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THE POWER OF COMMITMENT

THE Lower Churchill PROJECT

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DC1020 - HVdc System Integration Study

Volume 1 - Summary Report

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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.

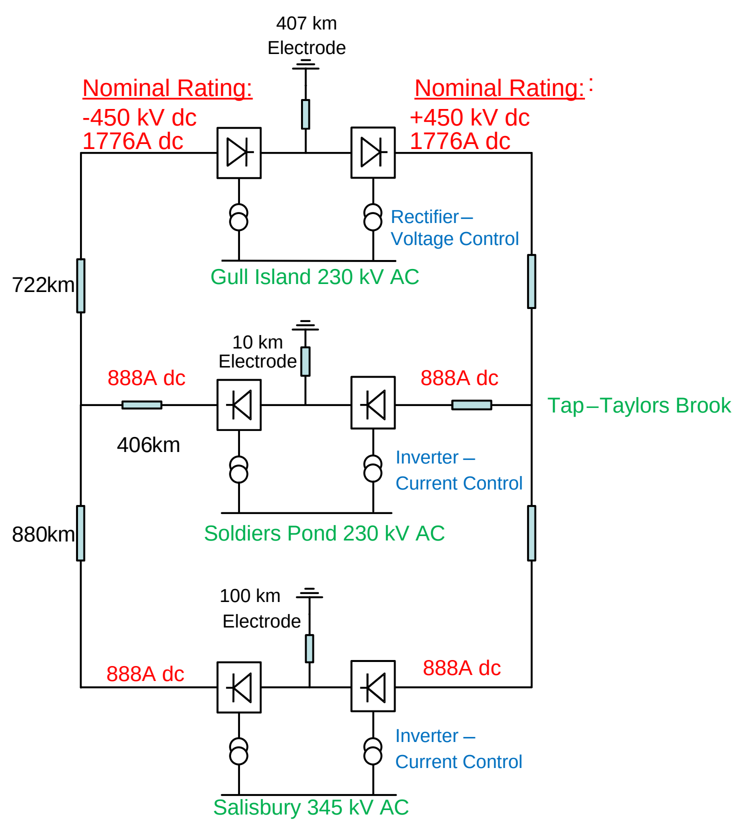
In order to complete the work and provide Hydro with results in a timely and efficient manner, a series of interim reports were submitted to Hydro for review and approval upon completion of the major study tasks identified within the WTO. The following interim reports have been previously submitted to 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.

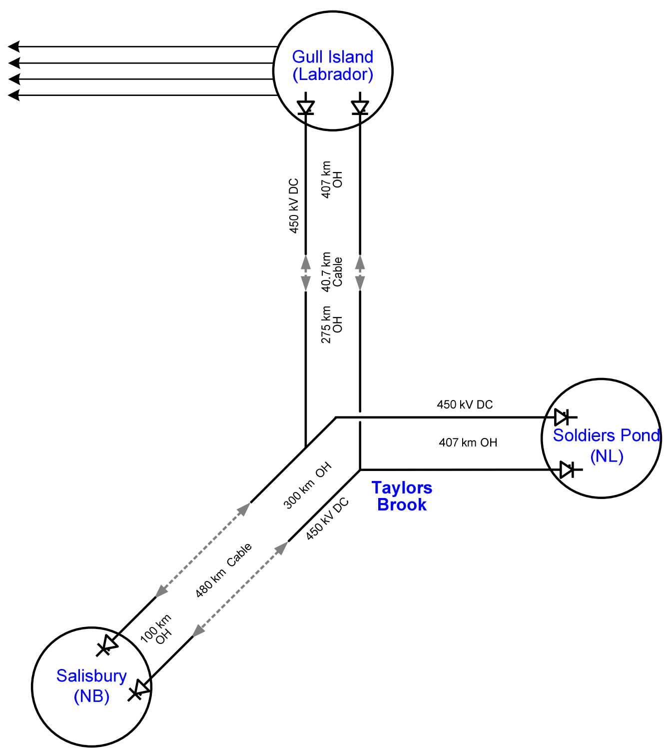


Figure 1 - Proposed Lower Churchill Multi-Terminal HVdc System

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.

