HOL NP 138]
CHNL# 527: [VOLT353 [SPF NP 138]
CHNL# 528: [VOLT354 [COL NP 138]
CHNL# 529: [VOLT357 [BRB NP 138]
TIME (SECONDS)
WED, JUL 21 2010 11:29
VOLTAGE

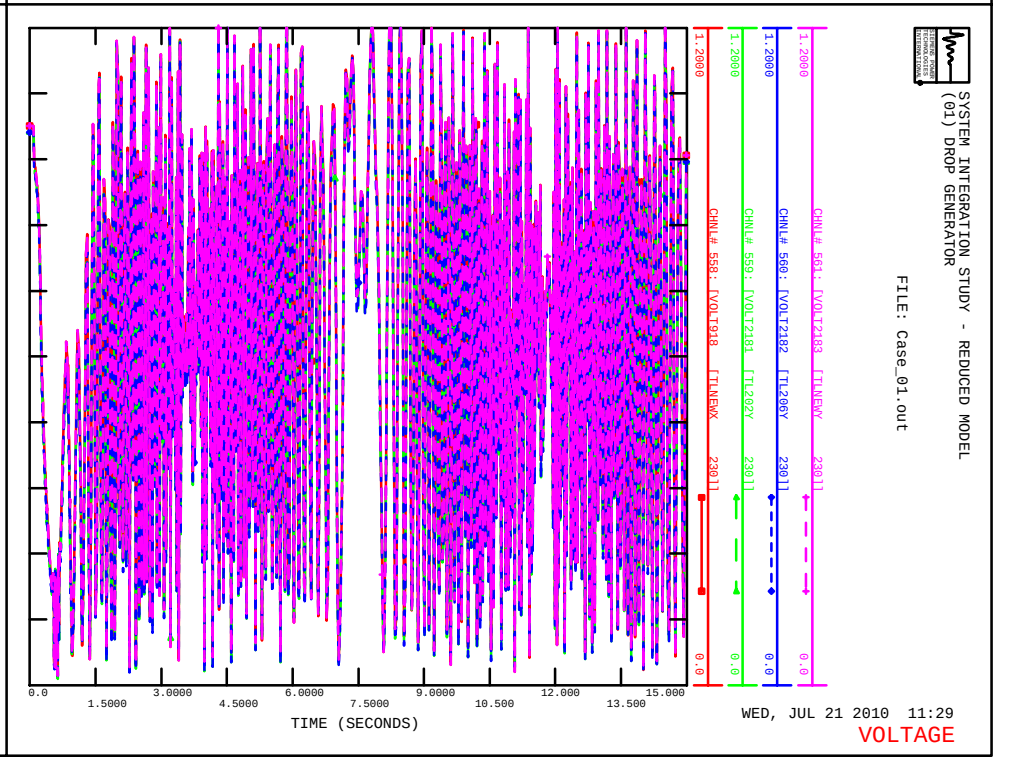

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 530: [VOLT359 [MSY NP 138]
CHNL# 531: [VOLT371 [SPO NP 138]
CHNL# 532: [VOLT603 [BBK B3 138]
TIME (SECONDS)
WED, JUL 21 2010 11:29
VOLTAGE

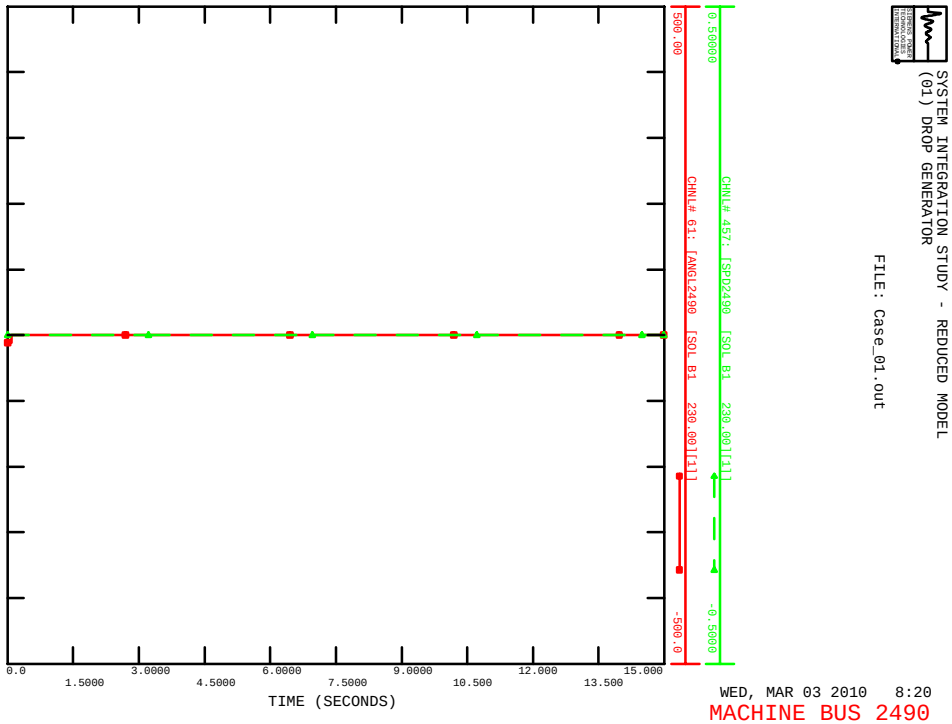

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 536: [VOLT136 [CAT L47 230]
CHNL# 537: [VOLT205 [BBK B1 230]
CHNL# 538: [VOLT206 [SVL B1 230]
CHNL# 539: [VOLT208 [MOR B1B5 230]
CHNL# 540: [VOLT211 [NLREFINE 230]
TIME (SECONDS)
WED, JUL 21 2010 11:29
VOLTAGE

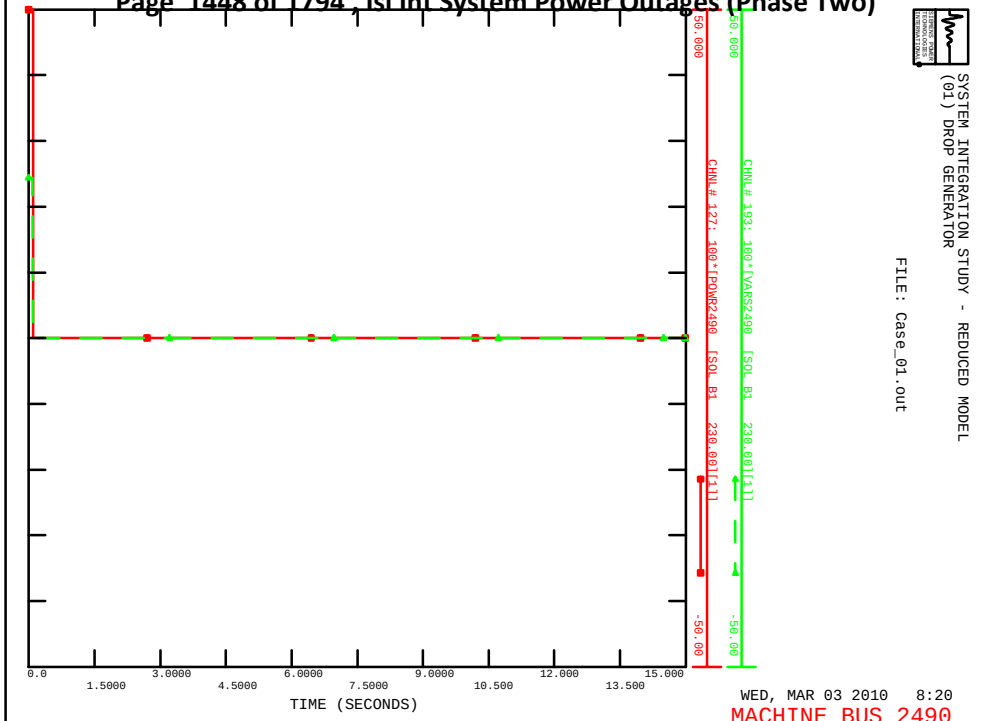

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL # 543: [VOLT218 [PIPERS H 230]
CHNL # 544: [VOLT221 [BDE TS 230]
CHNL # 545: [VOLT222 [SSD B1 230]
CHNL # 546: [VOLT227 [CBC B1B2 230]
CHNL # 547: [VOLT229 [WAV B1B3 230]
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:29
VOLTAGE

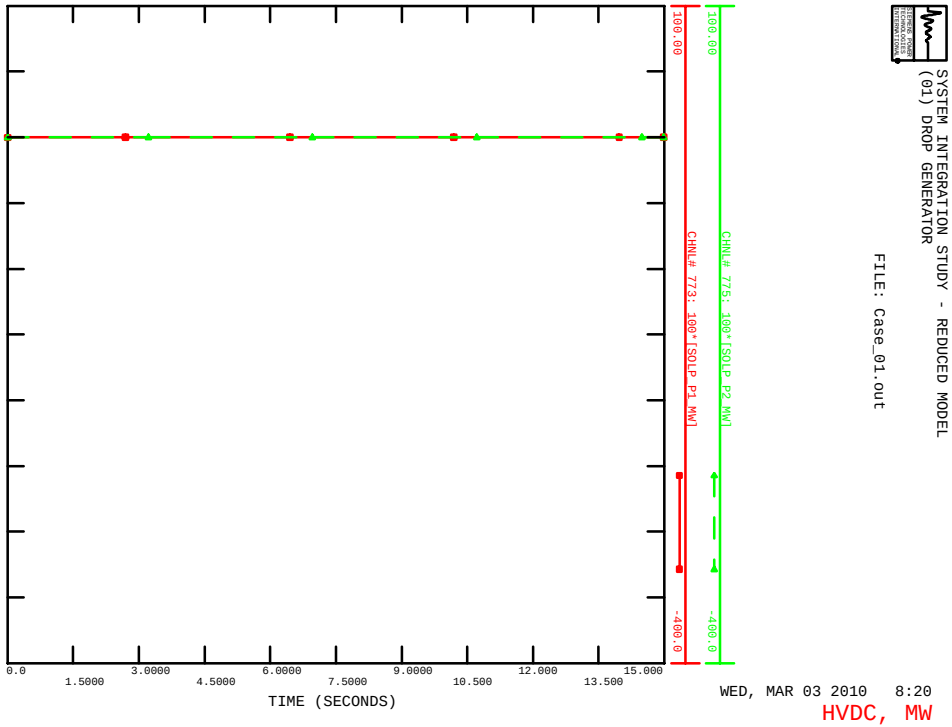

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL # 548: [VOLT230 [LHR B1 230]
CHNL # 549: [VOLT234 [HRD TS 230]
CHNL # 550: [VOLT236 [HWD B1B2 230]
CHNL # 551: [VOLT238 [QPD B1 230]
CHNL # 552: [VOLT260 [ACS SVI 230]
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:29
VOLTAGE

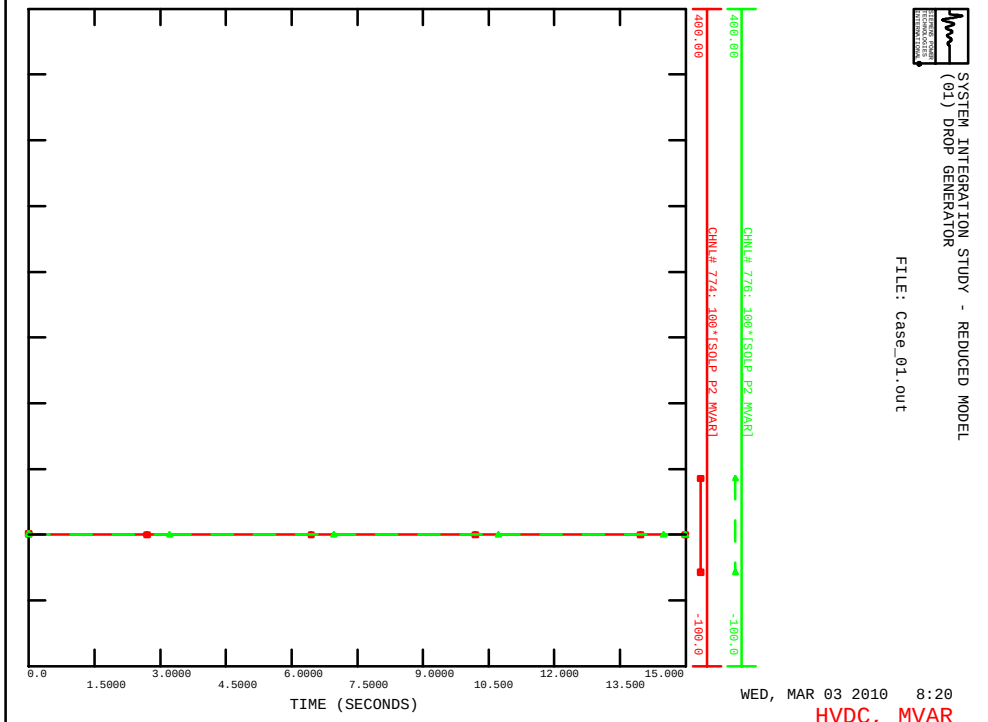

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 553: [VOLT261 [ACG GFL 230]
CHNL# 554: [VOLT291 [GCL L63 230]
CHNL# 555: [VOLT405 [USL L34 230]
CHNL# 556: [VOLT912 [TL202X 230]
CHNL# 557: [VOLT916 [TL206X 230]
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:29
VOLTAGE

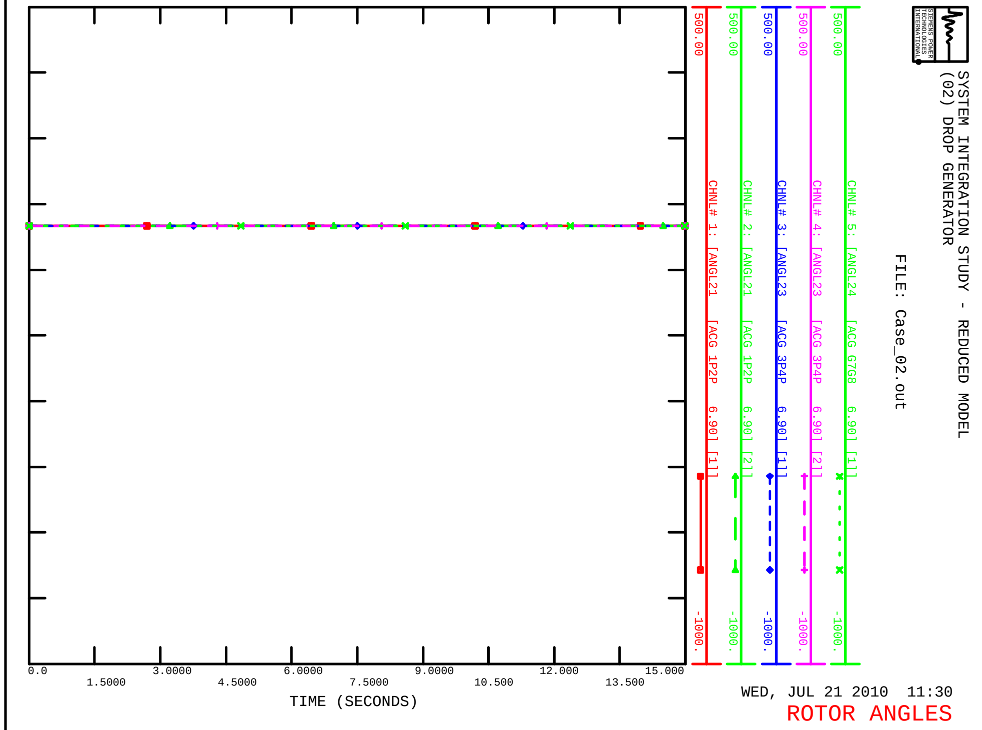

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
CHNL# 558: [VOLT918 [TLNEWX 230]
CHNL# 559: [VOLT2181 [TL202Y 230]
CHNL# 560: [VOLT2182 [TL206Y 230]
CHNL# 561: [VOLT2183 [TLNEWY 230]
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:29
VOLTAGE

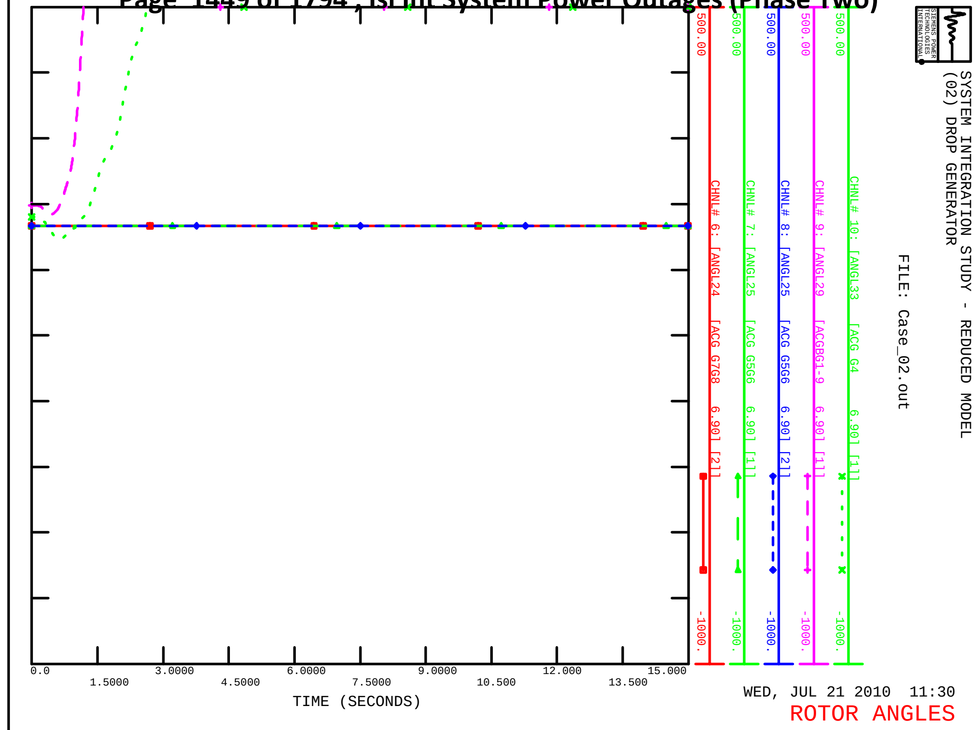

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
500.00
CHNL# 61: [ANGL2490 [SOL B1 230.00][1]]
-500.0
0.50000
CHNL# 457: [SPD2490 [SOL B1 230.00][1]]
-0.50000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, MAR 03 2010 8:20
MACHINE BUS 2490

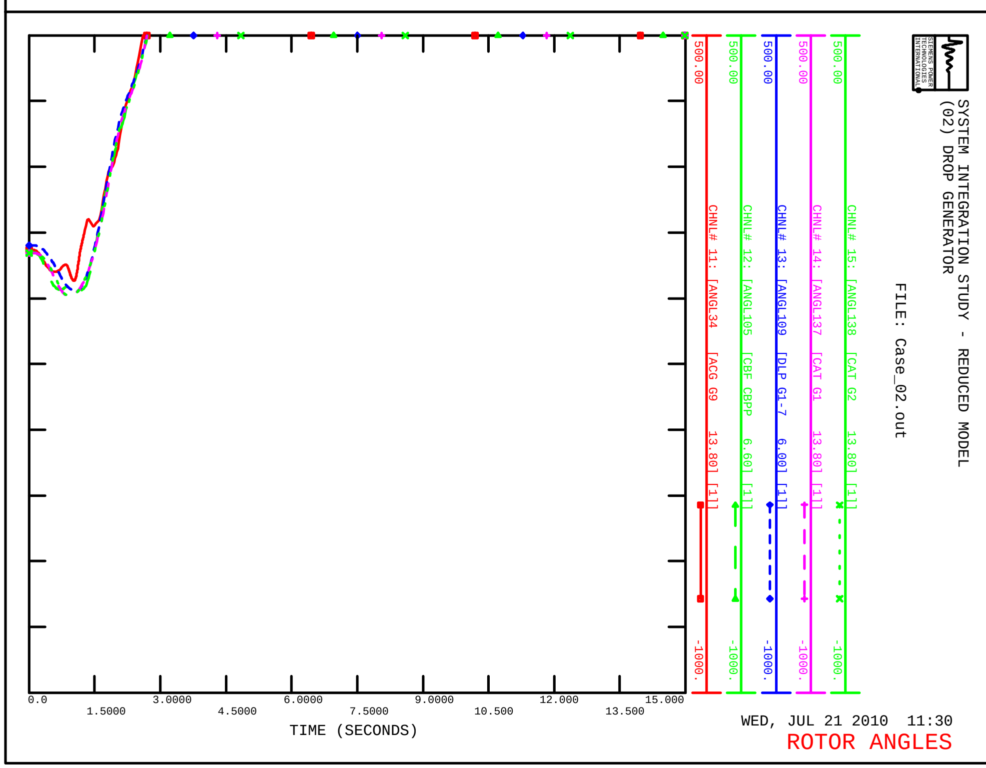

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
50.000
CHNL# 127: 100*[POWR2490 [SOL B1 230.00][1]]
-50.000
50.000
CHNL# 193: 100*[VARS2490 [SOL B1 230.00][1]]
-50.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, MAR 03 2010 8:20
MACHINE BUS 2490

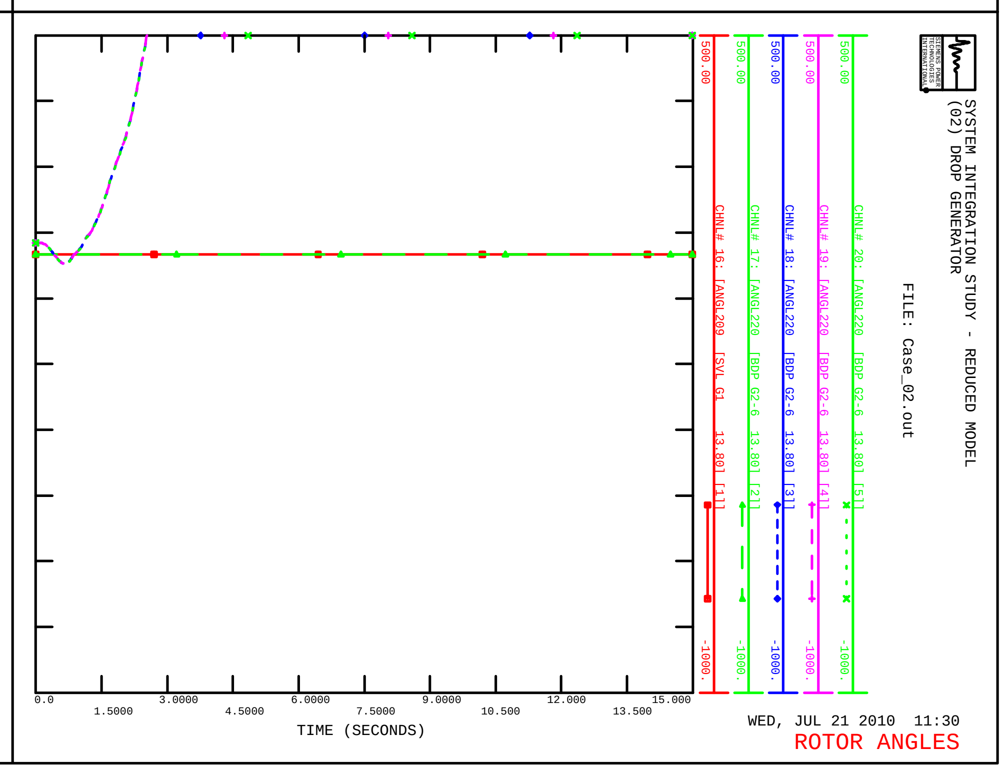

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
100.00
CHNL# 773: 100*[SOLP P1 MW]
-400.0
100.00
CHNL# 775: 100*[SOLP P2 MW]
-400.0
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, MAR 03 2010 8:20
HVDC, MW

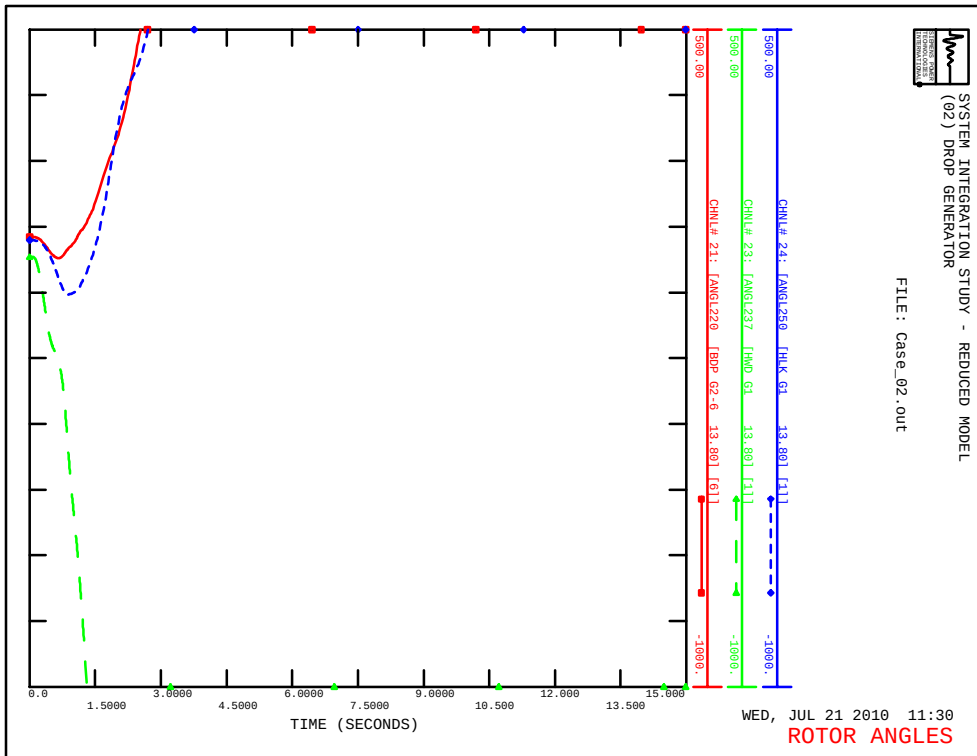

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(01) DROP GENERATOR
FILE: Case_01.out
400.00
CHNL# 774: 100*[SOLP P2 MVAR]
-100.0
400.00
CHNL# 776: 100*[SOLP P2 MVAR]
-100.0
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, MAR 03 2010 8:20
HVDC, MVAR

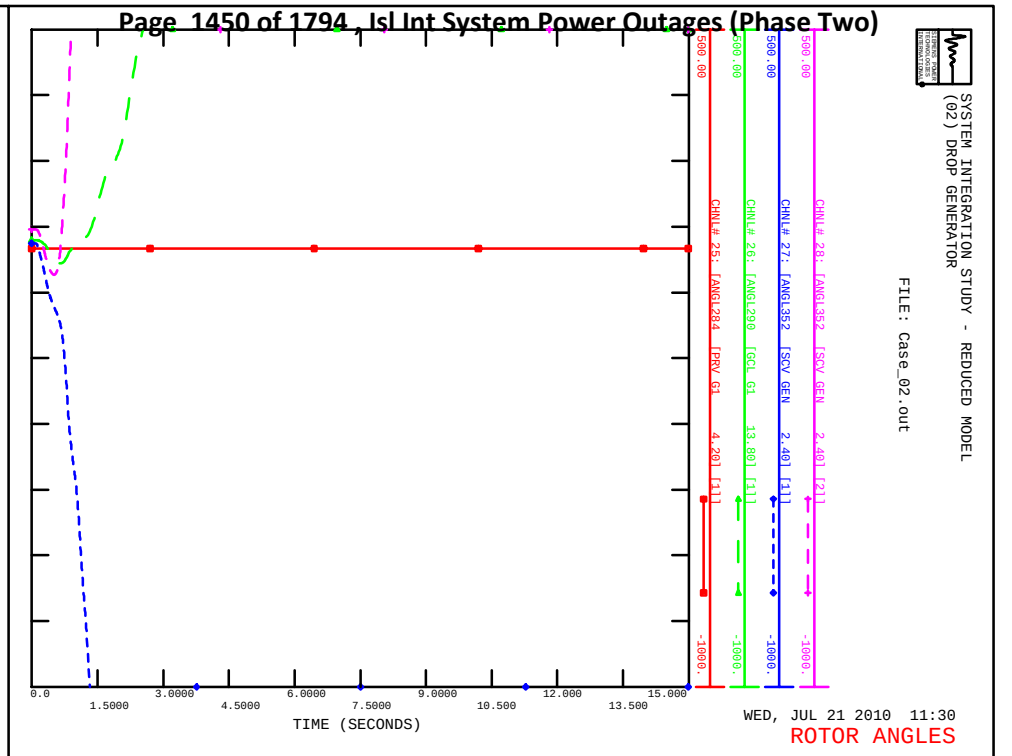

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 1: [ANGL21 [ACG 1P2P 6.90] [1]]
CHNL# 2: [ANGL21 [ACG 1P2P 6.90] [2]]
CHNL# 3: [ANGL23 [ACG 3P4P 6.90] [1]]
CHNL# 4: [ANGL23 [ACG 3P4P 6.90] [2]]
CHNL# 5: [ANGL24 [ACG G7G8 6.90] [1]]
500.00
-1000.
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

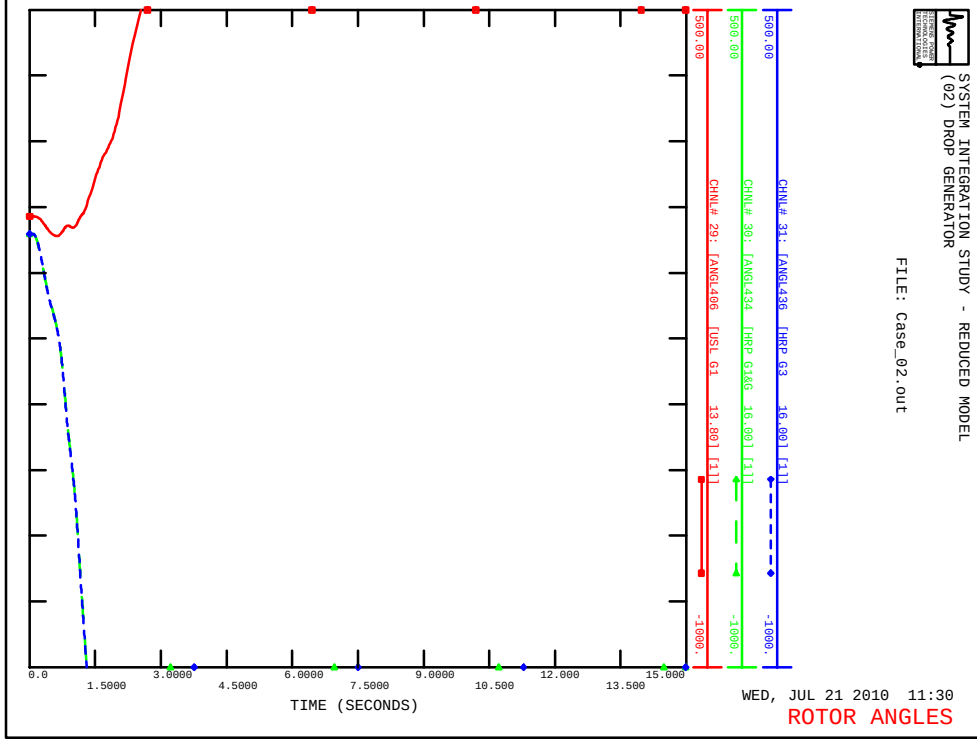

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 6: [ANGL24 [ACG G7G8 6.90] [2]]
CHNL# 7: [ANGL25 [ACG G5G6 6.90] [1]]
CHNL# 8: [ANGL25 [ACG G5G6 6.90] [2]]
CHNL# 9: [ANGL29 [ACGBG1-9 6.90] [1]]
CHNL# 10: [ANGL33 [ACG G4 6.90] [1]]
500.00
-1000.
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

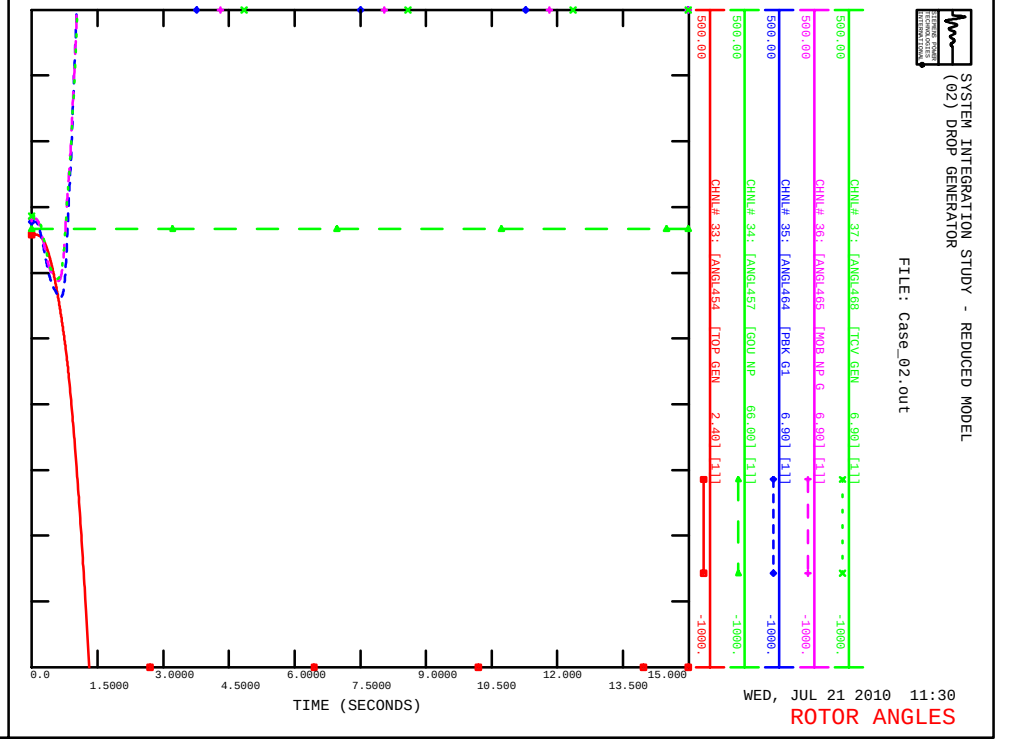

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 11: [ANGL34 [ACG G9 13.80] [1]]
CHNL# 12: [ANGL105 [CBF CBPP 6.60] [1]]
CHNL# 13: [ANGL109 [DLP G1-7 6.00] [1]]
CHNL# 14: [ANGL137 [CAT G1 13.80] [1]]
CHNL# 15: [ANGL138 [CAT G2 13.80] [1]]
500.00
-1000.
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

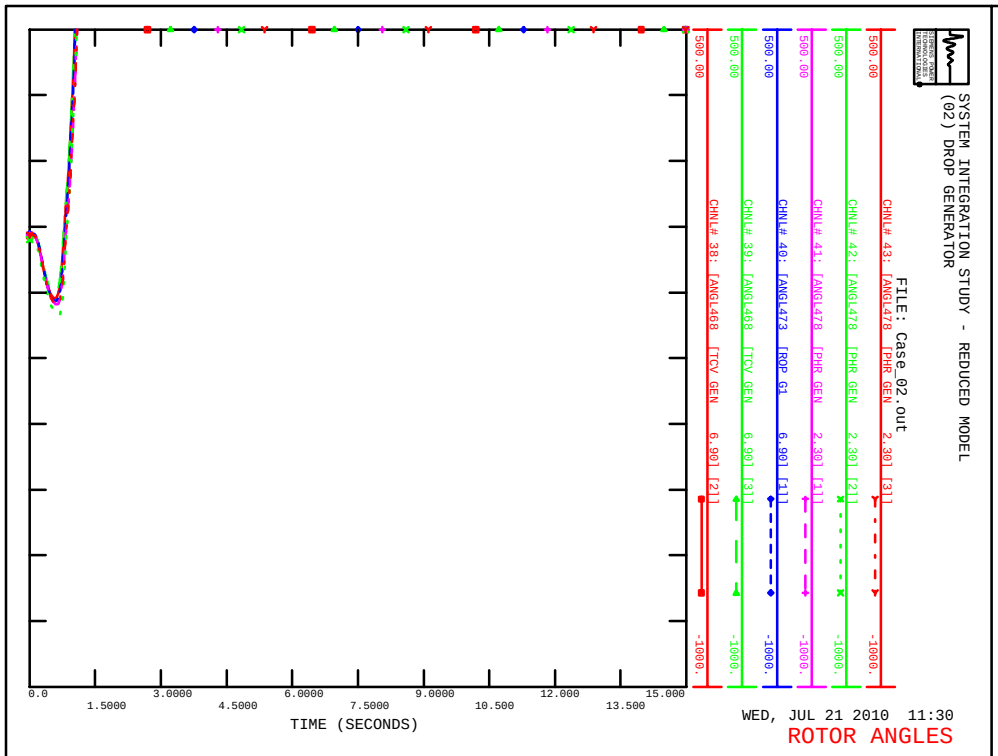

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 16: [ANGL209 [SVL G1 13.80] [1]]
CHNL# 17: [ANGL220 [BDP G2-6 13.80] [2]]
CHNL# 18: [ANGL220 [BDP G2-6 13.80] [3]]
CHNL# 19: [ANGL220 [BDP G2-6 13.80] [4]]
CHNL# 20: [ANGL220 [BDP G2-6 13.80] [5]]
500.00
-1000.
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

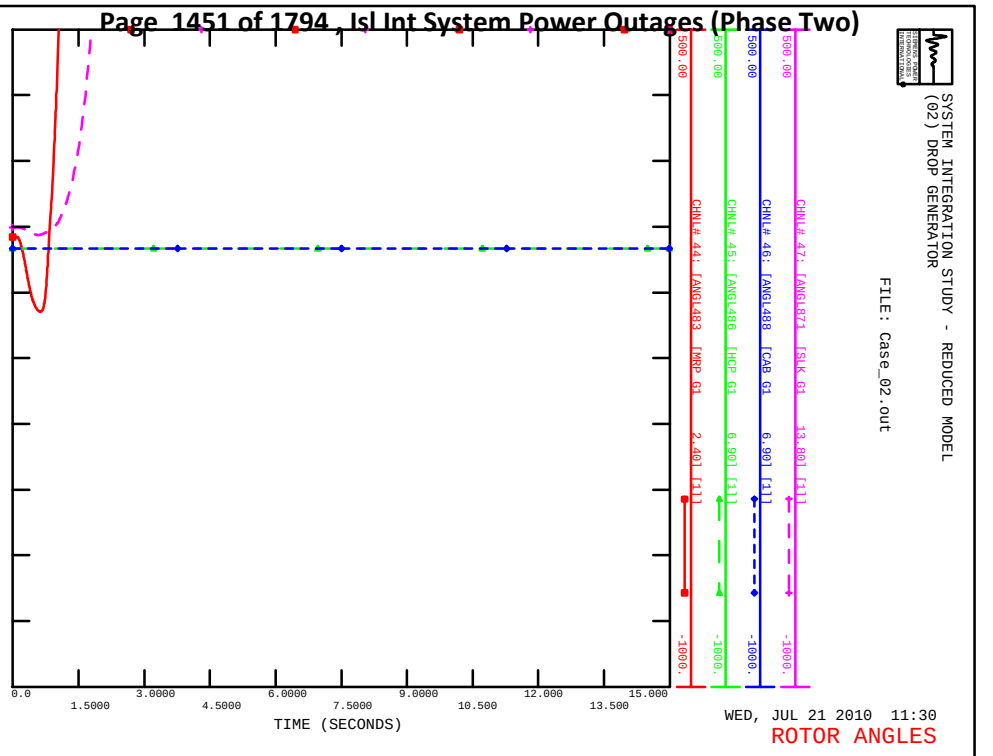

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 21: [ANGL220 [BDP G2-6 13.80] [61]
CHNL# 23: [ANGL237 [HND G1 13.80] [1]
CHNL# 24: [ANGL250 [HLK G1 13.80] [11]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

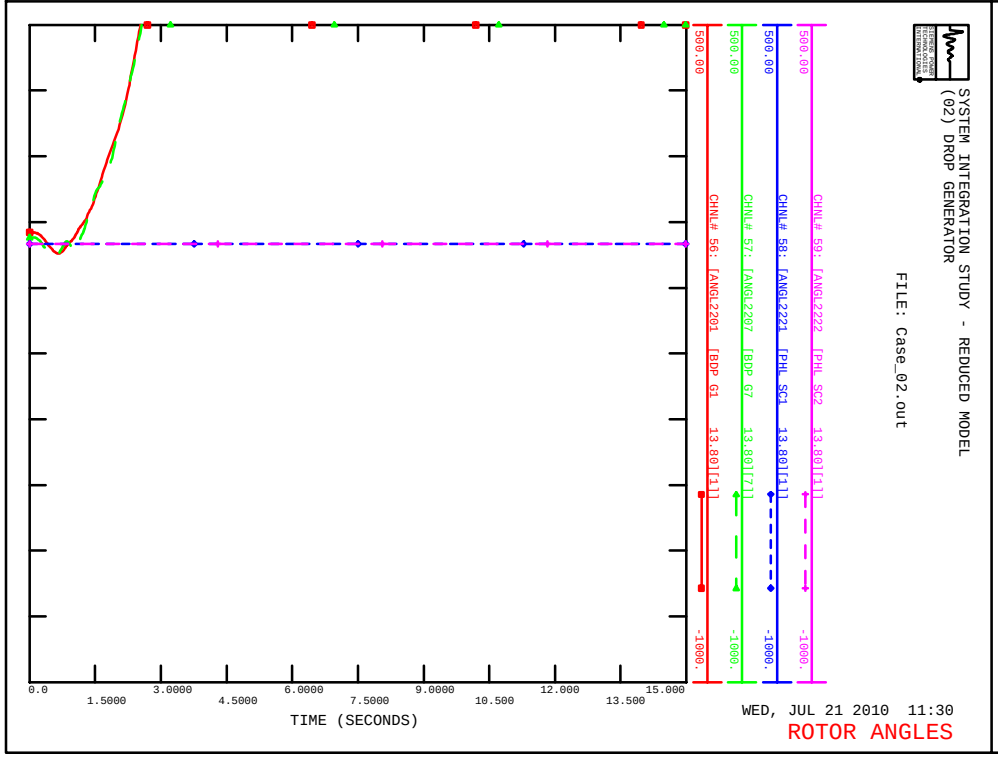

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 25: [ANGL284 [PRV G1 4.20] [11]
CHNL# 26: [ANGL290 [GCL G1 13.80] [11]
CHNL# 27: [ANGL352 [SCV GEN 2.40] [11]
CHNL# 28: [ANGL352 [SCV GEN 2.40] [21]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

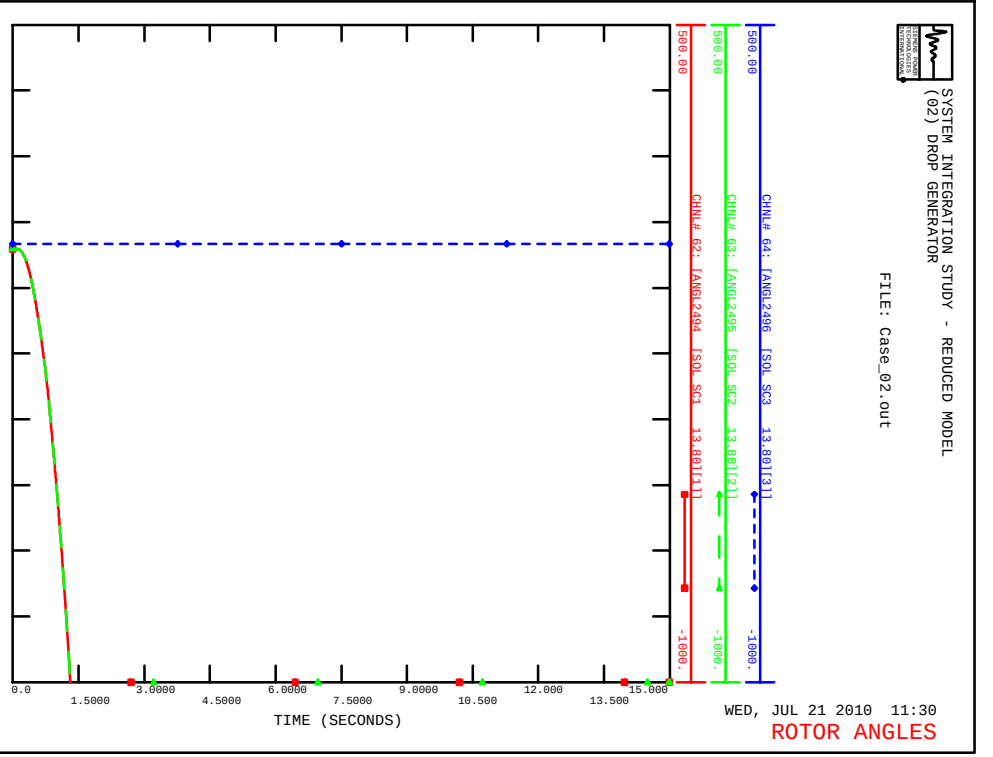

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 29: [ANGL406 [USL G1 13.80] [11]
CHNL# 30: [ANGL434 [HRP G1&G 16.00] [11]
CHNL# 31: [ANGL436 [HRP G3 16.00] [11]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

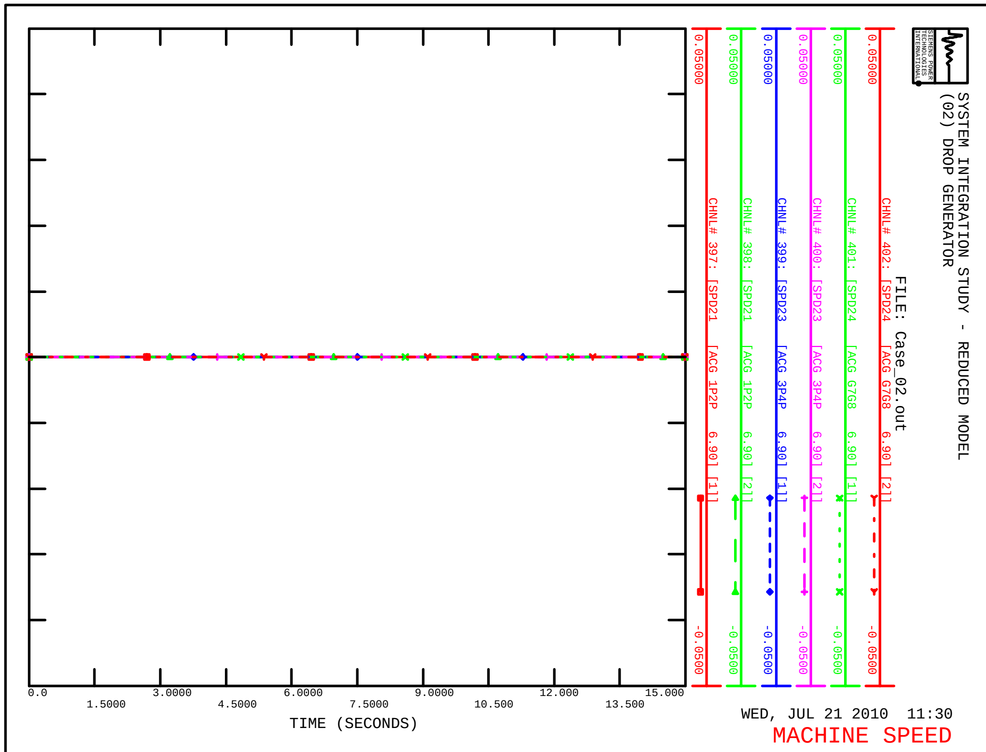

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 33: [ANGL454 [TOP GEN 2.40] [11]
CHNL# 34: [ANGL457 [CGU NP 66.00] [11]
CHNL# 35: [ANGL464 [PBK G1 6.90] [11]
CHNL# 36: [ANGL465 [MOB NP G 6.90] [11]
CHNL# 37: [ANGL468 [TCV GEN 6.90] [11]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

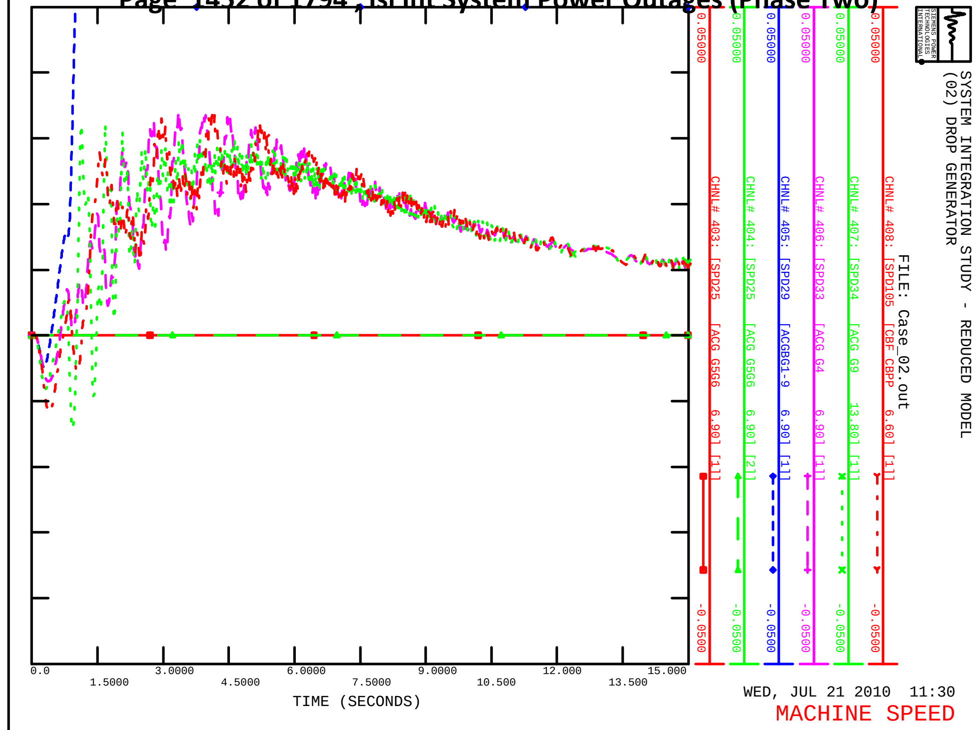

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 38: [ANGL468 [TCV GEN 6.90] [2]
CHNL# 39: [ANGL468 [TCV GEN 6.90] [3]
CHNL# 40: [ANGL473 [ROP G1 6.90] [1]
CHNL# 41: [ANGL478 [PHR GEN 2.30] [1]
CHNL# 42: [ANGL478 [PHR GEN 2.30] [2]
CHNL# 43: [ANGL478 [PHR GEN 2.30] [3]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

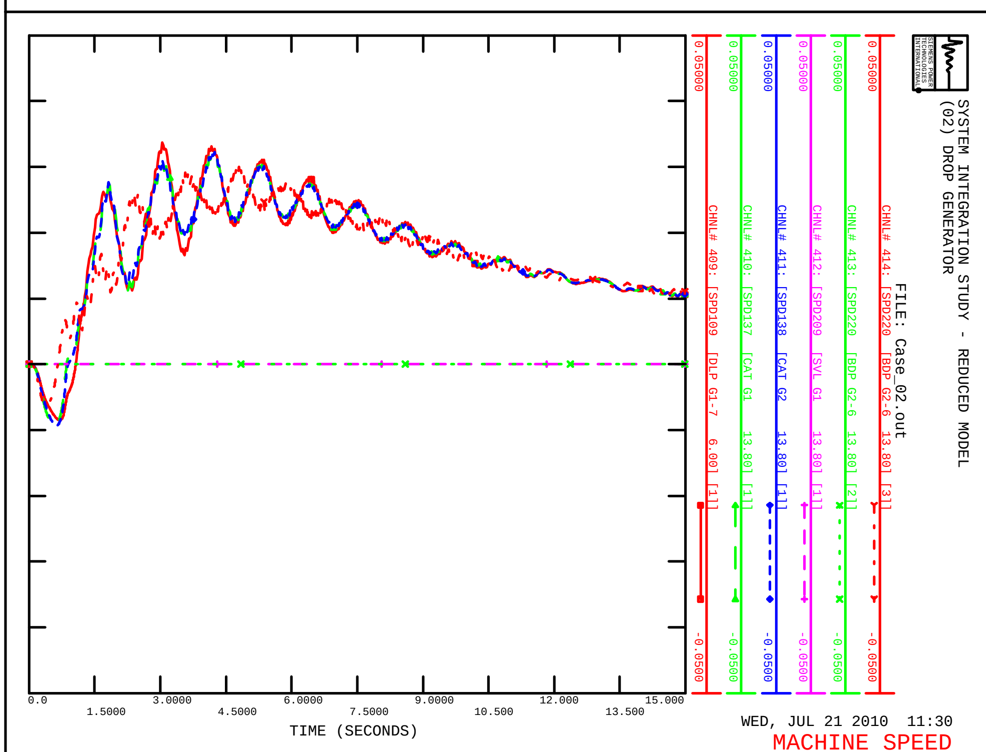

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 44: [ANGL483 [MRP G1 2.40] [1]
CHNL# 45: [ANGL486 [HCP G1 6.90] [1]
CHNL# 46: [ANGL488 [CAB G1 6.90] [1]
CHNL# 47: [ANGL871 [SLK G1 13.80] [1]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

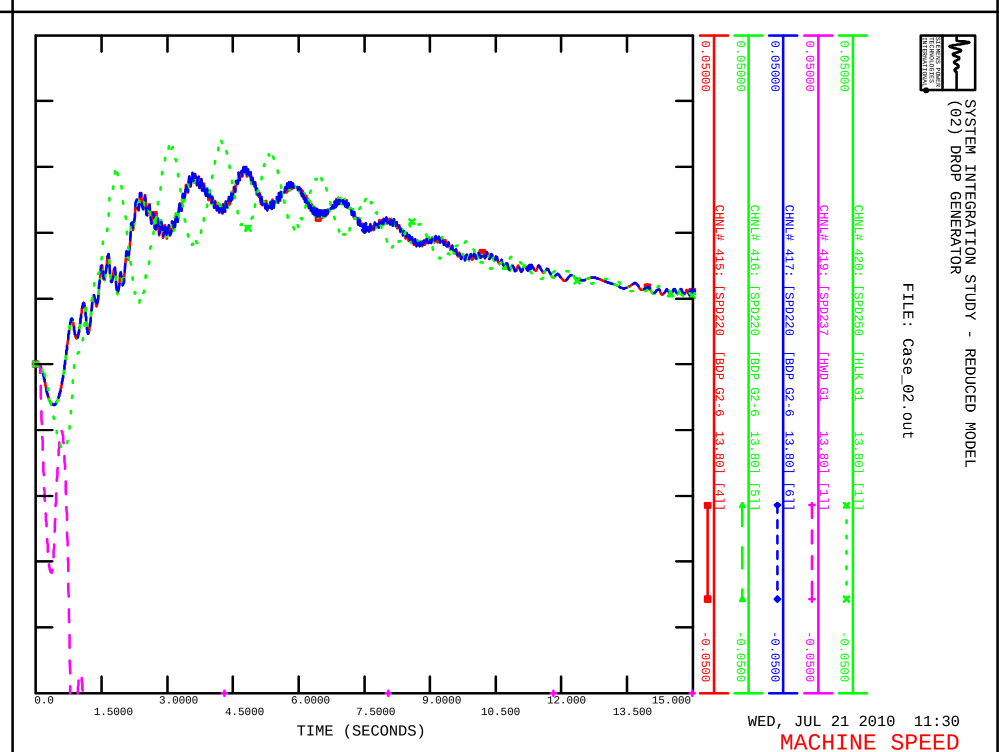

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 56: [ANGL2201 [BDP G1 13.80] [1]
CHNL# 57: [ANGL2207 [BDP G7 13.80] [7]
CHNL# 58: [ANGL2221 [PHL SC1 13.80] [1]
CHNL# 59: [ANGL2222 [PHL SC2 13.80] [1]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

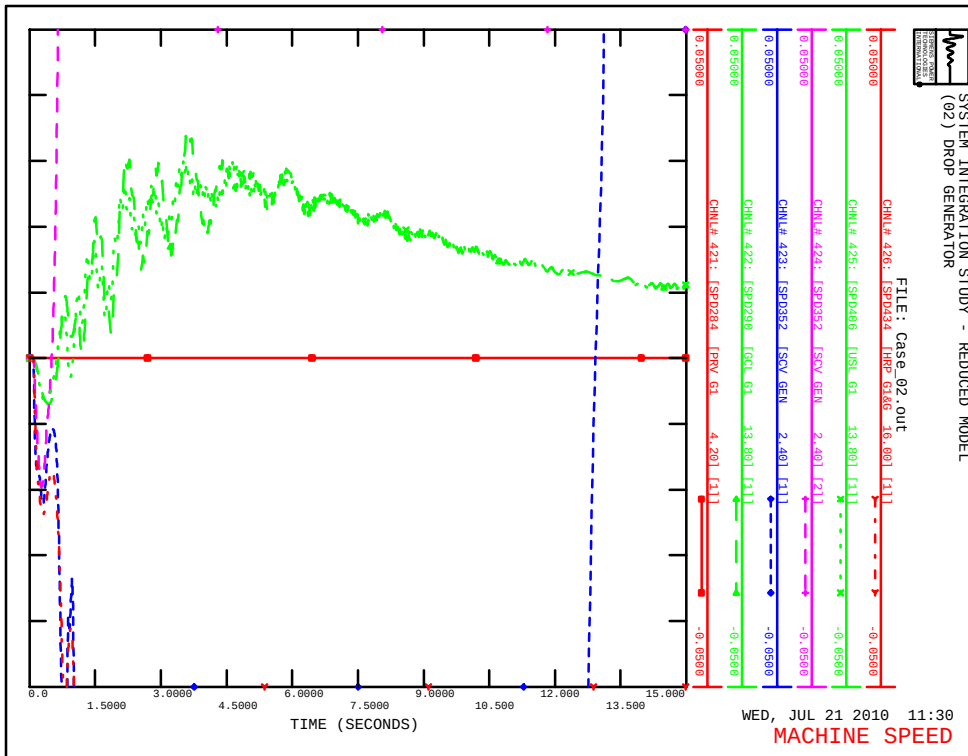

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 62: [ANGL2494 [SOL SC1 13.80] [1]
CHNL# 63: [ANGL2495 [SOL SC2 13.80] [2]
CHNL# 64: [ANGL2496 [SOL SC3 13.80] [3]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

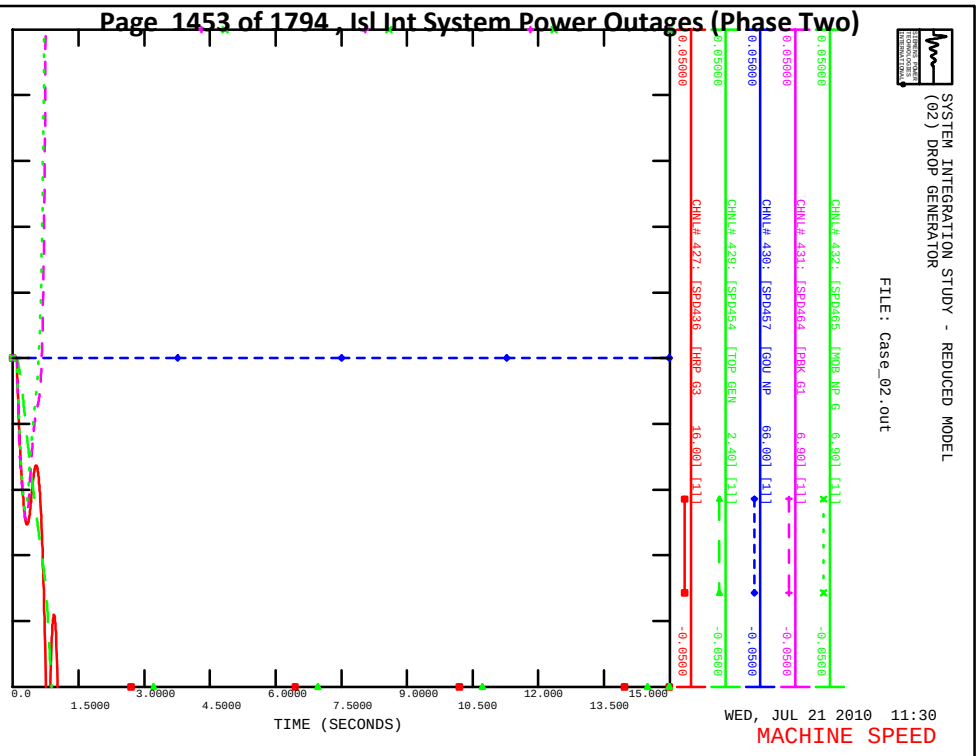

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 397: [SPD21 [ACG 1P2P 6.90] [1]]
CHNL# 398: [SPD21 [ACG 1P2P 6.90] [2]]
CHNL# 399: [SPD23 [ACG 3P4P 6.90] [1]]
CHNL# 400: [SPD23 [ACG 3P4P 6.90] [2]]
CHNL# 401: [SPD24 [ACG G7G8 6.90] [1]]
CHNL# 402: [SPD24 [ACG G7G8 6.90] [2]]
0.05000
-0.0500
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

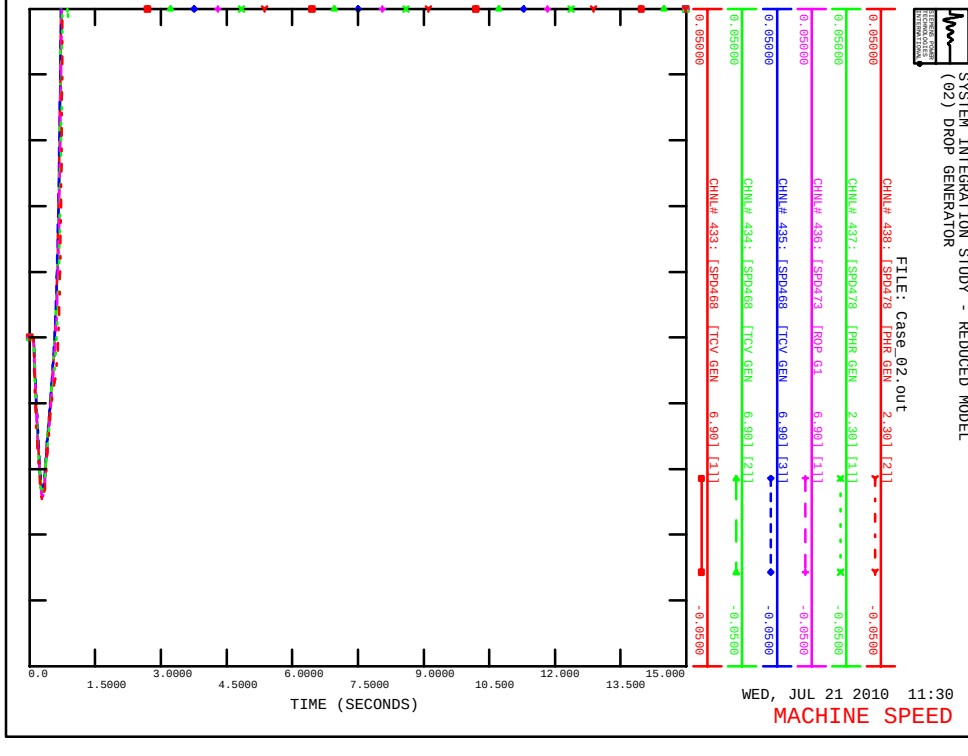

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 403: [SPD25 [ACG G5G6 6.90] [1]]
CHNL# 404: [SPD25 [ACG G5G6 6.90] [2]]
CHNL# 405: [SPD29 [ACGBG1-9 6.90] [1]]
CHNL# 406: [SPD33 [ACG G4 6.90] [1]]
CHNL# 407: [SPD34 [ACG G9 13.80] [1]]
CHNL# 408: [SPD105 [CBF CBPP 6.60] [1]]
0.05000
-0.0500
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

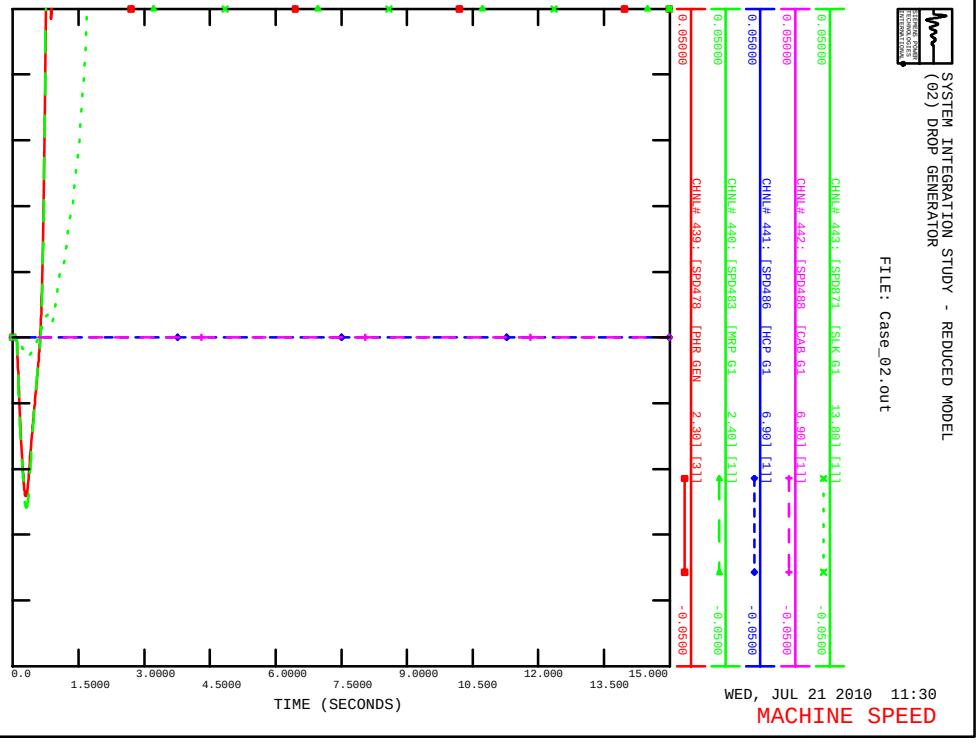

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 409: [SPD109 [DLP G1-7 6.00] [1]]
CHNL# 410: [SPD137 [CAT G1 13.80] [1]]
CHNL# 411: [SPD138 [CAT G2 13.80] [1]]
CHNL# 412: [SPD209 [SVL G1 13.80] [1]]
CHNL# 413: [SPD220 [BDP G2-6 13.80] [2]]
CHNL# 414: [SPD220 [BDP G2-6 13.80] [3]]
0.05000
-0.0500
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

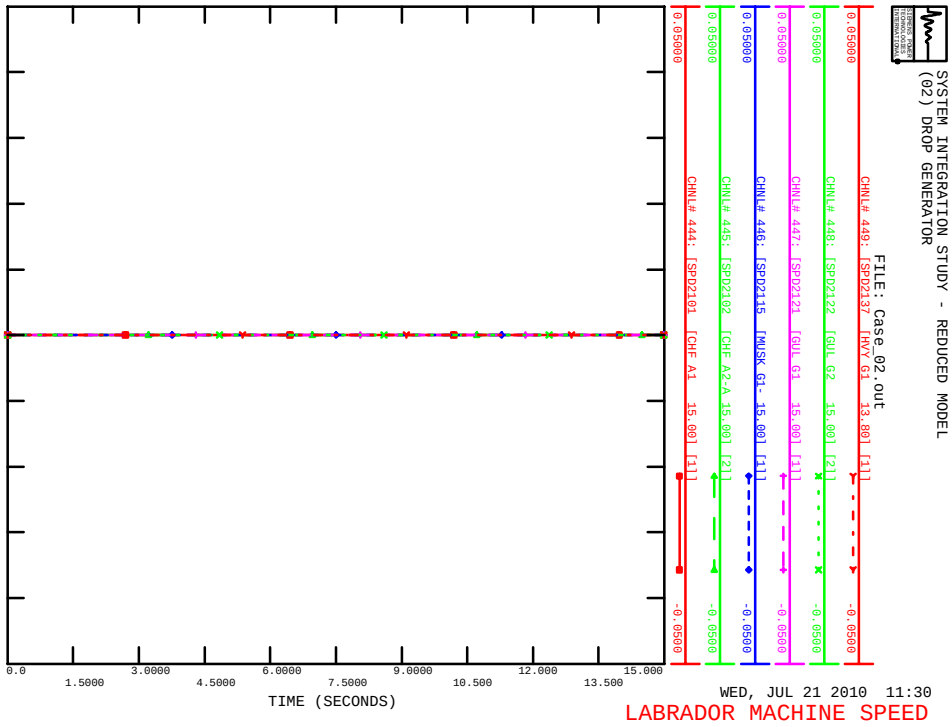

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 415: [SPD220 [BDP G2-6 13.80] [4]]
CHNL# 416: [SPD220 [BDP G2-6 13.80] [5]]
CHNL# 417: [SPD220 [BDP G2-6 13.80] [6]]
CHNL# 419: [SPD237 [HWD G1 13.80] [1]]
CHNL# 420: [SPD250 [HLK G1 13.80] [1]]
0.05000
-0.0500
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

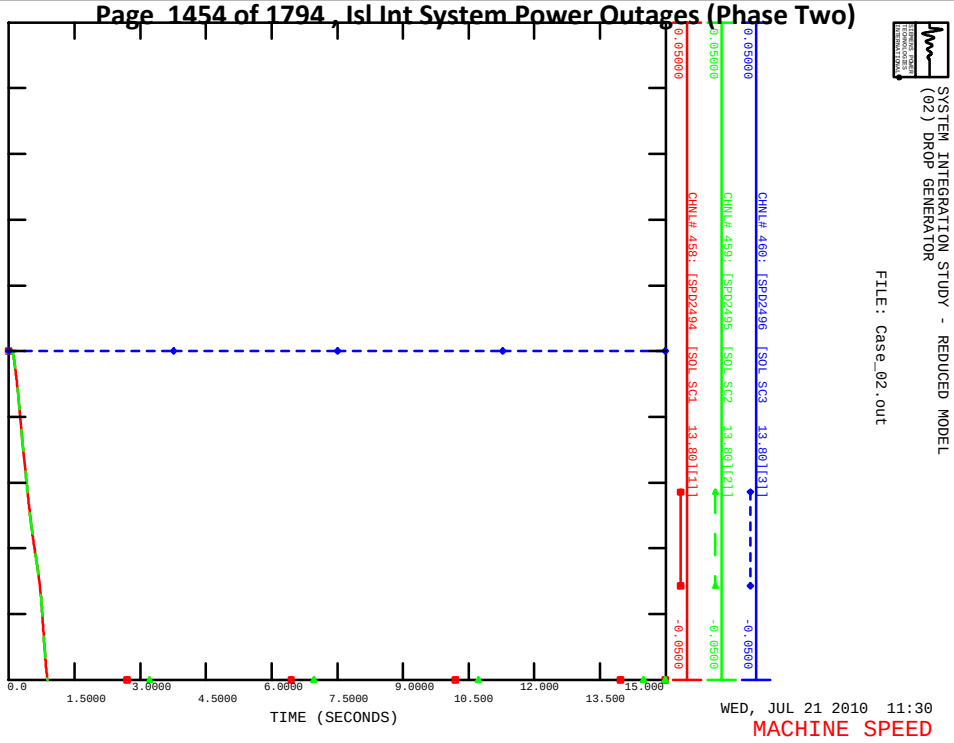

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 421: [SPD284 [PRV G1 4.20] [1]]
CHNL# 422: [SPD290 [GOL G1 13.80] [1]]
CHNL# 423: [SPD352 [SCV GEN 2.40] [1]]
CHNL# 424: [SPD352 [SCV GEN 2.40] [2]]
CHNL# 425: [SPD406 [USL G1 13.80] [1]]
CHNL# 426: [SPD434 [HRP G1&G 16.00] [1]]
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

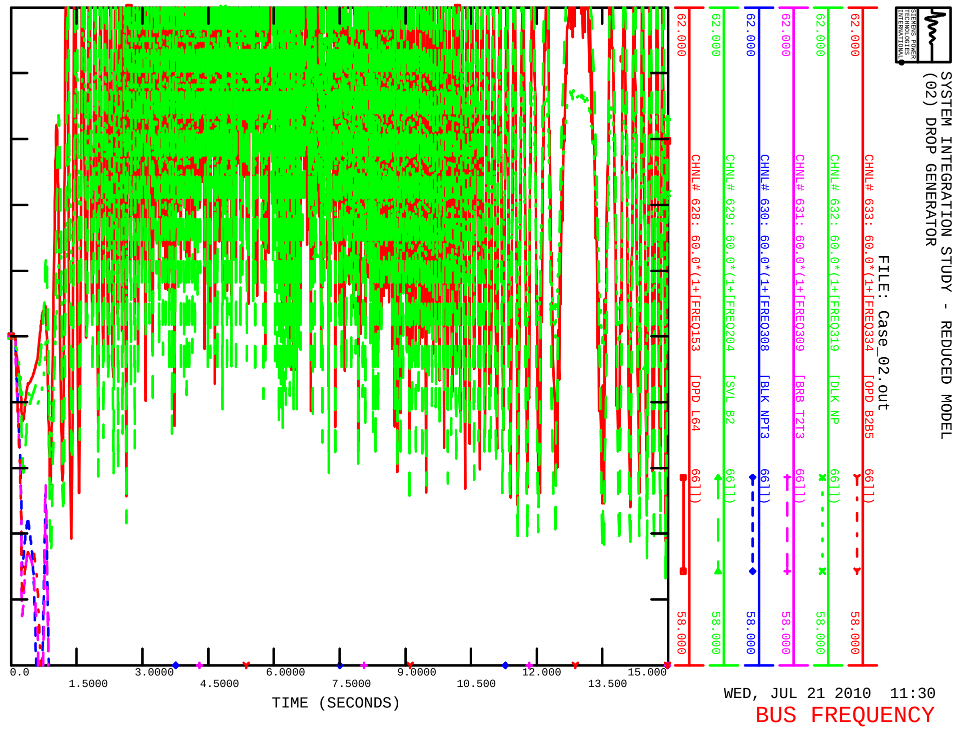

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 427: [SPD436 [HRP G3 16.00] [1]]
CHNL# 429: [SPD454 [TOP GEN 2.40] [1]]
CHNL# 430: [SPD457 [GOU NP 66.00] [1]]
CHNL# 431: [SPD464 [PBK G1 6.90] [1]]
CHNL# 432: [SPD465 [MOB NP G 6.90] [1]]
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

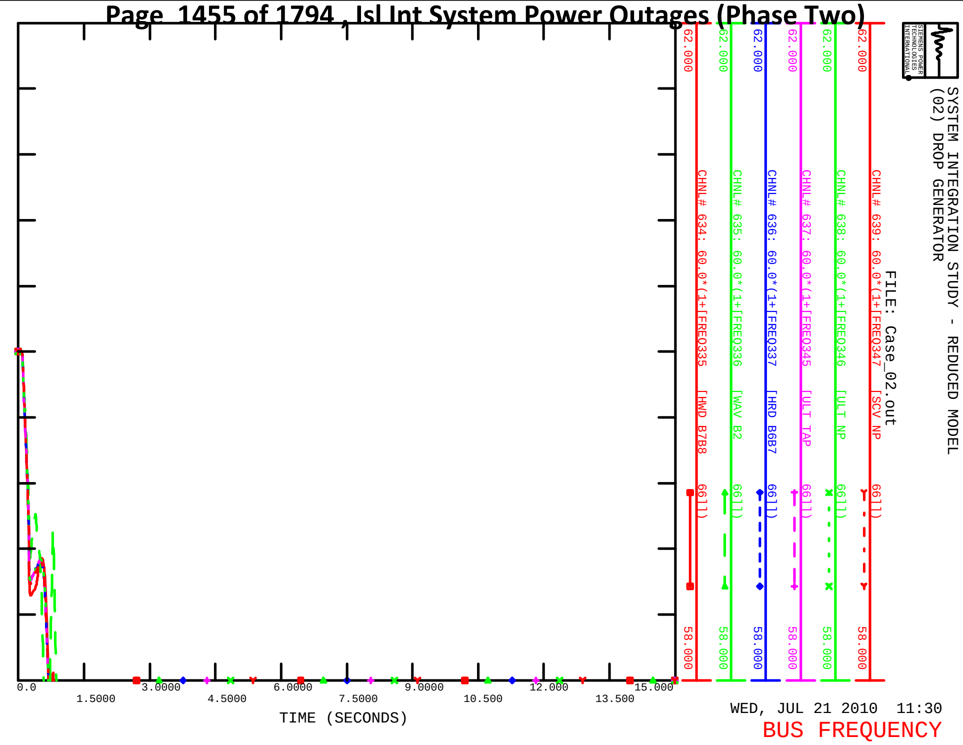

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 433: [SPD468 [TCV GEN 6.90] [1]]
CHNL# 434: [SPD468 [TCV GEN 6.90] [2]]
CHNL# 435: [SPD468 [TCV GEN 6.90] [3]]
CHNL# 436: [SPD473 [ROP G1 6.90] [1]]
CHNL# 437: [SPD478 [PHR GEN 2.30] [1]]
CHNL# 438: [SPD478 [PHR GEN 2.30] [2]]
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

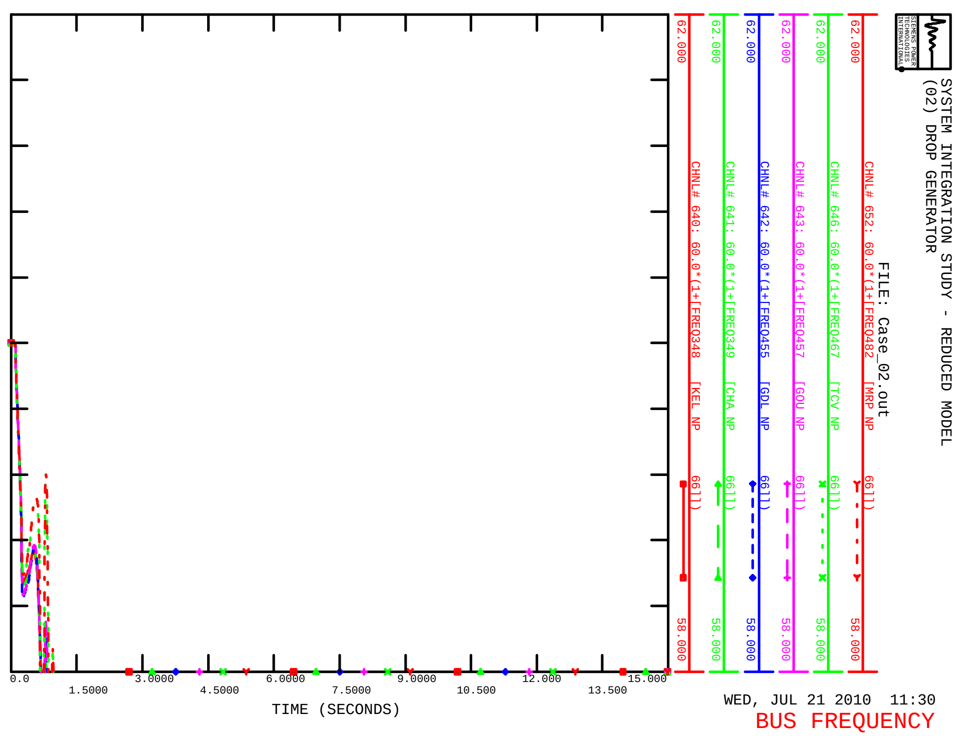

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 439: [SPD478 [PHR GEN 2.30] [3]]
CHNL# 440: [SPD483 [MRP G1 2.40] [1]]
CHNL# 441: [SPD486 [HCP G1 6.90] [1]]
CHNL# 442: [SPD488 [CAB G1 6.90] [1]]
CHNL# 443: [SPD871 [SLK G1 13.80] [1]]
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

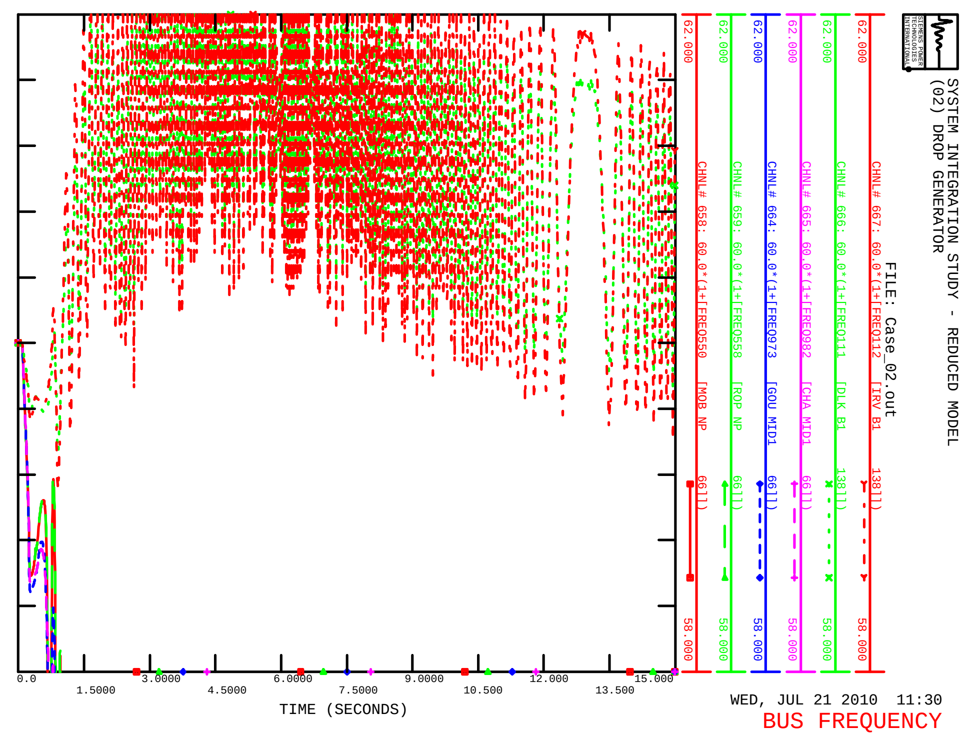

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 444: [SPD2101 [CHF A1 15.00] [1]]
CHNL# 445: [SPD2102 [CHF A2-A 15.00] [2]]
CHNL# 446: [SPD2115 [MUSK G1- 15.00] [1]]
CHNL# 447: [SPD2121 [GUL G1 15.00] [1]]
CHNL# 448: [SPD2122 [GUL G2 15.00] [2]]
CHNL# 449: [SPD2137 [HVY G1 13.80] [1]]
0.05000
-0.0500
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
LABRADOR MACHINE SPEED

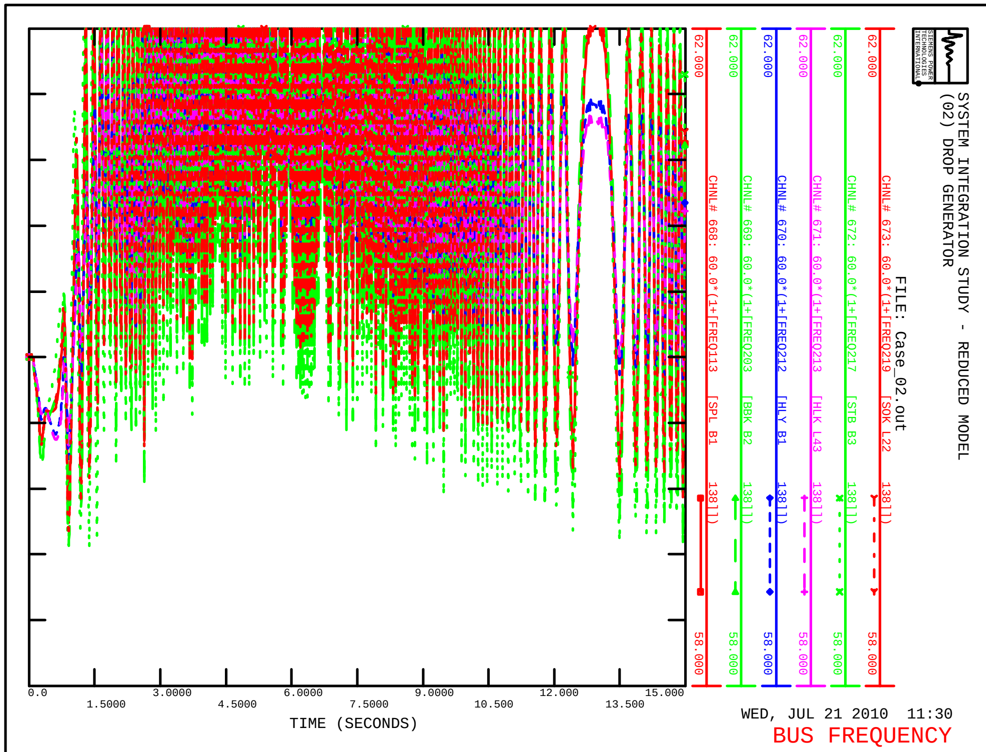

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 458: [SPD2494 [SOL SC1 13.80] [1]]
CHNL# 459: [SPD2495 [SOL SC2 13.80] [2]]
CHNL# 460: [SPD2496 [SOL SC3 13.80] [3]]
0.05000
-0.0500
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

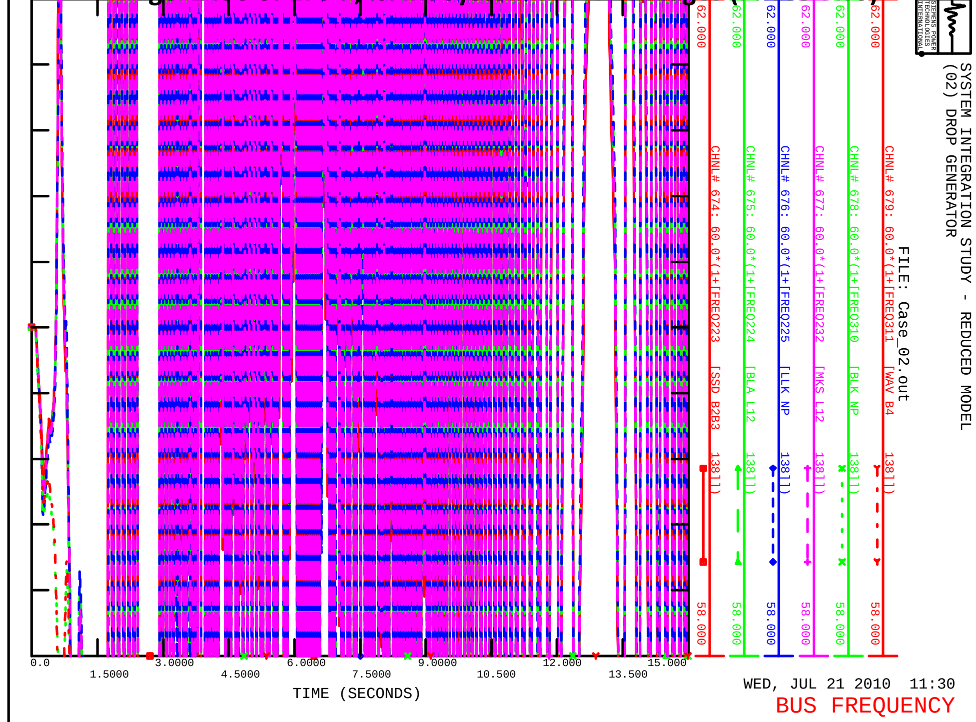

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 628: 60.0*(1+[FREQ153 [DPD L64 661])
CHNL# 629: 60.0*(1+[FREQ204 [SVL B2 661])
CHNL# 630: 60.0*(1+[FREQ308 [BLK NPT3 661])
CHNL# 631: 60.0*(1+[FREQ309 [BRB T2T3 661])
CHNL# 632: 60.0*(1+[FREQ319 [DLK NP 661])
CHNL# 633: 60.0*(1+[FREQ334 [OPD B2B5 661])
62.000
58.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

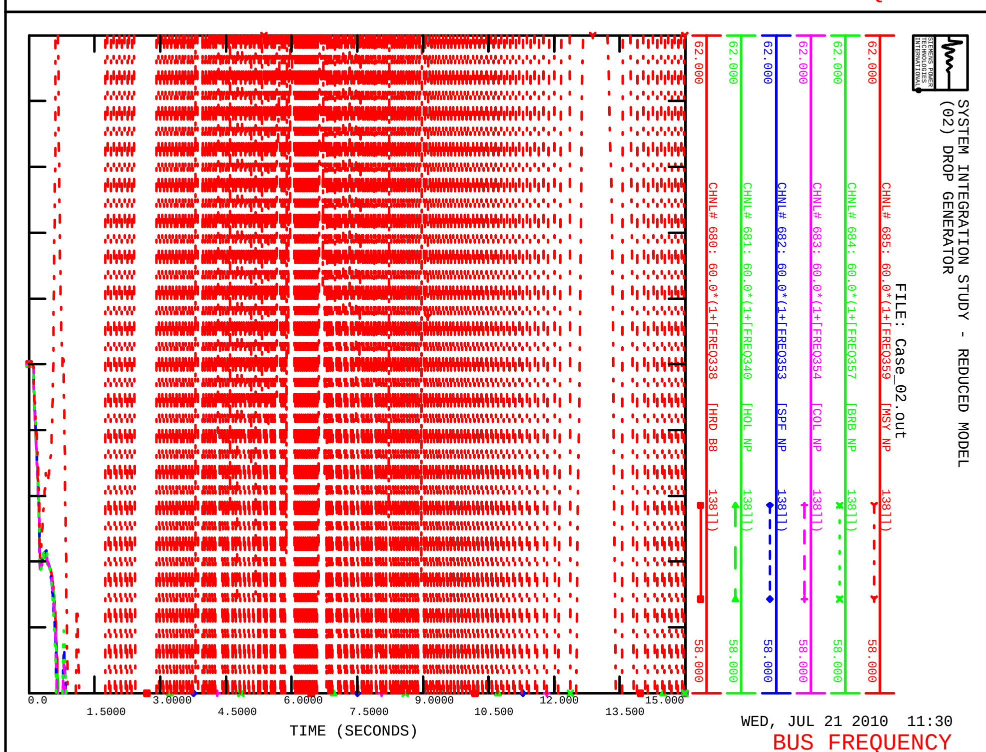

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 634: 60.0*(1+[FREQ335 [HWD B7B8 661])
CHNL# 635: 60.0*(1+[FREQ336 [WAV B2 661])
CHNL# 636: 60.0*(1+[FREQ337 [HRD B6B7 661])
CHNL# 637: 60.0*(1+[FREQ345 [ULT TAP 661])
CHNL# 638: 60.0*(1+[FREQ346 [ULT NP 661])
CHNL# 639: 60.0*(1+[FREQ347 [SCV NP 661])
62.000
58.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

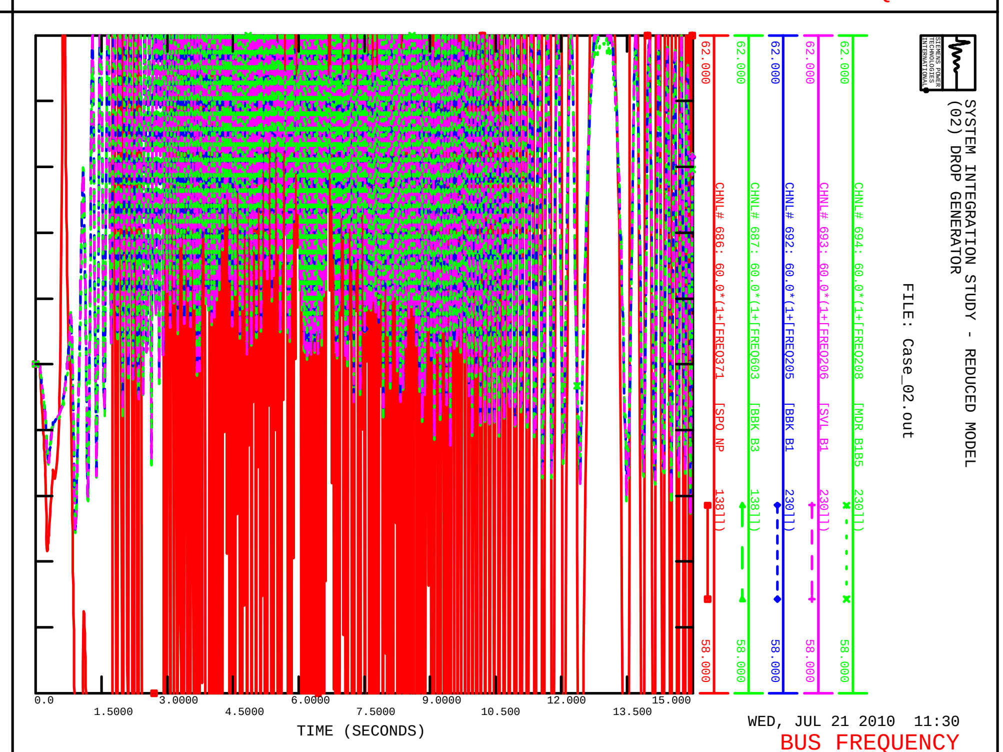

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 640: 60.0*(1+[FREQ348 [KEL NP 661])
CHNL# 641: 60.0*(1+[FREQ349 [CHA NP 661])
CHNL# 642: 60.0*(1+[FREQ455 [GDL NP 661])
CHNL# 643: 60.0*(1+[FREQ457 [GOU NP 661])
CHNL# 646: 60.0*(1+[FREQ467 [TCV NP 661])
CHNL# 652: 60.0*(1+[FREQ482 [MRP NP 661])
62.000
58.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

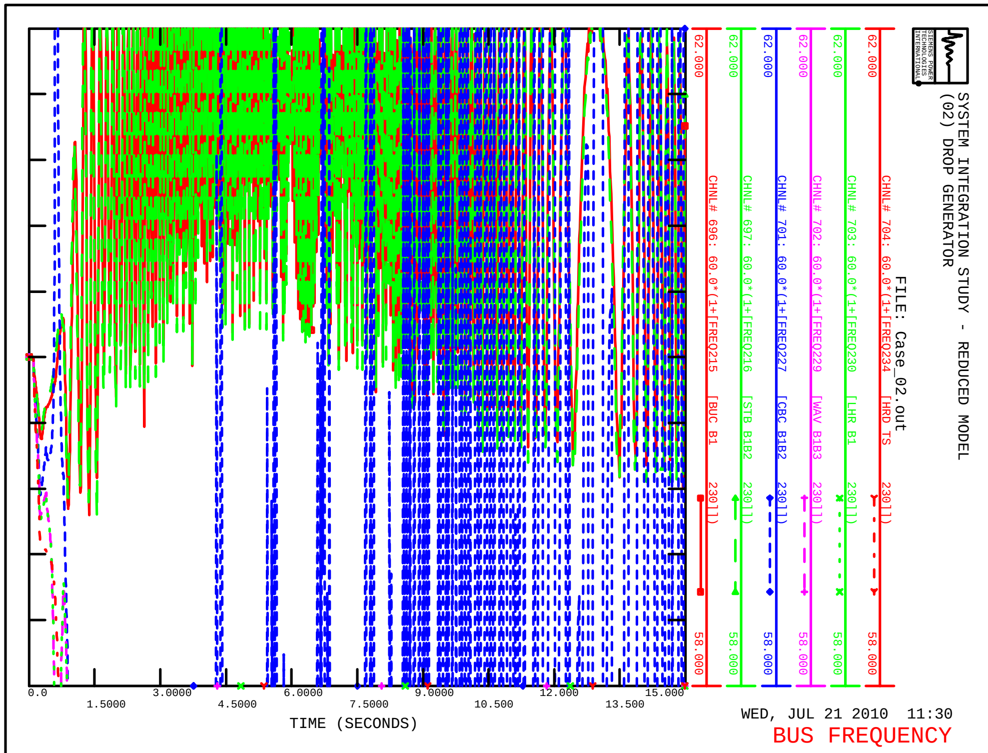

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 658: 60.0*(1+[FREQ550 [MOB NP 661])
CHNL# 659: 60.0*(1+[FREQ558 [ROP NP 661])
CHNL# 664: 60.0*(1+[FREQ973 [GOU MID1 661])
CHNL# 665: 60.0*(1+[FREQ982 [CHA MID1 661])
CHNL# 666: 60.0*(1+[FREQ111 [DLK B1 1381])
CHNL# 667: 60.0*(1+[FREQ112 [IRV B1 1381])
62.000
58.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

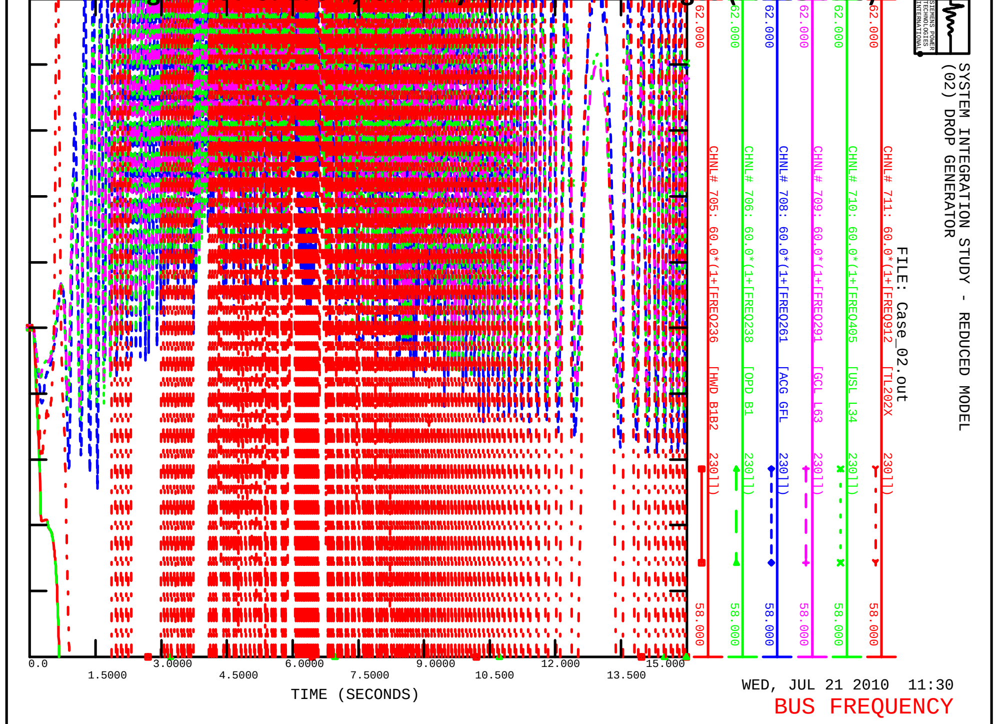

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 668: 60.0*(1+[FREQ113 [SPL B1 138]])
CHNL# 669: 60.0*(1+[FREQ203 [BBK B2 138]])
CHNL# 670: 60.0*(1+[FREQ212 [HLY B1 138]])
CHNL# 671: 60.0*(1+[FREQ213 [HLK L43 138]])
CHNL# 672: 60.0*(1+[FREQ217 [STB B3 138]])
CHNL# 673: 60.0*(1+[FREQ219 [SOK L22 138]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

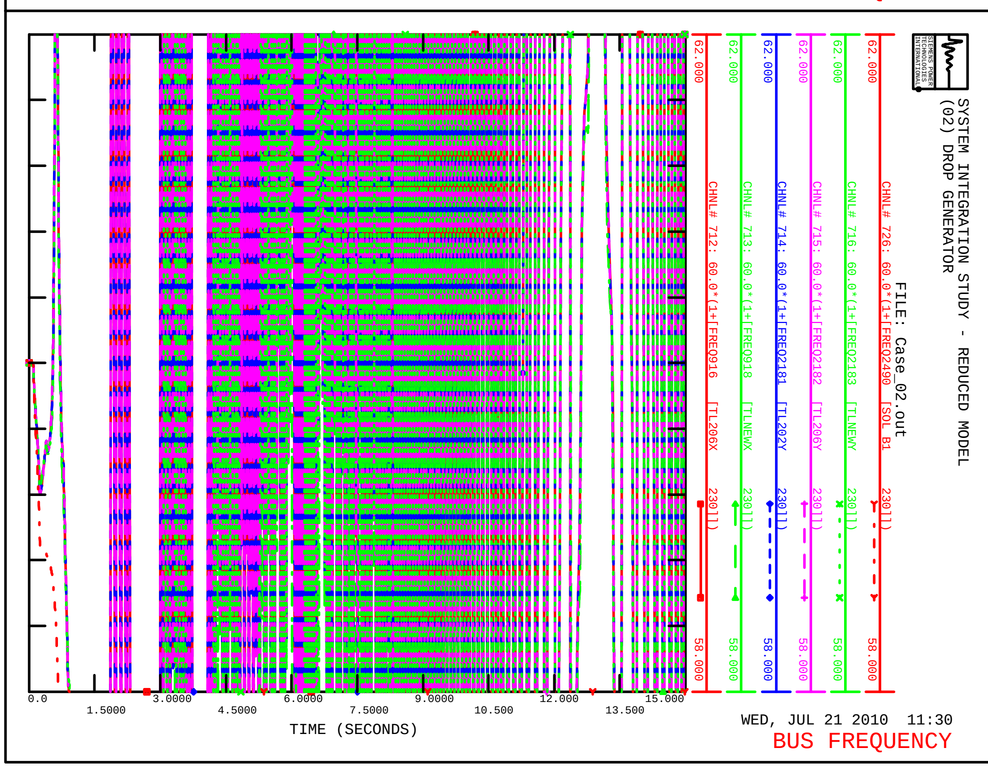

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 674: 60.0*(1+[FREQ223 [SSD B2B3 138]])
CHNL# 675: 60.0*(1+[FREQ224 [BLA L12 138]])
CHNL# 676: 60.0*(1+[FREQ225 [LLK NP 138]])
CHNL# 677: 60.0*(1+[FREQ232 [MKS L12 138]])
CHNL# 678: 60.0*(1+[FREQ310 [BLK NP 138]])
CHNL# 679: 60.0*(1+[FREQ311 [WAV B4 138]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

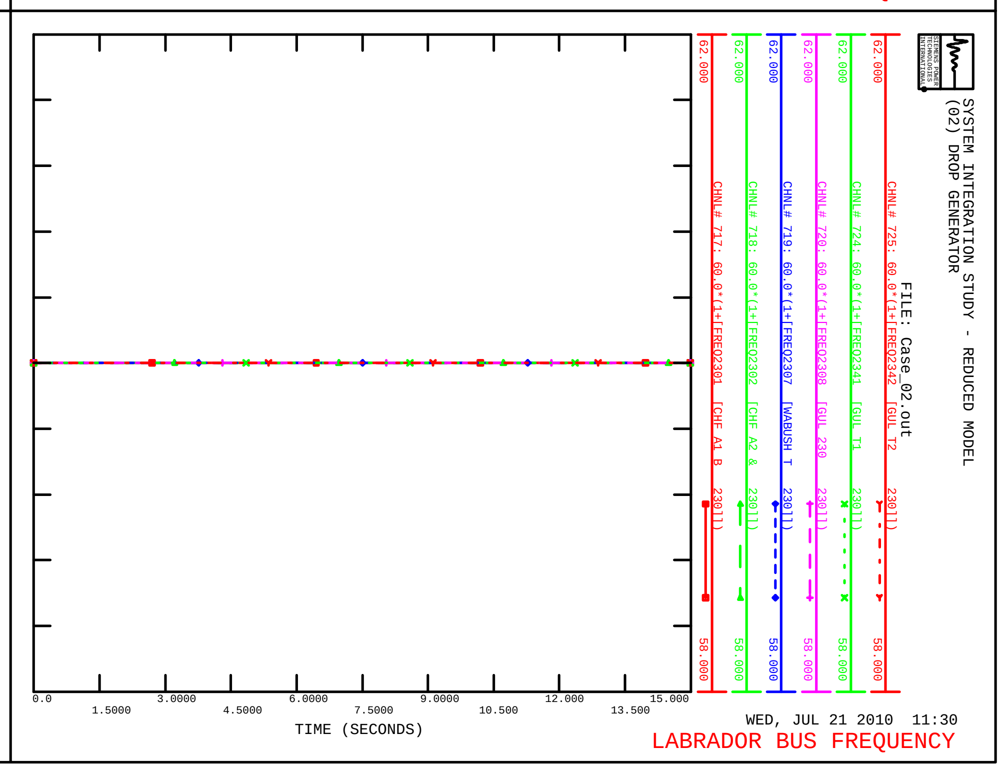

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 680: 60.0*(1+[FREQ338 [HRD B8 138]])
CHNL# 681: 60.0*(1+[FREQ340 [HOL NP 138]])
CHNL# 682: 60.0*(1+[FREQ353 [SPF NP 138]])
CHNL# 683: 60.0*(1+[FREQ354 [COL NP 138]])
CHNL# 684: 60.0*(1+[FREQ357 [BRB NP 138]])
CHNL# 685: 60.0*(1+[FREQ359 [MSY NP 138]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

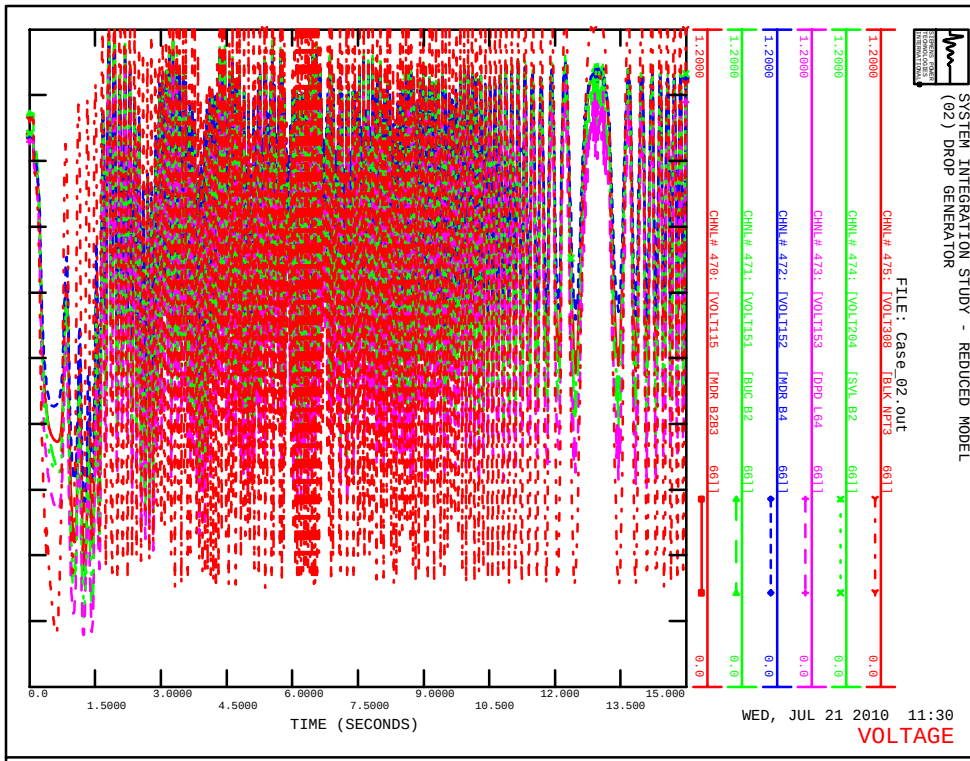

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 686: 60.0*(1+[FREQ371 [SPO NP 138]])
CHNL# 687: 60.0*(1+[FREQ603 [BBK B3 138]])
CHNL# 692: 60.0*(1+[FREQ205 [BBK B1 230]])
CHNL# 693: 60.0*(1+[FREQ206 [SVL B1 230]])
CHNL# 694: 60.0*(1+[FREQ208 [MDR B1B5 230]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

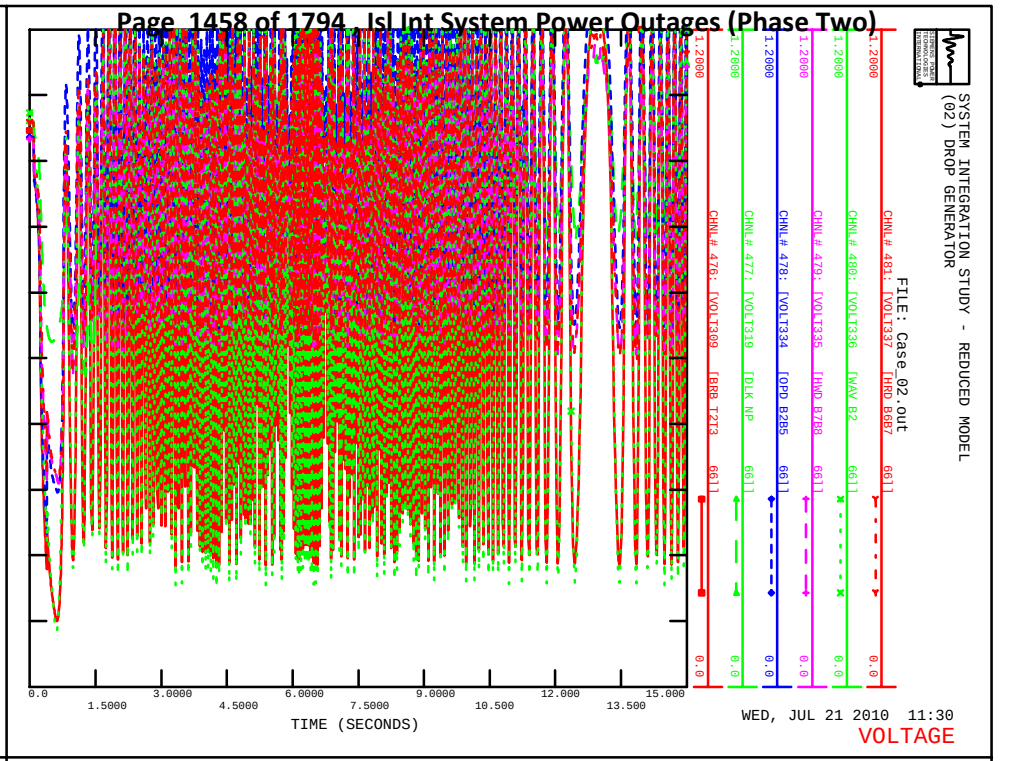

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 696: 60.0*(1+[FREQ215 [BUC B1 230]])
CHNL# 697: 60.0*(1+[FREQ216 [STB B1B2 230]])
CHNL# 701: 60.0*(1+[FREQ227 [CBC B1B2 230]])
CHNL# 702: 60.0*(1+[FREQ229 [WAV B1B3 230]])
CHNL# 703: 60.0*(1+[FREQ230 [LHR B1 230]])
CHNL# 704: 60.0*(1+[FREQ234 [HRD TS 230]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

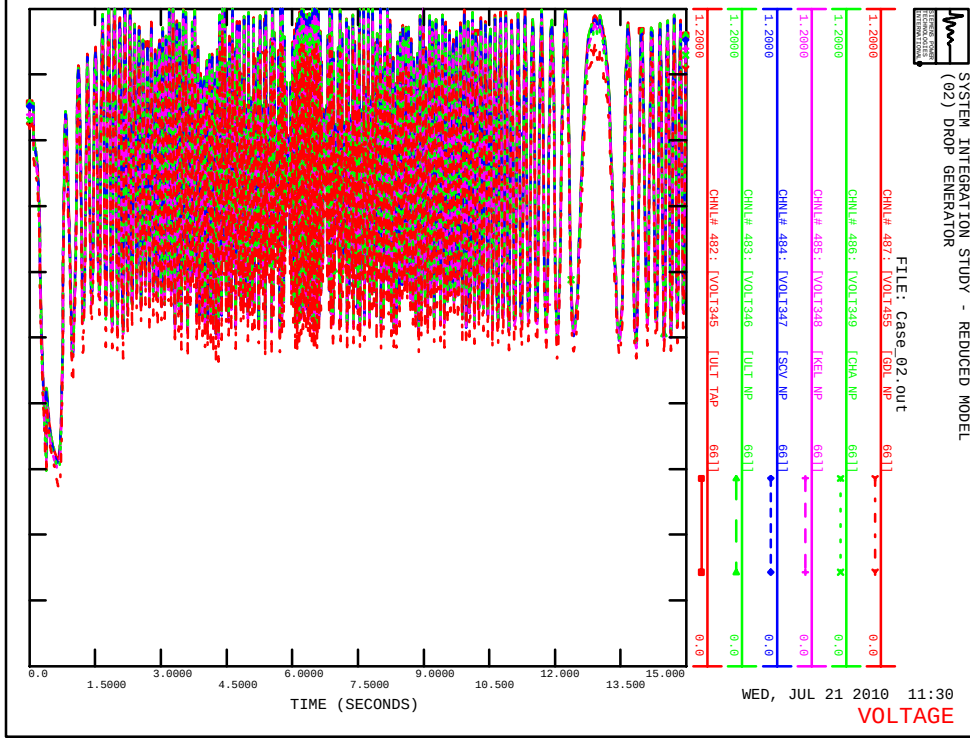

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 705: 60.0*(1+[FREQ236 [HWD B1B2 230]])
CHNL# 706: 60.0*(1+[FREQ238 [OPD B1 230]])
CHNL# 708: 60.0*(1+[FREQ261 [ACG GFL 230]])
CHNL# 709: 60.0*(1+[FREQ291 [GCL L63 230]])
CHNL# 710: 60.0*(1+[FREQ405 [USL L34 230]])
CHNL# 711: 60.0*(1+[FREQ912 [TL202X 230]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

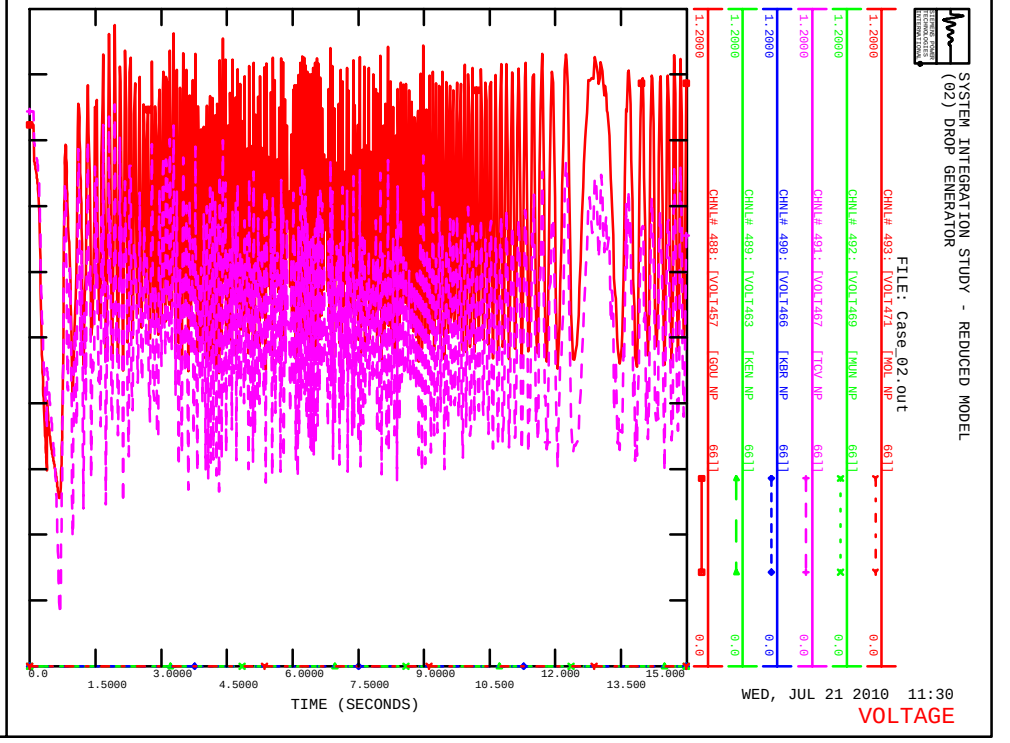

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 712: 60.0*(1+[FREQ916 [TL206X 230]])
CHNL# 713: 60.0*(1+[FREQ918 [TLNEWX 230]])
CHNL# 714: 60.0*(1+[FREQ2181 [TL202Y 230]])
CHNL# 715: 60.0*(1+[FREQ2182 [TL206Y 230]])
CHNL# 716: 60.0*(1+[FREQ2183 [TLNEWY 230]])
CHNL# 726: 60.0*(1+[FREQ2490 [SOL B1 230]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

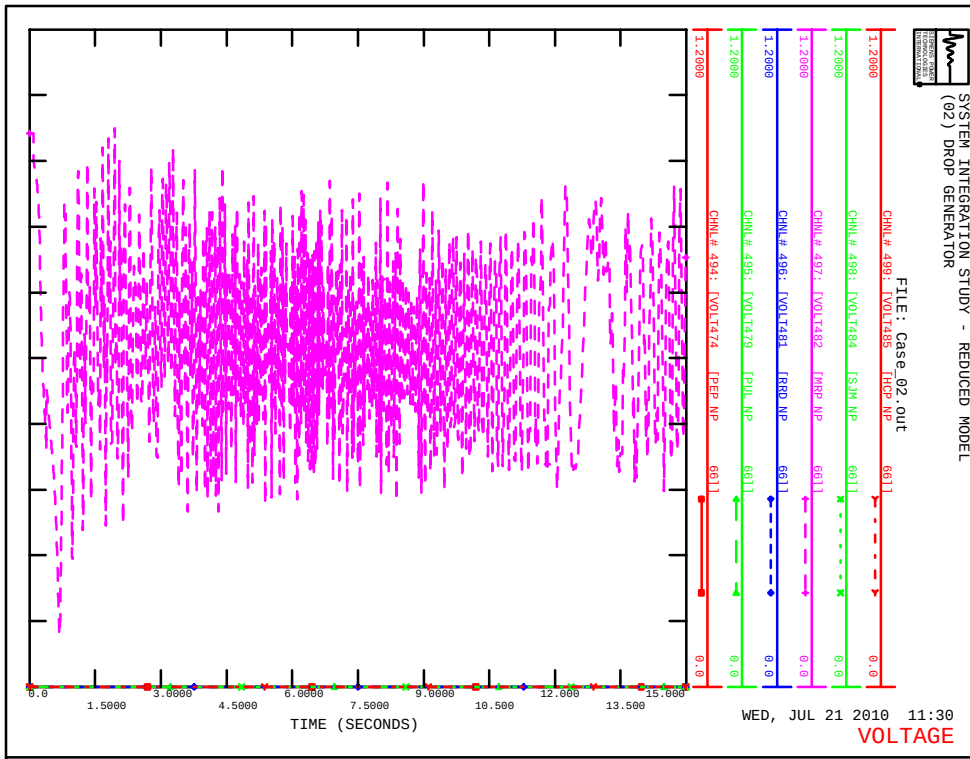

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 717: 60.0*(1+[FREQ2301 [CHF A1 B 230]])
CHNL# 718: 60.0*(1+[FREQ2302 [CHF A2 & 230]])
CHNL# 719: 60.0*(1+[FREQ2307 [WABUSH T 230]])
CHNL# 720: 60.0*(1+[FREQ2308 [GUL 230 230]])
CHNL# 724: 60.0*(1+[FREQ2341 [GUL T1 230]])
CHNL# 725: 60.0*(1+[FREQ2342 [GUL T2 230]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
LABRADOR BUS FREQUENCY

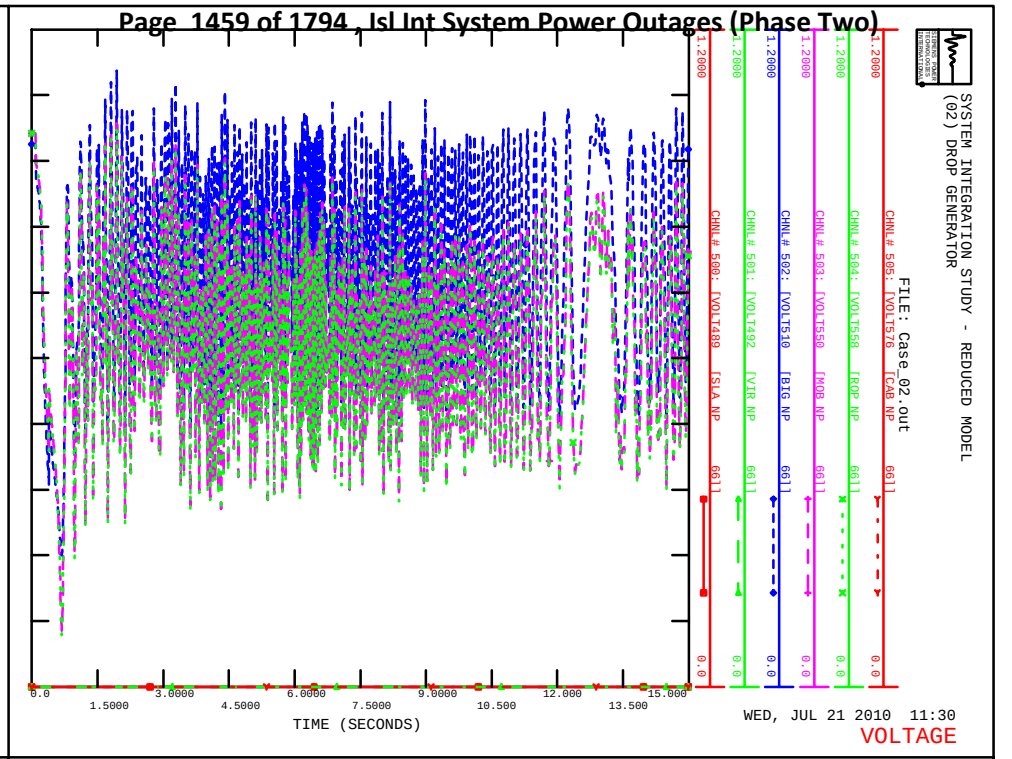

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 470: [VOLT115 [MDR B2B3 661]
CHNL# 471: [VOLT151 [BUC B2 661]
CHNL# 472: [VOLT152 [MDR B4 661]
CHNL# 473: [VOLT153 [DPD L64 661]
CHNL# 474: [VOLT204 [SVL B2 661]
CHNL# 475: [VOLT308 [BLK NPT3 661]
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

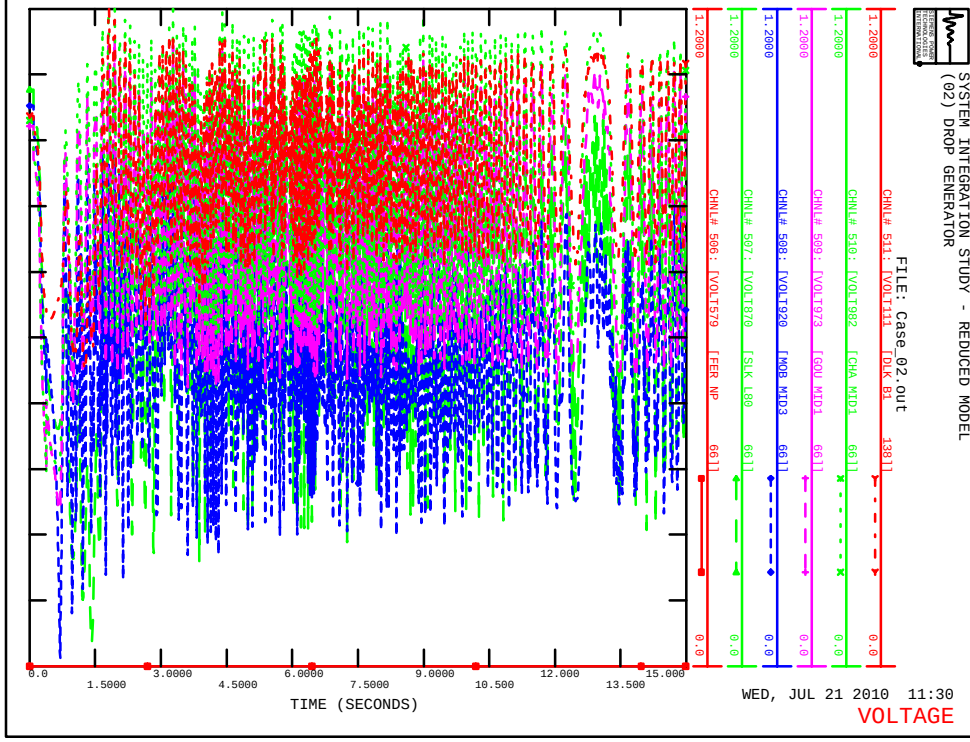

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 476: [VOLT309 [BBB T2T3 661]
CHNL# 478: [VOLT334 [QPD B2B5 661]
CHNL# 479: [VOLT335 [HWD B7B8 661]
CHNL# 480: [VOLT336 [WAV B2 661]
CHNL# 481: [VOLT337 [HRD B6B7 661]
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

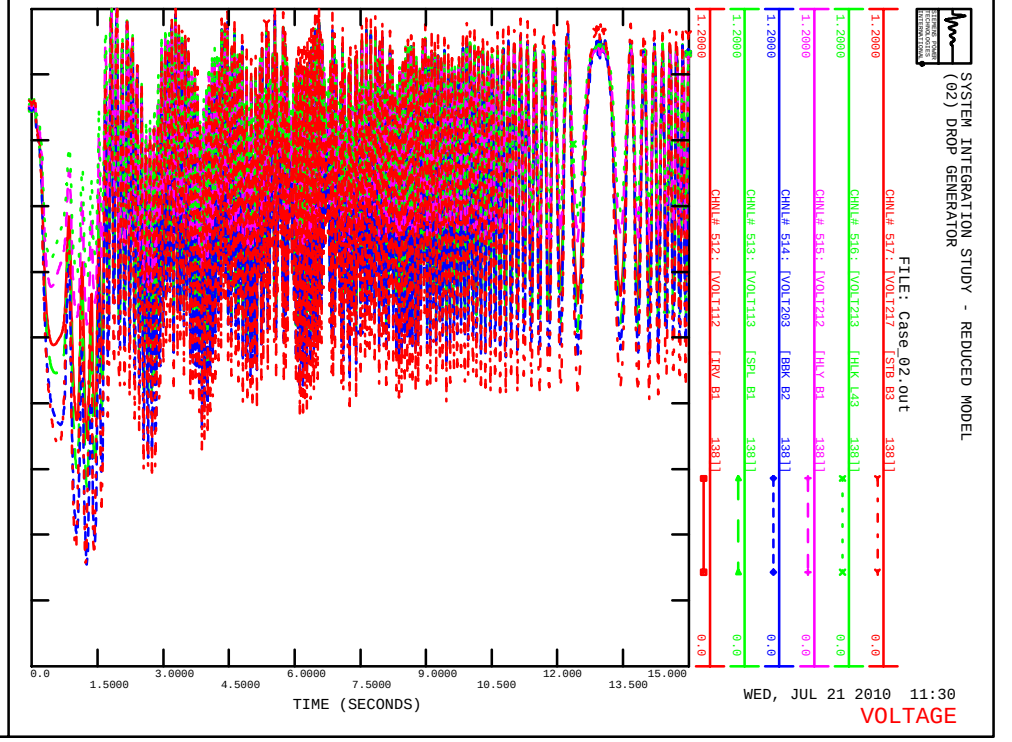

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 482: [VOLT345 [ULT TAP 661]
CHNL# 483: [VOLT346 [ULT NP 661]
CHNL# 484: [VOLT347 [SCV NP 661]
CHNL# 485: [VOLT348 [KEL NP 661]
CHNL# 486: [VOLT349 [CHA NP 661]
CHNL# 487: [VOLT455 [GOL NP 661]
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

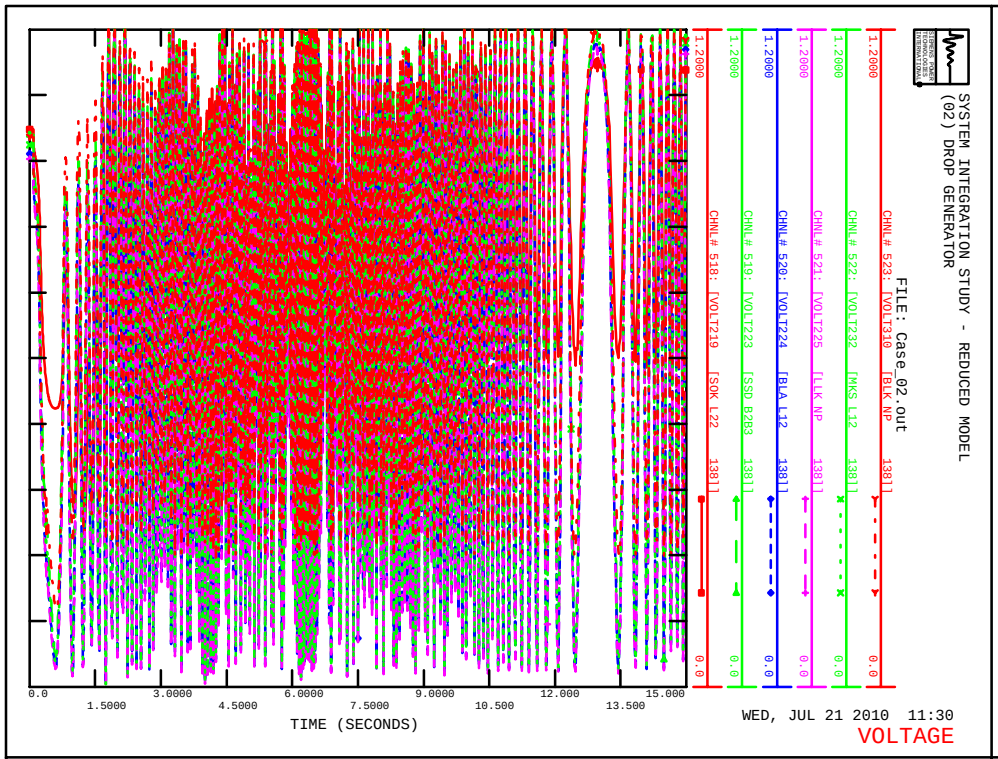

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 488: [VOLT457 [GOU NP 661]
CHNL# 490: [VOLT466 [KBR NP 661]
CHNL# 491: [VOLT467 [TCV NP 661]
CHNL# 492: [VOLT469 [MUN NP 661]
CHNL# 493: [VOLT471 [MOL NP 661]
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

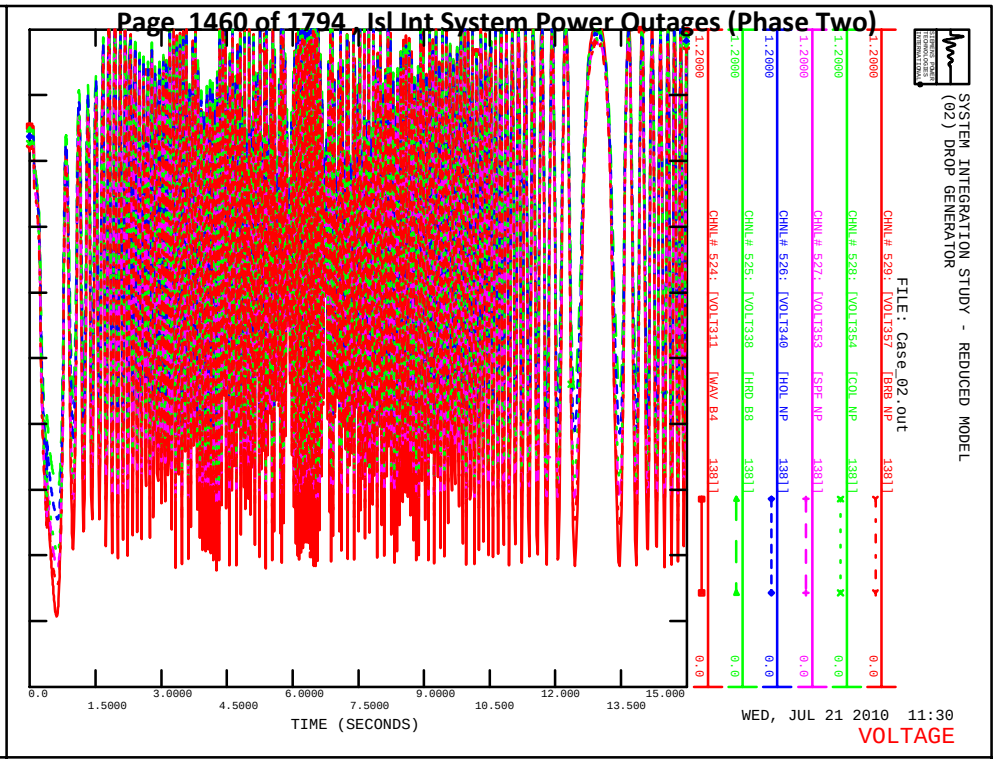

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 494: [VOLT474 [PEP NP 661]
CHNL# 495: [VOLT479 [PUL NP 661]
CHNL# 496: [VOLT481 [RRD NP 661]
CHNL# 497: [VOLT482 [MPP NP 661]
CHNL# 498: [VOLT484 [SJM NP 661]
CHNL# 499: [VOLT485 [HCP NP 661]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

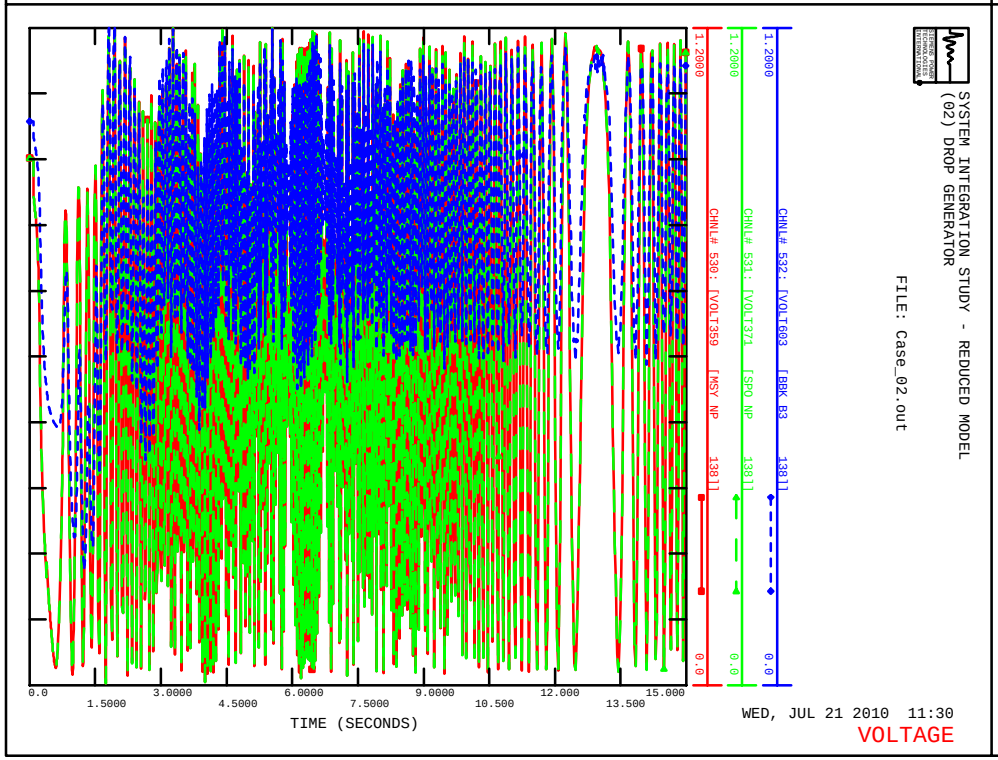

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 500: [VOLT489 [SLA NP 661]
CHNL# 501: [VOLT492 [VIR NP 661]
CHNL# 502: [VOLT510 [BIG NP 661]
CHNL# 503: [VOLT550 [MOB NP 661]
CHNL# 504: [VOLT558 [ROP NP 661]
CHNL# 505: [VOLT576 [CAB NP 661]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

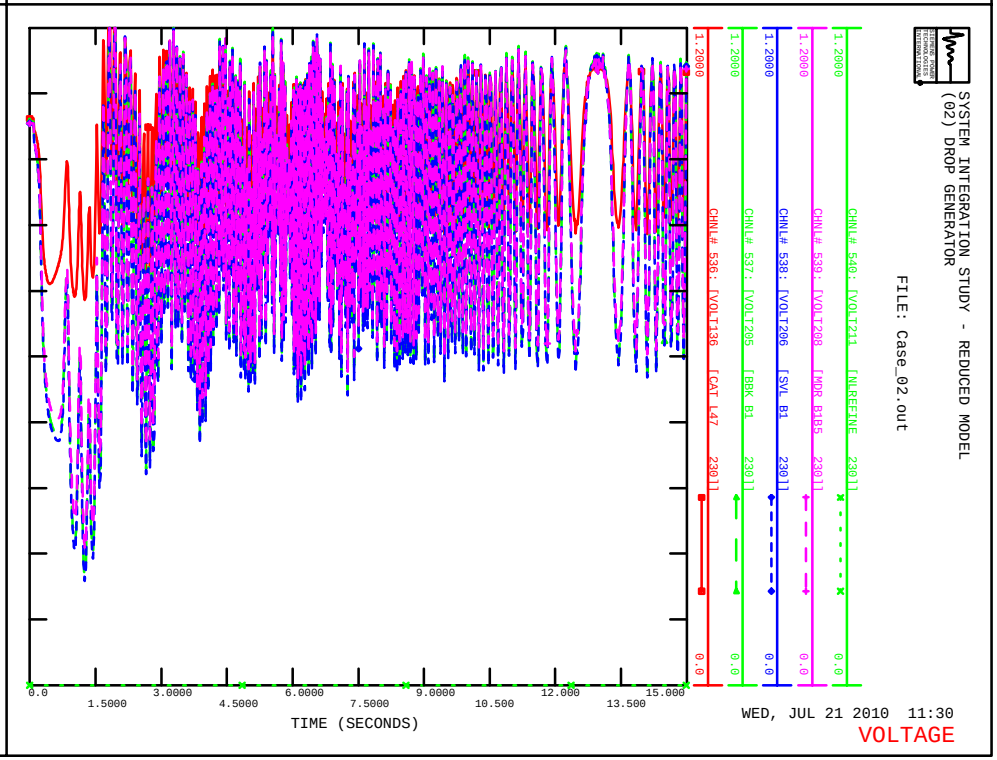

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 506: [VOLT579 [FER NP 661]
CHNL# 507: [VOLT870 [SLK L80 661]
CHNL# 508: [VOLT920 [MOB MID3 661]
CHNL# 509: [VOLT973 [GOU MID1 661]
CHNL# 510: [VOLT982 [CHA MID1 661]
CHNL# 511: [VOLT111 [OLK B1 1381]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

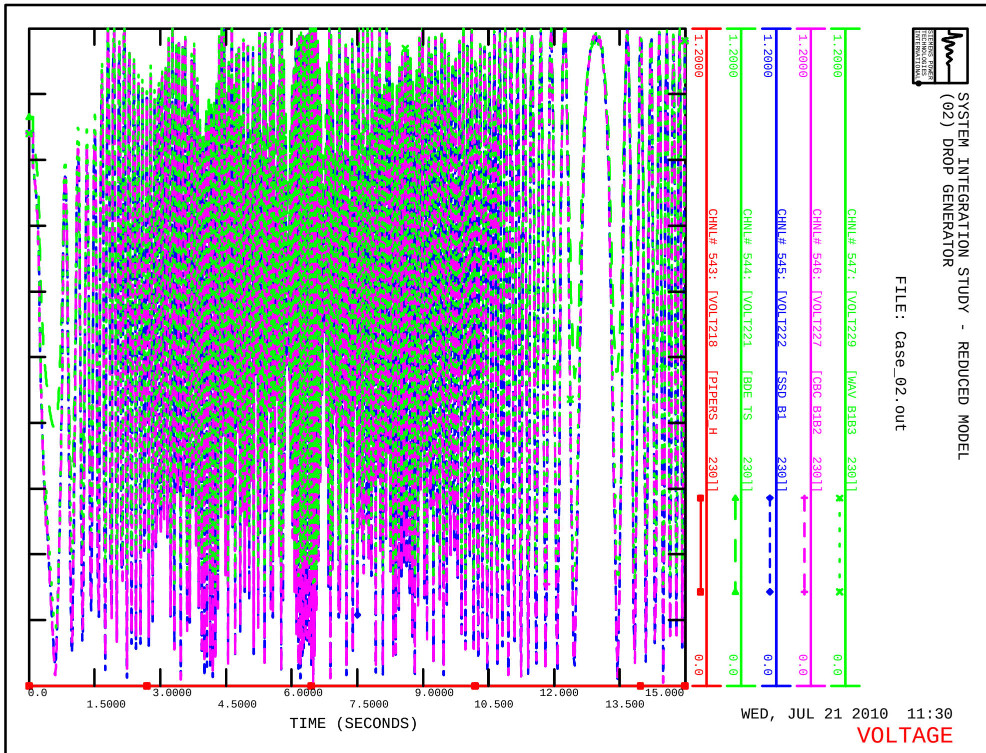

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 512: [VOLT112 [IRV B1 1381]
CHNL# 513: [VOLT113 [SPL B1 1381]
CHNL# 514: [VOLT203 [BBK B2 1381]
CHNL# 515: [VOLT232 [HLY B1 1381]
CHNL# 516: [VOLT213 [HLK 143 1381]
CHNL# 517: [VOLT237 [STB B3 1381]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

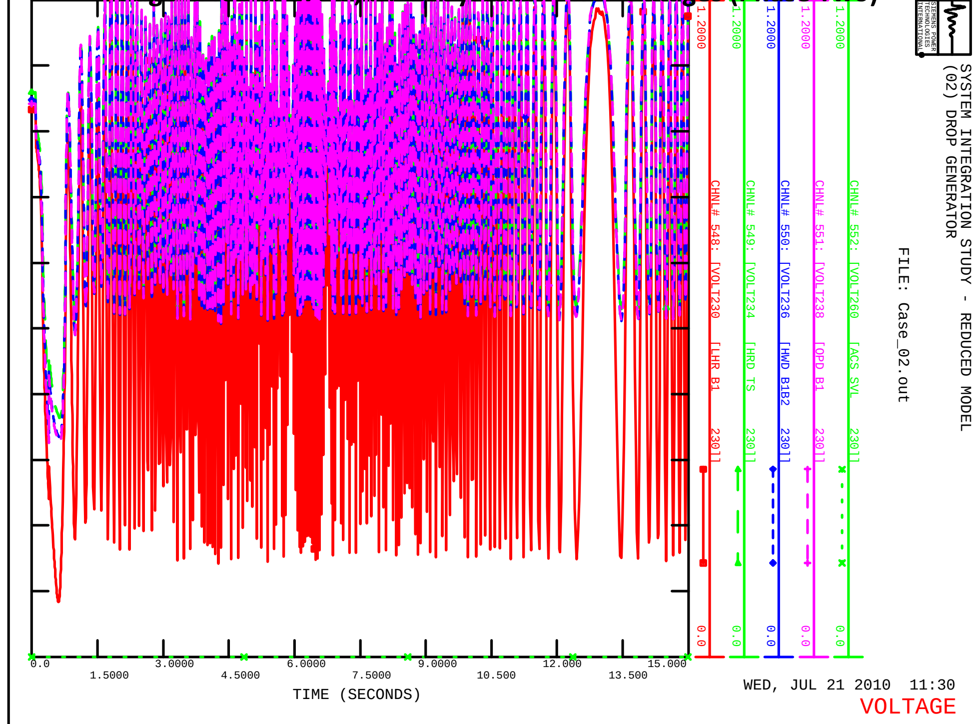

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 518: [VOLT219 [SOK L22 138]
CHNL# 519: [VOLT223 [SSD B2B3 138]
CHNL# 520: [VOLT224 [BLA L32 138]
CHNL# 521: [VOLT225 [LLK NP 138]
CHNL# 522: [VOLT232 [MKS L32 138]
CHNL# 523: [VOLT310 [BLK NP 138]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

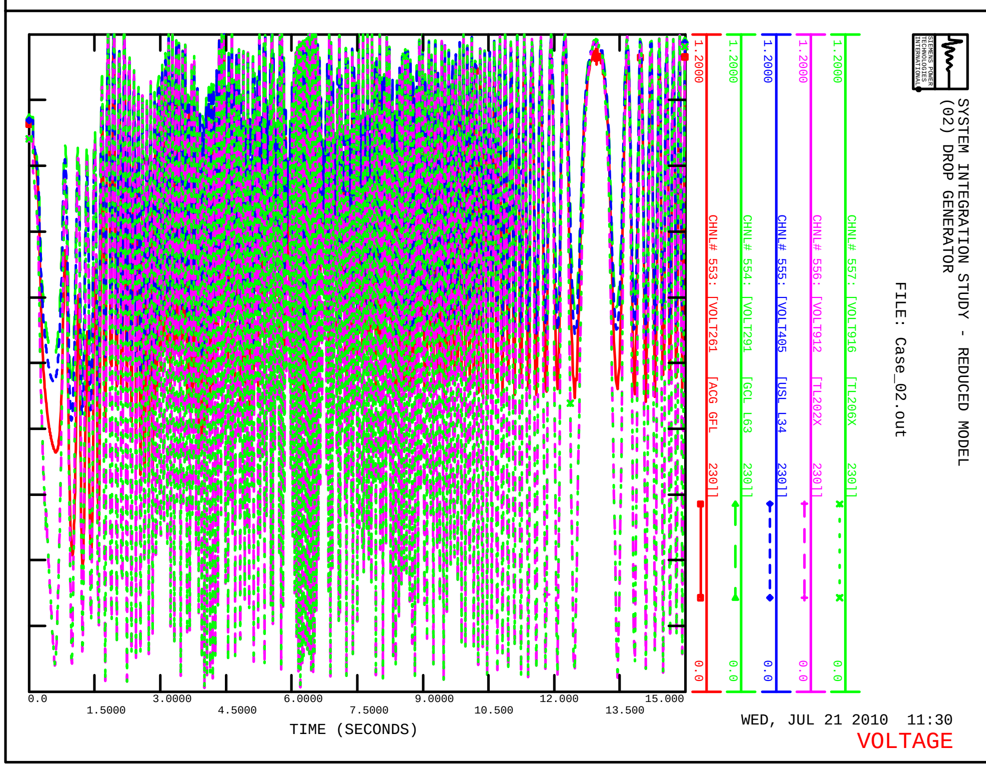

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 524: [VOLT311 [WAV B4 138]
CHNL# 525: [VOLT338 [HRD B8 138]
CHNL# 526: [VOLT340 [HOL NP 138]
CHNL# 527: [VOLT353 [SPF NP 138]
CHNL# 528: [VOLT354 [COL NP 138]
CHNL# 529: [VOLT357 [BRB NP 138]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

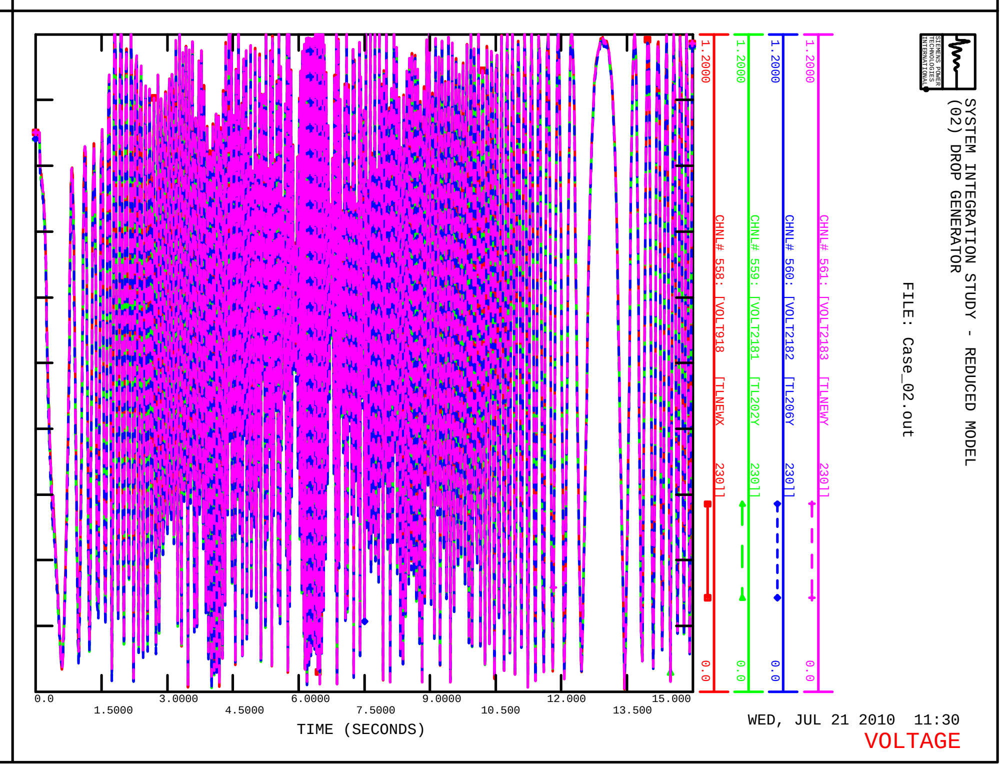

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 530: [VOLT359 [MSY NP 138]
CHNL# 531: [VOLT371 [SPO NP 138]
CHNL# 532: [VOLT603 [BBK B3 138]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

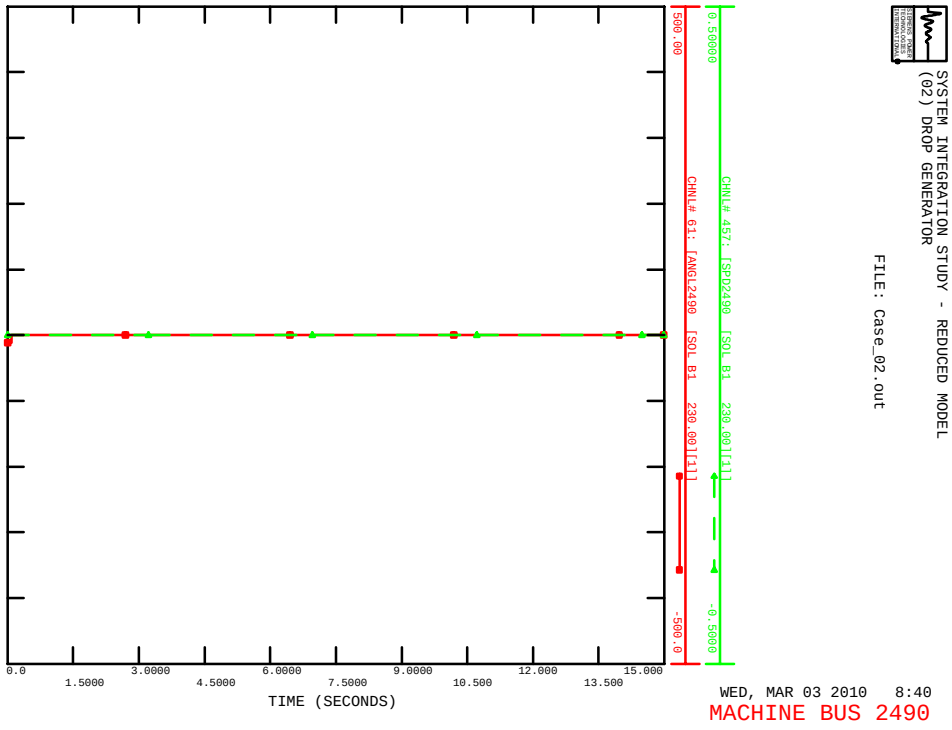

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 536: [VOLT136 [CAT L47 230]
CHNL# 537: [VOLT205 [BBK B1 230]
CHNL# 538: [VOLT206 [SVL B1 230]
CHNL# 539: [VOLT208 [MOR B1B5 230]
CHNL# 540: [VOLT211 [NLREFINE 230]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

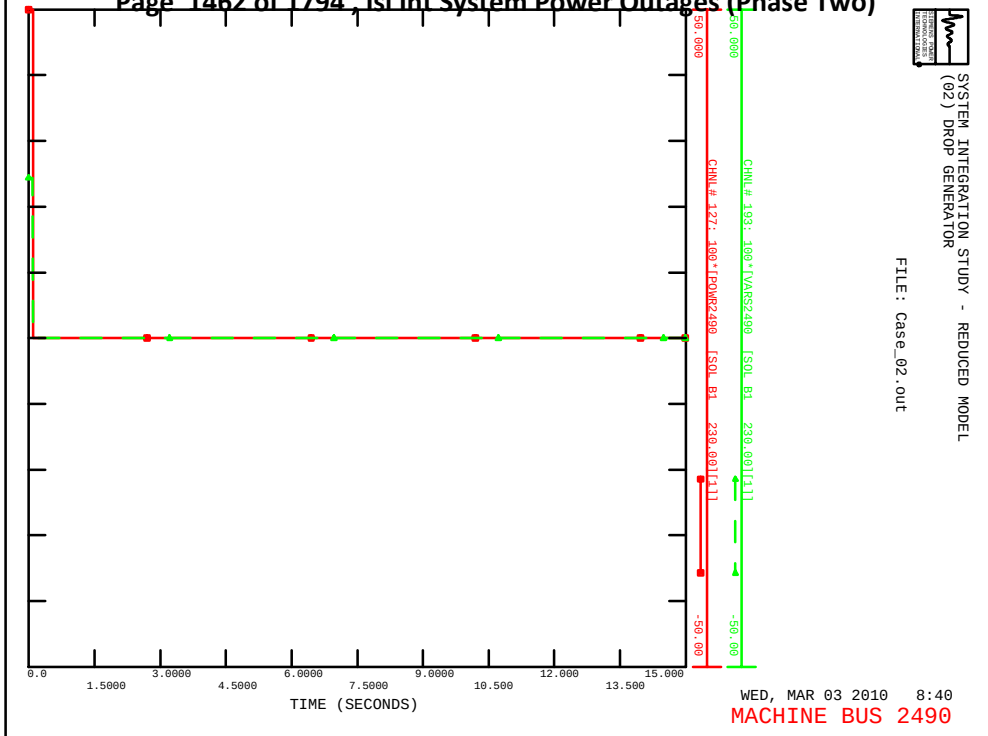

SIEMENS POWER TECHNOLOGIES INTERNATIONAL
SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 543: [VOLT218 [PIPERS H 230]]
CHNL# 544: [VOLT221 [BDE TS 230]]
CHNL# 545: [VOLT222 [SSD B1 230]]
CHNL# 546: [VOLT227 [CBC B1B2 230]]
CHNL# 547: [VOLT229 [WAV B1B3 230]]
1.2000
0.0
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

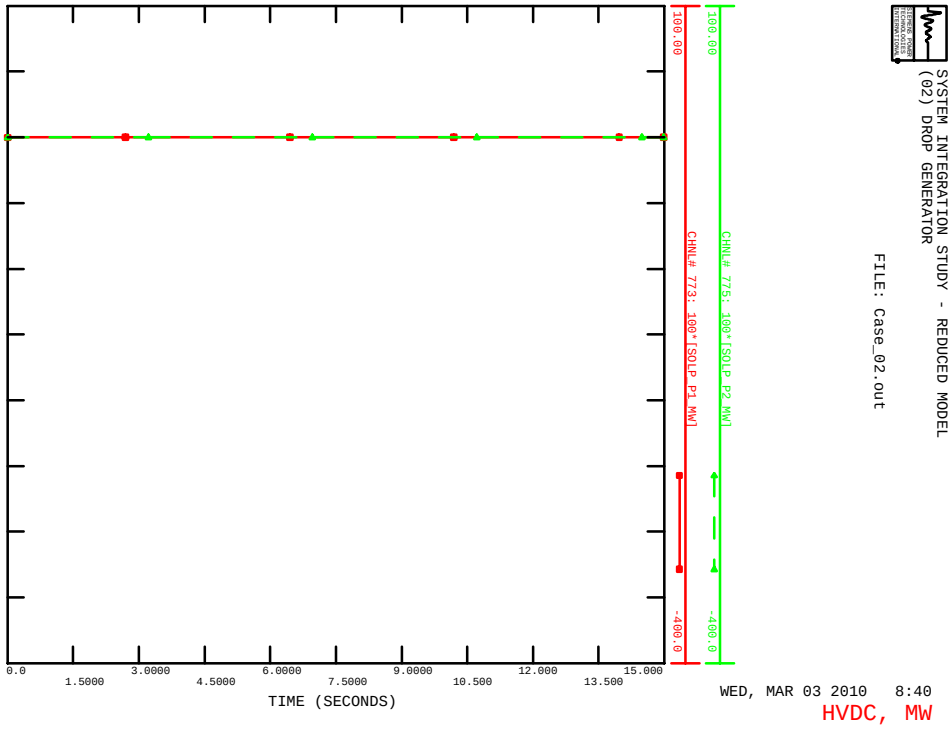

SIEMENS POWER TECHNOLOGIES INTERNATIONAL
SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 548: [VOLT230 [LHR B1 230]]
CHNL# 549: [VOLT234 [HRD TS 230]]
CHNL# 550: [VOLT236 [HWD B1B2 230]]
CHNL# 551: [VOLT238 [OPD B1 230]]
CHNL# 552: [VOLT260 [ACS SVL 230]]
1.2000
0.0
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

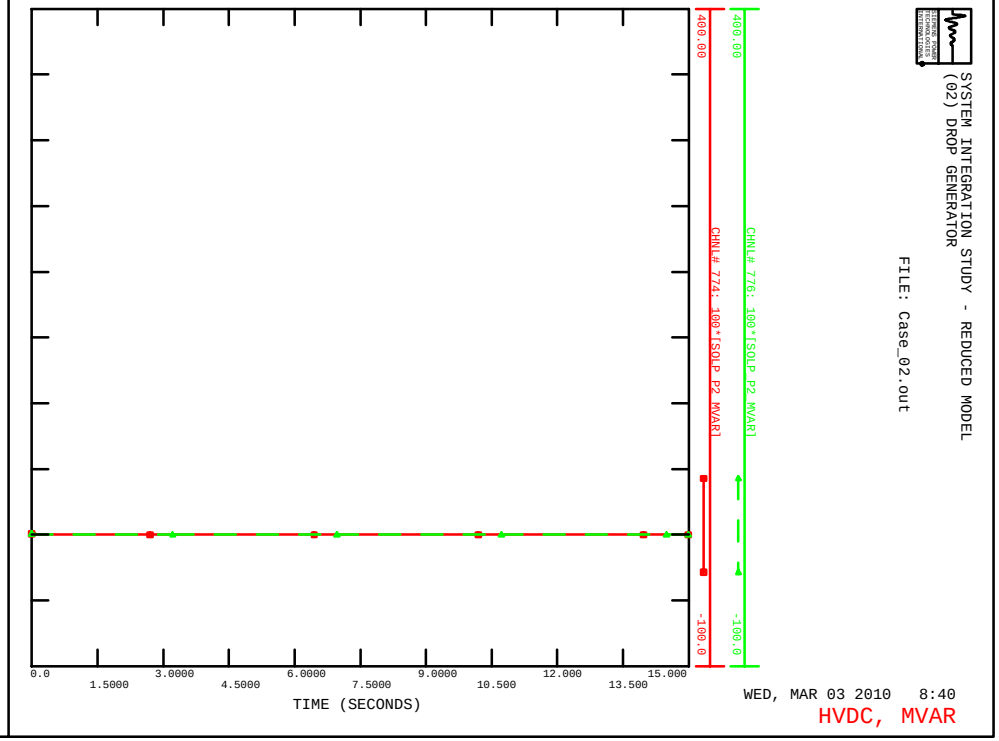

SIEMENS POWER TECHNOLOGIES INTERNATIONAL
SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 553: [VOLT261 [ACG GFL 230]]
CHNL# 554: [VOLT291 [GCL L63 230]]
CHNL# 555: [VOLT405 [USL L34 230]]
CHNL# 556: [VOLT912 [TL202X 230]]
CHNL# 557: [VOLT916 [TL206X 230]]
1.2000
0.0
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

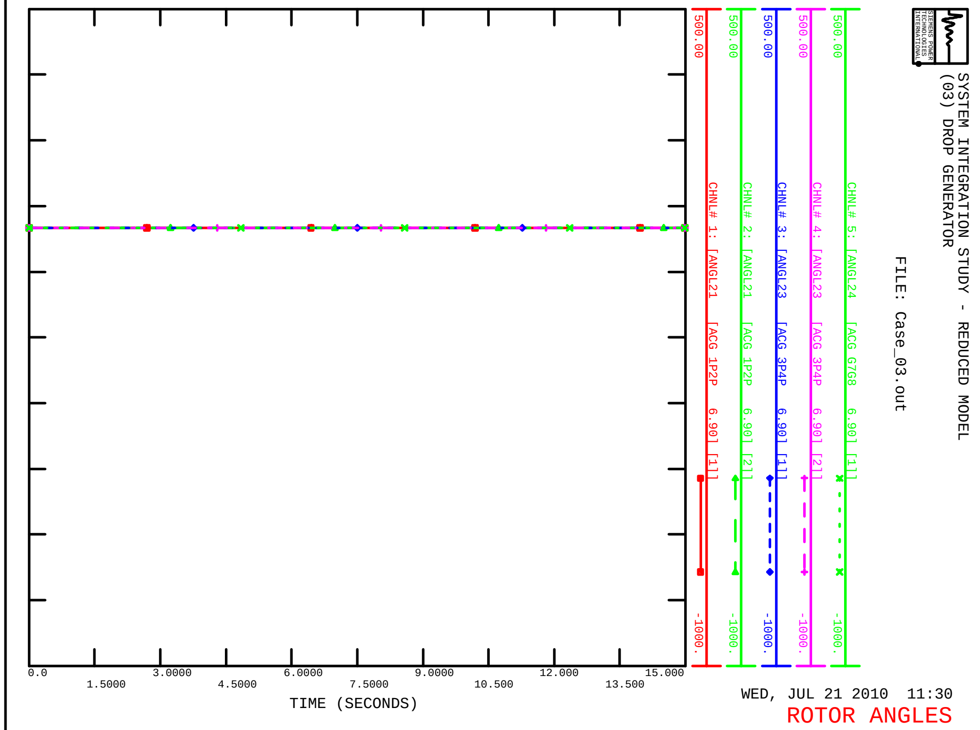

SIEMENS POWER TECHNOLOGIES INTERNATIONAL
SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
CHNL# 558: [VOLT918 [TLNEWX 230]]
CHNL# 559: [VOLT2181 [TL202Y 230]]
CHNL# 560: [VOLT2182 [TL206Y 230]]
CHNL# 561: [VOLT2183 [TLNEWY 230]]
1.2000
0.0
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

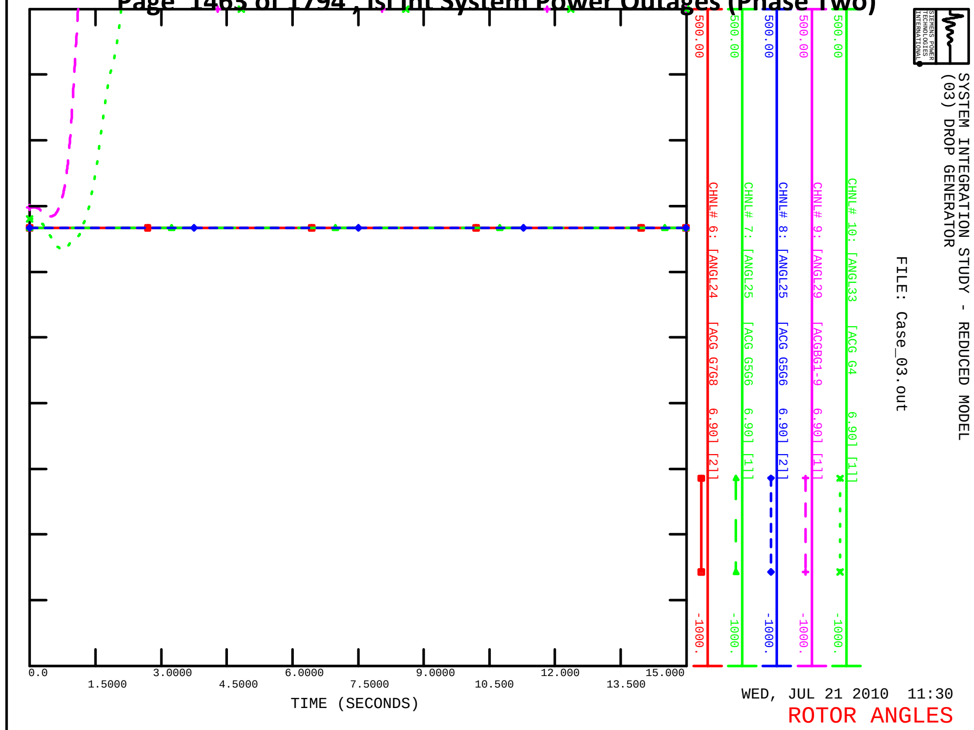

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
500.00
CHNL# 61: [ANGL2490 [SOL B1 230.00][1]]
-500.0
0.50000
CHNL# 457: [SPD2490 [SOL B1 230.00][1]]
-0.5000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, MAR 03 2010 8:40
MACHINE BUS 2490

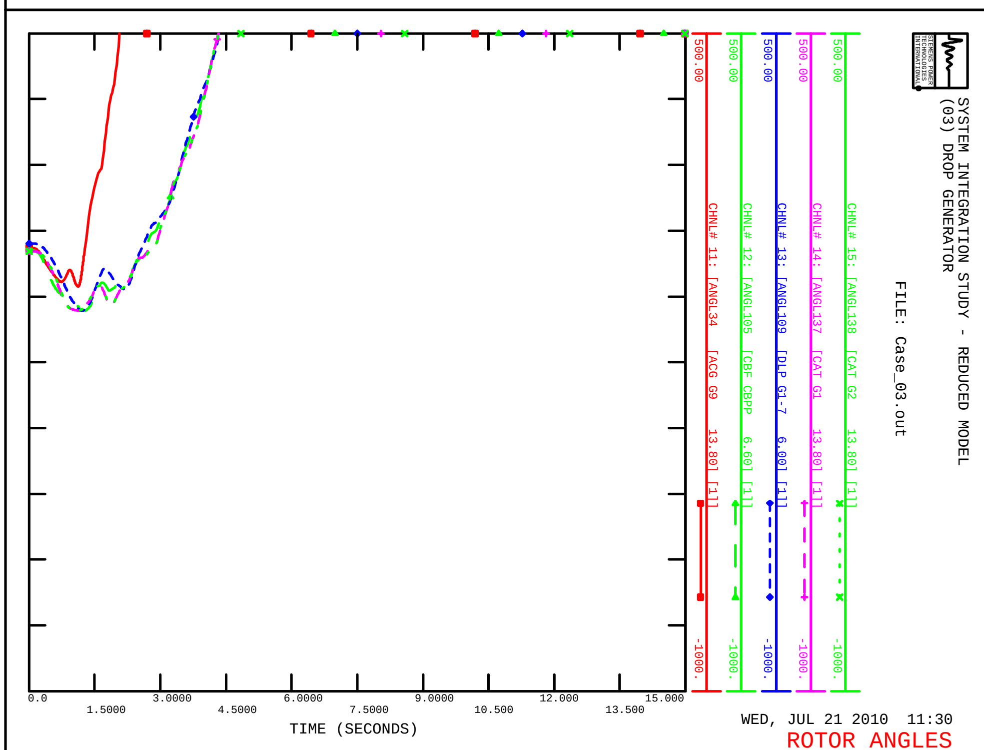

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
50.000
CHNL# 127: 100*[POWR2490 [SOL B1 230.00][1]]
-50.00
50.000
CHNL# 193: 100*[VARS2490 [SOL B1 230.00][1]]
-50.00
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, MAR 03 2010 8:40
MACHINE BUS 2490

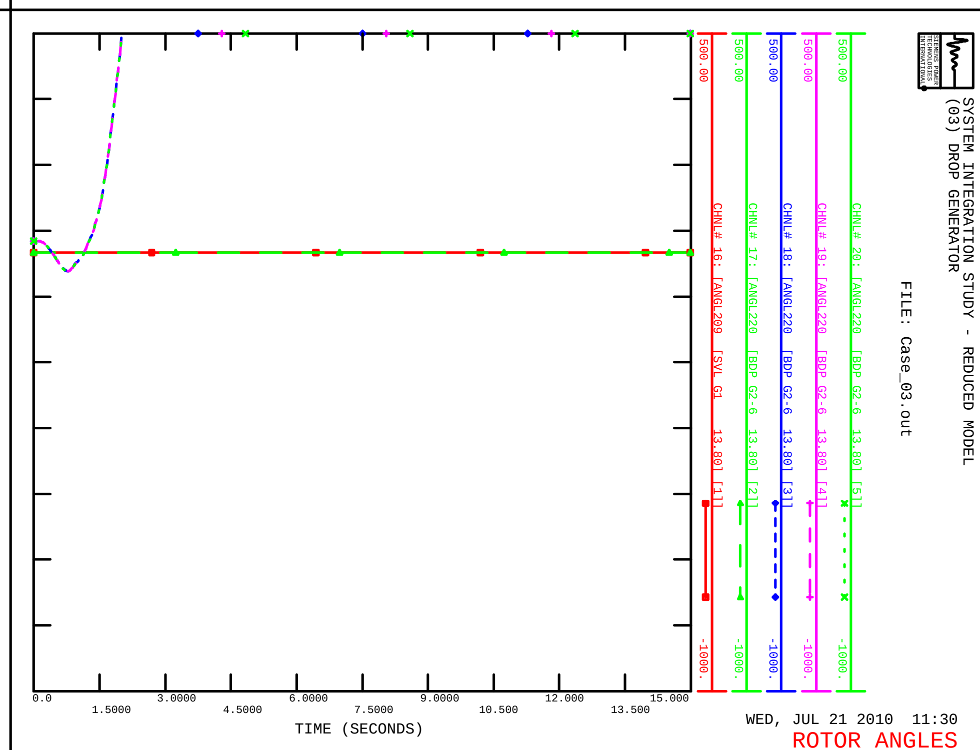

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
100.00
CHNL# 773: 100*[SOLP P1 MW]
-400.0
100.00
CHNL# 775: 100*[SOLP P2 MW]
-400.0
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, MAR 03 2010 8:40
HVDC, MW

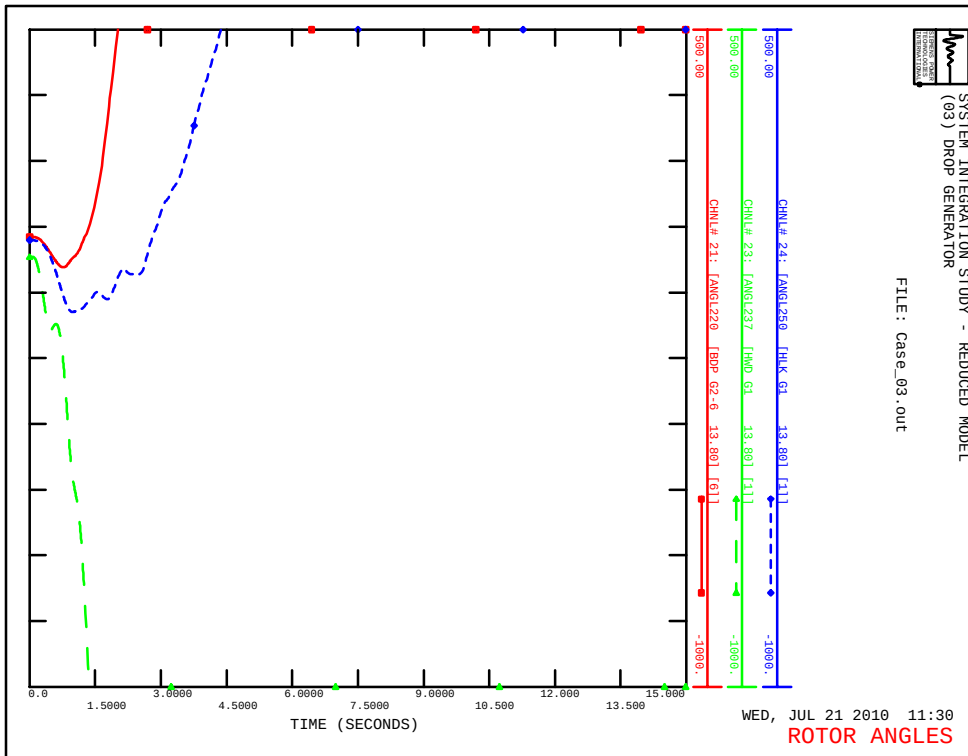

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(02) DROP GENERATOR
FILE: Case_02.out
400.00
CHNL# 774: 100*[SOLP P2 MVAR]
-100.0
400.00
CHNL# 776: 100*[SOLP P2 MVAR]
-100.0
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, MAR 03 2010 8:40
HVDC, MVAR

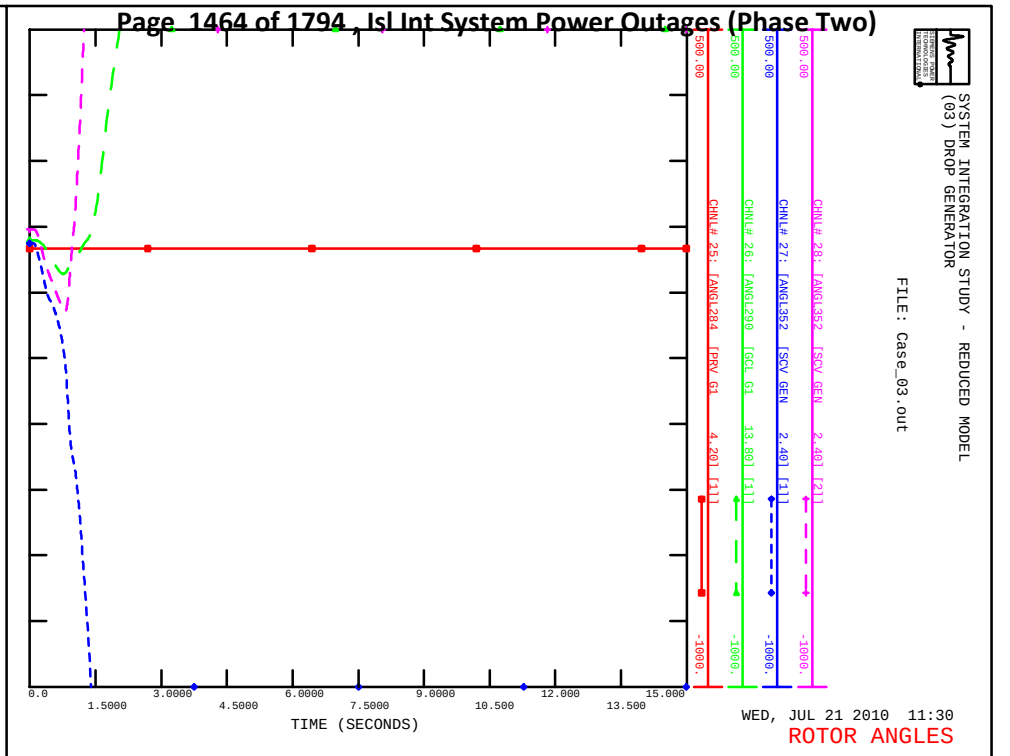

SIEMENS POWER TECHNOLOGIES INTERNATIONAL
SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 1: [ANGL21 [ACG 1P2P 6.90] [1]]
CHNL# 2: [ANGL21 [ACG 1P2P 6.90] [2]]
CHNL# 3: [ANGL23 [ACG 3P4P 6.90] [1]]
CHNL# 4: [ANGL23 [ACG 3P4P 6.90] [2]]
CHNL# 5: [ANGL24 [ACG G7G8 6.90] [1]]
500.00
-1000.
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

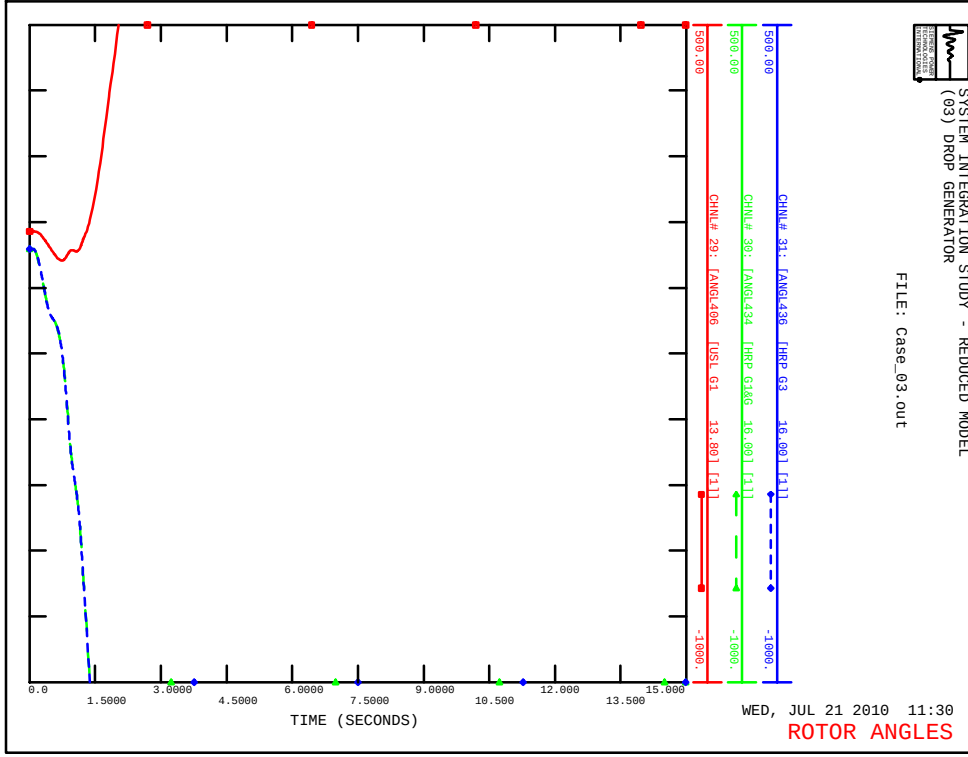

SIEMENS POWER TECHNOLOGIES INTERNATIONAL
SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 6: [ANGL24 [ACG G7G8 6.90] [2]]
CHNL# 7: [ANGL25 [ACG G5G6 6.90] [1]]
CHNL# 8: [ANGL25 [ACG G5G6 6.90] [2]]
CHNL# 9: [ANGL29 [ACGBG1-9 6.90] [1]]
CHNL# 10: [ANGL33 [ACG G4 6.90] [1]]
500.00
-1000.
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

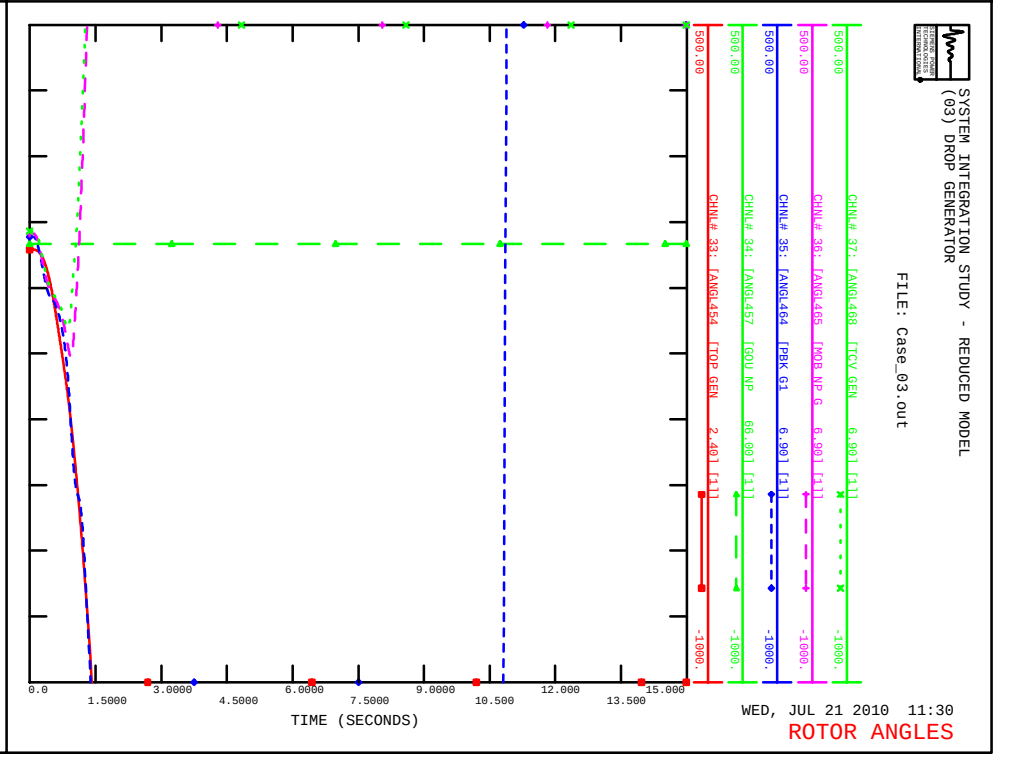

SIEMENS POWER TECHNOLOGIES INTERNATIONAL
SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 11: [ANGL34 [ACG G9 13.80] [1]]
CHNL# 12: [ANGL105 [CBF CBPP 6.60] [1]]
CHNL# 13: [ANGL109 [DLP G1-7 6.00] [1]]
CHNL# 14: [ANGL137 [CAT G1 13.80] [1]]
CHNL# 15: [ANGL138 [CAT G2 13.80] [1]]
500.00
-1000.
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

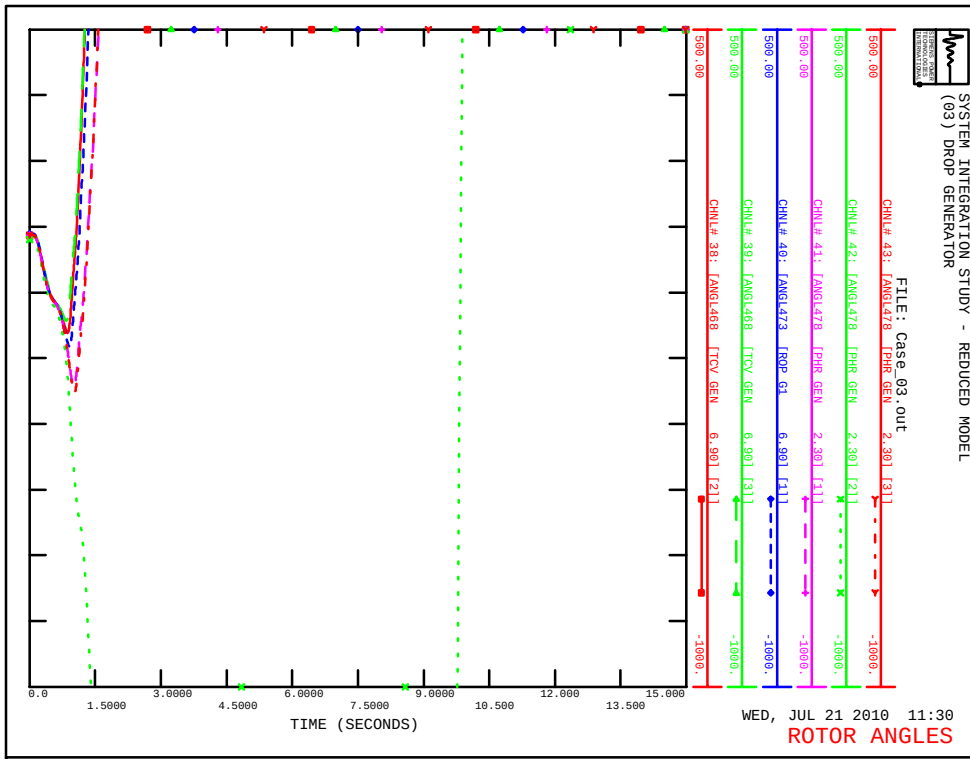

SIEMENS POWER TECHNOLOGIES INTERNATIONAL
SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 16: [ANGL209 [SVL G1 13.80] [1]]
CHNL# 17: [ANGL220 [BDP G2-6 13.80] [2]]
CHNL# 18: [ANGL220 [BDP G2-6 13.80] [3]]
CHNL# 19: [ANGL220 [BDP G2-6 13.80] [4]]
CHNL# 20: [ANGL220 [BDP G2-6 13.80] [5]]
500.00
-1000.
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

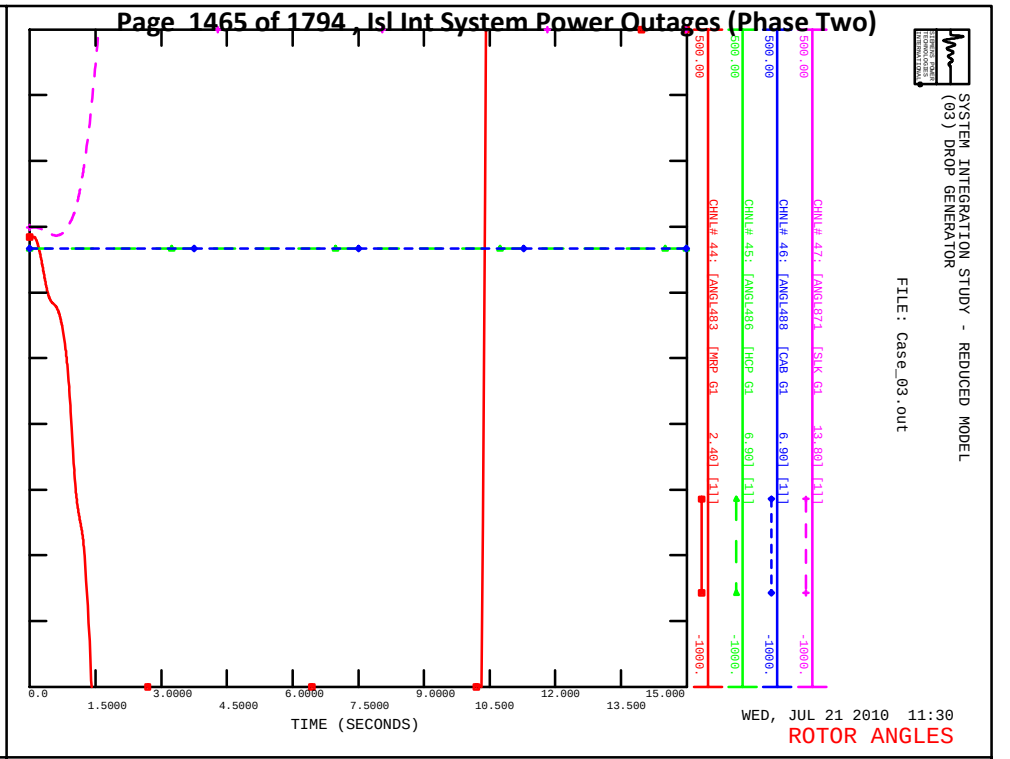

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 21: [ANGL220 [BDP G2-6 13.80] [61]
CHNL# 23: [ANGL237 [HND G1 13.80] [1]
CHNL# 24: [ANGL250 [HLK G1 13.80] [11]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

