newfoundland labrador
hydro
a nalcor energy company

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

August 4, 2017

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

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

Dear Ms. Blundon:

Re: The Board's Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System – Availability of Requested Information from Hydro, August 4, 2017 Update

By letter dated May 3, 2017, the Board requested certain information from Hydro. Hydro responded by letters dated May 15, 2017, May 26, 2017 and July 5, 2017. By letters dated July 19, 2017 and July 21, 2017, the Board wrote to Hydro with questions in respect of the information filed and noting concern that certain information sought by the Board would not be available "for some time" and "that filing dates were not provided in relation to several items."

In response to the Board's questions and concerns, Hydro wishes to provide further clarity with respect to the noted items as follows:

1. ***No date was provided for the provision of information with respect to the commercial arrangements for the purchase of recall power and energy and use of the necessary transmission facilities. Hydro identified that first power transfer over the Labrador Island Link ("LIL") is expected in Q3, 2018. It is noted that the Board's conclusion in its May 12, 2017 letter that no immediate steps were necessary to reduce the risks to adequate and reliable supply on the Island Interconnected system as currently configured was based, in part, on Hydro's planned reliance on the availability of recall power prior to interconnection.*** **[May 3, 2017 letter, items #8 and 14]**

   Mature drafts of agreements concerning the use of necessary transmission facilities for recall power have been developed and are in circulation with the parties (Hydro as the transmission user, Newfoundland Labrador System Operator as transmission service provider, and the Labrador Transmission Company and Labrador-Island Link Limited Partnership as transmission owners). The purchase arrangement for recall power is in development. It is anticipated that these commercial arrangements will be completed and executed in 2017.

In addition, opportunities for sources of energy that can be imported through Labrador, and transmitted via the Labrador-Island Link (LIL) to serve island load have been investigated. A number of high potential opportunities have been identified, and negotiations are advanced. While the details of the agreements that are expected to result from these negotiations are confidential, they are based on commonly used templates which are publicly available,[1] and which establish the relationship between the two parties to enable future energy transactions with minimal negotiation, other than to agree on price, quantity and timing of delivery. These agreements will serve to reduce the amount of energy produced by the Holyrood Thermal Generating Station for Island needs, and will provide some capacity to the system; however, as previously demonstrated, these agreements provide for supply that is over and above the interconnected Island system requirements as presented in the Near-Term Generation Adequacy Report.

2. ***A first draft of the emergency restoration plans for the LIL, which Hydro contemplates utilizing in 2018, will not be available until November 2017.*** **[May 3, 2017 letter, item #7]**

The contractor's key dates for delivery of the emergency restoration plans for the LIL are outlined below:

Item	Date
Develop, Release and Award Contract	July 31, 2017
Contract Kick-off	July 31, 2017
Complete site visits and Risk Workshop	August 2017
Delivery of Risk Severity Matrix	September 2017
Design Solutions and Presentation/Selection of Repair Approach, forming the basis of the Draft Emergency Response Plan	November 2017
Deliver Final Emergency Response Plan and Incident Response Approach	January 2018

[1] Power purchase agreements are based on the "Master Power Purchase & Sale Agreement - Edison Electric Institute", which is publicly available at www.eei.org/resourcesandmedia/mastercontract/Documents/contract0004.doc.

3. ***No date was provided for the filing of information with respect to the emergency power and reserve sharing arrangements with Atlantic Canadian utilities.* [May 3, 2017 letter, item #11]**

As previously noted, as a part of the Interconnection Operators Agreement (IOA) executed between Hydro and Nova Scotia Power (NSPI), there are provisions whereby both parties agree to formalize arrangements to share operating reserves and to provide emergency and security energy to one another. These arrangements will be detailed in the schedules contemplated in the IOA.

Both NSPI and Hydro have been working towards finalizing the contents of the schedules. Changes recently proposed by Hydro will be discussed at the next meeting of the Interconnection Operators Committee, which is scheduled for August 30, 2017. The intent is to finalize the schedules prior to energization of the Maritime Link (ML).

4. ***The planning criteria applicable following interconnection will not be provided until Q4, 2018.* [May 3, 2017 letter, item #17]**

Hydro continues to investigate the most appropriate planning criteria for the provincial electricity system following the in-service of the LIL, the ML, and the Muskrat Falls Generating Station. Hydro recognizes the importance of the outcomes of this decision, and particularly the potential impact it will have on customers. Hydro must ensure that it provides acceptable levels of reliability for customers, while balancing the overall cost of the system to ensure rates remain as reasonable as possible. While additional investment can increase reliability for customers, such investment needs to be optimized to ensure that the cost of the investment is justified. This means that any decisions to modify planning criteria must be made prudently, with the engagement of Hydro's stakeholders and in full consideration of customer expectations, and potential system impacts.

To assist in this assessment, Hydro is developing the following:

- ***A new software model for generation planning, developed in PLEXOS (Plexos).*** This software is capable of modelling Hydro's electrical system with greater accuracy and detail. Further, the model will include representation of Hydro's bulk transmission system, ensuring the deliverability of Hydro's resources to meet customer requirements. More details about the implementation of the Plexos model are provided below; and
- ***An evaluation of the impacts of compliance with North American reliability standards.*** Hydro is conducting analysis to determine what reliability standards are most appropriate for Hydro's system, and what modifications (if any) would be required to adopt such standards. Hydro is conducting this analysis for both deterministic (i.e., Reserve Margin) and probabilistic (i.e., Loss of Load Expectation) reliability assessments.

Plexos is a power system simulation tool developed by Energy Exemplar. In selecting the software, Hydro engaged in several discussions with both the vendor and model users to ensure it best met Hydro's modelling requirements. A few notable benefits of this software over that currently used by Hydro are:

- Plexos is widely used in industry, and is currently used by both NSPI and New Brunswick Power (NBP). This will enable better sharing of information between Hydro and its neighboring utilities;
- The software is also used by many primarily hydro-based utilities. This indicates that the software is capable of modelling the complexities of hydro-based systems;
- The software includes modelling of the underlying bulk transmission system, ensuring resource deliverability between source and load; and
- The software is capable of hourly modelling, allowing Hydro to model its system with a greater level of detail, particularly for periods near peak.

In addition to leasing the software, Hydro has engaged Energy Exemplar to develop the base system model. As part of that implementation effort, Energy Exemplar will be on site for project kickoff and software training, then work closely with Hydro's Resource and Production Planning department to develop a comprehensive model of Hydro's interconnected system. The project kick-off meetings and training are scheduled for the week of August 28, 2017. The system model is expected to be complete by year-end 2017, with extensive model testing and refinement to come in Q1 of 2018.

Following the completion of the model, Hydro will be able to fully assess the reliability of the current system and evaluate the potential impact of compliance with North American reliability standards.

Once the above has been compiled and assessed, Hydro will make its recommendations on appropriate planning criteria to the Board in 2018, as previously noted.

Hydro proposes these activities culminate in the "Resource Adequacy" report to the Board, to be delivered November 15, 2018. This proposed report will address both near-term and long-term resource adequacy and will discuss:

- demand and energy projections in the operational (less than 3 years) and planning (3-10 years) horizons;
- asset integrity, in-service and retirement plans;
- system adequacy analysis including the identification of potential capacity or energy surplus/deficit;
- discussion of near-term resource options;
- generation expansion analysis;
- sensitivity analysis; and
- other issues as required.

To summarize, the following provides a high-level schedule for the above activities:

Item	Date
Plexos Modelling: Project Kick-off and Software Training	August 28-31, 2017
Interconnected System Model Developed	December 31, 2017
Model Testing and Refinement	January to April 2018
Assessment of Hydro's System Adequacy and Determination of Planning Criteria	May to September 2018
Analysis of results and report development	September to November 2018
Resource Adequacy Report	November 15, 2018

Note that in advance of the interconnected system model and approved planning criteria, Hydro will continue to provide its assessment of Near-term Generation Adequacy in a manner consistent with that last provided on May 15, 2017. Hydro proposes that the above-mentioned Resource Adequacy report will replace the Near-term Generation Adequacy report at that time.

5. ***Discussions are ongoing in relation to opportunities for near term supply from Nova Scotia Power and New Brunswick Power but are not expected to conclude until Q4, 2017.*** **[May 3, 2017 letter, item #18]**

As previously reported to the Board, NSPI and NBP were approached in late 2016 and early 2017 to discuss potential opportunities for the near term supply of energy without firm capacity to the island over the ML. Both NSPI and NBP indicated that opportunities will likely materialize to provide energy via the ML, but such arrangements were not identifiable for contract in advance. It is expected that these opportunities will materialize closer to the dates of anticipated delivery, based on what they will have available in excess of their actual requirements for their customers at the time.

Nalcor Energy Marketing (NEM) already has agreements in place with both NSPI and NBP, and while the details of these agreements are confidential, they are based on a commonly used template that is publicly available.[2] These agreements establish the relationship between the parties and enables future energy transactions to require minimal negotiation, other than to agree on price, quantity and timing of delivery. In addition, NEM is in negotiations with these parties to develop framework agreements to

[2] See footnote 1.

streamline further the negotiation process to enable mutually beneficial trade opportunities.

With respect to available capacity from the Maritimes, the resource adequacy in the Maritimes has been described in a publicly available Northeast Power Coordinating Council (NPCC) report, *2016 Maritimes Area Comprehensive Review of Resource Adequacy,*[3] attached as Appendix "A".

6. ***A number of studies related to supply from the Muskrat Falls Generating Station are not scheduled to be completed until 2018* [May 3, 2017 letter, items # 6, 9, 10, 12, 13, 19, 20, 21, and 24]**

Hydro has established a plan for the completion of operational studies and has staged these studies to match the anticipated in-service date of new assets. The stages are summarized as follows:

Stage I	Addition of the ML
Stage II	Addition of the Soldiers Pond Synchronous Condensers
Stage III	Addition of the LIL and Labrador Transmission Asset
Stage IV	Addition of Muskrat Falls Generation

Hydro is committed to providing updates pertaining to operational studies and submitting all completed reports upon receipt. Details relating to the plan including the forecasted timeline for the submission of all reports are provided in Appendix "B".

