Q. Please provide the report completed in about 2012 that evaluated the impact of NERC compliance and the associated cost and benefit.

A. A report evaluating the impact of NERC compliance and the associated costs and benefit was not completed in 2012. However, please refer to PUB-NLH-157 Attachments 1 and 2 for the draft analysis in reference to same.

Nalcor Energy Lower Churchill Project

Strategic Alignment, Benefits, Reliability Framework and Compliance – NERC Reliability Standards and NPCC Regional Reliability Criteria

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Executive Summary

With the development of phase 1 of the Lower Churchill Project (LCP), Newfoundland and Labrador (NL) will be interconnected to the North American power grid through the province of Nova Scotia with the Maritime Link (ML) and through Quebec with the Labrador Island Link (LIL), Muskrat Falls (MF), Labrador Transmission Assets (LTA) and Churchill Falls (Labrador) Corporation (CF(L)Co). As a result of this, there is a need to assess the potential requirements and implications of adopting the North American Electric Reliability Corporation (NERC) reliability standards and the Northeast Power Coordinating Council (NPCC) regional reliability criteria. This report outlines the benefits associated with adopting the NERC reliability standards and the NPCC regional reliability criteria and how it aligns strategically with the goals and direction of Nalcor Energy (Nalcor). It also outlines a potential reliability framework and compliance program for the province.

A companion report titled “Cost Assessment – NERC Reliability Standards and NPCC Regional Reliability Criteria” has been completed which details a cost estimate for Nalcor (including Newfoundland and Labrador Hydro (NLH) and its other subsidiaries) to adopt these standards and criteria. The analysis showed that using 30% for a contingency factor, the range for the total overall cost estimates would be: $5,000,000 - $6,500,000 (amounts shown to the nearest $100,000). This estimate includes both initial costs to get to a compliance level ($4,000,000 - $5,200,000) and ongoing annual costs (in 2012 dollars) to maintain compliance ($1,000,000 - $1,300,000).

NERC is the Electric Reliability Organization (ERO), as authorized by the United States (US) Federal Energy Regulatory Commission (FERC), is responsible for the creation, implementation, monitoring and enforcement of mandatory reliability standards for the Bulk Electric System (BES) in the US. However, while NERC does not have jurisdiction in Canada, 8 of the 10 provinces have either adopted or are in the process of adopting all or some of the NERC reliability standards. There is also Regional Reliability Organizations (RRO) across North America that are recognized by NERC. Through delegation agreements with NERC, they ensure the reliability of the power grid in their region. They may have their own reliability standards or criteria that are specific to their region. They are also mainly responsible for the compliance monitoring and enforcement of the reliability standards for their region. The RRO responsible for the northeastern power grid (adjacent to NL) is NPCC.

Adopting some or all of the reliability standards would align with the strategic direction and goals of Nalcor. Nalcor is striving to be a world class leader in safety, a leader in the environment, operational excellence in areas of reliability and asset management, to be recognized as one of the best employers in Canada and have strong corporate reputation in the community. In working towards these goals, Nalcor has implemented many tools and processes, promoted the adoption of best practices, implemented compliance measures and use benchmark criteria. Adopting NERC reliability standards can be considered best practice adoption, improve reliability through compliance measures and enhance the reputation of Nalcor through its commitment to the reliability of the North American BES. These can be considered strategic benefits for Nalcor.

There are a number of clear benefits that would be gained by the province of NL if some or all of the reliability standards and the regional reliability criteria were adopted. On a high level basis, the benefits are as follows:

1. Nalcor would have a clear, consistent and technically sound set of reliability standards.
2. NL would be consistent with other jurisdictions in Canada in terms of reliability practices.
3. Compliance measures would ensure reliability is maintained and improved and;
4. Membership in NERC and NPCC will enable the shaping of the content and efficiency of the standards to improve reliability.

A review has also been completed on a potential reliability framework for the province in which oversight and compliance monitoring could be established. While a final determination will be made by the provincial government, the review outlines a potential approach to implement the reliability framework.

The approach discusses the Public Utilities Board (PUB) playing a significant role. In particular, the PUB could have the responsibility for approving the NERC reliability standards and NPCC regional reliability criteria that are applicable to the province. The approval process could involve an initial assessment and recommendation from Nalcor or other utilities (as applicable) and then final approval by the PUB.

This approach is considered to offer transparency in the adoption process and to provide a reliability oversight for the province. The provincial government would also need to consider other utilities and entities operating within the province, particularly Newfoundland Power (NP), when making a determination on the framework for the province.

In order to implement this reliability framework in NL, the following may be required:

1. A Memorandum of Understanding (MOU) developed between NERC, NPCC and the PUB
2. Amendments required to the Public Utilities Act
3. An MOU developed between NERC, NPCC, NLH and Nalcor
    - This may include other utilities depending on the provincial government determination

The other component to the reliability framework is to ensure compliance with the NERC reliability standards and NPCC regional reliability criteria. A compliance and enforcement program is very important and was noted as one of the benefits to adopting the standards and criteria. The program would ensure that the reliability of the BES is maintained and improved and that violations are mitigated.

Based on the benefits discussed in this report, a number of recommendations have been put forth. They are as follows:

1. Nalcor adopt some or all of the NERC reliability standards that were determined to be required or optional in the cost assessment report.

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2. Nalcor adopt the NPCC regional reliability criteria and determine the facilities that these criteria would apply. This would be done through a Bulk Power System (BPS) assessment using NPCC – A-10 and discussions with NPCC.
3. Nalcor to become a member of NERC and NPCC to ensure maximum benefits are gained from adopting the reliability standards and regional reliability criteria.
4. Nalcor develop an implementation plan for the NERC reliability standards and NPCC regional reliability criteria.
5. The provincial government should determine the reliability framework and compliance program for NL. This would include investigating the inclusion of other utilities and entities in the province.

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1.0 Introduction

As part of the development of the Lower Churchill Project (LCP), a system integration team was formed to look at the potential requirements for integrating the current power system in Newfoundland and Labrador (NL) with the new facilities for the LCP. One of these requirements was in the area of reliability, in particular, the potential adoption of North American Electric Reliability Corporation (NERC) reliability standards and Northeast Power Coordinating Council (NPCC) regional reliability criteria.

There is a cost associated with adopting the NERC reliability standards and NPCC regional reliability criteria. A companion report titled "Cost Assessment – NERC Reliability Standards and NPCC Regional Reliability Criteria for Nalcor Energy" has been completed to provide a high level estimate of the cost to adopt and maintain compliance with these standards and criteria. The overall cost range using a 30% contingency was estimated to be $5,000,000 - $6,500,000 (amounts shown to the nearest $100,000). The cost range for the initial costs would be $4,000,000 - $5,200,000. The cost range for the ongoing annual costs would be $1,000,000 - $1,300,000 (in 2012 dollars).

This report identifies the benefits to Nalcor Energy (Nalcor) and its subsidiaries associated with adopting the NERC reliability standards and NPCC regional reliability criteria and a potential industry framework for reliability and compliance that could be adopted for NL.

In addition, the following assumptions have been made in this report.

1. Nalcor refers to Nalcor Energy and its subsidiaries, including its subsidiary company Newfoundland and Labrador Hydro (NLH).
2. NLH is used specifically when referring to the current operation of the island Bulk Electric System (BES) and parts of Labrador and Nalcor is used when referring to the LCP Phase 1 development.

1.1 Background

NLH has a mandate to deliver safe, reliable, least cost power to industrial, utility and direct customers in NL. In the area of reliability, NLH has developed its own operating guidelines and procedures that help ensure the reliability of the power system. As an example, NLH operates the system to an N-1 contingency criterion. This ensures that the power system can withstand the worst case single contingency event. This includes events such as the loss of a generator or transmission element.

In North America, NERC is responsible for developing and administering reliability standards. In the United States (US) these reliability standards are both mandatory and enforceable for utilities. In Canada, these reliability standards have been adopted or are in the process of being adopted by 8 of the 10 provinces. All of these provinces are interconnected to the North American power grid through various transmission systems both nationally and internationally (with the US).

The island power system is electrically isolated and therefore not connected to the North American grid. In this respect, NLH has not adopted the NERC reliability standards in a formal manner. In general, the concepts of the NERC reliability standards are being followed by NLH. The reliability guidelines and procedures developed meet many of the NERC reliability standard requirements. However, with the development of the LCP, NL will be interconnected with the North American grid and the potential adoption of NERC standards has to be considered.

1.2 Overview of NERC

NERC was established in 1968, by the electric utility industry, in response to a blackout that occurred in 1965. As well, Regional Reliability Organization's (RRO) were formalized under NERC, which included NPCC. Regional planning coordination guides were also formalized, which NERC maintained. NERC was originally named the National Electric Reliability Council until it changed its name to the North American Electric Reliability Council in 1981 to recognize Canada's participation. It further changed its name to what it is today in 2007 as it has a large membership base representing a cross-section of the industry.

In 2003, North America experienced its worst blackout ever as 50 million people lost power in the Northeastern and Midwestern US and Ontario. From this, a joint US-Canada task force was formed to investigate the cause of the blackout. In its final report, the task force concluded that the single most important recommendation for preventing future blackouts and reducing the scope of those that occur is for the US government to make reliability standards mandatory and enforceable.

In 2005, the US Federal Power Act (FPA) was amended to provide the legislative framework for the creation, implementation, monitoring and enforcement of mandatory reliability standards for the Bulk Power System (BPS) in the US by an Electric Reliability Organization (ERO) certified by Federal Energy Regulatory Commission (FERC).

In 2006, NERC filed an application with FERC to become the ERO in the US as well as to have 102 reliability standards adopted. NERC filed this same information with the Canadian provincial authorities in Alberta, British Columbia, Manitoba, New Brunswick, Nova Scotia, Ontario, Quebec and Saskatchewan and the National Energy Board of Canada for recognition as the ERO in Canada.

In 2007, FERC adopted 83 of the NERC reliability standards, which were the first set of legally enforceable standards for the US BES. Compliance, in the US, with these standards became mandatory later in 2007.

1.3 Overview of NPCC

NPCC is a not-for-profit corporation in the state of New York responsible for promoting and improving the reliability of the international, interconnected BPS in Northeastern North America. NPCC carries out its mission through:

a) The development of regional reliability standards and compliance assessment and enforcement of continent wide and regional reliability standards, coordination of system planning, design and operations and assessment of reliability.

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b) The establishment of regionally specific criteria, and monitoring and enforcement of compliance with such criteria.

NPCC provides the functions and services for Northeastern North America of a cross-border regional entity through its regional entity division, as well as regionally-specific criteria services for Northeastern North America through its criteria services division.

The NPCC geographic region includes the State of New York, the six New England states (Maine, New Hampshire, Vermont, Massachusetts, Rhode Island and Connecticut) and the Canadian provinces of Ontario, Quebec, New Brunswick and Nova Scotia. Overall, NPCC covers an area of nearly 1.2 million square miles, populated by more than 55 million people.

NPCC's regional entity division operates under a delegation agreement with the NERC. This agreement recognizes that NPCC meets the qualifications for delegation of certain roles, responsibilities and authorities of a cross-border regional entity as defined by Section 215 of the FPA in the U.S. and through Canadian provincial regulatory and/or governmental Memorandum of Understanding (MOU) or Agreements.

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2.0 Strategic Alignment

The foundation of Nalcor lies in its base business of the generation and transmission of electrical power, to ensure safe, reliable least cost power to its customers. Beyond the base business, Nalcor has expanded into the broader energy sector. Guided by the provinces energy plan, Nalcor is leading the development of the provinces energy resources. Based on this, the vision at Nalcor is to build a strong economic future for successive generations of Newfoundlanders and Labradorians.

Nalcor has put in place strategic goals to ensure the base business remains strong and the corporate vision is fulfilled. Safety is goal number one within the corporation. Other goals within the corporation are environment, business excellence, people and community.

The following sections discuss each of these goals and how adopting the NERC reliability standards and the NPCC regional reliability criteria align with them.

2.1 Safety

The Nalcor corporate goal for safety is "to be a world class safety leader". The safety of employees, visitors and the public is the number one priority. There is a relentless commitment to have a workplace where nobody gets hurt and a working environment where each and every employee is always concerned for their own safety and the safety of others.

Nalcor has in place a safety framework to achieve a safety performance to world class standards. There are many tools and processes in place as a part of this framework. Some examples of this are the Safe Workplace Observation Program (SWOP), Step Back 5x5, Safety Credo, Internal Responsibility System (IRS) and the Work Protection Code (WPC). Each of these have been developed or updated as part of the framework to achieve safety excellence within Nalcor.

Another component of the safety framework is to have an interdependent safety culture. Within the organization, the belief is that zero harm is sustainable. There is cooperation within and across teams, teams are fully engaged, you are your brothers/sisters keeper and employees demonstrate best in class safety leadership behaviors. In order to achieve this type safety culture, the organization has delivered safety culture training and a BeSafe safety coaching workshop.

Nalcor is also working towards implementation of the OHSAS 18001 standard. OHSAS 18001 is an international standard and is recognized as an effective Occupational Health and Safety Management System (OHSMS). The standard assists organizations in managing and controlling their health and safety risks and improving their OH&S performance.

2.2 Environment

The Nalcor corporate goal for the environment is "to be an environmental leader". Nalcor has in place a corporate wide framework outlining innovative, achievable answers for the provinces long term environmental sustainability and in the process becoming recognized in the industry as an environmental leader. In this context, Nalcor is developing the LCP which will reduce greenhouse gas

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emissions and make the provinces electricity supply 98% renewable. Nalcor also has in place alternative energy resources (wind, wind-hydrogen-diesel), species and habitant diversity programs and energy efficiency and conservations programs (takeCHARGE).

Nalcor maintains a high standard of environmental responsibility and performance through the implementation of a comprehensive Environmental Management System (EMS). The three key principles of Nalcor's EMS are the prevention of pollution, improve continually and comply with legislation.

Nalcor's EMS is ISO 14001 certified and provides the framework for the organizations environmental responsibilities. ISO 14001 is an internationally accepted, voluntary standard which describes specific requirements for an EMS. The certification is valid for 3 years and follow up external audits are completed annually. The ISO certification clearly demonstrates Nalcor's environmental commitment to its stakeholders and its ability to manage its environmental risks.

Through its long term sustainability framework, environmental programs and ISO 14001 EMS, Nalcor has demonstrated a clear commitment to the environment and demonstrating it is an environmental leader.

2.3 Business Excellence

The Nalcor corporate goal for business excellence is "through operational excellence, to provide exceptional value to all customers of our energy". Business excellence incorporates a number of concepts including finance, project execution and reliable cost of effective electricity supply and customer service. However another key component of business excellence that Nalcor has put a major focus on is asset management.

Asset management is the comprehensive management of asset requirements, planning, procurement, operations, maintenance and evaluation in terms of life extension or rehabilitation, replacement or retirement to achieve maximum value for the stakeholders based on the required standard of service to current and future generations. It is a holistic, cradle to grave lifecycle view on how assets are managed.

There are many drivers for excellence in asset management. Safety is a key driver such that it contributes in achieving Nalcor's goal of zero injuries and the need to ensure the safety of the employees, contractors, visitors and the general public at all times. Two other key drivers of asset management that are important to note are reliability and best practice adoption.

Reliability is of utmost importance to asset management. Nalcor's base business is the generation and transmission of electrical power. This service must be reliable to satisfy the requirements of the customers. Through the asset management process, the assets required for the base business are operated, maintained and renewed such that they are able to provide reliable service. Assets are operated in accordance with basis of design and operating parameters. Assets are maintained by ensuring preventative maintenance is completed, critical spares are obtained and rehabilitated to maintain acceptable service levels. Assets are renewed such that life extension strategies are

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considered before asset replacement decisions are made. In terms of reliability measures, NLH is currently a member of the Canadian Electricity Association (CEA). NLH sets reliability related targets each year and uses the CEA statistics for other utilities as a benchmark.

Best practice adoption is very important to asset management. Best practices are considered to be methods or techniques that have consistently shown results superior to those achieved with other means and that are used as benchmarks. They are used to maintain quality as an alternative to mandatory legislated standards and can be based on self-assessment or benchmarking. From this perspective, Nalcor promotes operational excellence through innovation and the pro-active adoption of best practices for all of their lines of business.

2.4 People

The Nalcor corporate goal for people is "to ensure a highly skilled and motivated team of employees who are strongly committed to Nalcor's success and future direction". Employees need to feel valued and be engaged in the direction of Nalcor. This requires leadership from all levels and employees that are skilled and performance focused.

One important objective of this goal is to improve all levels of employee engagement to a level where Nalcor would qualify for recognition as one of Canada's best employers. This would be measured to some acceptable external benchmark and maintained each year.

2.5 Community

The Nalcor corporate goal for community is "to be a valued corporate citizen in Newfoundland and Labrador". Corporate social responsibility is a key to Nalcor's ongoing relationship with their customers, their communities and the province as a whole. At all times, Nalcor strives to be a committed and innovative corporate citizen which sees the responsibilities to the province as paramount to their business.

Nalcor has in place a community investment program. Giving back to the communities of the province is a priority and every effort is given to improve the quality of life for people throughout the province. The community investments are focused on safety and health, education and youth, arts and culture and environment and conservation.

One important objective of this goal is to increase the percentage of the public who believe that Nalcor has a strong reputation. Overall, Nalcor's excellence in safety, environment and business excellence will strengthen the reputation as a progressive company and a valued corporate citizen.

2.6 Strategic Alignment with Nalcor goals and NERC reliability standards

Nalcor is striving to be the best in everything it does. Throughout all of Nalcor's goals, there are words used such as world class, leader, excellence, recognition and strong reputation that show a strong commitment to be a frontrunner in the utility industry.

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NERC reliability standards are considered to be the industry standard for ensuring the reliability of the BES in North America. The standards are mandatory in the United States and in some provinces in Canada. In the other provinces in Canada where they are not mandatory, they have adopted or are in the process of adopting the reliability standards (with the exception of Prince Edward Island and NL). As well, the National Energy Board (NEB) in Canada has made it mandatory for companies owning an International Power Line (IPL) to adopt and comply with NERC reliability standards. Overall, this shows that NERC reliability standards are the industry standard in North America.

In adopting the NERC reliability standards, there would be an alignment with Nalcor's strategic direction and goals. The key areas that demonstrate this are best practice adoption, compliance and recognition/reputation of the company.

Adopting NERC reliability standards can be considered best practice adoption that is outlined in business excellence and more specifically, asset management. The standards have been developed by NERC through direct input from utility industry professionals. Considering this, the reliability of the BES is considered by the industry to be maintained with the best results by adopting the NERC reliability standards. Essentially, NERC reliability standards are the benchmark for reliability standards.

An important component of NERC reliability standards is compliance. In adopting the reliability standards, compliance with the requirements will help with improving reliability (this is discussed in section 2.0). Compliance with reliability standards can be assessed by audits completed by an outside entity. This compliance aspect is shown in Nalcor's environmental EMS. The EMS is ISO 14001 certified and must go through compliance specifications to maintain this certification. As well, while Nalcor has a clear, relentless commitment to safety, it is also looking to implement an OHSAS 18001 standard which would require a compliance component.

While Nalcor's base business remains the same, it has expanded into other areas of energy development in the province. The province promotes itself as having an energy warehouse with Nalcor playing a significant role in developing the resources. In essence, Nalcor (and the province) has become a significant player in the energy industry. Hence, it has to have a solid reputation and be recognized throughout the industry.

Compliance with NERC reliability standards can also enhance the reputation of Nalcor. As discussed, the NERC reliability standards are used throughout the utility industry. With the BES in NL being interconnected, there is an added responsibility to not impact on the reliability of the North American BES. In this light, adopting the NERC reliability standards demonstrates a commitment to the reliability of the North American BES. With the adoption of NERC standards, Nalcor will be recognized as a leader and have the reputation of a strong commitment in the area of reliability.

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3.0 Benefits – NERC reliability standards and NPCC regional reliability criteria

In adopting the NERC reliability standards and NPCC regional reliability criteria, there are a number of clear benefits that would be gained by the province of NL. These benefits are

1. Implementing clear, consistent and technically sound standards.
2. Consistency with other jurisdictions in Canada.
3. Ensuring reliability is maintained and improved by implementing compliance measures and;
4. Shaping the content and efficiency of the standards to improve reliability.

The following sections discuss each of these benefits in more detail.

3.1 Implementing clear, consistent and technically sound standards

Reliability standards that are clear, consistent and technically sound form the foundation of NERC's efforts to help maintain and improve the reliability of North America's BES.

NERC reliability standards are the planning and operating rules that electric utilities follow to ensure system reliability. These standards are developed by the industry using a balanced, open, fair and inclusive process. They must be just and reasonable, not unduly discriminatory or preferential and in the public interest. Participation by industry experts in the standards development process ensures that the standards are technically sound, fair and balanced. The standards development process is accredited by the American National Standards Institute (ANSI).

Reliability is a key goal for NLH as outlined in its mandate to deliver safe, reliable, least cost power to its end-use customers. NLH does have in place both planning and operating criteria that are being followed to ensure the reliability of the island interconnected system and portions of Labrador. However, these criteria are not fully documented as a set of reliability standards in the same context as the NERC reliability standards.

Adopting the NERC reliability standards would provide the benefit to Nalcor of having a set of standards that have been developed by the utility industry. They are used throughout the industry and are generally considered to be a part of adhering to Good Utility Practice. Again, the key is that industry has the final say on the reliability standards and the input on standard development would come from experts and years of experience in the industry.

While the NERC reliability standards are developed to maintain and improve the reliability for the North American BES, there could be similar reliability improvements for the BES in NL. The key areas would be in protection and control, facilities maintenance and personnel training and qualifications.

3.1.1 Protection and Control

Protection systems are a key component of the BES. They are designed to protect the BES equipment from possible failure and to limit the effect of contingencies on the BES. In essence, they are designed to maintain the reliability of the BES during contingencies. However, for protection systems to be

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effective, they not only must be designed properly but maintained and tested to ensure they continue to function as expected.

NLH has a protection and control department that is responsible for the design of the protection systems. They also are responsible for disturbance monitoring equipment and assisting with analysis of protection system operations. The maintenance and testing of the protection systems is completed by transmission and rural operations (TRO). While all of this is in place, there could be improvements to reliability as a result of the following:

<u>Maintenance and Testing</u>

There are a number of NERC reliability standards and an NPCC directory that have requirements for maintenance and testing of protection systems. These include both transmission and generator protection. NLH does perform maintenance and testing on these systems but there could be performance improvements due to standards requirements on frequency and potentially to the inclusion of systems that may not be tested currently.

<u>Special Protection Systems (SPS)</u>

NLH does not currently have any SPS's. However, LCP development will require implementation of SPS's to protect against certain contingencies. There are NERC reliability standards and an NPCC directory that have requirements for SPS review, assessments, maintenance and testing. These standards are developed by the industry which would constitute experience and knowledge in this area. There would be benefits from these standards to ensure the SPS are designed and maintained properly to ensure correct operation.

<u>Disturbance Monitoring</u>

There is a NERC reliability standard that has requirements for disturbance monitoring equipment. In particular, there are requirements to monitor certain BES elements (i.e. transmission lines, transformers) such that faults are recorded and information on a contingency event is retained. There are also requirements on the capability and the maintenance and testing of the equipment.

While NLH currently has fault recording equipment in the majority of its terminal stations, there could be some improvements gained in reliability due to adopting this standard. The main reason for this is that there could be more information obtained due to increased monitoring to ensure events are analyzed in the most detailed manner. As well, it could improve the maintenance and testing of the fault recording equipment to ensure the equipment captures the information when required.

3.1.2 Facilities Maintenance

The potential reliability benefit to the NL BES due to facilities maintenance would be in the area of transmission vegetation management. The purpose of the NERC reliability standard on this is to "improve reliability of the electric transmission systems by preventing outages from vegetation located

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on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW and maintaining clearances between transmission lines and vegetation on and along ROW".

NLH currently has a vegetation management program in place but there would have to be changes made to it to meet the requirements of the NERC reliability standard. However, by making the changes to the program, the NL BES could benefit from a reliability perspective as it could improve on the outages currently caused by vegetation. The changes to the program would include a more formalized plan and increasing the amount and type of inspections.

3.1.3 Personnel Training and Qualifications

There are NERC reliability standards that have requirements for personnel responsible for operating the BES. Personnel must have a valid certificate either as a Reliability Coordinator, Transmission Operator or Balancing Authority. The responsible personnel must then maintain this certification through a continuing education program.

NLH currently has a training program in place for its operators. Once they are qualified through this program to operate the BES, there is a continuing training program in place that uses simulation training to ensure the operators remain skilled to respond to system events.

While the training program ensures that the operating personnel are competent to operate the BES, there could be some benefits to having its operating personnel having NERC certification. In particular, it would ensure that the operating personnel are trained in all concepts relating to NERC reliability standards. This will be very important once interconnected as operating in an interconnected environment would be very different than the isolated environment in which they currently operate. They would be dealing with other jurisdictions and any operations dealing with the interconnection could affect the reliability on the NL BES. In addition, it would offer consistency with other jurisdictions. This is discussed further in the next section.

3.2 Consistency with other Canadian provinces

NERC filed applications with 8 provincial authorities to be recognized as the ERO. It also filed the reliability standards to be adopted. While NERC does not have jurisdiction in Canada, these provinces have either adopted or are in the process of adopting all or some of the NERC reliability standards. In North America, the NERC reliability standards have essentially become the industry standard for utilities to ensure reliability of the power grid.