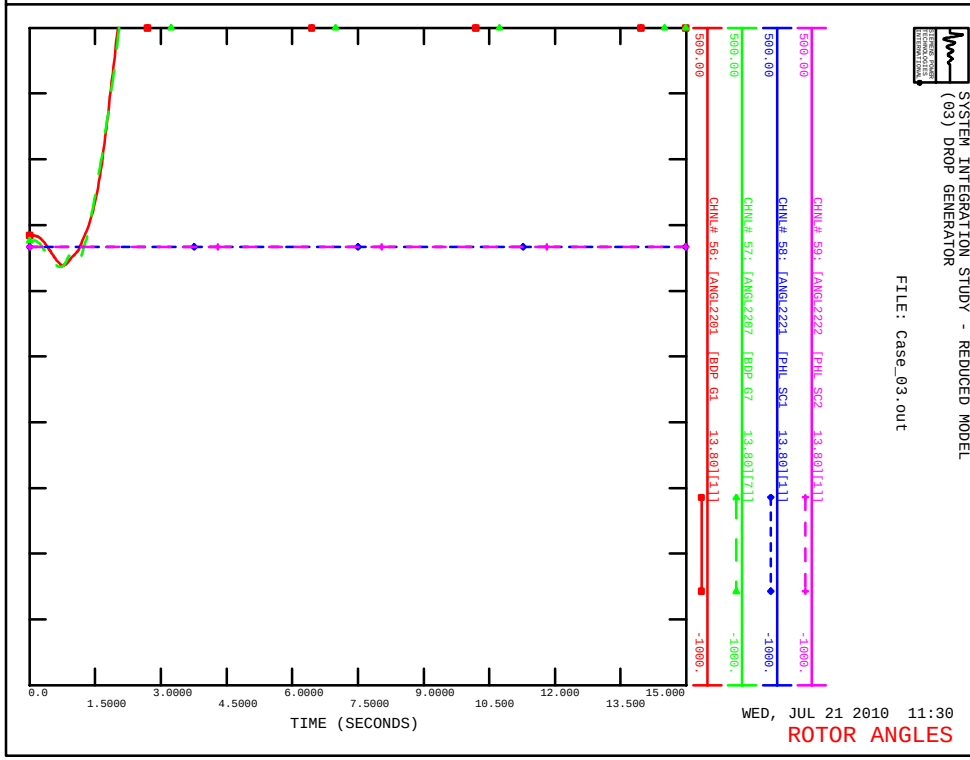

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 25: [ANGL284 [PRV G1 4.20] [11]
CHNL# 26: [ANGL290 [GCL G1 13.80] [11]
CHNL# 27: [ANGL352 [SCV GEN 2.40] [11]
CHNL# 28: [ANGL352 [SCV GEN 2.40] [21]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

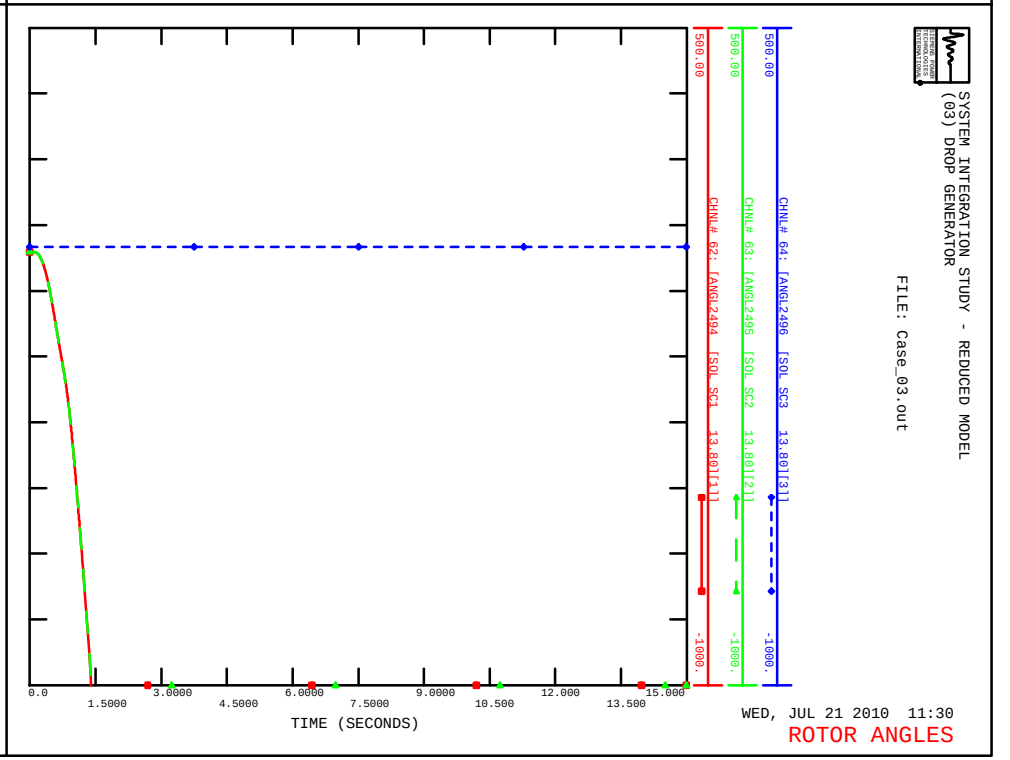

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 29: [ANGL406 [USL G1 13.80] [11]
CHNL# 30: [ANGL434 [HRP G1&G 16.00] [11]
CHNL# 31: [ANGL436 [HRP G3 16.00] [11]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

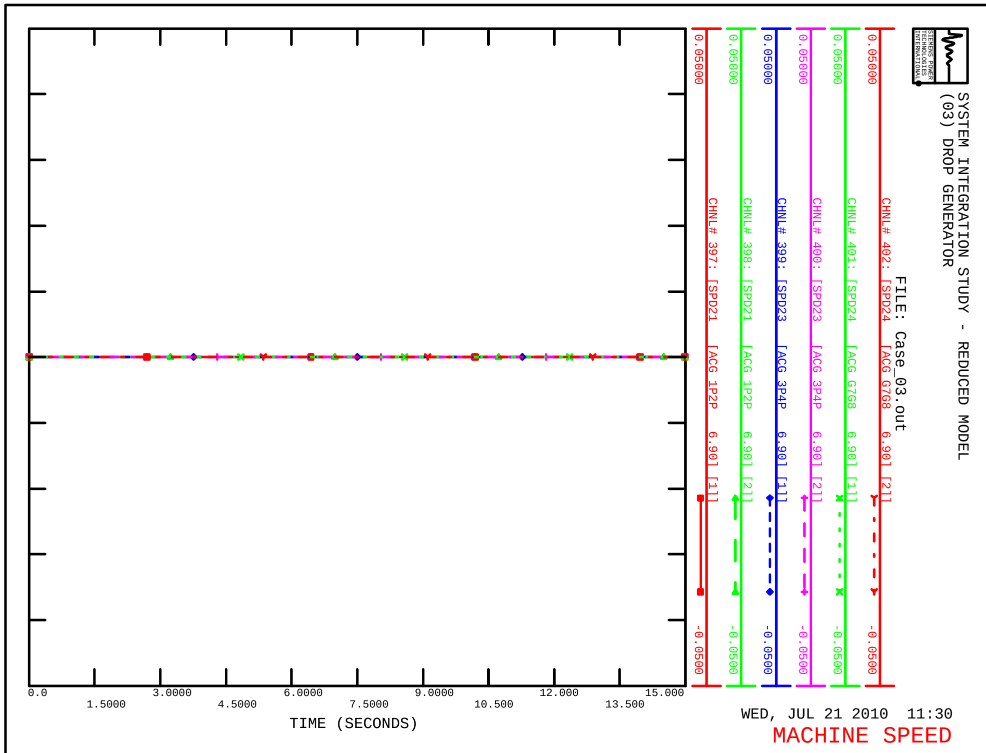

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 33: [ANGL454 [TOP GEN 2.40] [11]
CHNL# 34: [ANGL457 [CGU NP 66.00] [11]
CHNL# 35: [ANGL464 [PBK G1 6.90] [11]
CHNL# 36: [ANGL465 [MOB NP G 6.90] [11]
CHNL# 37: [ANGL468 [TCV GEN 6.90] [11]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

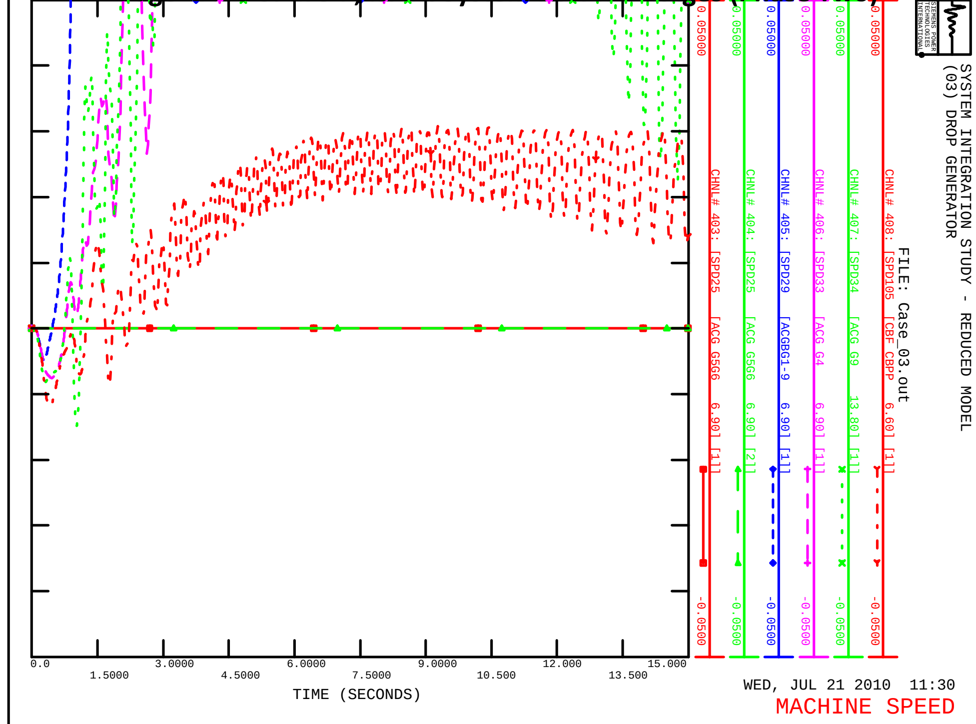

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 38: [ANGL468 [TCV GEN 6.90] [2]
CHNL# 39: [ANGL468 [TCV GEN 6.90] [3]
CHNL# 40: [ANGL473 [ROP G1 6.90] [1]
CHNL# 41: [ANGL478 [PHR GEN 2.30] [1]
CHNL# 42: [ANGL478 [PHR GEN 2.30] [2]
CHNL# 43: [ANGL478 [PHR GEN 2.30] [3]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

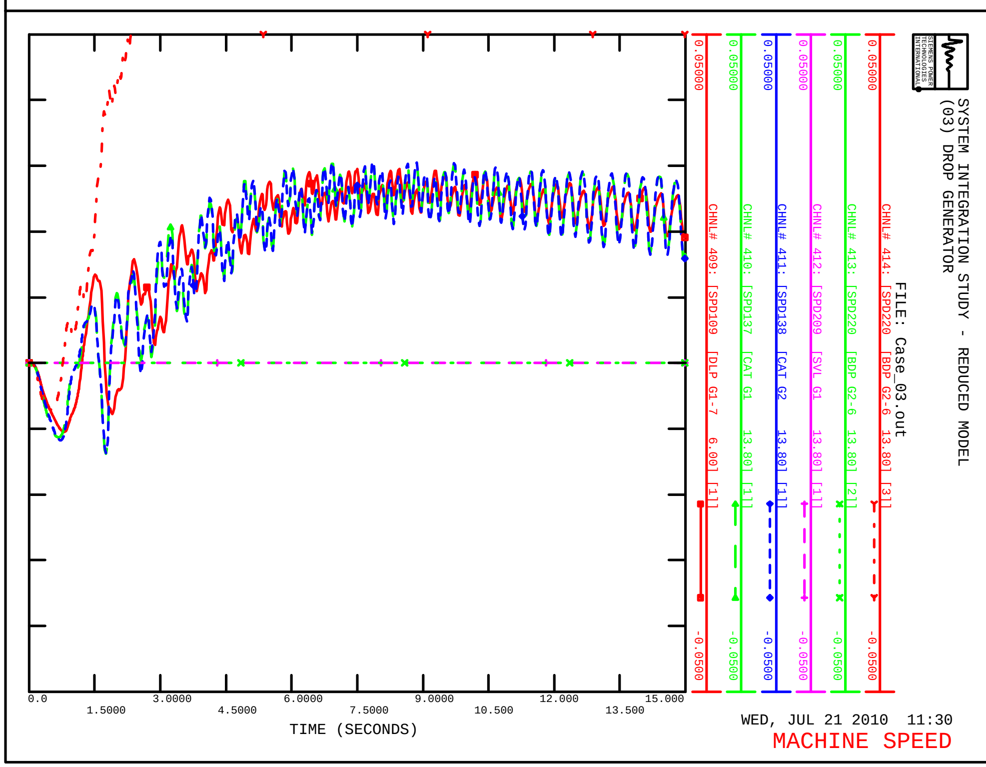

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 44: [ANGL483 [MRP G1 2.40] [1]
CHNL# 45: [ANGL486 [HCP G1 6.90] [1]
CHNL# 46: [ANGL488 [CAB G1 6.90] [1]
CHNL# 47: [ANGL871 [SLK G1 13.80] [1]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

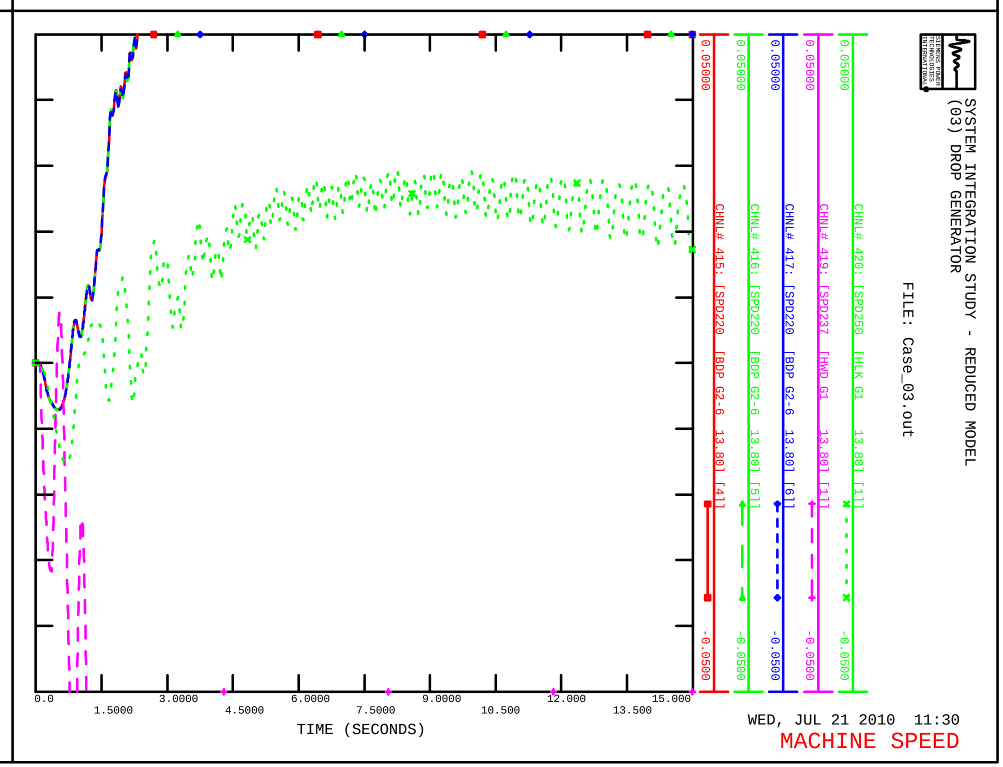

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 56: [ANGL2201 [BDP G1 13.80] [1]
CHNL# 57: [ANGL2207 [BDP G7 13.80] [7]
CHNL# 58: [ANGL2221 [PHL SC1 13.80] [1]
CHNL# 59: [ANGL2222 [PHL SC2 13.80] [1]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

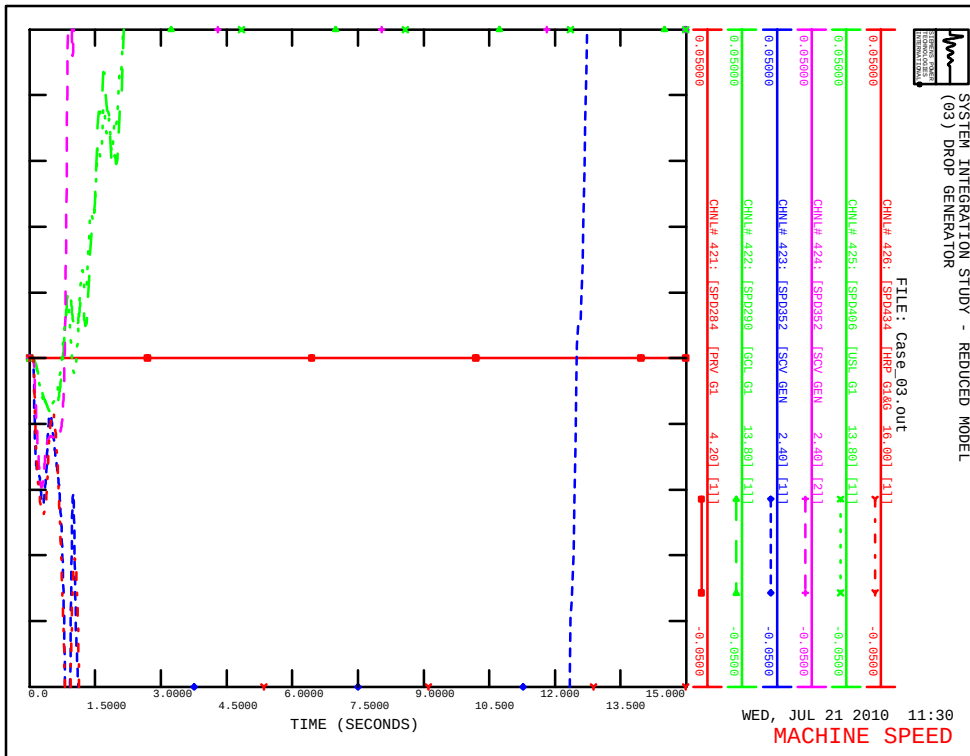

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 62: [ANGL2494 [SOL SC1 13.80] [1]
CHNL# 63: [ANGL2495 [SOL SC2 13.80] [2]
CHNL# 64: [ANGL2496 [SOL SC3 13.80] [3]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

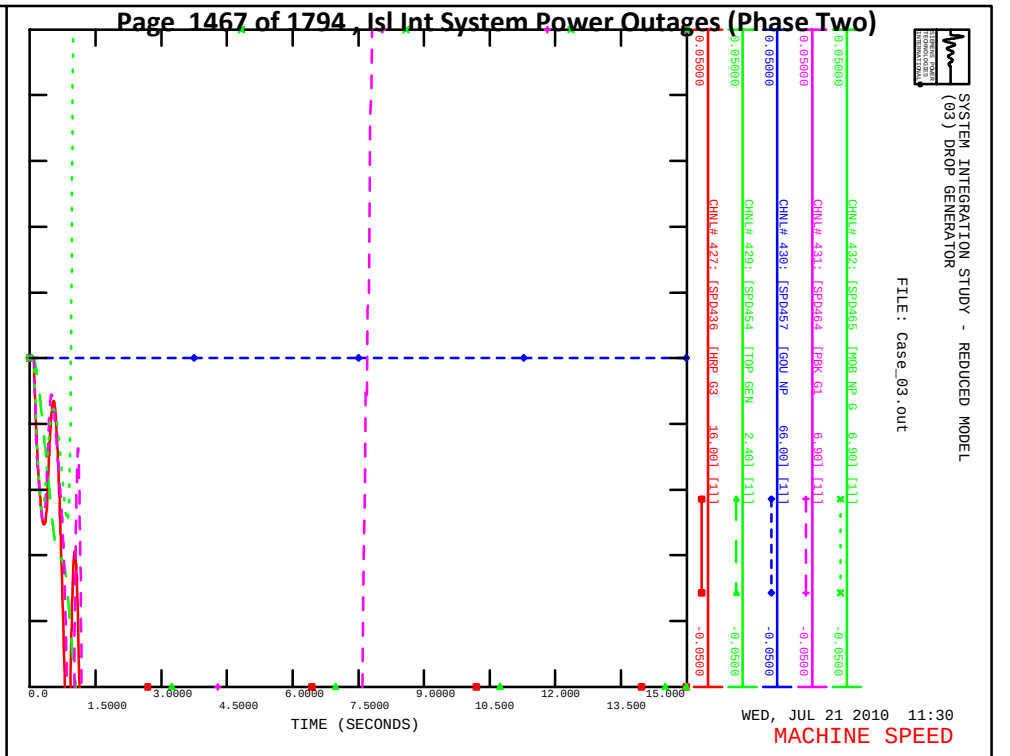

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 397: [SPD21 [ACG 1P2P 6.90] [1]
CHNL# 398: [SPD21 [ACG 1P2P 6.90] [2]
CHNL# 399: [SPD23 [ACG 3P4P 6.90] [1]
CHNL# 400: [SPD23 [ACG 3P4P 6.90] [2]
CHNL# 401: [SPD24 [ACG G7G8 6.90] [1]
CHNL# 402: [SPD24 [ACG G7G8 6.90] [2]
0.05000
-0.0500
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

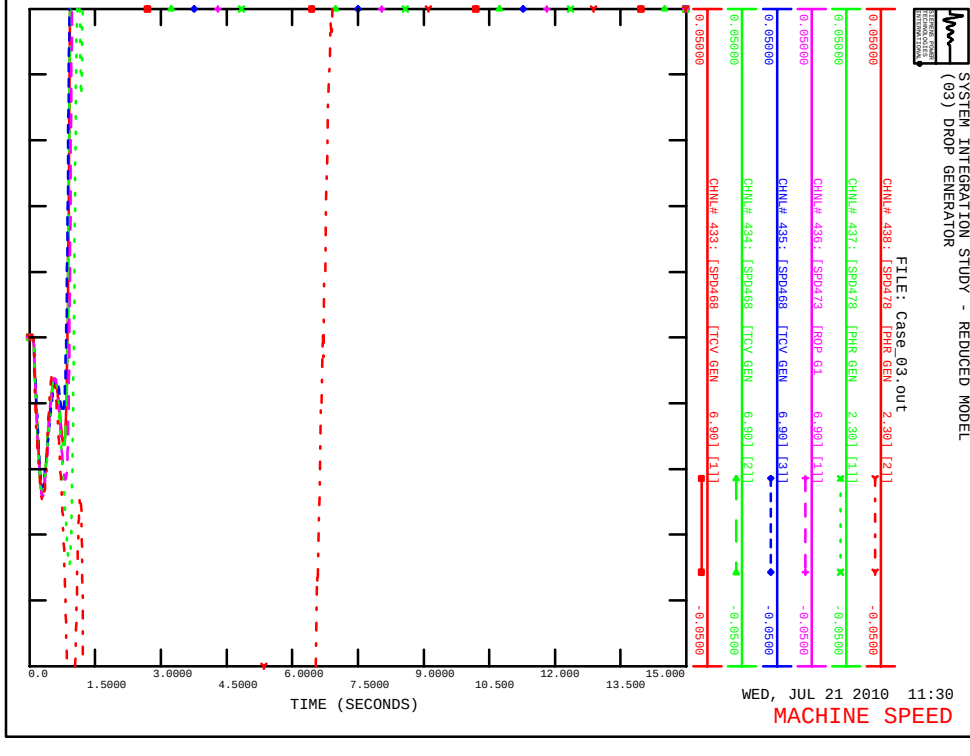

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 403: [SPD25 [ACG G5G6 6.90] [1]
CHNL# 404: [SPD25 [ACG G5G6 6.90] [2]
CHNL# 405: [SPD29 [ACGBG1-9 6.90] [1]
CHNL# 406: [SPD33 [ACG G4 6.90] [1]
CHNL# 407: [SPD34 [ACG G9 13.80] [1]
CHNL# 408: [SPD105 [CBF CBPP 6.60] [1]
0.05000
-0.0500
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

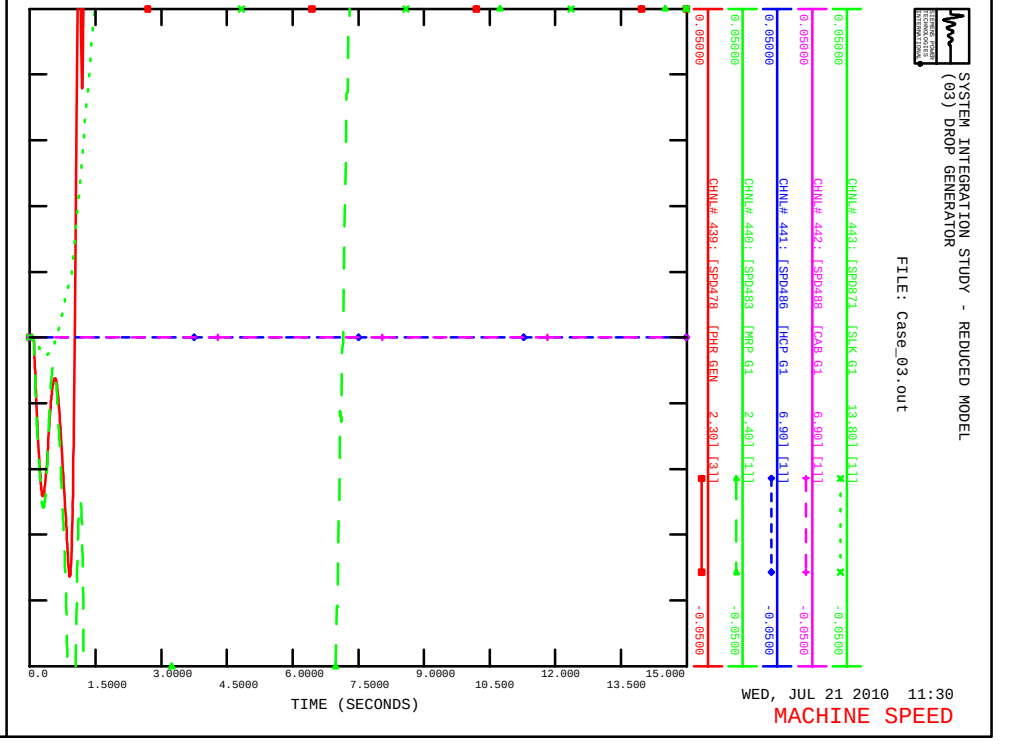

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 409: [SPD109 [DLP G1-7 6.00] [1]
CHNL# 410: [SPD137 [CAT G1 13.80] [1]
CHNL# 411: [SPD138 [CAT G2 13.80] [1]
CHNL# 412: [SPD209 [SVL G1 13.80] [1]
CHNL# 413: [SPD220 [BDP G2-6 13.80] [2]
CHNL# 414: [SPD220 [BDP G2-6 13.80] [3]
0.05000
-0.0500
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

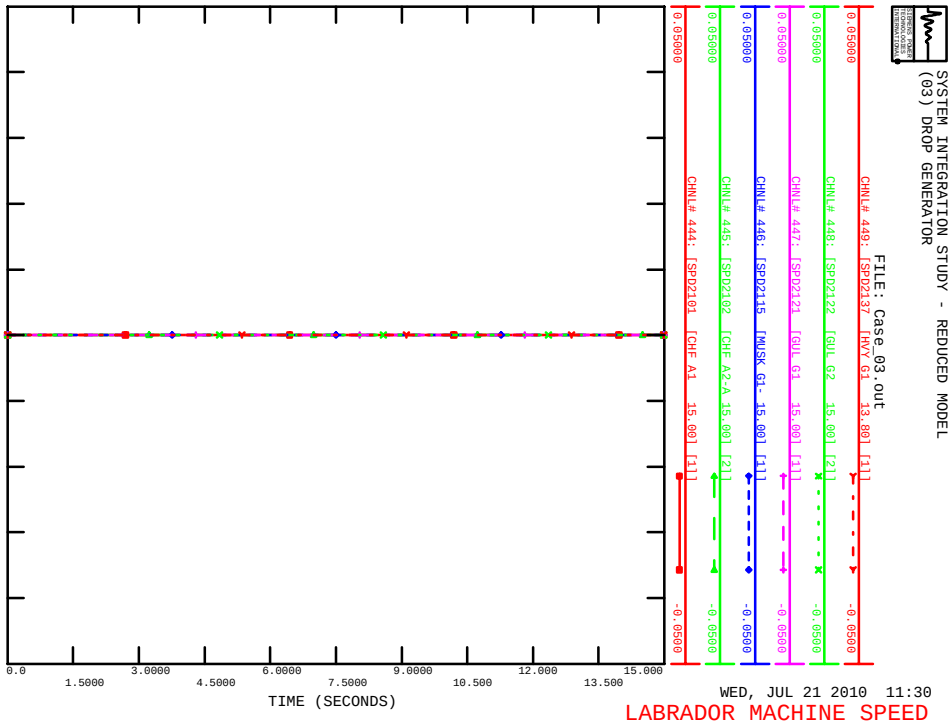

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 415: [SPD220 [BDP G2-6 13.80] [4]
CHNL# 416: [SPD220 [BDP G2-6 13.80] [5]
CHNL# 417: [SPD220 [BDP G2-6 13.80] [6]
CHNL# 419: [SPD237 [HWD G1 13.80] [1]
CHNL# 420: [SPD250 [HLK G1 13.80] [1]
0.05000
-0.0500
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

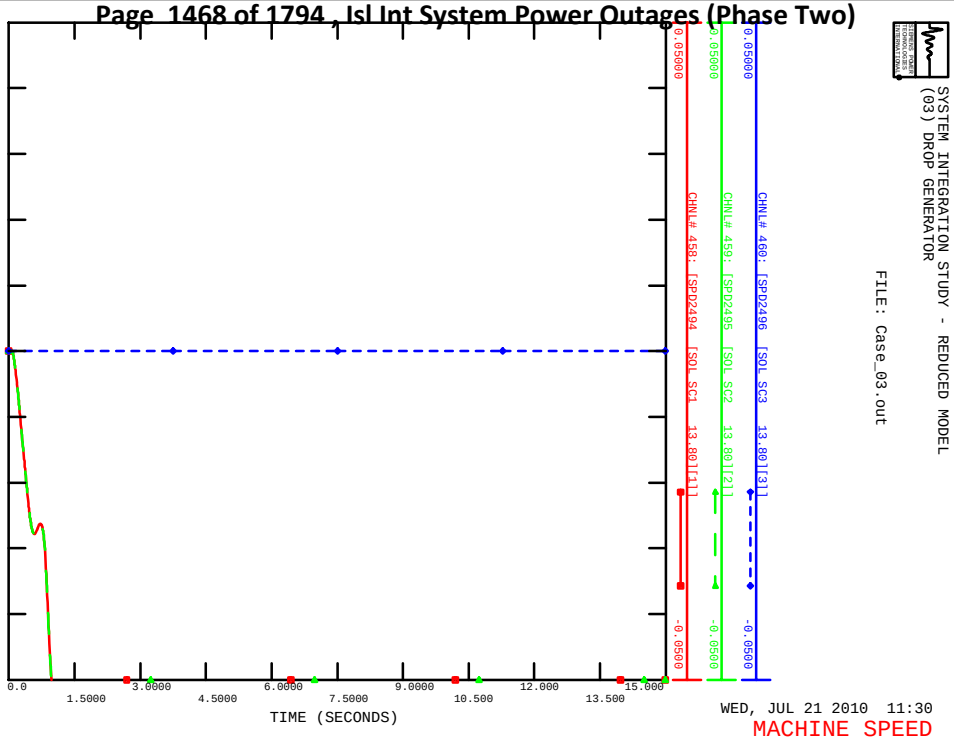

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 421: [SPD284 [PRV G1 4.20] [1]]
CHNL# 422: [SPD290 [GOL G1 13.80] [1]]
CHNL# 423: [SPD352 [SCV GEN 2.40] [1]]
CHNL# 424: [SPD352 [SCV GEN 2.40] [2]]
CHNL# 425: [SPD406 [USL G1 13.80] [1]]
CHNL# 426: [SPD434 [HRP G1&G 16.00] [1]]
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

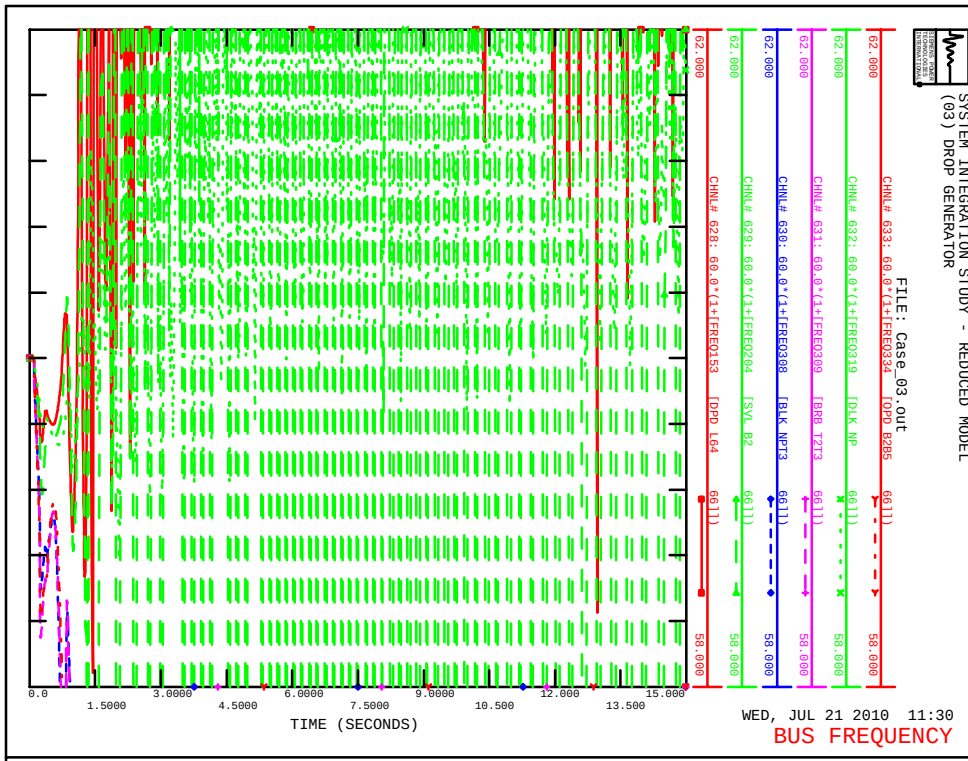

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 427: [SPD436 [HRP G3 16.00] [1]]
CHNL# 429: [SPD454 [TOP GEN 2.40] [1]]
CHNL# 430: [SPD457 [GOU NP 66.00] [1]]
CHNL# 431: [SPD464 [PBK G1 6.90] [1]]
CHNL# 432: [SPD465 [MOB NP G 6.90] [1]]
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

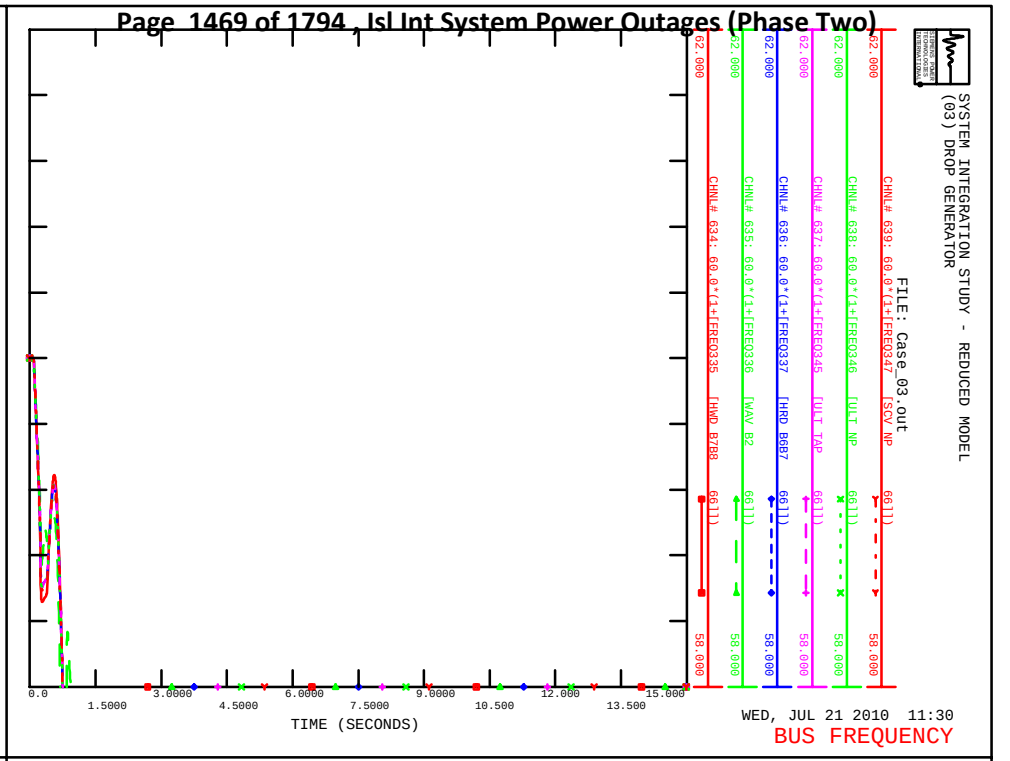

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 433: [SPD468 [TCV GEN 6.90] [1]]
CHNL# 434: [SPD468 [TCV GEN 6.90] [2]]
CHNL# 435: [SPD468 [TCV GEN 6.90] [3]]
CHNL# 436: [SPD473 [ROP G1 6.90] [1]]
CHNL# 437: [SPD478 [PHR GEN 2.30] [1]]
CHNL# 438: [SPD478 [PHR GEN 2.30] [2]]
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

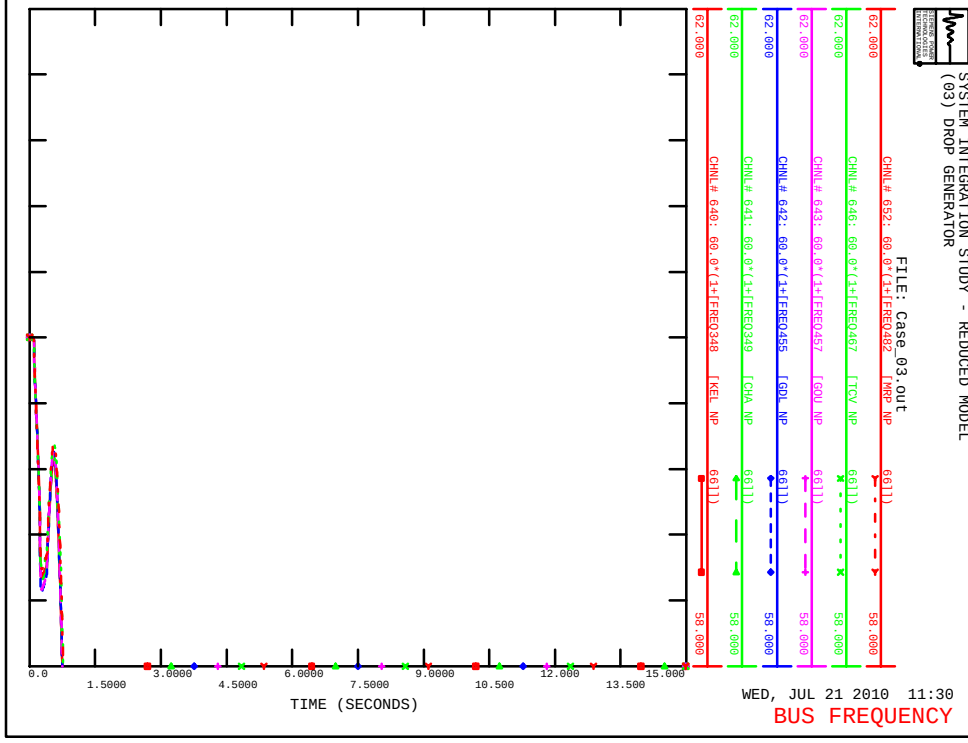

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 439: [SPD478 [PHR GEN 2.30] [3]]
CHNL# 440: [SPD483 [MRP G1 2.40] [1]]
CHNL# 441: [SPD486 [HCP G1 6.90] [1]]
CHNL# 442: [SPD488 [CAB G1 6.90] [1]]
CHNL# 443: [SPD871 [SLK G1 13.80] [1]]
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

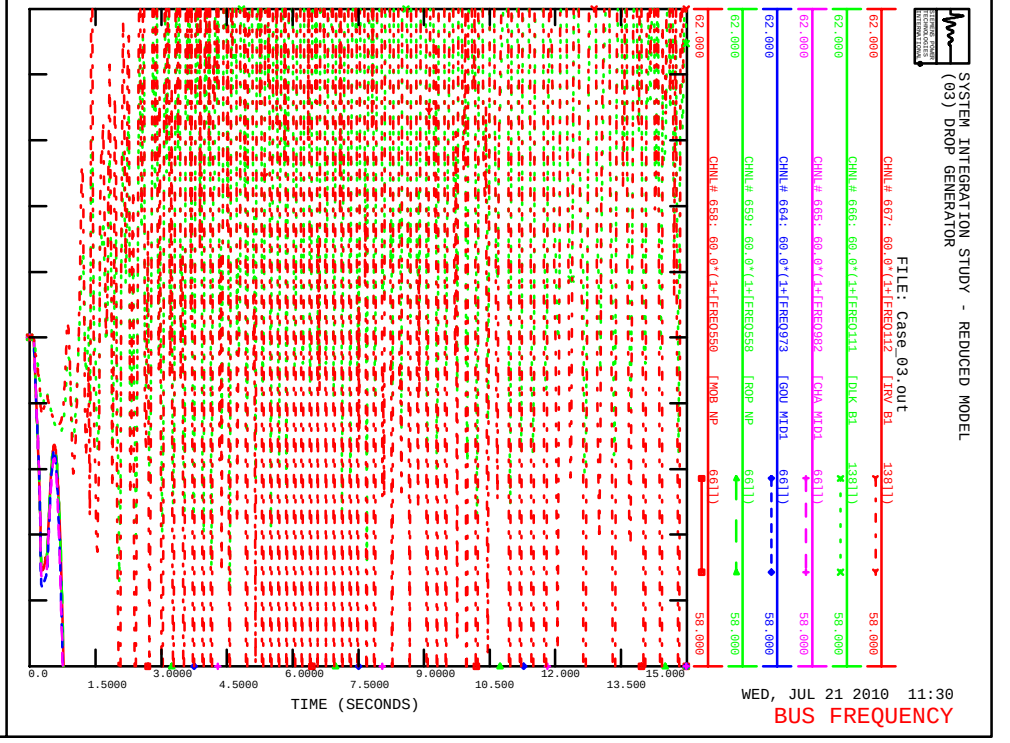

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 444: [SPD2101 [CHF A1 15.00] [1]]
CHNL# 445: [SPD2102 [CHF A2-A 15.00] [2]]
CHNL# 446: [SPD2115 [MUSK G1- 15.00] [1]]
CHNL# 447: [SPD2121 [GUL G1 15.00] [1]]
CHNL# 448: [SPD2122 [GUL G2 15.00] [2]]
CHNL# 449: [SPD2137 [HVY G1 13.80] [1]]
0.05000
-0.0500
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
LABRADOR MACHINE SPEED

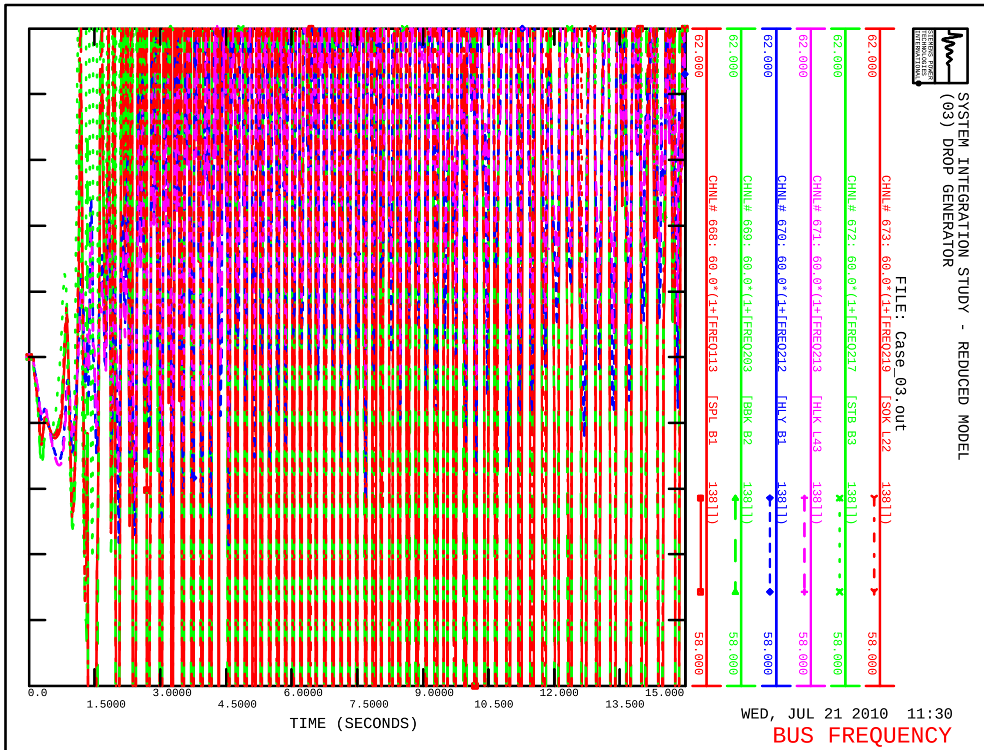

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 458: [SPD2494 [SOL SC1 13.80] [1]]
CHNL# 459: [SPD2495 [SOL SC2 13.80] [2]]
CHNL# 460: [SPD2496 [SOL SC3 13.80] [3]]
0.05000
-0.0500
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

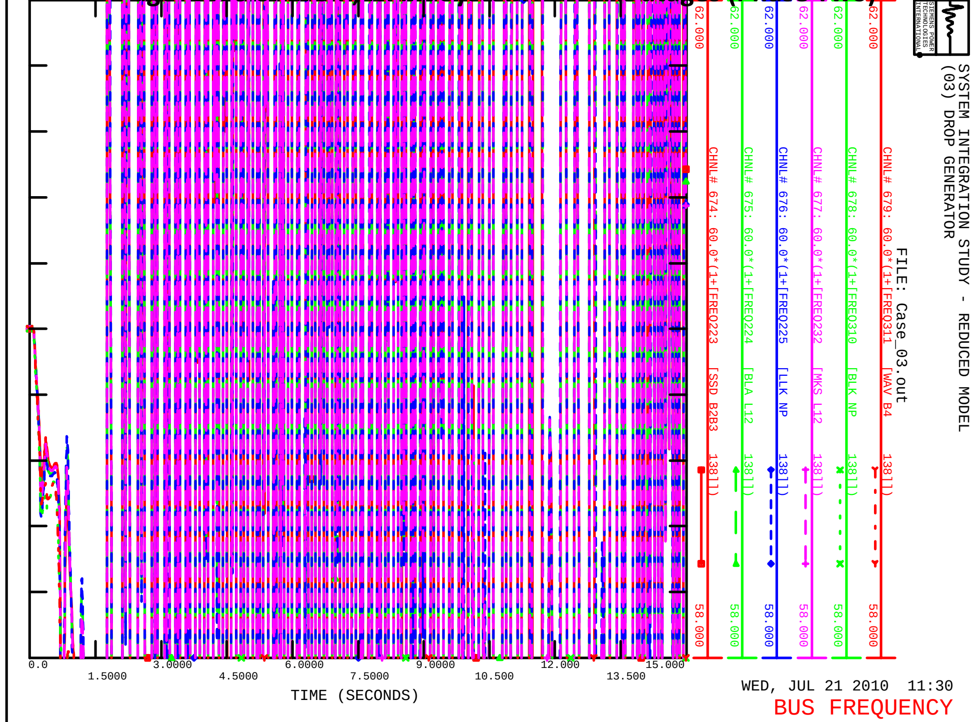

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 628: 60.0*(1+FREQ0153 [DPD L64 6611)
CHNL# 629: 60.0*(1+FREQ0204 [SVL B2 6611)
CHNL# 630: 60.0*(1+FREQ0308 [BLK NPT3 6611)
CHNL# 631: 60.0*(1+FREQ0309 [BRB T2T3 6611)
CHNL# 632: 60.0*(1+FREQ0319 [DLK NP 6611)
CHNL# 633: 60.0*(1+FREQ0334 [DPD B2B5 6611)
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

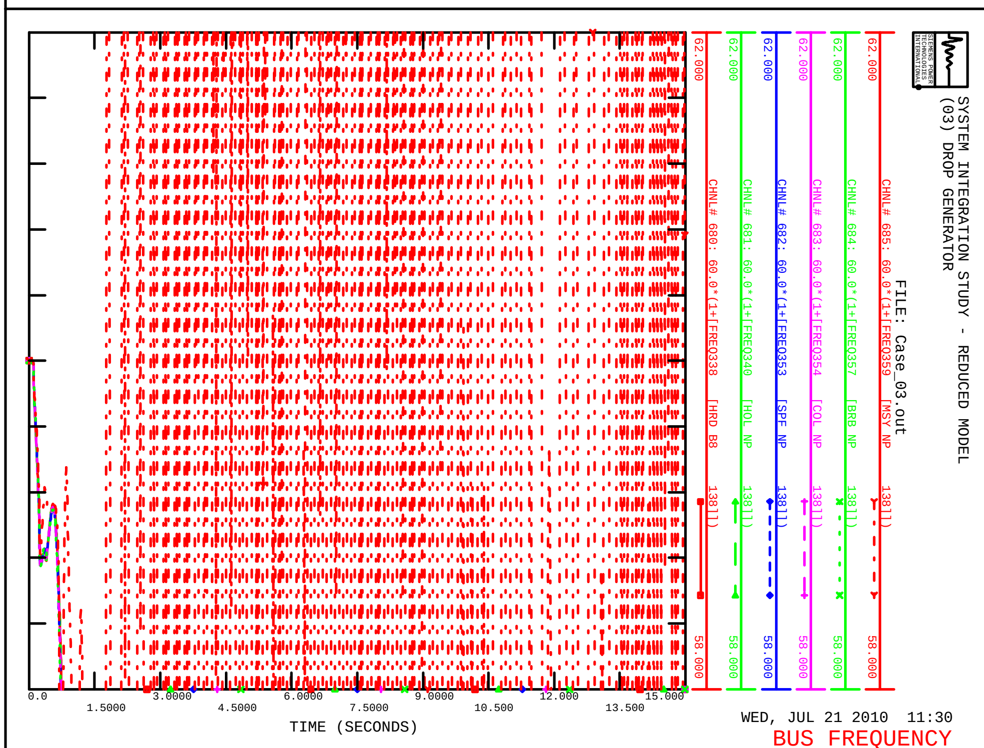

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 634: 60.0*(1+FREQ0335 [RND B7B8 6611)
CHNL# 635: 60.0*(1+FREQ0336 [WAV B2 6611)
CHNL# 636: 60.0*(1+FREQ0337 [HRD B6B7 6611)
CHNL# 637: 60.0*(1+FREQ0345 [ULT TAP 6611)
CHNL# 638: 60.0*(1+FREQ0346 [ULT NP 6611)
CHNL# 639: 60.0*(1+FREQ0347 [SCV NP 6611)
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

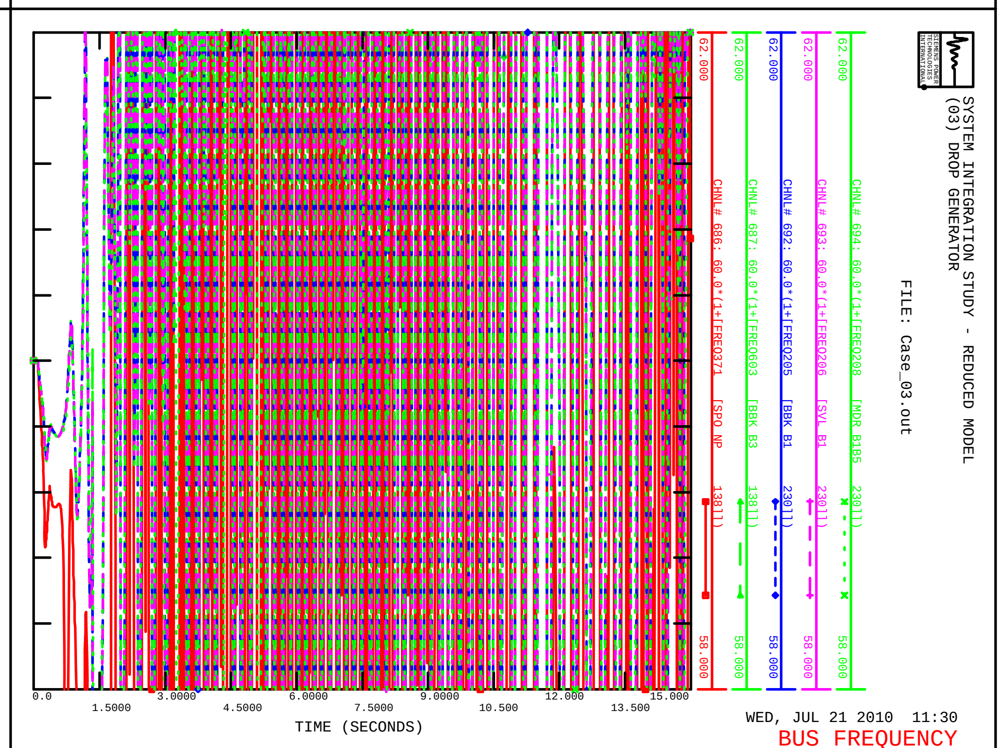

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 640: 60.0*(1+FREQ0348 [KEL NP 6611)
CHNL# 641: 60.0*(1+FREQ0349 [CHA NP 6611)
CHNL# 642: 60.0*(1+FREQ0455 [GDL NP 6611)
CHNL# 643: 60.0*(1+FREQ0457 [GOU NP 6611)
CHNL# 646: 60.0*(1+FREQ0467 [TCV NP 6611)
CHNL# 652: 60.0*(1+FREQ0482 [MRP NP 6611)
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

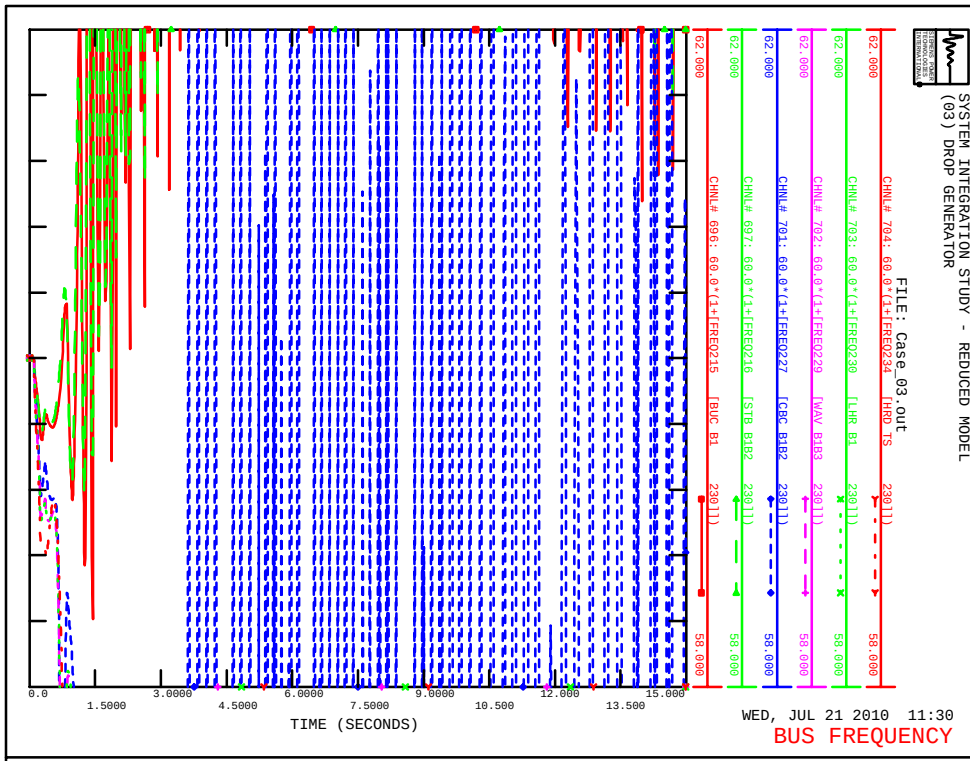

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 658: 60.0*(1+FREQ0550 [MOB NP 6611)
CHNL# 659: 60.0*(1+FREQ0558 [ROP NP 6611)
CHNL# 664: 60.0*(1+FREQ0973 [GOU MID1 6611)
CHNL# 665: 60.0*(1+FREQ0982 [CHA MID1 6611)
CHNL# 666: 60.0*(1+FREQ0111 [DLK B1 13811)
CHNL# 667: 60.0*(1+FREQ0112 [TRY B1 13811)
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

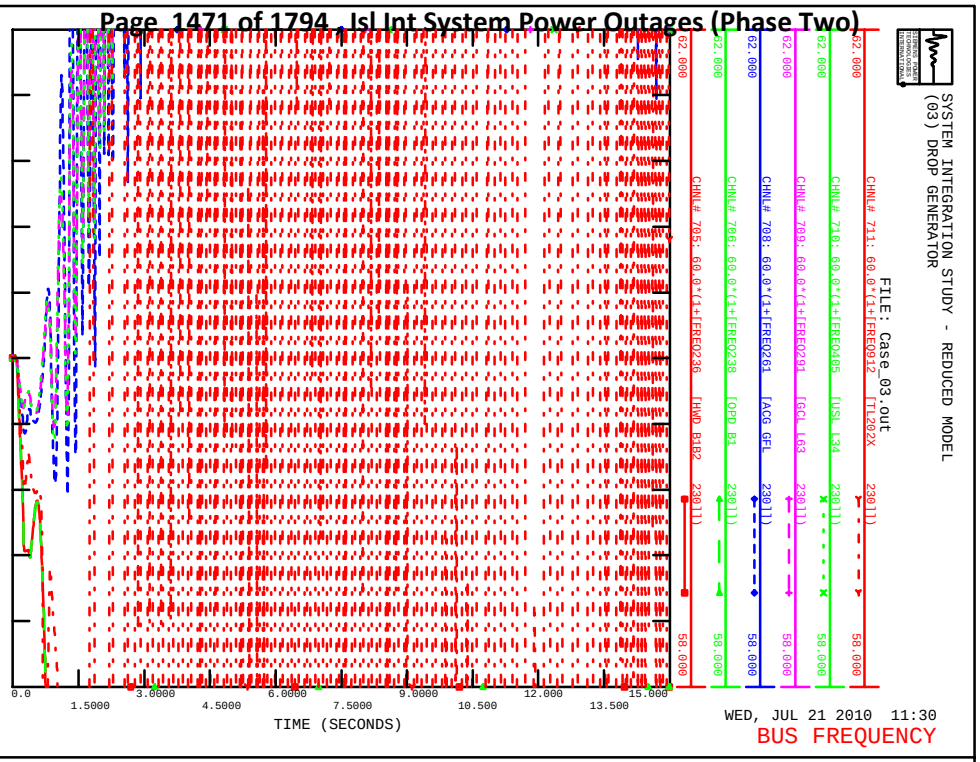

SIEMENS POWER TECHNOLOGIES INTERNATIONAL
SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 668: 60.0*(1+[FREQ113 [SPL B1 138]])
CHNL# 669: 60.0*(1+[FREQ203 [BBK B2 138]])
CHNL# 670: 60.0*(1+[FREQ212 [HLY B1 138]])
CHNL# 671: 60.0*(1+[FREQ213 [HLK L43 138]])
CHNL# 672: 60.0*(1+[FREQ217 [STB B3 138]])
CHNL# 673: 60.0*(1+[FREQ219 [SOK L22 138]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

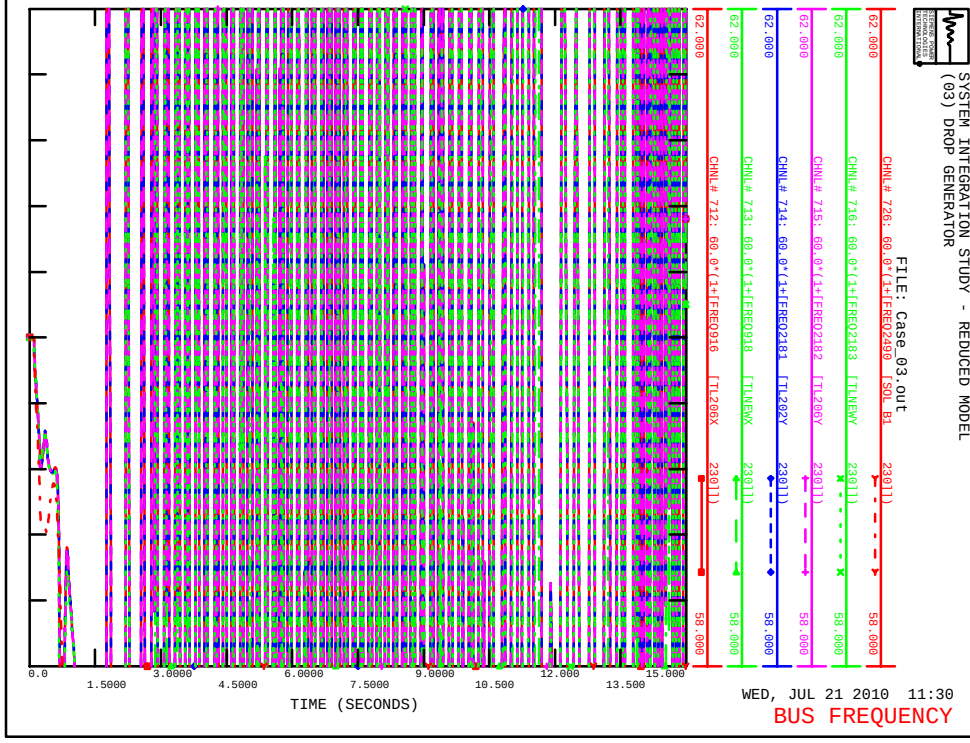

SIEMENS POWER TECHNOLOGIES INTERNATIONAL
SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 674: 60.0*(1+[FREQ223 [SSD B2B3 138]])
CHNL# 675: 60.0*(1+[FREQ224 [BLA L12 138]])
CHNL# 676: 60.0*(1+[FREQ225 [LLK NP 138]])
CHNL# 677: 60.0*(1+[FREQ232 [MKS L12 138]])
CHNL# 678: 60.0*(1+[FREQ310 [BLK NP 138]])
CHNL# 679: 60.0*(1+[FREQ311 [WAV B4 138]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

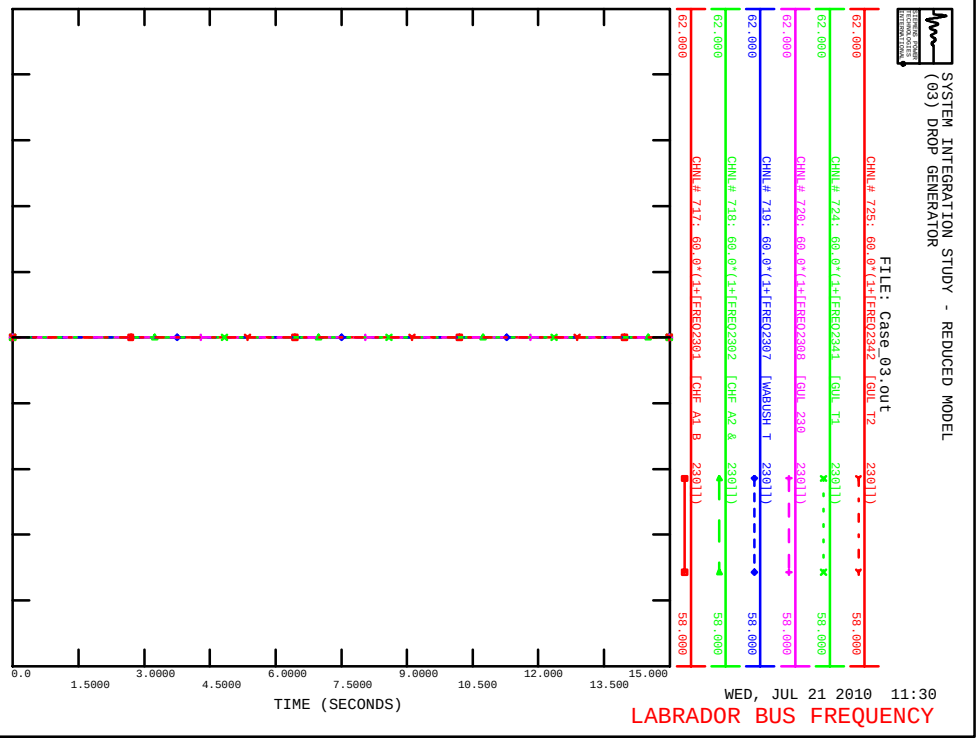

SIEMENS POWER TECHNOLOGIES INTERNATIONAL
SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 680: 60.0*(1+[FREQ338 [HRD B8 138]])
CHNL# 681: 60.0*(1+[FREQ340 [HOL NP 138]])
CHNL# 682: 60.0*(1+[FREQ353 [SPF NP 138]])
CHNL# 683: 60.0*(1+[FREQ354 [COL NP 138]])
CHNL# 684: 60.0*(1+[FREQ357 [BRB NP 138]])
CHNL# 685: 60.0*(1+[FREQ359 [MSY NP 138]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

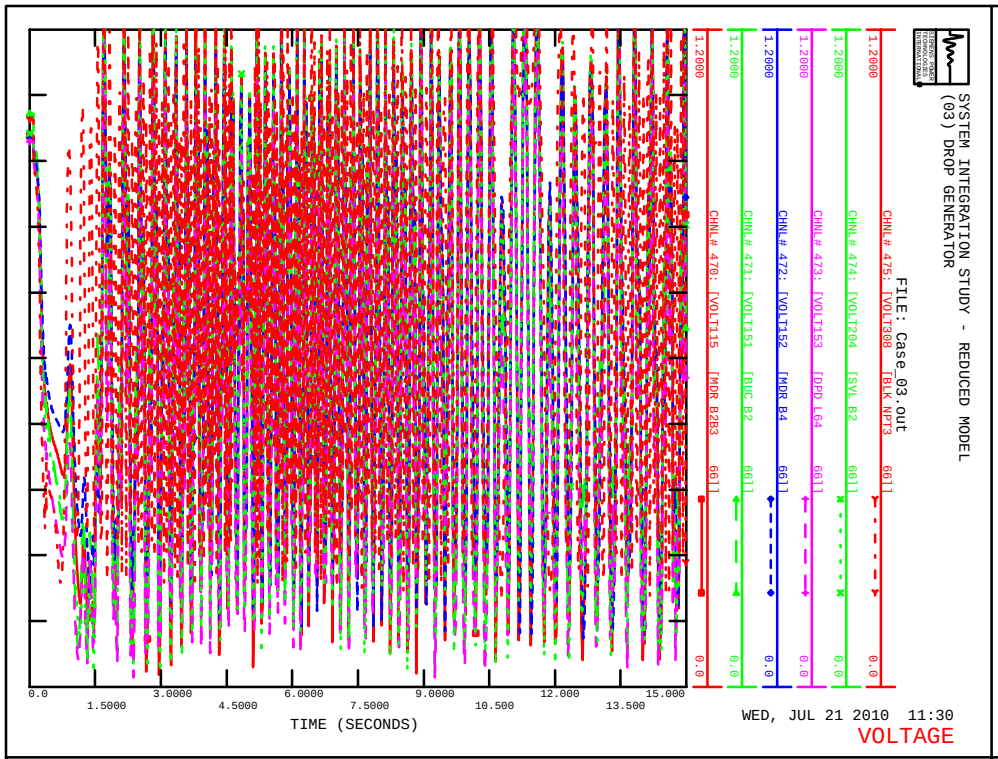

SIEMENS POWER TECHNOLOGIES INTERNATIONAL
SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 686: 60.0*(1+[FREQ371 [SPO NP 138]])
CHNL# 687: 60.0*(1+[FREQ603 [BBK B3 138]])
CHNL# 692: 60.0*(1+[FREQ205 [BBK B1 230]])
CHNL# 693: 60.0*(1+[FREQ206 [SVL B1 230]])
CHNL# 694: 60.0*(1+[FREQ208 [MDR B1B5 230]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

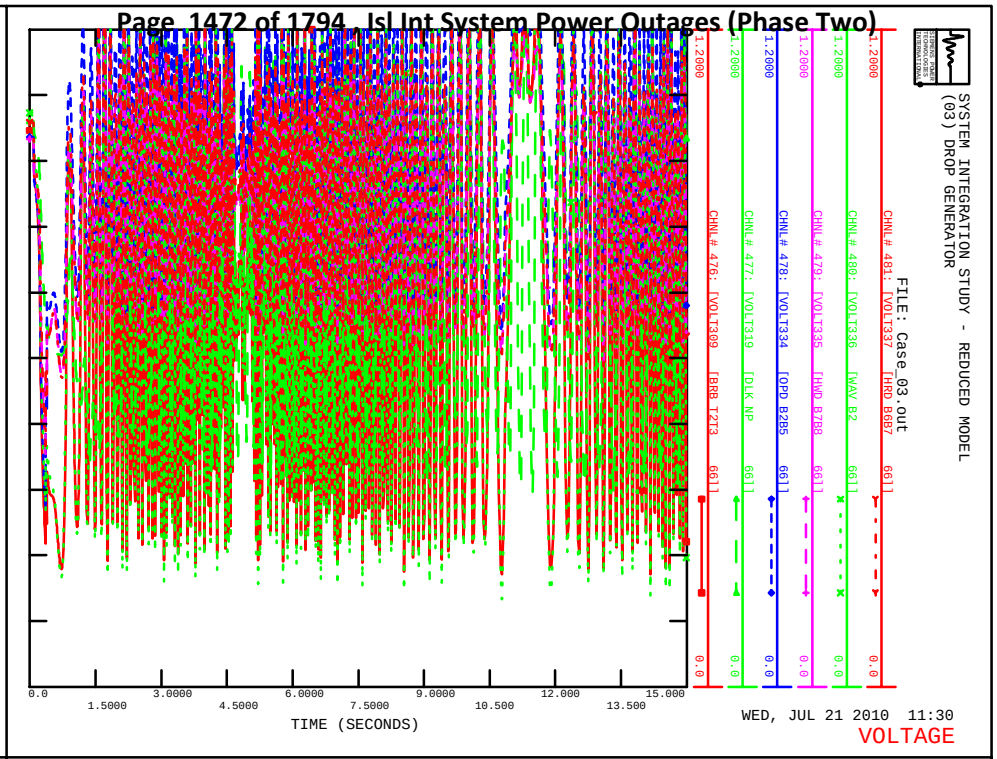

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 696: 60.0*(1+FREQ0215 [BUC B1 230])
CHNL# 697: 60.0*(1+FREQ0216 [STB B1B2 230])
CHNL# 701: 60.0*(1+FREQ0227 [CBC B1B2 230])
CHNL# 702: 60.0*(1+FREQ0229 [WAV B1B3 230])
CHNL# 703: 60.0*(1+FREQ0230 [LHR B1 230])
CHNL# 704: 60.0*(1+FREQ0234 [HRD TS 230])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

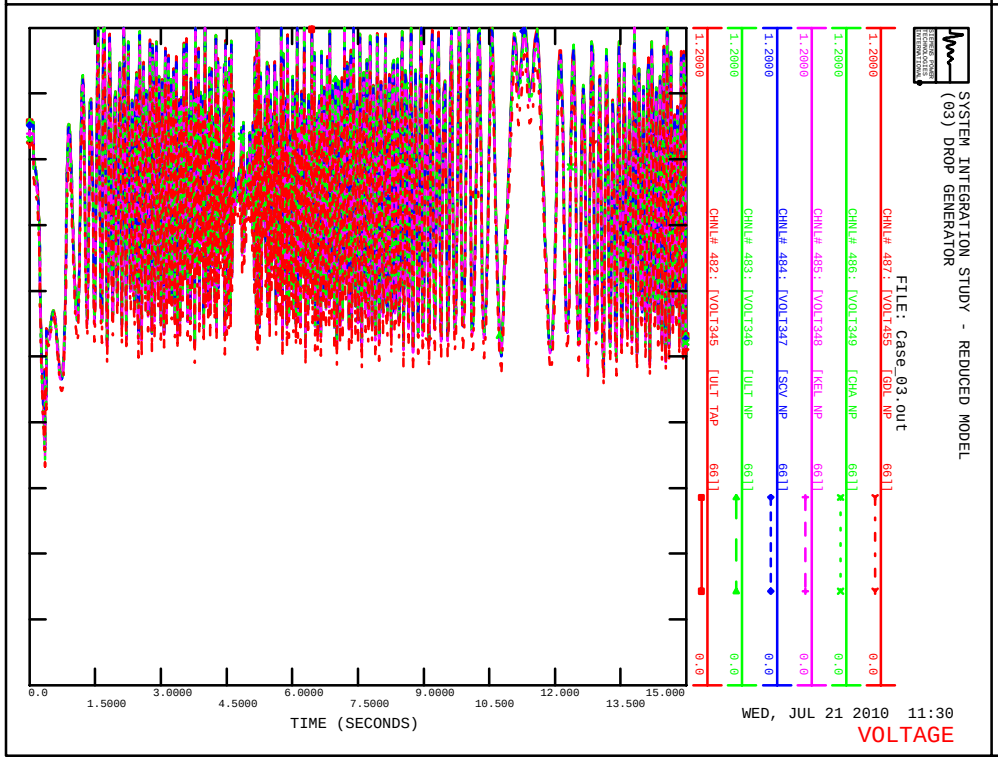

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 705: 60.0*(1+FREQ0236 [HWD B1B2 230])
CHNL# 706: 60.0*(1+FREQ0238 [OPD B1 230])
CHNL# 708: 60.0*(1+FREQ0261 [ACG GFL 230])
CHNL# 709: 60.0*(1+FREQ0291 [GCL L63 230])
CHNL# 710: 60.0*(1+FREQ0405 [USL L34 230])
CHNL# 711: 60.0*(1+FREQ0312 [TL202X 230])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

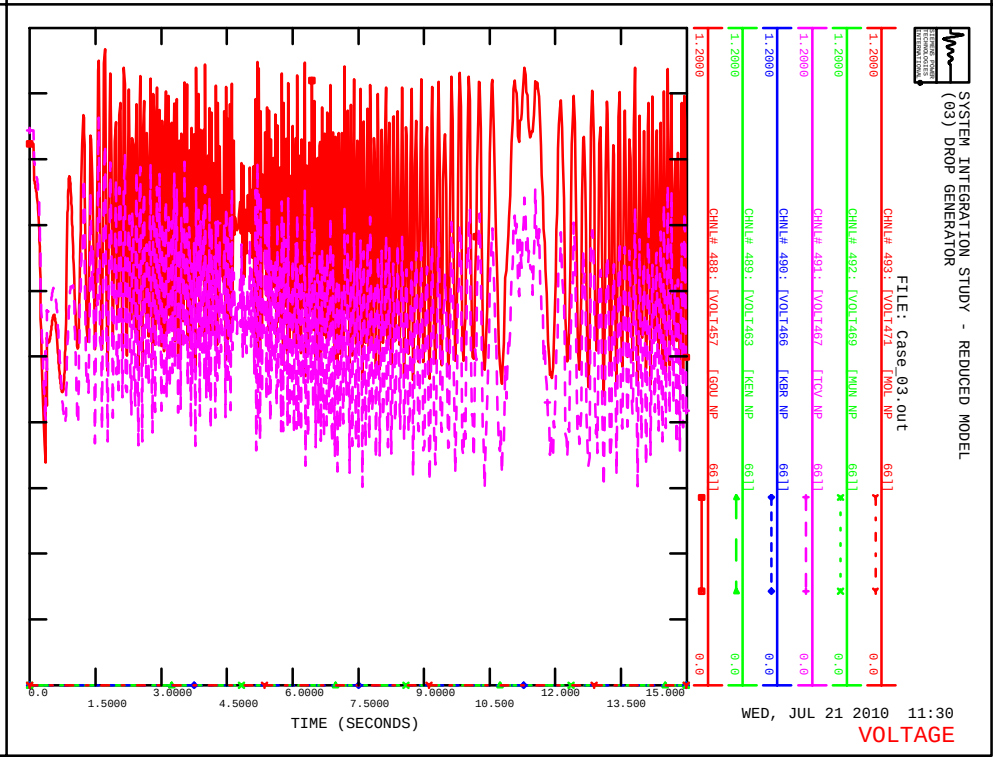

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 712: 60.0*(1+FREQ0916 [TL206X 230])
CHNL# 713: 60.0*(1+FREQ0918 [TLNEWX 230])
CHNL# 714: 60.0*(1+FREQ2181 [TL202Y 230])
CHNL# 715: 60.0*(1+FREQ2182 [TL206Y 230])
CHNL# 716: 60.0*(1+FREQ2183 [TLNEWY 230])
CHNL# 726: 60.0*(1+FREQ2299 [SOL B1 230])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

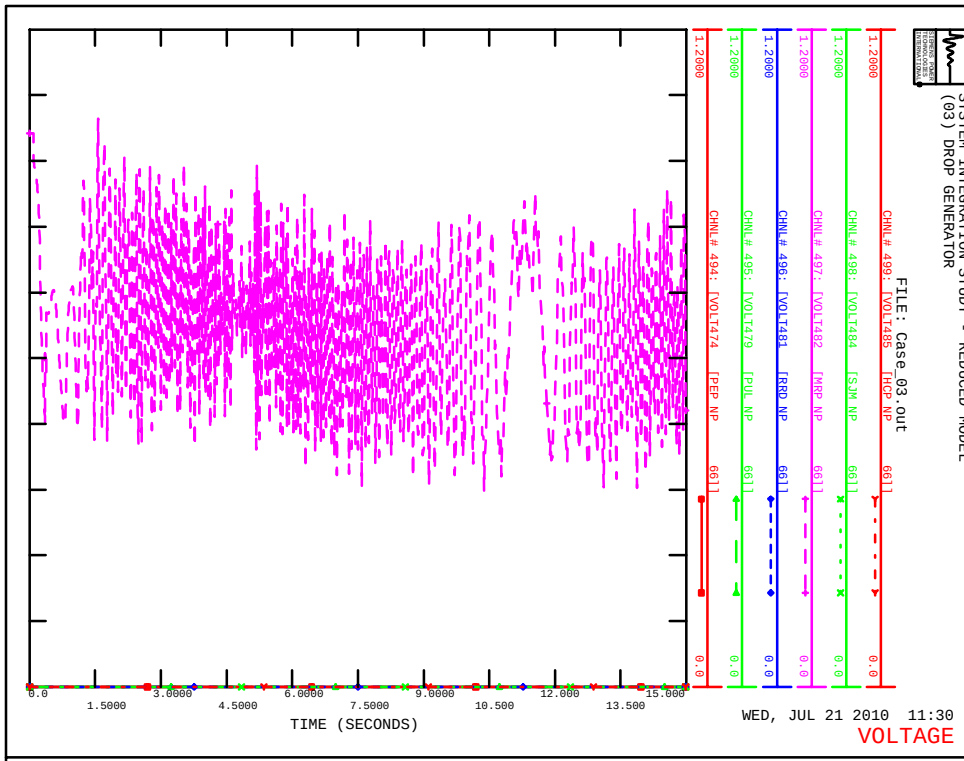

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 717: 60.0*(1+FREQ2301 [CHF A1 B 230])
CHNL# 718: 60.0*(1+FREQ2302 [CHF A2 & 230])
CHNL# 719: 60.0*(1+FREQ2307 [WABUSH T 230])
CHNL# 720: 60.0*(1+FREQ2308 [GUL 230 230])
CHNL# 724: 60.0*(1+FREQ2341 [GUL T1 230])
CHNL# 725: 60.0*(1+FREQ2342 [GUL T2 230])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
LABRADOR BUS FREQUENCY

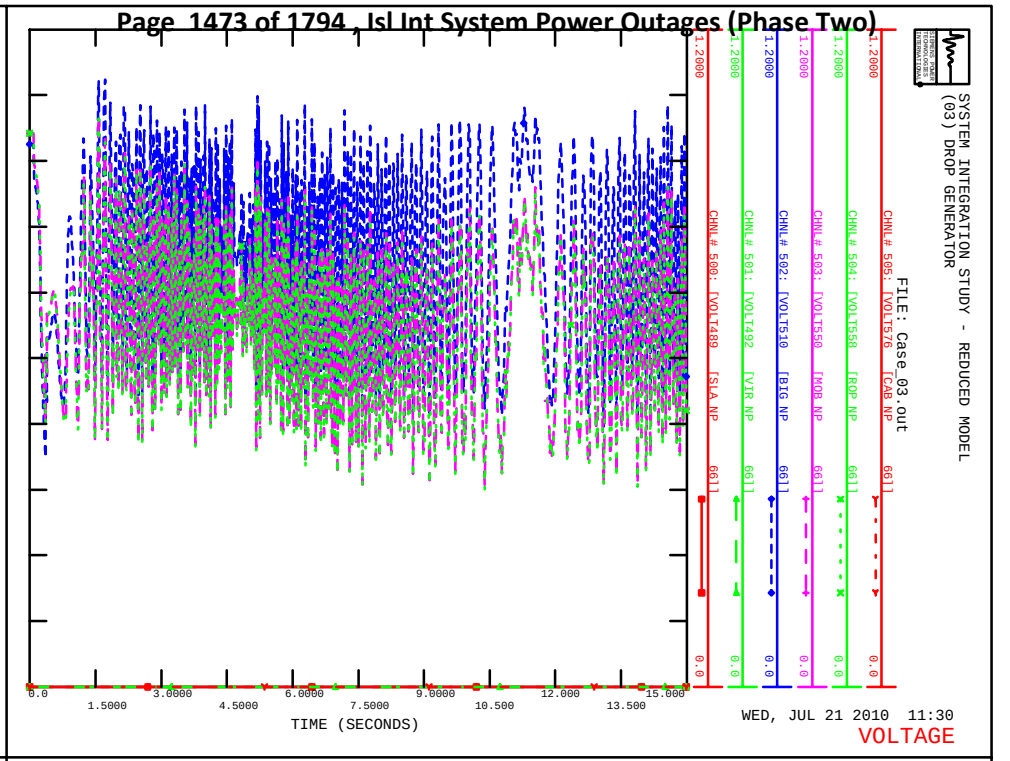

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 470: [VOLT115 [MOR B2B3 661]
CHNL# 471: [VOLT151 [BUC B2 661]
CHNL# 472: [VOLT152 [MOR B4 661]
CHNL# 473: [VOLT153 [OPD L64 661]
CHNL# 474: [VOLT204 [SVL B2 661]
CHNL# 475: [VOLT308 [BLK NPT3 661]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

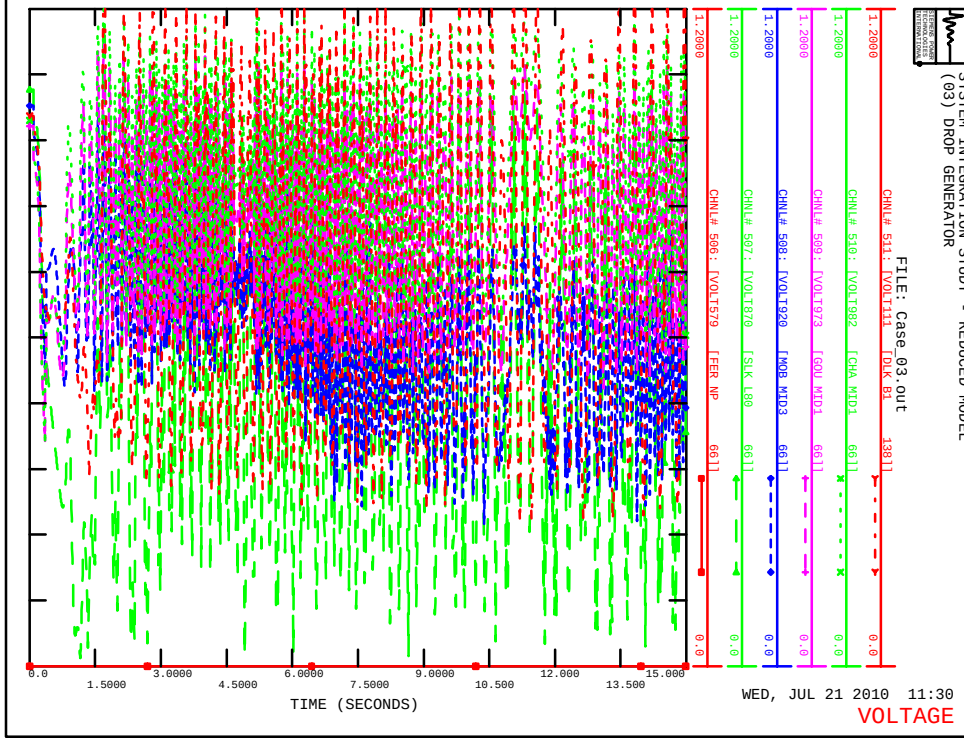

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 476: [VOLT309 [BBB T2T3 661]
CHNL# 478: [VOLT334 [OPD B2B5 661]
CHNL# 479: [VOLT335 [HWD B7B8 661]
CHNL# 480: [VOLT336 [WAV B2 661]
CHNL# 481: [VOLT337 [HRD B6B7 661]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

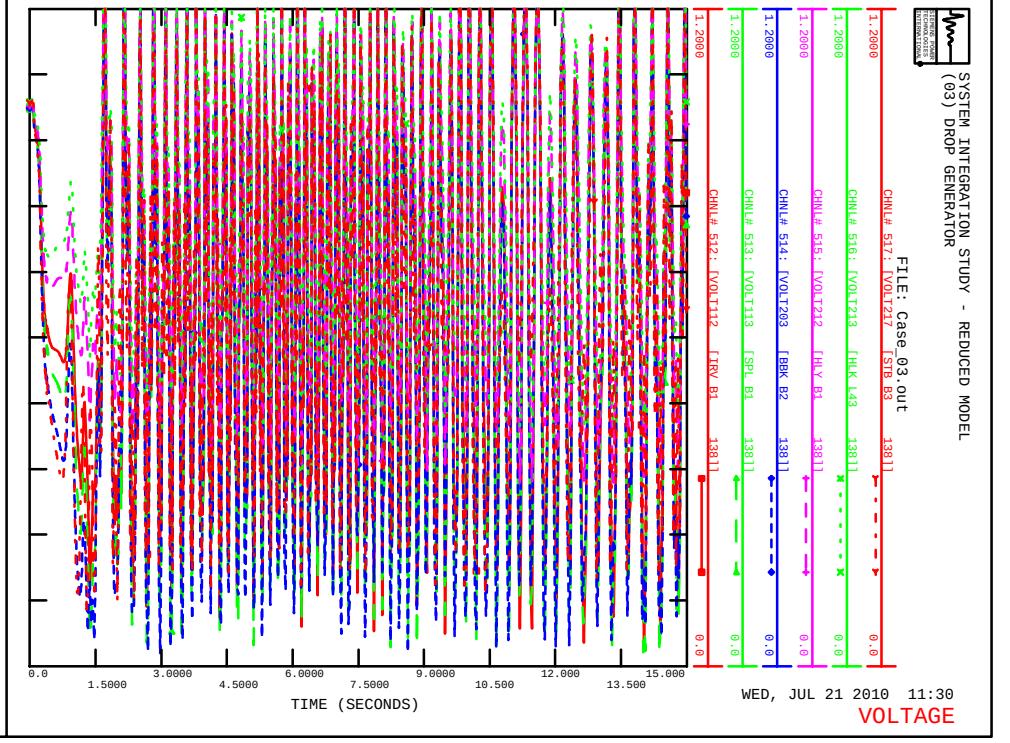

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 482: [VOLT345 [ULT TAP 661]
CHNL# 483: [VOLT346 [ULT NP 661]
CHNL# 484: [VOLT347 [SCV NP 661]
CHNL# 485: [VOLT348 [KEL NP 661]
CHNL# 486: [VOLT349 [CHA NP 661]
CHNL# 487: [VOLT455 [GDL NP 661]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

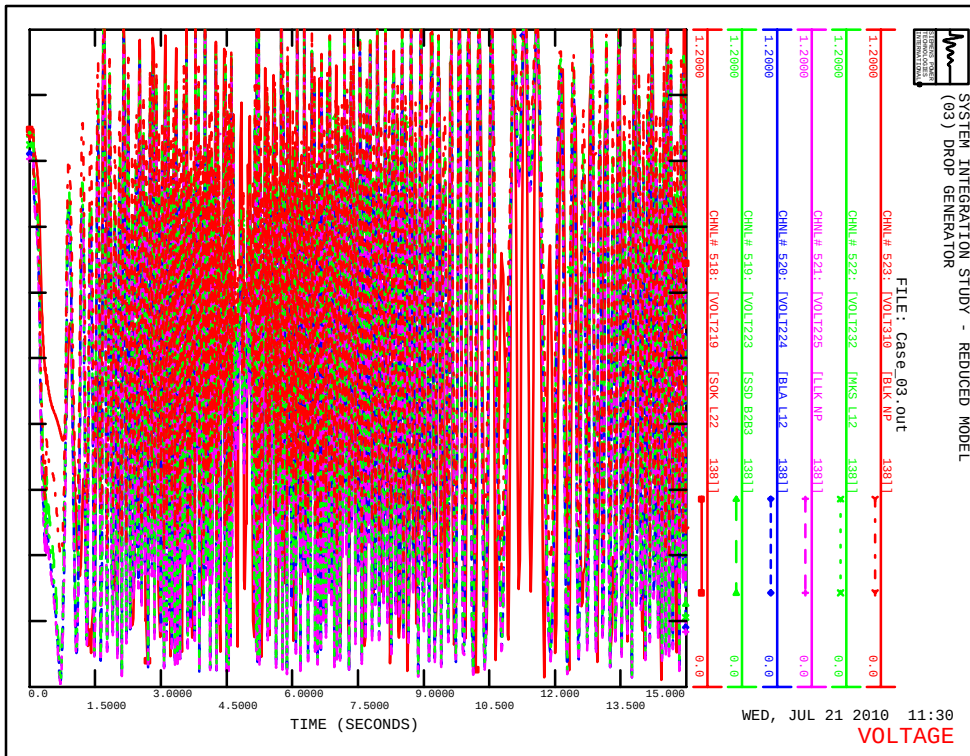

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 488: [VOLT457 [GOU NP 661]
CHNL# 489: [VOLT463 [KEN NP 661]
CHNL# 490: [VOLT466 [KBR NP 661]
CHNL# 491: [VOLT467 [TCV NP 661]
CHNL# 492: [VOLT469 [MUN NP 661]
CHNL# 493: [VOLT471 [MOL NP 661]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

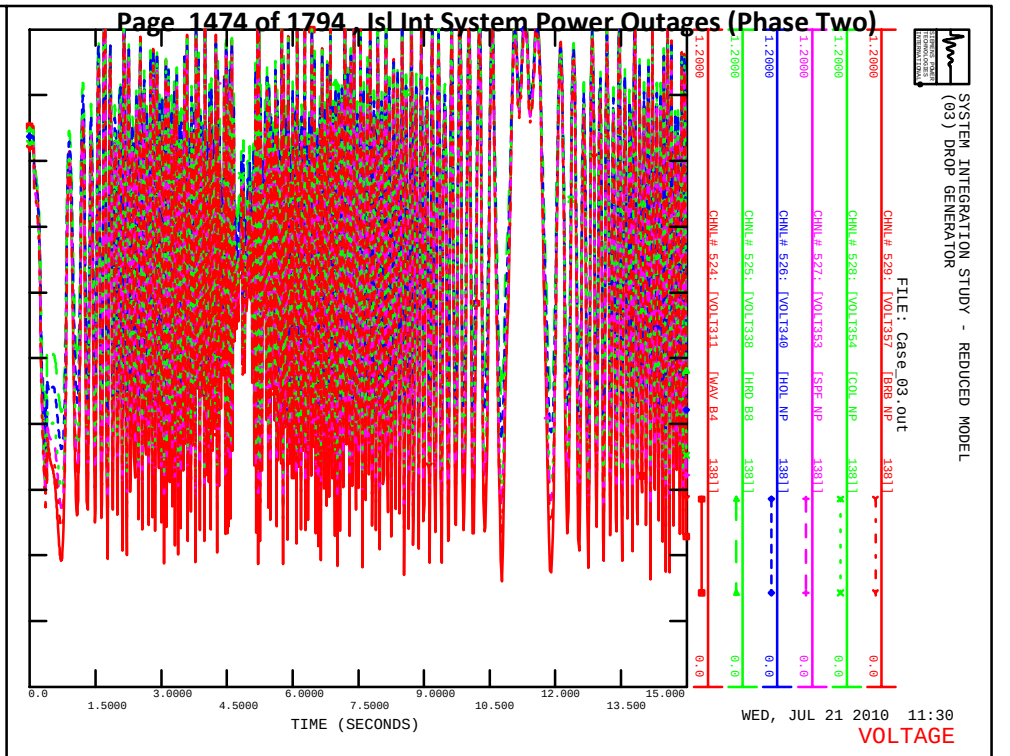

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 494: [VOLT474 [PEP NP 661]
CHNL# 495: [VOLT479 [PUL NP 661]
CHNL# 496: [VOLT481 [RRD NP 661]
CHNL# 497: [VOLT482 [MPP NP 661]
CHNL# 498: [VOLT484 [SJM NP 661]
CHNL# 499: [VOLT485 [HCP NP 661]
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

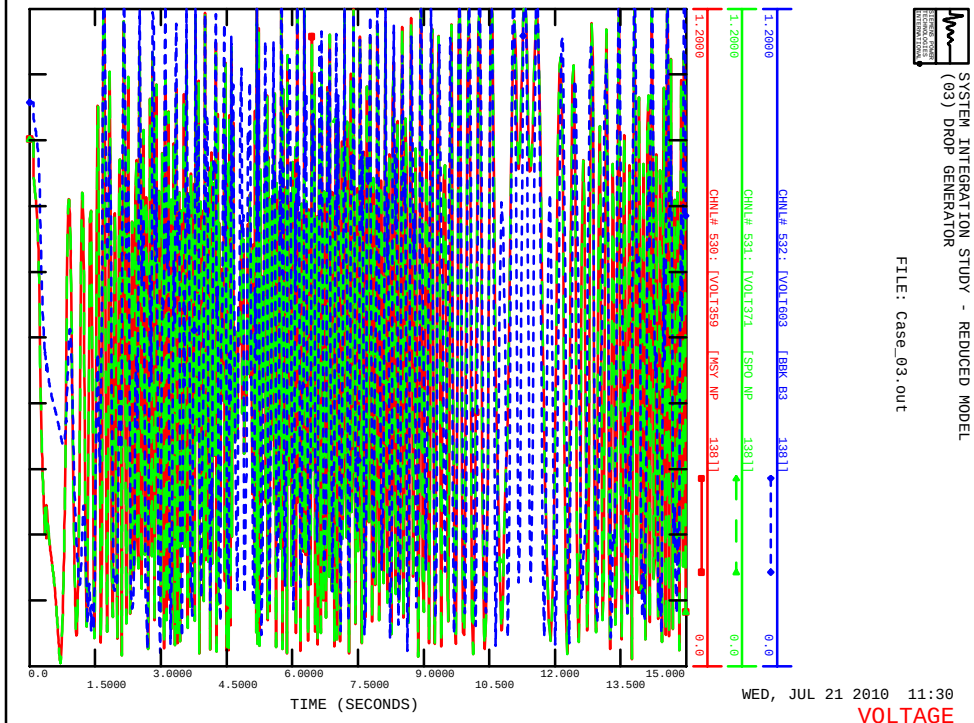

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 500: [VOLT489 [SLA NP 661]
CHNL# 501: [VOLT492 [VIR NP 661]
CHNL# 502: [VOLT510 [BIG NP 661]
CHNL# 503: [VOLT550 [MOB NP 661]
CHNL# 504: [VOLT558 [ROP NP 661]
CHNL# 505: [VOLT576 [CAB NP 661]
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

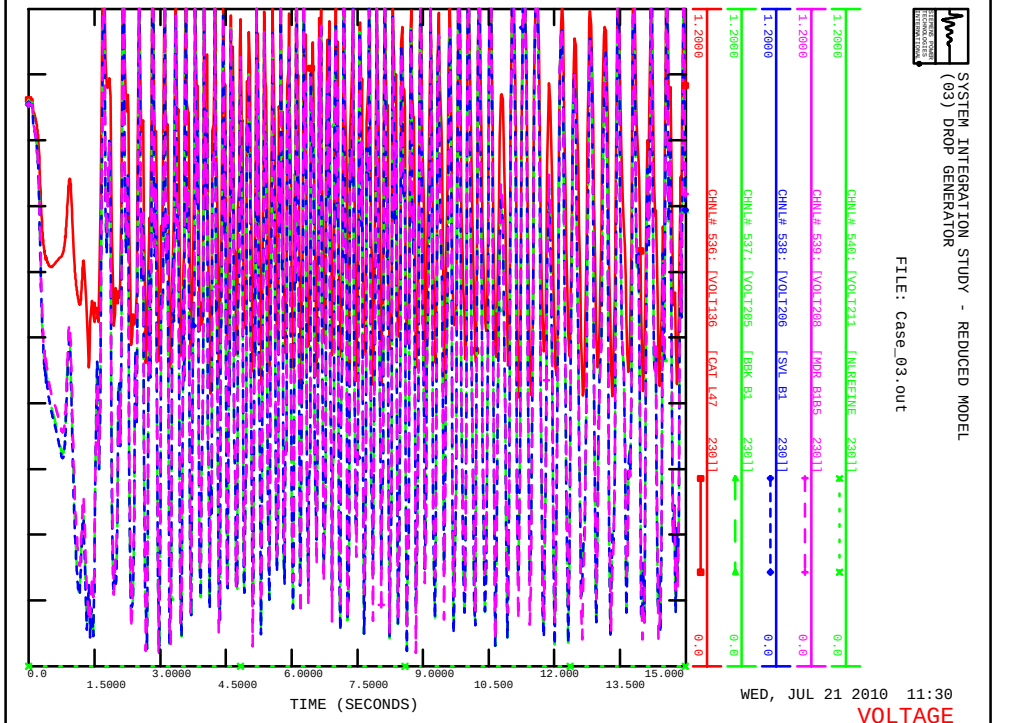

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 506: [VOLT579 [FER NP 661]
CHNL# 507: [VOLT870 [SLK L80 661]
CHNL# 508: [VOLT920 [MOB MID3 661]
CHNL# 509: [VOLT973 [GOU MID1 661]
CHNL# 510: [VOLT982 [CHA MID1 661]
CHNL# 511: [VOLT111 [DLK B1 1381]
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

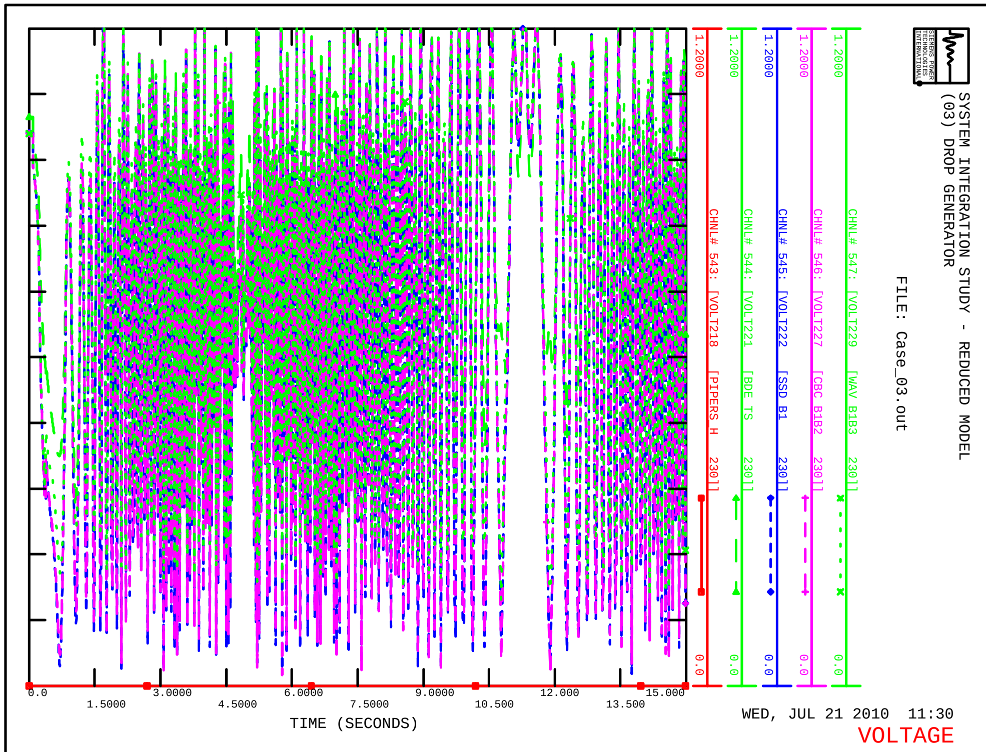

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 512: [VOLT112 [IRV B1 1381]
CHNL# 513: [VOLT113 [SPL B1 1381]
CHNL# 514: [VOLT203 [BBK B2 1381]
CHNL# 515: [VOLT232 [HLY B1 1381]
CHNL# 516: [VOLT213 [HLK L43 1381]
CHNL# 517: [VOLT237 [STB B3 1381]
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

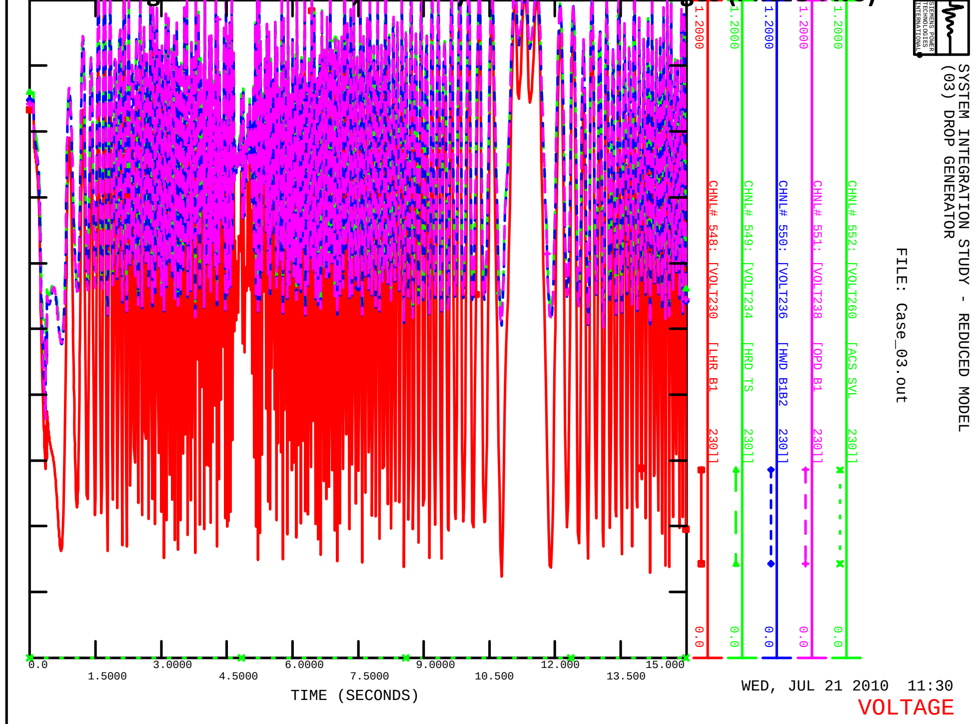

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 518: [VOLT219 [SOK L22 138]
CHNL# 519: [VOLT223 [SSD B2B3 138]
CHNL# 520: [VOLT224 [BLA L12 138]
CHNL# 521: [VOLT225 [LLK NP 138]
CHNL# 522: [VOLT232 [MKS L12 138]
CHNL# 523: [VOLT310 [BLK NP 138]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

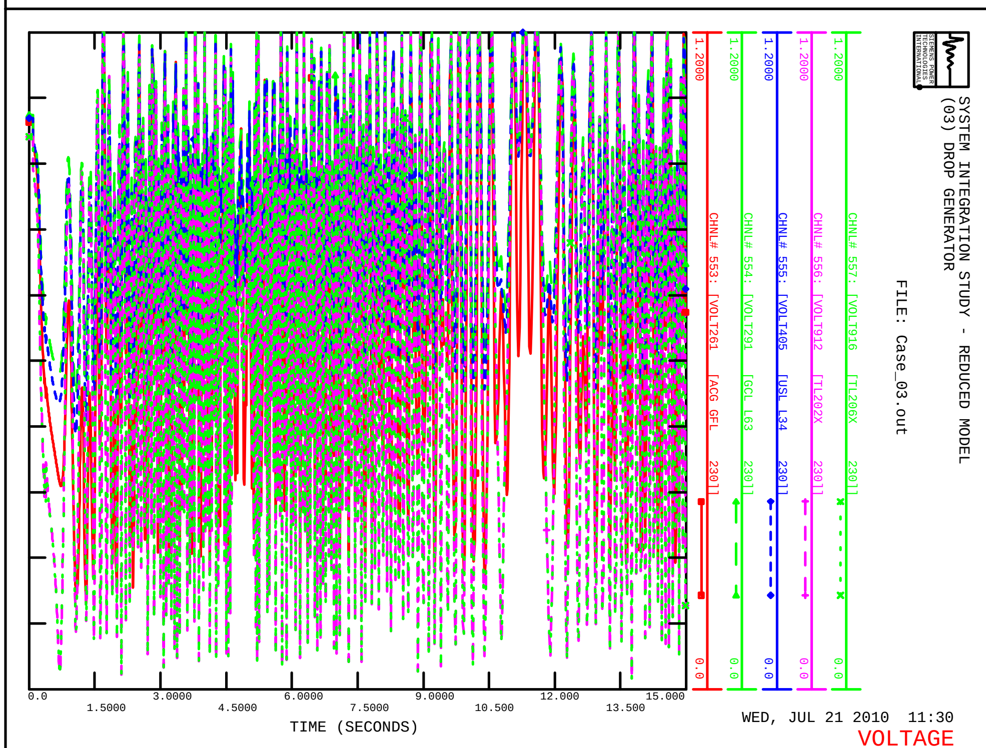

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 524: [VOLT311 [WAV B4 138]
CHNL# 525: [VOLT338 [HRD B8 138]
CHNL# 526: [VOLT340 [HOL NP 138]
CHNL# 527: [VOLT353 [SPF NP 138]
CHNL# 528: [VOLT354 [COL NP 138]
CHNL# 529: [VOLT357 [BRB NP 138]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

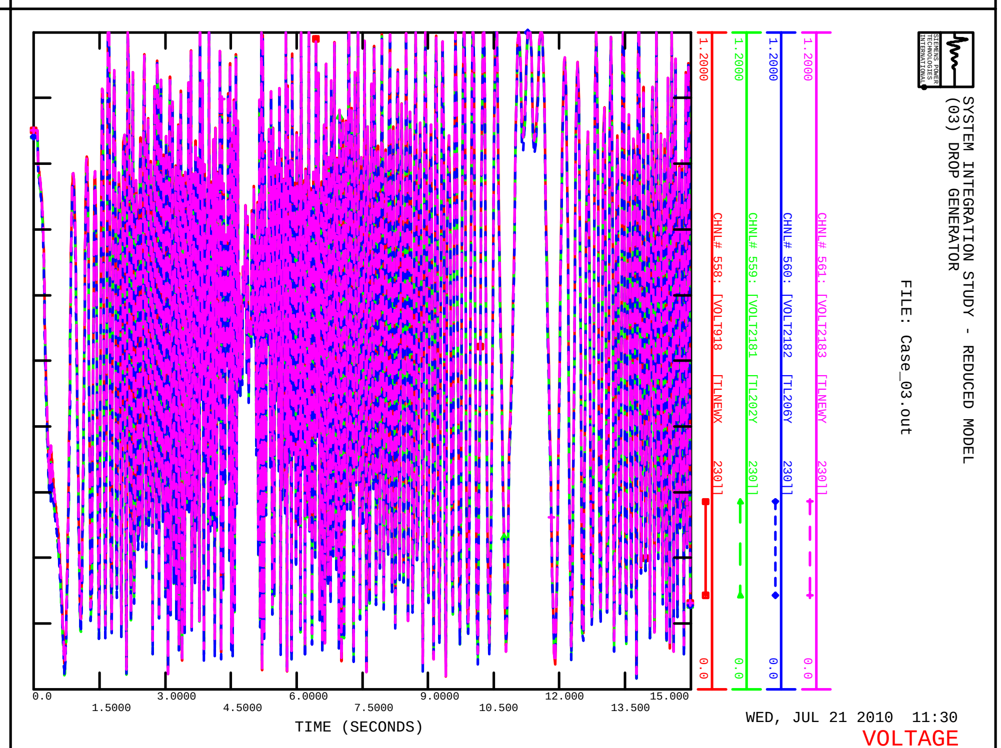

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 530: [VOLT359 [MSY NP 138]
CHNL# 531: [VOLT371 [SPO NP 138]
CHNL# 532: [VOLT603 [BBK B3 138]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

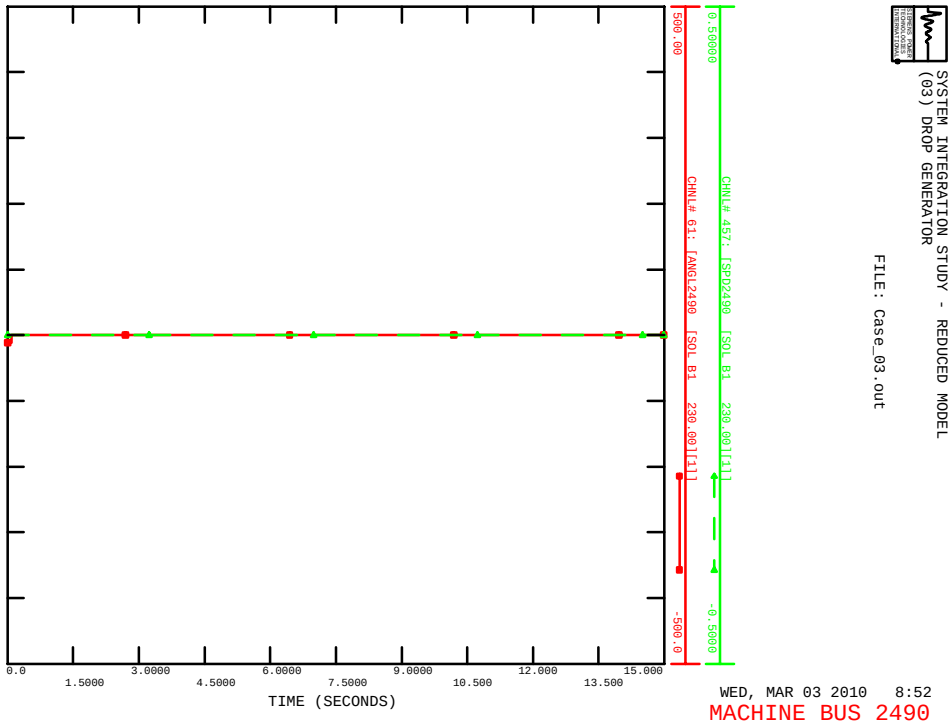

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 536: [VOLT136 [CAT L47 230]
CHNL# 537: [VOLT205 [BBK B1 230]
CHNL# 538: [VOLT206 [SVL B1 230]
CHNL# 539: [VOLT208 [MOR B1B5 230]
CHNL# 540: [VOLT211 [NLREFINE 230]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

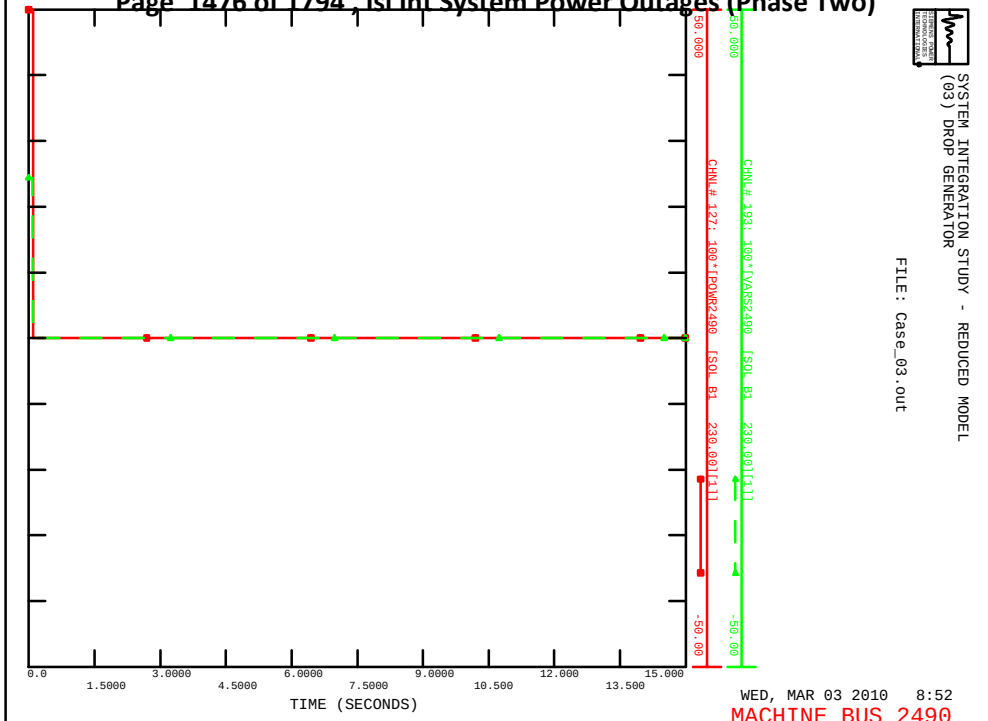

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 543: [VOLT218 [PIPERS H 230]]
CHNL# 544: [VOLT221 [BDE TS 230]]
CHNL# 545: [VOLT222 [SSD B1 230]]
CHNL# 546: [VOLT227 [CBC B1B2 230]]
CHNL# 547: [VOLT229 [WAV B1B3 230]]
1.2000
0.0
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

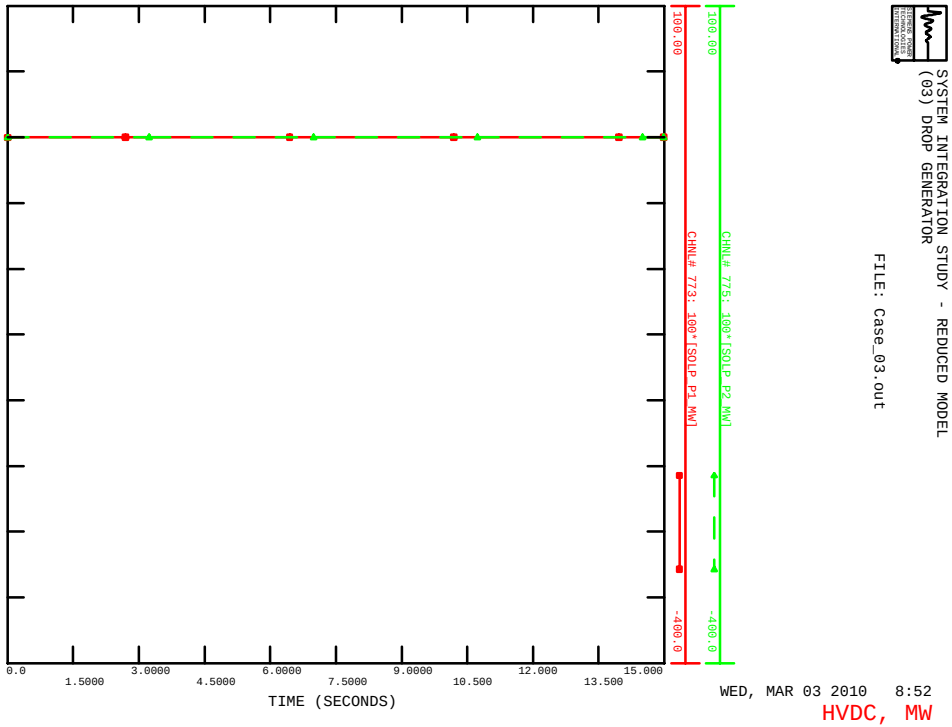

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 548: [VOLT230 [LHR B1 230]]
CHNL# 549: [VOLT234 [HRD TS 230]]
CHNL# 550: [VOLT236 [HWD B1B2 230]]
CHNL# 551: [VOLT238 [OPD B1 230]]
CHNL# 552: [VOLT260 [ACS SVL 230]]
1.2000
0.0
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

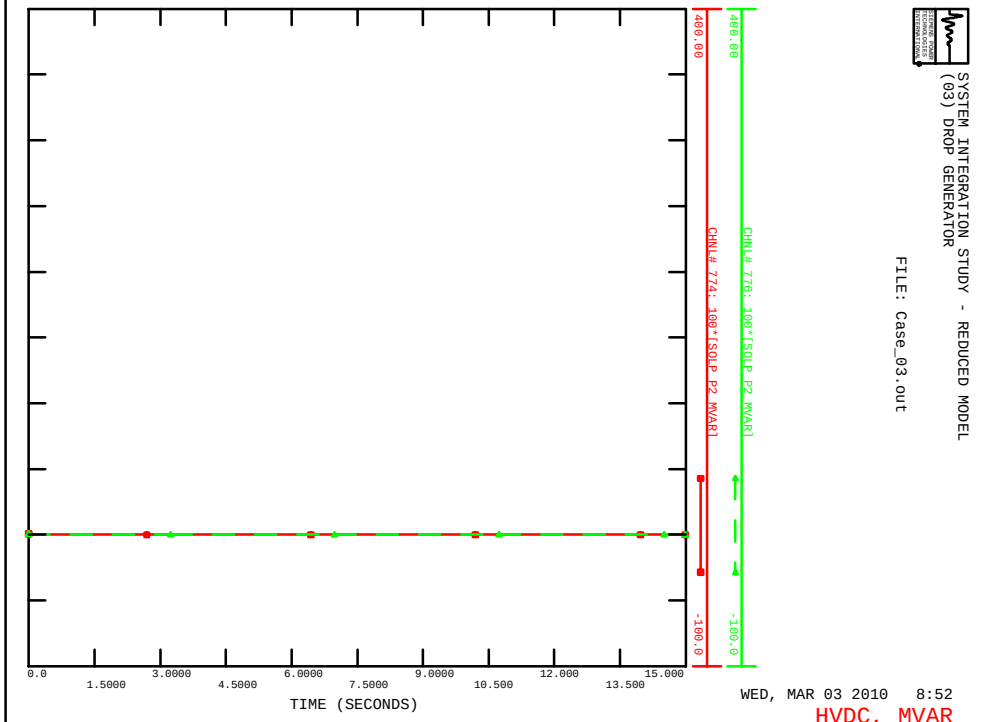

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 553: [VOLT261 [ACG GFL 230]]
CHNL# 554: [VOLT291 [GCL L63 230]]
CHNL# 555: [VOLT405 [USL L34 230]]
CHNL# 556: [VOLT912 [TL202X 230]]
CHNL# 557: [VOLT916 [TL206X 230]]
1.2000
0.0
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

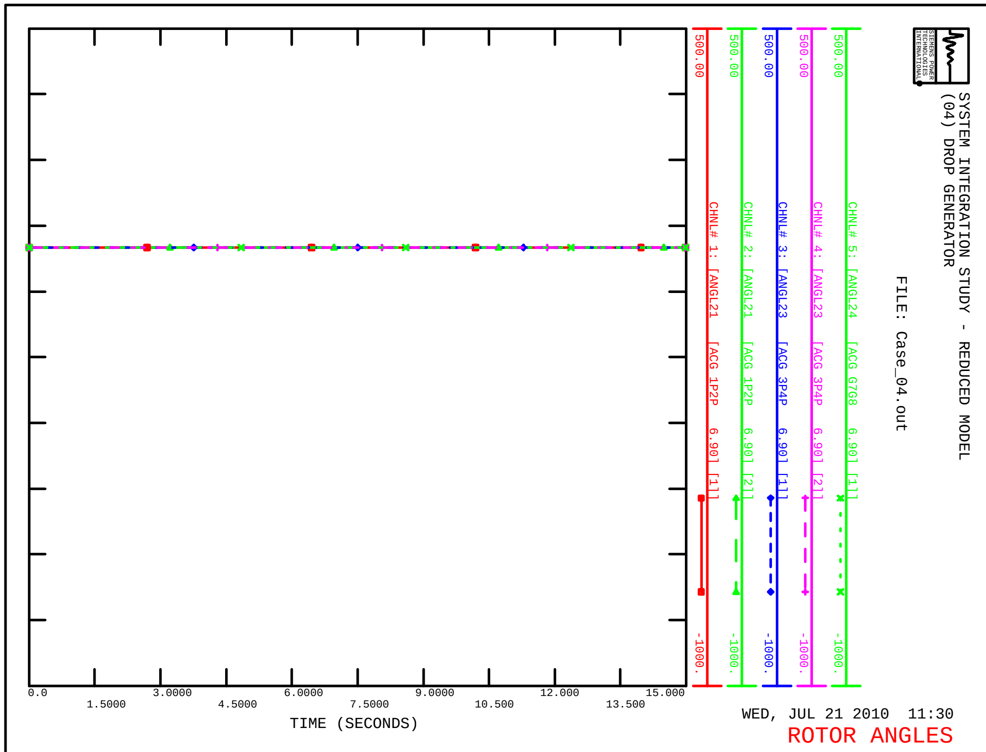

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
CHNL# 558: [VOLT918 [TLNEWX 230]]
CHNL# 559: [VOLT2181 [TL202Y 230]]
CHNL# 560: [VOLT2182 [TL206Y 230]]
CHNL# 561: [VOLT2183 [TLNEWY 230]]
1.2000
0.0
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

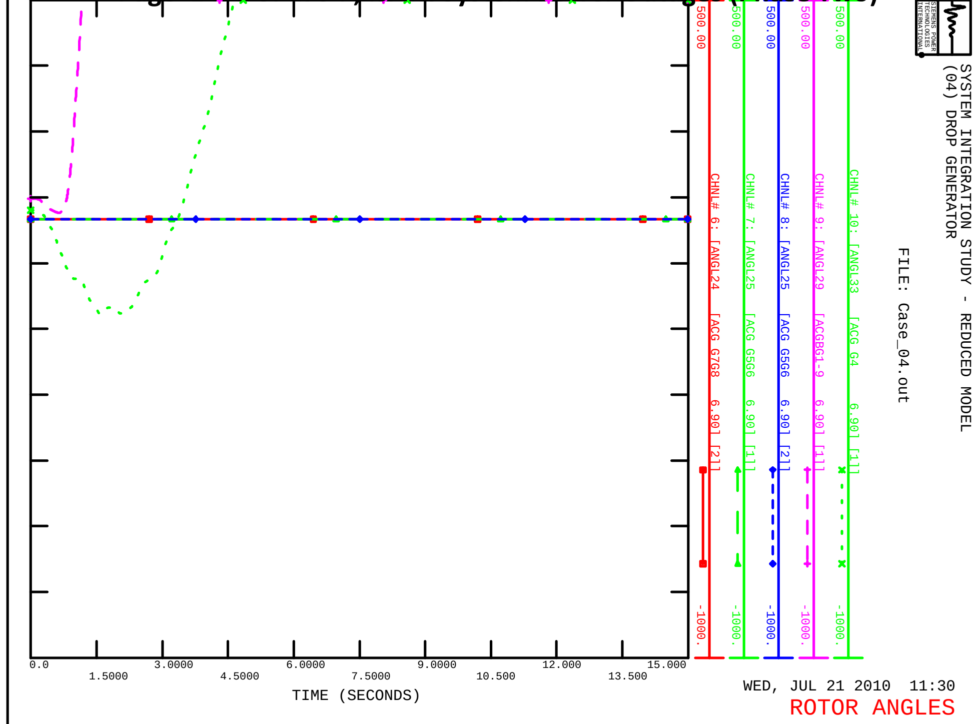

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
500.00
CHNL# 61: [ANGL2490 [SOL B1 230.00[11]
-500.0
0.50000
CHNL# 457: [SPD2490 [SOL B1 230.00[11]
-0.5000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, MAR 03 2010 8:52
MACHINE BUS 2490

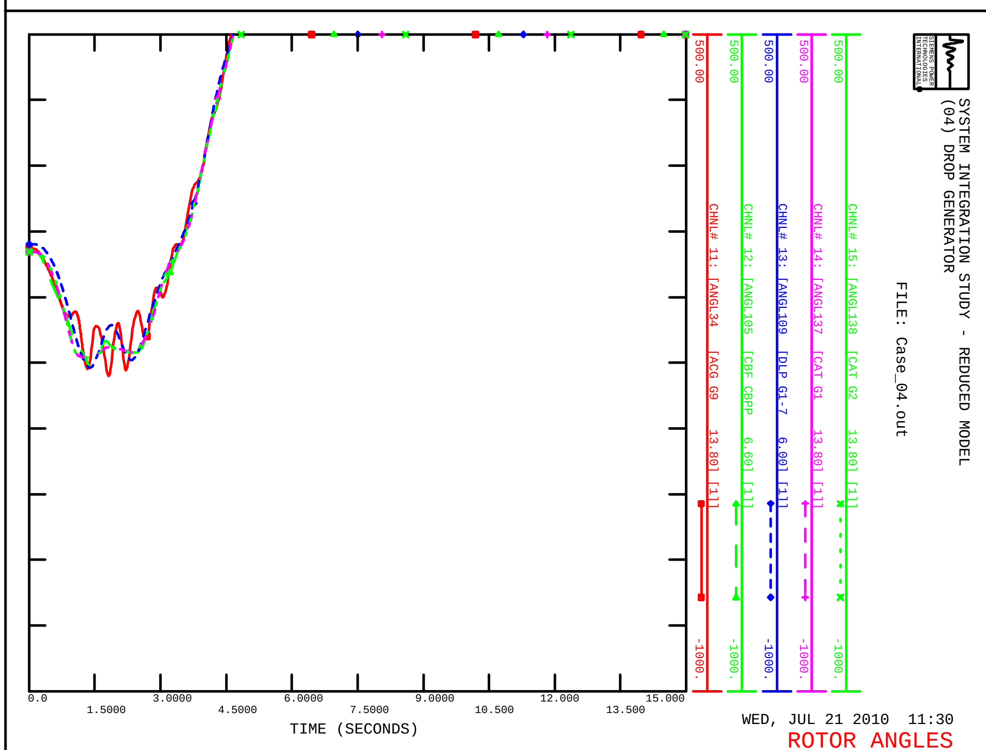

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
50.000
CHNL# 127: 100*[POWR2490 [SOL B1 230.00[11]
-50.00
50.000
CHNL# 193: 100*[VARS2490 [SOL B1 230.00[11]
-50.00
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, MAR 03 2010 8:52
MACHINE BUS 2490

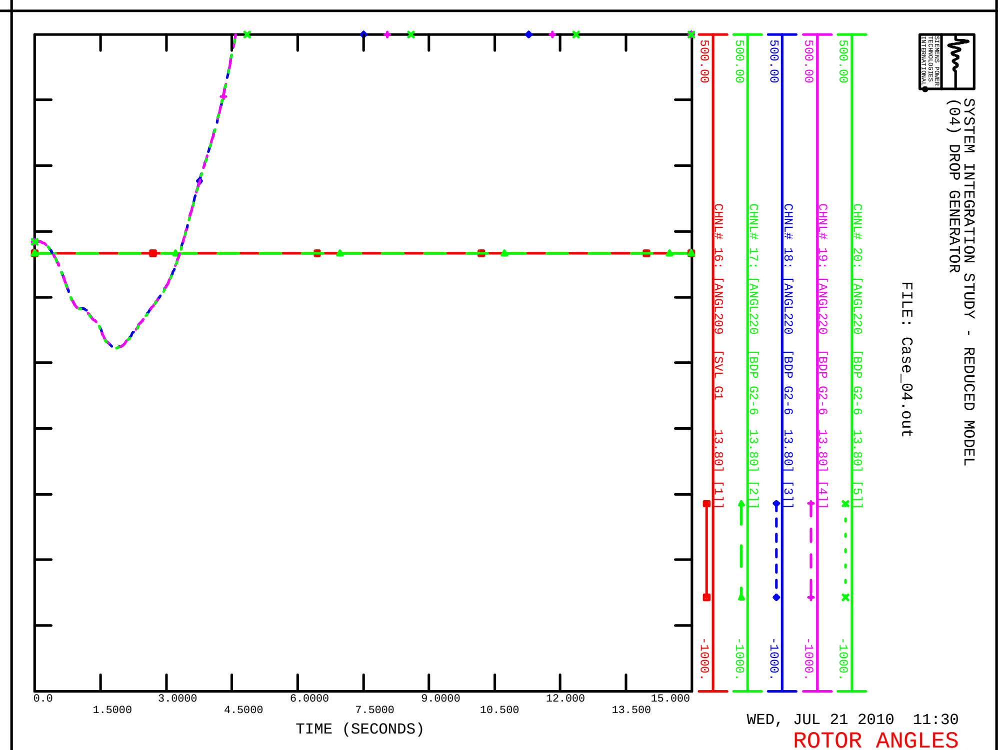

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
100.00
CHNL# 773: 100*[SOLP P1 MW]
-400.0
100.00
CHNL# 775: 100*[SOLP P2 MW]
-400.0
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, MAR 03 2010 8:52
HVDC, MW

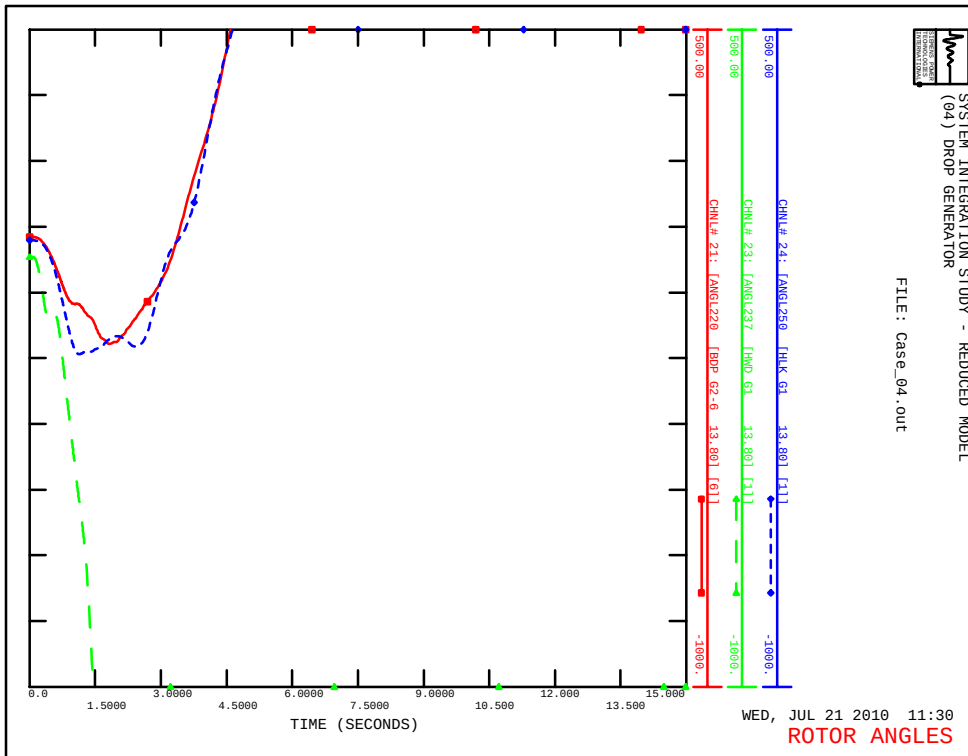

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(03) DROP GENERATOR
FILE: Case_03.out
400.00
CHNL# 774: 100*[SOLP P2 MVAR]
-100.0
400.00
CHNL# 776: 100*[SOLP P2 MVAR]
-100.0
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, MAR 03 2010 8:52
HVDC, MVAR

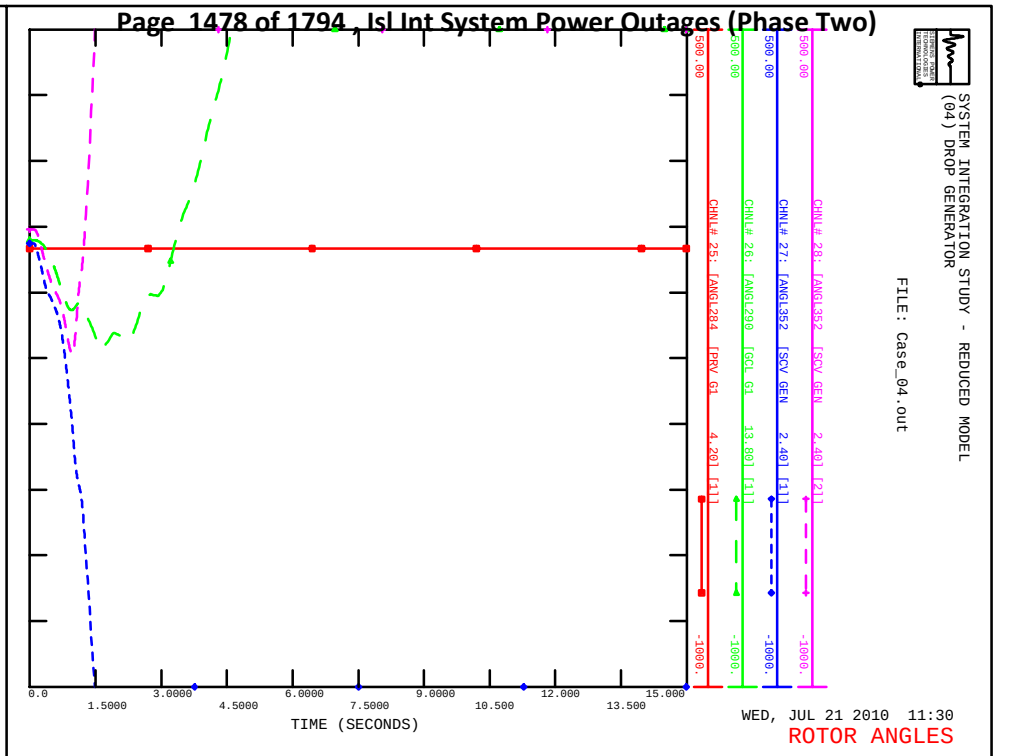

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 1: [ANGL21 [ACG 1P2P 6.90] [1]]
CHNL# 2: [ANGL21 [ACG 1P2P 6.90] [2]]
CHNL# 3: [ANGL23 [ACG 3P4P 6.90] [1]]
CHNL# 4: [ANGL23 [ACG 3P4P 6.90] [2]]
CHNL# 5: [ANGL24 [ACG G7G8 6.90] [1]]
500.00
-1000.
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

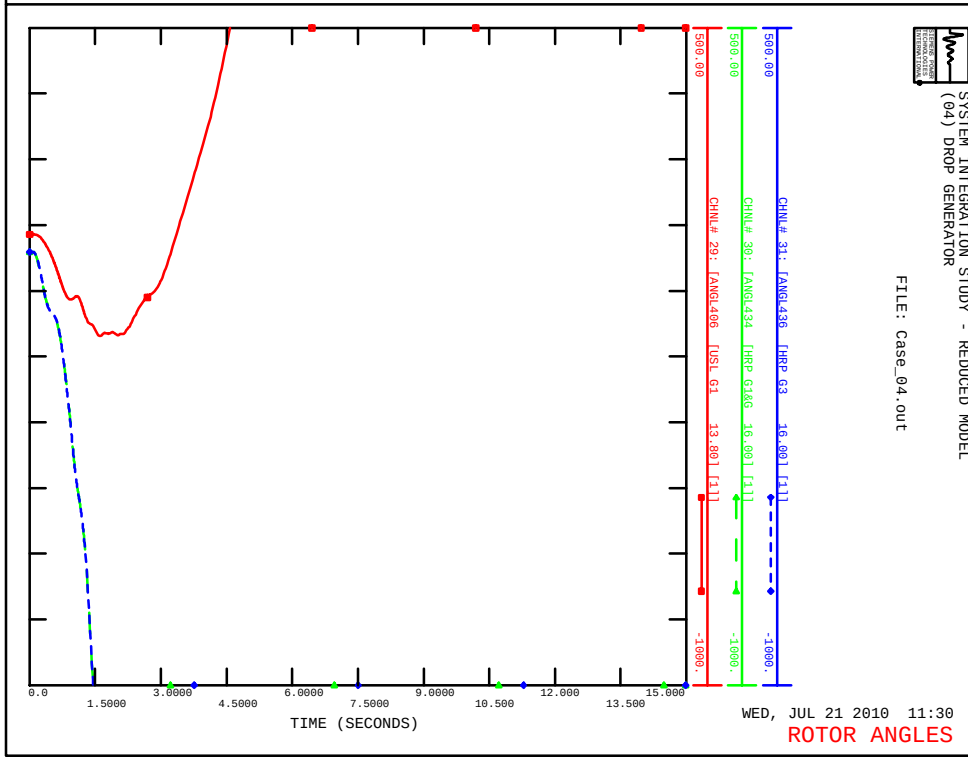

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 6: [ANGL24 [ACG G7G8 6.90] [2]]
CHNL# 7: [ANGL25 [ACG G5G6 6.90] [1]]
CHNL# 8: [ANGL25 [ACG G5G6 6.90] [2]]
CHNL# 9: [ANGL29 [ACGBG1-9 6.90] [1]]
CHNL# 10: [ANGL33 [ACG G4 6.90] [1]]
500.00
-1000.
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

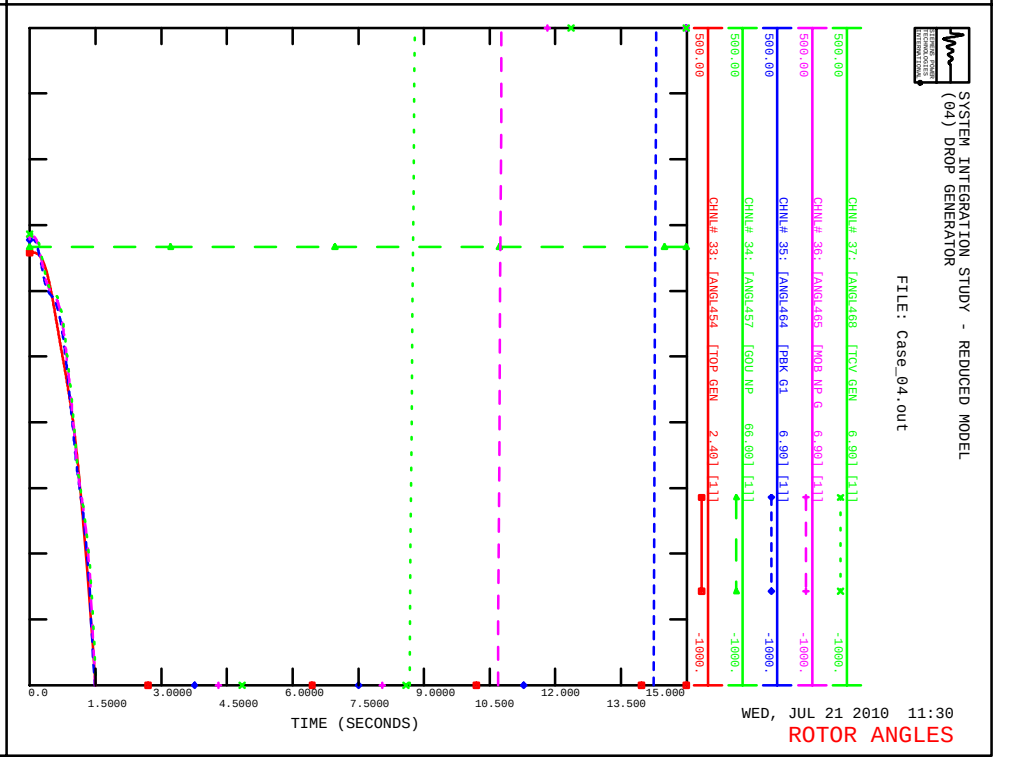

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 11: [ANGL34 [ACG G9 13.80] [1]]
CHNL# 12: [ANGL105 [CBF CBPP 6.60] [1]]
CHNL# 13: [ANGL109 [DLP G1-7 6.00] [1]]
CHNL# 14: [ANGL137 [CAT G1 13.80] [1]]
CHNL# 15: [ANGL138 [CAT G2 13.80] [1]]
500.00
-1000.
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

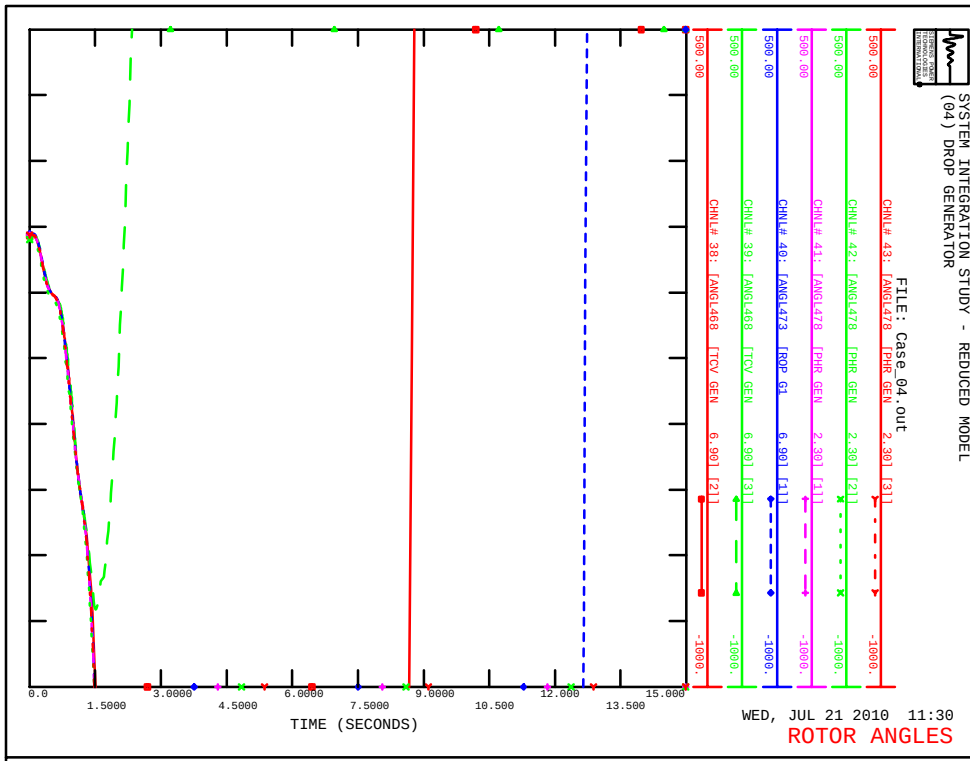

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 16: [ANGL209 [SVL G1 13.80] [1]]
CHNL# 17: [ANGL220 [BDP G2-6 13.80] [2]]
CHNL# 18: [ANGL220 [BDP G2-6 13.80] [3]]
CHNL# 19: [ANGL220 [BDP G2-6 13.80] [4]]
CHNL# 20: [ANGL220 [BDP G2-6 13.80] [5]]
500.00
-1000.
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

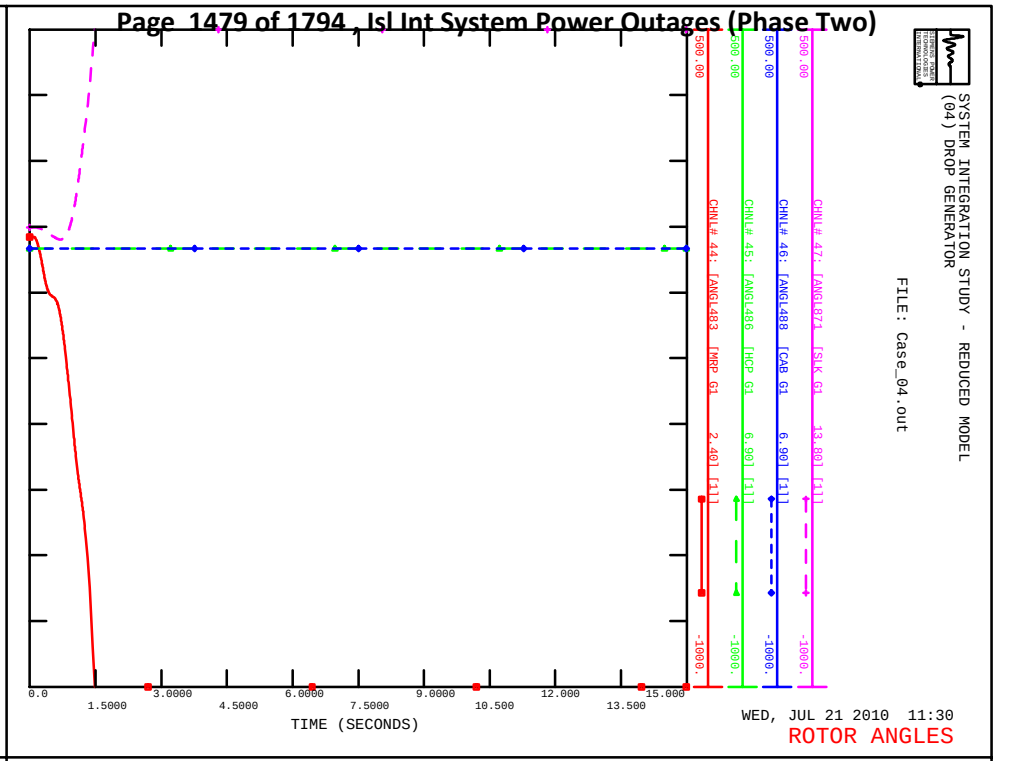

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 21: [ANGL220 [BDP G2-6 13.80] [61]
CHNL# 23: [ANGL237 [HND G1 13.80] [1]
CHNL# 24: [ANGL250 [HLK G1 13.80] [11]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

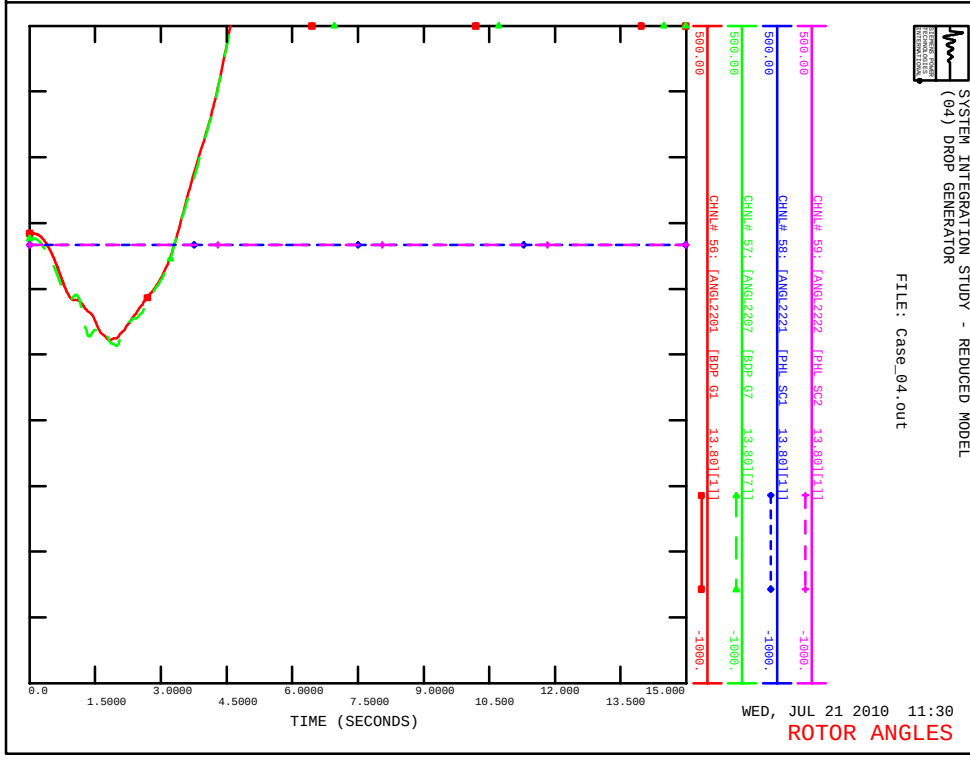

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 25: [ANGL284 [PRV G1 4.20] [11]
CHNL# 26: [ANGL290 [GCL G1 13.80] [11]
CHNL# 27: [ANGL352 [SCV GEN 2.40] [11]
CHNL# 28: [ANGL352 [SCV GEN 2.40] [21]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

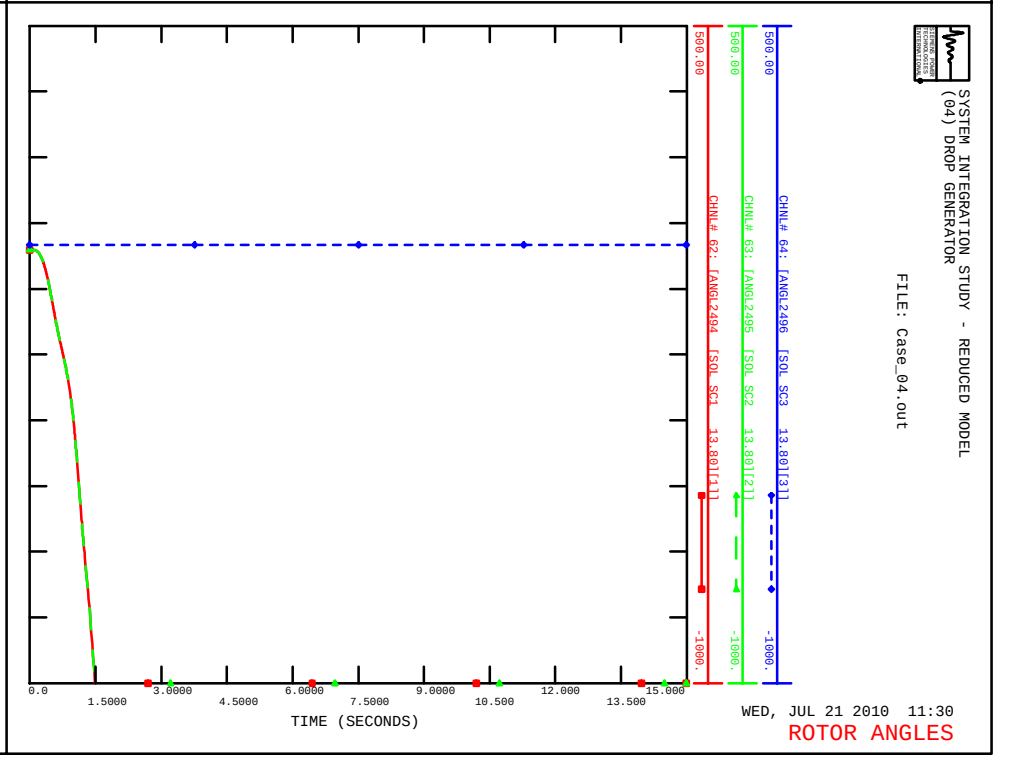

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 29: [ANGL406 [USL G1 13.80] [11]
CHNL# 30: [ANGL434 [HRP G1&G 16.00] [11]
CHNL# 31: [ANGL436 [HRP G3 16.00] [11]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

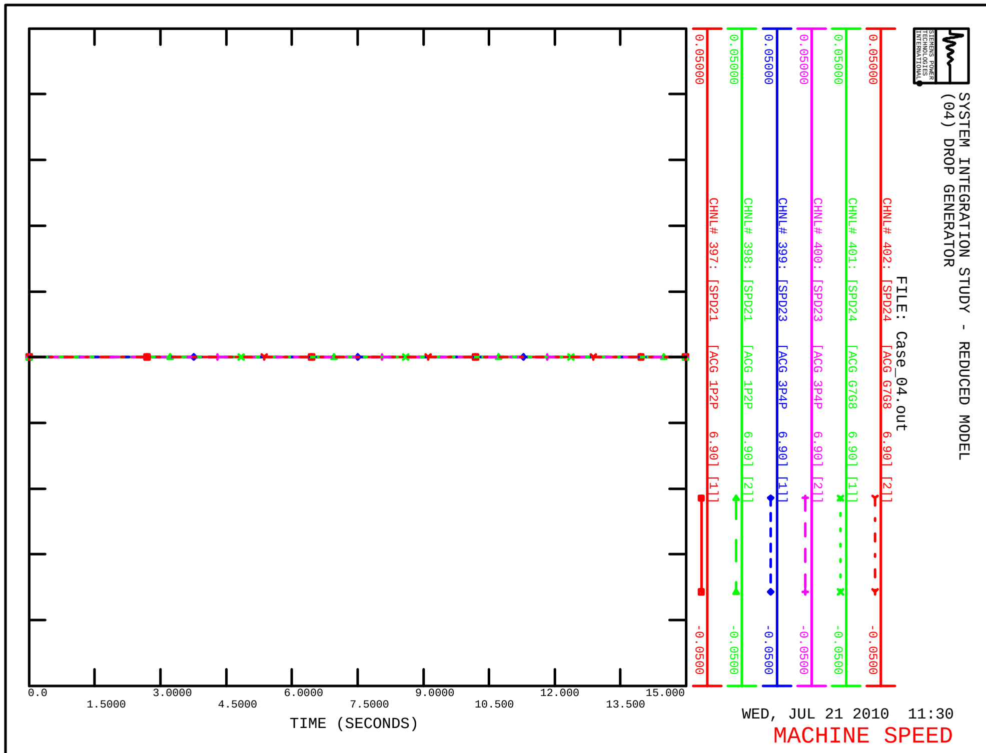

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 33: [ANGL454 [TOP GEN 2.40] [11]
CHNL# 34: [ANGL457 [CGU NP 66.00] [11]
CHNL# 35: [ANGL464 [PBK G1 6.90] [11]
CHNL# 36: [ANGL465 [MOB NP G 6.90] [11]
CHNL# 37: [ANGL468 [TCV GEN 6.90] [11]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

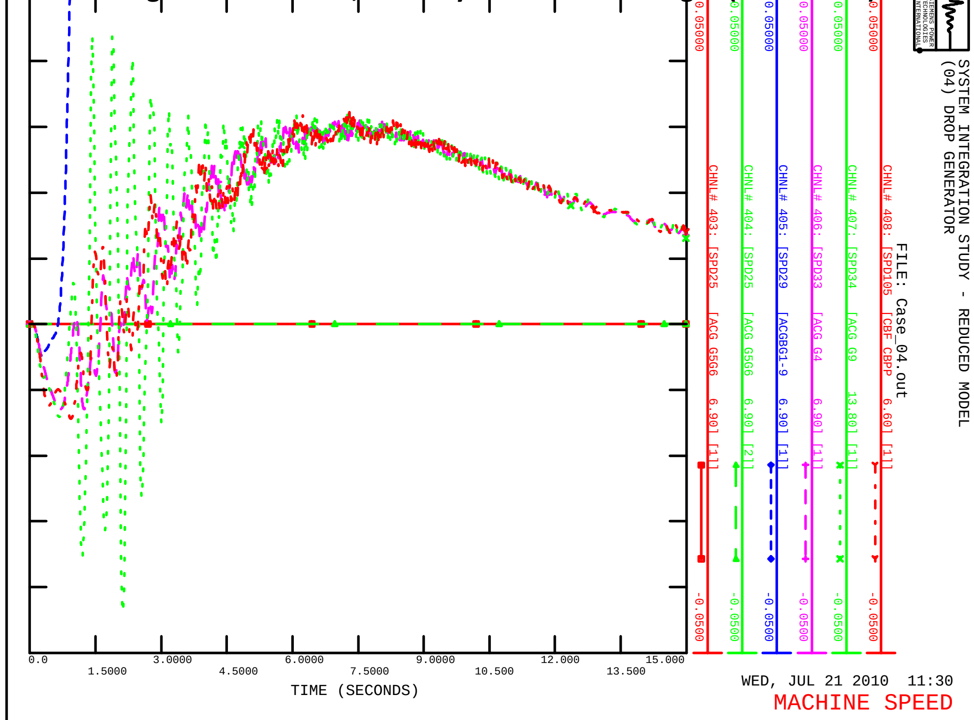

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 38: [ANGL468 TCV GEN 6.90] [2]
CHNL# 39: [ANGL468 TCV GEN 6.90] [3]
CHNL# 40: [ANGL473 TROP G1 6.90] [1]
CHNL# 41: [ANGL478 TPHR GEN 2.30] [1]
CHNL# 42: [ANGL478 TPHR GEN 2.30] [2]
CHNL# 43: [ANGL478 TPHR GEN 2.30] [3]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

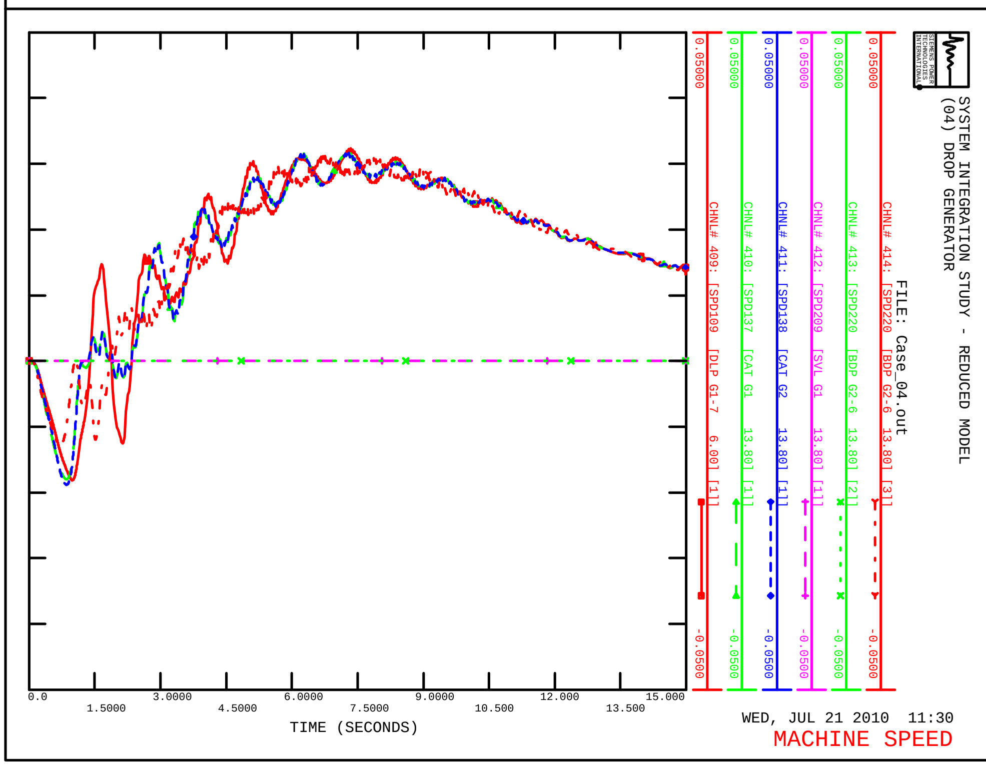

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 44: [ANGL483 TMRP G1 2.40] [1]
CHNL# 45: [ANGL486 THCP G1 6.90] [1]
CHNL# 46: [ANGL488 TCAB G1 6.90] [1]
CHNL# 47: [ANGL871 TSLK G1 13.80] [1]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

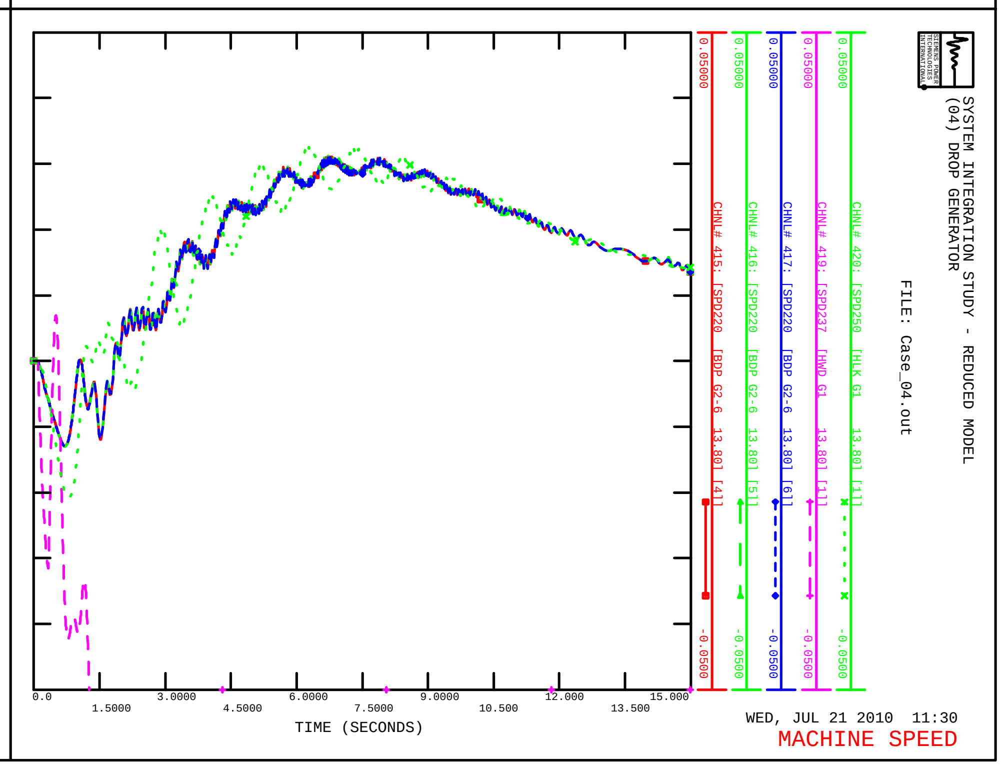

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 56: [ANGL2201 TBDP G1 13.80] [1]
CHNL# 57: [ANGL2207 TBDP G7 13.80] [7]
CHNL# 58: [ANGL2221 TPHL SC1 13.80] [1]
CHNL# 59: [ANGL2222 TPHL SC2 13.80] [1]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

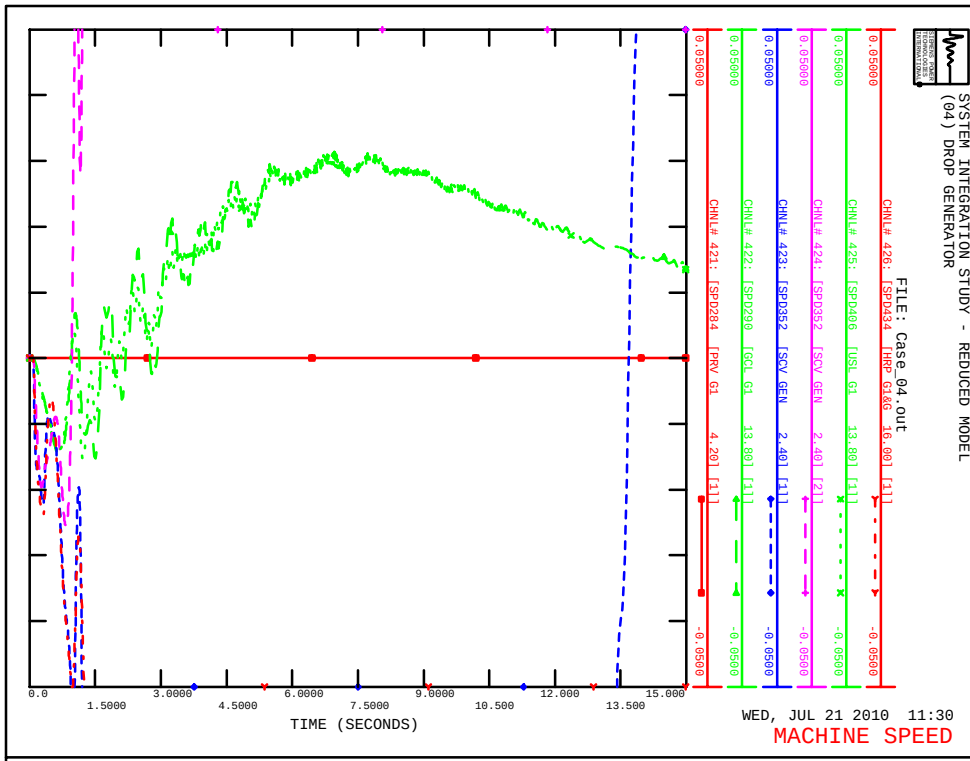

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 62: [ANGL2494 TSOL SC1 13.80] [1]
CHNL# 63: [ANGL2495 TSOL SC2 13.80] [2]
CHNL# 64: [ANGL2496 TSOL SC3 13.80] [3]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

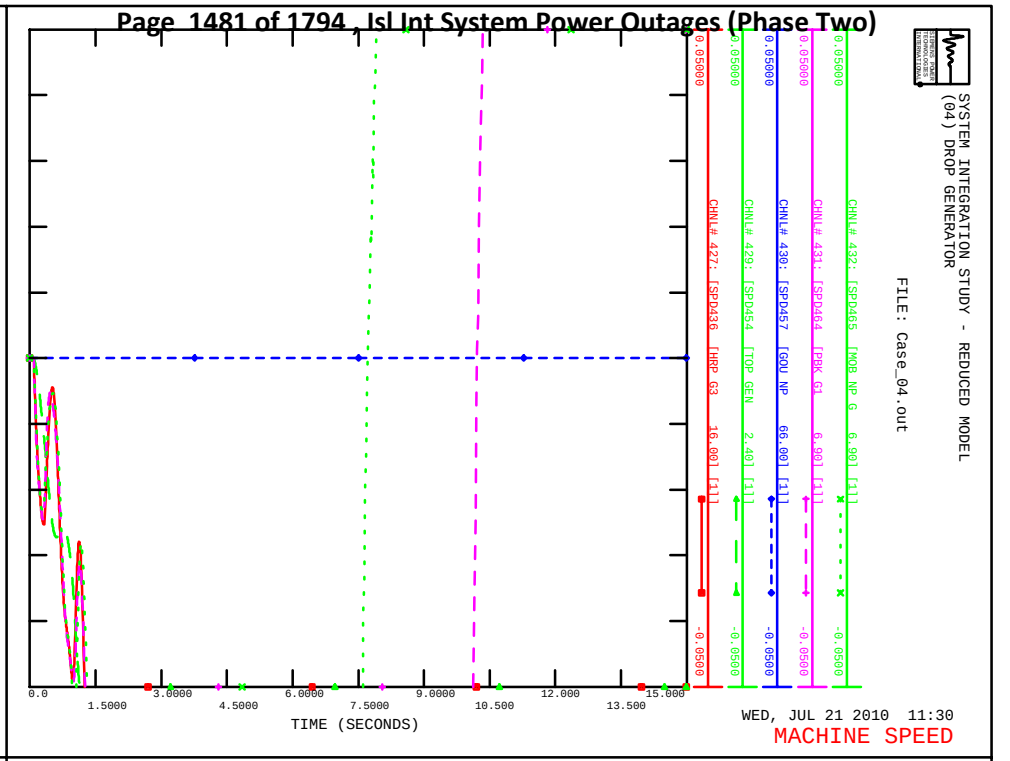

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 397: [SPD21 [ACG 1P2P 6.90] [1]]
CHNL# 398: [SPD21 [ACG 1P2P 6.90] [2]]
CHNL# 399: [SPD23 [ACG 3P4P 6.90] [1]]
CHNL# 400: [SPD23 [ACG 3P4P 6.90] [2]]
CHNL# 401: [SPD24 [ACG G7G8 6.90] [1]]
CHNL# 402: [SPD24 [ACG G7G8 6.90] [2]]
0.05000
-0.0500
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

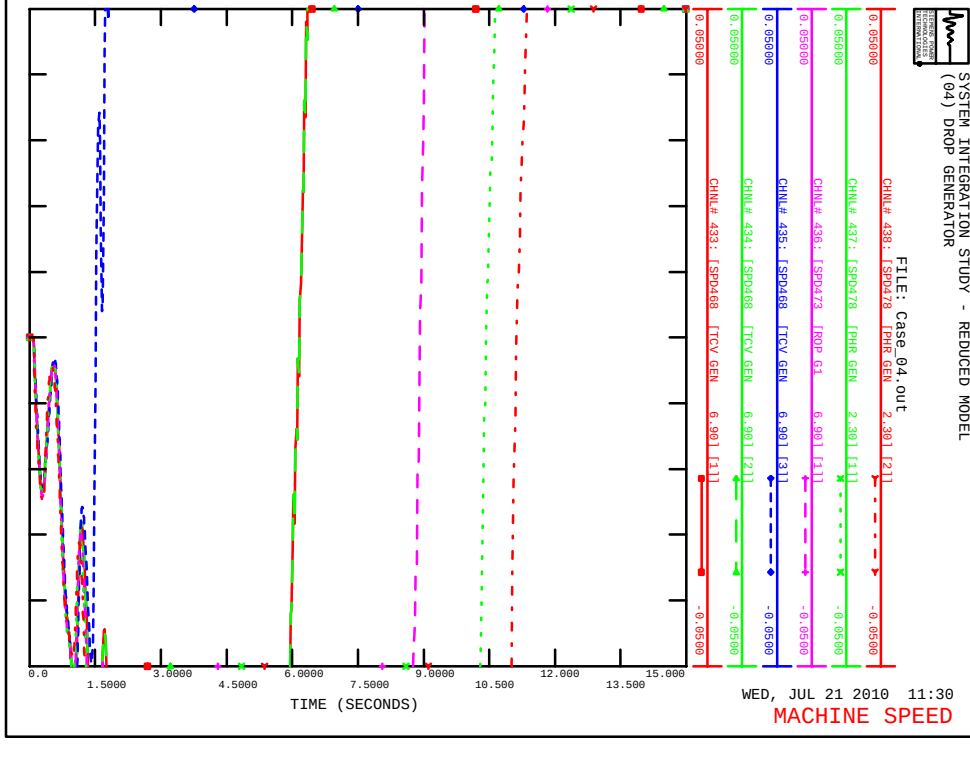

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 403: [SPD25 [ACG G5G6 6.90] [1]]
CHNL# 404: [SPD25 [ACG G5G6 6.90] [2]]
CHNL# 405: [SPD29 [ACGBG1-9 6.90] [1]]
CHNL# 406: [SPD33 [ACG G4 6.90] [1]]
CHNL# 407: [SPD34 [ACG G9 13.80] [1]]
CHNL# 408: [SPD105 [CBF CBPP 6.60] [1]]
0.05000
-0.0500
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

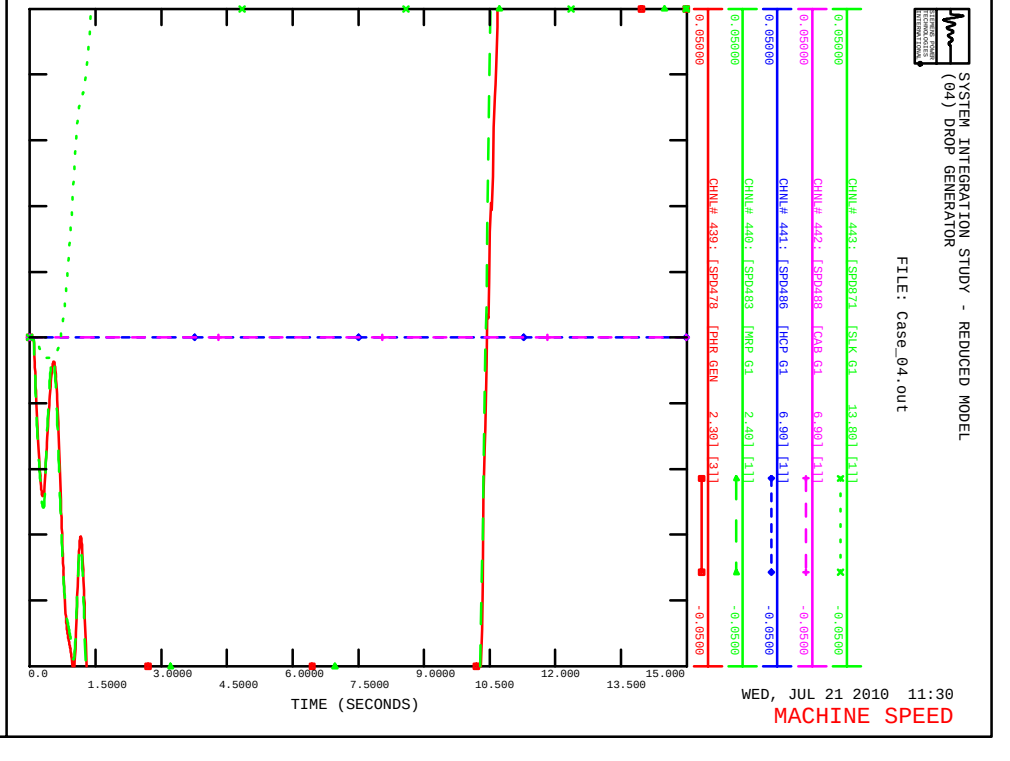

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 409: [SPD109 [DLP G1-7 6.00] [1]]
CHNL# 410: [SPD137 [CAT G1 13.80] [1]]
CHNL# 411: [SPD138 [CAT G2 13.80] [1]]
CHNL# 412: [SPD209 [SVL G1 13.80] [1]]
CHNL# 413: [SPD220 [BDP G2-6 13.80] [2]]
CHNL# 414: [SPD220 [BDP G2-6 13.80] [3]]
0.05000
-0.0500
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

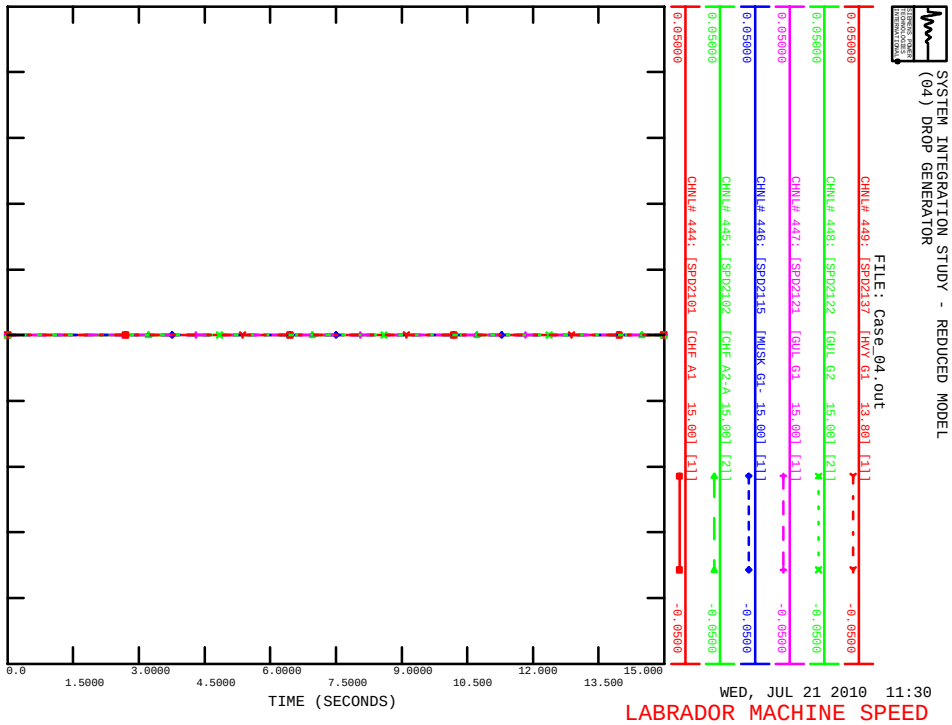

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 415: [SPD220 [BDP G2-6 13.80] [4]]
CHNL# 416: [SPD220 [BDP G2-6 13.80] [5]]
CHNL# 417: [SPD220 [BDP G2-6 13.80] [6]]
CHNL# 419: [SPD237 [HWD G1 13.80] [1]]
CHNL# 420: [SPD250 [HLK G1 13.80] [1]]
0.05000
-0.0500
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

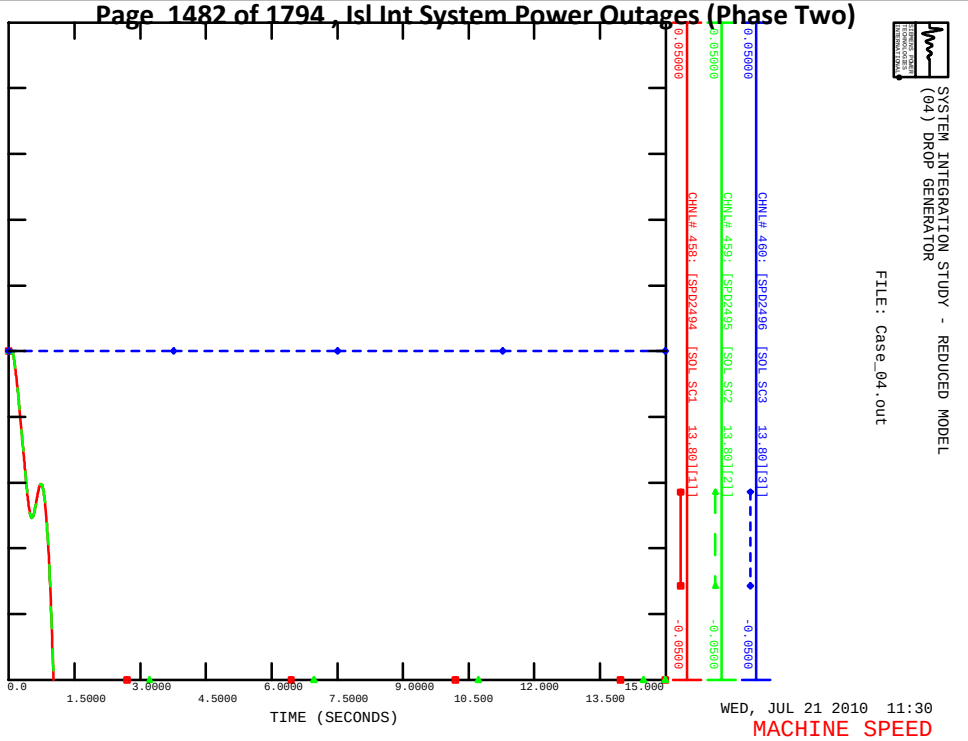

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 421: [SPD284 [PRV G1 4.20] [1]]
CHNL# 422: [SPD290 [GGL G1 13.80] [1]]
CHNL# 423: [SPD352 [SCV GEN 2.40] [1]]
CHNL# 424: [SPD352 [SCV GEN 2.40] [2]]
CHNL# 425: [SPD406 [USL G1 13.80] [1]]
CHNL# 426: [SPD434 [HRP G1&G 16.00] [1]]
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

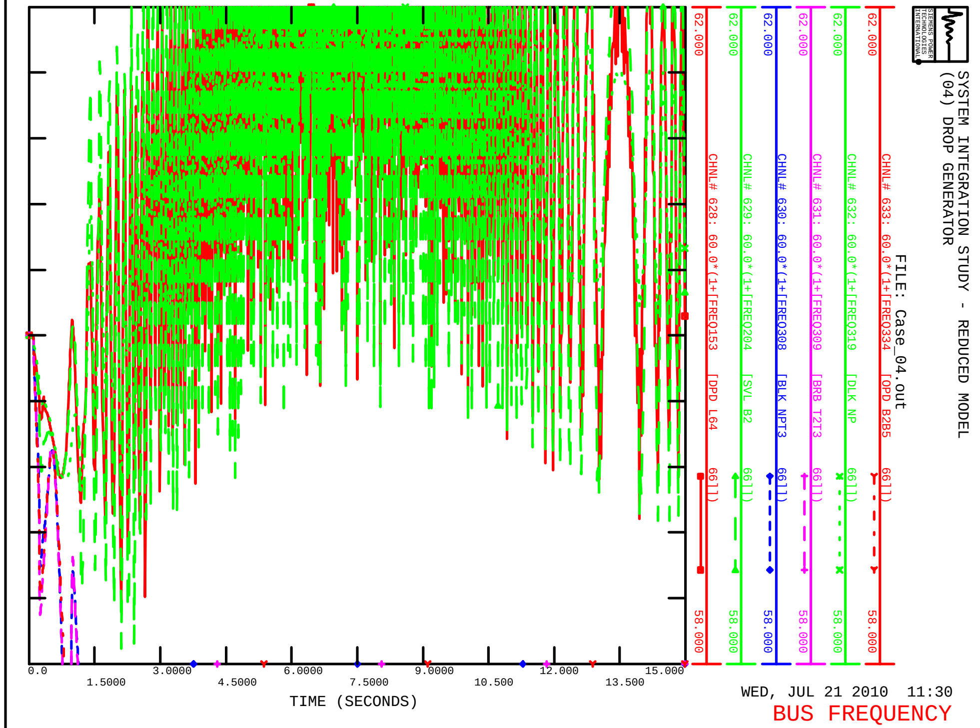

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 427: [SPD436 [HRP G3 16.00] [1]]
CHNL# 429: [SPD454 [TOP GEN 2.40] [1]]
CHNL# 430: [SPD457 [GOU NP 66.00] [1]]
CHNL# 431: [SPD464 [PBK G1 6.90] [1]]
CHNL# 432: [SPD465 [MOB NP G 6.90] [1]]
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

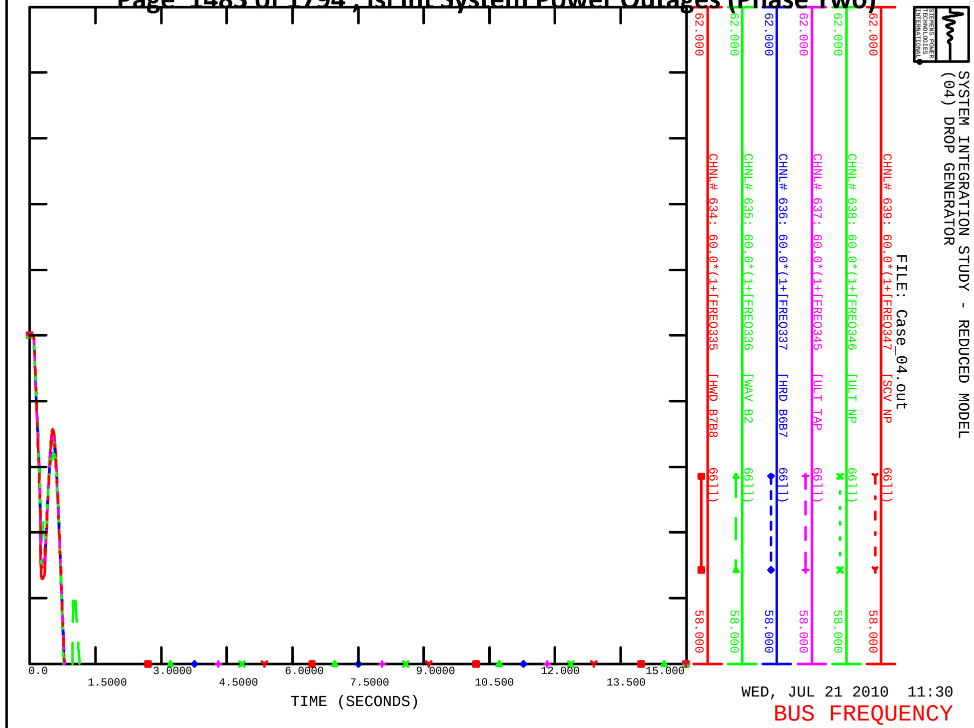

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 433: [SPD468 [TCV GEN 6.90] [1]]
CHNL# 434: [SPD468 [TCV GEN 6.90] [2]]
CHNL# 435: [SPD468 [TCV GEN 6.90] [3]]
CHNL# 436: [SPD473 [ROP G1 6.90] [1]]
CHNL# 437: [SPD478 [PHR GEN 2.30] [1]]
CHNL# 438: [SPD478 [PHR GEN 2.30] [2]]
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

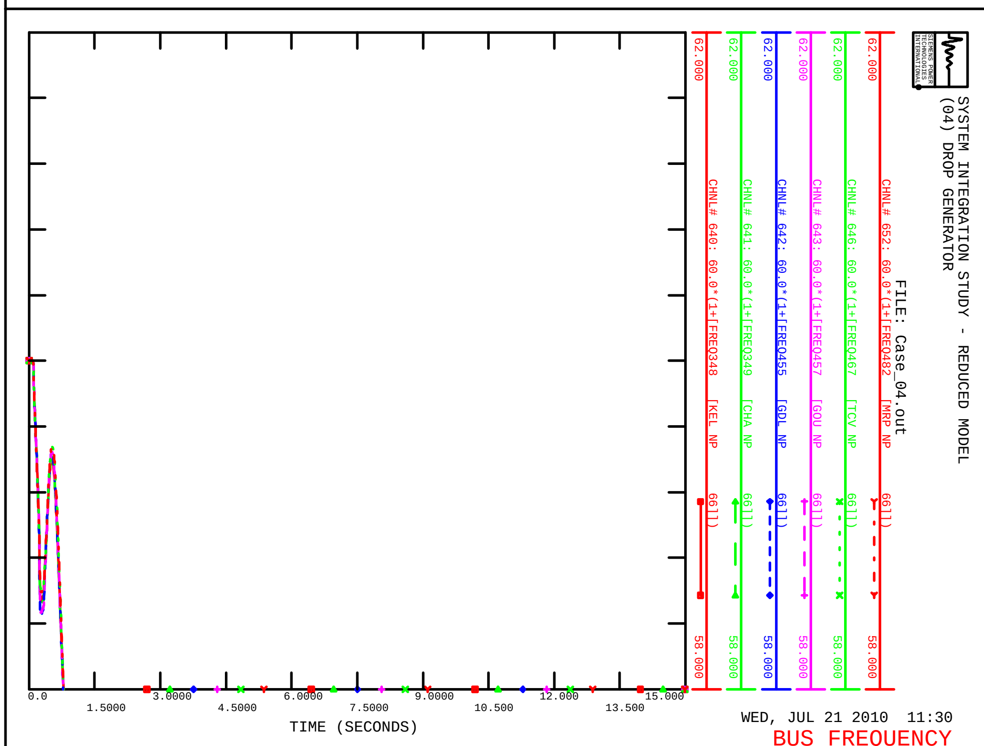

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 439: [SPD478 [PHR GEN 2.30] [3]]
CHNL# 440: [SPD483 [MRP G1 2.40] [1]]
CHNL# 441: [SPD486 [HCP G1 6.90] [1]]
CHNL# 442: [SPD488 [CAB G1 6.90] [1]]
CHNL# 443: [SPD871 [SLK G1 13.80] [1]]
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