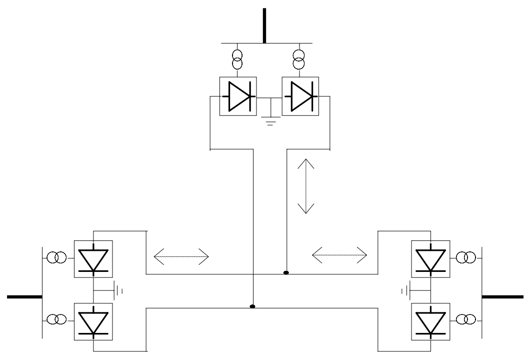


Figure 2 - Basic Configuration of the HVdc Transmission System

- 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	$2.5 >= \text{ESCR} >= 1.5$
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

<table>
<tr><th>Overloaded Line</th><th>Contingency</th><th>Rate</th><th>Power Flow</th><th>Overload (%)</th><th>Pre-Contingency HVdc Infeed (MW)</th><th>Post-Contingency Redispatch (MW)</th></tr>
<tr><td rowspan="4">Piper's Hole-Bay d'Espoir TL202, TL206</td><td rowspan="4">C9</td><td>A</td><td>BC12-DC10</td><td>101.4</td><td>80 BP</td><td>+10 DC import</td></tr>
<tr><td>B</td><td>BC7*</td><td></td><td>80 BP</td><td>+175 DC import</td></tr>
<tr><td>A</td><td>BC8*</td><td></td><td>-200 BP</td><td>0 DC export
+75 Holyrood</td></tr>
<tr><td>C</td><td>BC2-DC5</td><td>100.3</td><td>600 MP</td><td>n/a</td></tr>
<tr><td>Sunnyside-Western Avalon TL203</td><td>C5,C6</td><td>A</td><td>BC8</td><td>146.7</td><td>-200 BP</td><td>-125 DC export</td></tr>
<tr><td rowspan="2">Piper's Hole-Sunnyside TL202</td><td rowspan="2">C8</td><td>A</td><td>BC8</td><td>148.6</td><td>-200 BP</td><td>-160 DC export</td></tr>
<tr><td>B</td><td>BC7-DC1</td><td>108.9</td><td>80 BP</td><td>+35 DC import</td></tr>
<tr><td>Sunnyside-Come By Chance TL207</td><td>C7</td><td>A</td><td>BC8</td><td>150.3</td><td>-200 BP</td><td>-130 DC export</td></tr>
<tr><td>Come By Chance-Western Avalon TL237</td><td>C7</td><td>A</td><td>BC8</td><td>142.7</td><td>-200 BP</td><td>-110 DC export</td></tr>
</table>