In Canada, regulation of electricity and the development and enforcement of reliability standards is primarily within provincial jurisdiction. Each province has differed in their approach to the adoption of reliability standards, registering as functional entities and memberships in NERC and their respective RRO's. Detailed information and summary for each province can be found in Appendix B.

While the approach is somewhat different in each case, the underlying commonality is that each province has accepted NERC as the ERO responsible for maintaining and improving reliability on the

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North American BES. Hence they have acknowledged the potential benefits of adopting the reliability standards.

The same can be said in the case of NL. The island and Labrador will be connected to North America. So there is understanding that events on the BES in NL will not impact the greater interconnection. Once NL is interconnected, Nalcor would want the same understanding that the other systems are operated to the highest reliability standards. It can then be stated that NERC reliability standards is the accepted measure. This becomes even more important once Gull Island, phase 2 of the LCP is developed.

As well, for the operating personnel responsible for the NL BES, there is benefit to operate to a common set of reliability standards when dealing with interconnection operations. In essence, it is being able to talk the same language with other jurisdictions and have a common understanding when it comes to reliability standards. This is particularly important when dealing with the provinces of Nova Scotia and Quebec and other areas which receive energy from NL. Some areas of the reliability standards that a common understanding would be very important are communication, emergency preparedness and operations, interchange scheduling and reliability/transmission operations.

3.3 Compliance with reliability standards

Reliability standards are a key part of ensuring that the BES is operated in a reliable manner. As indicated, adopting and following NERC reliability standards and NPCC regional reliability criteria on their own will provide benefits. However, implementing a compliance program will provide additional benefits to the province of NL.

Compliance is a key component for improving the reliability of the BES. A compliance program would ensure that the right practices are in place so that the likelihood and severity of future system disturbances are kept at an acceptable level.

Currently, there is no oversight authority for enforcing reliability standards in NL. While NLH has a mandate to deliver reliable power to its end-use customers, there is no requirement to show compliance with any reliability standards. For disturbances and outages affecting NLH customers, a report has to be filed with the Public Utilities Board (PUB). An investigation has to be completed as to the cause and a mitigation plan may be required. The utility has to act to mitigate the problem. This is also the case with Newfoundland Power (NP).

With the adoption of NERC reliability standards and NPCC regional reliability criteria, there would be clear benefits to implementing a compliance monitoring program. It would ensure utilities are complying with the reliability standards and are committed to maintaining and improving reliability. If there is a non-compliance concern, the oversight authority would ensure a mitigation plan is developed and implemented to improve reliability. The end-use customers in NL would benefit in that an oversight authority would ensure compliance and improvements and the process would be transparent, fair and consistent.

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3.4 NERC and NPCC Membership

Membership in NERC is open to all entities with an interest in the reliability of the BES. NERC members contribute their expertise with BPS planning and operations and participate in various NERC committees.

NERC members join one of twelve industry sectors and are eligible for selection as a sector representative on the NERC member representative committee. The committee elects the NERC independent trustees, votes on amendments to the bylaws and provides advice to the board with respect to the development of annual budgets, business plans and funding mechanisms and other matters pertinent to the purpose and operations of NERC. A list of industry sectors can be found in Appendix C.

NERC reliability standards are approved by a registered ballot body. They are then sent to the NERC board and then to applicable government authorities for their approval.

Any person or entity may join the registered ballot body to vote on reliability standards, whether or not such person or entity is a member of NERC. Each person or entity would then become eligible to be member of an industry segment to which they will be able to vote on reliability standards. A list of industry segments is contained in Appendix C.

The NERC standards committee consists of two representatives from each of the ten industry segments. Members are elected by the segment they represent. The standard committee reports to the NERC board of trustees and oversees the development of the reliability standards.

Membership in NPCC is defined under 2 categories

1. <u>General Membership</u> is voluntary and is open to any person or entity, including any entity participating in the Registered Ballot Body of the ERO that has an interest in the reliable operation of the Northeastern North American BPS. General Members that are also registered entities within the NPCC Region are subject to compliance with reliability standards, consistent with their registration, and are also entitled to receive additional services from the Regional Entity division of NPCC.
2. <u>Full Membership</u> shall be available to entities which are General Members that also participate in electricity markets in the international, interconnected BPS in Northeastern North America. Independent system operators ("*ISOs*"), regional transmission organizations ("*RTOs*"), Transcos and other organizations or entities that perform the Balancing Authority function (discussed in section 2.1.2) operating in Northeastern North America are expected to be Full Members of NPCC. The New York State Reliability Council and any other sub-regional reliability councils which may be formed are also expected to be Full Members. Full Members are subject to compliance with regionally-specific more stringent reliability criteria for their generation and transmission facilities on which faults or disturbances can have a significant adverse impact outside of the local area and which are identified utilizing a reliability impact-based

methodology. Full Members are also subject to compliance with reliability standards, and are entitled to receive additional services from the Criteria Services division of NPCC.

As well, members are eligible to vote in one of seven stakeholder voting sectors. On application for membership, a request shall be made for assignment to one of the sectors. A list of these sectors is contained in Appendix C.

If the NERC reliability standards and NPCC regional reliability criteria are adopted, it would also be beneficial to become members of both of these organizations. The main reason is that you have an input into the content of reliability standards and regional reliability criteria. The benefit to the province is it could improve reliability and have an impact on the efficiency and cost of implementing and complying with the standards and criteria.

Membership would also give the added benefit of being a part of task forces and operating committees that deal with system reliability. Being able to interact with other utilities and industry peers is very valuable to gain an understanding of any reliability issues they may have. It also provides the opportunity to share your own experiences and influence decisions based on this.

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4.0 Reliability Framework for NL

Other provinces in Canada have taken their own approach in the adoption of NERC reliability standards. The following sections outline an approach to reliability standards that could be adopted in NL if NERC reliability standards and NPCC reliability criteria were to be made mandatory. While the provincial government will make the final determination on the framework, this approach is considered to offer transparency in the adoption process and be consistent with other regulated activities in the province.

The reliability framework is generally described in terms of Nalcor only. However, the provincial government would also need to consider other utilities and entities operating within the province, particularly NP, when making a determination on the framework for the province. This is discussed later in this section.

4.1 Role of the Provincial Government and the Public Utilities Board

In other Canadian provinces, the provincial government has had direct involvement in shaping the direction of reliability standards for their province. In most cases, legislation was established or directives issued to allow for the adoption of reliability standards.

As well, a number of the provinces are using the provincial utilities boards to approve the reliability standards and oversee compliance. Where NLH presently has its activities regulated by the PUB, it would be appropriate for the PUB to have oversight on the adoption of reliability standards. It would also allow for potential public input which would provide transparency in the adoption process.

Therefore, the reliability framework outlined has the provincial government amending legislation such that the PUB will have oversight for the reliability standards that are being adopted in NL. To implement this there would have to be amendments to the NL Public Utilities Act.

4.1.1 Amendments to the Public Utilities Act

The Public Utilities Act would be amended to include a section on reliability standards. The primary requirement in the amendments would be to give the PUB the authority to approve reliability standards. The section would also contain the following requirements:

1. Define who submits the reliability standards to the PUB for approval
2. A process for the PUB to approve the reliability standards
3. A directive on who the reliability standards would apply

To outline who submits the reliability standards to the PUB, a definition of a standard making body would be used. The definition would specifically reference NERC and NPCC (or successor organizations) or generally reference an organization that has expertise in developing reliability standards.

In regards to the process for the PUB to approve the reliability standards, one approach could be as follows:

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1. NERC to file reliability standards for approval. The NERC reliability standards filed should only be the ones that have been approved by FERC. NPCC to file regional reliability criteria and any regional reliability standards for approval.
2. The PUB will direct Nalcor and other utilities (if applicable) to review and assess the filings. The assessment would include the following:
   a. Ensure that adopting the reliability standards and regional reliability criteria would maintain or improve the current level of reliability on the NL BES. The reliability standards and regional reliability criteria should have requirements that are as or more stringent than what is currently being adhered.
   b. The functionality of the reliability standards and regional reliability criteria. This refers to reviewing the requirements in the reliability standards and regional reliability to ensure they are aligned with the current and future operating requirements for the NL BES.
   c. The potential cost of the reliability standard or regional reliability criteria if it were adopted. This would include one-time capital costs and requirements for ongoing costs.
3. Once the assessment is completed, it would be submitted to the PUB with a recommendation to do one of the following for the reliability standards or regional reliability criteria:
   a. Approve and adopt.
   b. Reject as not applicable.
   c. Remand back to NERC or NPCC. This may be done if there is another version on the horizon and it would make sense to wait to review at a later time.
4. Once the PUB receives the assessment, it would be posted for public review for a specified period. Interested parties would be able to submit comments on the assessment reports and a hearing on the matter can be requested.
5. The PUB would then make a final decision. It should follow the recommendations of the assessment unless it is determined from the public comments (as received) and/or public hearing that
   a. The assessment is not technically sufficient or
   b. Is not in the public interest (Cost vs. Benefit).

The benefit to using this approach is that it provides clear oversight and transparency to the reliability standards adoption process. It would provide provisions for public input and it would ensure that only the reliability standards that would provide benefit to the province would be adopted.

In addition to the approval process, a directive would be required in the amendments to outline who the reliability standards would apply. This directive is required to ensure that the reliability standards would only apply to certain utilities operating in the province. This directive can be approached as follows:

1. State that the reliability standards and regional reliability criteria will only apply to specific utilities operating in the province or

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2. Designate specific applicability to owners and operators of facilities on the BES. Some examples of this could include but are not limited to:
   - Owner or operator of a transmission facility of 230 kV or above
   - Owner or operator of a generation unit that is greater than 40 megavolt amperes (MVA) gross nameplate rating and is directly connected to the BES.
   - Owner or operator of a generation facility with a combined nameplate rating of greater than 95 MVA and is directly connected to the BES.

4.2 MOU – NERC, NPCC, NLH/Nalcor and provincial government/PUB

MOU development is also a key component to a reliability framework. This is required such that there is a clear understanding and expectations of all parties. The MOU's would be developed between:

1. NERC, NPCC and the PUB (or the provincial government on behalf of the PUB).
2. NERC, NPCC and Nalcor.

It could also include other utilities as determined by the reliability framework.

The MOU's would address, but not be limited to the following:

1. Acknowledgement of the intent of the MOU.
2. Acknowledgement of the signatories of the MOU and what they represent.
3. Acknowledgement that Nalcor will comply with reliability standards and regional reliability criteria once adopted by the PUB.
4. Responsibilities of all parties once the reliability standards and regional reliability criteria have been filed for adoption.
5. Agreement that Nalcor can use NERC and NPCC as required in the assessment process.
6. Roles of all parties if there is stakeholder participation required in the process of adopting the reliability standards and regional reliability criteria by the PUB.
7. Potential compliance requirements for all parties.
8. Funding of NERC and NPCC.
9. Amendment and/or termination requirements of the MOU.

4.3 Impact of reliability framework on NP

NP owns and operates high voltage transmission lines (138 kV and 66 kV) and hydro/thermal generation (20 MVA and below) within the province. They have the largest customer base for providing electricity in the province. They also are regulated by the PUB.

With regards to NERC reliability standards and Functional Entities, NP has some similar reliability related roles as NLH. For example, they would be a Transmission Owner (TO), Transmission Operator (TOP), Load Serving Entity (LSE) and Distribution Provider (DP). There is also much coordination with NLH regarding reliability related issues and ensuring the customer demand is continually met.

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The number of reliability standards to be adopted by NP would be less than Nalcor due to reliability related roles. While it should be noted that problems with these facilities are not anticipated to impact the reliability of other jurisdictions in North America, reliability benefits to the province could be gained if NP were to adopt the reliability standards. The benefits would be similar to the ones described earlier in this report.

The costs to NP to adopt the reliability standards have been briefly looked at in the companion report "Cost Assessment – NERC Reliability Standards and NPCC Regional Reliability Criteria for Nalcor Energy". It was completed as a proration of the cost to Nalcor based on the size of the utility and the roles it would undertake based on the NERC criteria. In this respect, it is not a detailed analysis.

Given the above information, the provincial government should consider NP when determining the reliability framework and which entities the reliability standards will apply.

4.4 Impact of reliability framework on other utilities and entities in NL

Within the province of NL, there are other utilities and entities that own and operate both transmission and generation assets. NP has been previously described. The other utilities and entities are Deer Lake Power, Corner Brook Pulp and Paper, Exploits Generation, Algonquin Power and wind farms.

Deer Lake Power owns and operates high voltage transmission lines (66 kV) and hydro generation. The primary generation that operates into the BES has an approximate overall capacity of 93 MVA with the largest unit being approximately 12 MVA. There is also an 18 MW cogeneration facility that is owned and operated by Corner Brook Pulp and Paper.

Exploits generation is owned by the province of NL but operational responsibility has been assumed by Nalcor. Exploits generation has an installed capacity of approximately 95 MVA with the largest unit being approximately 30 MVA. This is all hydro generation.

Algonquin Power own and operate a 4 MW hydro generating facility located in Rattle Brook. The facility is a run of the river plant. NLH has a Power Purchase Agreement (PPA) in place with Algonquin Power for this facility.

There are also wind farms in the province of NL which are located in St. Lawrence and Fermeuse. NLH has a PPA in place with each of these facilities. Each wind farm has an overall capacity of 27 MW and has nine wind turbines. Each turbine has a 3 MW capacity.

While each of these utilities and entities has a role in supplying and providing electricity in the province, it is not anticipated that problems with these facilities will impact the overall reliability of the interconnection to North America. In addition, unlike Nalcor and potentially NP, the benefit to the province would not be of the same magnitude for maintaining and improving reliability. This is primarily due to the size of the facilities and the role they have in reliability. However, since the provincial government will determine the reliability framework, consideration should be given to including these utilities and organizations.

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5.0 Compliance monitoring and enforcement

An important piece of adopting the NERC reliability standards and NPCC regional reliability criteria is to ensure compliance. A compliance program would help ensure that the reliability of the BES is sustained once adoption is complete. More specifically, a compliance program would help ensure that the right practices are in place so that the likelihood and severity of future system disturbances are kept at an acceptable level, while recognizing that no standards or enforcement process can fully prevent all such disturbances from occurring. Compliance was outlined as a benefit earlier in this report.

The following sections discuss the NERC compliance monitoring and enforcement program and the potential implementation of a compliance monitoring and enforcement program for NL.

5.1 NERC compliance monitoring and enforcement program

NERC has in place a Compliance Monitoring and Enforcement Program (CMEP). This program is administered by the RRO's on behalf of NERC based on delegation agreements with each one.

The CMEP has three key activities. They are as follows:

1. Compliance Monitoring
   - The process used to assess, investigate, evaluate, and audit in order to measure compliance with NERC standards.
2. Compliance Enforcement
   - The process by which NERC issues sanctions and ensures mitigation of confirmed violations of mandatory NERC reliability standards. The violations that are determined are based heavily upon the Violation Risk Factors and Violation Severity Levels of the standards requirements violated and the violations duration.
3. Due Process
   - This provides registered entities the opportunity to contest any finding of a violation of a NERC reliability standard. The process allows for hearings at the regional entity and appeals before NERC. Further appeals may be possible at the appropriate governmental authority.

Each province in Canada, that has adopted or is in the process of adopting the NERC reliability standards, has implemented some form of compliance monitoring program. In some cases, they have developed their own program while others use the CMEP in place by NERC. However, the one distinction is that the programs in Canada do not use the NERC enforcement or due process components of the program.

In Canada, NERC does not have jurisdiction. Therefore, it cannot impose sanctions on entities as outlined in their CMEP. To that extent, the majority of jurisdictions in Canada do not impose sanctions for violations of the reliability standards. The exceptions to this are Alberta, Quebec and New Brunswick where there can be potential monetary penalties imposed.

5.1.1 Potential compliance monitoring program for NL

For the province of NL, the provincial government would determine the requirements for compliance with reliability standards and regional reliability criteria. In general, a compliance program would consist of the following:

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1. Compliance Audits
2. Self-Certification
3. Spot-Checking
4. Self-Reporting
5. Periodic Data Submittals
6. Exception Reporting

The majority of the components outlined above involve an outside entity for audits and reporting. As mentioned, this is typically done by the RRO. In the case of NL, this would be NPCC. However, as noted, the involvement of the RRO may not be required, as determined by the provincial government.

5.1.2 Potential enforcement of reliability standards for NL and role of the PUB

As discussed, each province handles compliance monitoring and enforcement somewhat differently. However, in many cases, the entity responsible for compliance, enforcement and ensuring mitigation plans is the utilities board within the province. Some examples of this are Nova Scotia and British Columbia.

For the province of NL, the PUB could be responsible for ensuring compliance with reliability standards and regional reliability criteria. However, the provincial government would determine the level and potential process for enforcement, which may also include monetary penalties.

In general, a process for enforcement involving a utilities board would be as follows:

1. RRO would make recommendations to the utilities board as to whether there has been a violation of a reliability standard or regional reliability criteria. The RRO can identify the appropriate reliability standard or regional criteria for which the violation has occurred. The RRO would also inform the company of the alleged violation.
2. The utilities board would review this recommendation with the information provided by the RRO. This review would be held under the utilities board direction. The utilities board would determine if a violation has occurred or not. Under this review, the company can make a submission on this as required.
3. If it is determined that a violation has occurred, a notification would be sent to the company confirming the violation.

As well, if a violation of a reliability standard or regional reliability criteria has been confirmed, the utilities board would require the company to develop and submit (to the RRO and the utilities board) a mitigation plan to address the violation. The mitigation plan should include the following:

1. Plan to correct the confirmed violation.
2. Plan to prevent recurrence of the confirmed violation.
3. Impact of the mitigation plan on the BES reliability.

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4. A timetable for completion of the mitigation plan. This would include when the confirmed violation would be corrected.

5.1.3 Violation Risk Factors and Violation Severity Levels

Within the reliability standards, NERC has defined Violation Risk Factors (VRF's) and Violation Severity Levels (VSL's) for the standards requirements.

Both the VRF's and the VSL's are used to assist in determining the penalty (monetary) amounts for particular violations in the US. In Canada, most provinces do not have monetary penalties. This could be the case in NL as well, depending on how the provincial government determines compliance requirements. So in this respect, the VRF's and VSL's would not have applicability to the enforcement of reliability standards.

However, the VRF's and VSL's could be beneficial to a compliance program if there has to be a review of a potential violation of a reliability standard. From an informational and guidance point of view, it would help in the understanding of the seriousness of the violation and what actions should be identified in the mitigation plan to address the violation.

More detailed information can be found on VRF's and VSL's in Appendix D.

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6.0 Recommendations

Based on the assessment that has been completed in this report with regards to NERC reliability standards and NPCC regional reliability criteria, the following is recommended:

1. Nalcor adopt some or all of the NERC reliability standards that were determined to be required or optional in the companion report "Cost Assessment – NERC Reliability Standards and NPCC Regional Reliability Criteria".

   There is clear strategic alignment with adopting the NERC reliability standards and the direction and goals of Nalcor. This was detailed in the report for all the Nalcor corporate goals.

   There are a number of clear benefits that would be gained for the province of NL which are:

   1. Implementing clear, consistent and technically sound standards.
   2. Consistency with other jurisdictions in Canada.
   3. Ensuring reliability is maintained and improved by implementing compliance measures and;
   4. Shaping the content and efficiency of the standards to improve reliability.

2. Nalcor adopt the NPCC regional reliability criteria and determine the facilities that these criteria would apply.

   The same clear benefits would be gained for the province as with adopting the NERC reliability standards.

   A BPS assessment should be completed and discussions with NPCC held, to determine which facilities on the NL BPS that these criteria apply.

3. Nalcor become a member of NERC and NPCC to ensure maximum benefits are gained from adopting the reliability standards and regional reliability criteria.

   Once the NERC reliability standards and NPCC regional reliability criteria are adopted, having an input into the content is very important. The benefits to the province are it could improve reliability and have an impact to the efficiency and cost of implementing and complying with the standards and criteria.

   Membership would also give the added benefit of being a part of task forces and operating committees that deal with system reliability. Being able to interact with other utilities and industry peers is very valuable to gain an understanding of any reliability issues they may have. It also provides the opportunity to share your own experiences and influence decisions based on this.

4. Nalcor develop an implementation plan for the NERC reliability standards and NPCC regional reliability criteria.

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This would be required to ensure Nalcor would be in a position to be compliant with the reliability standards and regional reliability criteria once the province is interconnected.

The implementation plan would include consultations with government to ensure alignment, discussions with NERC and NPCC to finalize the adoption of standards and criteria and to ensure alignment with roles and responsibilities and engaging consultants to review reports and completing mock audits in the future.

5. The provincial government should determine the reliability framework and compliance program for NL.

   This report outlines a potential reliability framework and compliance program for the province of NL. The provincial government would decide on how to implement the reliability framework. The reliability framework and compliance program outlined has the PUB having a significant role. Also, there may be potential legislation changes and MOU development between the parties (i.e. Nalcor, government/PUB, NERC and NPCC). The government would also need to determine how the reliability framework applies to other utilities and entities operating in the province

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7.0 Conclusion

This report outlines the benefits associated with adopting NERC reliability standards and NPCC regional reliability criteria. It also presents a reliability framework and compliance program for the province of NL.

Based on these benefits and the cost assessment (reference companion report titled "Cost Assessment – NERC Reliability Standards and NPCC Regional Reliability Criteria"), it was determined that Nalcor move forward with adopting the reliability standards and regional reliability criteria. By doing this, there are clear benefits that could improve reliability for the province of NL. The provincial government should also determine the reliability framework and compliance program for NL. The framework outlined in the report outlines the PUB having oversight on reliability for the province. The end-use customers in NL would benefit in that oversight authority would ensure compliance and improvements and the process would be transparent, fair and consistent. Consideration should also be given by government for requirements for other utilities and entities operating in the province when determining the reliability framework and compliance program.

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Appendix A – Abbreviations and Definitions

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Abbreviations

Abbreviation	Definition
ANSI	American National Standards Institute
BES	Bulk Electric System
BPS	Bulk Power System
CEA	Canadian Electricity Association
CF(L)Co	Churchill Falls (Labrador) Corporation
CMEP	Compliance Monitoring and Enforcement Program
DP	Distribution Provider
ERO	Electric Reliability Organization
ECA	Energy and Capacity Agreement
EMS	Environmental Management System
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act (US)
HQ	Hydro Quebec
HQP	Hydro Quebec Production
HQTE	Hydro Quebec TransEnergie
IRS	Internal Responsibility System
IPL	International Power Line
kV	Kilovolt
LIL	Labrador Island Link
LTA	Labrador Transmission Assets
LSE	Load Serving Entity
LCP	Lower Churchill Project
ML	Maritime Link
MVA	Megavolt Ampere
MW	Megawatt
MOU	Memorandum of Understanding
MF	Muskrat Falls
NEB	National Energy Board
NL	Newfoundland and Labrador
NLH	Newfoundland and Labrador Hydro
NP	Newfoundland Power
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OHSMS	Occupational Health and Safety Management System
PPA	Power Purchase Agreement
PUB	Public Utilities Board
RRO	Regional Reliability Organization
RTO	Regional Transmission Organization
SWOP	Safe Work Observation Program
SPS	Special Protection System
TOP	Transmission Operator

Abbreviation	Definition
TO	Transmission Owner
US	United States
VRF	Violation Risk Factor
VSL	Violation Severity Level
WPC	Work Protection Code

Definitions:

Bulk Electric System – The electrical generation resources, transmission lines, and interconnections with neighbouring systems and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.

Bulk Power System – The interconnected electrical systems within north-eastern North America comprised of system elements on which faults or disturbances can have a significant adverse impact outside of a Local Area.

Canadian Electricity Association – The national forum and voice of the evolving electricity business in Canada. The association contributes to the regional, national and international success of its members through the delivery of quality value added services.

Energy and Capacity Agreement – The agreement between Nalcor and Emera relating to the sale and delivery of energy to Nova Scotia.

Federal Energy Regulatory Commission – The United States federal agency with jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing and oil pipeline rates. It also reviews and authorizes liquefied natural gas terminals, interstate natural gas pipelines and non-federal hydro power projects.

Functional Entity – A class of entity that carries out reliability tasks within the Functional Model.

Good Utility Practice – Those project management, design, procurement, construction, operation, maintenance, repair, removal and disposal practices, methods, and acts that are engaged in by a significant portion of the electric utility industry in Canada during the relevant time period, or any other practices, methods or acts that, in the exercise of reasonable judgment in light of the facts known at the time a decision is made, could have been expected to accomplish a desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be the optimum practice, method, or act to the exclusion of others, but rather to be a spectrum of acceptable practices, methods, or acts generally accepted in such electric utility industry for the project management, design, procurement, construction, operation, maintenance, repair, removal and disposal of electric utility facilities in Canada. Good Utility Practice shall not be determined after the fact in light of the results achieved by the practices, methods or acts undertaken but rather shall be

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determined based upon the consistency of the practices, methods, or acts when undertaken with the standard set forth in the first two sentences of this definition at such time;

International Power Line – Transmission line built for the purpose of transmitting electricity from or to a place in Canada from or to a place outside Canada.