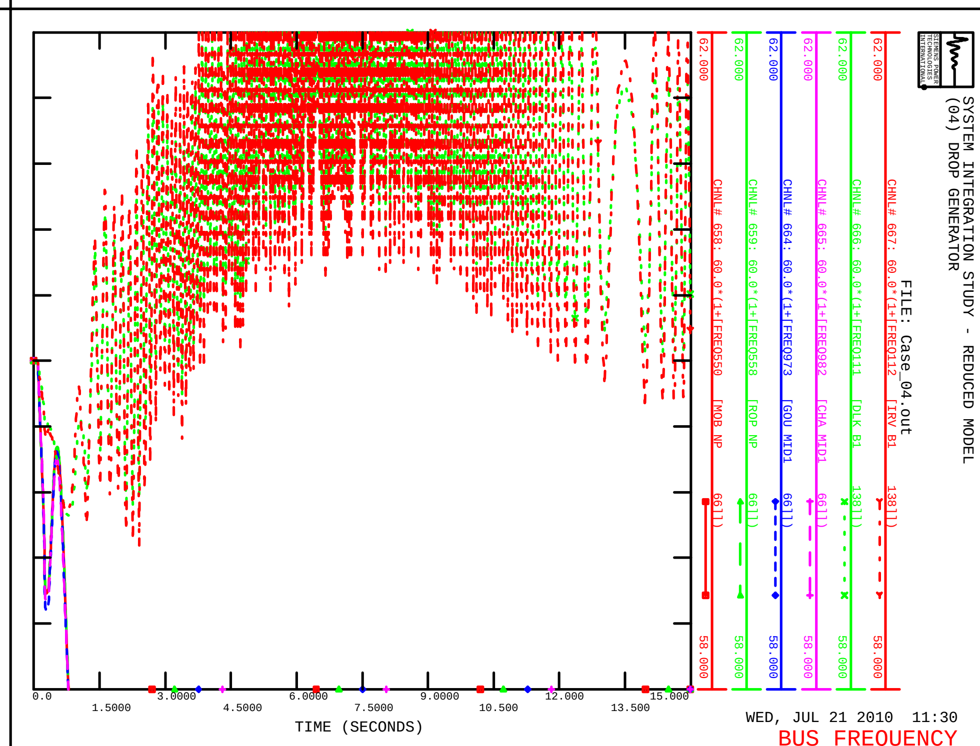

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 444: [SPD2101 [CHF A1 15.00] [1]]
CHNL# 445: [SPD2102 [CHF A2-A 15.00] [2]]
CHNL# 446: [SPD2115 [MUSK G1- 15.00] [1]]
CHNL# 447: [SPD2121 [GUL G1 15.00] [1]]
CHNL# 448: [SPD2122 [GUL G2 15.00] [2]]
CHNL# 449: [SPD2137 [HVY G1 13.80] [1]]
0.05000
-0.0500
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
LABRADOR MACHINE SPEED

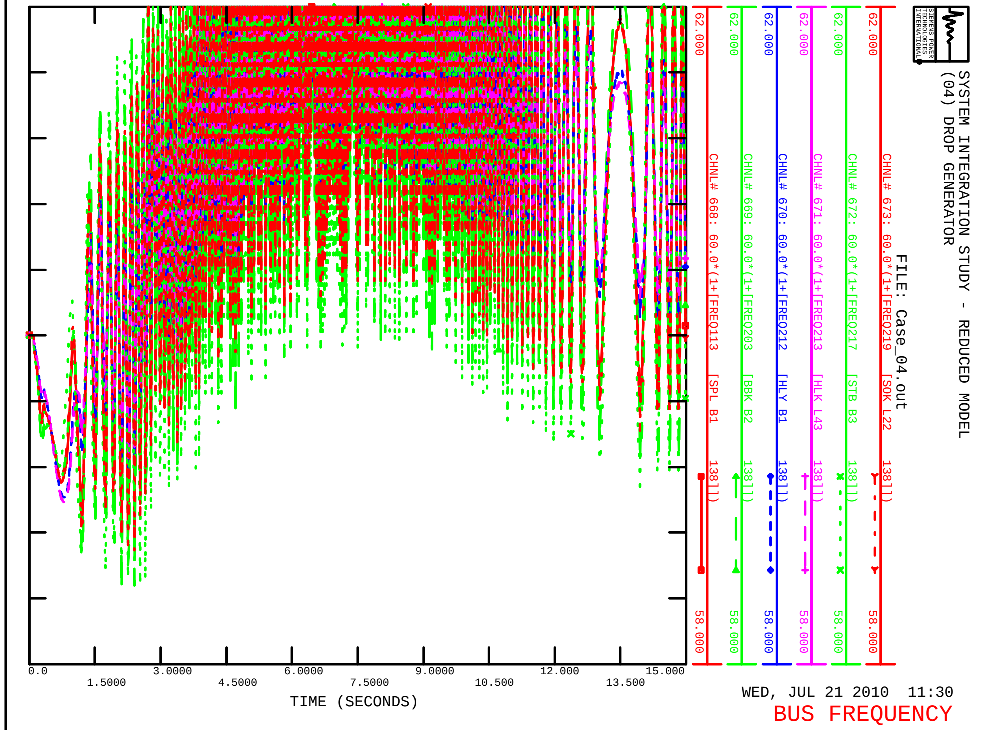

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 458: [SPD2494 [SOL SC1 13.80] [1]]
CHNL# 459: [SPD2495 [SOL SC2 13.80] [2]]
CHNL# 460: [SPD2496 [SOL SC3 13.80] [3]]
0.05000
-0.0500
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
MACHINE SPEED

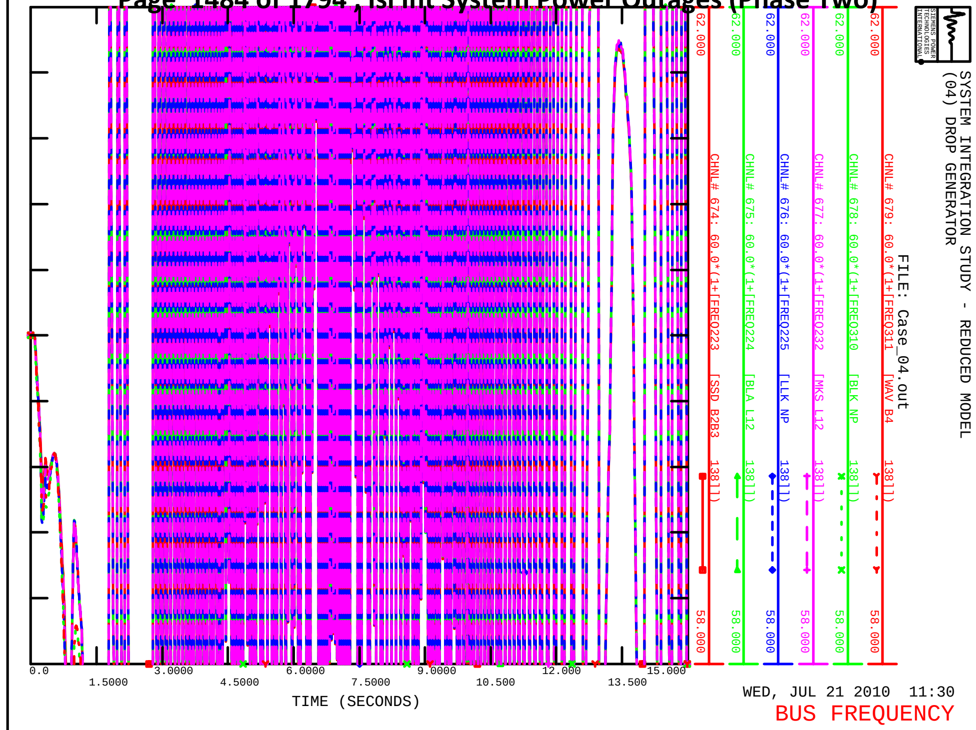

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 628: 60.0*(1+[FREQ153 [DPD L64 6611])
CHNL# 629: 60.0*(1+[FREQ204 [SVL B2 6611])
CHNL# 630: 60.0*(1+[FREQ308 [BLK NPT3 6611])
CHNL# 631: 60.0*(1+[FREQ309 [BRB T2T3 6611])
CHNL# 632: 60.0*(1+[FREQ319 [DLK NP 6611])
CHNL# 633: 60.0*(1+[FREQ334 [OPD B2B5 6611])
62.000
58.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

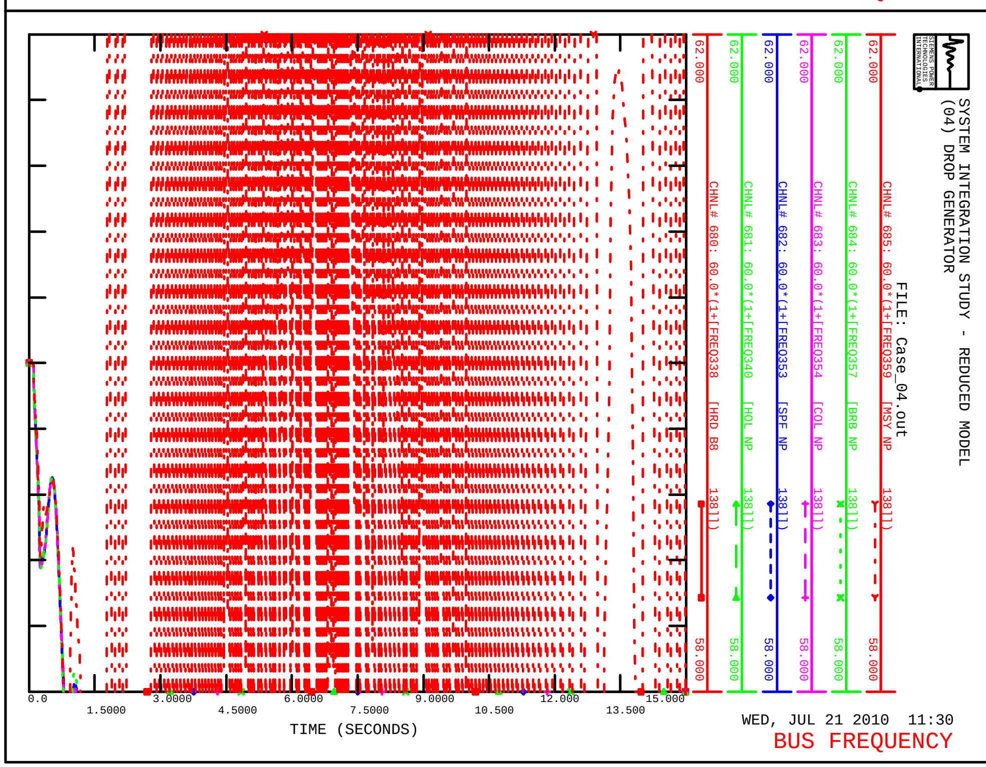

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 634: 60.0*(1+[FREQ335 [HWD B7B8 6611])
CHNL# 635: 60.0*(1+[FREQ336 [WAV B2 6611])
CHNL# 636: 60.0*(1+[FREQ337 [HRD B6B7 6611])
CHNL# 637: 60.0*(1+[FREQ345 [ULT TAP 6611])
CHNL# 638: 60.0*(1+[FREQ346 [ULT NP 6611])
CHNL# 639: 60.0*(1+[FREQ347 [SCV NP 6611])
62.000
58.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

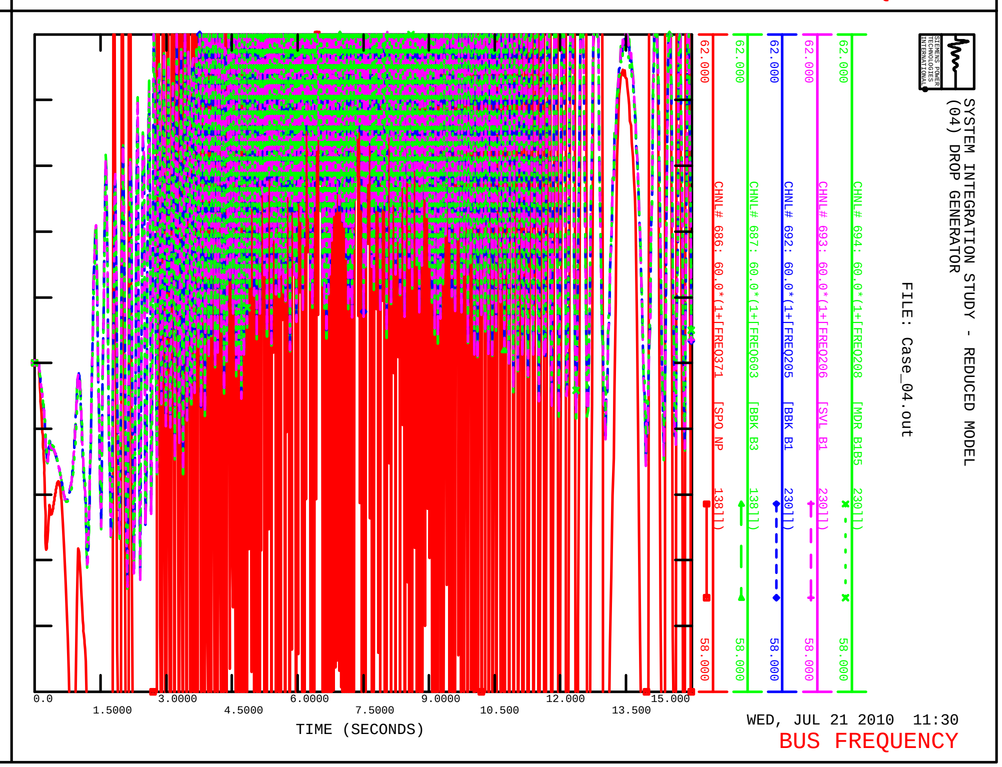

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 640: 60.0*(1+[FREQ348 [KEL NP 6611])
CHNL# 641: 60.0*(1+[FREQ349 [CHA NP 6611])
CHNL# 642: 60.0*(1+[FREQ455 [GDL NP 6611])
CHNL# 643: 60.0*(1+[FREQ457 [GOU NP 6611])
CHNL# 646: 60.0*(1+[FREQ467 [TCV NP 6611])
CHNL# 652: 60.0*(1+[FREQ482 [MRP NP 6611])
62.000
58.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

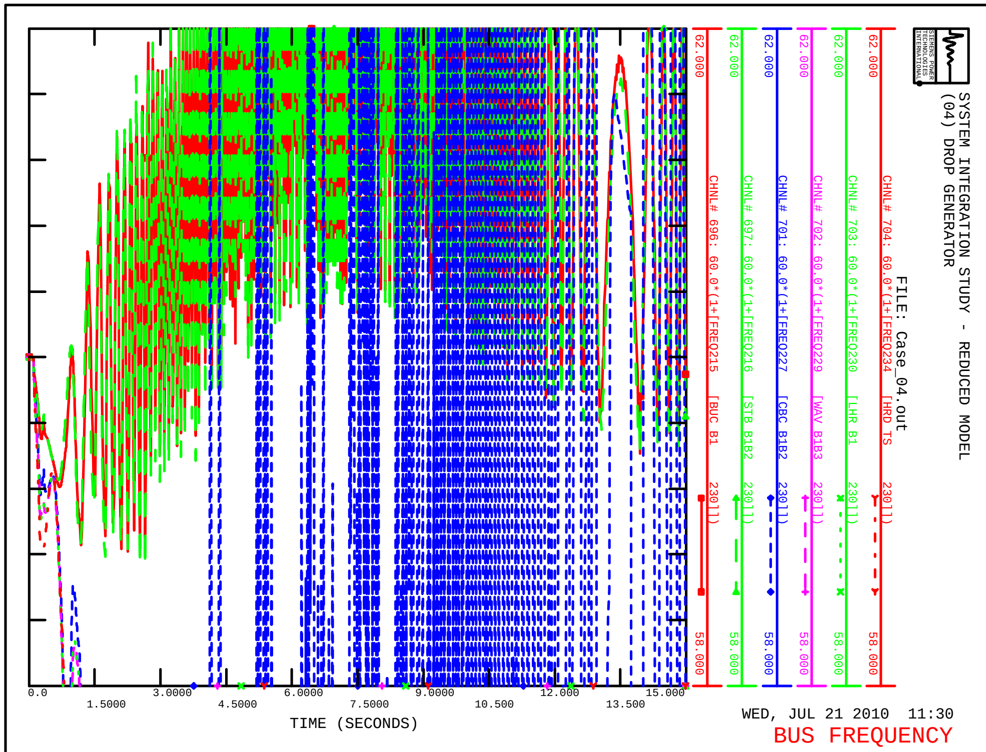

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 658: 60.0*(1+[FREQ550 [MOB NP 6611])
CHNL# 659: 60.0*(1+[FREQ558 [ROP NP 6611])
CHNL# 664: 60.0*(1+[FREQ973 [GOU MID1 6611])
CHNL# 665: 60.0*(1+[FREQ982 [CHA MID1 6611])
CHNL# 666: 60.0*(1+[FREQ111 [DLK B1 13811])
CHNL# 667: 60.0*(1+[FREQ112 [IRV B1 13811])
62.000
58.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

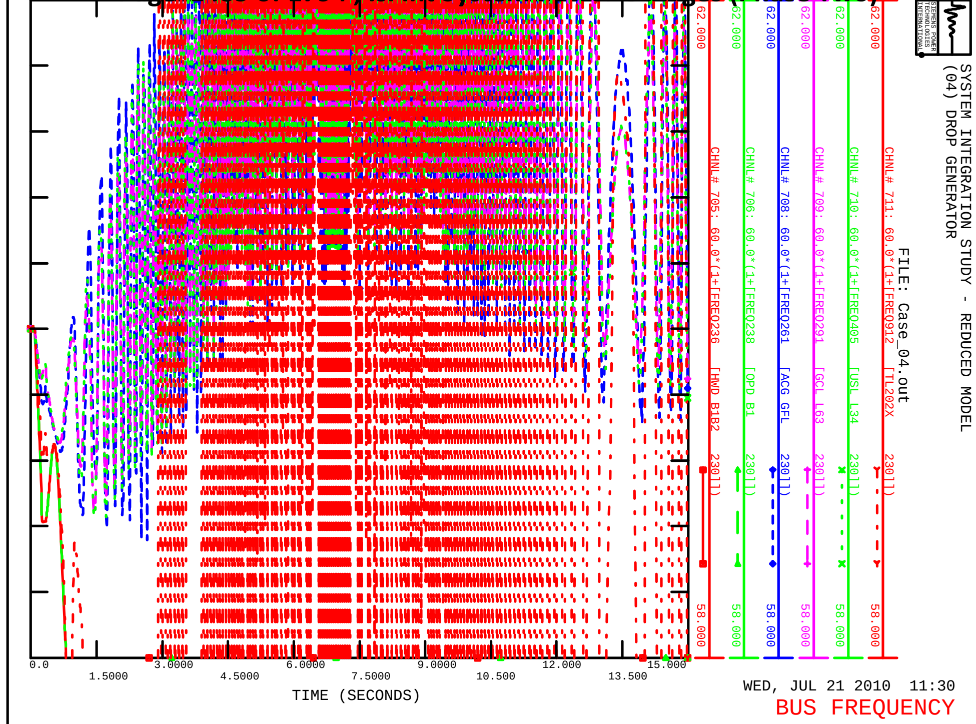

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 668: 60.0*(1+[FREQ113 [SPL B1 138]])
CHNL# 669: 60.0*(1+[FREQ203 [BBK B2 138]])
CHNL# 670: 60.0*(1+[FREQ212 [HLY B1 138]])
CHNL# 671: 60.0*(1+[FREQ213 [HLK L43 138]])
CHNL# 672: 60.0*(1+[FREQ217 [STB B3 138]])
CHNL# 673: 60.0*(1+[FREQ219 [SOK L22 138]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

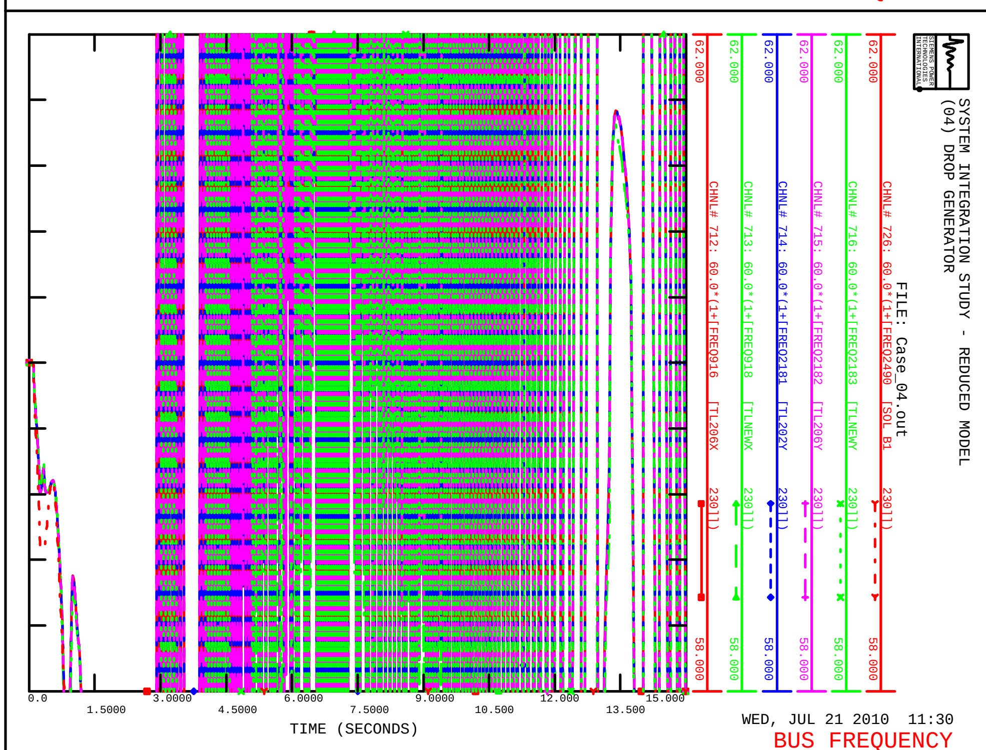

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 674: 60.0*(1+[FREQ223 [SSD B2B3 138]])
CHNL# 675: 60.0*(1+[FREQ224 [BLA L12 138]])
CHNL# 676: 60.0*(1+[FREQ225 [LLK NP 138]])
CHNL# 677: 60.0*(1+[FREQ232 [MKS L12 138]])
CHNL# 678: 60.0*(1+[FREQ310 [BLK NP 138]])
CHNL# 679: 60.0*(1+[FREQ311 [WAV B4 138]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

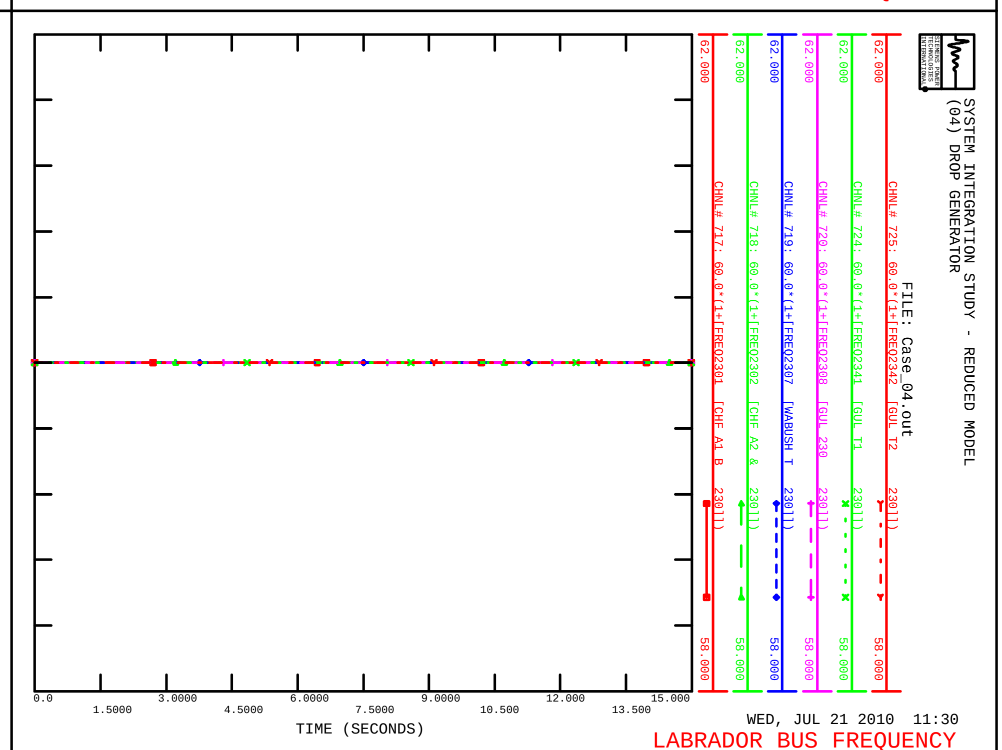

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 680: 60.0*(1+[FREQ338 [HRD B8 138]])
CHNL# 681: 60.0*(1+[FREQ340 [HOL NP 138]])
CHNL# 682: 60.0*(1+[FREQ353 [SPF NP 138]])
CHNL# 683: 60.0*(1+[FREQ354 [COL NP 138]])
CHNL# 684: 60.0*(1+[FREQ357 [BRB NP 138]])
CHNL# 685: 60.0*(1+[FREQ359 [MSY NP 138]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

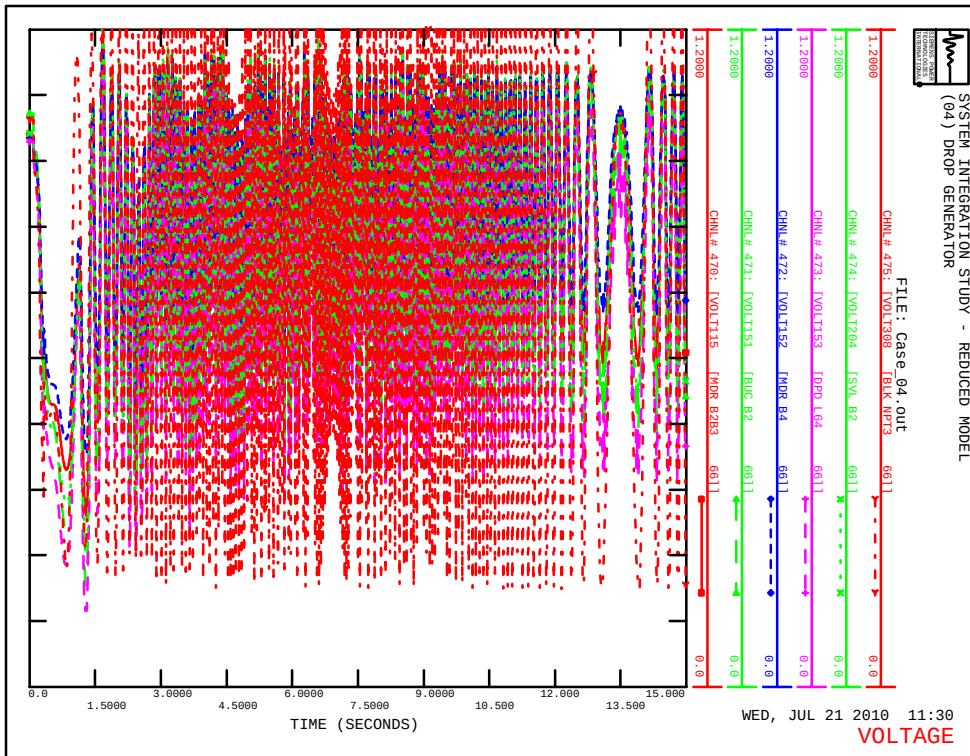

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 686: 60.0*(1+[FREQ371 [SPO NP 138]])
CHNL# 687: 60.0*(1+[FREQ603 [BBK B3 138]])
CHNL# 692: 60.0*(1+[FREQ205 [BBK B1 230]])
CHNL# 693: 60.0*(1+[FREQ206 [SVL B1 230]])
CHNL# 694: 60.0*(1+[FREQ208 [MDR B1B5 230]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

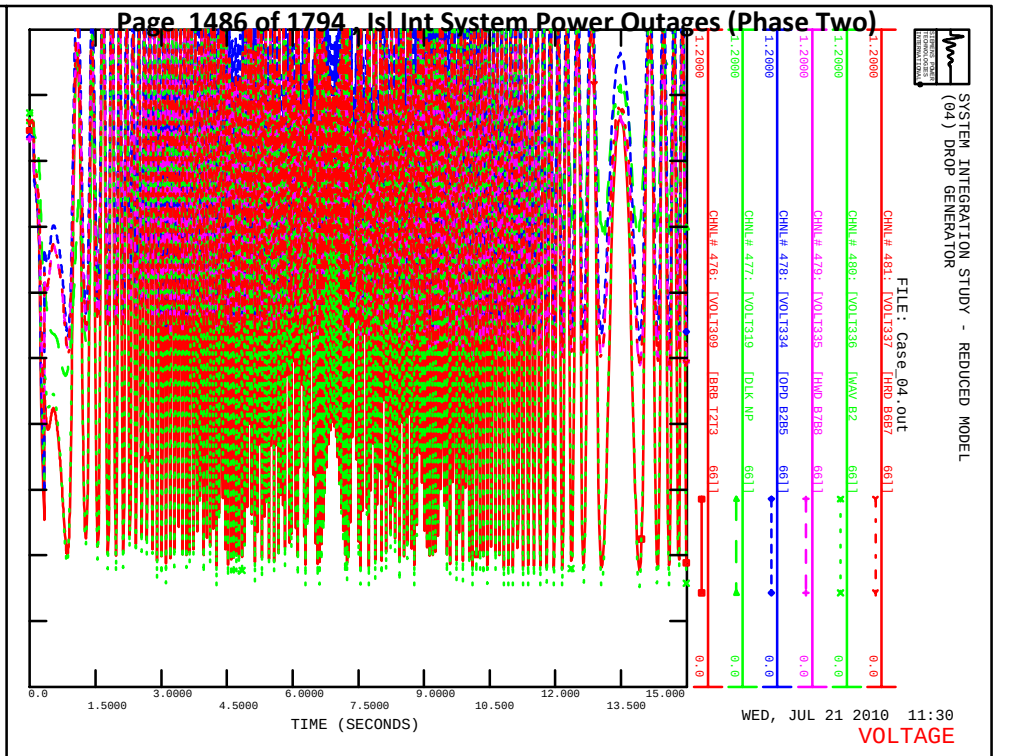

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 696: 60.0*(1+[FREQ215 [BUC B1 230]])
CHNL# 697: 60.0*(1+[FREQ216 [STB B1B2 230]])
CHNL# 701: 60.0*(1+[FREQ227 [CBC B1B2 230]])
CHNL# 702: 60.0*(1+[FREQ229 [WAV B1B3 230]])
CHNL# 703: 60.0*(1+[FREQ230 [LHR B1 230]])
CHNL# 704: 60.0*(1+[FREQ234 [HRD TS 230]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

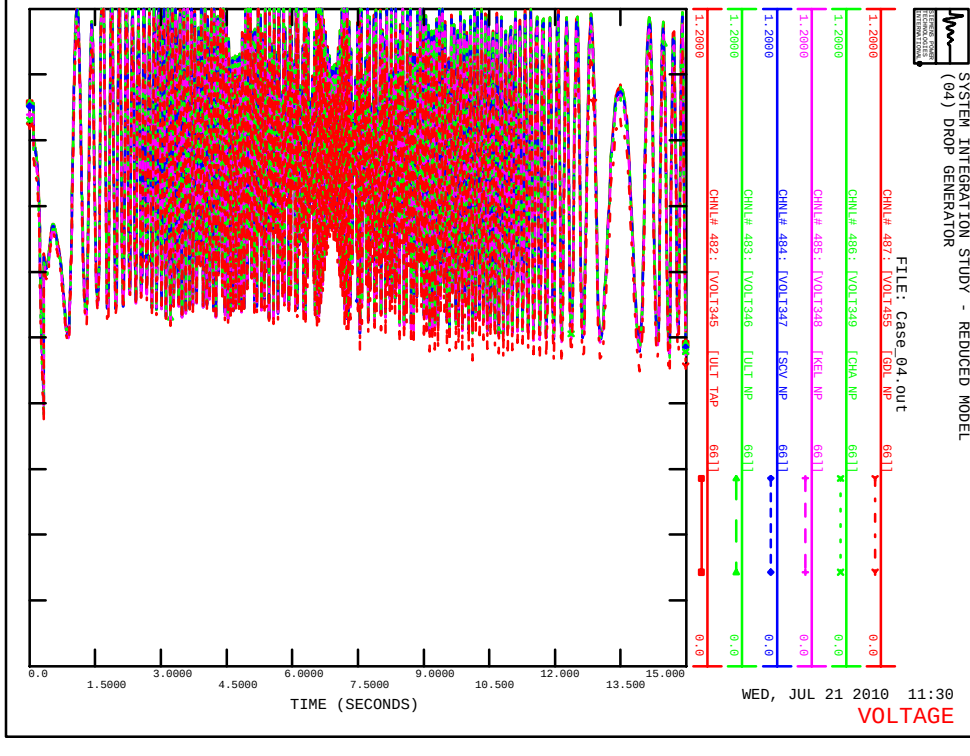

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 705: 60.0*(1+[FREQ236 [HWD B1B2 230]])
CHNL# 706: 60.0*(1+[FREQ238 [OPD B1 230]])
CHNL# 708: 60.0*(1+[FREQ261 [ACG GFL 230]])
CHNL# 709: 60.0*(1+[FREQ291 [GCL L63 230]])
CHNL# 710: 60.0*(1+[FREQ405 [USL L34 230]])
CHNL# 711: 60.0*(1+[FREQ912 [TL202X 230]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

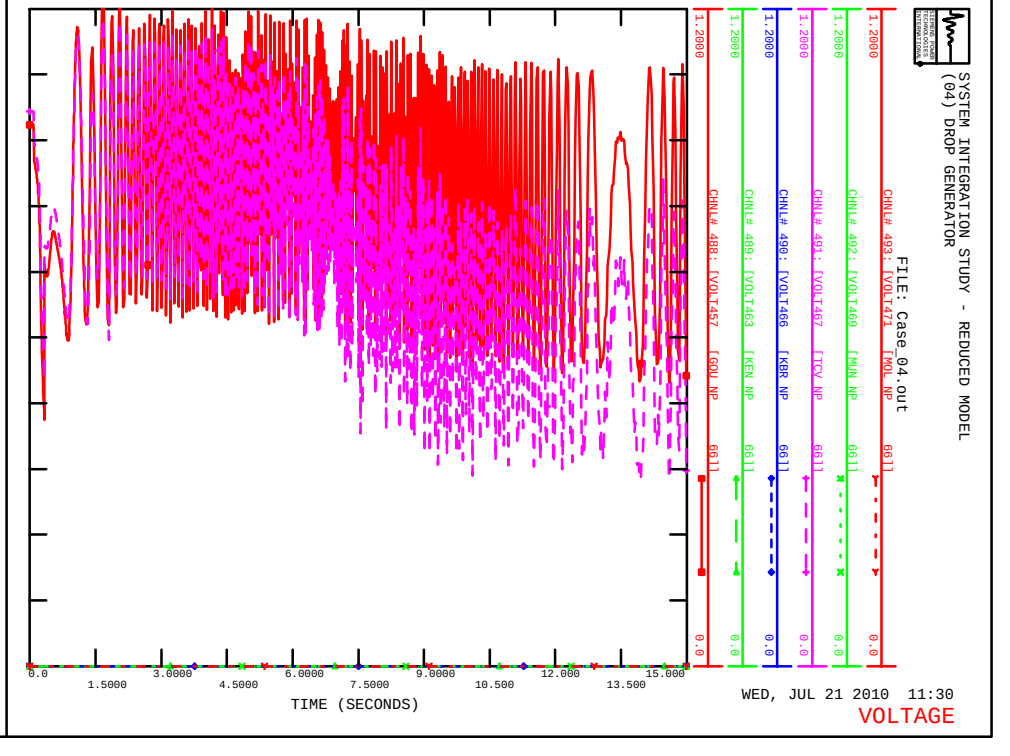

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 712: 60.0*(1+[FREQ916 [TL206X 230]])
CHNL# 713: 60.0*(1+[FREQ918 [TLNEWX 230]])
CHNL# 714: 60.0*(1+[FREQ2181 [TL202Y 230]])
CHNL# 715: 60.0*(1+[FREQ2182 [TL206Y 230]])
CHNL# 716: 60.0*(1+[FREQ2183 [TLNEWY 230]])
CHNL# 726: 60.0*(1+[FREQ2490 [SOL B1 230]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

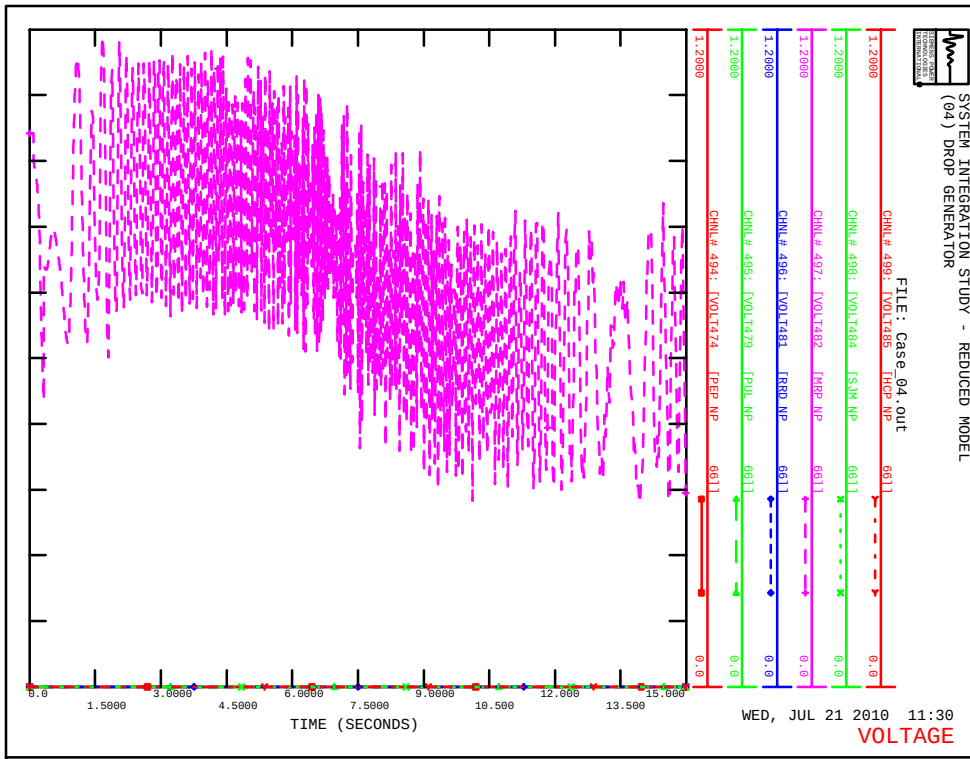

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 717: 60.0*(1+[FREQ2301 [CHF A1 B 230]])
CHNL# 718: 60.0*(1+[FREQ2302 [CHF A2 & 230]])
CHNL# 719: 60.0*(1+[FREQ2307 [WABUSH T 230]])
CHNL# 720: 60.0*(1+[FREQ2308 [GUL 230 230]])
CHNL# 724: 60.0*(1+[FREQ2341 [GUL T1 230]])
CHNL# 725: 60.0*(1+[FREQ2342 [GUL T2 230]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
LABRADOR BUS FREQUENCY

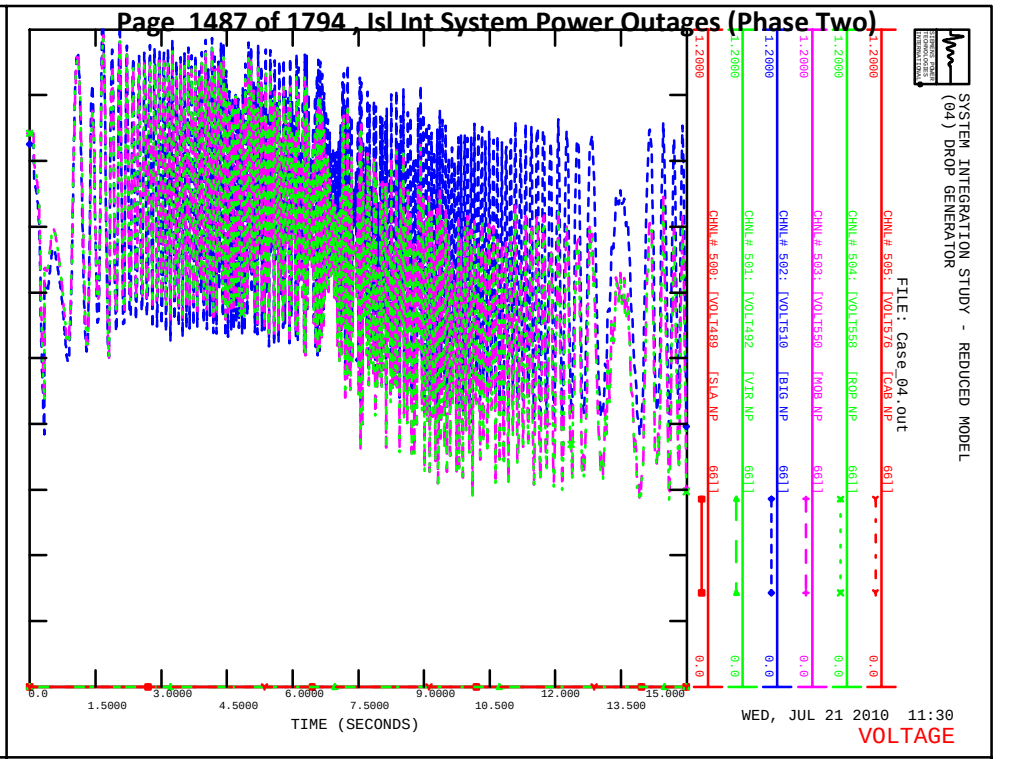

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 470: [VOLT115 [MOR B2B3 661]
CHNL# 471: [VOLT151 [BUC B2 661]
CHNL# 472: [VOLT152 [MOR B4 661]
CHNL# 473: [VOLT153 [OPD L64 661]
CHNL# 474: [VOLT204 [SVL B2 661]
CHNL# 475: [VOLT308 [BLK NPT3 661]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

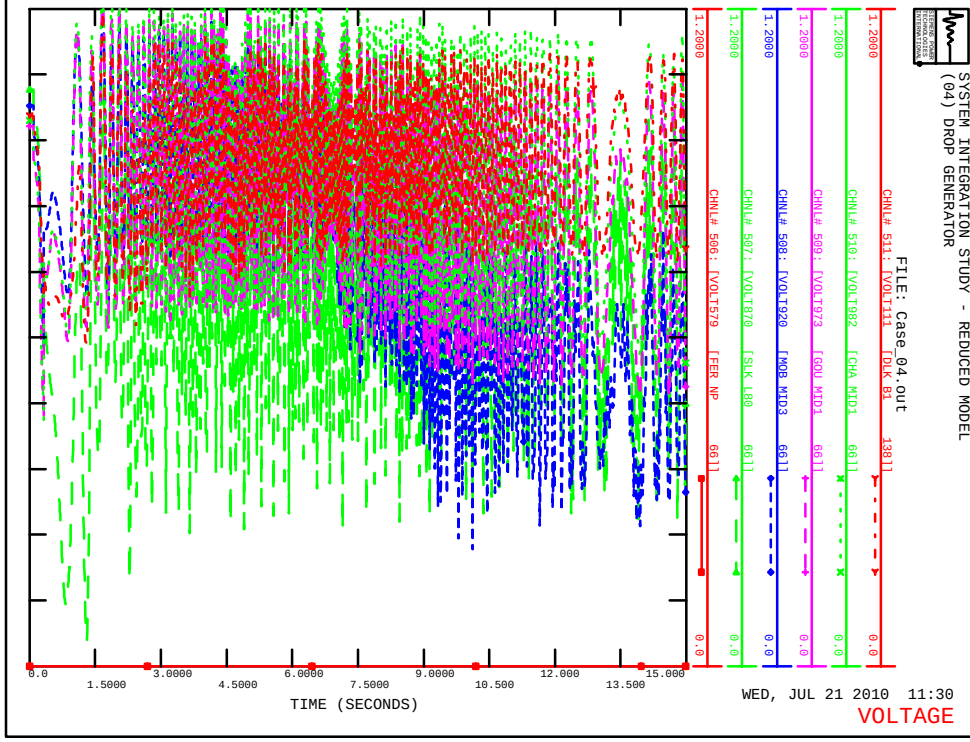

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 476: [VOLT309 [BBB T2T3 661]
CHNL# 477: [VOLT319 [DLK NP 661]
CHNL# 478: [VOLT334 [OPD B2B5 661]
CHNL# 479: [VOLT335 [HWD B7B8 661]
CHNL# 480: [VOLT336 [WAV B2 661]
CHNL# 481: [VOLT337 [HRD B6B7 661]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

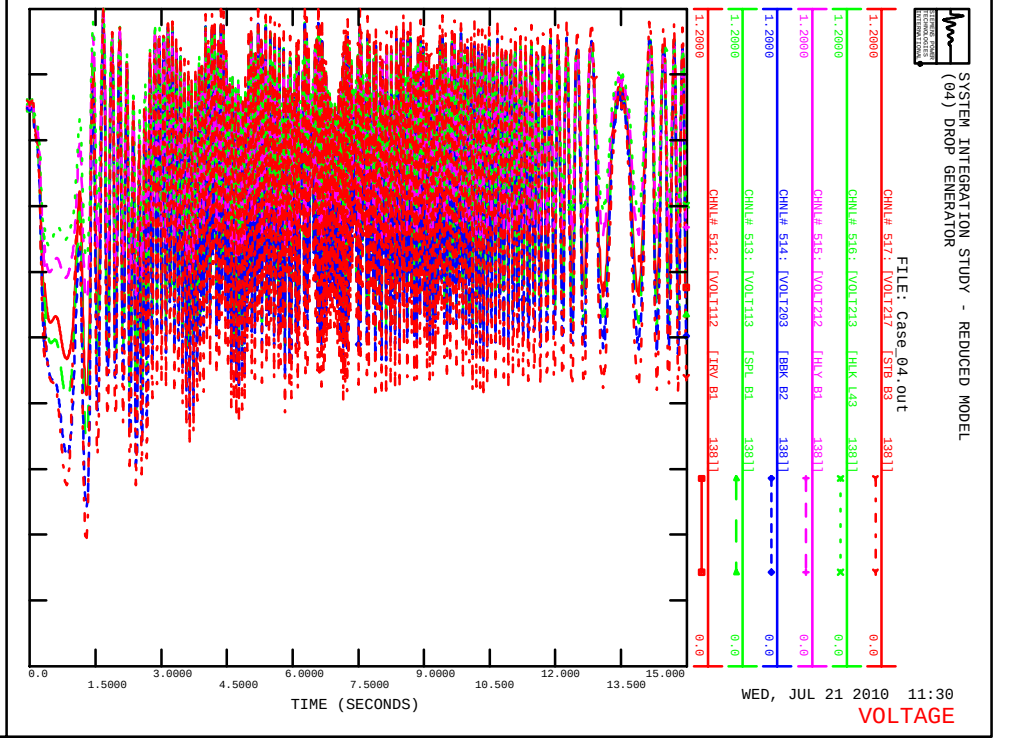

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 482: [VOLT345 [ULT TAP 661]
CHNL# 483: [VOLT346 [ULT NP 661]
CHNL# 484: [VOLT347 [SCV NP 661]
CHNL# 485: [VOLT348 [KEL NP 661]
CHNL# 486: [VOLT349 [CHA NP 661]
CHNL# 487: [VOLT455 [GDL NP 661]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

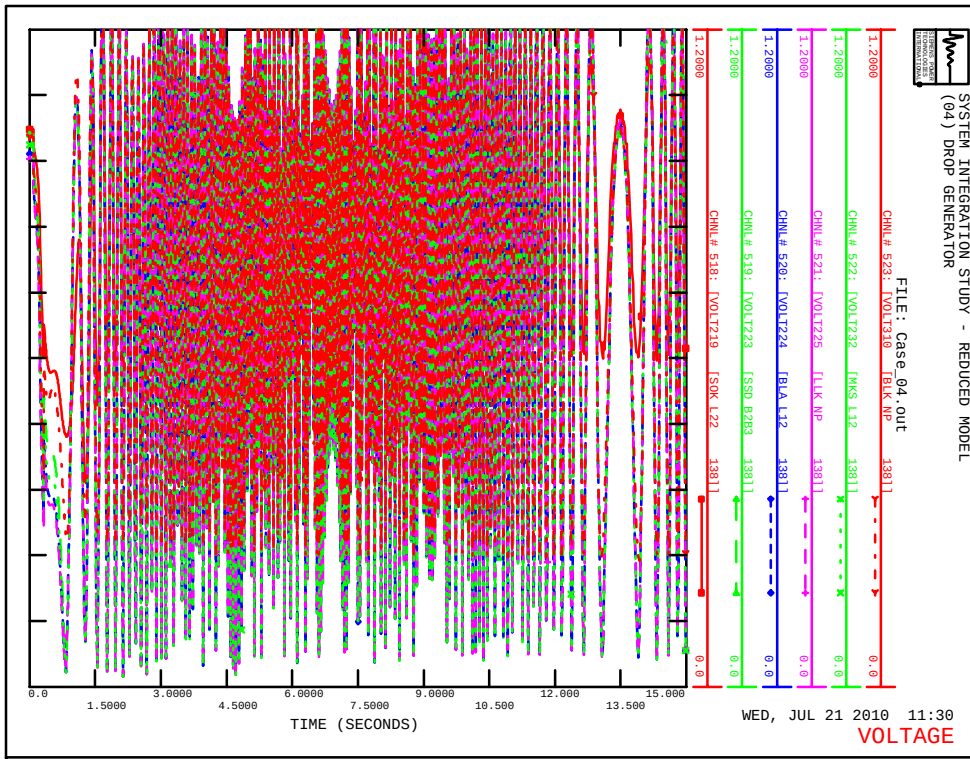

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 488: [VOLT457 [GOU NP 661]
CHNL# 489: [VOLT463 [KEN NP 661]
CHNL# 490: [VOLT466 [KBR NP 661]
CHNL# 491: [VOLT467 [TCV NP 661]
CHNL# 492: [VOLT469 [MUN NP 661]
CHNL# 493: [VOLT471 [MOL NP 661]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

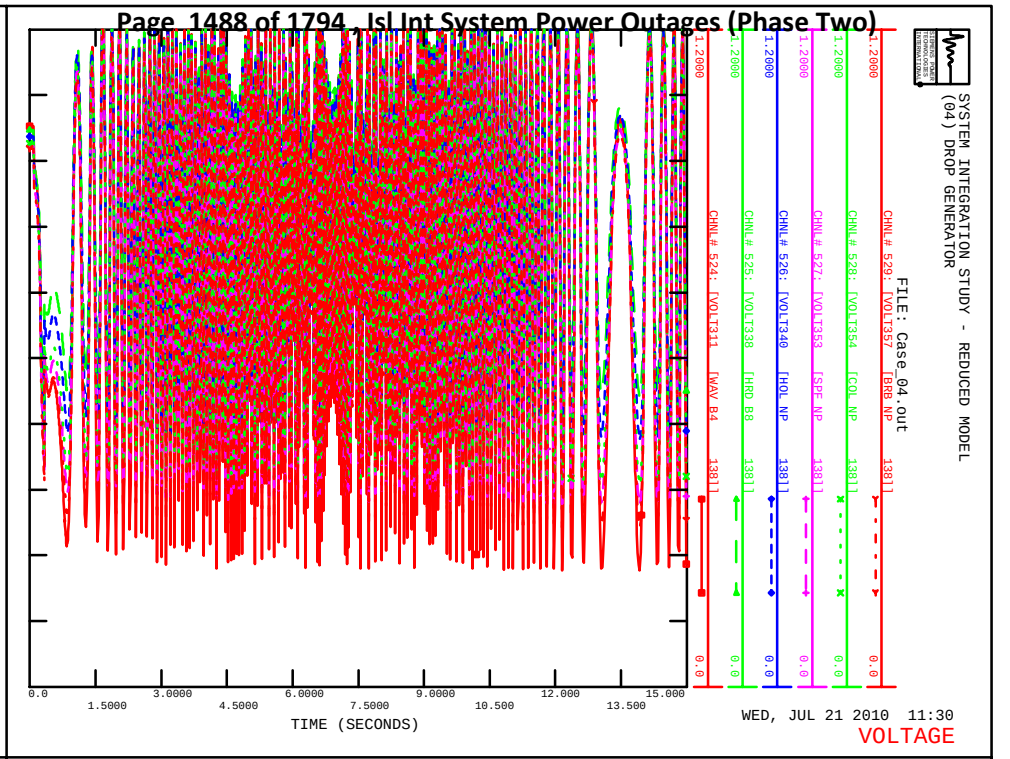

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 494: [VOLT474 [PEP NP 661]
CHNL# 495: [VOLT479 [PUL NP 661]
CHNL# 496: [VOLT481 [RRD NP 661]
CHNL# 497: [VOLT482 [MRP NP 661]
CHNL# 498: [VOLT484 [SJM NP 661]
CHNL# 499: [VOLT485 [HCP NP 661]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

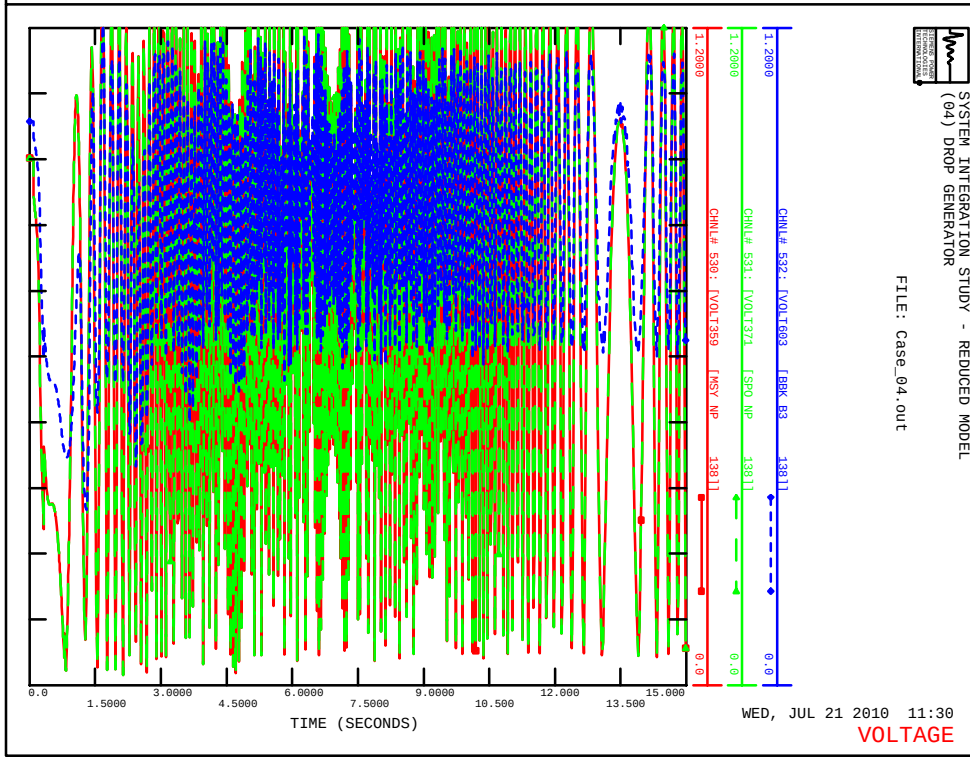

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 500: [VOLT489 [SLA NP 661]
CHNL# 501: [VOLT492 [VIR NP 661]
CHNL# 502: [VOLT510 [BIG NP 661]
CHNL# 503: [VOLT550 [MOB NP 661]
CHNL# 504: [VOLT558 [ROP NP 661]
CHNL# 505: [VOLT576 [CAB NP 661]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

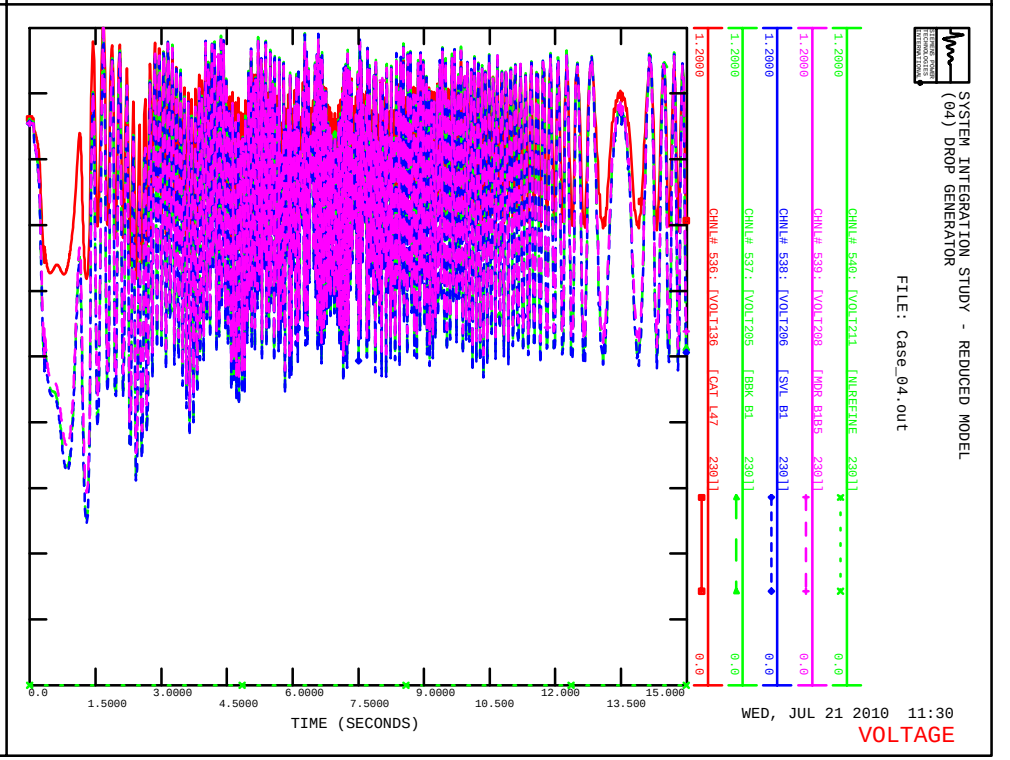

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 506: [VOLT579 [FER NP 661]
CHNL# 507: [VOLT870 [SLK L80 661]
CHNL# 508: [VOLT920 [MOB MID3 661]
CHNL# 509: [VOLT973 [GOU MID1 661]
CHNL# 510: [VOLT982 [CHA MID1 661]
CHNL# 511: [VOLT111 [DLK B1 1381]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

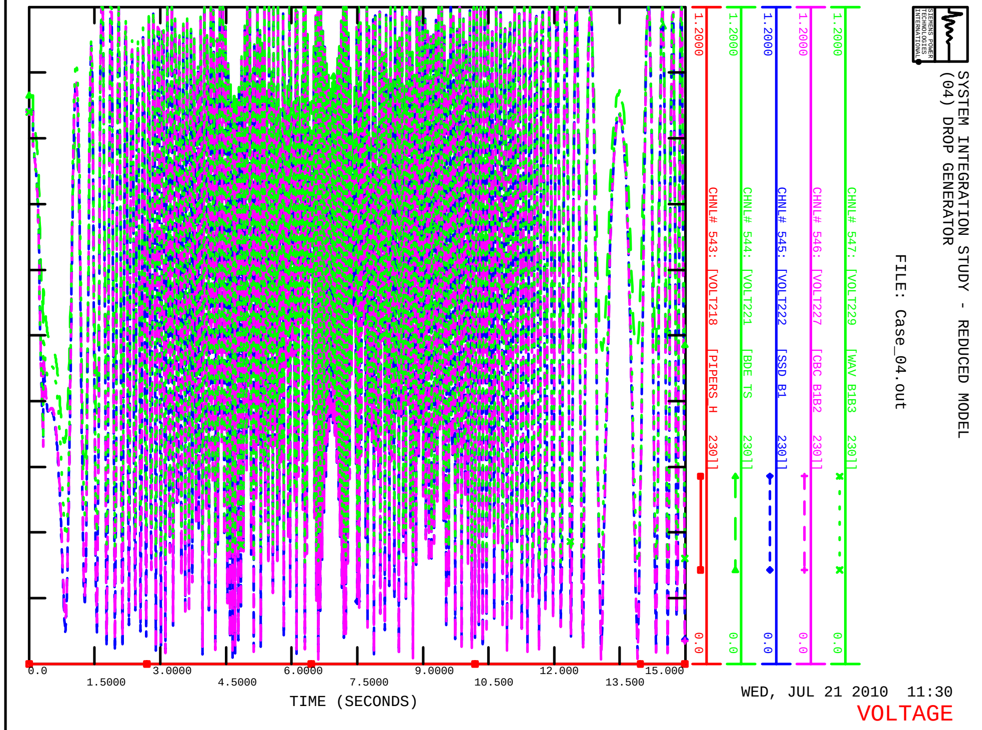

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 512: [VOLT112 [IRV B1 1381]
CHNL# 513: [VOLT113 [SPL B1 1381]
CHNL# 514: [VOLT203 [BBK B2 1381]
CHNL# 515: [VOLT232 [HLY B1 1381]
CHNL# 516: [VOLT213 [HLK L43 1381]
CHNL# 517: [VOLT237 [STB B3 1381]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

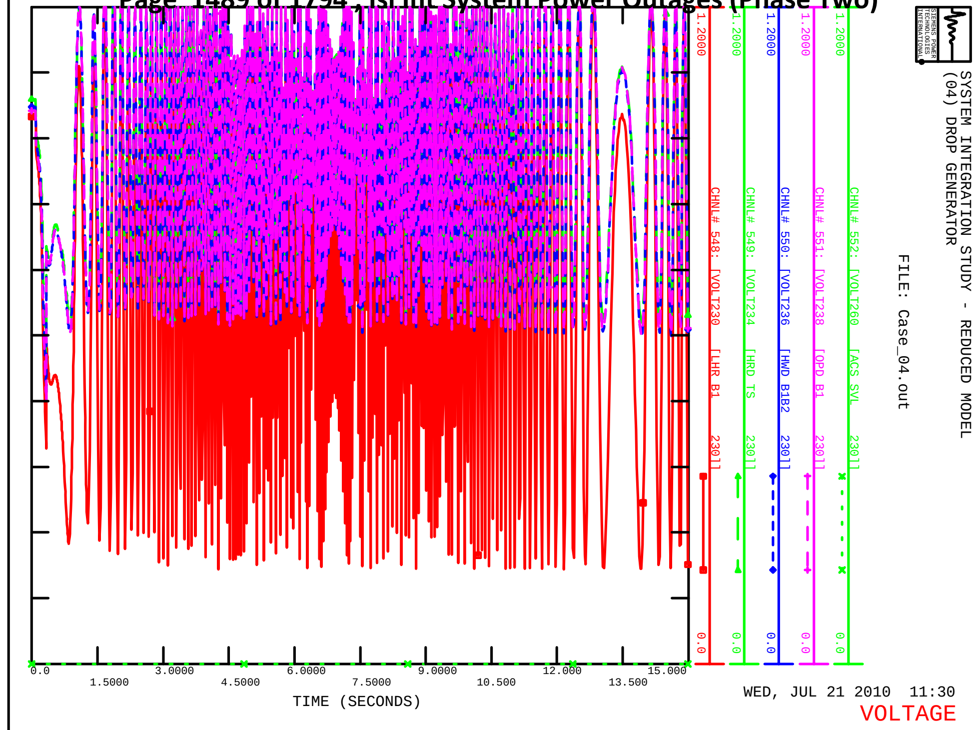

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 518: [VOLT219 [SOK L22 138]
CHNL# 519: [VOLT223 [SSD B2B3 138]
CHNL# 520: [VOLT224 [BLA L12 138]
CHNL# 521: [VOLT225 [LLK NP 138]
CHNL# 522: [VOLT232 [MKS L12 138]
CHNL# 523: [VOLT310 [BLK NP 138]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

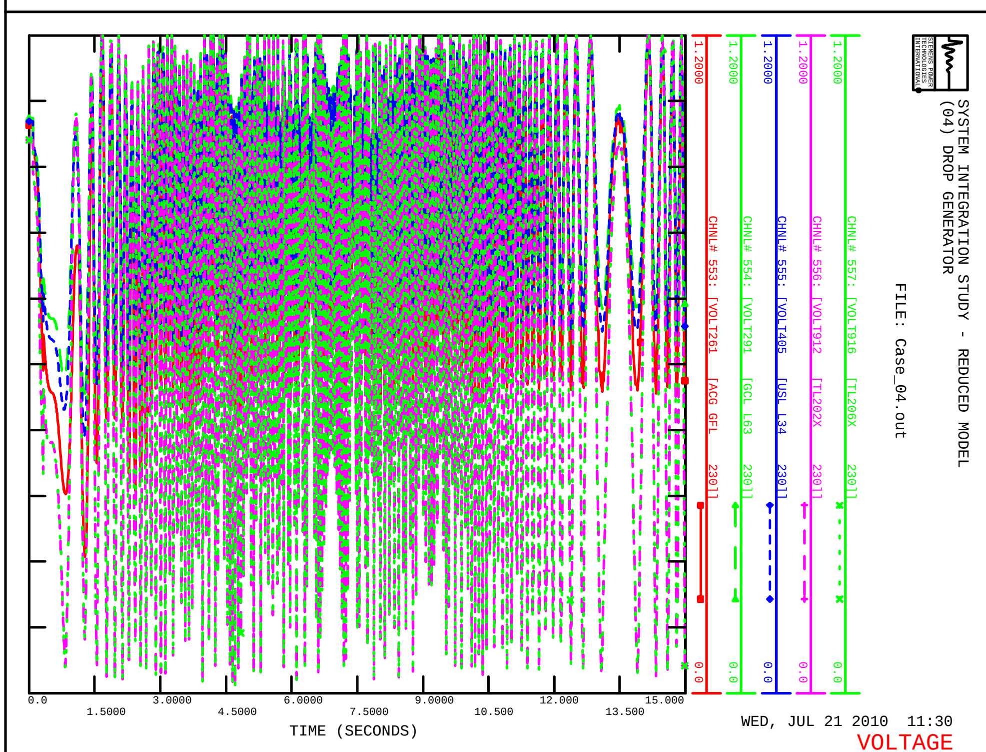

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 524: [VOLT311 [WAV B4 138]
CHNL# 525: [VOLT338 [HRD B8 138]
CHNL# 526: [VOLT340 [HOL NP 138]
CHNL# 527: [VOLT353 [SPF NP 138]
CHNL# 528: [VOLT354 [COL NP 138]
CHNL# 529: [VOLT357 [BKB NP 138]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

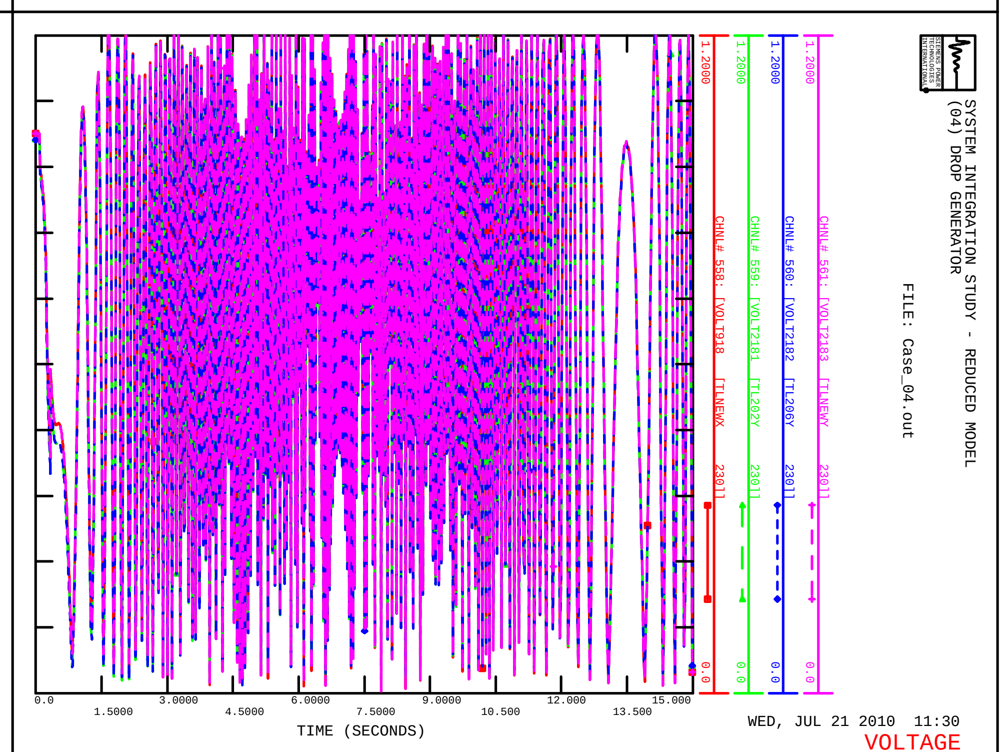

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 530: [VOLT359 [MSY NP 138]
CHNL# 531: [VOLT371 [SPD NP 138]
CHNL# 532: [VOLT603 [BBK B3 138]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

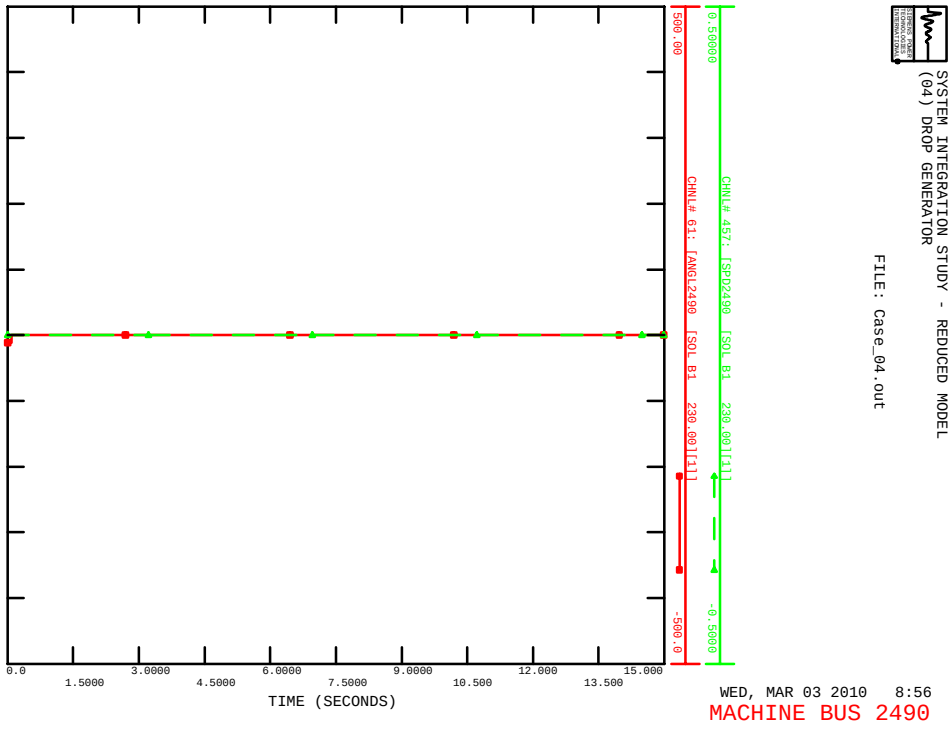

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 536: [VOLT136 [CAT L47 230]
CHNL# 537: [VOLT205 [BBK B1 230]
CHNL# 538: [VOLT206 [SVL B1 230]
CHNL# 539: [VOLT208 [MOR B1B5 230]
CHNL# 540: [VOLT211 [NLREFINE 230]
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

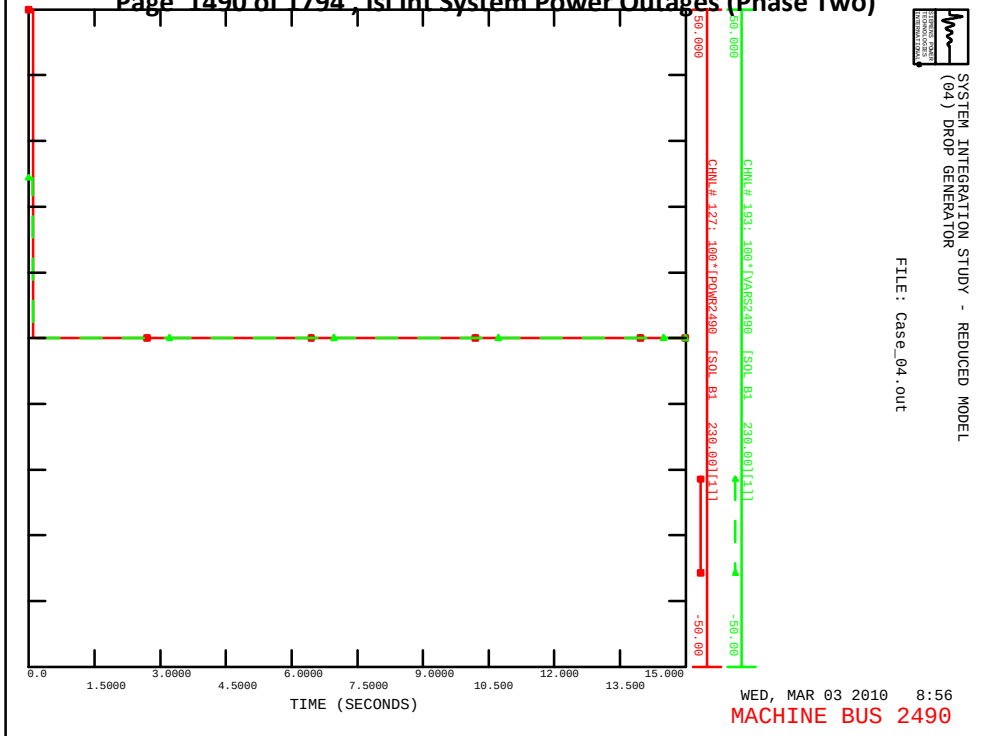

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 543: [VOLT218 [PIPERS H 230]]
CHNL# 544: [VOLT221 [BDE TS 230]]
CHNL# 545: [VOLT222 [SSD B1 230]]
CHNL# 546: [VOLT227 [CBC B1B2 230]]
CHNL# 547: [VOLT229 [WAV B1B3 230]]
1.2000
0.0
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

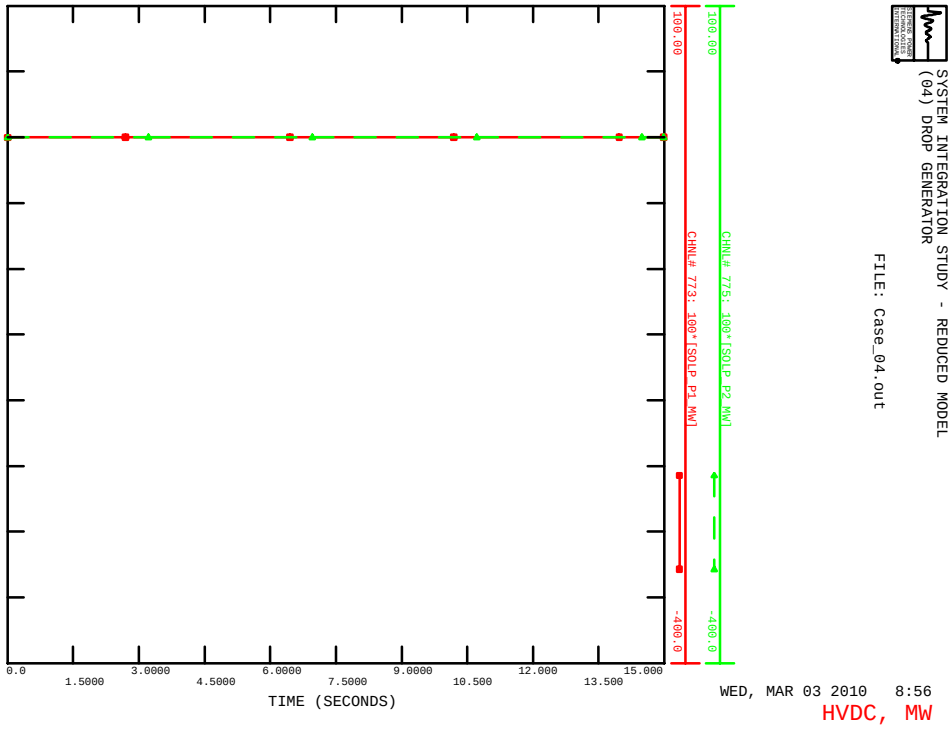

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 548: [VOLT230 [LHR B1 230]]
CHNL# 549: [VOLT234 [HRD TS 230]]
CHNL# 550: [VOLT236 [HWD B1B2 230]]
CHNL# 551: [VOLT238 [OPD B1 230]]
CHNL# 552: [VOLT260 [ACS SVL 230]]
1.2000
0.0
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

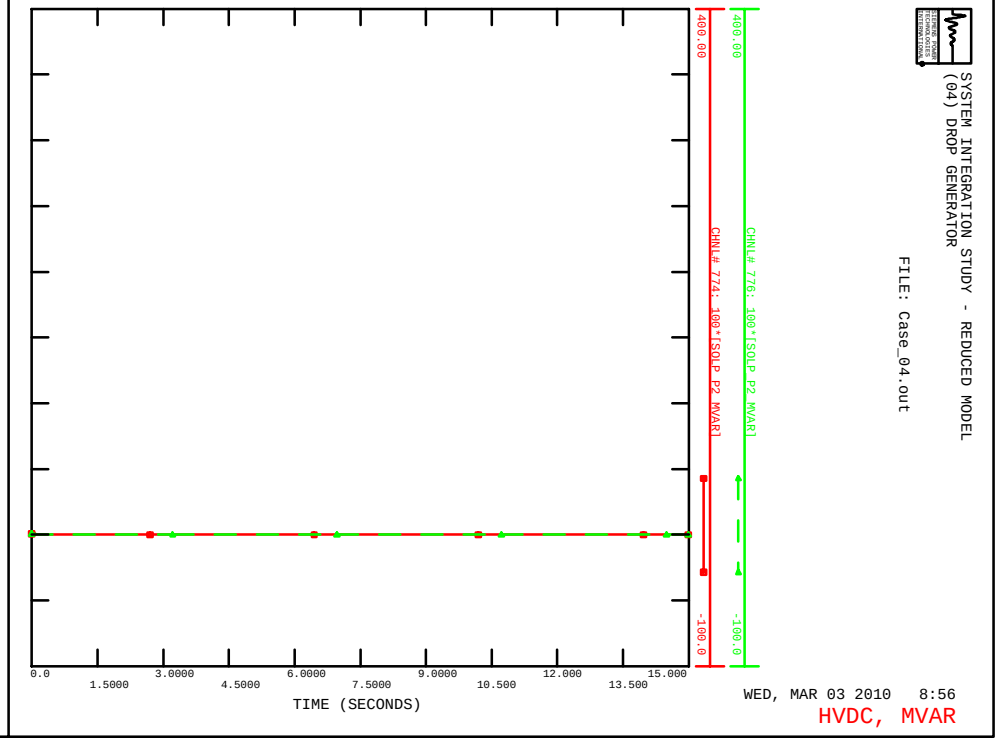

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 553: [VOLT261 [ACG GFL 230]]
CHNL# 554: [VOLT291 [GCL L63 230]]
CHNL# 555: [VOLT405 [USL L34 230]]
CHNL# 556: [VOLT912 [TL202X 230]]
CHNL# 557: [VOLT916 [TL206X 230]]
1.2000
0.0
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

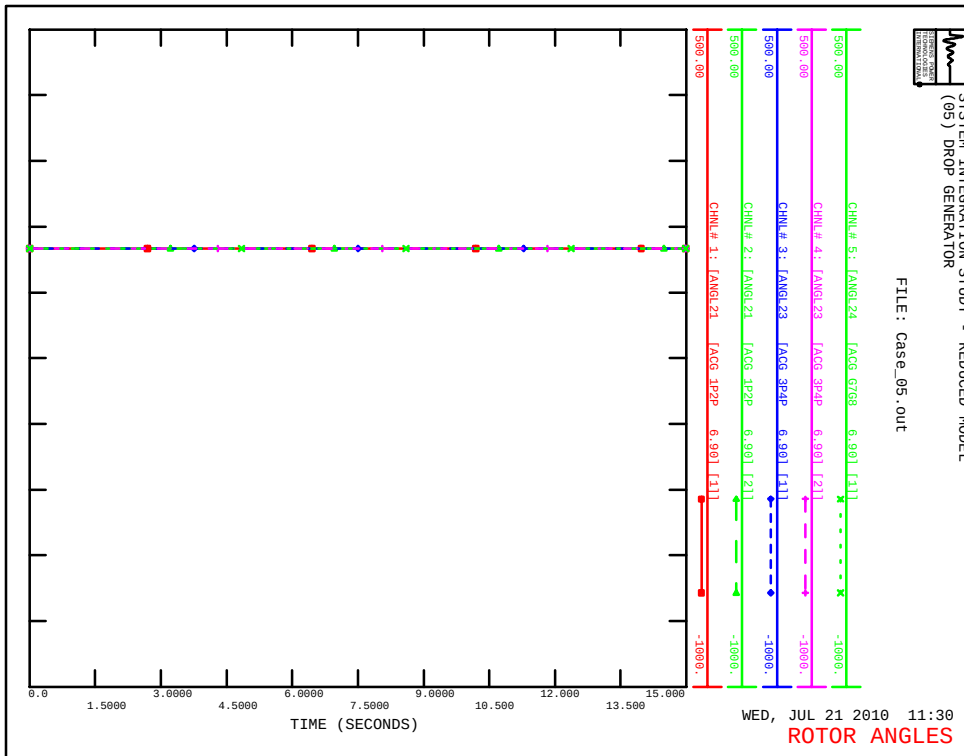

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
CHNL# 558: [VOLT918 [TLNEWX 230]]
CHNL# 559: [VOLT2181 [TL202Y 230]]
CHNL# 560: [VOLT2182 [TL206Y 230]]
CHNL# 561: [VOLT2183 [TLNEWY 230]]
1.2000
0.0
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
VOLTAGE

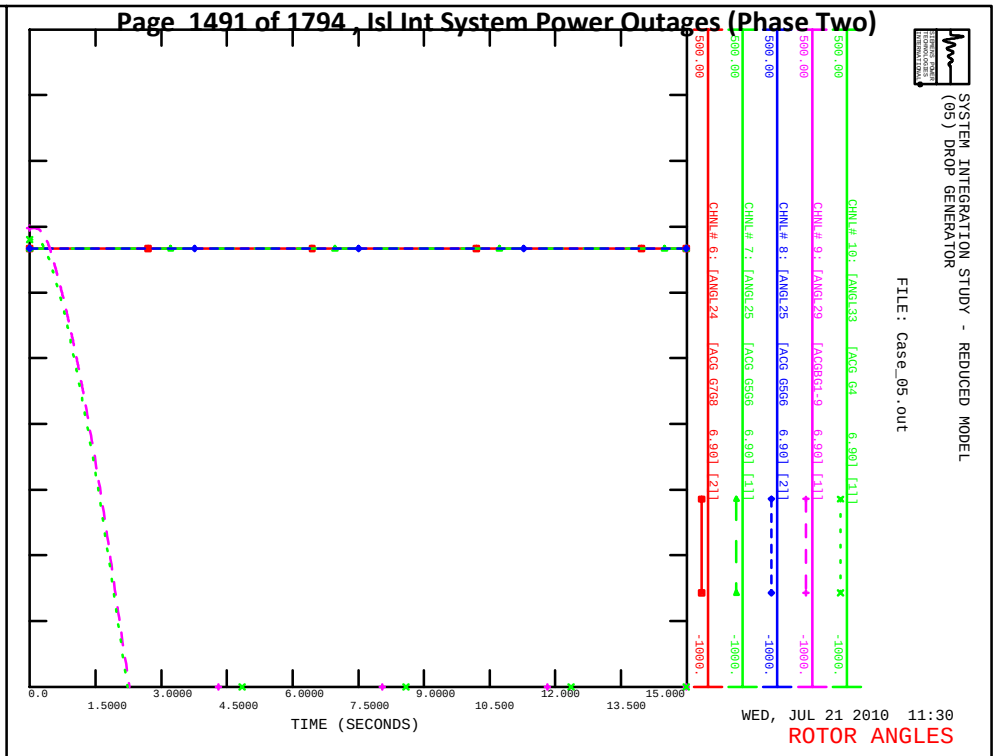

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
500.00
CHNL# 61: [ANGL2490 [SOL B1 230.00[11]
-500.0
0.50000
CHNL# 457: [SPD2490 [SOL B1 230.00[11]
-0.5000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, MAR 03 2010 8:56
MACHINE BUS 2490

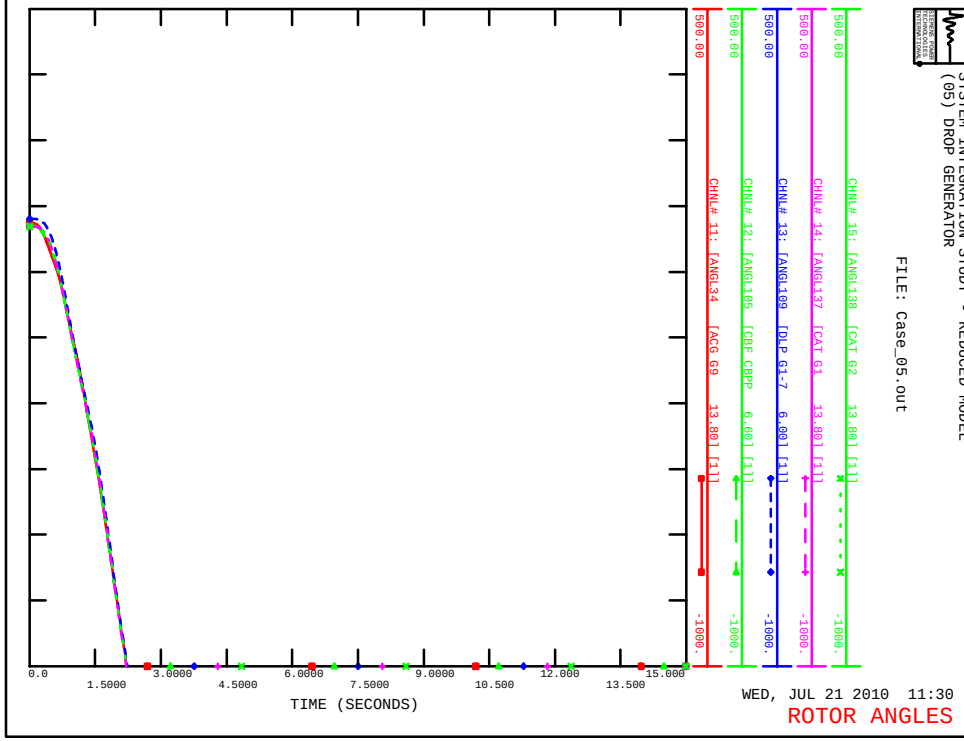

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
50.000
CHNL# 127: 100*[POWR2490 [SOL B1 230.00[11]
-50.00
50.000
CHNL# 193: 100*[VARS2490 [SOL B1 230.00[11]
-50.00
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, MAR 03 2010 8:56
MACHINE BUS 2490

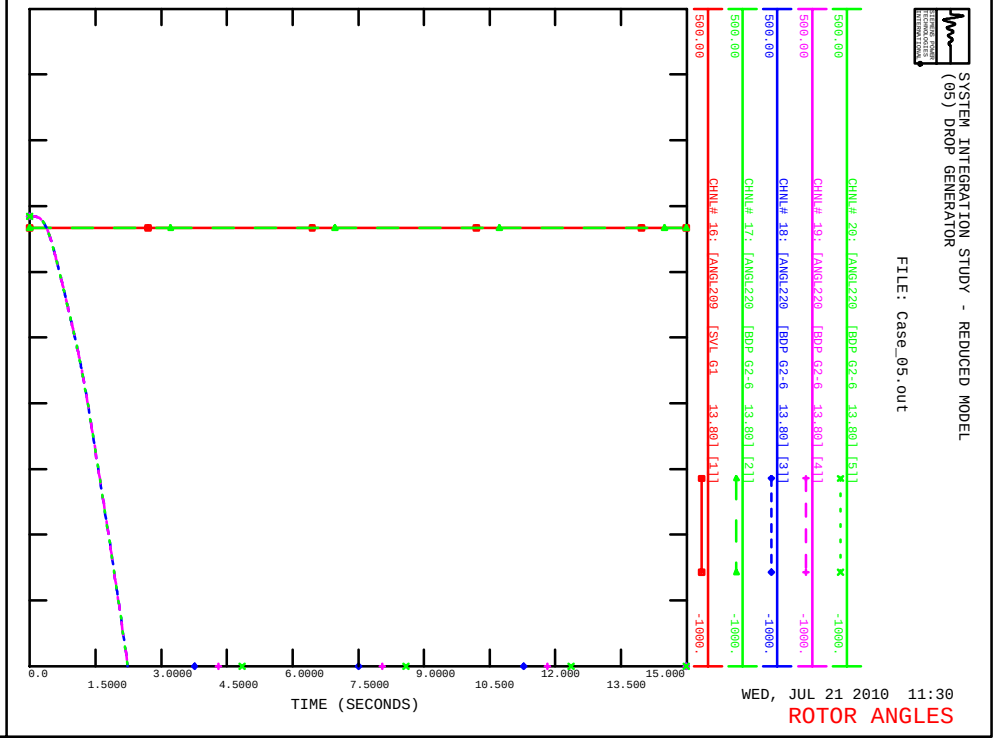

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
100.00
CHNL# 773: 100*[SOLP P1 MW]
-400.0
100.00
CHNL# 775: 100*[SOLP P2 MW]
-400.0
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, MAR 03 2010 8:56
HVDC, MW

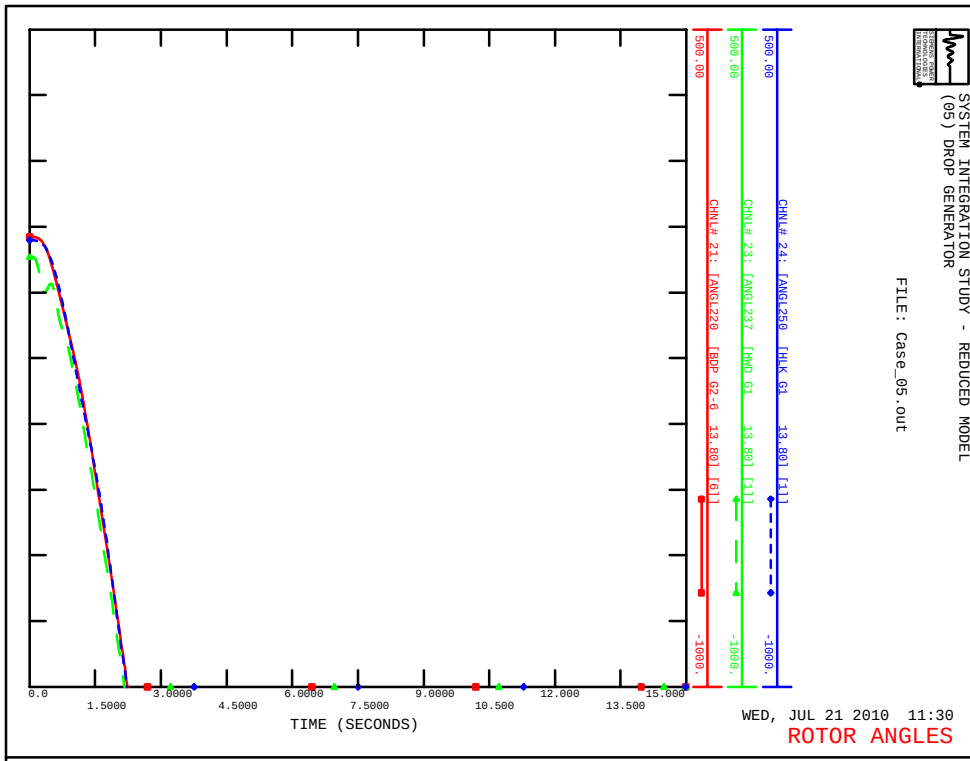

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(04) DROP GENERATOR
FILE: Case_04.out
400.00
CHNL# 774: 100*[SOLP P2 MVAR]
-100.0
400.00
CHNL# 776: 100*[SOLP P2 MVAR]
-100.0
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, MAR 03 2010 8:56
HVDC, MVAR

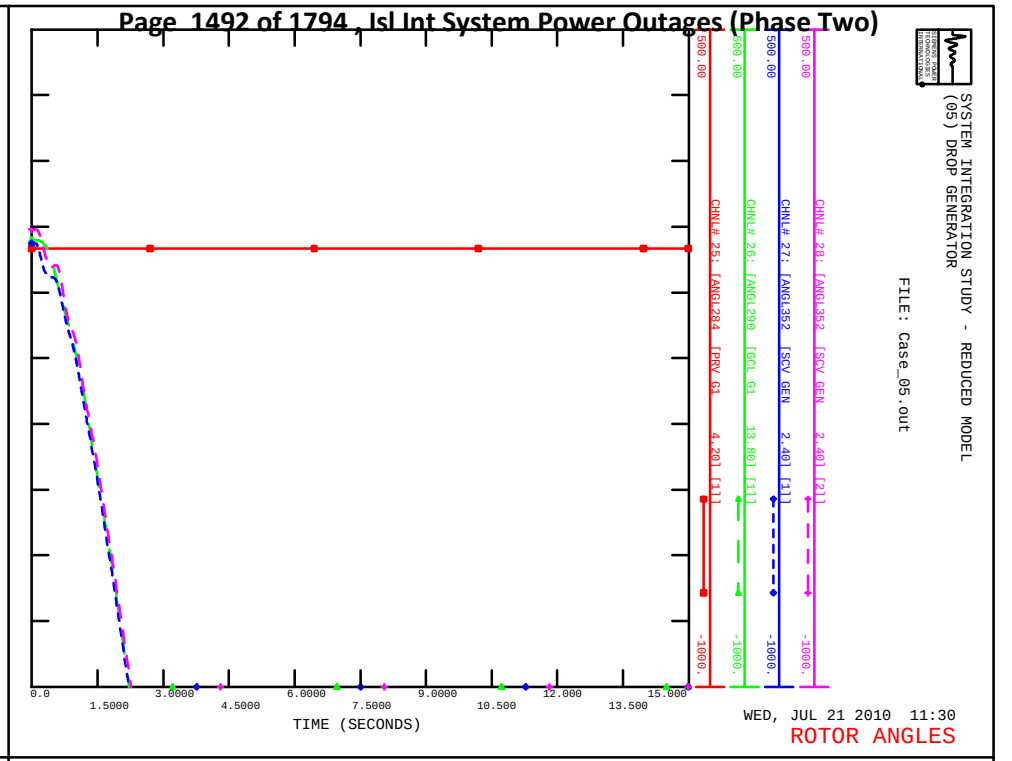

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 1: [ANGL21 [ACG 1P2P 6.90] [1]]
CHNL# 2: [ANGL21 [ACG 1P2P 6.90] [2]]
CHNL# 3: [ANGL23 [ACG 3P4P 6.90] [1]]
CHNL# 4: [ANGL23 [ACG 3P4P 6.90] [2]]
CHNL# 5: [ANGL24 [ACG G7G8 6.90] [1]]
500.00
-1000.
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

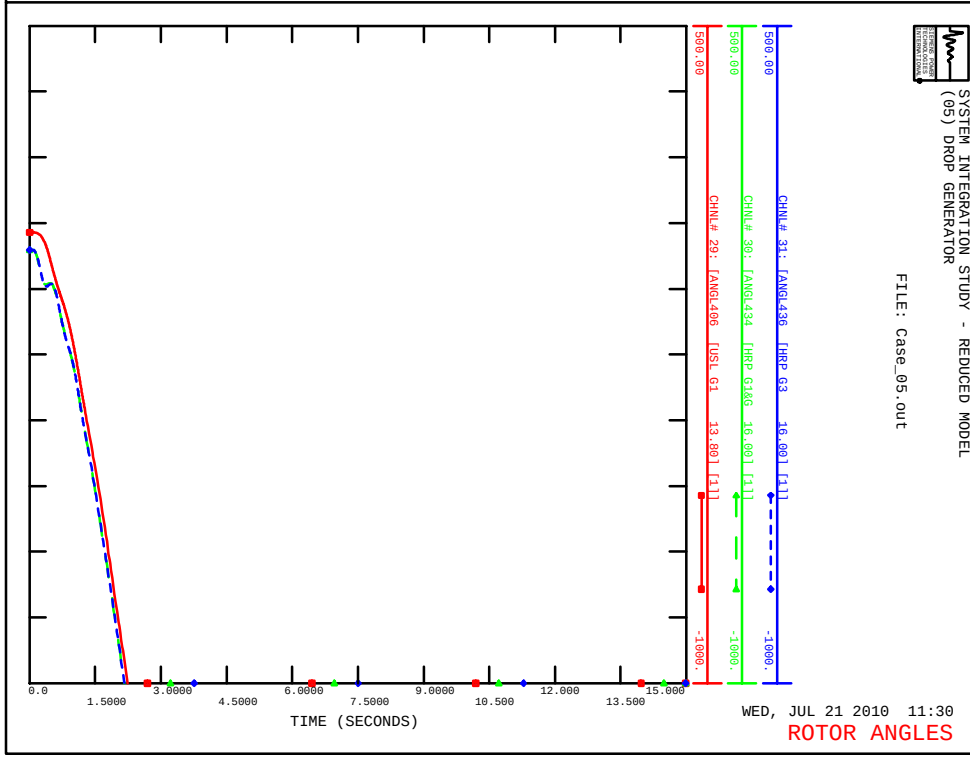

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 6: [ANGL24 [ACG G7G8 6.90] [2]]
CHNL# 7: [ANGL25 [ACG G5G6 6.90] [1]]
CHNL# 8: [ANGL25 [ACG G5G6 6.90] [2]]
CHNL# 9: [ANGL29 [ACGBG1-9 6.90] [1]]
CHNL# 10: [ANGL33 [ACG G4 6.90] [1]]
500.00
-1000.
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

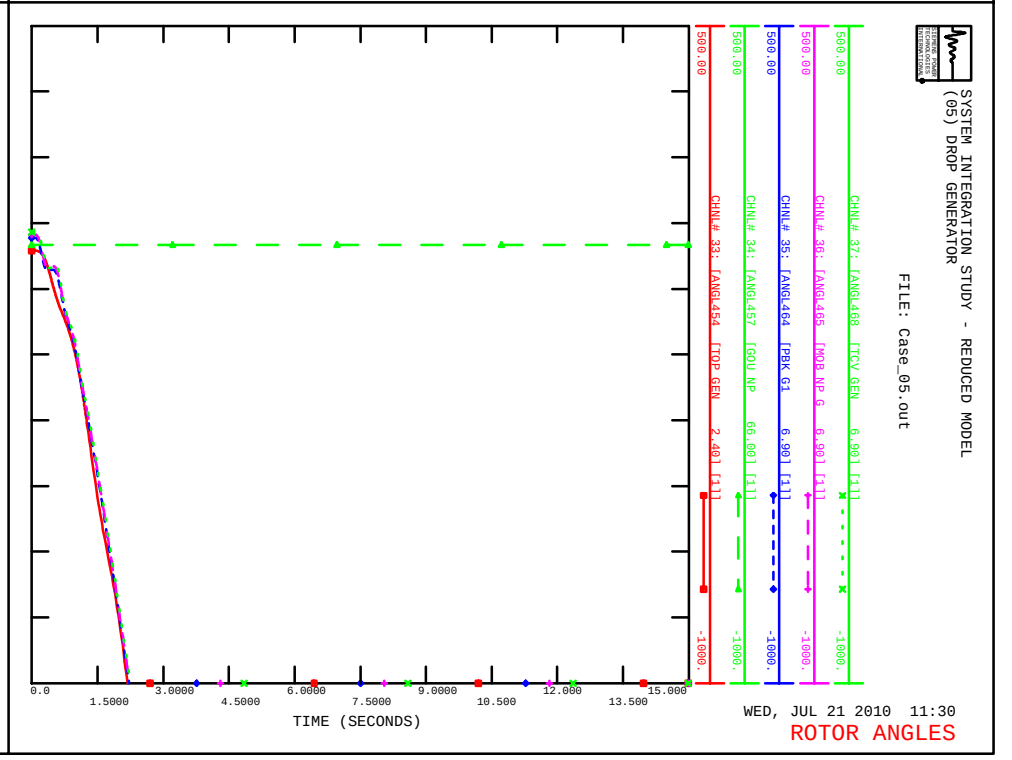

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 11: [ANGL34 [ACG G9 13.80] [1]]
CHNL# 12: [ANGL105 [CBF CBPP 6.60] [1]]
CHNL# 13: [ANGL109 [DLP G1-7 6.00] [1]]
CHNL# 14: [ANGL137 [CAT G1 13.80] [1]]
CHNL# 15: [ANGL138 [CAT G2 13.80] [1]]
500.00
-1000.
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

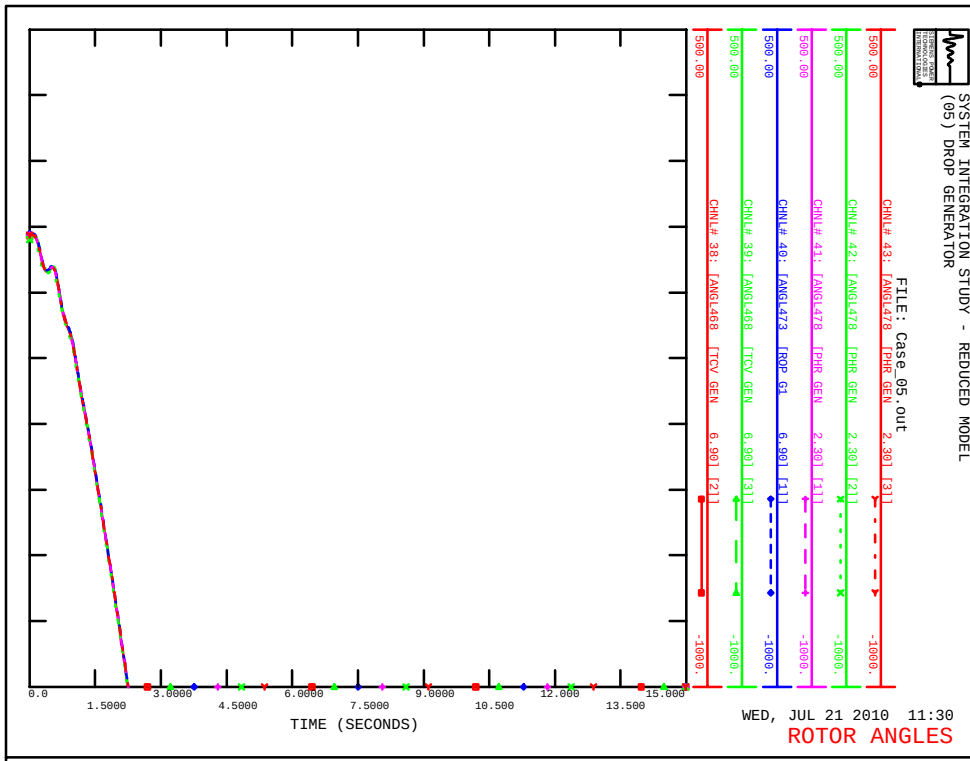

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 16: [ANGL209 [SVL G1 13.80] [1]]
CHNL# 17: [ANGL220 [BDP G2-6 13.80] [2]]
CHNL# 18: [ANGL220 [BDP G2-6 13.80] [3]]
CHNL# 19: [ANGL220 [BDP G2-6 13.80] [4]]
CHNL# 20: [ANGL220 [BDP G2-6 13.80] [5]]
500.00
-1000.
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

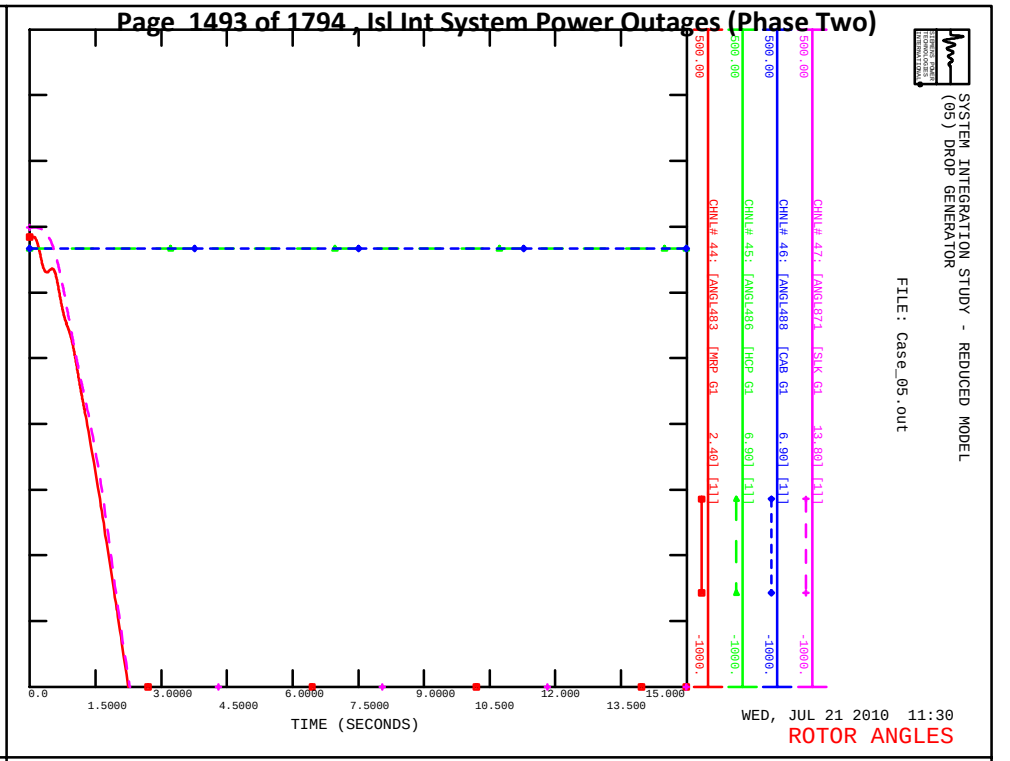

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 21: [ANGL220 [BDP G2-6 13.80] [61]
CHNL# 23: [ANGL237 [HND G1 13.80] [1]
CHNL# 24: [ANGL250 [HLK G1 13.80] [11]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

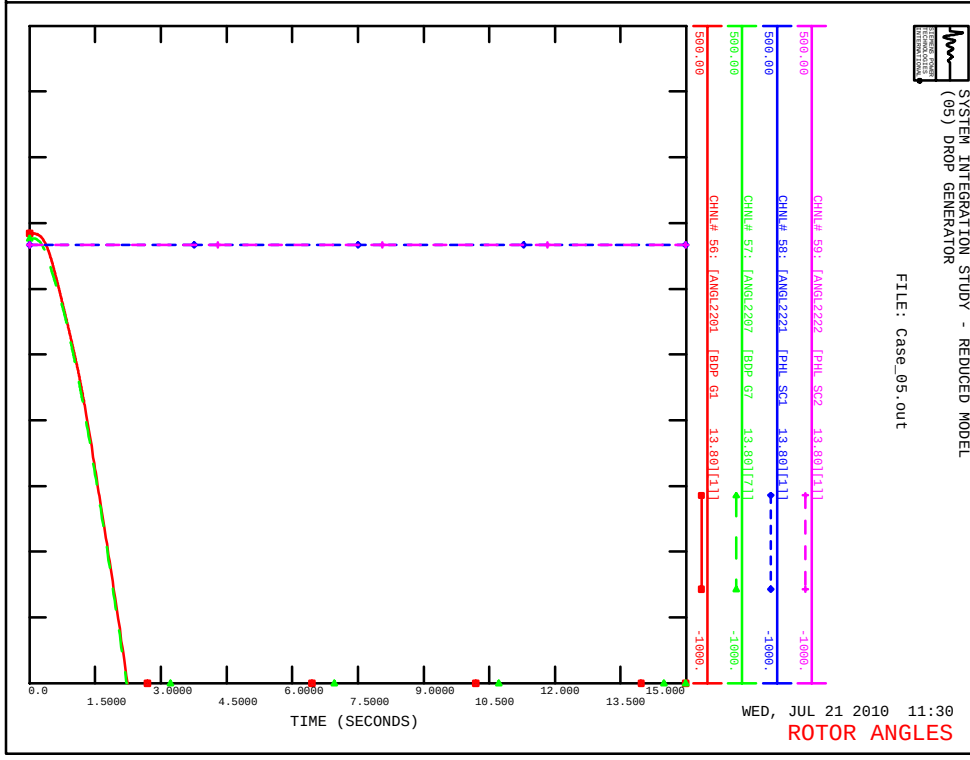

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 25: [ANGL284 [PRV G1 4.20] [11]
CHNL# 26: [ANGL290 [GCL G1 13.80] [11]
CHNL# 27: [ANGL352 [SCV GEN 2.40] [11]
CHNL# 28: [ANGL352 [SCV GEN 2.40] [21]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

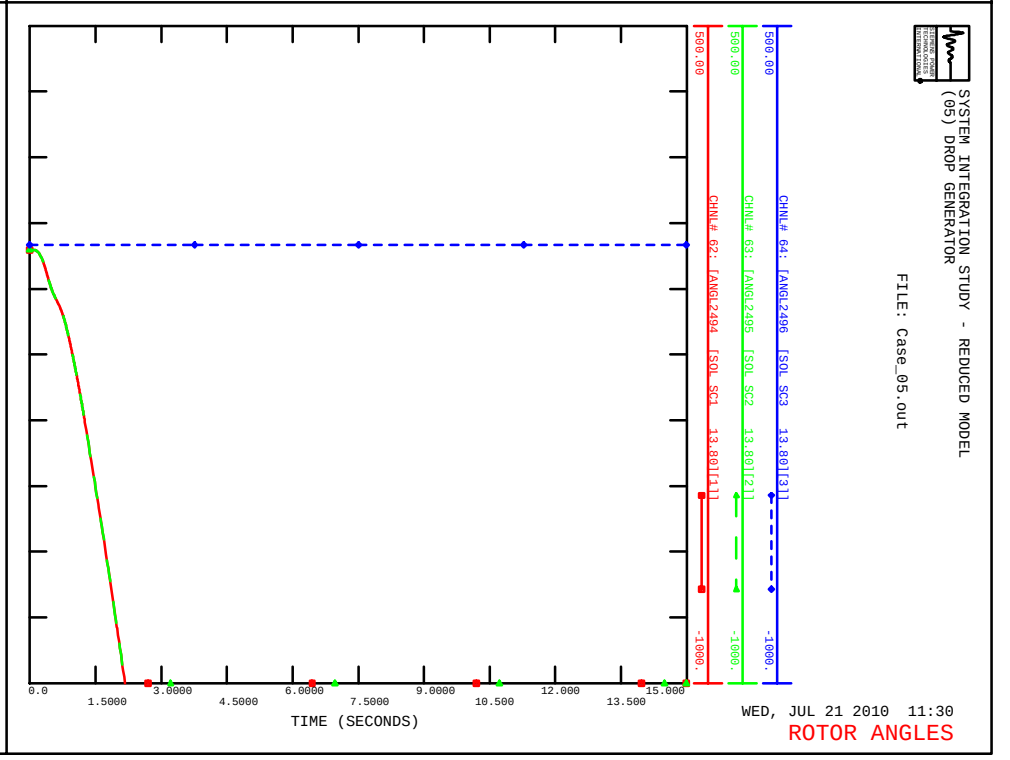

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 29: [ANGL406 [USL G1 13.80] [11]
CHNL# 30: [ANGL434 [HRP G1&G 16.00] [11]
CHNL# 31: [ANGL436 [HRP G3 16.00] [11]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

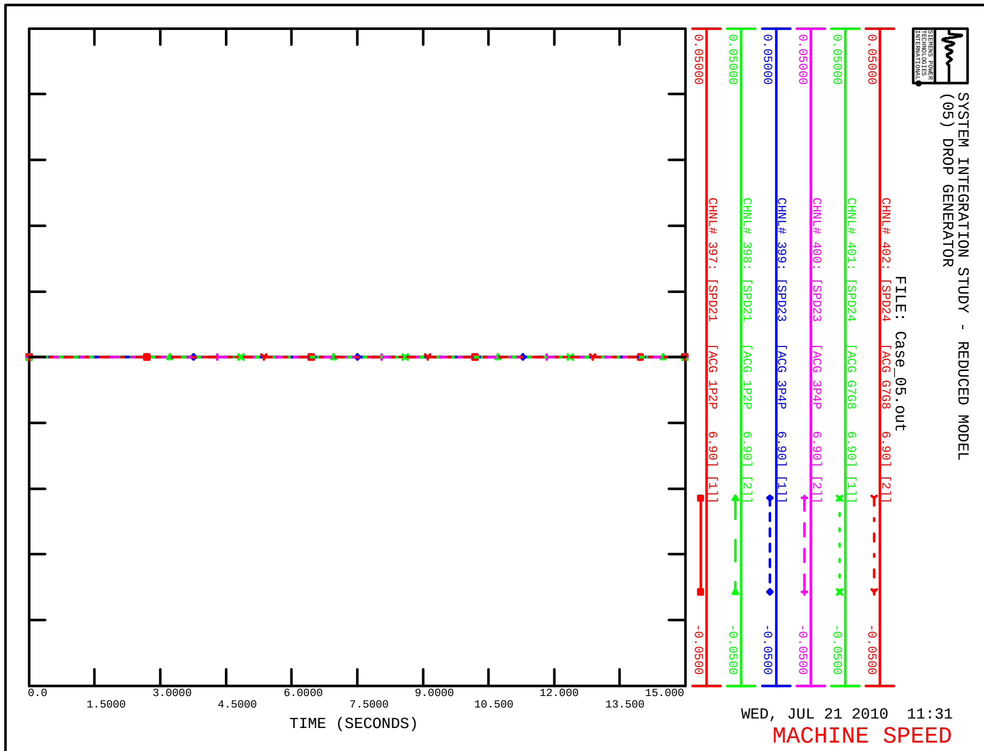

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 33: [ANGL454 [TOP GEN 2.40] [11]
CHNL# 34: [ANGL457 [CGU NP 66.00] [11]
CHNL# 35: [ANGL464 [PBK G1 6.90] [11]
CHNL# 36: [ANGL465 [MOB NP G 6.90] [11]
CHNL# 37: [ANGL468 [TCV GEN 6.90] [11]
TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

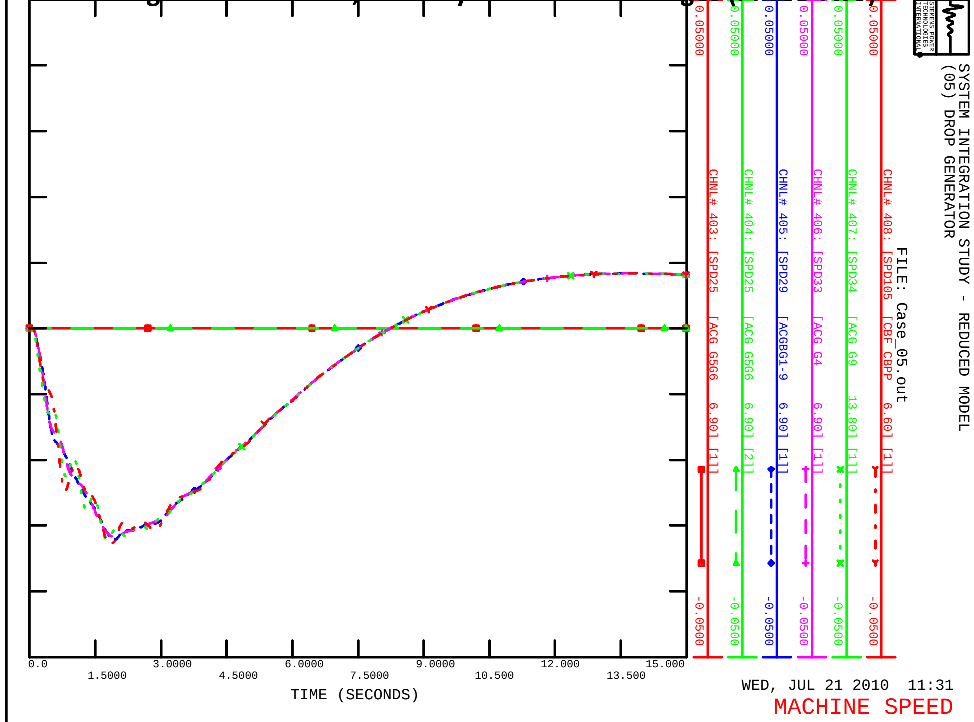

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 38: [ANGL468 [TCV GEN 6.90] [2]]
CHNL# 39: [ANGL468 [TCV GEN 6.90] [3]]
CHNL# 40: [ANGL473 [ROP G1 6.90] [1]]
CHNL# 41: [ANGL478 [PHR GEN 2.30] [1]]
CHNL# 42: [ANGL478 [PHR GEN 2.30] [2]]
CHNL# 43: [ANGL478 [PHR GEN 2.30] [3]]
500.00
-1000.
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TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

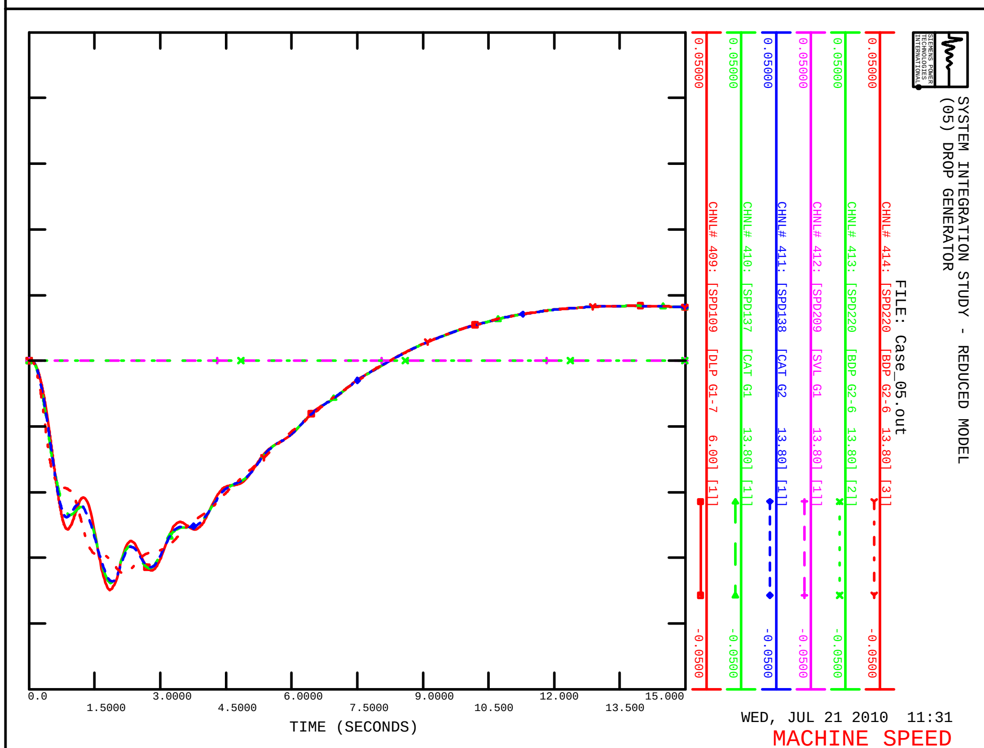

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 44: [ANGL483 [MRP G1 2.40] [1]]
CHNL# 45: [ANGL486 [HCP G1 6.90] [1]]
CHNL# 46: [ANGL488 [CAB G1 6.90] [1]]
CHNL# 47: [ANGL871 [SLK G1 13.80] [1]]
500.00
-1000.
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TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

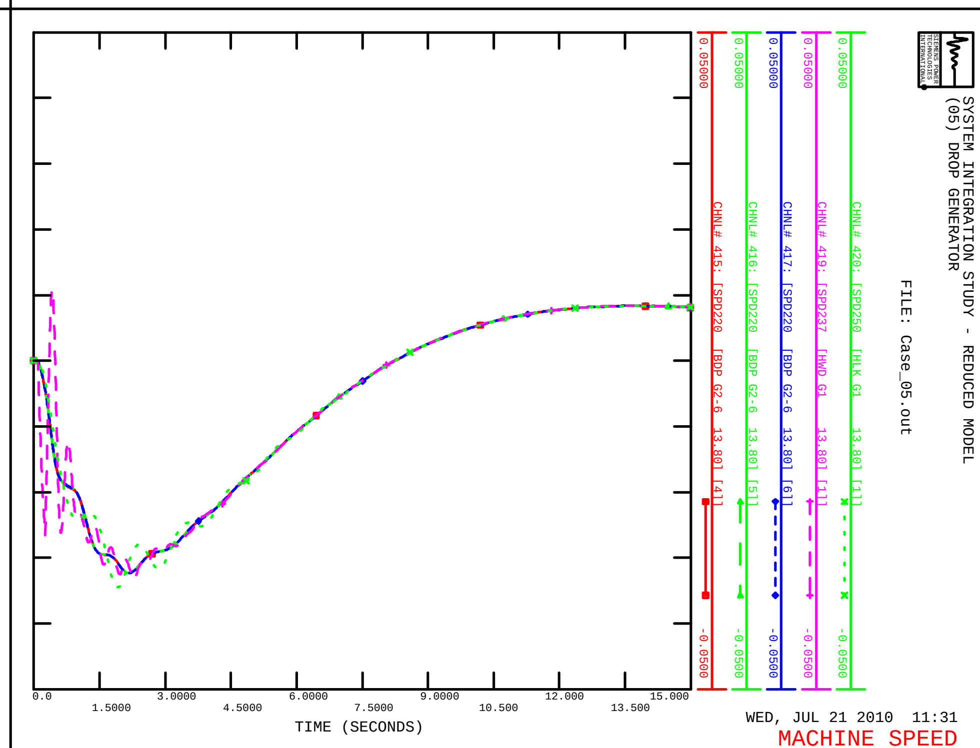

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 56: [ANGL2201 [BDP G1 13.80] [1]]
CHNL# 57: [ANGL2207 [BDP G7 13.80] [7]]
CHNL# 58: [ANGL2221 [PHL SC1 13.80] [1]]
CHNL# 59: [ANGL2222 [PHL SC2 13.80] [1]]
500.00
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TIME (SECONDS)
WED, JUL 21 2010 11:30
ROTOR ANGLES

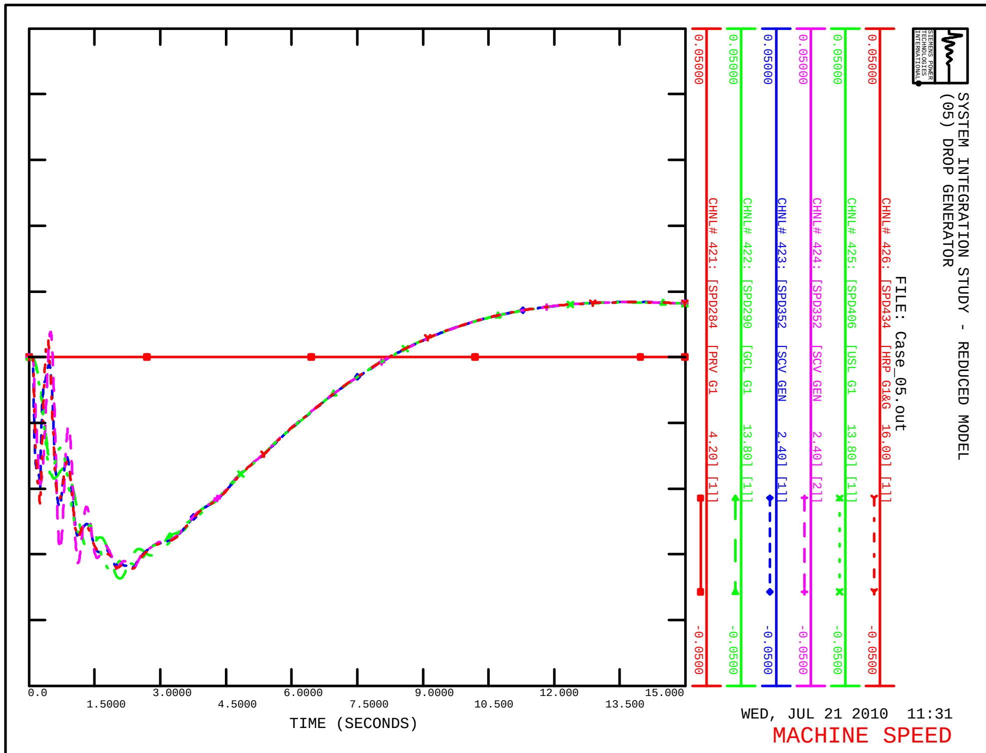

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 62: [ANGL2494 [SOL SC1 13.80] [1]]
CHNL# 63: [ANGL2495 [SOL SC2 13.80] [2]]
CHNL# 64: [ANGL2496 [SOL SC3 13.80] [3]]
500.00
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WED, JUL 21 2010 11:30
ROTOR ANGLES

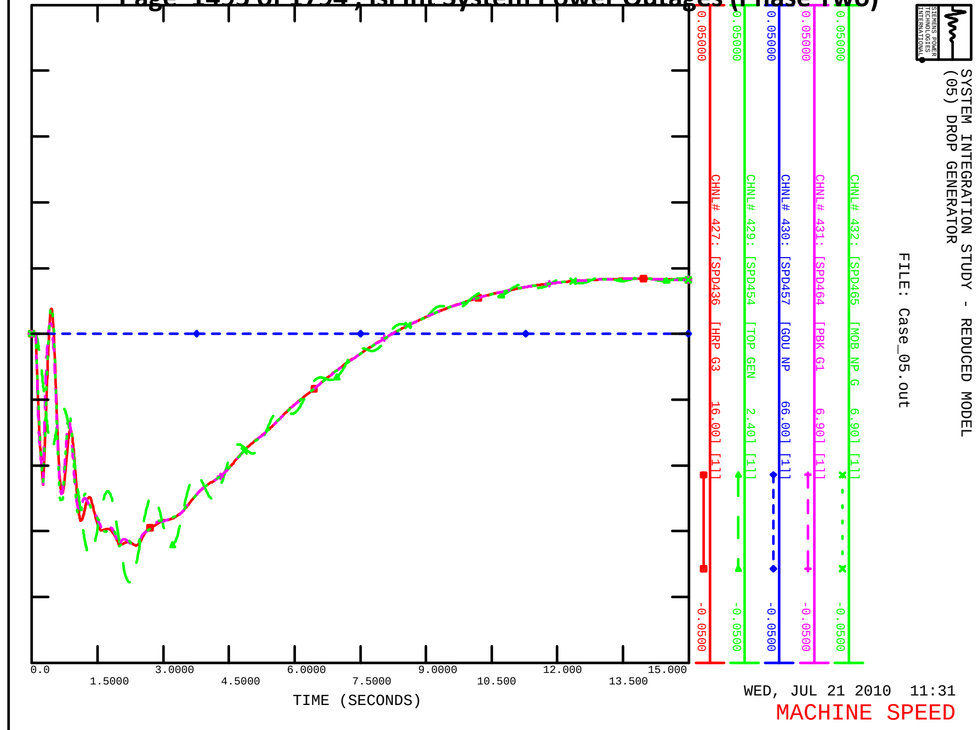

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 397: [SPD21 [ACG 1P2P 6.90] [1]
CHNL# 398: [SPD21 [ACG 1P2P 6.90] [2]
CHNL# 399: [SPD23 [ACG 3P4P 6.90] [1]
CHNL# 400: [SPD23 [ACG 3P4P 6.90] [2]
CHNL# 401: [SPD24 [ACG G7G8 6.90] [1]
CHNL# 402: [SPD24 [ACG G7G8 6.90] [2]
0.05000
-0.0500
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TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

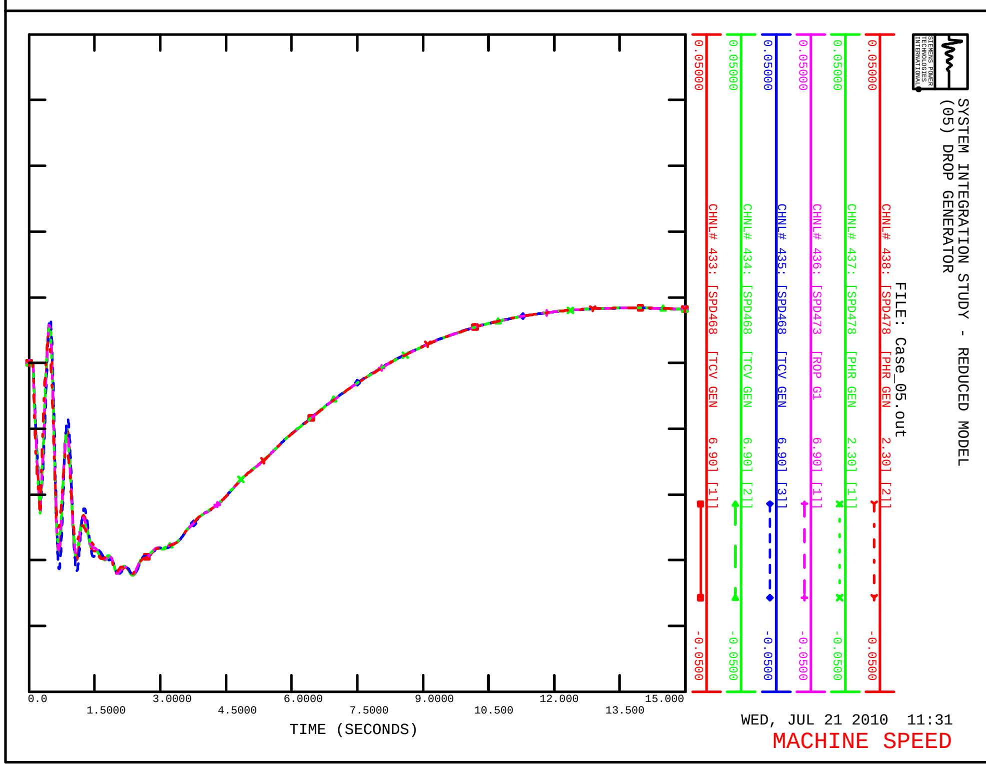

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 403: [SPD25 [ACG G5G6 6.90] [1]
CHNL# 404: [SPD25 [ACG G5G6 6.90] [2]
CHNL# 405: [SPD29 [ACGBG1-9 6.90] [1]
CHNL# 406: [SPD33 [ACG G4 6.90] [1]
CHNL# 407: [SPD34 [ACG G9 13.80] [1]
CHNL# 408: [SPD105 [CBF CBPP 6.60] [1]
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TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

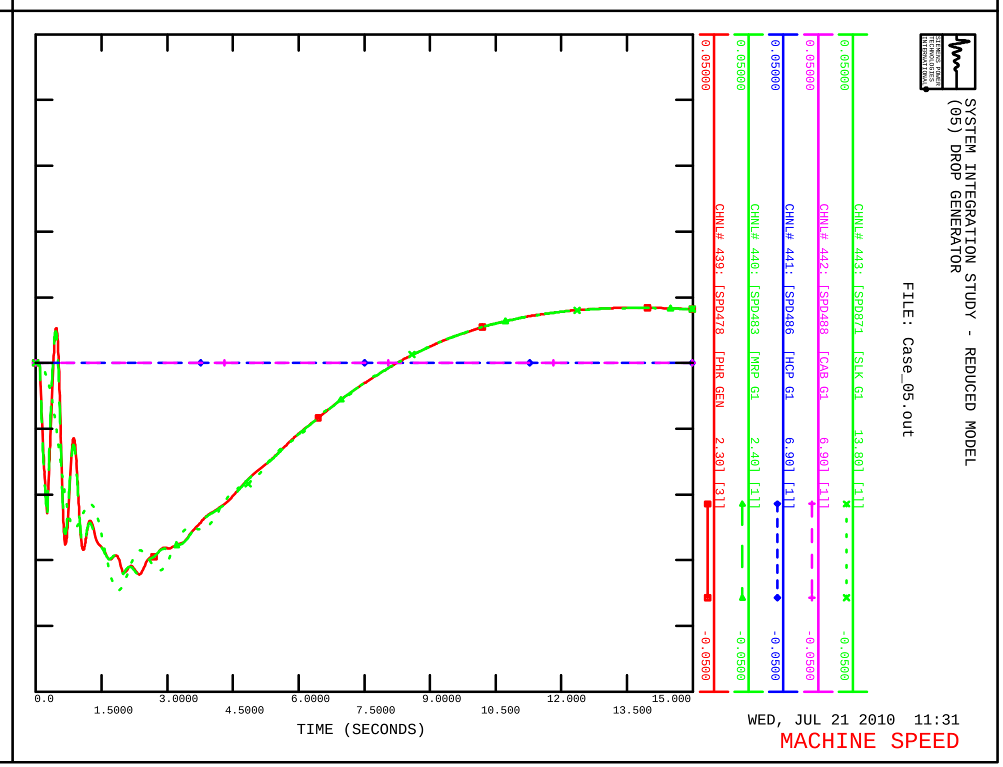

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 409: [SPD109 [DLP G1-7 6.00] [1]
CHNL# 410: [SPD137 [CAT G1 13.80] [1]
CHNL# 411: [SPD138 [CAT G2 13.80] [1]
CHNL# 412: [SPD209 [SVL G1 13.80] [1]
CHNL# 413: [SPD220 [BDP G2-6 13.80] [2]
CHNL# 414: [SPD220 [BDP G2-6 13.80] [3]
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TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

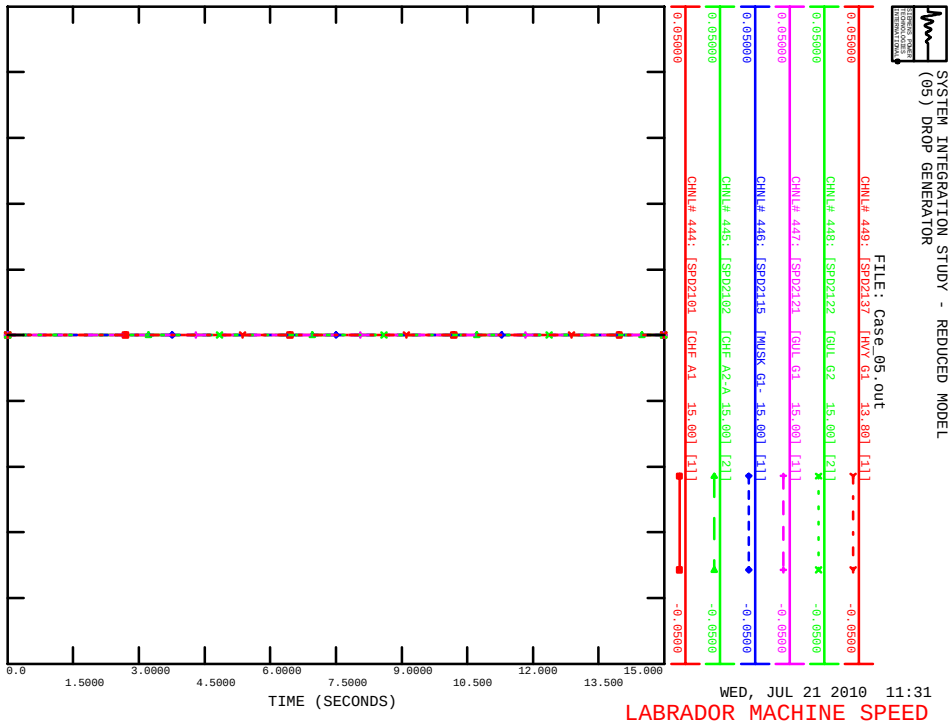

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 415: [SPD220 [BDP G2-6 13.80] [4]
CHNL# 416: [SPD220 [BDP G2-6 13.80] [5]
CHNL# 417: [SPD220 [BDP G2-6 13.80] [6]
CHNL# 419: [SPD237 [HWD G1 13.80] [1]
CHNL# 420: [SPD250 [HLK G1 13.80] [1]
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12.000
13.500
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TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

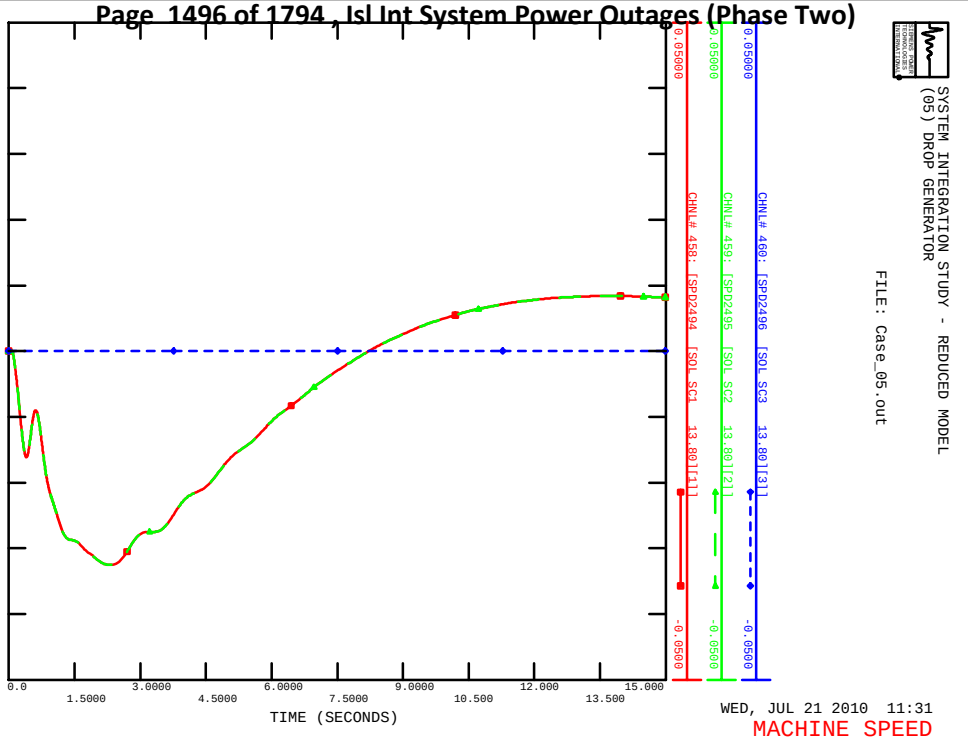

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 421: [SPD284 [PRV G1 4.20] [1]
CHNL# 422: [SPD290 [GCL G1 13.80] [1]
CHNL# 423: [SPD352 [SCV GEN 2.40] [1]
CHNL# 424: [SPD352 [SCV GEN 2.40] [2]
CHNL# 425: [SPD406 [USL G1 13.80] [1]
CHNL# 426: [SPD434 [HRP G1&G 16.00] [1]
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12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

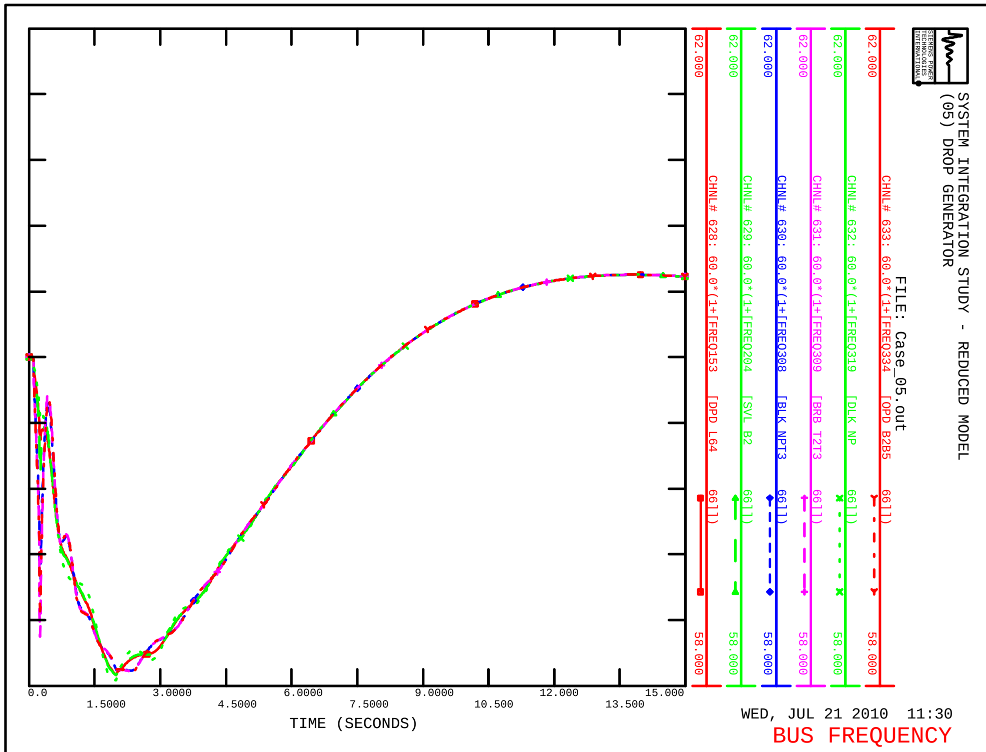

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 427: [SPD436 [HRP G3 16.00] [1]
CHNL# 429: [SPD454 [TOP GEN 2.40] [1]
CHNL# 430: [SPD457 [GOU NP 66.00] [1]
CHNL# 431: [SPD464 [PBK G1 6.90] [1]
CHNL# 432: [SPD465 [MOB NP G 6.90] [1]
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1.5000
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10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

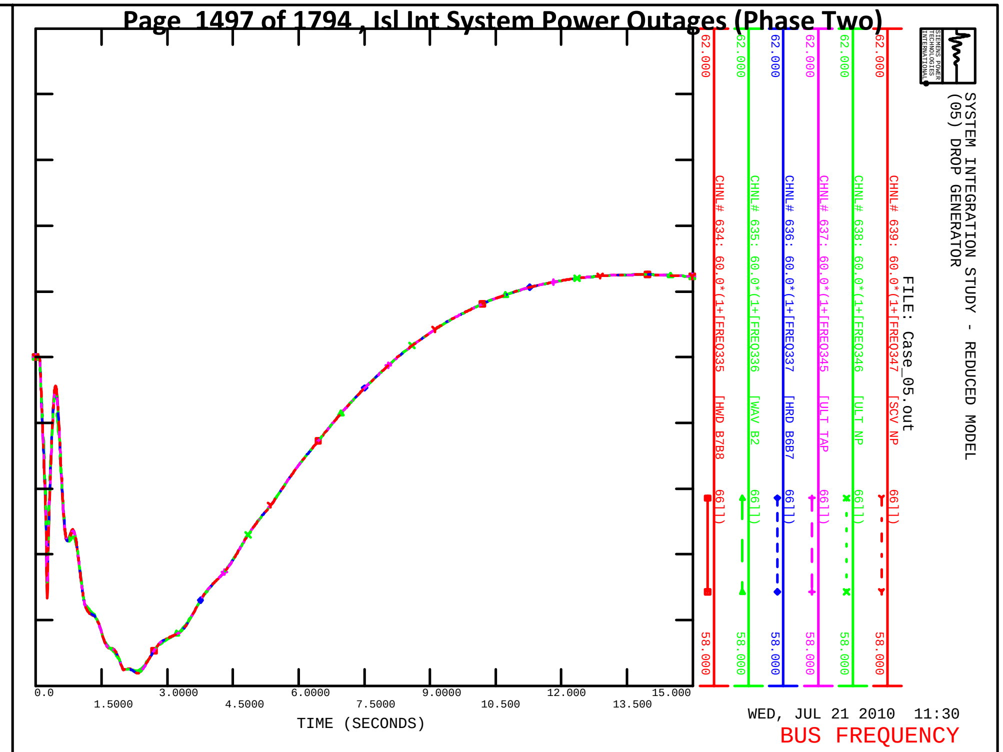

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 433: [SPD468 [TCV GEN 6.90] [1]
CHNL# 434: [SPD468 [TCV GEN 6.90] [2]
CHNL# 435: [SPD468 [TCV GEN 6.90] [3]
CHNL# 436: [SPD473 [ROP G1 6.90] [1]
CHNL# 437: [SPD478 [PHR GEN 2.30] [1]
CHNL# 438: [SPD478 [PHR GEN 2.30] [2]
0.05000
-0.0500
0.0
1.5000
3.0000
4.5000
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12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

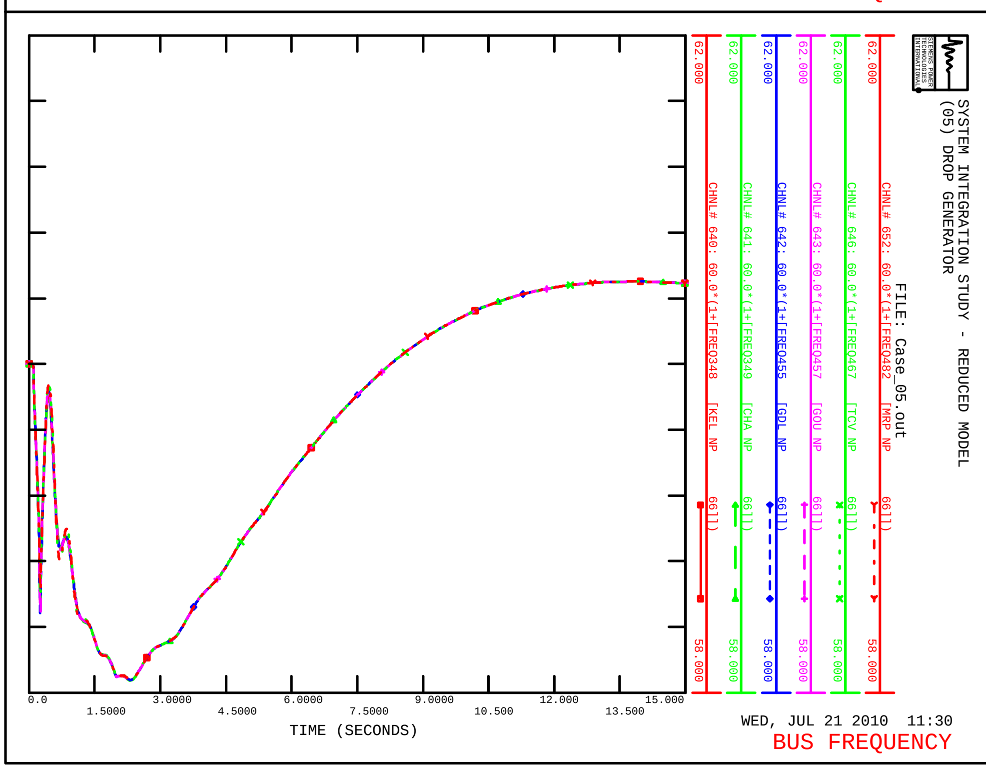

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 439: [SPD478 [PHR GEN 2.30] [3]
CHNL# 440: [SPD483 [MRP G1 2.40] [1]
CHNL# 441: [SPD486 [HCP G1 6.90] [1]
CHNL# 442: [SPD488 [CAB G1 6.90] [1]
CHNL# 443: [SPD871 [SLK G1 13.80] [1]
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-0.0500
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1.5000
3.0000
4.5000
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7.5000
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12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

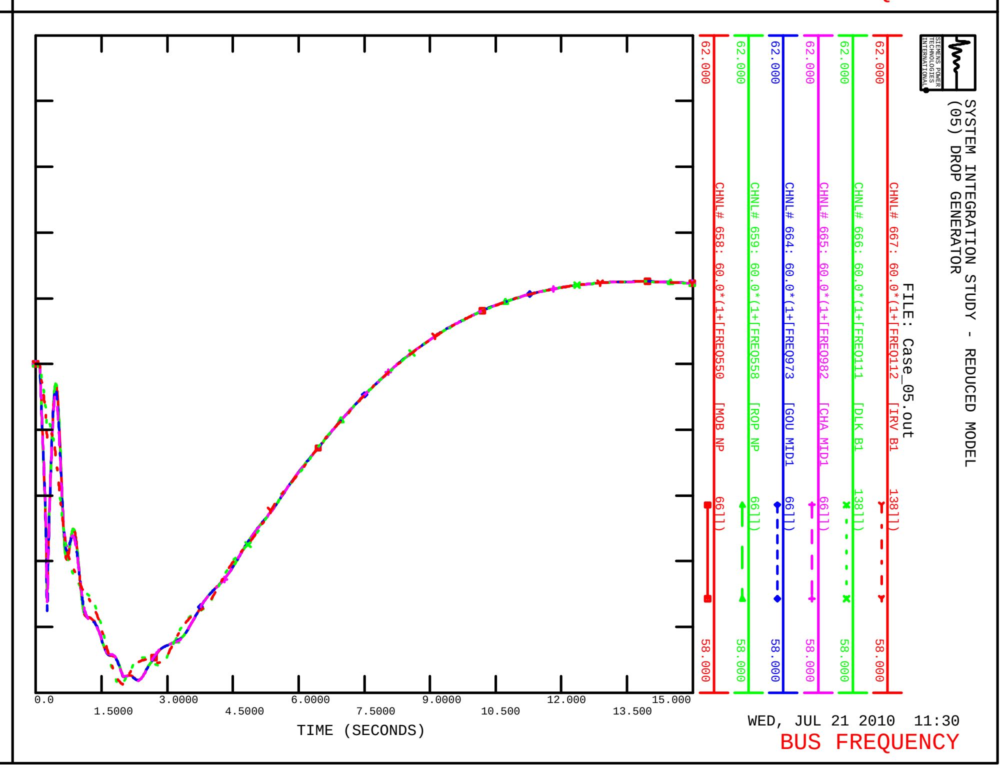

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 444: [SPD2101 [CHF A1 15.00] [1]]
CHNL# 445: [SPD2102 [CHF A2-A 15.00] [2]]
CHNL# 446: [SPD2115 [MUSK G1- 15.00] [1]]
CHNL# 447: [SPD2121 [GUL G1 15.00] [1]]
CHNL# 448: [SPD2122 [GUL G2 15.00] [2]]
CHNL# 449: [SPD2137 [HVY G1 13.80] [1]]
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TIME (SECONDS)
WED, JUL 21 2010 11:31
LABRADOR MACHINE SPEED

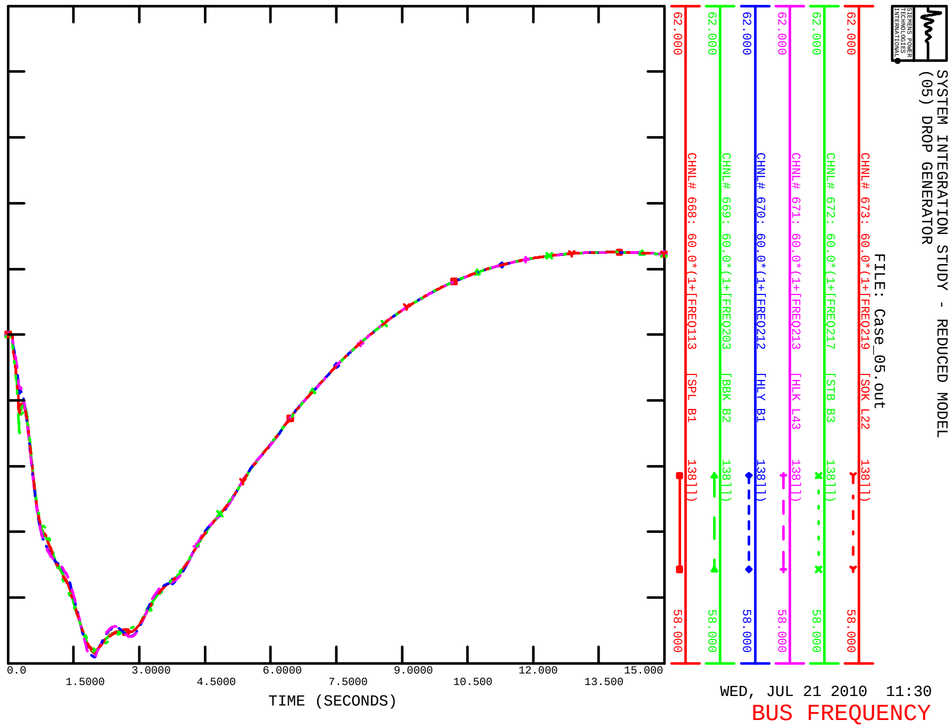

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 458: [SPD2494 [SOL SC1 13.80] [1]]
CHNL# 459: [SPD2495 [SOL SC2 13.80] [2]]
CHNL# 460: [SPD2496 [SOL SC3 13.80] [3]]
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TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

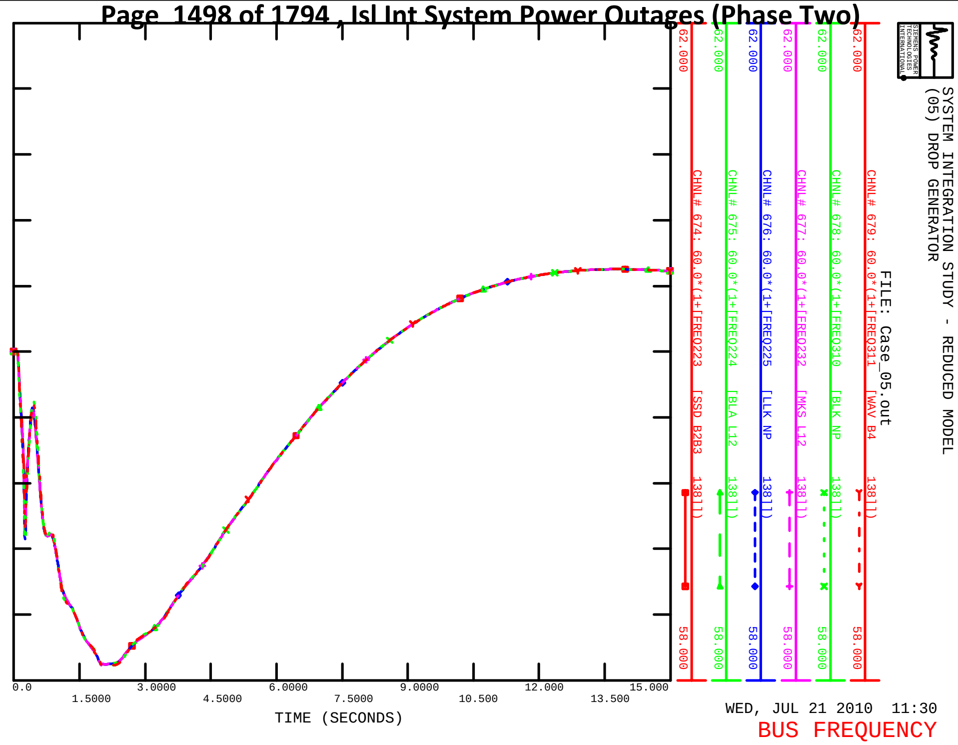

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 628: 60.0*(1+[FREQ153 [DPD L64 661])
CHNL# 629: 60.0*(1+[FREQ204 [SVL B2 661])
CHNL# 630: 60.0*(1+[FREQ308 [BLK NPT3 661])
CHNL# 631: 60.0*(1+[FREQ309 [BRB T2T3 661])
CHNL# 632: 60.0*(1+[FREQ319 [DLK NP 661])
CHNL# 633: 60.0*(1+[FREQ334 [OPD B2B5 661])
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58.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

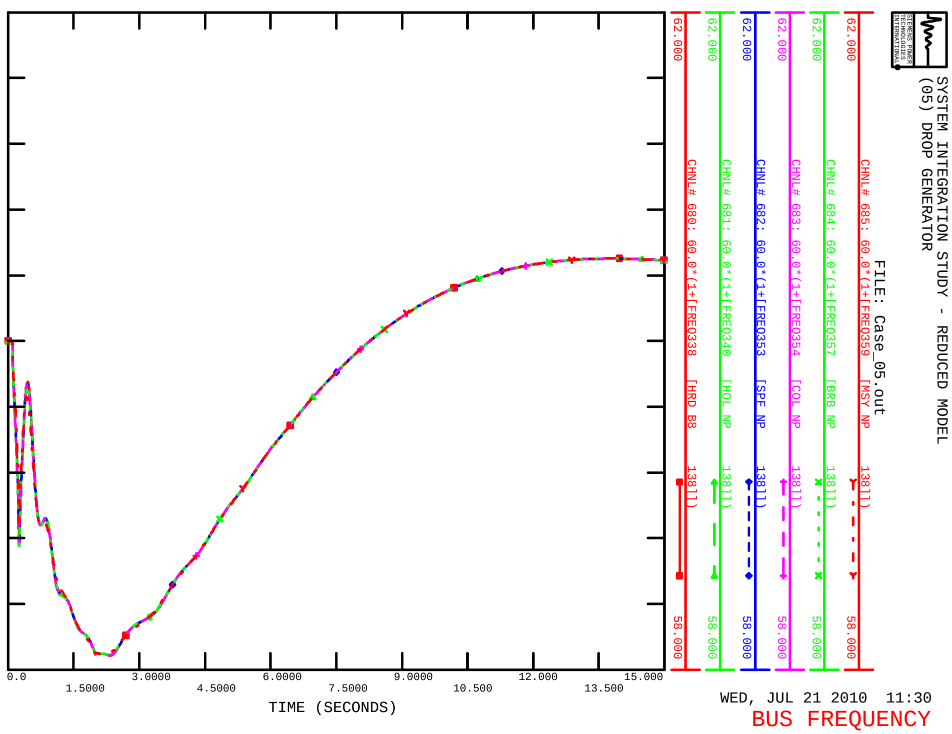

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 634: 60.0*(1+[FREQ335 [HWD B7B8 661])
CHNL# 635: 60.0*(1+[FREQ336 [WAV B2 661])
CHNL# 636: 60.0*(1+[FREQ337 [HRD B6B7 661])
CHNL# 637: 60.0*(1+[FREQ345 [ULT TAP 661])
CHNL# 638: 60.0*(1+[FREQ346 [ULT NP 661])
CHNL# 639: 60.0*(1+[FREQ347 [SCV NP 661])
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58.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

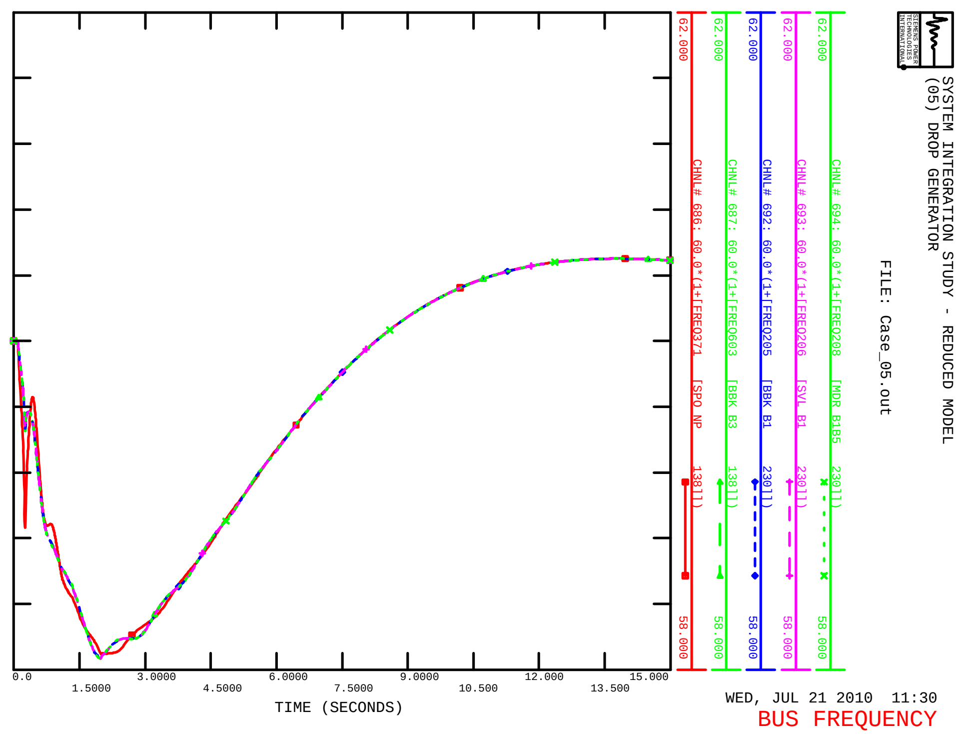

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 640: 60.0*(1+[FREQ348 [KEL NP 661])
CHNL# 641: 60.0*(1+[FREQ349 [CHA NP 661])
CHNL# 642: 60.0*(1+[FREQ455 [GDL NP 661])
CHNL# 643: 60.0*(1+[FREQ457 [GOU NP 661])
CHNL# 646: 60.0*(1+[FREQ467 [TCV NP 661])
CHNL# 652: 60.0*(1+[FREQ482 [MRP NP 661])
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58.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

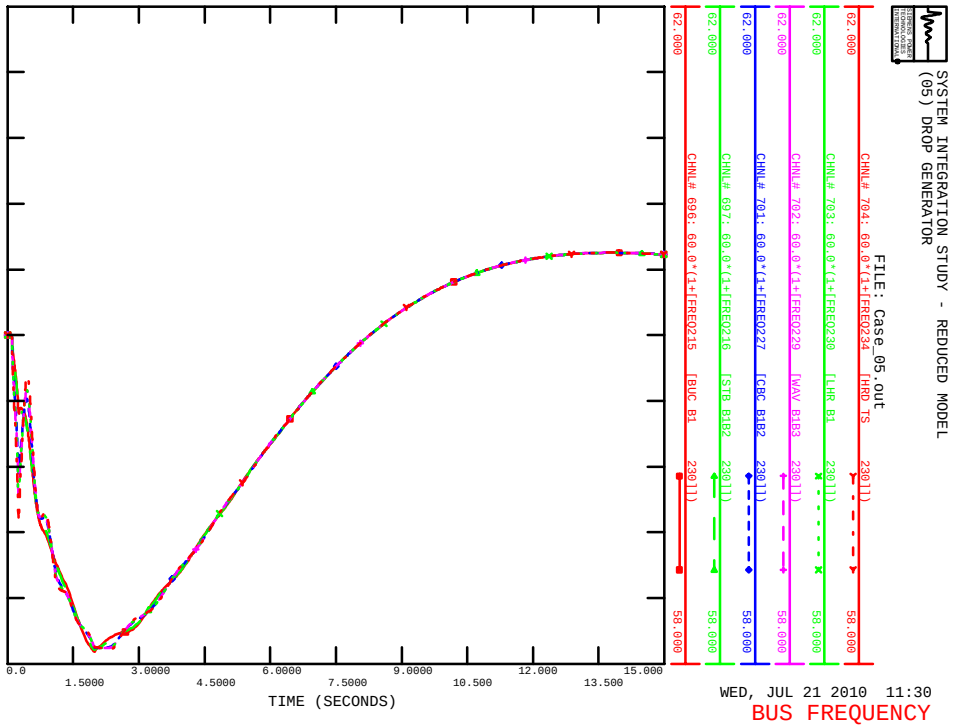

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 658: 60.0*(1+[FREQ550 [MOB NP 661])
CHNL# 659: 60.0*(1+[FREQ558 [ROP NP 661])
CHNL# 664: 60.0*(1+[FREQ973 [GOU MID1 661])
CHNL# 665: 60.0*(1+[FREQ982 [CHA MID1 661])
CHNL# 666: 60.0*(1+[FREQ111 [DLK B1 1381])
CHNL# 667: 60.0*(1+[FREQ112 [IRV B1 1381])
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58.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

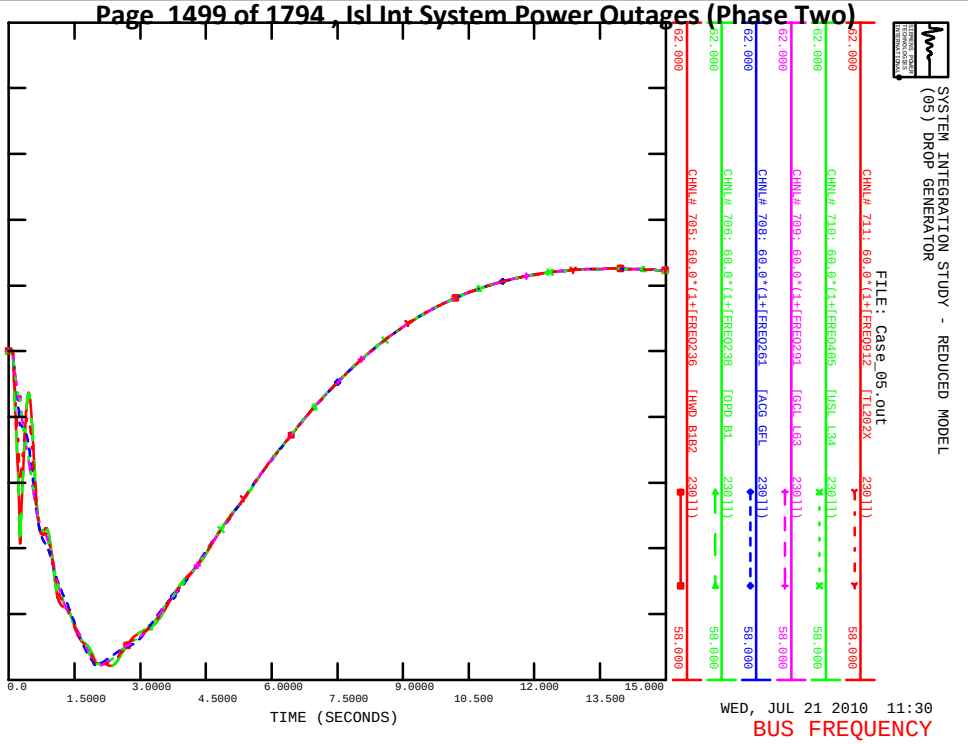

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TIME (SECONDS)
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CHNL# 668: 60.0*(1+[FREQ113 [SPL B1 138]])
CHNL# 669: 60.0*(1+[FREQ203 [BBK B2 138]])
CHNL# 670: 60.0*(1+[FREQ212 [HLY B1 138]])
CHNL# 671: 60.0*(1+[FREQ213 [HLK L43 138]])
CHNL# 672: 60.0*(1+[FREQ217 [STB B3 138]])
CHNL# 673: 60.0*(1+[FREQ219 [SOK L22 138]])
58.000
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
WED, JUL 21 2010 11:30
BUS FREQUENCY

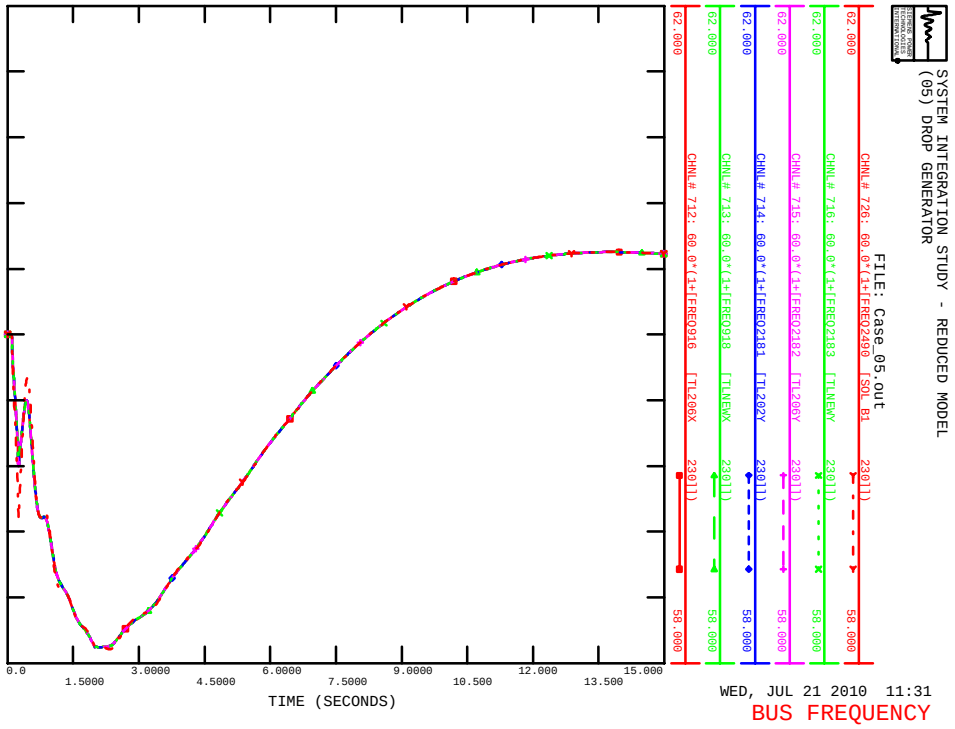

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TIME (SECONDS)
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CHNL# 674: 60.0*(1+[FREQ223 [SSD B2B3 138]])
CHNL# 675: 60.0*(1+[FREQ224 [BLA L12 138]])
CHNL# 676: 60.0*(1+[FREQ225 [LLK NP 138]])
CHNL# 677: 60.0*(1+[FREQ232 [MKS L12 138]])
CHNL# 678: 60.0*(1+[FREQ310 [BLK NP 138]])
CHNL# 679: 60.0*(1+[FREQ311 [WAV B4 138]])
58.000
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
WED, JUL 21 2010 11:30
BUS FREQUENCY

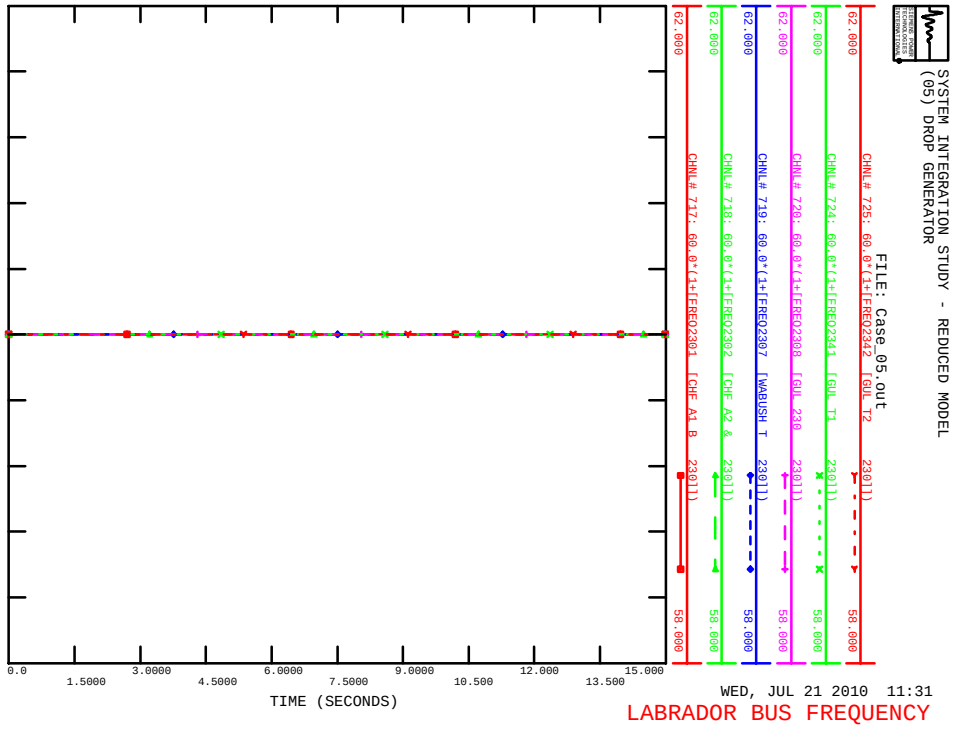

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TIME (SECONDS)
62.000
CHNL# 680: 60.0*(1+[FREQ338 [HRD B8 138]])
CHNL# 681: 60.0*(1+[FREQ340 [HOL NP 138]])
CHNL# 682: 60.0*(1+[FREQ353 [SPF NP 138]])
CHNL# 683: 60.0*(1+[FREQ354 [COL NP 138]])
CHNL# 684: 60.0*(1+[FREQ357 [BRB NP 138]])
CHNL# 685: 60.0*(1+[FREQ359 [MSY NP 138]])
58.000
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
WED, JUL 21 2010 11:30
BUS FREQUENCY

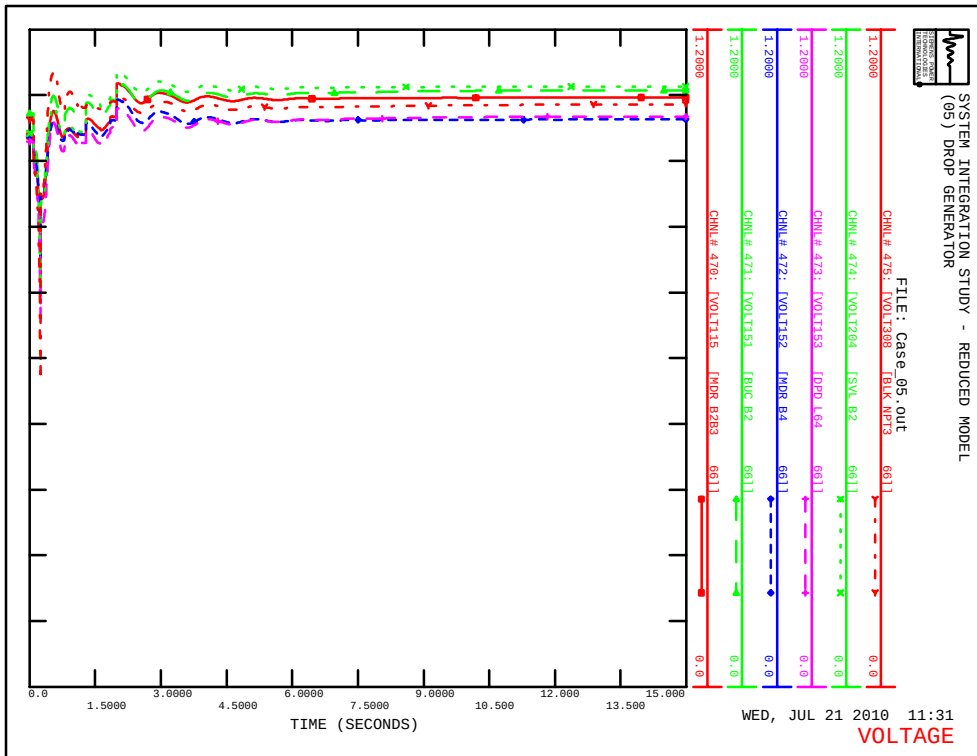

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15.000
TIME (SECONDS)
62.000
CHNL# 686: 60.0*(1+[FREQ371 [SPO NP 138]])
CHNL# 687: 60.0*(1+[FREQ603 [BBK B3 138]])
CHNL# 692: 60.0*(1+[FREQ205 [BBK B1 230]])
CHNL# 693: 60.0*(1+[FREQ206 [SVL B1 230]])
CHNL# 694: 60.0*(1+[FREQ208 [MDR B1B5 230]])
58.000
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
WED, JUL 21 2010 11:30
BUS FREQUENCY

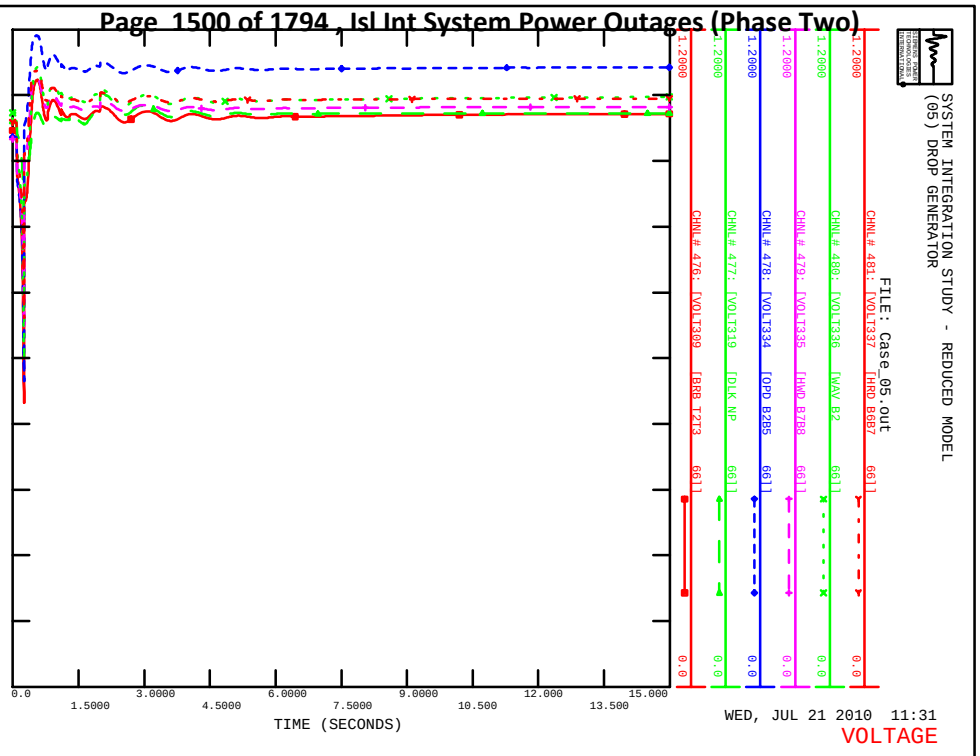

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 696: 60.0*(1+FREQ0215 [BUC B1 230])
CHNL# 697: 60.0*(1+FREQ0216 [STB B1B2 230])
CHNL# 701: 60.0*(1+FREQ0227 [CBC B1B2 230])
CHNL# 702: 60.0*(1+FREQ0229 [WAV B1B3 230])
CHNL# 703: 60.0*(1+FREQ0230 [LHR B1 230])
CHNL# 704: 60.0*(1+FREQ0234 [HRD TS 230])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

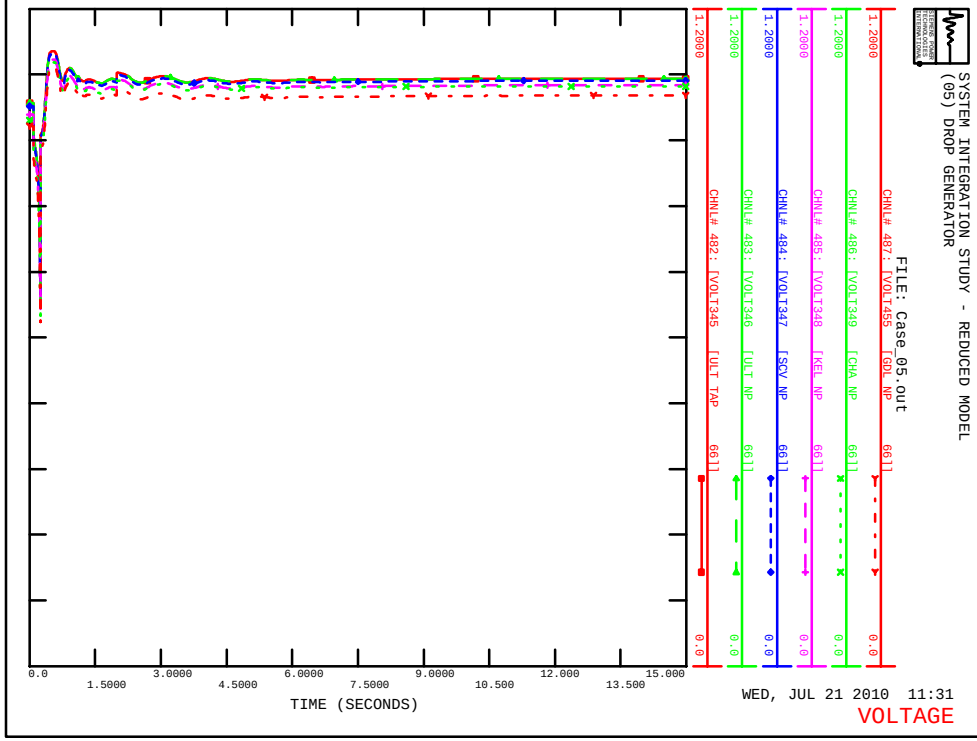

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 705: 60.0*(1+FREQ0236 [HWD B1B2 230])
CHNL# 706: 60.0*(1+FREQ0238 [OPD B1 230])
CHNL# 708: 60.0*(1+FREQ0261 [ACG GFL 230])
CHNL# 709: 60.0*(1+FREQ0291 [GCL L63 230])
CHNL# 710: 60.0*(1+FREQ0405 [USL L34 230])
CHNL# 711: 60.0*(1+FREQ0312 [TL202X 230])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:30
BUS FREQUENCY

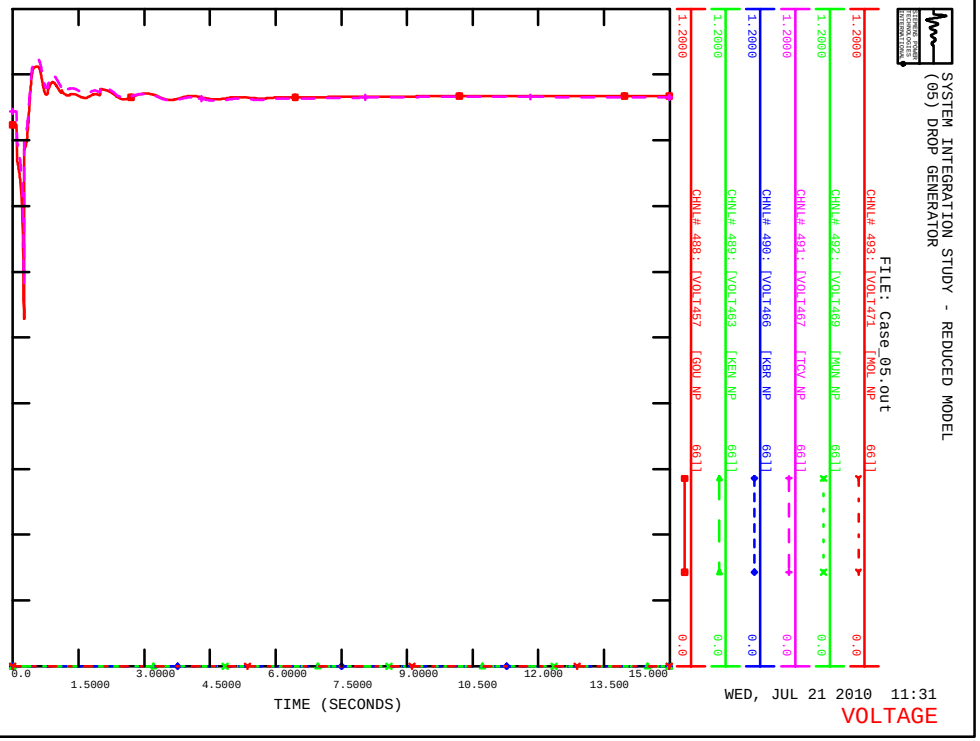

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 712: 60.0*(1+FREQ0916 [TL206X 230])
CHNL# 713: 60.0*(1+FREQ0918 [TLNEWX 230])
CHNL# 714: 60.0*(1+FREQ2181 [TL202Y 230])
CHNL# 715: 60.0*(1+FREQ2182 [TL206Y 230])
CHNL# 716: 60.0*(1+FREQ2183 [TLNEWY 230])
CHNL# 726: 60.0*(1+FREQ2290 [SOL B1 230])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
BUS FREQUENCY

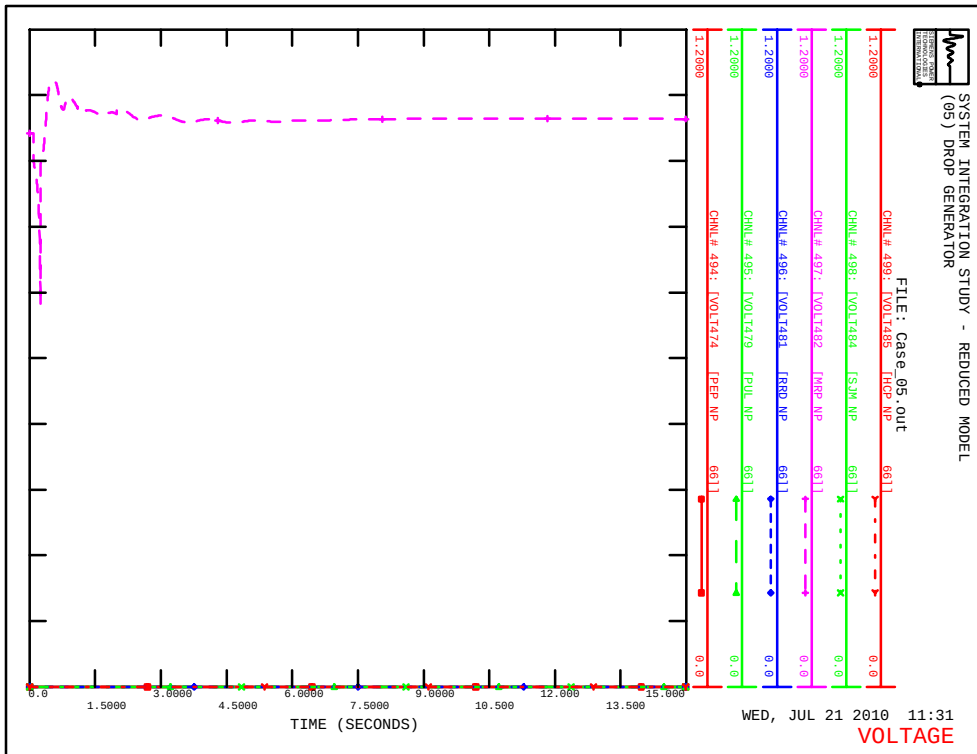

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 717: 60.0*(1+FREQ2301 [CHF A1 B 230])
CHNL# 718: 60.0*(1+FREQ2302 [CHF A2 & 230])
CHNL# 719: 60.0*(1+FREQ2307 [WABUSH T 230])
CHNL# 720: 60.0*(1+FREQ2308 [GUL 230 230])
CHNL# 724: 60.0*(1+FREQ2341 [GUL T1 230])
CHNL# 725: 60.0*(1+FREQ2342 [GUL T2 230])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
LABRADOR BUS FREQUENCY