For further clarity, each study would cover the requested information as noted below:

Item #	Description	Study Stage
6	HVdc converter station contractors' studies and copies of any completed study	Stage IV
9	Interaction studies between the IIS and the ML completed since Preliminary Interconnection Studies dated August 2014, including with the ML in and out of service [High Power]	Stage I, II, III, IV
10	Update on study regarding additional reactive power	Stage IV
12	Frequency Controller study for the ML	Stage I, II, III, IV
13	Systems Studies to determine reserve sharing between LIL and IIS generation	Stage IV
19	Bay d'Espoir instability studies	Stage IV

[3] https://www.npcc.org/Library/Resource Adequacy/2016 Maritimes Area CRRA for RCCpaf.pdf

Item #	Description	Study Stage
20	Underfrequency Load Shedding scheme post Muskrat Falls	Stage IV
21	Operational Studies regarding IIS post Muskrat Falls	Stage IV
24	Studies of the performance of the IIS with the ML in service and with it out of service (and resulting operating guidelines)	Stage III, IV

7. ***The requested updated post Muskrat Falls interconnection energy supply assessment, which Liberty noted in its August 2016 report (page 87) was underway with expected completion in 2016, appears to have been replaced with a proposal to provide annual generation capability updates following interconnection.* [May 3, 2017 letter, item #16]**

Please see Hydro's response to #4 above.

8. ***Hydro's reply with respect to four items was unclear requiring the Board to seek further clarification in its letter of July 19, 2017.***

In Hydro's previous correspondence, the following note was included with several items:

> *The nature of the information provided may be subject to any response by Hydro to this recommendation and the Board's final determination on (i) Liberty's recommendations and (ii) the parties' submissions.*

This note was originally provided in respect of items noted in the table below, as it was expected that further Board directives would be issued in respect of recommendations from Phase 2 Liberty Report, to which Hydro may have been required to respond. As this process did not take place before the information was requested in May 2017, Hydro was uncertain as to whether the form of information to be provided in each instance would be sufficiently defined at this stage to satisfy the Board's ultimate requirements.

Further comment in respect of each item is noted below.

Item #	Description	Reference	Hydro Comment
6	Update on studies for HVdc converter station contractors' studies and copies of any completed study	Liberty Report, page 79, Recommendation IV-2	This request was based on Liberty's recommendations that the converter station contractor should perform "transient stability studies with multiple restart attempts for HVdc OHL faults". While certain elements of this requirement may be met by the high power studies currently underway (noted above), this may not ultimately take the form requested by the Board, absent specific direction to that effect.
16	Updated Energy Supply Risk Assessment Post Muskrat Falls	Liberty Report, page 87, Recommendation V-3 and page 112, Recommendation V-3	Please see #4 and #7, above. As noted, Hydro will be putting certain planning information before the Board in the 2018 period, and following receipt of Board direction will be filing the appropriate form of "Resource Adequacy" report.
22	Update on multi-year reliability compliance program and Provincial Reliability Framework	Liberty Report, Recommendation s VI-15, page 106	Hydro provided a response to this request on July 5, 2017. As the current course of action as described in that response is unlikely to be impacted by the outcome of this proceeding, Hydro should have removed this note in its July response.
23	Status of plan for compliance with NERC	Liberty Report, page 101-102 and Recommendation VI-14, page 106	Hydro provided a response to this request on July 5, 2017. As the current course of action as described in that response is unlikely to be impacted by the outcome of this proceeding, Hydro should have removed this note in its July response.

9. ***A detailed Integrated Project Schedule setting out all activities required to ensure successful transition to operations (see Liberty's August 19, 2016 report, pages 93-94). To allow the Board to fully understand the nature of the necessary work and the planning for and completion of this work, Hydro should also file the associated underlying data, including the following information, regarding the transition schedule:***

- ***A listing of all scheduled activities, together with baseline start and finish dates as well as the current forecasted start and finish dates***
- ***Indicators of the status of each task vis-à-vis the critical path***
- ***Resources associated with each task, as and if loaded into the schedule***
- ***Sample schedule reports being used by transition team management***
- ***Key assumptions underlying the schedule***

Please see the attached Appendix "C".

Further updates will be provided as soon as they are available.

Please advise if you have any questions with respect to the attached.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

fby

Geoffrey P. Young
Corporate Secretary & General Counsel

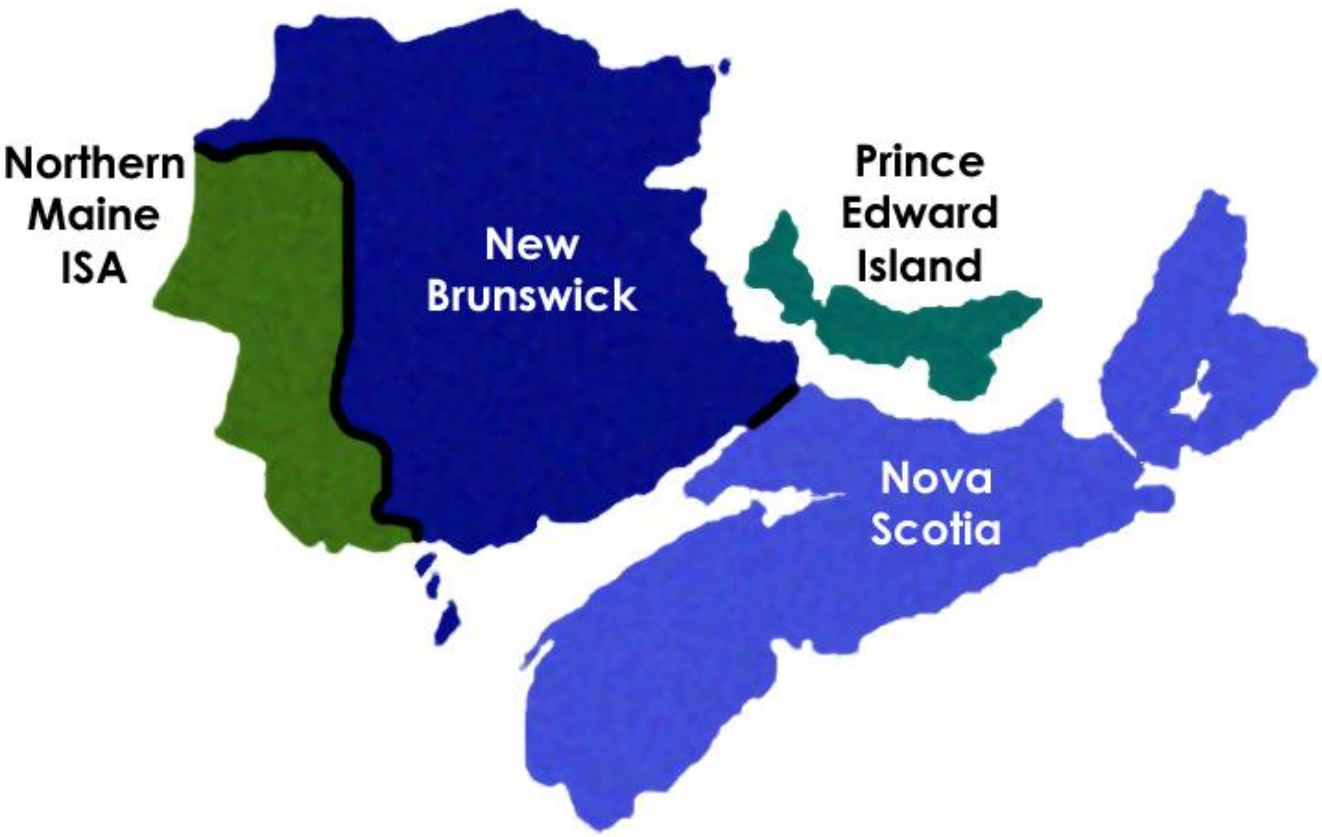
GPY/vc

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Roberta Frampton Benefiel – Grand Riverkeeper Labrador
Dennis Browne, Q.C. – Consumer Advocate
Danny Dumaresque

ecc: Denis Fleming- Vale Newfoundland & Labrador Limited
Larry Bartlett – Teck Resources Ltd.

NPCC
2016 MARITIMES AREA
COMPREHENSIVE REVIEW OF RESOURCE ADEQUACY

Approved by RCC December 6, 2016



NEW BRUNSWICK POWER CORP.
NOVA SCOTIA POWER INCORPORATED
MARITIME ELECTRIC COMPANY, LIMITED
NORTHERN MAINE ISA, INC.

September 2016

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EXECUTIVE SUMMARY

The 2016 Maritimes Area Comprehensive Review of Resource Adequacy, covering the period of January 2017 through December 2021, has been prepared to satisfy the compliance requirements as established by the Northeast Power Coordinating Council (NPCC). The guidelines for this review are specified in the *NPCC Regional Reliability Directory #1 Appendix D (Approved: September 30, 2015)*. This review supplants the previous Comprehensive Review that was performed in 2013 and approved by the RCC on December 3, 2013.

Table 1 provides a summary of the major assumptions and results of this review.