Labrador Island Link – The transmission facilities to be constructed by or on behalf of the Labrador Island Link Limited Partnership from central Labrador to Soldiers Pond, NL.

Labrador Island Link Limited Partnership – A subsidiary of Nalcor Energy which will have majority ownership of the LIL.

Labrador Transmission Assets – The transmission facilities to be constructed by an affiliate of Nalcor between the Muskrat Falls plant and the generating plant located at Churchill Falls.

Memorandum of Understanding – A document that describes the general principles of an agreement between parties, but does not amount to a substantive contract.

National Energy Board – An independent federal agency established in 1959 by the Parliament of Canada to regulate international and interprovincial aspects of the oil, gas and electric utility industries. The purpose of the NEB is to regulate pipelines, energy development and trade in the Canadian public interest.

Public Utilities Act – An act established in NL which guides the operation of the PUB and utilities operating in NL.

Regional Reliability Organization – An entity that ensures a defined area of the Bulk Electric System is reliable, adequate and secure. The Regional Reliability Organization is a member of NERC and can serve as the Compliance Monitor.

Regional Transmission Organization – An entity that is independent from all generation and power marketing interests and has exclusive responsibility for grid operations, short-term reliability, and transmission service within a region.

Special Protection System – An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) Underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). These are also called Remedial Action Schemes.

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Appendix B – Summary of Canadian Provinces reliability models

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British Columbia

In 2007, the British Columbia government released an Energy Plan which stated:

"Because our transmission system is part of a much larger, interconnected grid, we need to work with other jurisdictions to maximize the benefits of interconnection, remain consistent with evolving North American reliability standards, and ensure British Columbia's infrastructure remains capable of meeting customer needs."

To address this need, the provincial government made an amendment to the Utilities Commission Act which gave British Columbia the legal framework to make Reliability Standards mandatory and enforceable. The amendment gave the British Columbia Utilities Commission (BCUC) the exclusive jurisdiction to determine whether a reliability standard is in the public interest and should be adopted in BC. As part of the adoption process, BC Hydro must review each Reliability Standard and provide a report to the commission assessing

a) any adverse impact of the reliability standard on the reliability of electricity transmission in British Columbia if the reliability standard were adopted
b) the suitability of the reliability standard for British Columbia
c) the potential cost of the reliability standard if it were adopted
d) any other matter prescribed by regulation or identified by order of the commission

As well, as part of the amendment, a regulation was issued by the Minister responsible for the BCUC which establishes that the reliability standards adopted will apply to every "prescribed owner, operator and direct user of the bulk power system" and every "prescribed generator and distributor of electricity".

In June 2009, 103 Reliability Standards were adopted and are mandatory and enforceable. There is also a compliance monitoring program in place for the province. The Western Electricity Coordinating Council (WECC), which is an RRO, has been established as Administrator of the program. It should also be noted that the province, the BCUC or any of the utilities in British Columbia, do not have a Memorandum of Understanding (MOU) with NERC. It considers its membership with WECC as the cornerstone of its reliability

Alberta

As part of the Alberta Transmission Regulation, reliability standards in Alberta are mandatory and enforceable to the extent they are adopted by the Alberta Electric System Operator (AESO). The reliability standards that apply are NERC and WECC and they are known as the Alberta Reliability Standards (ABR).

The process of adopting the reliability standards involves the AESO consulting with Market participants and completing a detailed review of each standard. As applicable, amendments can be made to the standards such that they comply with the unique Alberta operational requirements and Alberta law. The AESO then makes a recommendation to the Alberta Utilities Commission (AUC) to accept or reject them. The AUC must follow the recommendation unless an interested person satisfies the AUC that the recommendation is

a) technically deficient, or
b) not in the public interest

Currently, there are 42 ARS reliability standards that have been adopted by the AUC in Alberta. Another 42 NERC/WECC standards have gone through the adoption process and have been rejected as they were deemed not to be applicable in Alberta. The AESO is responsible for monitoring compliance of market participants with regards to the ARS and has established a compliance monitoring program. There is an agreement with WECC which outlines their role in monitoring the AESO with regards to the ARS. The AUC also has specific financial penalties for non-compliance with the reliability standards.

It should also be noted that an MOU is established between the AESO, WECC and NERC outlining commitment to reliability and respective roles.

<u>Saskatchewan</u>

The bulk power system in Saskatchewan is operated by SaskPower (SPC). In 2004, SPC committed to formally adopt NERC Reliability Standards. Given the lack of a quasi-judicial regulator and the small size of the Saskatchewan jurisdiction, the current approach is to utilize the current Power Corporation Act's unambiguous Authorities to set and enforce Reliability Standards for the electric system. The term "Saskatchewan Authority" refers to the framework of oversight adopted by SPC within the formal legislative authority of SPC.

Typically NERC Board of Trustees approved Reliability Standards shall be viewed as being automatically adopted in Saskatchewan, unless

a) a particular standard has been remanded by any jurisdiction
b) as a result of a Saskatchewan Authority review, a standard may be remanded back to NERC or set aside by the Saskatchewan Authority, or a variance has been duly requested by SPC through the NERC rules or the Saskatchewan Authority chooses to set aside a standard for other reasons

Once a reliability standard is adopted, and not remanded, challenged, or set aside, compliance with the reliability standard is required. The oversight unit within SPC is the monitoring, compliance and enforcement authority for the province, as per their legislative authority.

It should also be noted that an MOU (and respective processes) was developed and signed by the Midwest Reliability Organization (MRO), SPC, and NERC in March 2009. To the degree practicable SPC will utilize NERC and MRO almost in an audit role and Saskatchewan retains all formal authority.

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<u>Manitoba</u>

The bulk power system in Manitoba is operated by Manitoba Hydro. Manitoba Hydro is currently required to comply with NERC Reliability Standards through its membership in the MRO and its membership in NERC, subject to exceptions based on provincial law.

The Manitoba Hydro Act (2004) authorized Manitoba Hydro to join the MRO and adopt its Reliability Standards (and hence NERC Standards) and requirements. This was approved by the province through an order of council subject to the exception that MRO/NERC Reliability Standards are not binding on Manitoba Hydro to the extent suspended, disallowed or remanded by the Lieutenant Governor in Council.

In June 2008, an Interim Agreement on Compliance Enforcement and Monitoring was reached between Manitoba Hydro, NERC and MRO. The Public Utilities Board (Manitoba) would be responsible for determining violations of Reliability Standards and imposing sanctions, upon recommendation by MRO and/or NERC. In February 2009, the government passed an order that the Public Utilities Board (Manitoba) has the authority to carry out the responsibilities defined in the interim agreement.

In June 2009, The Manitoba Hydro Amendment and Public Utilities Board Amendment Act (Electrical Reliability) was passed by the Manitoba legislature. The Bill establishes the framework for the adoption and enforcement of Reliability Standards.

<u>Ontario</u>

The Electricity Act, 1998 (Ontario) established the Independent Electricity System Operator (IESO). The IESO oversees the reliability of the power system in Ontario and operates the province's electricity markets.

Compliance with the market rules (and thus with NERC Reliability Standards) is a condition of license from the Ontario Energy Board (OEB) for each market participant and the IESO. NERC Reliability Standards therefore currently have effect in Ontario under the market rules, subject to the provisions of the market rules and of applicable legislation. A process is in place whereby the OEB can initiate a review, remand, and revoke the application of NERC Reliability Standards in Ontario. As well, a review process is in place by the OEB for the adoption of reliability standards.

In terms of compliance, the IESO is the sole entity in Ontario accountable to NERC for compliance with NERC reliability standards applicable to Ontario for both the IESO and Ontario market participants. The IESO is subject to NERC's compliance monitoring and enforcement processes. The IESO is also the sole entity in Ontario accountable to the NPCC for compliance with NPCC regional reliability criteria applicable to Ontario. As well, the IESO itself is subject to the compliance monitoring and enforcement processes. The IESO also has authority to impose financial penalties for non-compliance with market rules (and thus reliability standards).

It should also be noted that an MOU was developed and signed between the OEB and NERC in April of 2006. As well, another MOU was developed and signed by the IESO, NPCC and NERC in November 2006.

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Quebec

In 2006, the Quebec government adopted legislation (Bill 52) to give the Regie de l'energie du Quebec (Regie) jurisdiction regarding mandatory Reliability Standards in Quebec. An amendment was passed to this bill in 2010 which gives the Regie clear authority for mandatory electric Reliability Standards and to give formal authority for their enforcement.

In 2007, the Regie designated Hydro Quebec TransEnergie (HQT) as Reliability Coordinator (RC) for Quebec. Per the legislation, the RC must

a) carry out any duties devolved to it under a Reliability Standard adopted by the Regie and issue operating directives
b) file with the Regie the Reliability Standards proposed by a recognized reliability body with which the Regie has entered into an agreement and any variant or other Reliability Standard that the RC considers necessary
c) file an evaluation of the relevance and impact of the Reliability Standards
d) submit to the Regie, for approval, a Register identifying the registered entities that are subject to the reliability standards adopted by the Regie

With respect to the adoption of Reliability Standards, the Regie may request the RC to modify a Reliability Standard filed or submit a new one, on the conditions it sets, adopt Reliability Standards and set the date of their coming into force.

In June 2009, the RC filed an application with the Regie seeking the adoption of 95 reliability standards applicable to Quebec. These standards are rigorously identical to the NERC reliability standards. No reliability standards specific to Quebec were filed. As of this writing, a decision has not been reached by the Regie on the application.

With regards to compliance, an agreement is in place between the Regie, NERC and NPCC. The agreement states that NERC and NPCC shall develop, taking into account Quebec's legal and regulatory environment and in accordance with their applicable compliance monitoring procedures, specific procedures and a program for monitoring of the application of reliability standards in Quebec. The Regie would be responsible for the procedures and programs.

It should also be noted that an MOU was developed and signed between the Regie and NERC in November, 2006.

<u>New Brunswick</u>

The New Brunswick System Operator (NBSO) was established under the Electricity Act (NB) in October 2004. The NBSO is responsible to maintain the adequacy and reliability of the integrated electricity system.

NERC Reliability Standards are currently adopted in the wholesale rules that are developed and administered by the NBSO by means of a market rule obligation imposed on various market participants to comply with all applicable Reliability Standards. Compliance with the market rules (and thus with NERC reliability standards as well as NPCC regional reliability criteria) is a condition of license of each market participant and of NBSO. NERC reliability standards therefore have effect in New Brunswick under the market rules. These reliability standards are mandatory and enforceable in New Brunswick.

The process that is in place under the Electricity Act for making and amending market rules applies to the adoption of NERC reliability standards. When a reliability standard is approved by the NERC Board of Trustees or an NPCC criterion is approved by the NPCC Board of Directors, the NBSO will initiate the adoption process for the province. The NBSO will review the content and implementation plan for a Reliability Standard and develop a schedule to adopt the Reliability Standard as an amendment to this Market Procedure. The NBSO will post the proposed Reliability Standard, implementation plan and adoption date on the NBSO Website for a thirty (30) day review period before the Reliability Standard comes into effect unless the NBSO deems the amendment to be urgent and files with the Energy and Utilities Board (EUB) to adopt the Reliability Standard in less than thirty (30) days. During the review period interested parties may seek additional information or clarification from the NBSO on the proposed amendments or may apply to the EUB for a formal review of the proposed Reliability Standard. The EUB has the authority under the Electricity Act to revoke the adoption of a reliability standard and remand it back to the NBSO for further consideration.

In terms of compliance, the NBSO is the sole New Brunswick entity accountable to NERC for compliance with the reliability standards by it or by market participants and will be subject to NERC's standards processes and compliance monitoring and enforcement processes, which will be monitored by NPCC. It will however register, monitor and assess and enforce compliance of market participants in New Brunswick. The NBSO has the authority to impose financial penalties for non-compliance and the EUB has the authority to impose administrative penalties.

It should also be noted that an MOU was developed and signed between the province of New Brunswick, the NBSO and NERC in October, 2008. As well, another MOU was developed and signed between the NBSO, NPCC and NERC in November, 2008.

<u>Nova Scotia</u>

Nova Scotia Power Inc. (NSPI), which is an investor owned utility, is the largest public utility regulated by the Nova Scotia Utility and Review Board (NSUARB). NSPI provides 95 per cent of the generation, transmission and distribution of electricity in Nova Scotia.

An MOU was signed in December, 2006 between the NSUARB and NERC outlining a process by which NERC Reliability Standards would be made mandatory and enforced. The MOU further recognizes that once the NSUARB approves a standard, compliance with the standard is mandatory in Nova Scotia. Another MOU was signed in May 2010 between NERC, NPCC and NSPI which defines the methodology to approve and implement the mandatory Reliability Standards and criteria in Nova Scotia.

The methodology is that NERC and NPCC will file the Reliability Standards with the NSUARB. The NSUARB will then direct NSPI to review and provide comment on the filing. A notice of filing will also be issued publicly to allow for comments. A public hearing would take place if deemed necessary. NSPI would recommend to the UARB to either

a) approve the NERC Reliability Standards or NPCC Regional Reliability Criteria as mandatory
b) request additional information
c) remand
d) adopt the NSUARB's own reliability standard on the issue
e) dismiss as not relevant to Nova Scotia or
f) other action as NSPI considers appropriate

In July, 2011, the NSUARB adopted all of the NERC reliability standards as filed in 2010 and recommended by NSPI.

For compliance monitoring and enforcement, NSPI, as a registered entity with NERC, will be subject to NERC's compliance monitoring and enforcement program, as implemented by NPCC. NPCC in its determination of an NSPI violation may identify the specific NERC standard that was violated. As applicable, NPCC will review for acceptability from a reliability perspective, any NSPI mitigation plans to bring NSPI into compliance and may propose a non-monetary penalty to the NSUARB. The NSUARB will then ultimately determine if there was any violation and if so, what remedial measures or non-monetary penalties should be imposed.

Province	Key Points
British Columbia	• 103 Reliability Standards adopted and are mandatory. These are NERC standards with some parts not adopted (i.e. compliance section). • BCUC has exclusive jurisdiction to determine whether a Reliability Standard should be adopted in BC. • Compliance Monitoring and Enforcement being administered by WECC.
Alberta	• 69 standards have been evaluated and 41 have been approved and are in effect. Standards can (and have) been amended to reflect Alberta system. • NERC reliability standards apply to the extent they are adopted by the AESO. • There is a compliance monitoring program. Monitored by WECC.
Manitoba	• Manitoba Hydro is currently required to comply with NERC Reliability Standards through its membership in the MRO and its membership in NERC, subject to exceptions based on provincial law. • NERC Reliability Standards are not binding

Province	Key Points
	on Manitoba Hydro to the extent suspended, disallowed or remanded by the Lieutenant Governor in Council. Currently, all NERC Reliability Standards apply to Manitoba Hydro. • An interim Compliance Enforcement and Monitoring agreement is in place in which the PUB (Manitoba) would be responsible for compliance.
Saskatchewan	• Standards apply to SaskPower. Approach is to utilize the current Power Corporation Act's unambiguous Authorities to set and enforce Reliability Standards for the electric system. • Typically, NERC approved Reliability Standards shall be viewed as being automatically adopted in Saskatchewan. • NERC and MRO used in an audit role for compliance monitoring.
Ontario	• Compliance with the market rules (and thus with NERC Reliability Standards) is a condition of license from the OEB for each market participant and the IESO. NERC Reliability Standards therefore have effect in Ontario under the market rules. • The OEB can initiate a review, remand, and revoke the application of NERC Reliability Standards. • The IESO is the sole Ontario entity accountable to NERC for compliance.
Quebec	• Regie (Utilities Board) has clear authority for mandatory Reliability Standards and for their enforcement. • HQT must file with the Regie the Reliability Standards that are considered required for their adoption. • 95 Standards (NERC) were filed with the Regie for adoption.
New Brunswick	• NERC Reliability Standards are currently adopted in the wholesale market rules administered by the NBSO • Standards are mandatory and enforceable. Standards are filed with the EUB for approval and are not able to be modified. • NBSO is the sole New Brunswick entity accountable to NERC for compliance.

Province	Key Points
Nova Scotia	• All NERC standards are adopted and are mandatory and enforceable (with the exception of NUC standard). • NSPI completes a review of standards and submits to the NSUARB for approval. • Registered entities are subject to NERC's compliance monitoring and enforcement program.

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Appendix C – NERC/NPCC Membership Sectors and NERC Ballot Pool Segments

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The following is a list of the NERC Membership sectors:

1. Investor-owned utility
2. State or municipal utility
3. Cooperative utility
4. Federal or provincial utility/power marketing administrator
5. Transmission-dependent utility
6. Merchant electricity generator
7. Electricity marketer
8. Large end-use electricity customer
9. Small end-use electricity customer
10. Independent system operator/regional transmission organization
11. Regional Entity
12. Government representative

The following is a list of the NPCC voting sectors:

1. Transmission Owners
2. Reliability Coordinators
3. Transmission Dependent Utilities, Distribution Companies and Load Serving Entities
4. Generator Owners
5. Marketers, Brokers and Aggregators
6. State and Provincial Regulatory and/or Governmental Authorities
7. Sub-Regional Reliability Councils, Customers, Other Regional Entities and Interested Entities

The following is a list of NERC registered ballot pool segments:

1. Transmission Owners
2. Regional Transmission Organizations/Independent System Operators
3. Load-Serving Entities
4. Transmission Dependent Utilities
5. Electric Generators
6. Electricity Brokers, Aggregators and Marketers
7. Large Electricity End Users
8. Small Electricity Users
9. Federal, State and Provincial Regulatory or other Government Entities
10. Regional Reliability Organizations and Regional Entities

Appendix D – Violation Risk Factors/Severity Levels – NERC Reliability Standards

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The risk factor assesses the impact to reliability of violating a specific requirement. The risk factors are defined as follows:

1. High
    - A requirement, if violated, could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures; or
    - A requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to BES system instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to normal condition.
2. Medium
    - A requirement, if violated, could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of a medium risk requirement is unlikely to lead to BES instability, separation, or cascading failures; or
    - A requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
3. Lower
    - A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES; or
    - A requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES.
    - A planning requirement that is administrative in nature.

The severity levels define the degree to which compliance with a requirement was not achieved. The severity levels are based on the following guidelines:

1. Severe
    - The performance or product measured does not substantively meet the intent of the requirement.
2. High

- The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.

3. Moderate
    - The performance or product measured meets the majority of the intent of the requirement.
4. Lower
    - The performance or product measured almost meets the full intent of the requirement.

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Nalcor Energy Lower Churchill Project

Cost assessment – NERC Reliability Standards and NPCC Regional Reliability Criteria for Nalcor

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Date:
Document Number:
Revision:

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Approved for Release **Date**

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Executive Summary

With the development of phase 1 of the Lower Churchill Project (LCP), Newfoundland and Labrador (NL) will be interconnected to the North American power grid through the province of Nova Scotia with the Maritime Link (ML) and through Quebec with the Labrador Island Link (LIL), Muskrat Falls (MF), Labrador Transmission Assets (LTA) and Churchill Falls (Labrador) Corporation (CF(L)Co). As a result of this, there is a need to assess the implications of adopting the North American Electric Reliability Corporation (NERC) reliability standards and the Northeast Power Coordinating Council (NPCC) regional reliability criteria. This report outlines the costs associated with adopting the NERC reliability standards and the NPCC regional reliability criteria. A companion report titled "Strategic Alignment, Benefits, Risks, Reliability Framework and Compliance – NERC Reliability Standards and NPCC Regional Reliability Criteria" has also been completed which looks at the benefits, risks and a potential reliability framework for NL.

NERC is the Electric Reliability Organization (ERO) responsible for the creation, implementation, monitoring and enforcement of mandatory reliability standards for the Bulk Power System (BPS) in the United States. However, while NERC does not have jurisdiction in Canada, 8 of the 10 provinces have either adopted or are in the process of adopting all or some of the NERC reliability standards. The NERC reliability standards have essentially become the industry standard for utilities to ensure reliability of the power grid.

There are also Regional Reliability Organization's (RRO) across North America that work in coordination with NERC to ensure the reliability of the power grid by region. They may have their own reliability standards or criteria that are specific to their region. They are also mainly responsible for the compliance monitoring and enforcement of the reliability standards for their region. The RRO responsible for northeastern North America is NPCC.

Currently, there are 120 NERC reliability standards and 11 NPCC directories containing the regional reliability criteria. For the cost estimate, the following outlines the process used in the assessment.

1. Identify the Functional Entities that would potentially apply to Nalcor Energy (Nalcor)
    - These are functions/roles that Nalcor would perform in the area of reliability of the Bulk Electric System (BES).
2. Identify the NERC reliability standards that would potentially apply to Nalcor based on the Functional Entity assessment.
    - Each NERC reliability standard applies to one or more Functional Entities.
3. Assess each of the reliability standards identified in item #2 to determine which are required, not required or optional.
    - Required – These are the reliability standards that would need to be adopted based on commitments made through agreements with Emera and/or NSPI.
    - Not Required – The reliability standard would not fit both from a functional and technical point of view.

- Optional – Based on the Functional Entity determination for Nalcor, these standards would maintain and in some cases improve the current levels of reliability.

4. Complete cost assessment on the NERC reliability standards that were classified as required or optional and the NPCC regional reliability criteria.
    - The cost assessment takes into account both initial costs to get to compliance and ongoing annual costs to maintain compliance.
    - Initial costs include one-time capital, internal labour and external assistance requirements.
    - Ongoing costs include labour, new staff requirements and NERC/NPCC funding requirements.

From this assessment, the following results were determined:

1. There are 12 Functional Entities that could be applicable to Nalcor:
    - Reliability Coordinator
    - Balancing Authority
    - Interchange Coordinator
    - Generator Owner
    - Generator Operator
    - Transmission Owner
    - Transmission Operator
    - Planning Coordinator
    - Transmission Planner
    - Resource Planner
    - Transmission Service Provider
    - Load-Serving Entity
    - Purchasing-Selling Entity
2. There are 110 reliability standards that would potentially apply to the Functional Entities determined for Nalcor.
3. Of the 110 NERC reliability standards, there are:
    - 10 reliability standards that are considered required.
    - 8 reliability standards that are considered not required.
    - 92 reliability standards that are considered optional.
4. Some risks and testing requirements were determined for the NPCC regional reliability criteria.

The cost assessment based on the required and optional NERC reliability standards and NPCC regional reliability criteria was determined to be:

- Initial Cost for implementing standards and criteria: $3,940,000
    - This cost would be over a 4 – 5 year period.
- Ongoing annual cost: $1,002,800

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Using a 30% contingency factor, the range for the total overall cost estimates would be: $4,942,800 - $6,425,640

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1.0 Introduction

With the development of phase 1 of the LCP, a system integration team was formed to look at the potential requirements for integrating the current system power system in NL with the new facilities for the LCP. One of these requirements was in the area of reliability, in particular, the potential adoption of NERC reliability standards and NPCC regional reliability criteria.

This report presents a cost assessment for Nalcor if they were to adopt the NERC reliability standards and NPCC regional reliability criteria. The process for the assessment involves determining the Functional Entities that may apply to Nalcor. Based on these Functional Entities, a determination is then made as to the reliability standards that may potentially apply to Nalcor. From that, a cost estimate was completed for both the NERC reliability standards and the NPCC regional reliability criteria. The cost estimate takes into account initial costs to implement the standards and the ongoing costs to maintain compliance.

1.1 Assumptions used in the cost assessment

The following assumptions have been made in this assessment.

1. Nalcor refers to Nalcor Energy and its subsidiaries, including its subsidiary company Newfoundland and Labrador Hydro (NLH). NLH is used specifically when referring to the current operation of the island BES and parts of Labrador.
2. There is no industry structural change and NLH will continue to perform the functions it currently undertakes.
3. NLH will undertake all operating and maintenance responsibilities for the new facilities which Nalcor or Emera NL are the facility owners. Nalcor may take on a functional entity role in the future if they are not assigned to NLH.
4. There have been Full Time Equivalent (FTE's) positions identified for several departments throughout Nalcor. These FTE's are required to implement the reliability standards (including CIP standards) to a level that would meet compliance (20 FTE's) and to maintain compliance (2 FTE's) with the reliability standards. The initial implementation would be over a 4 – 5 year period. It is assumed that while some of this work can be completed with existing staff, some new hires will be required. A further assessment will be required by each department identified and the costs associated with the FTE's are not included in this report.
5. CF(L)Co, Emera NL and Newfoundland Power (NP) and other utilities and entities are not included in the assessment of Functional Entities, reliability standards and final cost estimation. For cost estimation for NP, a prorated portion of 30% - 40% can be used based on the roles it would undertake based on the NERC criteria.
6. The assessment on the Functional Entities (Section 2.0) and reliability standards (Section 3.0) does not include consultation with NERC or NPCC.
7. Standard rates used by Nalcor when creating capital budgets are used in this cost estimates for internal labour ($3,200 per week) and external consultants ($7,000 per week).

8. Some of the capital costs identified are listed for information only. They would be required for infrastructure to achieve and maintain compliance with NERC reliability standards. However, the capital costs associated with this are assumed to be part of the overall LCP project and will be absorbed by the project. Each is identified in the appropriate section.

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2.0 Assessment of Functional Entities Applicable to Nalcor

In order to determine the reliability standards that are potentially applicable, an assessment is required to see which of the Functional Entities apply to Nalcor. From this, an initial cost assessment can be made as to the adoption of the reliability standards.