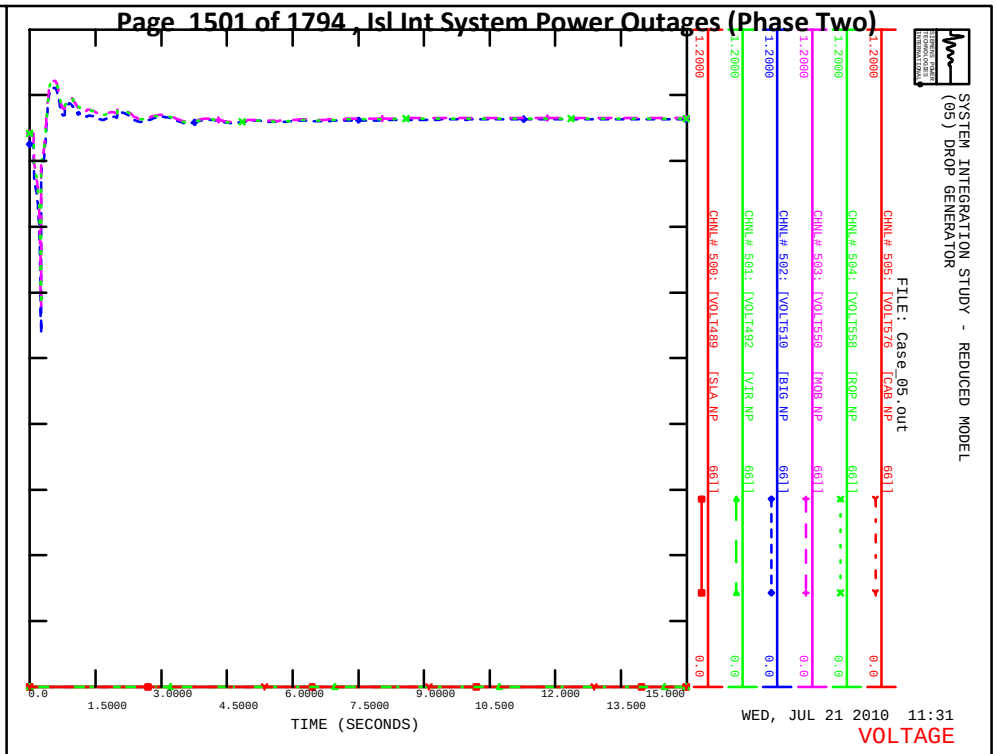

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 470: [VOLT115 [MDR B2B3 661]
CHNL# 471: [VOLT151 [BUC B2 661]
CHNL# 472: [VOLT152 [MDR B4 661]
CHNL# 473: [VOLT153 [OPD L64 661]
CHNL# 474: [VOLT204 [SVL B2 661]
CHNL# 475: [VOLT308 [BLK NPT3 661]
1.2000
0.0
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

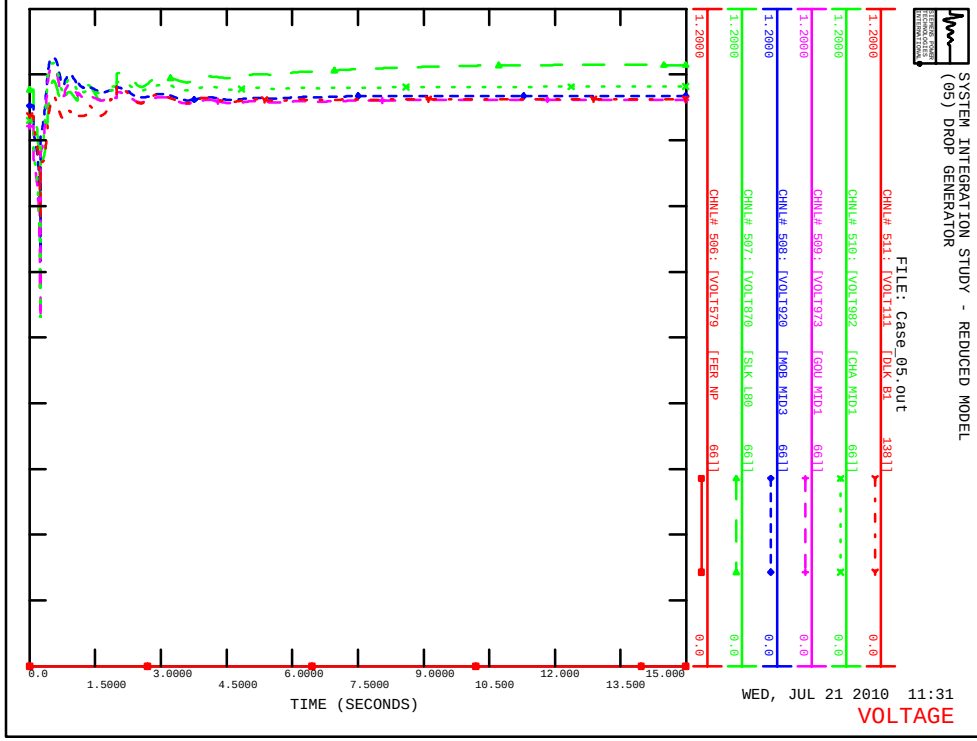

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 476: [VOLT309 [BBB T2T3 661]
CHNL# 477: [VOLT319 [DLK NP 661]
CHNL# 478: [VOLT334 [OPD B2B5 661]
CHNL# 479: [VOLT335 [HWD B7B8 661]
CHNL# 480: [VOLT336 [WAV B2 661]
CHNL# 481: [VOLT337 [HRD B6B7 661]
1.2000
0.0
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

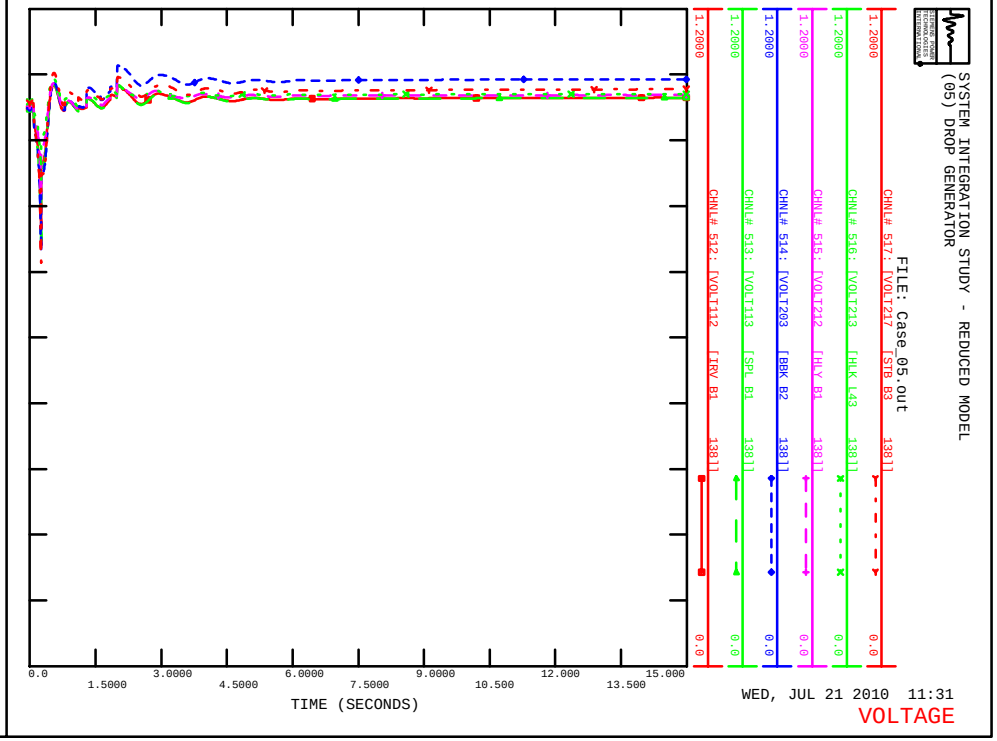

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 482: [VOLT345 [ULT TAP 661]
CHNL# 483: [VOLT346 [ULT NP 661]
CHNL# 484: [VOLT347 [SCV NP 661]
CHNL# 485: [VOLT348 [KEL NP 661]
CHNL# 486: [VOLT349 [CHA NP 661]
CHNL# 487: [VOLT455 [GDL NP 661]
1.2000
0.0
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

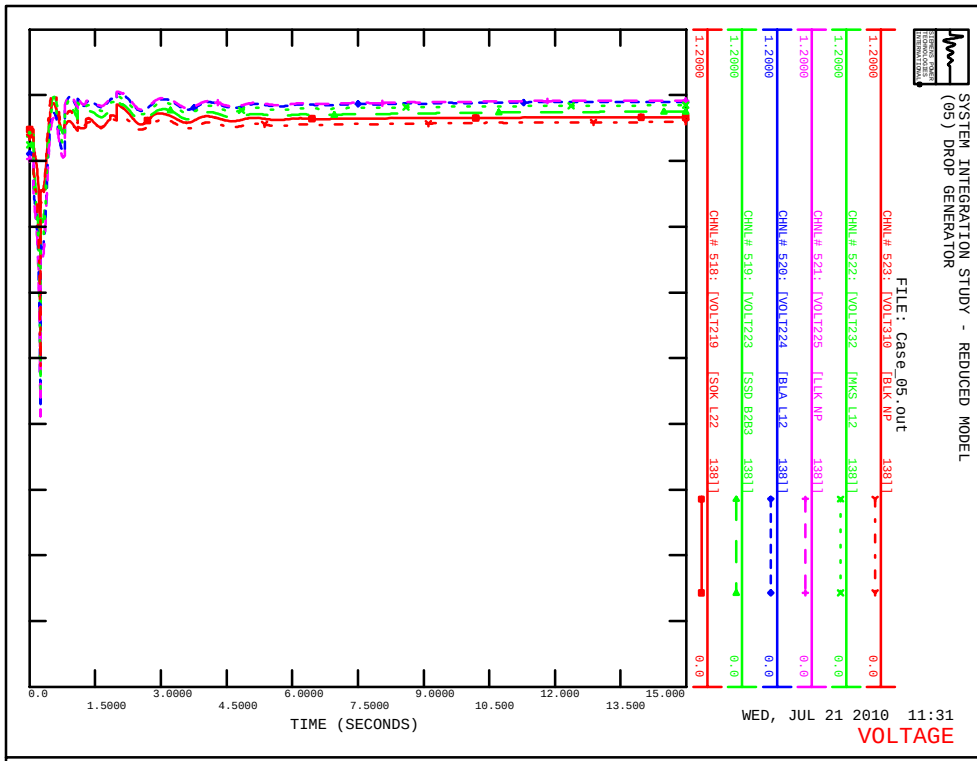

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 488: [VOLT457 [GOU NP 661]
CHNL# 489: [VOLT463 [KEN NP 661]
CHNL# 490: [VOLT466 [KBR NP 661]
CHNL# 491: [VOLT467 [TCV NP 661]
CHNL# 492: [VOLT469 [MUN NP 661]
CHNL# 493: [VOLT471 [MOL NP 661]
1.2000
0.0
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

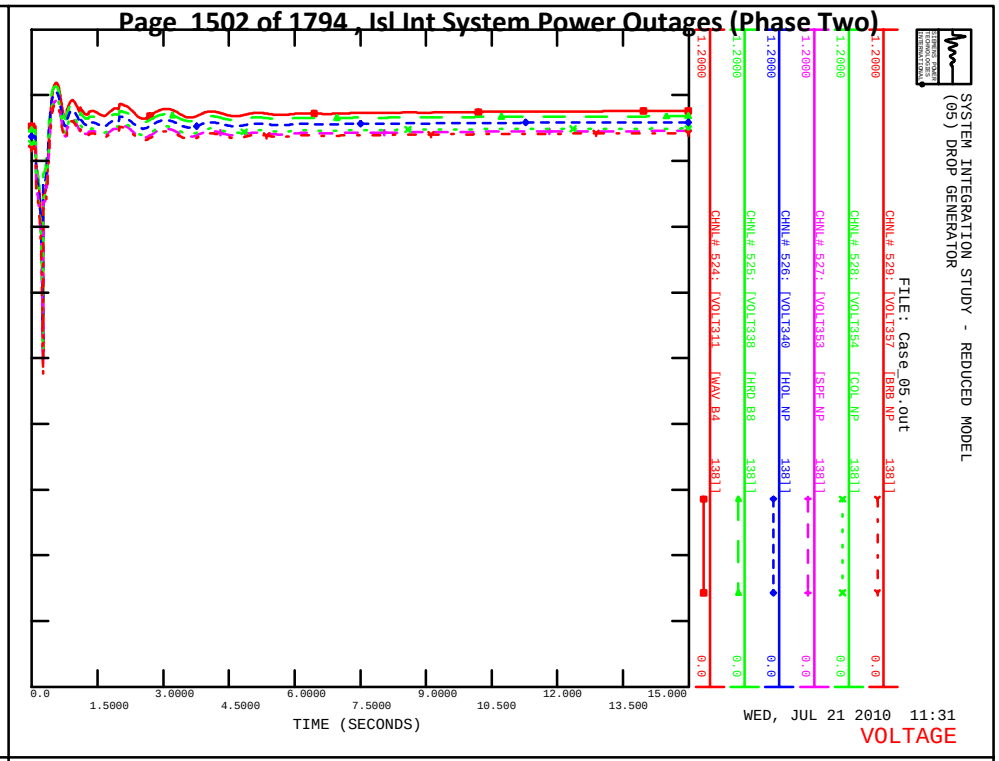

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 494: [VOLT474 [PEP NP 661]
CHNL# 495: [VOLT479 [PUL NP 661]
CHNL# 496: [VOLT481 [RRD NP 661]
CHNL# 497: [VOLT482 [MRP NP 661]
CHNL# 498: [VOLT484 [SJM NP 661]
CHNL# 499: [VOLT485 [HCP NP 661]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

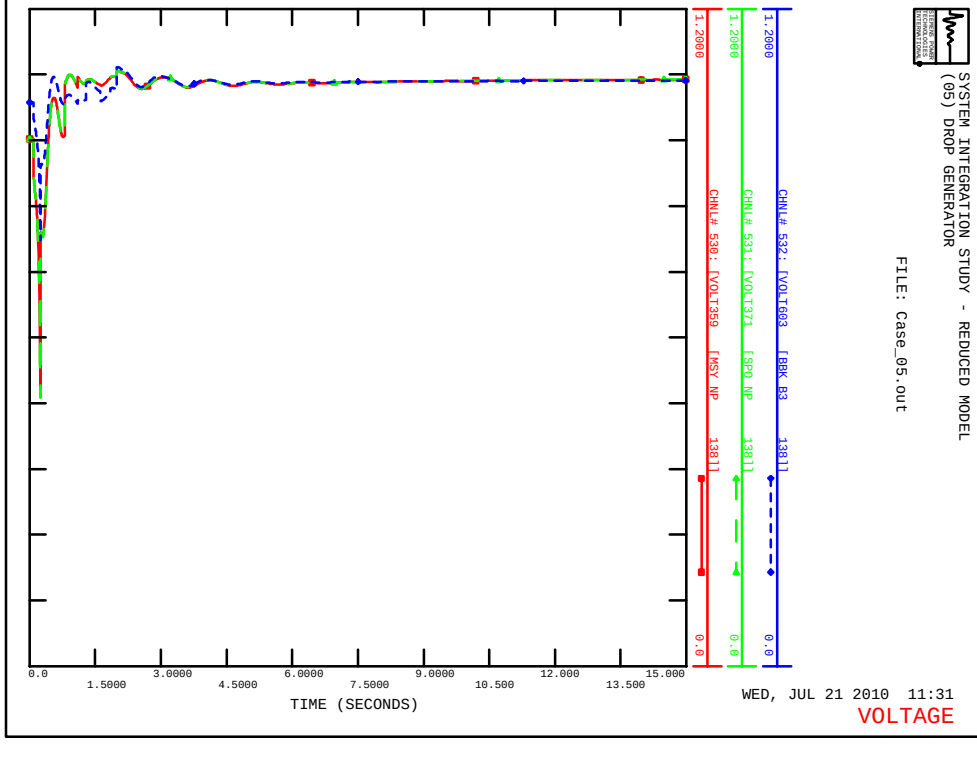

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 500: [VOLT489 [SLA NP 661]
CHNL# 501: [VOLT492 [VIR NP 661]
CHNL# 502: [VOLT510 [BIG NP 661]
CHNL# 503: [VOLT550 [MOB NP 661]
CHNL# 504: [VOLT558 [ROP NP 661]
CHNL# 505: [VOLT576 [CAB NP 661]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

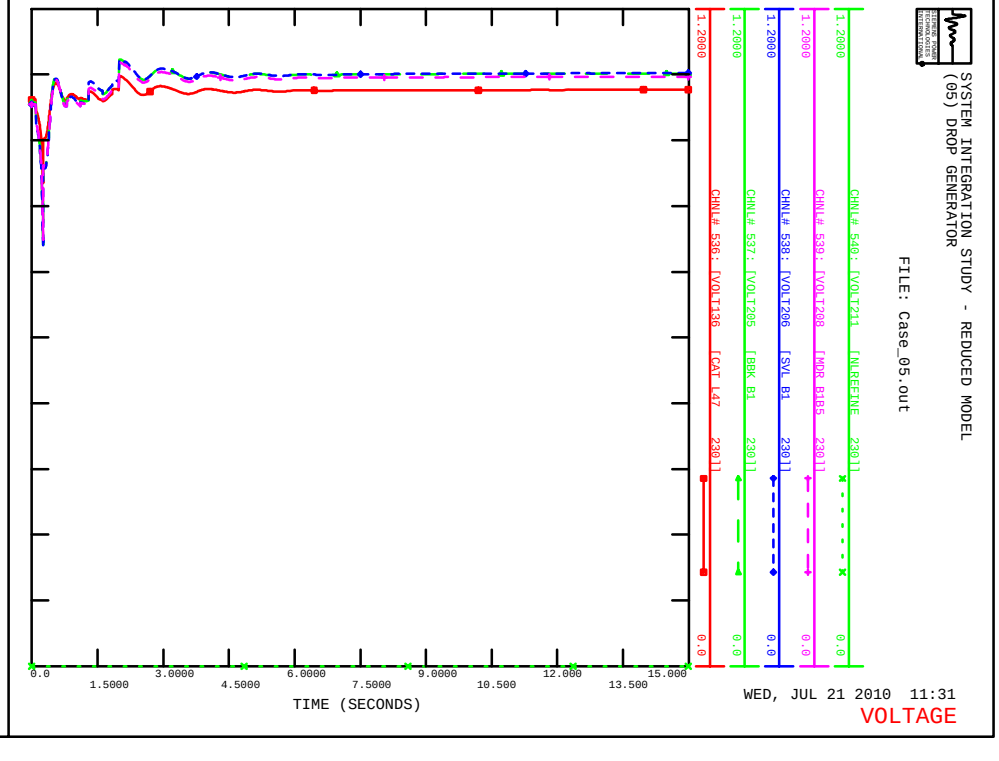

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 506: [VOLT579 [FER NP 661]
CHNL# 507: [VOLT870 [SLK 180 661]
CHNL# 508: [VOLT920 [MOB MID3 661]
CHNL# 509: [VOLT973 [GOU MID1 661]
CHNL# 510: [VOLT982 [CHA MID1 661]
CHNL# 511: [VOLT111 [DLK B1 1381]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

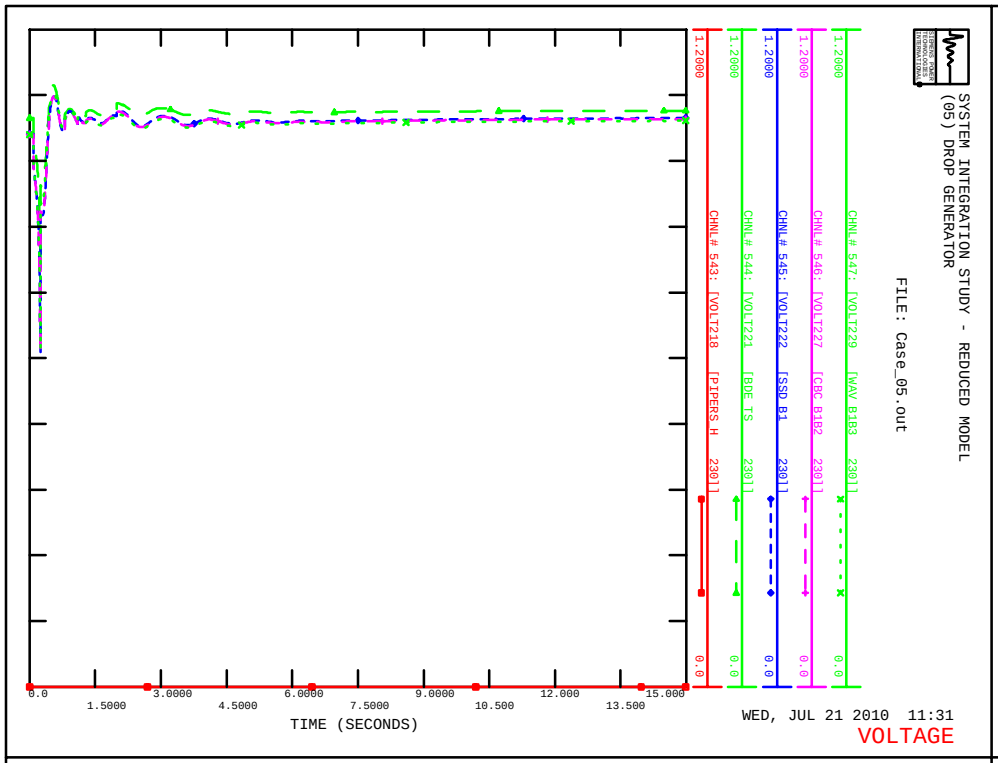

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 512: [VOLT112 [IRV B1 1381]
CHNL# 513: [VOLT113 [SPL B1 1381]
CHNL# 514: [VOLT203 [BBK B2 1381]
CHNL# 515: [VOLT232 [HLY B1 1381]
CHNL# 516: [VOLT213 [HLK 143 1381]
CHNL# 517: [VOLT237 [STB B3 1381]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

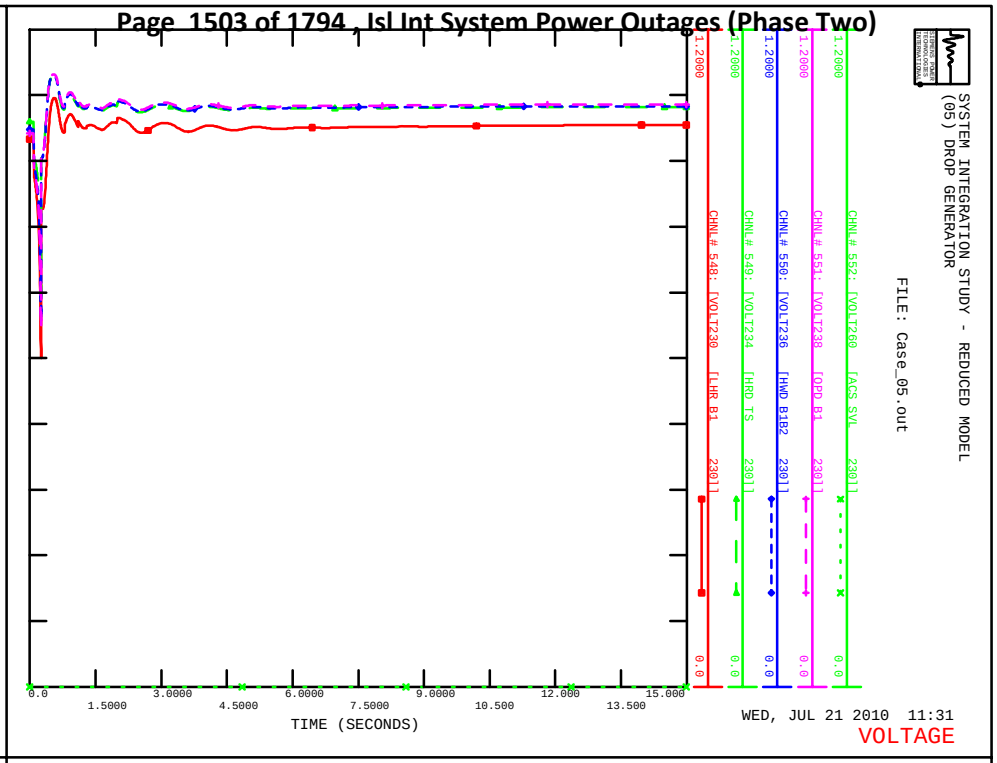

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 518: [VOLT219 [SOK L22 138]
CHNL# 519: [VOLT223 [SSD B2B3 138]
CHNL# 520: [VOLT224 [BLA L32 138]
CHNL# 521: [VOLT225 [LLK NP 138]
CHNL# 522: [VOLT232 [MKS L12 138]
CHNL# 523: [VOLT310 [BLK NP 138]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

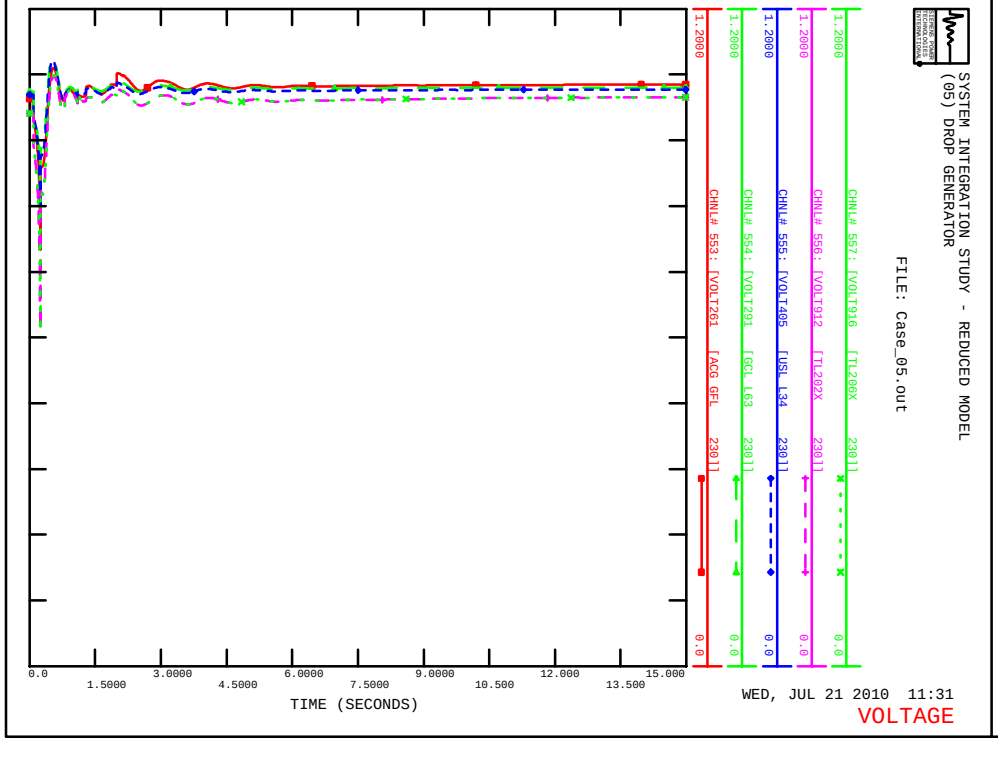

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 524: [VOLT311 [WAV B4 138]
CHNL# 525: [VOLT338 [HRD B8 138]
CHNL# 526: [VOLT340 [HOL NP 138]
CHNL# 527: [VOLT353 [SPF NP 138]
CHNL# 528: [VOLT354 [COL NP 138]
CHNL# 529: [VOLT357 [BRB NP 138]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

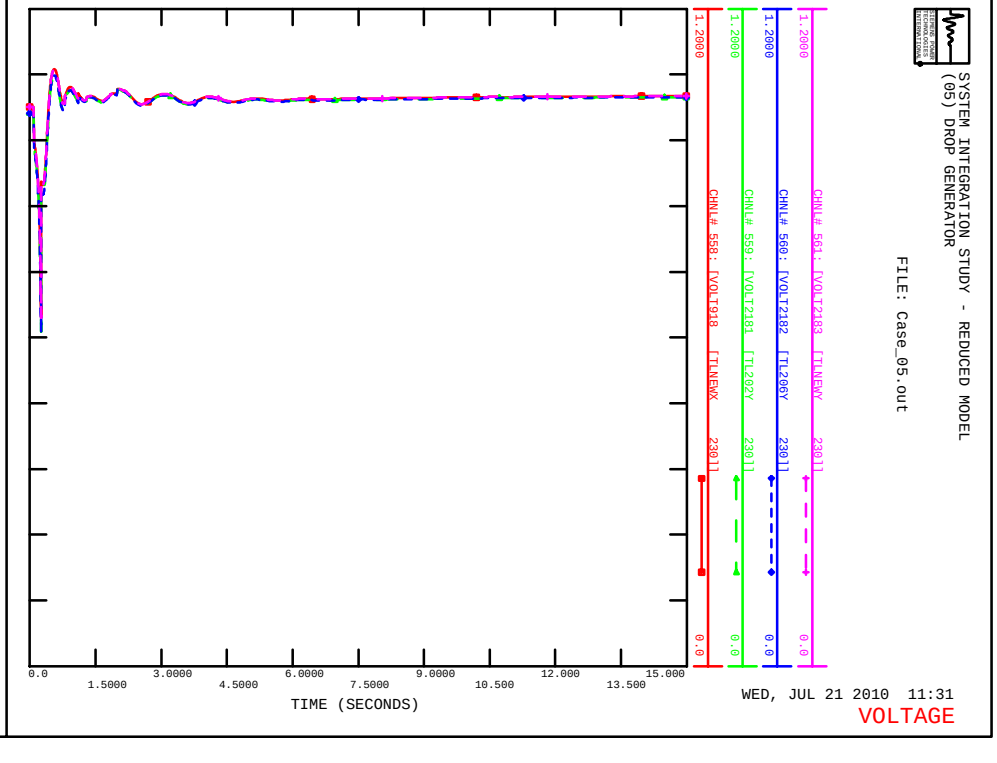

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 530: [VOLT359 [MSY NP 138]
CHNL# 531: [VOLT371 [SPD NP 138]
CHNL# 532: [VOLT603 [BBK B3 138]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

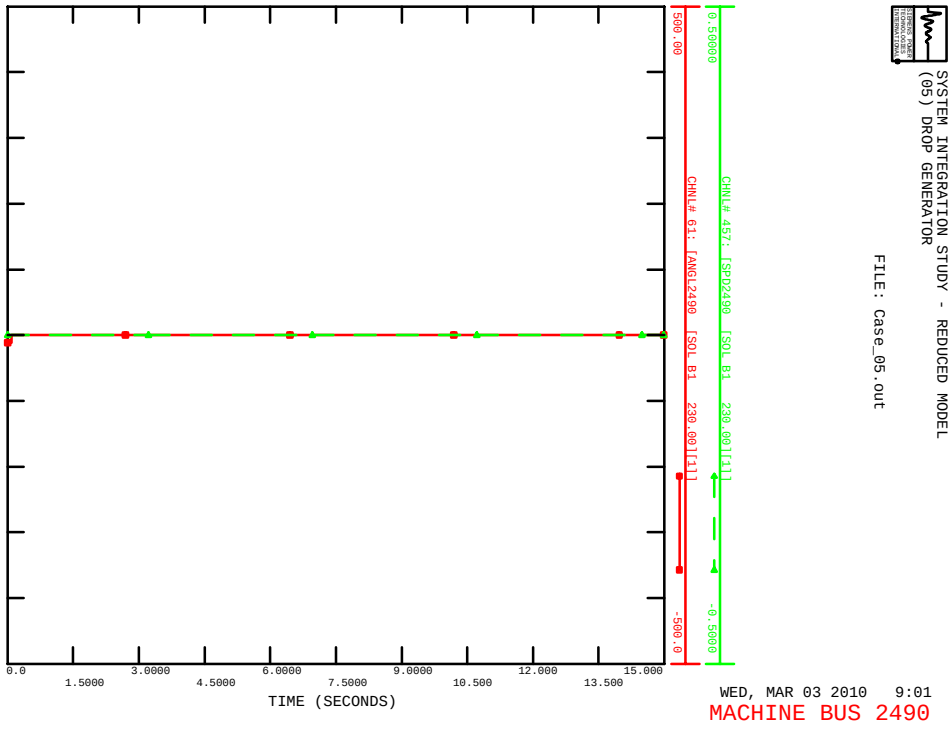

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 536: [VOLT136 [CAT L47 230]
CHNL# 537: [VOLT205 [BBK B1 230]
CHNL# 538: [VOLT206 [SVL B1 230]
CHNL# 539: [VOLT208 [MOR B1B5 230]
CHNL# 540: [VOLT211 [NLREFINE 230]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

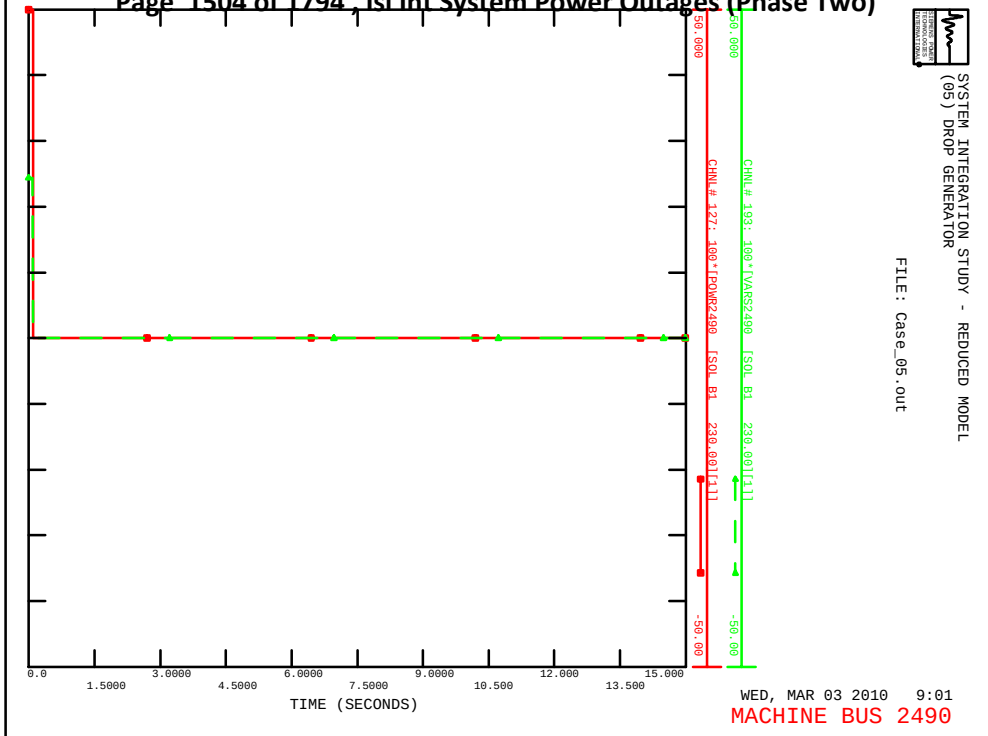

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 543: [VOLT218 [PIPERS H 230]
CHNL# 544: [VOLT221 [BDE TS 230]
CHNL# 545: [VOLT222 [SSD B1 230]
CHNL# 546: [VOLT227 [CBC B1B2 230]
CHNL# 547: [VOLT229 [WAV B1B3 230]
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

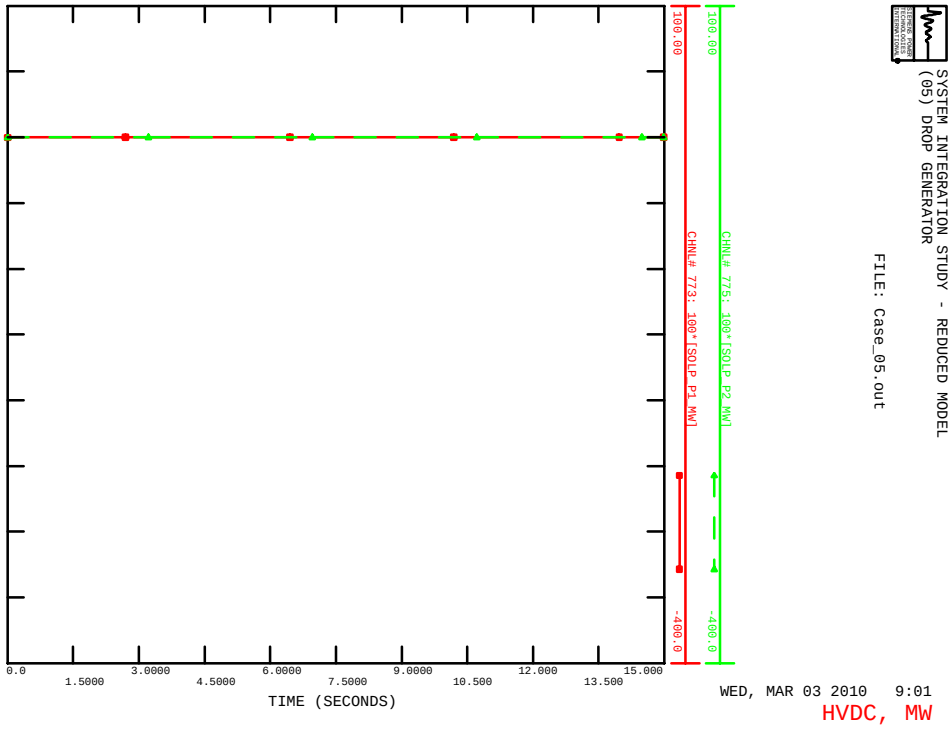

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 548: [VOLT230 [LHR B1 230]
CHNL# 549: [VOLT234 [HRD TS 230]
CHNL# 550: [VOLT236 [HWD B1B2 230]
CHNL# 551: [VOLT238 [OPD B1 230]
CHNL# 552: [VOLT260 [ACS SVC 230]
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

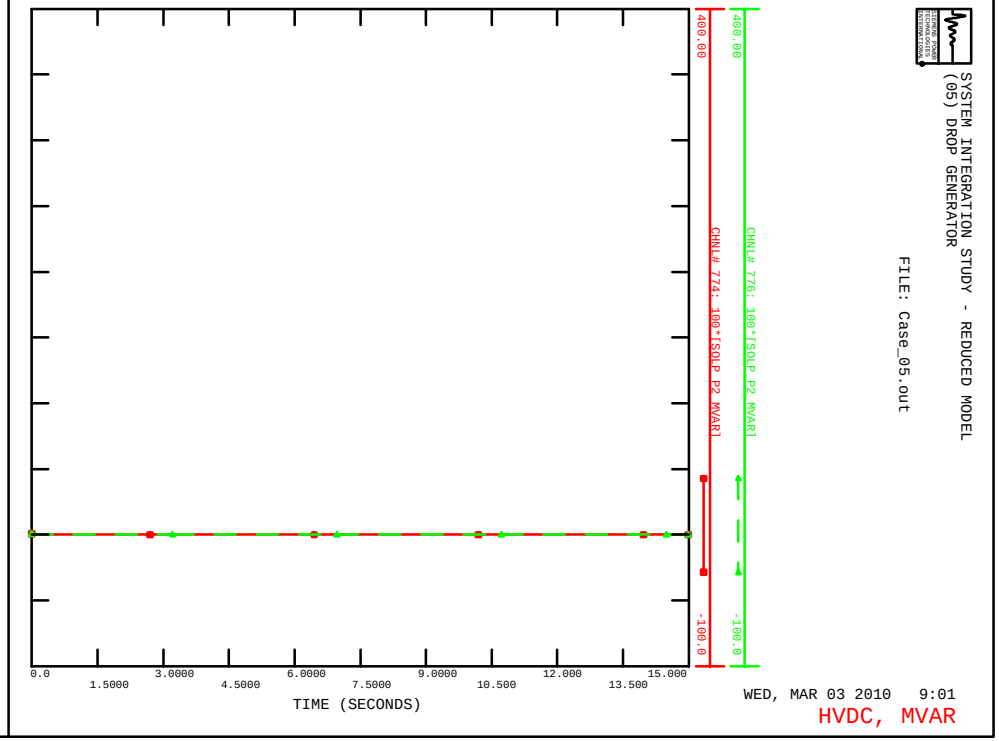

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 553: [VOLT261 [ACG GFL 230]
CHNL# 554: [VOLT291 [GCL L63 230]
CHNL# 555: [VOLT405 [USL L34 230]
CHNL# 556: [VOLT912 [TL202X 230]
CHNL# 557: [VOLT916 [TL206X 230]
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

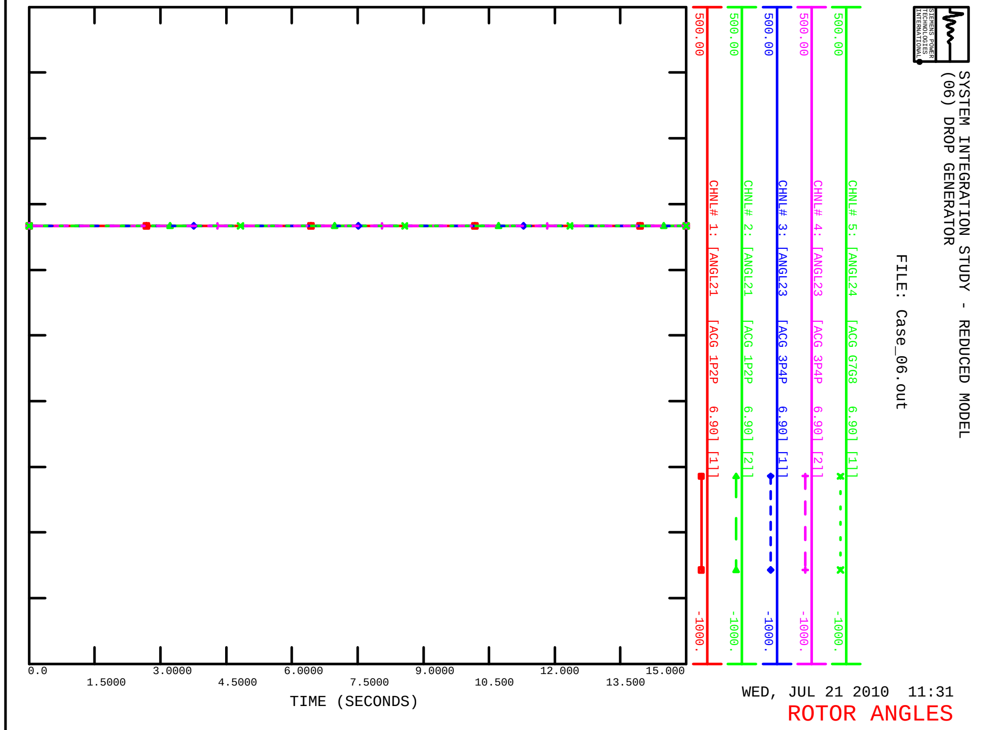

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 558: [VOLT918 [TLNEWX 230]
CHNL# 559: [VOLT2181 [TL202Y 230]
CHNL# 560: [VOLT2182 [TL206Y 230]
CHNL# 561: [VOLT2183 [TLNEWY 230]
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

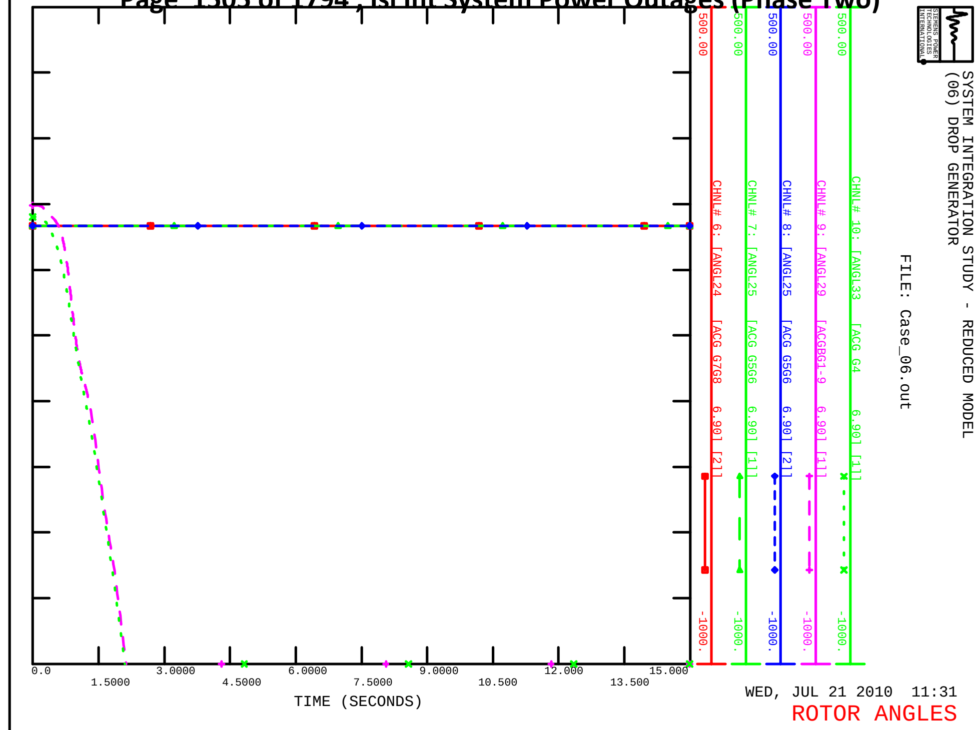

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 61: [ANGL2490 [SOL B1 230.00][1]]
CHNL# 457: [SPD2490 [SOL B1 230.00][1]]
500.00
-500.0
0.50000
-0.5000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, MAR 03 2010 9:01
MACHINE BUS 2490

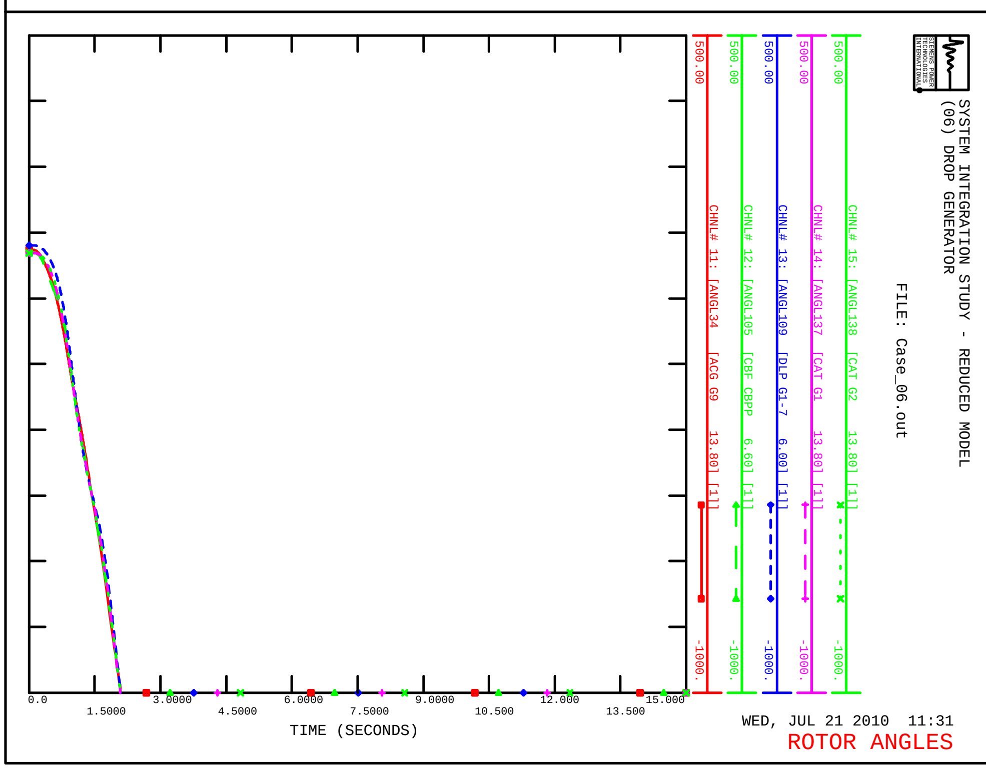

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 127: 100*[POWR2490 [SOL B1 230.00][1]]
CHNL# 193: 100*[VARS2490 [SOL B1 230.00][1]]
50.000
-50.00
50.000
-50.00
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, MAR 03 2010 9:01
MACHINE BUS 2490

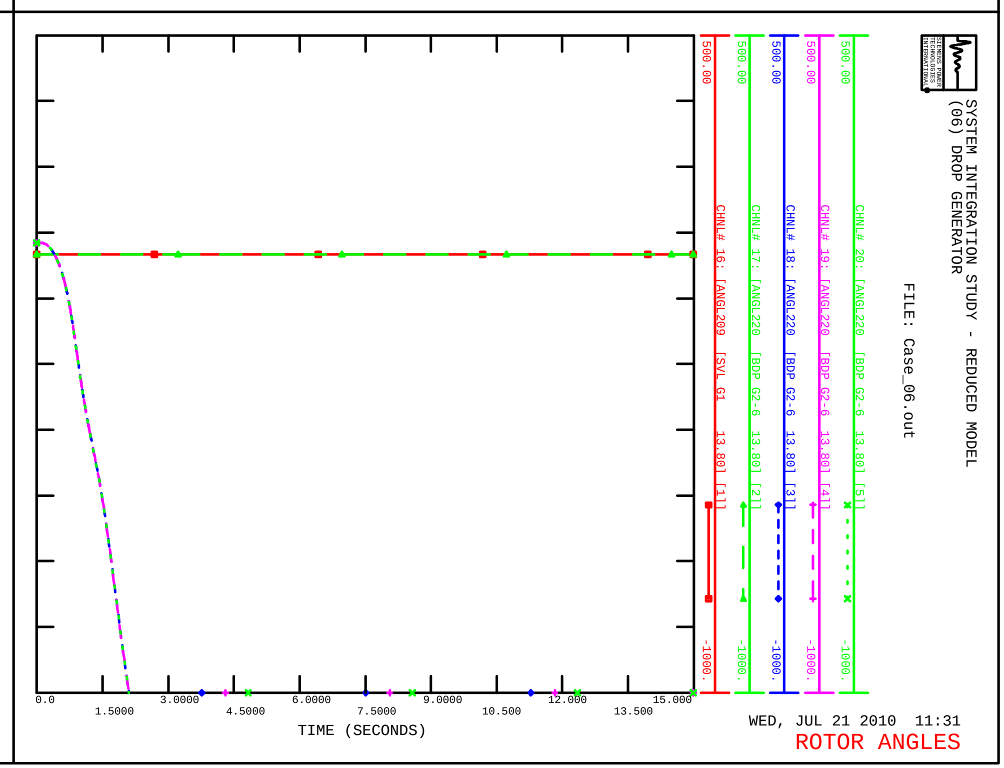

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 773: 100*[SOLP P1 MW]
CHNL# 775: 100*[SOLP P2 MW]
100.00
-400.0
100.00
-400.0
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, MAR 03 2010 9:01
HVDC, MW

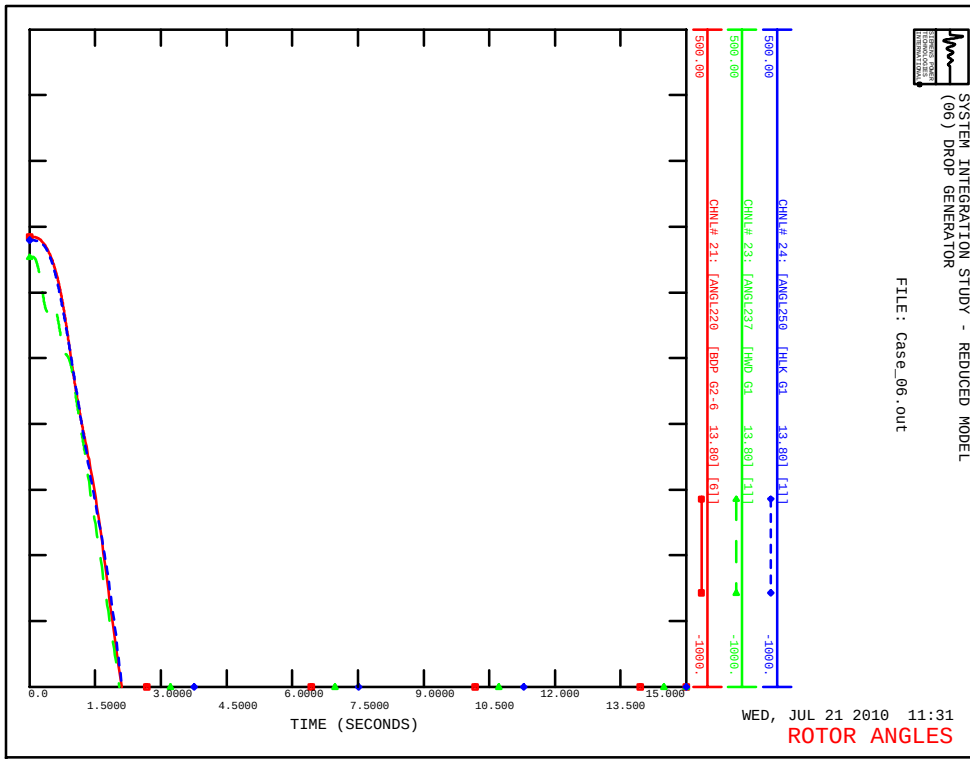

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(05) DROP GENERATOR
FILE: Case_05.out
CHNL# 774: 100*[SOLP P2 MVAR]
CHNL# 776: 100*[SOLP P2 MVAR]
400.00
-100.0
400.00
-100.0
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, MAR 03 2010 9:01
HVDC, MVAR

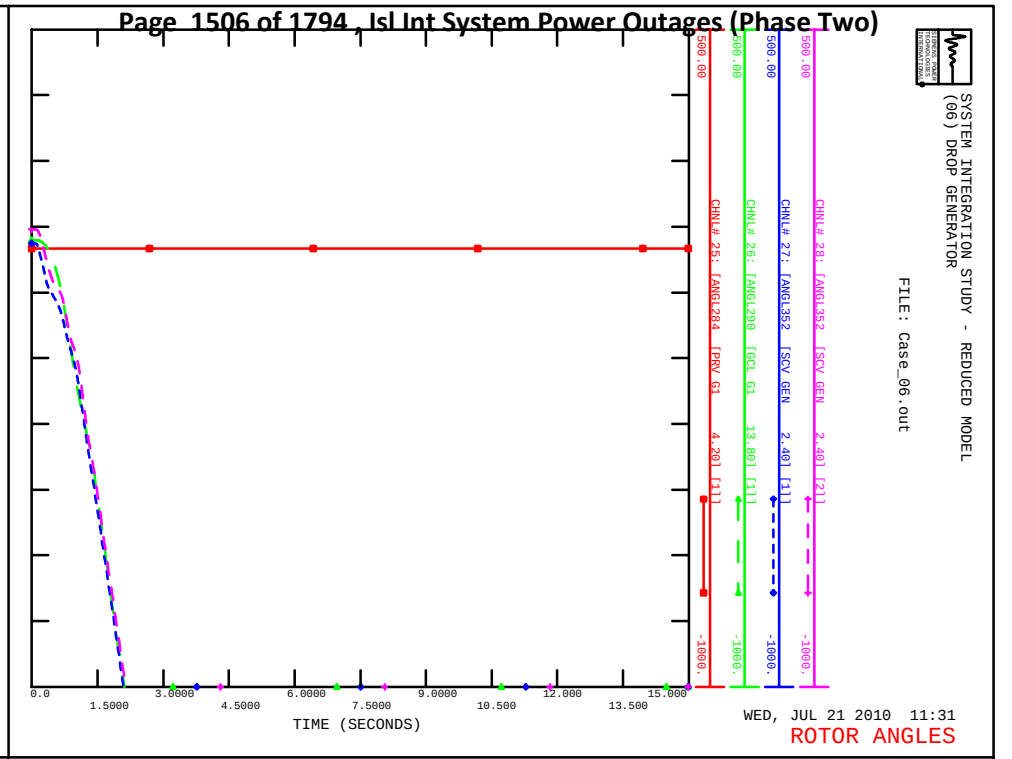

500.00
-1000.
CHNL# 1: [ANGL21 [ACG 1P2P 6.90] [1]]
CHNL# 2: [ANGL21 [ACG 1P2P 6.90] [2]]
CHNL# 3: [ANGL23 [ACG 3P4P 6.90] [1]]
CHNL# 4: [ANGL23 [ACG 3P4P 6.90] [2]]
CHNL# 5: [ANGL24 [ACG G7G8 6.90] [1]]
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
WED, JUL 21 2010 11:31
ROTOR ANGLES

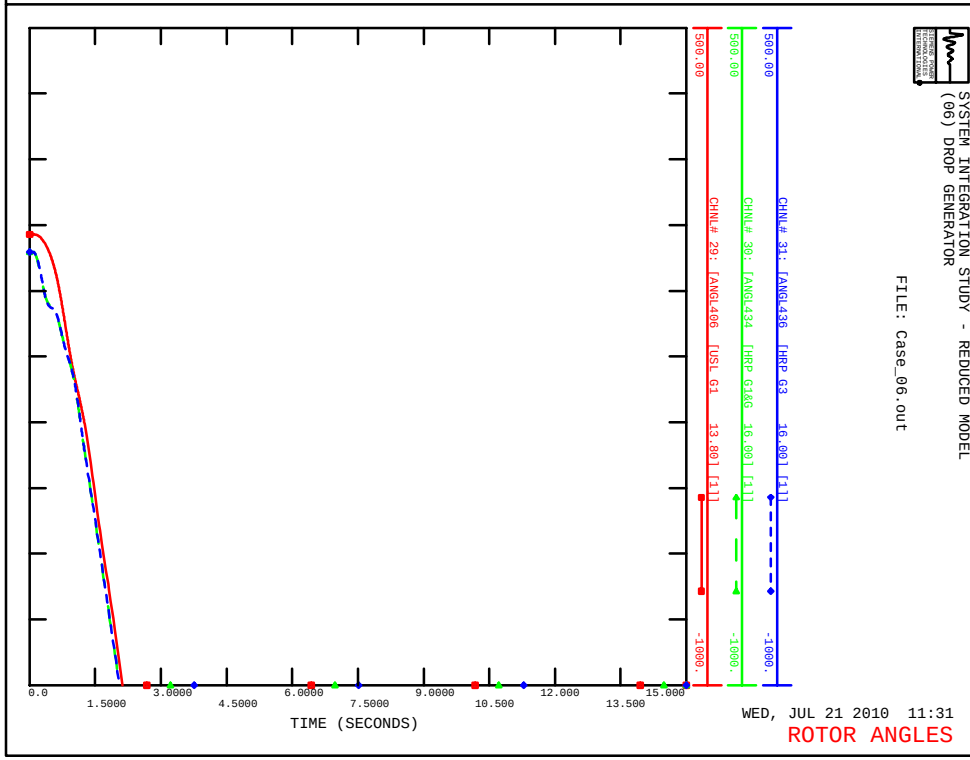

500.00
-1000.
CHNL# 6: [ANGL24 [ACG G7G8 6.90] [2]]
CHNL# 7: [ANGL25 [ACG G5G6 6.90] [1]]
CHNL# 8: [ANGL25 [ACG G5G6 6.90] [2]]
CHNL# 9: [ANGL29 [ACGBG1-9 6.90] [1]]
CHNL# 10: [ANGL33 [ACG G4 6.90] [1]]
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
WED, JUL 21 2010 11:31
ROTOR ANGLES

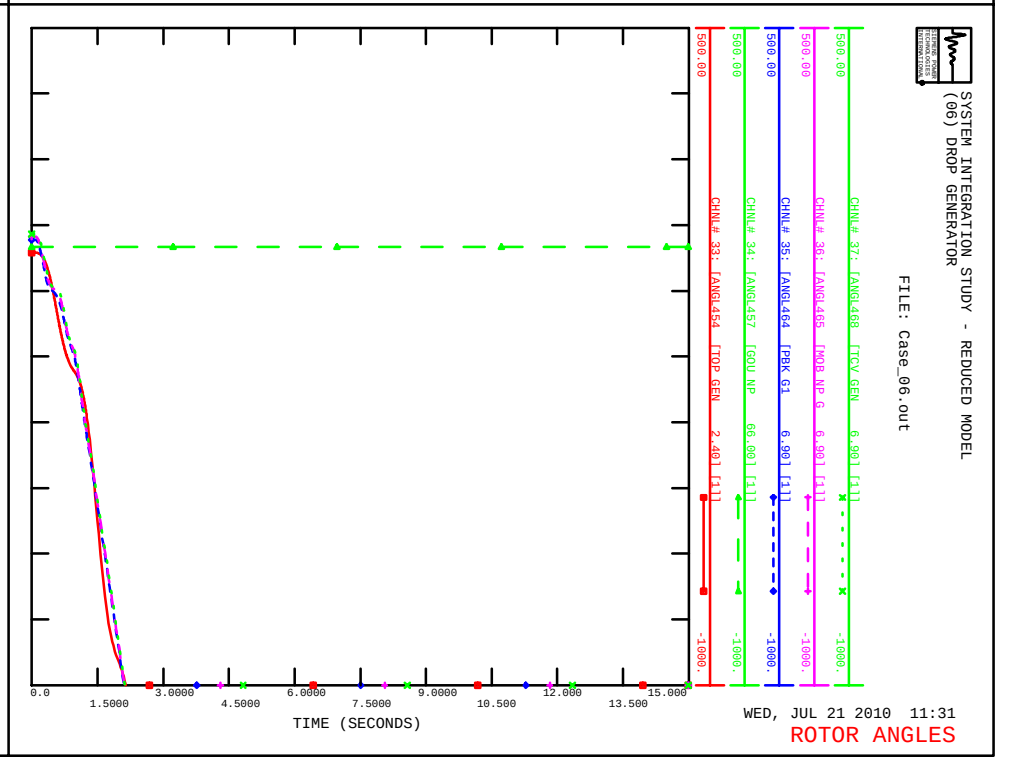

500.00
-1000.
CHNL# 11: [ANGL34 [ACG G9 13.80] [1]]
CHNL# 12: [ANGL105 [CBF CBPP 6.60] [1]]
CHNL# 13: [ANGL109 [DLP G1-7 6.00] [1]]
CHNL# 14: [ANGL137 [CAT G1 13.80] [1]]
CHNL# 15: [ANGL138 [CAT G2 13.80] [1]]
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
WED, JUL 21 2010 11:31
ROTOR ANGLES

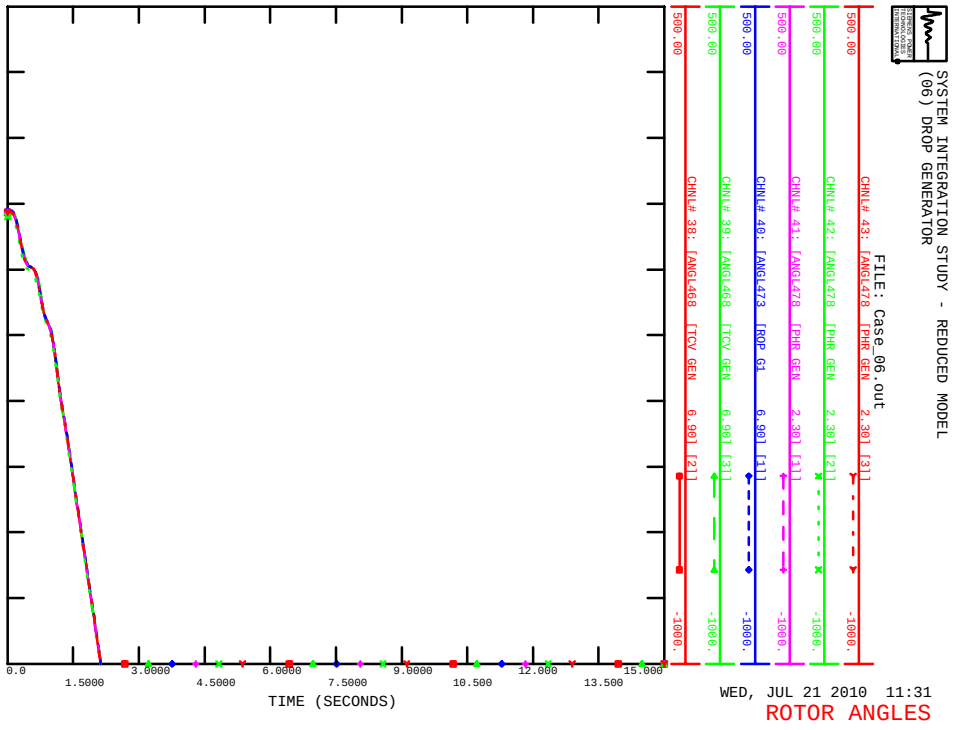

500.00
-1000.
CHNL# 16: [ANGL209 [SVL G1 13.80] [1]]
CHNL# 17: [ANGL220 [BDP G2-6 13.80] [2]]
CHNL# 18: [ANGL220 [BDP G2-6 13.80] [3]]
CHNL# 19: [ANGL220 [BDP G2-6 13.80] [4]]
CHNL# 20: [ANGL220 [BDP G2-6 13.80] [5]]
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
WED, JUL 21 2010 11:31
ROTOR ANGLES

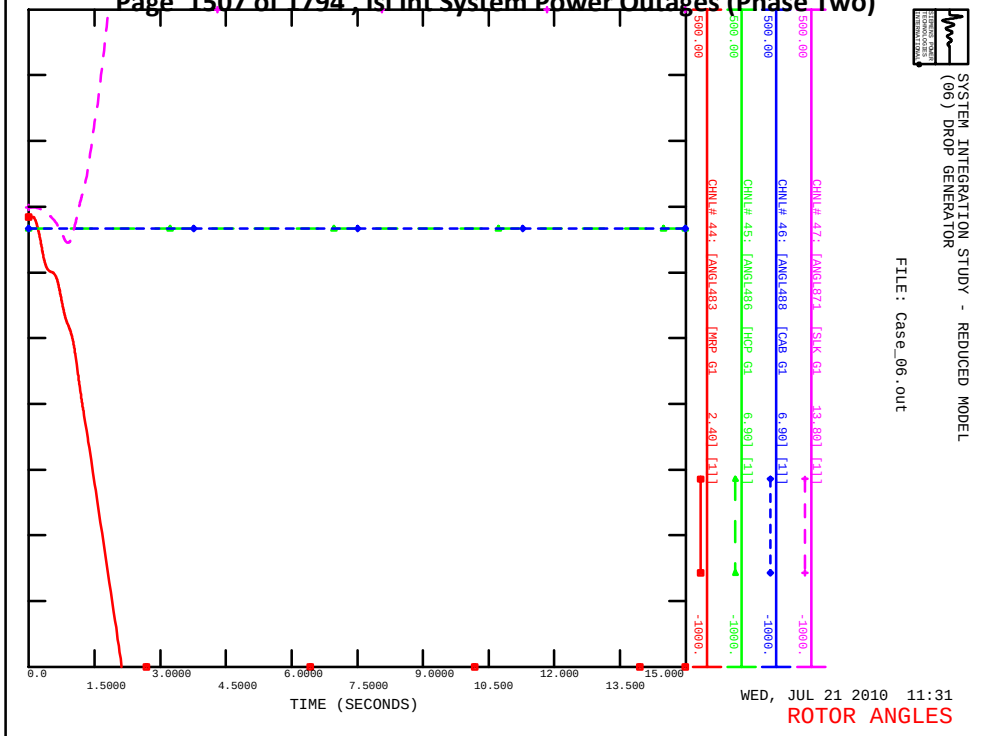

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 21: [ANGL220 [BDP G2-6 13.80] [61]
CHNL# 23: [ANGL237 [HND G1 13.80] [1]]
CHNL# 24: [ANGL250 [HLK G1 13.80] [11]
TIME (SECONDS)
WED, JUL 21 2010 11:31
ROTOR ANGLES

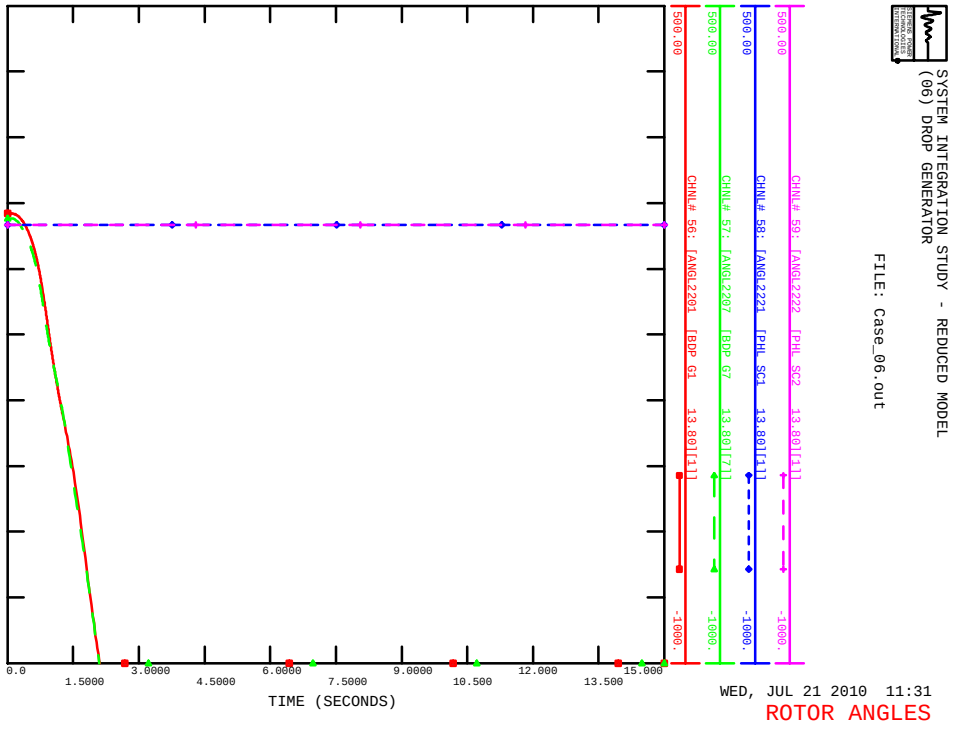

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 25: [ANGL284 [PRV G1 4.20] [11]
CHNL# 26: [ANGL290 [GCL G1 13.80] [11]
CHNL# 27: [ANGL352 [SCV GEN 2.40] [11]
CHNL# 28: [ANGL352 [SCV GEN 2.40] [21]
TIME (SECONDS)
WED, JUL 21 2010 11:31
ROTOR ANGLES

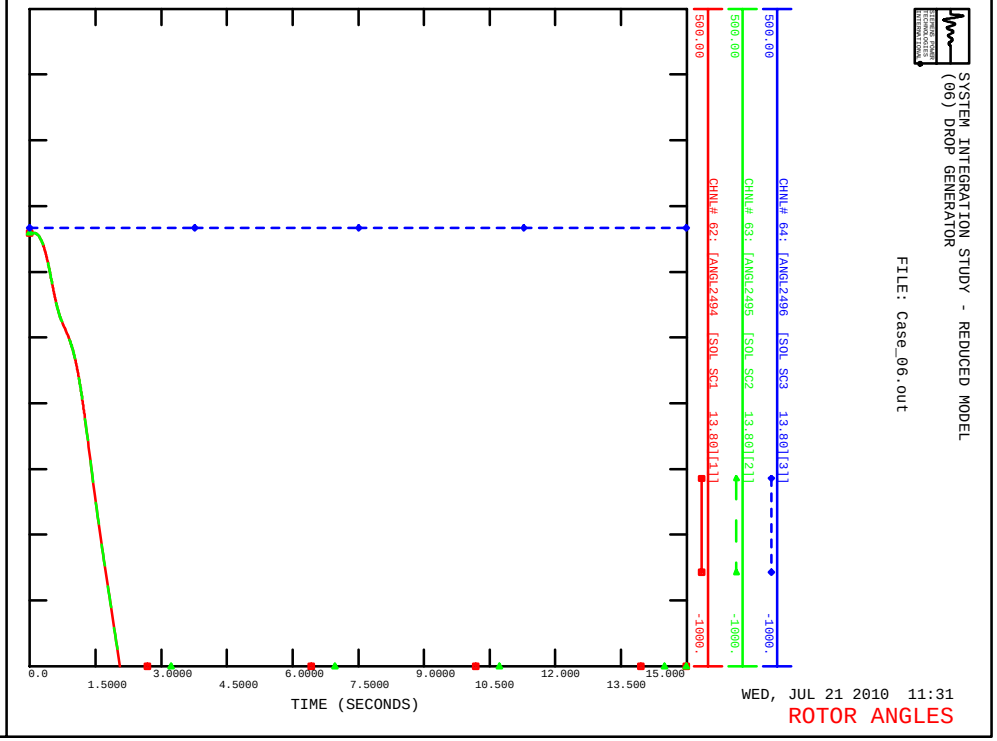

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 29: [ANGL406 [USL G1 13.80] [11]
CHNL# 30: [ANGL434 [HRP G1&G 16.00] [11]
CHNL# 31: [ANGL436 [HRP G3 16.00] [11]
TIME (SECONDS)
WED, JUL 21 2010 11:31
ROTOR ANGLES

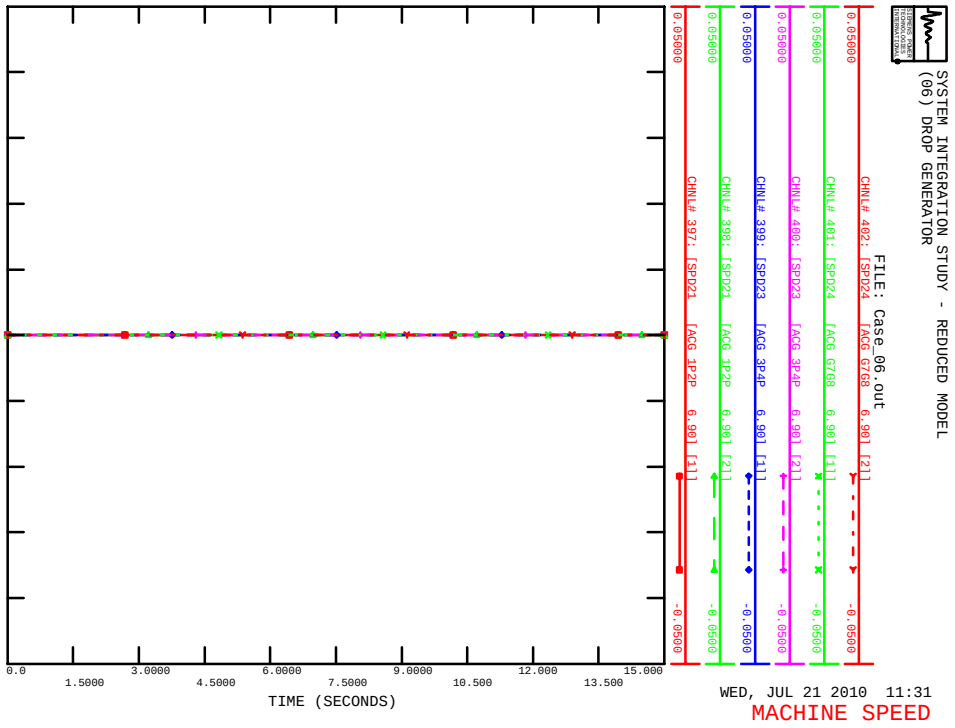

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 33: [ANGL454 [TOP GEN 2.40] [11]
CHNL# 34: [ANGL457 [CGU NP 66.00] [11]
CHNL# 35: [ANGL464 [PBK G1 6.90] [11]
CHNL# 36: [ANGL465 [MOB NP G 6.90] [11]
CHNL# 37: [ANGL468 [TCV GEN 6.90] [11]
TIME (SECONDS)
WED, JUL 21 2010 11:31
ROTOR ANGLES

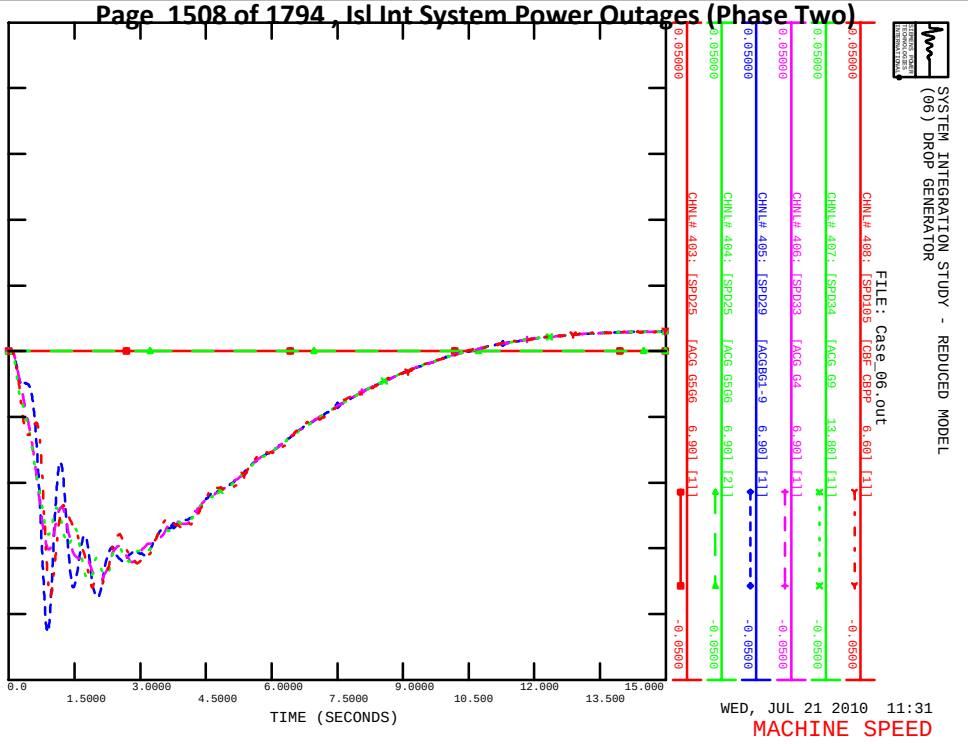

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 38: [ANGL468 [TCV GEN 6.90] [2]
CHNL# 39: [ANGL468 [TCV GEN 6.90] [3]
CHNL# 40: [ANGL473 [ROP G1 6.90] [1]
CHNL# 41: [ANGL478 [PHR GEN 2.30] [1]
CHNL# 42: [ANGL478 [PHR GEN 2.30] [2]
CHNL# 43: [ANGL478 [PHR GEN 2.30] [3]
TIME (SECONDS)
WED, JUL 21 2010 11:31
ROTOR ANGLES

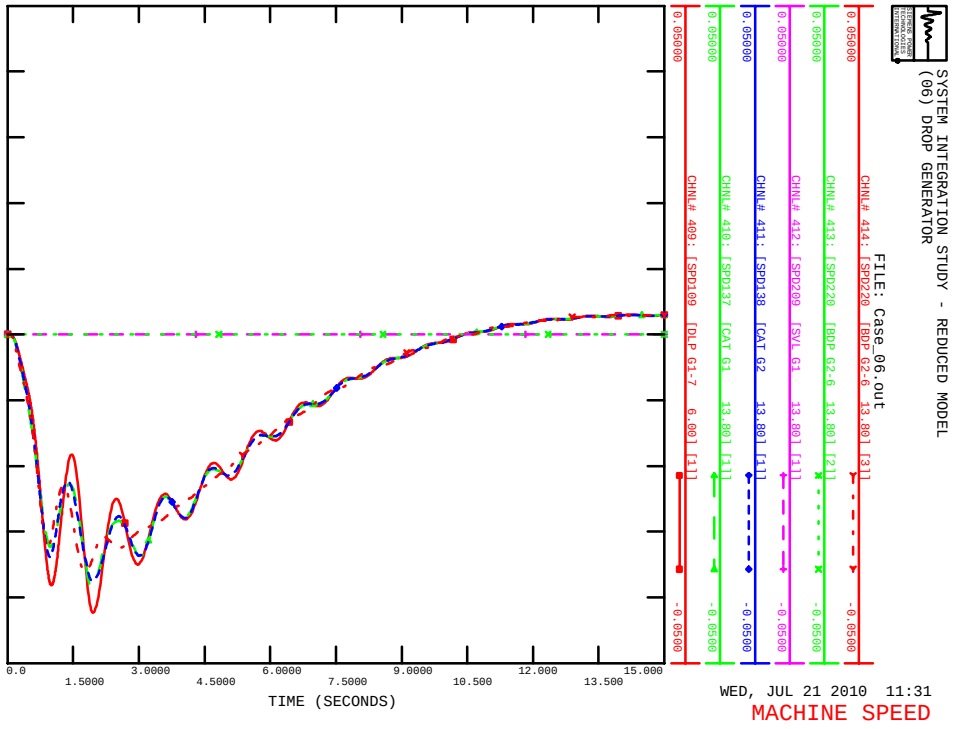

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 44: [ANGL483 [MRP G1 2.40] [1]
CHNL# 45: [ANGL486 [HCP G1 6.90] [1]
CHNL# 46: [ANGL488 [CAB G1 6.90] [1]
CHNL# 47: [ANGL871 [SLK G1 13.80] [1]
TIME (SECONDS)
WED, JUL 21 2010 11:31
ROTOR ANGLES

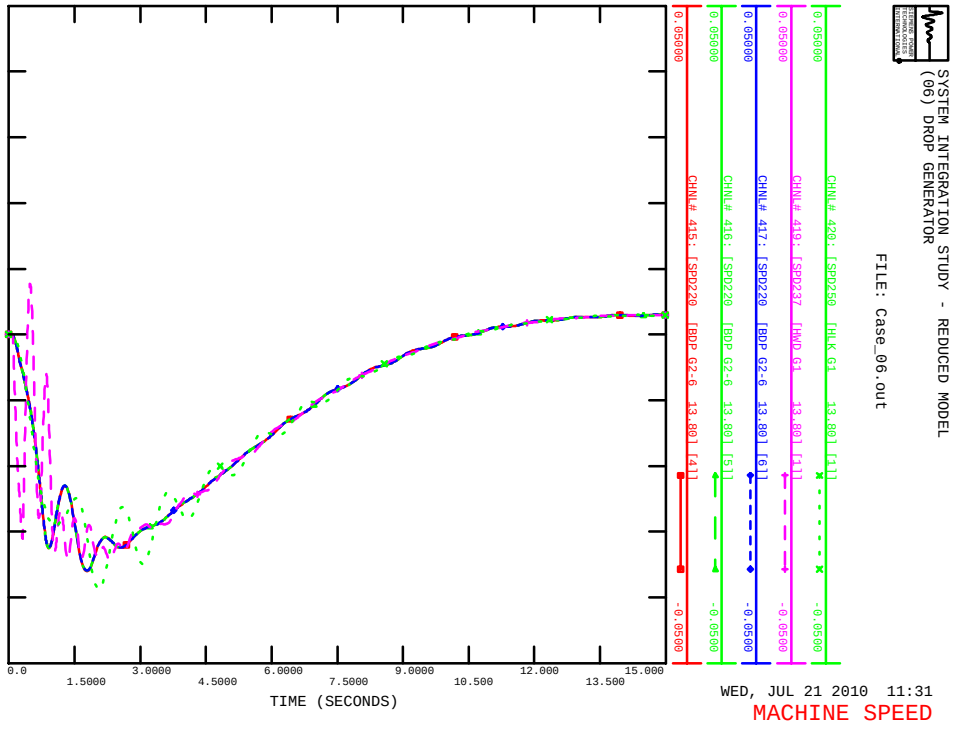

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 56: [ANGL2201 [BDP G1 13.80] [1]
CHNL# 57: [ANGL2207 [BDP G7 13.80] [7]
CHNL# 58: [ANGL2221 [PHL SC1 13.80] [1]
CHNL# 59: [ANGL2222 [PHL SC2 13.80] [1]
TIME (SECONDS)
WED, JUL 21 2010 11:31
ROTOR ANGLES

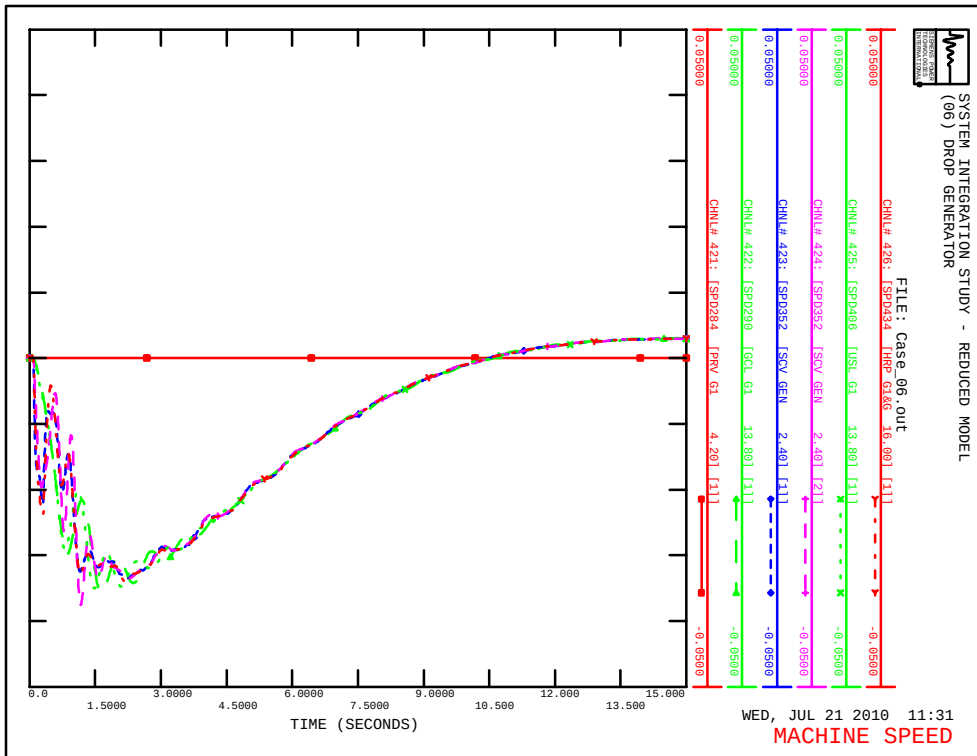

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 62: [ANGL2494 [SOL SC1 13.80] [1]
CHNL# 63: [ANGL2495 [SOL SC2 13.80] [2]
CHNL# 64: [ANGL2496 [SOL SC3 13.80] [3]
TIME (SECONDS)
WED, JUL 21 2010 11:31
ROTOR ANGLES

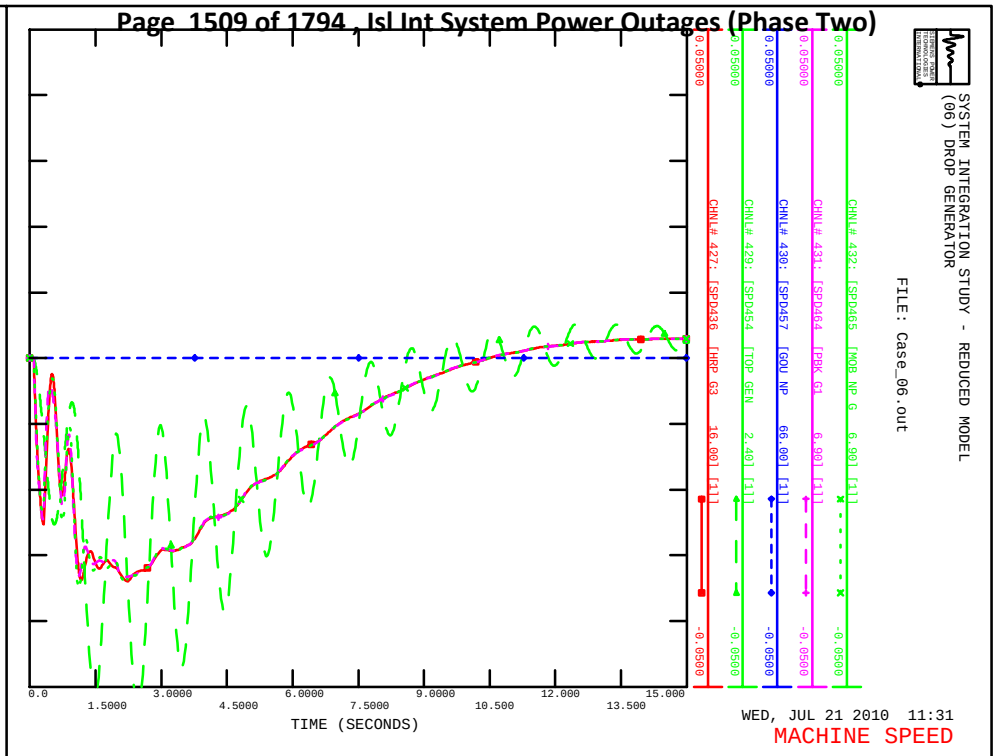

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 397: [SPD21 [AGG 1P2P 6.90] [1]]
CHNL# 398: [SPD21 [AGG 1P2P 6.90] [2]]
CHNL# 399: [SPD23 [AGG 3P4P 6.90] [1]]
CHNL# 400: [SPD23 [AGG 3P4P 6.90] [2]]
CHNL# 401: [SPD24 [AGG G768 6.90] [1]]
CHNL# 402: [SPD24 [AGG G768 6.90] [2]]
TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

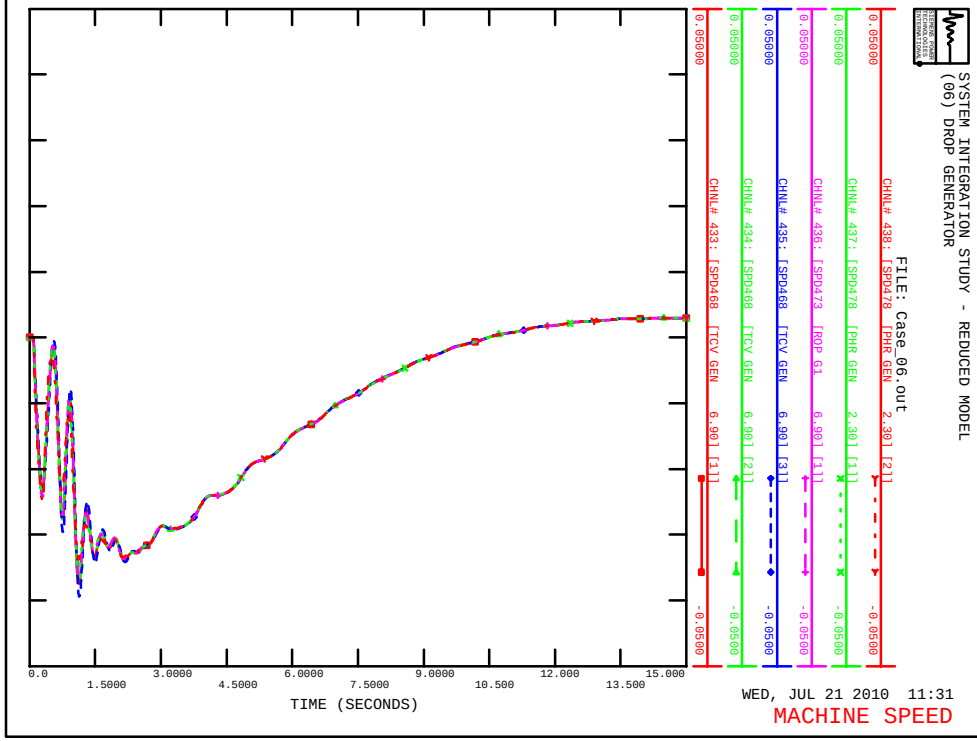

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 403: [SPD25 [AGG G566 6.90] [1]]
CHNL# 404: [SPD25 [AGG G566 6.90] [2]]
CHNL# 405: [SPD29 [AGGB61-9 6.90] [1]]
CHNL# 406: [SPD33 [AGG G4 6.90] [1]]
CHNL# 407: [SPD34 [AGG G9 13.80] [1]]
CHNL# 408: [SPD105 [CBF CBPP 6.60] [1]]
TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

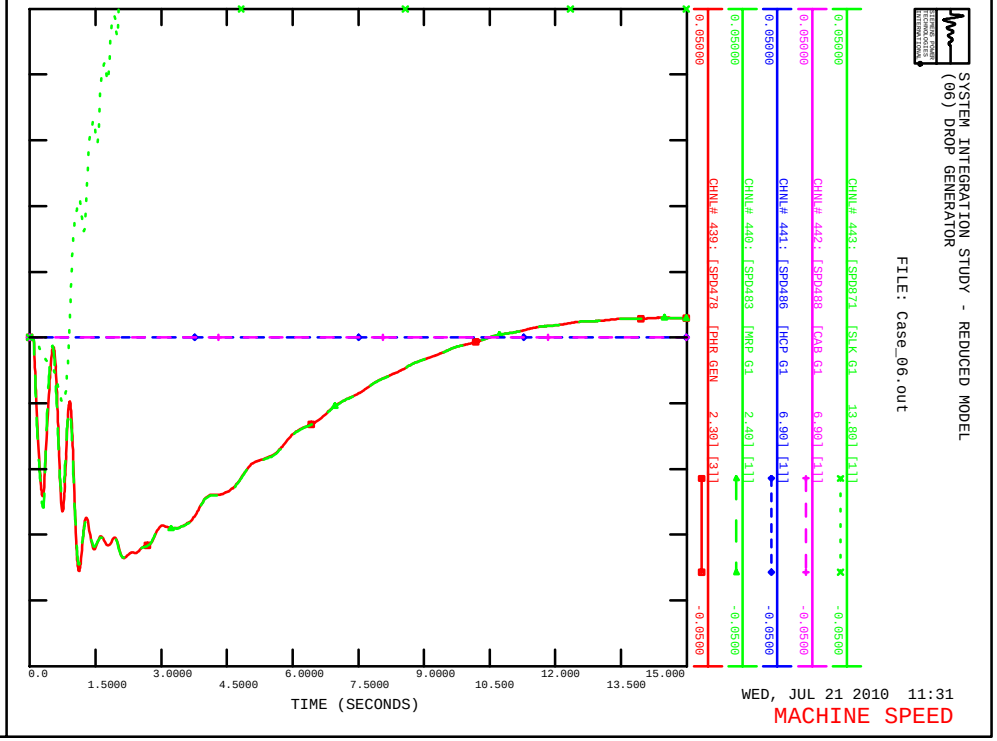

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 409: [SPD109 [DLP G1-7 6.00] [1]]
CHNL# 410: [SPD137 [CAT G1 13.80] [1]]
CHNL# 411: [SPD138 [CAT G2 13.80] [1]]
CHNL# 412: [SPD209 [SVL G1 13.80] [1]]
CHNL# 413: [SPD220 [BDP G2-6 13.80] [2]]
CHNL# 414: [SPD220 [BDP G2-6 13.80] [3]]
TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

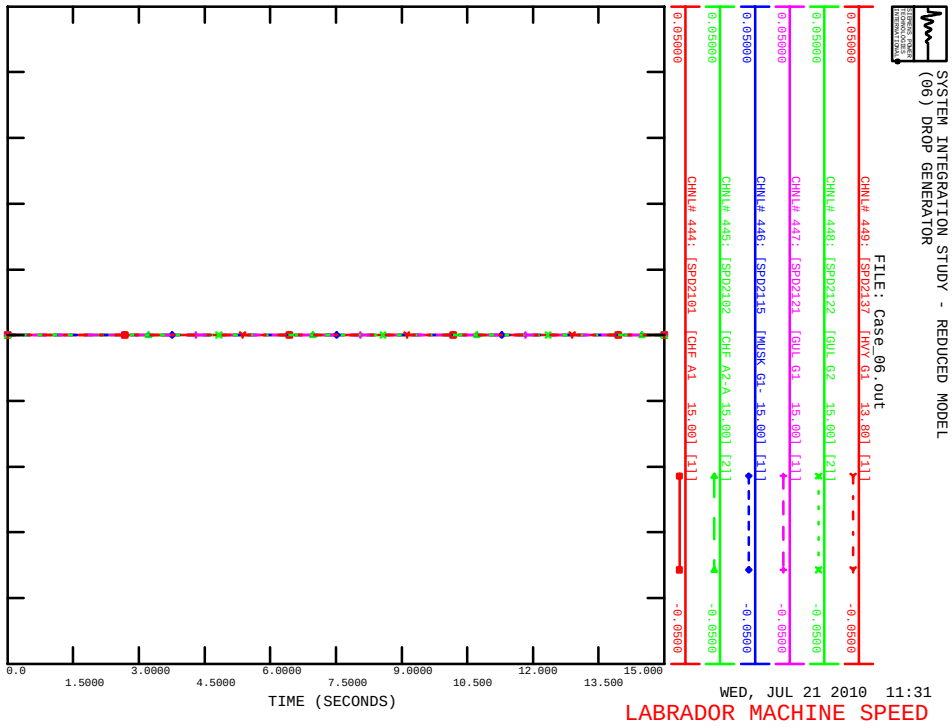

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 415: [SPD220 [BDP G2-6 13.80] [4]]
CHNL# 416: [SPD220 [BDP G2-6 13.80] [5]]
CHNL# 417: [SPD220 [BDP G2-6 13.80] [6]]
CHNL# 419: [SPD237 [MWD G1 13.80] [1]]
CHNL# 420: [SPD250 [HLK G1 13.80] [1]]
TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

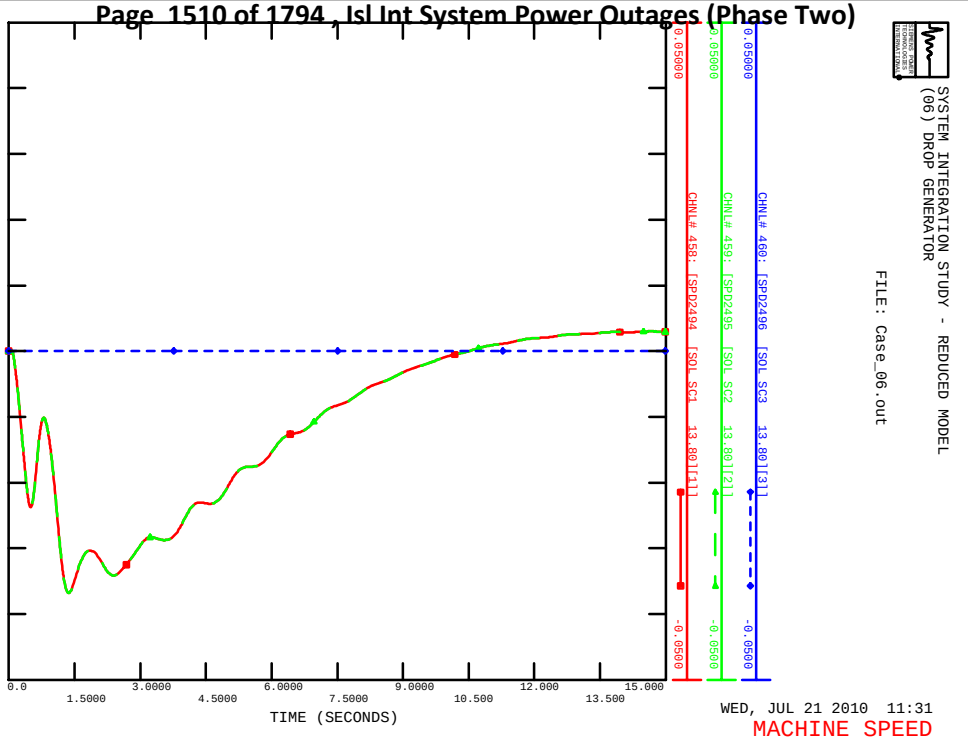

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 421: [SPD284 [PRV G1 4.20] [1]]
CHNL# 422: [SPD290 [GCL G1 13.80] [1]]
CHNL# 423: [SPD352 [SCV GEN 2.40] [1]]
CHNL# 424: [SPD352 [SCV GEN 2.40] [2]]
CHNL# 425: [SPD406 [USL G1 13.80] [1]]
CHNL# 426: [SPD434 [HRP G1&G 16.00] [1]]
TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

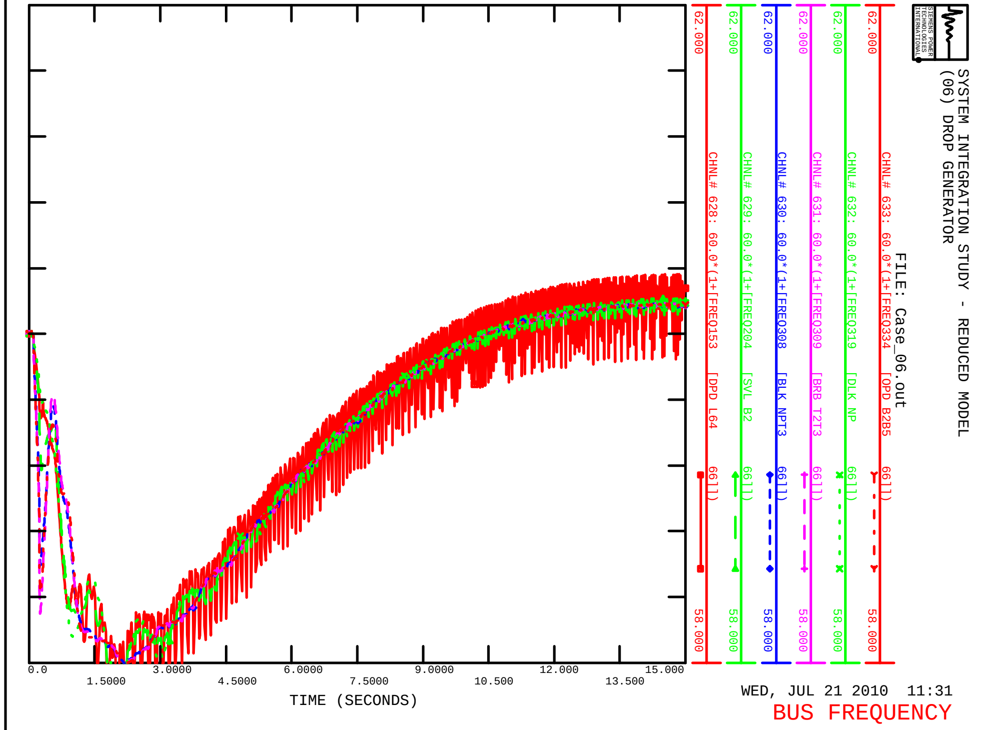

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 427: [SPD436 [HRP G3 16.00] [1]]
CHNL# 429: [SPD454 [TOP GEN 2.40] [1]]
CHNL# 430: [SPD457 [GOU NP 66.00] [1]]
CHNL# 431: [SPD464 [PBK G1 6.90] [1]]
CHNL# 432: [SPD465 [MOB NP G 6.90] [1]]
TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

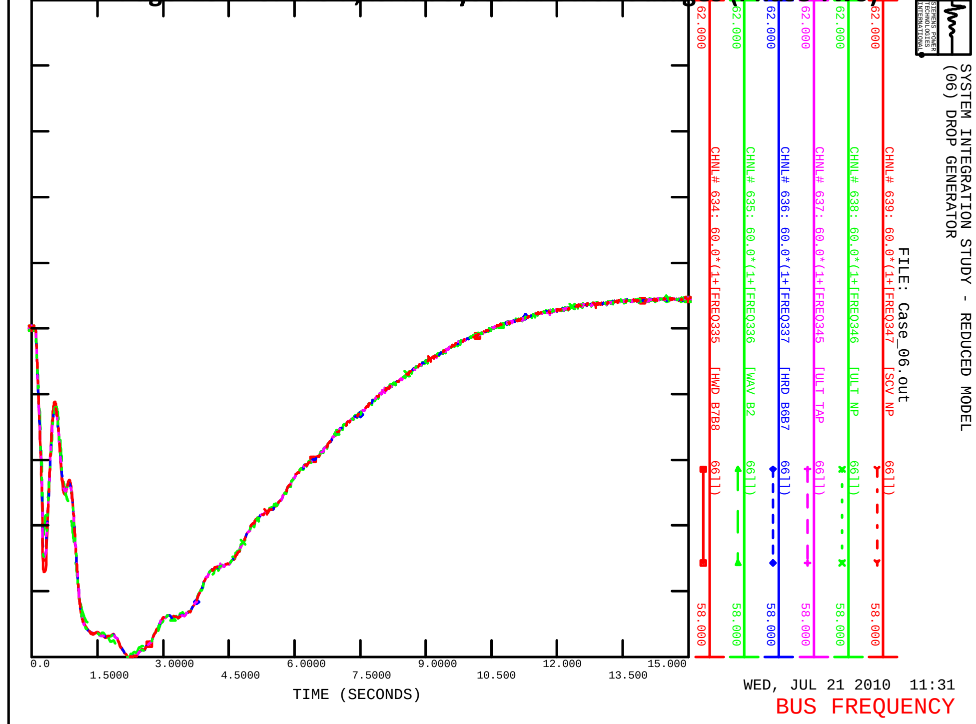

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 433: [SPD468 [TCV GEN 6.90] [1]]
CHNL# 434: [SPD468 [TCV GEN 6.90] [2]]
CHNL# 435: [SPD468 [TCV GEN 6.90] [3]]
CHNL# 436: [SPD473 [ROP G1 6.90] [1]]
CHNL# 437: [SPD478 [PHR GEN 2.30] [1]]
CHNL# 438: [SPD478 [PHR GEN 2.30] [2]]
TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

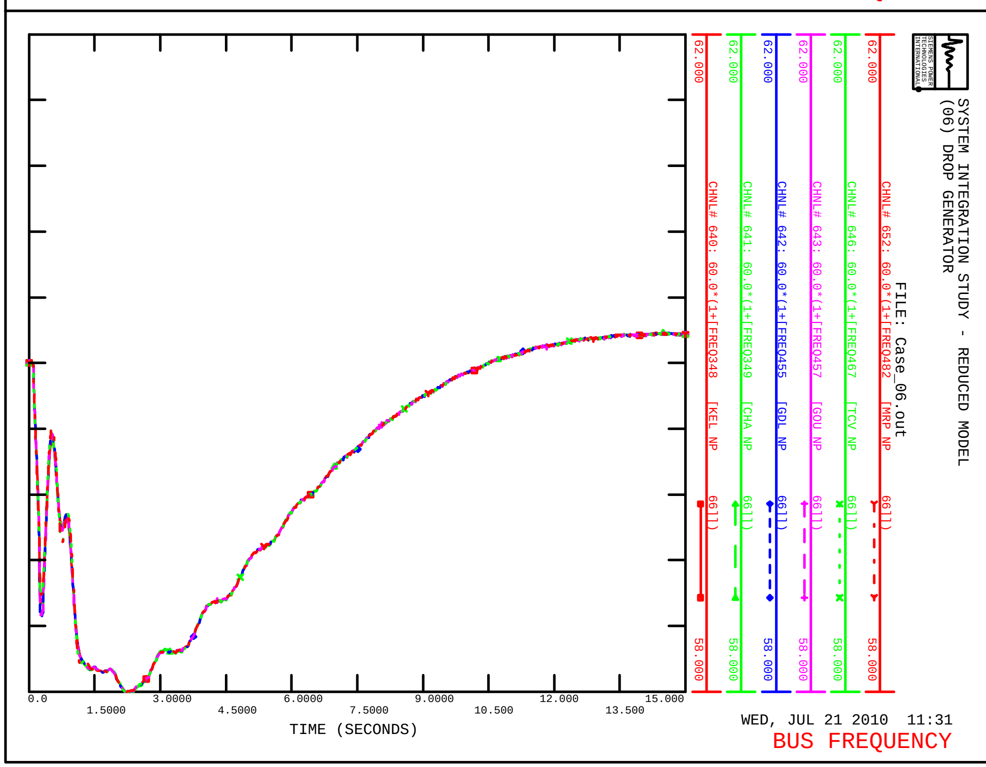

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 439: [SPD478 [PHR GEN 2.30] [3]]
CHNL# 440: [SPD483 [MRP G1 2.40] [1]]
CHNL# 441: [SPD486 [HCP G1 6.90] [1]]
CHNL# 442: [SPD488 [CAB G1 6.90] [1]]
CHNL# 443: [SPD871 [SLK G1 13.80] [1]]
TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

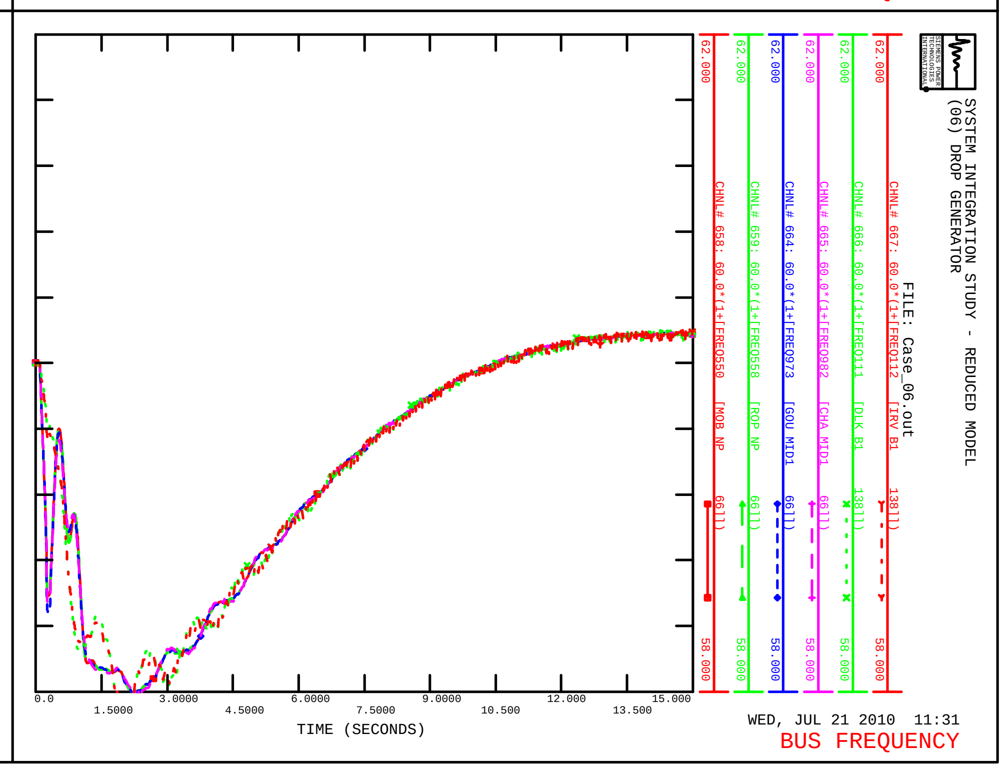

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 444: [SPD2101 [CHF A1 15.00] [1]]
CHNL# 445: [SPD2102 [CHF A2-A 15.00] [2]]
CHNL# 446: [SPD2115 [MUSK G1- 15.00] [1]]
CHNL# 447: [SPD2121 [GUL G1 15.00] [1]]
CHNL# 448: [SPD2122 [GUL G2 15.00] [2]]
CHNL# 449: [SPD2137 [HVY G1 13.80] [1]]
0.05000
-0.0500
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
LABRADOR MACHINE SPEED

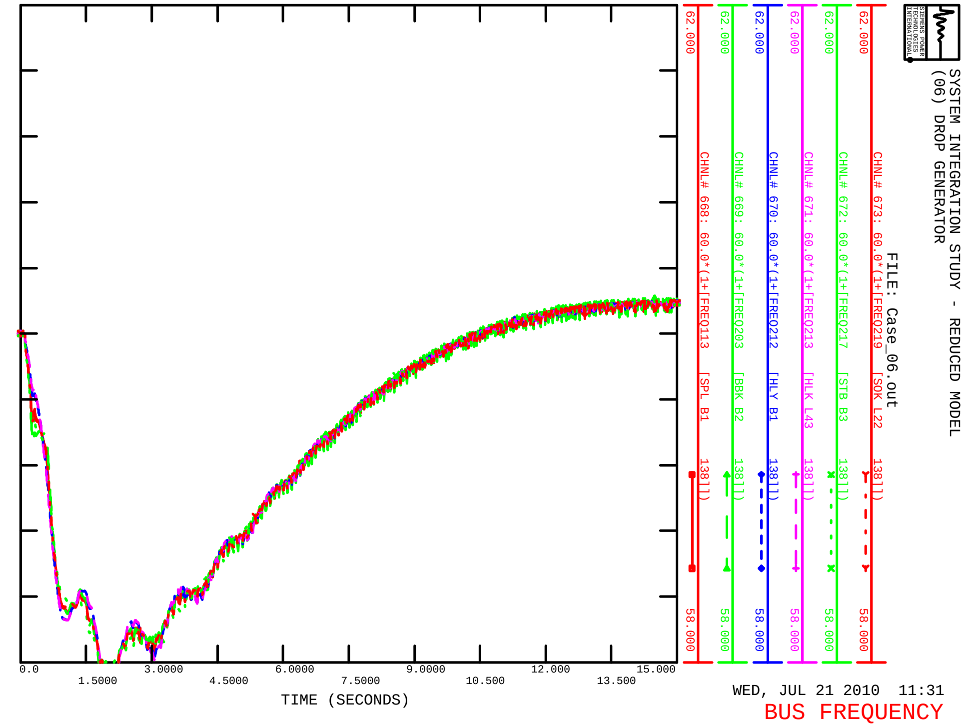

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 458: [SPD2494 [SOL SC1 13.80] [1]]
CHNL# 459: [SPD2495 [SOL SC2 13.80] [2]]
CHNL# 460: [SPD2496 [SOL SC3 13.80] [3]]
0.05000
-0.0500
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

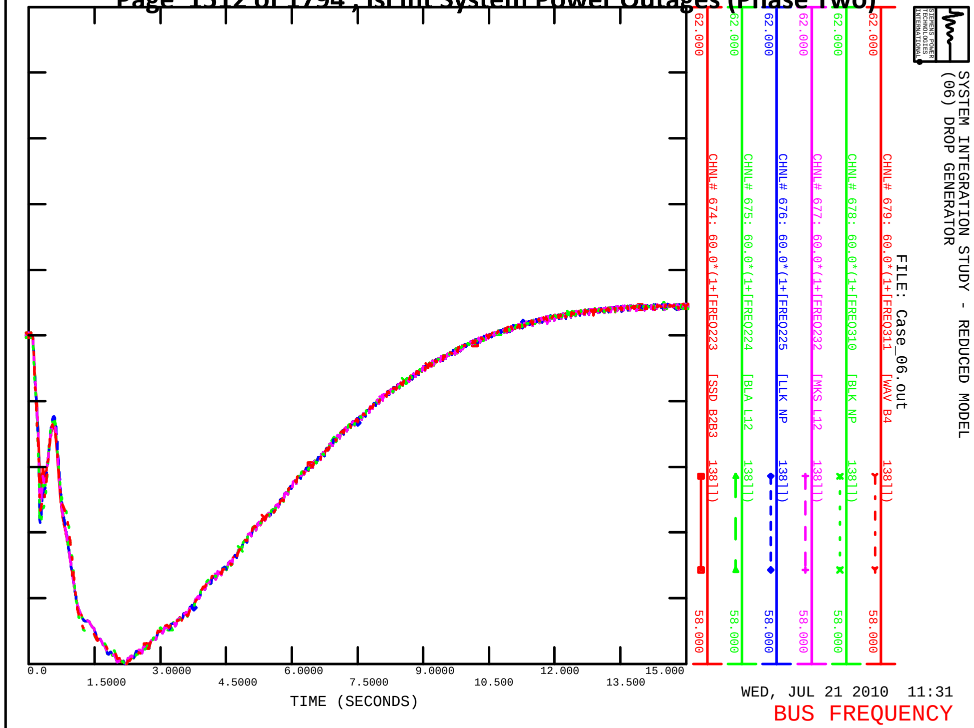

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 628: 60.0*(1+[FREQ0153 [DPD L64 6611])
CHNL# 629: 60.0*(1+[FREQ0204 [SVL B2 6611])
CHNL# 630: 60.0*(1+[FREQ0308 [BLK NPT3 6611])
CHNL# 631: 60.0*(1+[FREQ0309 [BRB T2T3 6611])
CHNL# 632: 60.0*(1+[FREQ0319 [DLK NP 6611])
CHNL# 633: 60.0*(1+[FREQ0334 [OPD B2B5 6611])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
BUS FREQUENCY

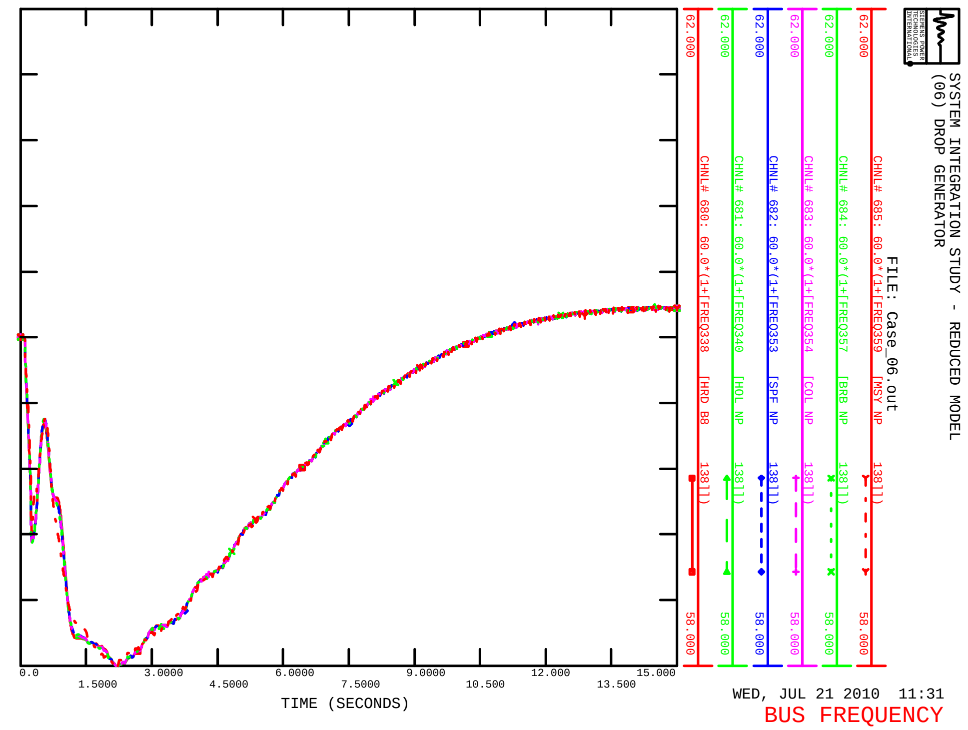

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 634: 60.0*(1+[FREQ0335 [HWD B7B8 6611])
CHNL# 635: 60.0*(1+[FREQ0336 [WAV B2 6611])
CHNL# 636: 60.0*(1+[FREQ0337 [HRD B6B7 6611])
CHNL# 637: 60.0*(1+[FREQ0345 [ULT TAP 6611])
CHNL# 638: 60.0*(1+[FREQ0346 [ULT NP 6611])
CHNL# 639: 60.0*(1+[FREQ0347 [SCV NP 6611])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
BUS FREQUENCY

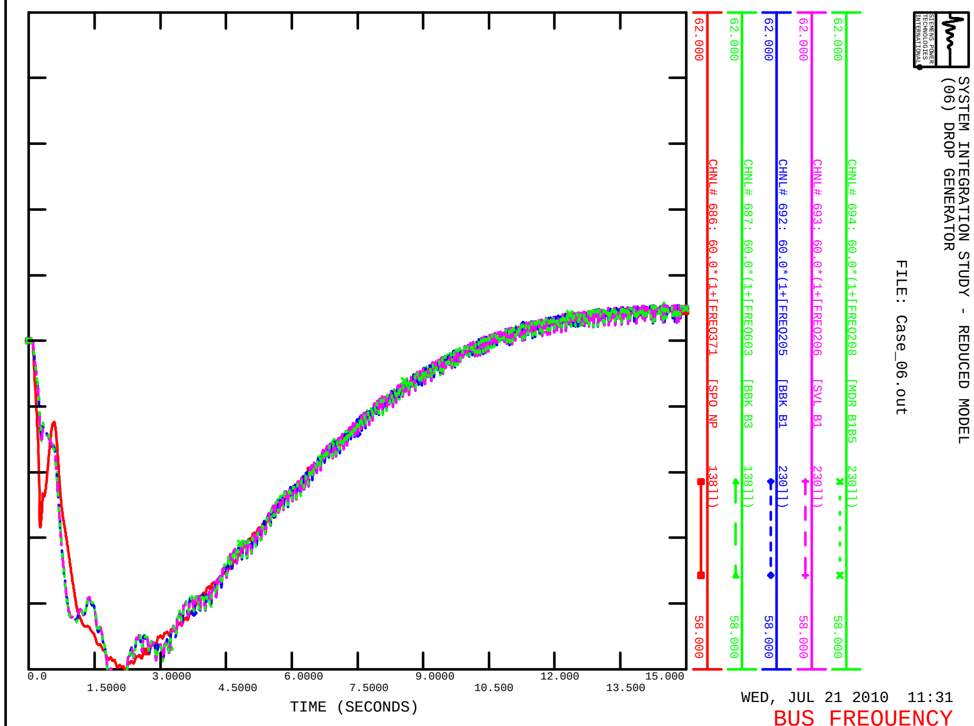

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 640: 60.0*(1+[FREQ0348 [KEL NP 6611])
CHNL# 641: 60.0*(1+[FREQ0349 [CHA NP 6611])
CHNL# 642: 60.0*(1+[FREQ0455 [GDL NP 6611])
CHNL# 643: 60.0*(1+[FREQ0457 [GOU NP 6611])
CHNL# 646: 60.0*(1+[FREQ0467 [TCV NP 6611])
CHNL# 652: 60.0*(1+[FREQ0482 [MRP NP 6611])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
BUS FREQUENCY

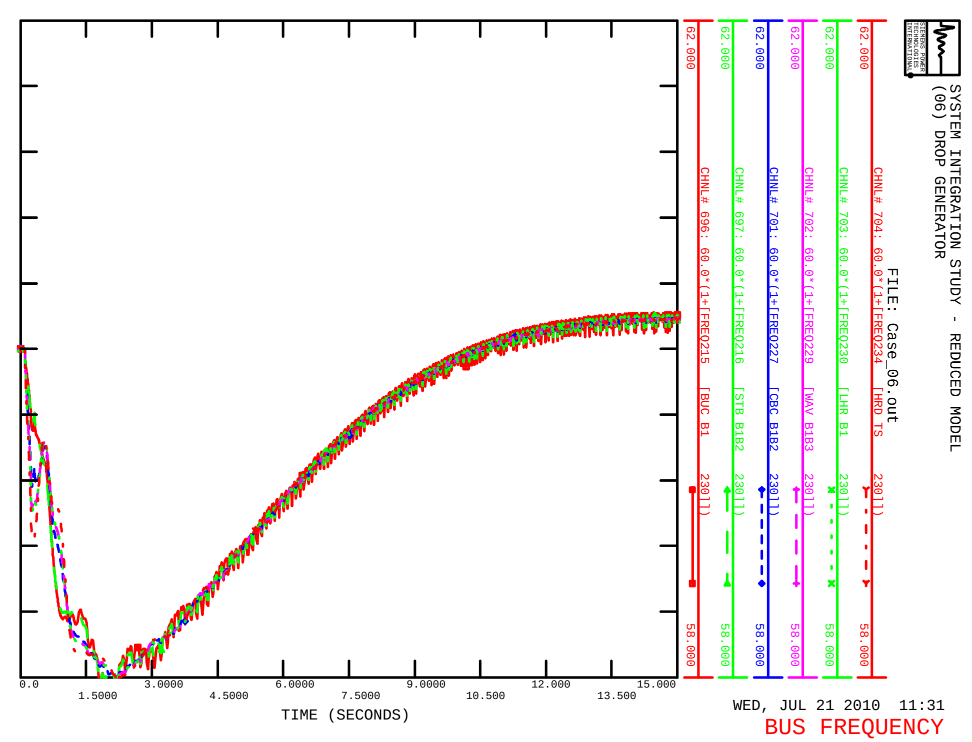

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 658: 60.0*(1+[FREQ0550 [MOB NP 6611])
CHNL# 659: 60.0*(1+[FREQ0558 [ROP NP 6611])
CHNL# 664: 60.0*(1+[FREQ0973 [GOU MID1 6611])
CHNL# 665: 60.0*(1+[FREQ0982 [CHA MID1 6611])
CHNL# 666: 60.0*(1+[FREQ0111 [DLK B1 13811])
CHNL# 667: 60.0*(1+[FREQ0112 [IRV B1 13811])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
BUS FREQUENCY

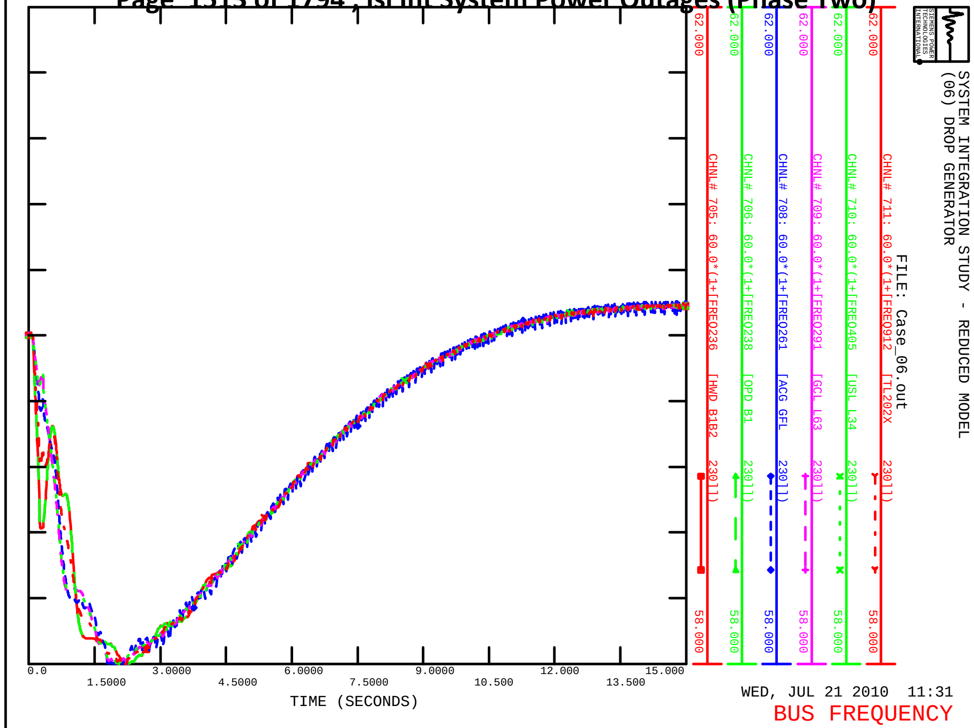

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 668: 60.0*(1+[FREQ113 [SPL B1 138]])
CHNL# 669: 60.0*(1+[FREQ203 [BBK B2 138]])
CHNL# 670: 60.0*(1+[FREQ212 [HLY B1 138]])
CHNL# 671: 60.0*(1+[FREQ213 [HLK L43 138]])
CHNL# 672: 60.0*(1+[FREQ217 [STB B3 138]])
CHNL# 673: 60.0*(1+[FREQ219 [SOK L22 138]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
BUS FREQUENCY

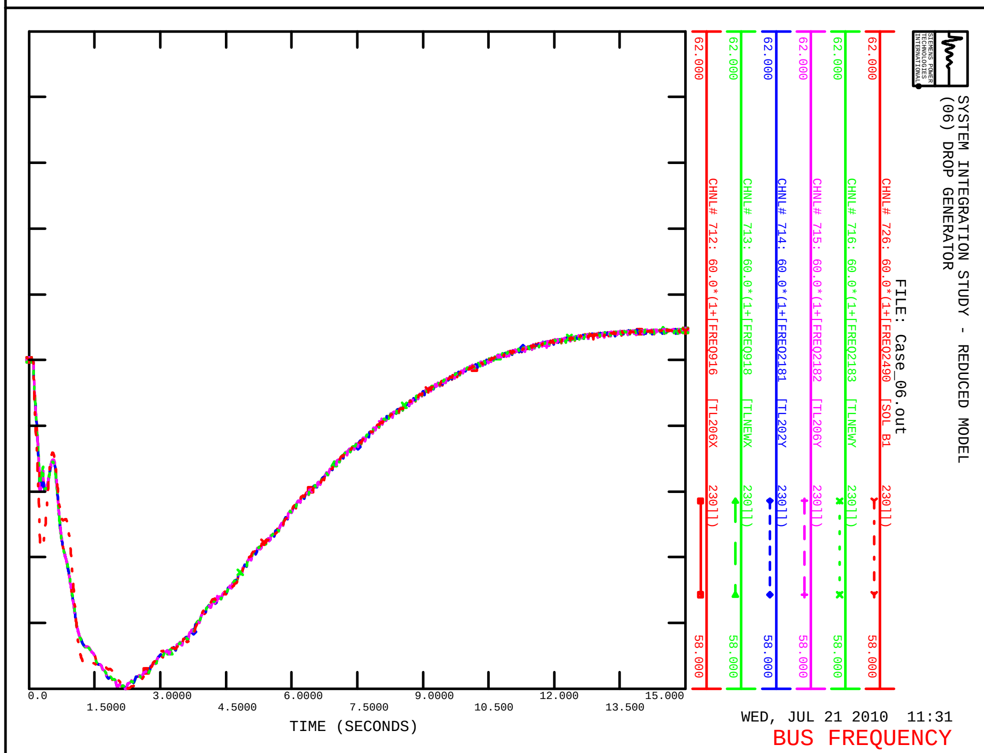

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 674: 60.0*(1+[FREQ223 [SSD B2B3 138]])
CHNL# 675: 60.0*(1+[FREQ224 [BLA L12 138]])
CHNL# 676: 60.0*(1+[FREQ225 [LLK NP 138]])
CHNL# 677: 60.0*(1+[FREQ232 [MKS L12 138]])
CHNL# 678: 60.0*(1+[FREQ310 [BLK NP 138]])
CHNL# 679: 60.0*(1+[FREQ311 [WAV B4 138]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
BUS FREQUENCY

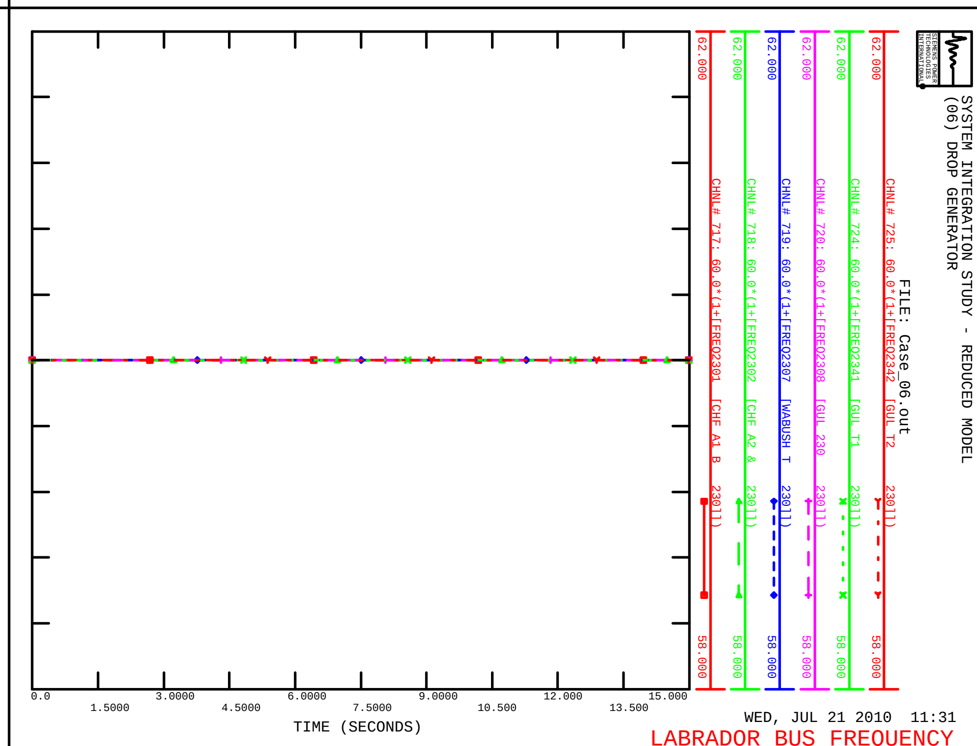

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 680: 60.0*(1+[FREQ338 [HRD B8 138]])
CHNL# 681: 60.0*(1+[FREQ340 [HOL NP 138]])
CHNL# 682: 60.0*(1+[FREQ353 [SPF NP 138]])
CHNL# 683: 60.0*(1+[FREQ354 [COL NP 138]])
CHNL# 684: 60.0*(1+[FREQ357 [BRB NP 138]])
CHNL# 685: 60.0*(1+[FREQ359 [MSY NP 138]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
BUS FREQUENCY

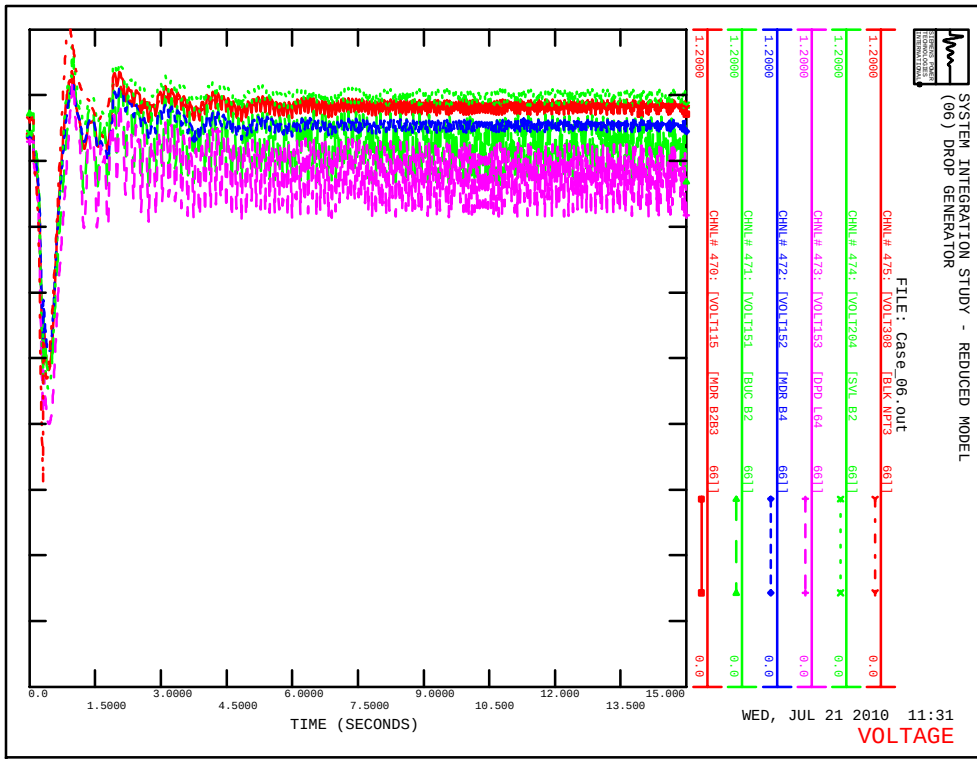

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 686: 60.0*(1+[FREQ371 [SPO NP 138]])
CHNL# 687: 60.0*(1+[FREQ603 [BBK B3 138]])
CHNL# 692: 60.0*(1+[FREQ205 [BBK B1 230]])
CHNL# 693: 60.0*(1+[FREQ206 [SVL B1 230]])
CHNL# 694: 60.0*(1+[FREQ208 [MDR B1B5 230]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
BUS FREQUENCY

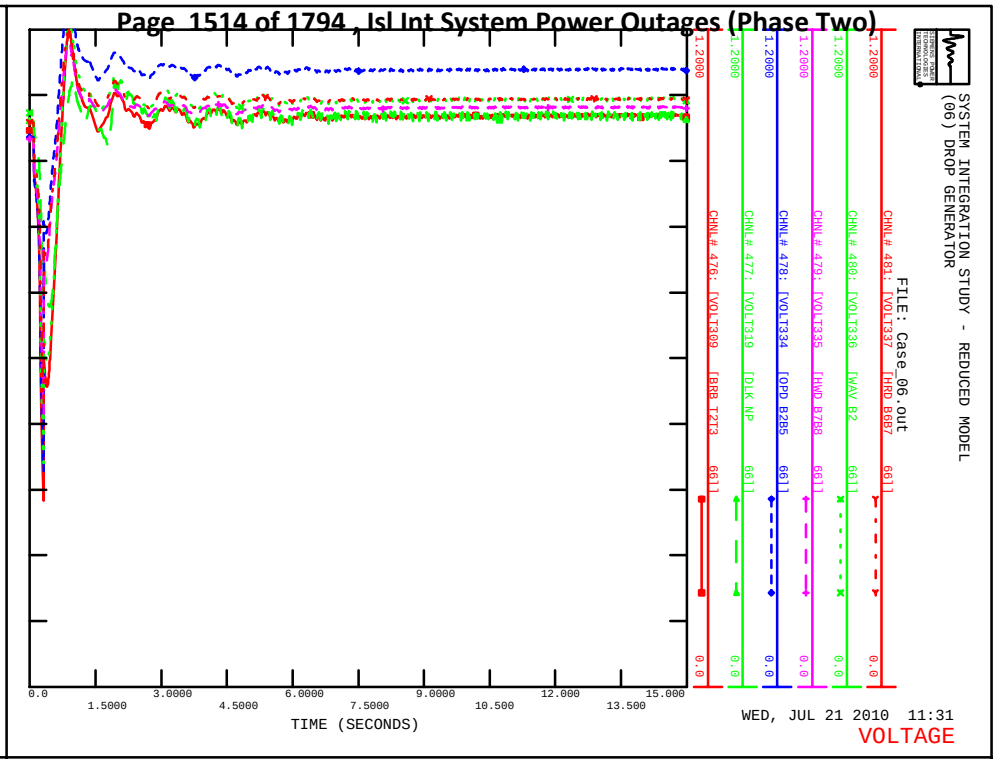

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 696: 60.0*(1+[FREQ215 [BUC B1 230]1])
CHNL# 697: 60.0*(1+[FREQ216 [STB B1B2 230]1])
CHNL# 701: 60.0*(1+[FREQ227 [CBC B1B2 230]1])
CHNL# 702: 60.0*(1+[FREQ229 [WAV B1B3 230]1])
CHNL# 703: 60.0*(1+[FREQ230 [LHR B1 230]1])
CHNL# 704: 60.0*(1+[FREQ234 [HRD TS 230]1])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
BUS FREQUENCY

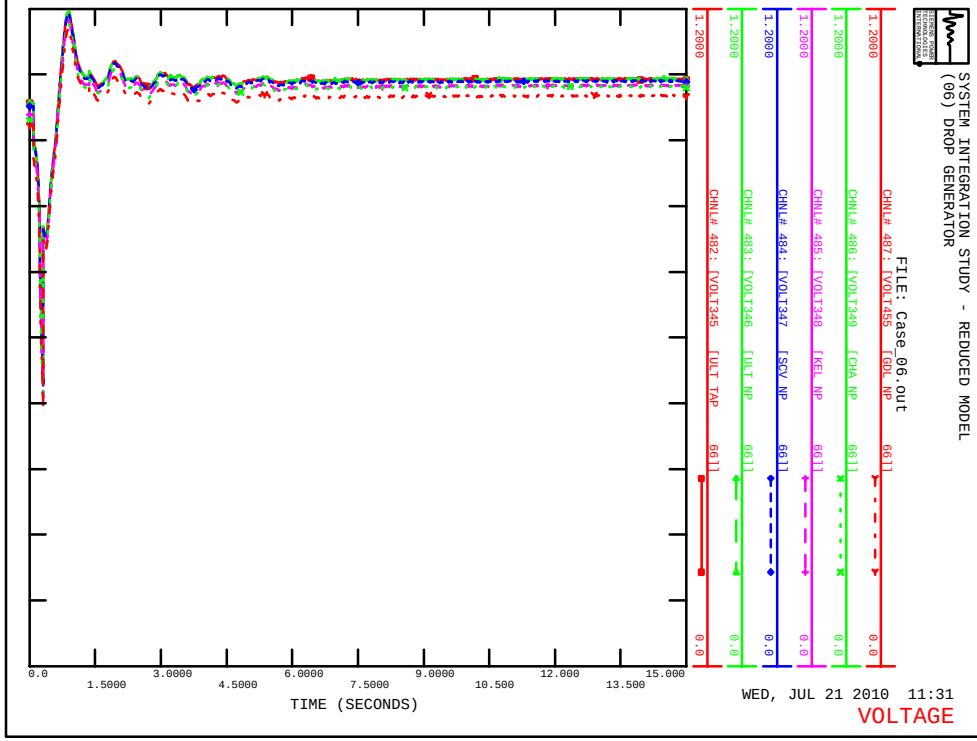

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 705: 60.0*(1+[FREQ236 [HWD B1B2 230]1])
CHNL# 706: 60.0*(1+[FREQ238 [OPD B1 230]1])
CHNL# 708: 60.0*(1+[FREQ261 [ACG GFL 230]1])
CHNL# 709: 60.0*(1+[FREQ291 [GCL L63 230]1])
CHNL# 710: 60.0*(1+[FREQ405 [USL L34 230]1])
CHNL# 711: 60.0*(1+[FREQ912 [TL202X 230]1])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
BUS FREQUENCY

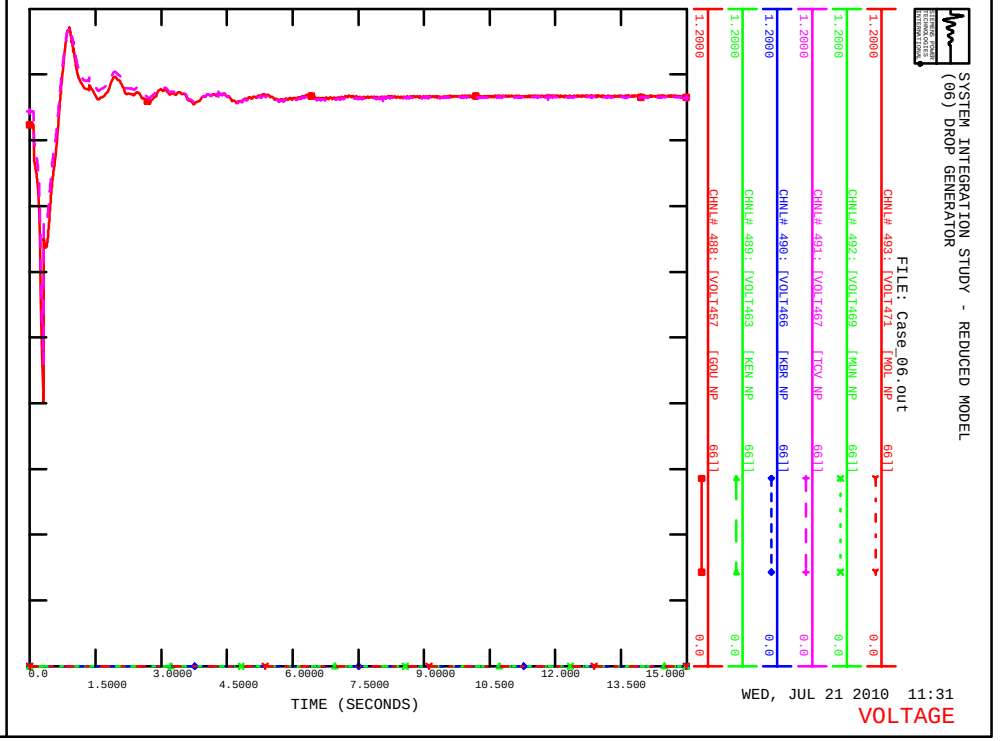

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 712: 60.0*(1+[FREQ916 [TL206X 230]1])
CHNL# 713: 60.0*(1+[FREQ918 [TLNEWX 230]1])
CHNL# 714: 60.0*(1+[FREQ2181 [TL202Y 230]1])
CHNL# 715: 60.0*(1+[FREQ2182 [TL206Y 230]1])
CHNL# 716: 60.0*(1+[FREQ2183 [TLNEWY 230]1])
CHNL# 726: 60.0*(1+[FREQ2490 [SOL B1 230]1])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
BUS FREQUENCY

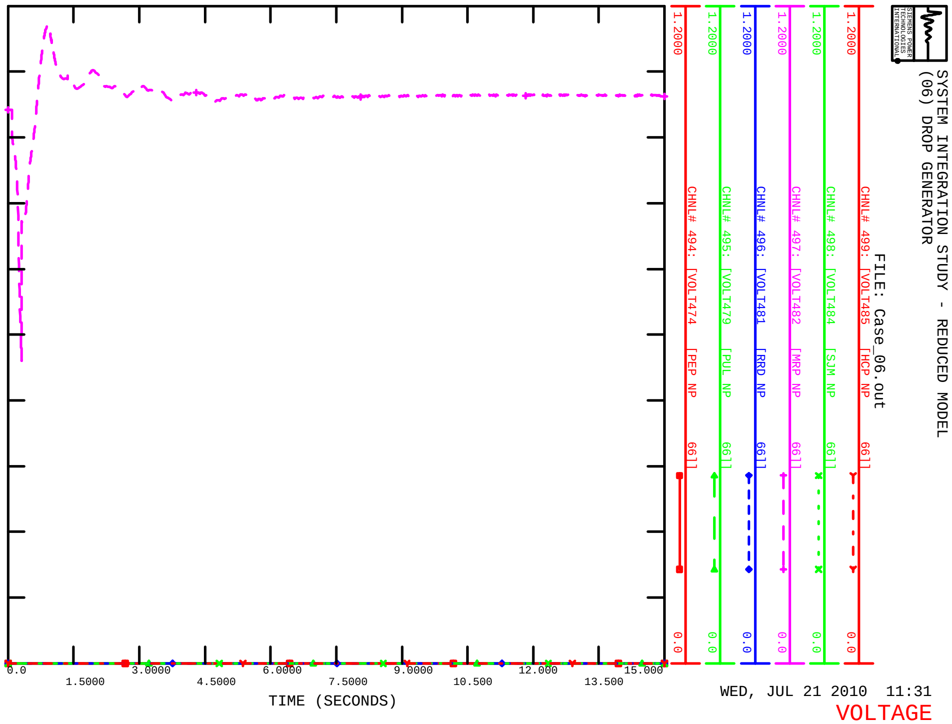

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 717: 60.0*(1+[FREQ2301 [CHF A1 B 230]1])
CHNL# 718: 60.0*(1+[FREQ2302 [CHF A2 & 230]1])
CHNL# 719: 60.0*(1+[FREQ2307 [WABUSH T 230]1])
CHNL# 720: 60.0*(1+[FREQ2308 [GUL 230 230]1])
CHNL# 724: 60.0*(1+[FREQ2341 [GUL T1 230]1])
CHNL# 725: 60.0*(1+[FREQ2342 [GUL T2 230]1])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
LABRADOR BUS FREQUENCY

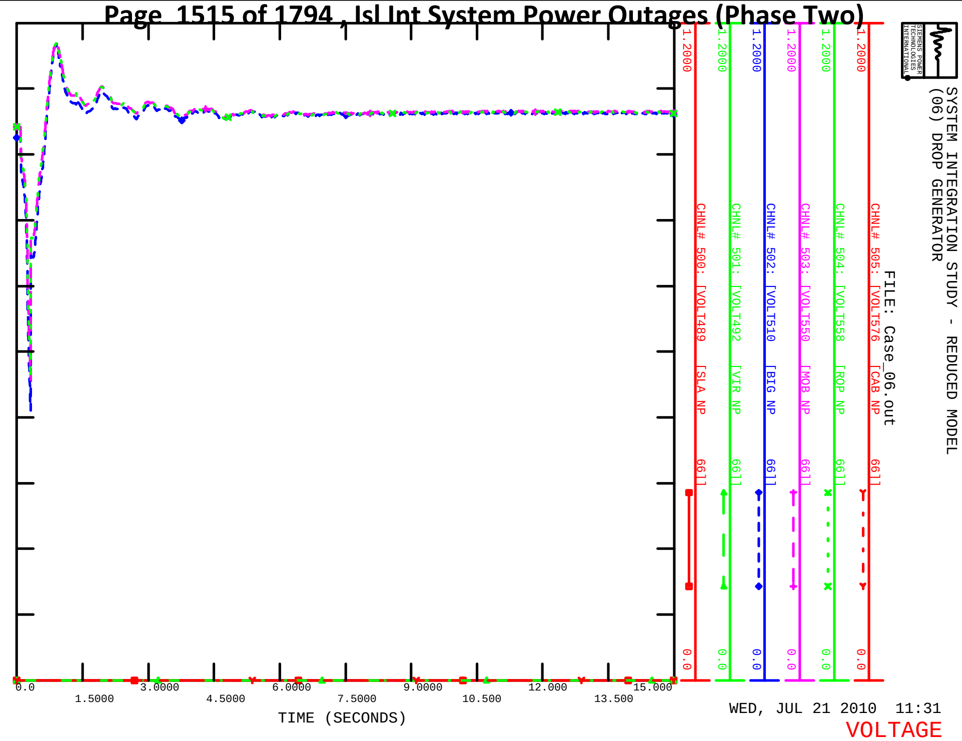

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 470: [VOLT115 [MDR B2B3 661]
CHNL# 471: [VOLT151 [BUC B2 661]
CHNL# 472: [VOLT152 [MDR B4 661]
CHNL# 473: [VOLT153 [OPD L64 661]
CHNL# 474: [VOLT204 [SVL B2 661]
CHNL# 475: [VOLT308 [BLK NPT3 661]
1.2000
0.0
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

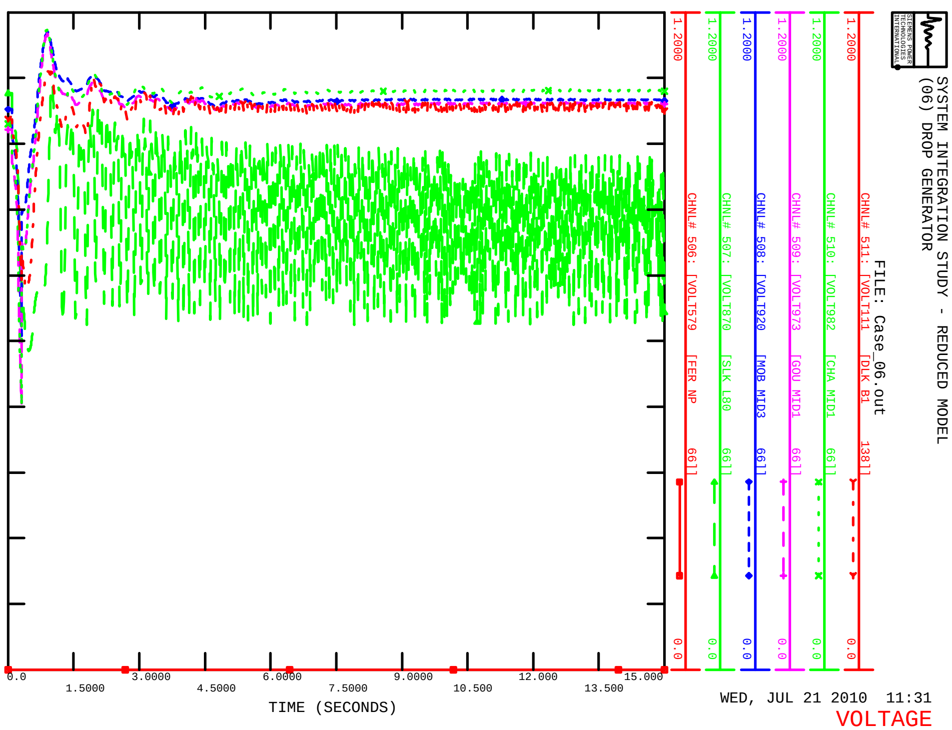

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 476: [VOLT309 [BBB T2T3 661]
CHNL# 477: [VOLT319 [DLK NP 661]
CHNL# 478: [VOLT334 [OPD B2B5 661]
CHNL# 479: [VOLT335 [HWD B7B8 661]
CHNL# 480: [VOLT336 [WAV B2 661]
CHNL# 481: [VOLT337 [HRD B6B7 661]
1.2000
0.0
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

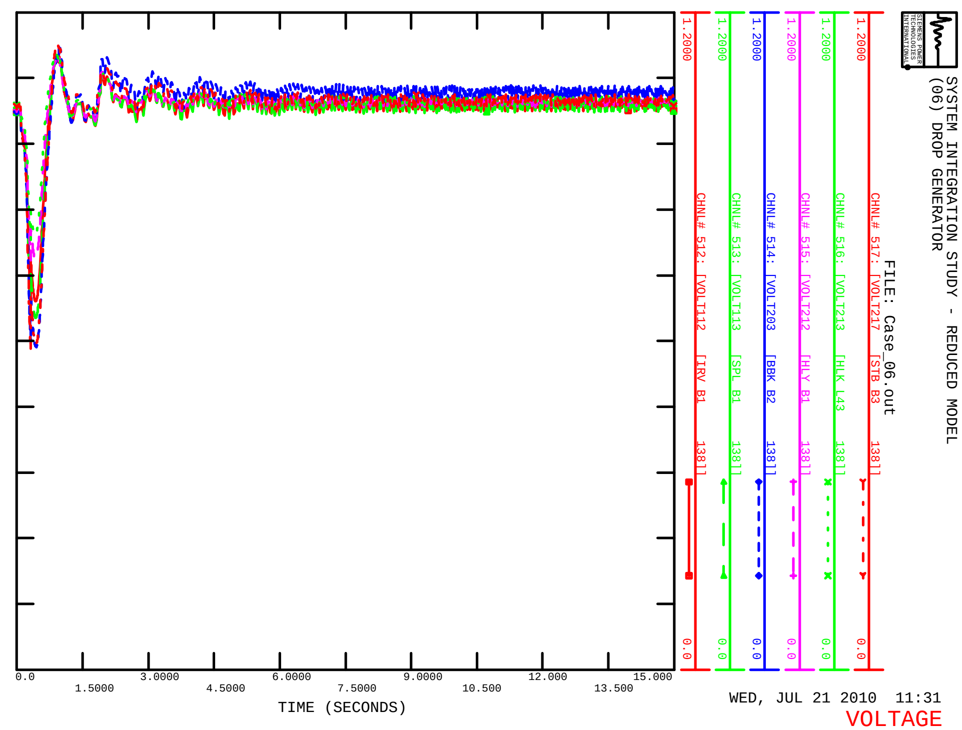

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 482: [VOLT345 [ULT TAP 661]
CHNL# 483: [VOLT346 [ULT NP 661]
CHNL# 484: [VOLT347 [SCV NP 661]
CHNL# 485: [VOLT348 [KEL NP 661]
CHNL# 486: [VOLT349 [CHA NP 661]
CHNL# 487: [VOLT455 [GDL NP 661]
1.2000
0.0
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

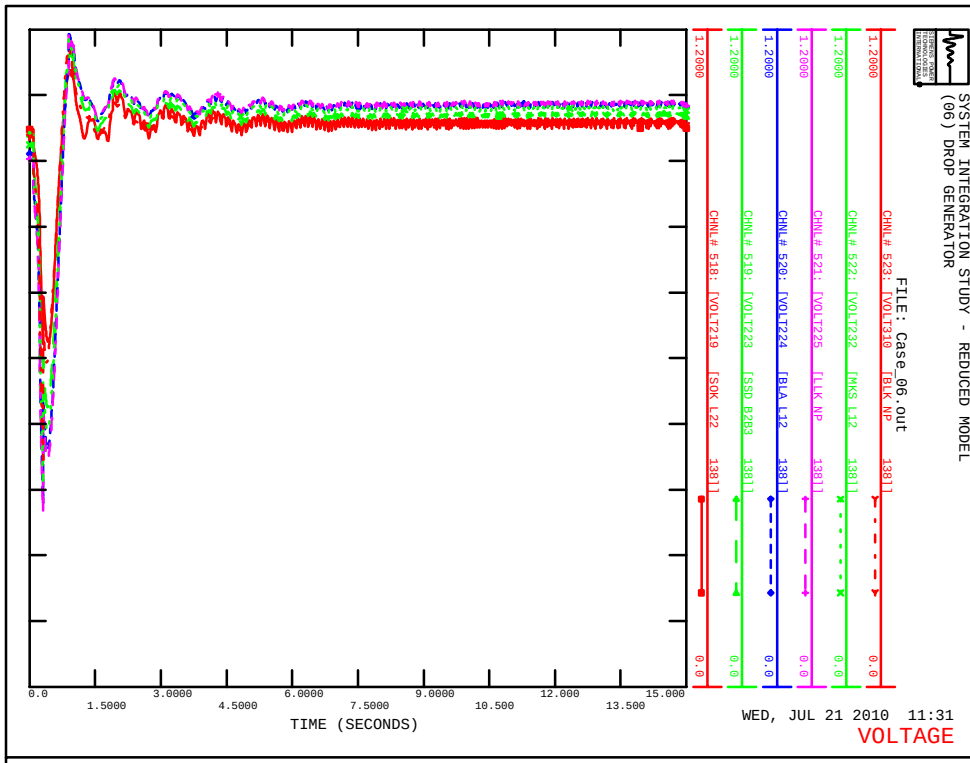

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 488: [VOLT457 [GOU NP 661]
CHNL# 489: [VOLT463 [KEN NP 661]
CHNL# 490: [VOLT466 [KBR NP 661]
CHNL# 491: [VOLT467 [TCV NP 661]
CHNL# 492: [VOLT469 [MUN NP 661]
CHNL# 493: [VOLT471 [MOL NP 661]
1.2000
0.0
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

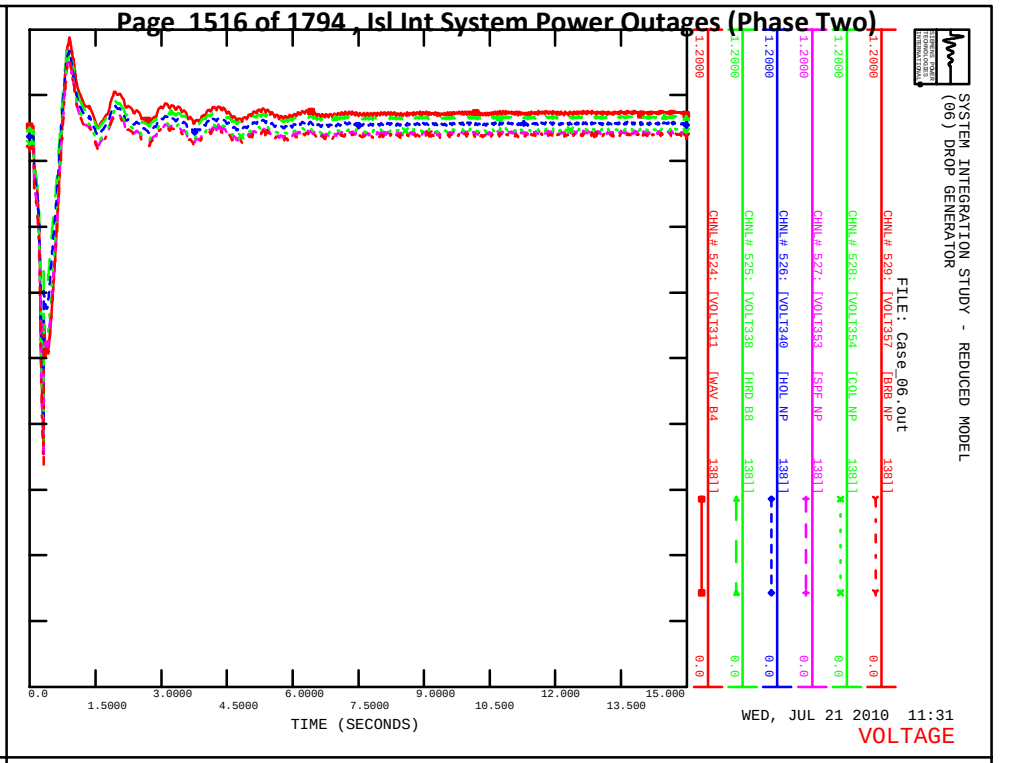

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 494: [VOLT474 [PEP NP 66]]
CHNL# 495: [VOLT479 [PUL NP 66]]
CHNL# 496: [VOLT481 [RRD NP 66]]
CHNL# 497: [VOLT482 [MRP NP 66]]
CHNL# 498: [VOLT484 [SJM NP 66]]
CHNL# 499: [VOLT485 [HCP NP 66]]
1.2000
0.0
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

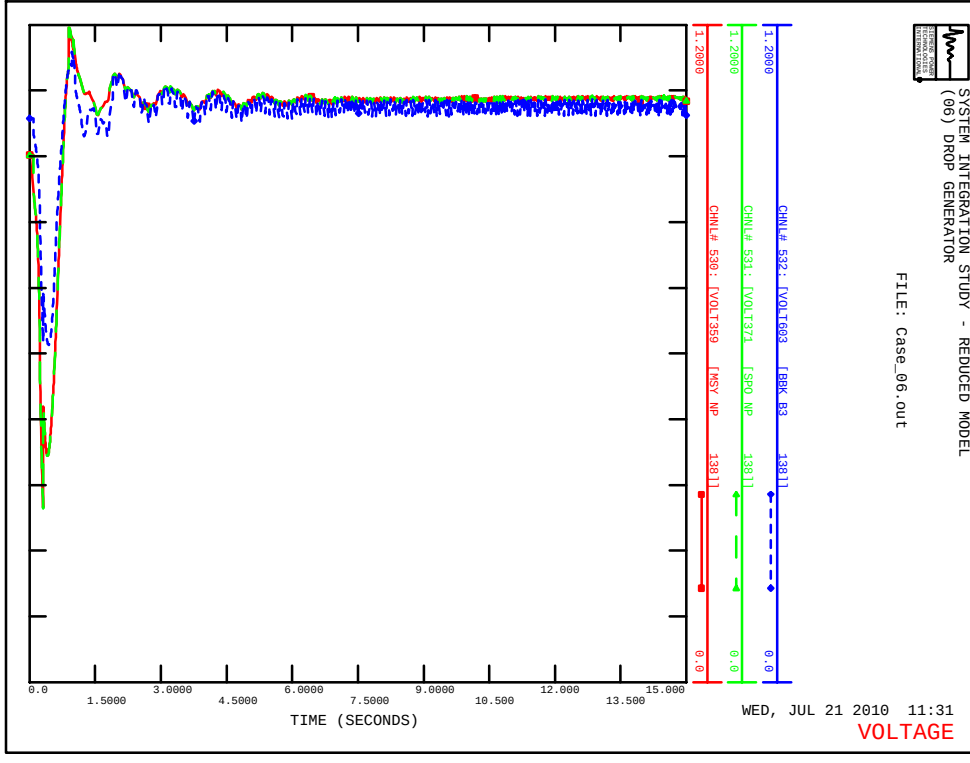

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 500: [VOLT489 [SLA NP 66]]
CHNL# 501: [VOLT492 [VIR NP 66]]
CHNL# 502: [VOLT510 [BIG NP 66]]
CHNL# 503: [VOLT550 [MOB NP 66]]
CHNL# 504: [VOLT558 [ROP NP 66]]
CHNL# 505: [VOLT576 [CAB NP 66]]
1.2000
0.0
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

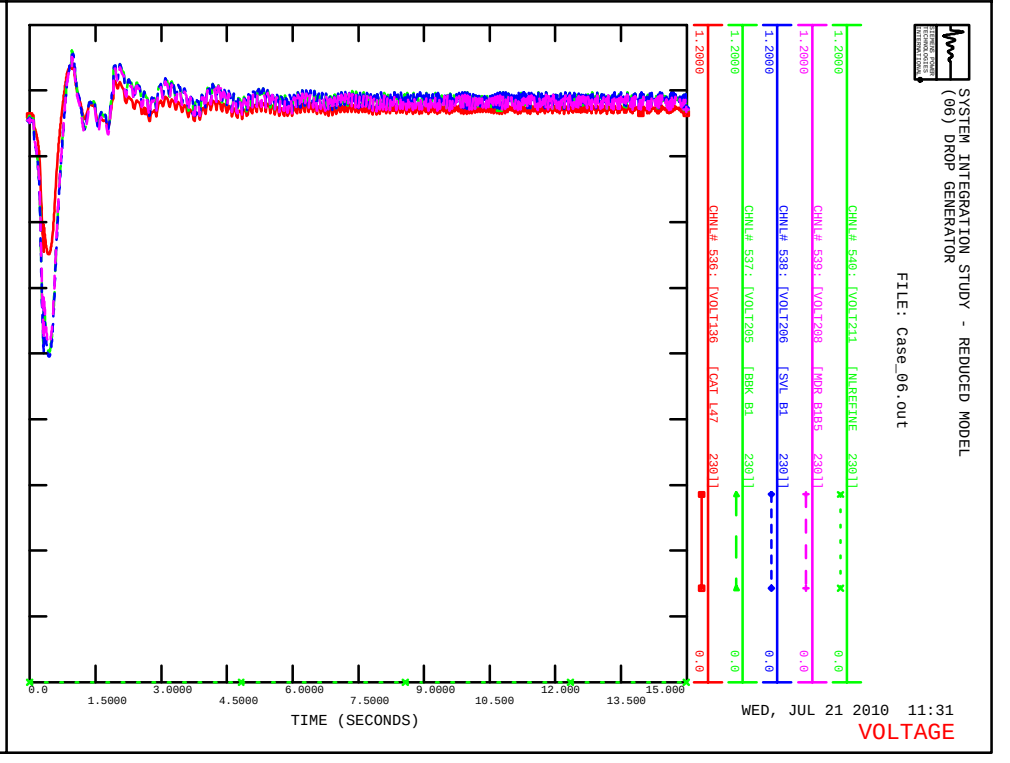

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 506: [VOLT579 [FER NP 66]]
CHNL# 507: [VOLT870 [SLK L80 66]]
CHNL# 508: [VOLT920 [MOB MID3 66]]
CHNL# 509: [VOLT973 [GOU MID1 66]]
CHNL# 510: [VOLT982 [CHA MID1 66]]
CHNL# 511: [VOLT111 [DLK B1 138]]
1.2000
0.0
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

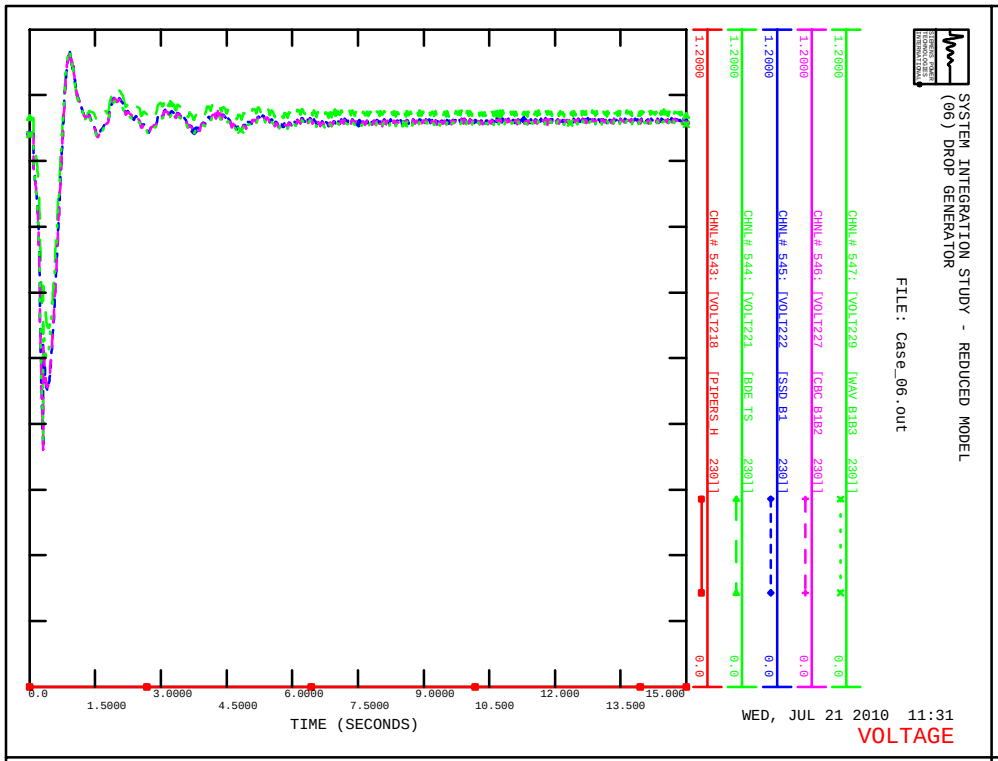

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 512: [VOLT112 [IRV B1 138]]
CHNL# 513: [VOLT113 [SPL B1 138]]
CHNL# 514: [VOLT203 [BBK B2 138]]
CHNL# 515: [VOLT212 [HLY B1 138]]
CHNL# 516: [VOLT213 [HLK L43 138]]
CHNL# 517: [VOLT217 [STB B3 138]]
1.2000
0.0
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

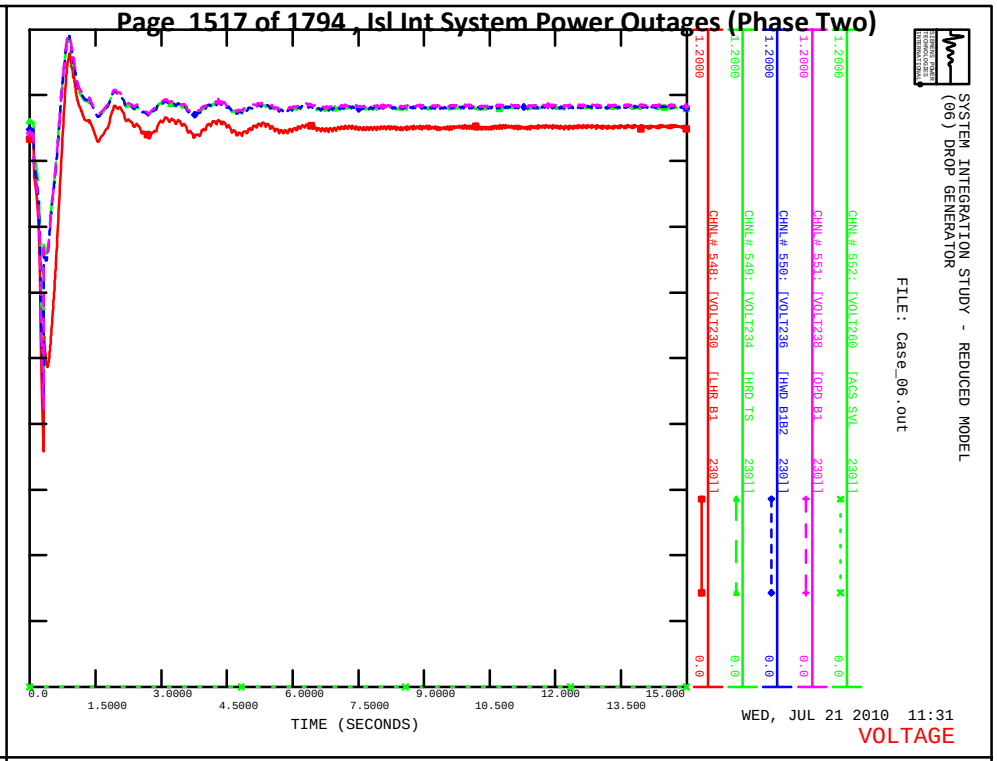

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 518: [VOLT219 [SOK L22 138]
CHNL# 519: [VOLT223 [SSD B2B3 138]
CHNL# 520: [VOLT224 [BLA L32 138]
CHNL# 521: [VOLT225 [LLK NP 138]
CHNL# 522: [VOLT232 [MKS L12 138]
CHNL# 523: [VOLT310 [BLK NP 138]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

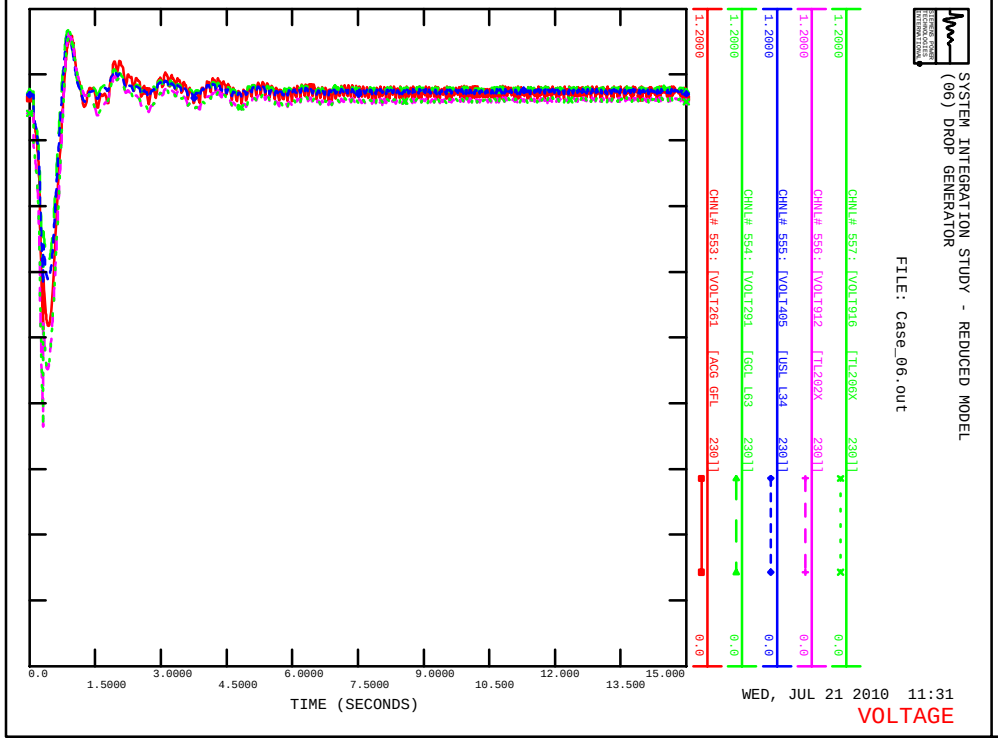

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 524: [VOLT311 [WAV B4 138]
CHNL# 525: [VOLT338 [HRD B8 138]
CHNL# 526: [VOLT340 [HOL NP 138]
CHNL# 527: [VOLT353 [SPF NP 138]
CHNL# 528: [VOLT354 [COL NP 138]
CHNL# 529: [VOLT357 [BRB NP 138]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

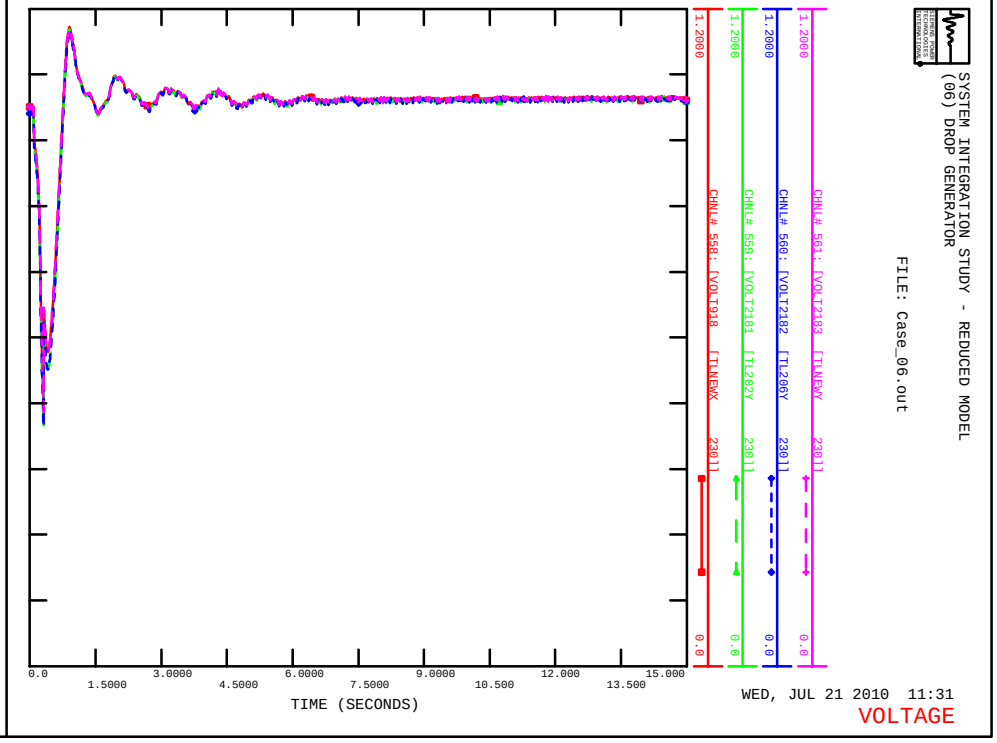

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 530: [VOLT359 [MSY NP 138]
CHNL# 531: [VOLT371 [SPD NP 138]
CHNL# 532: [VOLT603 [BBK B3 138]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

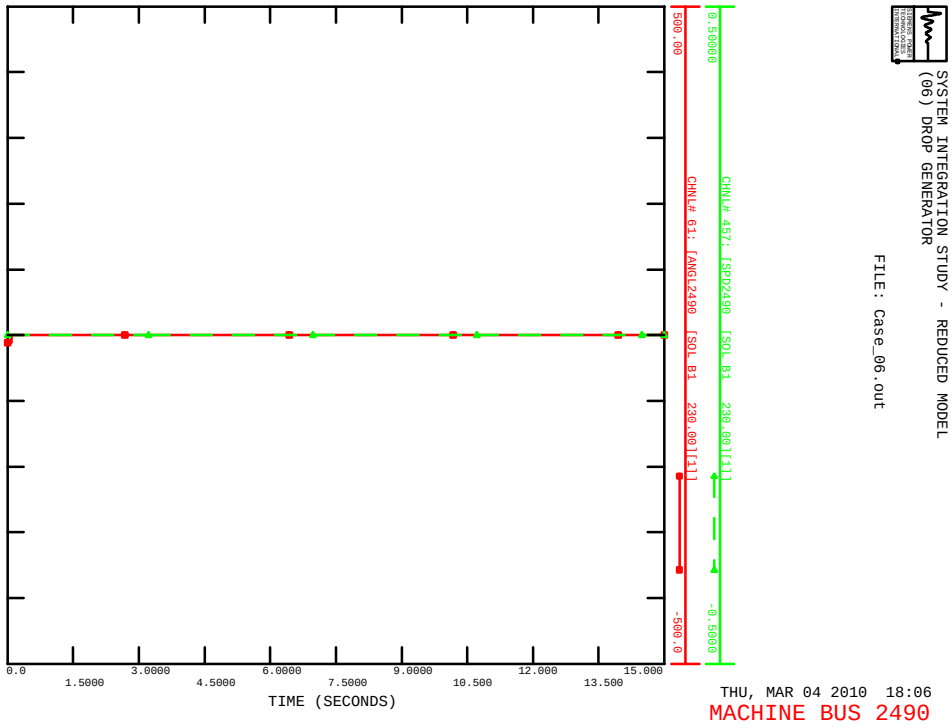

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 536: [VOLT136 [CAT L47 230]
CHNL# 537: [VOLT205 [BBK B1 230]
CHNL# 538: [VOLT206 [SVL B1 230]
CHNL# 539: [VOLT208 [MOR B1B5 230]
CHNL# 540: [VOLT211 [NLREFINE 230]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

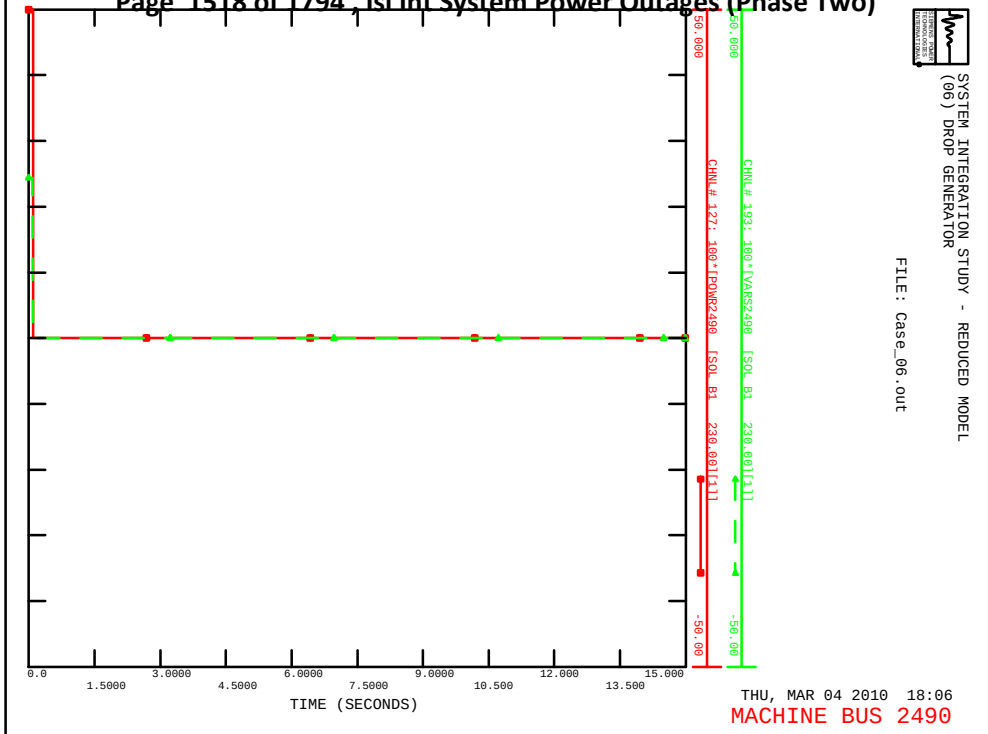

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 543: [VOLT218 [PIPERS H 230]
CHNL# 544: [VOLT221 [BDE TS 230]
CHNL# 545: [VOLT222 [SSD B1 230]
CHNL# 546: [VOLT227 [CBC B1B2 230]
CHNL# 547: [VOLT229 [WAV B1B3 230]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

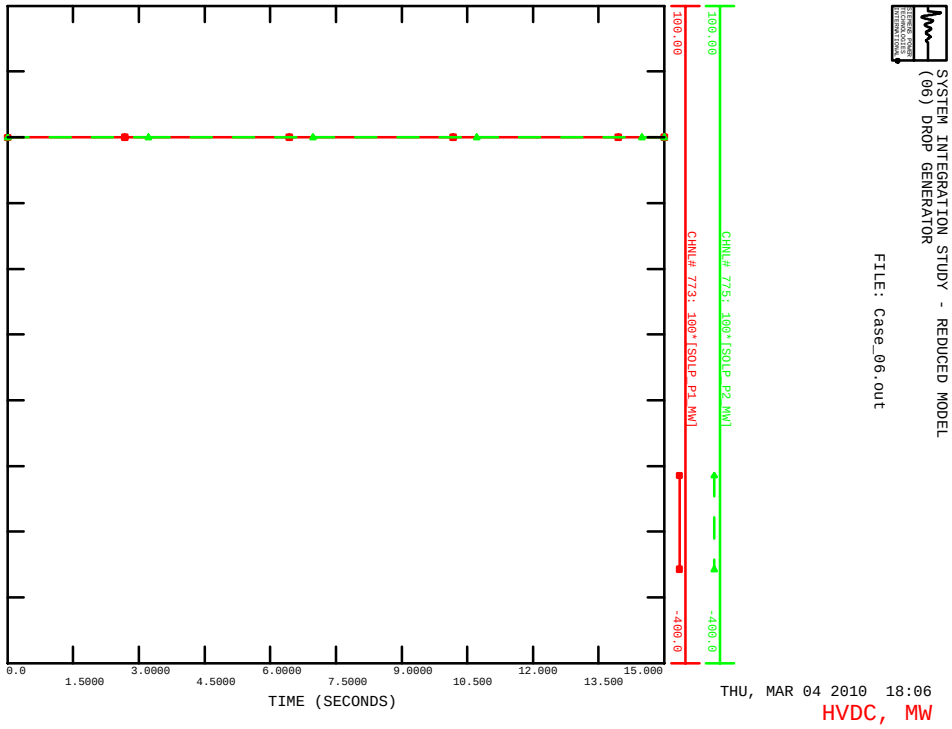

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 548: [VOLT230 [LHR B1 230]
CHNL# 549: [VOLT234 [HRD TS 230]
CHNL# 550: [VOLT236 [HWD B1B2 230]
CHNL# 551: [VOLT238 [PPD B1 230]
CHNL# 552: [VOLT260 [ACS SVC 230]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