Table 1: Summary of Major Assumptions and Results

MAJOR ASSUMPTIONS	
Load Forecast	2016 (all jurisdictions)
Load Shape	2011/12 (all years)
Resource Adequacy Criterion	Loss of Load Expectation not more than 0.1 days/year
Maritimes Required Reserve	20% of peak firm load
Interconnection Benefits	300 MW
Area Purchases/Sales	Sales of 200 MW and 114 MW during the 2016/17 and 2018/19 winter peak periods respectively
Maritime Link Project	153 MW of purchases from Newfoundland to Nova Scotia is forecast for mid-2020 coincident with a planned retirement of a 153 MW Nova Scotia generator
RESULTS	
Year	**Expected Number of Firm Load Disconnections days/year**
2017	0.003
2018	0.003
2019	0.003
2020	0.003
2021	0.004

The 2017 coincident peak demand forecast for the Maritimes Area is 5,392 MW, which is 125 MW above the 5,267 MW peak demand forecast in the 2013 Comprehensive Review. This increased peak demand forecast reflects increases in electric heating loads which are not quite offset by declines in industrial loads and demand shifting programs. The average annual demand growth over the 2017–2021 study period of this review is 0.16%, which is marginally higher than the -0.05% annual demand growth forecast in the 2013 review but still essentially flat.

The reserve criterion for the Maritimes Area is 20%, and adherence to this criterion is demonstrated in Section 2.4 to comply with the NPCC resource adequacy criterion.

The NPCC resource adequacy criterion of a Loss of Load Expectation (LOLE) of not more than 0.1 days per year of firm load disconnections is not exceeded by the Maritimes Area for all years covered by this review and varies between 0.003 to 0.004 days/year for the base load forecast. The Maritimes Area is also shown to adhere to its own 20% reserve criterion in all years for the base load forecast, with minimum reserve levels varying between 40% and 44%.

Sensitivity analyses were run to determine the LOLE effects of high load growth, zero wind generation, and removing all external tie benefits. The sensitivity results are shown in Table 2 and meet the NPCC resource adequacy criterion in all years.

Table 2: Summary of LOLE Results

Year	Base Case LOLE	High Load Growth LOLE	Zero Wind LOLE	No Tie Benefits LOLE
	days/year	days/year	days/year	days/year
2017	0.003	0.003	0.017	0.005
2018	0.003	0.003	0.012	0.003
2019	0.003	0.006	0.016	0.004
2020	0.003	0.010	0.019	0.004
2021	0.004	0.019	0.026	0.005

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1.0 INTRODUCTION

The 2016 Maritimes Area Comprehensive Review of Resource Adequacy, covering the period of January 2017 through December 2021, has been prepared to satisfy the compliance requirements as established by the Northeast Power Coordinating Council (NPCC). The guidelines for this review are specified in *NPCC Directory #1 Appendix D, Guidelines for Area Review of Resource Adequacy (Approved: September 30, 2015)*. This review supplants the previous Comprehensive Review that was performed in 2013 and approved by the RCC on December 3, 2013.

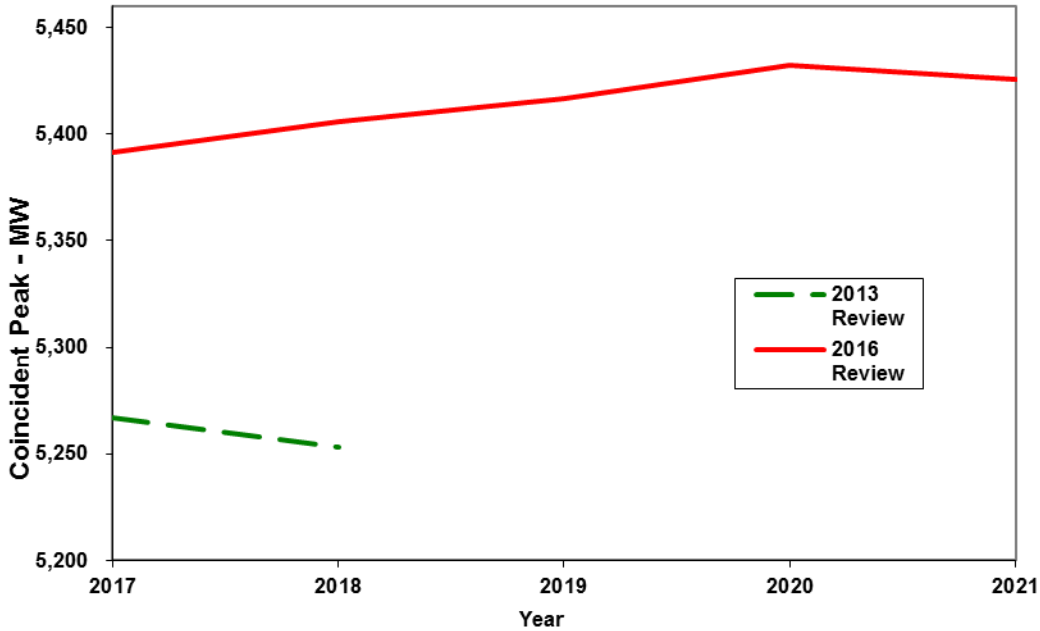
The Maritimes Area is a winter peaking area with separate jurisdictions and regulators in New Brunswick, Nova Scotia, Prince Edward Island (PEI), and Northern Maine. New Brunswick Power (NB Power) is the Reliability Coordinator for the Maritimes Area.

Table 3 and Figure 1 provide a comparison of the load forecasts in the 2016 and 2013 reviews. The coincident peak demand forecast for 2017 is 5,392 MW, which is 125 MW above the 5,267 MW forecast in the 2013 Comprehensive Review. This increased peak demand forecast reflects increases in electric heating demands which were not offset by declines in industrial loads and demand shifting programs. Demand shifting and energy efficiency programs are expected to reduce peak demand in the Maritimes Area by 100 MW to 280 MW during the Comprehensive Review period. The average annual demand growth over the period of this review is 0.16%, which is marginally higher than the 0.05% average demand growth forecast in the 2013 review but still essentially flat.

Table 3: Comparison of Load Forecasts

Winter Peak (Month of January)	2016 Review MW	2013 Review MW
2017	5,392	5,267
2018	5,406	5,253
2019	5,416	N/A
2020	5,432	N/A
2021	5,426	N/A
Five Year Period	**2017–2021**	**2014–2018**
Annual Average Growth Rate	0.16%	0.05%

Figure 1: Comparison of Load Forecasts



2.0 RESOURCE ADEQUACY CRITERION

2.1 Statement of Resource Adequacy Criterion

For planning purposes, New Brunswick, Nova Scotia, PEI and Northern Maine individually apply a capacity based criterion in determining their required reserves.

New Brunswick, Nova Scotia, and Northern Maine each plan for a reserve equal to greater of the capacity of the largest generator or 20% of the firm load. For this review, the latter criterion was applicable in all years. PEI plans for a reserve equal to 15% of its firm load. As a simplification, this review applies the 20% reserve criterion to the Maritimes Area as a whole because of the relatively small size of PEI compared to the rest of the Maritimes Area. Thermal and hydro generators are considered available at the Dependable Maximum Net Capability (DMNC) in the determination of the reserve margin.

The NPCC resource adequacy criterion (from *NPCC Directory #1 Design and Operation of the Bulk Power System, Requirement 4 (Dated: September 30, 2015*) states:

> "**R4** Each Planning Coordinator or Resource Planner shall probabilistically evaluate resource adequacy of its Planning Coordinator Area portion of the bulk power

system to demonstrate that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies is, on average, no more than 0.1 days per year.

R4.1 Make due allowances for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."

2.2 Emergency Operating Procedures

Although this document presents a review of resource adequacy for the interconnected Maritimes Area, each separate system remains under the exclusive control of its system operator for purposes of economic dispatch. For reliability purposes, however, reserve sharing agreements do exist and the systems operate as an Area in accordance with NPCC criteria and guidelines.

Actions taken by the Energy Coordinator/Dispatcher, when faced with a developing or sudden capacity shortage, are based upon a number of possible actions best suited to the prevailing system conditions. In practice, the corrective actions taken are one or more of the following Emergency Operation Procedures (EOP):

1. Synchronize and load all available hydro generators.

2. Bring on-line generators up to their DMNC.

3. Cancel economy and other external interruptible sales.

4. Begin start-up procedures for "cold-standby" thermal generators.

5. Synchronize and load combustion turbines.

6. Purchase capacity from Hydro-Québec.

7. Purchase capacity from New England.

8. Cut interruptible sales to industrial customers.

9. Maximize MVAR support (capacitor banks, synchronous condensers) if capacity shortage is causing a low voltage condition in a particular area.

10. Implement a 5% voltage reduction at selected substations within Nova Scotia (1–5 MW)

11. Appeal to the public for voluntary customer load reduction.

12. Disconnect customer loads as necessary to correct either a local or widespread problem.

Some or all of the above steps may be used in varying sequence to meet a capacity shortage depending on the generation pattern in effect at the time and whether or not the shortage results in localized internal system problems.

Although steps 10 and 11 are valid, the level of assistance available from these procedures is not modeled in this study.

2.3 Maritimes Area Required Reserve

The Maritimes Area employs a reserve criterion of 20% of firm load. The required installed reserve is shown in Section 3.1.

2.4 Relationship of Reserve Criterion to NPCC Reliability Criterion

To relate the Maritimes Area reserve criterion of 20% to the NPCC resource adequacy criterion as stated in Section 2.1, LOLE was evaluated with the Maritimes Area firm load scaled so that the reserve was equal to 20%. The results showed that a Maritimes Area reserve of 20% corresponds to an LOLE of approximately 0.086 days per year. At this load level, only 30 MW of additional load was required to match the NPCC LOLE resource adequacy criterion of 0.1 days per year.

The preceding demonstrates that the 20% Maritimes Area reserve criterion correlates closely with the 0.1 days/year NPCC LOLE resource adequacy criterion.

2.5 Recent Reliability Studies

Resource Planners in New Brunswick, Nova Scotia, PEI, and Northern Maine individually conduct internal reviews of their capacity requirements by comparison of generation sources with forecast loads according to the reserve criterion described previously.