As mentioned previously, each reliability standard has applicability to one or more Functional Entities. The following sections outline an assessment of the Functional Entities.

2.1 NERC Functional Model

The NERC Functional Model provides the framework for the development and applicability of NERC's reliability standards as follows:

- The model describes a set of functions that are performed to ensure the reliability of the BES. Each function consists of a set of related reliability tasks. The model assigns each function to a functional entity, that is, the entity that performs the function. The model also describes the interrelationships between that functional entity and other functional entities.

The model is a guideline for the development of standards and their applicability. The model itself is not a standard and does not have compliance requirements.

The Functional Entities are defined both in the NERC Reliability Functional Model (Version 5, November 2009) and in the NERC glossary of terms. It should also be noted that NPCC approaches the assignment of reliability requirements in the same manner as NERC. The Functional Entities defined in the Functional Model are:

1. Balancing Authority
2. Distribution Provider
3. Generator Operator
4. Generator Owner
5. Interchange Coordinator
6. Load-Serving Entity
7. Planning Coordinator
8. Purchasing-Selling Entity
9. Reliability Coordinator
10. Resource Planner
11. Transmission Operator
12. Transmission Owner
13. Transmission Planner
14. Transmission Service Provider

A table outlining the NERC definition for each Functional Entity can be found in Appendix B.

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2.1 Identification of Functional Entities for Nalcor

To identify the potential applicable Functional Entities, the NERC definitions for each were used and applied to the roles and functions that Nalcor would have in operating the BES. The following sections discuss each of the Functional Entities that potentially apply to Nalcor. In each case, the anticipated subsidiary within Nalcor that would perform the function is listed.

2.1.1 Reliability Coordinator (RC)

The RC is the Functional Entity that maintains the real-time operating reliability of the BES within a Reliability Coordinator Area.

In the current operating environment for the island power system, NLH is the primary generator and transmitter of electricity. Therefore, it currently has the wide area view of maintaining the reliability of the island system and shares it with CF(L)Co in Labrador.

With the interconnections to the island (LIL), NLH will have a much bigger influence in maintaining reliability for Labrador. As well, NLH will have an additional sphere of influence as it could affect the reliability of the interconnected North American BES due to its interconnections through Nova Scotia (ML) and Quebec (LIL, MF and CF(L)Co).

Therefore, NLH would perform the function of RC. The RC area would include both Newfoundland and Labrador (including CF(L)Co) and Labrador West) to the boundaries with the Hydro Quebec (HQ) system and the Nova Scotia Power Inc. (NSPI) system.

2.1.2 Balancing Authority (BA)

The BA is the Functional Entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

In the current operating environment, NLH is the primary supplier of generation for the island. Therefore, NLH is responsible for maintaining the load-generation balance for the island. NLH is also responsible for maintaining frequency for the island power system.

With the interconnection and development of the LCP, NLH would continue to be responsible for maintaining the generation-load balance for the province. In addition, with the ML and the LTA, NLH will be responsible for maintaining a load-interchange-generation balance for NL with Nova Scotia and Quebec. NLH will also support the interconnection frequency in real time.

Therefore, NLH would perform the function of BA for the NL BES. The BA area would include the generation, transmission and loads within Newfoundland and Labrador (including CF(L)Co).

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2.1.3 Interchange Coordinator (IC)

The IC is the Functional Entity that ensures communication of Arranged Interchange for reliability evaluation purposes and coordinates implementation of valid and balanced Confirmed Interchange between Balancing Authority Areas.

In the current operating environment, NLH does not perform the function of Interchange Coordinator.

With the interconnection to Nova Scotia via the ML, there will be an agreement in place for Nalcor to provide Emera a block of power each day during peak periods for 35 years. NLH will be responsible for implementing this interchange on a daily basis. NLH would also have to implement the interchange as required by Nalcor Energy Marketing (NEM). NLH would also implement the interchange requirements between CF(L)Co and Hydro Quebec Production (HQP).

Therefore, NLH would perform the function of IC as required. As mentioned above, the IC functions should be performed for all interchange transactions, including CF(L)Co.

2.1.4 Generator Owner (GO)

The GO is the Functional Entity that owns and maintains generating units.

NLH is currently the owner of a number of hydro and thermal generating units in NL. This will continue in the future.

Muskrat Falls Co. (MF Co.) would be the owner of the MF generating plant.

Therefore, both NLH and MF Co. would be considered a GO.

2.1.5 Generator Operator (GOP)

The GOP is the Functional Entity that operates generating unit(s) and performs the functions of supplying energy and reliability related services.

In the current operating environment, NLH is the primary operator of generating units and perform the function of supplying energy for the island system. This will continue in the future and would include the operation of the MF generating plant.

Therefore, NLH would perform the function of GOP for the NL BES.

2.1.6 Transmission Owner (TO)

The TO is the Functional Entity that owns and maintains transmission facilities.

NLH currently owns and maintains all of the 230 kV transmission facilities in NL. NLH also owns and maintains 138 kV and 66 kV transmission facilities in NL. This will continue in the future.

Labrador Island Link Limited Partnership (LIL LP) would be the primary owner of the LIL.

Labrador Transmission Co. (Lab TransCo.) would be the owner of the LTA.

Therefore, both NLH and LIL LP would be considered a TO.

2.1.7 Transmission Operator (TOP)

The TOP is the Functional Entity that ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.

In the current operating environment, NLH is responsible for the real-time operating reliability of all the 230 kV transmission assets and a portion of the 138 kV and 66 kV transmission assets on the island interconnected system. NLH is also responsible for the real-time operating reliability of the 138 kV and 46 kV transmission assets in Labrador. This responsibility will continue in the future.

With the development of the LCP, it is expected that NLH will have an expanded responsibility for the real-time operating reliability of transmission assets. This would now include the operation of LIL, LTA and the portion of the ML located in NL.

Therefore, NLH would perform the function of TOP for the NL BES.

2.1.8 Planning Coordinator (PC)

The PC is the Functional Entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas.

Currently, the system planning department within NLH performs this function. This is expected to continue in the future. However, as a result of the interconnection, there will be an expanded role within this function. The PC will have to work with adjoining PC's to conduct facilitated, coordinated, joint, centralized or regional planning activities to ensure the plans on one system will not adversely affect another.

Therefore, NLH would perform the function of PC as required.

2.1.9 Transmission Planner (TP)

The TP is the Functional Entity that develops a long term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within a Transmission Planner area.

Currently, the system planning department within NLH performs this function. This is expected to continue in the future. They are responsible for developing the long term reliability plans for both the island interconnected system and the Labrador interconnected system.

Therefore, NLH would perform the function of TP for the NL BES.

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2.1.10 Resource Planner (RP)

The RP is the Functional Entity that develops a long term (generally one year and beyond) plan for the resource adequacy or specific loads (customer demand and energy requirements) within a Resource Planning area.

Currently, the system planning department within NLH performs this function. This is expected to continue in the future. They are responsible for developing the long term reliability plans for both the island interconnected system and the Labrador interconnected system.

Therefore, NLH would perform the function of RP for the NL BES.

2.1.11 Transmission Service Provider (TSP)

The TSP is the Functional Entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.

In the current operating environment, NLH does not have a transmission service agreement and hence, does not perform the function of the TSP.

With the interconnection and development of the LCP, it is expected that NLH will be responsible for completing the function of the TSP. Some of the key tasks associated with this are:

a) Receive transmission service requests and process each request for service according to the requirements of the tariff.
b) Determine and post available transfer capability values.
c) Approve or deny transmission service requests.
d) Approve Arranged Interchange from transmission service arrangement perspective.
e) Allocate transmission losses (MW's or funds) among Balancing Authority Areas.

Therefore, NLH would perform the function of TSP as required.

2.1.12 Load-Serving Entity (LSE)

The LSE is the Functional Entity that secures energy and transmission service (and reliability related services) to serve the electrical demand and energy requirements of its end use customers.

In the current operating environment, NLH serves approximately 35,000 residential customers with the majority being supplied through radial transmission. NLH also serves industrial customers in NL which are being supplied at transmission level voltages. This will continue in the future.

Therefore, NLH would perform the function of LSE for the NL BES.

2.1.13 Purchasing-Selling Entity (PSE)

The PSE is the Functional Entity that purchases or sells, and takes title to, energy, capacity, and reliability related services.

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In the current operating environment, NLH does perform some of the functions of a PSE. NLH sells the majority of energy produced to NP. NLH also has Power Purchase Agreements (PPA) with independent generators on the island (i.e. wind, NUG's). This will continue in the future.

With the interconnection to Nova Scotia via the ML and development of MF, NEM will be selling and potentially purchasing energy to/from markets in North America. NLH would also have an additional PPA with MF Co.

Therefore, both NLH and NEM would perform the function of PSE. In the case of NEM, it would be for importing and exporting energy.

2.2 Functional Entities not applicable to Nalcor

The following sections discuss each of the Functional Entities that potentially would not apply to NLH. It should be noted here that this is just an initial review and a more detailed review would need to be completed at a later time.

2.2.1 Distribution Provider (DP)

The DP is the Functional Entity that provides facilities that interconnect to the end-use customer load and the electric system for the transfer of electrical energy to the end-use customer.

The DP provides the physical connection between the end-use customers and the electric system, including customers served at transmission level voltages. The DP is not defined by a specific voltage, but rather as performing the distribution function at any voltage. The DP provides the switches and reclosers required for emergency action. Also, the same organization may serve as the DP and LSE.

In the current operating environment, NLH does serve as the DP in certain areas of NL. In particular, it serves general service, residential and industrial customers. For the general service and residential customers, the primary distribution provider on the island is NP. For NLH, the majority of the distribution loads are radial in nature. In the case of industrial customers, these are served at transmission level voltages by NLH. Overall, this situation will be the same with the development of the LCP.

Therefore, NLH will perform some of the functions of DP as outlined above. However, it is expected that NLH would be performing the function of LSE and these functions can be bundled together if NERC standards are adopted.

2.3 Summary of Functional Entities for Nalcor

The following table highlights the potential functional entities that have been identified for Nalcor through the assessment.

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	BA	DP	GO	GOP	IC	LSE	PA	PSE	RC	RP	TO	TOP	TP	TSP
Entity Name														
NLH	BA		GO	GOP	IC	LSE	PA	PSE	RC	RP	TO	TOP	TP	TSP
MF Co.			GO											
LIL LP											TO			
Lab TransCo.											TO			
NEM								PSE						

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3.0 Initial Assessment of Reliability Standards and Regional Reliability Criteria

Overall, there are a total of 120 NERC reliability standards that are in effect (as of this writing). They are categorized as follows:

1. Resource and Demand Balancing – BAL
2. Communications – COM
3. Critical Infrastructure Protection – CIP
4. Emergency Preparedness and Operations – EOP
5. Facilities Design, Connections, and Maintenance – FAC
6. Interchange Scheduling and Coordination – INT
7. Interconnection Reliability Operations and Coordination – IRO
8. Modeling, Data, and Analysis – MOD
9. Nuclear – NUC
10. Personnel Performance, Training, and Qualifications – PER
11. Protection and Control – PRC
12. Transmission Operations – TOP
13. Transmission Planning – TPL
14. Voltage and Reactive –VAR

In the following sections, the reliability standards are assessed to determine which are required, not required and optional. From this, a cost assessment is completed for adopting the required and optional standards. The first step in this process was to determine which Functional Entities should apply to Nalcor. This was completed throughout section 2. From that, contained within each of the standards, is an applicability section which states which Functional Entity the standard would apply. This then determined the number of standards that were assessed.

As well, NPCC has 11 directories that contain regional reliability criteria. They are categorized as follows:

1. Directory #1 – Design and Operation of the Bulk Power System
2. Directory #2 – Emergency Operations
3. Directory #3 – Maintenance Criteria for BPS Protection
4. Directory #4 – System Protection Criteria
5. Directory #5 – Reserve
6. Directory #6 – Reserve Sharing Groups
7. Directory #7 – Special Protection Systems
8. Directory #8 – System Restoration
9. Directory #9 – Generator Gross/Net Real Power Capability
10. Directory #10 – Generator Gross/Net Reactive Power Capability
11. Directory #12 – UFLS Program Requirements

The following sections look at the applicable reliability standards and the regional reliability criteria and make an assessment on each one.

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3.1 Current reliability standards that apply to Nalcor Functional Entities

Based on the Functional Entity determination for Nalcor, there are 101 reliability standards and nine Critical Infrastructure Protection (CIP) standards that would be applicable for assessment. The following list outlines the number of reliability standards that would apply to each of the reliability standard categories. As well, a detailed table showing the individual standards can be found in Appendix C.

1. Resource and Demand Balancing – BAL
    - There are 6 reliability standards applicable in this category
2. Communications – COM
    - There are 2 reliability standards applicable in this category
3. Critical Infrastructure Protection – CIP
    - There are 9 reliability standards applicable in this category
4. Emergency Preparedness and Operations – EOP
    - There are 7 reliability standards applicable in this category
5. Facilities Design, Connections, and Maintenance – FAC
    - There are 10 reliability standards applicable in this category
6. Interchange Scheduling and Coordination – INT
    - There are 9 reliability standards applicable in this category
7. Interconnection Reliability Operations and Coordination – IRO
    - There are 13 reliability standards applicable in this category
8. Modeling, Data, and Analysis – MOD
    - There are 19 reliability standards applicable in this category
9. Personnel Performance, Training, and Qualifications – PER
    - There are 4 reliability standards applicable in this category
10. Protection and Control – PRC
    - There are 17 reliability standards applicable in this category
11. Transmission Operations – TOP
    - There are 8 reliability standards applicable in this category
12. Transmission Planning – TPL
    - There are 4 reliability standards applicable in this category
13. Voltage and Reactive – VAR
    - There are 2 reliability standards applicable in this category

As well, based on the Functional Entity determination for Nalcor, there are 10 reliability standards that would not be applicable for assessment. The following list outlines the number of reliability standards that would not apply to each of the reliability standard categories. As well, a detailed table showing these individual standards can be found in Appendix C.

1. Modeling, Data, and Analysis – MOD
    - There are 2 reliability standards that would not be applicable in this category

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2. Nuclear – NUC
    - There is 1 reliability standard that would not be applicable in this category
3. Protection and Control – PRC
    - There are 5 reliability standards that would not be applicable in this category
4. Transmission Planning – TPL
    - There are 2 reliability standards that would not be applicable in this category

The following sections assess the 110 reliability standards for potential requirements and cost implications.

3.2 Determination of reliability standards potentially applicable to Nalcor

To determine the applicable reliability standards for Nalcor, a review was completed on which standards would be Required, Not Required or Optional. The following gives a brief description on each of the categories.

1. Required
    - These are the reliability standards that would need to be adopted based on commitments made through agreements with Emera and/or NSPI.
2. Not Required
    - The reliability standard would not fit both from a functional and technical point of view.
3. Optional
    - Based on the Functional Entity determination for Nalcor, these standards would maintain and in some cases improve the current levels of reliability.

To further elaborate on the optional category, consideration was given to the requirements in each of the reliability standards and the requirements that are currently being adhered. To ensure that adopting the reliability standards would maintain or improve the level of reliability on the NL BES, the reliability standards should have requirements that are as or more stringent than what is currently being adhered. The current operations of Nalcor will continue with the additional responsibility of ensuring that no aspect of its operation will impact the reliability of the North American BES. These standards have been developed by the industry and adopting these reliability standards would ensure consistency with other jurisdictions in North America. Therefore, it is anticipated that adopting these reliability standards would maintain and in some cases improve the level of reliability.

3.2.1 Required, Not Required and Optional reliability standards for Nalcor

Based on the definitions from the previous section, the following outlines the number of reliability standards that would be considered required, not required and optional for Nalcor. Note that detailed tables outlining specific reliability standards can be found in Appendix D.

1. Required reliability standards

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- There are a total of 10 reliability standards that have been assessed as required. They are in the Interchange Scheduling and Coordination (9 standards) and the Resource and Demand Balancing (1 standard) categories.

2. Not Required reliability standards
    - There are a total of 8 reliability standards that have been assessed as not required. They are in the Modeling, Data and Analysis (4 standards) and Protection and Control (4 standards) categories.
3. Optional reliability standards
    - There are a total of 92 reliability standards that have been assessed as optional. They are in all of the categories of the NERC reliability standards.

3.2.2 Assessment of Cost of reliability standards for Nalcor

With adopting the NERC reliability standards, there is a cost associated with achieving and maintaining compliance. The cost assessment in the following sections is completed on the reliability standards that were determined to be required or optional.

The following costs were considered for each reliability standard in this assessment:

1. One time capital costs.
2. Potential internal labour costs.
3. Potential ongoing labour/administrative costs.

In addition, on an overall basis, the following costs were considered:

1. Staffing or new hire considerations.
2. NERC Funding.
3. External assistance (e.g. consulting).

It should be noted that the costs associated with the CIP standards are not included here and are addressed in section 3.4.2.

3.2.2.1 Capital Costs for reliability standards

The following list outlines the one-time capital cost, details on the requirements and the reliability standard that it is required for.

1. Inter-Control Center Communications Protocol (ICCP) Links for Energy Management System (EMS) – Project cost.
    - Required for reliability standards
        i. BAL-005-0-2b – Automatic Generation Control
        ii. COM-001-1.1 – Telecommunications
        iii. COM-002-2a – Communication and Coordination
        iv. IRO-002-2 – Reliability Coordination – Facilities
        v. IRO-003-2 – Reliability Coordination – Wide Area View

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vi. TOP-005-2a – Operational Reliability Information

- This is required for communication and data exchange to neighbouring control centers in Nova Scotia, Quebec and potentially New Brunswick.

2. Frequency monitoring and tie line metering equipment – Project cost.
   - Required for reliability standards
     i. BAL-005-0-2b – Automatic Generation Control
     ii. BAL-006-2 – Inadvertent Interchange
   - Each BA shall provide redundant and independent frequency monitoring equipment that shall automatically activate upon detection of failure of the primary source. In addition, tie line metering equipment is required for monitoring MW flows on the ML.

3. Application for posting Available Transfer Capability (ATC) and calculating Inadvertent Interchange – Project cost.
   - Can be used to meet requirements for reliability standards
     i. BAL-006-2 – Inadvertent Interchange
     ii. MOD-001-1a – Available Transmission System Capability
   - BAL-006-2 requires that inadvertent interchange be calculated and reported. MOD-001-1a requires that ATC be calculated and posted such that other entities can see the ATC within the Transmission operating area.
   - An application, such as one that has been developed by Open Access Technology Inc. (OATI) can meet these requirements. This web based software is widely used within the utility industry.

4. Potential upgrade to fault recording equipment.
   - Required for reliability standards
     i. PRC-002-NPCC-01 – Disturbance Monitoring
     ii. PRC-018-1 - Disturbance Monitoring Equipment Installation and Data Reporting
   - The reliability standards above reference the disturbance monitoring equipment and more specifically, the fault recorders which are required for BES facilities. However, one of the reliability standards has been developed by NPCC for their region. In discussion with them, they indicated that the BES facilities that this standard applies to can be determined using the NPCC criteria (Document A-10) for determining BPS elements (See Appendix H)
   - For this estimate, there were 4 BPS facilities used for the current system. This is based on discussions with the system planning department on the work they have completed to date. However, it should be noted that testing, as per the A-10 NPCC criteria, has not been completed as of this writing.
   - Each of these facilities would have fault recording equipment, as all of the major 230 kV facilities on the island have this equipment. However, upgrades to the fault recording

equipment would potentially be required to allow for 100% coverage of the required elements at the facilities as per the reliability standard. In discussion with P&C engineering (department within NLH), the fault recorders have the capability to be upgraded and would not have to be replaced. This would require upgrading the amount of channels on each unit and wiring.

- For the new facilities being constructed as part of the LCP, it is required to install fault recording equipment that meets the requirements of the standards. This would be a project cost.

Item Description	UOM	Rate/UOM	Number Required	Estimated Cost
Upgrade Fault Recording Equipment	EA	$80,000	4	$320,000
			Total Cost	**$320,000**

5. Potential software for monitoring compliance.
   - Can be used for monitoring compliance on all reliability standards.
   - Software can be used to track compliance on all reliability standards. This would assist with document management requirements for reliability standards.
   - An application, such as one that has been developed by OATI can meet these requirements.

Item Description	UOM	Rate/UOM	Number Required	Estimated Cost
Compliance Management Software	EA	100,000	1	$100,000
			Total Cost	**$100,000**

3.2.2.2 Potential internal costs for reliability standards

To be in position for compliance with NERC reliability standards there are many requirements that would need to be met. Based on the reliability standards that were determined to be required or optional, an assessment was completed to determine the potential internal cost associated with each reliability standard. The internal costs noted are based on labour by departments which have been identified to have responsibilities within the reliability standards. It takes into consideration instances where there would be considerable internal effort to bring each standard to a compliance level. This involves activities such as writing plans, protocols and procedures, identifying methodologies and putting in place programs for testing and maintenance.

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The following table indicates the potential internal costs:

Item Description	UOM	Rate/UOM	Number Required	Estimated Cost
System Planning Labour	Weeks	3,200	180	$576,000
System Operations Labour	Weeks	3,200	151	$483,200
TRO Labour	Weeks	3,200	91	$291,200
Project Execution and Technical Support Labour	Weeks	3,200	68	$217,600
Hydro Generation Labour	Weeks	3,200	49	$156,800
Energy Systems Labour	Weeks	3,200	5	$16,000
Network Services Labour	Weeks	3,200	3	$9,600
Energy Efficiency Labour	Weeks	3,200	1	$3,200
			Total Potential Internal Cost	**$1,753,600**

Of the total potential internal cost, $38,400 is for the required reliability standards identified earlier in this report.

There were a total of 548 person weeks identified to implement the reliability standards to a level that would meet compliance. This equates to approximately 11 FTE's. It should be noted that this work would be completed over a 4 - 5 year period with everything in place to meet compliance before the LCP project it completed.

In addition to the above mentioned internal costs, there would be potential additional costs associated with compliance for reliability standard PER-003.1. This reliability standard outlines the operating personnel credentials and the requirements for NERC certificates for the Energy Control Centre (ECC) operators. There would be an exam fee for each operator and travel costs to get to a certified exam centre. As of this writing, the nearest exam centre is in Halifax, Nova Scotia. However, there would be potential in the future, if this standard applies, to be able to write the exams without travel by having a certified exam center in St. John's, NL. This would be done through negotiations with NERC and NPCC. For the identification of potential costs here, it is assumed the operators would be required to travel. As well, included in the cost is potential training requirements for operators to prepare for writing the certification. While the majority of preparation can be completed internally, there may be a requirement for additional training. In discussions with NSPI, they indicated that they do use an external provider to enhance their internal training. The external training can be done online.

The following table identifies these costs:

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Item Description	UOM	Rate/UOM	Number Required	Estimated Cost
External Preparation Training	Each	3000	15	$45,000
Travel Costs (Flight, Hotel)	Each	1500	15	$22,500
Exam Fees	Each	700	15	$10,500
			Total Potential Internal Cost	**$78,000**

More detailed cost information can be found in Appendix E. The Appendix contains a table outlining each individual reliability standard, the labour required for each department, the estimated weeks and potential internal cost.

3.2.2.3 Potential ongoing costs for reliability standards

As mentioned previously, there are a number of things that are required to be compliant with each reliability standard. Once these requirements are in place, there would be ongoing costs to maintain compliance with each standard.

These ongoing costs would be labour and administration costs that are associated with each reliability standard. This would primarily be information or assessments required to be completed by certain departments or regions, for purposes of reporting to NERC, NPCC or other entities. They also include ongoing maintenance and testing programs and training requirements identified in the reliability standards.

The following table indicates the potential ongoing internal costs:

Item Description	UOM	Rate/UOM	Number Required	Estimated Cost
System Planning Labour	Weeks	3,200	42	$134,400
TRO Labour and program costs	Weeks	3,200	20	$124,000
Project Execution and Technical Support Labour	Weeks	3,200	18	$57,600
System Operations Labour	Weeks	3,200	14	$44,800
Hydro Generation Labour	Weeks	3,200	9	$28,800
Energy Systems Labour	Weeks	3,200	1	$3,200
			Total Potential Ongoing Internal Cost	**$392,800**

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Of the total potential ongoing internal cost, $6,400 is for the required reliability standards identified earlier in this report.

In addition, there are other labour costs associated with certain reliability standards such that when certain events happen on the BES, assessments and reports are required. It is anticipated that these assessments and reports would be required very infrequently.

The following table identifies the departments who would be responsible for these assessments and reports when necessary:

Item Description	UOM	Rate/UOM	Number Required	Estimated Cost
System Operations Labour	Weeks	3,200	14	$44,800
Project Execution and Technical Support Labour	Weeks	3,200	8	$25,600
System Planning Labour	Weeks	3,200	6	$19,200
			Total Potential Internal Cost	**$89,600**

There were a total of 104 person weeks identified to maintain compliance with the reliability standards. This equates to approximately 2 FTE's. This would include completing the potential reports and assessments as required for specific BES events as outlined above. As well, there would be assistance provided by the compliance team that is discussed in section 3.2.2.4.