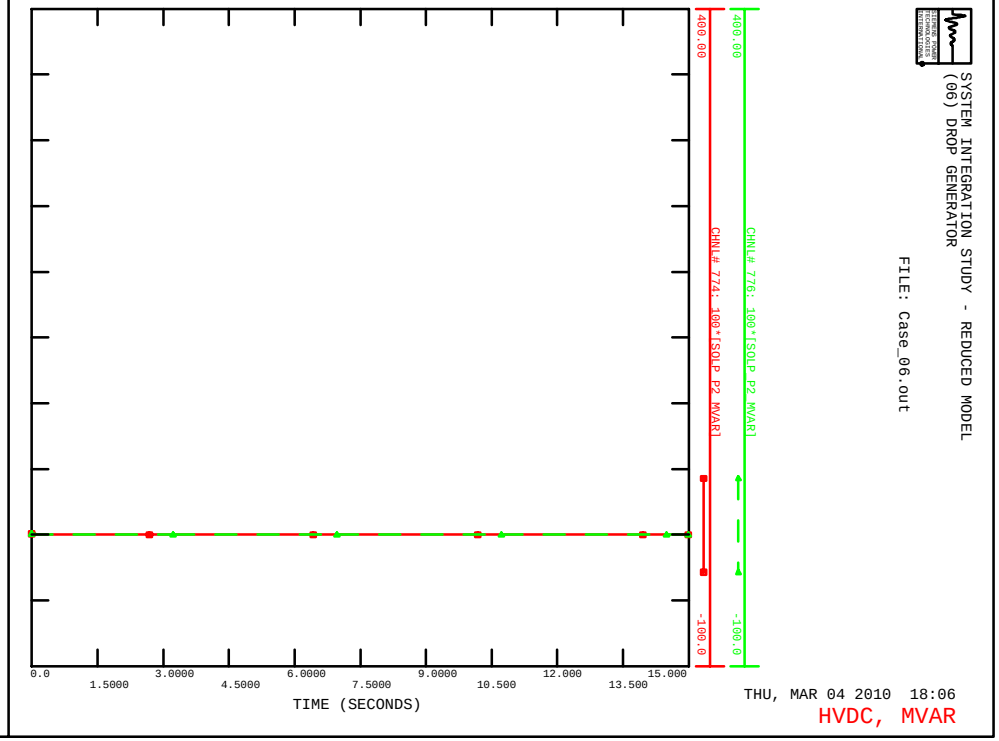

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 553: [VOLT261 [ACG GFL 230]
CHNL# 554: [VOLT291 [GCL L63 230]
CHNL# 555: [VOLT405 [USL L34 230]
CHNL# 556: [VOLT912 [TL202X 230]
CHNL# 557: [VOLT916 [TL206X 230]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

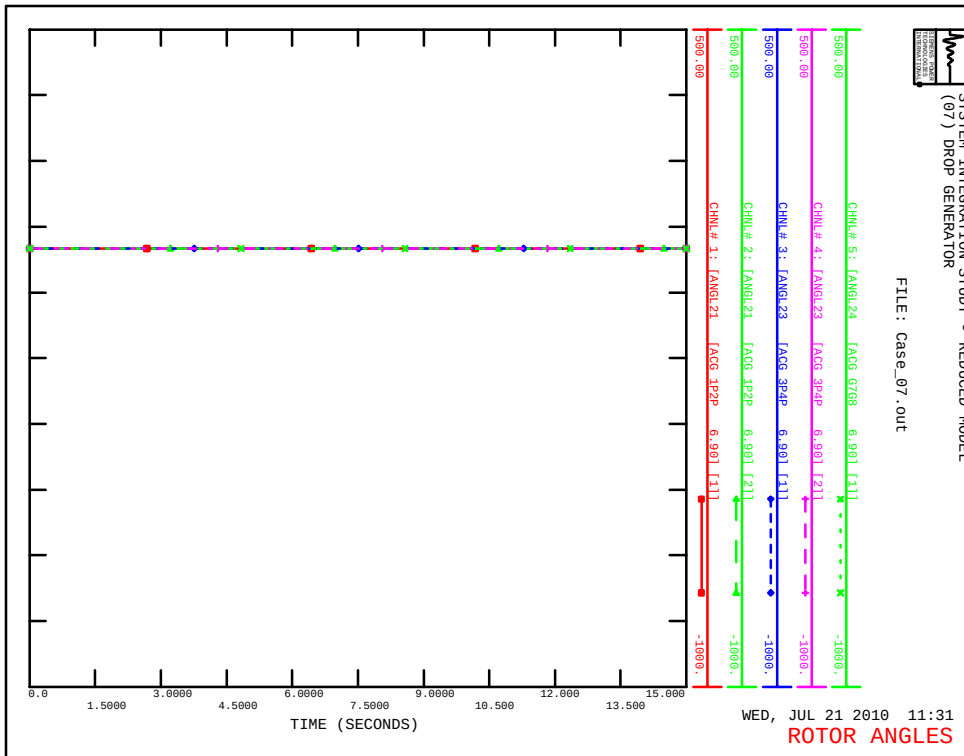

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
CHNL# 558: [VOLT918 [TLNEWX 230]
CHNL# 559: [VOLT2181 [TL202Y 230]
CHNL# 560: [VOLT2182 [TL206Y 230]
CHNL# 561: [VOLT2183 [TLNEWY 230]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

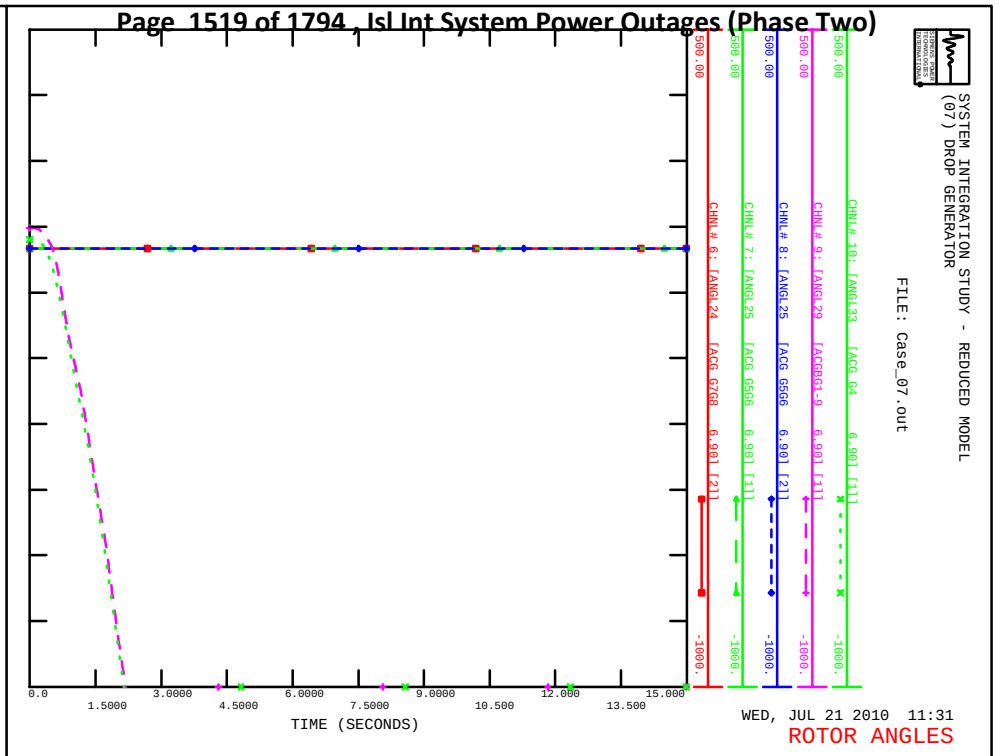

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
500.00
CHNL# 61: [ANGL2490 [SOL B1 230.00][1]]
-500.0
0.50000
CHNL# 457: [SPD2490 [SOL B1 230.00][1]]
-0.50000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
THU, MAR 04 2010 18:06
MACHINE BUS 2490

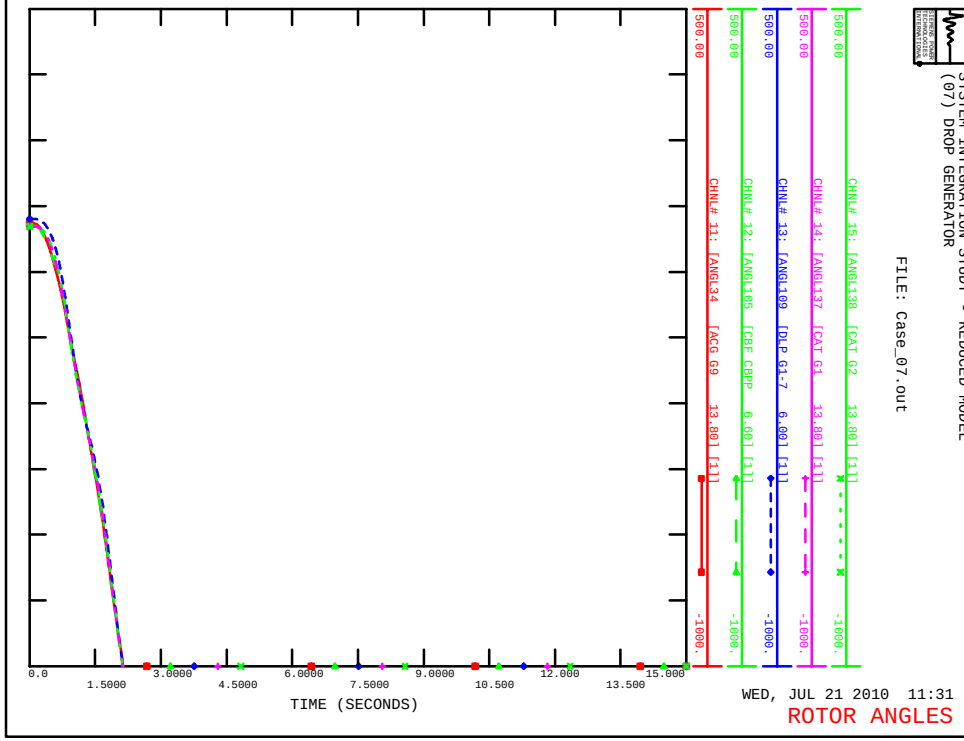

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
50.000
CHNL# 127: 100*[POWR2490 [SOL B1 230.00][1]]
-50.000
50.000
CHNL# 193: 100*[VARS2490 [SOL B1 230.00][1]]
-50.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
THU, MAR 04 2010 18:06
MACHINE BUS 2490

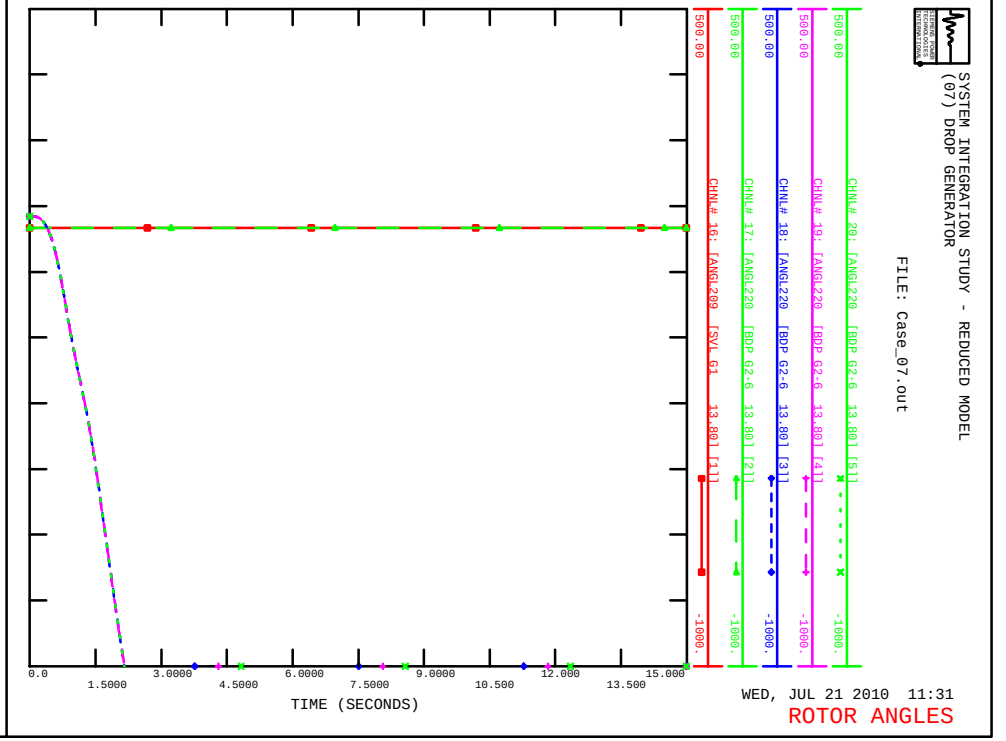

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
100.00
CHNL# 773: 100*[SOLP P1 MW]
-400.0
100.00
CHNL# 775: 100*[SOLP P2 MW]
-400.0
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
THU, MAR 04 2010 18:06
HVDC, MW

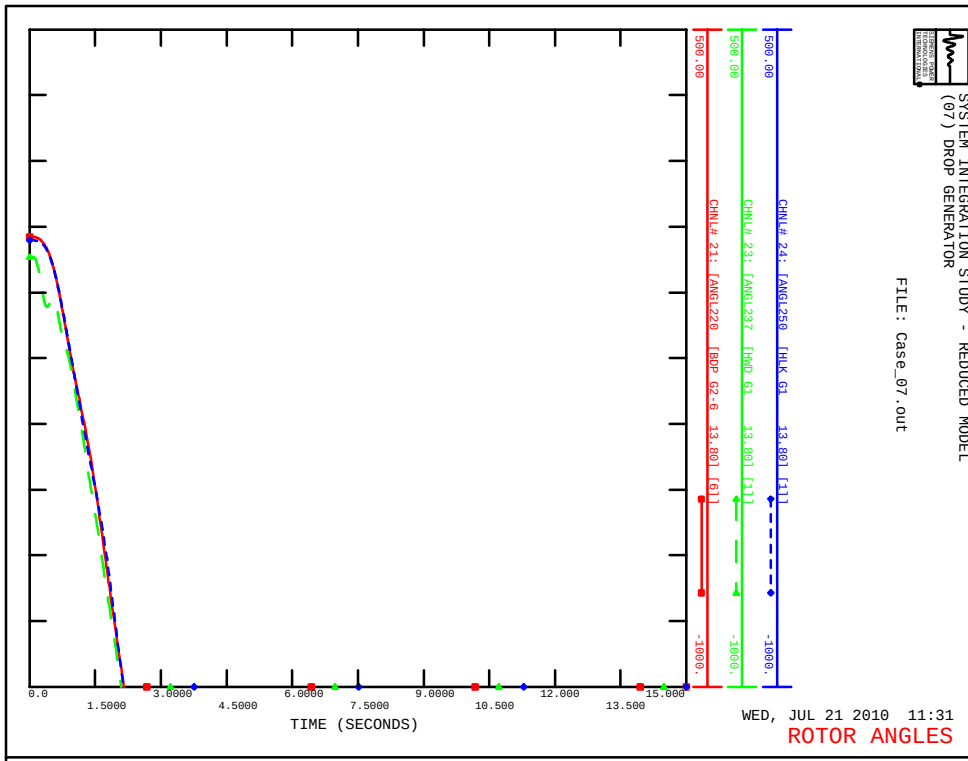

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(06) DROP GENERATOR
FILE: Case_06.out
400.00
CHNL# 774: 100*[SOLP P2 MVAR]
-100.0
400.00
CHNL# 776: 100*[SOLP P2 MVAR]
-100.0
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
THU, MAR 04 2010 18:06
HVDC, MVAR

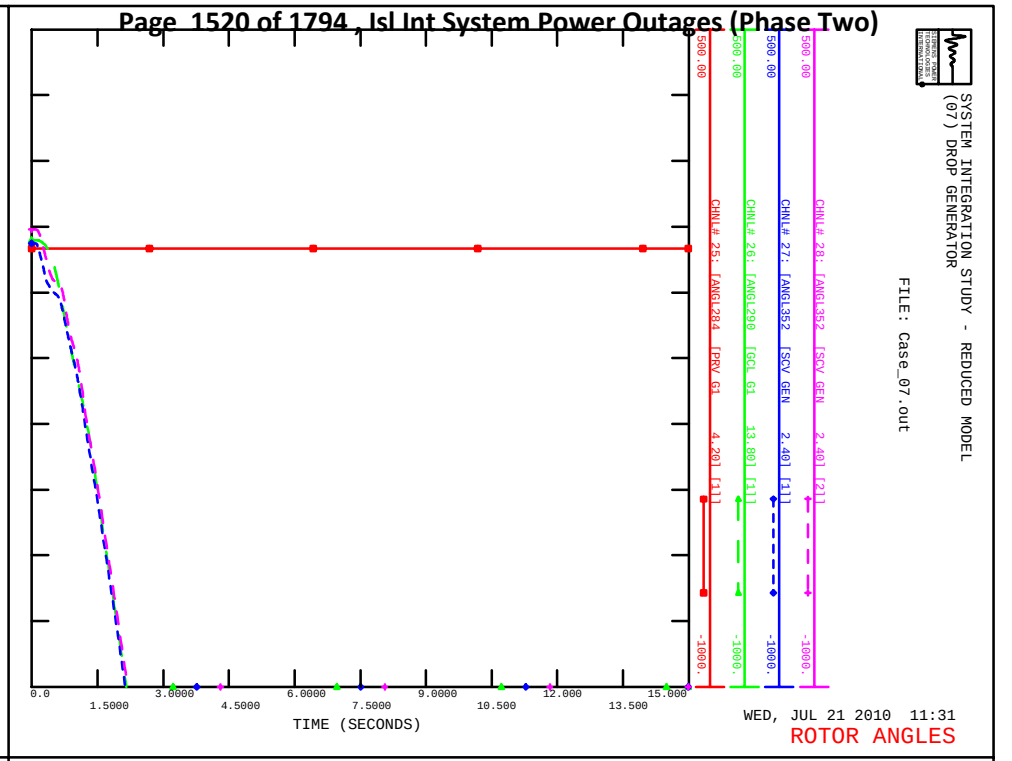

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 1: [ANGL21 [ACG 1P2P 6.90] [1]]
CHNL# 2: [ANGL21 [ACG 1P2P 6.90] [2]]
CHNL# 3: [ANGL23 [ACG 3P4P 6.90] [1]]
CHNL# 4: [ANGL23 [ACG 3P4P 6.90] [2]]
CHNL# 5: [ANGL24 [ACG G7G8 6.90] [1]]
500.00
-1000.
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
ROTOR ANGLES

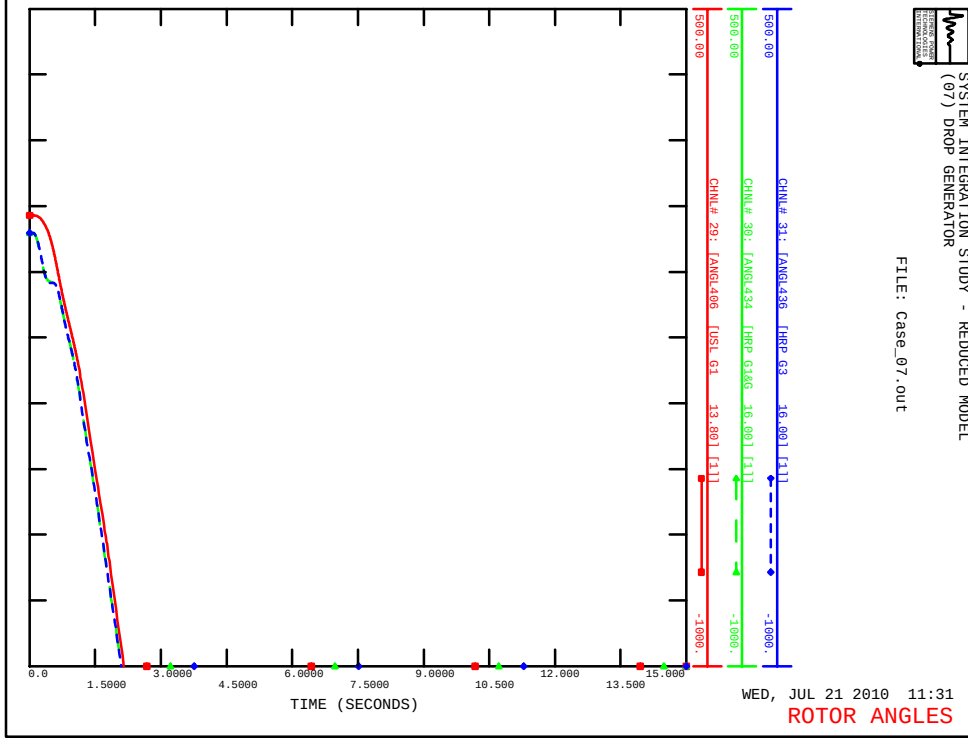

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 6: [ANGL24 [ACG G7G8 6.90] [2]]
CHNL# 7: [ANGL25 [ACG G5G6 6.90] [1]]
CHNL# 8: [ANGL25 [ACG G5G6 6.90] [2]]
CHNL# 9: [ANGL29 [ACGBG1-9 6.90] [1]]
CHNL# 10: [ANGL33 [ACG G4 6.90] [1]]
500.00
-1000.
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
ROTOR ANGLES

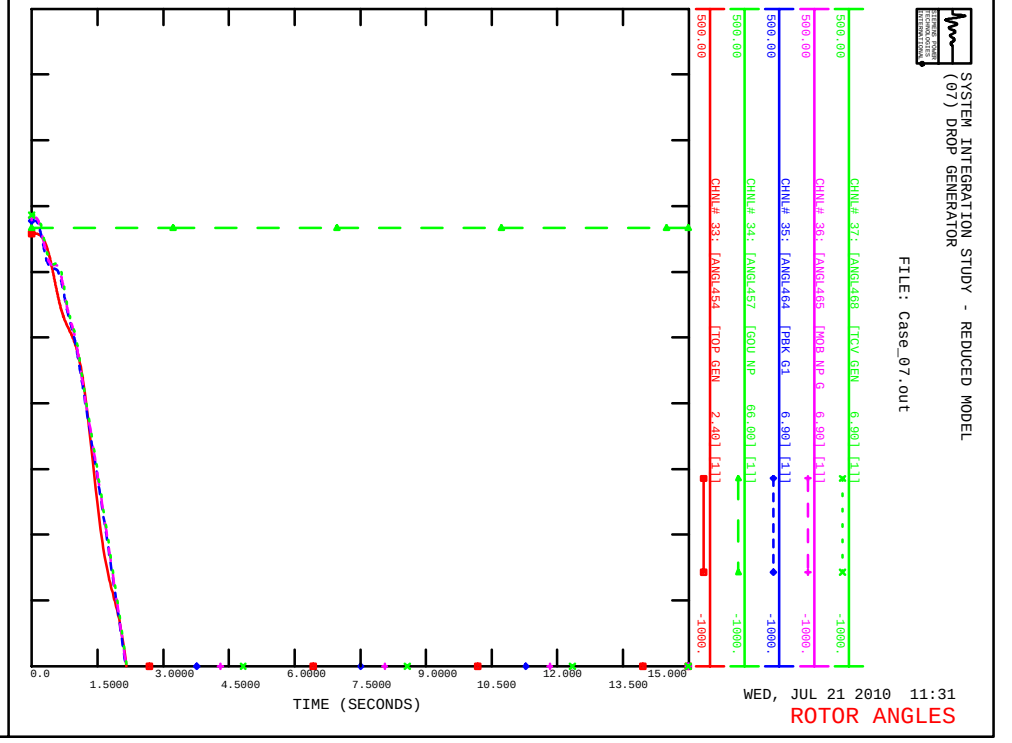

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 11: [ANGL34 [ACG G9 13.80] [1]]
CHNL# 12: [ANGL105 [CBF CBPP 6.60] [1]]
CHNL# 13: [ANGL109 [DLP G1-7 6.00] [1]]
CHNL# 14: [ANGL137 [CAT G1 13.80] [1]]
CHNL# 15: [ANGL138 [CAT G2 13.80] [1]]
500.00
-1000.
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
ROTOR ANGLES

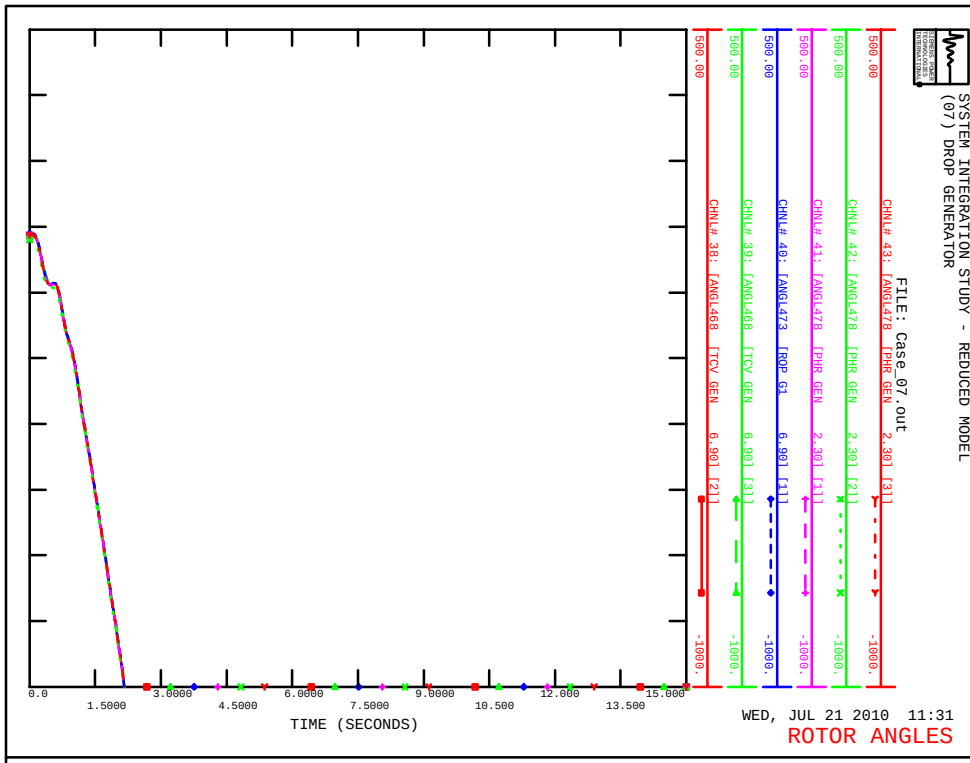

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 16: [ANGL209 [SVL G1 13.80] [1]]
CHNL# 17: [ANGL220 [BDP G2-6 13.80] [2]]
CHNL# 18: [ANGL220 [BDP G2-6 13.80] [3]]
CHNL# 19: [ANGL220 [BDP G2-6 13.80] [4]]
CHNL# 20: [ANGL220 [BDP G2-6 13.80] [5]]
500.00
-1000.
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
ROTOR ANGLES

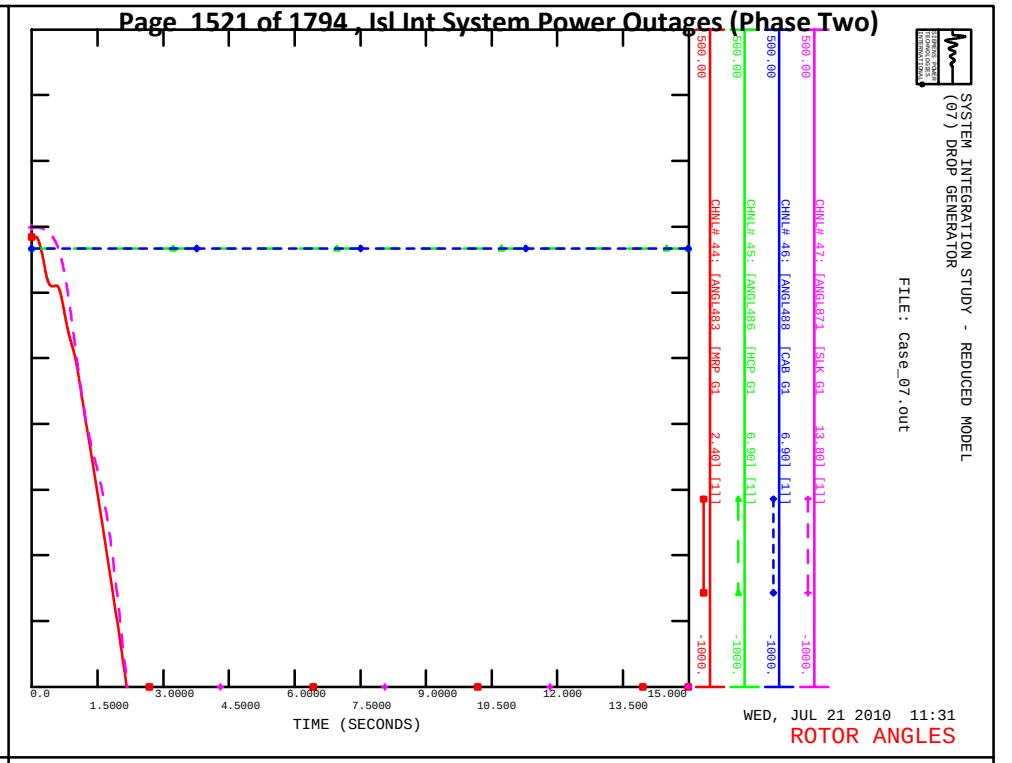

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
500.00
-1000.
CHNL# 21: [ANGL220 [BDP G2-6 13.80] [61]
CHNL# 23: [ANGL237 [HND G1 13.80] [1]
CHNL# 24: [ANGL250 [HLK G1 13.80] [11]
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
ROTOR ANGLES

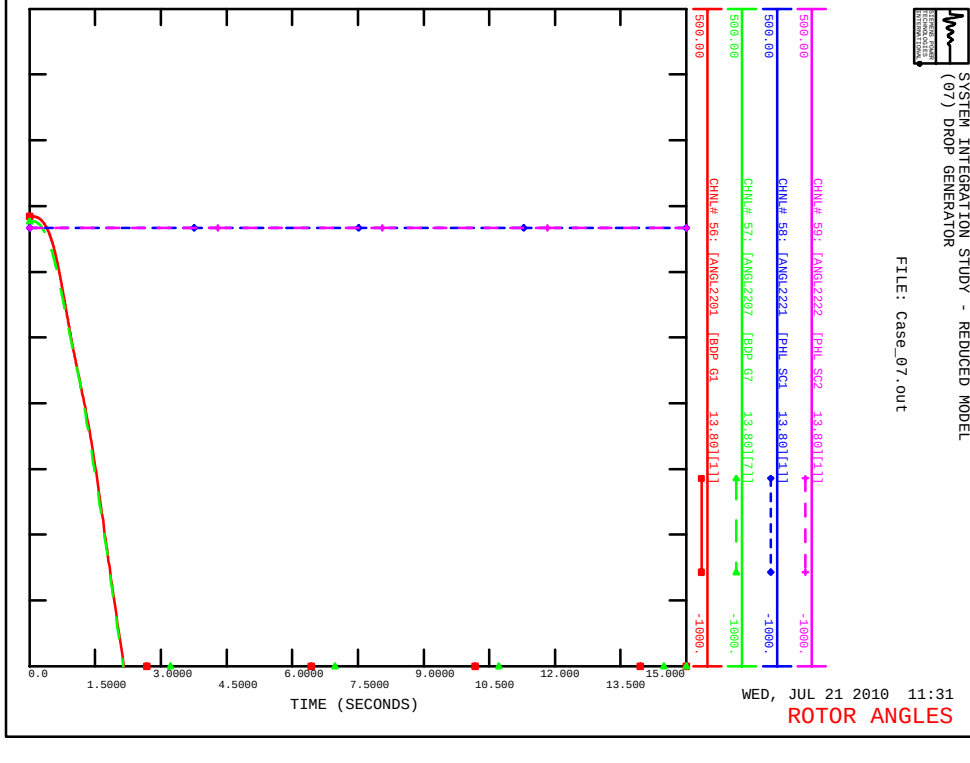

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
500.00
-1000.
CHNL# 25: [ANGL284 [PRV G1 4.20] [11]
CHNL# 26: [ANGL290 [GCL G1 13.80] [11]
CHNL# 27: [ANGL352 [SCV GEN 2.40] [11]
CHNL# 28: [ANGL352 [SCV GEN 2.40] [21]
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
ROTOR ANGLES

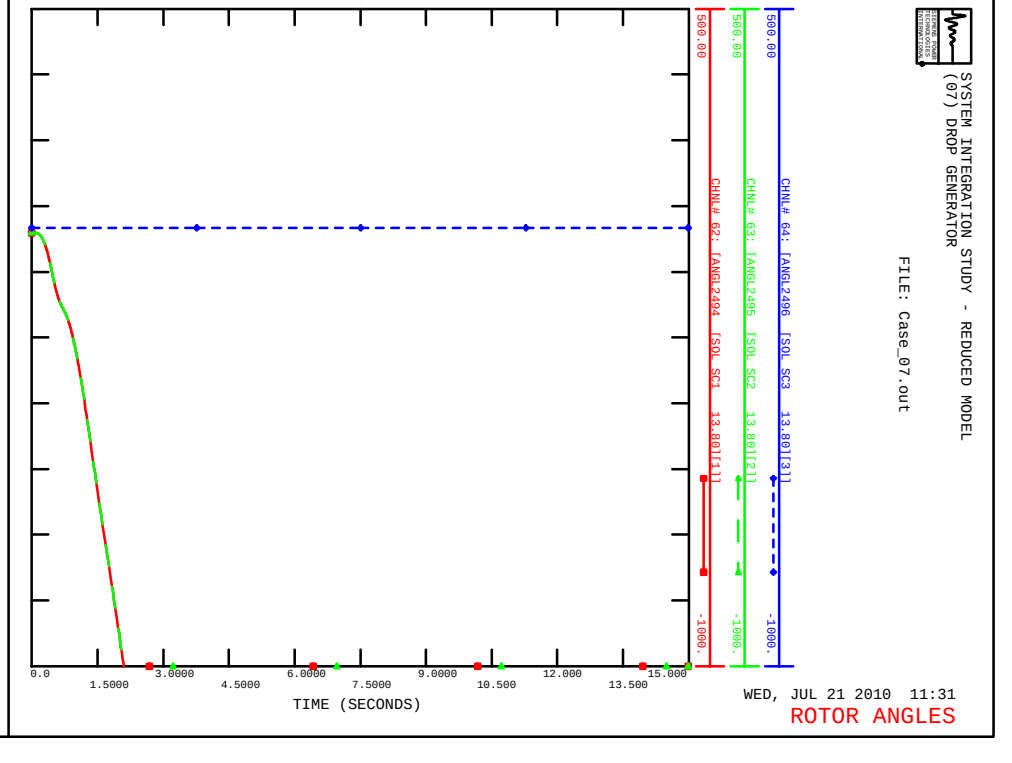

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
500.00
-1000.
CHNL# 29: [ANGL406 [USL G1 13.80] [11]
CHNL# 30: [ANGL434 [HRP G1&G 16.00] [11]
CHNL# 31: [ANGL436 [HRP G3 16.00] [11]
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
ROTOR ANGLES

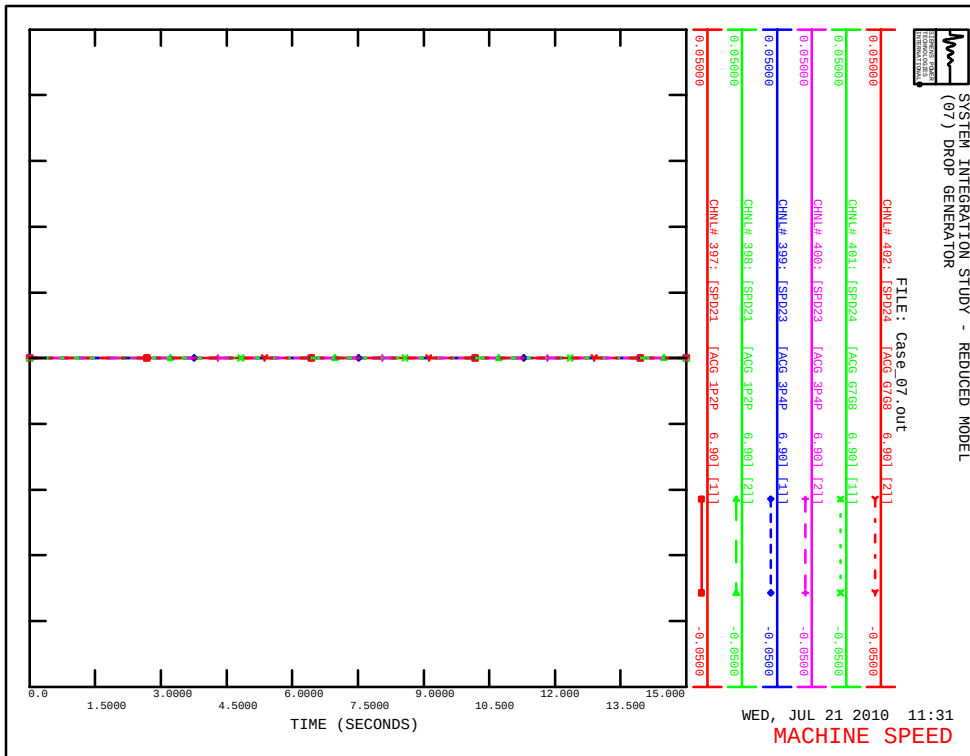

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
500.00
-1000.
CHNL# 33: [ANGL454 [TOP GEN 2.40] [11]
CHNL# 34: [ANGL457 [GOU NP 66.00] [11]
CHNL# 35: [ANGL464 [PBK G1 6.90] [11]
CHNL# 36: [ANGL465 [MOB NP G 6.90] [11]
CHNL# 37: [ANGL468 [TCV GEN 6.90] [11]
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
ROTOR ANGLES

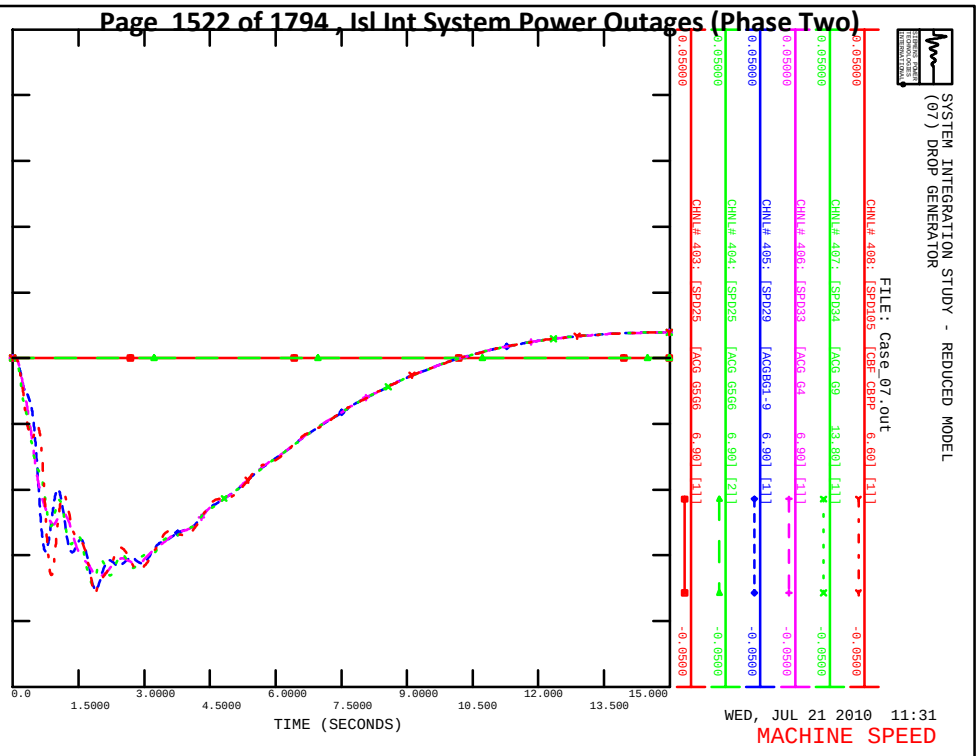

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 38: [ANGL468 [TCV GEN 6.90] [2]
CHNL# 39: [ANGL468 [TCV GEN 6.90] [3]
CHNL# 40: [ANGL473 [ROP G1 6.90] [1]
CHNL# 41: [ANGL478 [PHR GEN 2.30] [1]
CHNL# 42: [ANGL478 [PHR GEN 2.30] [2]
CHNL# 43: [ANGL478 [PHR GEN 2.30] [3]
500.00
-1000.
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
ROTOR ANGLES

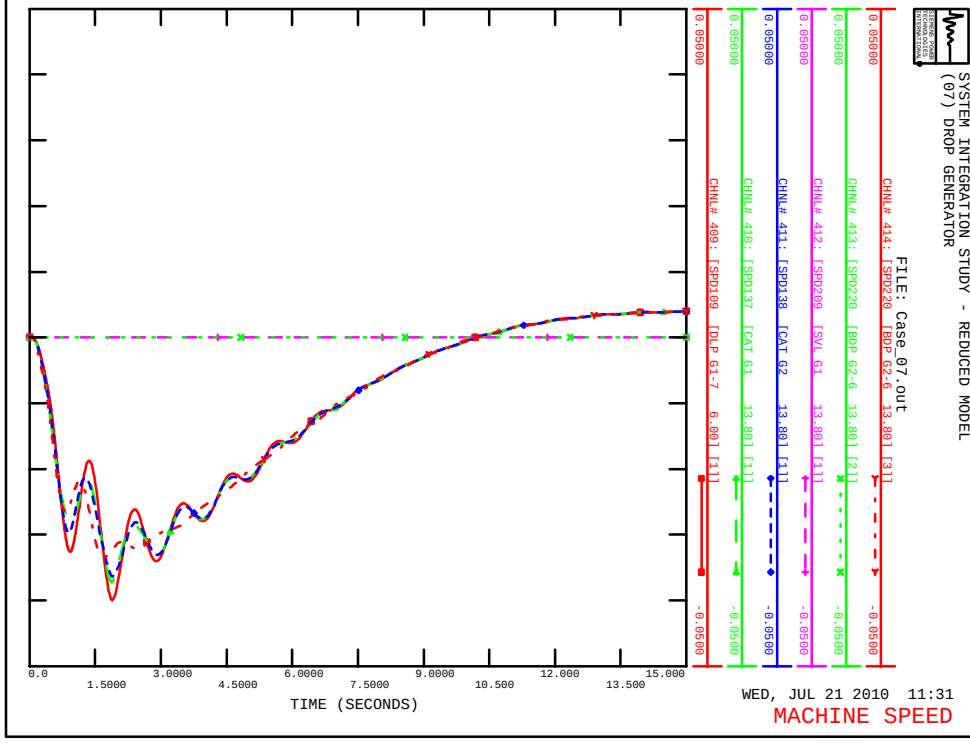

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 44: [ANGL483 [MRP G1 2.40] [1]
CHNL# 45: [ANGL486 [HCP G1 6.90] [1]
CHNL# 46: [ANGL488 [CAB G1 6.90] [1]
CHNL# 47: [ANGL871 [SLK G1 13.80] [1]
500.00
-1000.
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
ROTOR ANGLES

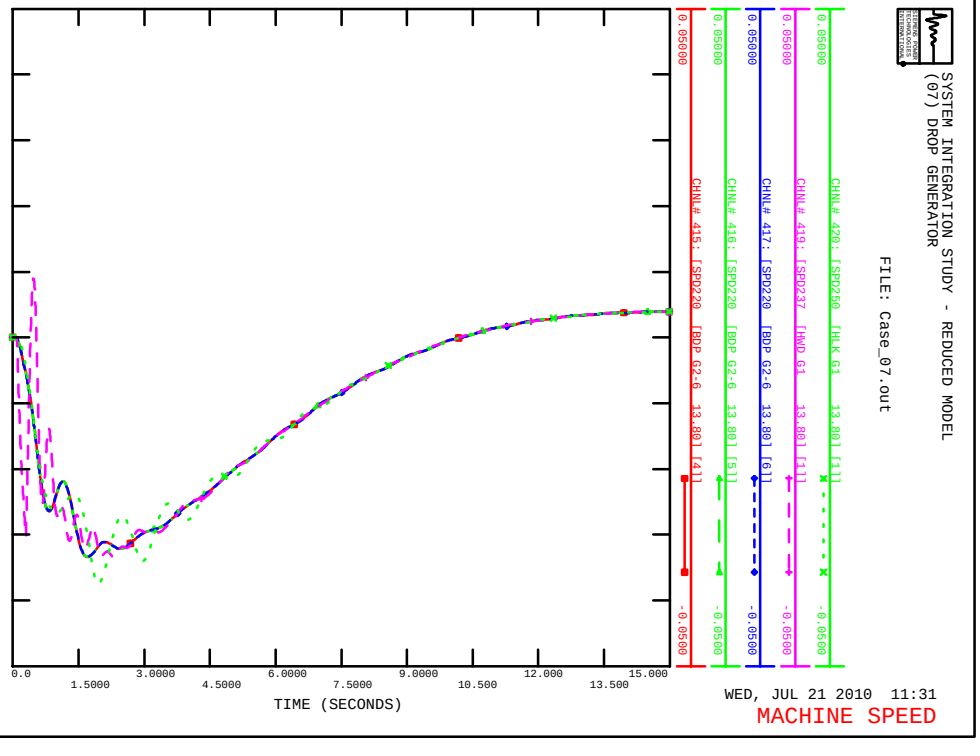

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 56: [ANGL2201 [BDP G1 13.80] [1]
CHNL# 57: [ANGL2207 [BDP G7 13.80] [7]
CHNL# 58: [ANGL2221 [PHL SC1 13.80] [1]
CHNL# 59: [ANGL2222 [PHL SC2 13.80] [1]
500.00
-1000.
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
ROTOR ANGLES

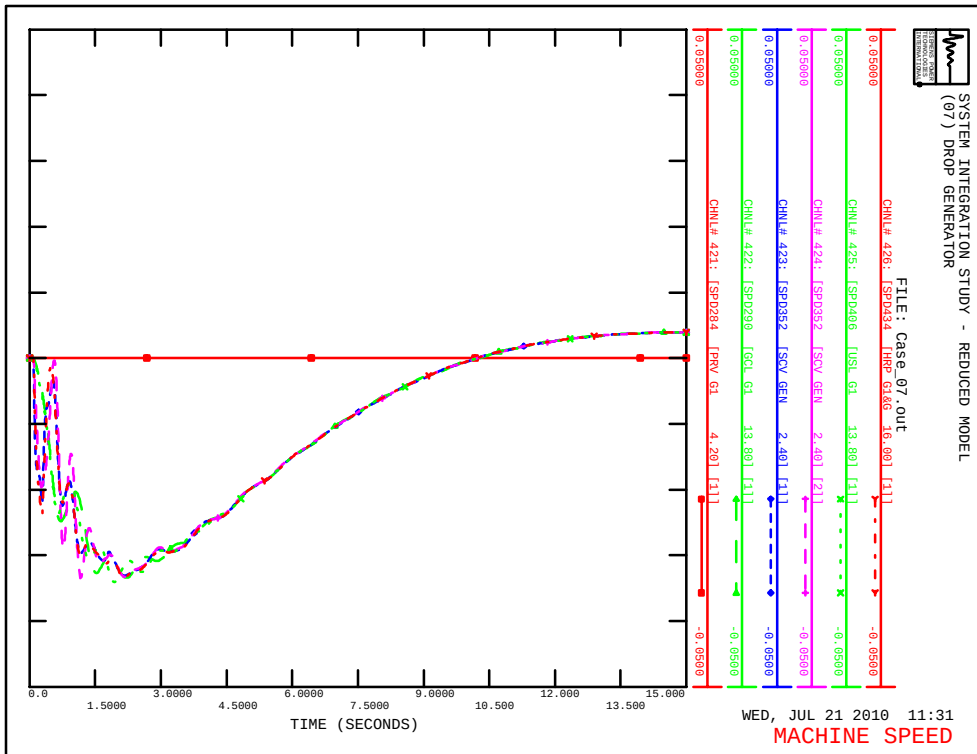

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 62: [ANGL2494 [SOL SC1 13.80] [1]
CHNL# 63: [ANGL2495 [SOL SC2 13.80] [2]
CHNL# 64: [ANGL2496 [SOL SC3 13.80] [3]
500.00
-1000.
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
ROTOR ANGLES

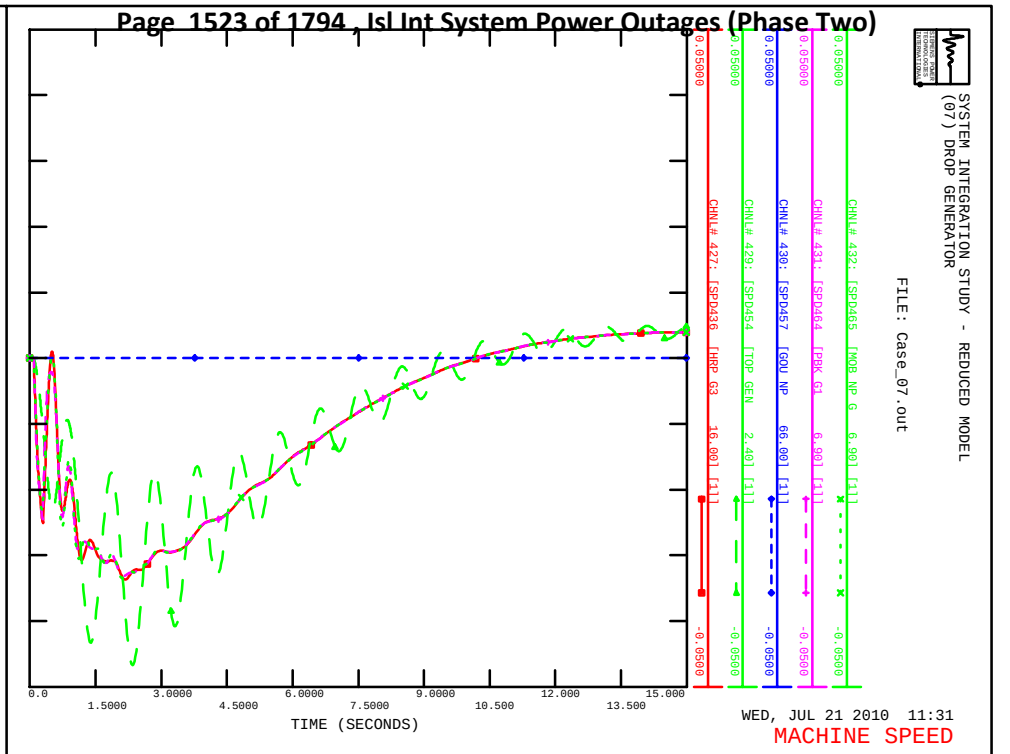

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 397: [SPD21 [AGG 1P2P 6.90] [1]]
CHNL# 398: [SPD21 [AGG 1P2P 6.90] [2]]
CHNL# 399: [SPD23 [AGG 3P4P 6.90] [1]]
CHNL# 400: [SPD23 [AGG 3P4P 6.90] [2]]
CHNL# 401: [SPD24 [AGG G768 6.90] [1]]
CHNL# 402: [SPD24 [AGG G768 6.90] [2]]
TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

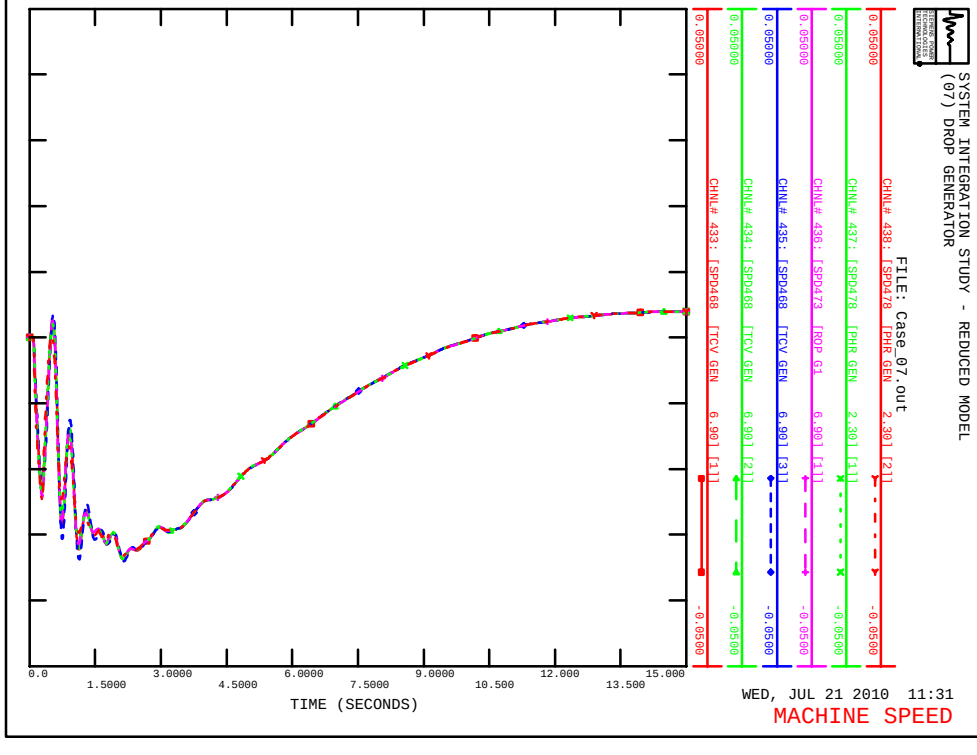

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 403: [SPD26 [AGG G566 6.90] [1]]
CHNL# 404: [SPD25 [AGG G566 6.90] [2]]
CHNL# 405: [SPD29 [AGBB61-9 6.90] [1]]
CHNL# 406: [SPD33 [AGG G4 6.90] [1]]
CHNL# 407: [SPD34 [AGG G9 13.80] [1]]
CHNL# 408: [SPD105 [CBF CBPP 6.60] [1]]
TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

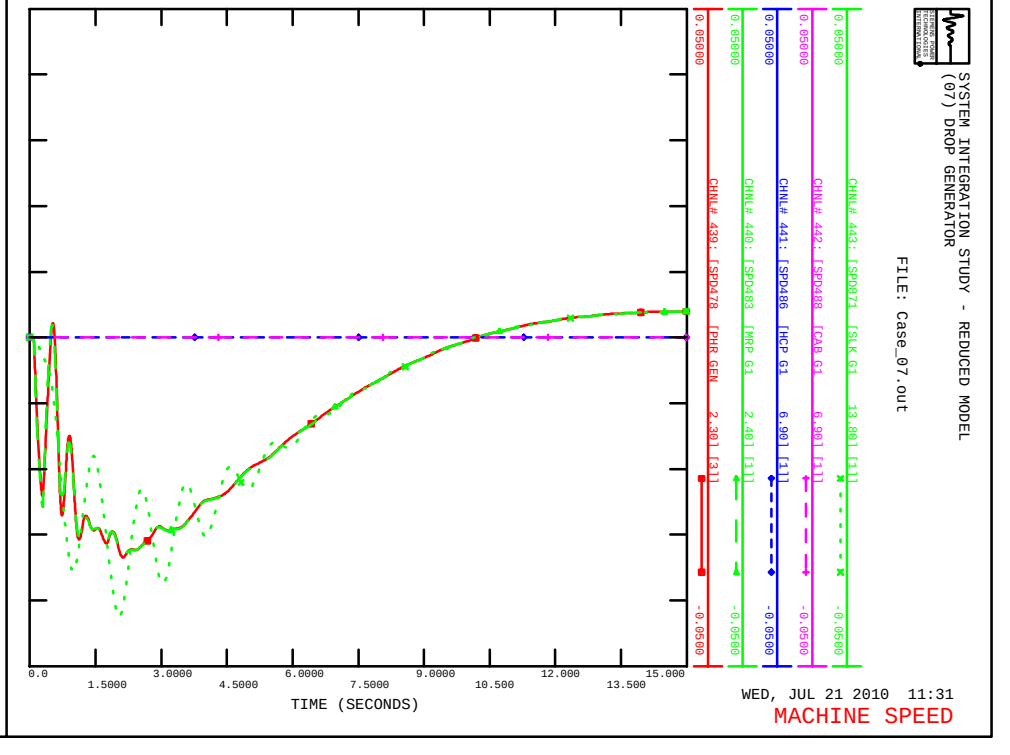

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 409: [SPD109 [DLP G1-7 6.00] [1]]
CHNL# 410: [SPD137 [CAT G1 13.80] [1]]
CHNL# 411: [SPD138 [CAT G2 13.80] [1]]
CHNL# 412: [SPD209 [SVL G1 13.80] [1]]
CHNL# 413: [SPD220 [BDP G2-6 13.80] [2]]
CHNL# 414: [SPD220 [BDP G2-6 13.80] [3]]
TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

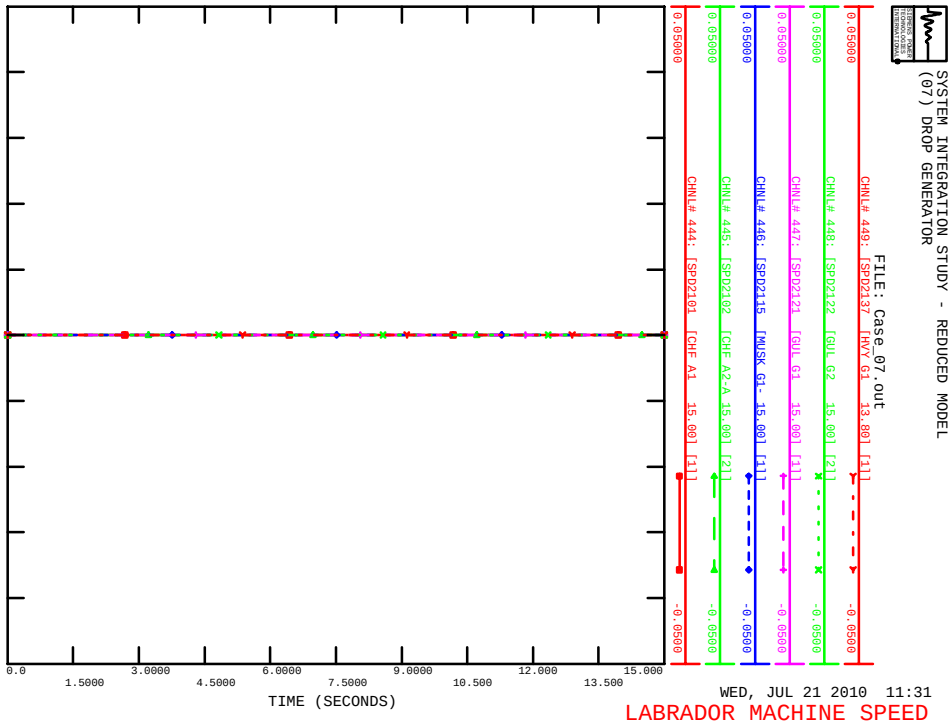

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 415: [SPD220 [BDP G2-6 13.80] [4]]
CHNL# 416: [SPD220 [BDP G2-6 13.80] [5]]
CHNL# 417: [SPD220 [BDP G2-6 13.80] [6]]
CHNL# 419: [SPD237 [HWD G1 13.80] [1]]
CHNL# 420: [SPD250 [HLK G1 13.80] [1]]
TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

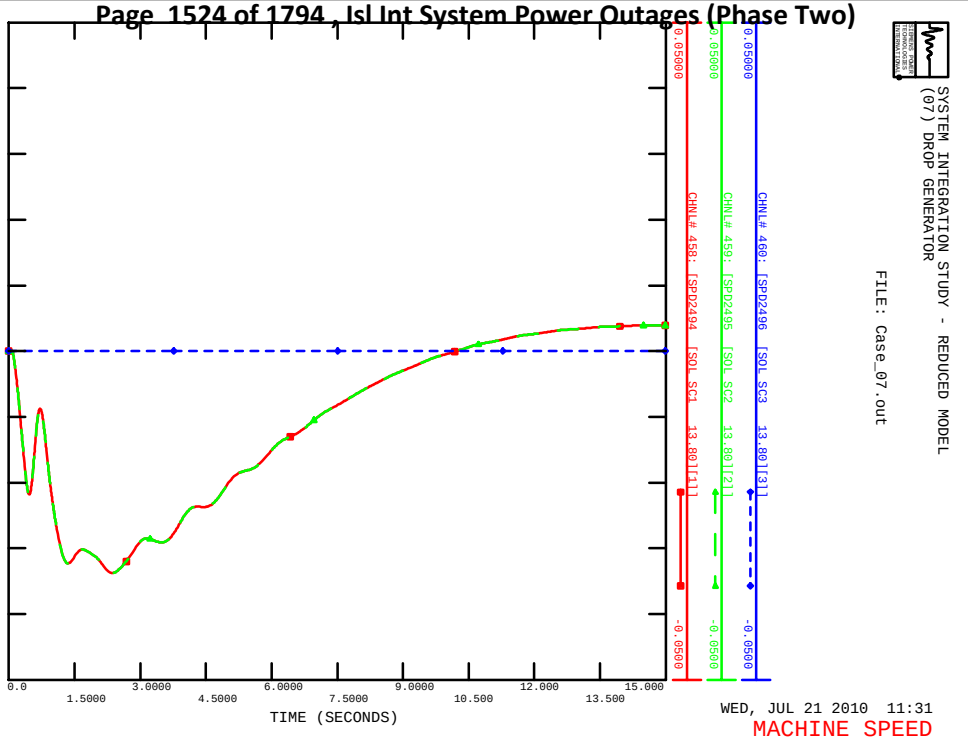

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 421: [SPD284 [PRV G1 4.20] [1]]
CHNL# 422: [SPD290 [GOL G1 13.80] [1]]
CHNL# 423: [SPD352 [SCV GEN 2.40] [1]]
CHNL# 424: [SPD352 [SCV GEN 2.40] [2]]
CHNL# 425: [SPD406 [USL G1 13.80] [1]]
CHNL# 426: [SPD434 [HRP G1&G 16.00] [1]]
TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

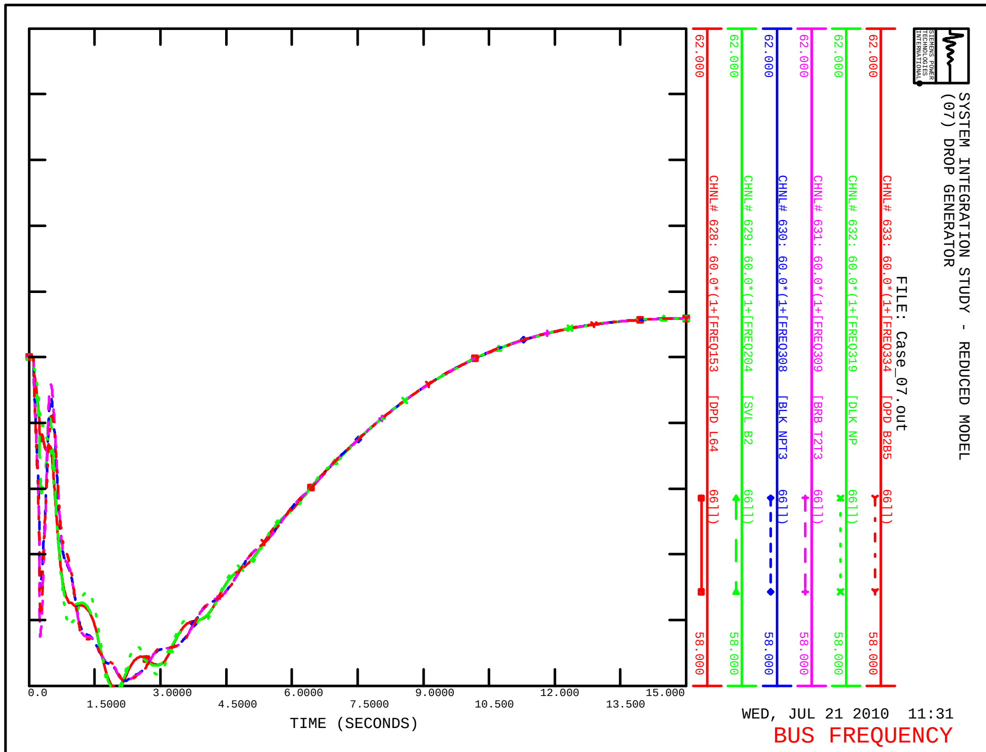

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 427: [SPD436 [HRP G3 16.00] [1]]
CHNL# 429: [SPD454 [TOP GEN 2.40] [1]]
CHNL# 430: [SPD457 [GOU NP 66.00] [1]]
CHNL# 431: [SPD464 [PBK G1 6.90] [1]]
CHNL# 432: [SPD465 [MOB NP G 6.90] [1]]
TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

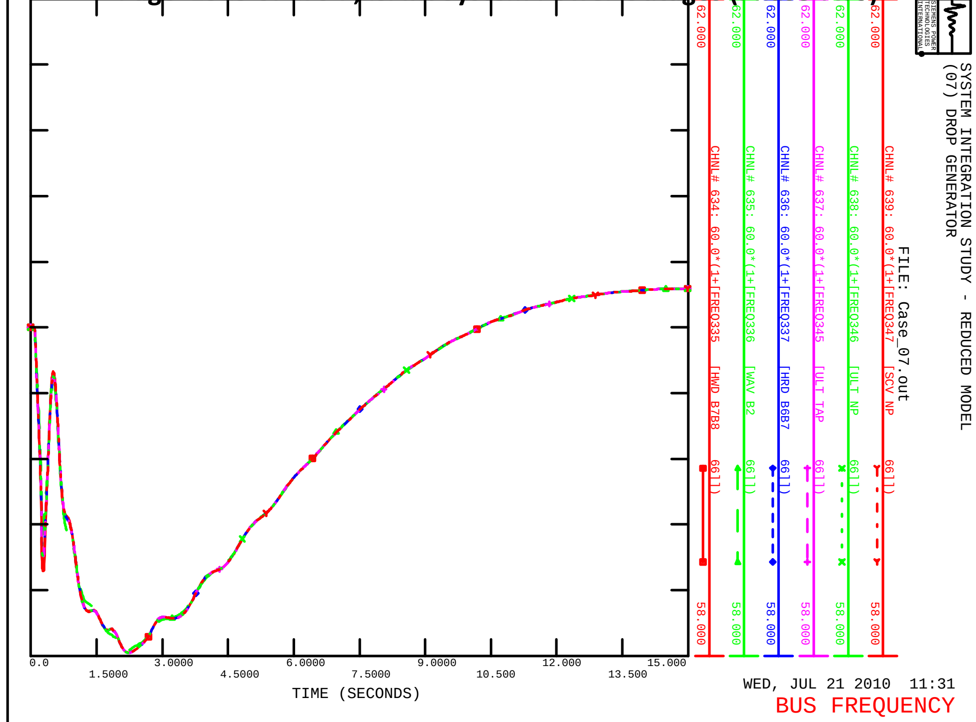

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 433: [SPD468 [TCV GEN 6.90] [1]]
CHNL# 434: [SPD468 [TCV GEN 6.90] [2]]
CHNL# 435: [SPD468 [TCV GEN 6.90] [3]]
CHNL# 436: [SPD473 [ROP G1 6.90] [1]]
CHNL# 437: [SPD478 [PHR GEN 2.30] [1]]
CHNL# 438: [SPD478 [PHR GEN 2.30] [2]]
TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

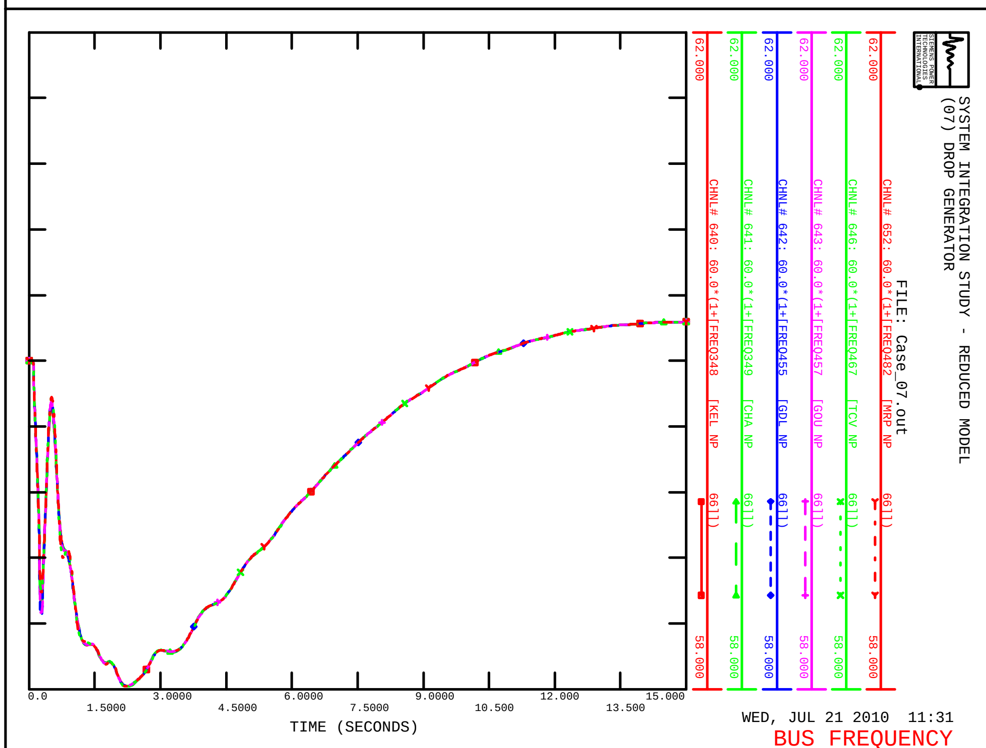

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 439: [SPD478 [PHR GEN 2.30] [3]]
CHNL# 440: [SPD483 [MRP G1 2.40] [1]]
CHNL# 441: [SPD486 [HCP G1 6.90] [1]]
CHNL# 442: [SPD488 [CAB G1 6.90] [1]]
CHNL# 443: [SPD871 [SLK G1 13.80] [1]]
TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

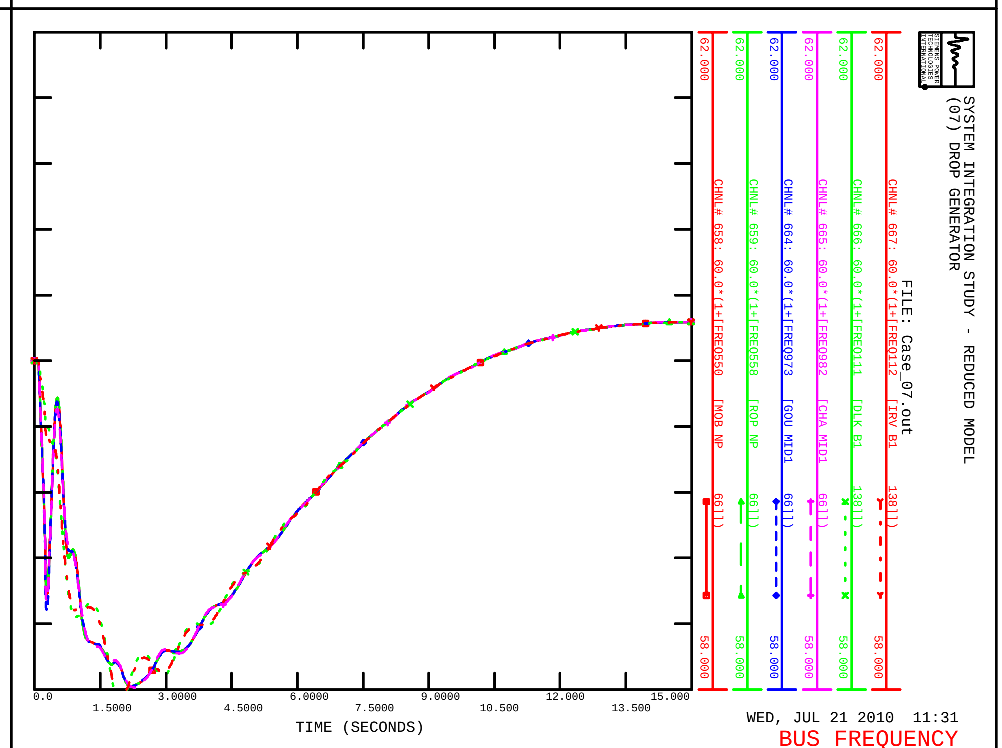

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 444: [SPD2101 [CHF A1 15.00] [1]]
CHNL# 445: [SPD2102 [CHF A2-A 15.00] [2]]
CHNL# 446: [SPD2115 [MUSK G1- 15.00] [1]]
CHNL# 447: [SPD2121 [GUL G1 15.00] [1]]
CHNL# 448: [SPD2122 [GUL G2 15.00] [2]]
CHNL# 449: [SPD2137 [HVY G1 13.80] [1]]
0.05000
-0.0500
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
LABRADOR MACHINE SPEED

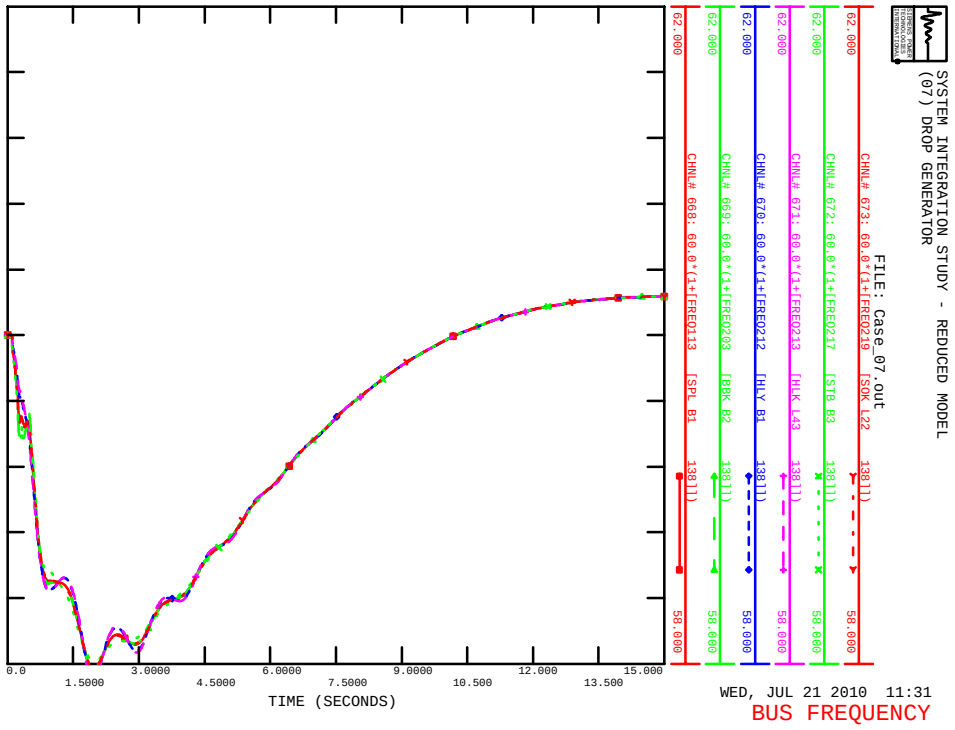

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 458: [SPD2494 [SOL SC1 13.80] [1]]
CHNL# 459: [SPD2495 [SOL SC2 13.80] [2]]
CHNL# 460: [SPD2496 [SOL SC3 13.80] [3]]
0.05000
-0.0500
0.0 1.5000 3.0000 4.5000 6.0000 7.5000 9.0000 10.500 12.000 13.500 15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
MACHINE SPEED

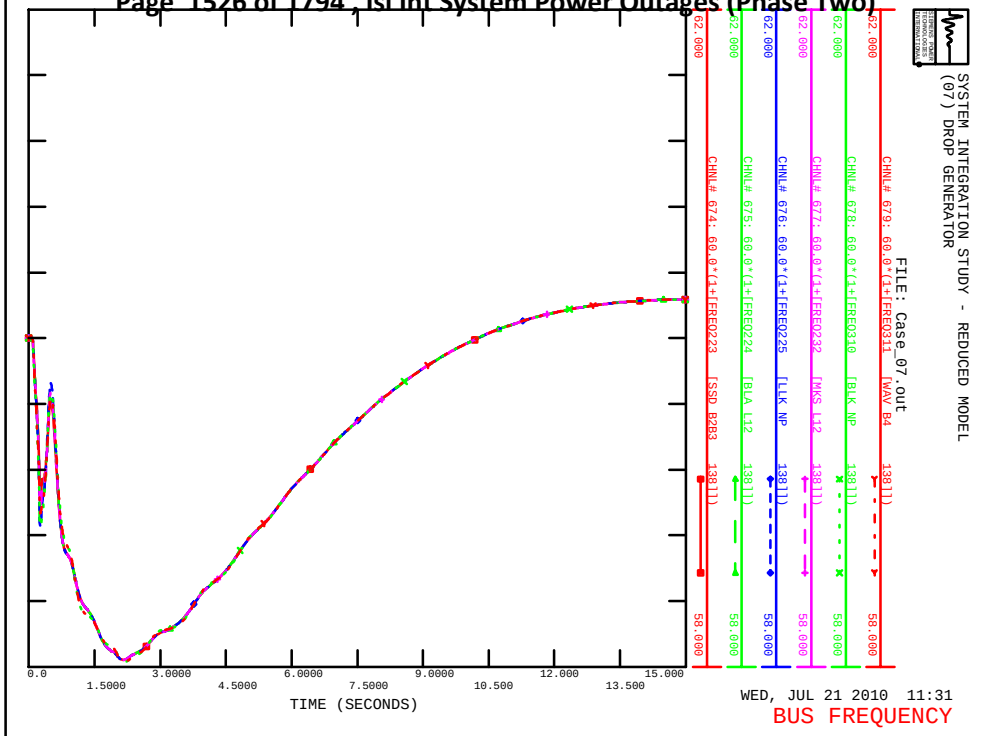

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 628: 60.0*(1+[FREQ153 [DPD L64 6611])
CHNL# 629: 60.0*(1+[FREQ204 [SVL B2 6611])
CHNL# 630: 60.0*(1+[FREQ308 [BLK NPT3 6611])
CHNL# 631: 60.0*(1+[FREQ309 [BRB T2T3 6611])
CHNL# 632: 60.0*(1+[FREQ319 [DLK NP 6611])
CHNL# 633: 60.0*(1+[FREQ334 [OPD B2B5 6611])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
BUS FREQUENCY

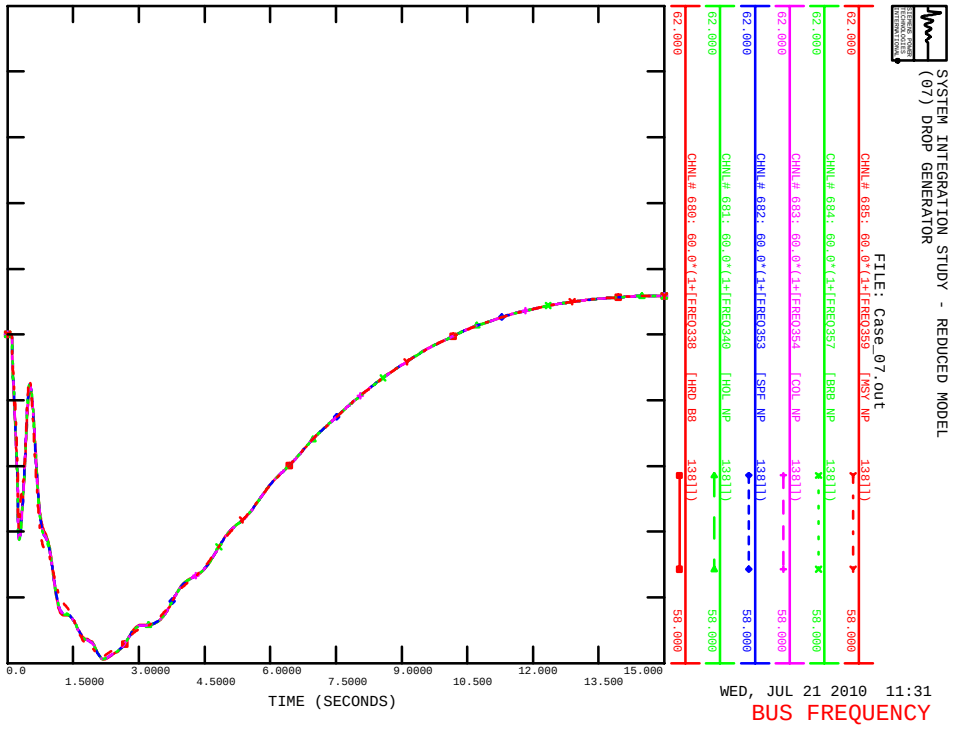

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 634: 60.0*(1+[FREQ335 [HWD B7B8 6611])
CHNL# 635: 60.0*(1+[FREQ336 [WAV B2 6611])
CHNL# 636: 60.0*(1+[FREQ337 [HRD B6B7 6611])
CHNL# 637: 60.0*(1+[FREQ345 [ULT TAP 6611])
CHNL# 638: 60.0*(1+[FREQ346 [ULT NP 6611])
CHNL# 639: 60.0*(1+[FREQ347 [SCV NP 6611])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
BUS FREQUENCY

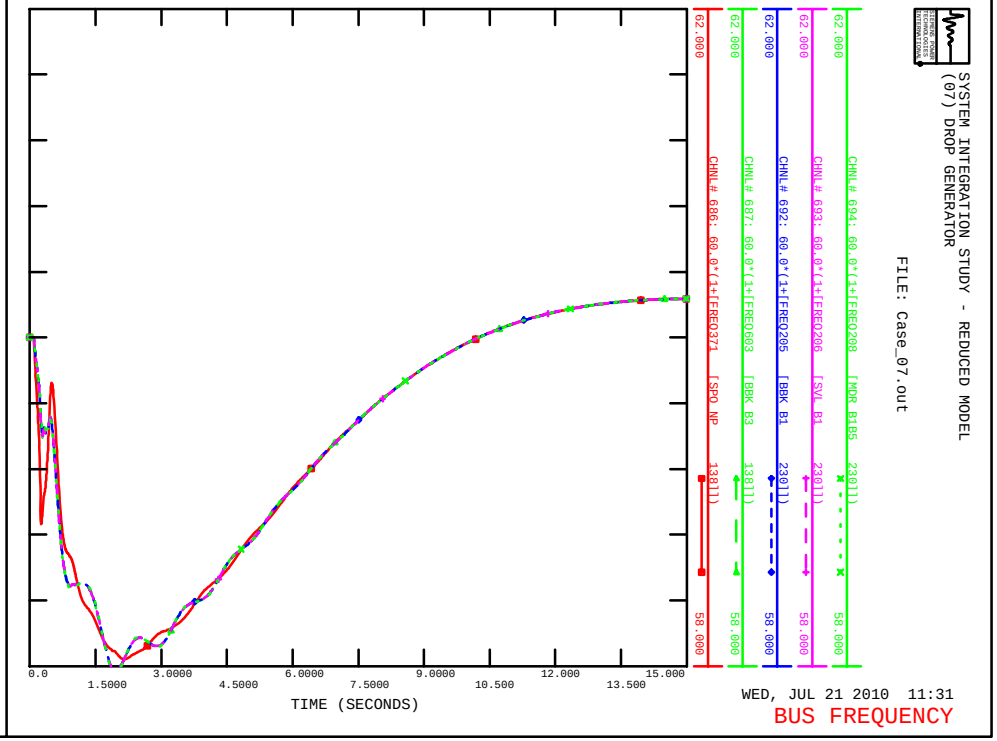

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 640: 60.0*(1+[FREQ348 [KEL NP 6611])
CHNL# 641: 60.0*(1+[FREQ349 [CHA NP 6611])
CHNL# 642: 60.0*(1+[FREQ455 [GDL NP 6611])
CHNL# 643: 60.0*(1+[FREQ457 [GOU NP 6611])
CHNL# 646: 60.0*(1+[FREQ467 [TCV NP 6611])
CHNL# 652: 60.0*(1+[FREQ482 [MRP NP 6611])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
BUS FREQUENCY

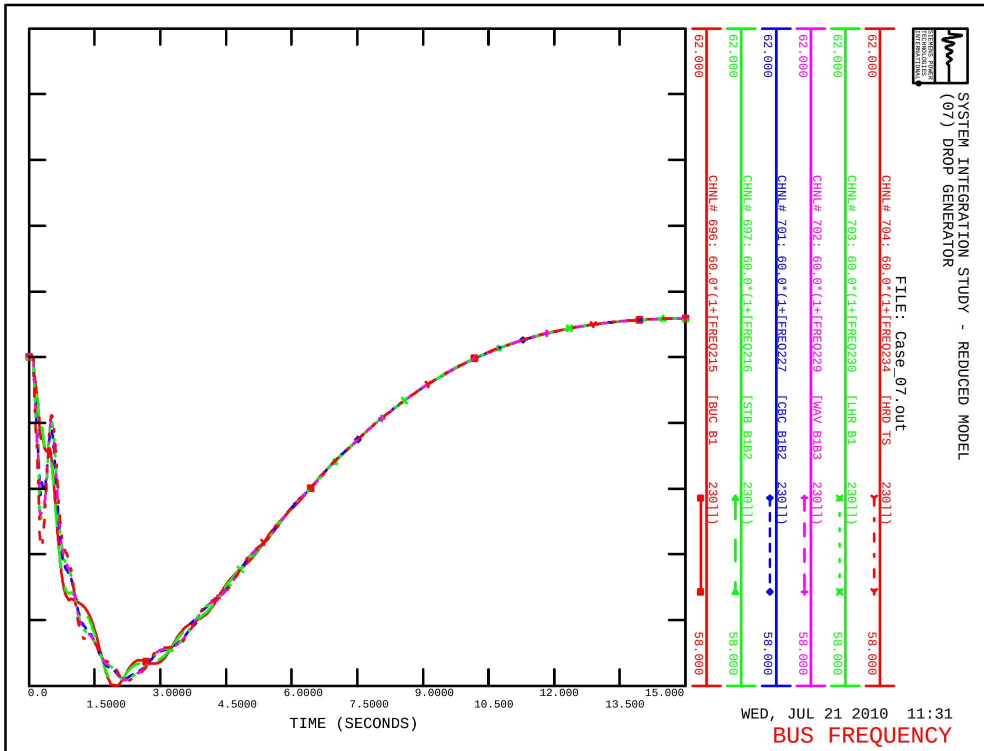

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 658: 60.0*(1+[FREQ550 [MOB NP 6611])
CHNL# 659: 60.0*(1+[FREQ558 [ROP NP 6611])
CHNL# 664: 60.0*(1+[FREQ973 [GOU MID1 6611])
CHNL# 665: 60.0*(1+[FREQ982 [CHA MID1 6611])
CHNL# 666: 60.0*(1+[FREQ111 [DLK B1 13811])
CHNL# 667: 60.0*(1+[FREQ112 [IRV B1 13811])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
BUS FREQUENCY

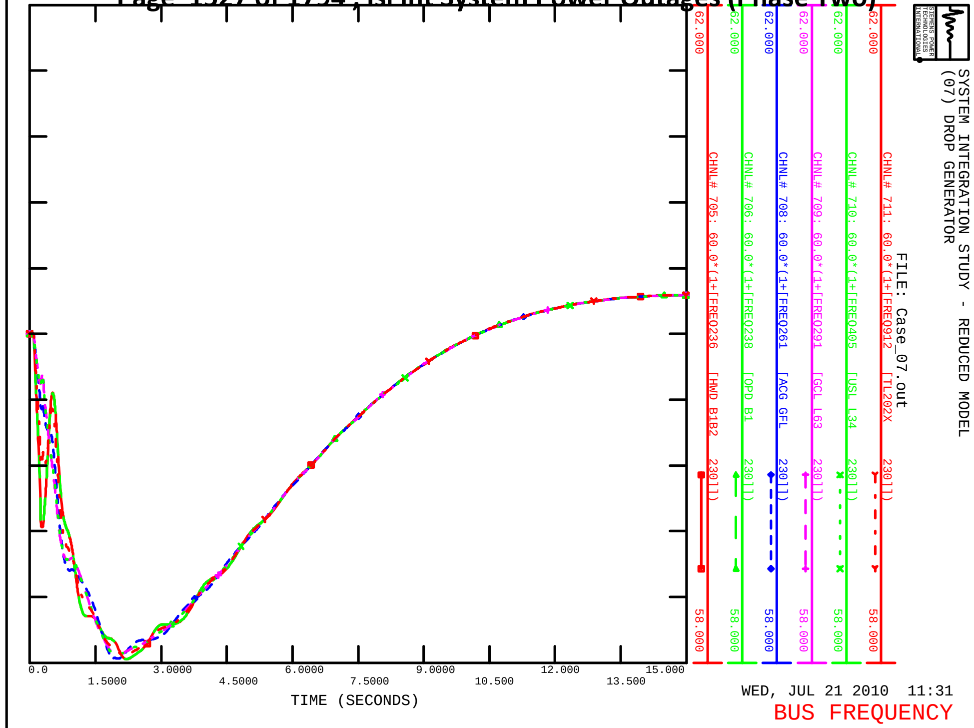

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 668: 60.0*(1+FREQ0113 [SPL B1 13811)
CHNL# 669: 60.0*(1+FREQ0203 [BBK B2 13811)
CHNL# 670: 60.0*(1+FREQ0212 [HLY B1 13811)
CHNL# 671: 60.0*(1+FREQ0213 [HLK L43 13811)
CHNL# 672: 60.0*(1+FREQ0217 [STB B3 13811)
CHNL# 673: 60.0*(1+FREQ0219 [SOK L22 13811)
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
BUS FREQUENCY

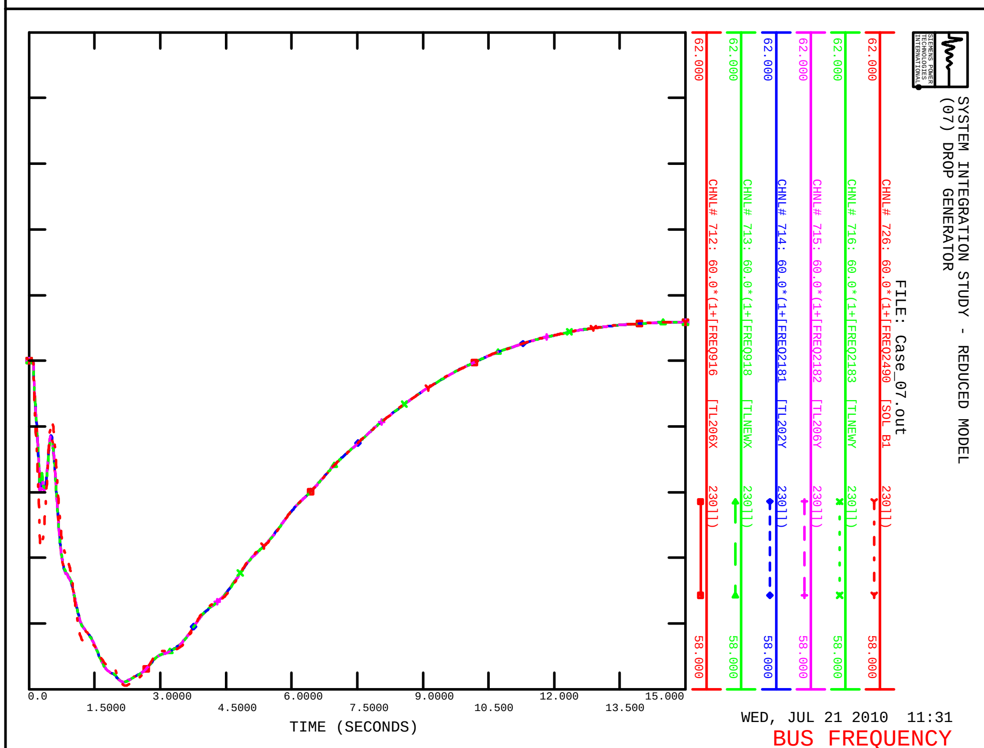

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 674: 60.0*(1+FREQ0223 [SSD B2B3 13811)
CHNL# 675: 60.0*(1+FREQ0224 [BLA L12 13811)
CHNL# 676: 60.0*(1+FREQ0225 [LLK NP 13811)
CHNL# 677: 60.0*(1+FREQ0232 [MKS L12 13811)
CHNL# 678: 60.0*(1+FREQ0310 [BLK NP 13811)
CHNL# 679: 60.0*(1+FREQ0311 [WAV B4 13811)
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
BUS FREQUENCY

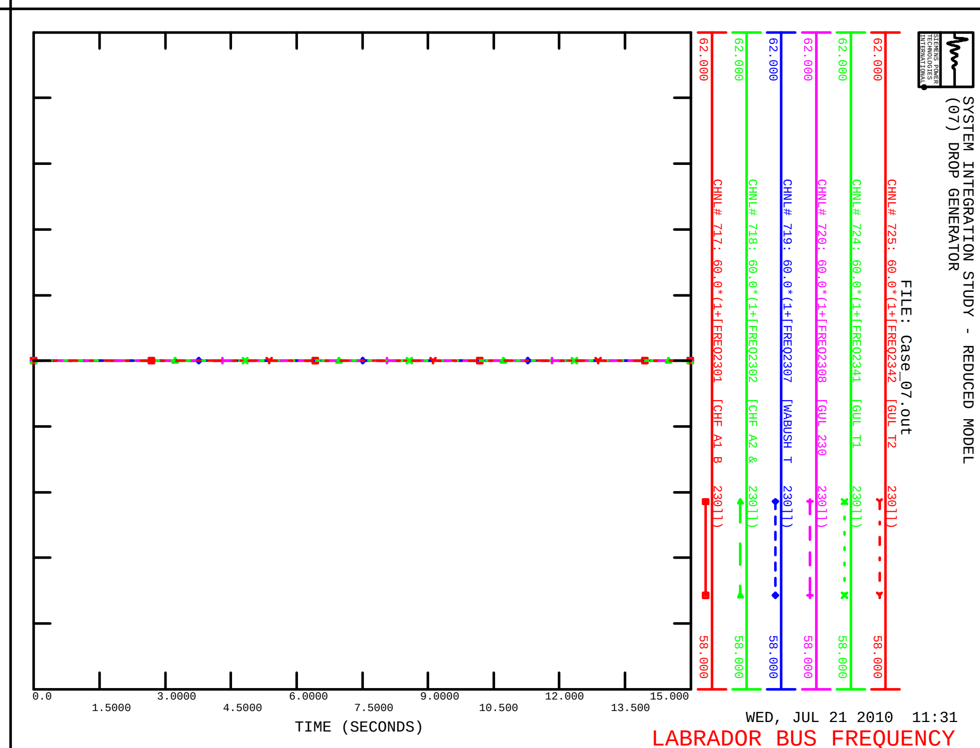

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 680: 60.0*(1+FREQ0338 [HRD B8 13811)
CHNL# 681: 60.0*(1+FREQ0340 [HOL NP 13811)
CHNL# 682: 60.0*(1+FREQ0353 [SPF NP 13811)
CHNL# 683: 60.0*(1+FREQ0354 [COL NP 13811)
CHNL# 684: 60.0*(1+FREQ0357 [BRR NP 13811)
CHNL# 685: 60.0*(1+FREQ0359 [MSY NP 13811)
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
BUS FREQUENCY

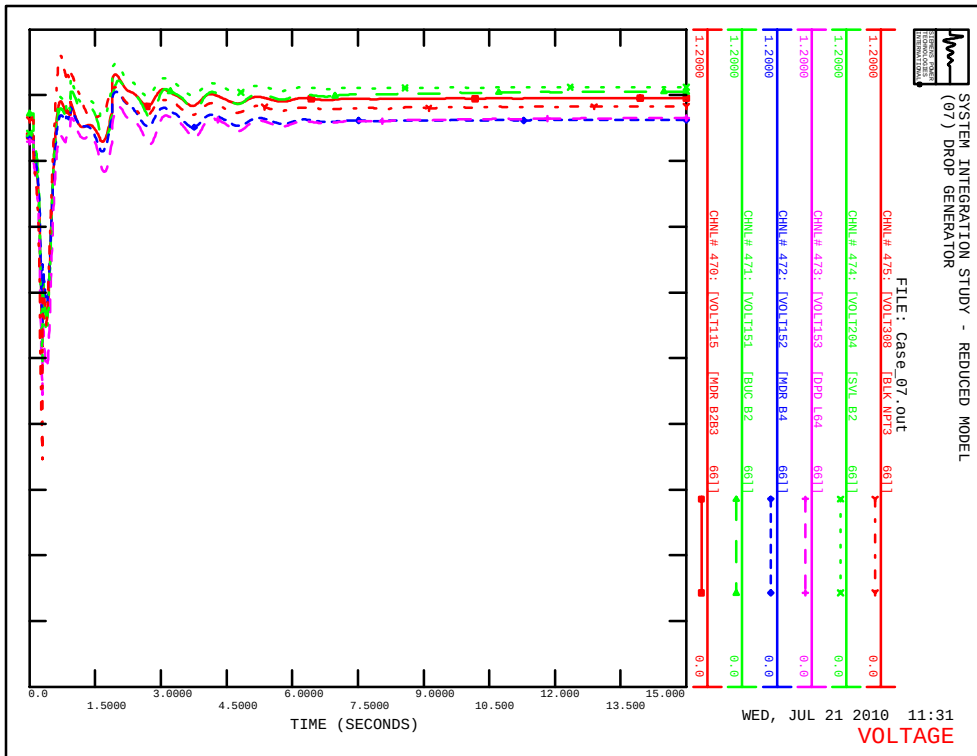

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 686: 60.0*(1+FREQ0371 [SPO NP 13811)
CHNL# 687: 60.0*(1+FREQ0603 [BBK B3 13811)
CHNL# 692: 60.0*(1+FREQ0205 [BBK B1 23011)
CHNL# 693: 60.0*(1+FREQ0206 [SYL B1 23011)
CHNL# 694: 60.0*(1+FREQ0208 [MDR B1B5 23011)
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
BUS FREQUENCY

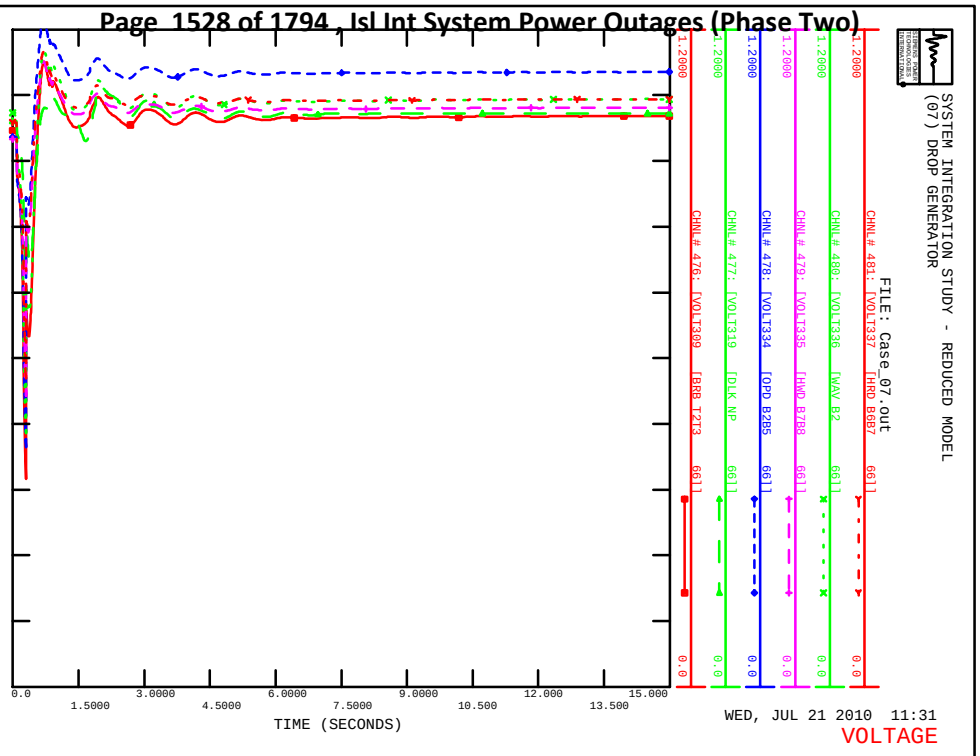

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 696: 60.0*(1+[FREQ215 [BUC B1 230]])
CHNL# 697: 60.0*(1+[FREQ216 [STB B1B2 230]])
CHNL# 701: 60.0*(1+[FREQ227 [CBC B1B2 230]])
CHNL# 702: 60.0*(1+[FREQ229 [WAV B1B3 230]])
CHNL# 703: 60.0*(1+[FREQ230 [LHR B1 230]])
CHNL# 704: 60.0*(1+[FREQ234 [HRD TS 230]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
BUS FREQUENCY

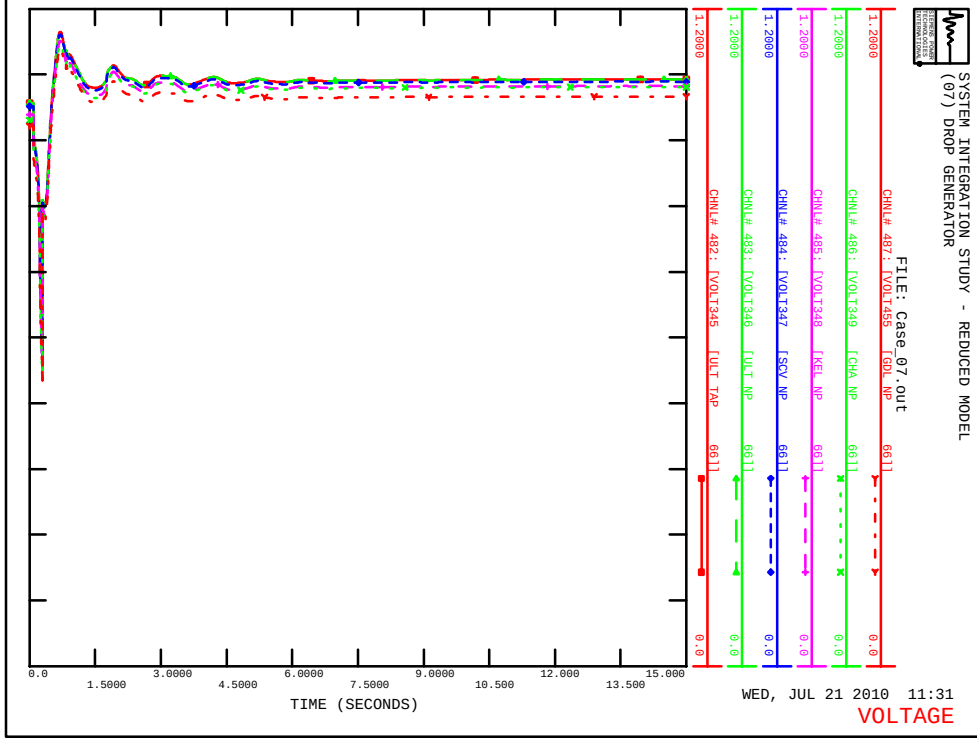

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 705: 60.0*(1+[FREQ236 [HWD B1B2 230]])
CHNL# 706: 60.0*(1+[FREQ238 [OPD B1 230]])
CHNL# 708: 60.0*(1+[FREQ261 [ACG GFL 230]])
CHNL# 709: 60.0*(1+[FREQ291 [GCL L63 230]])
CHNL# 710: 60.0*(1+[FREQ405 [USL L34 230]])
CHNL# 711: 60.0*(1+[FREQ912 [TL202X 230]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
BUS FREQUENCY

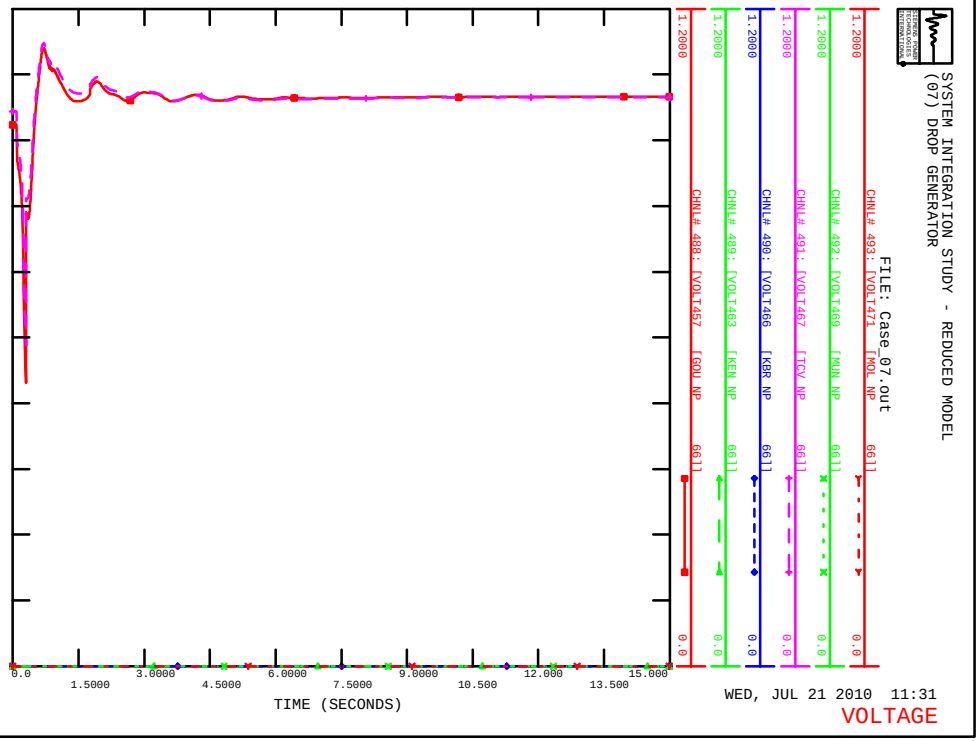

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 712: 60.0*(1+[FREQ916 [TL206X 230]])
CHNL# 713: 60.0*(1+[FREQ918 [TLNEWX 230]])
CHNL# 714: 60.0*(1+[FREQ2181 [TL202Y 230]])
CHNL# 715: 60.0*(1+[FREQ2182 [TL206Y 230]])
CHNL# 716: 60.0*(1+[FREQ2183 [TLNEWY 230]])
CHNL# 726: 60.0*(1+[FREQ2490 [SOL B1 230]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
BUS FREQUENCY

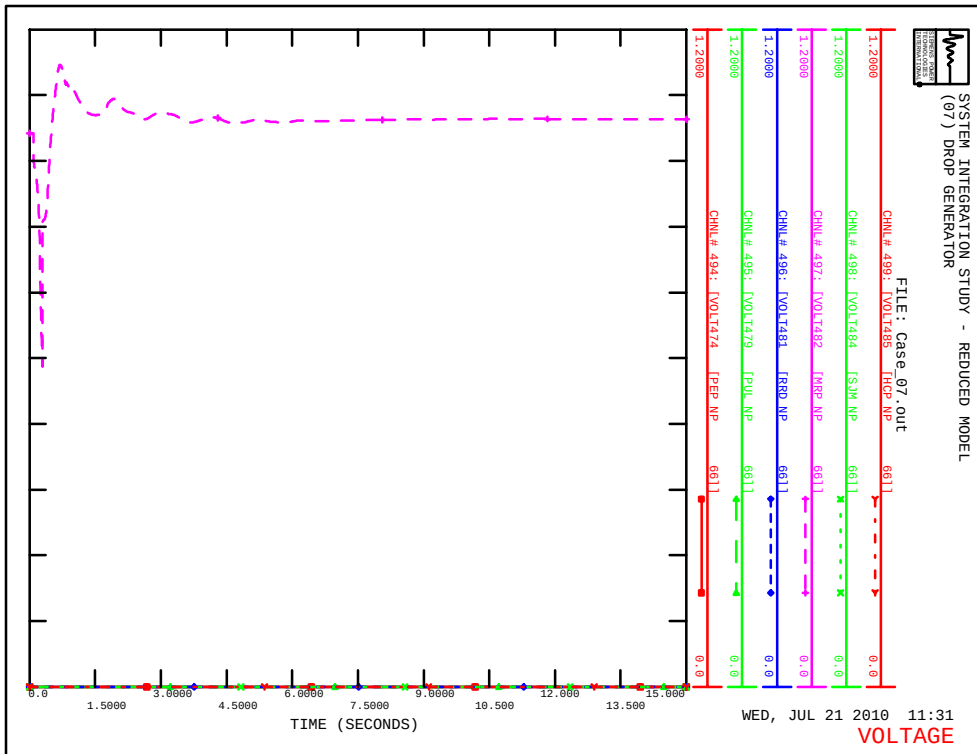

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 717: 60.0*(1+[FREQ2301 [CHF A1 B 230]])
CHNL# 718: 60.0*(1+[FREQ2302 [CHF A2 & 230]])
CHNL# 719: 60.0*(1+[FREQ2307 [WABUSH T 230]])
CHNL# 720: 60.0*(1+[FREQ2308 [GUL 230 230]])
CHNL# 724: 60.0*(1+[FREQ2341 [GUL T1 230]])
CHNL# 725: 60.0*(1+[FREQ2342 [GUL T2 230]])
62.000
58.000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
WED, JUL 21 2010 11:31
LABRADOR BUS FREQUENCY

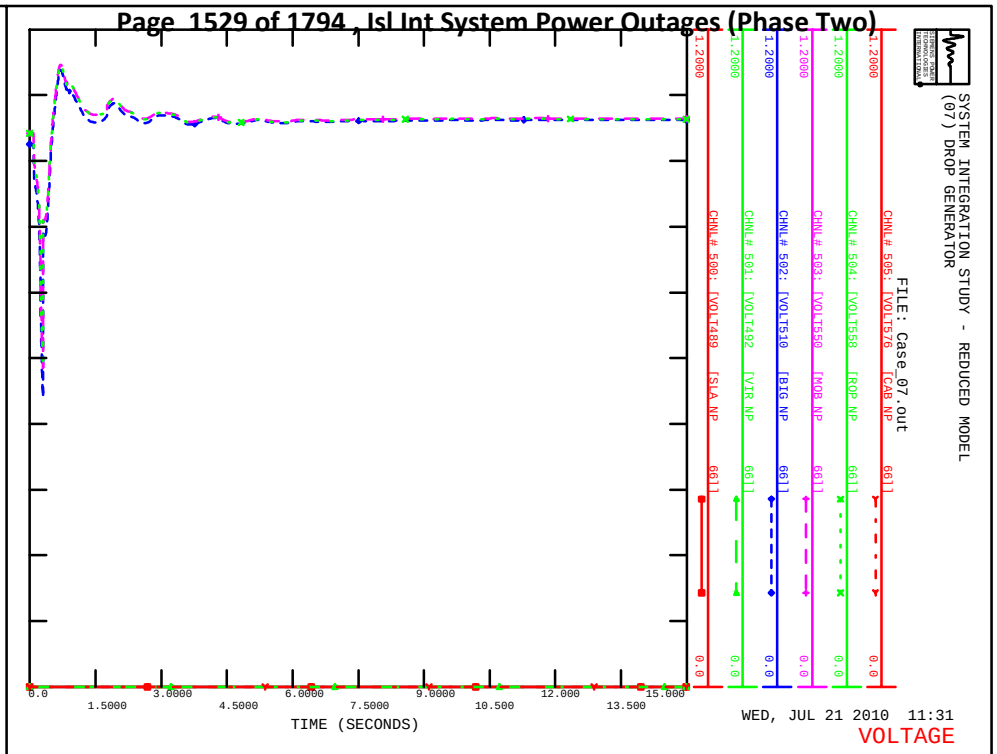

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 470: [VOLT115 [MDR B2B3 661]
CHNL# 471: [VOLT151 [BUC B2 661]
CHNL# 472: [VOLT152 [MDR B4 661]
CHNL# 473: [VOLT153 [DPD L64 661]
CHNL# 474: [VOLT204 [SVL B2 661]
CHNL# 475: [VOLT308 [BLK NPT3 661]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

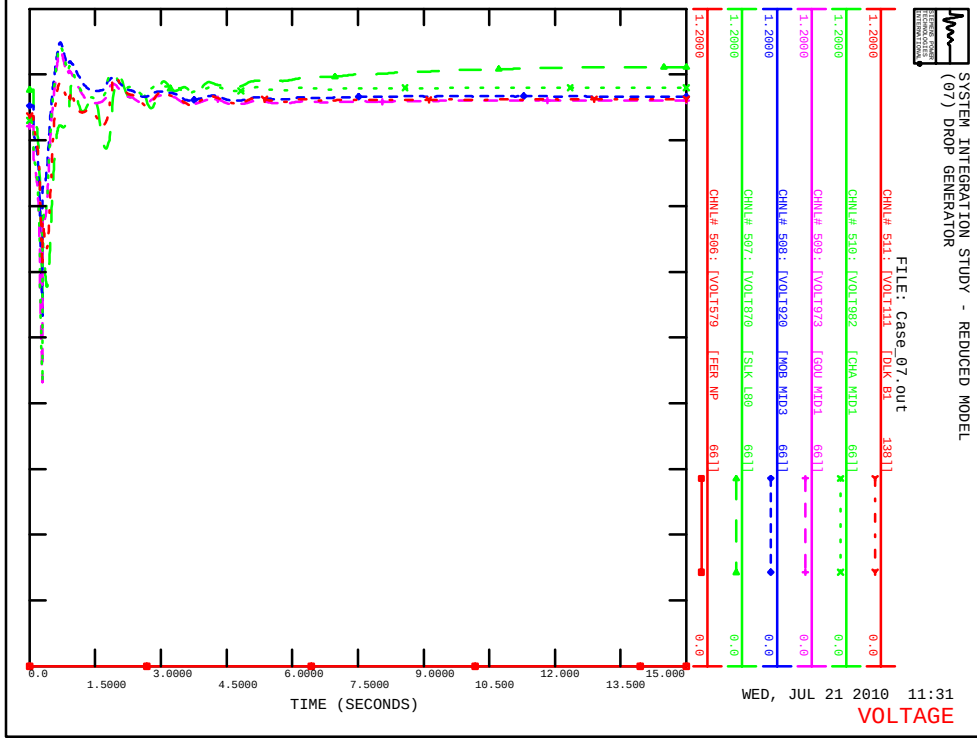

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 476: [VOLT309 [BBB T2T3 661]
CHNL# 477: [VOLT319 [DLK NP 661]
CHNL# 478: [VOLT334 [OPD B2B5 661]
CHNL# 479: [VOLT335 [HWD B7B8 661]
CHNL# 480: [VOLT336 [WAV B2 661]
CHNL# 481: [VOLT337 [HRD B6B7 661]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

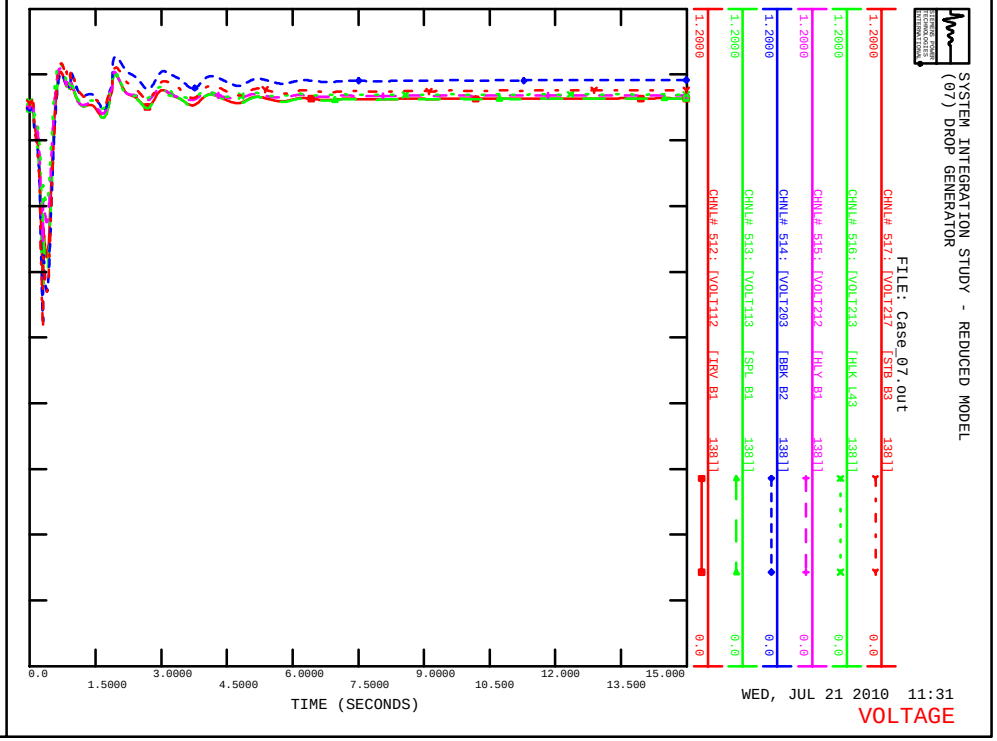

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 482: [VOLT345 [ULT TAP 661]
CHNL# 483: [VOLT346 [ULT NP 661]
CHNL# 484: [VOLT347 [SCV NP 661]
CHNL# 485: [VOLT348 [KEL NP 661]
CHNL# 486: [VOLT349 [CHA NP 661]
CHNL# 487: [VOLT455 [GDL NP 661]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

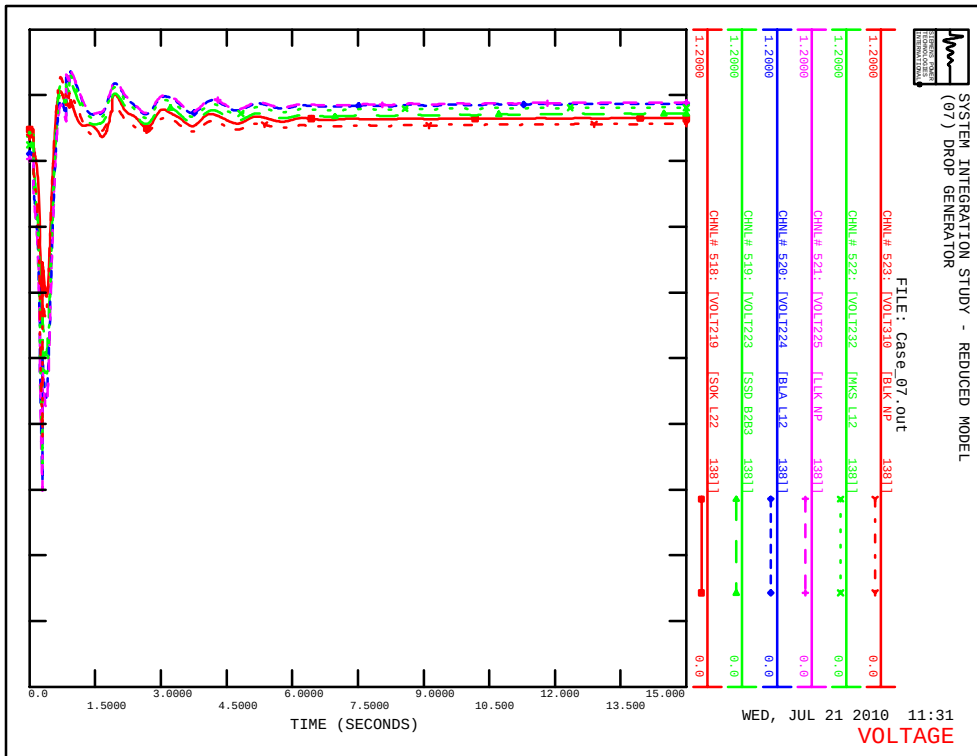

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 488: [VOLT457 [GOU NP 661]
CHNL# 489: [VOLT463 [KEN NP 661]
CHNL# 490: [VOLT466 [KBR NP 661]
CHNL# 491: [VOLT467 [TCV NP 661]
CHNL# 492: [VOLT469 [MUN NP 661]
CHNL# 493: [VOLT471 [MOL NP 661]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

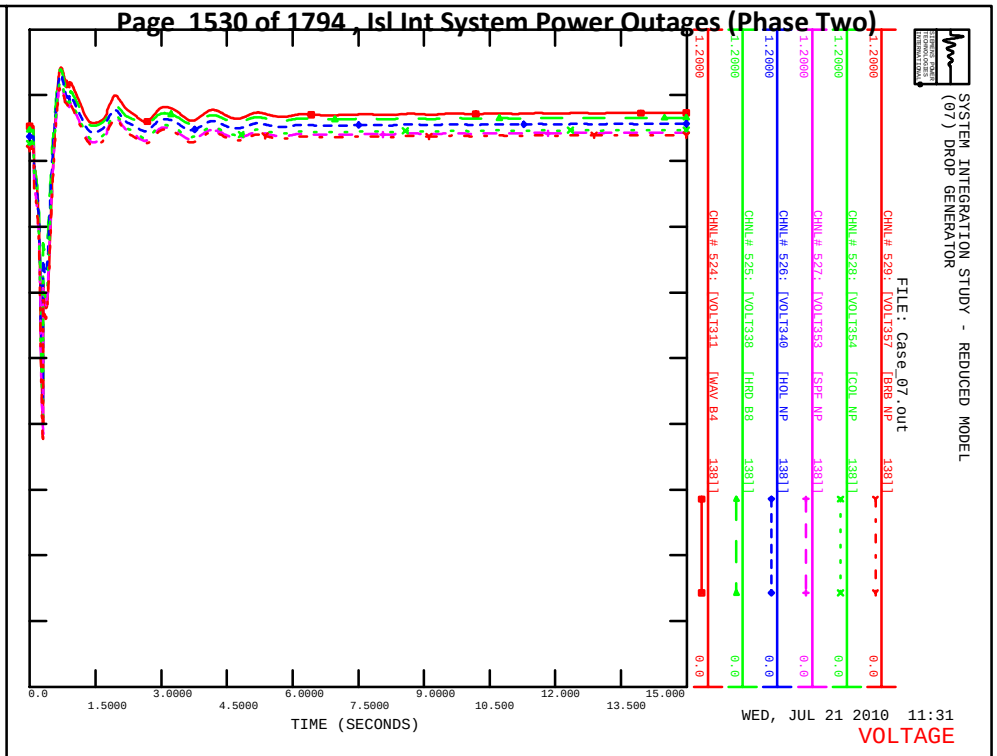

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 494: [VOLT474 [PEP NP 661]
CHNL# 495: [VOLT479 [PUL NP 661]
CHNL# 496: [VOLT481 [RRD NP 661]
CHNL# 497: [VOLT482 [MRP NP 661]
CHNL# 498: [VOLT484 [SJM NP 661]
CHNL# 499: [VOLT485 [HCP NP 661]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

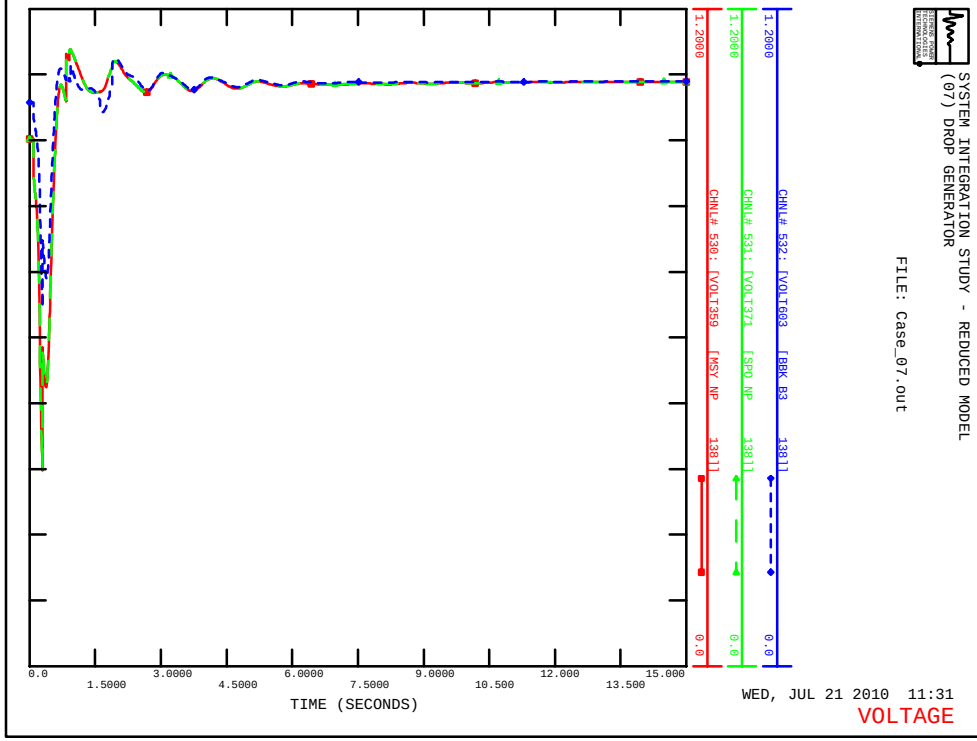

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 500: [VOLT489 [SLA NP 661]
CHNL# 501: [VOLT492 [VIR NP 661]
CHNL# 502: [VOLT510 [BIG NP 661]
CHNL# 503: [VOLT550 [MOB NP 661]
CHNL# 504: [VOLT558 [ROP NP 661]
CHNL# 505: [VOLT576 [CAB NP 661]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

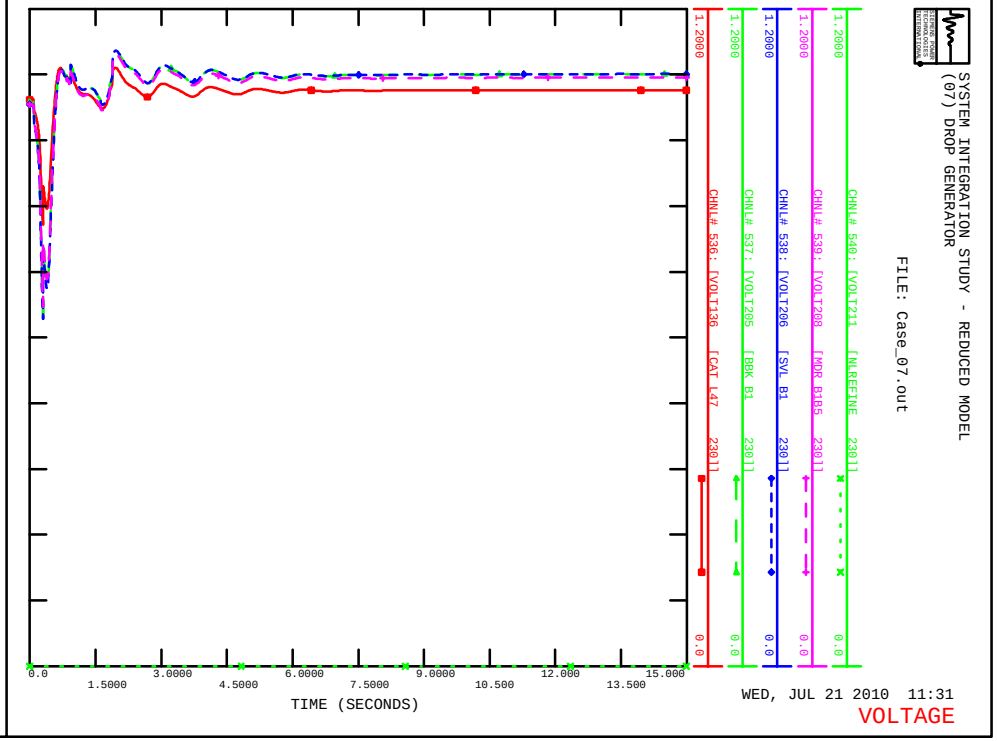

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 506: [VOLT579 [FER NP 661]
CHNL# 507: [VOLT870 [SLK 180 661]
CHNL# 508: [VOLT920 [MOB MID3 661]
CHNL# 509: [VOLT973 [GOU MID1 661]
CHNL# 510: [VOLT982 [CHA MID1 661]
CHNL# 511: [VOLT111 [DLK B1 1381]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

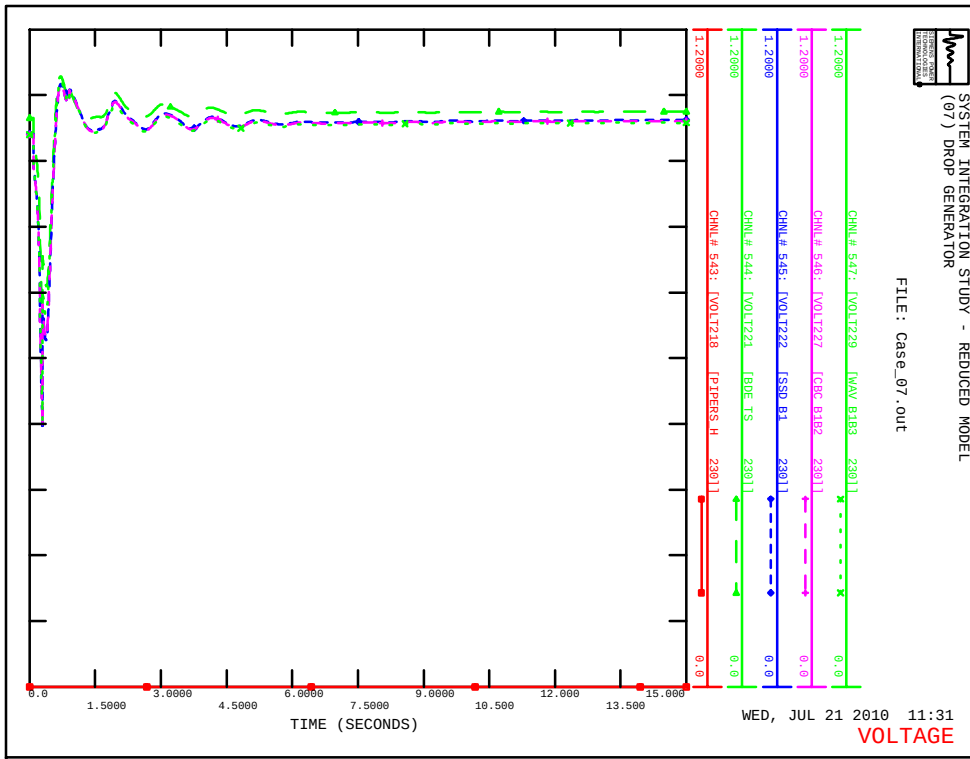

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 512: [VOLT112 [IRV B1 1381]
CHNL# 513: [VOLT113 [SPL B1 1381]
CHNL# 514: [VOLT203 [BBK B2 1381]
CHNL# 515: [VOLT212 [HLY B1 1381]
CHNL# 516: [VOLT213 [HLK 143 1381]
CHNL# 517: [VOLT217 [STB B3 1381]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

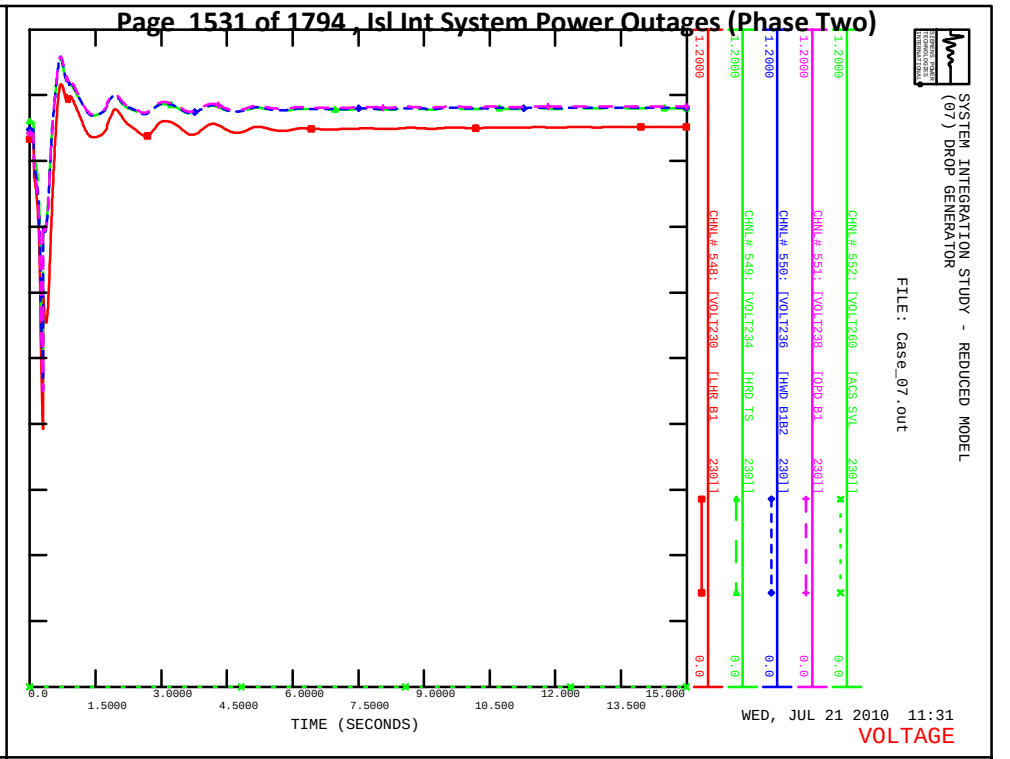

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 518: [VOLT219 [SOK L22 138]
CHNL# 519: [VOLT223 [SSD B2B3 138]
CHNL# 520: [VOLT224 [BLA L12 138]
CHNL# 521: [VOLT225 [LLK NP 138]
CHNL# 522: [VOLT232 [MKS L12 138]
CHNL# 523: [VOLT310 [BLK NP 138]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

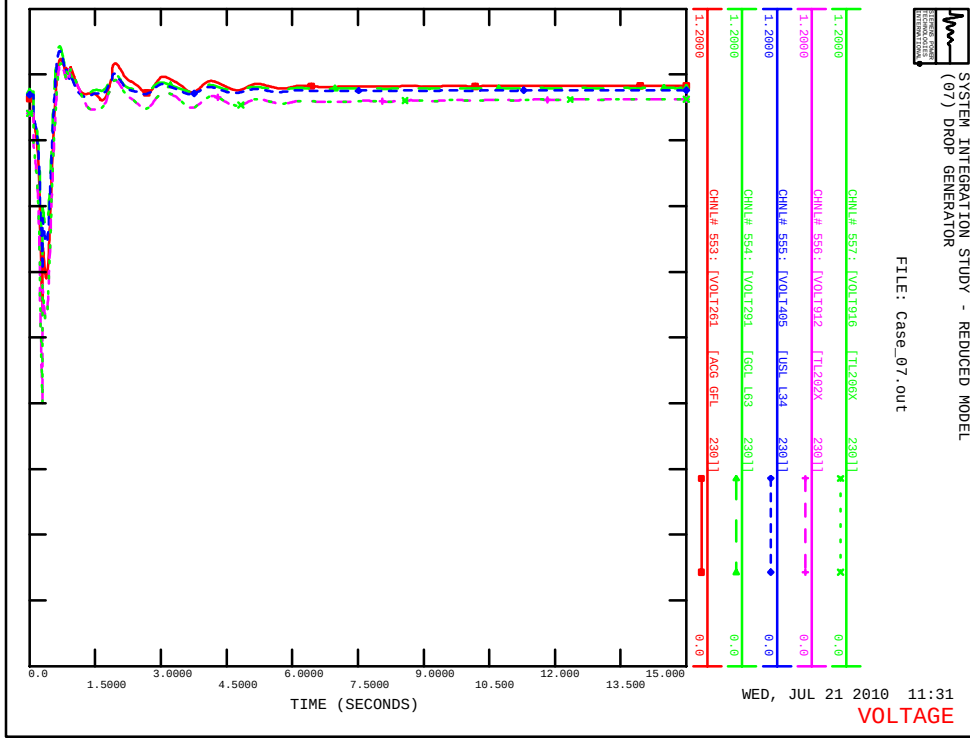

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 524: [VOLT311 [WAV B4 138]
CHNL# 525: [VOLT338 [HRD B8 138]
CHNL# 526: [VOLT340 [HOL NP 138]
CHNL# 527: [VOLT353 [SPF NP 138]
CHNL# 528: [VOLT354 [COL NP 138]
CHNL# 529: [VOLT357 [BRB NP 138]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

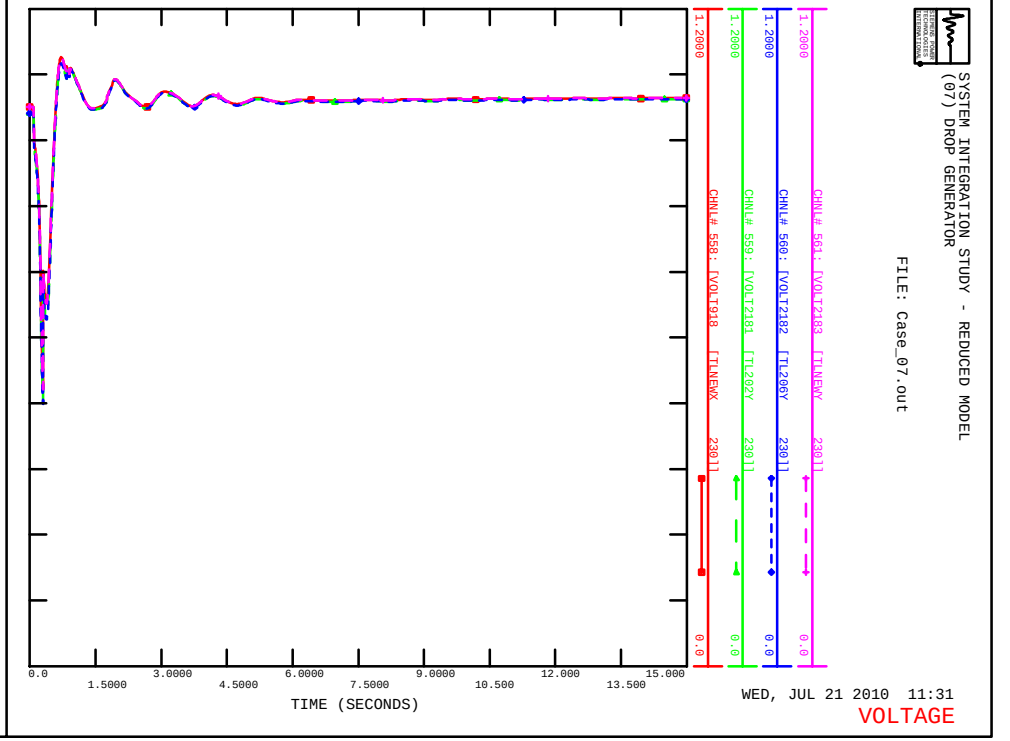

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 530: [VOLT359 [MSY NP 138]
CHNL# 531: [VOLT371 [SPO NP 138]
CHNL# 532: [VOLT603 [BBK B3 138]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

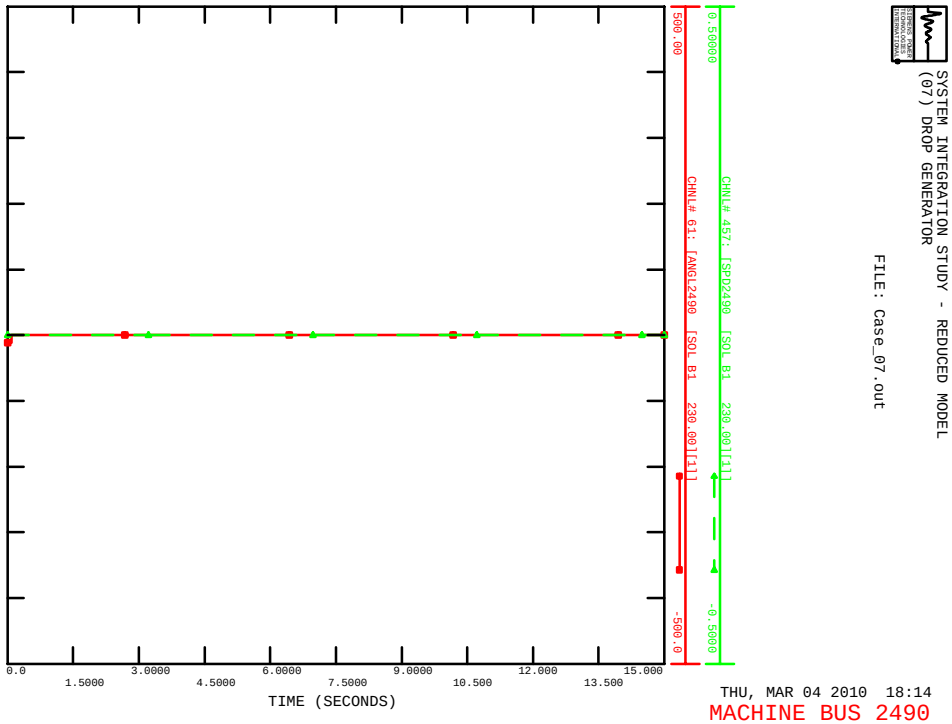

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 536: [VOLT136 [CAT L47 230]
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CHNL# 538: [VOLT206 [SVL B1 230]
CHNL# 539: [VOLT208 [MOR B1B5 230]
CHNL# 540: [VOLT211 [NLREFINE 230]
TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

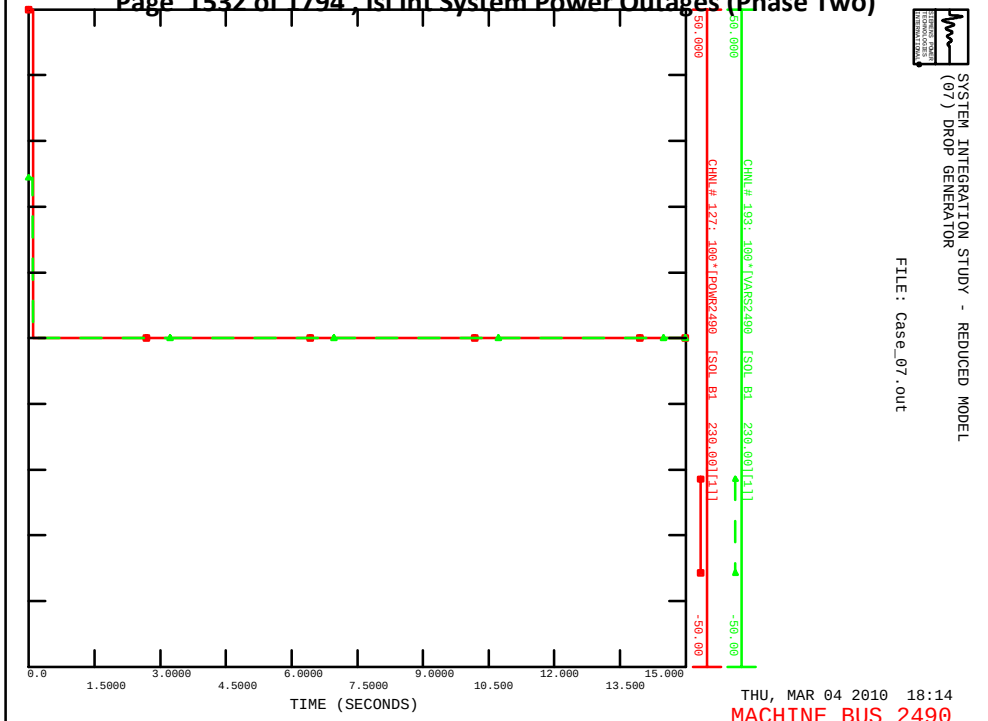

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
CHNL# 543: [VOLT218 [PIPERS H 230]
CHNL# 544: [VOLT221 [BDE TS 230]
CHNL# 545: [VOLT222 [SSD B1 230]
CHNL# 546: [VOLT227 [CBC B1B2 230]
CHNL# 547: [VOLT229 [WAV B1B3 230]
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TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

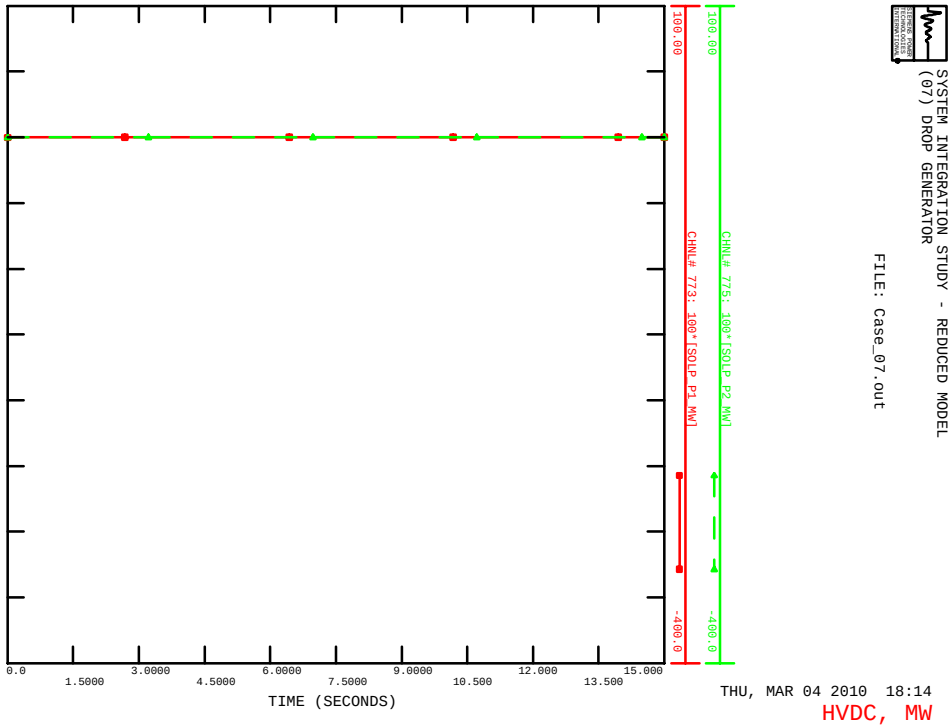

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CHNL# 549: [VOLT234 [HRD TS 230]
CHNL# 550: [VOLT236 [HWD B1B2 230]
CHNL# 551: [VOLT238 [OPD B1 230]
CHNL# 552: [VOLT260 [ACS SVC 230]
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TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE

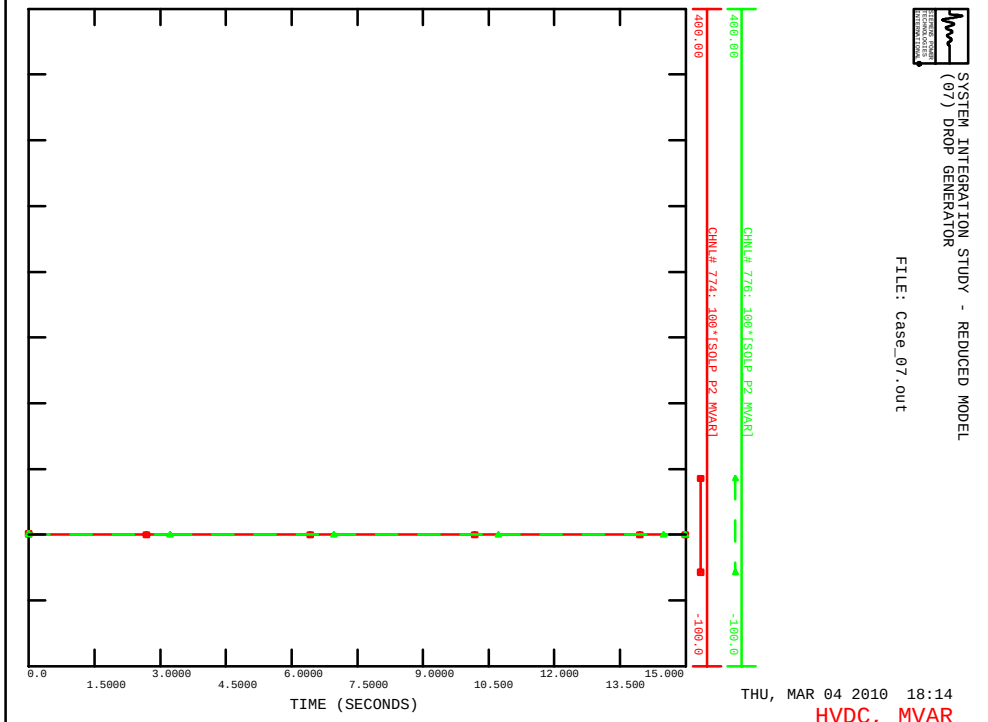

SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
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CHNL# 554: [VOLT291 [GCL L63 230]
CHNL# 555: [VOLT405 [USL L34 230]
CHNL# 556: [VOLT912 [TL202X 230]
CHNL# 557: [VOLT916 [TL206X 230]
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TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE


SYSTEM INTEGRATION STUDY - REDUCED MODEL
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CHNL# 559: [VOLT2181 [TL202Y 230]
CHNL# 560: [VOLT2182 [TL206Y 230]
CHNL# 561: [VOLT2183 [TLNEWY 230]
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TIME (SECONDS)
WED, JUL 21 2010 11:31
VOLTAGE


SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
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CHNL# 61: [ANGL2490 [SOL B1 230.00][1]]
-500.0
0.50000
CHNL# 457: [SPD2490 [SOL B1 230.00][1]]
-0.50000
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
THU, MAR 04 2010 18:14
MACHINE BUS 2490


SYSTEM INTEGRATION STUDY - REDUCED MODEL
(07) DROP GENERATOR
FILE: Case_07.out
50.000
CHNL# 127: 100*[POWR2490 [SOL B1 230.00][1]]
-50.00
50.000
CHNL# 193: 100*[VARS2490 [SOL B1 230.00][1]]
-50.00
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
THU, MAR 04 2010 18:14
MACHINE BUS 2490


SYSTEM INTEGRATION STUDY - REDUCED MODEL
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100.00
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-400.0
100.00
CHNL# 775: 100*[SOLP P2 MW]
-400.0
0.0
1.5000
3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
THU, MAR 04 2010 18:14
HVDC, MW


SYSTEM INTEGRATION STUDY - REDUCED MODEL
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-100.0
400.00
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0.0
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3.0000
4.5000
6.0000
7.5000
9.0000
10.500
12.000
13.500
15.000
TIME (SECONDS)
THU, MAR 04 2010 18:14
HVDC, MVAR

APPENDIX C9 – SNC LAVALIN LOAD FLOW AND SHORT CIRCUIT STUDIES – APRIL 2012

Document Front Sheet

nalcor energy
LOWER CHURCHILL PROJECT

NE-LCP Contractor/Supplier

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- [x] 01 – REVIEWED AND ACCEPTED – NO COMMENTS
- [ ] 02 – REVIEWED – INCORPORATE COMMENTS, REVISE AND RESUBMIT
- [ ] 03 – REVIEWED - NOT ACCEPTED
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- [ ] 05 – NOT REVIEWED

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Lower Churchill Project

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Date: 05-Apr-2012

Prepared by: _____
for Mohamed El Chehaly

Verified by: _____
Peter Anderson

Approved by: _____
Satish Sud

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
SATISH SUD
SIGNATURE
5-APR-2012
DATE
NEWFOUNDLAND & LABRADOR

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Appendices

APPENDIX-A Base Case Load Flow Plots

NLH Index of Substation Names

Location	ID	Location	ID
Barachoix	BCX	Holyrood	HRD
Bay d'Espoir	BDE	Howley	HLY
Bay L'Argent	BLA	Indian River	IRV
Bear Cove	BCV	Jackson's Arm	JAM
Berry Hill	BHL	Linton Lake	LLK
Bottom Brook	BBK	Long Harbour	LHR
Bottom Waters	BWT	Main Brook	MBK
Buchans	BUC	Massey Drive	MDR
Cat Arm	CAT	Monkstown	MKS
Churchill Falls	CFA	Muskrat Falls	MFA
Come-by-Chance	CBC	Oxen Pond	OPD
Coney Arm	CAM	Paradise River	PRV
Conne River	CRV	Parson's Pond	PPD
Corner Brook Freq. Conv.	CBF	Peter's Barren	PBN
Cow Head	CHD	Plum Point	PPT
Daniels Harbour	DHR	Rattle Brook	RBK
Deer Lake	DLK	Rocky Harbour	RHR
Doyles	DLS	Roddicton Woodchip	RWC
Duck Pond	DPD	Sally's Cove	SCV
English Harbour West	EHW	Soldiers Pond	SPD
Farewell Head	FHD	South Brook	SOK
Glenburnie	GLB	Springdale	SPL
Glenwood	GWD	St.Anthony Airport	STA
Grand Bay	GBY	St.Anthony Diesel Plant	SDP
Grandy Brook	GBK	Star Lake	SLK
Grand Falls Freq. Conv.	GFC	Stephenville	SVL
Granite Canal	GCL	Stony Brook	STB
Hampden	HDN	Sunnyside	SSD
Happy Valley	HVY	Upper Salmon	USL
Hardwoods	HWD	Western Avalon	WAV
Hawkes Bay	HBY	Wiltondale	WDL
Hinds Lake	HLK		

1 INTRODUCTION

This Report presents the results of the load flow studies carried out to examine the steady-state performance of the Newfoundland and Labrador (NLH) power system with the HVdc interconnections between Muskrat Falls and Soldiers Pond and between Bottom Brook and the Nova Scotia (NS) power system. The present Design Basis considers, for the Muskrat Falls-Soldiers Pond link (the "Island" link), a dc voltage level of ±350 kV and a nominal bipole rating of 900 MW and, for the Bottom Brook-Nova Scotia link (the "Maritime" link), a dc voltage level of ±200 kV and a nominal bipole rating of 500 MW. This is interpreted to mean that these rated power levels and rated voltages apply at the rectifier ends (Muskrat Falls and Bottom Brook).

In addition to the nominal ratings above, the Design Basis calls for a 10-minute overload capability of 200% and a continuous overload capability of 150%, both in mono-polar mode on the Island link. This is to enable the island system to ride through a permanent pole outage on the Island link without having to shed load. It may be necessary, after such a permanent pole outage, to reduce the export to Nova Scotia on the Maritime link. The Island link will be essentially unidirectional from Labrador to Newfoundland, although there will be nothing in the design of the link to prevent operation in the reverse direction. The Maritime link is required to have a 500 MW continuous capability in bipolar mode in both directions.

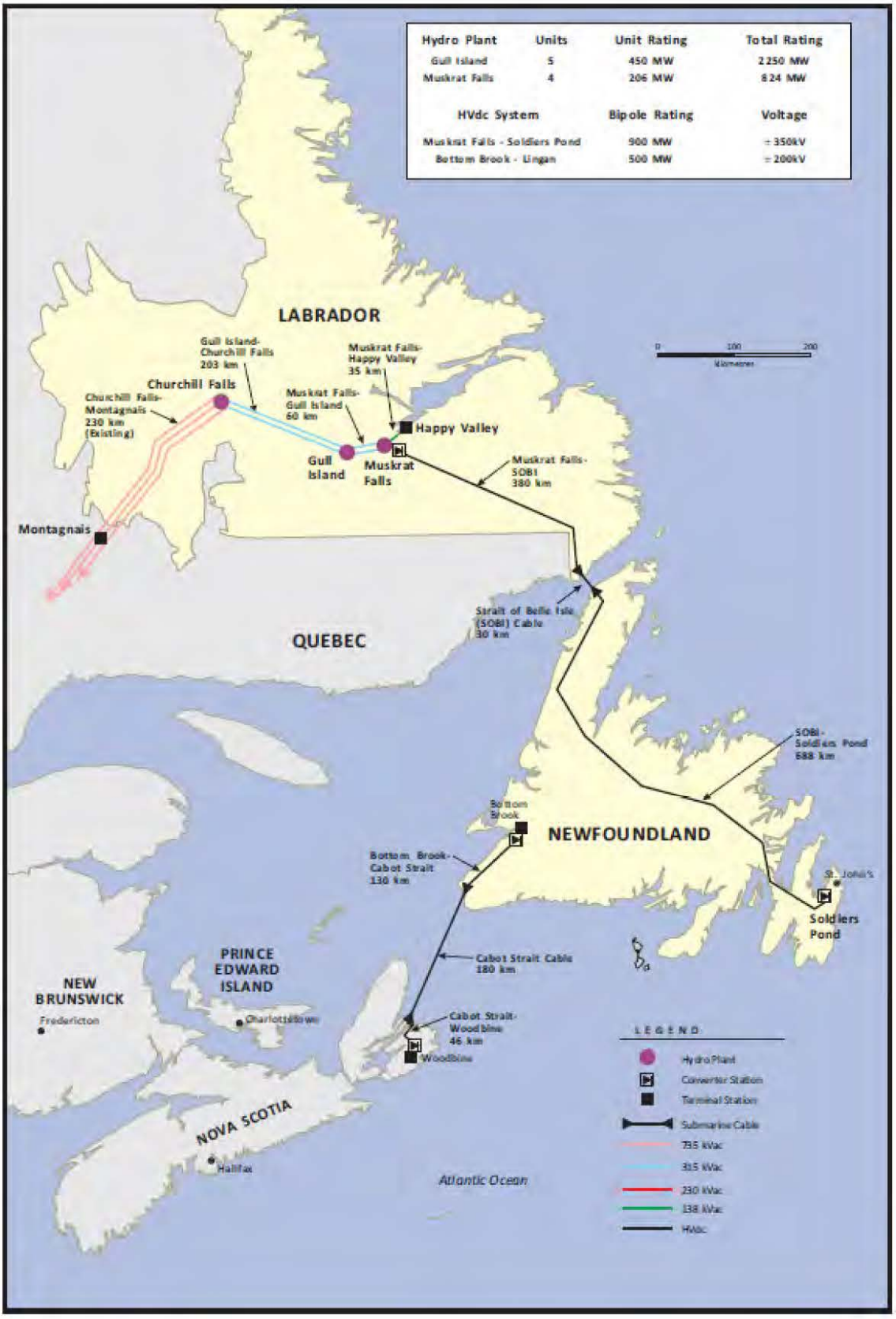
Figure 1-1 provides an overview of the areas considered in these studies. The connection to the Trans-Energie 735 kV system in Quebec was represented by a simple equivalent at the Montagnais substation. The Emera system in Nova Scotia was represented by a simple equivalent at the inverter station of the Maritime link. The ac system between Churchill Falls and Muskrat Falls and the on-island ac system (see Figure 1-2) were modelled in detail.

Starting from the base case scenarios provided by Nalcor, the present load flow studies are designed to:

- quantify the operating modes that will be possible, both in normal and outage conditions
- define the overload requirements for the Island link,
- define the limits on the export levels on the Maritime link,
- determine the reactive compensation requirements in the Island system under a variety of operating modes,
- determine the maximum and minimum short circuit levels (fault levels) that will occur at the converter station ac busses at Muskrat Falls, Soldiers Pond and Bottom Brook,
- identify any system conditions that will result in overloads or under-voltages, requiring mitigating measures on the ac systems in Labrador and on the Island.

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Figure 1-1: Project Area Map



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Figure 1-2: Provincial Transmission Grid



2 STUDY BASIS

NALCOR provided nineteen base case scenarios for examination. These scenarios are presented in Table 2-1.

Load flow studies were carried out for each scenario, considering normal system conditions (all equipment in service) and outage conditions. In addition to pole outages on the two dc links, the automatic sequential contingency feature of PSS®E was used to examine all single contingency outages on the ac systems.

The Nalcor base case study files modelled the dc converters as generators with positive and negative real power outputs for the inverter and rectifier respectively. These models also provided reactive power control to maintain the ac bus voltage at a pre-set level. This type of model is representative of a voltage source converter (VSC), which has a controllable reactive capability. In order to make the modelling more generic and include the behaviour of a current source converter (more commonly referred to as a line commutated converter or LCC), the dc links were explicitly modelled in PSS®E as dc lines with LCC converters. Shunt capacitor banks were connected at each ac terminal bus to represent the harmonic filters that would be required with LCC converters.

Four basic generation dispatch levels were considered for these studies:

- Economic dispatch – hydro generation set to its most efficient level to optimize the hydro usage,
- Maximum Dispatch – all available generation set to its maximum output,
- Minimum Dispatch 1 – dispatch matched to light load conditions.
- Minimum Dispatch 2 – dispatch matched to extreme light load conditions.

These four dispatch levels are shown on a plant basis in Table 2-2.

The existing thermal units at Holyrood (2x194 MVA+1x177 MVA) will be converted to operate as synchronous condensers by the year 2017.

Although the transmission, subtransmission and distribution systems were modeled, only the 230 kV equipment were monitored. Any overloading on the 138 kV and the 69 kV systems are considered as local issues and therefore these are not included in the scope of work of this study.

The load flow analysis will be performed under two possible situations, that is:

Normal operating conditions (N-0): the transmission system is entirely available (no equipment has been forced out of service).

Contingency operating conditions (N-1): one component of the transmission system (line or transformer) is out of service. Only outages of equipment at the bulk transmission levels will be considered.

For each of these two operating conditions, the following criteria are applied to the analyses.

- The acceptable voltage range for operating the system under normal and contingency conditions are as follows:

Condition	Acceptable Voltage Range
Normal Conditions (N-0)	95% - 105%
Contingency Conditions (N-1)	90% - 110%

- The thermal loading of a transmission line or transformer should not exceed 100% of the following:

  - Rate A – Summer season (30 degrees C ambient) – light load and extreme light load
  - Rate B – Spring/Fall season (15 degrees C ambient) – intermediate load
  - Rate C – Winter season (0 degrees C ambient) – peak load

Table 2-1: Base Case Scenarios

No.	NLH System Load	NS Export Bottom Brook	Island Import Muskrat Falls/Soldiers Pond	Island Generation	Comments
BC-1	Peak-2017 (1552MW)	158MW	900/814MW	Economic Dispatch	Winter Peak 3-units @ Muskrat Falls
BC-2	Peak-2017(1552MW)	239MW	900/814MW	Maximum	Winter Peak 3-units @ Muskrat Falls
BC-3	Peak-2017(1552MW)	158MW	798/730MW	Maximum	Winter Peak
BC-4	Peak-2041(1900MW)	0MW	900/814MW	Maximum	Winter Peak
BC-5	Intermediate-2017(1100MW)	158MW	900/814MW	Economic Dispatch	Spring/Fall day
BC-6	Intermediate-2017(1100MW)	158MW	276/268	Maximum	Spring/Fall day
BC-7	Intermediate-2017 (1100MW)	500MW	900/814MW	Economic Dispatch	Spring/Fall day
BC-8	Light (700MW)	158MW	420/400MW	Minimum	Summer day
BC-9	Light (700MW)	158MW	81/80MW	Economic Dispatch	Summer day
BC-10	Light (700MW)	500MW	900/814MW	Economic Dispatch	Summer day
BC-11	Extreme Light (420MW)	0MW	81/80MW	Economic Dispatch	Summer night
BC-12	Extreme Light (420MW)	320MW	81/80MW	Economic Dispatch	Summer night
BC-13	Extreme Light (420MW)	320MW	457/435MW	Minimum	Summer night
BC-14	Peak-2017 (1552MW)	-260MW	286/260MW-Monopole	Maximum	Winter Peak
BC-15	Intermediate-2017(1100MW)	158MW	378/333MW-Monopole	Economic Dispatch	Spring/Fall day
BC-16	Light (700MW)	500MW	638/518MW-Monopole	Minimum	Summer day
BC-17	Extreme Light (420MW)	0MW	215/200MW-Monopole	Minimum	Summer night
BC-18	Peak-2017 (1552MW)	158MW	900/814MW	Economic Dispatch	Winter Peak 4-units @ Muskrat Falls
BC-19	Intermediate-2017(1100MW)	500MW	900/814MW	Economic Dispatch	Winter Peak 4-units @ Muskrat Falls

Table 2-2: Generation Dispatch Levels

Station	Installed Capacity(MW)	Maximum Dispatch	Economic Dispatch	Minimum Dispatch	Extreme Minimum
Thermal Plants					
Holyrood 1	175	-	-	-	-
Holyrood 2	175	SC	SC	SC	SC
Holyrood 3	160	SC	SC	SC	SC
Hardwoods 1-2	100	SC	SC	SC	SC
Stephenville	50	-	-	-	-
Sub-total Thermal	660	-	-	-	-
Hydro Plants					
Labrador					
Churchill Falls	5428	4229	4219	2963	2959
CF Net Delivery to Muskrat Falls	-	282	298	76	-26
Muskrat Falls[1]	824	618	602	824	476
Sub-total Labrador		900	900	900	450
Newfoundland					
Bay d'Espoir 1-6[2]	450	450	420	263	66
Bay d'Espoir 7	154	154	145	-	135
Cat Arm 1-2	130	130	100	36	36
Upper Salmon	84	84	78	70	-
Hinds Lake	75	75	70	-	-
Granite Canal	40	40	32	27	27
Paradise River	8	8	8	7	-
Sub-total Newfoundland		941	853	403	264
NUGS					
CBP&P		18	18	18	18
Exploits		76	76	76	76
ACI-CHI Star Lake		17.4	17.4	17.4	17.4
Algonquin Power		3.6	3.6	3.6	3.6
Sub-total NUGS		115	115	115	115
Total Generation		1956	1868	1418	829
Export to Nova Scotia		239	158	500	320
NLH Load		1552	1552	700	420
Total Load		1791	1710	1200	740

Notes:

[1]-Output of Muskrat Falls adjusted for different export levels to the Island

[2]-Bay d'Espoir #2-6 used as swing bus (exact output determined from load flow)

3 RESULTS OF THE STUDIES

Line overloads found under normal conditions and contingencies can be eliminated using the following alternatives:

- Running available combustion turbines (CTs) continuously,
- Starting the CTs following an outage which can take several minutes,
- Increasing the thermal rating of the overloaded circuits,
- Adding new circuits close to the overloaded ones,
- Adjusting the import/export levels on the HVdc interconnections,
- Re-dispatching of the generation on the Island,
- Re-locating the Bottom Brook converter station to Bay d'Espoir.

Following the Client's recommendation, the import from Labrador and the export to Nova Scotia has been adjusted to eliminate all overloads. The Client shall decide which of the mentioned alternatives will be employed to operate under the capability of the 230 kV equipment.

3.1 BASE CASE SCENARIOS: BC-1, BC-2

No.	NLH System Load(MW)	NS Export BBK(MW)	Island Import MFA/SPD(MW)	Island Generation	Comments
BC-1	1552	158	900/814	Economic	Winter Peak-2017 3-units @ Muskrat Falls
BC-2	1552	239	900/814	Maximum	Winter Peak-2017 3-units @ Muskrat Falls

These scenarios consider the peak system load in the year 2017 (1,552 MW), with the maximum import on the Island link (900 MW at Muskrat Falls) and an export on the Maritime link of 158 MW at the economic on-Island dispatch level of 853 MW and an export of 239 MW at the maximum on-Island dispatch level of 941 MW. Neither of these dispatches included the gas turbines at Hardwoods (2x50 MW) and Stephenville (1x50 MW). These units are normally operated as synchronous

condensers for voltage support, but can be brought into service as generators within 10 minutes. In addition two of the three units at Holyrood were operated as synchronous condensers.

The system performance for both cases is shown in Appendix A.

The overall comments on both cases are summarized below:

BC-1

Low voltage at Soldiers Pond 230 kV (< 95%) was corrected by adding a reactive power source (shunt capacitor bank) at Soldiers Pond since the two synchronous condensers at Holyrood were already operating at close to maximum output. A reactive power source output of 240 MVAr achieves a bus voltage close to 100%.

Low voltage at Bottom Brook 230 kV was corrected by adding a reactive power source (shunt capacitor bank) at Bottom Brook 230 kV. An output of 75 MVAr achieves a bus voltage close to 100%. This will be an addition to the 25 MVAr representing the filters of the HVdc.

Low voltage at Wabush 230 kV was not considered further in any of these studies as reinforcement to this area is presently under review.

No overloads were observed in the base case.

Line outages:

Removing the 230 kV circuit, TL242E, between Soldiers Pond and Hardwoods results in a 7% overload on the remaining circuit, TL201E. No mitigating measures were considered for this small overload, but it will increase in subsequent years and will need to be addressed in the future system planning.

Generator Outage:

Largest unit at Bay d'Espoir (Bay d'Espoir #7-154 MW)-The remaining generation was re-dispatched to maximum levels and the export to NS was reduced to 96 MW.

BC-2

With the reactive power source at Soldiers Pond 230 kV the voltage was satisfactory with an output of 240 MVAr as in BC-1.

The output of the reactive power source at Bottom Brook 230 kV increased to 130 MVAr.

No overloads were observed in the base case.

Line outages:

Same as in BC-1 plus the outage of the 230 kV line between Granite Canal and Bottom Brook (future line, not yet designated) required additional reactive support at Bottom Brook to prevent under-voltages at nearby buses, the reactive production increasing from 130 MVAr in the base case to 150 MVAr. This problem could also be solved by reducing the export to NS from 239 MW to 229 MW.

Generator Outage:

Largest unit at Bay d'Espoir (Bay d'Espoir #7-154 MW)-No generation re-dispatch is available as the units are already at maximum output. The export to NS was reduced from 239 MW to 96 MW as in BC-1 and the reactive support at Bottom Brook was disconnected to avoid over-voltages in that area.

3.2 BASE CASE SCENARIO: BC-3

No.	NLH System Load(MW)	NS Export BBK(MW)	Island Import MFA/SPD(MW)	Island Generation	Comments
BC-3	1552	158	798/730	Maximum	Winter Peak-2017

In this case, a reduced power export of 798 MW from Labrador over the Island link was considered, the island generation was dispatched to its maximum and the export to NS over the Maritime link was set at 158 MW. The system performance is shown in Appendix A. The same general observations and comments apply to this case as described for BC-1 and BC-2, however for the loss of the largest unit at Bay d'Espoir, a limited number of options are available as the island generation is already at its maximum:

- Increase the export from Labrador on the Island link from 798 MW to 900 MW. If this power increase cannot be supplied by Muskrat Falls, it will have to come from Churchill Falls,
- Reduce the export to NS to 10 MW,
- A combination of the above; for example, increasing the export over the Island link by 75 MW and reducing the export to NS by 75 MW.

3.3 POLE OUTAGES

Following on from the base cases presented above, the effect of a permanent pole outage on the Island link was examined. It was assumed that following a pole outage, the island generation would automatically be re-dispatched up to its maximum under AGC and operator control. Thus, in terms of the island generation dispatch, scenarios BC-1, BC-2 and BC-3 become identical. The following table shows the required capacity on the remaining, healthy pole of the Island link, considering different courses of action with respect to the Maritime link. The percentage loadings for the Island link are based on a nominal capacity of 450 MW per pole. The export on the Maritime link of 158 MW corresponds to the economic dispatch of the island generation. The export level of 239 MW corresponds to maximum island dispatch.

Monopole operation of the Island link is simulated by taking into consideration the electrode lines. The resistance of these lines is added to the resistance of the healthy pole which includes the overhead line resistance and the resistance of the submarine cable.

Table 3-1: Healthy Pole Loading Levels following a Pole Outage

Maritime Link(MW)		Island Link(MW)		
Pre-fault	Post-fault	Pre-fault	Post-fault	
158	158	900	1010	224%
158	100	900	900	200%
158	0	900	730	162%
239	239	900	1200	267%
239	100	900	900	200%
239	0	900	730	162%

The maximum loading (200%) is reached with an export to Nova Scotia reduced to 100 MW. The loadings shown above would apply for a 10-minute period, during which time the 3x50 MW gas turbines at Hardwoods and Stephenville could be brought into service. Following this action, the loadings above on the Island link could be reduced by approximately 150 MW. The maximum loading of 900 MW/200 % would then be reduced to 650 MW/145%. These results confirm the Design Basis requirement for a 10-minute overload rating of 200% of nominal rating and a continuous overload rating of 150% of nominal rating, provided that in the event of a pole outage the export on the Maritime link must be reduced to no more than 100 MW and the Island generation must be run up to its maximum. If the Island generation cannot be taken to its maximum, then the export on the Maritime link would need to be reduced to zero.

3.4 BASE CASE SCENARIO BC-4

No.	NLH System Load(MW)	NS Export BBK(MW)	Island Import MFA/SPD(MW)	Island Generation	Comments
BC-4	1900	0	900/814	Maximum	Winter Peak-2041

This scenario considers a long-term future year (2041) in which the Island link is operating at 900 MW, the island generation is at its maximum level and the export to NS over the Maritime link is set at 0 MW. In this condition, the system is operating with no reserve and any generator outage or pole outage on the Island link will result in load shedding. No further studies have been carried out on this scenario at this time. The system performance is shown in Appendix A.

3.5 BASE CASE SCENARIO BC-5

No.	NLH System Load(MW)	NS Export BBK(MW)	Island Import MFA/SPD(MW)	Island Generation	Comments
BC-5	1100	158	900/814	Economic	Spring/Fall day-2017

This scenario considers the full export from Labrador and the nominal export to Nova Scotia during the Spring/Fall seasons. In this scenario, lower ratings apply to the transmission lines due to the higher ambient temperature.

The system performance is shown in Appendix A.

Because of the reduced load levels, the reactive compensation required at Soldiers Pond reduced from 240 MVAr to 140 MVAr and the reactive support at Bottom Brook reduced from 75 MVAr to 45 MVAr.

Line Outages:

The outage of the Western Avalon-Soldiers Pond 230 kV line TL217W (load flow circuit #1) results in a 16% overload on 230 kV line TL201W (load flow circuit #2) because of the reduced line rating in the Spring/Fall seasons.

Generator Outage:

The outage of the largest generator (Upper Salmon-75MW) will require a reduction in the export to Nova Scotia. The spinning reserve on the system for this scenario is only 40 MW, spread over the Bay d'Espoir running units (21 MW), the unit at Granite Canal (12 MW) and the Hinds Lake (6 MW) and Paradise River (1 MW) units. Thus a reduction in the export to NS of 40 MW should be sufficient to correct this imbalance or an additional unit at Bay d'Espoir could be connected to provide sufficient spinning reserve.

3.6 BASE CASE SCENARIO BC-6

No.	NLH System Load(MW)	NS Export BBK(MW)	Island Import MFA/SPD(MW)	Island Generation	Comments
BC-6	1100	158	276/268	Maximum	Spring/Fall day-2017

This scenario considers a reduced export from Labrador and the nominal export to Nova Scotia during the Spring/Fall seasons. In this scenario, as a result of the lower import from Labrador, the island generation is set to its maximum. The system performance is shown in Appendix A.

No under-voltage or overload was seen for any line outage.

Generator Outage:

The loss of the largest unit at Bay d'Espoir (Bay d'Espoir #7-154 MW) would require the reduction of the export to NS to zero since the island generation is set at maximum output. Alternatively, if the power is available, an increase in the import

from Labrador would correct this imbalance or, as seen before, a combination of these two measures could be used.

3.7 BASE CASE SCENARIO BC-7

No.	NLH System Load(MW)	NS Export BBK(MW)	Island Import MFA/SPD(MW)	Island Generation	Comments
BC-7	1100	500	900/814	Economic	Spring/Fall day-2017

This scenario is similar to BC-5 except that the export to Nova Scotia is increased up to 500 MW by running three additional smaller units and the large unit at Bay d'Espoir.

The system performance is shown in Appendix A.

The additional export to Nova Scotia requires a significant increase in the reactive support at Bottom Brook with 320 MVAr being required to maintain a bus voltage of 100% in the base case.

Line Outages:

With an outage of the 230 kV line from Granite Canal to Bottom Brook (future line, not yet designated), the reactive support required at Bottom Brook to support the export of 500 MW to NS increases from 320 MVAr to 585 MVAr and by setting the voltage at Bottom Brook to 101%. This outage would also create under-voltages at Buchans, Stony Brook and Abitibi Consolidated Grand Falls. Alternatively, a reduction in the export to NS from 500 MW to 400 MW would require 300 MVAr of reactive support (close to the base case requirement).

A significant number of line overloads were observed under the following line outage conditions:

- Outage: Bottom Brook-Massey Drive (TL211)
    - Overload: Bottom Brook-Buchans (TL233)-115%
- Outage: Bottom Brook- Buchans(TL233)
    - Overload: Bottom Brook- Massey Drive (TL211)-134%

  - Overload: Massey Drive-Buchans (TL228)-146%

- Outage: Granite Canal-Bottom Brook (future line, not yet designated)
  - Overload: Bottom Brook-Massey Drive (TL211)-137%
  - Overload: Bottom Brook-Buchans (TL233)-127%
  - Overload: Massey Drive-Buchans (TL228)-151%
  - Overload: Buchans-Stony Brook (TL205)-132%
  - Overload: Stony Brook-Bay d'Espoir (TL204 and TL231)-101%
- Outage: Massey Drive- Buchans (TL228)
  - Overload: Bottom Brook-Buchans (TL233)-109%
- Outage: Buchans-Stony Brook (TL232)
  - Overload: Buchans-Stony Brook (TL205)-128%
- Outage: Bay d'Espoir-Upper Salmon (TL234)
  - Overload: Bottom Brook-Massey Drive (TL211)-102%
  - Overload: Massey Drive-Buchans (TL228)-108%
- Outage: Western Avalon-Soldiers Pond (TL217W)
  - Overload: Western Avalon-Soldiers Pond (TL201W)-115%
- Outage: Granite Canal-Upper Salmon (TL263)
  - Overload: Bottom Brook-Massey Drive (TL211)-124%
  - Overload: Bottom Brook-Buchans (TL233)-114%
  - Overload: Massey Drive-Buchans (TL228)-134%
  - Overload: Buchans-Stony Brook (TL205)-118%

A reduction in the export to NS to 350 MW with an accompanying reduction in the Island link to 750 MW would remove all of the above overloads. It should be noted that other alternatives can be employed as mentioned earlier.

Generator Outage:

Largest unit at Bay d'Espoir (Bay d'Espoir #7-135 MW)-The remaining generation was re-dispatched to maximum levels.

3.8 BASE CASE SCENARIO BC-8

No.	NLH System Load(MW)	NS Export BBK(MW)	Island Import MFA/SPD(MW)	Island Generation	Comments
BC-8	700	158	420/400	Minimum	Summer day-2017

This scenario considers light load conditions corresponding to a summer day with a reduced import from Labrador and the nominal export of 158 MW to Nova Scotia. Due to the higher ambient temperature, lower ratings apply to the transmission lines. The system performance is shown in Appendix A.

No under-voltage or overload was seen for any line outage.

Generator Outage:

The loss of the largest generator (Bay d'Espoir #7-135 MW) would require either two additional units at Bay d'Espoir to be running as spinning reserve or the export to NS would have to be reduced from 158 MW to 90 MW.

3.9 BASE CASE SCENARIO BC-9

No.	NLH System Load(MW)	NS Export BBK(MW)	Island Import MFA/SPD(MW)	Island Generation	Comments
BC-9	700	158	81/80	Economic	Summer day-2017

This scenario is similar to BC-8 but with a reduced import from Labrador compensated by increased generation on the Island.

The system performance is shown in Appendix A.

Line Outages:

For the outage of one 230 kV circuit between Bay d'Espoir and Sunnyside (TL202 or TL206) the loading on the remaining circuit reaches 104%. These overloads can be alleviated by increasing the import from the LIL to 100 MW.

Generator Outage:

Largest unit at Bay d'Espoir (Bay d'Espoir #7-135 MW)-The remaining generation was re-dispatched to maximum levels.

3.10 BASE CASE SCENARIO BC-10

No.	NLH System Load(MW)	NS Export BBK(MW)	Island Import MFA/SPD(MW)	Island Generation	Comments
BC-10	700	500	900/814	Economic	Summer day-2017

This scenario considers the full import from Labrador and an increased export of 500 MW to Nova Scotia under light load conditions in the summer season.

The system performance is shown in Appendix A.

Again, because of the high export level to NS, reactive support of 300 MVAr was required at Bottom Brook.

Even in the base case, the following line overloads were noted:

- Massey Drive-Buchans (TL228)-122%
- Buchans-Stony Brook (TL205)-102%
- Western Avalon-Soldiers Pond (TL201W)-141%

Line Outages:

Line outages between Bottom Brook and Granite Canal (future line, not yet designated) and Granite Canal and Upper Salmon (TL263) lead to system non-convergence. To counter this problem, the export to Nova Scotia is reduced to 400 MW (the import from Labrador is reduced to 800 MW on the rectifier side).

A number of 230 kV line outages resulted in overloading of other 230 kV lines before decreasing the export to Nova Scotia (from 500 MW to 400 MW). Lines that are overloaded under N-0 are omitted from this part:

- Outage: Deer Lake-Cat Arm (TL247)
  - Overload: Bottom Brook-Buchans (TL233)-103%
  - Overload: Granite Canal-Upper Salmon (TL263)-106%
- Outage: Deer Lake-Massey Drive (TL248)
  - Overload: Bottom Brook-Buchans (TL233)-103%
  - Overload: Granite Canal-Upper Salmon (TL263)-103%
- Outage: Bottom Brook-Massey Drive (TL211)
  - Overload: Bottom Brook-Buchans (TL233)-162%
  - Overload: Granite Canal-Upper Salmon (TL263)-123%
- Outage: Bottom Brook-Buchans (TL233)
  - Overload: Bottom Brook-Massey Drive (TL211)-185%
  - Overload: Granite Canal-Upper Salmon (TL263)-131%
- Outage: Massey Drive-Buchans (TL228)
  - Overload: Bottom Brook- Buchans (TL233)-166%
  - Overload: Granite Canal-Upper Salmon (TL263)-123%
- Outage: Buchans-Stony Brook (TL205)
  - Overload: Buchans-Stony Brook (TL232)-137%
  - Overload: Granite Canal-Upper Salmon (TL263)-114%
- Outage: Buchans-Stony Brook (TL232)

  - Overload: Granite Canal-Upper Salmon (TL263)-117%

- Outage: Stony Brook-Bay d'Espoir (TL204)
  - Overload: Stony Brook-Bay d'Espoir (TL231)-139%
  - Overload: Granite Canal-Upper Salmon (TL263)-120%
- Outage: Stony Brook-Bay d'Espoir (TL231)
  - Overload: Stony Brook-Bay d'Espoir (TL204)-139%
  - Overload: Granite Canal-Upper Salmon (TL263)-120%
- Outage: Stony Brook-Abitibi Consolidated Grand Falls (TL235)
  - Overload: Granite Canal-Upper Salmon (TL263)-103%
- Outage: Bay d'Espoir-Upper Salmon (TL234)
  - Overload: Bottom Brook-Massey Drive (TL211)-140%
  - Overload: Bottom Brook-Buchans (TL233)-140%
  - Overload: Buchans-Stony Brook (TL232)-110%
  - Overload: Stony Brook-Bay d'Espoir (TL204 and TL231)-111%
- Outage: Western Avalon-Come by Chance (TL237)
  - Overload: Western Avalon-Sunnyside (TL203)-120%
- Outage: Western Avalon-Soldiers Pond (TL217W)
  - Overload: Granite Canal-Upper Salmon (TL263)-101%
- Outage: Western Avalon-Soldiers Pond (TL201W)
  - Overload: Western Avalon-Soldiers Pond (TL217W)-138%
  - Overload: Granite Canal-Upper Salmon (TL263)-101%

Reducing the export to NS from 500 MW to 100 MW removed all of the above overloads including the ones found under N-0. It should be noted that other alternatives can be employed as mentioned earlier.

Generator Outage:

Largest unit at Upper Salmon (75MW) -The remaining generation was re-dispatched to maximum levels.

3.11 BASE CASE SCENARIO BC-11

No.	NLH System Load(MW)	NS Export BBK(MW)	Island Import MFA/SPD(MW)	Island Generation	Comments
BC-11	420	0	81/80	Economic	Summer night-2017

This scenario considers the system under extreme light load conditions, corresponding to a summer night. With no export to Nova Scotia and an economic generation dispatch, the import from Labrador is reduced to its minimum level (<10% of the rated value). The system performance is shown in Appendix A.

No under-voltage or overload was seen for any line outage.

Generator Outage:

Outage of the largest generator (Upper Salmon-75 MW) would require either two additional units at Bay d'Espoir as spinning reserve or an increase in the Island link import from 81 MW to 108 MW.

3.12 BASE CASE SCENARIO BC-12

No.	NLH System Load(MW)	NS Export BBK(MW)	Island Import MFA/SPD(MW)	Island Generation	Comments
BC-12	420	320	81/80	Economic	Summer night-2017

This scenario is similar to BC-11 but with an export to Nova Scotia of 320 MW provided by additional on-island generation.

The system performance is shown in Appendix A.

Line Outages:

The following 230 kV line outages resulted in overloading of other 230 kV lines:

- Outage: Bottom Brook-Buchans (TL233)
  - Overload: Bottom Brook-Massey Drive (TL211)-114%
- Outage: Bottom Brook-Granite Canal (future line, not yet designated)
  - Overload: Bottom Brook-Massey Drive (TL211)-104%

A reduction in the export to NS with an accompanying reduction in the import over the Island link would relieve these overloads. However, the Island link is already operating at its minimum level (< 10% rated capacity). A reduction of 50 MW in the export to NS would remove the above line overloads and either the Island link can be switched off or the on-island generation can be reduced to compensate for this. It should be noted that other alternatives can be employed as mentioned earlier.

Generator Outage:

Largest unit at Upper Salmon (75MW) -The remaining generation was re-dispatched to maximum levels.

3.13 BASE CASE SCENARIO BC-13

No.	NLH System Load(MW)	NS Export BBK(MW)	Island Import MFA/SPD(MW)	Island Generation	Comments
BC-13	420	320	457/435	Minimum	Summer night-2017

This scenario is similar to BC-12 except that the export to Nova Scotia is provided by the import from Labrador rather than on-island generation.

The system performance is shown in Appendix A.

Line Outages:

The following 230 kV line outages result in overloading of other 230 kV lines:

- Outage: Bottom Brook-Buchans (TL233)
  - Overload: Bottom Brook-Massey Drive (TL211)-110%

- Overload: Massey Drive-Buchans (TL228)-124%

- Outage: Bottom Brook-Granite Canal (future line, not yet designated)
  - Overload: Massey Drive-Buchans (TL228)-106%

- Outage: Buchans-Stony Brook (TL232)
  - Overload: Buchans-Stony Brook (TL205)-106%

- Outage: Western Avalon-Soldiers Pond (TL217W)
  - Overload: Western Avalon-Soldiers Pond (TL201W)-140%

A reduction in the export to NS to 240 MW, with an accompanying reduction in the Island link to 372 MW, removes these overloads. It should be noted that other alternatives can be employed as mentioned earlier.

Generator Outage:

The outage of the largest generator (Bay d'Espoir #7-135 MW) would require the addition of two units at Bay d'Espoir as spinning reserve or a reduction in the export to NS to 240 MW.

3.14 BASE CASE SCENARIO BC-14

No.	NLH System Load(MW)	NS Export BBK(MW)	Island Import MFA/SPD(MW)	Island Generation	Comments
BC-14	1552	-260	286/260Monopole	Maximum	Winter Peak-2017

This scenario considers a permanent pole outage on the Island link under peak load conditions with the remaining pole operating at 62% of rated capacity and the balance of load being supplied by an import of 260 MW from Nova Scotia.

The system performance is shown in Appendix A.