The results presented in this review are based upon an evaluation conducted during the third quarter of 2016 for the period 2017 through 2021. This review supplants the previous Comprehensive Review that was performed in 2013 and approved by the RCC on December 3, 2013. Interim reviews of resource adequacy for the Maritimes Area were completed in the years 2014 and 2015 covering the years 2015–2018 and 2016–2018 respectively. The results of the interim reviews for the two overlapping years 2017 and 2018 compare well with the results of this review. The NPCC resource adequacy criterion was met in both years for all base and sensitivity cases. The same is true for this review.

2.6 Load Forecast Uncertainty

To determine load forecast uncertainty (LFU) an analysis of the historical load forecasts of the Maritimes Area utilities has shown that the standard deviation of the load forecast errors is approximately 4.6% based upon the four year lead time required to add new resources. To incorporate LFU, two additional load models were created from the base load forecast by increasing it by 4.6 and 9.2 percent (one or two standard deviations) respectively. The reliability analysis was repeated for these two load models.

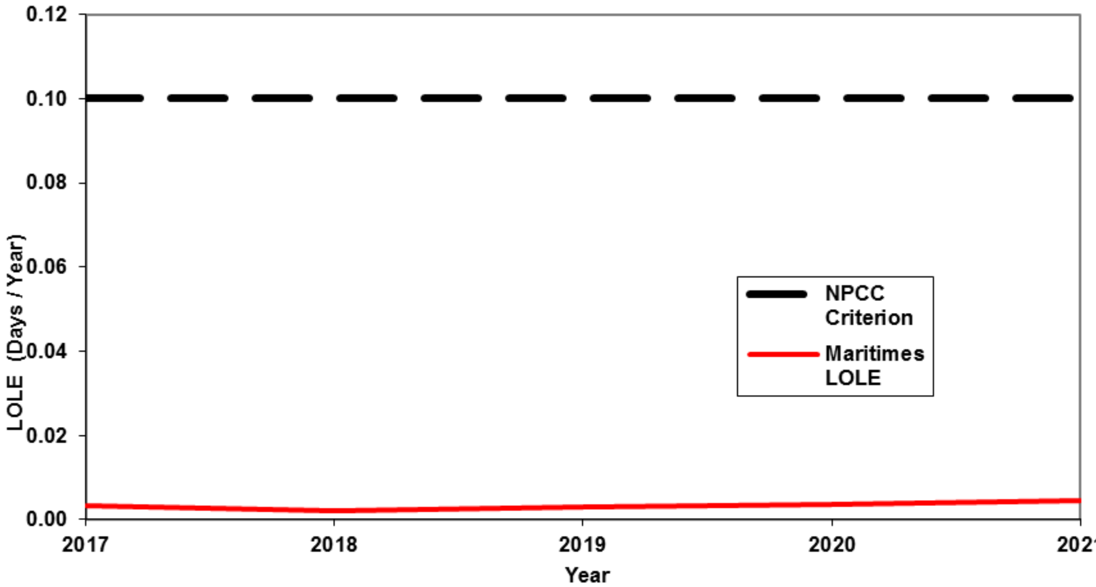
It is assumed that the forecast error is approximately normally distributed around the forecast value and that the contribution to system LOLE is negligible when loads are less than the forecast value by more than ½ a standard deviation. These assumptions result in weighting factors of 0.383, 0.242, and 0.067 for the three results obtained using the base, 4.6 percent increased, and 9.2 percent increased load models respectively.

The results of the LFU evaluation as indicated in Table 4 and Figure 2 demonstrate that the Maritimes Area system meets the NPCC resource adequacy criterion of no more than 0.1 days/year from 2017 to 2021.

Table 4: LOLE days/year – Base Case with Load Forecast Uncertainty

Calendar Year	Expected Number of Firm Load Disconnections days/year
2017	0.003
2018	0.003
2019	0.003
2020	0.003
2021	0.004

Figure 2: LOLE (days/year) – Base Case with Load Forecast Uncertainty



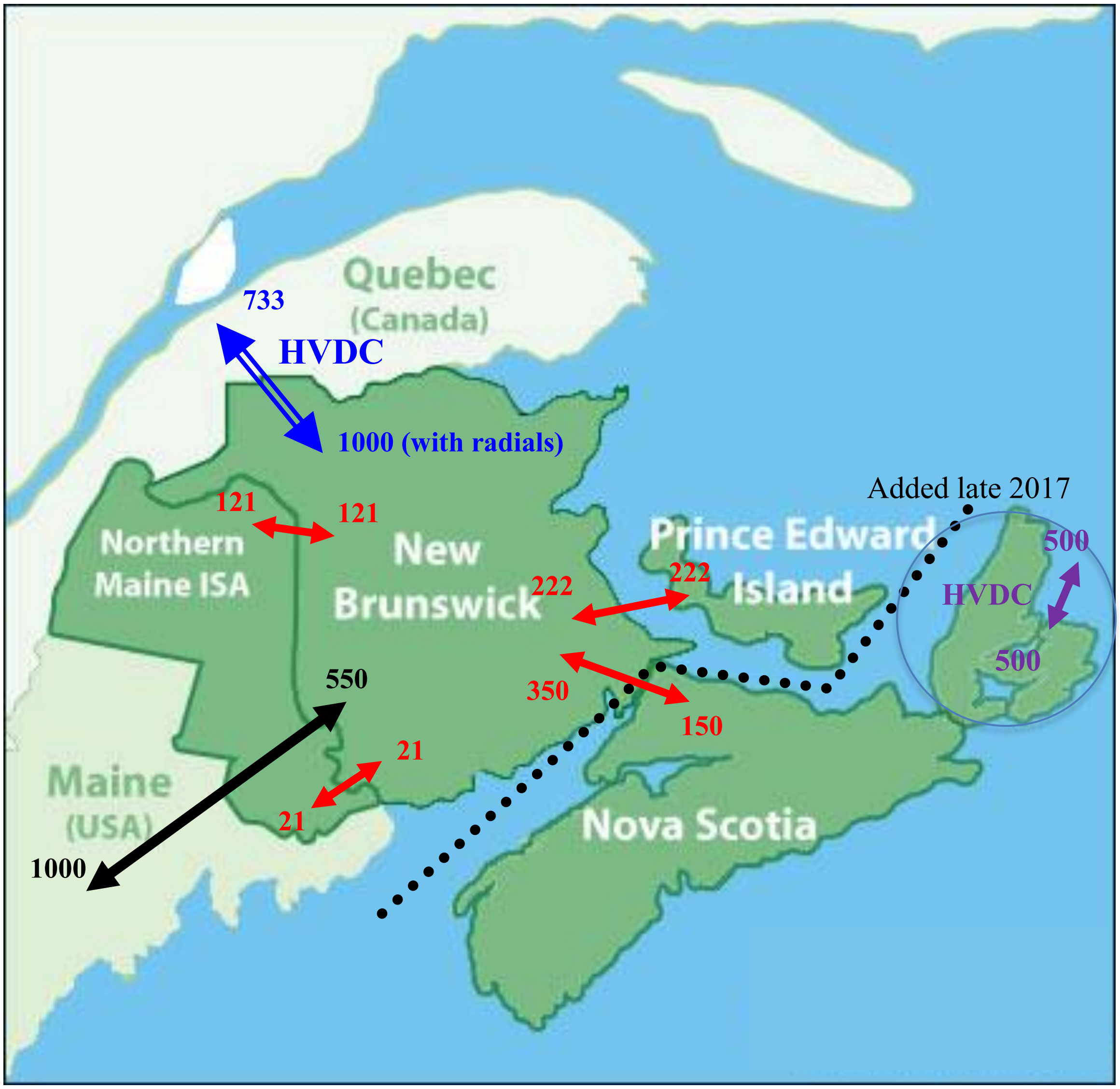
2.7 Intra-Area Transmission Capacity Limits

Within the Maritimes Area, the areas of Nova Scotia, PEI, and Northern Maine are each connected only to New Brunswick as per Figure 3. A transmission congestion issue of consequence to the LOLE occurs for only one of these three interconnections, the tie between New Brunswick and Nova Scotia.

Transmission capacity limits between Northern Maine and New Brunswick were not modeled for this analysis. These normal limits are a result of parallel operation of four lines (two 138 kV, two 69 kV) that Northern Maine keeps below thermal ratings to ensure that the trip of one of these lines doesn't overload the others. Should one or more contingencies occur in Northern Maine, the lines can be switched from parallel to radial operating modes. This effectively allows a high enough transfer limit from New Brunswick to meet the peak load in Northern Maine.

Late in 2016, PEI is installing two additional undersea cables between that province and New Brunswick. Based on a tripling of cable capacity and two additional parallel paths, the single cable contingency limiting flows from PEI to NB has been eliminated. For this review, the transmission limit for this return path was assumed to equal the transmission limit in the NB to PEI direction and as a result the PEI to NB limit was increased from 124 MW to 222 MW. This change has a negligible effect on the Maritimes Area LOLE values since there is little need for PEI capacity to supply NB loads given the high amount of reserve capacity available to NB from other resources.

Figure 3: Maritimes Area Transmission Capacity Limits



3.0 RESOURCE ADEQUACY ASSESSMENT

3.1 Comparison of Forecast and Required Reserve – Base Case

In the comparison of the forecast and required reserve, the following definitions apply. The required reserve of 20% is the reserve criterion of the Maritimes Area. The forecast reserve is the actual reserve that will occur for the load forecast and resource plan used in this study.

Table 5 and Figure 4 represent the results of the reserve comparison for the base load forecast. The forecast reserve levels reflect reserves calculated using wind generation levels at the hour of the Maritimes Area coincident peak demand. In 2017, the wind generation modeled on peak was 496 MW. Based on the wind and load shapes modeled, the minimum hourly reserve expected during 2017 is 1993 MW coinciding with a total Maritimes Area wind generation of 83 MW. In each year of the analysis, the forecast reserve is greater than the required reserve.