As well, one other ongoing cost would be for the ECC operators to maintain their NERC certificates. The initial cost to obtain the NERC certificates was identified in section 3.2.1.2 and this certificate is valid for three years. To maintain the validity of the certificate, each operator must earn a required amount of continuing education (CE) hours over the three year period. The majority of the CE hours can be obtained internally by the current operator training program, which includes the use of the Operator Training Simulator (OTS). However, external training may be required to gain the required amount of CE hours. In discussions with NSPI, they indicated that they do use an external provider to gain additional CE hours. The external training can be done online.

The following table identifies these costs:

Item Description	UOM	Rate/UOM	Number Required	Estimated Cost
External training to maintain NERC certificate	Each	600	15	$9,000
			Total Potential Internal Cost	**$9,000**

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More detailed cost information can be found in Appendix E. The Appendix contains a table outlining each individual reliability standard, the labour required for each department, the estimated weeks and potential ongoing internal costs.

3.2.2.4 Staffing considerations for reliability standards

When looking at the potential for new staffing requirements, consideration was given to what would be required to maintain compliance.

Each reliability standard contains certain measures that are required to be met for compliance. In order to ensure compliance, a centralized compliance team could be formed within Nalcor. This team would

1. Work closely with departments and regions to ensure all information required to maintain compliance is obtained.
2. Submit any compliance information to NERC or RRO in a timely and consistent manner.
3. Monitor NERC reliability standards for changes and communicate all requirements to appropriate stakeholders as required.
4. Prepare for audits if required.
5. Participate with NERC and RRO on committees on development or changes to reliability standards as required.
6. Represent Nalcor for voting on reliability standards as required.
7. Other work as required.

This team would require the following new position:

1. Reliability Compliance Manager

This position would have responsibility to ensure compliance with reliability standards for Nalcor and to ensure that all requirements are being met. As well, the position would ensure that information provided to NERC and/or RRO is accurate and consistent and done in a timely manner.

In addition to this new position, the current position of Reliability Standards Engineer would remain and be a part of the compliance team. This would be required to assist the Reliability Compliance Manager and provide technical assistance as required with the reliability standards.

Another area that has been identified as potentially requiring new positions is for vegetation management. In consultation with appropriate stakeholders within Nalcor, it was determined that to meet compliance, the following positions would be required:

1. Permanent Inspectors (2).
2. Extension of Seasonal Inspector.

As well, the addition of staff for the ECC is not included in this cost assessment. There will be a requirement for additional staff for the ECC. However, this staff would be required as a result of the LCP regardless if the NERC reliability standards are adopted by NLH.

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The following table indicates the potential staffing requirements:

Item Description	UOM	Rate/UOM	Number Required	Estimated Cost
Reliability Compliance Manager	EA	Hay	1	$130,000
Permanent Inspectors	EA	Union	2	$85,000
Seasonal Inspector	EA	Union	1	$40,000
			Total Cost	**$255,000**

3.2.2.5 NERC funding

Each year, NERC develops a business plan and budget. Generally, the activities associated with this plan are in the areas of reliability standard development, compliance, event analysis, reliability assessments and training/education.

In order to determine the amount of funding requirements, the Net Energy for Load (NEL) criteria is used. NEL is defined in Appendix A. From the NERC perspective, each LSE (or designee) has to provide funding based on the NEL criteria.

To get an estimate on the amount of funding that would be required for Nalcor, the following parameters were used:

1. 8 GWH NEL
2. NERC 2012 budget estimate of $53,112,272
3. Other NERC entities and their NEL's (taken from NERC data)

Based on these parameters, it is estimated that the funding requirements would be $90,000 annually.

Item Description	UOM	Rate/Year	Number Required	Estimated Cost
NERC Funding	Yearly	90,000	Annual	$90,000
			Total Cost	**$90,000**

3.2.2.6 External consultant requirements

An external consultant would be required for assistance in the area of NERC reliability standards. Currently, the expertise with NERC reliability standards within NLH is limited. The position of Reliability Standards Engineer has been created to help bridge that gap going forward. However, the reliability standards impact many different departments and areas within Nalcor and others areas outside the corporation (i.e. provincial government).

Initially, the consultant would assist in helping NLH staff become familiar with what is required to be compliant with NERC reliability standards. They would assist with helping staff understand the

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requirements of gathering information from within the company and making sure it is what NERC and the RRO would require.

It would also be essential that the consultant complete a mock audit on the reliability standards. This would help prepare Nalcor for any potential audit requirements and to understand the amount of effort it would take for an audit. It would also help determine what gaps exist (if any) for compliance.

Item Description	UOM	Rate/UOM	Number Required	Estimated Cost
Consultant	Weeks	7000	8	$56,000
			Total Cost	**$56,000**

3.3 NPCC regional reliability criteria

As mentioned in section 3.0, there are 11 directories developed by NPCC that contain regional reliability criteria. The directories are designed around NERC reliability standards and have applicability to functional entities. As well, some of the directories also have applicability to BPS facilities. However, the criteria that are specified in each directory are more stringent than what is contained in the NERC reliability standards.

As with the NERC reliability standards, the regional reliability criteria should have requirements that are as or more stringent than what is currently being adhered, such that reliability would be maintained or improved on the island BES. The current operations of Nalcor will continue with the additional responsibility of ensuring that no aspect of its operation will impact the reliability of the North American BES and in particular for NPCC, Northeastern North America. These criteria have been developed by the industry and adopting these criteria would ensure consistency with other jurisdictions in North America. Therefore, it is anticipated that adopting these criteria would maintain and in some cases improve the current level of reliability.

It also should be noted that the NPCC bylaws state that "Independent System Operators (ISOs), regional transmission organizations (RTOs), Transcos and other organizations or entities that perform the Balancing Authority function operating in Northeastern North America are expected to be Full Members of NPCC. Full Members are subject to compliance with regionally-specific more stringent reliability criteria for their generation and transmission facilities on which faults or disturbances can have a significant adverse impact outside of the local area and which are identified utilizing a reliability impact based methodology". Nalcor (more specifically NLH) will be performing the Balancing Authority function. However, the extent to which the regional reliability criteria would apply will depend on the results of NPCC BPS testing criteria (NPCC document A10) and through discussions with NPCC.

The following sections outline the potential cost impact from adopting the NPCC regional reliability criteria.

3.3.1 Assessment of Cost on regional reliability criteria for Nalcor

For this initial cost assessment, the following costs were considered for each reliability standard:

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1. One time capital costs.
2. Potential internal labour costs.
3. Potential ongoing labour/administrative costs.

In addition, on an overall basis, the following costs were considered:

1. Staffing or new hire considerations.
2. NPCC Funding.
3. External assistance (e.g. consulting).

3.3.1.1 Potential capital costs for regional reliability criteria

In review of the NPCC regional reliability criteria, it is anticipated that there would be no capital costs required for the adoption of these criteria. However, it is worth noting that there may be some gaps and/or risks associated with the directory criteria and these are discussed below.

Directory #1 – Design and Operation of the Bulk Power System has a requirement on Loss of Load Expectation (LOLE). The requirement is that the LOLE of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year (one day in ten years). Currently, NLH has its own criteria of meeting a one day in five year LOLE. For NLH to apply a LOLE criteria of one day in ten years, additional generating capacity would have to be built and maintained, the cost of which would be included in NLH's rate base. For this reason, a one day in five year LOLE criteria was adopted. With the LCP, NLH used the same criteria of one day in five years. However, the analysis did not include any available capacity or energy that could be supplied by the ML from the Maritime Provinces. Further work is required in this area to determine the LOLE with the addition of the ML. While it is not anticipated that there will be a capital cost associated with this, it is noted here as gap and potential risk as there may be new generation required to meet the NPCC LOLE criteria.

Directory #4 – System Protection Criteria does have specific requirements for protection on BPS facilities. Through discussions with NPCC on this, they have indicated that "the existing facilities be treated as pre-criteria facilities, and subject to a "grandfathering" exemption. However, upgrading to meet criteria would be done in accordance with the criteria in the directories as the facilities are replaced or renewed (See Appendix H). For the discussion with NPCC, the BPS facilities were considered to be all the 230 kV facilities in NL. However, an assessment of this would be required. Therefore, there would be no requirements to ensure the current BPS facilities meet the criteria in directory #4.

Directory #7 – Special Protection Systems (SPS) has specific requirements around SPS's and their design. For the LCP, SPS have been identified as being a requirement. However, since NLH does not currently have any SPS's, all of the infrastructure would be new. Therefore, the capital costs associated with this are included in the project design and will not be an additional cost attributable to the reliability standards.

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3.3.1.2 Potential initial internal costs for regional reliability criteria

As previously mentioned, each of the regional reliability criteria are associated with a number of NERC reliability standards. In fact, their design is based on these reliability standards. However, they expand on these reliability standards and create more stringent criteria applicable to the NPCC region.

With this in mind, the potential internal costs have already been taken into account in the internal cost assessment for the NERC reliability standards. However, there are two exceptions to this.

The first is the requirement to complete an assessment to determine the BPS facilities. This would be done in accordance with NPCC document A-10 – Classification of Bulk Power System Elements. The BPS facilities identified in this assessment would then be applied to the regional reliability criteria as required.

The second is the requirements around SPS's in directory #4 – Special Protection Systems. While there has been some internal labour allocated for this in the reliability standards assessment, a more detailed look at this directory would be required.

The following table outlines the potential internal costs.

NPCC Document/Directory	Labour Required	UOM	Number Required	Estimated Cost ($3,200/Week)
A-10 – Classification of Bulk Power System	Sys Plan (1)	Weeks	12	$38,400
Directory #4 – Special Protection Systems	Sys Plan (1)	Weeks	12	$38,400
			Total Cost	**$76,800**

3.3.1.3 Potential ongoing costs for regional reliability criteria

As with the potential initial internal costs, the ongoing costs for the regional reliability criteria have already been taken into account in the cost assessment for the NERC reliability standards.

Therefore, there would be no additional ongoing costs in adopting the regional reliability criteria.

3.3.1.4 Staffing considerations for regional reliability criteria

When looking at the potential for new staffing requirements, consideration was given to what would be required to maintain compliance with the regional reliability criteria. For this, the compliance team and new staff previously identified for the NERC reliability standards would also ensure compliance with the regional reliability criteria.

Therefore, there would be no additional staffing requirements to maintain compliance with regional reliability criteria.

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3.3.1.5 NPCC funding

Each year, NPCC develops a business plan and budget. Within this plan there are two separate divisions which have separate budget expenses. The divisions and activities are:

1. Regional Entity Division
    - Active participation in the development of NERC reliability standards for the BPS, and as needed, development of reliability standards applicable within the NPCC cross-border regional entity.
    - Monitoring and enforcement of approved reliability standards, including the registration of responsible entities, and as needed, certification of such entities.
    - Assessment of the present and future reliability of the BPS.
    - Operational coordination and situation awareness support.
    - Event analysis and identifying lessons learned to improve reliability.
    - Effective training and education of reliability personnel.
    - Promoting the protection of critical electric infrastructure.
2. Criteria Services Division
    - Activities are in the development, maintenance and promulgation of regionally specific more stringent criteria as well as criteria establishing resource adequacy requirements within the region.

In order to determine the amount of funding requirements, the NEL criterion is used (see definition in Appendix A). From the NPCC perspective, each BA has to provide funding based on the NEL criteria.

For the Regional Entity Division, the NEL percentage is applied to each BA. The one difference with this compared to the NERC allocation, is that 60% is based on how the BA uses NPCC in compliance and enforcement activities.

For the Criteria Services Division, the NEL percentage is applied to each BA.

To estimate the amount of funding that would be required for NLH, the following parameters were used:

1. 8 GWH NEL
2. NPCC 2012 budget estimates of $13,357,567 for the Regional Entity Division and $956,900 for the Criteria Services Division
3. Other NPCC entities and their NEL's (taken from NPCC data)

Based on these parameters, it is estimated that the funding requirements would be $109,700 for the Regional Entity Division and $11,900 for the Criteria Services Division annually.

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Item Description	UOM	Rate/Year	Number Required	Estimated Cost
NPCC Funding – Regional Entity Division	Yearly	109,700	Annual	$109,700
NPCC Funding – Criteria Services Division	Yearly	11,900	Annual	$11,900
			Total Cost	**$121,600**

3.3.1.6 External assistance requirements

As with the NERC reliability standards, it is anticipated that an external consultant would be required for assistance in the area of the NPCC regional reliability criteria. This consultant would perform the same type of assessments as outlined previously for NERC reliability standards. However, it should be noted here that the costs associated with an external consultant for the regional reliability criteria have been taken into account for the consultant for the NERC reliability standards. It is assumed that the external consultant would be familiar with both the NERC reliability standards and the NPCC regional reliability criteria.

Therefore, there would be no additional external consulting costs in adopting the regional reliability criteria.

In addition to an external consultant, it is anticipated that there would be much interaction and discussion with NPCC leading up to adopting the regional reliability criteria. This would potentially include things like Memorandum of Understanding (MOU) development, compliance program development and setting out expectations of all parties. However, this work would be completed by the compliance personnel that were previously identified.

As a result of this, there could be a requirement to provide funding to NPCC. This would occur over the next 5 years leading up to the time of being interconnected to the North American grid. At that time, if the regional reliability criteria are adopted, the annual funding to NPCC would start. Therefore, a cost estimate is included for NPCC's potential services (including potential travel) over the next 5 years.

Item Description	UOM	Rate/UOM	Number Required	Estimated Cost
NPCC Services	n/a	n/a	n/a	$50,000
			Total Cost	**$50,000**

3.4 CIP reliability standards

The NERC CIP standards provide a cyber-security framework for the identification and protection of Critical Cyber Assets to support the reliable operation of the BES. The standards recognize the criticality and vulnerability of these assets that are needed to manage BES reliability and the risks to which they are exposed.

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Business and operational demands for managing and maintaining a reliable BES increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

The CIP reliability standards continue to undergo changes in order to ensure the protection of Cyber Assets is done in the best way possible. Currently, CIP version 3 is in effect. CIP version 4 has been approved by the Federal Energy Regulatory Commission (FERC) and will come into effect in 2014. However, the NERC standard drafting team is working on CIP version 5 and this version is currently in the voting stages. The target is for CIP version 5 to be approved by FERC in 2014 and to become effective in 2015. If this occurs, CIP version 4 would be superseded.

While there are some differences between CIP versions 4 and 5, the idea is to first identify Critical Assets and then identify the Critical Cyber Assets associated with each Critical Asset. Version 5 goes somewhat further in rating the Critical Assets as high, medium or low impact. However, essentially the idea is the same in both versions. In doing the cost analysis, a combination of CIP versions 4 and 5 is used as more than likely, one of these will be in effect.

3.4.1 Initial assessment of Critical Assets

An assessment is required to determine the Critical Assets first before determining the Critical Cyber Assets. Reliability standard CIP-002-4 – Critical Cyber Asset Identification, contains a list of what would be considered Critical Assets. As well, reliability standard CIP-002-5 (which is in development), contains two items that could potentially impact the identification of Critical Assets. The full list can be found in Appendix F.

Based on the requirements for Critical Cyber Asset identification, there are 12 facilities that have been identified as potentially being Critical Assets. They are:

1. Energy Control Center
2. Backup Control Center
3. Muskrat Falls Terminal Station
4. Muskrat Falls Generating Station
5. Soldiers Pond Terminal Station
6. Bay d'Espoir Terminal Station
7. Bay d'Espoir Generating Station
8. Bottom Brook Terminal Station
9. Western Avalon Terminal Station
10. Stony Brook Terminal Station
11. Hardwoods Terminal Station
12. Bay d'Espoir Control Room

The applicable criteria and what facilities apply to each one can be found in Appendix F.

3.4.2 Assessment of cost for CIP standards for Nalcor

With adopting the NERC CIP standards, there is a cost associated with achieving compliance. To be consistent with other cost estimates in this report, the cost assessment in this section is completed on all the CIP standards as they were determined to be optional in section 3.2.1.

For this initial cost assessment, the following were considered for each reliability standard:

1. One time capital costs.
2. Potential internal labour costs.
3. Potential ongoing labour/administrative costs.

In addition, on an overall basis, the following costs were considered:

1. Staffing or new hire considerations.
2. External assistance (e.g. consulting)

3.4.2.1 Potential capital costs for CIP standards

The following list outlines the potential one-time capital costs, details on the requirements and the CIP standards that it is required for.

1. Centralized logging server
    - Required for all CIP standards.
    - This would be required to log and monitor all activities on the items identified as Critical Cyber Assets to ensure the security of the equipment

Item Description	UOM	Rate/UOM	Number Required	Estimated Cost
Logging Server	EA	50,000	1	$50,000
			Total Cost	**$50,000**

2. Firewalls
    - Required for all CIP standards.
    - A firewall is used to keep a network secure. Its primary objective is to control incoming and outgoing network traffic by analyzing the data and determining if it should be allowed through, based on a predetermined rule set.
    - This would be required to establish an electronic security perimeter at all locations that were determined to be critical in section 3.4.1

Item Description	UOM	Rate/UOM	Number Required	Estimated Cost
Firewalls	EA	3,000	10	$30,000
			Total Cost	**$30,000**

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3.4.2.2 Potential internal costs for CIP standards

To be in position for compliance with the CIP standards, there are many requirements that would need to be met. The main component of this would be in the area of documentation which would involve things like change management, disaster recovery and programs for testing and maintenance. In order to do this, there would be a considerable amount of internal labour that would be required.

A team could be put in place within Nalcor that would be responsible for assessing and implementing the infrastructure required for CIP compliance. They would also ensure the correct documentation is developed for meeting compliance. This would include staff from Energy Systems, Operations (TRO), Hydro Generation and Information Systems. It would also include assistance from the compliance team as required.

The following list outlines the potential internal costs and the details on the requirements.

1. Energy Systems, TRO and Hydro Generation
    - Documentation requirements for the Energy Control Center's and Backup Control Center's EMS.
    - Identifying Critical Cyber Assets.
    - Development of change control and configuration management process.
    - Development of processes for logging and monitoring.
    - Training program for personnel having access to Critical Cyber Assets.
    - Deployment of firewalls.
    - Development of vulnerability testing processes.
    - Development of backup and/or disaster recovery and incident management processes for Critical Cyber Assets.

Item Description	UOM	Rate/UOM	Number Required	Estimated Cost
Energy Systems Labour	Weeks	3,200	220	$704,000
TRO Labour	Weeks	3,200	104	$332,800
Hydro Generation Labour	Weeks	3,200	78	$249,600
			Total Potential Internal Cost	**$1,286,400**

2. Information Systems
    - There are potential requirements for assistance from the information systems department with regards to security. The assistance from this department would be to ensure that all processes and procedures are being carried out in the appropriate manner based on existing policies within NLH and to develop any new policies as required.
    - The amount of assistance from this position is unknown at this time. For this estimate, 26 weeks is used.

Item Description	UOM	Rate/UOM	Number Required	Estimated Cost
Information Systems Labour	Weeks	3,200	26	$83,200
			Total Cost	**$83,200**

There were a total of 428 person weeks identified to implement the CIP reliability standards to a level that would meet compliance. This equates to approximately 9 FTE's. It should be noted that this work would be completed over a 3 - 5 year period with everything in place to meet compliance before the LCP project it completed.

3.4.2.3 Potential ongoing costs for CIP standards

As mentioned previously, there are a number of things that are required to be compliant with each CIP standard. Once these requirements are in place, there would be ongoing costs to maintain compliance with each standard.

These ongoing costs would be labour and administration costs that would be associated with each CIP standard. This would primarily be ongoing annual requirements to review documentation, processes, training and testing. The estimate is based on the amount of annual requirements that are listed in the CIP standards and does not break it out by individual standard.

The following table indicates the potential ongoing internal costs for CIP standards:

Item Description	UOM	Rate/UOM	Number Required	Estimated Cost
Energy Systems Labour	Weeks	3,200	8	$25,600
TRO Labour	Weeks	3,200	4	$12,800
Hydro Generation Labour	Weeks	3,200	2	$6,400
			Total Potential Ongoing Cost	**$44,800**

3.4.2.4 Staffing considerations for CIP standards

When looking at the potential for new staffing requirements, consideration was given to what would be required to maintain compliance with CIP standards. For this, the compliance team identified for the NERC reliability standards would also ensure compliance with the CIP standards.

It should be noted that there has not been any additional staff requirements included here for other areas in the company for ongoing compliance. This includes Energy Systems, Hydro Generation and TRO. However, a closer assessment would be required by the individual areas to ensure this would be the case.

Therefore, there were no additional staffing requirements included here to maintain compliance with the CIP standards.

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3.4.2.5 External assistance requirements

An external consultant would be required for assistance in the area of CIP standards. Currently, there is some knowledge with CIP standards within NLH (i.e. Energy Systems, Reliability Standards Engineer). However, since these standards have not been adopted, the knowledge is not direct and comes from keeping up to date with the standards and implementing where practical.

The consultant would complete a mock audit on the CIP standards, once the initial work has been completed to ensure potential compliance. This would help prepare Nalcor for any audit requirements, the amount of effort it would take for an audit and help determine what gaps exist (if any) for compliance.

Item Description	UOM	Rate/UOM	Number Required	Estimated Cost
Consultant	Weeks	7000	8	$56,000
			Total Cost	**$56,000**

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4.0 Overall cost summary

The following tables give a summary of the overall cost estimate for adopting NERC reliability standards, NPCC regional reliability criteria and CIP standards. The first table summarizes the initial costs to adopt the standards and get to a level of compliance. The second table summarizes the ongoing costs to maintain compliance.

Item	NERC Reliability Standards	NPCC Regional Reliability Criteria	CIP Standards	
Capital Costs	$420,000	n/a	$80,000	
Internal Labour Costs	$1,831,600	$76,800	$1,369,600	
External Assistance Costs	$56,000	$50,000	$56,000	
Total	$2,307,600	$126,800	$1,505,600	$3,940,000

Item	NERC Reliability Standards	NPCC Regional Reliability Criteria	CIP Standards	
Ongoing Labour Costs	$491,400	n/a	$44,800	
New Staff Costs	$255,000	n/a	n/a	
Ongoing Funding Costs	$90,000	$121,600	n/a	
Total	$836,400	$121,600	$44,800	$1,002,800

Using a 30% contingency factor, the range for the total overall cost estimates would be:

- Lower Cost: $4,942,800
- Upper Cost: $6,425,640

Appendix A – Abbreviations and Definitions

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Abbreviations

Abbreviation	Definition
ATC	Available Transfer Capability
BA	Balancing Authority
BES	Bulk Electric System
BPS	Bulk Power System
CE	Continuing Education
CF(L)Co	Churchill Falls (Labrador) Corporation
CIP	Critical Infrastructure Protection
DP	Distribution Provider
ERO	Electric Reliability Organization
ECC	Energy Control Center
EMS	Energy Management System
FERC	Federal Energy Regulatory Commission
FTE	Full Time Equivalent
GOP	Generator Operator
GO	Generator Owner
HQ	Hydro Quebec
HQP	Hydro Quebec Production
ISO	Independent System Operator
IC	Interchange Coordinator
ICCP	Inter-Control Center Communications Protocol
kV	Kilovolt
Lab Transco.	Labrador Transmission Co.
LIL	Labrador Island Link
LIL LP	Labrador Island Link Limited Partnership
LTA	Labrador Transmission Assets
LSE	Load-Serving Entity
LOLE	Loss Of Load Expectation
LCP	Lower Churchill Project
ML	Maritime Link
MW	Megawatt
MOU	Memorandum of Understanding
MF	Muskrat Falls
MF Co.	Muskrat Falls Co.
NEM	Nalcor Energy Marketing
NEL	Net Energy for Load
NL	Newfoundland and Labrador
NLH	Newfoundland and Labrador Hydro
NP	Newfoundland Power
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NSPI	Nova Scotia Power Inc.

Abbreviation	Definition
OATI	Open Access Technology Inc.
OTS	Operator Training Simulator
PC	Planning Coordinator
PPA	Power Purchase Agreement
PUB	Public Utilities Board
PSE	Purchasing-Selling Entity
RRO	Regional Reliability Organization
RTO	Regional Transmission Organization
RC	Reliability Coordinator
RP	Resource Planner
SPS	Special Protection Systems
TOP	Transmission Operator
TO	Transmission Owner
TP	Transmission Planner
TSP	Transmission Service Provider

Definitions:

Arranged Interchange – The state where the interchange coordinator has received the interchange information (initial or revised).

Available Transfer Capability – A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.

Balancing Authority Area – The collection of generation, transmission and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

Bulk Electric System – The electrical generation resources, transmission lines, and interconnections with neighbouring systems and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.

Bulk Power System – The interconnected electrical systems within north-eastern North America comprised of system elements on which faults or disturbances can have a significant adverse impact outside of a Local Area.

Confirmed Interchange – The state where the interchange coordinator has verified the Arranged Interchange.

Critical Cyber Asset – Cyber Assets essential to the reliable operation of Critical Assets.

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Critical Assets – Facilities, systems and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.

Federal Energy Regulatory Commission – The United States federal agency with jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing and oil pipeline rates. It also reviews and authorizes liquefied natural gas terminals, interstate natural gas pipelines and non-federal hydro power projects.

Functional Entity – A class of entity that carries out reliability tasks within the Functional Model.

Interconnection – When capitalized, any of the three major electric systems in North America: Eastern, Western and ERCOT.

Muskrat Falls Co. – A subsidiary company of Nalcor Energy which will own the Muskrat Falls generating plant.