Line Outages:

Although any line or generator outage under these conditions could be considered as a double contingency, these outages were nonetheless examined. The outage of one 230 kV circuit between Bay d'Espoir and Sunnyside (TL202 or TL206), or Bay d'Espoir and Western Avalon (future line, not yet designated) or Western Avalon and

Soldiers Pond (TL217W or TL201W) required reactive support at Soldiers Pond. The maximum support level was 204 MVAr for the outage of the Bay d'Espoir-Western Avalon line (future line, not yet designated).

Generator Outage:

The outage of the largest generator (Bay d'Espoir #7-154MW) would require an increase in the import from Labrador or Nova Scotia of 135 MW.

3.15 BASE CASE SCENARIO BC-15

No.	NLH System Load(MW)	NS Export BBK(MW)	Island Import MFA/SPD(MW)	Island Generation	Comments
BC-15	1100	158	378/333Monopole	Economic	Spring/Fall day-2017

This scenario considers a permanent pole outage under intermediate load conditions with the healthy pole operating at 80% of rated capacity and with Nova Scotia being supplied a nominal export of 158 MW.

The system performance is shown in Appendix A.

Although any line or generator outage under these conditions could be considered as a double contingency, these outages were nonetheless examined. No under-voltage or overload was seen for any line outage. For the outage of the largest generator (Bay d'Espoir #7-150 MW), the export to Nova Scotia would need to be reduced from 158 MW to 76 MW or the import from Labrador is increased from 378 MW to 555 MW. It should be noted that other alternatives can be employed as mentioned earlier.

3.16 BASE CASE SCENARIO BC-16

No.	NLH System Load(MW)	NS Export BBK(MW)	Island Import MFA/SPD(MW)	Island Generation	Comments
BC-16	700	500	638/518Monopole	Minimum	Summer day-2017

This scenario considers a permanent pole outage under light load conditions with the healthy pole operating at 132% of rated capacity and an increased export of 500 MW to Nova Scotia, supplied from the Island link with minimum on-island generation.

The system performance is shown in Appendix A.

Because of the high export to Nova Scotia, the reactive support required at Bottom Brook is 240 MVAr. The 230 kV line between Massey Drive and Bottom Brook (TL211) is overloaded at 110% of its summer rating.

Line Outages:

The following 230 kV line outages resulted in overloads in other 230 kV lines. Lines that are overloaded under N-0 are omitted from this part:

- Outage: Deer Lake-Cat Arm (TL247)
  - Overload: Massey Drive-Buchans (TL228)-115%
- Outage: Deer Lake-Massey Drive (TL248)
  - Overload: Massey Drive-Buchans (TL228)-117%
- Outage: Bottom Brook-Massey Drive (TL211)
  - Overload: Bottom Brook-Buchans (TL233)-164%
  - Overload: Granite Canal-Upper Salmon (TL263)-113%
- Outage: Bottom Brook-Buchans (TL233)
  - Overload: Massey Drive-Buchans (TL228)-178%
  - Overload: Granite Canal-Upper Salmon (TL263)-110%
- Outage: Bottom Brook-Granite Canal (future line, not yet designated)
  - Overload: Massey Drive-Buchans (TL228)-160%
  - Overload: Buchans-Stony Brook (TL205)-146%
  - Overload: Buchans-Stony Brook (TL232)-109%
  - Overload: Stony Brook-Bay d'Espoir (TL204 and TL231)-109%
  - Overload: Bottom Brook-Buchans (TL233)-148%
- Outage: Massey Drive-Buchans (TL228)
  - Overload: Bottom Brook-Buchans (TL233)-137%
- Outage: Buchans-Stony Brook (TL205)
  - Overload: Buchans-Stony Brook (TL232)-111%

- Outage: Buchans-Stony Brook (TL232)
  - Overload: Buchans-Stony Brook (TL205)-156%
- Outage: Stony Brook-Bay d'Espoir (TL204)
  - Overload: Stony Brook-Bay d'Espoir (TL231)-110%
- Outage: Stony Brook-Bay d'Espoir (TL231)
  - Overload: Stony Brook-Bay d'Espoir (TL204)-110%
- Outage: Bay d'Espoir-Upper Salmon (TL234)
  - Overload: Bottom Brook-Buchans (TL233)-115%
  - Overload: Massey Drive-Buchans (TL228)-122%
  - Overload: Buchans-Stony Brook (TL205)-111%
- Outage: Western Avalon-Soldiers Pond (TL217W)
  - Overload: Western Avalon-Soldiers Pond (TL201W)-120%
- Outage: Granite Canal-Upper Salmon (TL263)
  - Overload: Bottom Brook-Buchans (TL233)-138%
  - Overload: Massey Drive-Buchans (TL228)-148%
  - Overload: Buchans-Stony Brook (TL205)-135%

All the above overloads could be removed by reducing the export to NS to 250 MW with an accompanying reduction in the Island link import to 344 MW. It should be noted that other alternatives can be employed as mentioned earlier.

Generator Outage:

Largest unit at Bay d'Espoir (Bay d'Espoir #7-124 MW)-The remaining generation was re-dispatched to maximum levels.

3.17 BASE CASE SCENARIO BC-17

No.	NLH System Load(MW)	NS Export BBK(MW)	Island Import MFA/SPD(MW)	Island Generation	Comments
BC-17	420	0	215/200Monopole	Minimum	Summer night-2017

This scenario considers a permanent pole outage under extreme light load conditions with the healthy pole operating at 47% of rated capacity and no export to Nova Scotia and minimum on-island generation. The balance of load is supplied from the Island link.

The system performance is shown in Appendix A.

An over-voltage (> 105%) was observed at Bottom Brook with no export to Nova Scotia. This was corrected with a 100 MVAr shunt reactor.

No under-voltage or overload was seen for any line outage.

Generator Outage:

For the outage of the largest generator (Bay d'Espoir #1-61 MW), an additional unit at Bay d'Espoir would be required as spinning reserve or the import on the Island link could be increased by 20 MW, with all connected generators increasing to maximum dispatch.

3.18 BASE CASE SCENARIO BC-18

No.	NLH System Load(MW)	NS Export BBK(MW)	Island Import MFA/SPD(MW)	Island Generation	Comments
BC-18	1552	158	900/814	Economic	Winter Peak-2017 4-units @ Muskrat Falls

This scenario is the same as BC-1 except that all four units at Muskrat Falls were considered to be operating.

The system performance is shown in Appendix A.

The performance of the system was identical to that seen in BC-1.

3.19 BASE CASE SCENARIO BC-19

No.	NLH System Load(MW)	NS Export BBK(MW)	Island Import MFA/SPD(MW)	Island Generation	Comments
BC-19	1100	500	900/814	Economic	Winter Peak-2017 4-units @ Muskrat Falls

This scenario is the same as BC-7 except that all four units at Muskrat Falls were considered to be operating.

The system performance is shown in Appendix A.

The performance was virtually identical to that seen in BC-7.

4 SHORT CIRCUIT LEVELS

In terms of short-circuit levels, two major considerations are of interest:

- Maximum fault levels in terms of the fault-interrupting capabilities of the existing and future switchgear,

- Minimum fault levels combined with maximum converter loadings to determine the effective short-circuit ratio (ESCR) at the converter terminals. This parameter provides a useful indication of satisfactory converter operation and the risk of commutation failures.

Maximum short-circuit levels were determined using Scenario BC-4 (winter peak-2041) since this scenario considers all available generation on the island to be connected. The fault levels obtained were also checked using Scenario BC-2 (winter peak-2017) with a maximum generation dispatch and the fourth unit at Muskrat Falls connected.

For minimum fault levels combined with maximum converter loadings, the following scenarios were considered:

Muskrat Falls Converter

- BC-1: 3 units at Muskrat Falls with a converter load of 900 MW,

- BC-13: 2 units at Muskrat Falls with a converter load of 457 MW

Although BC-13 actually considers three units to be operating at Muskrat Falls, this scenario was used with only two units at Muskrat Falls to examine the impact on the fault level at the Muskrat Falls converter station.

Soldiers Pond Converter

- BC-5: 814 MW converter load with an economic dispatch for an intermediate load level of 1100 MW,

- BC-13: 435 MW converter load with an extreme minimum load level of 400 MW.

Bottom Brook Converter

- BC-10: 500 MW converter load with a light load level of 700 MW,

- BC-13: 320 MW converter load with an extreme minimum load of 420 MW.

4.1 MAXIMUM FAULT LEVELS

Under maximum generation conditions, the following table shows the maximum short-circuit level at each converter bus and the highest value of fault level on the island 230 kV and 138 kV system.

Table 4-1: Maximum Fault Levels

Station	kV	Three-phase		Single-phase	
		kA	MVA	kA	MVA
Muskrat Falls	315	6.2	3,400	8.0	4,350
Soldiers Pond	230	6.1	2,425	7.5	3,000
Bottom Brook	230	3.8	1,525	3.9	1,550
Bay d'Espoir	230	9.6	3,850	11.5	4,600
Stony Brook	138	5.9	2,200	7.3	2,725

It can be seen that none of the above fault levels are excessive and are all well within typical switchgear fault-interrupting capabilities.

The following table shows the same case with all machines at Holyrood connected and with 2x150 MVA synchronous condensers at Soldiers Pond.

Table 4-2: Maximum Fault Levels with 2x 150 MVAr SC at SPD

Station	kV	Three-phase		Single-phase	
		kA	MVA	kA	MVA
Muskrat Falls	315	6.2	3,400	8.0	4,350
Soldiers Pond	230	7.4	2,960	8.8	3,510
Bottom Brook	230	3.8	1,525	3.9	1,550
Bay d'Espoir	230	9.8	3,920	11.7	4,670
Stony Brook	138	5.9	1,410	7.3	1,740

The fault level will vary depending on the number and the size of synchronous condensers at Soldiers Pond. The following table shows the fault level of different configuration of synchronous condensers at Soldiers Pond.

Table 4-3: Maximum Fault Levels with Different SCs at SPD

Station	kV	Three-phase		Single-phase	
		kA	MVA	kA	MVA
No SC	230	6.1	2,425	7.5	3,000
2x150 MVAr	230	7.4	2,960	8.8	3,510
3x150 MVAr	230	8.1	3,228	10.8	4,275
2x300 MVAr	230	8.7	3,495	11.4	4,530

4.2 MINIMUM FAULT LEVELS

The following tables show the minimum 3-phase fault level and effective short-circuit ratio (ESCR) for the specific scenarios considered under normal conditions with all equipment in service. The ESCR was calculated using a typical ratio between the shunt compensation obtained from filters and the dc power level of 25% (converter reactive requirement is typically 50% of the dc power level and the filters typically provide 50% of this reactive power requirement).

$$ESCR = \frac{MVA_{SC} - Q_F}{P_{dc}} = \frac{MVA_{SC}}{P_{dc}} - 0.25$$

Table 4-4: Muskrat Falls Converter Station

Scenario	Converter MW	Min.Fault Level MVA	ESCR
BC-1	900	3,390	3.52
BC-13	457	2,755	5.85

Table 4-5: Soldiers Pond Converter Station

Scenario	Converter MW	Min.Fault Level MVA	ESCR
BC-5/10	814	2,310	2.52
BC-13	435	2,240	4.90

Table 4-6: Bottom Brook Converter Station

Scenario	Converter MW	Min.Fault Level MVA	ESCR
BC-10	500	1,345	2.44
BC-13	320	1,250	3.66

The minimum ESCR occurs for scenario BC-1 for Muskrat Falls, scenario BC-5 and BC-10 for Soldiers Pond and scenario BC-10 for Bottom Brook. All the minimum ESCRs occur at the rated power level for each converter station.

All the ESCRs are equal to or greater than the normally recommended minimum of 2.5 except for Bottom Brook where the value is less than 2.5. These values are for normal system conditions and will be lower under line outage conditions.

The worst line outage was analyzed for each of the scenarios above that resulted in minimum values of ESCR. The results are shown below.

Table 4-7: Minimum ESCR under Line Outage Conditions

Station	Scenario	Converter MW	Disconnected Line	Min.Fault Level MVA	ESCR
Muskrat Falls	BC-1	900	CHF-MFA	2,730	2.78
Soldiers Pond	BC-5	814	SPD-WAV (TL217W)	2,190	2.38
Bottom Brook	BC-10	500	BBK-MDR (TL211)	905	1.56

While the ESCR at Muskrat Falls remained above the minimum value of 2.5, the value at Soldiers Pond was marginally below 2.5 and the value at Bottom Brook was less than 2.0.

5 CONCLUSIONS

5.1 AC SYSTEM MITIGATING MEASURES

Although reinforcements to the ac system within Newfoundland are not within the scope of this present study, it is necessary to determine the impacts of outages so that the alternative mitigating measures can be examined with respect to defining the required operating modes of the two HVdc links.

Line outage, pole outage and generator outage cases were examined for the four distinct load levels corresponding to Winter peak, Spring/Fall daytime, Summer daytime and Summer night-time. Only the 230 kV was monitored and any violations were reported. Throughout all the cases examined, in order to avoid line overloads, load shedding within Newfoundland, or excessive levels of reactive support, a common element appears to be that in the event of a line, pole or generator outage the power transfer to Nova Scotia could be reduced to ensure satisfactory system performance. Other alternatives were proposed as well to eliminate overloads such as running CTs continuously or starting them following an outage, increasing the thermal capability of the overloaded circuits, adding new circuits, re-dispatching the Island generation and re-locating the converter of the ML Link.

In a number of cases, the reduction in the export to Nova Scotia would need to be accompanied by a reduction in the power sent over the Island link. Such measures are required to relieve overloads within the Soldiers Pond-Western Avalon-Bay d'Espoir corridor. In other cases, a reduction in only the export to Nova Scotia is necessary to relieve overloads within the Bay d'Espoir-Stony Brook-Buchans-Massey Drive/Bottom Brook and Bay d'Espoir-Upper Salmon-Granite Canal-Bottom Brook corridors.

The alternative to such mitigating measures would be to reinforce each of the above corridors with an additional transmission circuit. The Granite Canal-Bottom Brook transmission line is already a reinforcement of the existing system.

It was also found necessary to provide significant levels of reactive support at both the Soldiers Pond converter station (240 MVAr) and the Bottom Brook converter station (+320/-100 MVAr).

The variations in the reactive support required at Bottom Brook, together with a need to change the ordered dc power whenever there is an outage on the ac system would suggest that the compensation should be provided in the form of a static var compensators, synchronous condensers, or the converter may be of the VSC type with an inherent reactive control capability and lower requirements in terms of short-circuit ratio. The variations in reactive support are not as frequent at Soldiers Pond as they are at Bottom Brook. The need for specialized reactive support equipment (SVC or synchronous condenser) will be determined in the stability studies of the interconnected network.

Given the above requirements for the Bottom Brook converter station, the prospect must be raised as to the suitability of Bottom Brook as a location for the converter station of the Maritime link. The short-circuit level is low (ESCR <2.5), significant levels of reactive support are required and in the event of an outage on the Island system, the export to Nova Scotia has to be reduced to avoid overloading the transmission lines in the western part of the island. This would suggest that the Bay d'Espoir generating station would prove to be a more suitable location for this converter. The short-circuit level is higher, the lines in the western part of the system do not need to carry the export power and there is a significant reactive capability at the generating station. This would reduce the number of outage situations requiring a reduction in the export to Nova Scotia. It would also avoid the need to build the transmission link between Granite Canal and Bottom Brook but would, however, require additional dc transmission from the submarine cable transition station in Newfoundland to Bay d'Espoir.

5.2 OPERATING MODES

The steady-state operating modes of both the Island link and the Maritime link were examined over the following dc power ranges:

- Island link: 900 MW to 81 MW
- Maritime link: 500 MW export to 260 MW import

Pole outage cases confirmed the Design Basis requirements for a 200% overload capability for 10 minutes and a continuous overload capability of 150% in mono-polar mode.

In addition to operation over the ranges stated above, certain operating levels, as defined in the base case scenarios, are not sustainable under certain line and/or generator outage conditions and reductions in the power transfer levels will need to be made in the event of line outages.

For the individual base case scenarios, the following adjustments to the power transfer levels were identified:

BC-1/BC-2 (Winter Peak)

For the loss of the largest generator at Bay d'Espoir:

- Reduce export on the Maritime link from 158 MW (BC-1) or 239 MW (BC-2) to 96 MW

BC-3 (Winter Peak)

For the loss of the largest generator at Bay d'Espoir:

- Reduce export on the Maritime link from 158 MW to 10 MW.

BC-5 (Spring/Fall Peak)

For the loss of circuit #1 between Soldiers Pond and Western Avalon (TL217W);

- Reduce the export on the Maritime link from 158 MW to 98 MW.
- Reduce the import from the Island link from 814 MW to 774 MW.

For the loss of the largest generator at Upper Salmon:

- Reduce export on the Maritime link from 158 MW to 124 MW.

BC-6 (Spring/Fall Peak)

For the loss of the largest generator at Bay d'Espoir:

- Reduce export on the Maritime link from 158 MW to zero.

BC-7 (Spring/Fall Peak)

For the loss of almost any 230 kV line on the Soldiers Pond-Bottom Brook corridor:

- Reduce export on the Maritime link from 500 MW to 350 MW,
- Reduce import from the Island link from 814 MW to 664 MW.

BC-8 (Summer Light)

For the loss of the largest generator at Bay d'Espoir:

- Reduce export on the Maritime link from 158 MW to 90 MW.

BC-9 (Summer Light)

No operating reductions required.

BC-10 (Summer Light)

For the loss of almost any 230 kV line on the Soldiers Pond-Bottom Brook corridor:

- Reduce export on the Maritime link from 500 MW to 100 MW,
- Reduce import from the Island link from 814 MW to 414 MW.

BC-11 (Summer Extreme Light)

For the loss of the largest generator at Upper Salmon:

- Increase import on the Island link from 81 MW to 108 MW

.**BC-12 (Summer Extreme Light)**

For the loss of the 230 kV line from Bottom Brook and Buchans (TL233):

- Reduce export on the Maritime link from 320 MW to 240 MW

BC-13 (Summer Extreme Light)

For the loss of almost any 230 kV line on the Soldiers Pond-Bottom Brook corridor:

- Reduce export on the Maritime link from 320 MW to 240 MW,
- Reduce import on the Island link from 435 MW to 355 MW

For the loss of the largest generator at Bay d'Espoir

- Reduce export on the Maritime link from 320 MW to 240 MW,

BC-14 (Winter Peak)

For the loss of the largest generator at Bay d'Espoir

- Increase import on the Maritime or Island link by 135 MW,

BC-15 (Spring/Fall Peak)

For the loss of the largest generator at Bay d'Espoir

- Reduce export on the Maritime link from 158 MW to 76 MW,

BC-16 (Summer Light)

For the loss of almost any 230 kV line on the Soldiers Pond-Bottom Brook corridor:

- Reduce export on the Maritime link from 500 MW to 250 MW,
- Reduce import on the Island link from 518 MW to 344 MW

BC-17 (Summer Extreme Light)

For the loss of the largest generator at Bay d'Espoir

- Increase import on the Island link from 200 MW to 220 MW,

BC-18 (Winter Peak)

For the loss of the largest generator at Bay d'Espoir

- Reduce export on the Maritime link from 158 MW to 96 MW,

BC-19 (Spring/Fall Peak)

For the loss of almost any 230 kV line on the Soldiers Pond-Bottom Brook corridor:

- Reduce export on the Maritime link from 500 MW to 350 MW,
- Reduce import on the Island link from 814 MW to 664 MW

In summary, during most of the year, the loss of the largest generator on the system (usually Bay d'Espoir #7) will require a reduction in the export on the Maritime link.

During the winter peak load period, line outages do not present a problem in terms of overloads and no adjustment of dc power levels is required.

During the Spring/Fall and Summer periods, because of the reduced ratings of the transmission lines, many transmission line overloads were observed under line outage conditions. These overloads occurred on the Soldiers Pond-Bay d'Espoir corridor and on the Bay d'Espoir-Bottom Brook corridors requiring a reduction in the dc power levels on both links for Soldiers Pond-Bay d'Espoir overloads and on the Maritime link only for Bay d'Espoir-Bottom Brook overloads.

A reduction in the dc power level of the Bottom Brook converter following a loss of generation on the island is relatively straightforward and could be accomplished with a frequency controller that would reduce the dc power level for a drop in frequency. The required reductions following line outages are somewhat more difficult and may need some form of voltage–based controller since many of the outages will be remote from the converter station. The coordination of reductions in the Island link dc power level that will accompany reductions in the Maritime link export for certain line outages is also a difficult control problem for the same reasons. These and other control and reactive power problems will be addressed during the stability studies.

If no reductions are made in the export to Nova Scotia as outlined above, the line overloads that will result on the 230 kV system are summarized in Table 5-1.

Table 5-1: Summary of 230 kV Line Overloads

Load Level	Export to NS	Line Outage			Line Overload			
		From	To	ID	From	To	ID	Loading
Winter Peak	158	Soldiers Pond	Hardwoods	TL242E	Soldiers Pond	Hardwoods	TL201E	107%
Spring/Fall Intermediate	158	Western Avalon	Soldiers Pond	TL217W	Western Avalon	Soldiers Pond	TL201W	116%
Spring/Fall Intermediate	500	Bottom Brook	Massey Drive	TL211	Bottom Brook	Buchans	TL233	115%
		Bottom Brook	Buchans	TL233	Bottom Brook	Massey Drive	TL211	134%
					Massey Drive	Buchans	TL228	146%
		Granite Canal	Bottom Brook	-	Bottom Brook	Massey Drive	TL211	137%
					Bottom Brook	Buchans	TL233	127%
					Massey Drive	Buchans	TL228	151%
					Buchans	Stony Brook	TL205	132%
					Stony Brook	Bay d'Espoir	TL204	101%
					Stony Brook	Bay d'Espoir	TL231	101%
		Massey Drive	Buchans	TL228	Bottom Brook	Buchans	TL233	109%
		Buchans	Stony Brook	TL232	Buchans	Stony Brook	TL205	128%
		Bay d'Espoir	Upper Salmon	TL234	Bottom Brook	Massey Drive	TL211	102%
					Massey Drive	Buchans	TL228	108%
		Western Avalon	Soldiers Pond	TL217W	Western Avalon	Soldiers Pond	TL201W	115%
		Granite Canal	Upper Salmon	TL263	Bottom Brook	Massey Drive	TL211	124%
					Bottom Brook	Buchans	TL233	114%
					Massey Drive	Buchans	TL228	134%
					Buchans	Stony Brook	TL205	118%
Summer Day Light	500	Base Case	-	-	Massey Drive	Buchans	TL228	122%
					Buchans	Stony Brook	TL205	102%
					Western Avalon	Soldiers Pond	TL201W	141%
		Deer Lake	Cat Arm	TL247	Bottom Brook	Buchans	TL233	103%
					Granite Canal	Upper Salmon	TL263	106%
		Deer Lake	Massey Drive	TL248	Bottom Brook	Buchans	TL233	103%
					Granite Canal	Upper Salmon	TL263	103%
		Bottom Brook	Massey Drive	TL211	Bottom Brook	Buchans	TL233	162%
					Granite Canal	Upper Salmon	TL263	123%
		Bottom Brook	Buchans	TL233	Bottom Brook	Massey Drive	TL211	185%
					Granite Canal	Upper Salmon	TL263	131%
		Massey Drive	Buchans	TL228	Bottom Brook	Buchans	TL233	166%
					Granite Canal	Upper Salmon	TL263	123%
		Buchans	Stony Brook	TL205	Buchans	Stony Brook	TL232	137%
					Granite Canal	Upper Salmon	TL263	114%
		Buchans	Stony Brook	TL232	Granite Canal	Upper Salmon	TL263	117%
		Stony Brook	Bay d'Espoir	TL204	Stony Brook	Bay d'Espoir	TL231	139%
					Granite Canal	Upper Salmon	TL263	120%
		Stony Brook	Bay d'Espoir	TL231	Stony Brook	Bay d'Espoir	TL231	139%
					Granite Canal	Upper Salmon	TL263	120%
		Stony Brook	Abitibi Consolidated	TL235	Granite Canal	Upper Salmon	TL263	103%
		Bay d'Espoir	Upper Salmon	TL234	Bottom Brook	Massey Drive	TL211	140%
					Bottom Brook	Buchans	TL233	140%
					Buchans	Stony Brook	TL232	110%
					Stony Brook	Bay d'Espoir	TL204	111%
					Stony Brook	Bay d'Espoir	TL231	111%
		Western Avalon	Come-by-Chance	TL237	Western Avalon	Sunnyside	TL203	120%
		Western Avalon	Soldiers Pond	TL217W	Granite Canal	Upper Salmon	TL263	101%
		Western Avalon	Soldiers Pond	TL201W	Western Avalon	Soldiers Pond	TL217W	138%
					Granite Canal	Upper Salmon	TL263	101%
Summer Night-Extreme Light	320	Bottom Brook	Buchans	TL233	Bottom Brook	Massey Drive	TL211	114%
					Massey Drive	Buchans	TL228	124%
		Bottom Brook	Granite Canal	-	Bottom Brook	Massey Drive	TL211	104%
					Massey Drive	Buchans	TL228	106%
		Buchans	Stony Brook	TL232	Buchans	Stony Brook	TL205	106%
		Western Avalon	Soldiers Pond	TL217W	Western Avalon	Soldiers Pond	TL201W	140%

5.3 ISLAND LINK MAIN PARAMETERS

The major parameters for the Island link are shown in the following table:

Table 5-2: Island Link Major Parameters

Parameter	Muskrat Falls		Soldiers Pond	
	Normal	Overload	Normal	Overload
System AC Bus Voltage (kVrms)	315	315	230	230
DC Voltage(kV)	±350	±350	±317	±269
DC Current (A)	1,286	1,929	1,286	1,929
DC Power (MW)	900	675	814	519
Firing/Margin Angle (degrees)	15	15	18	18
Converter Transformer Rating (MVA/pole)	523	785	481	613
Converter AC Bus Voltage (kV)	288	288	265	225

Note: Overload values assume mono-polar operation with ground return.

The above values are preliminary only and will be finalized during the design stage.

5.4 MARITIME LINK

The major parameters for the Maritime link are shown in the following table:

Table 5-3: Maritime Link Major Parameters

Parameter	Bottom Brook	Nova Scotia
	Normal	Normal
System AC Bus Voltage (kVrms)	230	230
DC Voltage(kV)	±200	±194
DC Current (A)	1,250	1,250
DC Power (MW)	500	484
Firing/Margin Angle (degrees)	15	18
Converter Transformer Rating (MVA/pole)	291	286
Converter AC Bus Voltage (kV)	164	162

Note: The above values are preliminary only and will be finalized during the design stage.

5.5 REACTIVE COMPENSATION REQUIREMENTS

The reactive support required at each converter station was examined for normal and outage conditions for each scenario.

For the Muskrat Falls converter station, no additional reactive support was required other than the 220 MVAr assumed for the harmonic filters associated with the converter station.

For the Soldiers Pond converter station, up to 240 MVAr of reactive support was required when importing the rated capacity of the Island link (900 MW at the rectifier, 814 MW at the inverter). This level of support was based on one of the three synchronous condensers at Holyrood being out of service.

For the Bottom Brook converter, provided reductions in the export to Nova Scotia can be made in the event of a line outage, reactive compensation over the range of +320/-100 MVAr was required. The application of VSC technology may well be appropriate at this location, given its inherent reactive control capability and the fact that the major portion of the link is composed of submarine cable.

5.6 SHORT-CIRCUIT LEVELS

Under maximum generation conditions, the following table shows the maximum short-circuit level at each converter bus and the highest value of fault level on the island 230 kV and 138 kV system.

Table 5-4: Maximum Fault Levels

Station	kV	Three-phase		Single-phase	
		kA	MVA	kA	MVA
Muskrat Falls	315	6.2	3,400	8.0	4,350
Soldiers Pond	230	6.1	2,425	7.5	3,000
Bottom Brook	230	3.8	1,525	3.9	1,550
Bay d'Espoir	230	9.6	3,850	11.5	4,600
Stony Brook	138	5.9	1,400	7.3	1,730

It can be seen that none of the above fault levels are excessive and are all well within typical switchgear fault-interrupting capabilities. The higher single-phase fault levels are due to the presence of a number of transformers (system and generator transformers) at the locations considered.

The following table shows the same case with all machines at Holyrood connected and with 2x150 MVA synchronous condensers at Soldiers Pond.

Table 5-5: Maximum Fault Levels with SC at SPD

Station	kV	Three-phase		Single-phase	
		kA	MVA	kA	MVA
Muskrat Falls	315	6.2	3,400	8.0	4,350
Soldiers Pond	230	7.4	2,960	8.8	3,510
Bottom Brook	230	3.8	1,525	3.9	1,550
Bay d'Espoir	230	9.8	3,920	11.7	4,670
Stony Brook	138	5.9	1,410	7.3	1,740

The inclusion of the disconnected machine at Holyrood and the addition of the two synchronous condensers only affected the short-circuit level at Soldiers Pond. The short-circuit current increased by approximately 1.3 kA.

The following table shows the minimum effective short-circuit ratio (ESCR) and the corresponding converter MW and 3-phase fault level for the specific scenarios considered under normal conditions with all equipment in service.

Table 5-6: Minimum ESCR/Fault Levels-System Normal

Station	Converter MW	Min.Fault Level MVA	ESCR
Muskrat Falls	900	3,390	3.52
Soldiers Pond	814	2,310	2.52
Bottom Brook	500	1,345	2.44

Under line outage conditions on the ac system, the short circuit level is decreased and the following fault level and short-circuit ratios will apply.

Table 5-7: Minimum ESCR/Fault Levels-Outage Conditions

Station	Converter MW	Disconnected Line	Min.Fault Level MVA	ESCR
Muskrat Falls	900	CHF-MFA	2,730	2.78
Soldiers Pond	814	SPD-WAV (TL217W)	2,190	2.38
Bottom Brook	500	BBK-MDR (TL211)	905	1.56

While the ESCR at Muskrat Falls remained above the normally accepted minimum value of 2.5, the value at Soldiers Pond was marginally below 2.5 and the value at Bottom Brook was less than 2.0. These values suggest that while the Muskrat Falls

converter should experience no particular difficulties in recovering from ac system disturbances, the Soldiers Pond converter may need some additional support in terms of reactive power and/or inertia and the Bottom Brook converter will almost certainly need special consideration in terms of location, additional support and/or the application of VSC technology.

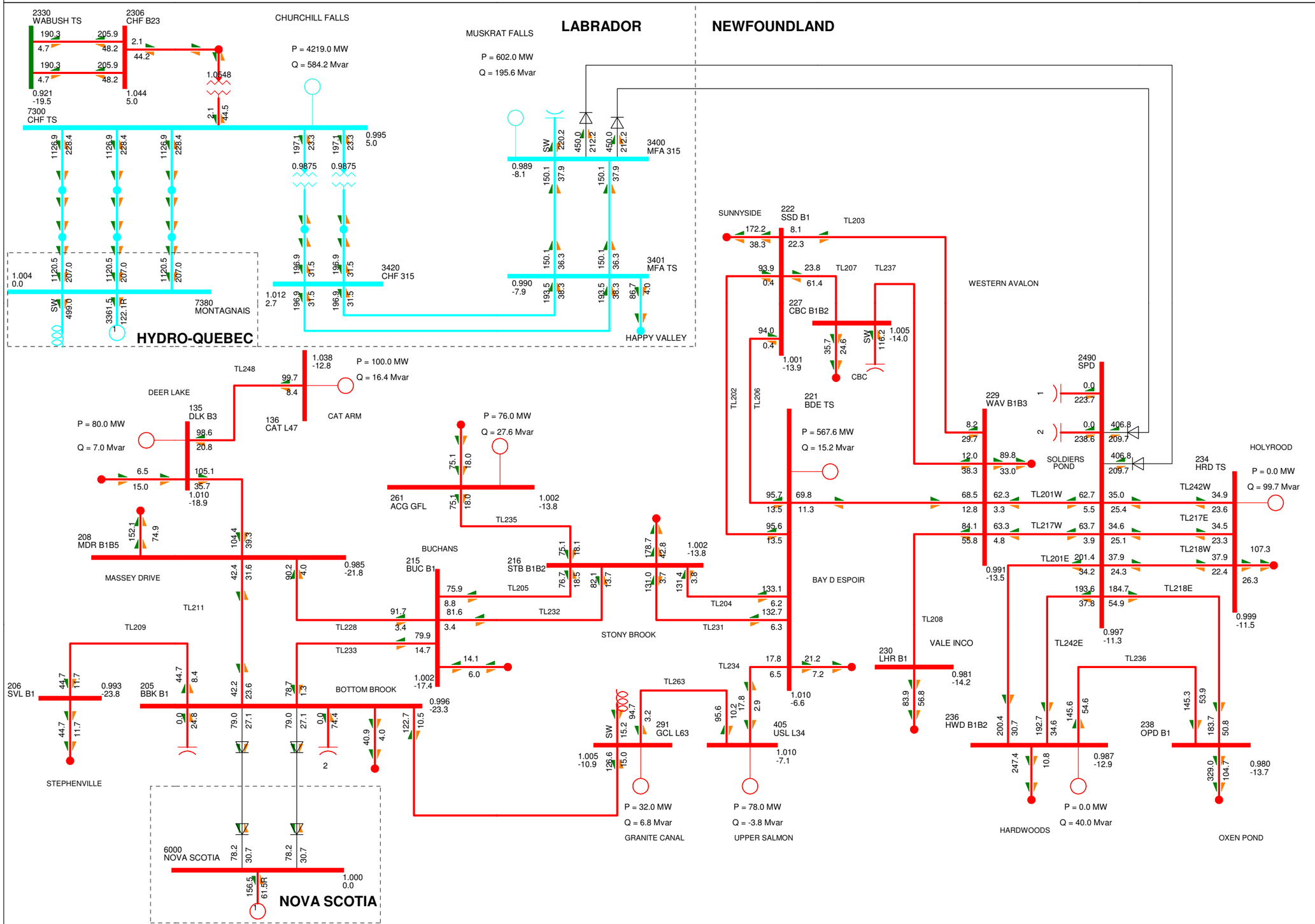
APPENDIX-A
BASE CASE LOAD FLOW PLOTS

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Attachment A- 1

BC-1 Peak 2017/Island Link 814MW/Maritime Link 158MW/Economic Dispatch



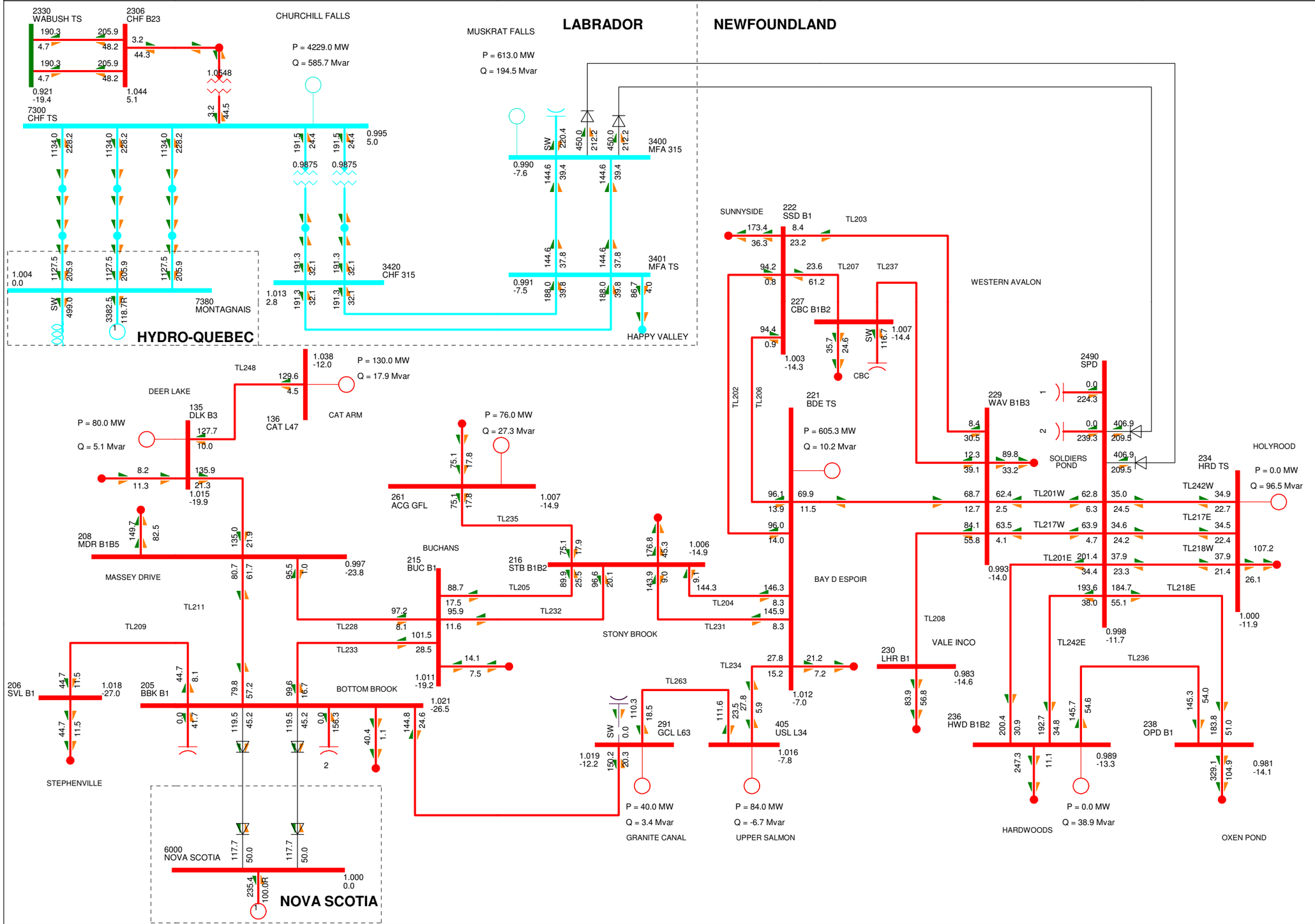
Bus - VOLTAGE (PU)/ANGLE
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%RATEC
1.050OV 0.950UV

kV: <=6.900 <=16.000 <=25.000 <=46.000 <=69.000 <=138.000 <=230.000 >230.000

- Base Case
- Generation: Economic dispatch
- Bipolar operation of Island HVDC
- Bipolar operation of Maritime HVDC

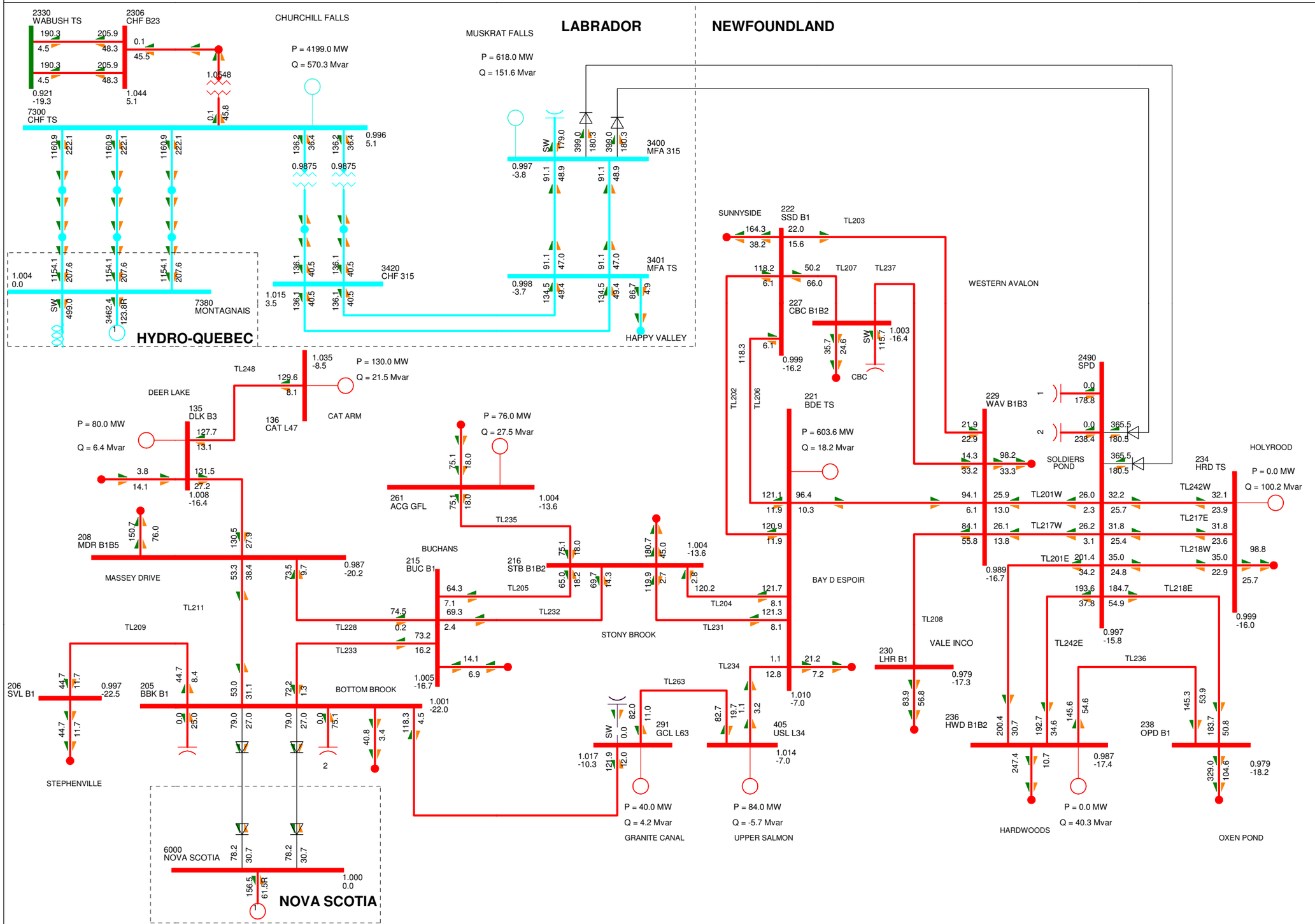
Attachment A- 2

BC-2 Peak 2017/Island Link 814MW/Maritime Link 239 MW/Maximum Dispatch


LABRADOR
NEWFOUNDLAND
HYDRO-QUEBEC
NOVA SCOTIA
2330 WABUSH TS
2306 CHF B23
CHURCHILL FALLS
P = 4229.0 MW
Q = 585.7 Mvar
MUSKRAT FALLS
P = 613.0 MW
Q = 194.5 Mvar
7300 CHF TS
3400 MFA 315
3401 MFA TS
3420 CHF 315
7380 MONTAGNAIS
HAPPY VALLEY
SUNNYSIDE
222 SSD B1
TL203
227 CBC B1B2
CBC
TL207
TL237
WESTERN AVALON
TL202
TL206
221 BDE TS
P = 605.3 MW
Q = 10.2 Mvar
229 WAV B1B3
2490 SPD
SOLDIERS POND
234 HRD TS
HOLYROOD
P = 0.0 MW
Q = 96.5 Mvar
TL242W
TL201W
TL217W
TL217E
TL218W
TL201E
TL218E
TL242E
TL236
BAY D ESPOIR
TL208
VALE INCO
230 LHR B1
236 HWD B1B2
238 OPD B1
HARDWOODS
P = 0.0 MW
Q = 38.9 Mvar
OXEN POND
DEER LAKE
TL248
P = 130.0 MW
Q = 17.9 Mvar
CAT ARM
136 CAT L47
135 DLK B3
P = 80.0 MW
Q = 5.1 Mvar
261 ACG GFL
P = 76.0 MW
Q = 27.3 Mvar
TL235
BUCHANS
208 MDR B1B5
MASSEY DRIVE
TL211
TL209
215 BUC B1
216 STB B1B2
TL205
TL232
TL228
TL233
BOTTOM BROOK
STONY BROOK
TL204
TL231
TL234
TL263
206 SVL B1
STEPHENVILLE
205 BBK B1
291 GCL L63
405 USL L34
P = 40.0 MW
Q = 3.4 Mvar
GRANITE CANAL
P = 84.0 MW
Q = -6.7 Mvar
UPPER SALMON
6000 NOVA SCOTIA
Bus - VOLTAGE (PU)/ANGLE
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%RATEC
1.050OV 0.950UV
kV: <=6.900 <=16.000 <=25.000 <=46.000 <=69.000 <=138.000 <=230.000 >230.000
- Base Case
- Generation: Maximum
- Bipolar operation of Island HVDC
- Bipolar operation of Maritime HVDC

Attachment A- 3

BC-3 Peak 2017/Island Link 730MW/Maritime Link 158MW/Maximum Dispatch



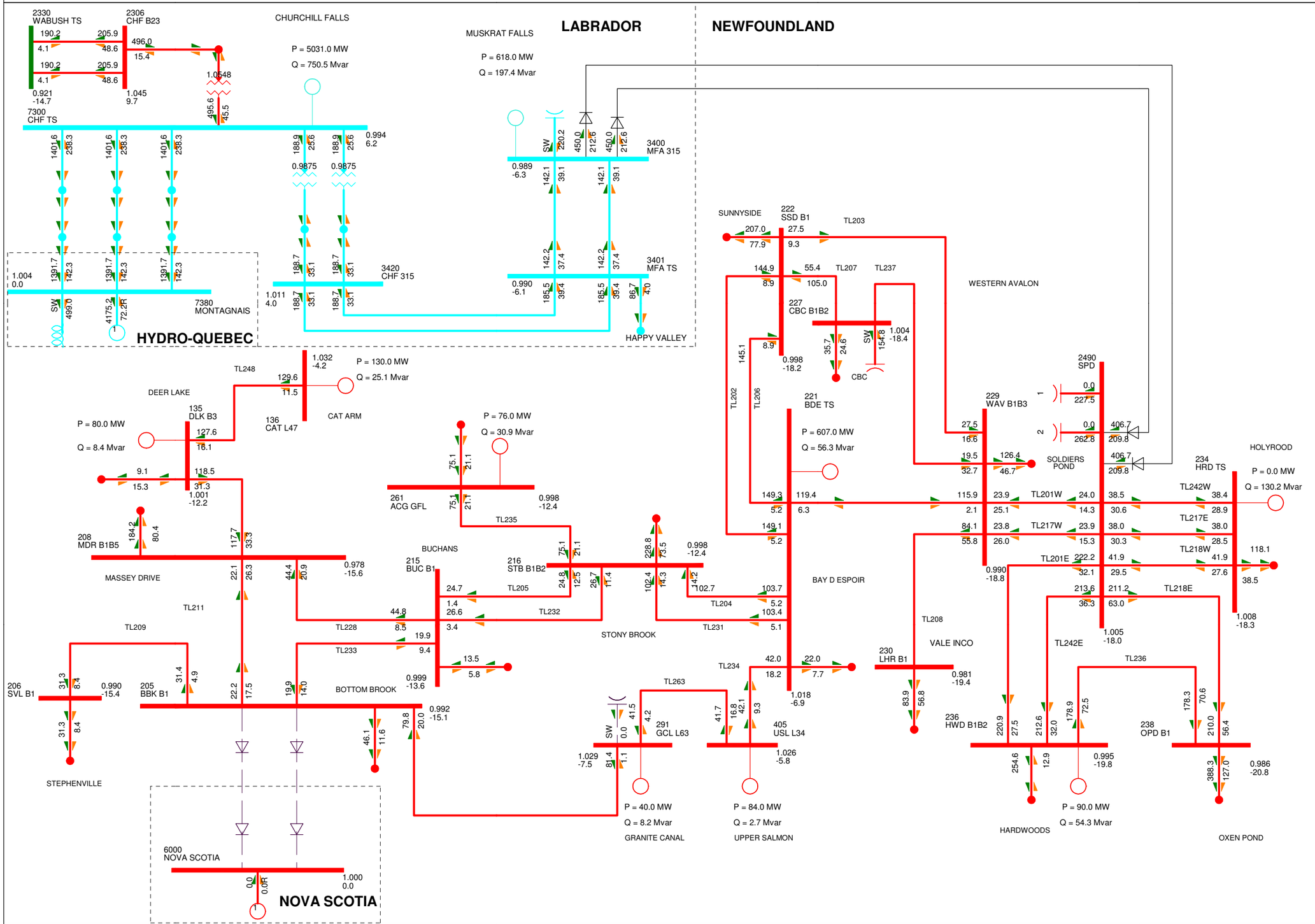
Bus - VOLTAGE (PU)/ANGLE
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%RATEC
1.050OV 0.950UV

kV: <=6.900 <=16.000 <=25.000 <=46.000 <=69.000 <=138.000 <=230.000 >230.000

- Base Case
- Generation: Maximum
- Bipolar operation of Island HVDC
- Bipolar operation of Maritime HVDC

Attachment A- 4

BC-4 Peak 2041/Island Link 814MW/Maritime Link 0MW/Maximum Dispatch



Bus - VOLTAGE (PU)/ANGLE
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%RATEC
1.050OV 0.950UV

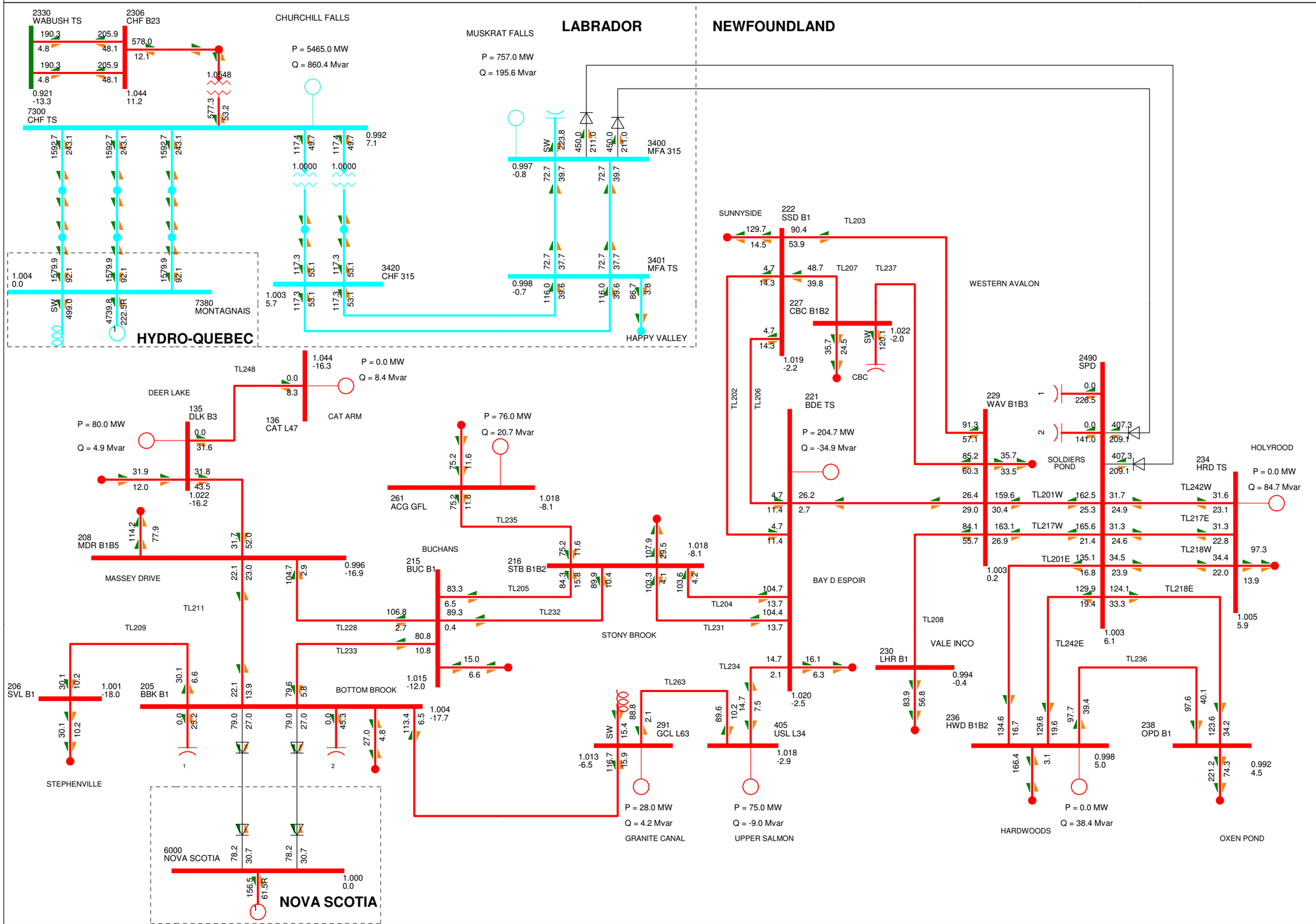
kV: <=6.900 <=16.000 <=25.000 <=46.000 <=69.000 <=138.000 <=230.000 >230.000

- Base Case
- Generation: Maximum
- Bipolar operation of Island HVDC
- Bipolar operation of Maritime HVDC

Attachment A- 5

BC-5 Intermediate 2017/Island Link 814MW/Maritime Link 158MW/Economic Dispatch

BC5 - SPRING/FALL INTERMEDIATE 2017, 1100 MW, 814 MW IMPORT AND 158 MW EXPORT



Bus - VOLTAGE (PU)/ANGLE
Branch - MW/Mvar
Equipment - MW/Mvar

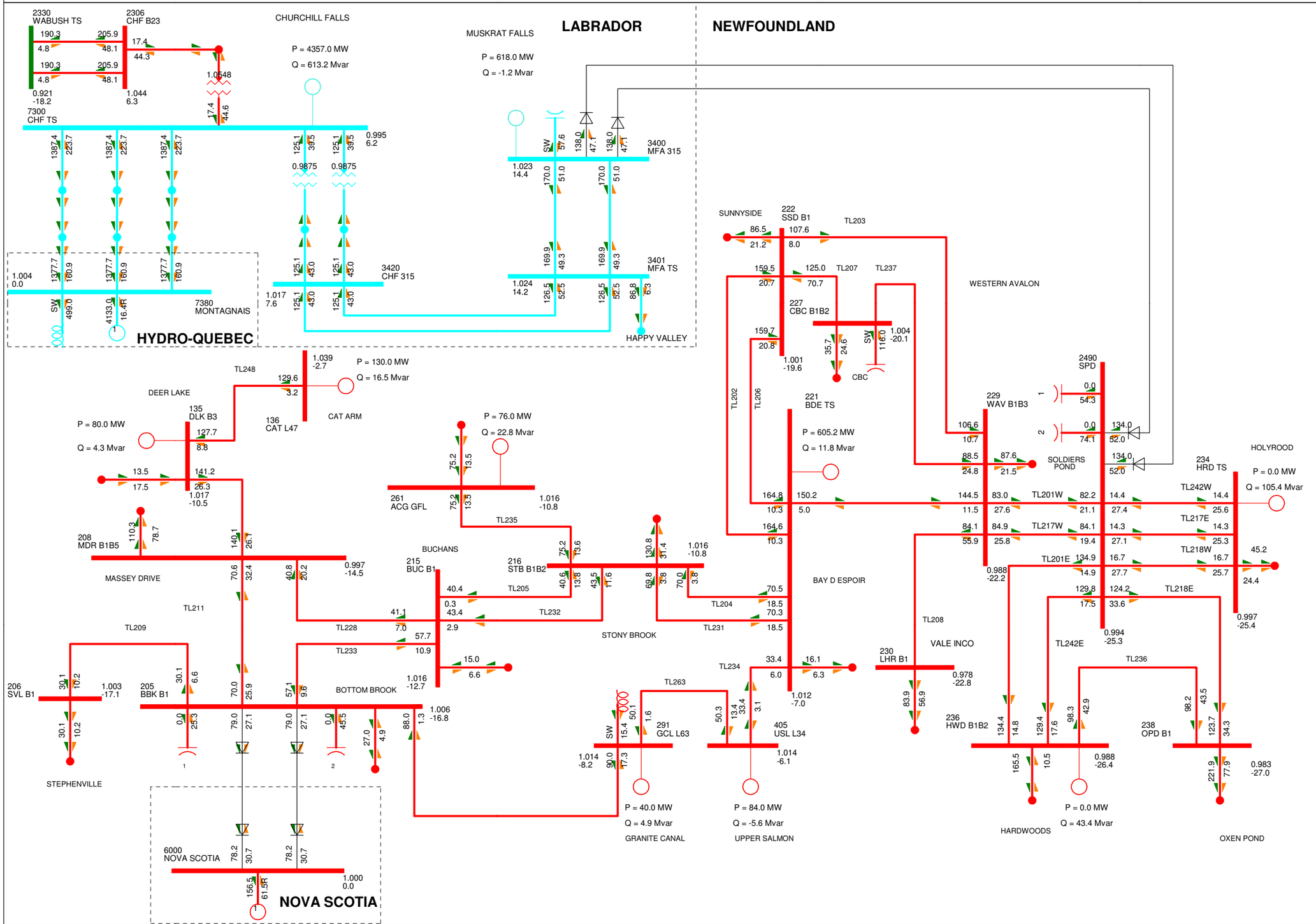
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kV: <=6.900 <=16.000 <=25.000 <=46.000 <=69.000 <=138.000 <=230.000 >230.000

- Base Case
- Generation: Economic Dispatch
- Bipolar operation of Island HVDC
- Bipolar operation of Maritime HVDC

Attachment A- 6

BC-6 Intermediate 2017/Island Link 268MW/Maritime Link 158MW/Maximum Dispatch

BC6 - SPRING/FALL INTERMEDIATE 2017, 1100 MW, 268 MW IMPORT AND 158 MW EXPORT



Bus - VOLTAGE (PU)/ANGLE
Branch - MW/Mvar
Equipment - MW/Mvar

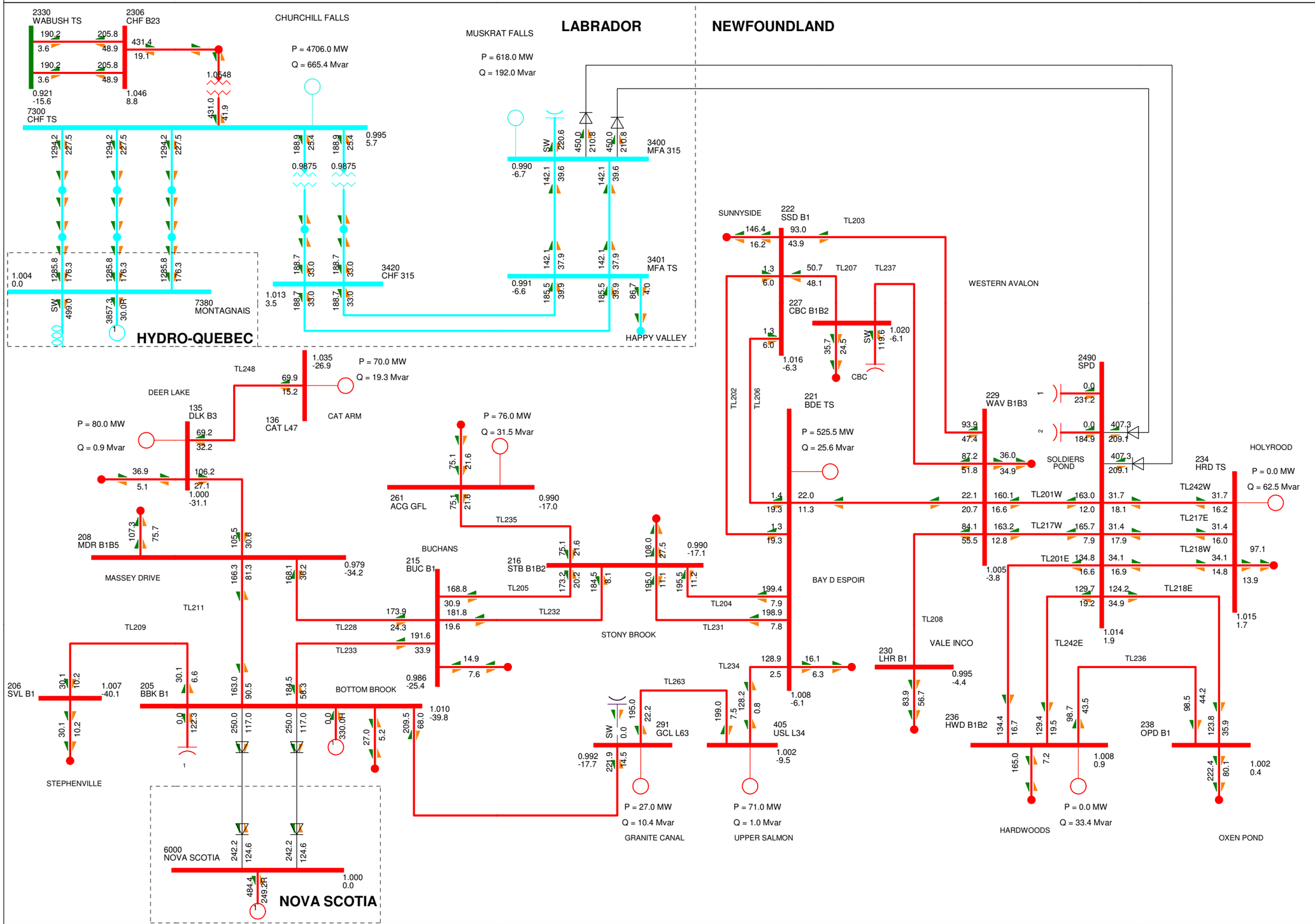
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kV: <=6.900 <=16.000 <=25.000 <=46.000 <=69.000 <=138.000 <=230.000 >230.000

- Base Case
- Generation: Maximum
- Bipolar operation of Island HVDC
- Bipolar operation of Maritime HVDC

Attachment A- 7

BC-7 Intermediate 2017/Island Link 814MW/Maritime Link 500MW/Economic Dispatch

BC7 - SPRING/FALL INTERMEDIATE 2017, 1100 MW, 814 MW IMPORT AND 500 MW EXPORT



Bus - VOLTAGE (PU)/ANGLE
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%RATEB
1.050OV 0.950UV

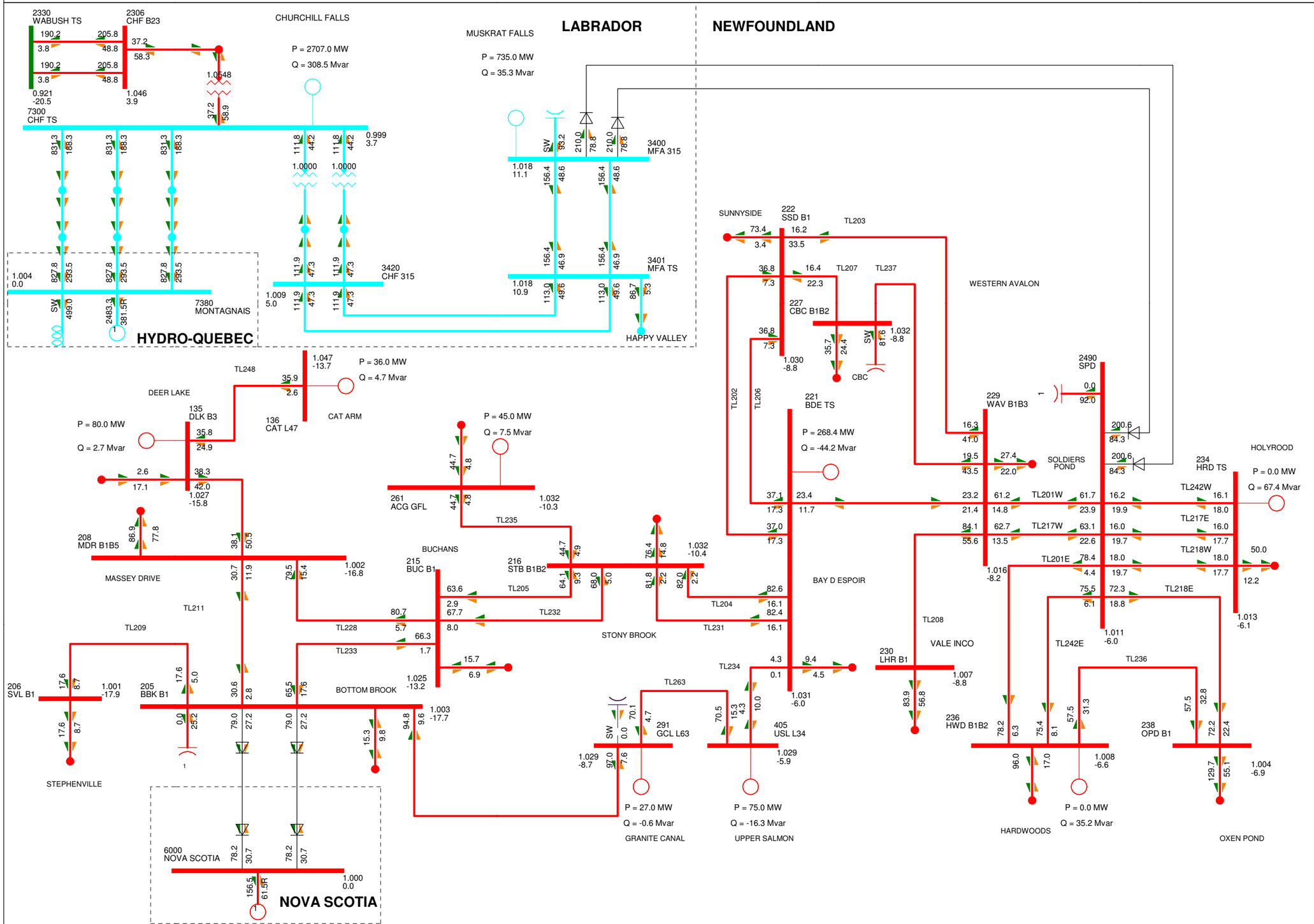
kV: <=6.900 <=16.000 <=25.000 <=46.000 <=69.000 <=138.000 <=230.000 >230.000

- Base Case
- Generation: Economic Dispatch
- Bipolar operation of Island HVDC
- Bipolar operation of Maritime HVDC

Attachment A- 8

BC-8 Light 2017/Island Link 400MW/Maritime Link 158MW/Minimum Dispatch

BC8 - SUMMER DAY LIGHT 2017, 700 MW, 400 MW IMPORT AND 158 MW EXPORT



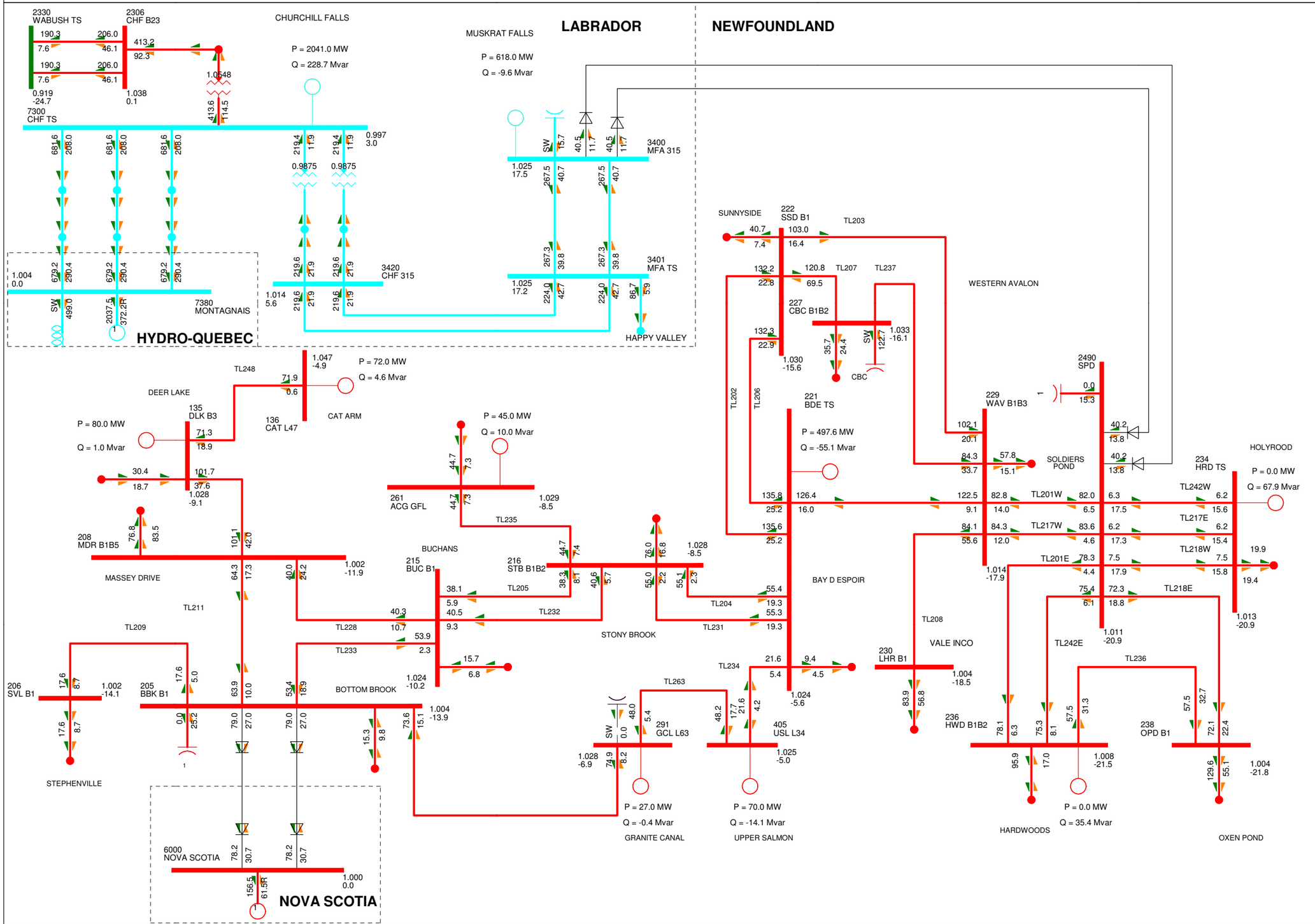
Bus - VOLTAGE (PU)/ANGLE
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%RATEA
1.050OV 0.950UV
kV: <=6.900 <=16.000 <=25.000 <=46.000 <=69.000 <=138.000<=230.000>230.000

- Base Case
- Generation: Minimum
- Bipolar operation of Island HVDC
- Bipolar operation of Maritime HVDC

Attachment A- 9

BC-9 Light 2017/Island Link 80MW/Maritime Link 158MW/Economic Dispatch

BC9 - SUMMER DAY LIGHT 2017, 700 MW, 80 MW IMPORT AND 158 MW EXPORT

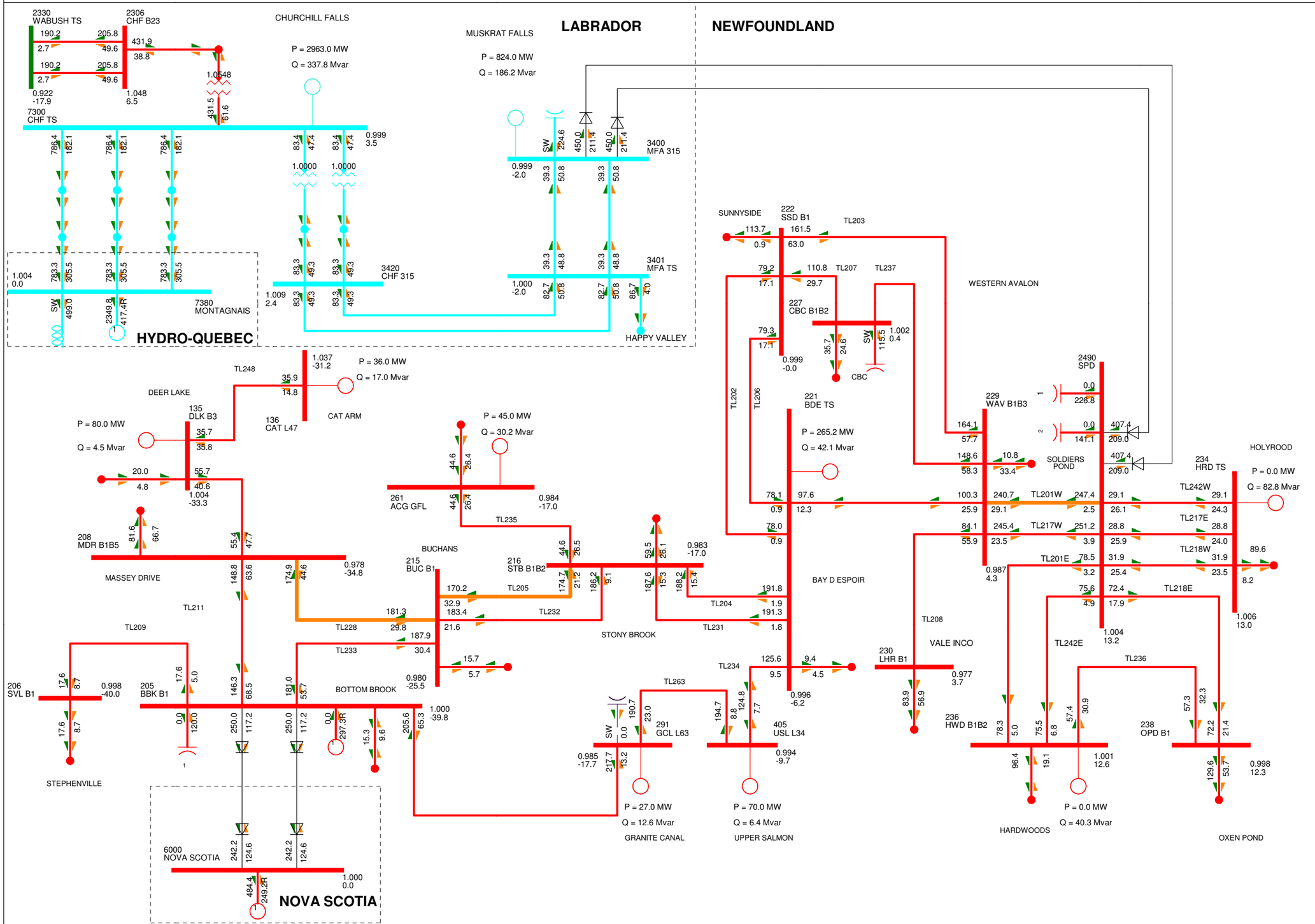


Bus - VOLTAGE (PU)/ANGLE
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%RATEA
1.050OV 0.950UV
kV: <=6.900 <=16.000 <=25.000 <=46.000 <=69.000 <=138.000<=230.000>230.000

- Base Case
- Generation: Economic Dispatch
- Bipolar operation of Island HVDC
- Bipolar operation of Maritime HVDC

Attachment A- 10

BC-10 Light 2017/Island Link 814MW/Maritime Link 500MW/Economic Dispatch



Bus - VOLTAGE (PU)/ANGLE
Branch - MW/Mvar
Equipment - MW/Mvar

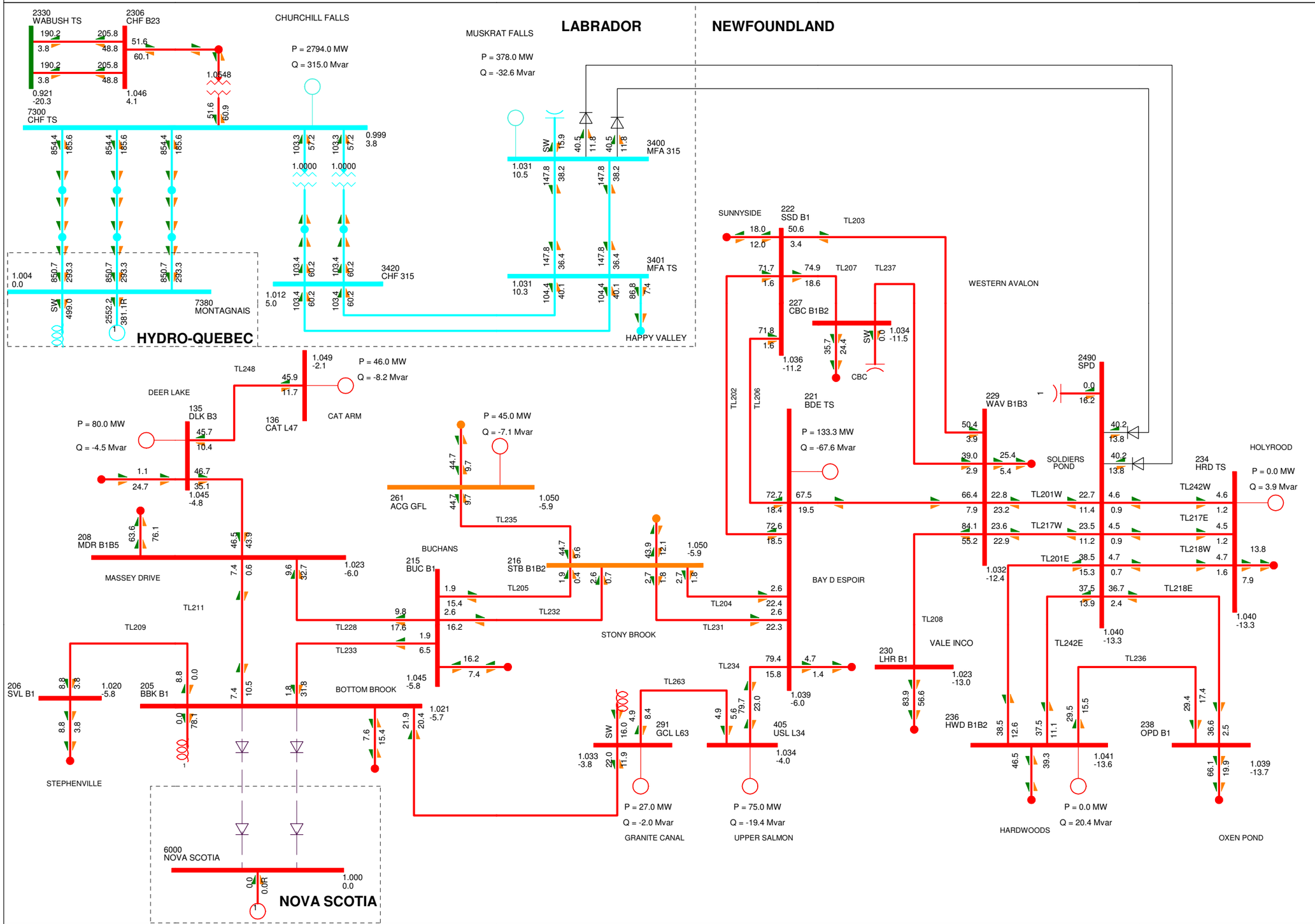
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1.050OV 0.950UV
kV: <=6.900 <=16.000 <=25.000 <=46.000 <=69.000 <=138.000 <=230.000>230.000

- Base Case
- Generation: Economic Dispatch
- Bipolar operation of Island HVDC
- Bipolar operation of Maritime HVDC

Attachment A- 11

BC-11 Extreme Light 2017/Island Link 80MW/Maritime Link 0MW/Economic Dispatch

BC11 - SUMMER NIGHT EXTREME LIGHT 2017, 420 MW, 80 MW IMPORT AND 0 MW EXPORT



Bus - VOLTAGE (PU)/ANGLE
Branch - MW/Mvar
Equipment - MW/Mvar

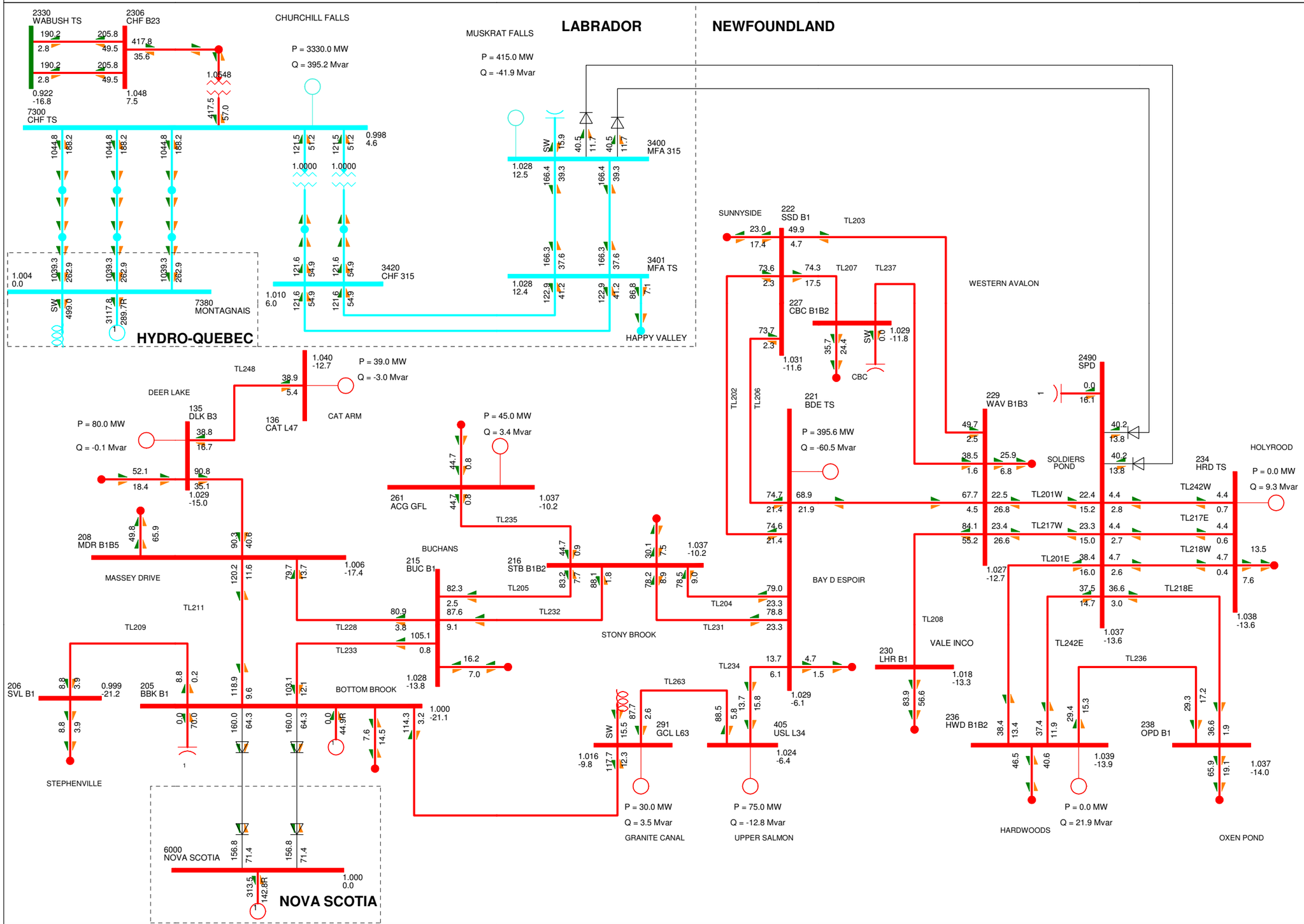
100.0%RATEA
1.050OV 0.950UV
kV: <=6.900 <=16.000 <=25.000 <=46.000 <=69.000 <=138.000 <=230.000 >230.000

- Base Case
- Generation: Economic Dispatch
- Bipolar operation of Island HVDC
- Bipolar operation of Maritime HVDC

Attachment A- 12

BC-12 Extreme Light 2017/Island Link 80MW/Maritime Link 320MW/Economic Dispatch

BC12 - SUMMER NIGHT EXTREME LIGHT 2017, 420 MW, 80 MW IMPORT AND 320 MW EXPORT



Bus - VOLTAGE (PU)/ANGLE
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%RATEA

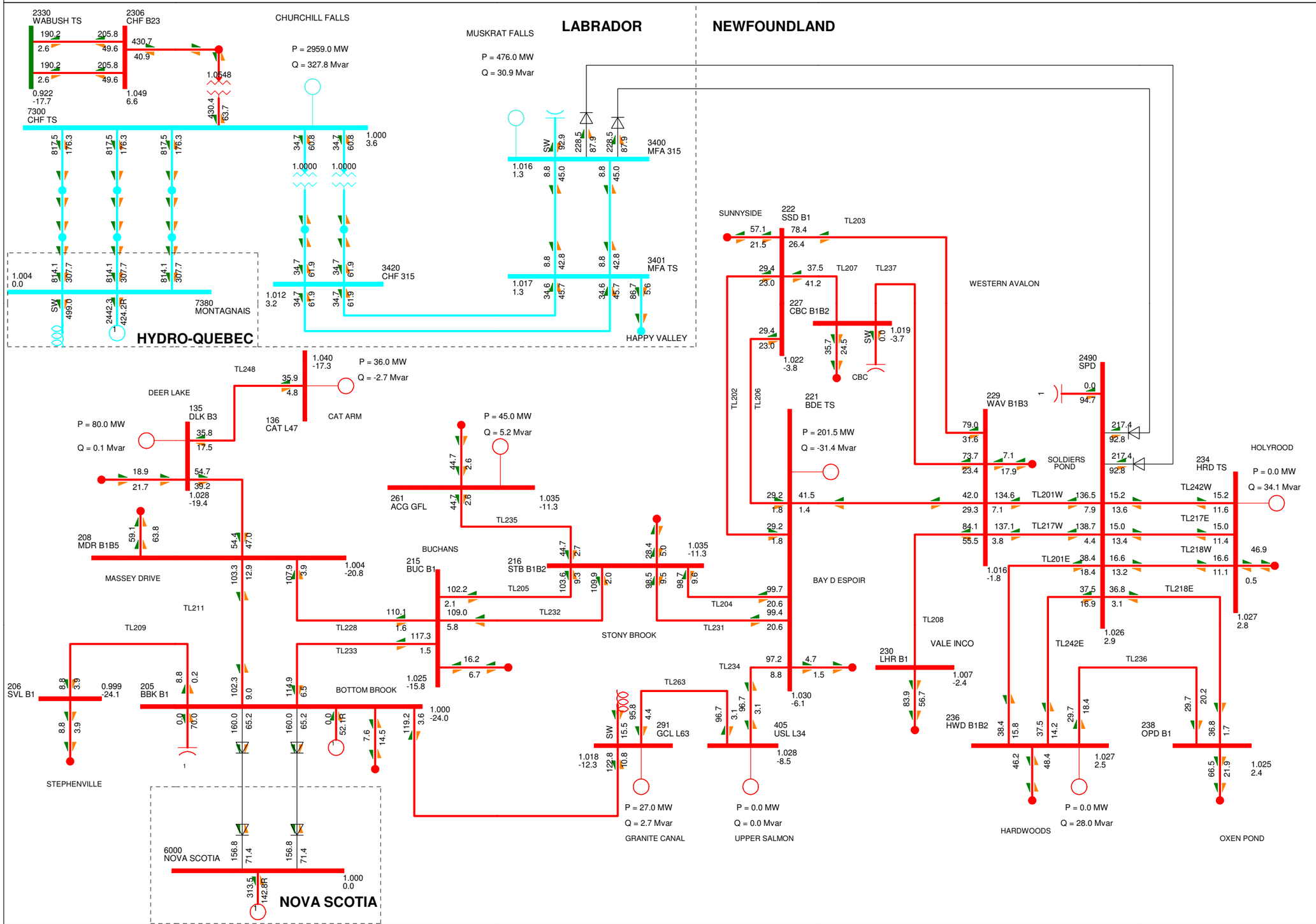
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- Base Case
- Generation: Economic Dispatch
- Bipolar operation of Island HVDC
- Bipolar operation of Maritime HVDC

Attachment A- 13

BC-13 Extreme Light 2017/Island Link 435MW/Maritime Link 320MW/Minimum Dispatch

BC13 - SUMMER NIGHT EXTREME LIGHT 2017, 420 MW, 435 MW IMPORT AND 320 MW EXPORT



Bus - VOLTAGE (PU)/ANGLE
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%RATEA

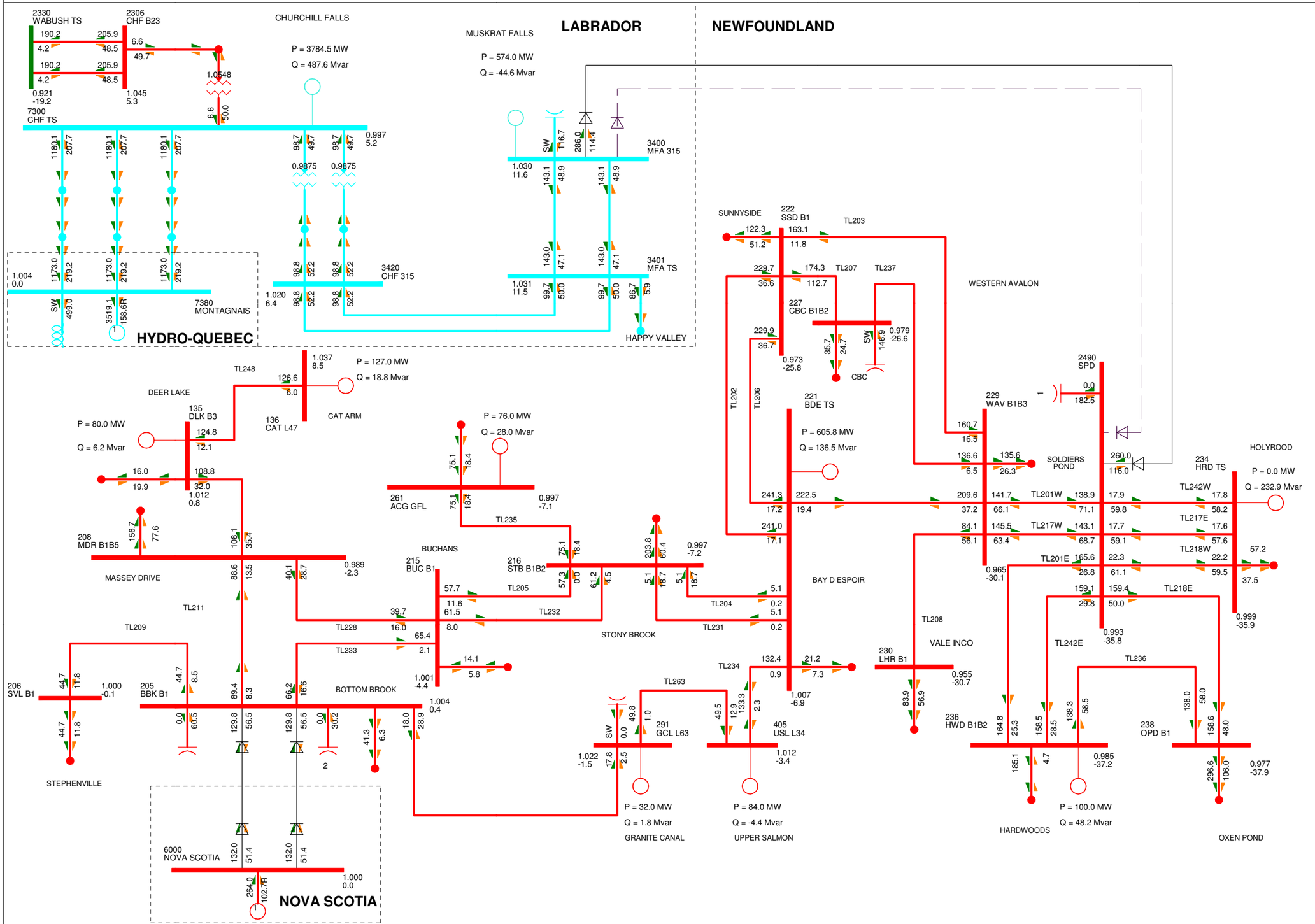
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kV: <=6.900 <=16.000 <=25.000 <=46.000 <=69.000 <=138.000 <=230.000 >230.000

- Base Case
- Generation: Minimum
- Bipolar operation of Island HVDC
- Bipolar operation of Maritime HVDC

Attachment A- 14

BC-14 Peak 2017/Island Link 260MW-Monopole/Maritime Link -260MW/ Maximum Dispatch

BC14 - WINTER PEAK 2017, 1552 MW, 260 MW IMPORT (LAB) AND 260 MW IMPORT (NS)



Bus - VOLTAGE (PU)/ANGLE
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%RATEC
1.050OV 0.950UV

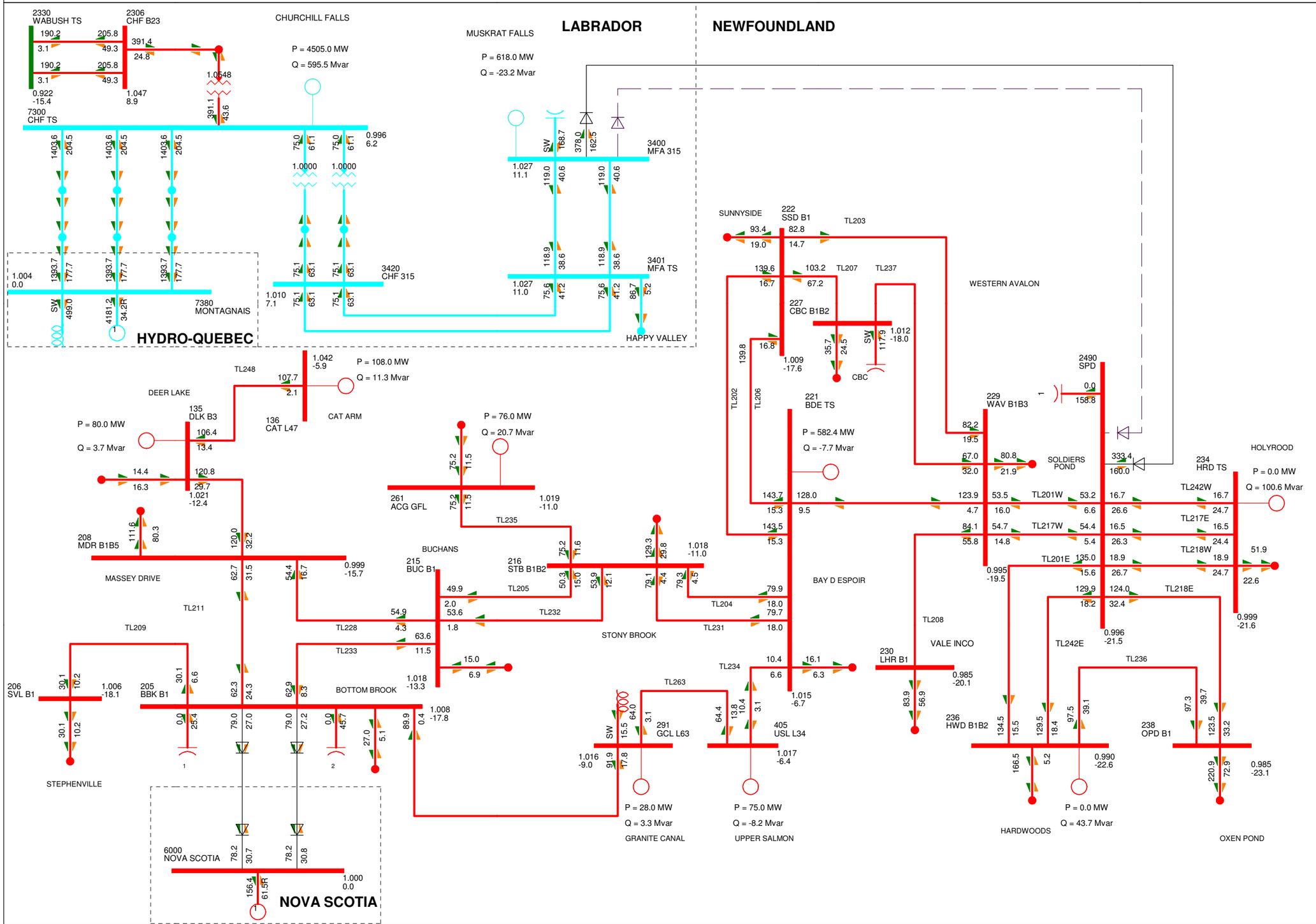
kV: <=6.900 <=16.000 <=25.000 <=46.000 <=69.000 <=138.000 <=230.000 >230.000

- Base Case
- Generation: Maximum
- Monopolar operation of Island HVDC
- Bipolar operation of Maritime HVDC

Attachment A- 15

BC-15 Intermediate 2017/Island Link 333MW-Monopole/Maritime Link 158MW/Economic Dispatch

BC15 - SPRING/FALL INTERMEDIATE 2017, 1100 MW, 333 MW IMPORT AND 158 MW EXPORT



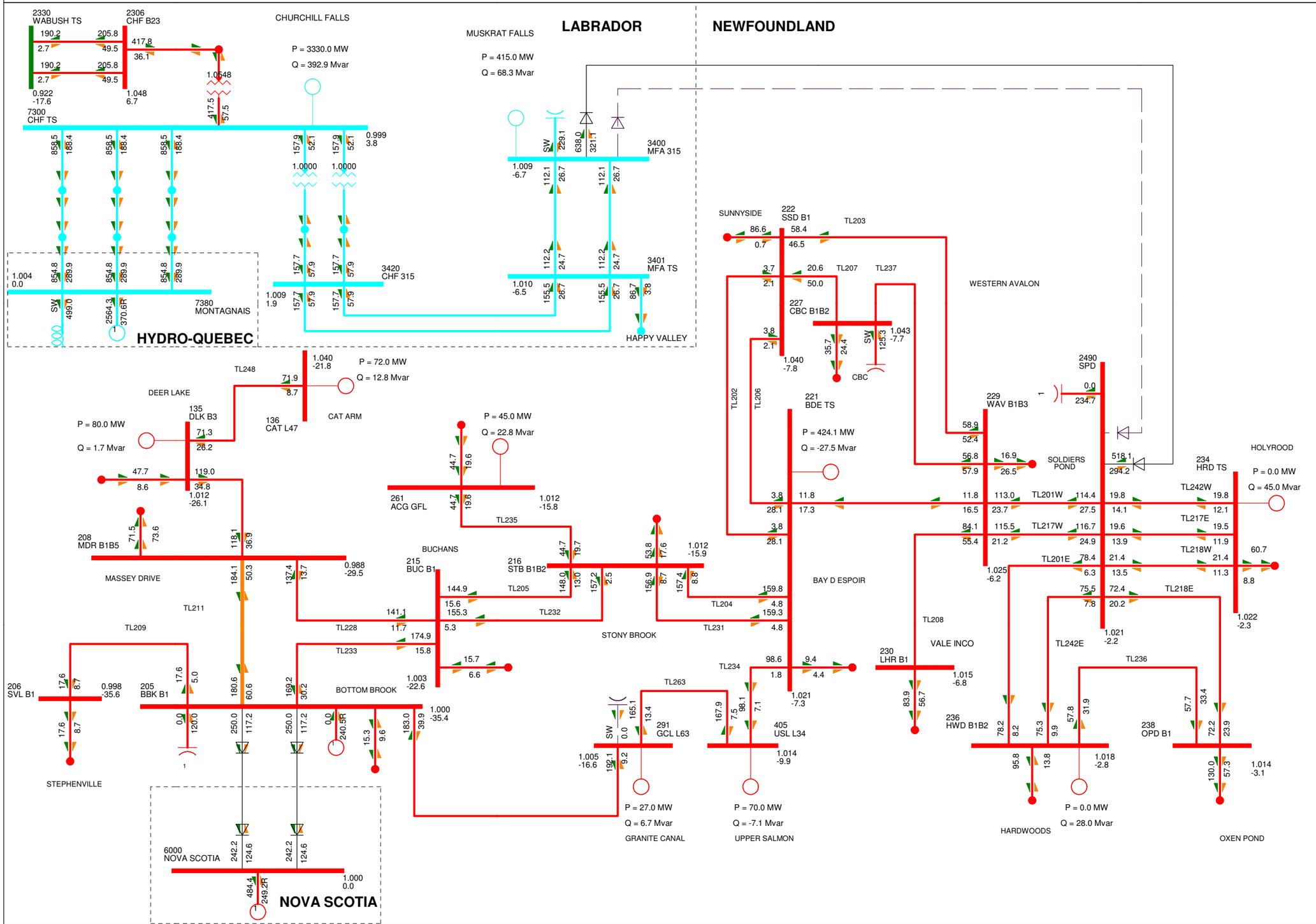
Bus - VOLTAGE (PU)/ANGLE
Branch - MW/Mvar
Equipment - MW/Mvar

100.0%RATEB
1.050OV 0.950UV
kV: <=6.900 <=16.000 <=25.000 <=46.000 <=69.000 <=138.000 <=230.000 >230.000

- Base Case
- Generation: Economic Dispatch
- Monopolar operation of Island HVDC
- Bipolar operation of Maritime HVDC

Attachment A- 16

BC-16 Light 2017/Island Link 518MW-Monopole/Maritime Link 500MW/ Minimum Dispatch



Bus - VOLTAGE (PU)/ANGLE
Branch - MW/Mvar
Equipment - MW/Mvar

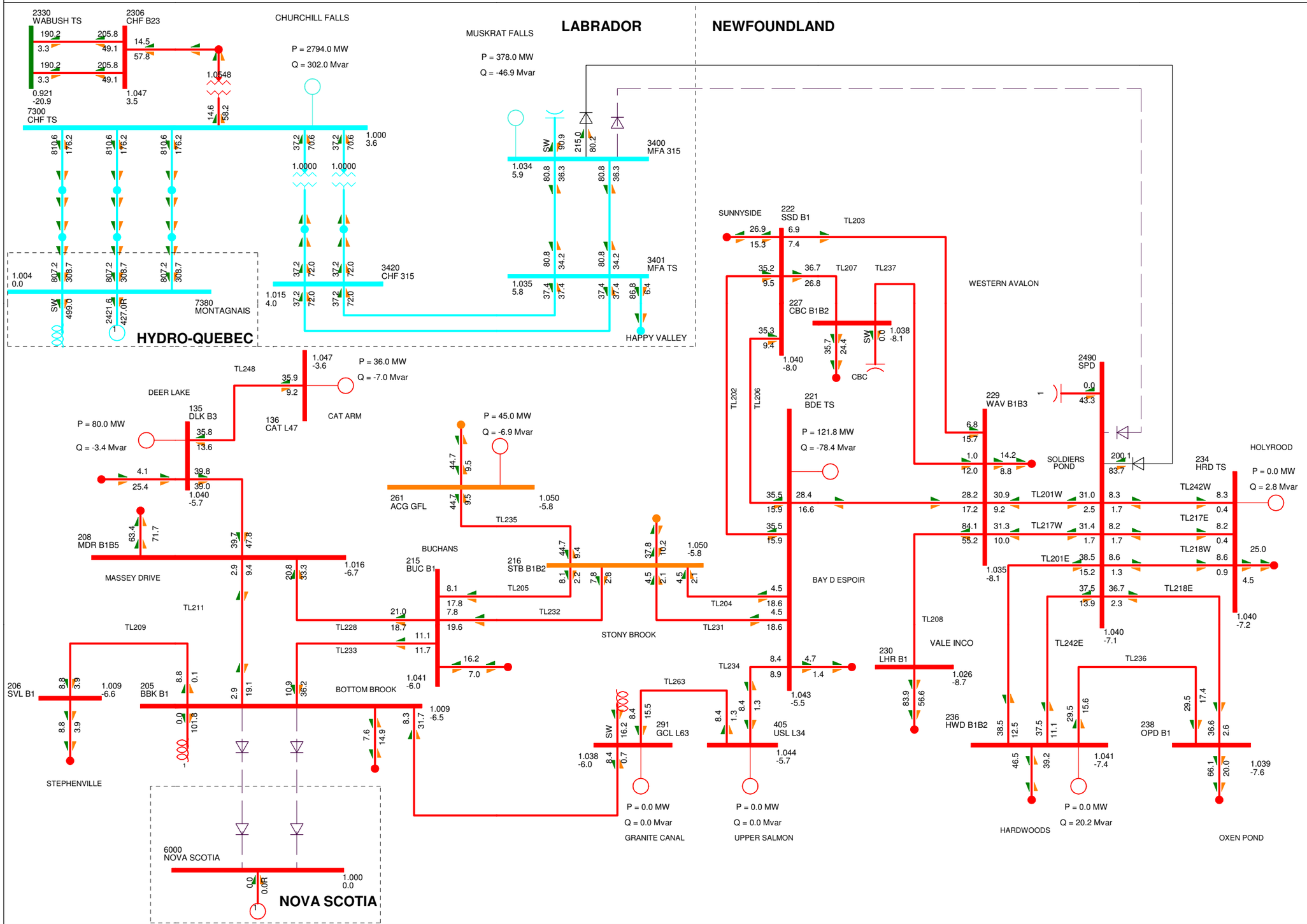
100.0%RATEA
1.050OV 0.950UV
kV: <=6.900 <=16.000 <=25.000 <=46.000 <=69.000 <=138.000 <=230.000>230.000

- Base Case
- Generation: Minimum
- Monopolar operation of Island HVDC
- Bipolar operation of Maritime HVDC

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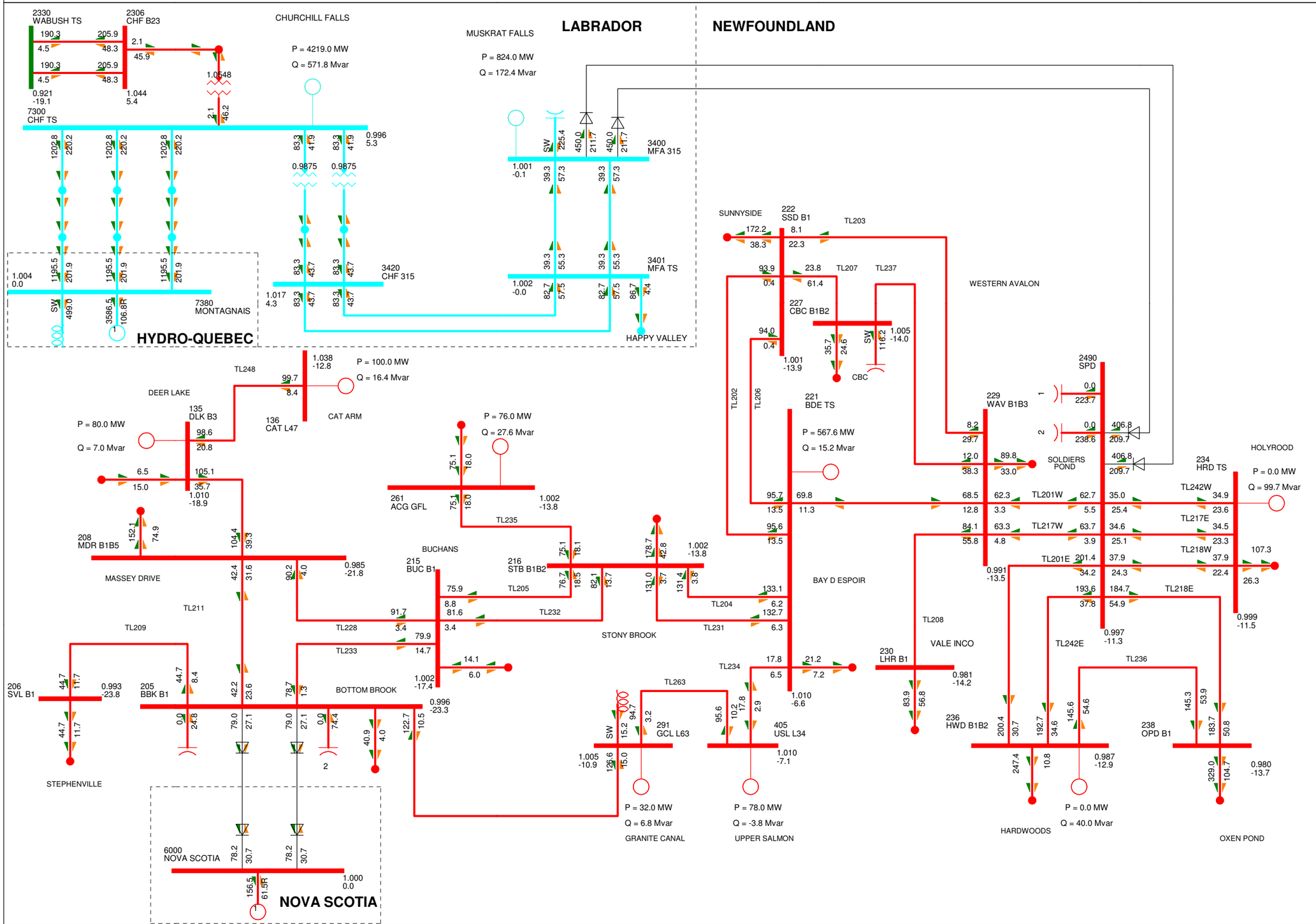
BC-17 Extreme Light 2017/Island Link 200MW-Monopole/Maritime Link 0MW/ Minimum Dispatch

BC17 - SUMMER NIGHT EXTREME LIGHT 2017, 420 MW, 200 MW IMPORT AND 0 MW EXPORT



Attachment A- 18

BC-18 Peak 2017/Island Link 814MW/Maritime Link 158MW/Economic Dispatch (4 units @Muskrat Falls)



Bus - VOLTAGE (PU)/ANGLE
Branch - MW/Mvar
Equipment - MW/Mvar
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1.050OV 0.950UV

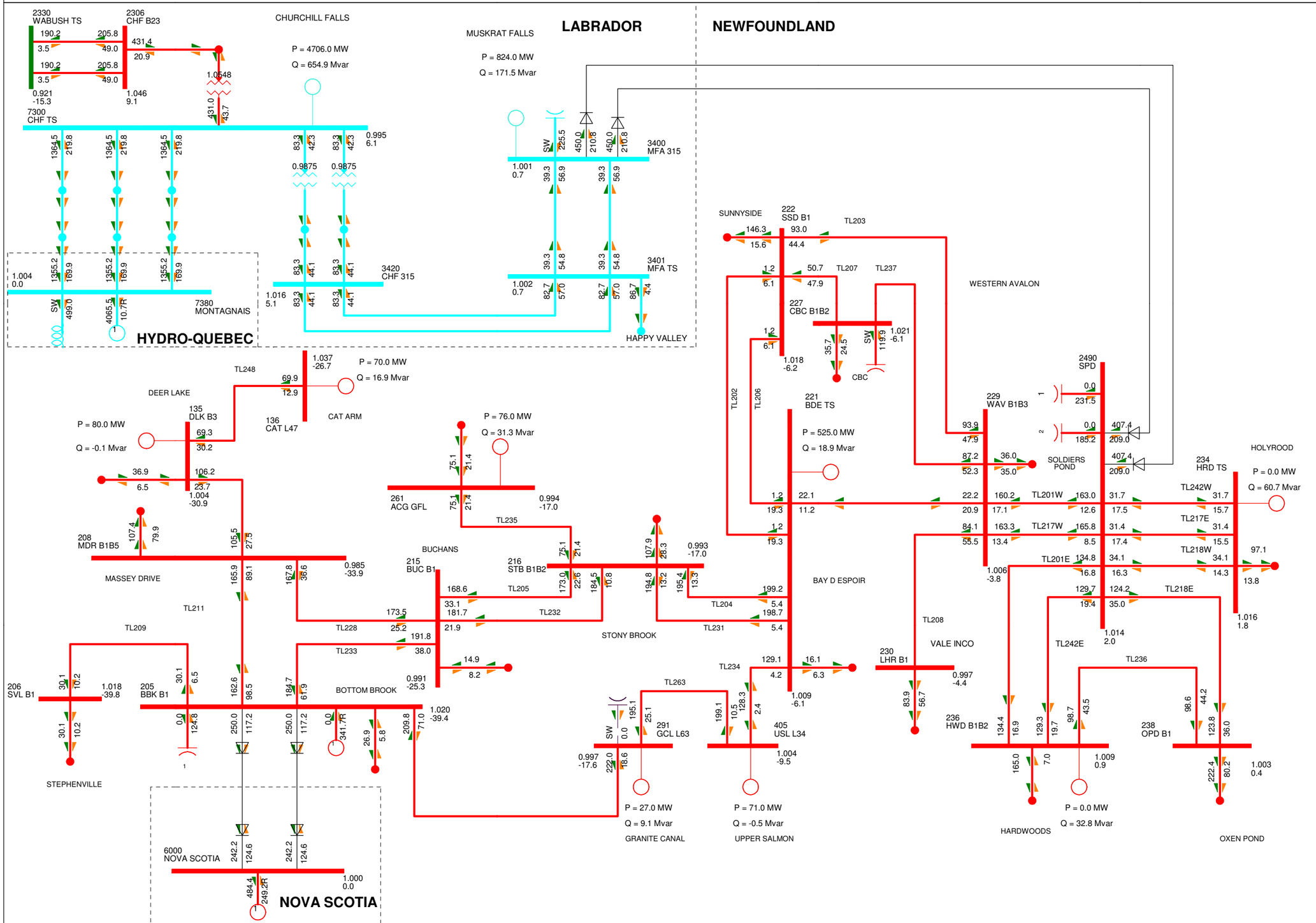
kV: <=6.900 <=16.000 <=25.000 <=46.000 <=69.000 <=138.000 <=230.000 >230.000

- Base Case
- Generation: Economic dispatch
- Muskrat Falls Generation: Maximum
- Bipolar operation of Island HVDC
- Bipolar operation of Maritime HVDC

Attachment A- 19

BC-19 Intermediate 2017/Island Link 814MW/Maritime Link 500MW/Economic Dispatch (4 units @Muskrat Falls)

BC19 - SPRING/FALL INTERMEDIATE 2017, 1100 MW, 814 MW IMPORT AND 500 MW EXPORT



Bus - VOLTAGE (PU)/ANGLE
Branch - MW/Mvar
Equipment - MW/Mvar

100.0%RATEB
1.050OV 0.950UV
kV: <=6.900 <=16.000 <=25.000 <=46.000 <=69.000 <=138.000 <=230.000 >230.000

- Base Case
- Generation: Economic Dispatch
- Muskrat Falls Generation: Maximum
- Bipolar operation of Island HVDC
- Bipolar operation of Maritime HVDC

APPENDIX C10 – SNC LAVALIN STABILITY STUDIES – MARCH 2012

Document Front Sheet

nalcor energy
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NE-LCP Contractor/Supplier

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Approver's Signature:	Date (dd-mmm-yyyy):	Review Class:
Satish Shah	06-Mar-2012	
Comments:		**Equipment Tag or Model Number:**

NE-LCP or EPC(M)

REVIEW DOES NOT CONSTITUTE APPROVAL OF DESIGN DETAILS, CALCULATIONS, TEST METHODS OR MATERIAL DEVELOPED AND/OR SELECTED BY THE CONTRACTOR, NOR DOES IT RELIEVE THE CONTRACTOR FROM FULL COMPLIANCE WITH CONTRACTUAL OR OTHER OBLIGATIONS.

- [x] 01 – REVIEWED AND ACCEPTED – NO COMMENTS
- [ ] 02 – REVIEWED – INCORPORATE COMMENTS, REVISE AND RESUBMIT
- [ ] 03 – REVIEWED - NOT ACCEPTED
- [ ] 04 – INFORMATION ONLY
- [ ] 05 – NOT REVIEWED

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	26-Mar-2012		

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nalcor energy

Lower Churchill Project

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Prepared by: Mohamed El Chehaly

Verified by: Peter Anderson

Approved by: Satish Sud

REGISTERED PROFESSIONAL ENGINEERS
PEG
Newfoundland and Labrador
SATISH SUD
Satish Sud
SIGNATURE
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Location	ID	Location	ID
Barachoix	BCX	Holyrood	HRD
Bay d'Espoir	BDE	Howley	HLY
Bay L'Argent	BLA	Indian River	IRV
Bear Cove	BCV	Jackson's Arm	JAM
Berry Hill	BHL	Linton Lake	LLK
Bottom Brook	BBK	Long Harbour	LHR
Bottom Waters	BWT	Main Brook	MBK
Buchans	BUC	Massey Drive	MDR
Cat Arm	CAT	Monkstown	MKS
Churchill Falls	CFA	Muskrat Falls	MFA
Come-by-Chance	CBC	Oxen Pond	OPD
Coney Arm	CAM	Paradise River	PRV
Conne River	CRV	Parson's Pond	PPD
Corner Brook Freq. Conv.	CBF	Peter's Barren	PBN
Cow Head	CHD	Plum Point	PPT
Daniels Harbour	DHR	Rattle Brook	RBK
Deer Lake	DLK	Rocky Harbour	RHR
Doyles	DLS	Roddicton Woodchip	RWC
Duck Pond	DPD	Sally's Cove	SCV
English Harbour West	EHW	Soldiers Pond	SPD
Farewell Head	FHD	South Brook	SOK
Glenburnie	GLB	Springdale	SPL
Glenwood	GWD	St.Anthony Airport	STA
Grand Bay	GBY	St.Anthony Diesel Plant	SDP
Grandy Brook	GBK	Star Lake	SLK
Grand Falls Freq. Conv.	GFC	Stephenville	SVL
Granite Canal	GCL	Stony Brook	STB
Hampden	HDN	Sunnyside	SSD
Happy Valley	HVY	Upper Salmon	USL
Hardwoods	HWD	Western Avalon	WAV
Hawkes Bay	HBY	Wiltondale	WDL
Hinds Lake	HLK		

1 INTRODUCTION

1.1 Overview of the System

This Report presents the results of the stability studies carried out to examine the dynamic performance of the ac and dc systems including the HVdc interconnections between Muskrat Falls and Soldiers Pond (Island Link) and between Bottom Brook and the Nova Scotia power system (Maritime Link). The present Design Basis considers, for the Island Link, a dc voltage level of ±350 kV and a nominal bipole rating of 900 MW and, for the Maritime Link, a dc voltage level of ±200 kV and a nominal bipole rating of 500 MW. This is interpreted to mean that these rated power levels and rated voltages apply at the rectifier ends (Muskrat Falls and Bottom Brook).

The Island Link will be essentially uni-directional from Labrador to Newfoundland, although there will be nothing in the design of the link to prevent operation in the reverse direction. The Maritime Link is required to have a 500 MW continuous capability in bipolar mode in both directions.

Figure 1-1 provides an overview of the areas considered in these studies. The connection to the Hydro-Quebec (TransEnergie) 735 kV system was represented by a simple equivalent at the Montagnais Substation. The Emera system in Nova Scotia was represented by a simple equivalent at the inverter station of the Maritime Link. The ac system between Churchill Falls and Muskrat Falls and the Island ac system were modelled in detail.

Starting from the base case scenarios provided by Nalcor Energy (Nalcor), the present studies are designed to determine the dynamic performance of the ac/dc systems following major faults on either the ac or dc systems. The faults considered result in the outage of a single element in either the ac or dc system. Because of the relative importance of the Island Link in the overall supply capability of the Island load, the temporary loss of both poles of the Island Link bipole was also considered.

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Figure 1-1: Project Area Map



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Figure 1-2: Provincial Transmission Grid



1.2 Objectives of the Studies

The stability studies were designed to achieve the following objectives:

- To verify that the interconnected systems of Newfoundland and Labrador with interconnections into Quebec and Nova Scotia can operate satisfactorily through a wide range of faults resulting in outages on the transmission network,
- To determine the requirements in terms of control functions that will be required on the Island and Maritime dc links,
- To determine the requirements for additional equipment, in the form of static var compensators and/or synchronous condensers, that will be required at or near the converter stations to ensure satisfactory dynamic performance,
- To verify that load shedding on the Island will not occur for the range of fault cases examined, and
- To determine any operating requirements that must be applied to the Island and Maritime dc links to ensure stable operation.

2 STUDY BASIS

Nalcor provided nineteen base case scenarios for examination. These scenarios are presented in Table 2-1. Scenarios BC-14 to BC-17 considered monopole operation of the Island Link. Since these scenarios already represent a single contingency outage on the system, they were not considered as the starting condition for any of the stability studies.

The major additions to the existing (2011) system planned by Nalcor consist of:

- A new 230 kV line from Granite Canal to Bottom Brook (name not yet designated) to strengthen the supply to Bottom Brook and the Western region, and
- A new 230 kV line from Bay d'Espoir to Western Avalon (name not yet designated) to increase system transfer capability and improve system stability.

The 230 kV supply to the Wabush/ Labrador City area in Western Labrador has been identified in Nalcor's five-year plan to require reinforcement to relieve low voltage conditions and improve system stability. As a result, this area was the source of stability problems for all the initial cases considered. Since the plans for this area are still under investigation, the supply to this area was represented as a fixed, lumped load at the Churchill Falls 230 kV bus.

Following the conclusions derived from the *Load Flow and Short-circuit Studies* (Nalcor ILK-SN-CD-8000-EL-SY-0001-01/ SLI 505573-480A-47ER-0003), a +320/-100 MVAr SVC was placed at Bottom Brook in all cases to ensure sufficient reactive power was provided to the system with the connection of the Maritime Link. Any fixed shunts representing reactive compensation were removed and only those representing ac filters were retained.

Load flow studies were carried out for each scenario, considering normal system conditions (all equipment in service) and outage conditions. In addition to pole outages on the Island dc link, the automatic sequential contingency feature of PSS®E was used to examine all single contingency outages on the ac systems. The results of these load flow studies were presented in the *Load Flow and Short-circuit Studies* report (Nalcor ILK-SN-CD-8000-EL-SY-0001-01/ SLI 505573-480A-47ER-0003) and

are not repeated here. However, for each stability study carried out, the base case load flows, showing the initial network conditions, are included in Appendix A.

2.1 Study Criteria

The criteria generally used to carry out stability studies are taken from the NLH Transmission Planning Manual and are summarized below.

- The system will be able to sustain the single contingency loss of any transmission element without loss of system stability,
- The system is able to sustain a successful single pole reclose for a line to ground fault,
- Multi-phase 230 kV faults shall be cleared in a maximum clearing time of 6-cycles,
- Load shedding should not occur for the loss of the largest generator in Newfoundland,
- Load shedding should not occur for the temporary loss of a pole or bipole of an HVdc link,
- The system response should be stable and well damped,
- Post-fault recovery voltages on the ac system shall be as follows:
    - Transient under-voltages following fault clearing should not drop below 0.7 pu,
    - The duration of voltage below 0.8 pu following fault clearance should not exceed 20-cycles,
- Post-fault frequencies should not drop below 59 Hz,
- Under-frequency load shedding should be minimized.

The above criteria have been in general use for Newfoundland and Labrador Hydro (NLH). Once commissioned, the Island Link will bring 900 MW from Muskrat Falls to Soldiers Pond with a delivered capacity of approximately 814 MW, allowing for losses on the nearly 1,100 km long link. Of this delivered power to the Island it is planned to export 158 MW over the Maritime Link while maintaining an economic dispatch of the Island generation. Under maximum Island dispatch conditions, the export over the Maritime Link could be increased to 239 MW. In 2017, when the peak Island load is forecast to be 1,552 MW, the net import on the Island Link (814-158=656 MW) will represent approximately 42% of the Island peak load. Given this relatively high level it is considered essential that the Island Link be designed to a very high level of reliability and availability and that the system should remain stable and able to operate without load shedding through the most severe single contingencies. Consequently, the system was studied for a series of permanent pole outages, temporary bipole outages and three-phase faults on the ac system to determine the dynamic performance of the system and to determine the additional equipment that would be required, in terms of dynamic support, to ensure stable performance. Given the above, it was not considered necessary to examine the system performance for a successful single pole re-closure of a single-line-to-ground fault as this is much less severe than a three-phase fault.

Given the above requirements to avoid load shedding on the Island for all system disturbances and in view of the limited spinning reserve that would be available on the Island, it was agreed with Nalcor that, in the event of a system disturbance that would result in a frequency depression, the export to Nova Scotia over the Maritime Link would be reduced to zero as quickly as possible, effectively providing additional spinning reserve to the Island system. In discussions with Emera, the Nova Scotia system would be operated with sufficient spinning reserve to maintain operations through such an event. Following system recovery, the Maritime Link could then be manually re-started at a level consistent with the available capacity from Newfoundland.

The only other modification to the above criteria concerns the post-fault ac system voltage. Inverters are susceptible to commutation failure when the ac voltage changes rapidly. Such failures can occur even for relatively small voltage changes,

but the probability of a commutation failure is considered small if the post-fault recovery voltage does not fall below 90% (CIGRE, Document 103, "Causes and Consequences of Commutation Failures", November 1995). Since the models used in the PSS®E program cannot automatically account for commutation failures, it is necessary to manually track the inverter ac voltage to check for compliance with the voltage criterion. An ac voltage criterion of 90% was therefore applied to the Soldiers Pond 230 kV bus.

The generation dispatch levels for each scenario considered are given in Table 2-2.

Table 2-1: Base Case Scenarios

No.	NLH System Load	NS Export Bottom Brook	Island Import Muskrat Falls/Soldiers Pond	Island Generation	Comments
BC-1	Peak-2017 (1552MW)	158MW	900/814MW	Economic Dispatch	Winter Peak 3-units @ Muskrat Falls
BC-2	Peak-2017(1552MW)	239MW	900/814MW	Maximum	Winter Peak 3-units @ Muskrat Falls
BC-3	Peak-2017(1552MW)	158MW	798/730MW	Maximum	Winter Peak
BC-4	Peak-2041(1900MW)	0MW	900/814MW	Maximum	Winter Peak
BC-5	Intermediate-2017(1100MW)	158MW	900/814MW	Economic Dispatch	Spring/Fall day
BC-6	Intermediate-2017(1100MW)	158MW	276/268	Maximum	Spring/Fall day
BC-7	Intermediate-2017 (1100MW)	500MW	900/814MW	Economic Dispatch	Spring/Fall day
BC-8	Light (700MW)	158MW	414/400MW	Minimum	Summer day
BC-9	Light (700MW)	158MW	81/80MW	Economic Dispatch	Summer day
BC-10	Light (700MW)	500MW	900/814MW	Economic Dispatch	Summer day
BC-11	Extreme Light (420MW)	0MW	81/80MW	Economic Dispatch	Summer night
BC-12	Extreme Light (420MW)	320MW	81/80MW	Economic Dispatch	Summer night
BC-13	Extreme Light (420MW)	320MW	457/435MW	Minimum	Summer night
BC-14	Peak-2017 (1552MW)	-260MW	286/260MW-Monopole	Maximum	Winter Peak
BC-15	Intermediate-2017(1100MW)	158MW	378/333MW-Monopole	Economic Dispatch	Spring/Fall day
BC-16	Light (700MW)	500MW	638/518MW-Monopole	Minimum	Summer day
BC-17	Extreme Light (420MW)	0MW	215/200MW-Monopole	Minimum	Summer night
BC-18	Peak-2017 (1552MW)	158MW	900/814MW	Economic Dispatch	Winter Peak 4-units @ Muskrat Falls
BC-19	Intermediate-2017(1100MW)	500MW	900/814MW	Economic Dispatch	Winter Peak 4-units @ Muskrat Falls

Table 2-2: Generation Dispatch Levels

	Unit Size		BC1	BC2	BC3	BC4	BC5	BC6	BC7	BC8	BC9	BC10	BC11	BC12	BC13	BC14	BC15	BC16	BC17	BC18	BC19
	MW	MVA																			
NLH System Load (MW)			1552	1552	1552	1900	1100	1100	1100	700	700	700	420	420	420	1552	1100	700	420	1552	1100
HVDC Export BBK (MW)			158	239	158	0	158	158	500	158	158	500	0	320	320	-260	158	500	0	158	500
Generation Dispatch																					
Churchill Falls Plant	6050	6722	4219	4229	4199	5031	5465	4357	4706	2707	2041	2963	2794	3330	2959	4205	4505	3330	2794	4219	4706
Muskrat Falls Plant	824	916	602	613	618	618	757	618	618	735	824	824	378	415	476	574	618	415	378	824	824
HVDC at Soldiers Pond			815	815	730	815	815	268.5	815	400	80	815	80	80	435	260	333	518	200	815	815
NLH - Hydro																					
Bay d'Espoir Unit 1	76.5	85	70	75	75	75	68	75	65	67	60.5	65.7	67	66	off	75	72	60	61	70	65
Bay d'Espoir Unit 2	76.5	85	70	75	75	75	off	75	65	off	60.5	off	off	66	66	75	72	off	off	70	65
Bay d'Espoir Unit 3	76.5	85	70	75	75	75	68	75	65	67	60.5	65.7	67	66	off	75	72	60	61	70	65
Bay d'Espoir Unit 4	76.5	85	70	75	75	75	off	75	65	off	60.5	off	off	66	off	75	72	60	off	70	65
Bay d'Espoir Unit 5	76.5	85	70	75	75	75	68	75	65	off	60.5	65.7	off	66	off	75	72	60	off	70	65
Bay d'Espoir Unit 6	76.5	85	70	75	75	75	off	75	65	off	60.5	65.7	off	66	off	75	72	60	off	70	65
Bay d'Espoir Unit 7	155	172	145	154	154	154	off	154	135	135	135	off	sc	off	135	154	150	124	sc	145	135
Cat Arm Unit 1	68	75.5	50	65	65	65	sc	65	35	36	36	36	46	39	36	63.5	54	36	36	50	35
Cat Arm Unit 2	68	75.5	50	65	65	65	sc	65	35	sc	36	sc	off	off	off	63.5	54	36	off	50	35
Upper Salmon	84	88.4	78	84	84	84	75	84	71	75	70	70	75	75	off	84	75	70	off	78	71
Hinds Lake	75	83	70	75	75	75	69	75	67	off	67	off	off	69	off	75	69	67	off	70	67
Granite Canal	40.5	45	32	40	40	40	28	40	27	27	27	27	27	30	27	32	28	27	off	32	27
Paradise River	9	10	8	8	8	8	7	8	7	off	7	7	off	7	off	8	7	7	off	8	7
NLH - Thermal																					
Hardwoods GT1/2	57	63.5	sc	sc	sc	45	sc	sc	sc	sc	sc	sc	sc	sc	sc	50	sc	sc	sc	sc	sc
Stephenville GT1	57	63.5	off	off	off	25	off	off	off	off	off	off	off	off	off	off	off	off	off	off	off
Holyrood Unit 1	175	194.4	off	off	off	off	off	off	off	off	off	off	off	off	off	off	off	off	off	off	off
Holyrood Unit 2	175	194.4	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc
Holyrood Unit 3	159	177.2	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc	sc
Holyrood CT1	16	17.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Holyrood CT2	16	17.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NUGS																					
Star Lake			17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4
Rattle Brook			3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
CBP&P			18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Exploits			76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76
Wind																					
St. Lawrence			off	off	off	off	off	off	off	off	off	off	off	off	off	off	off	off	off	off	off
Fermeuse			off	off	off	off	off	off	off	off	off	off	off	off	off	off	off	off	off	off	off
Total Generation			1783	1871	1786	1986	1313	1325	1697	922	936	1333	477	811	814	1405	1317	1300	473	1783	1697

2.2 System Models

In terms of system modelling, the ac system was represented by conventional models common to both steady-state and stability studies. This data was provided by Nalcor in the form of PSS®E data files.

All generators in the system were modelled by their sub-transient, 2-axis models as provided in the PSS®E model library. The data for each generator was provided by Nalcor and is shown in Appendix B. For each generator, Nalcor provided the exciter, stabilizer and governor models as appropriate. These models with their parameters are presented in Appendix B. The system loads were modeled as constant current loads for real power and constant admittance loads for reactive power.

The HVdc links (Island and Maritime) were modelled using the PSS®E library model CDC4T. The details of this model are provided in Appendix B. Both links were modeled as Line Commutated Converters (LCC).

Voltage Source Converters (VSC) are usually associated with dc cables since reclosing is not normally used for dc cable faults. Currently, the only method to clear a fault on the dc circuit is by opening the ac breakers. The duration of the fault clearance is at least 500 ms and can reach up to 1,500 ms. Therefore, ac systems can collapse due to frequency deviation.

Frequency controllers were applied at the Soldiers Pond (inverter) converter and the Bottom Brook (rectifier) converter using the PSS®E library model PAUX1T. The details of this model are provided in Appendix B. The purpose of these frequency controllers is as follows:

- The frequency controller at Bottom Brook was configured to reduce the dc power on the Maritime Link to zero in the event that the frequency at Bottom Brook falls below 60 Hz.

- The frequency controller at Soldiers Pond was configured to increase the dc power on the Island Link in the event that the frequency at Soldiers Pond falls below 60 Hz.

3 RESULTS OF THE STUDIES

3.1 Winter Peak Load Conditions

The forecast peak load on the Island system in 2017-18 is 1,552 MW. The first scenario to be examined under these conditions was BC-2, since this scenario involves the rated transfer across the Island Link (900 MW from Muskrat Falls) and the maximum transfer across the Maritime Link (239 MW from Bottom Brook) under peak load conditions. Figure A-1 in Appendix A shows the load flow of the initial conditions.

The following fault cases were examined:

BC2-ST01: Temporary Bipole Fault on the Island Link

BC2-ST02: Permanent Pole Fault on the Island Link with post-fault mono-polar operation

BC2-ST03: 3-phase/6-cycle fault at Muskrat Falls 315 kV on 315 kV line to Churchill Falls (name not yet designated)

BC2-ST04: 3-phase/6-cycle fault at Bay d'Espoir 230 kV on 230 kV line to Western Avalon (name not yet designated)

BC2-ST05: 3-phase/6-cycle fault at Soldiers Pond 230 kV on 230 kV line to Western Avalon (TL217W)

BC2-ST06: 3-phase/6-cycle fault at Bottom Brook 230 kV on 230 kV line to Granite Canal (name not yet designated)

BC2-ST07: 3-phase/6-cycle fault at Stony Brook 230 kV on 230 kV line to Bay d'Espoir (TL204)

BC2-ST08: 3-phase/6-cycle fault at Bay d'Espoir 230 kV on 230 kV line to Sunnyside (TL202)

BC2-ST09: 3-phase/6-cycle fault at Bay d'Espoir 230 kV with post-fault outage of Bay d'Espoir G7

The dynamic performance of the system is presented in a series of figures for each case showing:

- machine angles,
- ac and dc bus voltages,
- dc power levels,
- active and reactive output of synchronous condensers,
- system frequency.

3.1.1 BC2-ST01: Temporary Bipole Fault on the Island Link

This case represents the condition where a transient fault occurs on both poles of the Island Link. The fault duration was taken as 200 ms (12 cycles), composed of 25 ms (1.5 cycles) to detect the fault and reduce the dc current to zero plus a de-ionization time of 175 ms (10.5 cycles). After this period, the dc power can be ramped back up to any desired value. The ramp rates were selected to result in a ramp-up time to full power of 100 ms (6 cycles), giving a total time from fault initiation to a return to scheduled power of 300 ms (18 cycles).

Previous studies of the use of HVdc to supply the Island load showed a need for additional reactive support and inertia at the Soldiers Pond converter station. The study was therefore carried out with a high-inertia, synchronous condenser connected at Soldiers Pond as shown below (data provided by Hatch report "*DC1210 – HVdc System Sensitivity and VSC Risk Analysis*" based on the Toshiba synchronous condenser).

Table 3-1: High-Inertia Synchronous Condenser Data

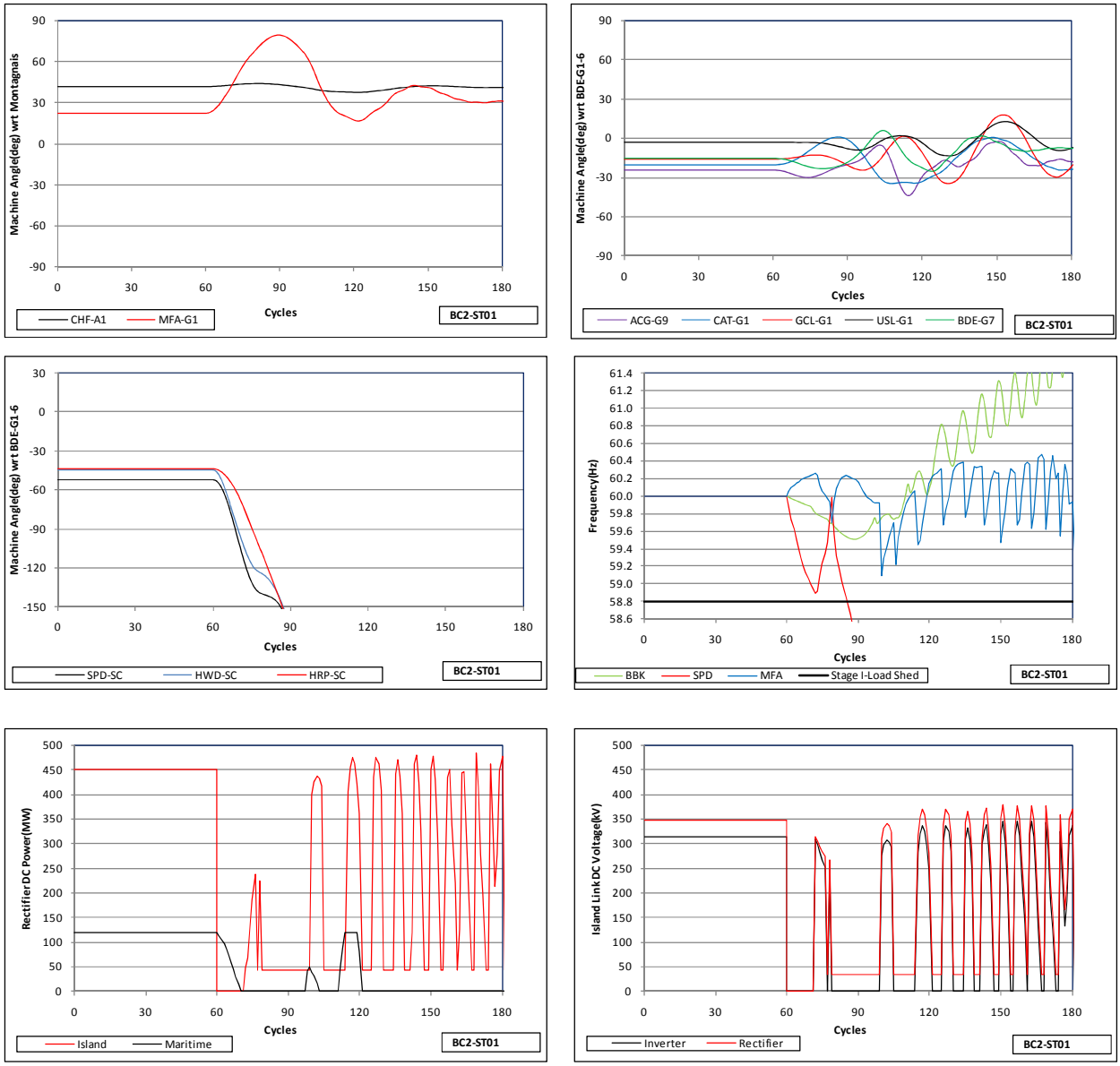
Parameter	Value	Parameter	Value
Rating	+300/-165 MVAr	Xl	0.09 pu
H	7.84 kW-s/kVA	S(1.0)	0.04
Xd	1.24 pu	S(1.2)	0.14
Xq	0.85 pu	T'd0	11 s
Xd'	0.27 pu	T"d0	0.08 s
Xd"	0.165 pu	T"q0	0.29 s
Xq"	0.177 pu		

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For the first case, the above model was scaled to represent a 150 MVAr synchronous condenser.

The results (machine angles, voltages and dc power flow) are shown in Figure 3-1.

Figure 3-1: BC2-ST01, Winter Peak/Island Link 900 MW/Maritime Link 239 MW Temporary Bipole Fault on the Island Link/150MVAr SC at Soldiers Pond



These results clearly demonstrate that the synchronous condensers at Soldiers Pond, Holyrood and Hardwoods quickly lose synchronism with the rest of the Island machines. As a result, the system voltages oscillate wildly and the dc link repeatedly by-passes or blocks.

To improve this performance, the rating of the synchronous condenser at Soldiers Pond was increased to 300 MVAr. The results are shown in Figure 3-2. The improvement in performance is significant in that all machines retain their synchronism and the system voltages recover quickly and in a stable and damped manner following the temporary fault. The contribution of the high-inertia synchronous condenser at Soldiers Pond amounted to 400 MW at the instant of the fault, when the Island Link is blocked. This contribution decays to zero over 15-cycles and then reverses as the system replaces the power extracted from the inertia of this machine. The reactive contribution of the high-inertia synchronous condenser is also significant, starting from a steady-state output of 250 MVAr and peaking at over 350 MVAr following the restart of the Island Link. The two Holyrood units, operating as synchronous condensers, contributed 110 MW of active support and 110 MVAr of reactive support over the same period.

The ramping down of the export over the Maritime Link to zero by the frequency controller at Bottom Brook is critical to the satisfactory recovery of the system. The export power level reduced from 239 MW to zero in approximately 200 ms/ 12-cycles after fault inception.

The frequency at Soldiers Pond fell quickly to a value of 59.14 Hz in 200 ms/ 12-cycles and then recovered quickly to 59.8 Hz in the next 100 ms/ 6-cycles. An overshoot of frequency to 60.25 Hz occurred between 1 and 2 s after fault initiation due to the action of the frequency controller on the Soldiers Pond converter. Following this the frequency settled down to a steady-state value of 60.15 Hz. This is well above the 1st-stage load shedding setting of 58.8 Hz, currently used on the system. The frequency at Muskrat Falls is essentially the frequency of the Hydro-Quebec system since Muskrat Falls is synchronously tied to this network via Churchill Falls. The equivalent model of the Hydro-Quebec system used the GENCLS model of PSS®E and as such it cannot be fitted with a governor control model. The governors applied at Muskrat Falls and Churchill Falls are very slow-

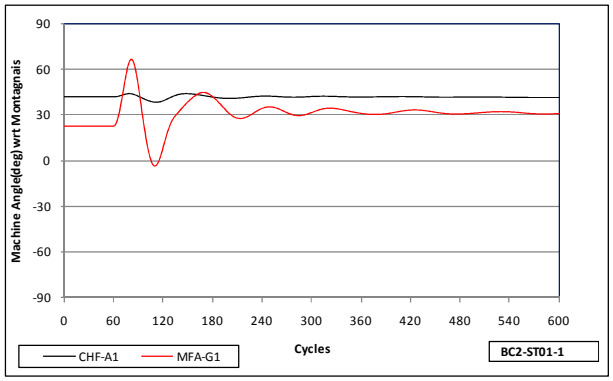
acting and cannot bring the frequency down quickly enough. In practice, the post-fault frequency at Muskrat Falls will be controlled by the overall frequency control scheme of Hydro-Quebec. Since this is not modeled in these simulations, the post-fault frequency at Muskrat Falls is not accurately determined. At some stage, it will be necessary for the frequency control of the Hydro Quebec system to be modeled correctly for such cases to confirm that the frequency at Churchill Falls and Muskrat Falls can be returned to a nominal value within a reasonable time frame.

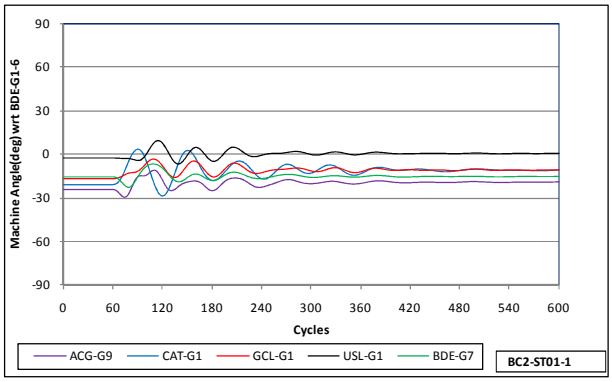
Immediately following the interruption of the bipole, the 315 kV voltage at Muskrat Falls increased to 119% and then decreased back to 100% over the next 267 ms/ 16-cycles. This temporary over-voltage is not considered particularly severe.

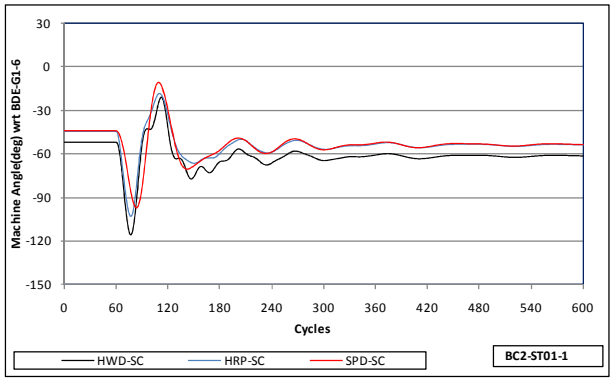
However, even with the reactive support provided by the high-inertia synchronous condensers at Soldiers Pond and the synchronous condensers at Holyrood and Hardwoods, the Soldiers Pond 230 kV ac bus voltage fell momentarily to 80% after fault clearance. At this level there is a significant risk of commutation failure of the inverter.

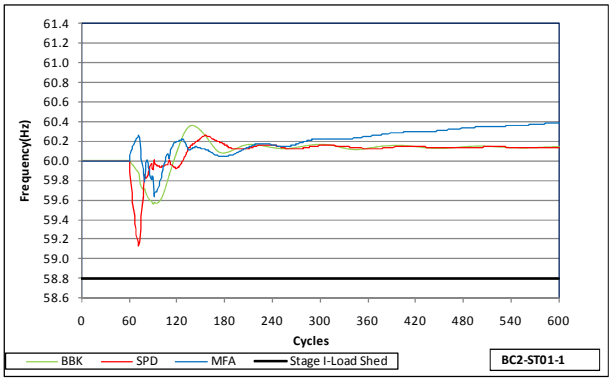
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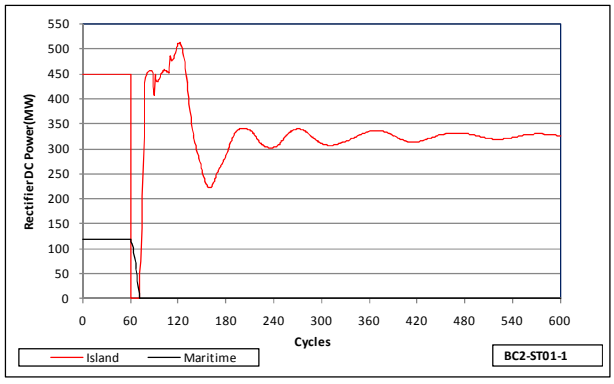
Figure 3-2: BC2-ST01-1, Winter Peak/Island Link 900 MW/Maritime Link 239 MW Temporary Bipole Fault on the Island Link/300MVAr SC at Soldiers Pond

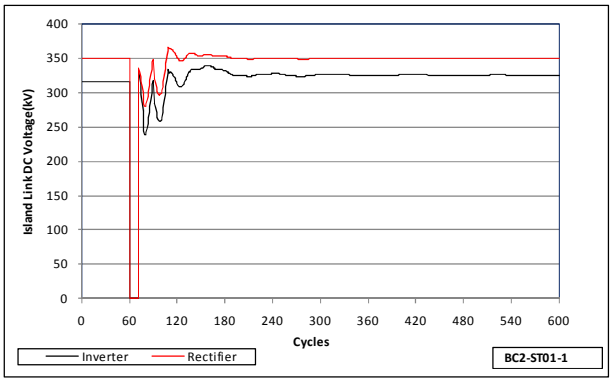




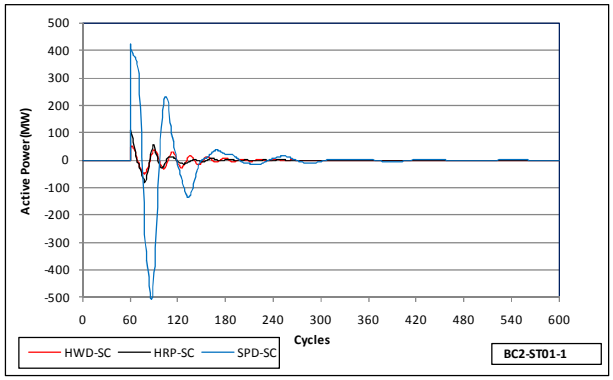


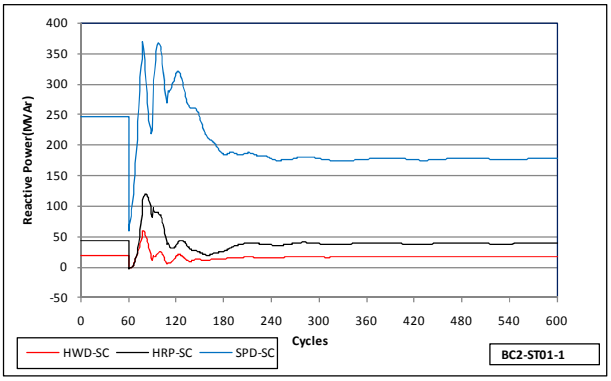


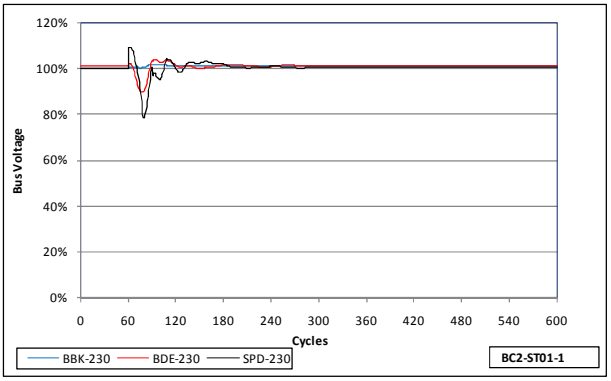


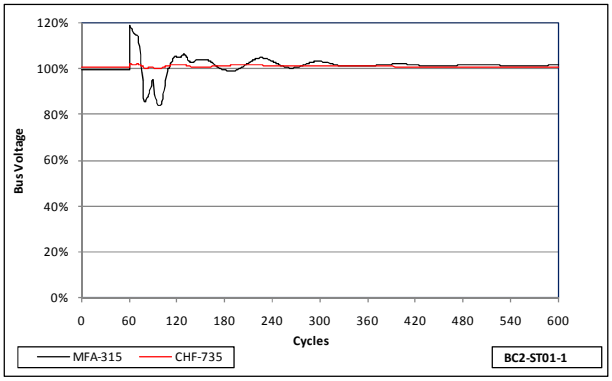


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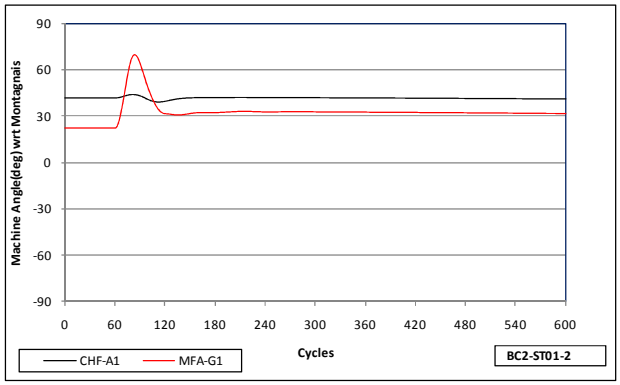
In order to alleviate this problem, the re-start of the Island Link was modified so that the dc power was ramped up in three stages:

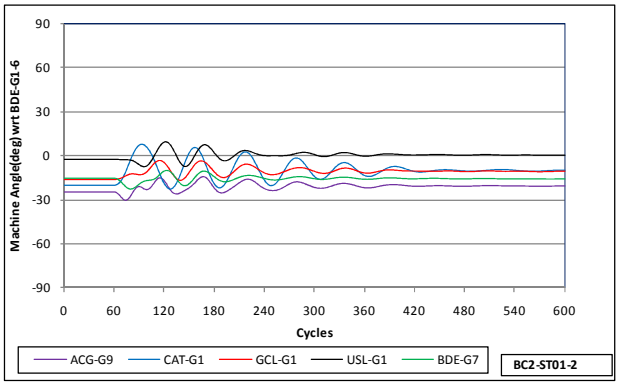
- At 12-cycles/200 ms after fault inception, the dc power was ramped up to 175 MW per pole,
- 18-cycles/300 ms later (30-cycles/500 ms after fault inception), the dc power was ramped up to 260 MW per pole,
- 18-cycles/300 ms later (48-cycles/800 ms after fault inception), the dc power was ramped up to 320 MW per pole,

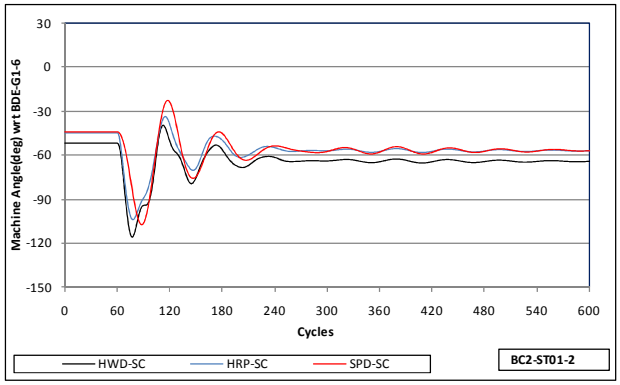
The resulting performance is shown in Figure 3-3. It can be seen that delaying the recovery of the dc power as described above, allows the voltage at Soldiers Pond 230 kV to recover without falling below 90%, thus minimizing the risk of a commutation failure. The staged recovery of the dc power described above is a close approximation to a frequently-used method of controlling the re-start of a dc converter that modifies the dc power level to maintain the ac voltage at or above a pre-set level that will minimize the risk of commutation failure.

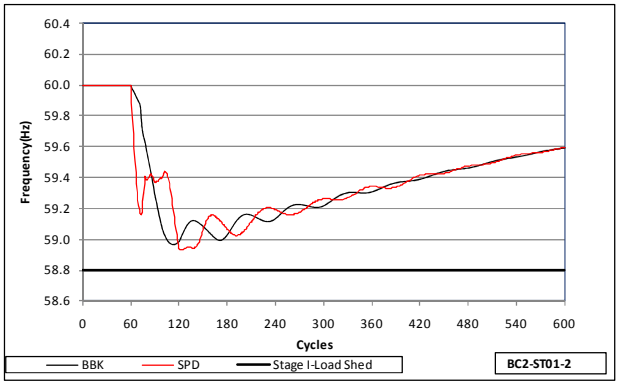
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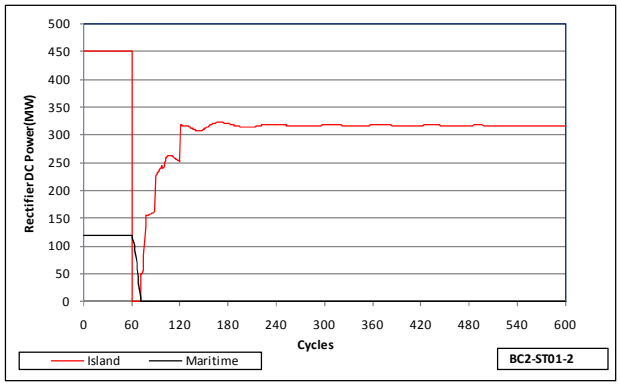
Figure 3-3: BC2-ST01-2, Winter Peak/Island Link 900 MW/Maritime Link 239 MW Temporary Bipole Fault on the Island Link/300MVAr SC at Soldiers Pond Island Link re-started in 3 Stages

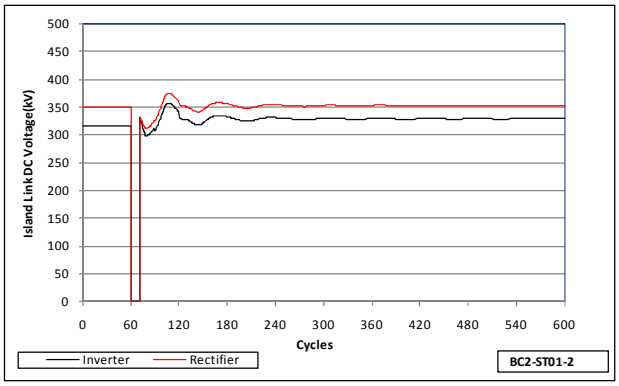




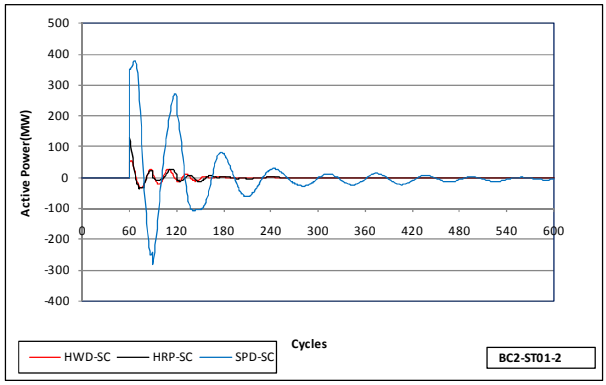


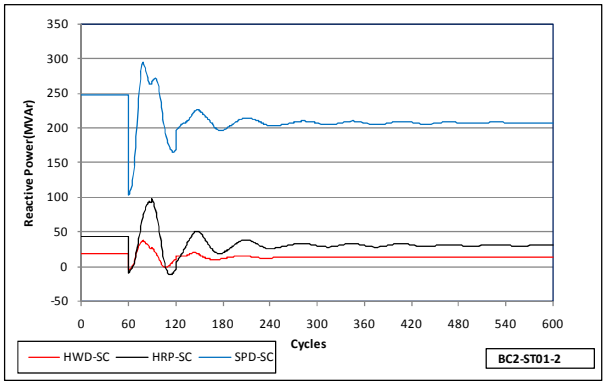


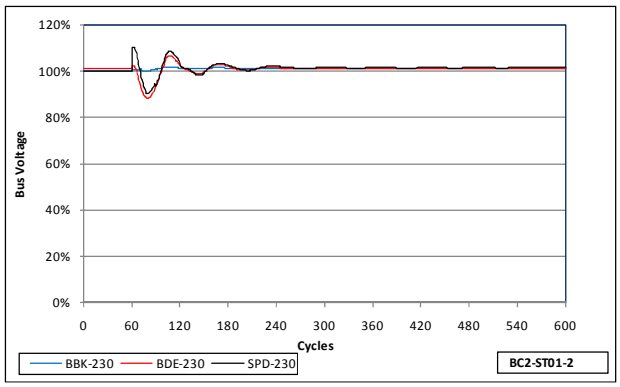


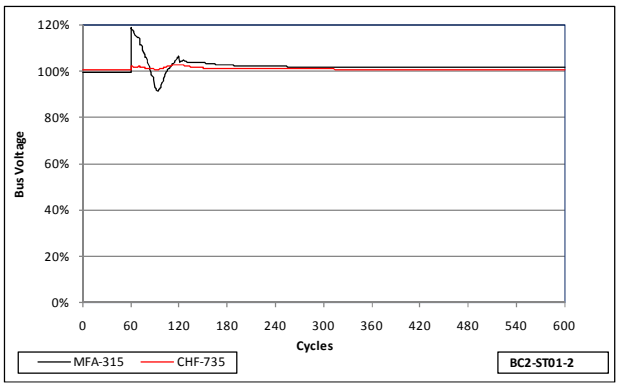


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3.1.2 BC2-ST02: Permanent Pole Fault on the Island Link

The next case considered a permanent dc fault on one pole of the Island Link. Based on the results of the previous case, the high-inertia synchronous condenser at Soldiers Pond was maintained as a 300 MVAr unit.

Following the fault, the dc resistance of the healthy pole was increased from 26 Ω to 42 Ω to represent the electrode lines as a return path. The overload capability of each pole can reach 200% in order to compensate for the dc transfer deficit caused by the loss of one pole.

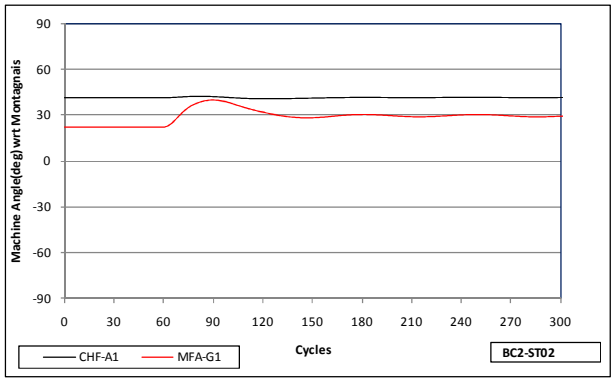
The results are shown in Figure 3-4, and indicate that the system recovers quickly from this disturbance. The frequency controller at Soldiers Pond should remain enabled to ensure a quick response from the healthy pole to compensate for the permanent pole outage. The healthy pole increased its dc power level from 450 MW before the fault to 730 MW after fault clearance.

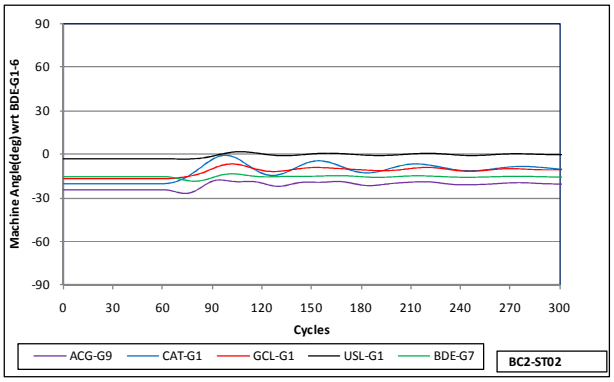
It was observed that the high-inertia synchronous condenser at Soldiers Pond settled down after the disturbance with an output of 340 MVAr, which is above its rated value of 300 MVAr. This situation will be temporary until such time as the converter transformer on the healthy pole makes adjustments to bring the firing angle (γ) back to its nominal value of 18 degrees. This will reduce the reactive power requirement of the converter and lower the loading on the synchronous condenser to below its rated value.

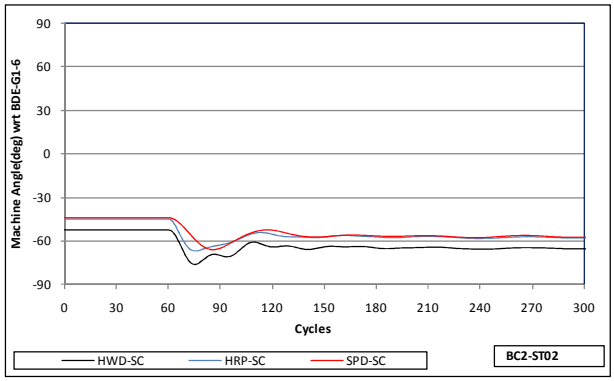
The frequency at Soldiers Pond stabilized at a value of 59.6 Hz. This value represents the balance point at which the frequency controller at Soldiers Pond provides a steady ordered value of dc power to the converter since the frequency is not changing. A slower-acting frequency controller will also be required to correct the frequency slowly back to 60 Hz if sufficient additional capacity is available on the Island Link to do this. This type of action can wait until the system has settled down after the disturbance and could even be handled manually by adjusting the power order on the Island Link or adjusting the available Island generation levels.

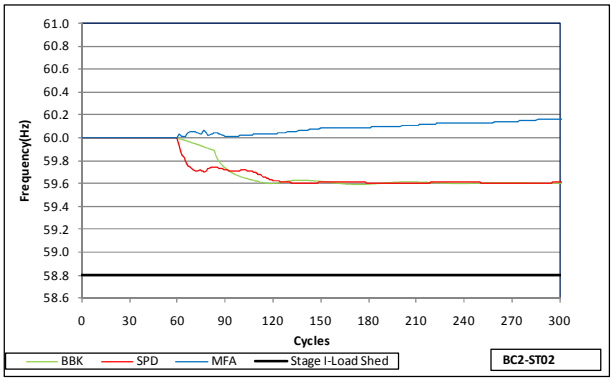
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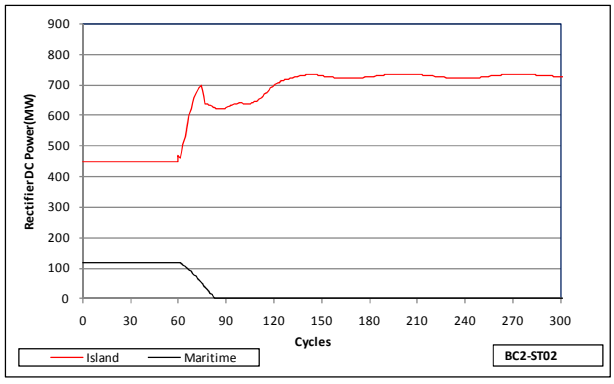
Figure 3-4: BC2-ST02, Winter Peak/Island Link 900 MW/Maritime Link 239 MW Permanent Pole Outage on the Island Link/300MVAr SC at Soldiers Pond

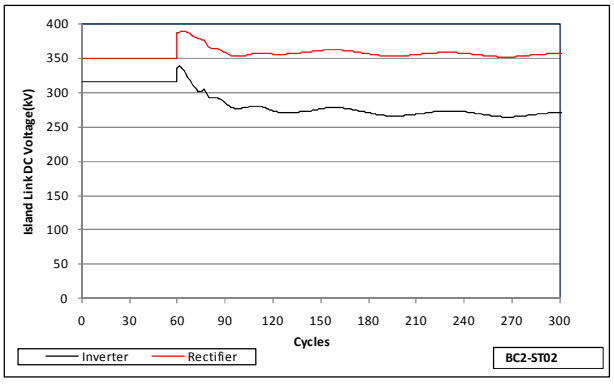




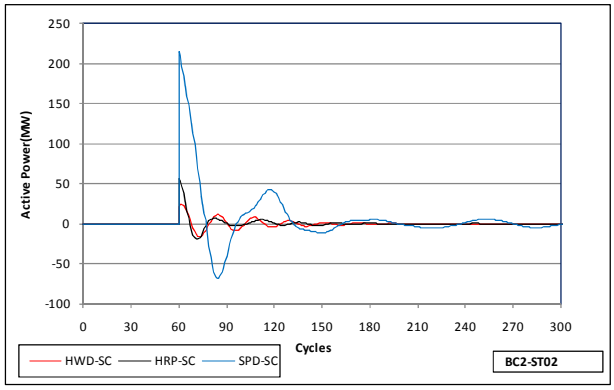


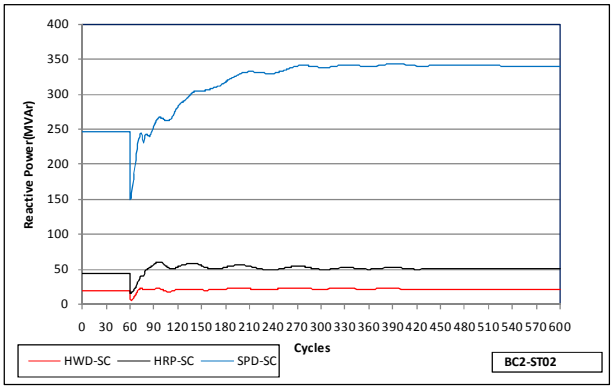


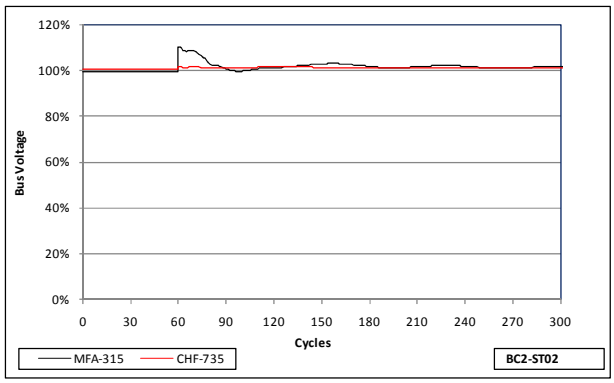


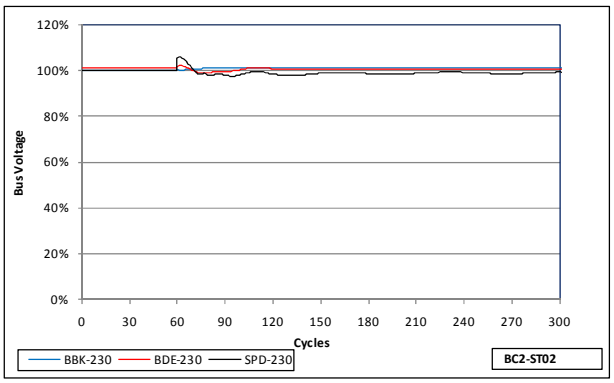


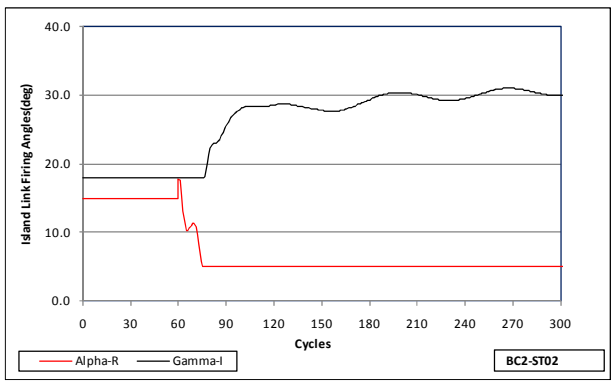
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3.1.3 BC2-ST03: Three Phase Fault at Muskrat Falls 315 kV on line to Churchill Falls

A 100 ms/ 6-cycle, 3-phase fault was applied at Muskrat Falls 315 kV resulting in the outage of one 315 kV circuit between Churchill Falls and Muskrat Falls. The voltage depression at the Muskrat Falls converter station will result in blocking of the converters at Muskrat Falls and an interruption of the export over the Island Link, in much the same way as the temporary bipole fault discussed earlier. However, in this case, because there are only 3 units operating at Muskrat Falls, the balance of the 900 MW pre-fault export and the load at Happy Valley is supplied from Churchill Falls. After fault clearance, restoration of the export level means that all the balance of power from Churchill Falls now has to flow down a single circuit from Churchill Falls. This is to some extent offset by the fact that the export over the Maritime Link will have been reduced to zero. However, when the Island Link first comes back into service after the block, the frequency controller at Soldiers Pond will not be operational since it was delayed for 500 ms in BC2-ST01-1. This delay represented the minimum time to allow for satisfactory recovery of the ac system. Deactivating the frequency controller helps the recovery of the ac system during faults at nearby buses. This means that the Island Link will return to its previous export level of 900 MW. The results are shown in Figure 3-5.

It can be seen that the system appears to perform reasonably through the duration of the fault and that recovery is being achieved when at the instant that the frequency controller at Soldiers Pond is enabled (1.50 s in the plots below) the frequency at Soldiers Pond is marginally below 60 Hz and the controller signals an increase in the dc power. This increase is sufficient to result in a depression of the dc and ac voltages to the point where the converters block momentarily, re-start and then block again. To avoid this situation which could, in practice lead to multiple commutation failures, the response of the frequency controller was modified such that:

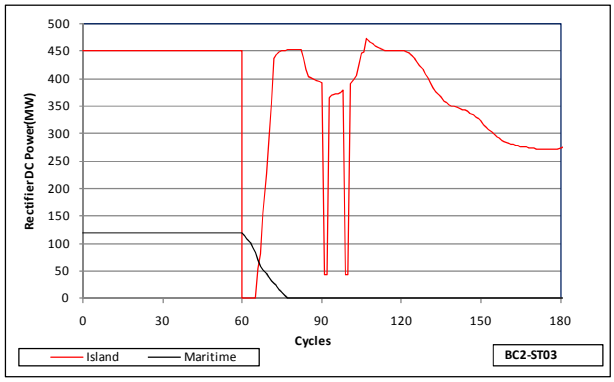
- 500 ms after the initiation of the fault, the power order on the Island Link was reduced from 450 MW per pole to 320 MW per pole. This value is based on the fact that the Maritime Link has been shut down and the Island Link can be reduced by approximately 240-250 MW to accommodate this.

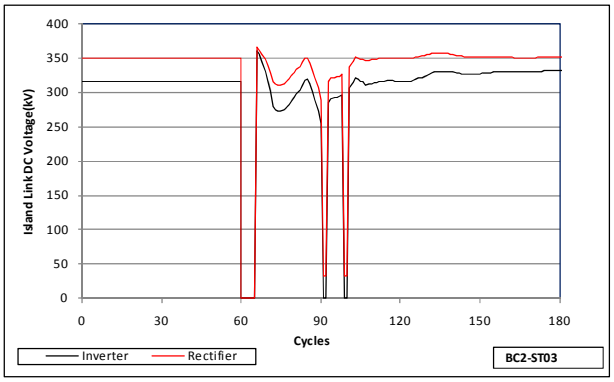
- The frequency controller was disabled until such time as the frequency at Soldiers Pond returned to 60 Hz.

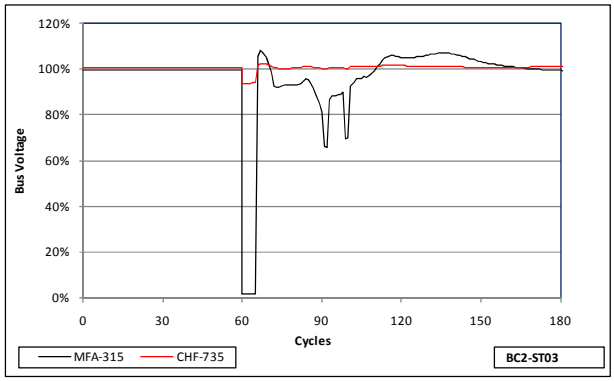
The results are shown in Figure 3-6 where it can be seen that the system recovers satisfactorily with the reduction in the dc power order allowing the ac and dc voltages to recover to satisfactory levels where a block will not occur. The frequency controller actually came into operation approximately 4 s/ 240-cycles after fault initiation. During the fault period, the frequency at Soldiers Pond fell to 59.4 HZ and during the recovery period, before the frequency controller is re-activated, the frequency varied with a minimum value of 59.8 Hz. Under the action of the frequency controller, the dc power was slightly reduced from 320 MW per pole to 315 MW per pole to maintain the frequency at 60 Hz.

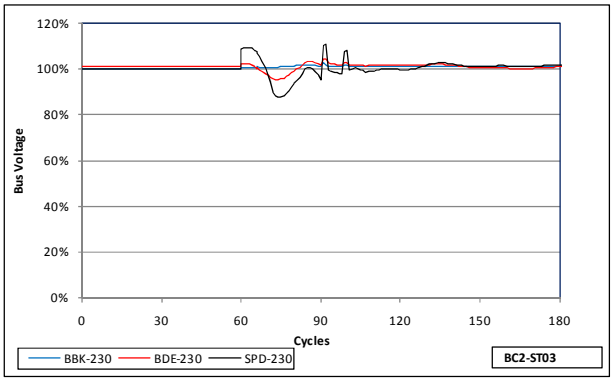
This type of control will require an auxiliary input signal to inform the converter control that the 315 kV line from Churchill Falls to Muskrat Falls has been tripped. This will be used to trigger the reduction in power order. Since the line is tripped at 100 ms/ 6-cycles and the power order reduction does not occur until 500 ms/ 30-cycles after fault initiation, there is ample time to acquire and process this information.

Figure 3-5: BC2-ST03, Winter Peak/Island Link 900 MW/Maritime Link 239 MW 6-cycle, 3-phase Fault at Muskrat Falls 315 kV on line to Churchill Falls









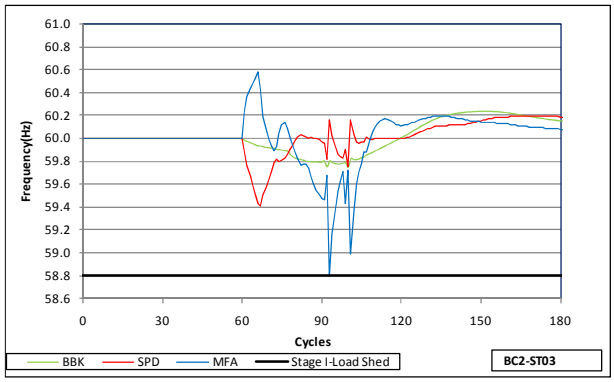
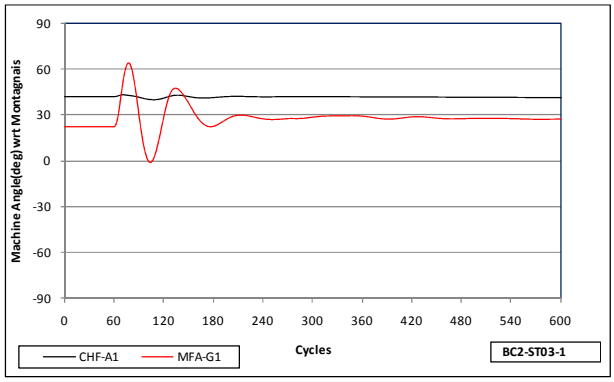
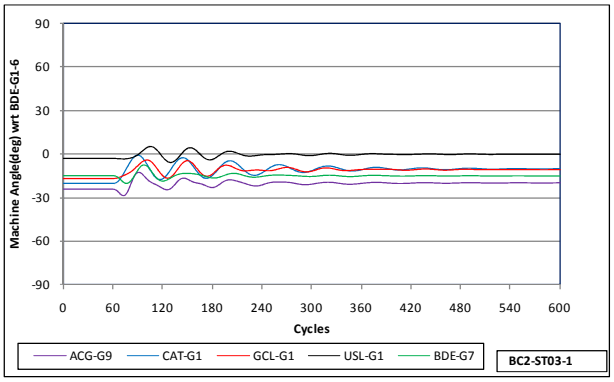
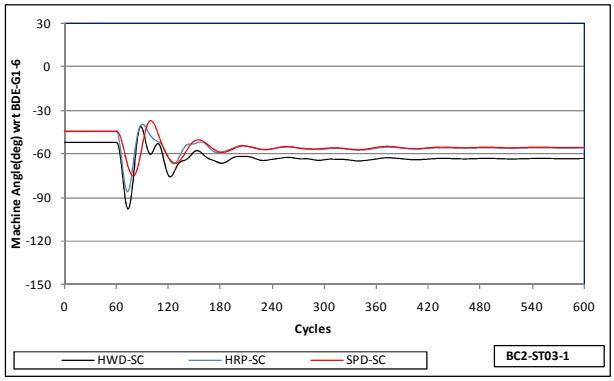
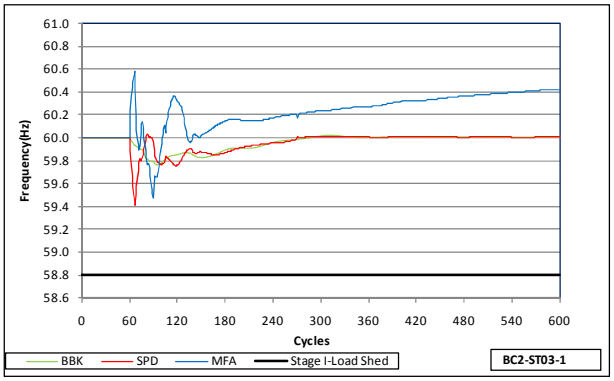


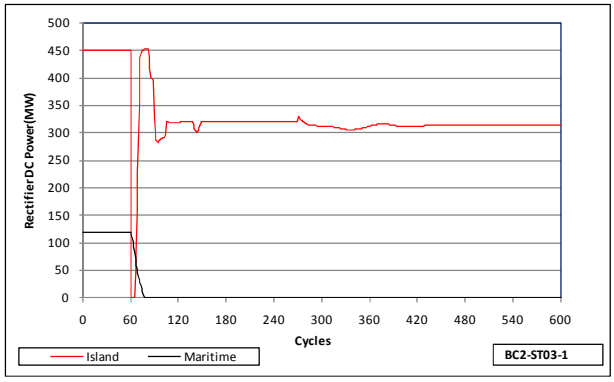
Figure 3-6: BC2-ST03-1, Winter Peak/Island Link 900 MW/Maritime Link 239 MW 6-cycle, 3-phase Fault at Muskrat Falls 315 kV on line to Churchill Falls (Power Order Reduction+Frequency Controller Delayed Operation)

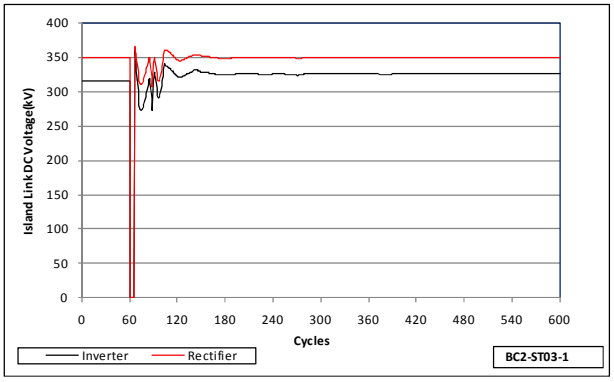




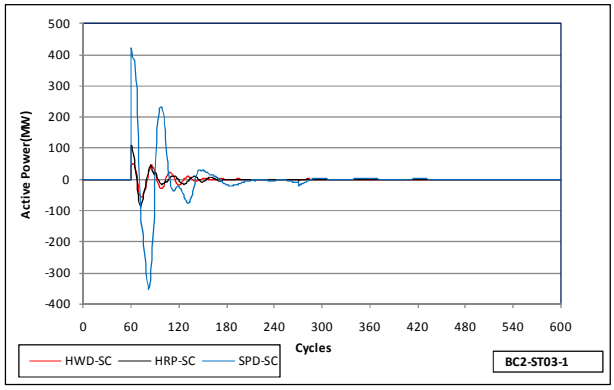


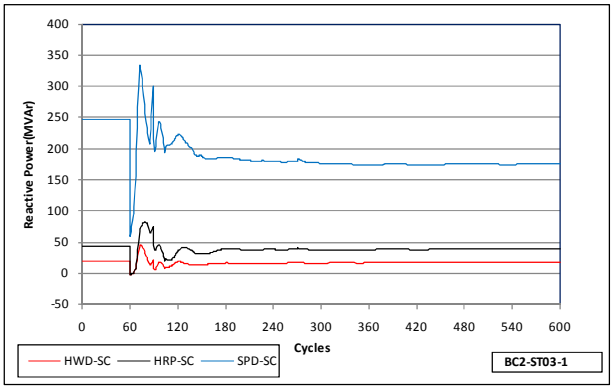


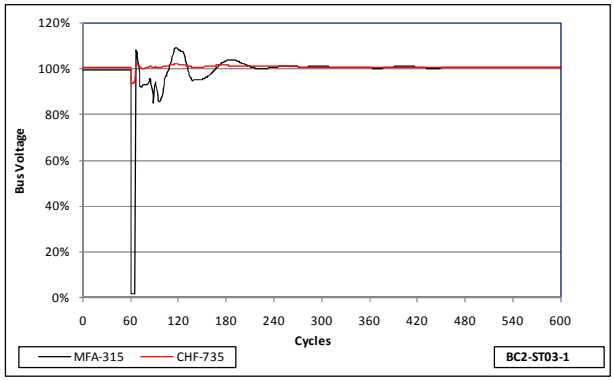


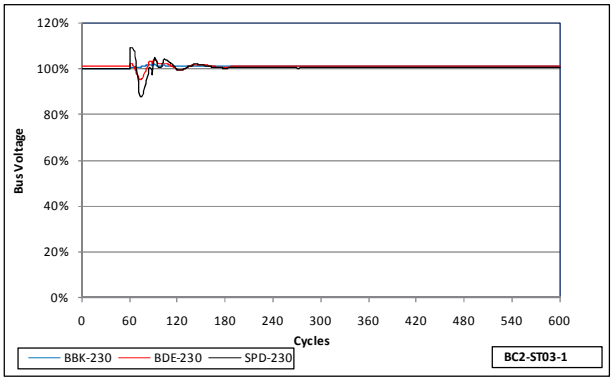


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3.1.4 BC2-ST04: Three Phase Fault at Bay d'Espoir 230 kV on line to Western Avalon

In this case a 6-cycle, 3-phase fault was applied at Bay d'Espoir 230 kV with a post-fault outage of the 230 kV line to Western Avalon.

The results are shown in Figure 3-7.

Since the voltage at Bay d'Espoir falls to zero during the fault, the voltages at Bottom Brook and Soldiers Pond suffer major depressions (below 80%). This will cause the Bottom Brook and Soldiers Pond converters to block immediately, reducing the power on the Island and Maritime Links to zero. However, as in previous cases, the Maritime Link was then held at zero power for the duration of the simulation. It may be noticed that the Island Link rectifier power does not reduce to zero in this case. This is a result of the type of model used in the program. The inverter model cannot model a commutation failure, such as would occur when the ac system voltage is depressed due to an ac fault. To get around this problem the inverter model has a feature that automatically bypasses (short-circuits) the inverter on the dc side. When this occurs, the rectifier increases its firing angle to reduce the dc current to its minimum value. This accounts for the small amount of power seen at the rectifier end due to the minimum dc current circulating around the two poles. This current does not pass through the inverter.

The system remained in synchronism and recovered quickly from the fault with 300 MVAr of synchronous condensers operating at Soldiers Pond. The power on the Island Link was reduced from 900 MW to approximately 640 MW as a result of the removal of the Maritime Link export. The frequency at Soldiers Pond fell momentarily to 59.2 Hz and following the re-start of the Island Link rose for a short period to 60.6 Hz at which time the frequency controller at Soldiers Pond was re-activated (500 ms following the fault) and stabilized the frequency between 60.1-60.2 Hz by reducing the Island Link dc power.

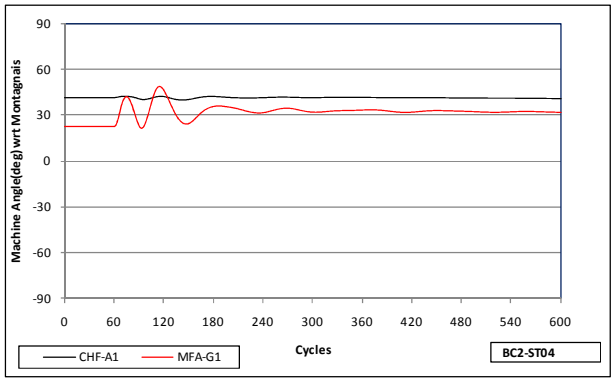
The high-inertia synchronous condenser at Soldiers Pond contributed up to 450 MW and 450 MVAr to the system during and after fault clearance.