**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.

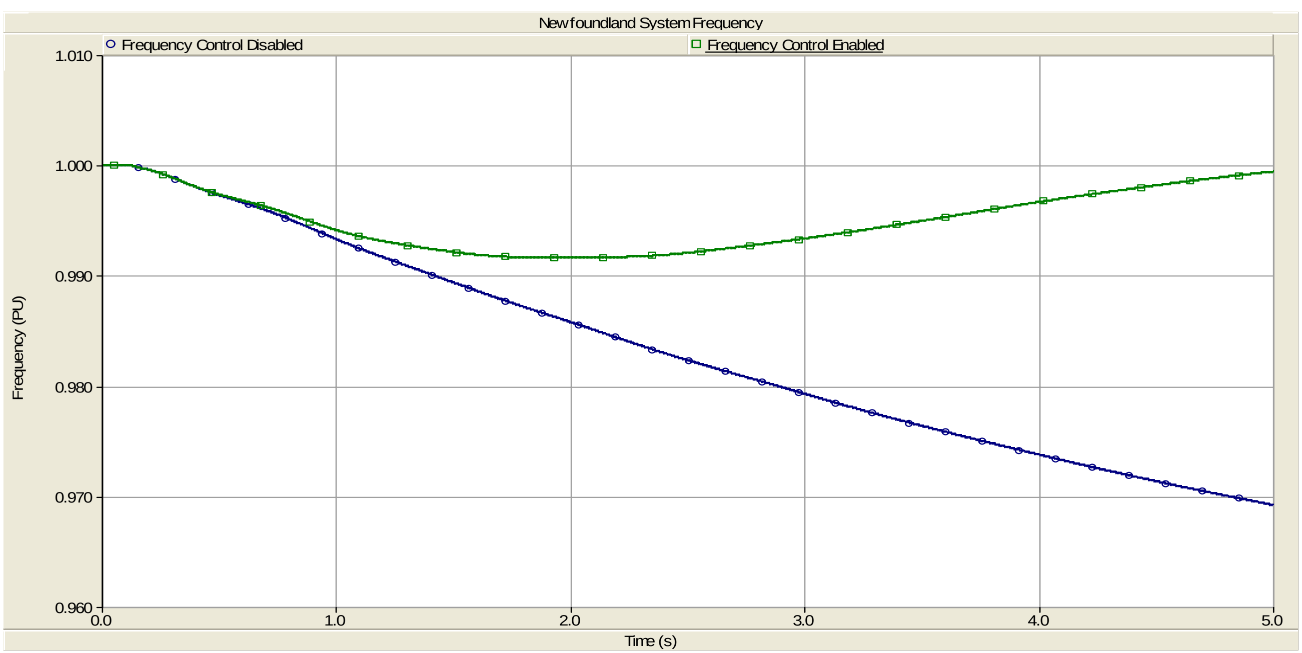


Figure 3 - Effect of HVdc Frequency Control on Newfoundland Island Frequency (Base-Case: BC1-DC1, Trip Unit #7 at Bay d'Espoir)

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.

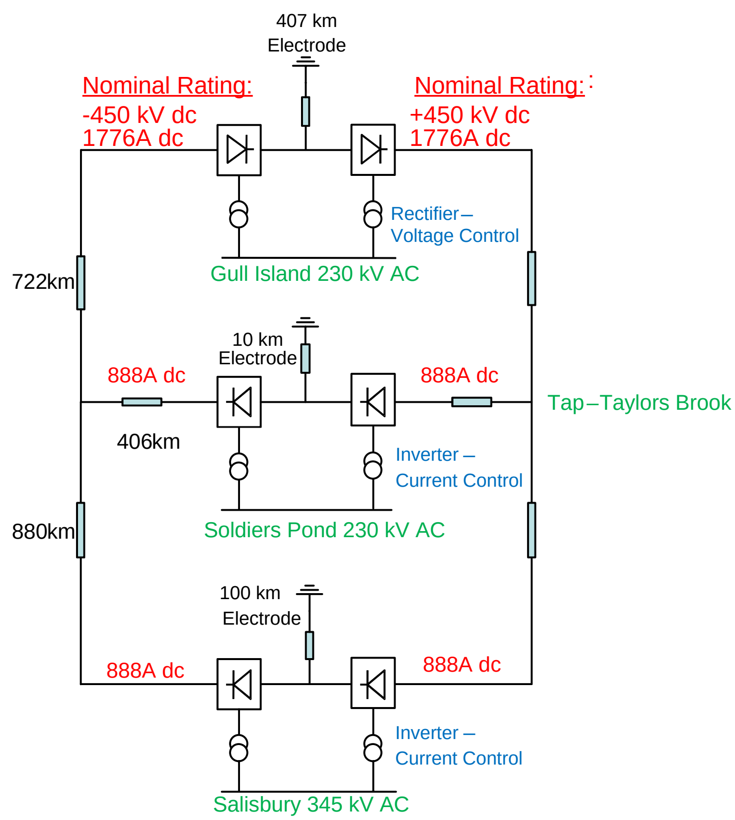


Figure 4 - Proposed Multi-Terminal HVdc System and Line Lengths

- 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