Table 5: Forecast, Minimum, and Required Reserve Levels – Base Case

Month Of January	Forecast Capacity	Coincident Peak Load	Inter. Load	Forecast Reserve		Minimum Hourly Reserve		Required Reserve	
	MW	MW	MW	MW	%	MW	%	MW	%
2017	7,207	5,392	268	2,083	41	1,993	41	1,025	20
2018	7,418	5,406	272	2,284	44	2,173	44	1,027	20
2019	7,299	5,416	272	2,154	42	2,021	40	1,029	20
2020	7,454	5,432	272	2,293	44	2,159	43	1,032	20
2021	7,454	5,426	272	2,300	45	2,153	43	1,031	20

$$\text{Forecast Reserve (\%)} = \left[\frac{\text{Forecast Capacity} - (\text{Peak Load} - \text{Inter. Load})}{(\text{Peak Load} - \text{Inter. Load})}\right] * 100\%$$

$$\text{Minimum Reserve (\%)} = \frac{\text{Min. of Hourly [Capacity} - (\text{Load} - \text{Inter. Load})]}{(\text{Load} - \text{Inter. Load})} * 100\%$$

3.2 LOLE results – High Load Growth

Table 6 and Figure 4 illustrate LOLE results if the average annual growth rate is 1% higher than forecast (i.e. 1.16% per year versus 0.16% per year compounded over the 4 year period of this review). The results show that the NPCC resource adequacy criterion is met in all years.

Table 6: Loads and LOLE Results – High Load Growth

Month Of January	High Load Growth Load	Base Case Load	Difference	High Load Growth LOLE	Base Case LOLE
	MW	MW	MW	days/year	days/year
2017	5,392	5,392	0	0.003	0.003
2018	5,454	5,406	48	0.003	0.003
2019	5,517	5,416	101	0.006	0.003
2020	5,581	5,432	149	0.010	0.003
2021	5,645	5,426	220	0.019	0.004

3.3 LOLE Results – Zero Wind

The Maritimes Area did not assign a fixed capacity credit to wind generation. Instead, simulated hourly wind capacity values were netted against corresponding hourly load values. Because there were no wind generation additions beyond 2017 and because the peak load day for the five years did not vary during the 2017 to 2021 period of this review, simulated wind capacity during peak demand was constant at 496 MW compared to an installed total of 974 MW. A sensitivity analysis was performed with the wind capacity on the system set to zero output for all hours. Table 7 and Figure 4 illustrate LOLE results for the zero wind generation scenarios. The results show that Maritimes Area is not reliant on wind capacity to meet the NPCC resource adequacy criterion.

Table 7: Capacity and LOLE Results – Zero Wind

Month Of January	Zero Wind Capacity	Base Case Capacity	Difference	Zero Wind Capacity LOLE	Base Case LOLE
	MW	MW	MW	days/year	days/year
2017	6,711	7,207	-496	0.017	0.003
2018	6,922	7,418	-496	0.012	0.003
2019	6,803	7,299	-496	0.016	0.003
2020	6,958	7,454	-496	0.019	0.003
2021	6,958	7,454	-496	0.026	0.004

3.4 LOLE Results – No Tie Benefits

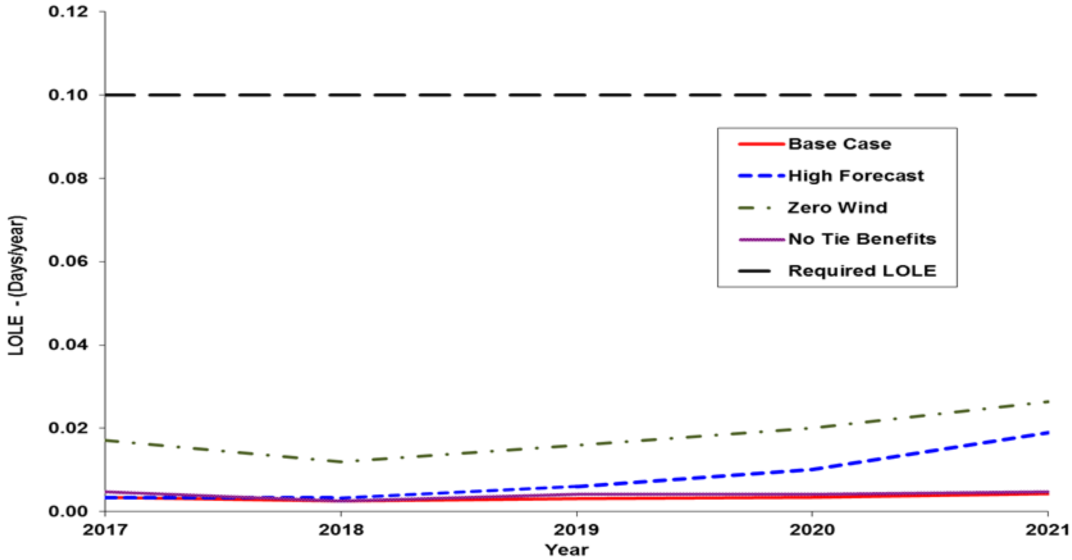
Since 2011, NBSO has assumed 300 MW of tie benefits to New Brunswick in its resource adequacy assessments. These tie benefits are based on a 2011 decision by the New Brunswick Market Advisory Committee to recognize the lowest historical Firm Transmission Capacity posted from summer peaking New England to winter peaking New Brunswick since the commissioning of the second 345 kV tie between these systems in December 2007. To the extent that future capacity purchases from New England to New Brunswick occur across this interface, these tie benefits will be reduced accordingly. Tie benefits from other neighbouring jurisdictions were not considered by the New Brunswick Market Advisory Committee because they also experience peak loads in winter.

In the CP-8 report *Review of Interconnection Assistance Reliability Benefits (December 31, 2015, Approved by RCC March 2, 2016)* the "As Is" estimated tie benefit potential for the Maritimes Area is 702 MW and 1012 MW for the years 2016 and 2020 with an export of 200 MW modeled in both test years. Based on this study, the 300 MW of tie benefits assumed for this 2016 Comprehensive Review is conservative. A sensitivity analysis performed for this review shows that the Area does not require interconnection assistance to meet the NPCC resource adequacy criterion. The results are shown in Table 8 and Figure 4.

Table 8: Capacity and LOLE Results – No Tie Benefits

Month Of January	No Tie Benefits Capacity	Base Case Capacity	Difference	No Tie Benefits LOLE	Base Case LOLE
	MW	MW	MW	days/year	days/year
2017	6,907	7,207	-300	0.005	0.003
2018	7,118	7,418	-300	0.003	0.003
2019	6,999	7,299	-300	0.004	0.003
2020	7,154	7,454	-300	0.004	0.003
2021	7,154	7,454	-300	0.005	0.004

Figure 4: LOLE Results – All Base and Sensitivity Cases



3.5 Contingency Plans

The Maritimes Area utilities' forecast high and low load growth scenarios, and their impact on the generation dispatch is continually being evaluated to address load and resource uncertainties. In the event of a higher than expected growth in load, a number of options would be considered. These options include the purchases of capacity and/or energy, the advancement of base load generation additions, and the installation of combustion turbines.

4.0 FORECAST RESOURCE CAPACITY MIX

4.1 Forecast Resource Capacity Mix

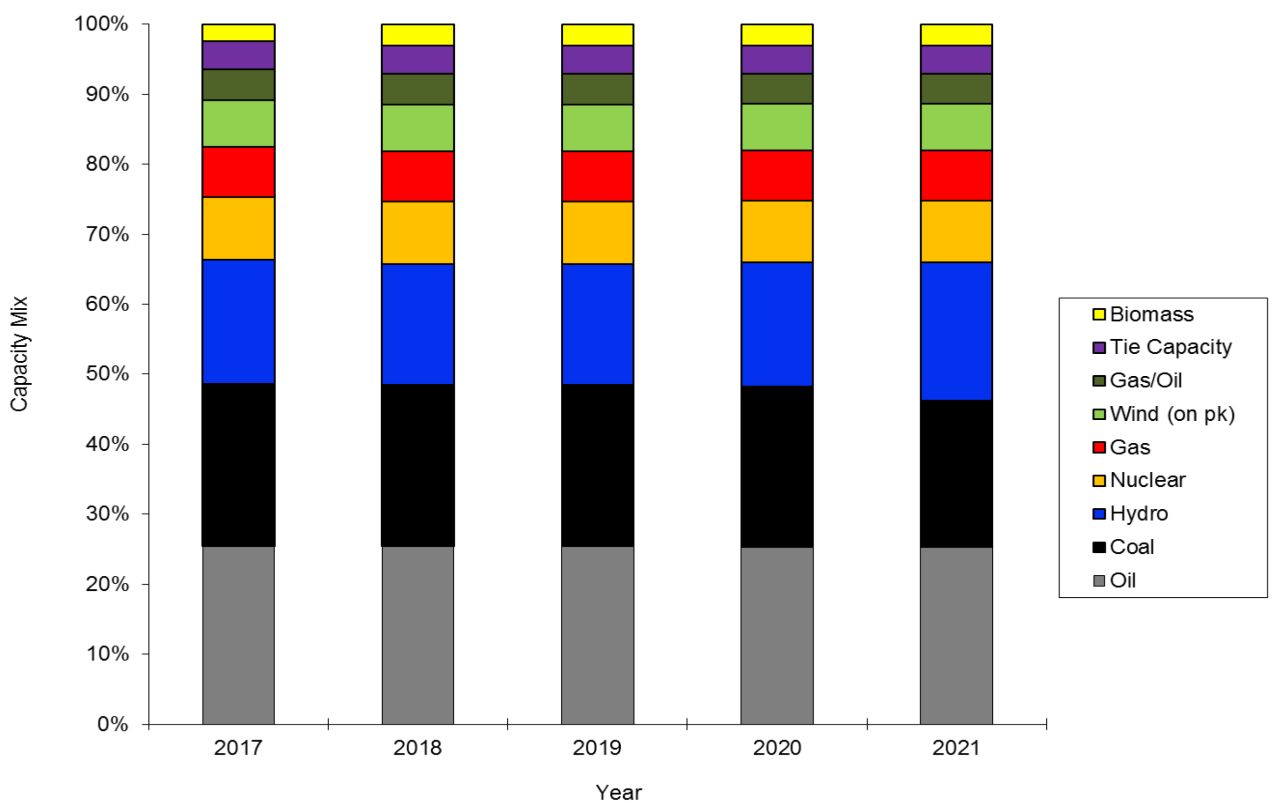
Table 9 and Figure 5 illustrate the forecast resource capacity mix for the Maritimes Area. Appendix A, Section 1.2, Table A-2 presents a detailed list of all capacity resources for the Maritimes Area.