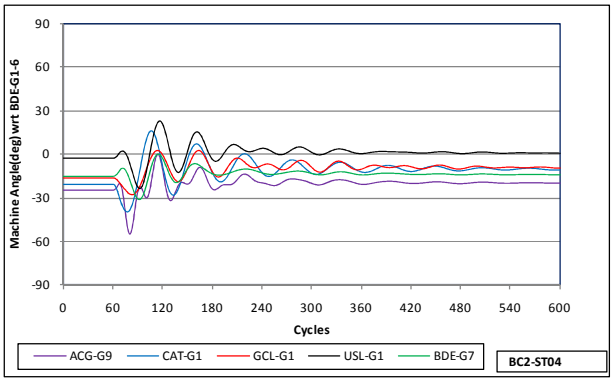
The rapid frequency decline at Soldiers Pond (0.8 Hz) occurred over the fault period (6-cycles/100 ms). This corresponds to a rate of change of frequency of 8 Hz/s,

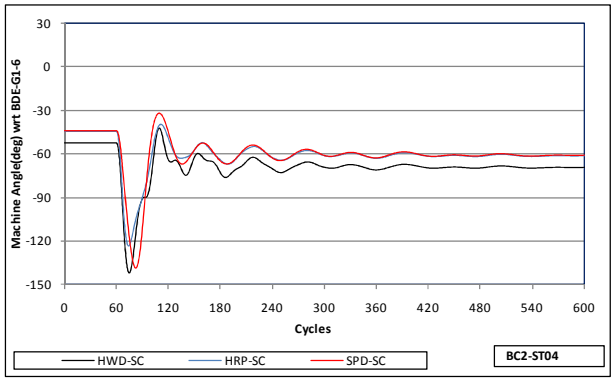
higher than the normal rate of change on the system, which is closer to 3 Hz/s. The reason for this higher rate of change of frequency is attributed to the fact that the three-phase fault at Bay d'Espoir effectively isolates Soldiers Pond from the inertia of the Bay d'Espoir generators and all other generators to the west of Bay d'Espoir during the fault period. The total inertia of the system (9,000 MW-s) is therefore not available to support the frequency at Soldiers Pond during this time. The only inertia available to Soldiers Pond comes from the synchronous condensers at Soldiers Pond itself, Holyrood and Hardwoods. This amounts to approximately 2,000 MW-s. The total load to the east of Bay d'Espoir is approximately 1,100 MW but, since the voltage is depressed, the effective load is approximately 800 MW. This gives an effective inertia constant in that part of the system of 3.45 MWs/MVA with a run-down time of 6.9 s. This translates to a rate of change of frequency of 8.7 Hz/s which is close to the value found in the simulation.

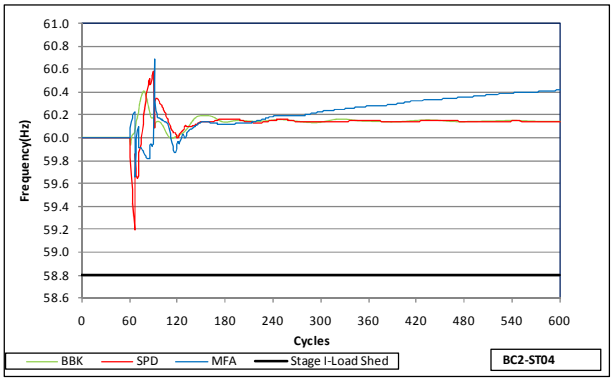
However, it can again be noted that following fault clearance and re-establishment of the Island Link, the voltage at Soldiers Pond 230 kV fell momentarily to less than 90%, raising the possibility of commutation failure on the Island Link inverter. It was observed that the voltage at Soldiers Pond 230 kV returned to barely above 90% following fault clearance and decreased from that value to 80% as the dc power was re-started. The main cause of this poor post-fault voltage appears to be even lower post-fault voltages at Western Avalon and Bay d'Espoir.

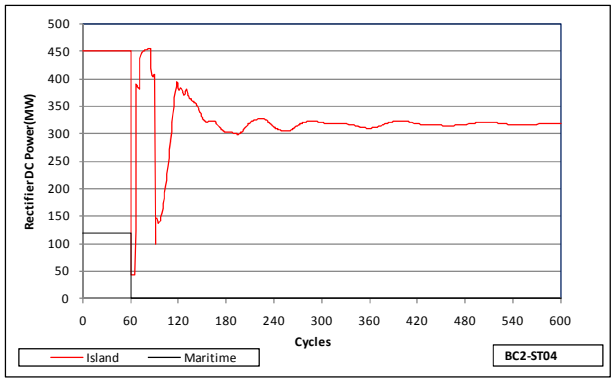
Figure 3-7: BC2-ST04, Winter Peak/Island Link 900 MW/Maritime Link 239 MW 6-cycle, 3-phase Fault at Bay d'Espoir 230 kV on line to Western Avalon

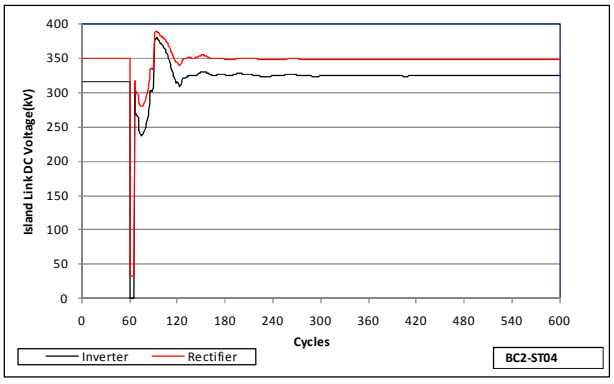




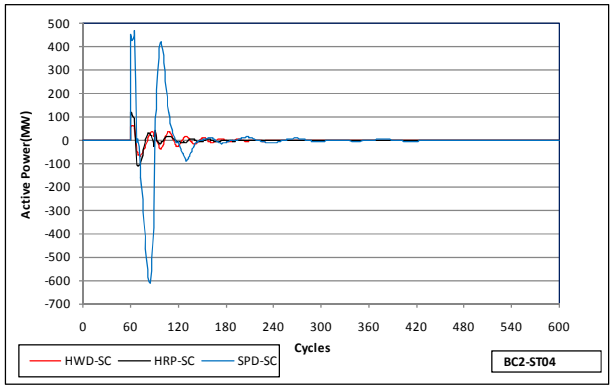


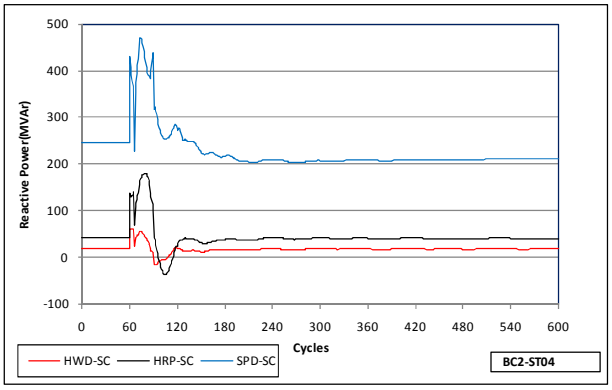


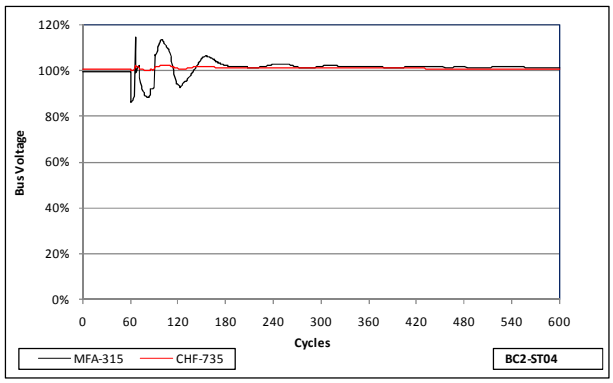


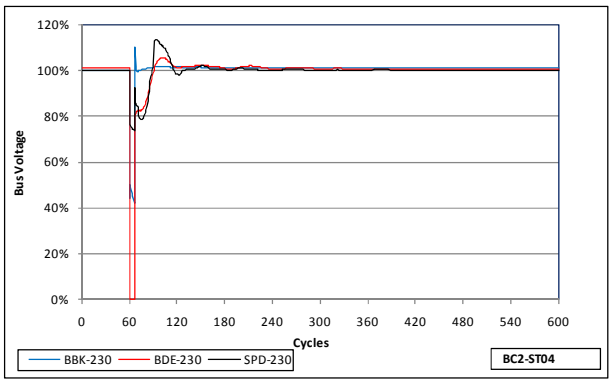


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Various strategies were investigated to alleviate this under-voltage:

- staging of the dc re-start,
- replacement of the exciters at Bay d'Espoir with high-gain, high ceiling exciters,
- the application of 50% series compensation to the 230 kV lines from Bay d'Espoir to Sunnyside [TL202 &TL206] and from Bay d'Espoir to Western Avalon [new line],
- the application of an SVC at Western Avalon,
- the application of an SVC at Bay d'Espoir, and
- increasing the number of synchronous condensers at Soldiers Pond and Holyrood.

The only effective solutions were:

- the application of an SVC at Bay d'Espoir or Western Avalon together with the third synchronous condenser at Holyrood, and
- to connect the third synchronous condenser at Holyrood and to increase the synchronous condenser rating at Soldiers Pond to 450 MVAr.

The other strategies failed to correct the voltage dip at Soldiers Pond sufficiently to remove the risk of commutation failure following the fault clearance.

The system performance with the SVC connected at Bay d'Espoir is shown in Figure 3-8 and the performance with the additional synchronous condensers at Holyrood and Soldiers Pond is shown in Figure 3-9.

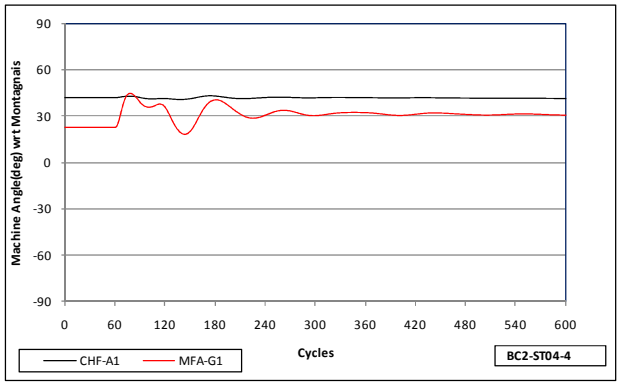
The SVC at Bay d'Espoir produced up to 250 MVAr following the fault clearance. It is worth noting that the rating of ±250 MVAr for this SVC corresponds exactly to the reactive capability of a 500 MW VSC converter, similar to one that could be employed at Bottom Brook for the Maritime Link.

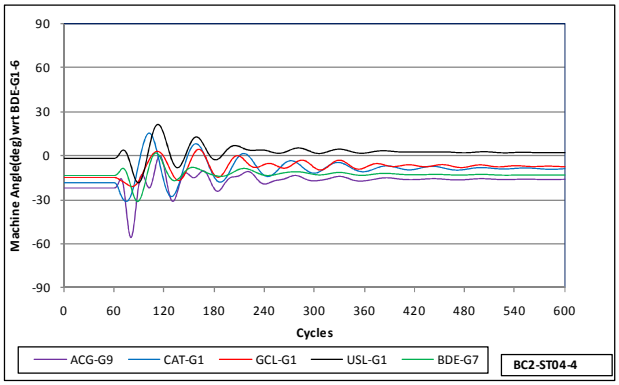
The synchronous condensers at Soldiers Pond produced close to 500 MW and 375 MVAr during and immediately after the fault, maintaining the voltage at Soldiers Pond 230 kV to 90% or above following fault clearance.

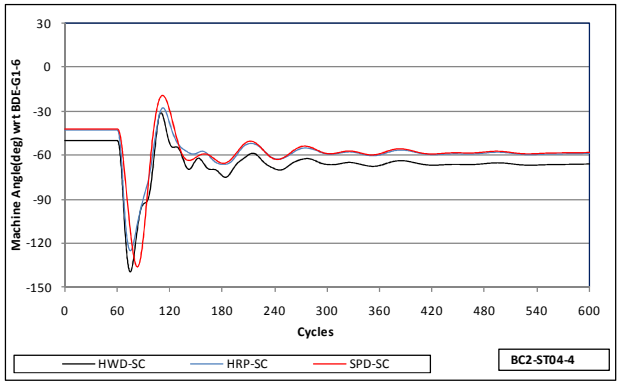
It can be seen that this fault case constitutes the defining case for the synchronous condenser requirements at Soldiers Pond.

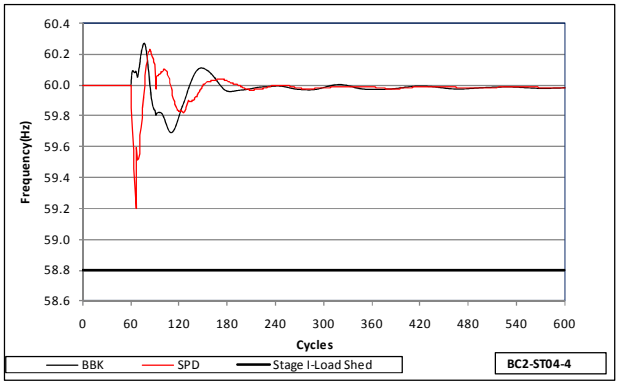
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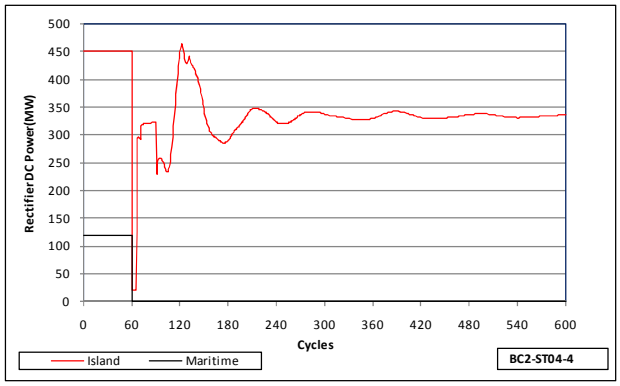
Figure 3-8: BC2-ST04-4, Winter Peak/Island Link 900 MW/Maritime Link 239 MW 6-cycle, 3-phase Fault at Bay d'Espoir 230 kV on line to Western Avalon +/-250MVAR-SVC at Bay d'Espoir+3-SC at Holyrood

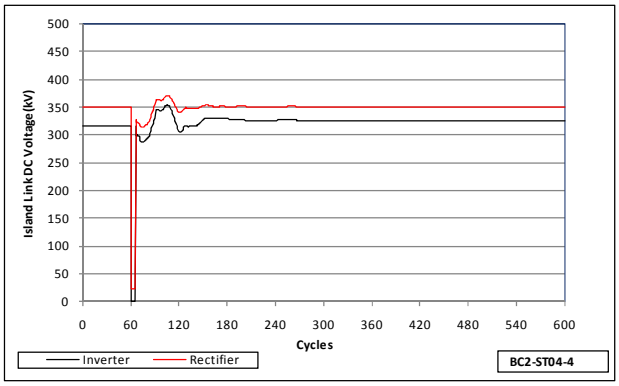




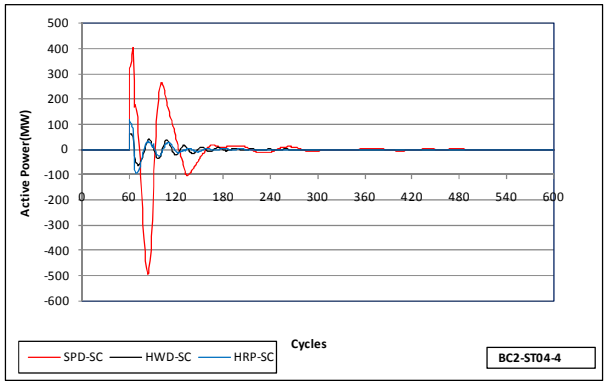


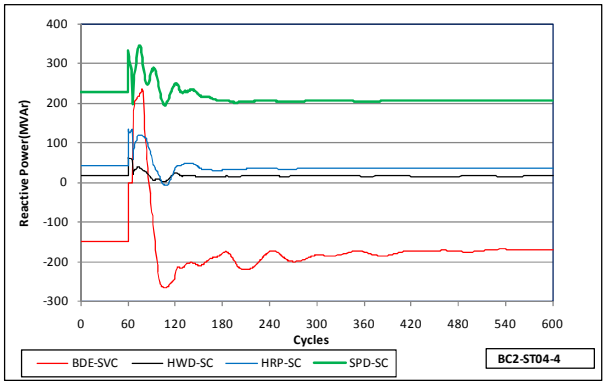


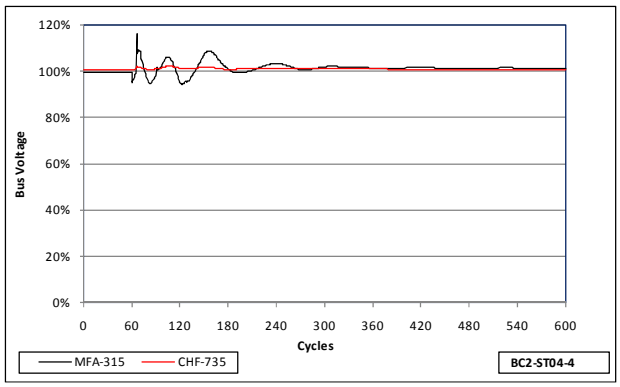


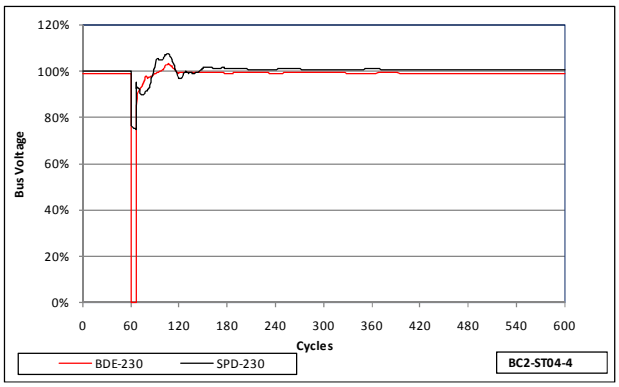


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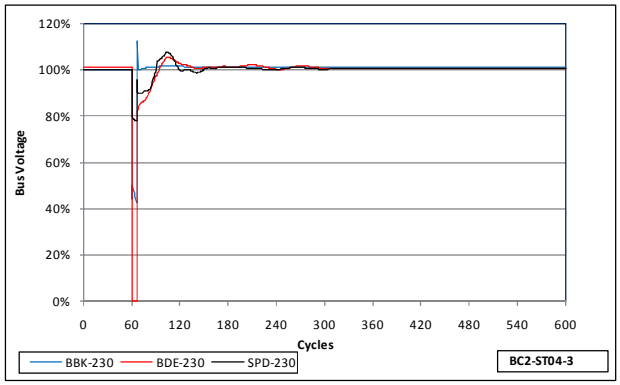


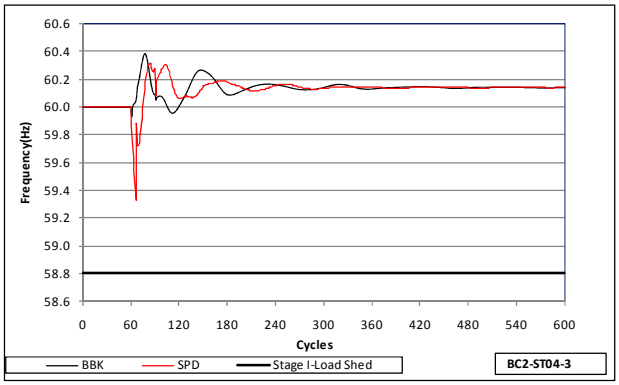


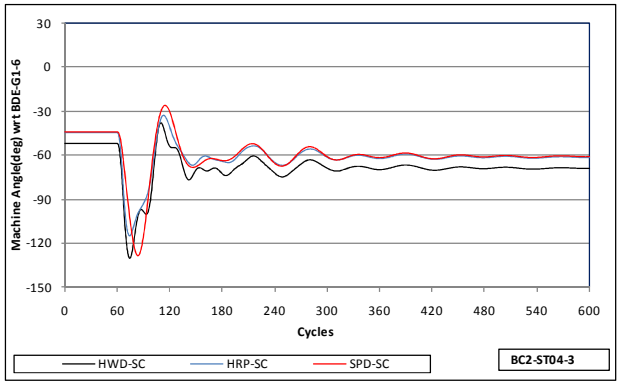


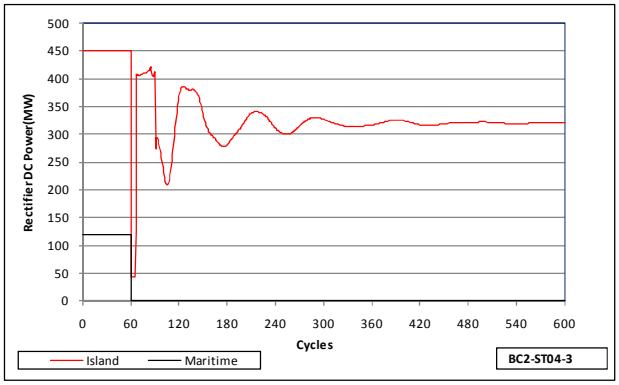
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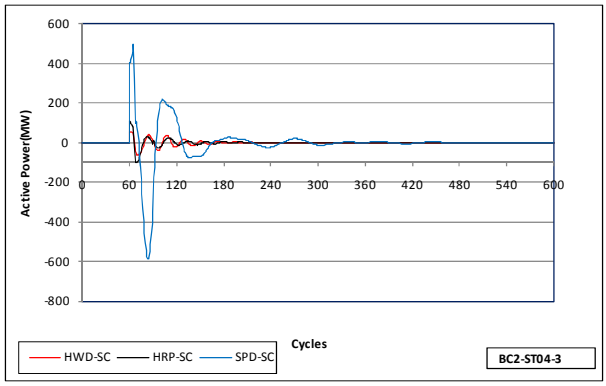
Figure 3-9: BC2-ST04-3, Winter Peak/Island Link 900 MW/Maritime Link 239 MW 6-cycle, 3-phase Fault at Bay d'Espoir 230 kV on line to Western Avalon 450MVAR-SC at Soldiers Pond+3-SC at Holyrood

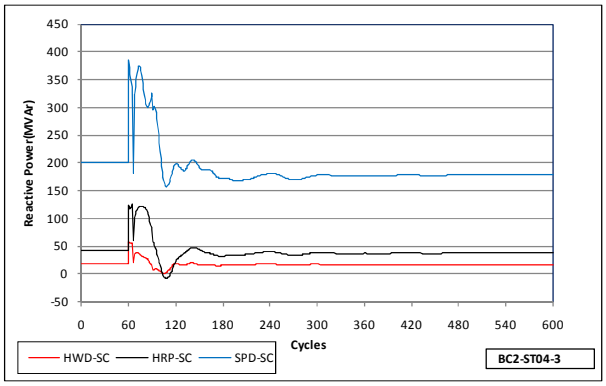












3.1.5 BC2-ST05: Three Phase Fault at Soldiers Pond 230 kV on line to Western Avalon (TL217W)

In the case of a 6-cycle, 3-phase fault at Soldiers Pond 230 kV on the line to Western Avalon, TL217W (Figure 3-10), the voltage depression at Soldiers Pond was sufficient to cause the Island Link to block. However, the voltage and frequency depressions at Bottom Brook were not severe enough to cause automatic blocking of the Maritime Link.

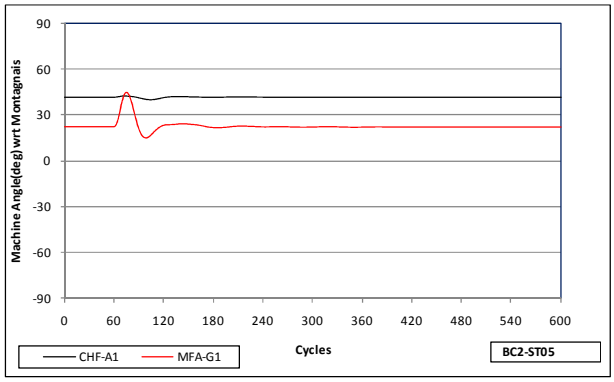
Following fault clearance, both dc links recovered quickly to their pre-fault levels and the system remained in synchronism with the system voltages recovering quickly.

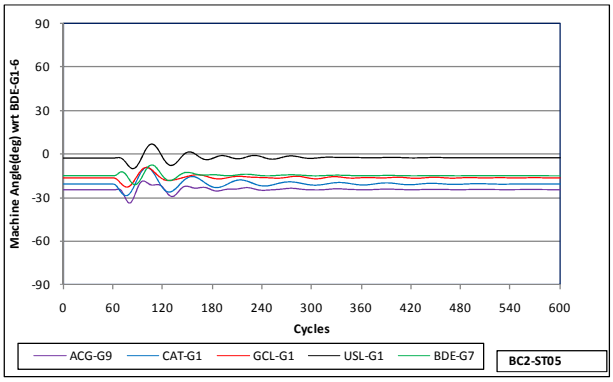
With only 300 MVAr of high-inertia synchronous condensers at Soldiers Pond and two synchronous condensers running at Holyrood, the same problem with the Soldiers Pond 230 kV voltage falling below 90% following fault clearance was seen in this case as in the previous case. To alleviate this problem it was necessary to reduce the export over the Maritime Link to zero and to delay the re-start of the Island Link until the voltage had recovered sufficiently at Soldiers Pond. This again approximates the control function that regulates the timing, level and rate at which the dc is ramped up as a function of the inverter ac bus voltage. The system performance is shown in Figure 3-11.

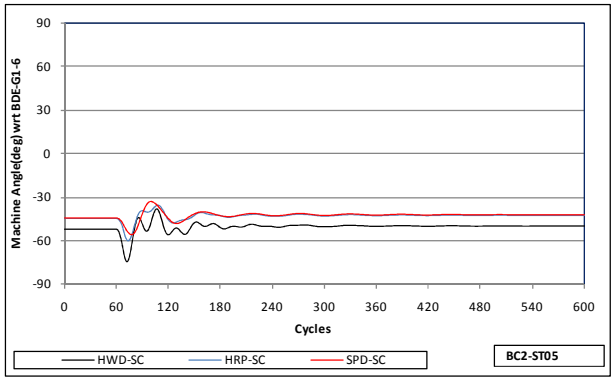
It was not found necessary to increase the rating of the synchronous condenser at Soldiers Pond.

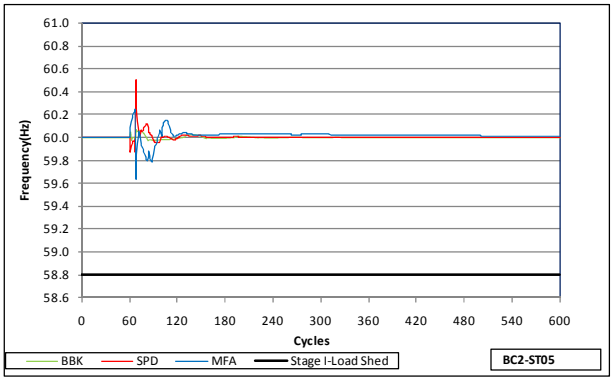
A similar result was found for a 3-phase fault at Sunny Side on the line to Western Avalon [TL203].

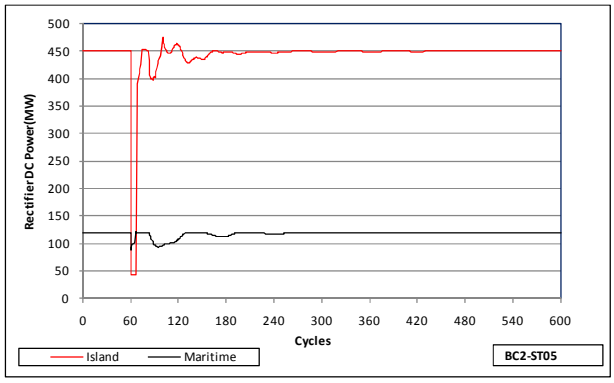
Figure 3-10: BC2-ST05, Winter Peak/Island Link 900 MW/Maritime Link 239 MW 6-cycle, 3-phase Fault at Soldiers Pond 230 kV on line to Western Avalon (TL217W)

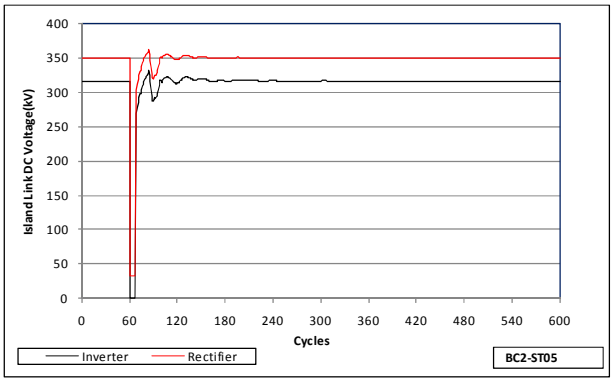




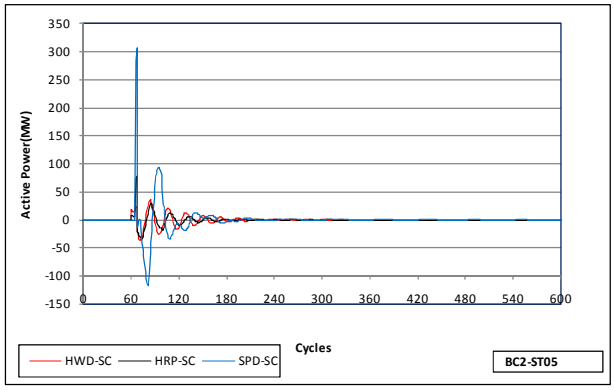


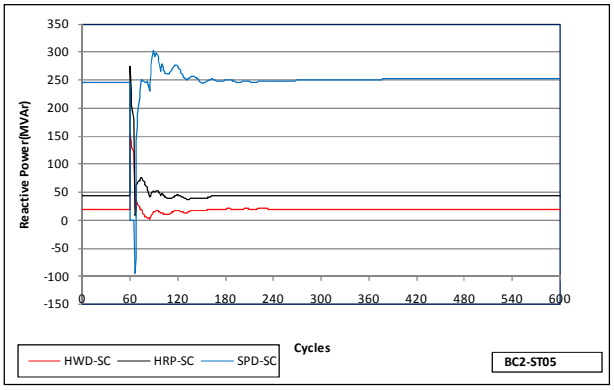


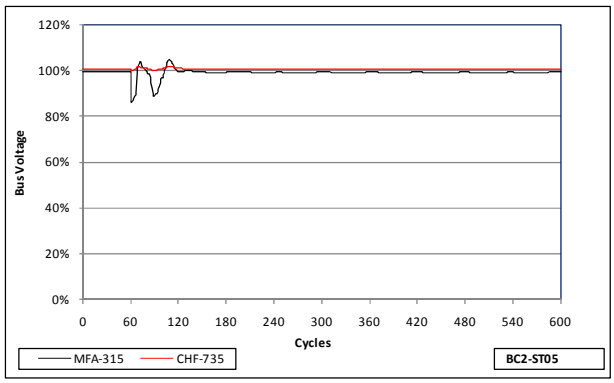




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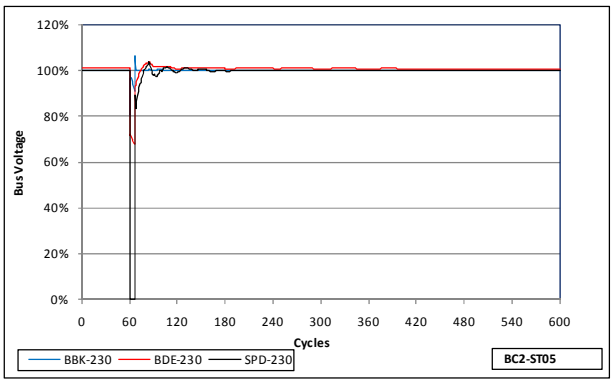
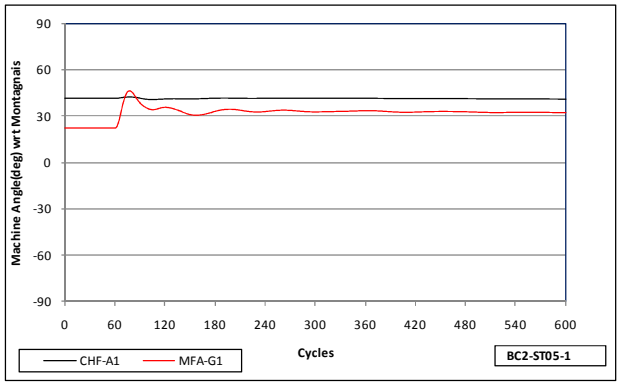
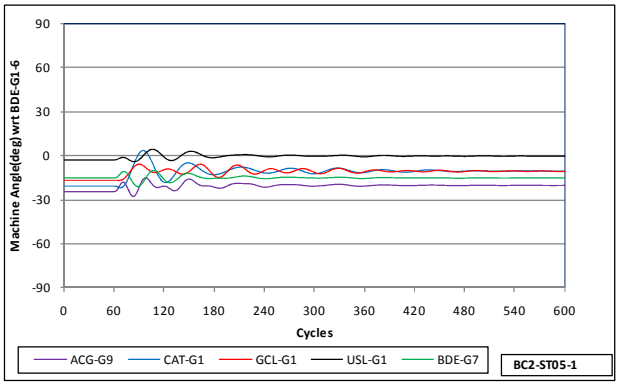
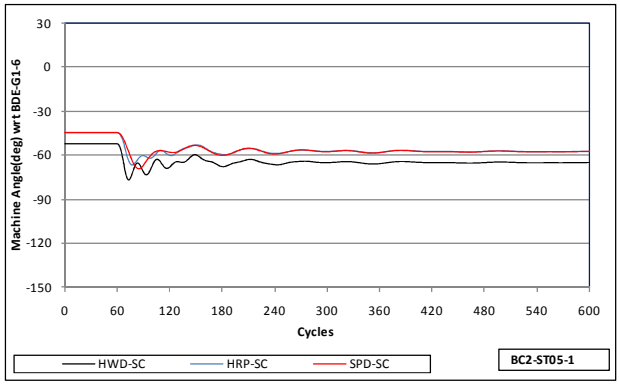
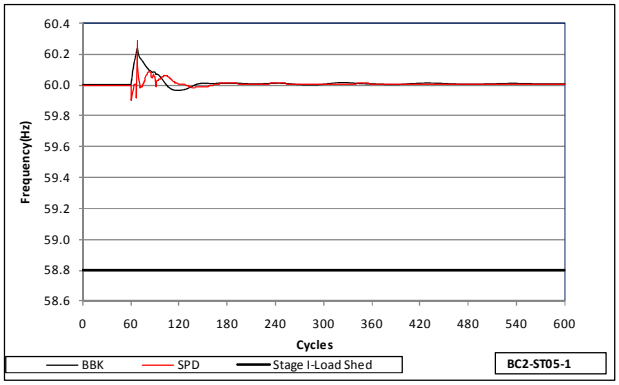


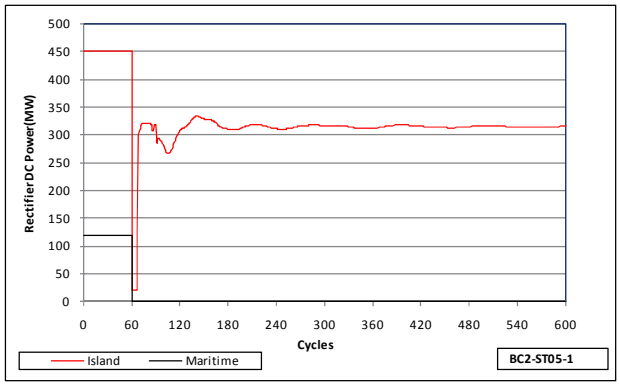
Figure 3-11: BC2-ST05-1, Winter Peak/Island Link 900 MW/Maritime Link 239 MW 6-cycle, 3-phase Fault at Soldiers Pond 230 kV on line to Western Avalon (TL217W), Island Link re-start delayed

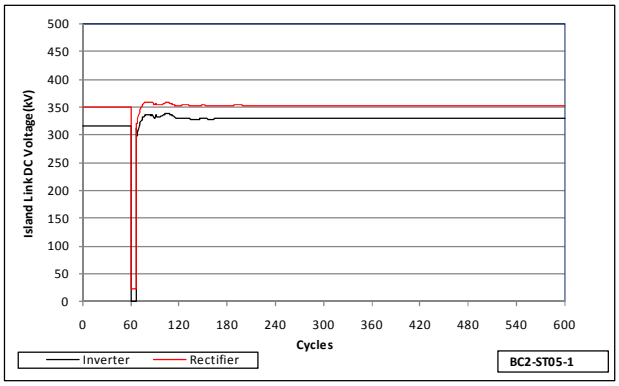




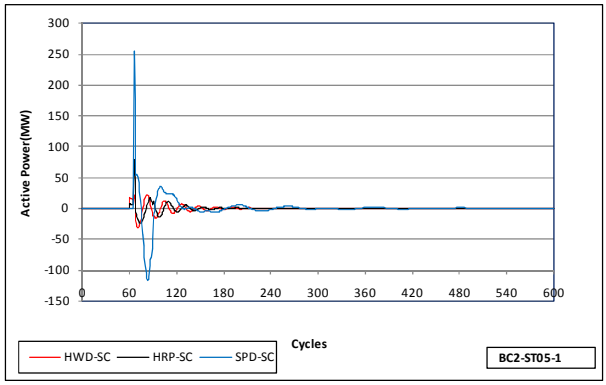


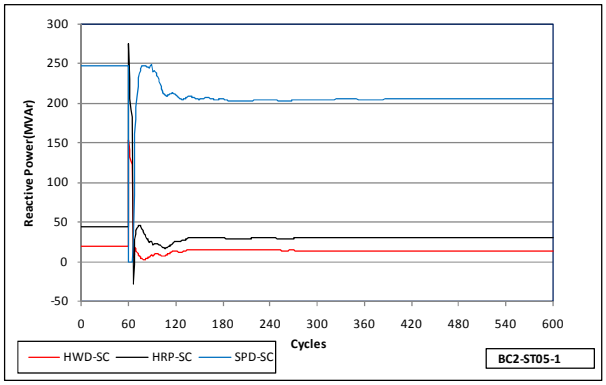


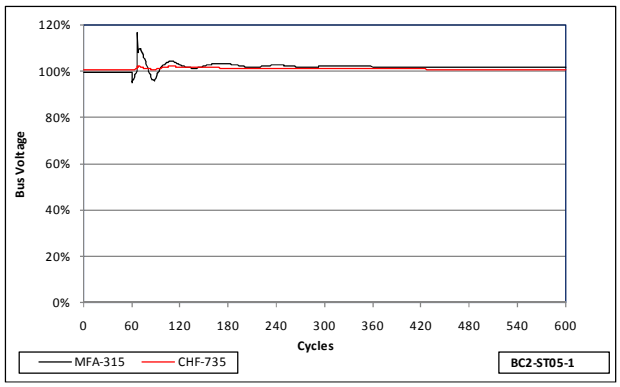


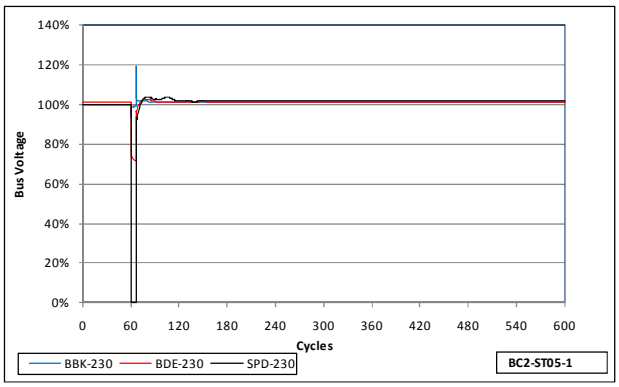


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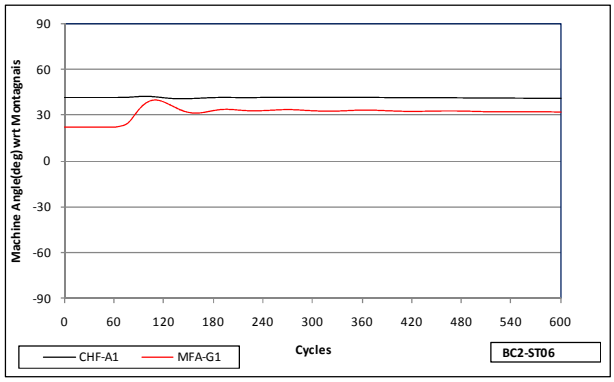
3.1.6 BC2-ST06: Three Phase Fault at Bottom Brook 230 kV on line to Granite Canal

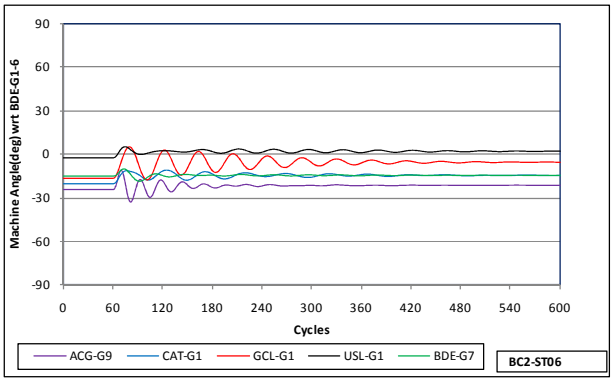
In this case, the voltage at Bottom Brook collapsed to zero, resulting in blocking of the Maritime Link (Figure 3-12). The Island Link continued to operate through the fault and the system recovered quickly. The dc power level on the Island Link was subsequently reduced due to the loss of the Maritime Link and the system frequency stabilized at 60.1-60.2 Hz.

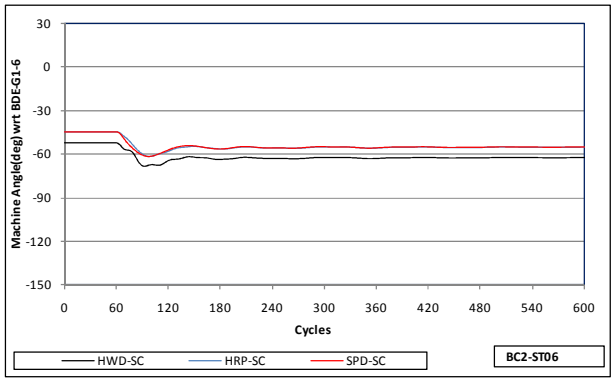
Due to action of the SVC at Bottom Brook in response to the fault, the post-fault voltage at Bottom Brook increased to approximately 130% for a few cycles until the SVC was able to reduce its output. This temporary over-voltage lasted only for a few cycles and is well within the temporary over-voltage capability of zinc oxide arresters (160% of maximum system voltage for 1s) and the substation equipment. The exact duration will depend upon the design of the SVC itself, but clearly, as shown in the plot of the reactive output of the Bottom Brook SVC reactive power, a fast-acting device is required. The steady-state rating of this SVC was determined in the load flow studies report to be +320/-100 MVAr. If VSC technology is employed for the Bottom Brook converter, the inherent reactive control properties of such converters can be usefully employed to avoid the need for an SVC at this location. Typically, VSC converters can provide or absorb reactive power. In Appendix C, two PQ-curves from ABB and Siemens show that the reactive power can reach 30%-40% and 25% of the rated power respectively when the VSC operates at rated power. For a 500 MW converter this would translate to a reactive capability of ±125 MVAr. The balance of 195 MVAr for the reactive production requirements could then be met with a smaller SVC or even shunt capacitors.

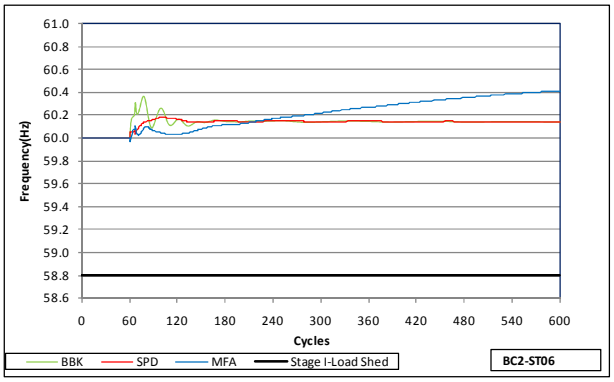
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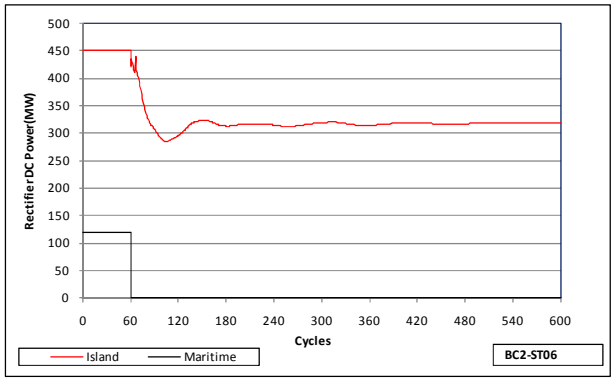
Figure 3-12: BC2-ST06, Winter Peak/Island Link 900 MW/Maritime Link 239 MW 6-cycle, 3-phase Fault at Bottom Brook 230 kV on line to Granite Canal

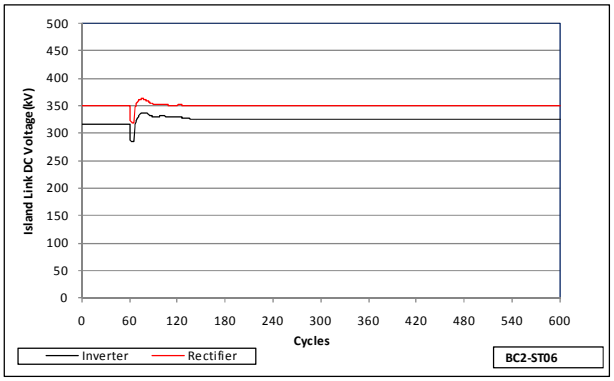




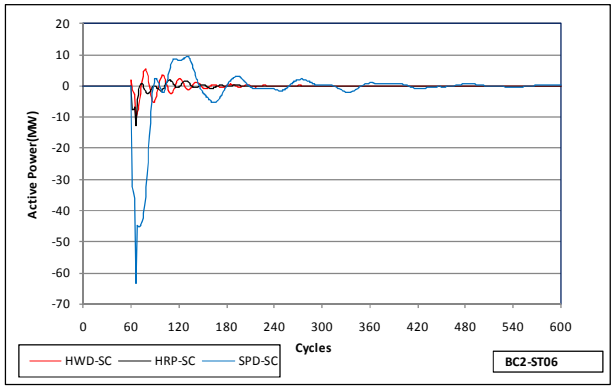


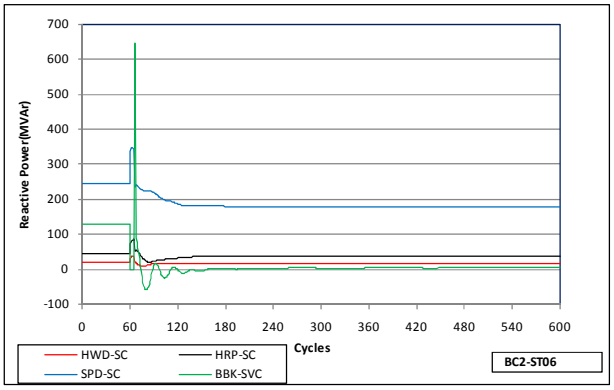


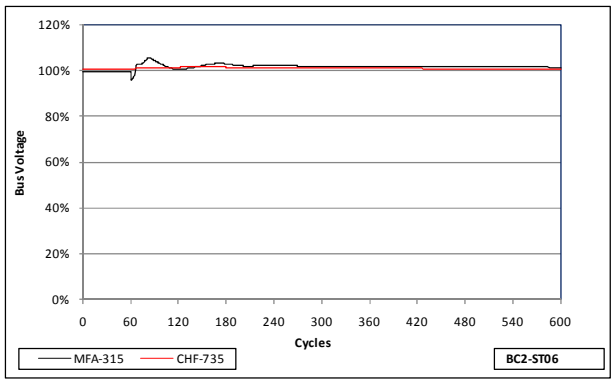


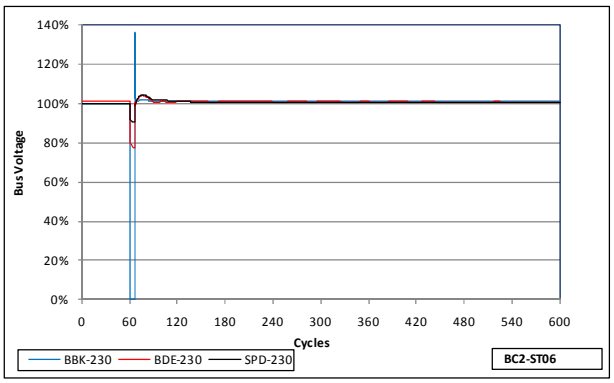


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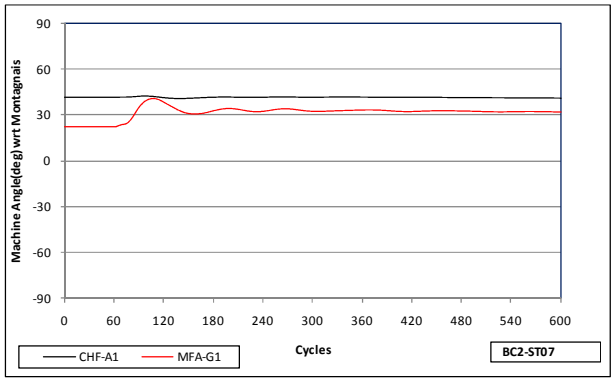


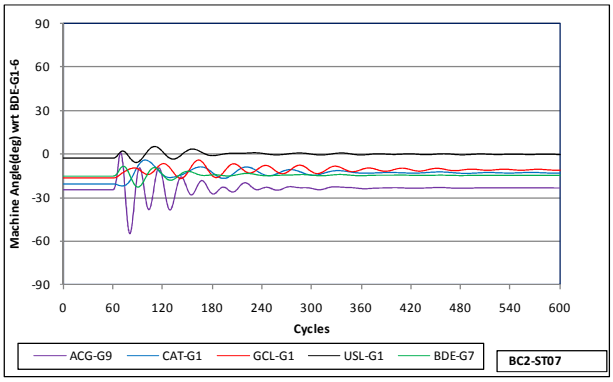


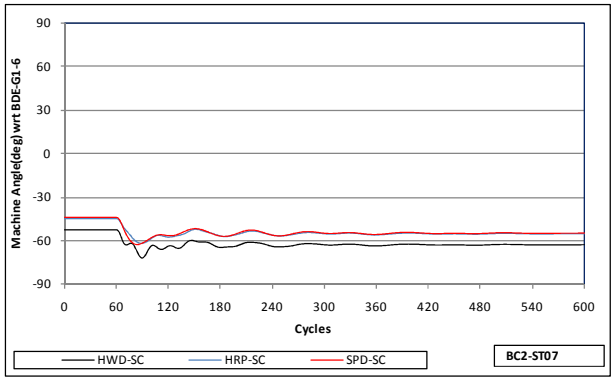
3.1.7 BC2-ST07: Three Phase Fault at Stony Brook 230 kV on line to Bay d'Espoir (TL204)

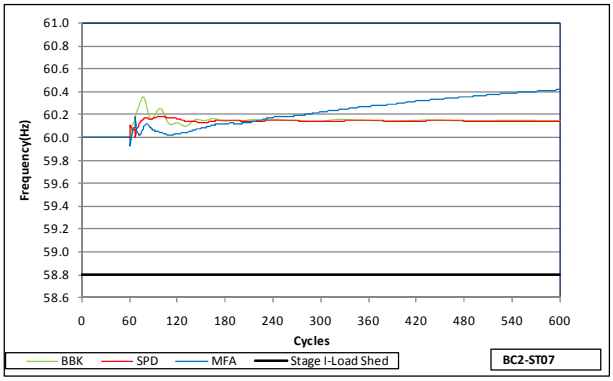
The voltage depression at Bottom Brook was severe enough to result in blocking of the Maritime Link but did not cause interruption of the Island Link. The system recovered quickly. The temporary over-voltage at Bottom brook was 120% for a few cycles. The results are shown in Figure 3-13.

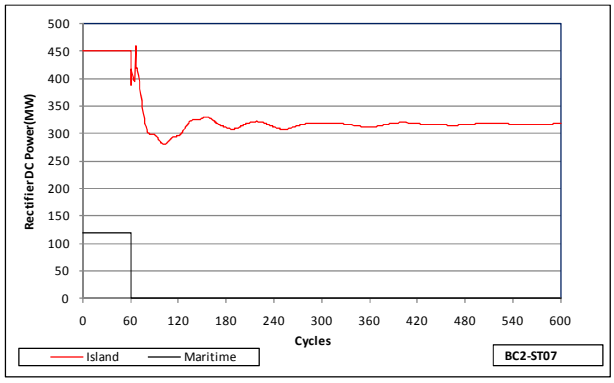
Figure 3-13: BC2-ST07, Winter Peak/Island Link 900 MW/Maritime Link 239 MW 6-cycle, 3-phase Fault at Stony Brook 230 kV on line to Bay d'Espoir (TL204)

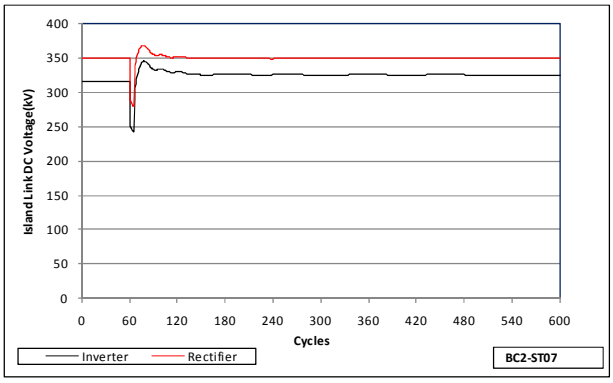




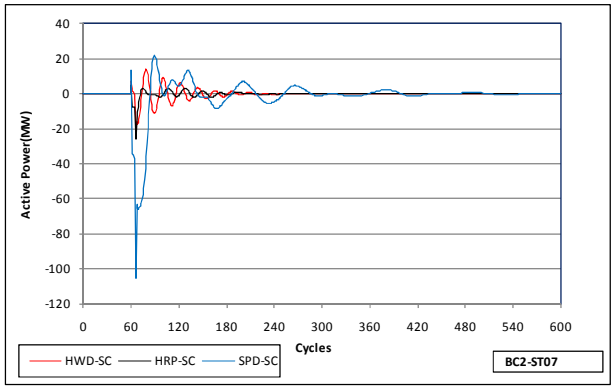


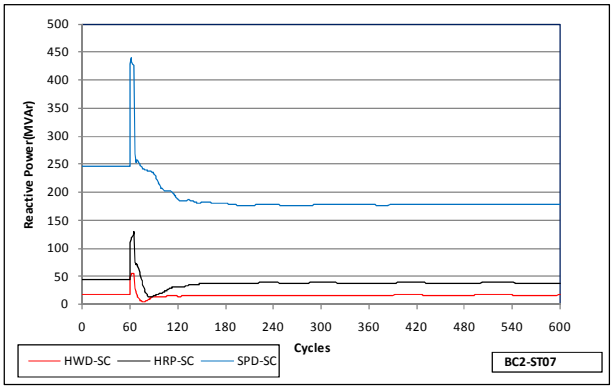


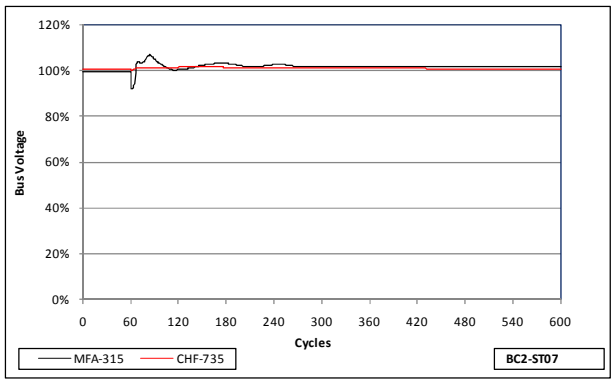


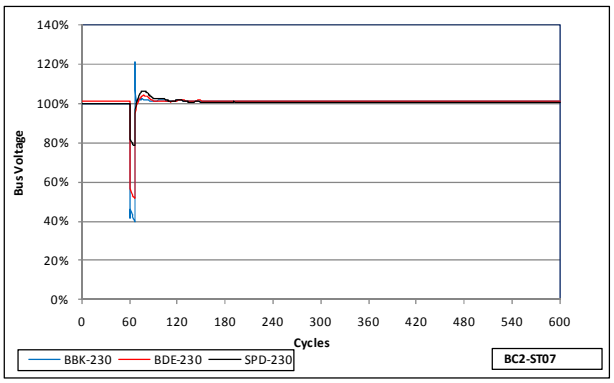


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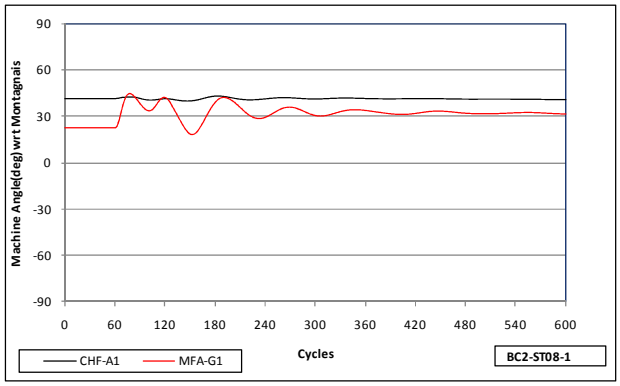
3.1.8 BC2-ST08: Three Phase Fault at Bay d'Espoir 230 kV on line to Sunnyside (TL202)

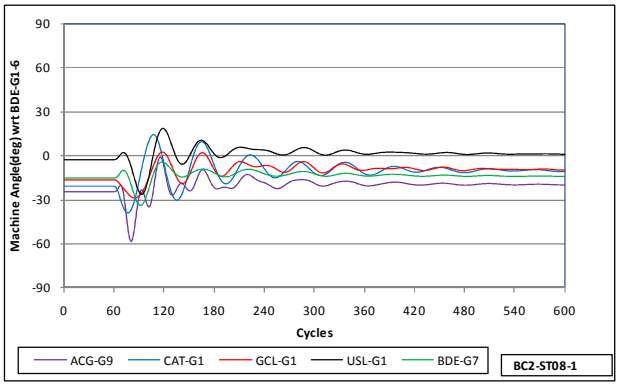
This case was similar to, though not as severe as, the case of a fault at Bay d'Espoir on the line to Western Avalon. As with the fault at Bay d'Espoir on the line to Western Avalon however, it was necessary to either:

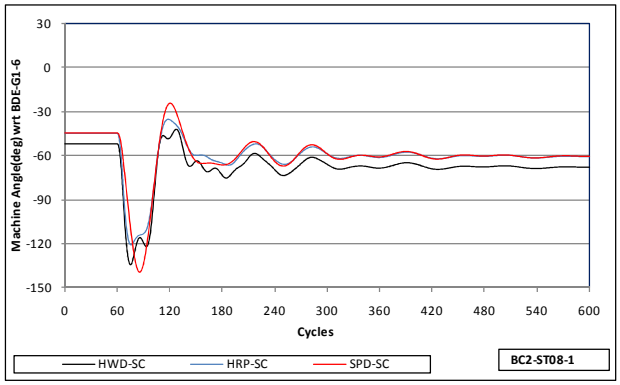
- increase the high-inertia synchronous condenser at Soldiers Pond to 450 MVAr and connect the third synchronous condenser at Holyrood, or
- install a ±250 MVAr SVC at Bay d'Espoir and connect the third synchronous condenser at Holyrood, to avoid a voltage reduction at Soldiers Pond following the fault clearance. The results with 450 MVAr of high-inertia synchronous condensers at Soldiers Pond are shown in Figure 3-14.

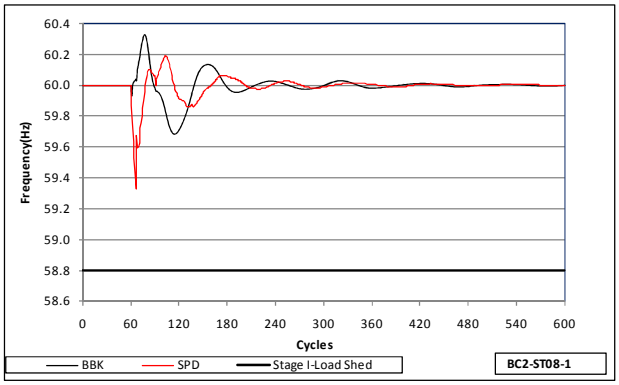
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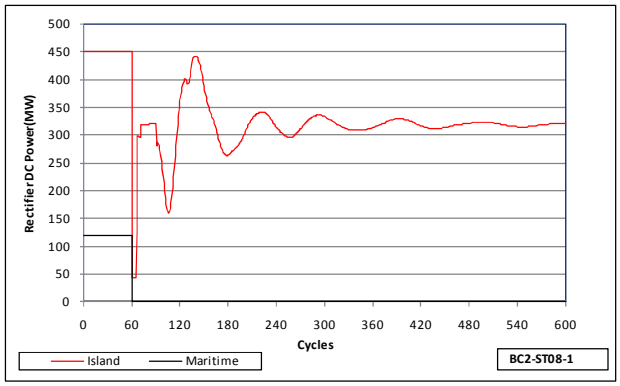
Figure 3-14: BC2-ST08-1, Winter Peak/Island Link 900 MW/Maritime Link 239 MW 6-cycle, 3-phase Fault at Bay d'Espoir 230 kV on line to Sunnyside (TL202)

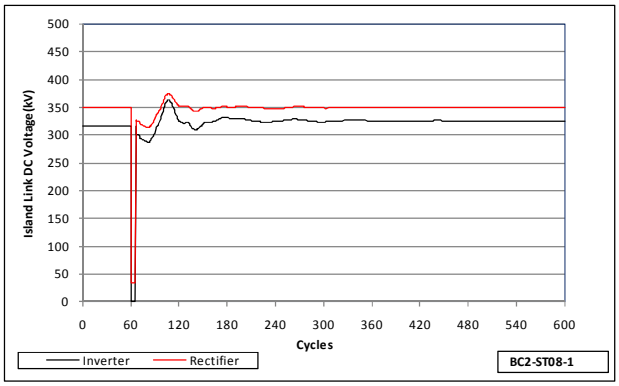




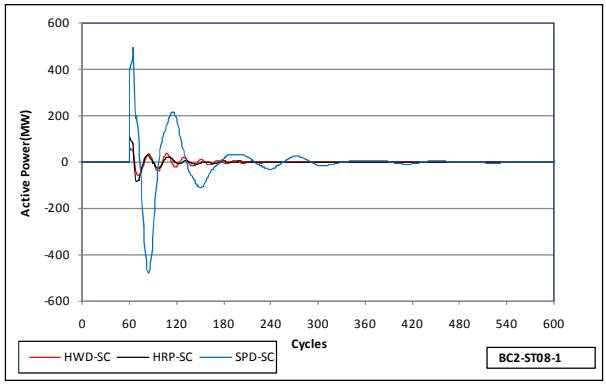


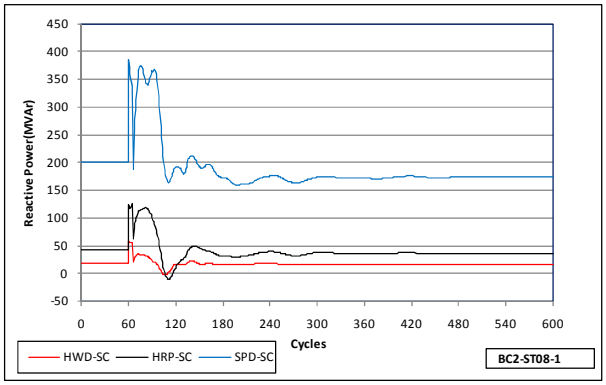


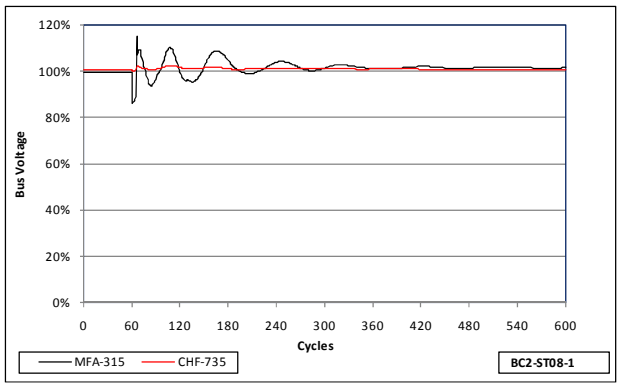


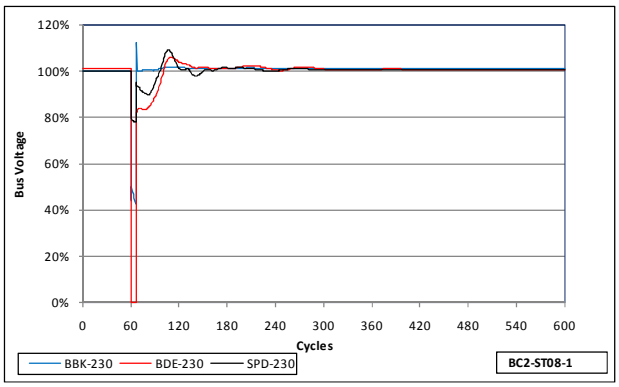


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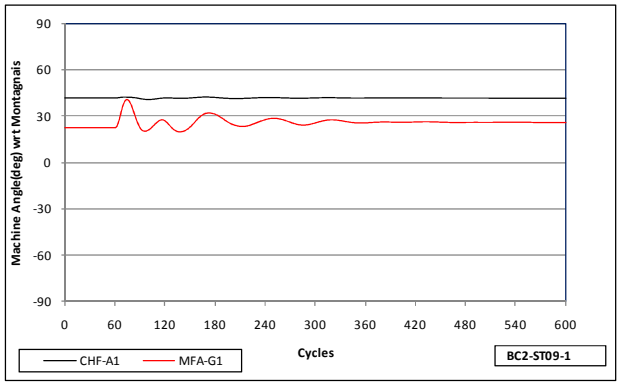


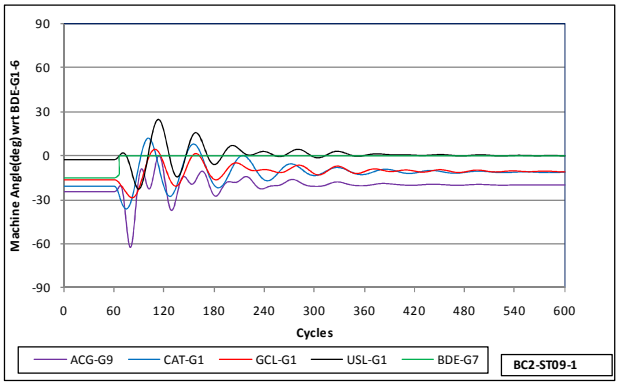
3.1.9 BC2-ST09: Three Phase Fault at Bay d'Espoir 230 kV-Generator Outage G7

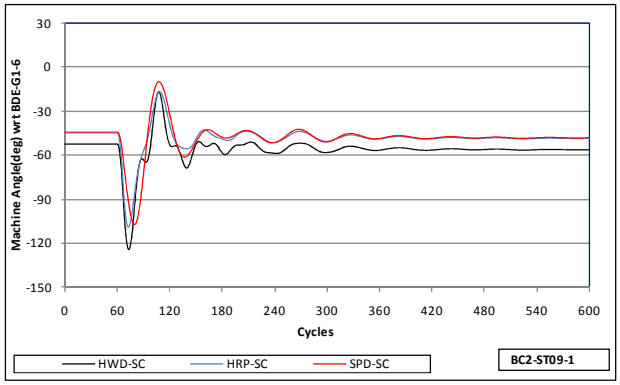
This case, shown in Figure 3-15, considered a 6-cycle, 3-phase fault at Bay d'Espoir 230 kV that resulted in the loss of the largest generator on the Island system (unit G7). As with other faults at Bay d'Espoir, a commutation failure can occur at the inverter of the LIL and the export to Nova Scotia is reduced to zero due to the voltage depression at Bottom Brook, and it was necessary to either:

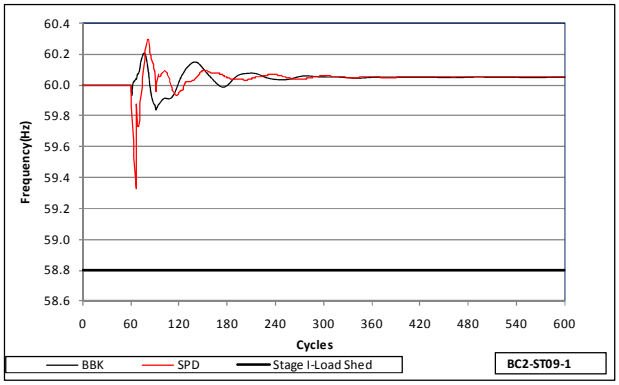
- increase the high-inertia synchronous condenser at Soldiers Pond to 450 MVAr and connect the third synchronous condenser at Holyrood, or
- install a ±250 MVAr SVC at Bay d'Espoir and connect the third synchronous condenser at Holyrood.

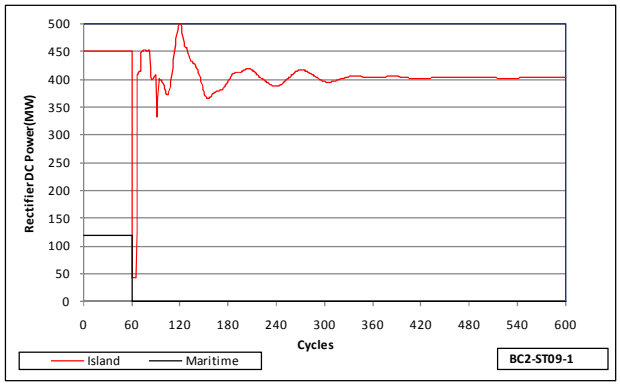
Figure 3-15: BC2-ST09-1, Winter Peak/Island Link 900 MW/Maritime Link 239 MW 6-cycle, 3-phase Fault at Bay d'Espoir 230 kV-Generator Outage G7 450MVAr-SC at Soldiers Pond+3-SC at Holyrood

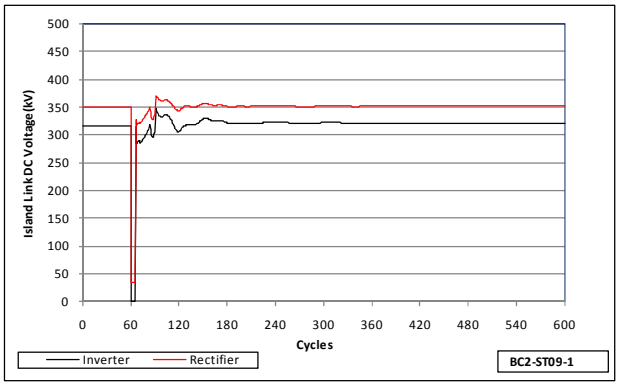




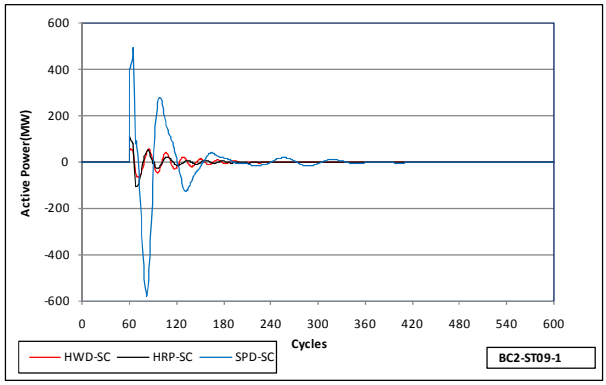


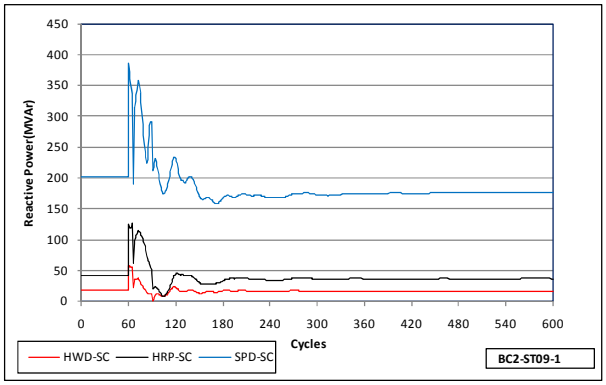


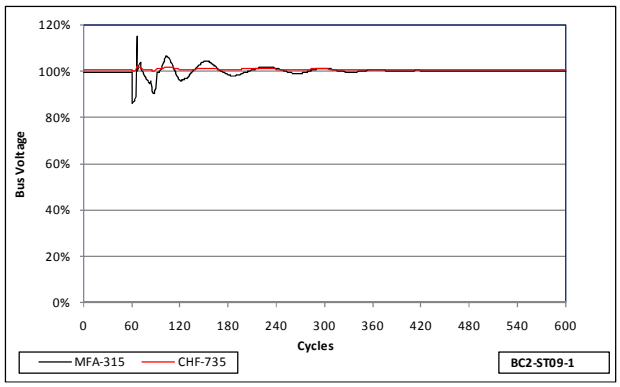


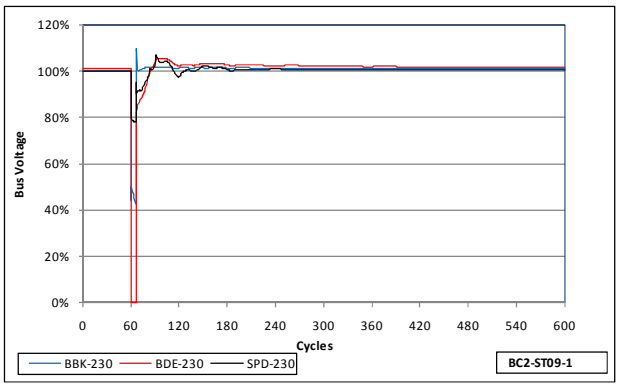


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3.2 Spring/Fall Intermediate Load Conditions

The forecast load on the Island system for the intermediate load level corresponding to Spring and Fall in 2017-18 is 1,100 MW. The first scenario to be examined under these conditions was BC-7, since this scenario involves the rated transfer across the Island Link (900 MW from Muskrat Falls) and the maximum transfer across the Maritime Link (500 MW from Bottom Brook). Figure A-2 in Appendix A shows the load flow of the initial conditions.

The same fault cases were examined for this load level as for the peak load level.

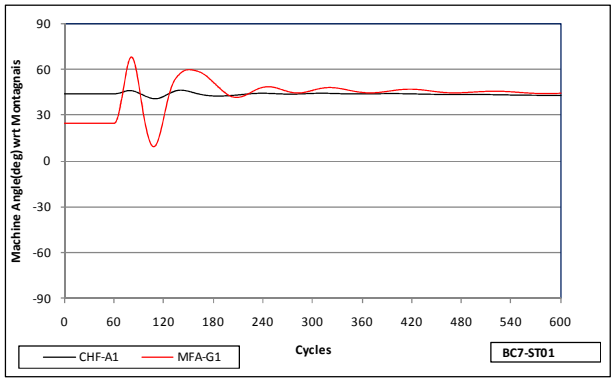
3.2.1 BC7-ST01: Temporary Bipole Fault on the Island Link

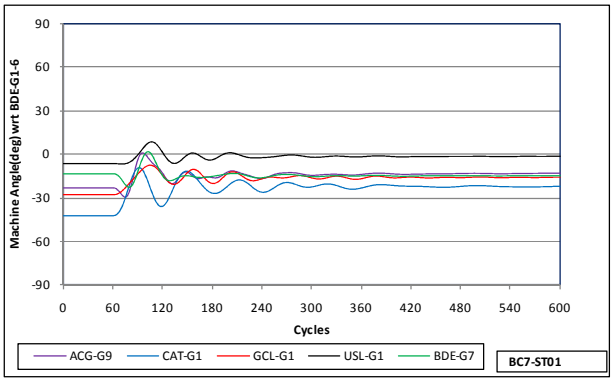
The results for this case are shown in Figure 3-16.

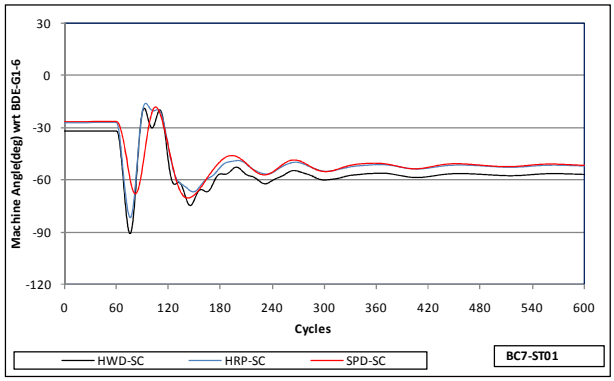
The voltage and frequency depression at Bottom Brook resulted in a ramping down of the Maritime export from 500 MW to zero. The Island Link returned to full power shortly after fault clearance as in previous cases, and the enabling of the Island Link frequency controller after 500 ms resulted in a reduction of the dc power over the Island Link to approximately 320 MW due to the loss of the Maritime export. The frequency at Soldiers Pond stabilized at approximately 60.3 Hz and the system returned to stable operation quickly.

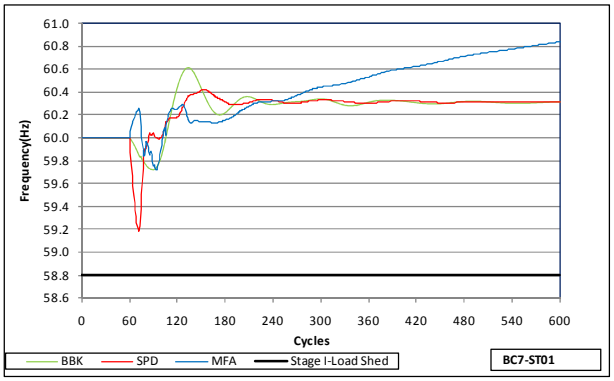
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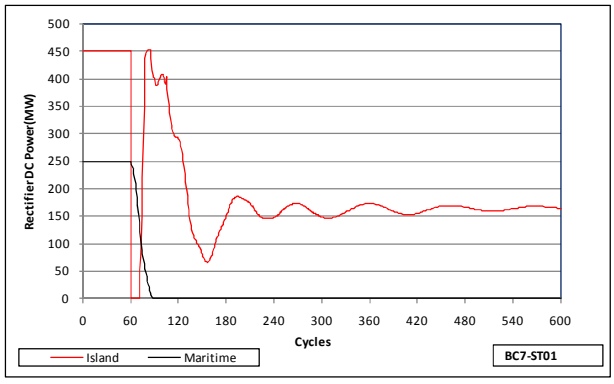
Figure 3-16: BC7-ST01, Intermediate/Island Link 900 MW/Maritime Link 500 MW Temporary Bipole Fault on Island Link

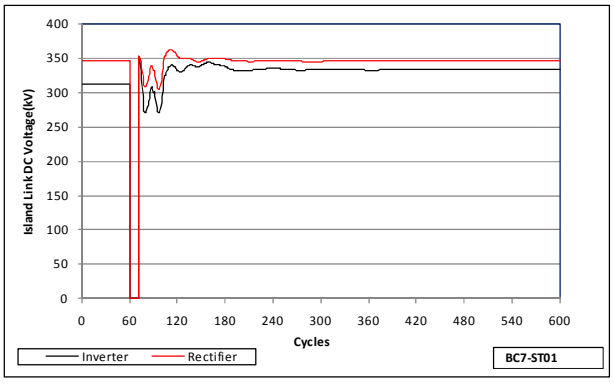




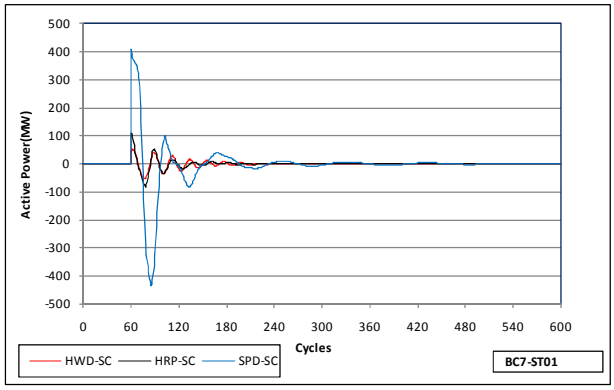


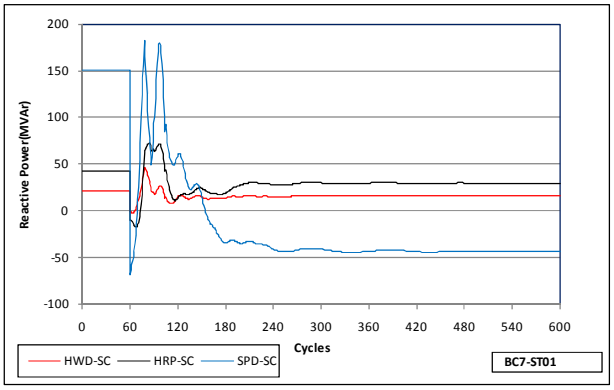


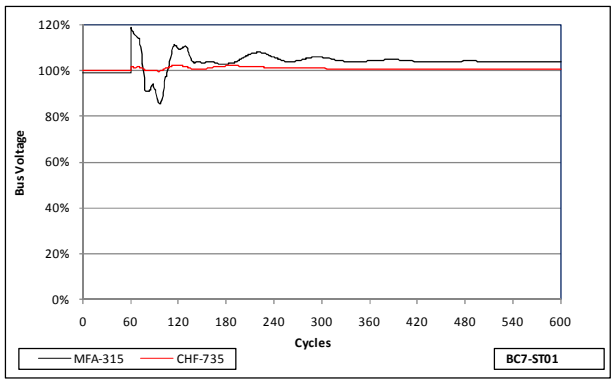


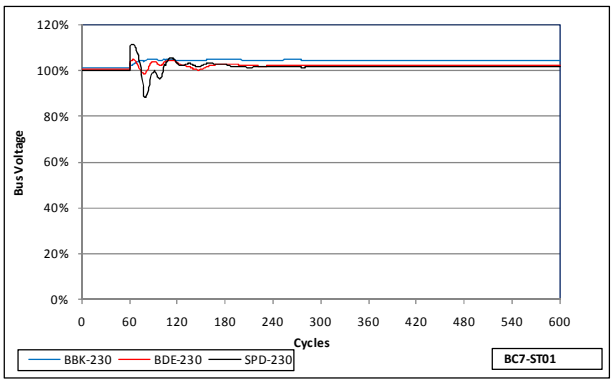


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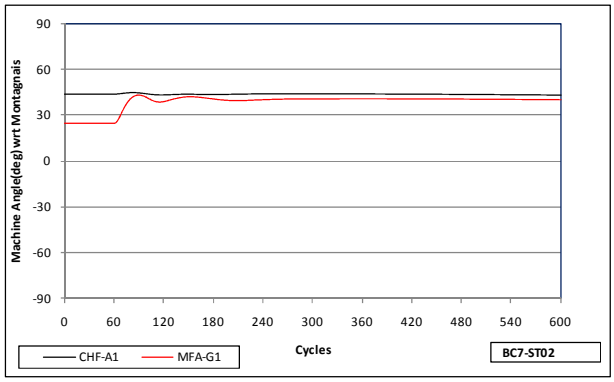
3.2.2 BC7-ST02: Permanent Pole Fault on the Island Link

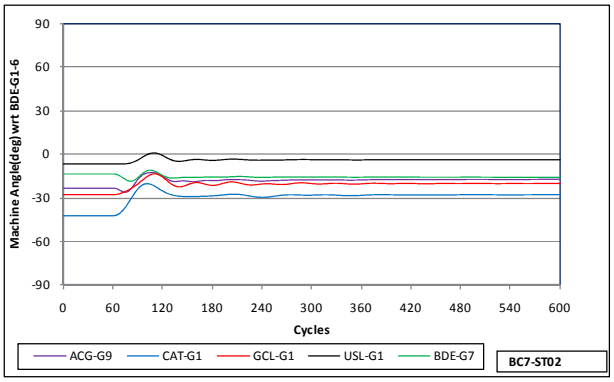
The results for this case are shown in Figure 3-17.

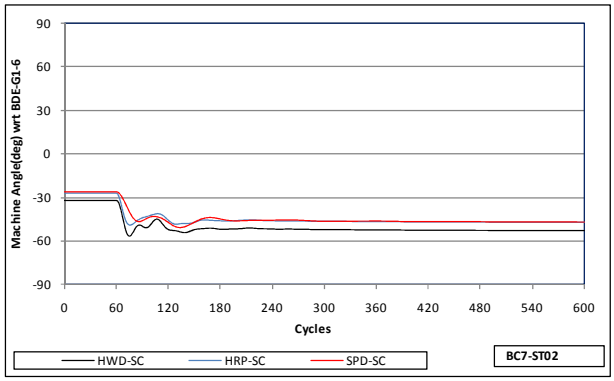
This case was seen to be less severe than the same fault in the BC2 Scenario in that the Maritime Link was not reduced to zero but fell to a value of approximately 160 MW from its initial value of 500 MW. The Island Link healthy pole was ramped up to a value of approximately 520 MW from its initial value of 450 MW (a 115% overload). The frequency at Soldiers Pond stabilized at approximately 59.85 Hz.

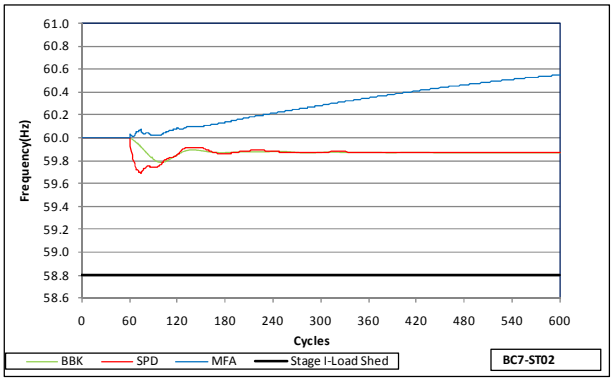
Once the system has settled down, it would be possible to manually reschedule the Island Link up to 675 MW (150% of its rated value) to allow the Maritime export to be increased from 160 MW to approximately 300 MW.

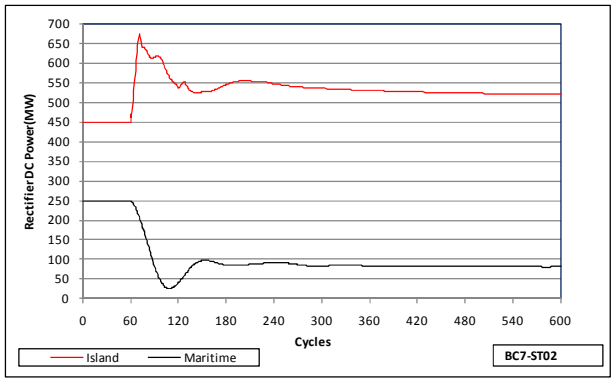
Figure 3-17: BC7-ST02, Intermediate/Island Link 900 MW/Maritime Link 500 MW Permanent Pole Outage on Island Link

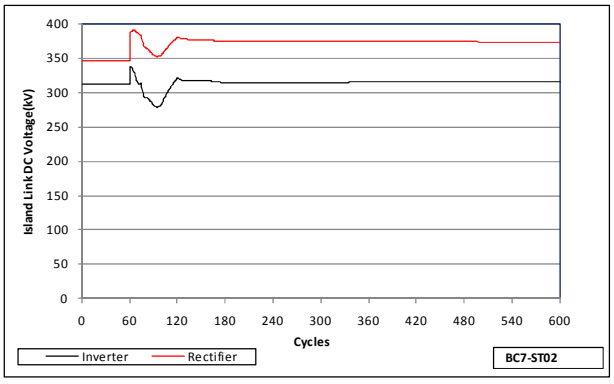




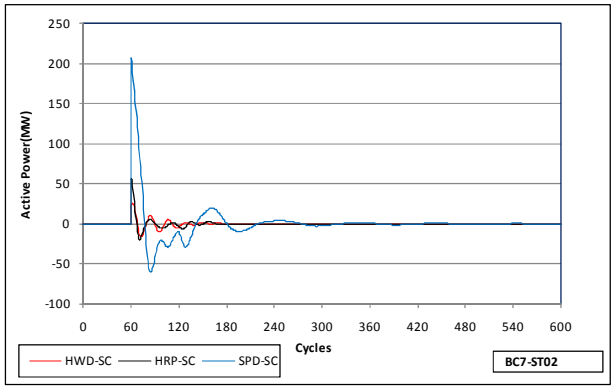


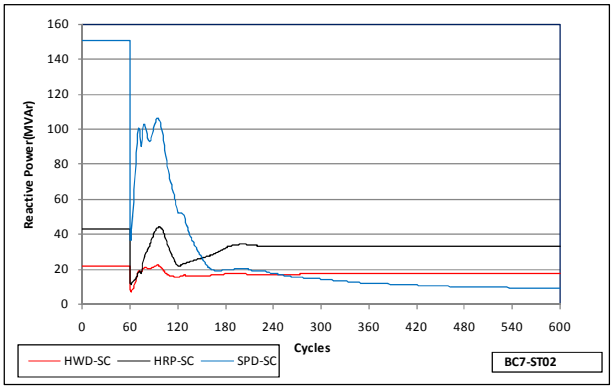


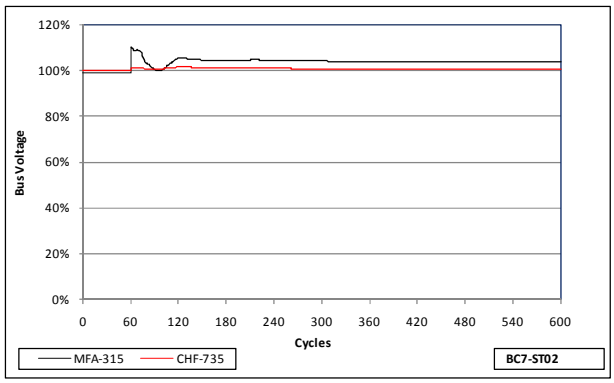


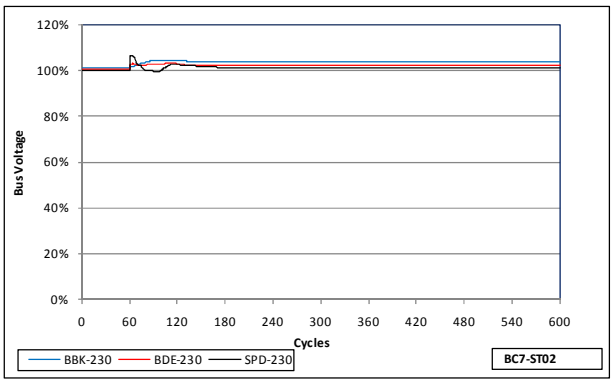


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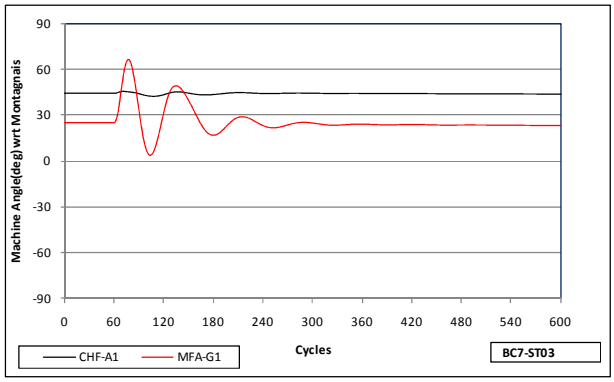


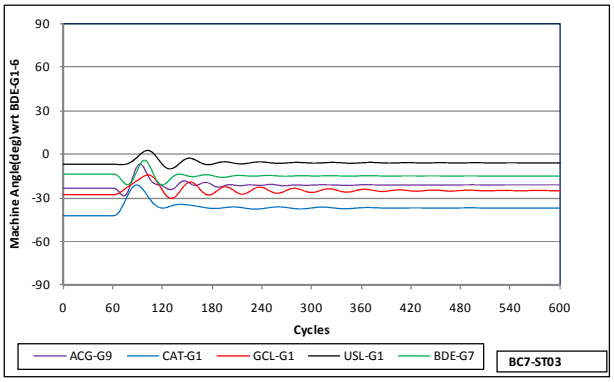


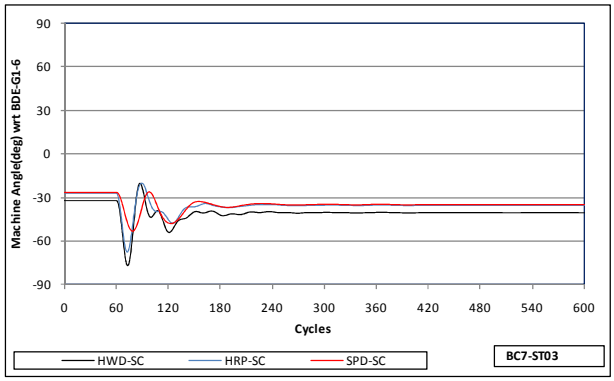
3.2.3 BC7-ST03: Three Phase Fault at Muskrat Falls 315 kV on line to Churchill Falls

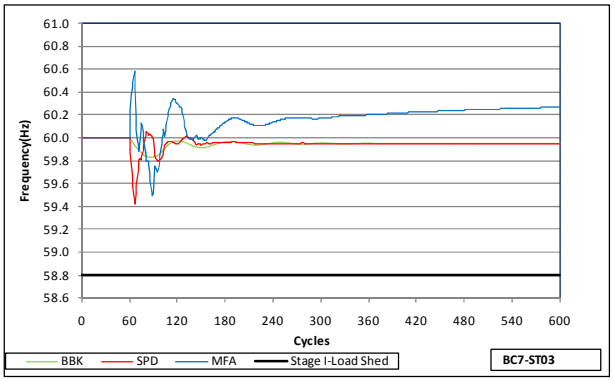
As with the permanent pole outage on the Island Link, this case (shown in Figure 3-18) was not as severe as the same fault under Scenario BC2. The Maritime Link did not fall to a zero export and was able to recover to an export level of approximately 380 MW, the Island Link decreasing from 900 MW to approximately 720 MW following the introduction of the frequency controller 500 ms following the fault. The Island frequency stabilized at just below 60 Hz.

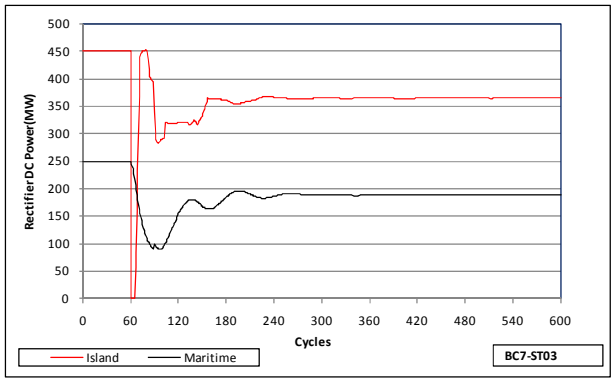
Figure 3-18: BC7-ST03, Intermediate/Island Link 900 MW/Maritime Link 500 MW 6-cycle, 3-phase Fault at Muskrat Falls 315 kV on line to Churchill Falls

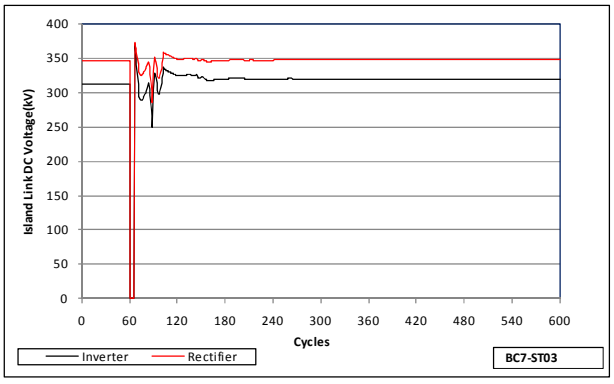




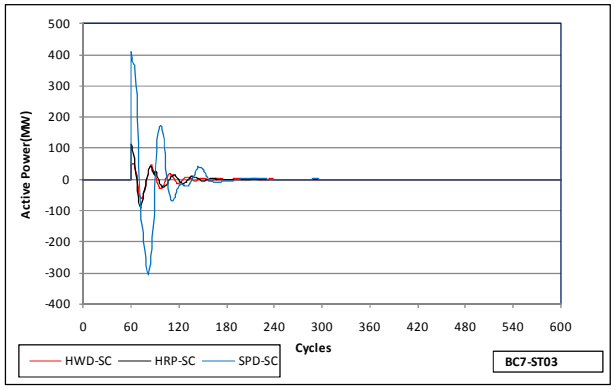


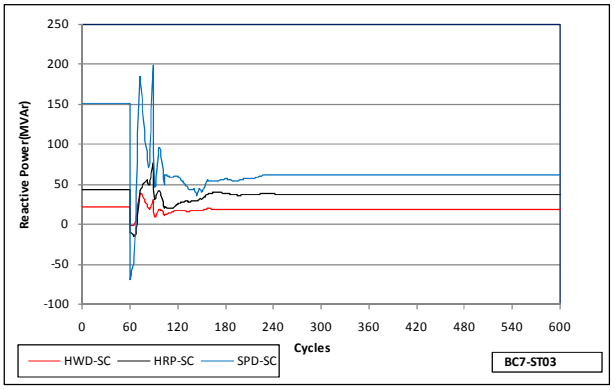


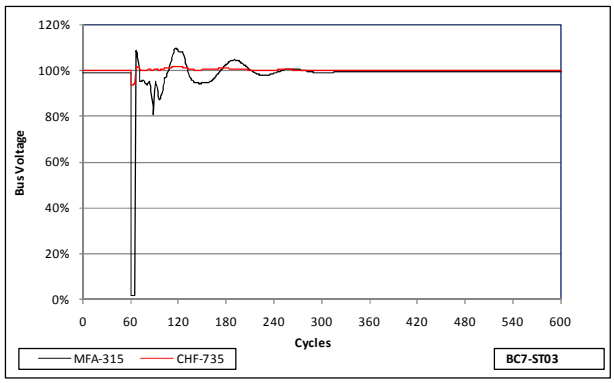


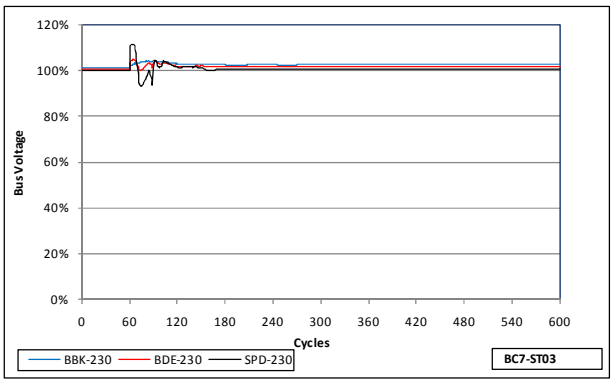


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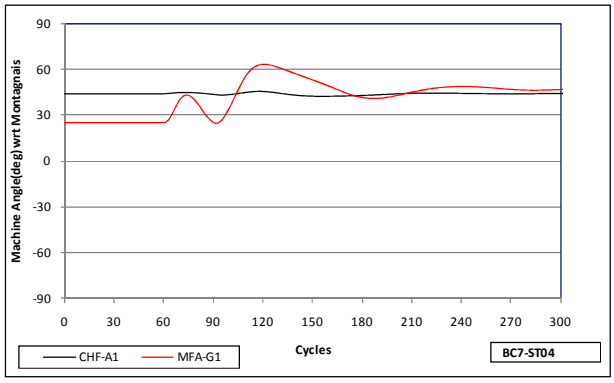


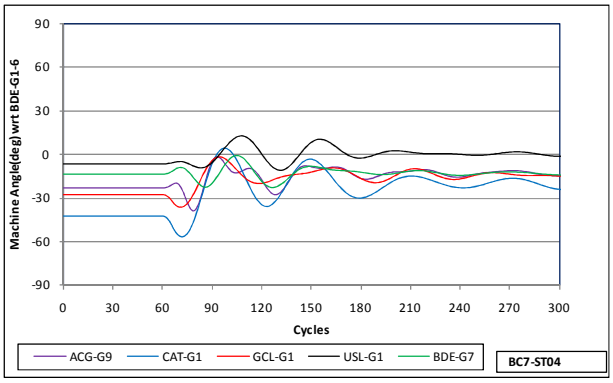
3.2.4 BC7-ST04: Three Phase Fault at Bay d'Espoir 230 kV on line to Western Avalon

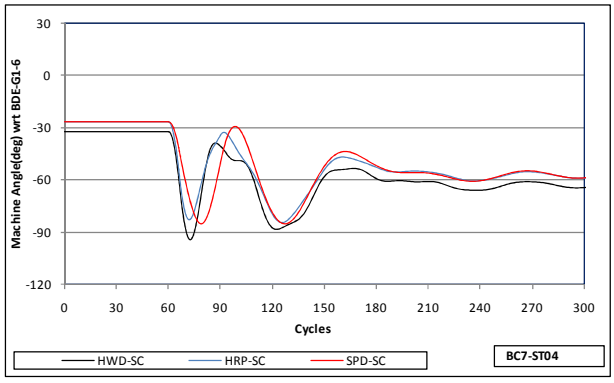
As with the permanent pole outage on the Island Link, this case (shown in Figure 3-19) was not as severe as the same fault under Scenario BC2. The Maritime Link still fell to a zero export due to the voltage depression at Bottom Brook. The Island Link decreased from 900 MW to approximately 300 MW as a result. The Island frequency stabilized at just 60.3 Hz.

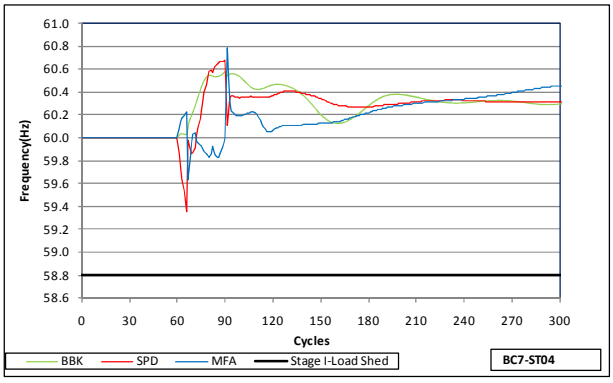
A temporary over-voltage was seen at Bottom Brook following the blocking of the Maritime Link and the subsequent fault clearance. This over-voltage which lasted only a few cycles was at a value of 125%.

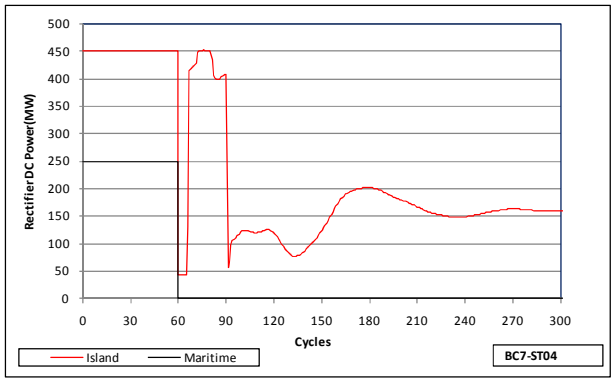
Figure 3-19: BC7-ST04, Intermediate/Island Link 900 MW/Maritime Link 500 MW 6-cycle, 3-phase Fault at Bay d'Espoir 230 kV on line to Western Avalon

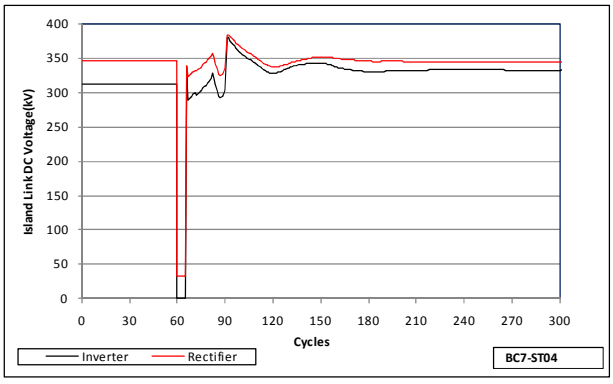




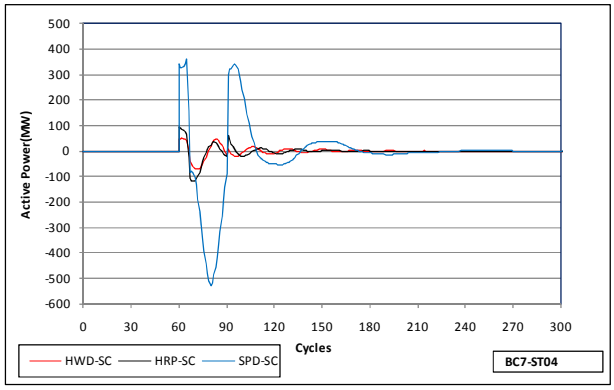


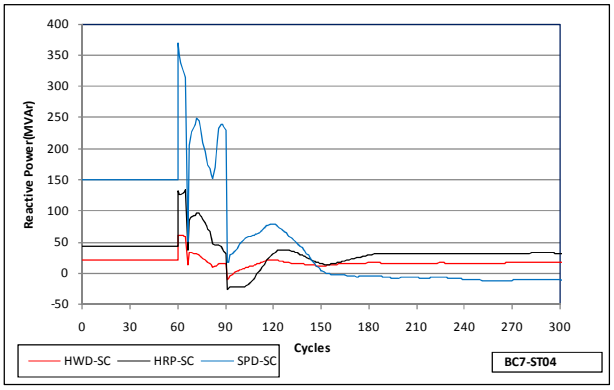


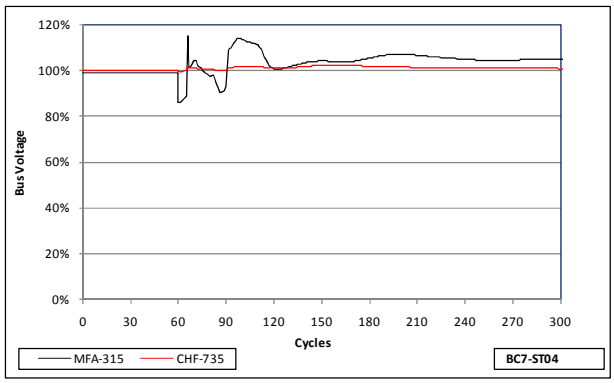


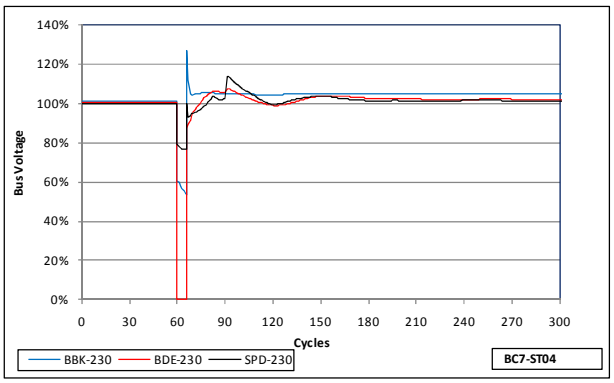


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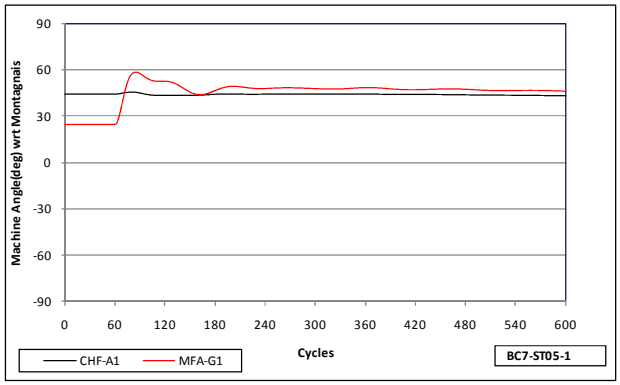


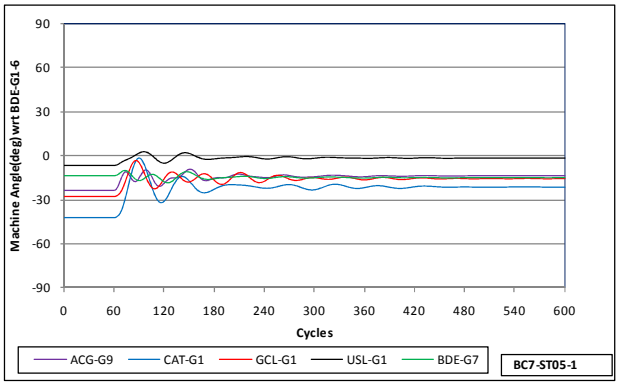


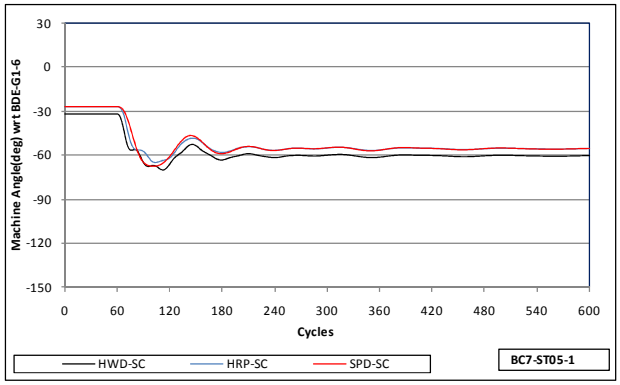
3.2.5 BC-7: Remaining Fault Cases

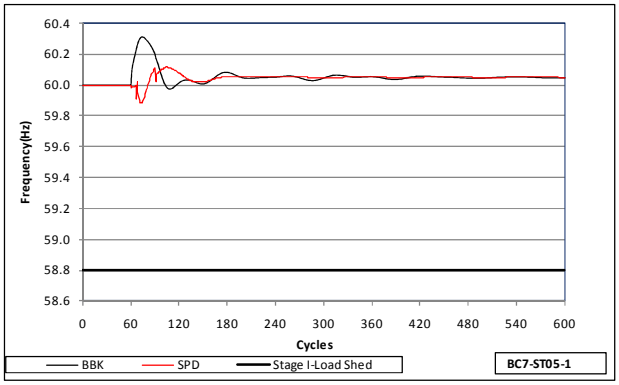
The remaining fault cases under BC-7 are shown in the following figures and indicate that the faults were not as severe as under Scenario BC-2 and that, in cases where the voltage depression at Bottom Brook was not too severe, the Maritime Link could be retained at a reduced power level. In general, for faults east of Bay d'Espoir the voltage at Bottom Brook remains high enough to allow continued operation of the Maritime Link. Faults at or west of Bay d'Espoir will result in a shutting down of the Maritime Link.

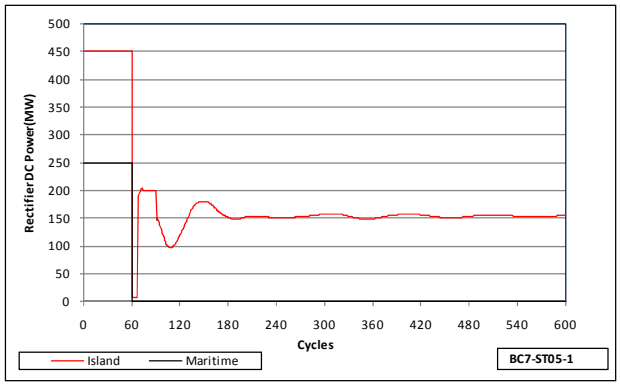
Figure 3-20: BC7-ST05-1, Intermediate/Island Link 900 MW/Maritime Link 500 MW 6-cycle, 3-phase Fault at Soldiers Pond 230 kV on line to Western Avalon (TL217W)

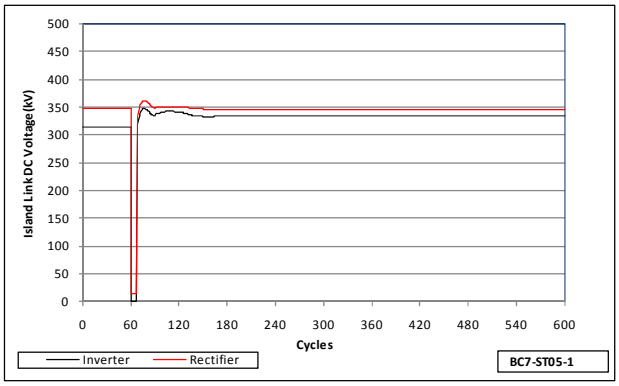




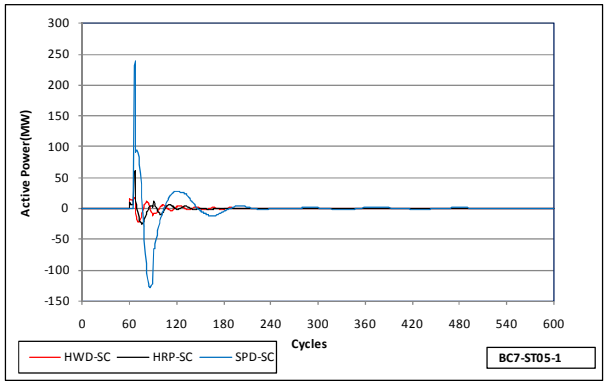


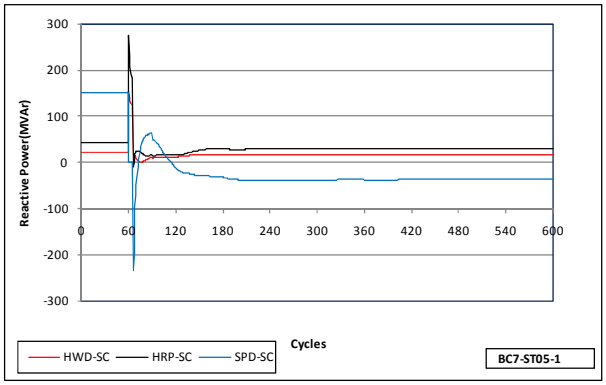


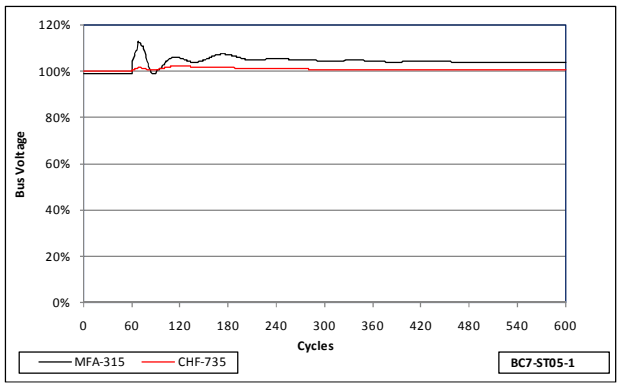


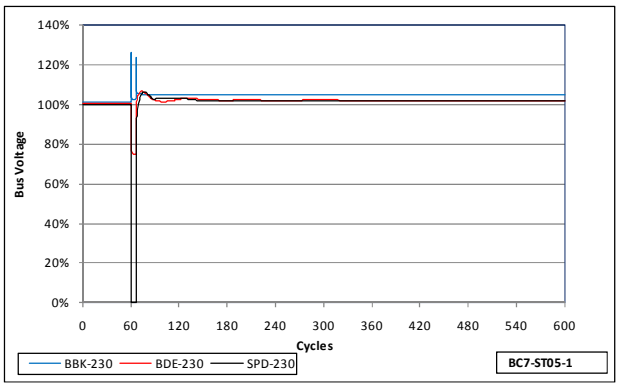


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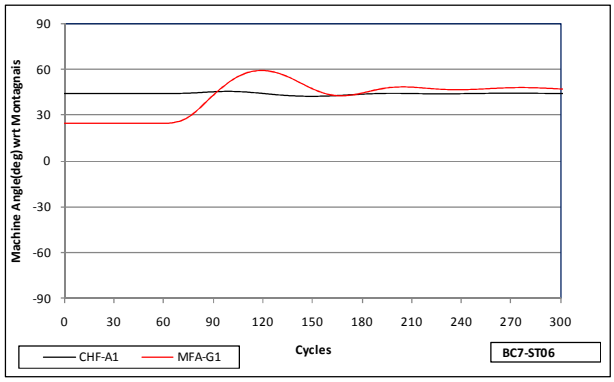


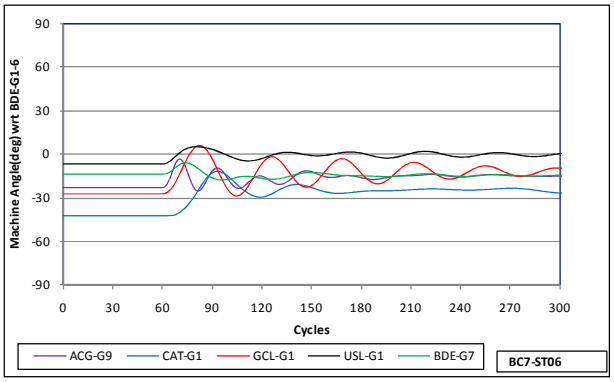


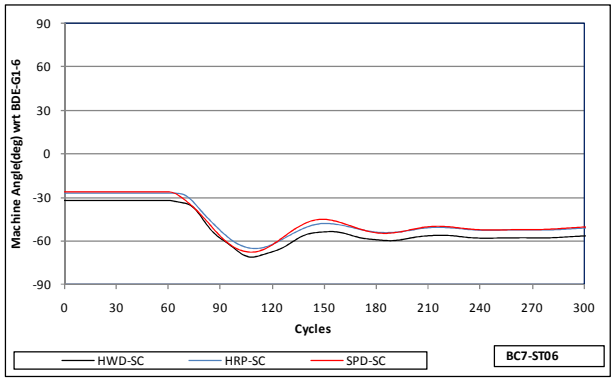


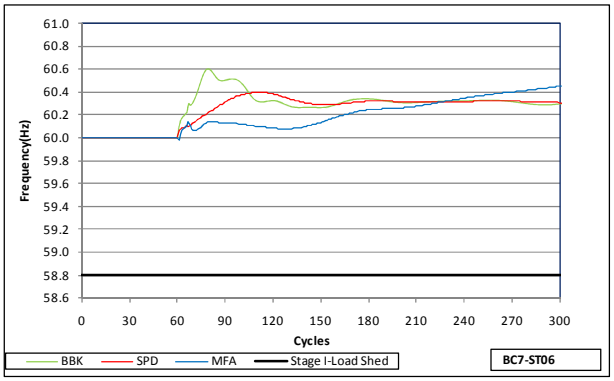
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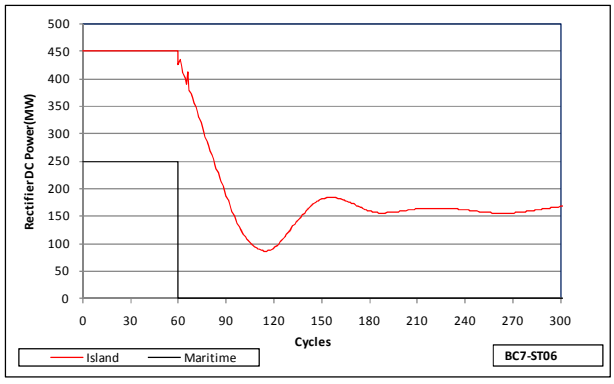
Figure 3-21: BC7-ST06, Intermediate/Island Link 900 MW/Maritime Link 500 MW 6-cycle, 3-phase Fault at Bottom Brook 230 kV on line to Granite Canal

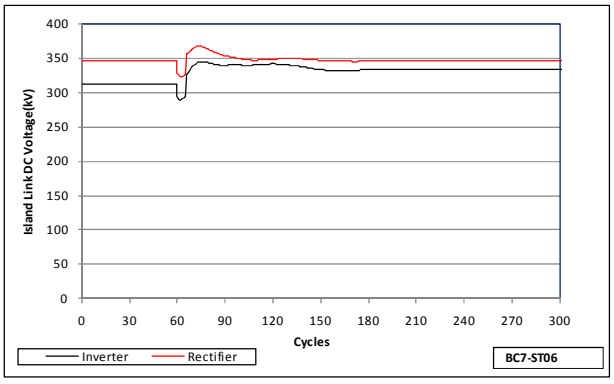




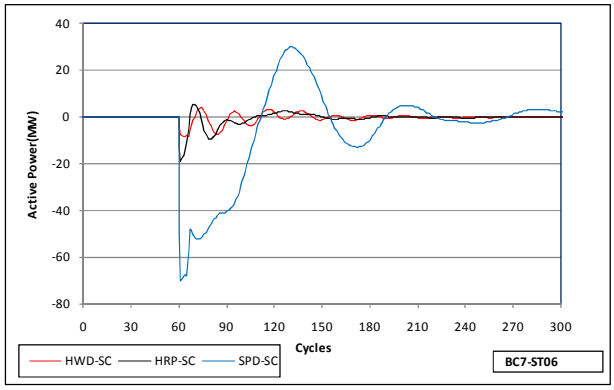


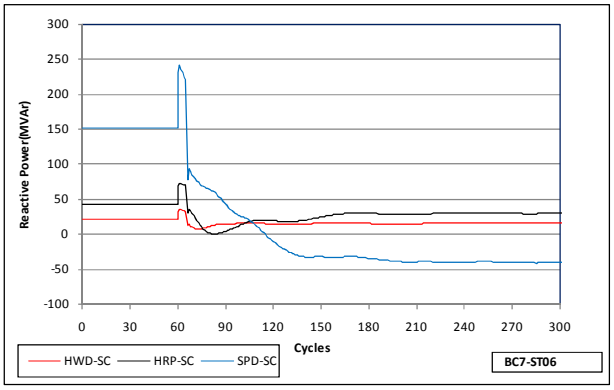


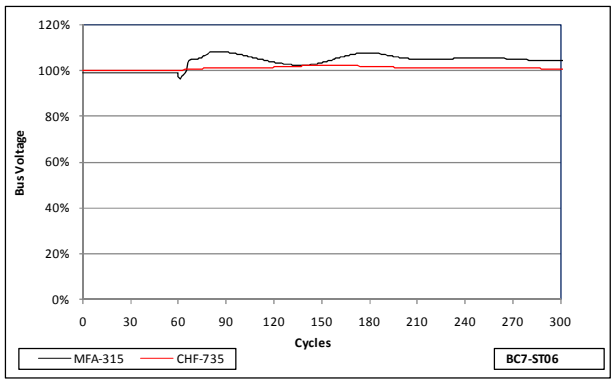


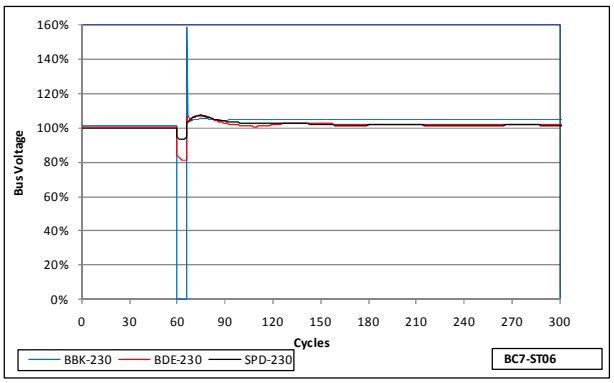


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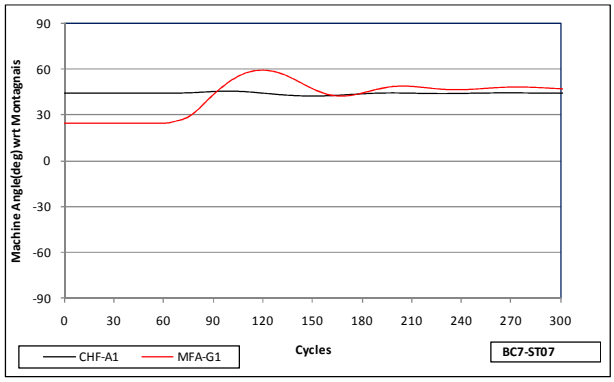


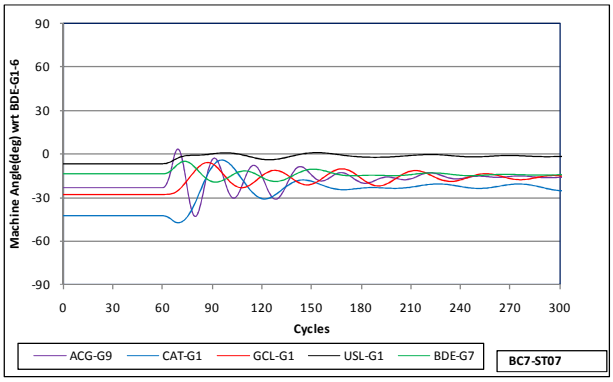


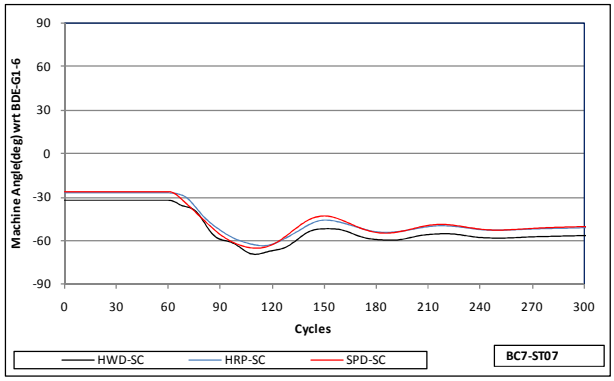


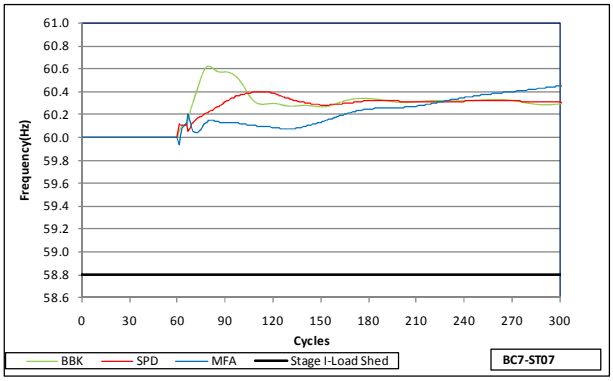
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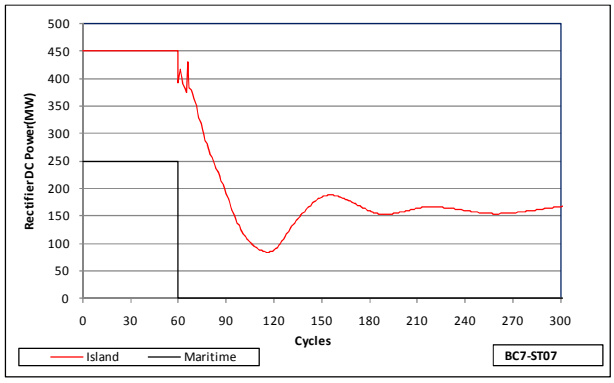
Figure 3-22: BC7-ST07, Intermediate/Island Link 900 MW/Maritime Link 500 MW 6-cycle, 3-phase Fault at Stony Brook 230 kV on line to Bay d'Espoir (TL204)

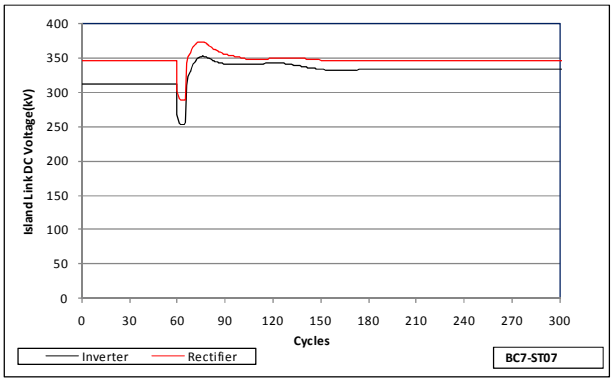




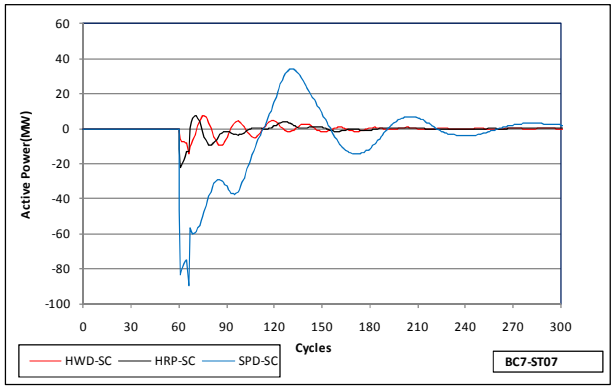


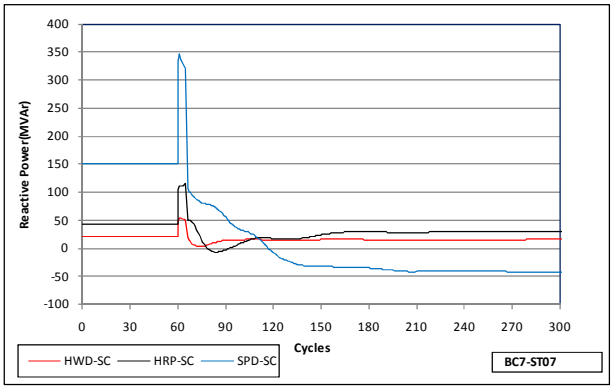


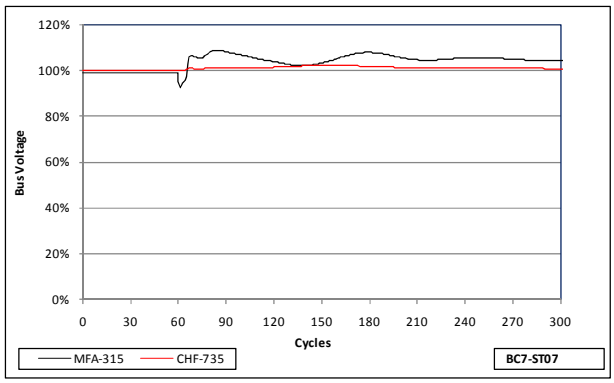




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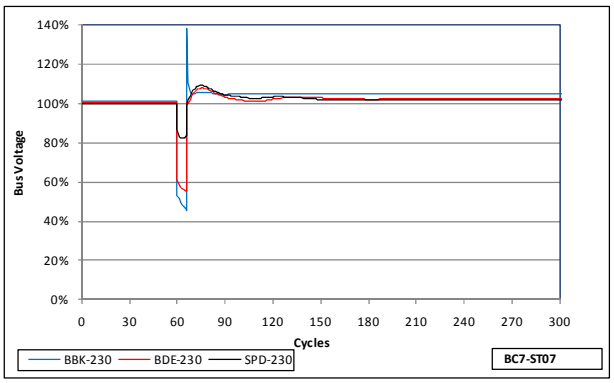
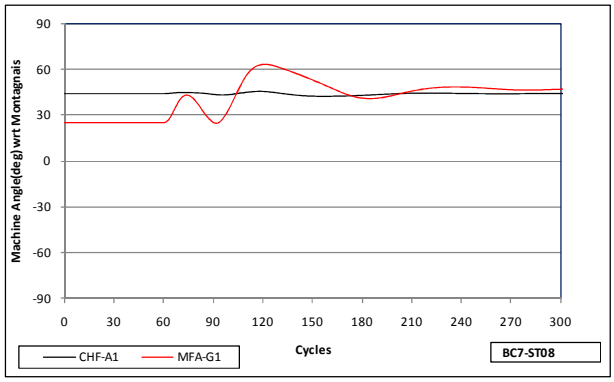
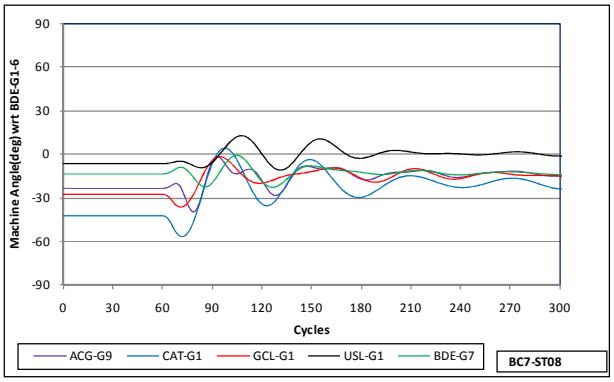
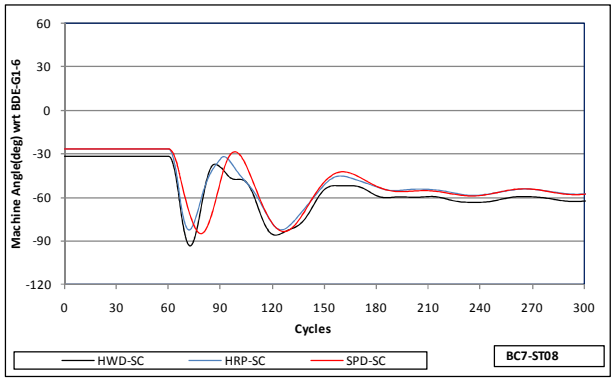
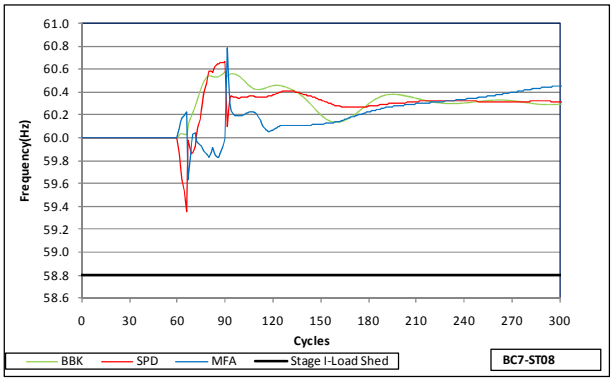


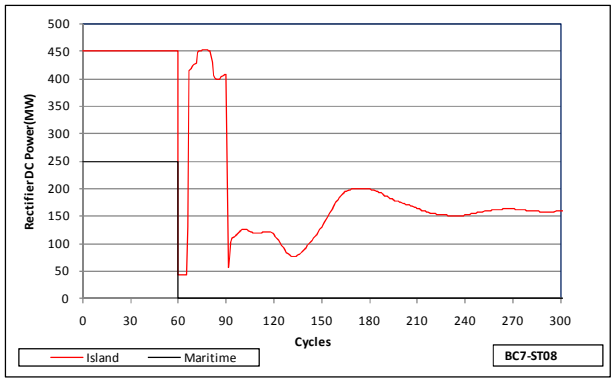
Figure 3-23: BC7-ST08, Intermediate/Island Link 900 MW/Maritime Link 500 MW 6-cycle, 3-phase Fault at Bay d'Espoir 230 kV on line to Sunnyside (TL202)

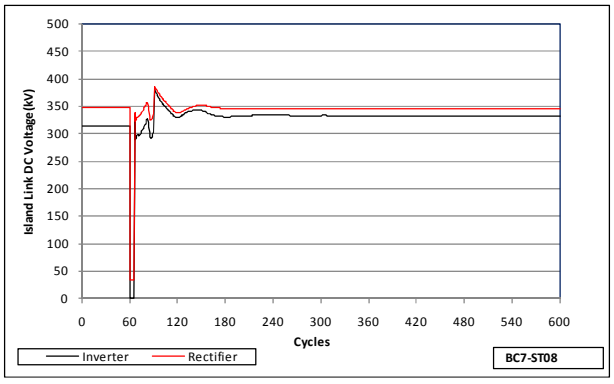




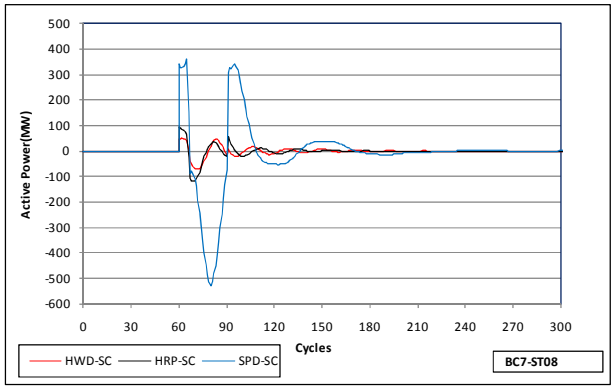


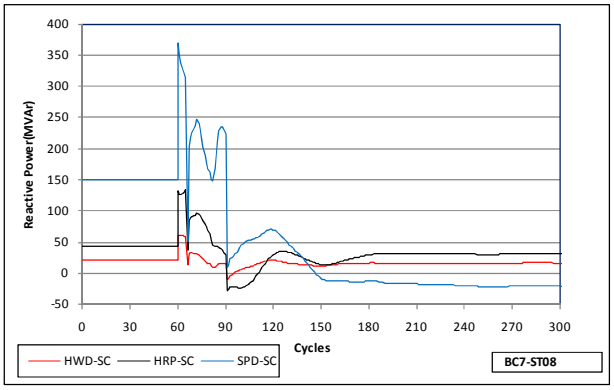


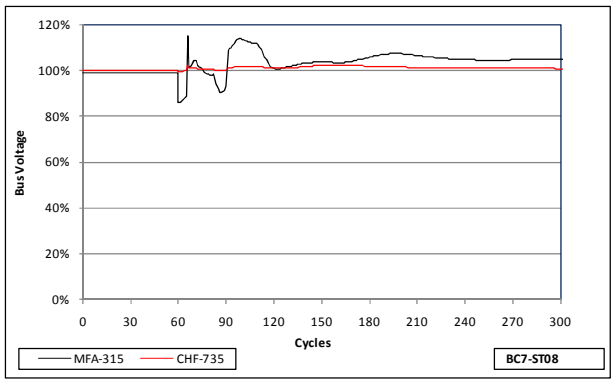


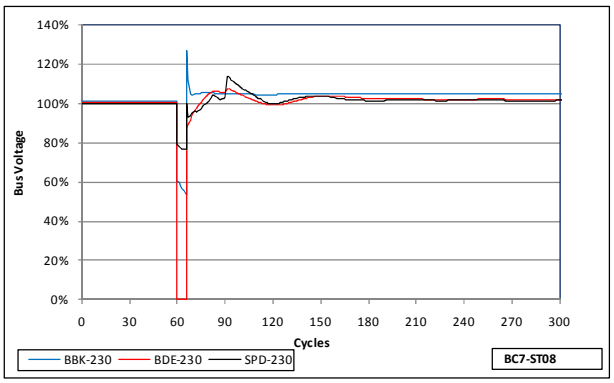


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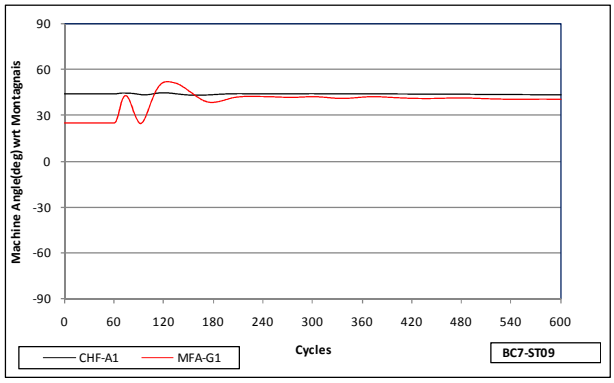


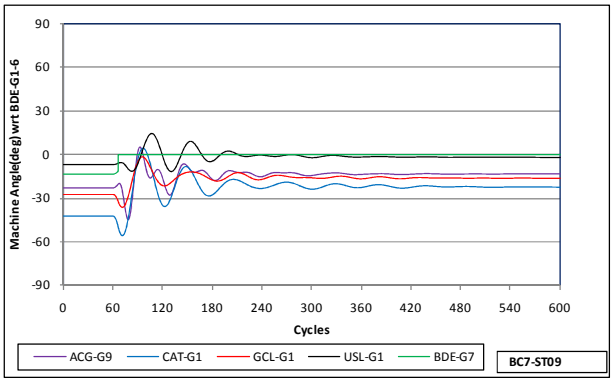


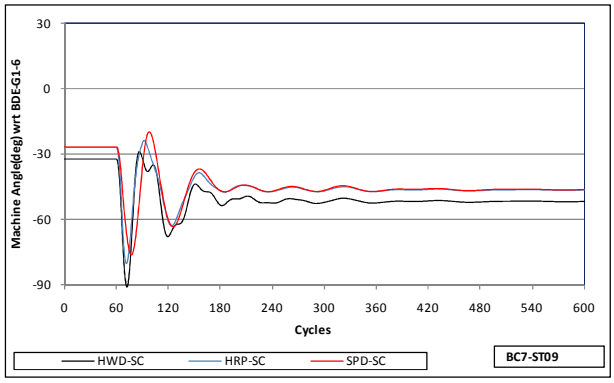


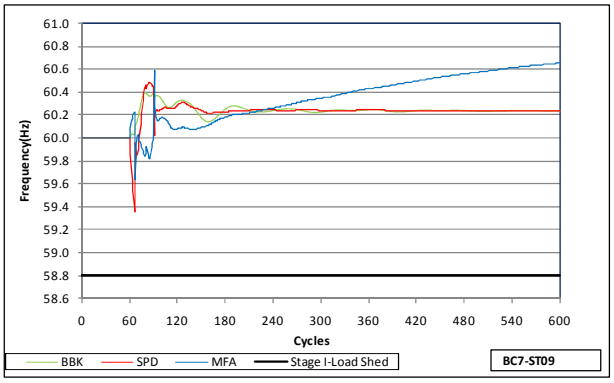
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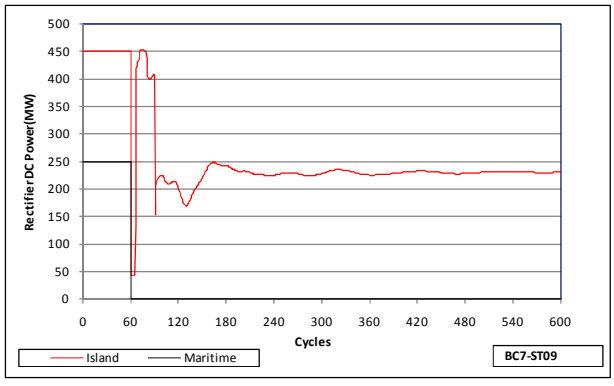
Figure 3-24: BC7-ST09, Intermediate/Island Link 900 MW/Maritime Link 500 MW 6-cycle, 3-phase Fault at Bay d'Espoir 230 kV-Generator Outage G7

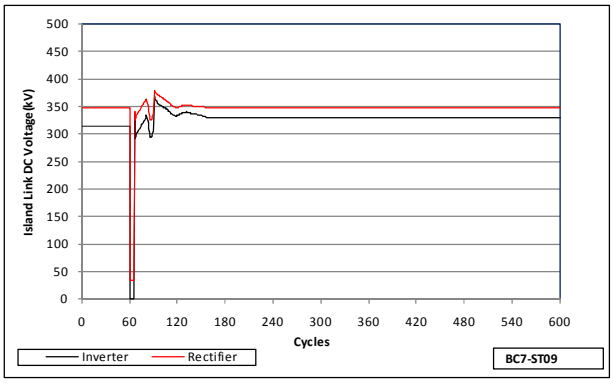




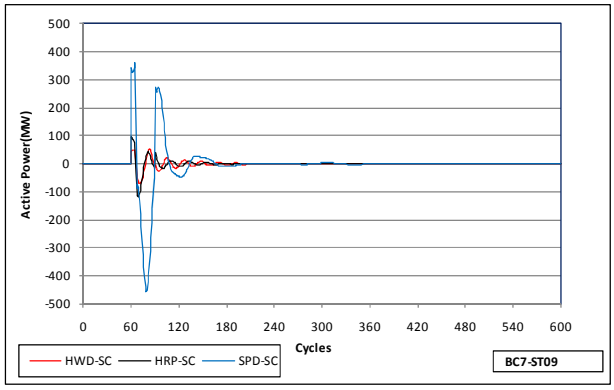


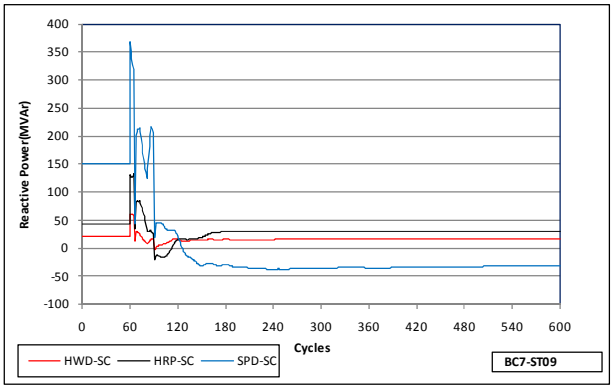


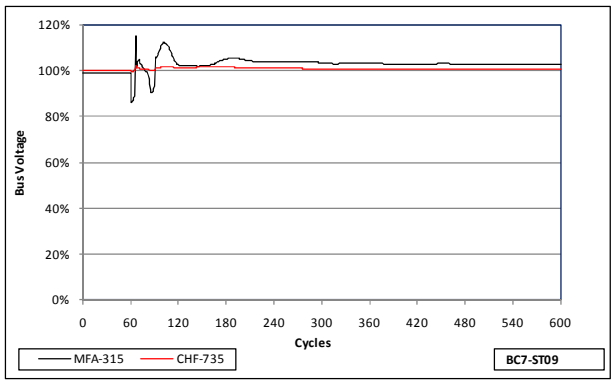


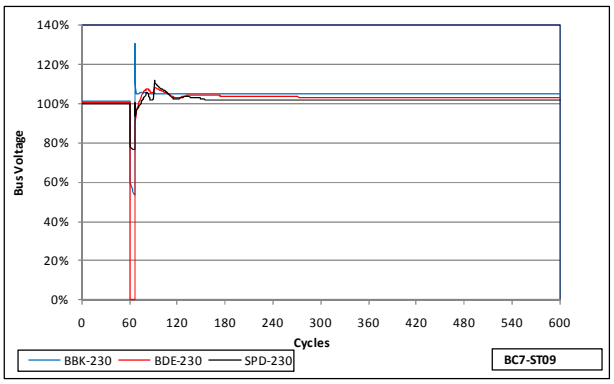


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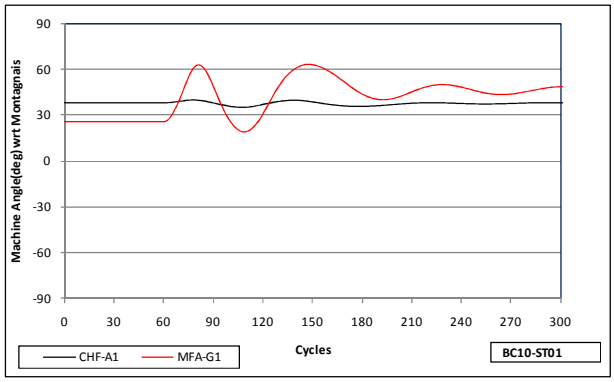
3.3 Summer Day Light Load Conditions

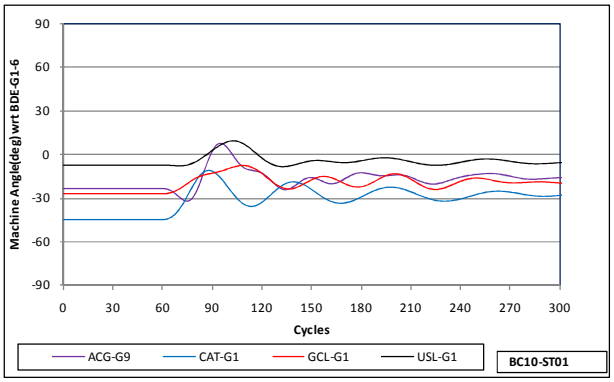
For summer daytime, light load conditions, an Island load of 700 MW was considered. Scenario BC-10 was selected for analysis as this scenario has the highest dc link loadings. The same fault cases were studied as for Scenarios BC-2 and BC-7. The faults were seen to be generally less severe under BC-10 and the general observations made for the previous scenarios apply to these results. The results under BC-10 are presented in the following figures.

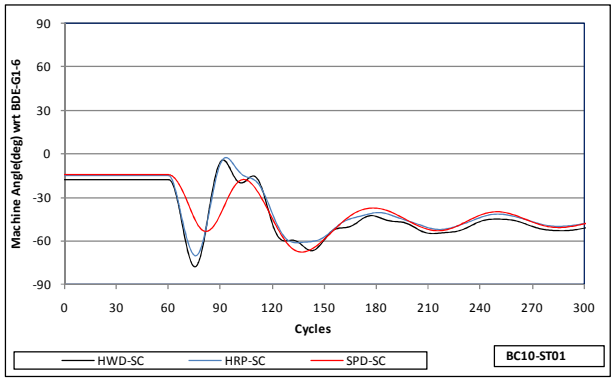
The only item of major significance from these studies is that the temporary over-voltages seen at Bottom Brook when the Maritime Link is blocked and the fault removed were higher than in the previous scenarios, reaching a maximum value of 170% for a fault at Bottom Brook 230 kV on the line to Granite Canal (Figure 3-30). As before, this temporary over-voltage lasts for only a few cycles and is within the temporary over-voltage capability of zinc oxide arresters (180% of maximum system voltage for 0.1 s) and the substation equipment.

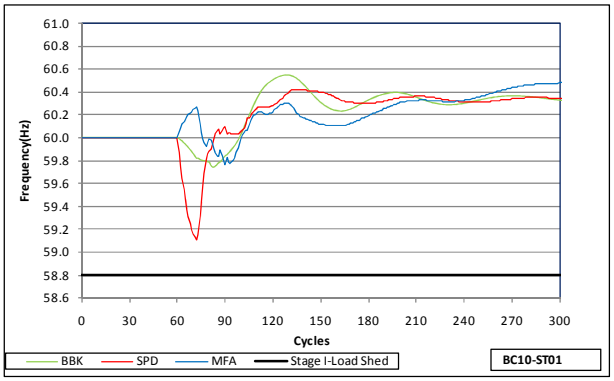
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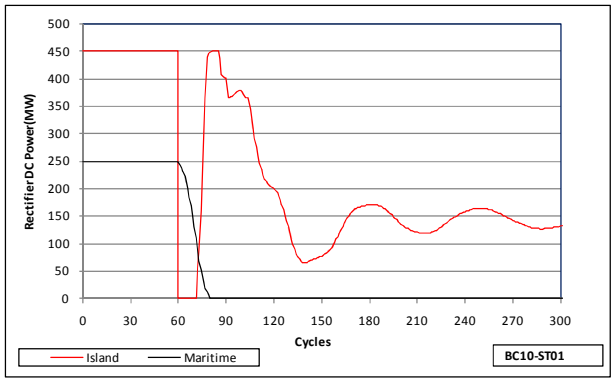
Figure 3-25: BC10-ST01, Light/Island Link 900 MW/Maritime Link 500 MW Temporary Bipole Fault on Island Link

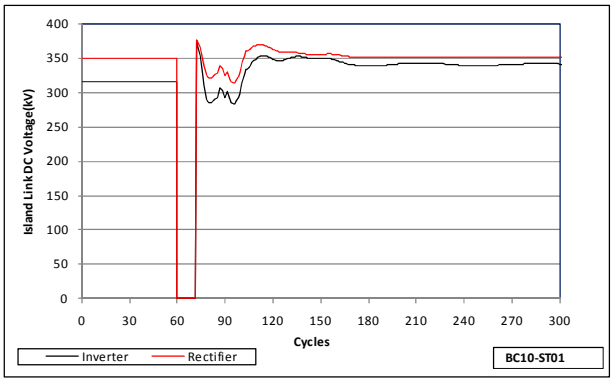




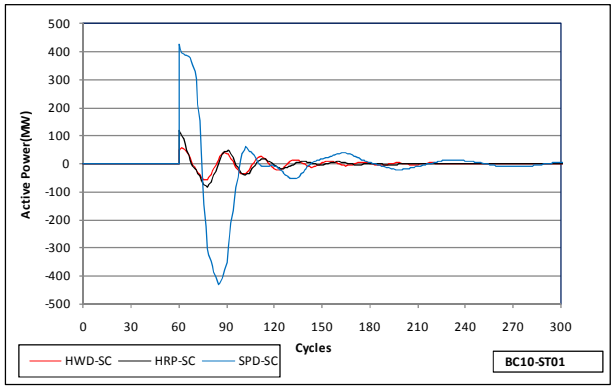


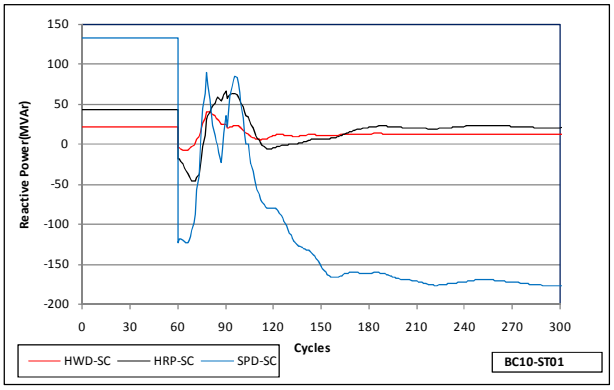


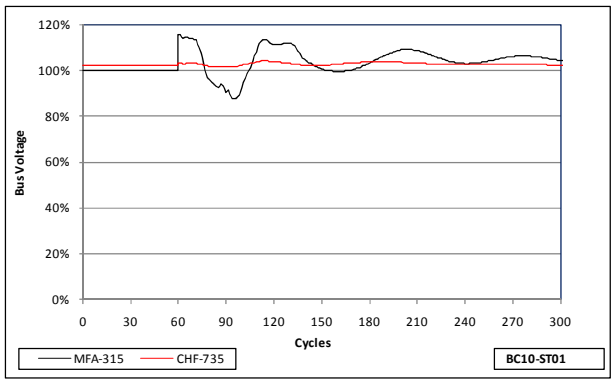


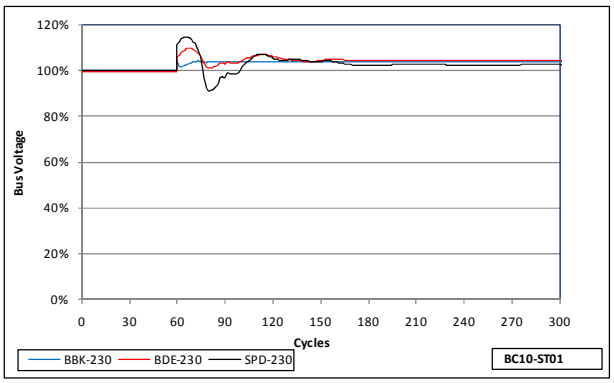


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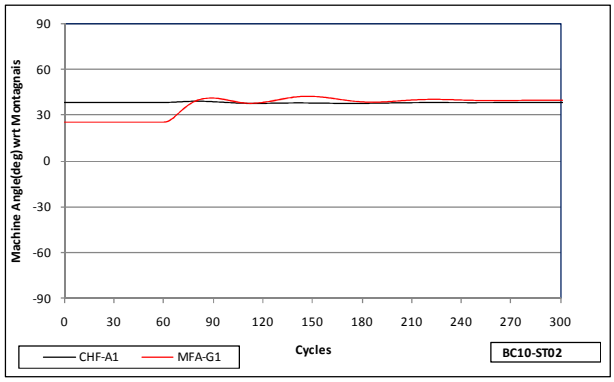


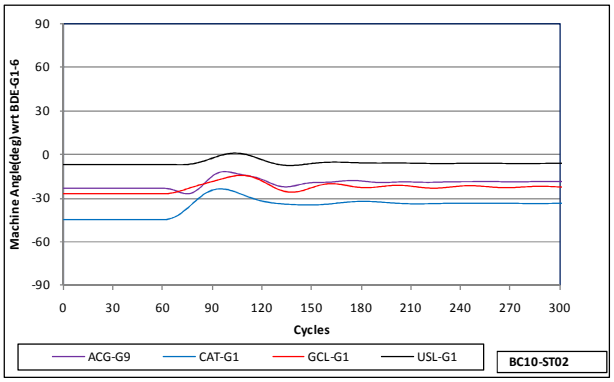


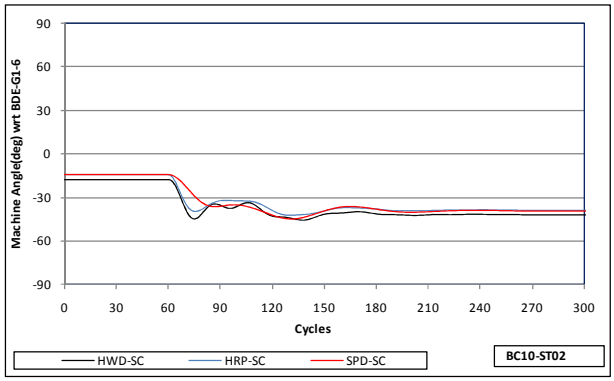


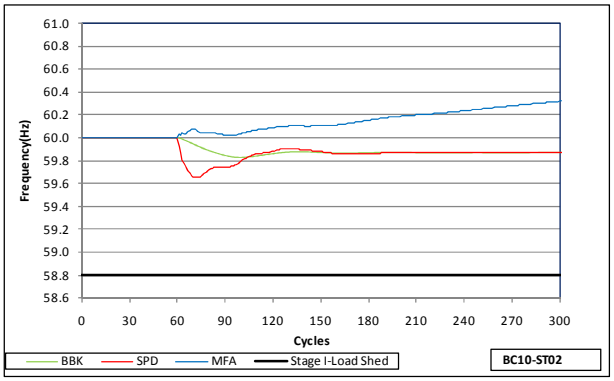
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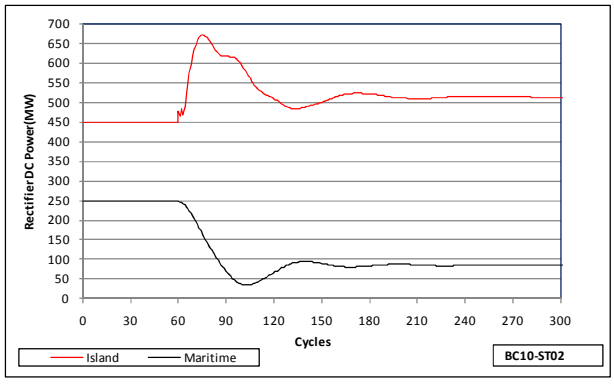
Figure 3-26: BC10-ST02, Light/Island Link 900 MW/Maritime Link 500 MW Permanent Pole Outage on Island Link

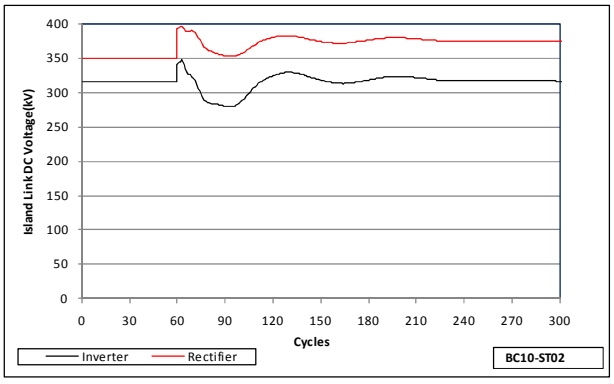




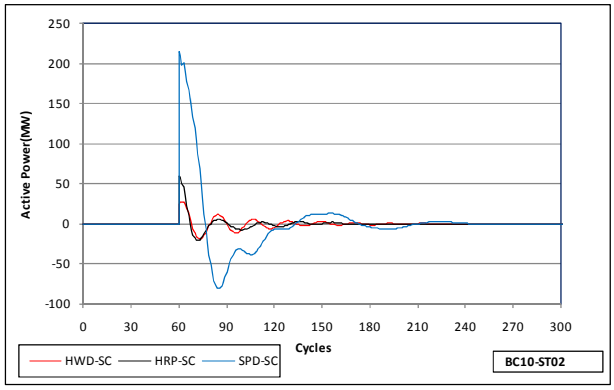


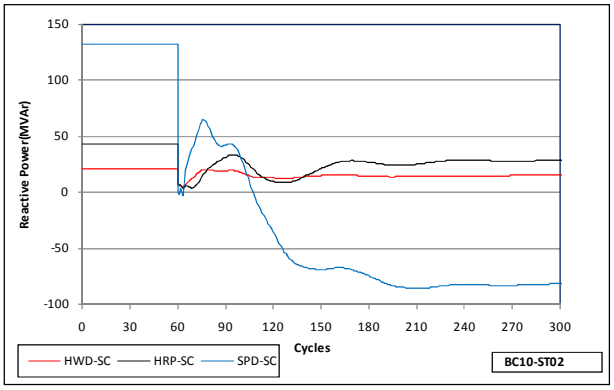


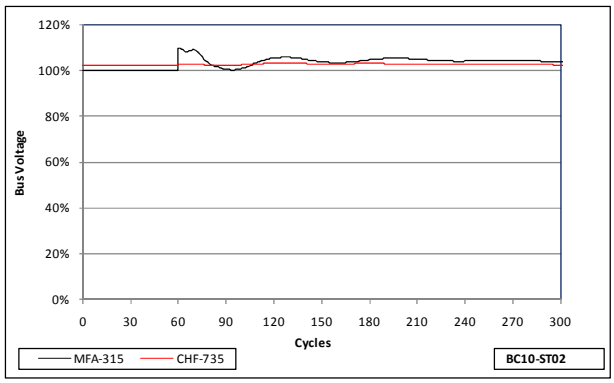


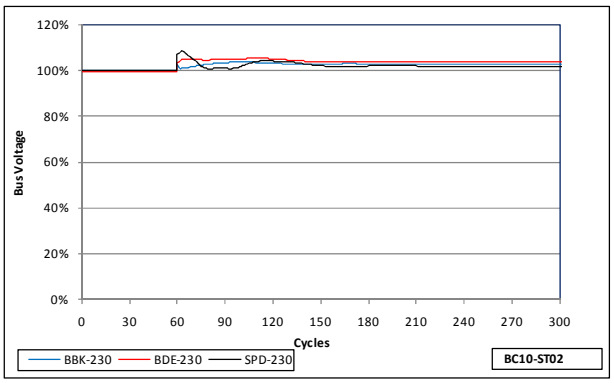


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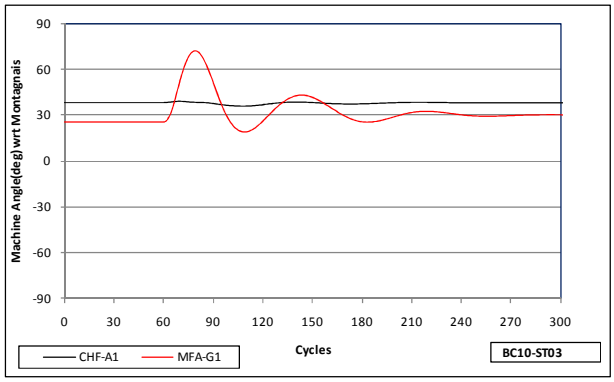


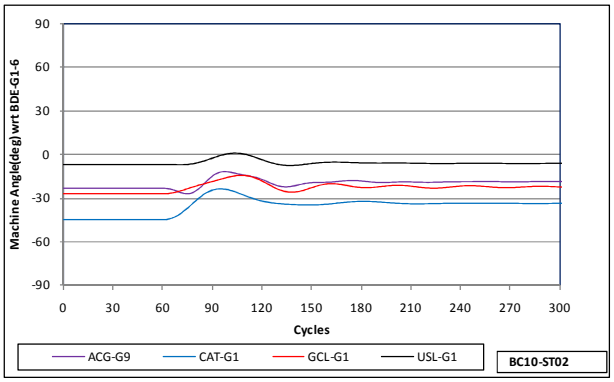


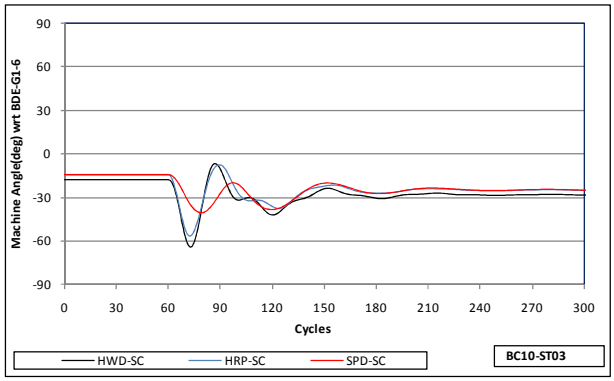


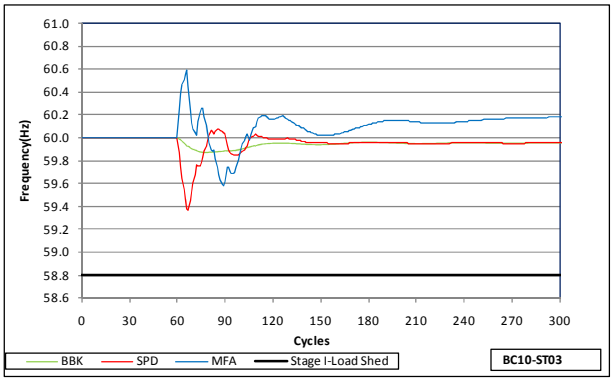
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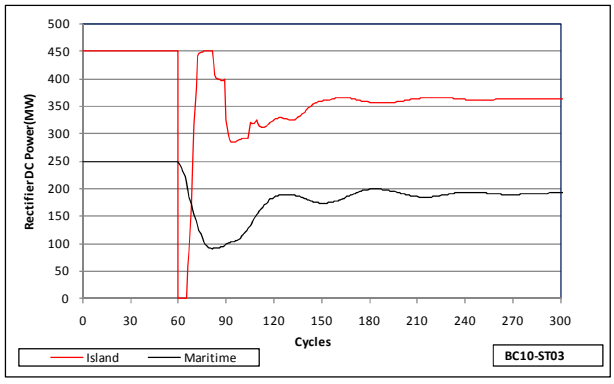
Figure 3-27: BC10-ST03, Light/Island Link 900 MW/Maritime Link 500 MW 6-cycle/3-phase Fault at Muskrat Falls 315 kV on line to Churchill Falls

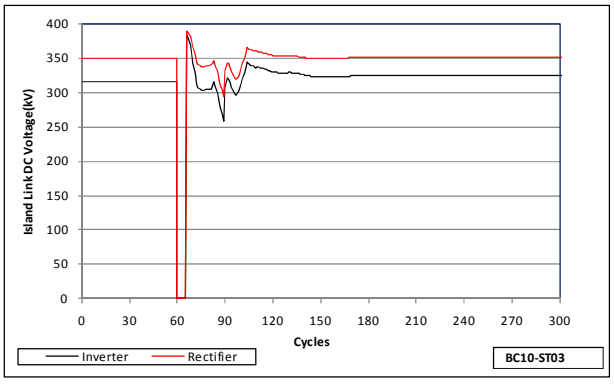




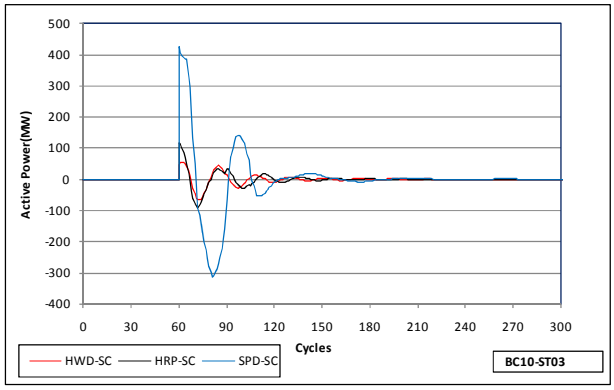


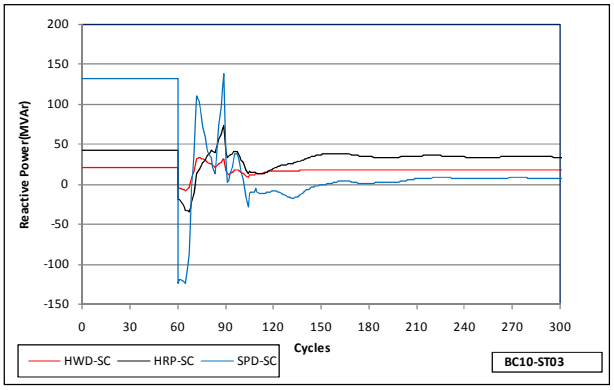


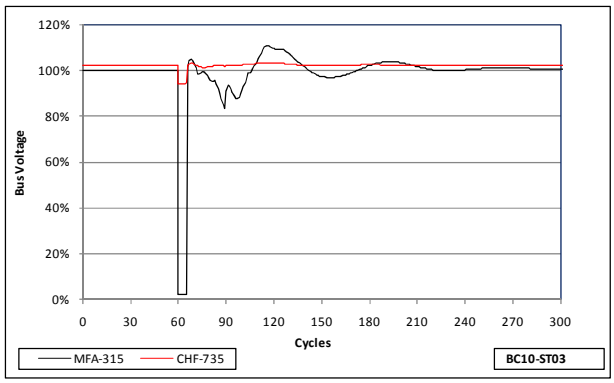


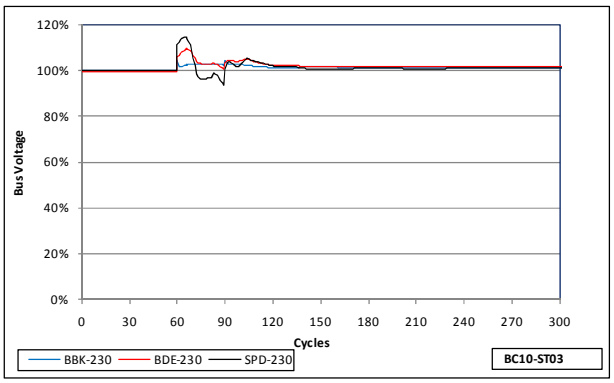


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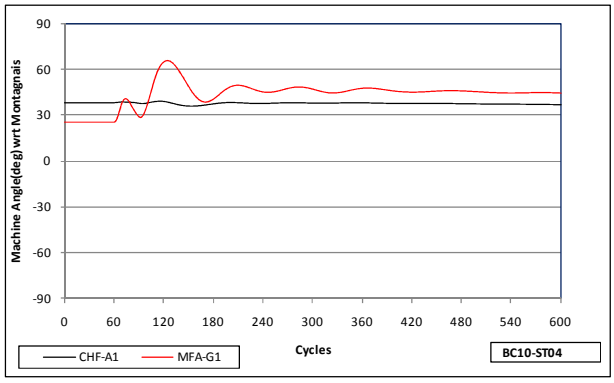


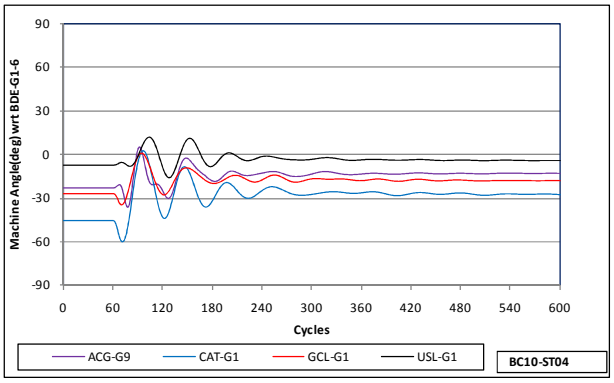


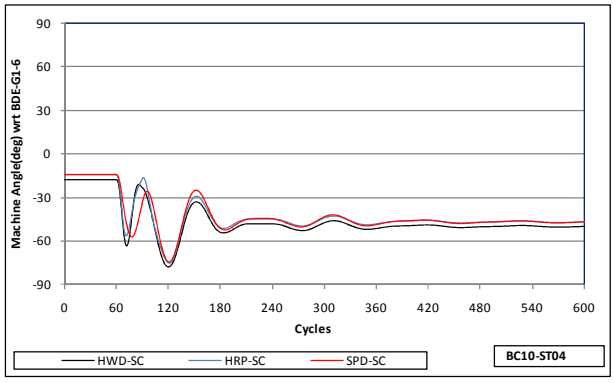


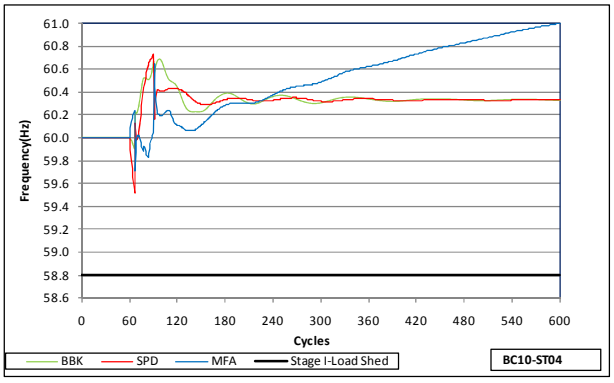
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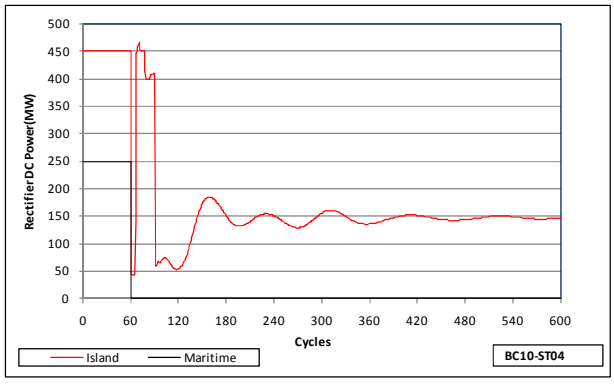
Figure 3-28: BC10-ST04, Light/Island Link 900 MW/Maritime Link 500 MW 6-cycle/3-phase Fault at Bay d'Espoir 230 kV on line to Western Avalon

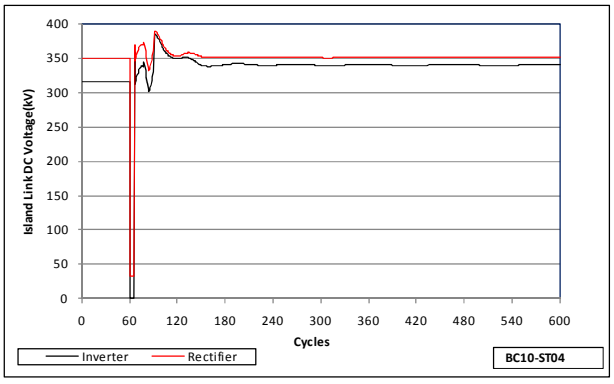




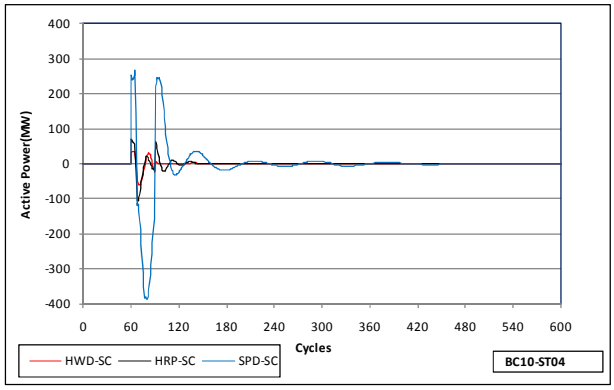


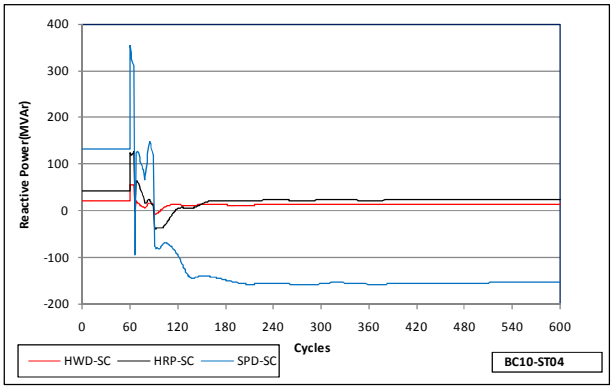


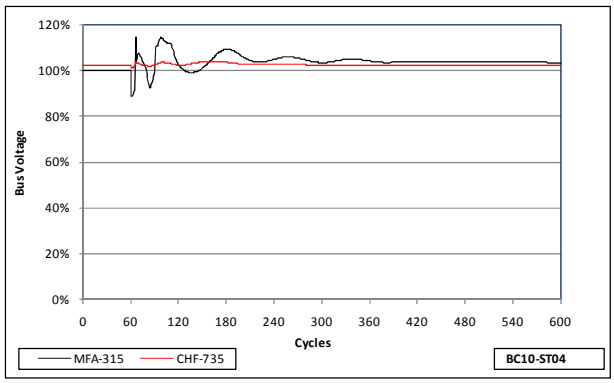




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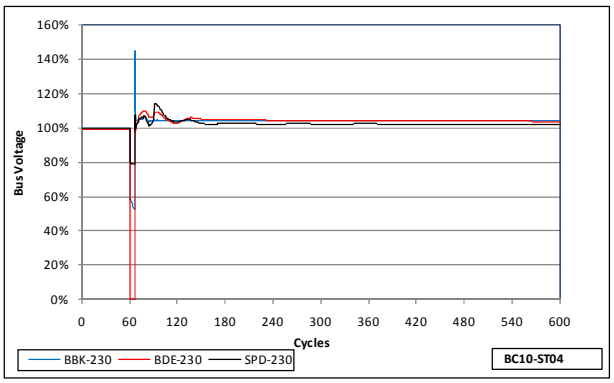
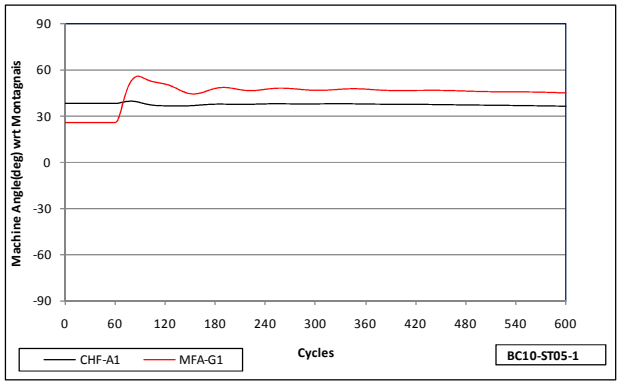
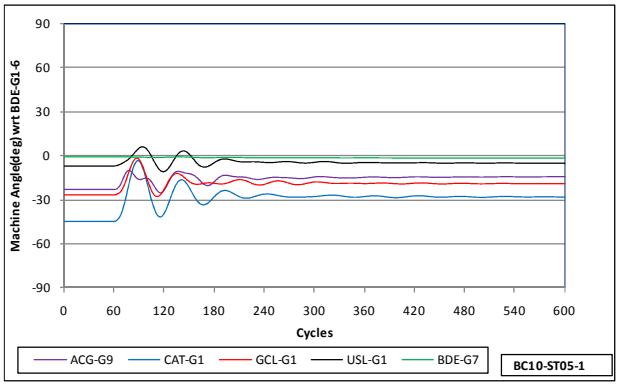
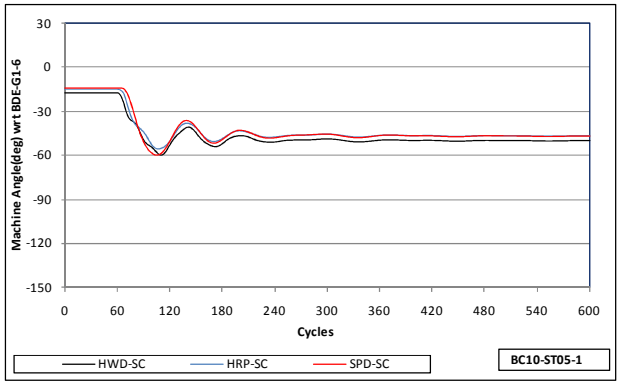
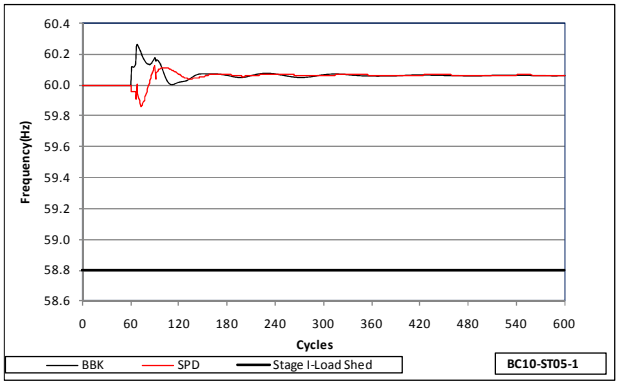


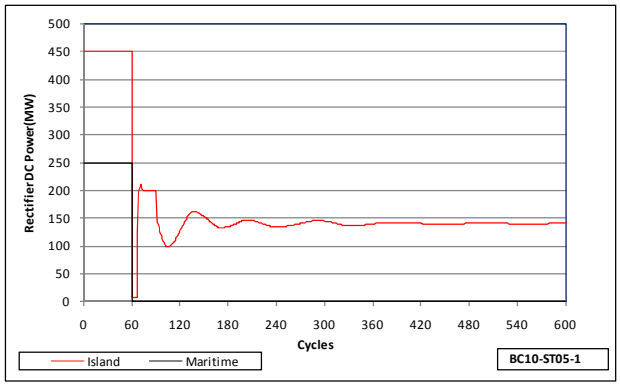
Figure 3-29: BC10-ST05-1, Light/Island Link 900 MW/Maritime Link 500 MW 6-cycle/3-phase Fault at Soldiers Pond 230 kV on line to Western Avalon (TL217W)

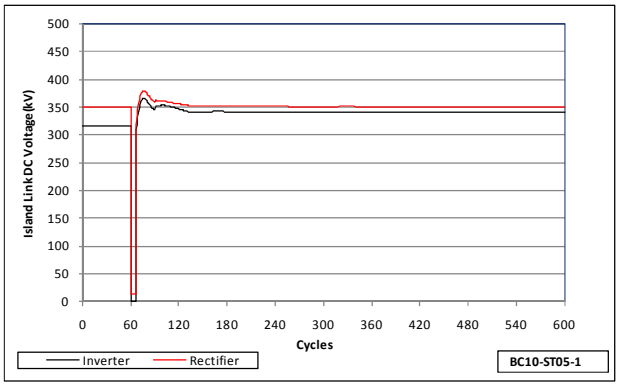




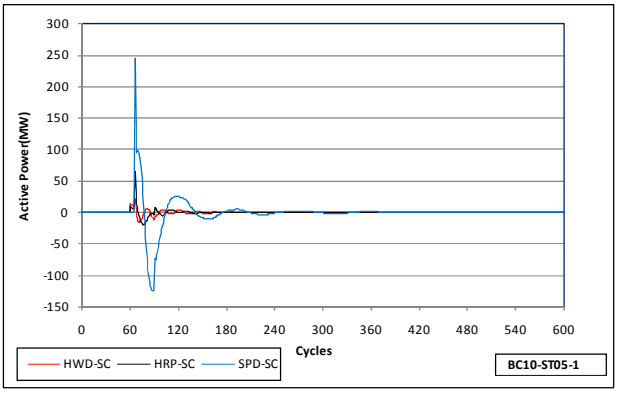


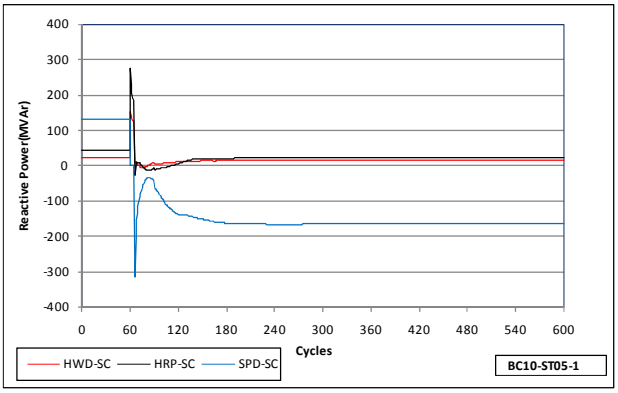


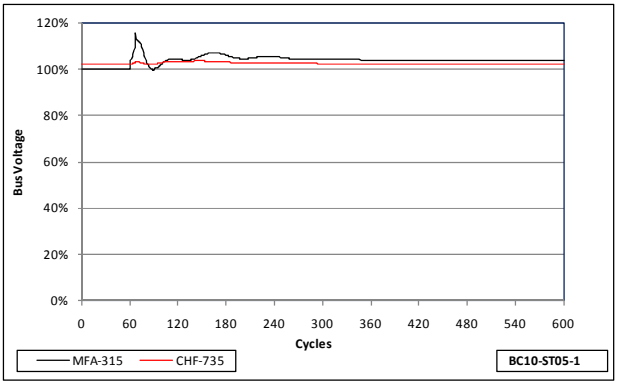




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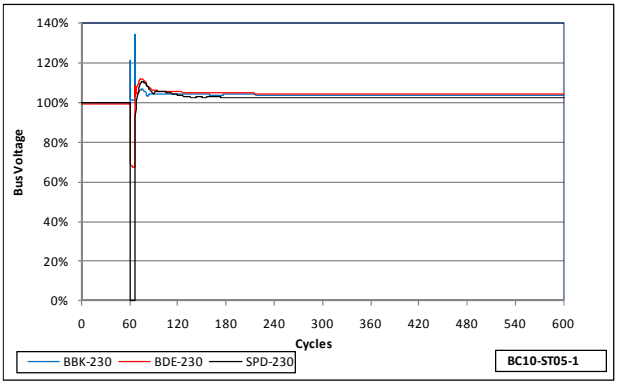
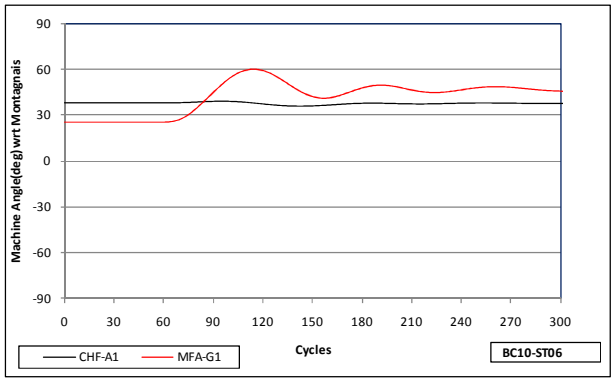
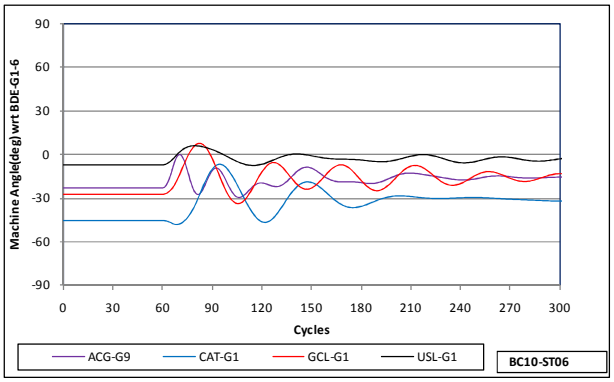
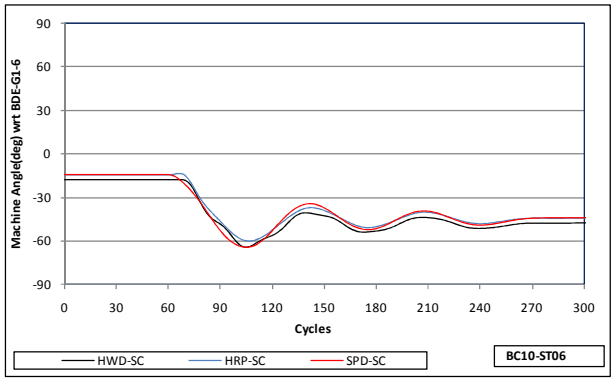
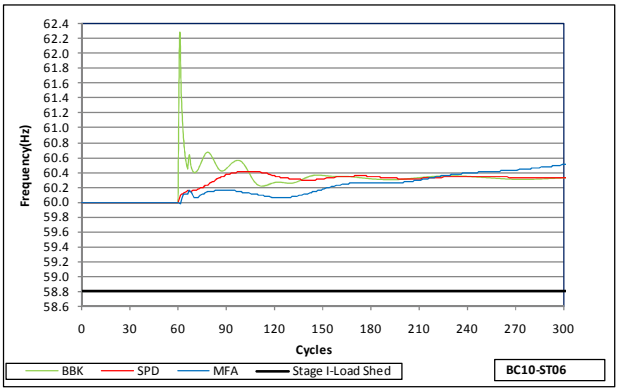