Labrador Island Link – The transmission facilities to be constructed by or on behalf of the Labrador Island Link Limited Partnership from central Labrador to Soldiers Pond, NL.

Labrador Island Link Limited Partnership – A subsidiary of Nalcor Energy which will have majority ownership of the LIL.

Labrador Transmission Assets – The transmission facilities to be constructed by an affiliate of Nalcor between the Muskrat Falls plant and the generating plant located at Churchill Falls.

Labrador Transmission Co. – A subsidiary of Nalcor Energy which will own the LTA.

Loss of Load Expectation – The probability (or risk) of disconnecting firm load due to resource deficiencies.

Memorandum of Understanding – A document that describes the general principles of an agreement between parties, but does not amount to a substantive contract.

Net Energy for Load – Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities".

Regional Reliability Organization – An entity that ensures that a defined area of the Bulk Electric System is reliable, adequate and secure. The Regional Reliability Organization is a member of NERC and can serve as the Compliance Monitor.

Regional Transmission Organization – An entity that is independent from all generation and power marketing interests and has exclusive responsibility for grid operations, short-term reliability, and transmission service within a region.

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Reliability Coordinator Area – The collection of generation, transmission and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.

Remedial Action Scheme – See definition of Special Protection System.

Special Protection System – An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) Underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). These are also called Remedial Action Schemes.

Transmission Customer – Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service or; any of the following responsible entities: Generator Owner, Load-Serving Entity or Purchasing-Selling Entity.

Transmission Operator Area – The collection of transmission assets over which the transmission operator is responsible for operating.

Transmission Service – Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a point of receipt to a point of delivery.

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Appendix B – NERC Functional Entities and Definitions

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	Functional Entity	Definition
1	Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
2	Distribution Provider	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any level.
3	Generator Operator	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
4	Generator Owner	Entity that owns and maintains generating units.
5	Interchange Coordinator	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.
6	Load-Serving Entity	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.
7	Planning Coordinator	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
8	Purchasing-Selling Entity	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.
9	Reliability Coordinator	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next day analysis and real time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operators vision.
10	Resource Planner	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.

	Functional Entity	Definition
11	Transmission Operator	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.
12	Transmission Owner	The entity that owns and maintains transmission facilities.
13	Transmission Planner	The entity that develops a long term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.
14	Transmission Service Provider	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.

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Appendix C – Reliability Standards that apply and don't apply to Nalcor Functional Entities

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	Reliability Standard	Applicable Functional Entity
1	BAL-001-0.1a -Real Power Balancing Control Performance	BA
2	BAL-002-1 - Disturbance Control Performance	BA
3	BAL-003-0.1b - Frequency Response and Bias	BA
4	BAL-004-0 - Time Error Correction	BA, RC
5	BAL-005-0-2b - Automatic Generation Control	BA, GOP, TOP
6	BAL-006-2 - Inadvertent Interchange	BA
7	COM-001-1.1 - Telecommunications	BA, RC, TOP
8	COM-002-2a - Communication and Coordination	BA, RC, GOP, TOP
9	CIP-001-2a - Sabotage Reporting	BA, RC, GOP, TOP, LSE
10	CIP-002-4 - Cyber Security – Critical Cyber Asset Identification (*)	BA, RC, GOP, TOP, GO, TO, IC, TSP, LSE
11	CIP-003-4 - Cyber Security – Security Management Controls (*)	BA, RC, GOP, TOP, GO, TO, IC, TSP, LSE
12	CIP-004-4 - Cyber Security – Personnel & Training (*)	BA, RC, GOP, TOP, GO, TO, IC, TSP, LSE
13	CIP-005-4a - Cyber Security – Electronic Security Perimeters (*)	BA, RC, GOP, TOP, GO, TO, IC, TSP, LSE
14	CIP-006-4d - Cyber Security – Physical Security of Critical Cyber Assets (*)	BA, RC, GOP, TOP, GO, TO, IC, TSP, LSE
15	CIP-007-4 - Cyber Security – Systems Security Management (*)	BA, RC, GOP, TOP, GO, TO, IC, TSP, LSE
16	CIP-008-4 - Cyber Security – Incident Reporting and Response Planning (*)	BA, RC, GOP, TOP, GO, TO, IC, TSP, LSE
17	CIP-009-4 - Cyber Security – Recovery Plans for Critical Cyber Assets (*)	BA, RC, GOP, TOP, GO, TO, IC, TSP, LSE
18	EOP-001-2.1b - Emergency Operations Planning (*)	BA, TOP
19	EOP-002-3.1 - Capacity and Energy Emergencies	BA, RC
20	EOP-003-2 - Load Shedding Plans (*)	BA, TOP
21	EOP-004-1 - Disturbance Reporting	BA, RC, GOP, TOP
22	EOP-005-1 - System Restoration Plans	BA, TOP
23	EOP-006-1 - Reliability Coordination – System Restoration	RC
24	EOP-008-1 - Loss of Control Center Functionality (*)	BA, RC, TOP
25	EOP-009-0 - Documentation of Blackstart Generating Unit Test Results	GOP, GO
26	FAC-001-0 - Facility Connection	TO

	Reliability Standard	**Applicable Functional Entity**
	Requirements	
27	FAC-002-1 - Coordination of Plans for New Generation, Transmission and End-User Facilities	GOP, TOP, TP
28	FAC-003-1 - Transmission Vegetation Management Program	TO
29	FAC-008-3 - Facility Ratings (*)	GO, TO
30	FAC-009-1 - Establish and Communicate Facility Ratings	GO, TO
31	FAC-010-2.1 - System Operating Limits Methodology for the Planning Horizon	PC
32	FAC-011-2 - System Operating Limits Methodology for the Operations Horizon	RC
33	FAC-012-1 - Transfer Capability Methodology	RC (*), PC (*)
34	FAC-013-2 - Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon (*)	RC (*), PC (*)
35	FAC-014-2 - Establish and Communicate System Operating Limits	RC, TOP, TP, PC
36	INT-001-3 - Interchange Information	BA
37	INT-003-3 - Interchange Transaction Implementation	BA
38	INT-004-2 - Dynamic Interchange Transaction Modifications	BA, RC, TOP
39	INT-005-3 - Interchange Authority Distributes Arranged Interchange	IC
40	INT-006-3 - Response to Interchange Authority	BA, TSP
41	INT-007-1 - Interchange Confirmation	IC
42	INT-008-3 - Interchange Authority Distributes Status	IC
43	INT-009-1 - Implementation of Interchange	BA
44	INT-010-1 - Interchange Coordination Exemptions	BA, RC
45	IRO-001-1.1 - Reliability Coordination - Responsibilities and Authorities	BA, RC, GOP, TOP, TSP, LSE
46	IRO-002-2 - Reliability Coordination - Facilities	RC
47	IRO-003-2 - Reliability Coordination -	RC

	Reliability Standard	Applicable Functional Entity
	Wide Area View	
48	IRO-004-2 - Reliability Coordination - Operations Planning	BA, TOP, TSP
49	IRO-005-3.1a - Reliability Coordination - Current Day Operations	BA, RC, GOP, TOP, TSP, LSE
50	IRO-006-5 - Reliability Coordination - Transmission Loading Relief (TLR)	BA, RC
51	IRO-006-EAST-1 - Transmission Loading Relief Procedure for the Eastern Interconnection	RC
52	IRO-008-1 - Reliability Coordinator Operational Analyses and Real-time Assessments	RC
53	IRO-009-1 - Reliability Coordinator Actions to Operate Within IROLs	RC
54	IRO-010-1a - Reliability Coordinator Data Specification and Collection	BA, RC, GOP, TOP, GO, TO, IC, LSE
55	IRO-014-1 - Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	RC
56	IRO-015-1 - Notifications and Information Exchange Between Reliability Coordinator	RC
57	IRO-016-1 - Coordination of Real-time Activities Between Reliability Coordinators	RC
58	MOD-001-1a - Available Transmission System Capability	TOP, TSP
59	MOD-004-1 - Capacity Benefit Margin	BA, TSP, TP, RP, LSE
60	MOD-008-1 - Transmission Reliability Margin Calculation Methodology	TOP
61	MOD-010-0 - Steady-State Data for Modeling and Simulation of the Interconnected Transmission System	GO, TO, TP, RP
62	MOD-011-0 - Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures	GO, TO, TP, RP (Only R1 if required by RRO)
63	MOD-012-0 - Dynamics Data for Modeling and Simulation of the Interconnected Transmission System	GO, TO, TP, RP
64	MOD-013-1 - Maintenance and Distribution of Dynamics Data Requirements and Reporting	GO, TO, TP, RP (Only R1 if required by RRO)

	Reliability Standard	**Applicable Functional Entity**
	Procedures	
65	MOD-016-1.1 - Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management	PC
66	MOD-017-0.1 - Aggregated Actual and Forecast Demands and Net Energy for Load	PC, RP, LSE
67	MOD-018-0 - Treatment of Non-member Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load	PC, TP, RP, LSE
68	MOD-019-0.1 - Reporting of Interruptible Demands and Direct Control Load Management	PC, TP, RP, LSE
69	MOD-020-0 - Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators	TP, RP, LSE
70	MOD-021-1 - Documentation of the Accounting Methodology for the Effects of Demand Side Management in Demand and Energy Forecasts	TP, RP, LSE
71	MOD-024-1 - Verification of Generator Gross and Net Real Power Capability	GO
72	MOD-025-1 - Verification of Generator Gross and Net Reactive Power Capability	GO
73	MOD-028-1 - Area Interchange Methodology	TOP, TSP
74	MOD-029-1a - Rated System Path Methodology	TOP, TSP
75	MOD-030-2 - Flowgate Methodology	TOP, TSP
76	PER-001-0.2 - Operating Personnel Responsibility and Authority	BA, TOP
77	PER-002-0 - Operating Personnel Training	BA, TOP
78	PER-003-1 - Operating Personnel Credentials (*)	BA, RC, TOP
	Reliability Standard	Applicable Functional Entity
79	PER-004-1 - Reliability Coordination	RC

	Reliability Standard	Applicable Functional Entity
	Staffing	
80	PRC-001-1.1 - System Protection Coordination	BA, GOP, TOP
81	PRC-002-NPCC-01 - Disturbance Monitoring	RC, GO, TO
82	PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations	GO, TO
83	PRC-005-1b - Transmission and Generation Protection System Maintenance and Testing	GO, TO
84	PRC-006-1 - Automatic Underfrequency Load Shedding (*)	TO, PC
85	PRC-007-0 - Assuring Consistency with Regional UFLS Program Requirements	TOP, TO
86	PRC-008-0 - Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program	TO
87	PRC-009-0 - Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event	TOP, TO
88	PRC-010-0 - Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program	TOP, TO, LSE
89	PRC-011-0 - Undervoltage Load Shedding System Maintenance and Testing	TO
90	PRC-015-0 - Special Protection System Data and Documentation	GO, TO
91	PRC-016-0-1 - Special Protection System Misoperations	GO, TO
92	PRC-017-0 - Special Protection System Maintenance and Testing	GO, TO
93	PRC-018-1 - Disturbance Monitoring Equipment Installation and Data Reporting	GO, TO
94	PRC-021-1 - Undervoltage Load Shedding Program Data	TO
95	PRC-022-1 - Undervoltage Load Shedding Program Performance	TO, LSE

	Reliability Standard	Applicable Functional Entity
96	PRC-023-2 - Transmission Relay Loadability	GO, TO, PC
97	TOP-001-1a - Reliability Responsibilities and Authorities	BA, GOP, TOP, LSE
98	TOP-002-2.1b - Normal Operations Planning	BA, GOP, TOP, TSP, LSE
99	TOP-003-1 - Planned Outage Coordination	BA, RC, GOP, TOP
100	TOP-004-2 - Transmission Operations	TOP
101	TOP-005-2a - Operational Reliability Information	BA, TOP
102	TOP-006-2 - Monitoring System Conditions	BA, RC, GOP, TOP
103	TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	RC, TOP
104	TOP-008-1 - Response to Transmission Limit Violations	TOP
105	TPL-001-0.1 - System Performance Under Normal (No Contingency) Conditions (Category A)	TP, PC
106	TPL-002-0b - System Performance Following Loss of a Single Bulk Electric System Element (Category B)	TP, PC
107	TPL-003-0a - System Performance Following Loss of Two or more Bulk Electric System Elements (Category C)	TP, PC
108	TPL-004-0 - System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)	TP, PC
109	VAR-001-2 - Voltage and Reactive Control	TOP, LSE
110	VAR-002-1-1b - Generator Operation for Maintaining Network Voltage Schedules	GOP, GO

Note: Standards in above table with (*) have been approved by both NERC and FERC and will come into effect at a date determined by the organizations.

	Reliability Standard	Applicability
1	MOD-014-0 - Development of Steady-State System Models	RRO
2	MOD-015-0.1 - Development of Dynamic System Models	RRO
3	NUC-001-2.1 - Nuclear Plant Interface Coordination	GOP (Nuclear Plant), other functional entities providing services to Nuclear Plants
4	PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems	RRO
5	PRC-012-0 - Special Protection System Review Procedure	RRO
6	PRC-013-0 - Special Protection System Database	RRO
7	PRC-014-0 - Special Protection System Assessment	RRO
8	PRC-020-1 - Under-voltage Load Shedding Program Database	RRO
9	TPL-005-0 - Regional and Interregional Self-Assessment Reliability Reports	RRO
10	TPL-006-0.1 - Data from the Regional Reliability Organization Needed to Assess Reliability	RRO

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Appendix D – Required, Not Required and Optional NERC Reliability Standards for Nalcor

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	Required reliability standards for NLH	**Category**
1	BAL-006-2 – Inadvertent Interchange	Resource and Demand Balancing (BAL)
2	INT-001-3 - Interchange Information	Interchange Scheduling and Coordination (INT)
3	INT-003-3 – Interchange Transaction Implementation	
4	INT-004-2 – Dynamic Interchange Transaction Modifications	
5	INT-005-3 – Interchange Authority Distributes Arranged Interchange	
6	INT-006-3 – Response to Interchange Authority	
7	INT-007-1 – Interchange Confirmation	
8	INT-008-3 – Interchange Authority Distributes Status	
9	INT-009-1 – Implementation of Interchange	
10	INT-010-1 – Interchange Coordination Exemptions	

	Optional reliability standards for NLH	**Category**
1	BAL-001-0.1a –Real Power Balancing Control Performance	Resource and Demand Balancing (BAL)
2	BAL-002-1 – Disturbance Control Performance	
3	BAL-003-0.1b – Frequency Response and Bias	
4	BAL-004-0 – Time Error Correction	
5	BAL-005-0-2b – Automatic Generation Control	
6	COM-001-1.1 – Telecommunications	Communications (COM)
7	COM-002-2a – Communication and Coordination	
8	CIP-001-2a – Sabotage Reporting	Critical Infrastructure Protection (CIP)
9	CIP-002-4 – Cyber Security – Critical Cyber Asset Identification (*)	
10	CIP-003-4 – Cyber Security – Security Management Controls (*)	
11	CIP-004-4 – Cyber Security – Personnel & Training (*)	
12	CIP-005-4a – Cyber Security – Electronic Security Perimeters (*)	
13	CIP-006-4d – Cyber Security – Physical Security of Critical Cyber Assets (*)	
14	CIP-007-4 – Cyber Security – Systems Security Management (*)	
15	CIP-008-4 – Cyber Security – Incident Reporting and Response Planning (*)	

	Optional reliability standards for NLH	**Category**
16	CIP-009-4 – Cyber Security – Recovery Plans for Critical Cyber Assets (*)	
17	EOP-001-2.1b – Emergency Operations Planning (*)	Emergency Preparedness and Operations (EOP)
18	EOP-002-3.1 - Capacity and Energy Emergencies	
19	EOP-003-2 – Load Shedding Plans (*)	
20	EOP-004-1 - Disturbance Reporting	
21	EOP-005-1 – System Restoration Plans	
22	EOP-006-1 – Reliability Coordination – System Restoration	
23	EOP-008-1 – Loss of Control Center Functionality (*)	
24	EOP-009-0 - Documentation of Blackstart Generating Unit Test Results	
25	FAC-001-0 - Facility Connection Requirements	Facilities Design, Connections, and Maintenance (FAC)
26	FAC-002-1 - Coordination of Plans for New Generation, Transmission and End-User Facilities	
27	FAC-003-1 – Transmission Vegetation Management Program	
28	FAC-008-3 - Facility Ratings (*)	
29	FAC-009-1 - Establish and Communicate Facility Ratings	
30	FAC-010-2.1 – System Operating Limits Methodology for the Planning Horizon	
31	FAC-011-2 - System Operating Limits Methodology for the Operations Horizon	
32	FAC-012-1 - Transfer Capability Methodology	
33	FAC-013-2 - Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon (*)	
34	FAC-014-2 - Establish and Communicate System Operating Limits	
35	IRO-001-1.1 – Reliability Coordination – Responsibilities and Authorities	Interconnection Reliability Operations and Coordination (IRO)
36	IRO-002-2 – Reliability Coordination – Facilities	
37	IRO-003-2 – Reliability Coordination – Wide Area View	
38	IRO-004-2 – Reliability Coordination – Operations Planning	
39	IRO-005-3.1a – Reliability Coordination – Current Day Operations	
40	IRO-006-5 – Reliability Coordination – Transmission Loading Relief (TLR)	
41	IRO-006-EAST-1 – Transmission Loading Relief Procedure for the Eastern Interconnection	
42	IRO-008-1 - Reliability Coordinator Operational Analyses	

	Optional reliability standards for NLH	Category
	and Real-time Assessments	
43	IRO-009-1 – Reliability Coordinator Actions to Operate Within IROLs	
44	IRO-010-1a - Reliability Coordinator Data Specification and Collection	
45	IRO-014-1 - Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	
46	IRO-015-1 - Notifications and Information Exchange Between Reliability Coordinator	
47	IRO-016-1 - Coordination of Real-time Activities Between Reliability Coordinators	
48	MOD-001-1a – Available Transmission System Capability	Modelling, Data, and Analysis (MOD)
49	MOD-010-0 – Steady-State Data for Modeling and Simulation of the Interconnected Transmission System	
50	MOD-011-0 – Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures	
51	MOD-012-0 – Dynamics Data for Modeling and Simulation of the Interconnected Transmission System	
52	MOD-013-1 – Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures	
53	MOD-016-1.1 – Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management	
54	MOD-017-0.1 – Aggregated Actual and Forecast Demands and Net Energy for Load	
55	MOD-018-0 – Treatment of Non-member Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load	
56	MOD-019-0.1 – Reporting of Interruptible Demands and Direct Control Load Management	
57	MOD-020-0 – Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators	
58	MOD-021-1 – Documentation of the Accounting Methodology for the Effects of Demand Side Management in Demand and Energy Forecasts	
59	MOD-024-1 - Verification of Generator Gross and Net Real Power Capability	
60	MOD-025-1 - Verification of Generator Gross and Net Reactive Power Capability	
61	MOD-029-1a – Rated System Path Methodology	

	Optional reliability standards for NLH	Category
62	PER-001-0.2 - Operating Personnel Responsibility and Authority	Personnel Performance, Training, and Qualifications (PER)
63	PER-002-0 – Operating Personnel Training	
64	PER-003-1 - Operating Personnel Credentials (*)	
65	PER-004-1 - Reliability Coordination Staffing	
66	PRC-001-1.1 - System Protection Coordination	Protection and Control (PRC)
67	PRC-002-NPCC-01 – Disturbance Monitoring	
68	PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations	
69	PRC-005-1b – Transmission and Generation Protection System Maintenance and Testing	
70	PRC-006-1 – Automatic Underfrequency Load Shedding (*)	
71	PRC-007-0 - Assuring Consistency with Regional UFLS Program Requirements	
72	PRC-008-0 - Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program	
73	PRC-009-0 - Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event	
74	PRC-015-0 – Special Protection System Data and Documentation	
75	PRC-016-0-1 – Special Protection System Misoperations	
76	PRC-017-0 – Special Protection System Maintenance and Testing	
77	PRC-018-1 - Disturbance Monitoring Equipment Installation and Data Reporting	
78	PRC-023-2 - Transmission Relay Loadability	
79	TOP-001-1a – Reliability Responsibilities and Authorities	Transmission Operations (TOP)
80	TOP-002-2.1b - Normal Operations Planning	
81	TOP-003-1 – Planned Outage Coordination	
82	TOP-004-2 – Transmission Operations	
83	TOP-005-2a – Operational Reliability Information	
84	TOP-006-2 – Monitoring System Conditions	
85	TOP-007-0 – Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	
86	TOP-008-1 – Response to Transmission Limit Violations	
87	TPL-001-0.1 – System Performance Under Normal (No	Transmission Planning (TPL)

	Optional reliability standards for NLH	**Category**
	Contingency) Conditions (Category A)	
88	TPL-002-0b – System Performance Following Loss of a Single Bulk Electric System Element (Category B)	
89	TPL-003-0a – System Performance Following Loss of Two or more Bulk Electric System Elements (Category C)	
90	TPL-004-0 – System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)	
91	VAR-001-2 – Voltage and Reactive Control	Voltage and Reactive (VAR)
92	VAR-002-1-1b – Generator Operation for Maintaining Network Voltage Schedules	

	Not required reliability standards for NLH	**Explanation**
1	MOD-004-1 - Capacity Benefit Margin	Would not have to be implemented for the NL system
2	MOD-008-1 - Transmission Reliability Margin Calculation Methodology	Would not have to be implemented for the NL system
3	MOD-028-1 - Area Interchange Methodology	NLH would not need to adopt this methodology as the Rated Path Methodology would be used.
4	MOD-030-2 - Flowgate Methodology	NLH would not need to adopt this methodology as the Rated Path Methodology would be used.
5	PRC-010-0 - Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program	NLH does not operate an UVLS scheme (*).
6	PRC-011-0 - Undervoltage Load Shedding System Maintenance and Testing	NLH does not operate an UVLS scheme (*).
7	PRC-021-1 - Undervoltage Load Shedding Program Data	NLH does not operate an UVLS scheme (*).
8	PRC-022-1 - Undervoltage Load Shedding Program Performance	NLH does not operate an UVLS scheme (*).

Note: Standards in above table with (*) indicate that NLH does not currently have an UVLS scheme. This may change with the development of the LCP. However, as of this writing, there has not been a UVLS requirement identified.