Table 9: Forecast Capacity Resource Mix

Month of January	Oil	Coal	Hydro	Nuclear	Gas	Wind*	Gas/Oil	Tie Benefits	Biomass
	%	%	%	%	%	%	%	%	%
2017	25	23	18	9	7	7	4	4	2
2018	25	23	17	9	7	7	4	4	3
2019	25	23	17	9	7	7	4	4	3
2020	25	23	18	9	7	7	4	4	3
2021	25	21	20	9	7	7	4	4	3

* Wind capacity based on 496 MW of wind capacity (out of 974 MW installed) during coincident peak

Figure 5: Forecast Capacity Resource mix



4.2 Reliability Impact of Resource Diversification Strategy

As can be seen from Table 9 and the associated Figure 5, the Maritimes Area has a diversified mix of resources such that there is not a high degree of reliance upon any one type or source of fuel. This resource diversification also provides flexibility to respond to any future environmental issues, such as potential restrictions to greenhouse gas emissions. The Renewable Energy Standard in Nova Scotia calls for 25% of energy sales to be supplied from renewable resources in 2016 and increases to 40% in 2020. The increase in renewable requirements in 2020 will largely be met by the import of hydro energy from Newfoundland and Labrador and will result in reduced fossil fuel generation.

APPENDIX A - DESCRIPTION OF RESOURCE RELIABILITY MODEL

DESCRIPTION OF RESOURCE RELIABILITY MODEL

1.0 Load Model

1.1 Fiscal year 2011/12 hourly system load data for the Maritimes Area utilities was used as the load shape for this study. Demand and energy forecasts for 2017 to 2021 inclusive were prepared by each resource planner. The combined load and energy forecasts for the Maritimes Area are shown in Table A-1.

Table A-1: Maritimes Area Load Forecast

COINCIDENT DEMAND MW													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Peak**
2017	5392	5181	4821	3946	3463	3222	3228	3145	3217	3672	4412	4894	5392
2018	5406	5193	4845	3952	3471	3228	3248	3170	3235	3689	4432	4924	5406
2019	5416	5200	4863	3981	3517	3275	3266	3183	3257	3707	4456	4947	5416
2020	5432	5214	4879	3989	3517	3271	3262	3188	3254	3702	4457	4956	5432
2021	5426	5220	4883	3974	3517	3269	3270	3190	3259	3703	4452	4961	5426
ENERGY GWh													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
2017	3018	2719	2702	2251	2029	1859	1935	1950	1874	2085	2359	2843	27622
2018	3042	2738	2728	2279	2058	1882	1955	1969	1894	2105	2381	2866	27897
2019	3067	2762	2742	2294	2077	1900	1961	1971	1898	2111	2390	2874	28047
2020	3077	2774	2756	2306	2081	1905	1964	1978	1902	2115	2396	2884	28138
2021	3078	2775	2758	2300	2081	1906	1965	1979	1903	2118	2393	2882	28138
INTERRUPTIBLE DEMAND MW													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	On Peak
2017	268	258	343	342	324	352	366	360	365	344	346	266	268
2018	272	262	348	347	329	352	366	360	365	345	346	267	272
2019	272	263	348	348	329	353	366	360	365	345	346	267	272
2020	272	263	348	347	329	352	366	360	365	345	346	267	272
2021	272	263	348	347	328	352	366	360	365	344	346	267	272

Note: The forecast coincident peak demand occurs in January.

1.2 Load forecast uncertainty (LFU) was considered in the analysis as described in Section 2.6 of the main report.

1.3 Some entities within the Maritimes Area supply a portion of their own electricity demand and energy requirements. Only the portions that are supplied by the Maritimes Area utilities were included in the area forecast.

1.4 The load forecast in Table A-1 includes the impact of DSM and efficiency programs.

2.0 Generator Resource Representation

Generator data for the four members of the Maritimes Area are presented in Table A-2. Table A-3 presents a summary of changes in resource data for the period 2017–2021 inclusive. The following sections document the tabulated data.

2.1 Generator Ratings

2.1.1 Definition

The generator capacity ratings represented in Table A-2 are the Dependable Maximum Net Capability (DMNC) winter ratings. These are evaluated periodically to establish each generator's sustained maximum net output over a two consecutive hour period.

2.1.2 Procedure for Verifying Ratings

Ratings of NB Power generators are tested annually, reaching a minimum of 95% of their declared capabilities for at least 1 full hour. This conforms to NPCC unit testing standard Directory #9 Verification of Generator Gross and Net Real Power Capability. Nova Scotia Power, Inc. (NSPI) reviews generator capability ratings at three year intervals and assumes successful verification at a minimum 98% of the declared value for at least one consecutive hour. This also conforms to the requirements outlined in NPCC Directory #9.

Table A-2: Maritimes Area Resources

New Brunswick Resources				
Plant	**Unit**	**Type**	**Capacity MW**	**Notes**
Point Lepreau	1	Nuclear	660	
		Diesel	5	
Belledune	2	Coal	466	
Coleson Cove	1	Oil	324	
	2	Oil	324	
	3	Oil	324	
Bayside	6	Natural Gas	290	Capacity (Combined Cycle Operation)
Grand Manan	3	Diesel	28	
Millbank	1	Diesel	99	Summer Capacity = 90 MW
	2	Diesel	99	Summer Capacity = 90 MW
	3	Diesel	99	Summer Capacity = 90 MW
	4	Diesel	99	Summer Capacity = 90 MW
Ste Rose	1	Diesel	99	Summer Capacity = 90 MW
Grandview	1	Natural Gas	49	Summer Capacity = 43 MW
	2	Natural Gas	49	Summer Capacity = 43 MW
NUG Purchases		Biomass	38	
		Hydro	15	
Mactaquac	1	Hydro	109	
	2	Hydro	109	
	3	Hydro	109	
	4	Hydro	115	
	5	Hydro	112	
	6	Hydro	112	
Beechwood	1	Hydro	36	
	2	Hydro	36	
	3	Hydro	41	
Grand Falls	1	Hydro	16	
	2	Hydro	16	
	3	Hydro	16	
	4	Hydro	16	
Tobique	1	Hydro	10	
	2	Hydro	10	
Nepisiguit Falls	1	Hydro	11	
Sisson	1	Hydro	9	
Milltown	1	Hydro	4	
Purchases/Sales (+/-)			-200	Firm Sale for January 2017
Tie Benefits			300	
NB Wind	All	Wind	120	Expected during peak (294 MW installed)
TOTAL CAPACITY			4174	Total Capacity as of January 2017

Table A-2: Maritimes Area Resources (cont'd)

Nova Scotia Resources				
Plant	**Unit**	**Type**	**Capacity MW**	**Notes**
Lingan	1	Coal	153	
	2	Coal	153	Assumed retirement mid-2020
	3	Coal	153	
	4	Coal	153	
Trenton	5	Coal	150	Summer Capacity = 135 MW
	6	Coal	157	
Pt. Tupper	2	Coal	152	
Tufts Cove	1	Gas/Oil	81	
	2	Gas/Oil	93	
	3	Gas/Oil	147	
	4	Natural Gas	49	Summer Capacity = 47 MW
	5	Natural Gas	49	Summer capacity = 47 MW
	6	Natural Gas	49	
Pt. Aconi	1	Coal	171	
Burnside	1	Lt Oil	33	Summer Capacity = 25 MW
	2	Lt Oil	33	Summer Capacity = 25 MW
	3	Lt Oil	33	Summer Capacity = 25 MW
	4	Lt Oil	33	Summer Capacity = 25 MW
Victoria Junction	1	Lt. Oil	33	Summer Capacity = 25 MW
	2	Lt. Oil	33	Summer Capacity = 25 MW
Tusket	1	Lt. Oil	24	Summer Capacity = 21 MW
NUG Purchases	All	Biomass/hydro	27.8	
PH Biomass		Biomass	0	Energy only during 2017
COMFIT Biomass	All	Biomass	25	
Wreck Cove	1	Hydro	105	
	2	Hydro	105	
Annapolis		Hydro	4	
Avon		Hydro	7	
Black River		Hydro	23	
Nictuax		Hydro	8	
Lequille		Hydro	13	
Paradise		Hydro	5	
Mersey		Hydro	43	
Sissiboo		Hydro	27	
Bear River		Hydro	11	
Tusket		Hydro	2	
St. Margarets		Hydro	11	
Sheet Harbour		Hydro	11	
Dickie Brook		Hydro	2	
Fall River		Hydro	1	
Other small hydro	All	Hydro	0.7	
NALCOR Firm Contract		Hydro	0	Expected mid-2020
NS Wind	All	Wind	238	Expected during peak (434 MW installed excluding 164 MW of energy only resources)
TOTAL CAPACITY			2601.5	Total Capacity as of January 2017