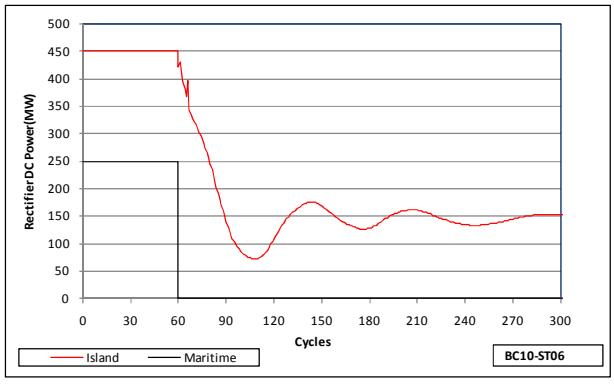
Figure 3-30: BC10-ST06, Light/Island Link 900 MW/Maritime Link 500 MW 6-cycle/3-phase Fault at Bottom Brook 230 kV on line to Granite Canal

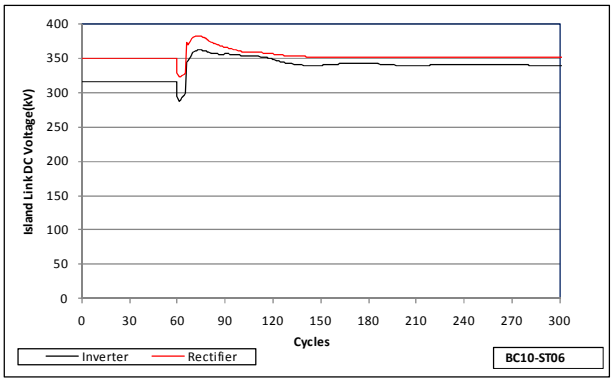




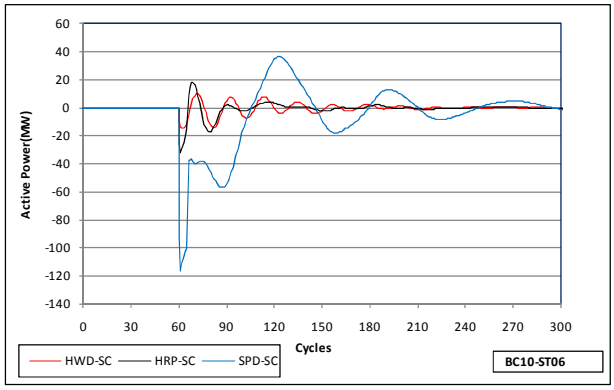


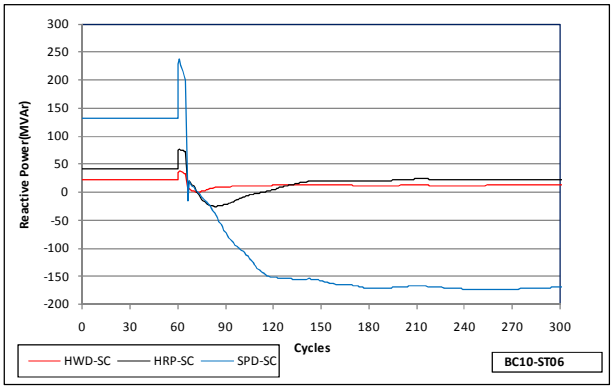


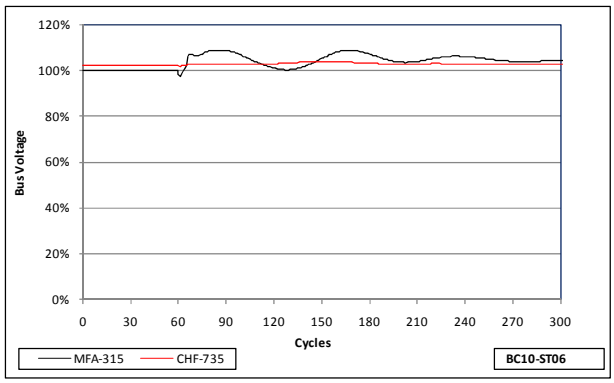


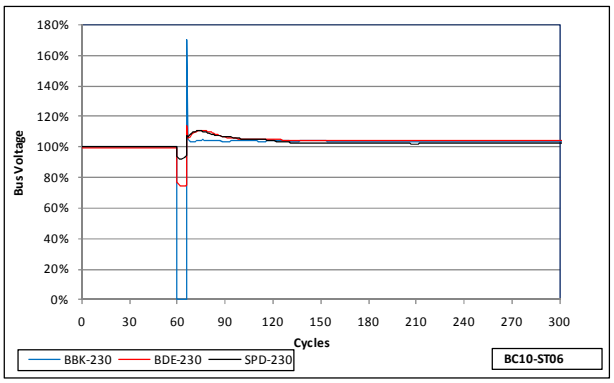


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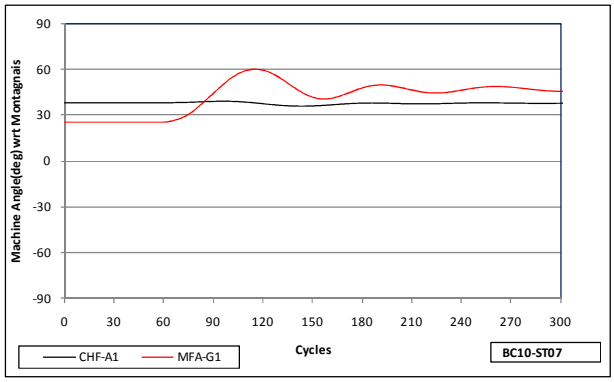


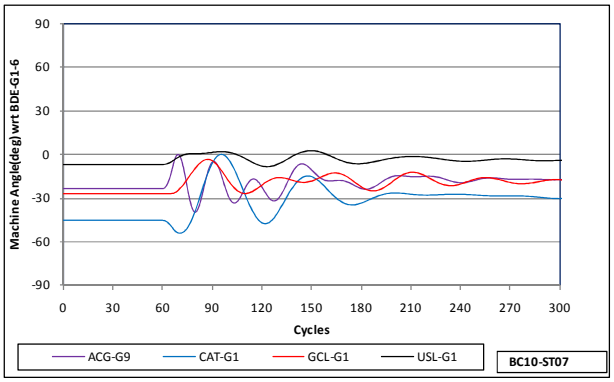


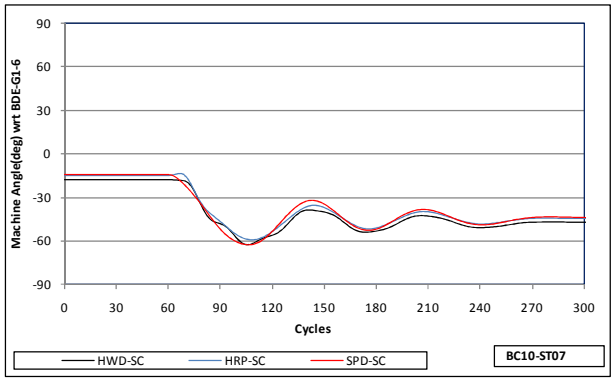


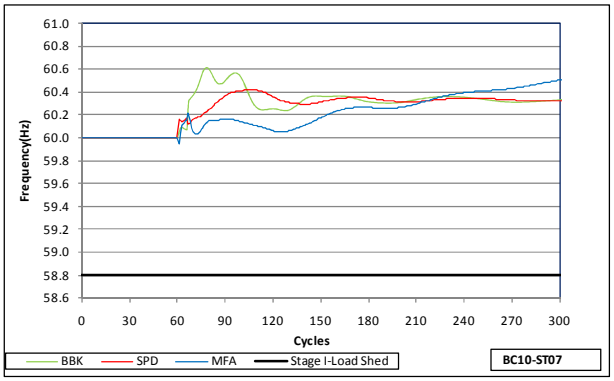
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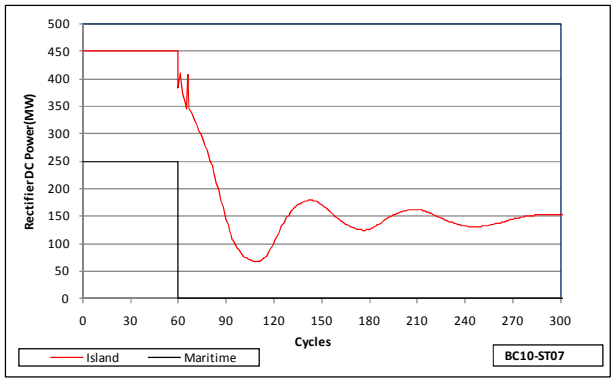
Figure 3-31: BC10-ST07, Light/Island Link 900 MW/Maritime Link 500 MW 6-cycle/3-phase Fault at Stony Brook 230 kV on line to Bay d'Espoir (TL204)

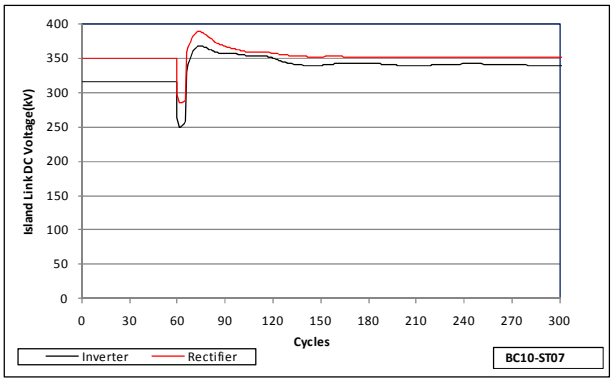




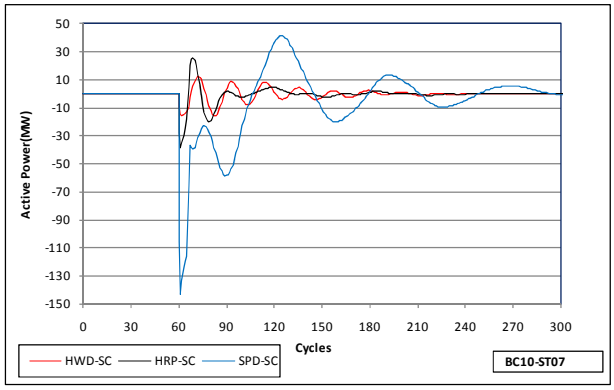


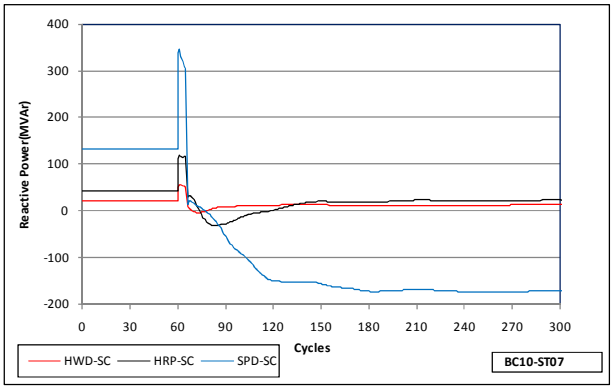


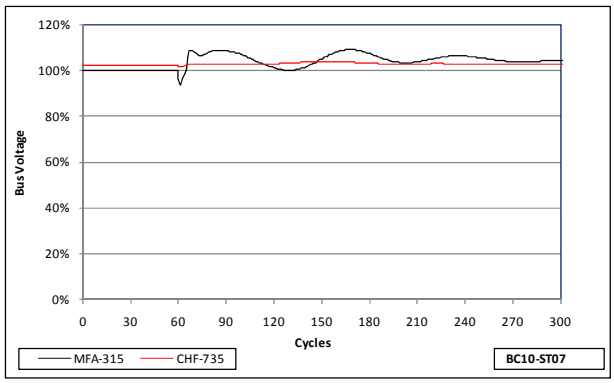




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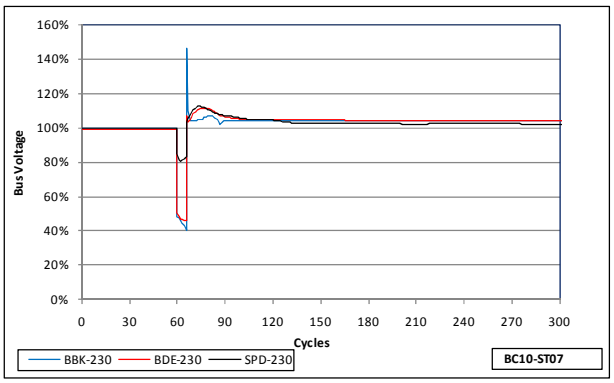
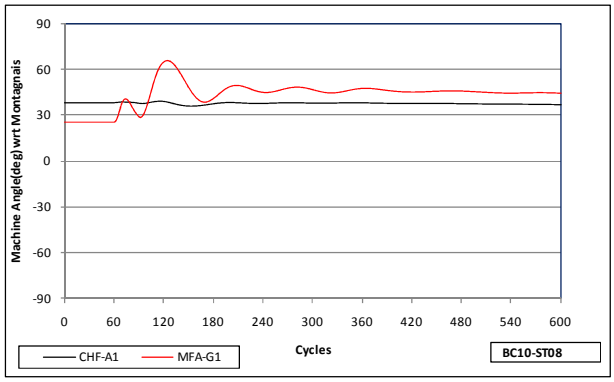
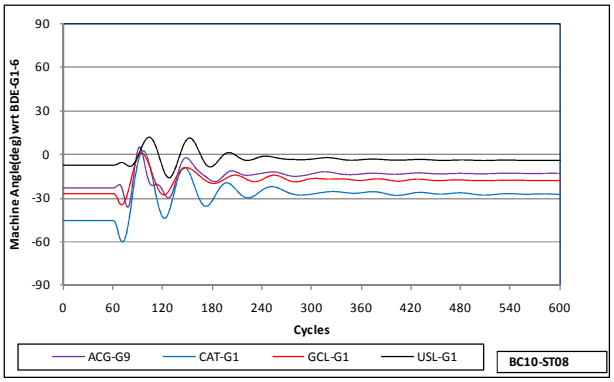
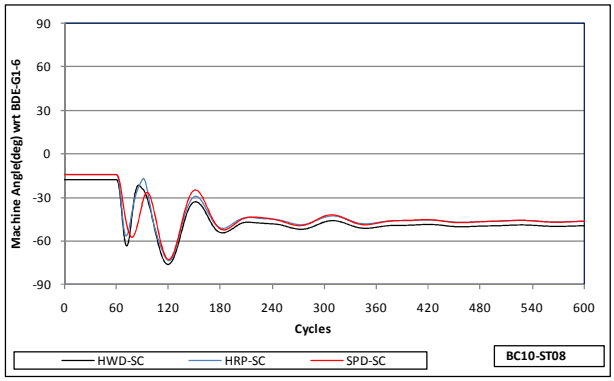
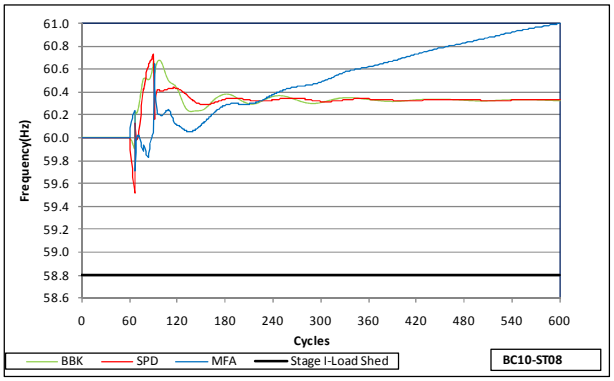


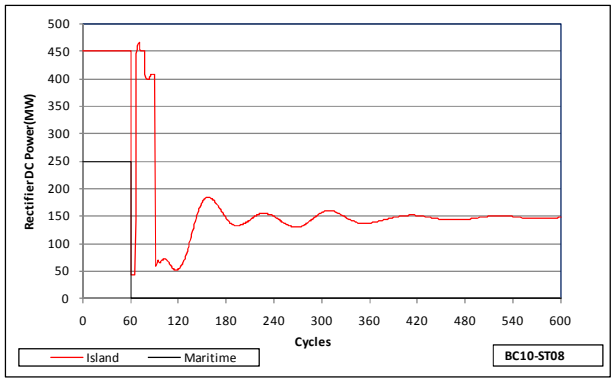
Figure 3-32: BC10-ST08, Light/Island Link 900 MW/Maritime Link 500 MW 6-cycle/3-phase Fault at Bay d'Espoir 230 kV on line to Sunnyside (TL202)

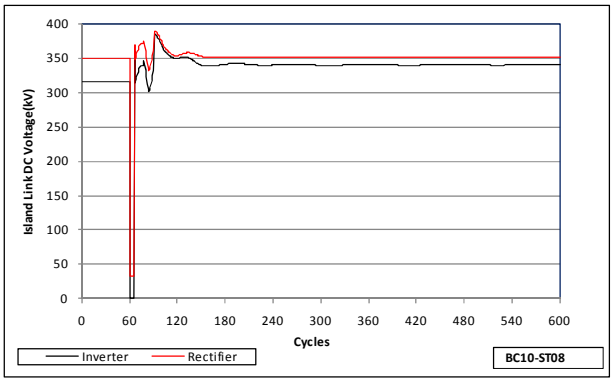




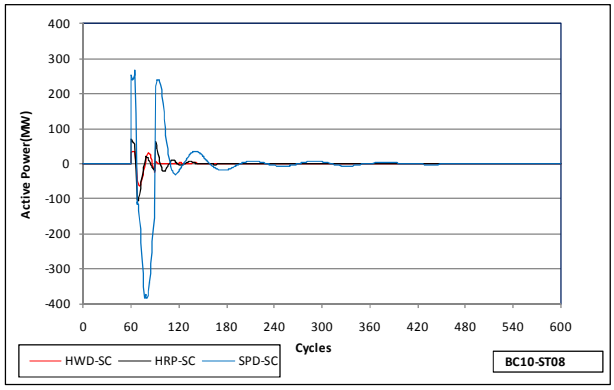


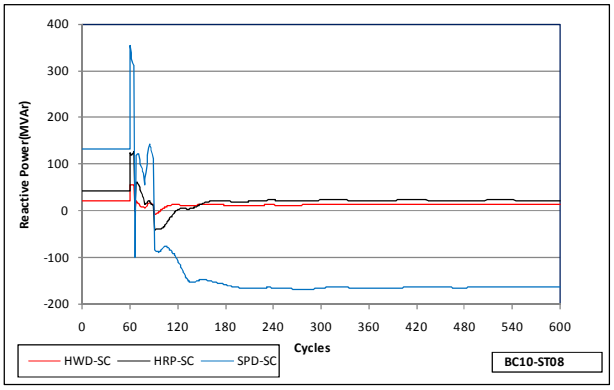


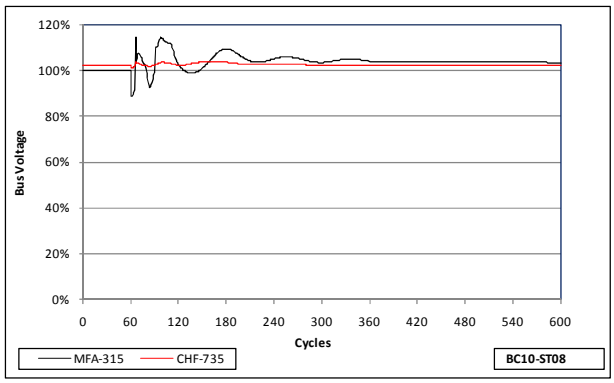




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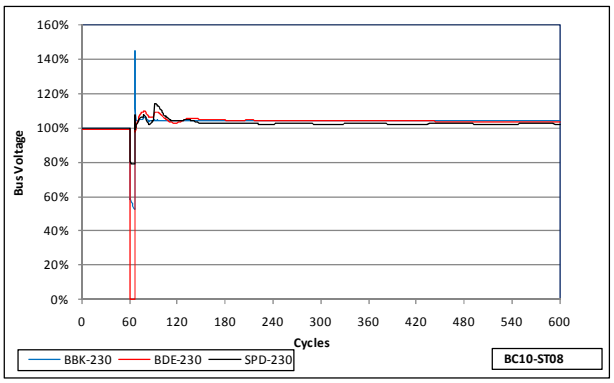
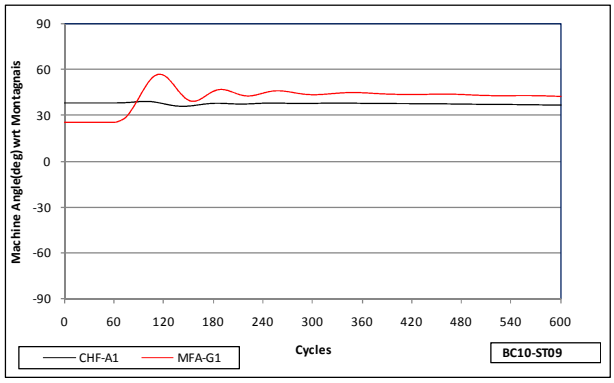
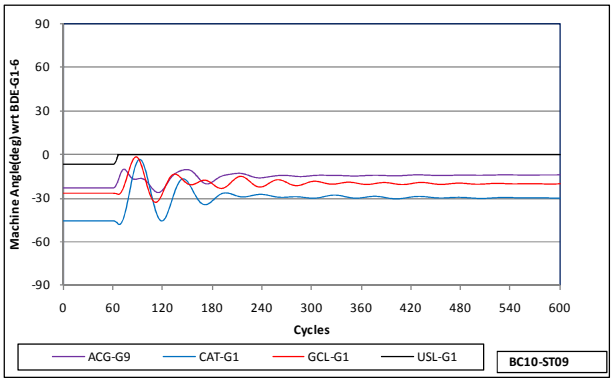
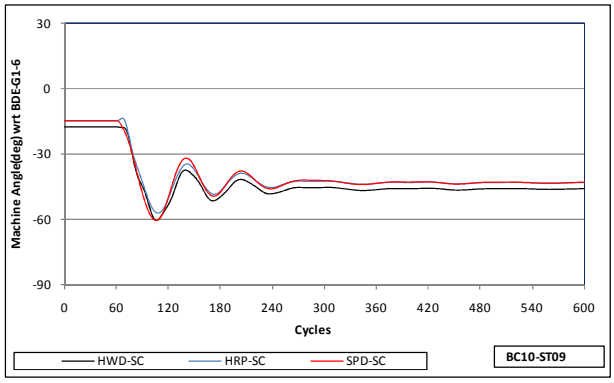
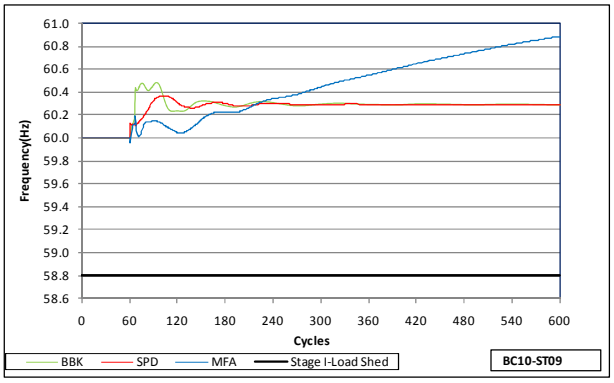


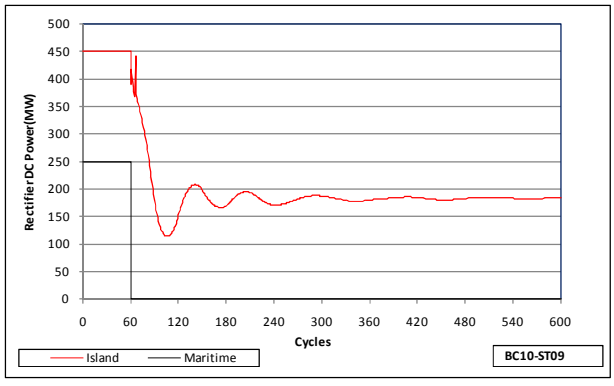
Figure 3-33: BC10-ST09, Light/Island Link 900 MW/Maritime Link 500 MW 6-cycle/3-phase Fault at Upper Salmon 230 kV-Generator Outage G1

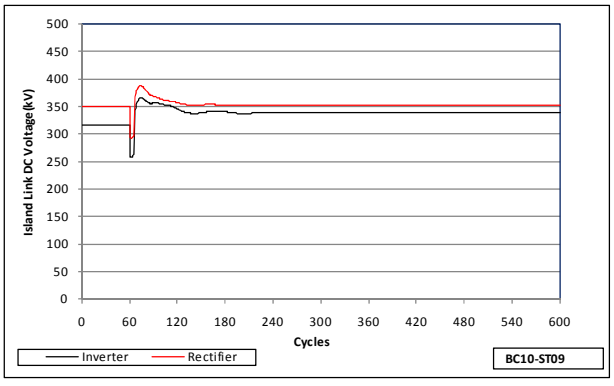




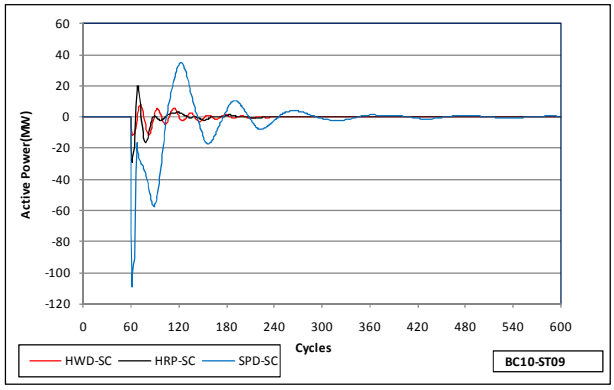


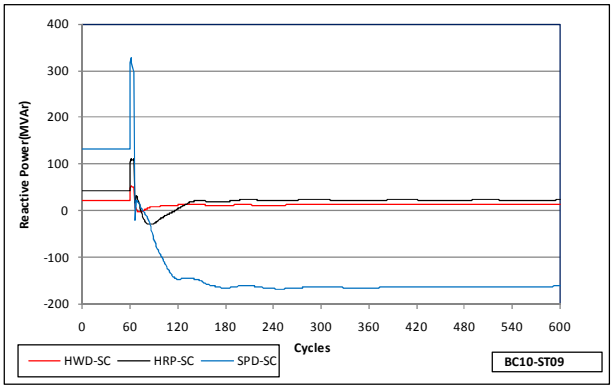


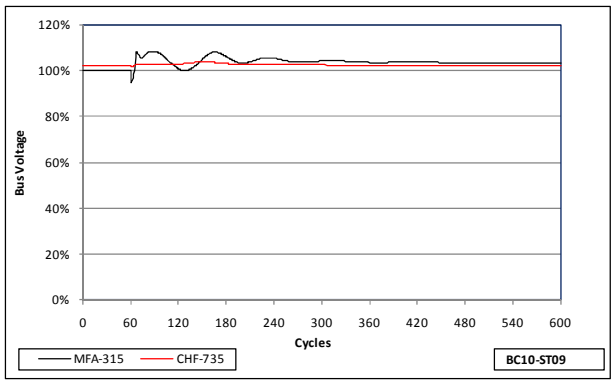


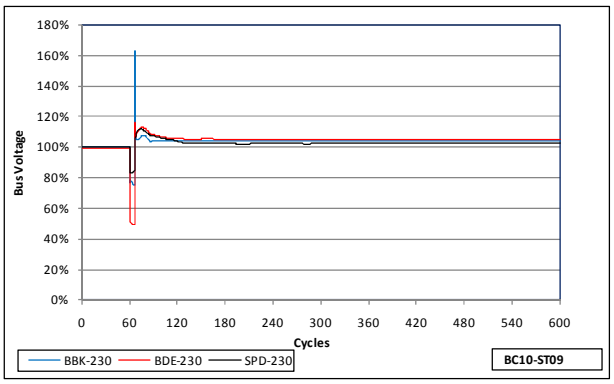


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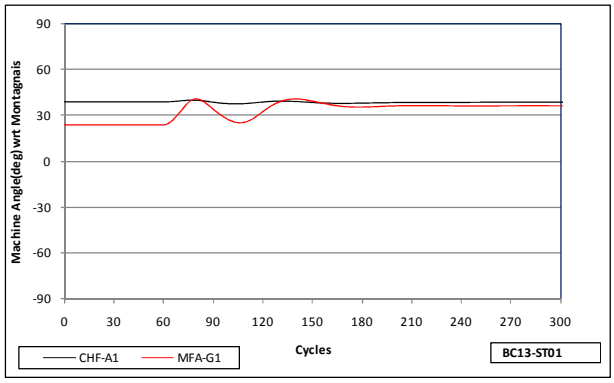


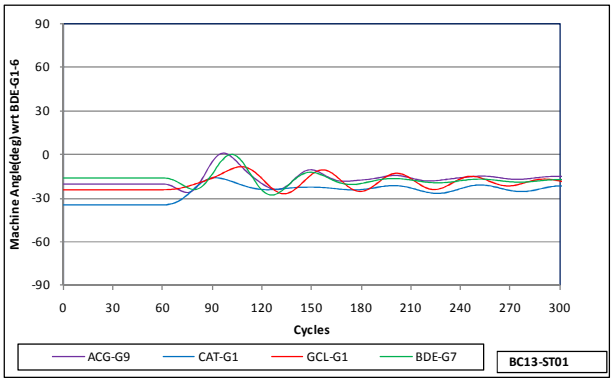
3.4 Summer Night Extreme Light Load Conditions

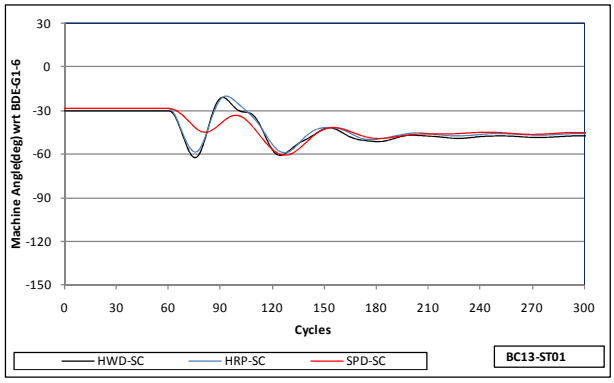
For summer night-time, extreme light load conditions, an Island load of 420 MW was considered. Scenario BC-13 was selected for analysis as this scenario has the highest dc link loadings. The same fault cases were studied as for Scenarios BC-2, BC-7 and BC-10. The faults were seen to be generally less severe under BC-13 and the general observations made for the previous scenarios apply to these results. The results under Scenario BC-13 are presented in the following figures.

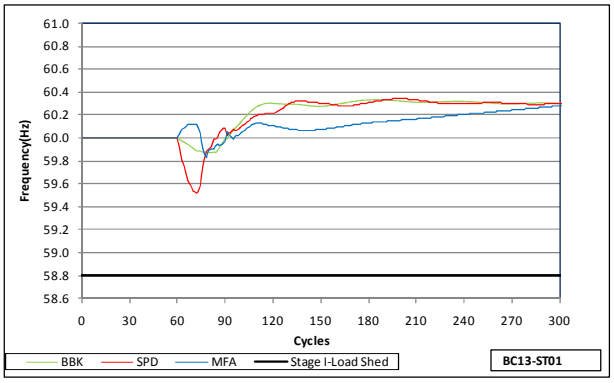
The only item of major significance from these studies is that the temporary over-voltages seen at Bottom Brook when the Maritime Link is blocked and the fault removed were higher than in the previous scenarios, reaching a maximum value of 180% for a fault at Bottom Brook 230 kV on the line to Granite Canal (Figure 3-39). As before, this temporary over-voltage lasts for only a few cycles and is within the temporary over-voltage capability of zinc oxide arresters (180% for 0.1 s) and the substation equipment.

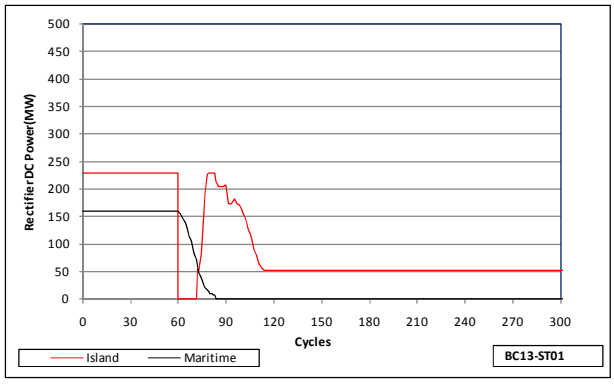
Figure 3-34: BC13-ST01, Extreme Light/Island Link 435 MW/Maritime Link 320 MW Temporary Bipole Fault on Island Link

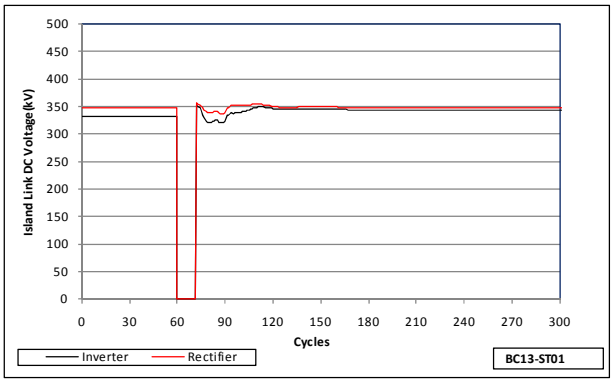




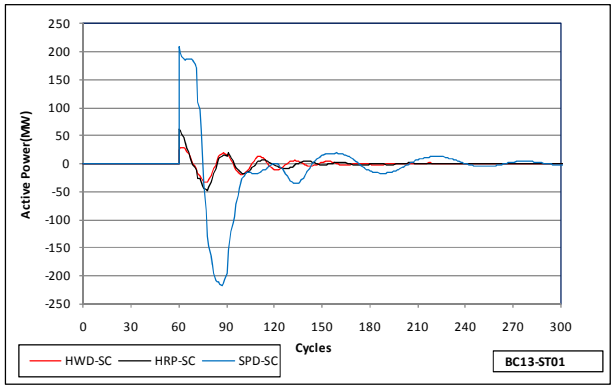


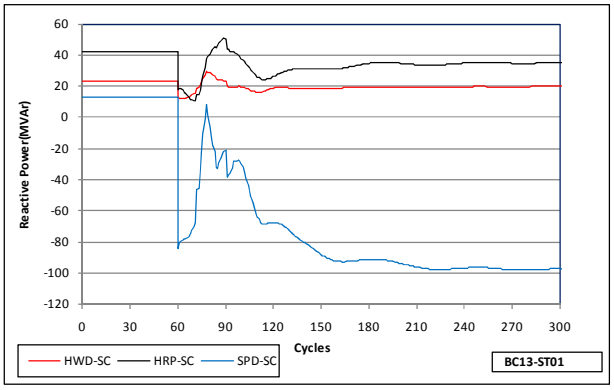


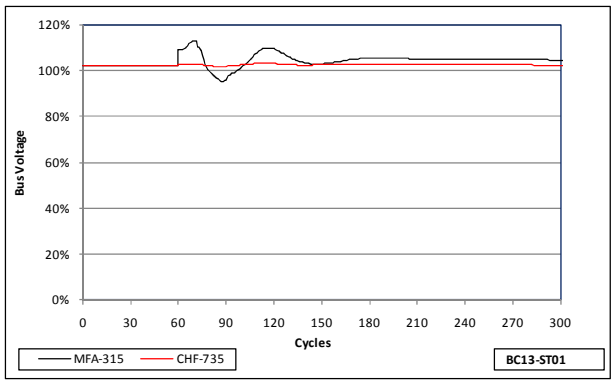


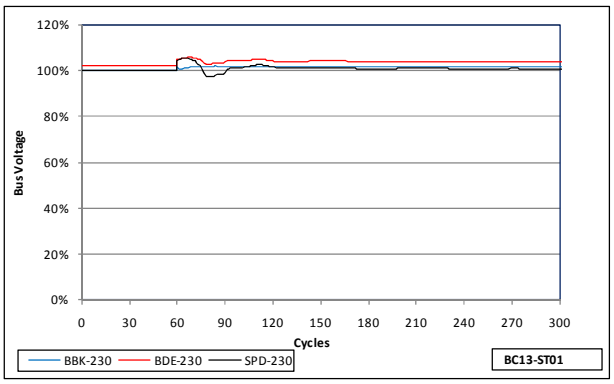


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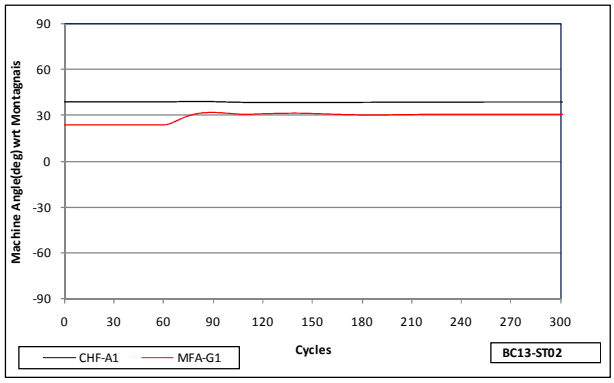


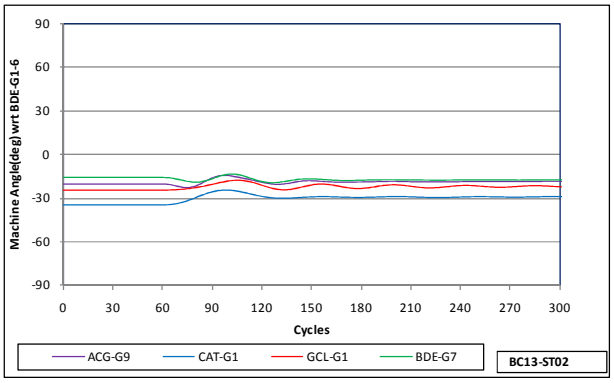


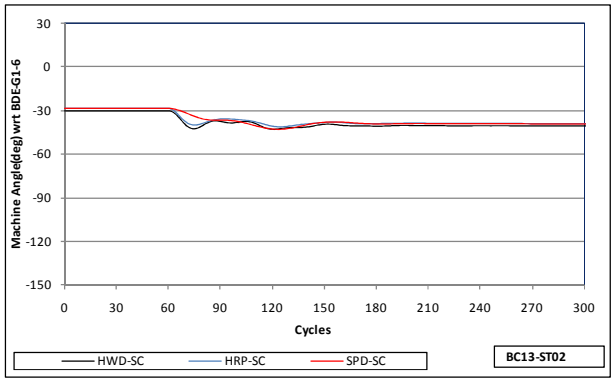


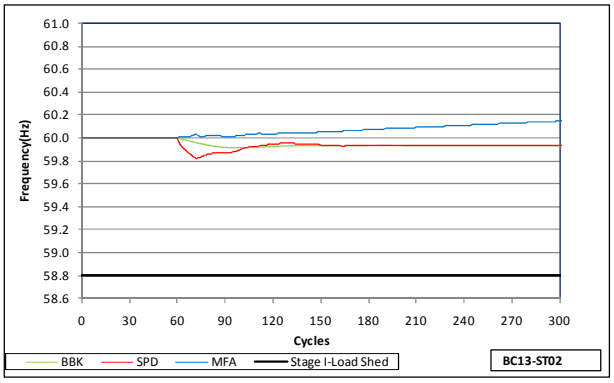
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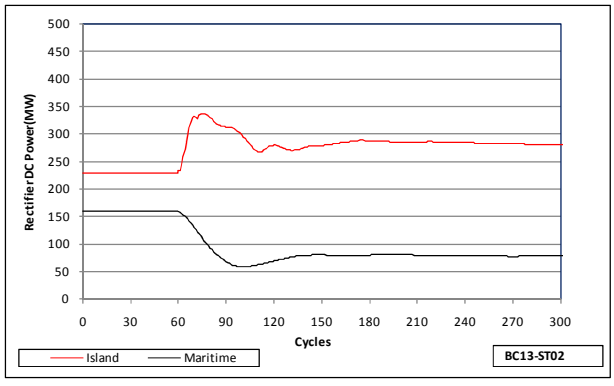
Figure 3-35: BC13-ST02, Extreme Light/Island Link 435 MW/Maritime Link 320 MW Permanent Pole Outage on Island Link

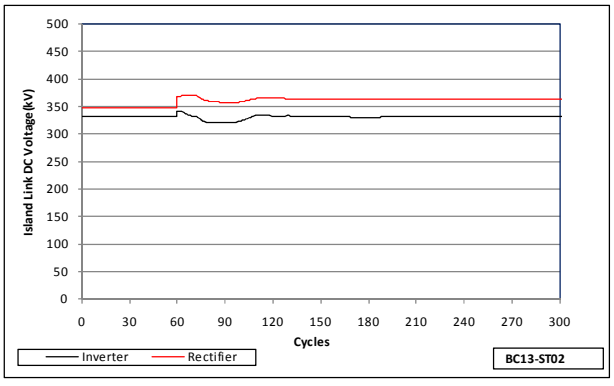




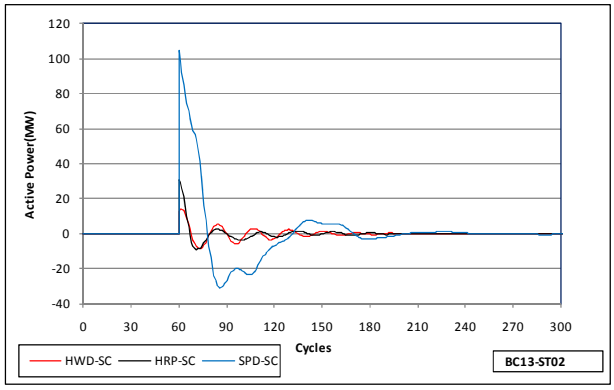


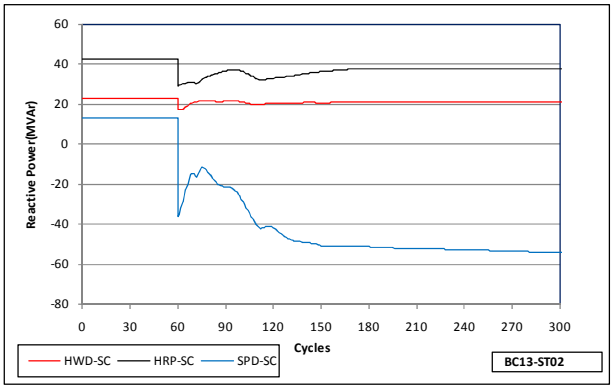


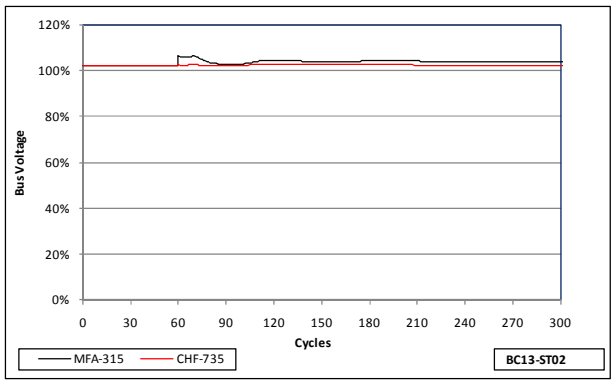




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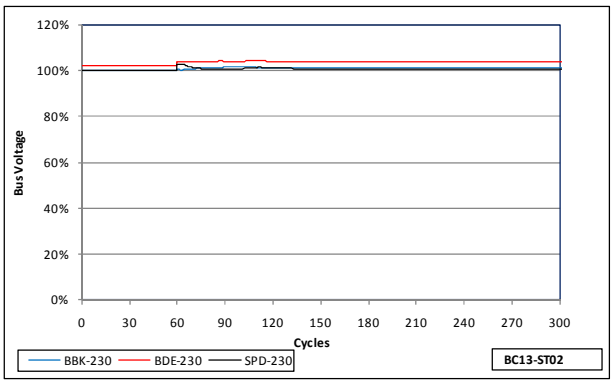
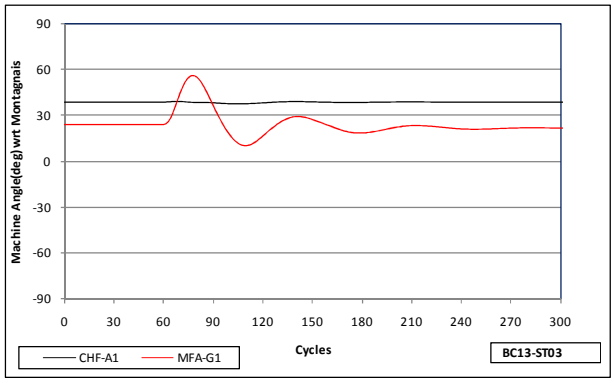
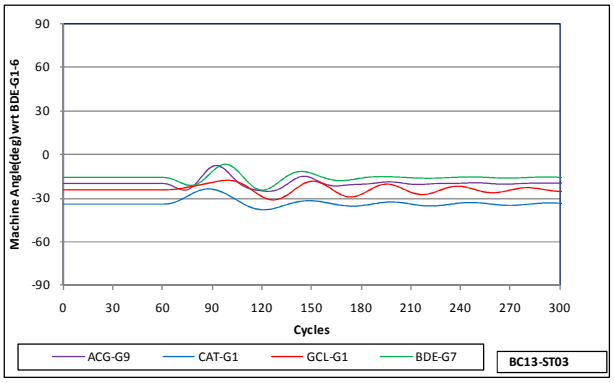
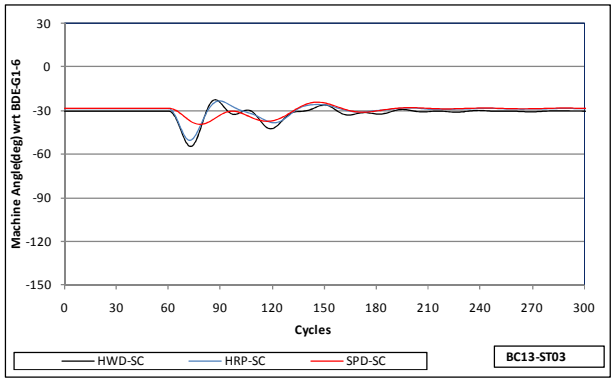
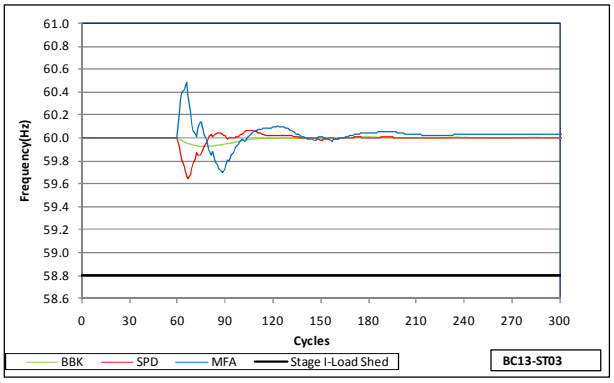


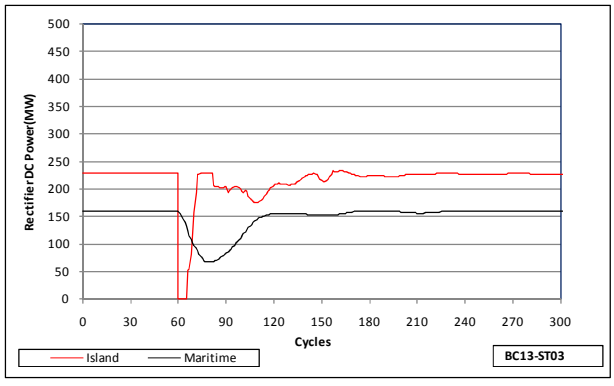
Figure 3-36: BC13-ST03, Extreme Light/Island Link 435 MW/Maritime Link 320 MW 6-cycle/3-phase Fault at Muskrat Falls 315 kV on line to Churchill Falls

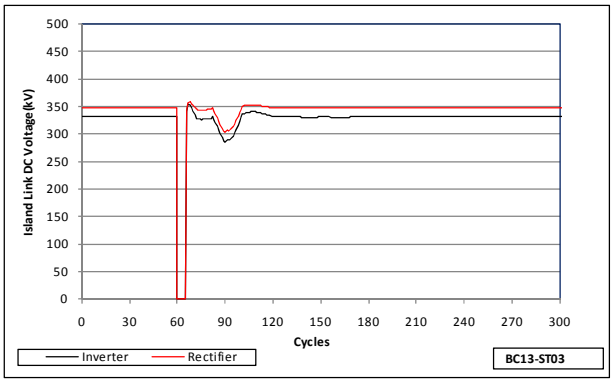




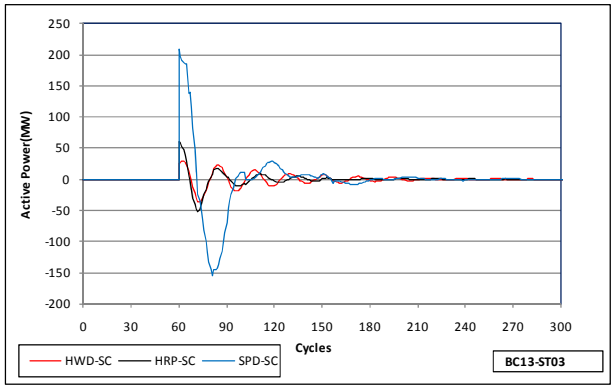


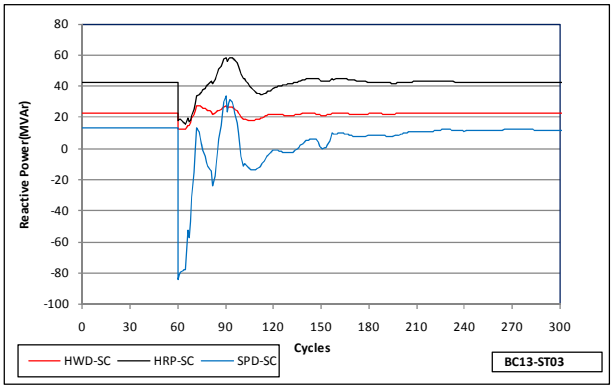


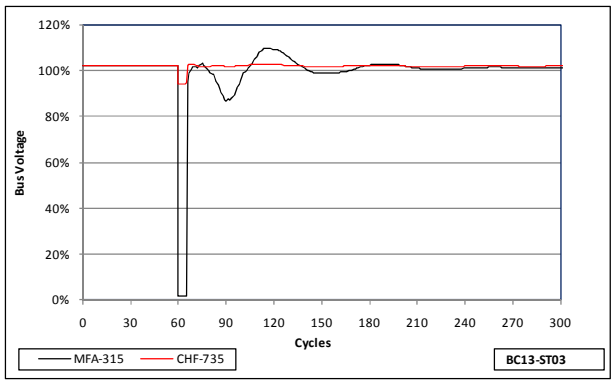




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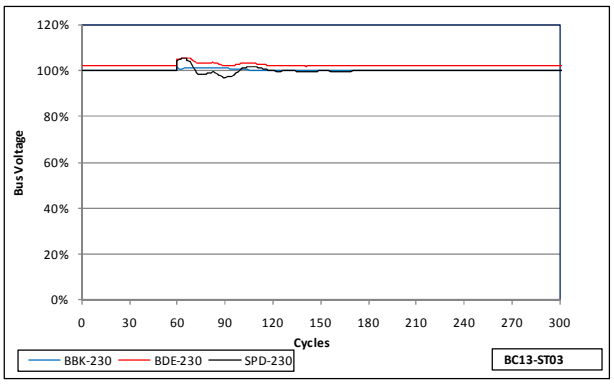
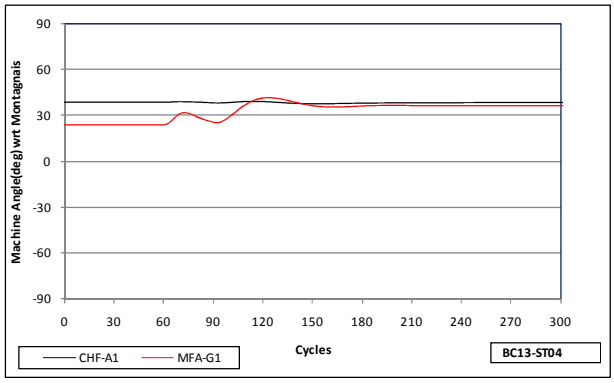
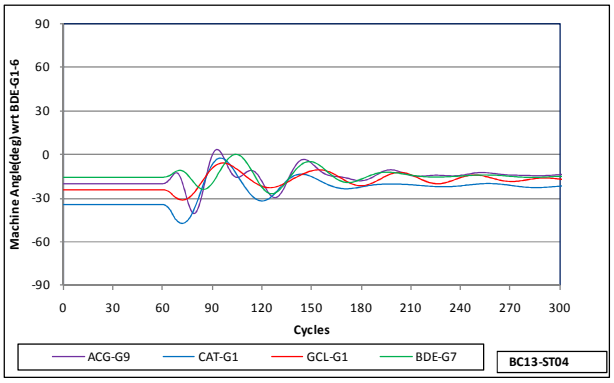
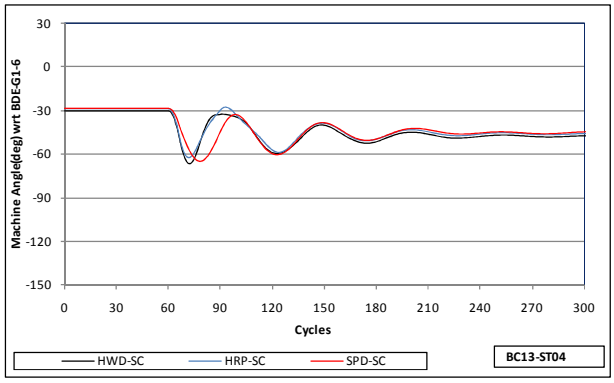
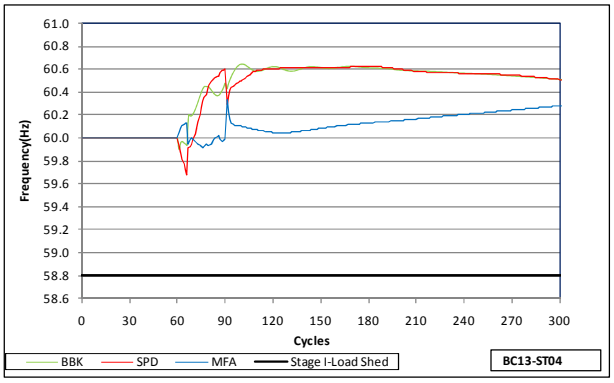


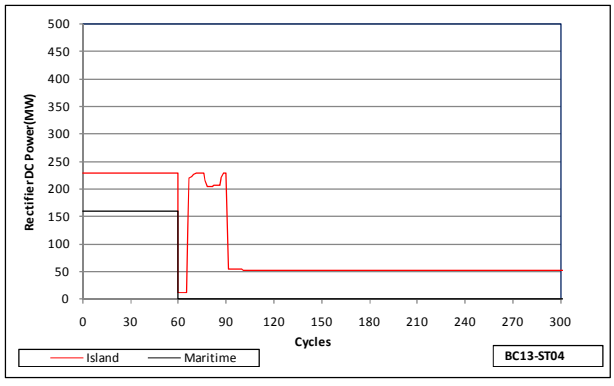
Figure 3-37: BC13-ST04, Extreme Light/Island Link 435 MW/Maritime Link 320 MW 6-cycle/3-phase Fault at Bay d'Espoir 230 kV on line to Western Avalon

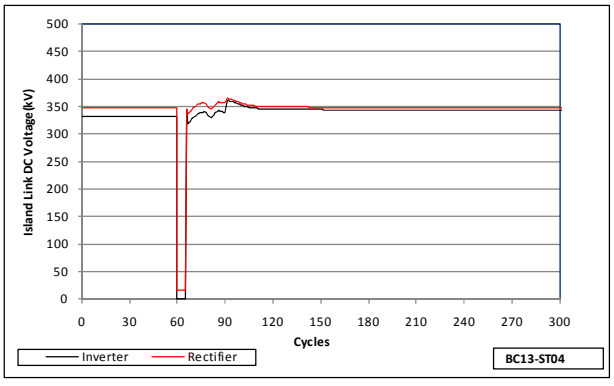




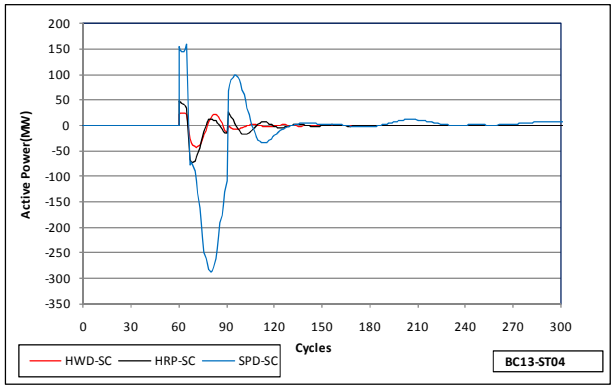


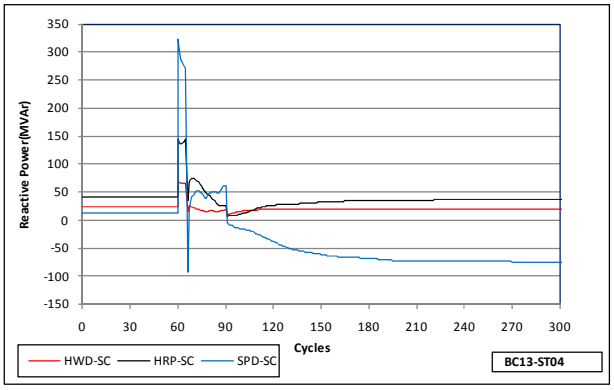


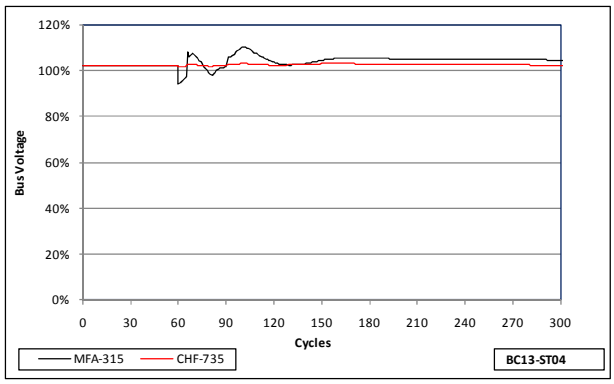




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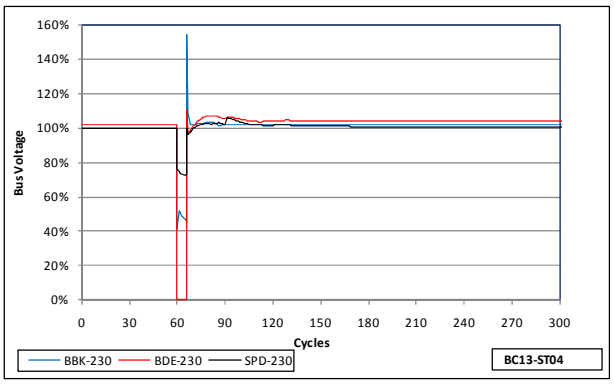
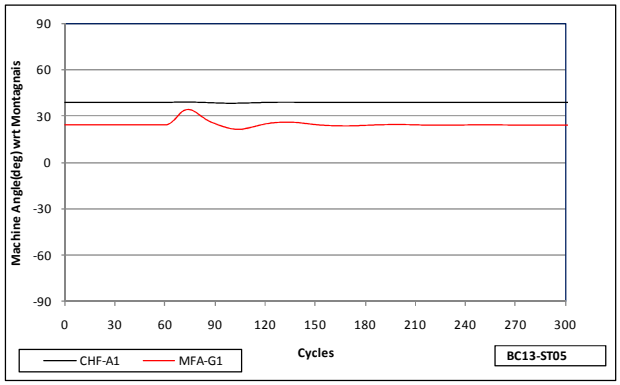
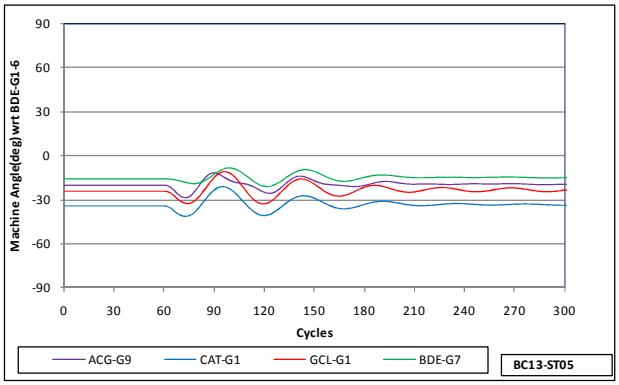
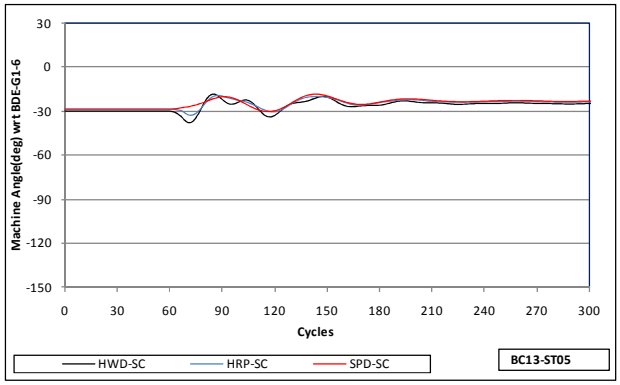
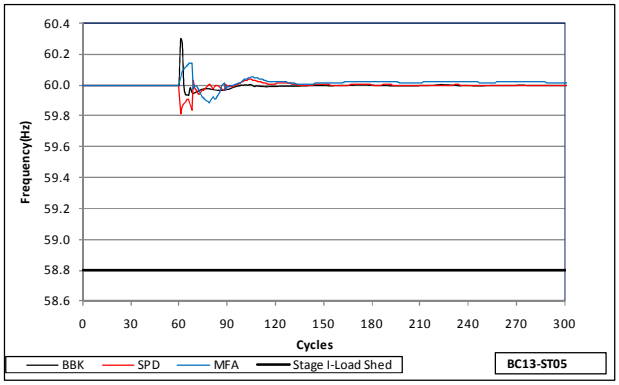


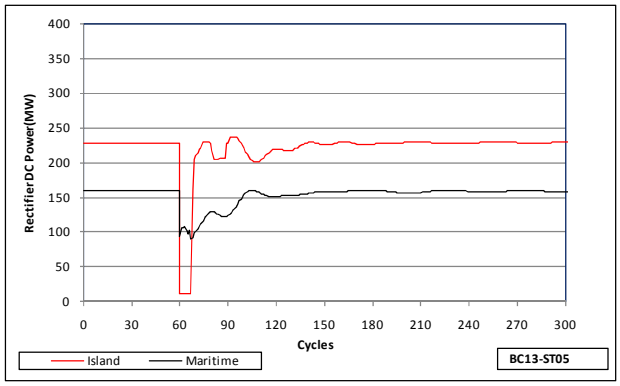
Figure 3-38: BC13-ST05, Extreme Light/Island Link 435 MW/Maritime Link 320 MW 6-cycle/3-phase Fault at Soldiers Pond 230 kV on line to Western Avalon (TL217W)

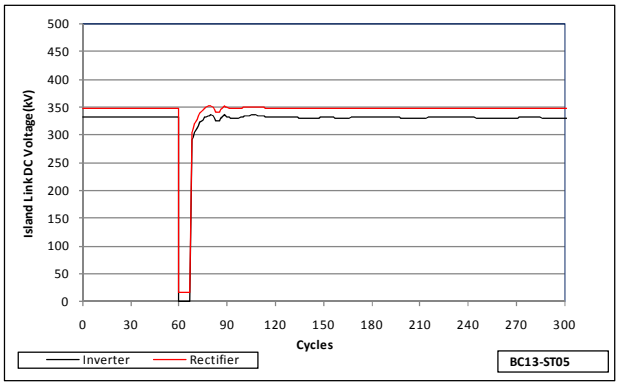




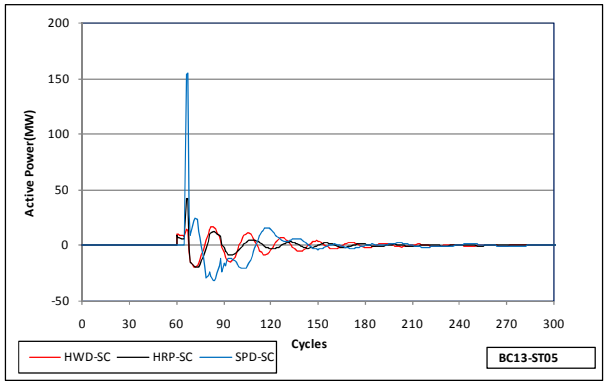


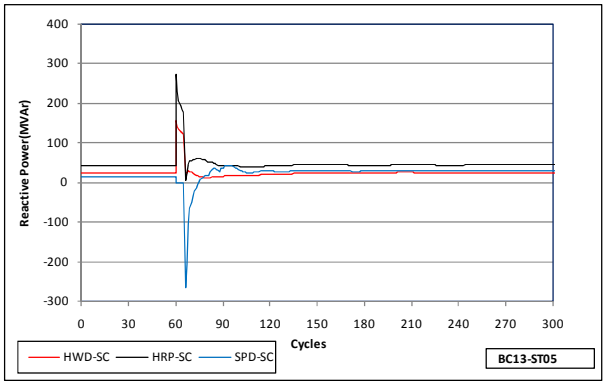


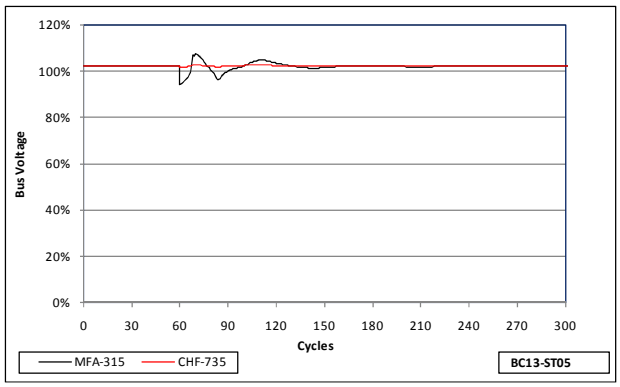




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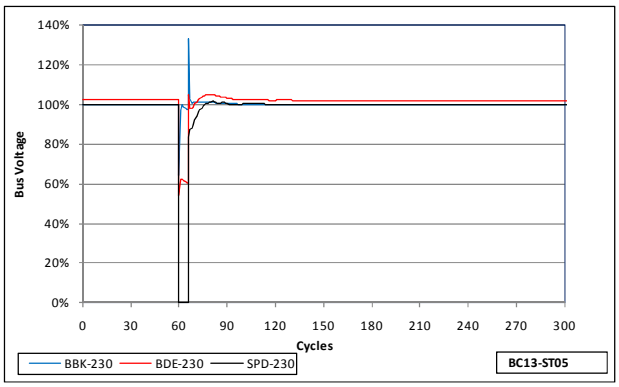
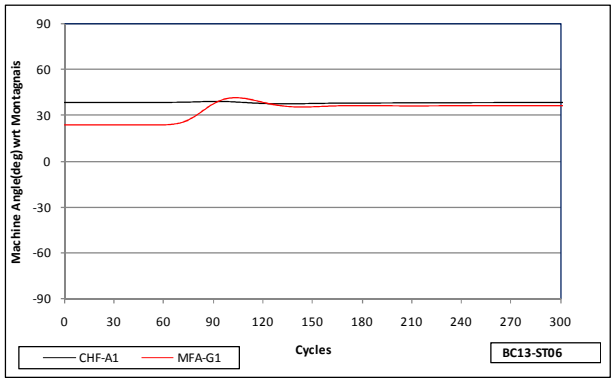
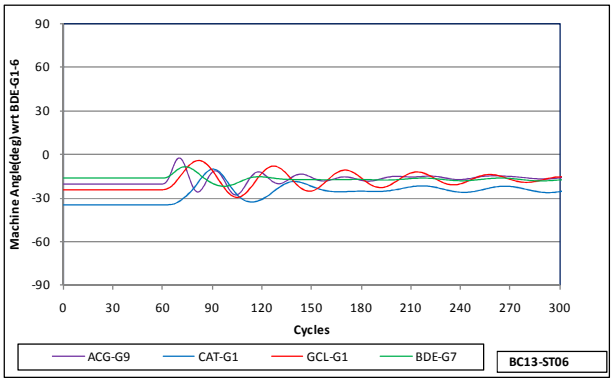
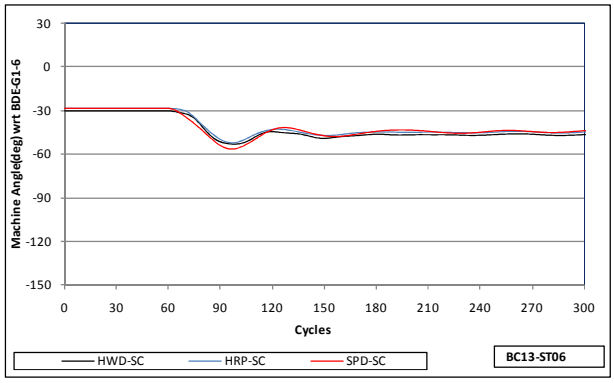
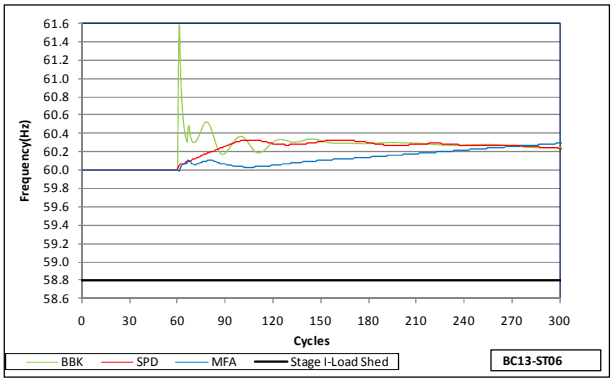


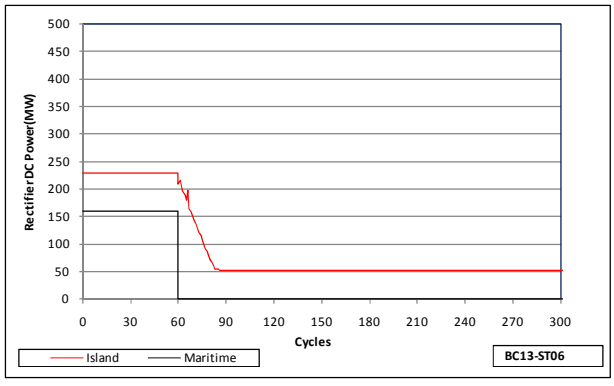
Figure 3-39: BC13-ST06, Extreme Light/Island Link 435 MW/Maritime Link 320 MW 6-cycle/3-phase Fault at Bottom Brook 230 kV on line to Granite Canal

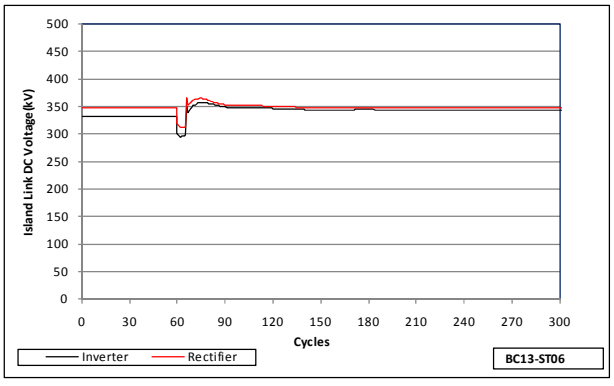




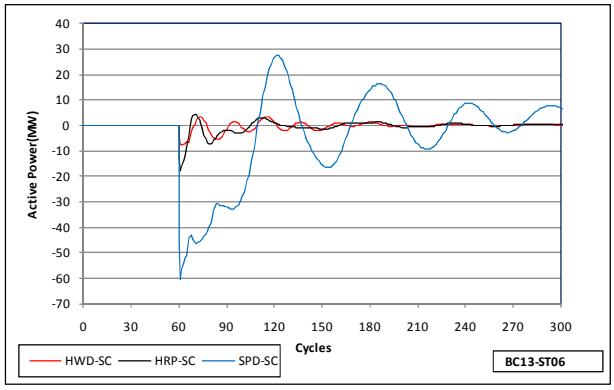


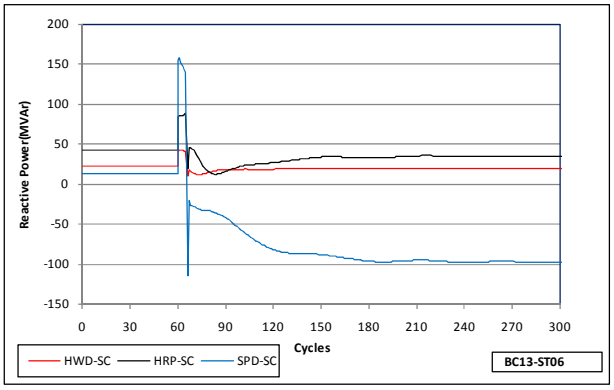


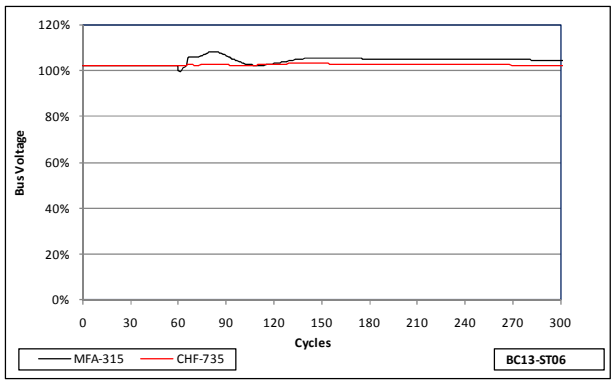




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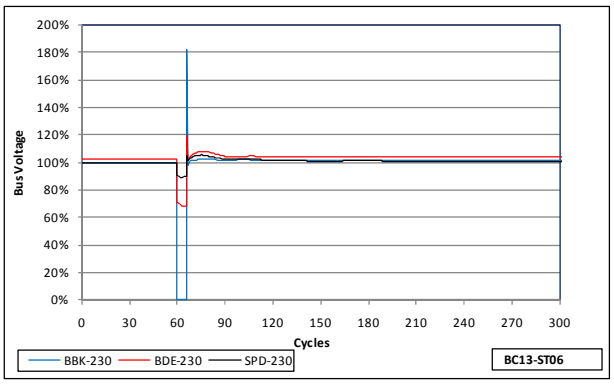
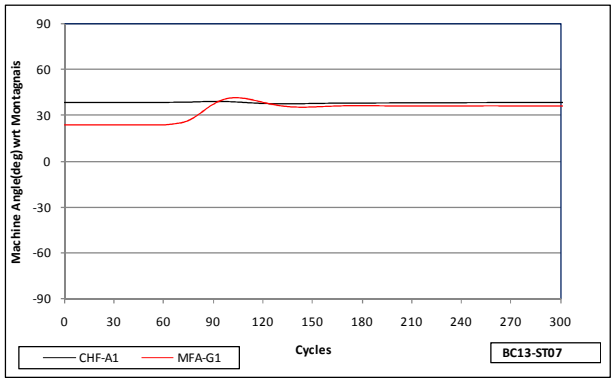
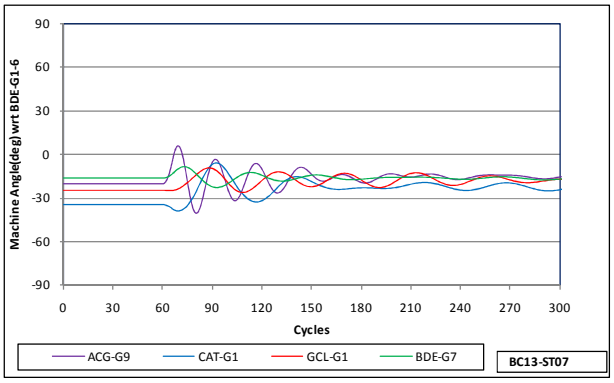
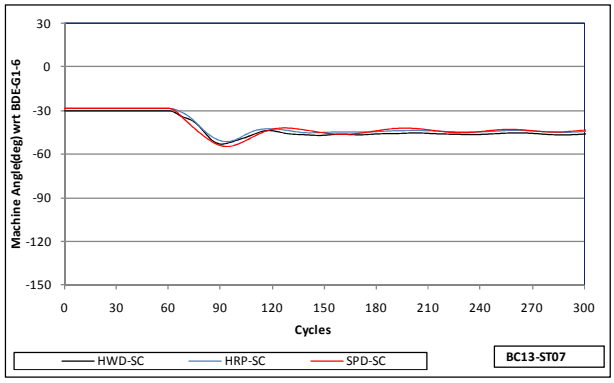
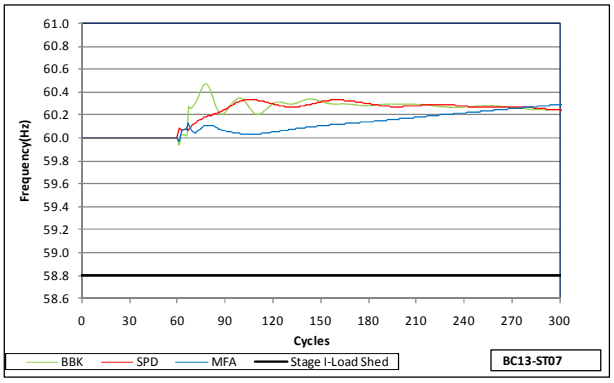


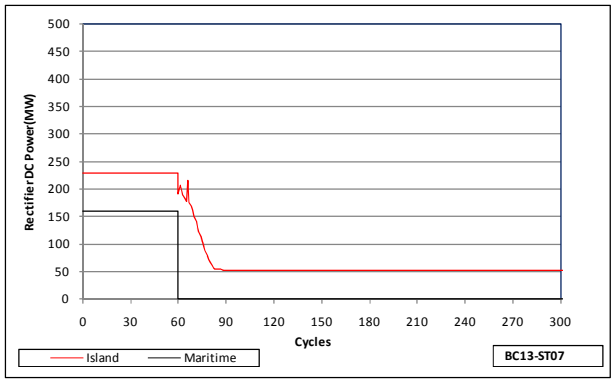
Figure 3-40: BC13-ST07, Extreme Light/Island Link 435 MW/Maritime Link 320 MW 6-cycle/3-phase Fault at Stony Brook 230 kV on line to Bay d'Espoir (TL204)

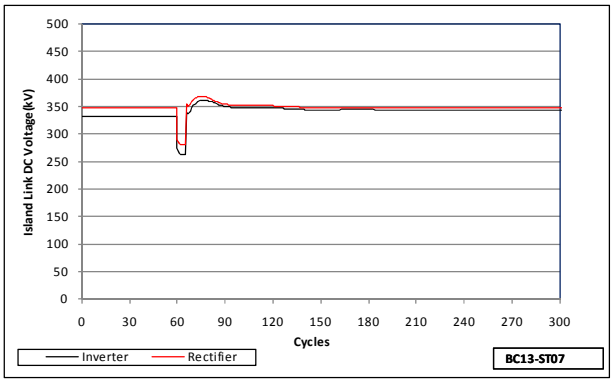




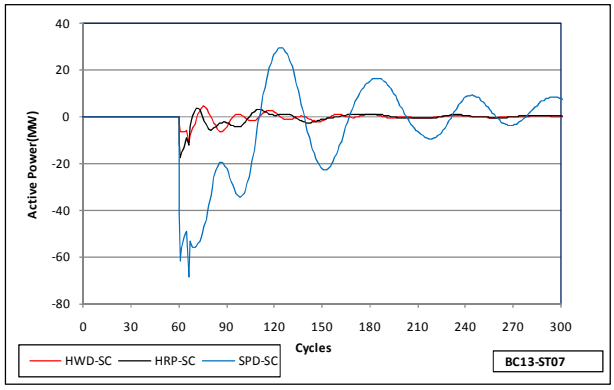


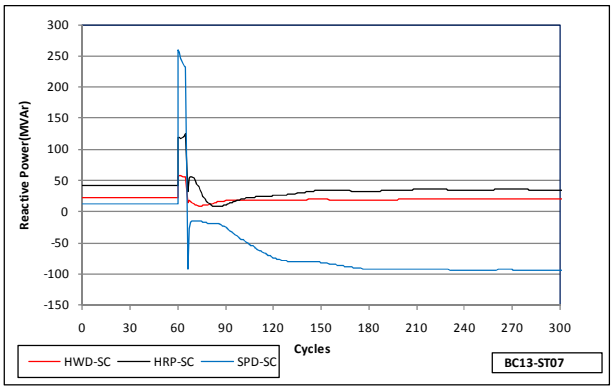


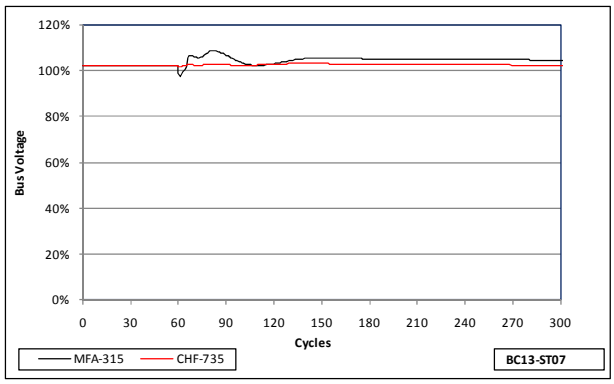




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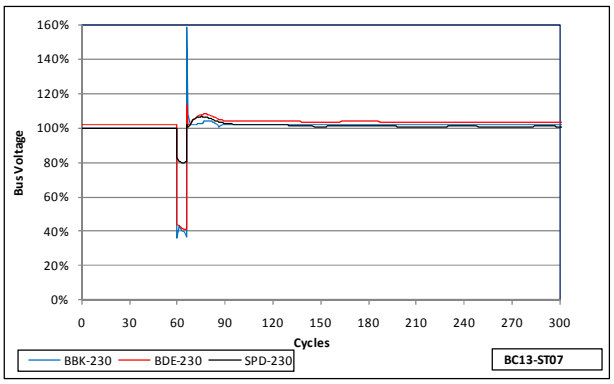
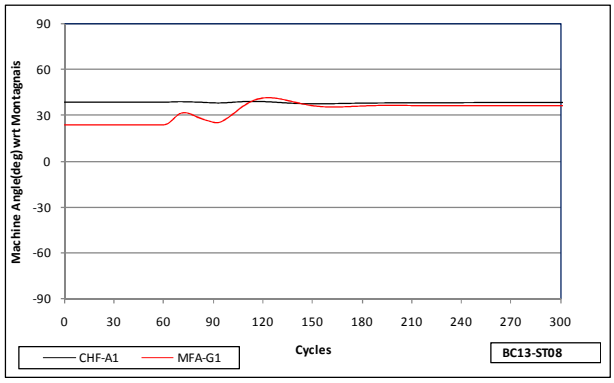
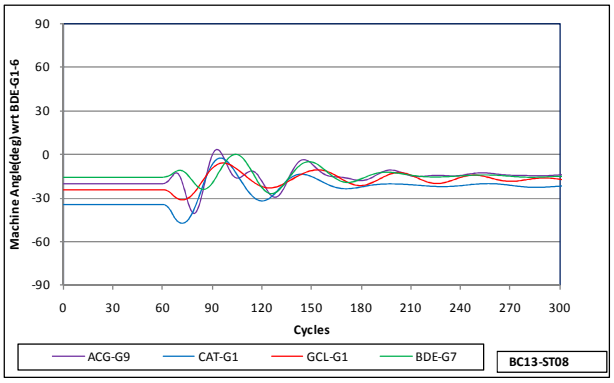
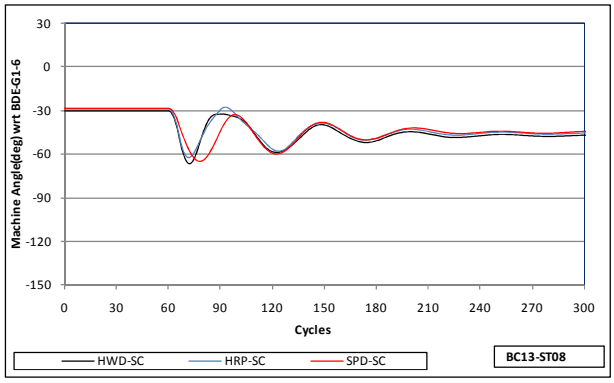
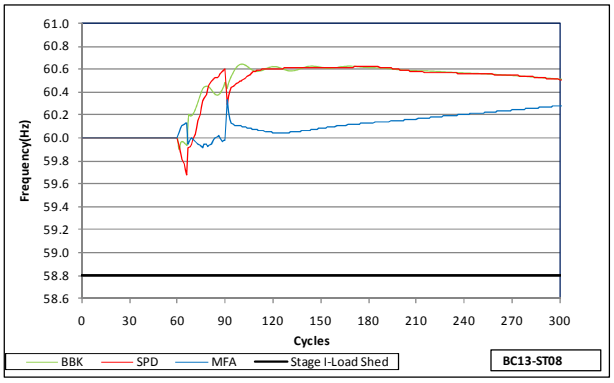


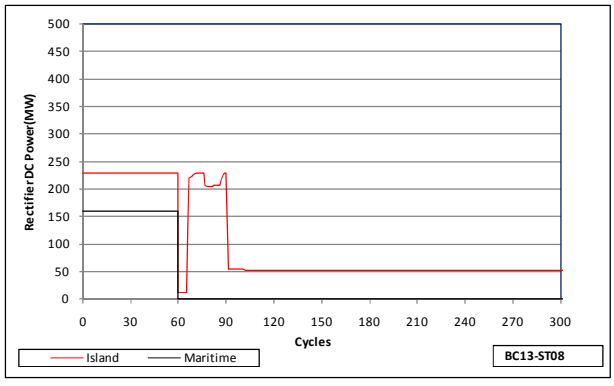
Figure 3-41: BC13-ST08, Extreme Light/Island Link 435 MW/Maritime Link 320 MW 6-cycle/3-phase Fault at Bay d'Espoir 230 kV on line to Sunnyside (TL202)

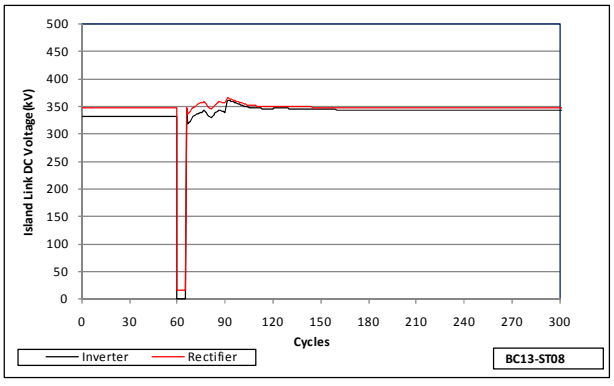




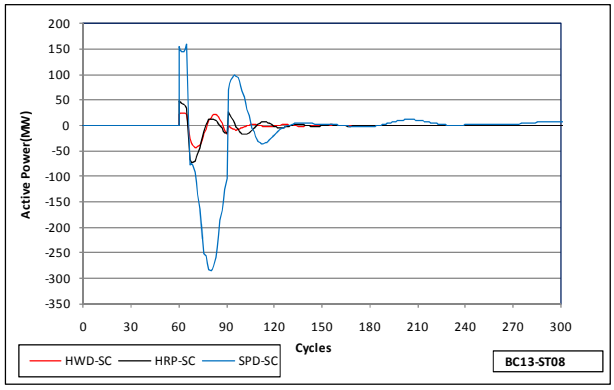


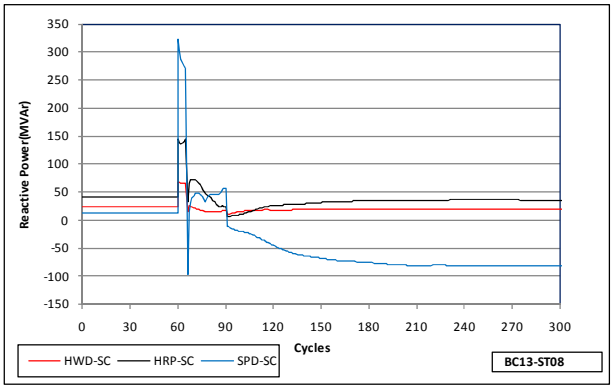


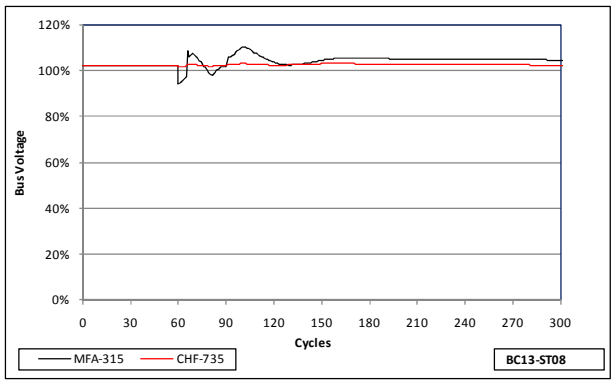




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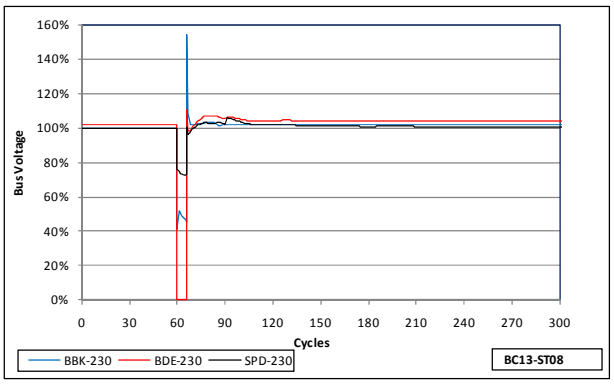
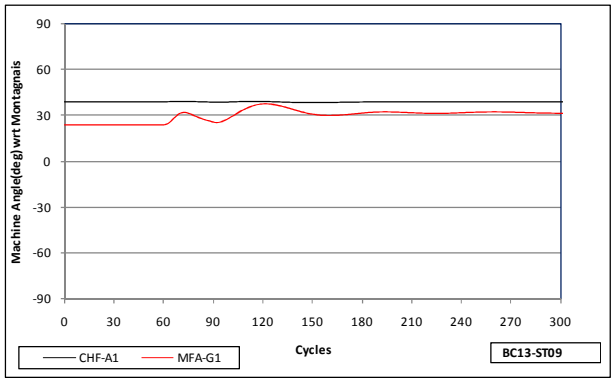
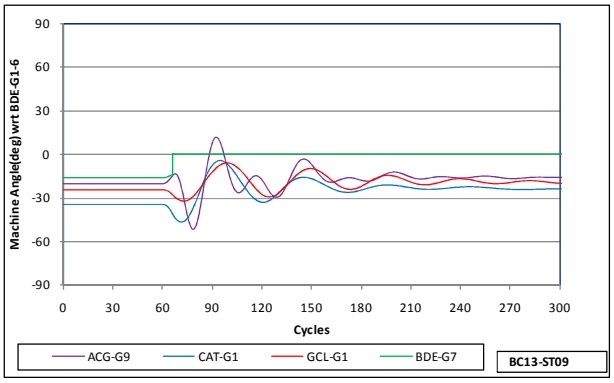
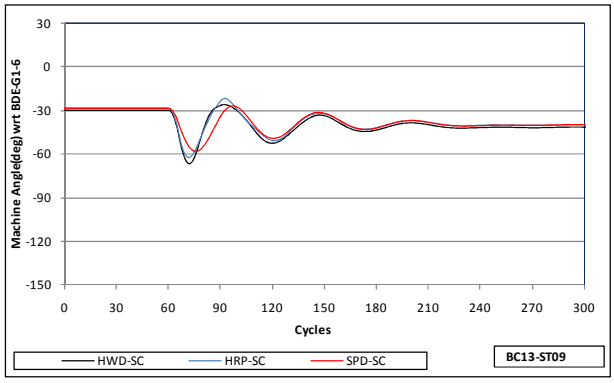
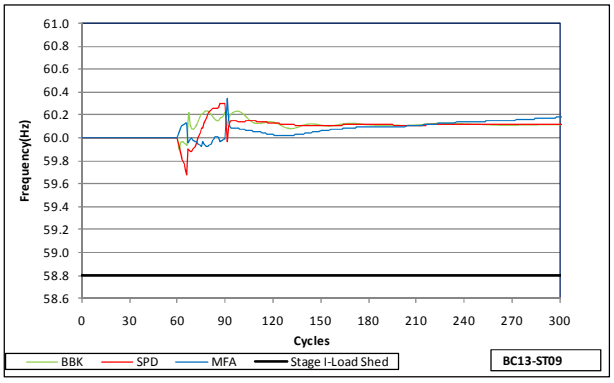


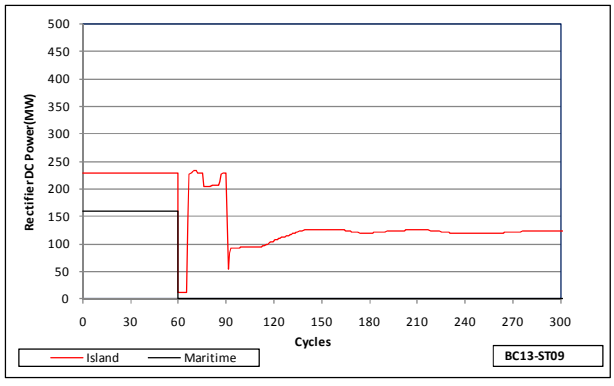
Figure 3-42: BC13-ST09, Extreme Light/Island Link 435 MW/Maritime Link 320 MW 6-cycle/3-phase Fault at Bay d'Espoir 230 kV-Generator Outage G7

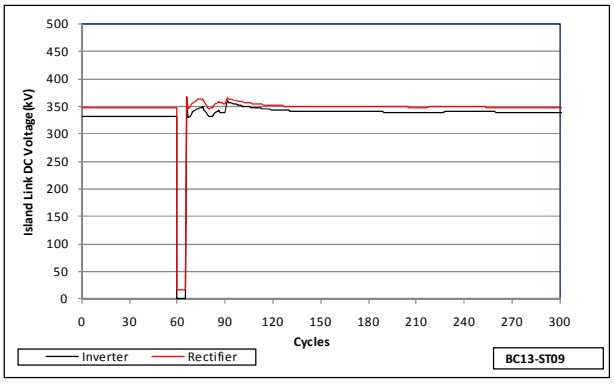




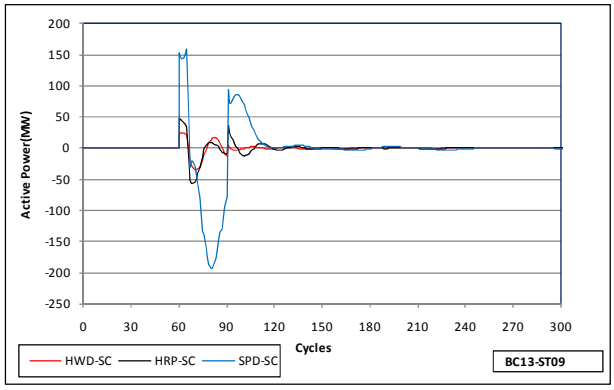


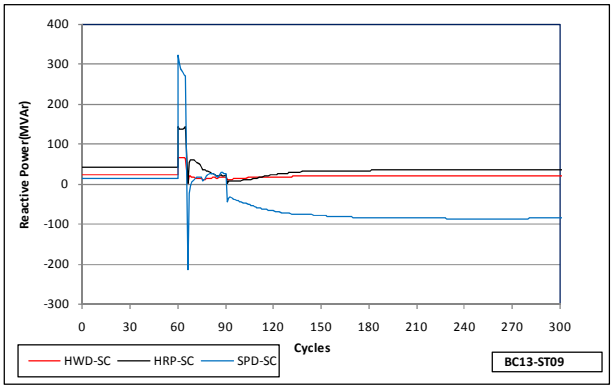


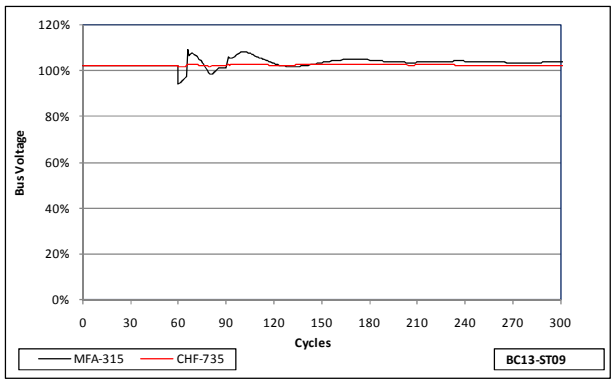


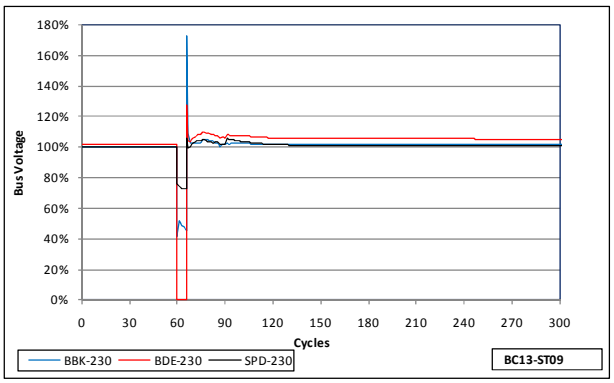


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3.5 Optimization of High Inertia Synchronous Condensers

In order to refine the selection of the high-inertia synchronous condensers at Soldiers Pond, a number of studies were conducted considering the temporary bipole fault under Scenario BC-2, which appeared to be one of the defining cases for the synchronous condenser requirements. The studies described above considered 300 MVA of synchronous condensers with an inertia constant of 7.84 kW-s/kVA. The studies below showed that the minimum requirement for the synchronous condensers was:

- 300 MVA of condensers with an inertia constant of 6.76 kW-s/kVA,
- 255 MVA of condensers with an inertia constant of 7.84 kW-s/kVA.

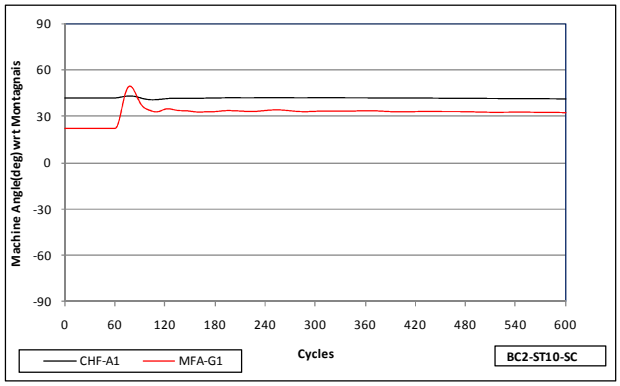
In both cases, the total inertia is approximately 2,000 MW-s.

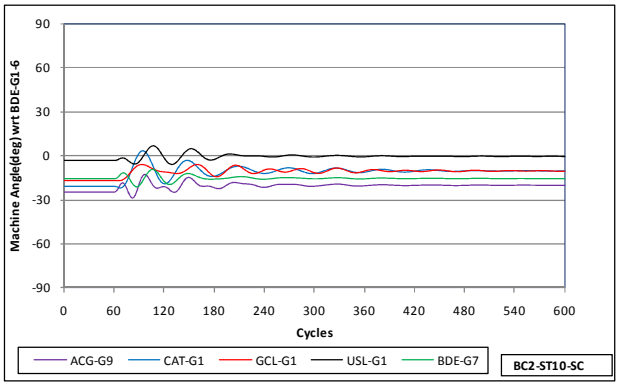
Since there will be occasions when a high-inertia synchronous condenser is not available, due to a fault or routine maintenance, it is essential to have a spare unit available. The question then arises as to whether this spare unit must be on-line at all times (hot spare) or whether it can remain off-line until required (cold spare). To assist in this decision, a study was carried out considering a 6-cycle/3-phase fault at Soldiers Pond 230 kV that resulted in the loss of 150 MVAr (H=7.84 kW-s/kVA) of synchronous condenser capacity. Faults at other locations would not result in the outage of a synchronous condenser. The results of this study are shown in Figure 3-43. It can be seen that the system recovery is satisfactory with the Maritime Link remaining in service, even though half of the synchronous condenser capacity was lost as a result of the fault. The same study was repeated with 1x300 MVAr synchronous condenser. As shown in Figure 3-44, the loss of a single 300 MVAr unit will result in system collapse.

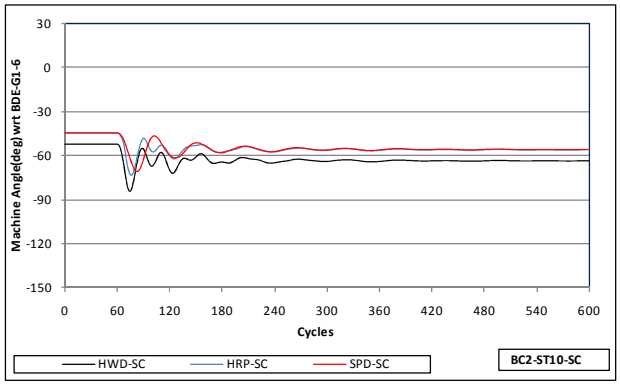
The implication of this result is that with 1x300 MVA synchronous condenser, a spare 1x300 MVAr unit would need to be operated as a hot spare. If 2x150 MVAr units are used with 1x150 MVAr spare unit, the spare unit can be used as a cold spare, resulting in a saving in losses and maintenance requirements.

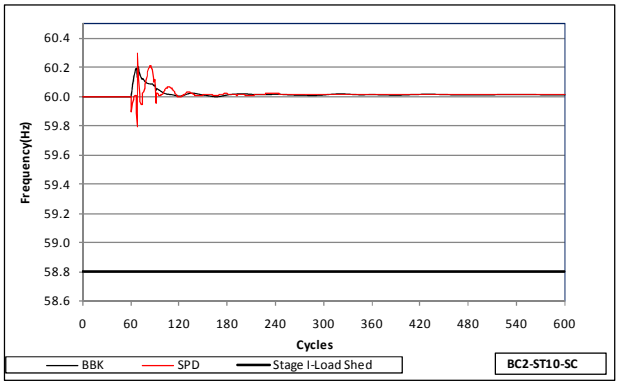
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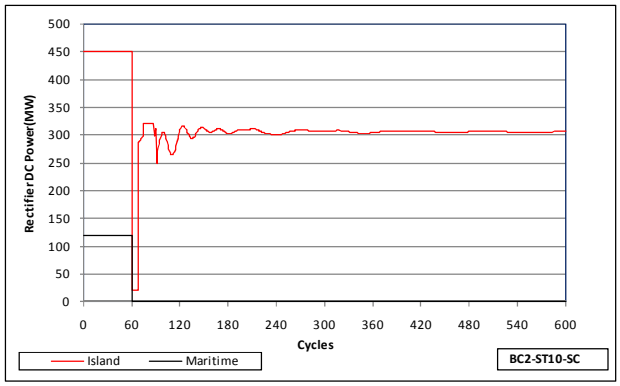
Figure 3-43: BC2-ST10, Winter Peak/Island Link 900 MW/Maritime Link 239 MW 6-cycle, 3-phase Fault at Soldiers Pond 230 kV-1x150 MVAr SC Outage

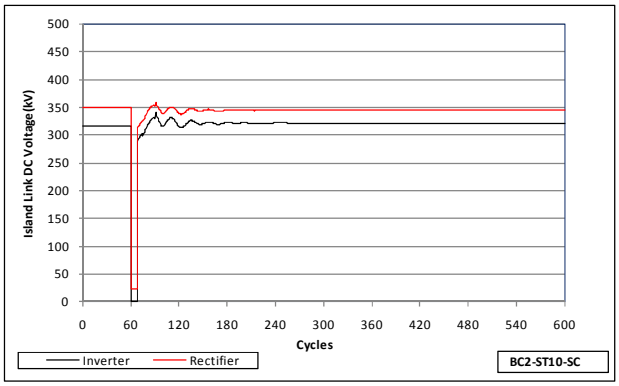




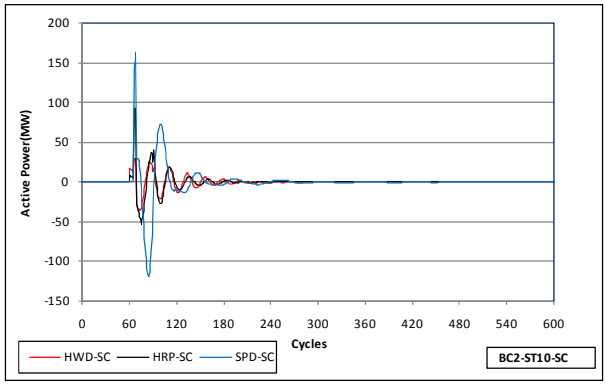


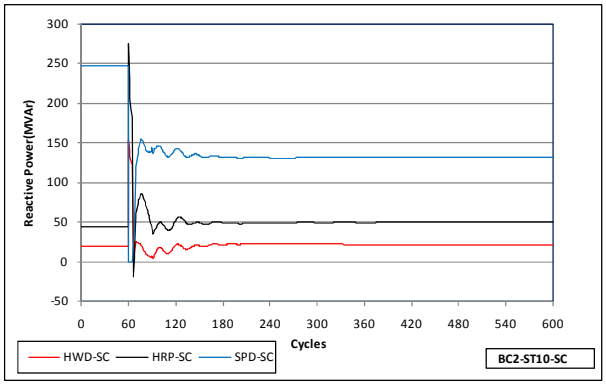


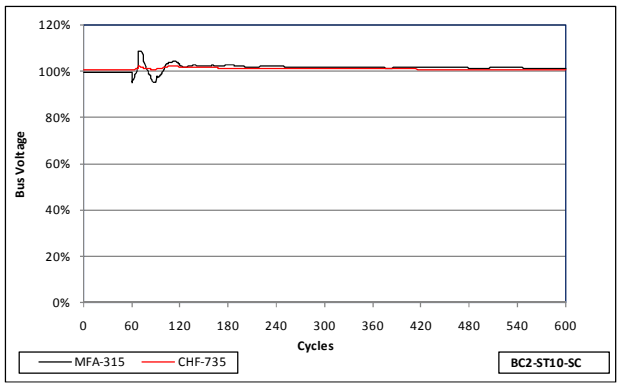


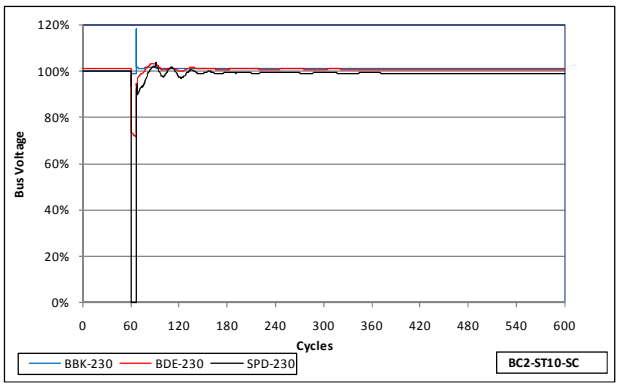


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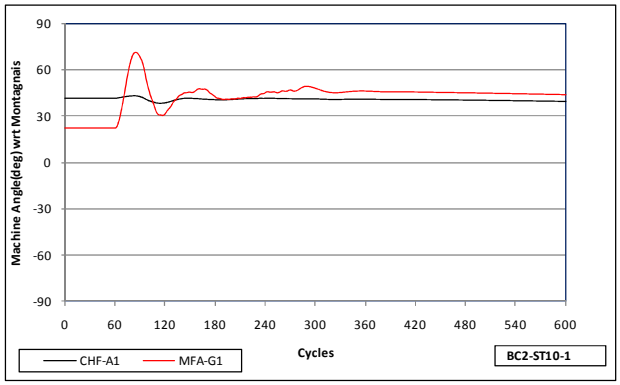


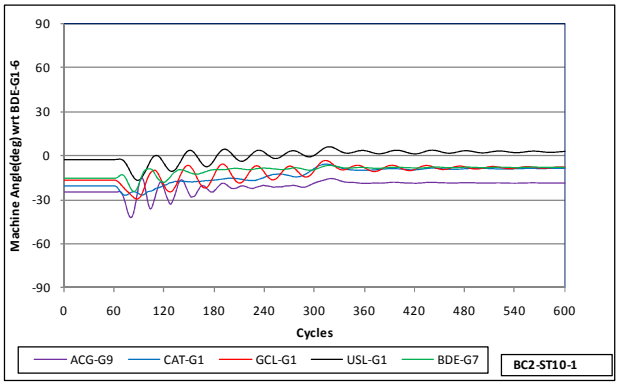


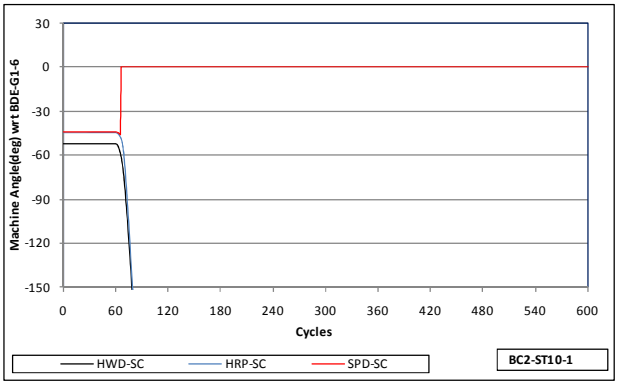


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Figure 3-44: BC2-ST10-1, Winter Peak/Island Link 900 MW/Maritime Link 239 MW 6-cycle, 3-phase Fault at Soldiers Pond 230 kV-1x300 MVAr SC Outage







3.6 Sensitivity of the Temporary Bipole Fault Re-Start Time

In the studies above, for a temporary bipole fault, the Island Link was blocked for 12-cycles/200 ms. This blocking time was developed from an allowance of 1.5-cycles/25 ms to detect the fault and change the operating mode of the converters to reduce the dc current to zero and 10.5-cycles/175 ms de-ionization time to ensure that the fault arcs had extinguished before re-starting the converters in normal operating mode. The starting time of the converters was approximately 6 – cycles/100 ms resulting in an overall time of 18-cycles/300 ms between fault initiation and a return to normal power. The base case considered 2x150 MVAr high-inertia synchronous condensers at Soldiers Pond.

Since the time required for de-ionization cannot be accurately determined and can vary with the nature of the fault, a range of studies were carried out to examine the maximum time that could be tolerated before the dc was re-started as a function of the number of high-inertia synchronous condensers installed at Soldiers Pond.

A series of study results are presented in Figure 3-45. For each of these cases, the re-start time was increased until the post-fault recovery was unsuccessful

For case BC2-ST01-3, 3x150 MVAr synchronous condensers were considered at Soldiers Pond; the second case (BC2-ST01-4) considered 4x150 MVAr units.

In the first case the re-start time was increased until 23-cycles/380 ms after fault inception and the dc power was ramped back up to 320 MW per pole; in the second case the re-start time was increased to 45-cycles/750 ms and the dc power was ramped back to 450 MW per pole following the re-start.

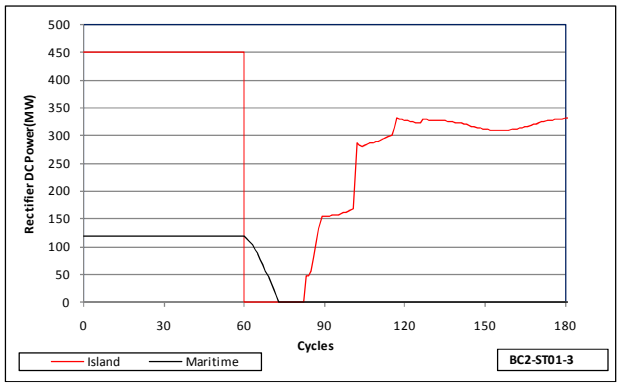
In both cases, the frequency at Soldiers Pond decreased to just above the first stage load shedding frequency of 58.8 Hz. However, it can be seen that the limiting factor is, in fact, the frequency to the west of Bay d'Espoir as seen by the frequency at Bottom Brook, which in the second case fell below the load shedding threshold frequency. A practical limit would therefore be less than the 45-cycles/750 ms considered in the study, as shown below:

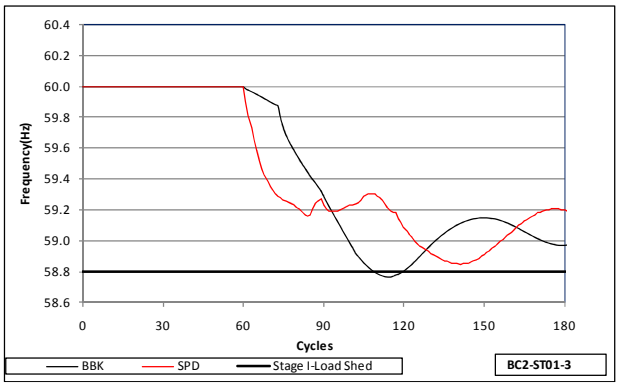
- With 2x150 MVAr synchronous condensers:
    - maximum re-start time = 12-cycles/200 ms
- With 3x150 MVAr synchronous condensers”
    - maximum re-start time = 23-cycles/380 ms
- With 4x150 MVAr synchronous condensers”
    - maximum re-start time = 34-cycles/567 ms

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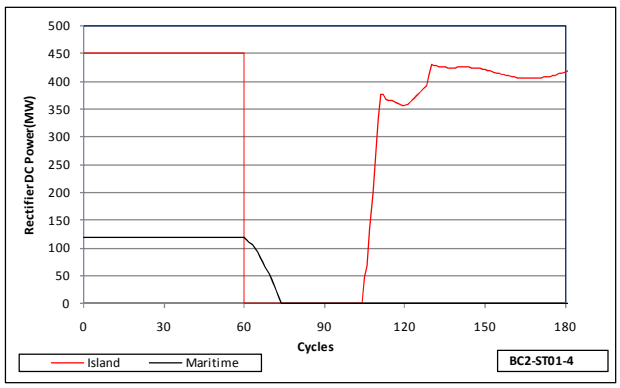
Figure 3-45: BC2-ST01-3/4, Winter Peak/Island Link 900 MW/Maritime Link 239 MW Temporary Bipole Fault-Synchronous Condenser Capacity at Soldiers Pond

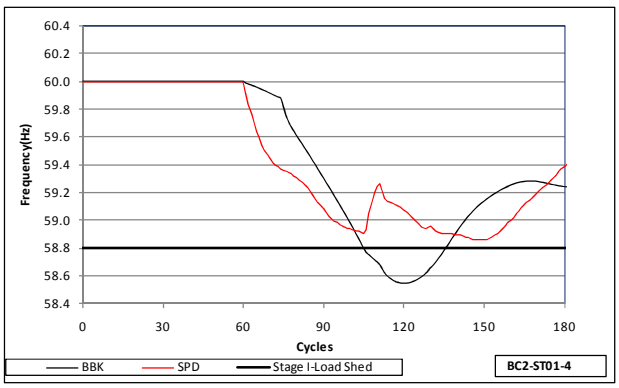
3-150 MVAr Synchronous Condensers





4-150 MVAr Synchronous Condensers





4 CONCLUSIONS AND RECOMMENDATIONS

4.1 Introduction

This report presented the results of the stability studies carried out to examine the dynamic performance of the ac and dc systems including the HVdc interconnections between Muskrat Falls and Soldiers Pond (Island Link) and between Bottom Brook and the Nova Scotia power system (Maritime Link). The present Design Basis considers, for the Island Link, a dc voltage level of ±350 kV and a nominal bipole rating of 900 MW and, for the Maritime Link, a dc voltage level of ±200 kV and a nominal bipole rating of 500 MW. This is interpreted to mean that these rated power levels and rated voltages apply at the rectifier ends (Muskrat Falls and Bottom Brook).

The Island Link will be essentially uni-directional from Labrador to Newfoundland, although there will be nothing in the design of the link to prevent operation in the reverse direction. The Maritime Link is required to have a 500 MW continuous capability in bipolar mode in both directions.

The connection to the TransEnergie 735 kV system in Quebec was represented by a simple equivalent at the Montagnais Substation. The Emera system in Nova Scotia was represented by a simple equivalent at the inverter station of the Maritime Link. The ac system between Churchill Falls and Muskrat Falls and the Island ac system were modelled in detail.

Starting from the base case scenarios provided by Nalcor, the present studies were designed to determine the dynamic performance of the ac/dc systems following major faults on either the ac or dc systems. The 6-cycle/3-phase faults considered resulted in the outage of a single element of either the ac or dc system. Because of the relative importance of the Island Link in the overall supply capability of the Island load, the temporary loss of both poles of the Island Link bipole was also considered.

4.2 Study Objectives

The stability studies were designed to achieve the following objectives:

Objective 1

To verify that the interconnected systems of Newfoundland and Labrador with interconnections into Quebec and Nova Scotia can operate satisfactorily through a wide range of faults resulting in outages on the transmission network.

Objective 2

To determine the requirements in terms of control functions that will be required on the Island and Maritime dc links,

Objective 3

To determine the requirements for additional equipment, in the form of static var compensators and/or synchronous condensers, that will be required at or near the converter stations to ensure satisfactory dynamic performance,

Objective 4

To verify that load shedding on the Island will not occur for the range of fault cases examined,

Objective 5

To determine any operating requirements that must be applied to the Island and Maritime dc links to ensure stable operation.

4.3 Results of the Studies

A major change from previous studies centres on the criterion that, in the event of a major disturbance on the Island or on the Island Link, the export over the Maritime Link can be discontinued. This means that the export over the Maritime Link is acting as a form of spinning reserve for the Island system and allows the Island system to recover quickly and successfully from all the faults considered in this study. This method of operation was simulated by using a frequency controller on the Maritime Link at the Bottom Brook converter to reduce the dc power level when

the frequency at Bottom Brook falls below 60 Hz. Although not available in the PSS®E model, this type of controller can operate with a dead-band to allow for normal frequency fluctuations.

For faults that occur on the Bay d'Espoir 230 kV bus or any other 230 kV bus to the west of Bay d'Espoir and for a temporary bipole fault on the Island Link, the voltage and/or frequency depressions at the Bottom Brook 230 kV converter bus will result in blocking of the Maritime Link. In some cases, faults at Soldiers Pond would also require that the export over the Maritime Link be temporarily suspended.

In order to survive a temporary bipole fault on the Island Link or a 6-cycle/3-phase fault at Muskrat Falls, it was found necessary to have 300 MVAr of high-inertia (H=7.84 kW-s/kVA) synchronous condensers at the Soldiers Pond 230 kV converter bus, in addition to two synchronous condensers at Holyrood. The Holyrood synchronous condensers have inertia constants of 1.182 kW-s/kVA and 1.29 kW-s/kVA and contribute approximately 230 MW-s each to the total inertia of the system. The Soldiers Pond synchronous condensers contribute 2,350 MW-s.

In order to survive a 6-cycle/3-phase fault at Bay d'Espoir during peak load periods only, it was necessary to have either:

- 450 MVAr of high-inertia synchronous condensers at Soldiers Pond and the three synchronous condensers at Holyrood to provide support to the voltage at Bay d'Espoir, or

- ±250 MVAr of reactive support at Bay d'Espoir together with 300 MVAr of high-inertia synchronous condensers at Soldiers Pond and the three synchronous condensers at Holyrood.

The application of 50% series compensation to the 230 kV lines from Bay d'Espoir to Sunny Side [TL203 & TL206] and to Western Avalon [new line] did not provide sufficient reactive support to enable the system to survive.

Objective 1

The study results confirmed that the interconnected systems of Newfoundland and Labrador with interconnections into Quebec and Nova Scotia can operate satisfactorily through a wide range of faults resulting in outages on the transmission network.

Objective 2

The studies indicated that some form of frequency control will be required on both the Soldiers Pond and Bottom Brook converters. The frequency controller at Soldiers Pond would act to increase the dc power on the Island Link for a fall in frequency on the Island. For any fault that results in blocking of the Island Link, the frequency controller at Soldiers Pond must be disabled for a minimum period of 500 ms following the block and until the time when the frequency at Soldiers Pond is 59.9 Hz or higher. The frequency controller at Bottom Brook would act to decrease the dc power on the Maritime Link for a fall in frequency on the Island. It should be noted that the application of a frequency controller at the Bottom Brook converter will preclude the use of the Maritime Link for frequency control in Nova Scotia as frequency controllers cannot be used simultaneously at both ends of a dc link. In addition, for a temporary bipole fault on the Island Link, an increase in the high-inertia synchronous condenser capacity at Soldiers Pond, would allow for a longer de-ionization period to be considered for the fault. With 300 MVAr of synchronous condenser capacity at Soldiers Pond, the maximum time permitted until re-start after a bipole fault is 12-cycles/200 ms. With 450 MVAr of synchronous condenser capacity, the re-start time can be extended to 380 ms.

In many of the cases examined, it was found necessary, following a block of the Island Link during ac system faults, to ramp the dc power back up in a staged manner. The use of a voltage-dependent recovery control in which the rate of ramp-up and the target dc power level is determined by the converter ac bus voltage is recommended.

Objective 3

The studies indicated that a minimum of 300 MVAr of high-inertia synchronous condenser capacity will be required at the Soldiers Pond 230 kV converter bus. The total inertia requirement is approximately 2,000 MW-s and, allowing for a spare unit, could be achieved with 2x300 MVAr units; the spare unit running as a hot spare, or with 3x150 MVAr units; the spare unit being operated as a cold spare. Since there is a requirement for synchronous condensers at Soldiers Pond, no advantage is seen in considering VSC technology for this converter station.

The defining cases in terms of synchronous condenser capacity requirements at Soldiers Pond are those cases that involve a three-phase fault at Bay d'Espoir during the winter peak load period. In such cases, the voltage recovery at Bay d'Espoir is relatively weak and this is reflected in the voltage at Soldiers Pond and all the substations in between. With 300 MVAr of synchronous condenser capacity at Soldiers Pond, the voltage at Soldiers Pond recovers within the normal 80% post-fault criterion currently is use in the NLH system and the system recovery is stable and well damped. However, an ac voltage of less than 90% involves a significant risk of commutation failure for the inverter when it attempts to re-start. In order to assist the voltage recovery, it was necessary to increase the synchronous condenser capacity at Soldiers Pond to 450 MVAr and connect all three synchronous condensers at Holyrood.

The low probability of a three-phase fault and the fact that this requirement only applies during the winter peak load period, raises the question of the total capacity requirements for the synchronous condensers. The minimum synchronous condenser capacity of 300 MVAr could be achieved with 3x150 MVAr units, which allows for one spare unit. This would mean that during the winter peak load period, either the risk of a three-phase fault at Bay d'Espoir is accepted or the third (spare) synchronous condenser is connected. With such an operating philosophy, maintenance work on any of the synchronous condensers at Soldiers Pond, Holyrood and Hardwoods could only be scheduled outside the winter peak load period. In the event of a synchronous condenser fault, that may involve a long repair time that extends into the winter season, the system would be placed at risk for a

three-phase fault at Bay d'Espoir. If such a fault occurred, extensive high-speed load shedding would be required to enable the system to recover.

At Bottom Brook, dynamic reactive power control will be required to control the temporary over-voltages that will occur when the Maritime Link blocks due to low voltage and/or low frequency. Under extreme light load conditions with a 320 MW export on this link, the temporary over-voltage can reach as high as 180% and must be reduced quickly to avoid equipment damage. This dynamic reactive power control could be achieved either in the form of a static var compensator (+320/-100 MVAr) or in the form of VSC technology for the Bottom Brook converter. The use of 2x250 MW VSC converters at Bottom Brook would provide up to 125 MVAr of reactive power control and an additional 195 MVAr of shunt compensation, in the form of an SVC or switched shunt capacitors would be required.

Bearing in mind the impact of a three-phase fault at Bay d'Espoir and the inherent reactive support that can be provided by a VSC converter for the Maritime Link, raises the question of the benefits that may be associated with locating the Maritime Link converter at Bay d'Espoir instead of at Bottom Brook. Although outside the scope of these studies, such a re-location would significantly affect the synchronous condenser capacity required at Soldiers Pond. For faults at Bay d'Espoir, which would require an additional 150 MVAr of high-inertia synchronous condenser at Soldiers Pond, the location of the Maritime Link converter of the VSC type would provide sufficient reactive support at Bay d'Espoir to enable the system to survive a three-phase fault at Bay d'Espoir with only 300 MVAr of high-inertia synchronous condenser capacity at Soldiers Pond.

Objective 4

With the addition of the high-inertia synchronous condensers at Soldiers Pond and the control functions described above, there will be no necessity for load shedding on the Island for the range of faults considered. It will be necessary to re-evaluate a small number of fast-acting, rate-of-change-of-frequency load shedding settings that are presently enabled on the Island system.

Objective 5

The only restrictions identified on the operating modes of the Island and Maritime Links were as follows:

- For many of the fault cases examined, it was found necessary to reduce the export over the Maritime Link to zero to ensure a satisfactory recovery of the Island system. The Maritime Link can be re-started manually after the Island system has settled down at a level commensurate with the Muskrat Falls and Island system capabilities following the fault.
- The studies showed that following a major disturbance on either the Island Link itself or on the Island ac system, the Island Link must be re-started in a controlled manner to avoid the risk of low voltages at the Soldiers Pond inverter bus that might lead to commutation failure of the inverter.

It was seen that for certain faults and at specific load levels, the export over the Maritime Link would need to be temporarily suspended. It may prove to be more convenient to adopt an operating philosophy that would temporarily suspend this export for all faults on the Island Link and Island 230 kV ac system. In any event, it will be necessary for the export level over the Maritime Link to be provided to the controllers of the Island Link to enable the required power level for a re-start of the Island Link to be determined.

4.4 Recommendations

Based on the results of the studies described above, the following recommendations are made:

- LCC converters to be installed for the LIL Link due to the long duration of dc fault clearance which would also require high-inertia synchronous condensers to avoid system collapse.
- 3x150 MVAr high-inertia (7.84 kW-s/kVA) synchronous condensers be installed at the Soldiers Pond converter station to provide active and reactive power support to the Island system. The normal requirement would be to have two of these units connected at all times with the third unit used as a cold spare. This

would allow maintenance to be carried out on the units at Soldiers Pond as well as those at Holyrood and Hardwoods.

- The re-start of the Island Link be controlled to account for the temporary shutdown of the Maritime Link following dc or 230 kV ac faults on the Island system. The control should take the form of a limit on the dc power level to maintain the 230 kV ac voltage at Soldiers Pond at 90% or above.

- Consideration be given to re-locating the VSC converter for the Maritime Link from Bottom Brook to Bay d'Espoir. This would avoid the need to reinforce the 230 kV system between Bay d'Espoir and Bottom Brook and would allow the Island system to survive a three-phase fault at Bay d'Espoir without having to install a fourth high-inertia synchronous condenser at Soldiers Pond.

- During periods when lightning activity is forecast along the route of the Island Link, the starting up of the third high-inertia synchronous condenser at Soldiers Pond would increase the maximum time delay that could be tolerated before re-starting the Island Link after a temporary bi-pole fault on the Island Link from 12-cycles/200 ms to 23-cycles/380 ms. This would allow more time for the fault path to de-ionize.

APPENDIX A

BASE CASE LOAD FLOWS

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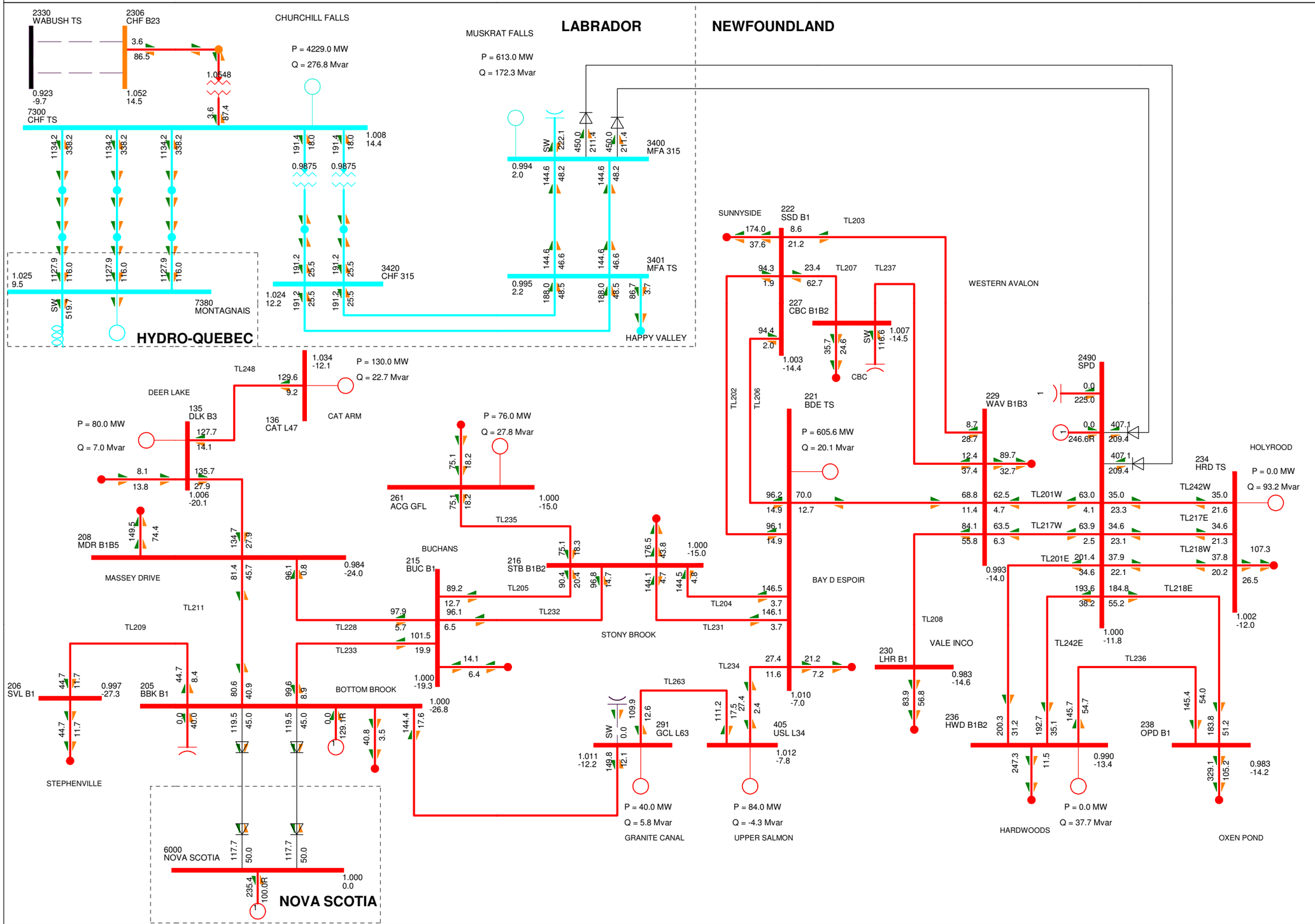
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BC7 – Spring / Fall Intermediate 2017 ..... A-3
BC10 – Summer Day Light 2017..... A-4
BC 13 – Summer Night Extreme Light 2017 ..... A-5

Attachment A-1

BC2 – Winter Peak 2017

1552 MW, 814 MW Import and 239 Export



Bus - VOLTAGE (PU)/ANGLE
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%RATEC
1.050OV 0.950UV

kV: <=6.900 <=16.000 <=25.000 <=46.000 <=69.000 <=138.000 <=230.000 >230.000

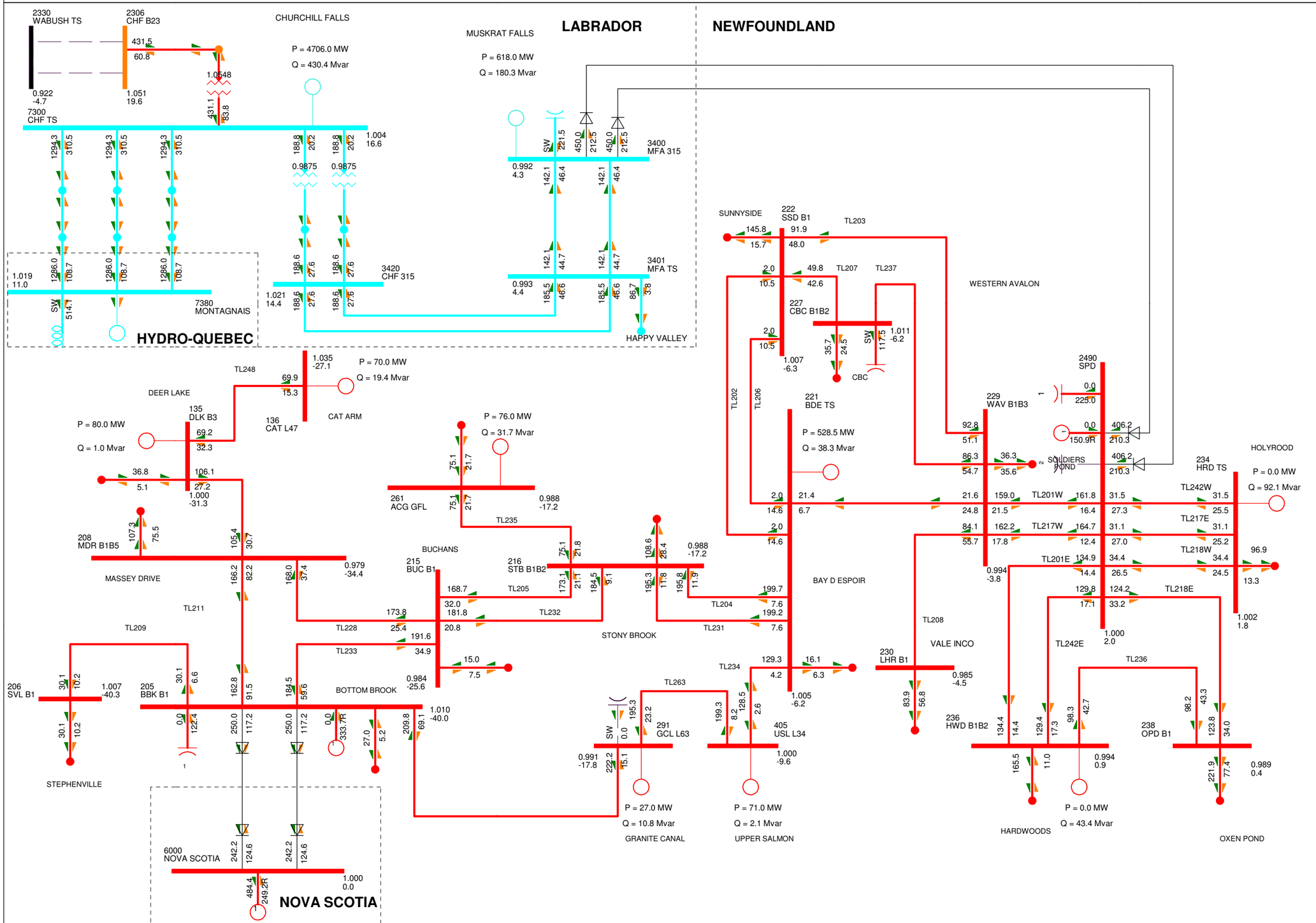
- Base Case
- Generation: Maximum
- Bipolar operation of Island HVDC
- Bipolar operation of Maritime HVDC

Attachment A-2

BC7 – Spring / Fall Intermediate 2017

1100 MW, 814 Import and 500 Export

BC7 - SPRING/FALL INTERMEDIATE 2017, 1100 MW, 814 MW IMPORT AND 500 MW EXPORT



Bus - VOLTAGE (PU)/ANGLE
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%RATEB
1.050OV 0.950UV

kV: <=6.900 <=16.000 <=25.000 <=46.000 <=69.000 <=138.000 <=230.000 >230.000

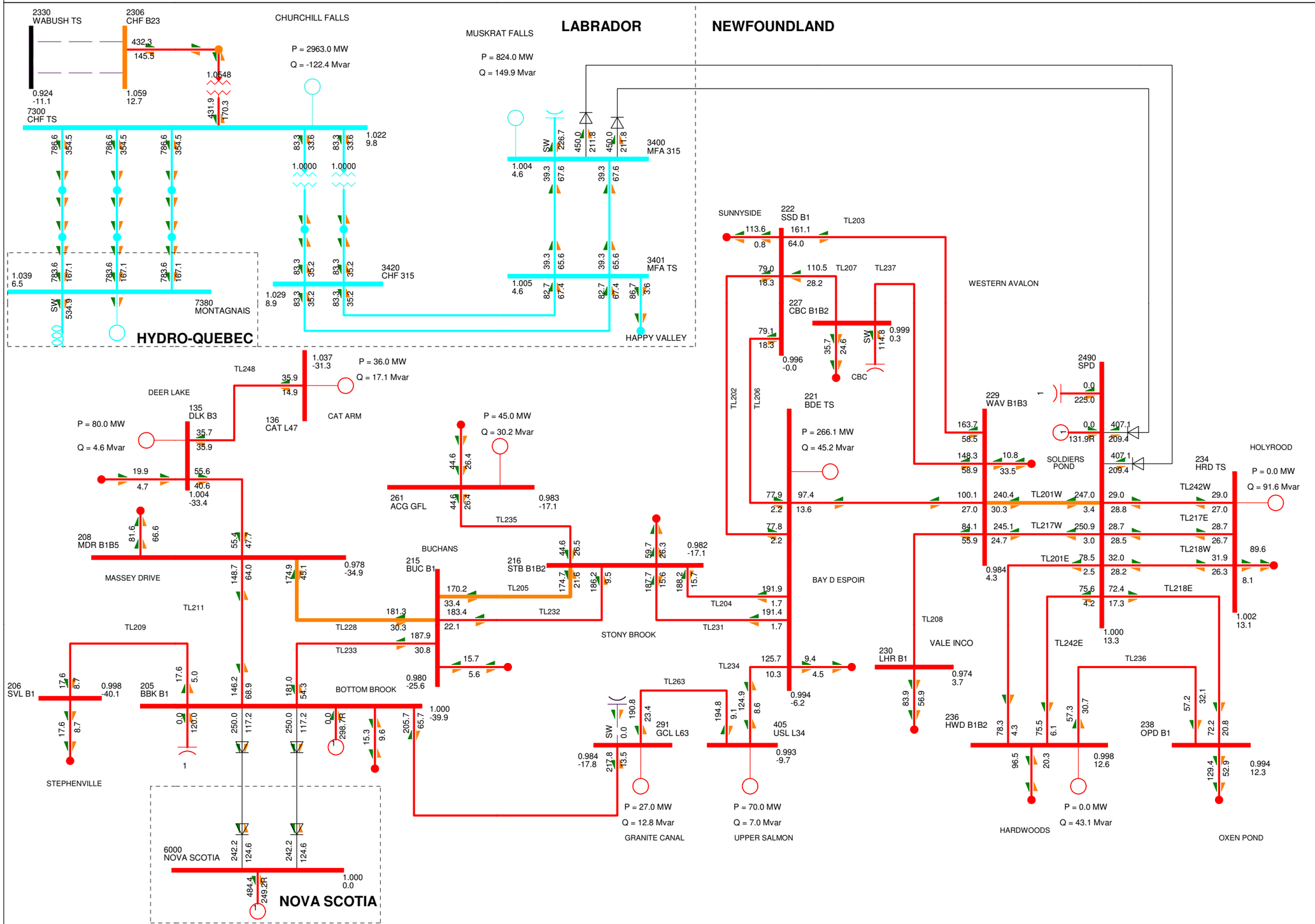
- Base Case
- Generation: Economic Dispatch
- Bipolar operation of Island HVDC
- Bipolar operation of Maritime HVDC

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Attachment A-3

BC10 – Summer Day Light 2017

700 MW, 814 MW Import and 500 MW Export



Bus - VOLTAGE (PU)/ANGLE
Branch - MW/Mvar
Equipment - MW/Mvar

100.0%RATEA
1.050OV 0.950UV
kV: <=6.900 <=16.000 <=25.000 <=46.000 <=69.000 <=138.000 <=230.000>230.000

- Base Case
- Generation: Economic Dispatch
- Bipolar operation of Island HVDC
- Bipolar operation of Maritime HVDC

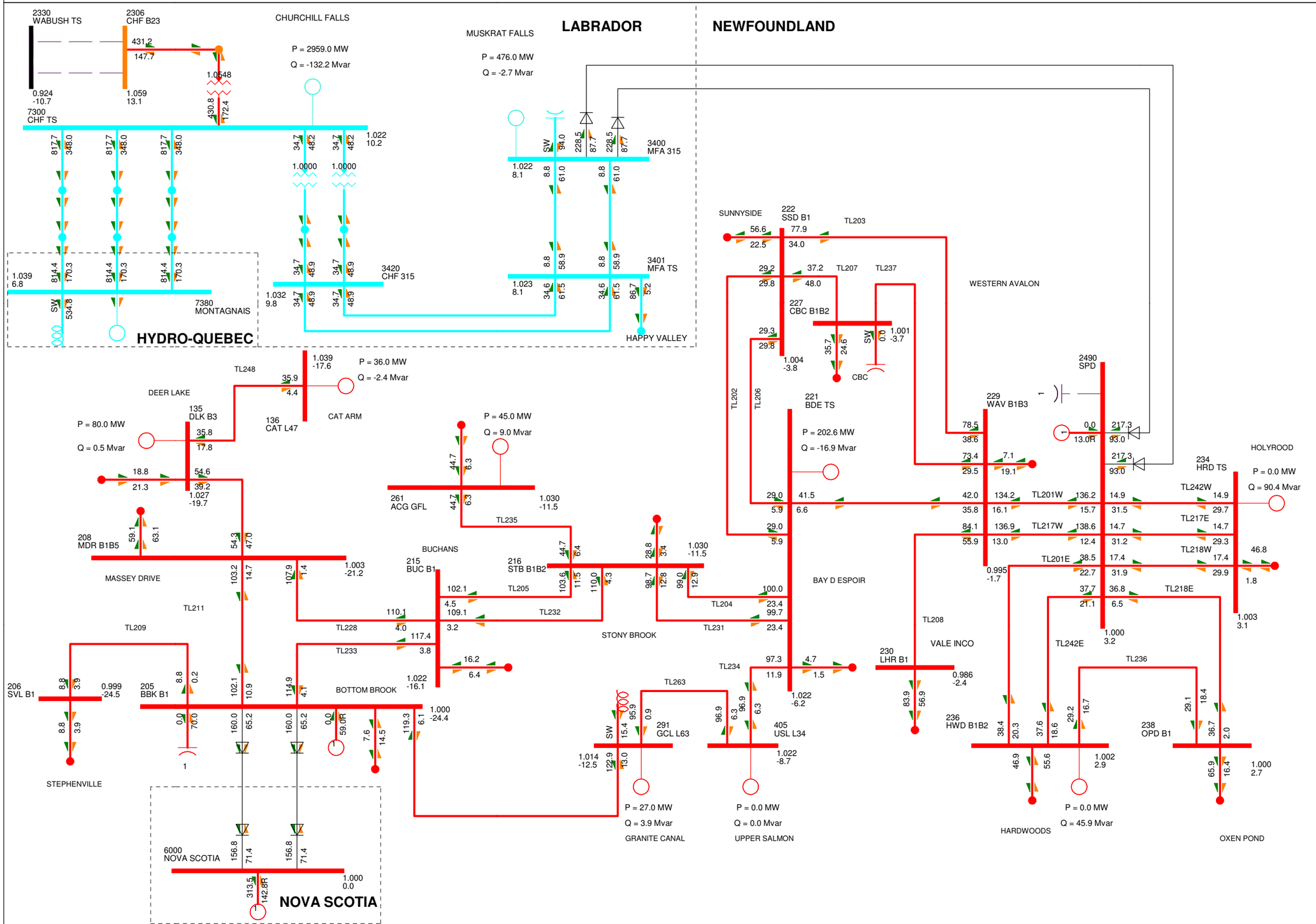
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Attachment A-4

BC 13 – Summer Night Extreme Light 2017

420 MW, 435 MW Import and 320 MW Export

BC13 - SUMMER NIGHT EXTREME LIGHT 2017, 420 MW, 435 MW IMPORT AND 320 MW EXPORT



Bus - VOLTAGE (PU)/ANGLE
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%RATEA

1.050OV 0.950UV
kV: <=6.900 <=16.000 <=25.000 <=46.000 <=69.000 <=138.000 <=230.000 >230.000

- Base Case
- Generation: Minimum
- Bipolar operation of Island HVDC
- Bipolar operation of Maritime HVDC

APPENDIX B

SYSTEM MODELS

SNC·LAVALIN	STABILITY STUDIES	Revision		
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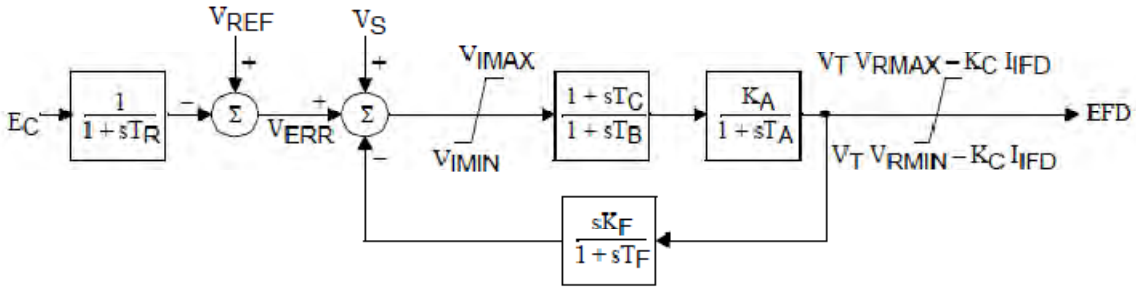
Table B-1: Generator Dynamic Data

	Unit-MVA	Td0' (s)	Td0" (s)	Tq0' (s)	Tq0" (s)	H (kW-s/kVA)	Xd	Xq	Xd'	Xq'	Xd"	Xl	S1.0	S1.2
							(pu on Machine Rating)							
THERMAL UNITS														
Soldiers Pond High Inertia Synchronous Condenser	+300/-165	11	0.08	-	0.29	7.84	1.24	0.85	0.27	-	0.165	0.09	0.04	0.14
Stephenville GasTurbine #1/2	63.5	11	0.05	1.0	0.060	2.06	2.1446	1.9551	0.1706	1.2	0.1584	0.1407	0.117	0.306
Holyrood Unit #1/2	194.4	3.845	0.035	1.0	0.060	1.182	2.1142	2.045	0.2859	0.4787	0.1923	0.1607	0.1335	0.638
Holyrood Unit #3	177.2	6.8	0.06	1.0	0.060	1.29	2.15	1.94	0.26	0.55	0.22	0.1152	0.078	0.254
Hardwoods Gas Turbine #1/2	63.5	10.2	0.04	1.0	0.060	2.06	1.82	1.67	0.14	0.121	0.102	0.091	0.1581	0.3348
NLP Greenhill Gas Turbine	31.1	7.3	0.038	1.0	0.060	1.093	1.72	1.62	0.174	0.3475	0.139	0.11	0.285	0.7
CBP&P Primary Refiner 1P/3P/4P/5P/6P	10.2	1.001	0.05	1.0	0.050	1.256	1.46	1.4	0.3	0.36	0.2	0.07	0.1	0.5
CBP&P SecondaryRefiner 1S/2S/3S/4S/5S/6S	10.2	1.001	0.05	1.0	0.050	1.433	1.18	1.13	0.27	0.29	0.17	0.06	0.1	0.5
CBP&P Rejects Refiner R5/R6/R7	10.19	1.001	0.05	1.0	0.050	1.433	1.18	1.13	0.27	0.29	0.17	0.06	0.1	0.5
CBP&P Steam Unit-G2	21.8	5.246	0.033	0.2	0.314	1.1	2.4	2.17	0.26	2.17	0.188	0.119	0.135	0.584
Corner Brook Frequency Converter-60Hz	25	6	0.048	-	0.060	2.48	1.27	0.73	0.301	-	0.19	0.11	0.111	0.2862
Corner Brook Frequency Converter-50Hz	25	12.45	0.06	-	0.060	2.48	1.6	0.81	0.327	-	0.19	0.1045	0.1994	0.5814
Happy Valley GT- SynchronousCondenser Operation	26.57	10.7	0.05	3.2	0.050	1.7377	1.93	1.77	0.213	0.305	0.158	0.122	0.1843	0.6471

	Unit-MVA	Td0' (s)	Td0" (s)	Tq0" (s)	H (kW-s/kVA)	Xd	Xq	Xd'	Xd"	Xl	S1.0	S1.2
						(pu on Machine Rating)						
HYDRO UNITS												
Churchill Falls Unit A1/3/5/7/9	500	9.23	0.07	0.107	3.881	0.98	0.65	0.29	0.22	0.14	0.191	0.464
Churchill Falls Unit A2/4/6/8/10/11	500	8.0	0.071	0.25	3.807	1.00	0.62	0.28	0.22	0.14	0.191	0.464
Muskrat Falls G1/4	228.9	7.41	0.07	0.07	4.1	1.027	0.559	0.34	0.254	0.15	0.086	0.293
Bay D'Espoir Unit #1	85	6.24	0.065	0.08	5.24	1.3396	0.7497	0.3001	0.1802	0.132	0.1702	0.5621
Bay D'Espoir Unit #2	85	6.24	0.065	0.08	4.868	1.3396	0.7497	0.3001	0.1802	0.132	0.1233	0.5158
Bay D'Espoir Unit #3-6	85	6.24	0.065	0.08	5.24	1.3396	0.7497	0.3001	0.1802	0.132	0.1339	0.5504
Bay D'Espoir Unit #7	172	7.2	0.07	0.08	3.883	0.945	0.357	0.229	0.142	0.12	0.1364	0.4151
Cat Arm Unit #1/2	75.5	7.3	0.083	0.06	4.02	0.912	0.4427	0.254	0.181	0.1708	0.122	0.391
Granite Canal	45	5.8	0.042	0.042	4.0	0.711	0.48	0.21	0.23	0.1569	0.1651	0.577
Hinds Lake	83	8.24	0.035	0.17	6.6	1.2871	0.75	0.225	0.196	0.1287	0.1012	0.3529
Upper Salmon	88.4	4.345	0.04	0.06	3.5	0.86	0.594	0.3	0.215	0.12	0.084	0.3889
Paradise River	8.9	0.65	0.05	0.06	3.5	1.30	0.84	0.36	0.275	0.1	0.1189	0.3788
Deer Lake PowerCompany 60 HzUnits G1-G7	13.3	5.0	0.05	0.06	4.32	1.32	0.83	0.35	0.27745	0.2	0.11	0.48
NLP Rattling Brook Hydro Plant	15	5.0	0.05	0.06	2.5	0.9	0.54	0.23	0.16	0.100	0.11	0.48
NLP Sandy BrookHydro Plant	7	5.0	0.05	0.06	3.0	1.07	0.643	0.314	0.28	0.100	0.11	0.48
Abitibi-Consolidated - GrandFalls G4	27.5	7.37	0.035	0.035	2.96	1.545	0.7451	0.359	0.3506	0.1753	0.1905	0.4741
Abitibi-Consolidated - GrandFalls G5-8	5	5.0	0.05	0.05	5.5	1.243	0.932	0.435	0.3108	0.124	0.1	0.25
ACI-CHI Star Lake Hydro Plant	20.44	3.79	0.05	0.05	6.25	1.212	1.04	0.329	0.264	0.1	0.1356	0.525
NLP Rose BlancheBrook HydroPlant	7.63	3.5	0.035	0.04	3.28	1.26	0.76	0.332	0.199	0.1	0.0545	0.2121
Deer Lake Power50 Hz G8-9	24	5.0	0.05	0.06	2.917	1.25	0.83	0.35	0.4008	0.11	0.11	0.48
Deer Lake Power50 Hz Watson's Brook Unit#1/2	5.1	5.0	0.05	0.06	6.792	1.28	0.83	0.23	0.1499	0.2	0.11	0.48
Abitibi-Consolidated - BeetonUnit G9	33.3	3.8	0.032	0.032	1.827	0.98	0.56	0.41	0.29	0.28	0.2	0.75
Abitibi-Consolidated - Bishop's Falls Plant typical data	20	5.0	0.05	0.06	2.0	1.5	1.2	0.4	0.2	0.12	0.03	0.25
Rattle Brook- G1 Algonquin Power	4.02	3.14	0.039	0.062	1.052	1.399	0.775	0.306	0.186	0.107	0.156	0.276
Montagnais HQ Equivalent	30,000	-	-	-	3.6	-	-	0.22	-	-	-	-
Nova Scotia Equivalent	2,000	-	-	-	3.6	-	-	0.2	-	-	-	-

Table B-2: Generator Exciter Models

Model ID: EXST1

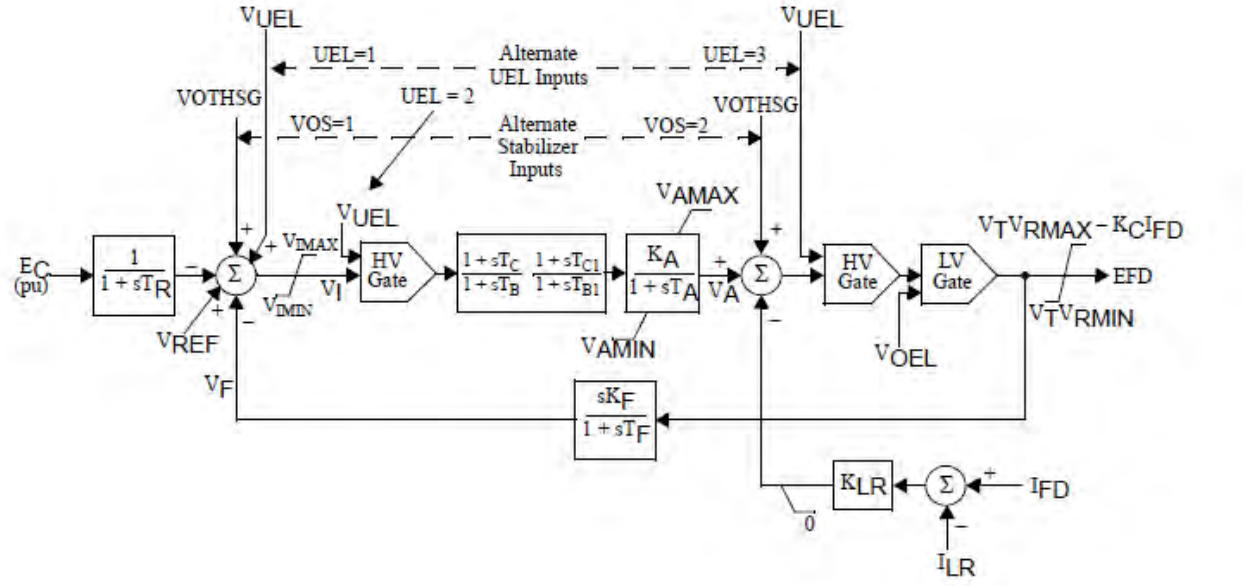


$V_S = VOTHSG + VUEL + VOEL$

Parameter	Churchill Falls	Muskrat Falls	HQ Equivalent	CB&P-G2	Grand Falls-G4
Tr	0.02	0.02		0	0
V_{Imax}	0.0262	0.0471		13.3	0.87
V_{Imin}	-0.027	-0.0476		-10.65	-0.87
Tc	0	0		1	0
Tb	0	0		1	0
Ka	400	400		200	90.676
Ta	0	0		0.001	0.02
Vrmax	7	12.3		13.3	7.5
Vrmin	-7.2	-12.7		-10.65	-0.1864
Kc	0	0		0	0.2
Kf	0	0		0	0.1609
Tf	1	1		1	1

Table B-3: Generator Exciter Models

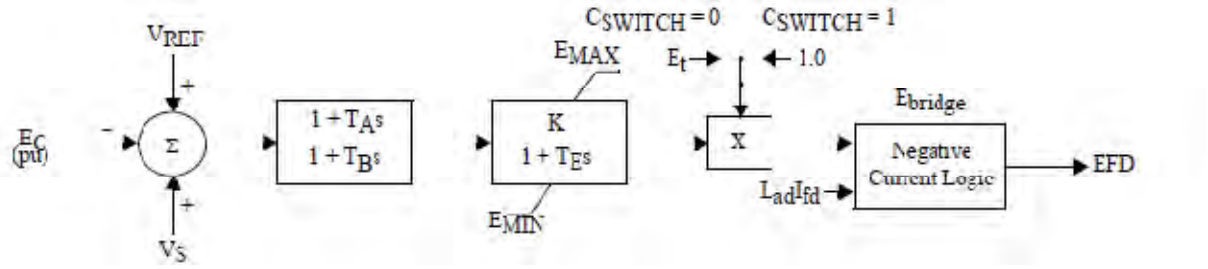
Model ID: ESST1A



Parameter	Bay d'Espoir						Cat Arm	Granite Canal
	G1	G2	G3	G4	G5	G6	G1	G1
Tr	0.02	0.02	0.02	0.02	0.02	0.02	0.0	0.0
V_{Imax}	3.6	3.4	3.5	3.48	4.13	4.16	6	6
V_{Imin}	-3.05	-2.88	-3	-2.95	-3.5	-3.52	-4.8	-4.8
Tc	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02
Tb	0.003	0.003	0.003	0.003	0.003	0.003	0.02	0.02
Tc1	2.5	2.5	2.5	2.5	2.5	2.5	2.59	1
Tb1	22.22	22.22	22.22	22.22	22.22	22.22	8.094	3.125
Ka	400	400	400	400	400	400	250	250
Ta	.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
V_{amax}	3.6	3.4	3.5	3.48	4.13	4.16	6	6
V_{amin}	-3.05	-2.88	-3	-2.95	-3.5	-3.52	-4.8	-4.8
V_{rmax}	3.6	3.4	3.5	3.48	4.13	4.16	6	6
V_{rmin}	-3.05	-2.88	-3	-2.95	-3.5	-3.52	-4.8	-4.8
Kc	0	0	0	0	0	0	0	0
Kf	0	0	0	0	0	0	0	0
Tf	1	1	1	1	1	1	1	1
K_{LR}	0	0	0	0	0	0	0	0
I_{LR}	0	0	0	0	0	0	0	0

Table B-3: Generator Exciter Models

Model ID: SCRX

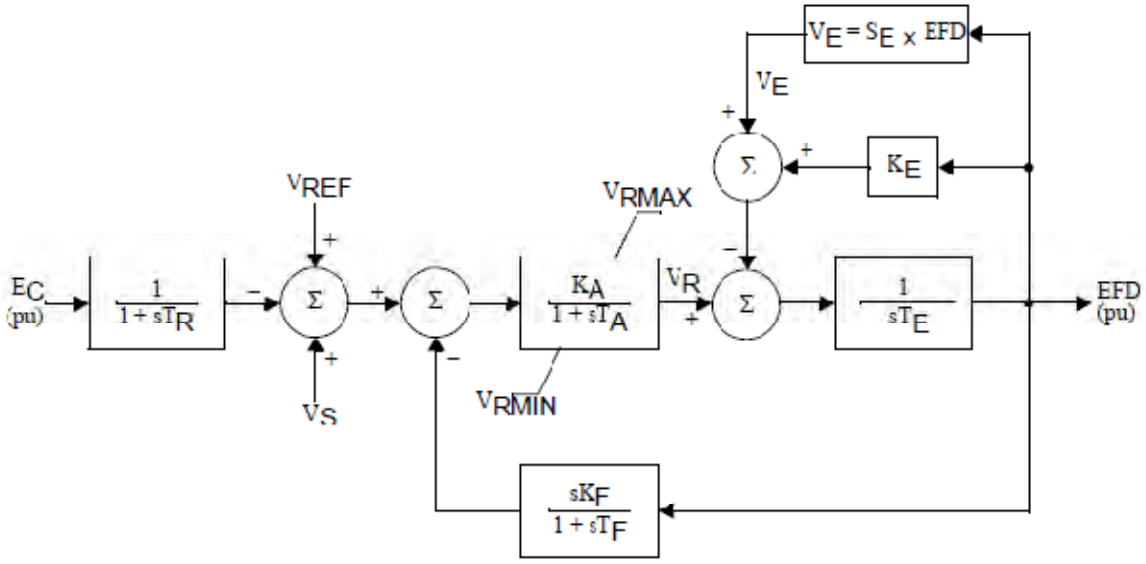


$V_S = VOTHSG + VUEL + VOEL$

Parameter	Bay d'Espoir G7	Holyrood G3	Hinds Lake G1	Upper Salmon G1	Grand Falls G5-8	CB&P Refiners -	Bishops Falls -
Ta/Tb	1	1	1	1	0.1	0.1	0.1
Tb	1	1	1	1	10	10	10
K	65	55	55	65	100	100	100
TE	0.035	0.035	0.035	0.035	0.05	0.05	0.05
Emin	-5.3	-6.32	-10.2	-4.48	0	0	0
Emax	6.1	7.32	11.7	5.56	2.5	5	2.5

Table B-3: Generator Exciter Models

Model ID: IEEET1



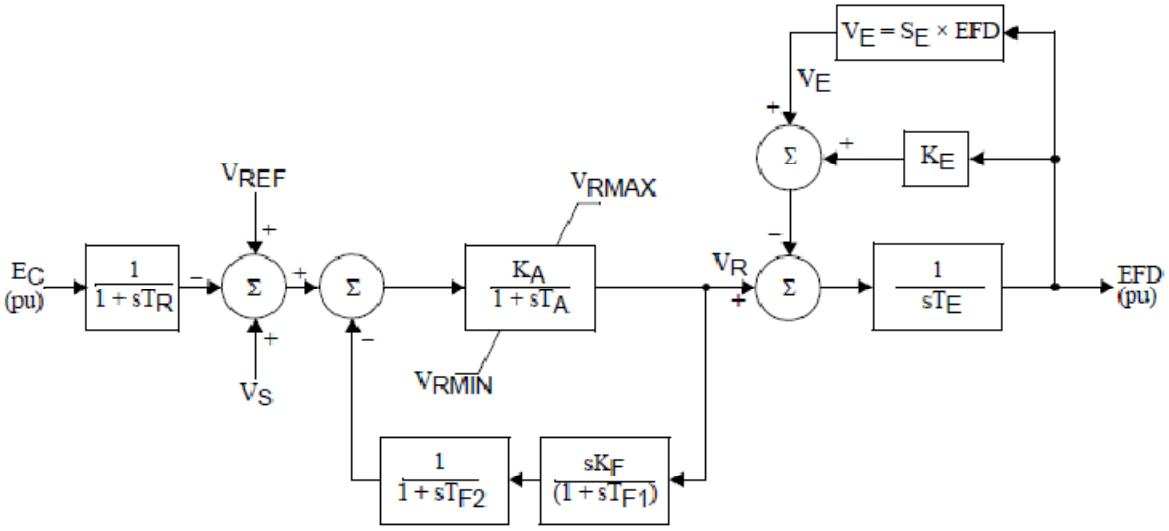
V_S = VOTHSG + VUEL + VOEL

Note: S_E is the saturation function

Parameter	Deer Lake G1-7
Tr	0
Ka	200
Ta	0.2
Vrmax	0
Vrmin	0
KE	0
TE	1
Kf	0.07
Tf	1
E1	3
S_{E1}	0.12
E2	4
S_{E2}	0.47

Table B-3: Generator Exciter Models

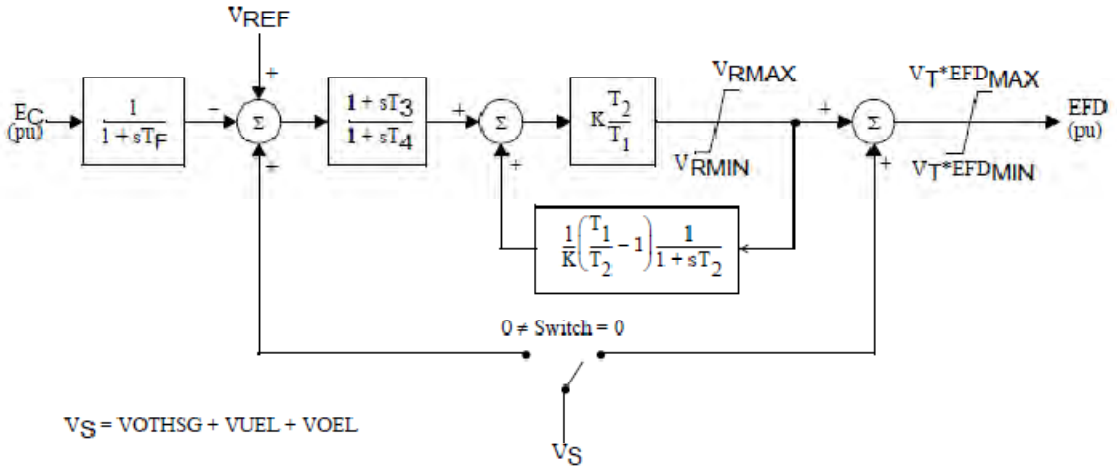
Model ID: IEEET2



Parameter	Stephenville GT1-2	Hardwoods GT1-2	Paradise River G1
Tr	0.035	0.035	0.015
Ka	700	700	400
Ta	0.22	0.22	5
Vrmax	12.5	2.573	7.5
Vrmin	0	0	0
KE	1	1	0.57
TE	1	1	0.5
Kf	0.04	0.04	0.09
Tf1	0.6	0.6	0.32
Tf2	1	1	0.07
E1	5.64	2.698	3.72
S_{E1}	0.127	0.1781	0.0034
E2	6.767	3.9116	4.24
E2	0.448	0.3008	0.0126

Table B-3: Generator Exciter Models

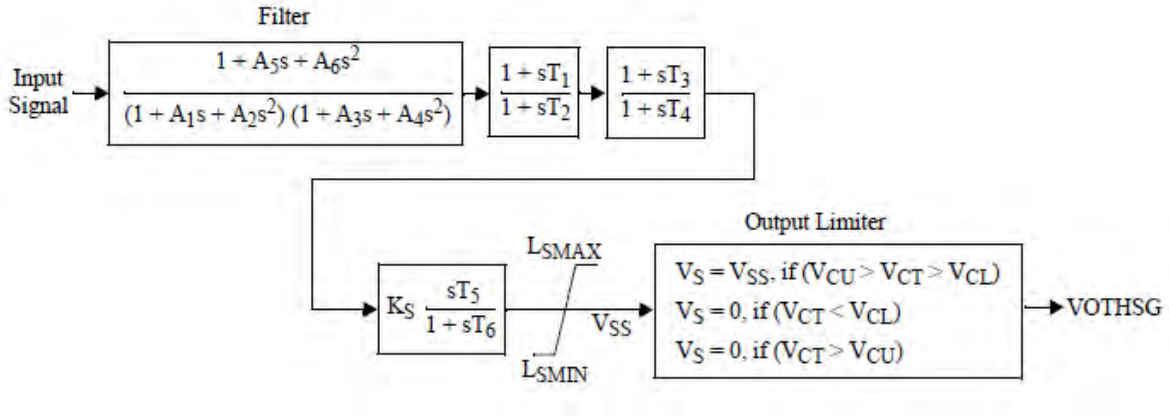
Model ID: BBSEX1



Parameter	Cat Arm G2
TF	0.035
T3	1.0
T4	3.91
T1	0.1
T2	0.035
K	70
Vrmax	8
Vrmin	-8
Efdmax	8
Efdmin	-6.4

Table B-4: Supplementary Stabilizer Models

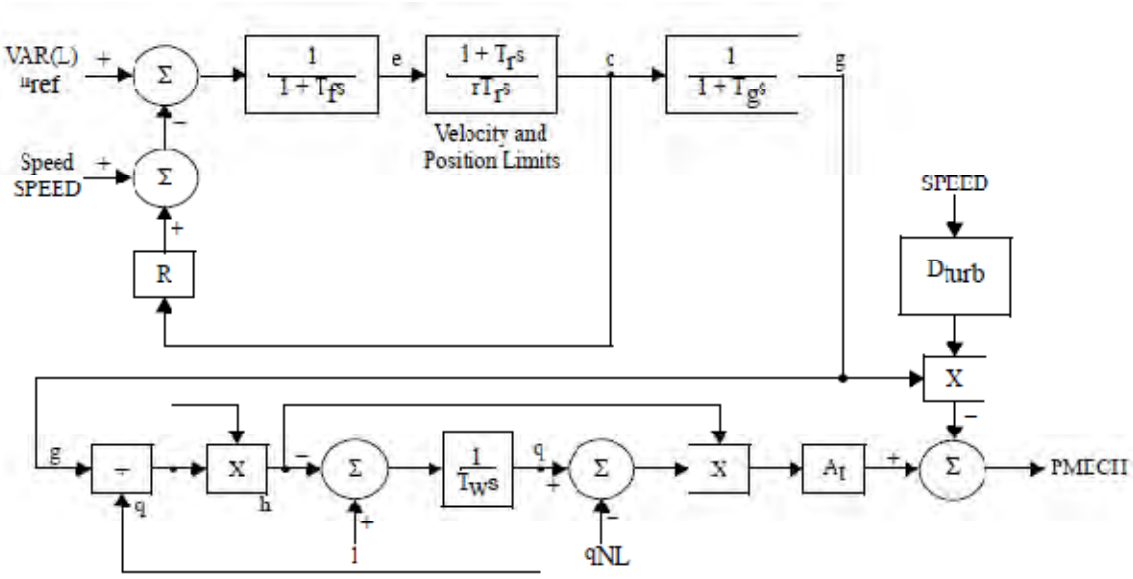
Model ID: IEEEST



Parameter	Churchill Falls G1-11	Muskrat Falls G1-4
A1	0	0
A2	0	0
A3	0	0
A4	0	0
A5	0	0
A6	0	0
T1	0	0
T2	1	1
T3	0.1	0.1
T4	1	1
T5	1	1
T6	0.08	0.08
Ks	3.5	3.5
Lsmax	0.1	0.1
Lsmin	-0.15	-0.15
Vcu	0	0
Vcl	0	0

Table B-5: Speed Governor Models

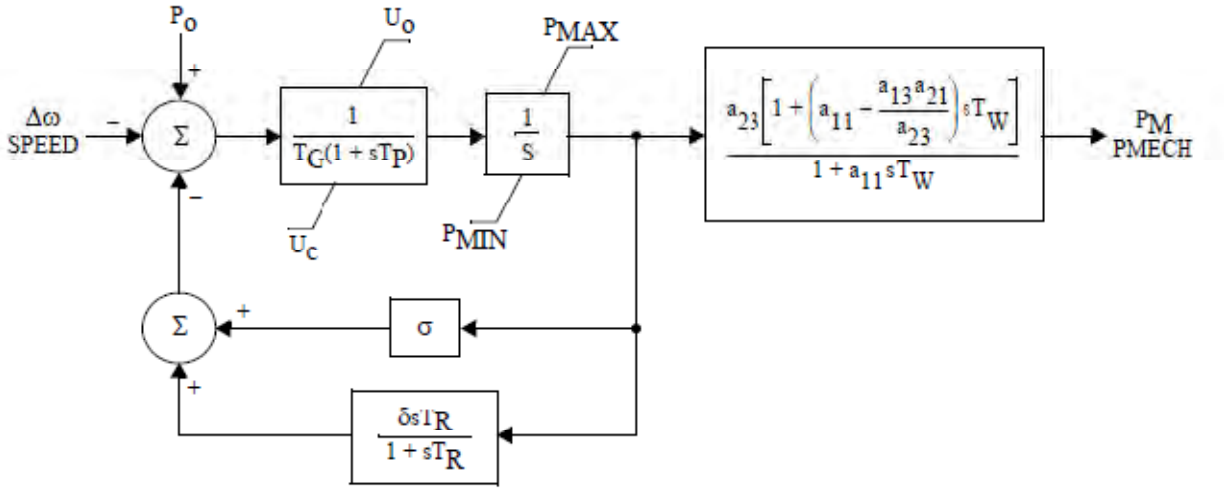
Model ID: HYGOV



Parameter	Muskrat Falls	Deer Lake	Bay d'Espoir						
	G1-4	G1-7	G1	G2	G3	G4	G5	G6	G7
R	0.05	0.06	0.02	0.01	0.02	0.02	0.01	0.02	0.01
r	0.44	0.5	0.44	0.35	0.26	0.41	0.34	0.34	0.4
Tr	4.88	6	14	8	12.5	14	12.5	8.25	17
Tf	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Tg	0.5	0.5	0.5	0.5	0.3	0.5	0.3	0.3	0.5
VELM	0.094	0.134	0.082	0.082	0.089	0.089	0.089	0.089	0.095
Gmax	0.945	0.79	0.835	0.835	0.892	0.892	0.892	0.892	0.947
Gmin	0	0.79	0	0	0	0	0	0	0
Tw	1.22	2	2.14	2.14	2.17	2.17	2.27	2.27	3.6
At	1.04	1.2	1.2	1.2	1.087	1.2	1.087	1.087	1.087
Dturb	0	0	0	0	0.75	0	3.5	1.25	1.15
Qnl	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.075

Table B-5: Speed Governor Models

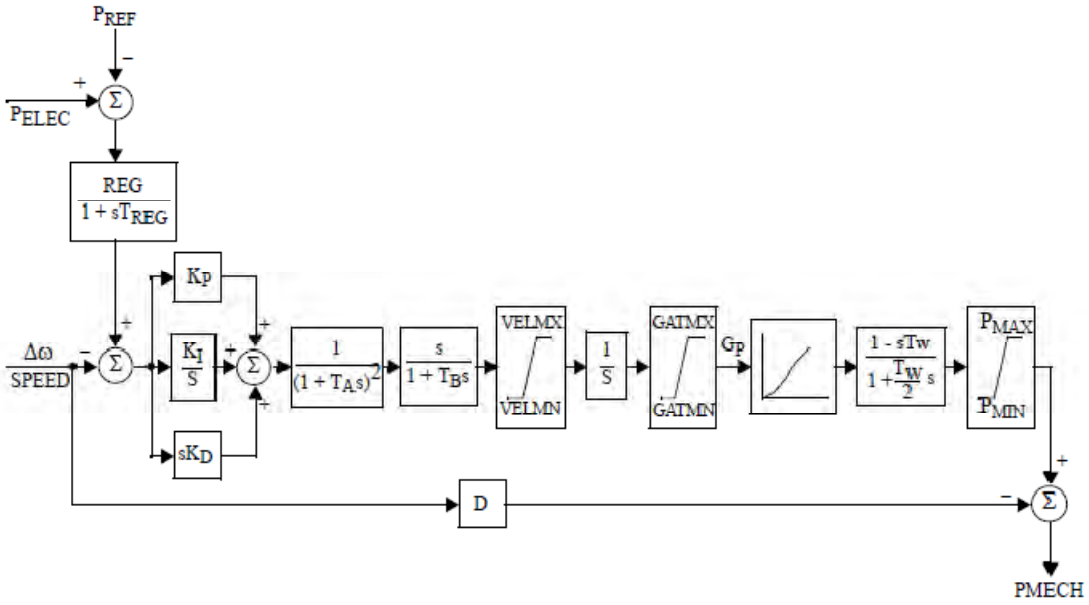
Model ID: IEEEG3



Parameter	Churchill Falls G1-11
Tg	0.3
Tp	0.04
Uo	.01
Uc	-0.1
Pmax	1
Pmin	0
σ	0.05
δ	0.293
Tr	5.5
Tw	1.1
a1	0.5
a2	1
a3	1.5
a4	1

Table B-5: Speed Governor Models

Model ID: WPIDHY

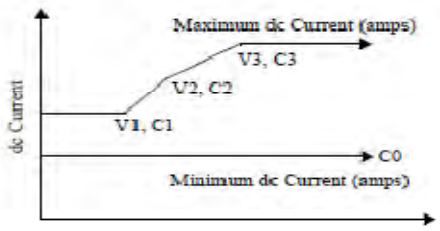


Parameter	Paradise River G1		
Treg	1.8	**G0**	0.15
REG	0.05	**G1**	0.5
Kp	1	**P1**	0.4118
Ki	1	**G2**	0.75
Kd	0	**P2**	0.7059
Ta	0.035	**P3**	1
Tb	0.035		
VELmax	0.1303		
VELmin	-0.1215		
GATmax	0.9647		
GATmin	0		
Tw	1.35		
Pmax	1		
Pmin	0		
D	0		

Table B-5: HVdc Converter Model

Model ID: CDC4T

Parameter	Units	Island Link	Maritime Link
ALFDY-Min. Alpha	deg	5	5
GAMDY-Min. Gamma	deg	18	18
TVDC-dc Voltage Transducer Time Constant	s	0.01	0.01
TIDC-dc Current Transducer Time Constant	s	0.01	0.01
VBLOCK-Rectifier ac Blocking Voltage	pu	0.6	0.6
VUNBL Rectifier ac Unblocking Voltage	pu	0.65	0.65
TBLOCK-Min. Blocking Time	S	0.1	20
VBYPAS-Inverter dc Bypassing Voltage	kV	235	0.6
VUNBY-Inverter ac Un-bypassing Voltage	pu	0.95	0.65
TBPAS-Min. Bypassing Time	s	0.1	0.1
RSVOLT-Min. dc Voltage following Block	kV	10	10
RSCUR-Min. dc Current following Block	A	10	10
VRAMP-Voltage Recovery Rate	pu/s	10	10
CRAMP-Current Recovery Rate	pu/s	10	10
C0-Min. Current Demand	A	150	0
V1-VDCOL Set Point	kV	100	60
C1-VDCOL Set Point	A	386	375
V2-VDCOL Set Point	kV	240	100
C2-VDCOL Set Point	A	2,580	1,300
V3-VDCOL Set Point	kV	320	200
C3-VDCOL Set Point	A	2,580	1,300
TCMODE-Min Time in Switched Mode	s	0.1	0.1



Voltage-Dependent Upper Current Limit

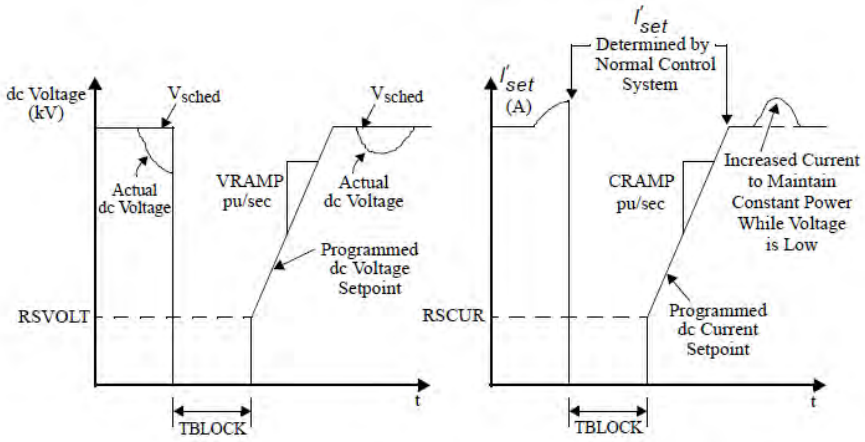
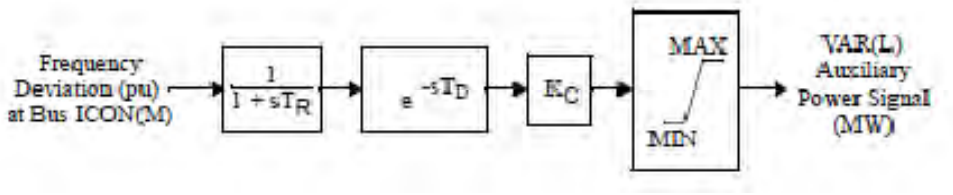

dc Voltage (kV)
Vsched
Vsched
Actual dc Voltage
VRAMP pu/sec
Actual dc Voltage
Programmed dc Voltage Setpoint
RSVOLT
t
TBLOCK
I'set
Determined by Normal Control System
I'set (A)
CRAMP pu/sec
Increased Current to Maintain Constant Power While Voltage is Low
RSCUR
Programmed dc Current Setpoint
t
TBLOCK

Table B-6: HVdc Frequency Control Model

Model ID: PAUX1



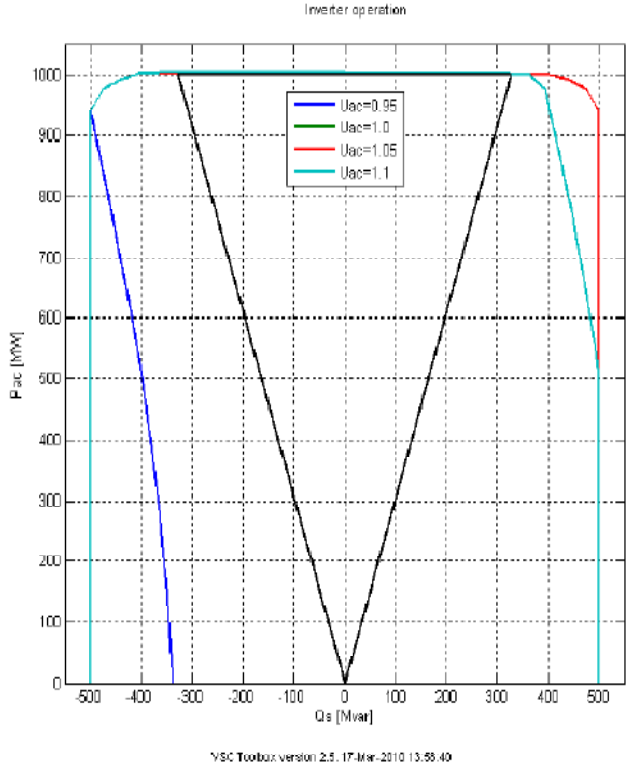
Parameter	Units	Soldiers Pond	Bottom Brook
Tr	s	0.05	0.05
TD	s	0	0
Kc	pu	-55,000	75,000
MAX	MW	10,000	0
MIN	MW	-1,050	-2,000

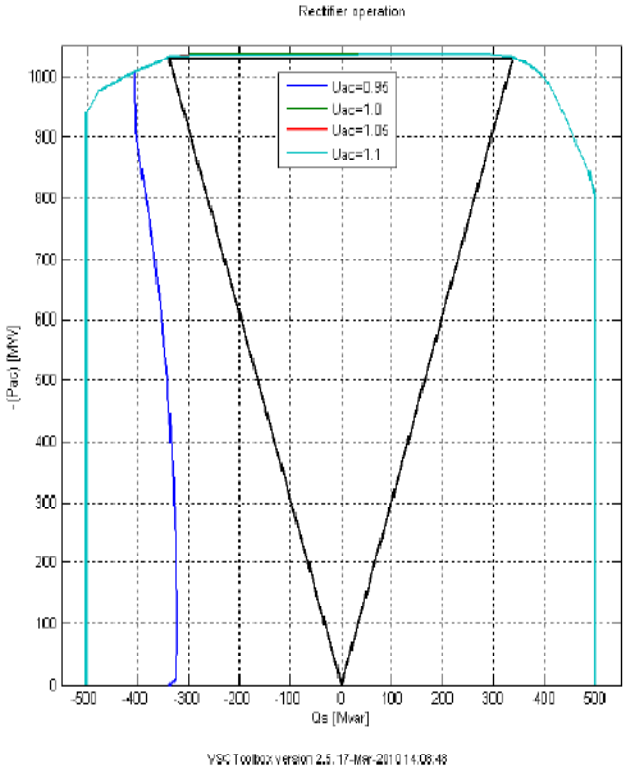
APPENDIX C

PQ CURVES OF TYPICAL VSC

SNC·LAVALIN	STABILITY STUDIES	Revision		
	Nalcor Doc. No. ILK -SN-CD-8000-EL-RP-0001-01	B2	Date	Page
	SLI Doc. No. 505573-480A-47ER-0004	01	06-Mar-2012	C-1

PQ-Curve from ABB





PQ-Curve from Siemens