Appendix E – Detailed Cost Assessment for NERC Reliability Standards

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Reliability Standard	Labour Required(*)	Estimated Weeks	Estimated Internal Cost ($3200/Week)
BAL-001-0.1a	Sys Ops (1)	2	$6400
BAL-002-1	n/a	n/a	n/a
BAL-003-0.1b	Sys Ops (1)	1	$3200
BAL-004-0	Sys Ops (1)	1	$3200
BAL-005-0-2b	Sys Ops (1), ES (1)	4 (Sys Ops), 1 (ES)	$16,000
BAL-006-2	Sys Ops (1), ES (1)	2 (Sys Ops), 2 (ES)	$12,800
COM-001-1.1	Sys Ops (1), ES (1), NS (1)	2 (Sys Ops), 2 (ES), 2 (NS)	$19,200
COM-002-2a	Sys Ops (1), NS (1)	1 (Sys Ops), 1 (NS)	$6400
EOP-001-2.1b	Sys Ops (1), Sys Plan (1)	8 (Sys Ops), 8 (Sys Plan)	$51,200
EOP-002-3.1	Sys Ops (1), Sys Plan (1)	4 (Sys Ops), 4 (Sys Plan)	$25,600
EOP-003-2	Sys Ops (1), Sys Plan (1), PETS (1)	2 (Sys Ops), 12 (Sys Plan), 8 (PETS)	$70,400
EOP-004-1	Sys Ops (1)	2 (Sys Ops)	$6400
EOP-005-1	Sys Ops (1), Sys Plan (1), Hydro Gen (1)	8 (Sys Ops), 4 (Sys Plan), 2 (Hydro Gen)	$44,800
EOP-006-1	Sys Ops (1), Sys Plan (1)	16 (Sys Ops), 8 (Sys Plan)	$76,800
EOP-008-1	n/a	n/a	n/a
EOP-009-0	n/a	n/a	n/a
FAC-001-0	Sys Plan (1), TRO (1)	12 (Sys Plan), 12 (TRO)	$76,800
FAC-002-1	n/a	n/a	n/a
FAC-003-1	TRO (1)	12	$38,400 (**)
FAC-008-3	Hydro Gen (1), TRO (1)	24 (Hydro Gen), 24 (TRO)	$153,600
FAC-009-1	n/a	n/a	n/a
FAC-010-2.1	Sys Plan (1)	24	$76,800
FAC-011-2	n/a	n/a	Costs included in FAC-010-2.1
FAC-012-1	Sys Plan (1)	16	$51,200
FAC-013-2	n/a	n/a	Costs included in FAC-012-1
FAC-014-2	n/a	n/a	Costs included in FAC-010-2.1
INT-003-3	Sys Ops (1)	2	$6400
INT-004-2	n/a	n/a	n/a
INT-005-3	Sys Ops (1)	2	$6400
INT-006-3	Sys Ops (1)	2	$6400
INT-007-1	n/a	n/a	n/a
INT-008-3	Sys Ops (1)	2	$6400
INT-009-1	n/a	n/a	n/a

Reliability Standard	Labour Required(*)	Estimated Weeks	Estimated Internal Cost ($3200/Week)
INT-010-1	n/a	n/a	n/a
IRO-001-1.1	Sys Ops (1)	12	$38,400
IRO-002-2	Sys Ops (1)	1	$3200
IRO-003-2	n/a	n/a	n/a
IRO-004-2	n/a	n/a	n/a
IRO-005-3.1a	Sys Ops (1)	1	$3200
IRO-006-5	n/a	n/a	n/a
IRO-006-EAST-1	Sys Ops (1)	2	$6400
IRO-008-1	Sys Ops (1)	2	$6400
IRO-009-1	Sys Ops (1)	4	$12,800
IRO-010-1a	Sys Ops (1)	4	$12,800
IRO-014-1	Sys Ops (1)	12	$38,400
IRO-015-1	n/a	n/a	Costs included in IRO-014-1
IRO-016-1	n/a	n/a	n/a
MOD-001-1a	Sys Ops (1), Sys Plan (1)	24 (Sys Ops), 24 (Sys Plan)	$153,600
MOD-010-0	n/a	n/a	n/a
MOD-011-0	Sys Plan (1)	12	$38,400
MOD-012-0	n/a	n/a	n/a
MOD-013-1	Sys Plan (1)	12	$38,400
MOD-016-1.1	Sys Plan (1)	1	$3200
MOD-017-0.1	n/a	n/a	n/a
MOD-018-0	Sys Plan (1)	1	$3200
MOD-019-0.1	n/a	n/a	n/a
MOD-020-0	n/a	n/a	n/a
MOD-021-1	Sys Plan (1), EE (1)	1 (Sys Plan), 1 (EE)	$6400
MOD-024-1	Sys Plan (1), Hydro Gen (1)	1 (Sys Plan), 4 (Hydro Gen)	$16,000
MOD-025-1	n/a	n/a	Costs included in MOD-024-1
MOD-029-1a	Sys Plan (1)	12	$38,400
PER-001-0.2	Sys Ops (1)	2	$6400
PER-002-0	Sys Ops (1)	4	$12,800
PER-003-1	Sys Ops	n/a	$33,000
PER-004-1	n/a	n/a	n/a
PRC-001-1.1	Sys Ops (1), PETS (1)	2 (Sys Ops), 1 (PETS)	$9600
PRC-002-NPCC-01	TRO (1), Hydro Gen (1), PETS (1)	2 (TRO), 2 (Hydro Gen), 12 (PETS)	$51,200
PRC-004-2.1a	Sys Ops (1), TRO (1), Hydro Gen (1)	1 (Sys Ops), 1 (TRO), 1 (Hydro Gen)	$9600

Reliability Standard	Labour Required(*)	Estimated Weeks	Estimated Internal Cost ($3200/Week)
PRC-005-1b	TRO (1), Hydro Gen (1)	8 (TRO), 8 (Hydro Gen)	$51,200
PRC-006-1	Sys Plan (1), PETS (1)	24 (Sys Plan), 24 (PETS)	$153,600
PRC-007-0	n/a	n/a	Costs included in PRC-006-1
PRC-008-0	TRO (1)	12	$38,400
PRC-009-0	n/a	n/a	n/a
PRC-015-0	PETS (1)	3	$9600
PRC-016-0-1	n/a	n/a	n/a
PRC-017-0	TRO (1), PETS (1)	12 (TRO), 4 (PETS)	$51,200
PRC-018-1	TRO (1), Hydro Gen (1)	8 (TRO), 8 (Hydro Gen)	$51,200
PRC-023-2	PETS (1)	12	$38,400
TOP-001-1a	n/a	n/a	n/a
TOP-002-2.1b	Sys Ops (1), Sys Plan (1)	4 (Sys Ops), 4 (Sys Plan)	$25,600
TOP-003-1	Sys Ops (1)	2	$6400
TOP-004-2	Sys Ops (1)	4	$12,800
TOP-005-2a	Sys Ops (1)	1	$3200
TOP-006-2	PETS (1)	4	$12,800
TOP-007-0	n/a	n/a	n/a
TOP-008-1	n/a	n/a	n/a
TPL-001-0.1	n/a	n/a	n/a
TPL-002-0b	n/a	n/a	n/a
TPL-003-0a	n/a	n/a	n/a
TPL-004-0	n/a	n/a	n/a
VAR-001-2	Sys Ops (1)	8	$25,600
VAR-002-1-1b	n/a	n/a	n/a
Total Potential Internal Costs			**$1,753,600**

Note:

(*) in table above means refer to Appendix I for further information.

(**) means refer to Appendix I.

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Reliability Standard	Labour Required (*)	Estimated Weeks	Estimated Internal Cost ($3200/Week)
BAL-001-0.1a	Sys Ops (1)	1	$3200
BAL-002-1	Sys Ops (1)	2	$6400
BAL-003-0.1b	n/a	n/a	n/a
BAL-004-0	n/a	n/a	n/a
BAL-005-0-2b	n/a	n/a	n/a
BAL-006-2	n/a	n/a	n/a
COM-001-1.1	n/a	n/a	n/a
COM-002-2a	n/a	n/a	n/a
EOP-001-2.1b	Sys Ops (1), Sys Plan (1)	2 (Sys Ops), 2 (Sys Plan)	$12,800
EOP-002-3.1	n/a	n/a	n/a
EOP-003-2	n/a	n/a	n/a
EOP-004-1	Sys Ops (1)	6	$19,200 (Only occurs if there are reportable incidents)
EOP-005-1	Sys Ops (1), Sys Plan (1), Hydro Gen (1)	2 (Sys Ops), 1 (Sys Plan), 1 (Hydro Gen)	$12,800
EOP-006-1	n/a	n/a	n/a
EOP-008-1	Sys Ops (1), ES (1)	1 (Sys Ops), 1 (ES)	$6400
EOP-009-0	n/a	n/a	n/a
FAC-001-0	n/a	n/a	n/a
FAC-002-1	Sys Plan (1)	6	$19,200 (Only occurs if there are assessments required)
FAC-003-1	TRO (1)	n/a	$60,000 (**)
FAC-008-3	n/a	n/a	n/a
FAC-009-1	n/a	n/a	n/a
FAC-010-2.1	Sys Plan (1)	8	$25,600
FAC-011-2	n/a	n/a	Costs included in FAC-010-2.1
FAC-012-1	n/a	n/a	Costs included in FAC-010-2.1
FAC-013-2	n/a	n/a	Costs included in FAC-010-2.1
FAC-014-2	n/a	n/a	Costs included in FAC-010-2.1
INT-003-3	Sys Ops (1)	2	$6400
INT-004-2	n/a	n/a	n/a
INT-005-3	n/a	n/a	n/a
INT-006-3	n/a	n/a	n/a
INT-007-1	n/a	n/a	n/a
INT-008-3	n/a	n/a	n/a
INT-009-1	n/a	n/a	n/a

Reliability Standard	Labour Required (*)	Estimated Weeks	Estimated Internal Cost ($3200/Week)
INT-010-1	n/a	n/a	n/a
IRO-001-1.1	n/a	n/a	n/a
IRO-002-2	n/a	n/a	n/a
IRO-003-2	n/a	n/a	n/a
IRO-004-2	n/a	n/a	n/a
IRO-005-3.1a	n/a	n/a	n/a
IRO-006-5	n/a	n/a	n/a
IRO-006-EAST-1	n/a	n/a	n/a
IRO-008-1	n/a	n/a	n/a
IRO-009-1	n/a	n/a	n/a
IRO-010-1a	n/a	n/a	n/a
IRO-014-1	Sys Ops (1)	2	$6400
IRO-015-1	n/a	n/a	n/a
IRO-016-1	n/a	n/a	n/a
MOD-001-1a	Sys Ops (1), Sys Plan (1)	2 (Sys Ops), 2 (Sys Plan)	$12,800
MOD-010-0	n/a	n/a	n/a
MOD-011-0	Sys Plan (1)	2	$6400
MOD-012-0	n/a	n/a	n/a
MOD-013-1	Sys Plan (1)	2	$6400
MOD-016-1.1	Sys Plan (1)	1	$3200
MOD-017-0.1	Sys Plan (1)	2	$6400
MOD-018-0	n/a	n/a	n/a
MOD-019-0.1	Sys Plan (1)	2	$6400
MOD-020-0	n/a	n/a	n/a
MOD-021-1	n/a	n/a	n/a
MOD-024-1	n/a	n/a	n/a
MOD-025-1	n/a	n/a	n/a
MOD-029-1a	n/a	n/a	n/a
PER-001-0.2	n/a	n/a	n/a
PER-002-0	n/a	n/a	n/a
PER-003-1	Sys Ops	n/a	$11,000 (*)
PER-004-1	n/a	n/a	n/a
PRC-001-1.1	n/a	n/a	n/a
PRC-002-NPCC-01	TRO (1), Hydro Gen (1), PETS (1)	4 (TRO), 4 (Hydro Gen), 2 (PETS)	$32,000
PRC-004-2.1a	Sys Ops (1), PETS (1)	4 (Sys Ops), 4 (PETS)	$25,600 (Only occurs if there are assessments required)
PRC-005-1b	TRO (1), Hydro Gen (1)	8 (TRO), 4 (Hydro Gen)	$38,400
PRC-006-1	Sys Plan (1), PETS (1)	4 (Sys Plan), 4 (PETS)	$25,600

Reliability Standard	Labour Required (*)	Estimated Weeks	Estimated Internal Cost ($3200/Week)
PRC-007-0	n/a	n/a	n/a
PRC-008-0	TRO (1)	4	$12,800
PRC-009-0	PETS (1)	4 (PETS)	$12,800
PRC-015-0	n/a	n/a	n/a
PRC-016-0-1	Sys Ops (1), PETS (1)	4 (Sys Ops), 4 (PETS)	$25,600(Only occurs if there are assessments required)
PRC-017-0	TRO (1)	4	$12,800
PRC-018-1	n/a	n/a	Costs included in PRC-002-NPCC-01
PRC-023-2	PETS (1)		$12,800
TOP-001-1a	n/a	n/a	n/a
TOP-002-2.1b	n/a	n/a	n/a
TOP-003-1	n/a	n/a	n/a
TOP-004-2	n/a	n/a	n/a
TOP-005-2a	n/a	n/a	n/a
TOP-006-2	n/a	n/a	n/a
TOP-007-0	n/a	n/a	n/a
TOP-008-1	n/a	n/a	n/a
TPL-001-0.1	Sys Plan (1)	4	$12,800
TPL-002-0b	Sys Plan (1)	4	$12,800
TPL-003-0a	Sys Plan (1)	4	$12,800
TPL-004-0	Sys Plan (1)	4	$12,800
VAR-001-2	n/a	n/a	n/a
VAR-002-1-1b	n/a	n/a	n/a
Total Potential Ongoing Costs			**$482,400 (***)**

Note:

(*) in table above means refer to Appendix I for further information.

(**) means refer to Appendix I.

(***) means this includes the $89,600 that was identified in section 3.2.2.3 as only required if events happen on the BES that require reporting. Excluding this, cost would be $392,800

Appendix F – Critical Cyber Asset Identification criteria – CIP Version 4 and 5

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CIP Version 4 – Critical Cyber Asset Identification

1. Each group of generating units (including nuclear generation) at a single plant location with an aggregate highest rated net Real Power capability of the preceding 12 months equal to or exceeding 1500 MW in a single Interconnection.
2. Each reactive resource or group of resources at a single location (excluding generation facilities) having aggregate net Reactive Power nameplate rating of 1000 MVAr or greater.
3. Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon.
4. Each Blackstart Resource identified in the Transmission Operators restoration plan.
5. The Facilities comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first interconnection point of the generation unit(s) to be started, or up to the point on the Cranking Path where two or more path options exist, as identified in the Transmission Operators restoration plan.
6. Transmission Facilities operated at 500 kV or higher.
7. Transmission Facilities operated at 300 kV or higher at stations or substations interconnected at 300 kV or higher with three or more other transmission stations or substations.
8. Transmission Facilities at a single station or substation location that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.
9. Flexible AC Transmission Systems (FACTS), at a single location or substation location, that are identified by the Reliability Coordinator, Planning Coordinator or Transmission Planner as critical to the derivation of IROLs and their associated contingencies.
10. Transmission Facilities providing the generation interconnection required to connect generator output to the transmission system that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the assets identified by any Generator Owner as a result of its application of Attachment 1, criterion 1.1 or 1.3.
11. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.
12. Each SPS, Remedial Action Scheme (RAS) or automated switching system that operates BES Elements that, if destroyed, degraded, misused, or otherwise rendered unavailable, would cause one or more IROL violations for failure to operate as designed.
13. Each system or Facility that performs automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program.
14. Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator.
15. Each control center or backup control center used to control generation at multiple plant locations, for any generation Facility or group of generation Facilities identified in criteria 1.1, 1.3, or 1.4. Each control center or backup control center used to control generation equal to or exceeding 1500 MW in a single Interconnection.

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16. Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12.
17. Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4 or 1.13. Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

CIP Version 5 – Critical Cyber Asset Identification

1. Transmission Facilities at a single station or substation that are operating between 200 kV and 499 kV, are connected to three or more other Transmission stations or substations, and which possess "aggregate weighted values" exceeding 3000. The "aggregate weighted values" for a Transmission Facility is determined by summing the "weight value per line" for each incoming or outgoing BES Transmission line that is connected to another Transmission station or substation. The "weight value per line" is determined with the following values.

Voltage Value of a Line	Weight Value per Line
100 kV to 199 kV	0 (not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300

   - This criterion will be used in the cost assessment instead of criteria #7 (listed above) in CIP version 4.
2. Control Centers and associated data centers not included in High Impact (H), above, that: (1) perform the functional obligations of Balancing Authority or Transmission Operator, or (2) control an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 300 MW or more BES generation.
   a. This criterion is not included in version 4 of the CIP criteria for Critical Assets.

Facilities considered Critical Assets

1. Each reactive resource or group of resources at a single location (excluding generation facilities) having aggregate net Reactive Power nameplate rating of 1000 MVAr or greater (Version 4, Criteria 2).
   - Soldiers Pond Terminal Station (Potentially)
2. Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon (Version 4, Criteria 3).
   - Muskrat Falls Generating Station
   - Bay D'Espoir Generating Station (Potentially)

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3. Each Blackstart Resource identified in the Transmission Operators restoration plan (Version 4, Criteria 4).
    - Muskrat Falls Generating Station (Potentially)
    - Bay d'Espoir Terminal/Generating Station (Potentially)
    - Hardwoods Terminal/Generating Station (Potentially)
4. The Facilities comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first interconnection point of the generation unit(s) to be started, or up to the point on the Cranking Path where two or more path options exist, as identified in the Transmission Operators restoration plan (Version 4, Criteria 5).
    - Muskrat Falls Terminal/Generating Station (Potentially)
    - Bay d'Espoir Terminal/Generating Station (Potentially)
    - Hardwoods Terminal/Generating Station (Potentially)
5. Transmission Facilities at a single station or substation location that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies (Version 4, Criteria 8).
    - Muskrat Falls Terminal Station
    - Soldiers Pond Terminal Station
    - Bottom Brook Terminal Station
6. Transmission Facilities at a single station or substation that are operating between 200 kV and 499 kV, are connected to three or more other Transmission stations or substations, and which possess "aggregate weighted values" exceeding 3000. The "aggregate weighted values" for a Transmission Facility is determined by summing the "weight value per line" for each incoming or outgoing BES Transmission line that is connected to another Transmission station or substation (Version 5).
    - Muskrat Falls Terminal Station
    - Soldiers Pond Terminal Station
    - Bay d'Espoir Terminal Station
    - Western Avalon Terminal Station
    - Stony Brook Terminal Station
    - Hardwoods Terminal Station
7. Control Centers and associated data centers not included in High Impact (H), above, that: (1) perform the functional obligations of Balancing Authority or Transmission Operator, or (2) control an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 300 MW or more BES generation (Version 5).
    - Bay d'Espoir Control Room

Appendix G – Information for Required and Optional Reliability Standards and Regional Criteria

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Required and Optional NERC reliability standards and NPCC regional criteria

1. BAL-001-0.1a –Real Power Balancing Control Performance
    - NLH will perform the BA function which is a very important function. Expect NPCC would expect NLH to follow standards relating to BA (email from NPCC)
    - This is currently being looked at by Sys Ops
2. BAL-002-1 – Disturbance Control Performance
    - Same comment as BAL-001-0.1a
    - Need to look at contingency reserve and access to it (i.e. Reserve Sharing or RSG)
3. BAL-003-0.1b – Frequency Response and Bias
    - Same comment as BAL-001-0.1a
    - Implemented now. Would need some review work for interconnection
4. BAL-004-0 – Time Error Correction
    - Same comment as BAL-001-0.1a
    - Implemented now. Would need some review work for interconnection
5. BAL-005-0-2b – Automatic Generation Control
    - Same comment as BAL-001-0.1a
    - Currently have frequency monitoring on island. Would require modifications to the AGC application and may require EMS vendor for assistance. Involvement from TRO for maintenance on frequency monitoring equipment
6. BAL-006-2 – Inadvertent Interchange
    - Same comment as BAL-001-0.1a
    - Potential requirement to develop tool for interchange recording/reporting. Modifications to AGC application for inadvertent interchange
7. COM-001-1.1 – Telecommunications
    - Standard relates to BA as well as communication requirements to other entities
    - Labour for ICCP implementation. Testing program for communication facilities. Plan for continued operation during loss of telecommunication facilities. Most other things being done now. Where applicable, facilities shall be redundant and diversely routed
8. COM-002-2a – Communication and Coordination
    - Same comment as COM-001-1.1
    - ICCP required as above. Voice communications configured between ECC and NS
9. CIP-001-2a – Sabotage Reporting
10. CIP-002-4 – Cyber Security – Critical Cyber Asset Identification (*)
11. CIP-003-4 – Cyber Security – Security Management Controls (*)
12. CIP-004-4 – Cyber Security – Personnel & Training (*)
13. CIP-005-4a – Cyber Security – Electronic Security Perimeters (*)
14. CIP-006-4d – Cyber Security – Physical Security of Critical Cyber Assets (*)
15. CIP-007-4 – Cyber Security – Systems Security Management (*)
16. CIP-008-4 – Cyber Security – Incident Reporting and Response Planning (*)
17. CIP-009-4 – Cyber Security – Recovery Plans for Critical Cyber Assets (*)

18. EOP-001-2.1b – Emergency Operations Planning (*)
    - Expect NPCC would require NLH to follow this standard for emergency planning
    - Emergency plans in place now for island. Would need to be modified for interconnection and involvement with NS and HQ (potentially). As well, operating agreements would have to be in place between BA's for emergency assistance
19. EOP-002-3.1 – Capacity and Energy Emergencies
    - Need to look at this in the context of the NL and NS system.
20. EOP-003-2 – Load Shedding Plans (*)
    - This standard is around having the capability and authority to shed load rather than risk a failure on interconnection. This would be required from an interconnection perspective
    - Determination (and potential development) of an automatic undervoltage load shedding plan for NLH and between NSPI and NLH. This would include having plans in place for operator controlled manual load shedding if required. Would also need to involve Newfoundland Power in this
21. EOP-004-1 - Disturbance Reporting
    - Reporting requirements are to NERC and NPCC. Need to evaluate further.
22. EOP-005-1 – System Restoration Plans
    - Expect NPCC would require NLH to follow this standard for system restoration. It is very important to the interconnection
    - Development of system restoration plan (including interconnection). OTS training development and delivery on restoration plan. Testing procedures for Blackstart resources. Training for personnel responsible for Blackstart in field. Training for switching personnel identified in plan
23. EOP-006-1 – Reliability Coordination – System Restoration
    - Same comment as EOP-005-1
    - This plan for the RC would be very similar to the restoration plan in EOP-005-1 since NLSO would be RC and TOP
24. EOP-008-1 – Loss of Control Center Functionality (*)
    - Expect NPCC would require NLH to follow this standard. It is very important to the interconnection
    - Current plan in place meets NERC standard. Assumption that communication to new facilities to the ECC will be configured to transfer to BCC as required
25. EOP-009-0 - Documentation of Blackstart Generating Unit Test Results
    - Standard would need to be looked at closer in terms of the RRO requirements.
26. FAC-001-0 - Facility Connection Requirements
    - Good to establish requirements for NLH system for anyone connecting new facility.
27. FAC-002-1 - Coordination of Plans for New Generation, Transmission and End-User Facilities
    - Good to establish coordination requirements for those connecting new facility.
28. FAC-003-1 – Transmission Vegetation Management Program

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- Currently there is a vegetation management program in place and expect NPCC would require NLH to follow program
- There is currently a program in place for NLH. A new standard (FAC-003-2) was filed with FERC and could be approved in 2012. Criteria would then change. Would also need to look at cost from the new transmission as well. Standard may have to be modified for NLH system

29. FAC-008-3 - Facility Ratings (*)
    - Would be good to establish to be consistent with other entities within NPCC.
30. FAC-009-1 - Establish and Communicate Facility Ratings
    - Would be good to establish to be consistent with other entities within NPCC.
31. FAC-010-2.1 – System Operating Limits Methodology for the Planning Horizon
32. FAC-011-2 - System Operating Limits Methodology for the Operations Horizon
    - Would be good to establish to be consistent with other entities within NPCC.
33. FAC-012-1 - Transfer Capability Methodology
    - Standard would need to be looked at closer in terms of the RRO requirements.
34. FAC-013-2 - Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon (*)
    - Standard would need to be looked at closer in terms of the RRO requirements.
35. FAC-014-2 - Establish and Communicate System Operating Limits
    - Would be good to establish to be consistent with other entities within NPCC.
36. INT-001-3 - Interchange Information
    - This standard applies only to sink BA
37. INT-003-3 – Interchange Transaction Implementation
    - Due to interconnection with NS and the IA development, NLH would adopt the INT standards
    - A communications protocol would need to be developed between appropriate parties
38. INT-004-2 – Dynamic Interchange Transaction Modifications
    - Due to interconnection with NS and the IA development, NLH would adopt the INT standards
    - This standard would just be done in real time. Compliance would come from E-tag information
39. INT-005-3 – Interchange Authority Distributes Arranged Interchange
    - May need to look at timing requirements in standard to ensure they are applicable to NLH
    - A communications protocol would need to be developed between appropriate parties
40. INT-006-3 – Response to Interchange Authority
    - Same comment as INT-003-3 and INT-005-3
    - A procedure to be developed on how to evaluate the Arranged Interchange
41. INT-007-1 – Interchange Confirmation
    - Same comment as INT-003-3
    - Standard as outlined is pretty clear in what is required

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42. INT-008-3 – Interchange Authority Distributes Status
    - Same comment as INT-003-3 and INT-005-3
    - Information could be part of the communication protocol identified for INT-005-3
43. INT-009-1 – Implementation of Interchange
    - Same comment as INT-003-3
    - Standard as outlined is pretty clear in what is required
44. INT-010-1 – Interchange Coordination Exemptions
    - Same comment as INT-003-3
    - Standard as outlined is pretty clear in what is required
45. IRO-001-1.1 – Reliability Coordination – Responsibilities and Authorities
    - If NLSO is the RC, then expect NPCC would require NLH to follow standards for RC given the importance of the function. Some of the IRO standards may have to be modified as per the comments in each below
    - IRO-001-2 has been approved by NERC BOT and IRO-001-3 is in development. Would need to have a Regional Reliability Plan developed with other areas as defined by the RRO (i.e. NPCC). Would potentially require agreements with other RC's. Would require authority within the company to authorize RC to have clear decision making authority
46. IRO-002-2 – Reliability Coordination – Facilities
    - Same comment as IRO-001-1.1
    - Assumed all new SCADA information on new facilities will be coming back to ECC as part of project. ICCP required. Development of outage management plan for analysis tools used by RC. Voice communications configured between ECC and NS. IRO-002-3 has been approved by NERC BOD and will replace this standard once approved by FERC
47. IRO-003-2 – Reliability Coordination – Wide Area View
    - Same comment as IRO-001-1.1
    - Standard as outlined is pretty clear in what is required
48. IRO-004-2 – Reliability Coordination – Operations Planning
    - Same comment as IRO-001-1.1
49. IRO-005-3.1a – Reliability Coordination – Current Day Operations
    - Same comment as IRO-001-1.1
    - Standard IRO-005-4 has been approved by the NERC BOT and will replace IRO-005-3a once approved by FERC. This new Standard has less measures and requirements. For this standard, development of mitigation plans are required for potential SOL, CPS and DCS violations. A procedure for issuing alerts to other RC's would also be required
50. IRO-006-5 – Reliability Coordination – Transmission Loading Relief (TLR)
    - Same comment as IRO-001-1.1
    - Standard as outlined is pretty clear in what is required
51. IRO-006-EAST-1 – Transmission Loading Relief Procedure for the Eastern Interconnection
    - Same comment as IRO-001-1.1
    - Standard as outlined is pretty clear in what is required. Development of a communications procedure on this would be helpful

52. IRO-008-1 - Reliability Coordinator Operational Analyses and Real-time Assessments
    - Standard would be acceptable to adopt. However, need to have a more detailed assessment/discussion on requirements in standard.
53. IRO-009-1 – Reliability Coordinator Actions to Operate Within IROLs
    - Same comment as IRO-001-1.1
    - Operating Processes, Procedures or Plans are required to address preventing and mitigating IROL's (as applicable)
54. IRO-010-1a - Reliability Coordinator Data Specification and Collection
    - Standard is good to have a consistent requirement for data for the Reliability Coordinator.
55. IRO-014-1 - Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
    - Need to look at this in the context of the NL and NS system and potentially New Brunswick System Operator (NBSO) as Reliability Coordinator for the Maritimes area.
56. IRO-015-1 - Notifications and Information Exchange Between Reliability Coordinator
    - Need to look at this in the context of the NL and NS system and potentially New Brunswick System Operator (NBSO) as Reliability Coordinator for the Maritimes area.
57. IRO-016-1 - Coordination of Real-time Activities Between Reliability Coordinators
    - Need to look at this in the context of the NL and NS system and potentially New Brunswick System Operator (NBSO) as Reliability Coordinator for the Maritimes area.
58. MOD-001-1a – Available Transmission System Capability
    - This standard would need to be adopted as it outlines the calculations required for ATC on the transmission system
    - A lot of work required here including selecting ATC methodology, developing ATC Implementation document, developing procedure for posting ATC and procedure for supplying requested information to other entities
59. MOD-010-0 – Steady-State Data for Modeling and Simulation of the Interconnected Transmission System
    - This goes with MOD-011. Standard may become Optional dependent on the RRO requirements (i.e. NPCC). Would expect that NPCC would require the models to analyze reliability
    - Would have to provide steady state data to NPCC for modelling requirements
60. MOD-011-0 – Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures
61. MOD-012-0 – Dynamics Data for Modeling and Simulation of the Interconnected Transmission System
    - This goes with MOD-013. Standard may become Optional dependent on the RRO requirements (i.e. NPCC). Would expect that NPCC would require the models to analyze reliability
    - Would have to provide dynamics data to NPCC for modelling requirements

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62. MOD-013-1 – Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures
63. MOD-016-1.1 – Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management
64. MOD-017-0.1 – Aggregated Actual and Forecast Demands and Net Energy for Load
    - This may become Optional depending on what NERC and NPCC require from NLH. Would expect that NPCC would require the information for demand forecasting
    - Would have to provide information on peak loading data and forecast load data
65. MOD-018-0 – Treatment of Non-member Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load
    - Same comment as MOD-017
    - Would have to provide data as outlined in the standard. Review of standard by Sys Planning
66. MOD-019-0.1 – Reporting of Interruptible Demands and Direct Control Load Management
    - Same comment as MOD-017
    - Would have to provide data as outlined in the standard
67. MOD-020-0 – Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators
    - This is probably being done now and should continue in the future
    - Would have to provide information to functional entities within NLH as requested
68. MOD-021-1 – Documentation of the Accounting Methodology for the Effects of Demand Side Management in Demand and Energy Forecasts
    - This is probably being done now and should continue in the future
    - Would have to provide data as outlined in the standard. Review of standard by Sys Planning and Energy Efficiency
69. MOD-024-1 - Verification of Generator Gross and Net Real Power Capability
    - Standard would need to be looked at closer in terms of the RRO requirements.
70. MOD-025-1 - Verification of Generator Gross and Net Reactive Power Capability
    - Standard would need to be looked at closer in terms of the RRO requirements.
71. MOD-029-1a – Rated System Path Methodology
    - This would be the standard that the NPCC guideline is based on (Document C-44)
    - Requires development and documentation of transfer capability calculations
72. PER-001-0.2 - Operating Personnel Responsibility and Authority
    - Need to look at the compliance measures before adopting standard.
73. PER-002-0 – Operating Personnel Training
    - When operating in the interconnection would expect NPCC/NERC would require NLH to have a sufficient training program that meets this standard
    - Sys Ops already has this training program in place now. A review of program objectives relating to NERC would be required
74. PER-003-1 - Operating Personnel Credentials (*)

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- A more detailed look and discussion is required on requirement for having NERC certified operators.