Table A-2 Maritimes Area Resources (cont'd)

Prince Edward Island Resources				
Plant	**Unit**	**Type**	**Capacity MW**	**Notes**
Charlottetown	7	Oil	7	
	8	Oil	10	
	9	Oil	19	
	10	Oil	19	
	11	Diesel	49	
Borden	1	Diesel	15	Summer Capacity = 12 MW
	2	Diesel	25	Summer Capacity = 20 MW
Summerside	1	Diesel	2	Owned by the City of Summerside
	2	Diesel	2	
	3	Diesel	2	
	5	Diesel	2	
	6	Diesel	1	
	7	Diesel	1	
	8	Diesel	4	
PEI Wind	All	Wind	103	Expected during peak (204 MW installed)
TOTAL CAPACITY			261	Total Capacity as of January 2014

Table A-2 Maritimes Area Resources (cont'd)

Northern Maine Resources				
Plant	**Unit**	**Type**	**Capacity MW**	**Notes**
Tinker	1-5	Hydro	35	
		Diesel	1	
Fort Fairfield		Wood	33	
Ashland		Wood	37	
Caribou		Hydro	1	
		Diesel	7	
Squa Pan		Hydro	1	
EMEC		Black Liquor/ Biomass/ Natural Gas	20	
NMISA Wind	All	Wind	35	Expected during peak (42 MW installed)
TOTAL CAPACITY			170	Total Capacity as of January 2014

Table A-3: Summary of Changes in Modeled Capacity

Year	Capacity in January MW	Capacity in December MW	January to January Capacity Change MW	January to December Capacity Change MW	Explanation -Total Capacities include tie benefits (MW) and the impact of firm purchases and/or sales and planned maintenance
2017	7,207	7,407	0	+200	Removal of 200 MW sale after January,
2018	7,418	7,340	+211	-78	For January; -36 MW removal of generator for maintenance until April, +45 MW of formerly transmission constrained biomass capacity, and +2 MW of biomass capacity. For December; +36 MW for return of unit under maintenance in April, -114 MW sale in December
2019	7,299	7,454	-119	-155	For January; -41 MW removal of generator for maintenance until April. For December; +114 MW removal of sale after January +41 MW for return of unit under maintenance in April
2020	7,454	7,454	+155	0	-153 MW of coal capacity in mid-2020 offset by +153 MW of hydro based capacity purchases
2021	7,454	7,454	0	0	No changes

2.2 Generator Unavailability Factors

2.2.1 Types of Unavailability Factors Represented

The types of unavailability factors represented in this reliability assessment are forced outages and planned outages. Forced outages include unplanned maintenance outages, deferrable forced outages, starting failure outages and generator derating adjustments. All except planned outages are included in the Forced Outage Rates (FORs) presented in Table A-4. Planned outages are scheduled manually for the reliability program based upon projected maintenance schedules.

New Brunswick forced outage rates are three year calculations using the Derating Adjusted Forced Outage Rate (DAFOR) methodology in IEEE Standard 762-2006, Section 8.17.4.

NSPI also uses three year average DAFOR calculations for forced outage rates consistent with IEEE Standard 762-2006, Section 8.17.4. NSPI maintains a database of combustion turbine and fossil generator reliability and performance data and is a contributing utility to the Canadian Electricity Association Equipment Reliability Information System (CEA-ERIS). The CEA-ERIS also calculates DAFOR using the industry standard definition as per IEEE 762-2006.

The forced outage rates for the smaller PEI and Northern Maine systems are modeled using forced outage rates for generators of similar size and fuel type in New Brunswick and Nova Scotia. Most of the small diesel and oil fuelled generators in these systems operate less than 100 hours per year, and statistics necessary for calculating their DAFOR values are not available. The modeled FOR values for generators in these systems are between 5 – 10 %.

2.2.2 Source of Unavailability Factors

Forced Outage Rates for existing generators are based on actual outage data as well as on data of similar sized generators as compiled by the Canadian Electricity Association (CEA).

FORs for new generators are based upon the utilities' experience with similar generators in conjunction with averages compiled by the Canadian Electricity Association (CEA).

2.2.3 Maturity Considerations

Immature FORs were not used in this evaluation.

2.2.4 Tabulation of Forced Outage Rates

The ranges of FORs used in the assessment are tabulated in Table A-4. These values are consistent with those used in the business plans of the Maritimes Area utilities and reflect the results of maintenance and operational strategies.

Table A-4: Maritimes Area Forced Outage Rates

Unit Type	Forced Outage Rate (%)	
	2016 Review	2013 Review
Oil	0 - 10	1 – 10
Coal	1 – 10*	2 –16*
Hydro	0 - 5	1 – 11**
Nuclear	7	6
Natural Gas	0 - 7	1 – 7
Wind	0	0
Oil/Gas	6 - 9	6 – 8
Biomass	2 - 8	1 – 8

* A single coal unit dropped from 16 % to 10 % during the period 2013 to 2016. The remaining coal units were less than 4% for the 2016 review and 7% for the 2013 review.

** One hydro plant had a forced outage rate as high as 11%. Its power house was flooded during an extreme weather event in 2011. All other hydro generators had forced outage rates of 1%.

2.3 Purchase and Sale Representation

Purchases and sales are represented as an adjustment to the capacity or load as appropriate.

2.4 Retirements

Retirements were considered by removing the generators from the model at their retirement date. The only known retirement assumed during the 2017 to 2021 period of this review is the mid-2020 retirement of the Lingan 2 unit in Nova Scotia. Reliability impacts will be negligible as the retirement is to be simultaneously offset by a similar sized hydro based firm capacity purchase.

3.0 Representation of Interconnected Systems

Since 2011, NB Power has assumed 300 MW of tie benefits to New Brunswick in its resource adequacy assessments. These tie benefits are based on a 2011 decision by the New Brunswick Market Advisory Committee to recognize the lowest historical Firm Transmission Capacity posted from summer peaking New England to winter peaking New Brunswick since the commissioning of the second 345 kV tie between these systems in December 2007. To the extent that future capacity purchases from New England to New Brunswick occur across this interface, these tie benefits will be reduced accordingly. Tie benefits from other neighbouring jurisdictions that are also winter peaking are not considered.

In the CP-8 report Review of Interconnection Assistance Reliability Benefits (December 31, 2015, Approved by RCC March 2, 2016) the "As Is" estimated tie benefit potential for the Maritimes Area is 702 MW to 1012 MW for the years 2016 and 2020 with an export of 200 MW modeled in both test years. Based on this study, the 300 MW of tie benefits assumed for this 2016 Comprehensive Review is conservative.

4.0 Modeling of Variable and Limited Energy Sources

Wind resources are modeled as simulated hourly values that are netted out against the hourly loads. The hourly wind shapes are based upon historical hourly wind generation values for the 2011-2012 fiscal year. New wind capacity forecast for a Maritimes Area jurisdiction is modeled by scaling the historical wind generation in that jurisdiction.

Under normal operating conditions, the hydro system is operated considerably below its DMNC rating due to economics. However, if required to maintain customer load, it would be operating at full capacity by utilizing the headponds and other existing storage reservoirs. This is one of the options documented in the Emergency Operating Procedures (Section 2.2 of the main report). Therefore, in the evaluation, hydro generators are considered available for all hours during which the generator is not on forced outage or maintenance. There are no seasonal adjustments to the DMNC ratings of the hydro generators.

5.0 Modeling of Demand Side Management

The expected monthly demand and energy reduction due to Demand Side Management programs for each sub-area is included in their respective forecasts and in the combined Maritimes Area forecast in Table A-1.

6.0 Modeling of Non-Utility Generation

Certain small non-utility generators are aggregated into single units with operating characteristics and FORs equivalent to other Maritimes Area generators of similar size. These are tabulated in Table A-2 and are identified by type NUG. In addition to these NUG units, a Nova Scotia's Community Fit (COMFIT) program generators are also non-utility generators. Some larger non-utility generators, such as Bayside 6, are shown separately because their size is comparable to the larger utility generators on the system.

7.0 Other Assumptions

The study assumed that there would be no generator slippages or deratings due to environmental constraints within the five-year timeframe of this review. Current emission limits are specified as annual system volumes rather than generator specific volumes, providing flexibility in the operation of the fleet.

Future regulations limiting greenhouse gas emissions and air pollutants are in place for the 2020-2030 timeframe in Nova Scotia. These regulations specify multi-year hard caps rather than annual limits which provide for some flexibility in the operation of the fleet over the specified compliance periods. System Operators in the Maritimes Area will be tracking such standards as they are implemented and may conduct analyses in the future regarding their impact on resource adequacy.

APPENDIX B - DESCRIPTION OF RELIABILITY PROGRAM

DESCRIPTION OF RELIABILITY PROGRAM

The program used for this assessment, LOLP, was originally developed at NB Power in 1984 to complete the Triennial Review of Resource Adequacy. Since that time the program has been improved, and its capabilities expanded, with the most recent modifications being completed during summer 2016.

The original program was a single area program that performed the classical LOLP analysis based upon the weekday peak hour load, as well as an LOLH and EENS analysis which is based upon all of the hourly loads. The results of the program were benchmarked against the results of the IEEE reliability test system, as well as against the results of the PICES program used by NSPI for the 1991 Triennial Review. The program was further benchmarked by evaluating its results against those documented in the 1992 CIGRE Task Force 38-03-10 report "Composite Power System Reliability Analysis Application to the New Brunswick Power Corporation System"". In all cases, excellent agreement of results was observed.