75. PER-004-1 - Reliability Coordination Staffing
    - A more detailed look and discussion is required on requirement for having NERC certified operators.
76. PRC-001-1.1 - System Protection Coordination
    - NLH will be performing functions but would be nice to have procedures in place to ensure changes happen as they should. As well, would need to coordinate with NSPI
    - Procedures would need to be developed to ensure coordination on protection systems occur with Generation Operators, Transmission Operators and neighbouring TOP and GOP (for interconnections)
77. PRC-002-NPCC-01 – Disturbance Monitoring
    - Expect NPCC would require NLH to adhere to this standard. Idea is fine with types of equipment (i.e. fault recording, SOE, DDR) but not sure on specifications. Need to discuss with NPCC
    - This was approved by FERC in October, 2011. May not be approved in each Canadian province within NPCC. There would have to be fault recording and disturbance monitoring equipment installed at existing and new facilitates. Need to ensure the proper SOE's are coming back to the ECC. Review or development of DDR maintenance and testing program
78. PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations
    - Expect NPCC would require NLH to adhere to this standard as protection systems play an important role in reliability of the interconnection. Need to look at requirements around what Regional Entity's procedures are
    - A procedure outlining how the analysis would be completed is required (i.e. who would do the analysis). Otherwise, this standard just ensures this is being completed as events happen. Standard as outlined is pretty clear in what is required. Training may be required by field staff to come up to speed on procedure and NERC requirements
79. PRC-005-1b – Transmission and Generation Protection System Maintenance and Testing
    - Expect NPCC would require NLH to adhere to this standard as protection systems play an important role in reliability of the interconnection
    - A review of the protection system maintenance and testing program would be needed and the program brought up to NERC standard. May just need to modify/upgrade program to comply with critical BES elements. Also program would need to be updated to include new facilities and equipment
80. PRC-006-1 – Automatic Underfrequency Load Shedding (*)
    - As mentioned in comments NPCC now has its own standard on this which will come into effect shortly. Expect NPPC would require NLH to comply with this standard
    - A review of the current UFLS program will be required including relays for generating facilities on island. Need to look at this from the perspective of the interconnection.

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PRC-006-NPCC-1 has been approved by NERC and has to go through regulatory approval (FERC) and filed with the provinces. Requirements then will be regional but no new infrastructure will be required. The new NPCC standard also references the NERC standard (PRC-006-1)

81. PRC-007-0 - Assuring Consistency with Regional UFLS Program Requirements
    - Standard would need to be looked at closer in terms of the RRO requirements and potential involvement of Newfoundland Power.
82. PRC-008-0 - Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program
    - Standard would need to be looked at closer in terms of the RRO requirements and potential involvement of Newfoundland Power.
83. PRC-009-0 - Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event
    - Standard would need to be looked at closer in terms of the RRO requirements. Currently, NLH does analysis on Underfrequency Load Shedding events.
84. PRC-015-0 – Special Protection System Data and Documentation
    - Due to the criticality of SPS on reliability, expect this standard would be required to be adhered too
    - SPS would have to be reviewed as per the RRO requirements. A procedure would have to written on how the data would be maintained. This standard references PRC-012-0 and PRC-013-0
85. PRC-016-0-1 – Special Protection System Misoperations
    - Due to the criticality of SPS on reliability, expect this standard would be required to be adhered too
    - Standard as outlined is pretty clear in what is required. This would be an ongoing requirement
86. PRC-017-0 – Special Protection System Maintenance and Testing
    - Due to the criticality of SPS on reliability, expect this standard would be required to be adhered too
    - A maintenance and testing program would need to be developed for SPS
87. PRC-018-1 - Disturbance Monitoring Equipment Installation and Data Reporting
    - Standard would need to be looked at closer in terms of the RRO requirements.
88. PRC-023-2 - Transmission Relay Loadability
    - Analysis of this standard is required to determine the applicability to the NL BES.
89. TOP-001-1a – Reliability Responsibilities and Authorities
    - This outlines the reliability responsibilities for each functional entity.
    - Standard as outlined is pretty clear in what is required
90. TOP-002-2.1b - Normal Operations Planning
    - This standard is like an operating instruction outlining responsibility for Normal Operations

- Operating plans would need to be developed. Standard as outlined is pretty clear in what is required

91. TOP-003-1 – Planned Outage Coordination
    - This standard would be required due to interaction with NSPI and potential requirements for reporting planned outages to NPCC
    - Procedure to be developed on how to communicate outages with NSPI, HQ and Eastern Interconnection (as required). Otherwise standard as outlined is pretty clear on requirements
92. TOP-004-2 – Transmission Operations
    - This standard would be required due to interaction with NSPI and mitigating impacts to the interconnection
    - The IA agreement between NS and NL should address compliance. Otherwise a procedure would have to be developed. Otherwise standard as outlined is pretty clear on requirements
93. TOP-005-2a – Operational Reliability Information
    - This standard would be required due to interaction with NSPI (and others as required) and providing the data to perform reliability assessments
    - May need a procedure/policy to supply other information (i.e. load forecast) to NS and others as required
94. TOP-006-2 – Monitoring System Conditions
95. TOP-007-0 – Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations
    - This standard would be required as there are directions for the TOP to take. NLH performing duties of the functional entities so communication requirements may all not be necessary
    - Standard as outlined is pretty clear in what is required
96. TOP-008-1 – Response to Transmission Limit Violations
    - These are directives that need to be taken by transmission operators that would be required
    - Standard as outlined is pretty clear in what is required
97. TPL-001-0.1 – System Performance Under Normal (No Contingency) Conditions (Category A)
    - Expect this standard would be required from NPCC perspective due to its criticality in planning the transmission system
    - Standard as outlined is pretty clear in what is required
98. TPL-002-0b – System Performance Following Loss of a Single Bulk Electric System Element (Category B)
    - Expect this standard would be required from NPCC perspective due to its criticality in planning the transmission system
    - Standard as outlined is pretty clear in what is required
99. TPL-003-0a – System Performance Following Loss of Two or more Bulk Electric System Elements (Category C)

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- Expect this standard would be required from NPCC perspective due to its criticality in planning the transmission system
- Standard as outlined is pretty clear in what is required

100. TPL-004-0 – System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)
    - Expect this standard would be required from NPCC perspective due to its criticality in planning the transmission system
    - Standard as outlined is pretty clear in what is required
101. VAR-001-2 – Voltage and Reactive Control
    - Due to the criticality of voltage control, would expect NPCC require NLH to adopt this standard
    - IA between NL and NS would help address compliance. A reactive power schedule may need to be developed between TOP and GOP on system
102. VAR-002-1-1b – Generator Operation for Maintaining Network Voltage Schedules
    - Same comment as VAR-001-2
    - Standard as outlined is pretty clear in what is required

1. Directory #1 – Design and Operation of the Bulk Power System
    - Full Members of NPCC would need to follow directory
    - This directory involves designing and operating the BPS based on contingences that can happen. There are some contingencies that are different then NERC standards, in particular the simultaneous permanent loss of both poles. However, it doesn't appear that it needs to be designed such that it doesn't cause load loss. Just need to show that stability is maintained. In this case SPS's can be used. Sys Planning would need to ensure the system remains stable and doesn't cause significant adverse impact to the interconnection. NERC standards associated with this directory are EOP-001-0, FAC-011-2, IRO-002-1, IRO-014-1, MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, MOD-015-0, MOD-016-1, TOP-001-1, TOP-002-2, TOP-003-0, TOP-004-2, TPL-001-0, TPL-002-0, TPL-003-0, TPL-004-0, TPL-005-0 TPL-006-0 and VAR-001-1
2. Directory #2 – Emergency Operations
    - Same comment as for Directory #1
    - May require development of guideline or procedure for operating under emergency conditions. However, directory as outlined is pretty clear on requirements. NERC standards that are associated with this directory are BAL-001, BAL-002, BAL-003, BAL-005, COM-001, COM-002, EOP-001, EOP-002, EOP-003, PRC-006, PRC-007, TOP-001, TOP-004, TOP-006, IRO-003, IRO-005, IRO-015 and IRO-016
3. Directory #3 – Maintenance Criteria for BPS Protection
    - Same comment as for Directory #1
    - Criteria in directory apply to all protection of the BES including Type 1 special protection systems and protection required for the NPCC Automatic Underfrequency Load

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Shedding Program. Directory as outlined is pretty clear on requirements but some discussion with NPCC would be required on this. May have to develop own maintenance plan. NERC standards associated with this directory are PRC-005-1, PRC-008-0, PRC-011-0, PRC-012-0, PRC-017-0

4. Directory #4 – System Protection Criteria
    - Same comment as for Directory #1
    - This directory involves the protection systems for the BPS. As per email from NPCC, existing stations can be treated as pre-criteria facilities and would be able to be grandfathered in. However any new facilities should be designed to follow these criteria. Therefore the cost associated with this directory to meet criteria would be in the project design. Sys Planning should also look at identifying BPS elements for existing stations such that protection can be upgraded as required over time. Directory as outlined is pretty clear on requirements. NERC standards associated with this directory are PRC-001, PRC-002 and PRC-012
5. Directory #5 – Reserve
    - Same comment as for Directory #1
    - This directory is around the requirements for reserve. It outlines things like 10 minute, 30 minute, and synchronized and inter-balancing area reserve. The requirements as outlined in the directory are clear. However discussion with NPCC, Nova Scotia and possibly New Brunswick will be required. There should be no cost implications for this directory. NERC standards associated with this directory are BAl-001, BAL-002, BAL-003, BAL-005 and EOP-002
6. Directory #6 – Reserve Sharing Groups
7. Directory #7 – Special Protection Systems
    - Same comment as for Directory #1
    - This directory is around the requirements for special protection systems and their design. Since NLH does not have SPS's now, this would be a new design and the infrastructure would be all new. Feel there could be a significant cost associated with designing these. SPS's are required for reliability but would have to be designed as per this directory. Sys planning would need to be involved in the design and their function. NERC standards associated with this directory are PRC-012-0, PRC-013-0, PRC-014-0, PRC-015-0, PRC-016-0 and PRC-017-0
8. Directory #8 – System Restoration
    - Same comment as for Directory #1
    - This directory involves the basic criteria with which each applicable entity must plan for and perform power system restoration following a major or total blackout. It also involves testing for key facilities that must be performed. Would involve developing a system restoration plan following the criteria in this directory as well as ongoing testing as outlined in directory. NERC standards associated with this directory are EOP-005-2 and EOP-006-2
9. Directory #9 – Generator Gross/Net Real Power Capability

- Same comment as for Directory #1
- This directory involves developing a program for verifying the generator gross and net real power capability. This would have to be discussed with NPCC as to what generators on the NLH system that this would apply to. NERC standards associated with this directory are MOD-024-1, TOP-002-2, FAC-008-1 and FAC-009-1

10. Directory #10 – Generator Gross/Net Reactive Power Capability
    - Same comment as for Directory #1
    - This directory involves developing a program for verifying the generator gross and net reactive power capability. This would have to be discussed with NPCC as to what generators on the NLH system that this would apply to. NERC standards associated with this directory are MOD-024-1, TOP-002-2, FAC-008-1 and FAC-009-1
11. Directory #12 – UFLS Program Requirements
    - Same comment as for Directory #1

This directory is centered on the UFLS requirements for the NPCC region. It would be similar to the NERC standards but specific to NPCC. NLH would need to review the load shedding requirements when interconnected to comply with this directory. Discussion with NPCC on this would also be required. NERC standards associated with this directory are EOP-003, PRC-006, and PRC-007

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Appendix H – Email from NPCC on Directory #4: February 2, 2012

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Jason,

Within NPCC, the BPS is determined by utilizing the testing described in our A-10 criteria which may be found on the NPCC website at;

https://www.npcc.org/Standards/Criteria/Forms/Public%20List.aspx

This testing of your existing facilities to determine if they are BPS from NPCC's perspective has not been done to my knowledge. The purpose of the "grandfathering" was to relieve the members from criteria where their already identified BPS elements preceded the development of the Directory 4 and bringing these facilities into compliance with Directory #4 would only need to be done during replacement or renewal. 1.6.2.2.2 involves new system changes, causing some part of the non-BPS to become BPS when annual evaluation using the A-10 is performed. In that instance, the reapplication of the A-10 and identification of an addition BPS facility which previously was not classified as BPS would require mitigation plan.

It is important to recognize that NPCC would encourage A-10 testing of all existing and new facilities to determine if they are in fact BPS. It would be my suggestion that the existing facilities be treated as pre-criteria facilities, and subject to "grandfathering"/exemption. However, upgrading to meet criteria in the Directories would be done in accordance with the criteria in the Directories as the facilities are replaced or renewed.

It would be NPCC's expectation that Nalcor would support the reliable operation of the BPS, if their facilities were so deemed BPS, through testing and take the appropriate steps over time to mitigate risks to the interconnection and that all new installations meet the criteria as written. Compliance with Reliability Standards from NERC is another matter, subject to the provincial authority and any future agreements between NERC-NPCC- and the provinces the facilities are located in. Let me know if you have further questions.

Thanks,

Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.
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New York, NY 10018
212-840-1070
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DRAFT

To: Guy V. Zito

Subject: Question on Directory 4

Good morning Mr.Zito,

In our ongoing review of NERC and NPCC standards and criteria we have looked at Directory 4 - Bulk Power System Protection Criteria and would like to know how this would apply to us in regards to our existing facilities

Section 1.6.2.2.1 - Planned Renewal or Upgrade to Existing BPS facilities states that "It is recognized that there may be portions of the bulk power system, which existed prior to each member's adoption of the Bulk Power System Protection Criteria (Document A-5) that do not meet these criteria.

However, if protection systems or sub-systems of these facilities are replaced as part of a planned renewal or upgrade to the facility and do not meet all of these criteria, then an assessment shall be conducted for those criteria that are not met."

As of right now, we would consider our 230 KV and above to be our BPS. However, in our situation we would not have been members prior to this adoption of criteria. Would this mean that these criteria would not apply to us? Or would Section 1.6.2.2.2 - Facility Classification Upgraded to Bulk Power System apply to us? This states that "These criteria apply to all existing facilities which become classified as bulk power system. A mitigation plan shall be required to bring such a facility into compliance with these criteria." We interpret this as we wouldn't be upgrading our facilities to BPS as they already exist. However we would like clarification on this to determine if this is correct

Your help in this area would be greatly appreciated as we continue to look at our requirements going forward

Thanks
Jason

Jason Tobin, P.Eng

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Appendix I – Email from Craig Parsons (NLH) on Vegetation Management Program: May 2, 2012

DRAFT

Jason

I have used the original questions from your email to answer your questions.

1. Although we have a very involved vegetation management program we are not currently compliant with either standard.

2. a) We do not have a formal vegetation management plan in place and we don't create a formal annual work plan outside of the contract. Much of this plan could be pulled together from existing practices, work methods, technical conditions from contracts, and our current reporting methods. This will require time on part of the vegetation control specialist. One of the components that we do not have in place currently is a formal inspection program. Currently we have an informal program where we piggyback on flights with the transmission group however there are considerable scheduling issues resulting in few actual flights. This is combined with feedback from line crews and others in the field though work requests and some limited ground inspections by our vegetation inspectors in early spring. At our current staffing levels our inspectors have very little time to do ground inspections and focus their time inspecting upcoming work areas. To carry out a more comprehensive ground survey program two of the seasonal inspectors we currently have 9-10 months a year would need to be made full time. We are working on a new inspection form for the formal inspection process but are not sure how what format we will be storing the data in who will maintain that data. Without additional staff time we will not meet this standard.

3. At a minimum the staffing needs to be compliant with this program would be a) Our current 3rd inspector would need to be extended for the entire field season (extended from 4 months to 9 months) b) need 2 full time inspectors with at least 2-3 months per year dedicated to surveys only. We will also need dedicated helicopter time for aerial inspections (estimating we would need 3-4 days a year of flying time - approximately 15-20 hours at approximately $12,000 - $15,000 annually). We would need enough helicopter hours to inspect the entire system once a year. Depending on how we store and manage our inspection data there may also be some need around software/hardware and training in how to use/maintain. We are also at risk because we do not have the means to properly deal with items like danger trees in house. We do not have year round inspectors on staff and are dependant upon the contractors schedule/availability. Most utilities have at least one dedicated tree trimming crew. This is not a must for compliance but is a risk.

4. In my opinion the cost at a minimum would be the additional cost of making 2 vegetation inspectors permanent, and extending the 3rd inspector from 4 months to ten months, the increased travel, overtime and vehicle cost associated with additional staff time, and approximately 3-5 days of helicopter time per year. Not sure what the costs would be with the data storage/software/hardware (I know from talking to NS Power they have a full time GIS technician dedicated to their vegetation management program). Our inspectors would also require some training in collection, storage, and manipulation of data with outside training. I

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cannot train them in this. In terms of field hardware I think field data loggers would be of benefit for this application.

Staffing cost breakdown:
2 permanent inspectors - $35,000 per year plus benefits and pension
extend seasonal inspector - $25,000 per year
additional expenses (hotels/per diems) - $7000 - $10,000 per year
equipment - $2,000 - $5,000
helicopter - $12,000 to $15,000 annually
additional fuel - $8,000 - $10,000 annually

total - $90,000 - $100,000 annually

Extension of the 3rd inspector would require vehicle availability for an additional 5 months.

There would also have to be more effort of the part of WPLM and the distribution folks to offer up a more comprehensive estimate of their requirements for the year. Currently WPLM is always under funded (usually around 40%) of their actual need for vegetation control. This would result in additional cost of $40,000 - $50,000 annually. When these projects go under estimated it puts strain on the maintenance budget which would in turn cause difficulty under NERC compliance where we have to meet certain standards within certain timeframes. The timing of responding to vegetation issues could also become problematic under NERC. Currently all staff including myself are on the road all over the province from April to December and could affect the time to respond to issues.

All of these factors taken into account I would put the total cost at $130,000 - $150,000 annually. This does not include any costs associated with data management, mapping, etc. If you have any additional questions or require additional information please feel free to give me a call. Thanks.

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DRAFT

Hi Paul,

I have recently moved into a position with the Lower Churchill Project. I have been tasked with looking at Reliability and in particular, the potential adoption of North American Electric Reliability Corporation (NERC) standards

One of the NERC standards falls under the Facilities Design, Connections and Maintenance (FAC) category. The standard is called "Transmission Vegetation Management Program". The purpose of the standard is to improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation related outages of the transmission systems to the respective Regional Reliability Organizations (RRO) and the North American Electric Reliability Council (NERC)

I realize that we have a program in place right now that addresses this. However, I was wondering, if we had to adopt this standard, how close we are to being compliant with it? The main questions would be

1. Are we compliant with this standard?
2. If not, what areas would we need to implement to become compliant?
3. What are the costs associated with modifying the program to become compliant?
4. What would be the ongoing costs (including labour) to maintain compliance as outlined in the standard? This cost would be incurred regardless if we are compliant currently or not
5. Is it possible for someone to review the standard, compare to our current program and provide answers to the questions above?

I have attached a copy of the standard. I have also attached a newer version of the standard. This one is not in effect yet but will be in the future. For review, both can be looked at to get a sense of the requirements going forward

Please let me know if you have any questions and don't hesitate to call so we can discuss further

Thanks in advance

Jason

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Appendix J – Email from Brian Hemeon (NLH) on CIP Standards Potential Cost: December 13, 2011

DRAFT

Jason

At this time I believe we could complete the necessary documentation with the existing staff assuming we would not have to be compliant until the 2015-16 time frame.

With regard to making the BES CIP compliant; to give you a feel for the magnitude.

- develop process to identify and document all critical assets and then identify the critical cyber assets. Assume 40 locations at 2 man weeks each.
- develop and have operations adopt a rigorous change control and configuration management process. 2 man years.
- develop necessary logging and monitoring processes for critical cyber assets. 2 man years.
- deploy centralized logging server. 3 man months + 50K capital
- Possibly deploy firewall to establish electronic security perimeter at all locations. Assume 40 locations at 3K each plus an additional 40 man weeks of labor.
- develop vulnerability testing processes for all critical cyber assets. 1 man year.
- develop backup/disaster recovery and incident management processes for all critical cyber assets. 2 man years
- Possibly have to implement encrypted communications between ECC/BCC and each of the locations that house critical cyber assets. (?)

These are the items that come to mind - I will give it a little more thought to see if there are other significant items.

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DRAFT

From: Jason Tobin/NLHydro
To: Brian Hemeon/NLHydro@NLHydro
Cc: Bob Butler/NLHydro@NLHydro
Date: 12/13/2011 03:01 PM
Subject: Re: NERC CIP and ECC

Hi Brian,

I think that this estimate would be fine for now. Since there would be no capital expenditures for the ECC, I think the estimate on man time is OK

One question is that would you see an addition to your staff for this or would your staffing now be sufficient?

As well, would you have a feel for the potential costing for NERC CIP compliance for the entire BES? I know there would be a tremendous amount involved but just a feel from your perspective on the things that would be required would be appreciated

Thanks

Jason

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From: Brian Hemeon/NLHydro
To: Jason Tobin/NLHydro@NLHydro
Cc: Bob Butler/NLHydro@NLHydro
Date: 12/13/2011 02:48 PM
Subject: NERC CIP and ECC

Jason

There are no identified capital expenditures required for the ECC/BCC to meet NERC CIP compliance.

Most of the required processes and procedures are in place.

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However there are significant documentation requirements that would be on the order of 12 (+-2 Months) man months of effort.

This is a crude estimate of the effort required, however does reflect the order of magnitude.

If the entire Bulk Electric System was required to meet NERC CIP I believe there would be significant capital and labor costs.

Is it warranted at this time to do a more detailed analysis of the effort to complete the documentation for ECC to meet NERC CIP requirements?

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