In the fall of 2007, modifications to the original program allowed it to perform a Monte Carlo analysis of a multi-area system with intra-area tie limits. This Monte Carlo simulation was written using MATLAB® software for programming and random number generation, and it performs as follows:

- For each daily coincident peak load, generation is simulated in each jurisdiction of the Maritimes. In the case of wind generation, hourly wind generation generation projections for the time of the Area coincident peak are netted against the loads. This simulation uses random numbers against a generator's Forced Outage Rate to determine the status of each generator. Planned generator maintenance is also enforced.
- Generation surpluses or deficits are determined for each intra-area jurisdiction. Because each jurisdiction other than New Brunswick (NB) is only connected to NB, these surpluses and deficits can be transferred to New Brunswick.
- Surpluses transferred to NB from another intra-area jurisdiction are limited by the export limit of the jurisdiction.
- Deficits in an intra-area jurisdiction other than NB that exceed the import capability from NB results in a loss of load event. Otherwise, the deficit is transferred to NB.
- With all transfer-limited intra-area surpluses and deficits transferred to NB, it is determined whether or not the simulated generation in NB plus transferred surpluses is adequate to supply both the NB load and any transferred deficits. If not, then a loss of load event occurs.
- The Monte Carlo simulation is performed for each daily peak hour of the year, and the yearly simulation is repeated 100,000 times to calculate the average LOLE in days/year.

The base load shape for the program is system hourly net loads for each jurisdiction comprising the Area. Monthly load shapes for the individual jurisdictions are created by scaling the hourly loads to match the load forecast values of both demand and energy.

This method preserves the effects of load chronology as well as load coincidence between the jurisdictions. This method is also identical between the new program and the old program. A separate monthly load shape comprising only the peak load of each day is created for the LOLE analysis.

2017 Reliability Improvements

August 4, 2017

A Report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

Table of Contents

Introduction

Newfoundland and Labrador Hydro (Hydro) and TransGrid Solutions (TGS) are undertaking operational studies in preparation for the interconnection of assets into the Newfoundland and Labrador Transmission System. The objective of the studies is to identify system impacts and operating limits to allow for the development of Operating Instructions to be used by operators in Hydro's Energy Control Centre (ECC).

Steady state and dynamic analyses are to be performed to assess contingencies within the provincial transmission system. The results of the studies are to be analysed to ensure that steady state and dynamic responses met the system performance requirements in accordance with Transmission Planning Criteria. Where criteria violations are discovered, system operating limits and/or mitigations are to be determined to avoid violations.
Operational studies have been staged to match the anticipated in service date of new assets and are summarized as follows: [1]

STAGE I - Addition of the Maritime Link;
STAGE II - Addition of the Soldiers Pond Synchronous Condensers;
STAGE III - Addition of the Labrador-Island Link and Labrador Transmission Asset; and
STAGE IV - Addition of Muskrat Falls Generation.

All studies shall be performed using Version 32 of PSS ®E software from Siemens PTI. The studies are summarized in the sections below.

Scope of Studies

For the purposes of this investigation, operational reviews shall be limited to the definition of system operating limits and assessment of contingencies in high voltage systems including:

- 230 kV transmission system on the Island of Newfoundland;

[1] Hydro has also performed internal analyses in preparation for other ac system additions including TL269 from Bottom Brook Terminal Station to Granite Canal Terminal Station. This line is to be placed in service in advance of the Maritime Link and operating instructions have been developed. Power flows in this transmission line corridor are not significant in advance of Maritime Link operation and the detailed specification of System Operating Limits will be included as part of the Stage I study.

- 138 kV transmission system from Deer Lake to Stony Brook;[2]
- Labrador-Island HVdc Link;
- Maritime HVdc Link; and
- 315 kV and 735 kV systems in Labrador.

Transmission Planning Criteria

The following Transmission Planning Criteria are to be applied in the analysis:

Steady State Analysis Criteria:

- With a transmission element (line, transformer, synchronous condenser, shunt or series compensation device) is out of service, power flow in all other elements of the power system should be at or below normal rating;
- For normal operations all voltages be maintained between 95% and 105%;
- For contingency or emergency situations all voltages be maintained between 90% and 110%; and
- Analysis will be conducted with one high inertia synchronous condenser out of service at Soldiers Pond (for studies where the units are included).

Transient Analysis Criteria:

- System response shall be stable and well damped following a disturbance
- System disturbances include:
  - Successful single pole reclosing on line to ground faults;
  - Unsuccessful single pole reclosing on line to ground faults;
  - Three phase faults;[3]
  - Loss of the largest generator on line on the Island System with and without fault;
  - Line to ground or three phase fault with tripping of a synchronous condenser;
  - Fault and tripping of a transmission line;

[2] Other 138 kV loops including the Western Avalon-Holyrood Loop and the Stony Brook-Sunnyside Loop serve primarily to serve network load and were not considered as part of the operational reviews.
[3] System responses following a three-phase fault at Bay d'Espoir coinciding with high power flows over the Labrador Island Link and peak loading conditions will be re-examined in Stage IV.

    - Temporary pole fault;
    - Permanent pole fault; and
    - Temporary bipole fault;
- Post fault recovery voltages on the ac system shall be as follows:
    - Transient under voltages following fault clearing should not drop below 70%;
    - The duration of the voltage below 80% following fault clearing should not exceed 20 cycles; and
- There shall be no commutation failures of the Labrador-Island Link during post fault recovery;[4]
- Low Power Operation (Pre-Muskrat Falls Generation);
    - Post fault system frequencies shall not drop below 58 Hz and shall not rise above 62 Hz;
    - Controlled underfrequency load shedding shall be permitted for loss of generation or loss of a pole/bipole;
    - The existing underfrequency load shedding scheme shall remain unchanged; and
- High Power Operation (Includes Muskrat Falls Generation);
    - Post fault system frequencies shall not drop below 59 Hz;
    - Underfrequency load shedding:
        - shall not occur for loss of on-island generation with the HVdc link in service;
        - shall not occur for permanent loss of HVdc pole;
        - shall not occur for a temporary bipole outage; and
        - shall be controlled for a permanent bipole outage.

[4] For low power operation, consideration will be given to the operation of the Labrador-Island Link in conditions with reduced short circuit levels (i.e., without Muskrat Falls Generation). Analysis will be performed to identify and assess any conditions that may cause the link to trip or experience commutation failures. System operating limits will be defined accordingly.

Stage I - Addition of the Maritime Link

Study Start Date – February 20, 2017
Expected Completion Date – September 30, 2017
Maritime Link In-Service Date – Q4, 2017

This study shall assess the addition of the Maritime Link and its impacts on the Island Interconnected Transmission System and shall include the following considerations:

- Identification of Maritime Link import and export limits;
- Identification of transfer limits in transmission corridors for n-0 and n-1 operating conditions;
- Impacts of the Maritime Link frequency controller; and
- Review of underfrequency load shedding with the existing scheme in place.

Stage II - Addition of Soldiers Pond Synchronous Condensers

Study Start Date – July 17, 2017
Expected Completion Date – October 31, 2017
Soldiers Pond Synchronous Condensers In-Service Date – Q2, 2018

This study shall assess the addition of the Soldiers Pond synchronous condensers and relevant impacts on the Island Interconnected Transmission System and shall include the following considerations:

- Update of Maritime Link import and export limits;
- Update of transfer limits in transmission corridors for n-0 and n-1 operating conditions; and
- Review of underfrequency load shedding with the existing scheme in place.

Stage III - Addition of Labrador-Island Link and Labrador Transmission Asset

Study Start Date – July 3, 2017

Expected Completion Date – December 31, 2017

Labrador-Island Link In-Service Date – Q2, 2018

This study shall assess the addition of the Labrador-Island Link and Labrador Transmission Asset[5] and relevant impacts on the Newfoundland and Labrador Transmission System. The study shall assess low power operation of the HVdc link (i.e., without Muskrat Falls generation) and shall include the following considerations:

- Identification of Labrador-Island Link import and export limits in monopole and bipole modes of operation;
- Update of Maritime Link import and export limits;
- Identification of transfer limits in Labrador transmission corridors for n-0 and n-1 operating conditions;
- Update of transfer limits in Newfoundland transmission corridors for n-0 and n-1 operating conditions;
- Review of underfrequency load shedding with the existing scheme in place;
- Impacts of the Labrador-Island Link frequency controller and coordination with the Maritime Link frequency controller;

Stage IV - Addition of Muskrat Falls Generation

Study Start Date – January 1, 2018

Expected Completion Date – September 30, 2018

Muskrat Falls Generation In-Service Date – Q3 2019-Q2 2020

[5] Hydro has also performed internal analyses in preparation for the energization of the Labrador Transmission Asset for the commissioning of the 315 kV terminal station at Muskrat Falls. Power flows in this transmission line corridor are not significant in advance of Labrador-Island Link operation and the detailed specification of System Operating Limits will be included as part of the Stage III study.

This study shall assess the addition of the Muskrat Falls Generation and operation of HVdc links up to rated capacities. The investigation of impacts on the Newfoundland and Labrador Transmission System shall include the following considerations:

- Update of Labrador-Island Link import and export limits;
- Update of Maritime Link import and export limits;
- Update of transfer limits in Labrador transmission corridors for n-0 and n-1 operating conditions;
- Update of transfer limits in Newfoundland transmission corridors for n-0 and n-1 operating conditions;
- Development of a new underfrequency load shedding scheme;
- Review of Power System Stabilizer applications for generators and HVdc links for improved system damping;
- Update to coordination of the Labrador-Island Link frequency controller and the Maritime Link frequency controller;
- Review of coordinated runbacks of HVdc links and operating restrictions with links out of service;
- Consideration of re-strikes on the Labrador Island HVdc Link;
- Review of power requirements for high power transfer on the Labrador-Island Link and evaluation of dynamic reactive additions at Soldiers Pond and Holyrood; and
- Review of Bay d'Espoir instabilities under a three-phase fault condition.

Conclusion

Work is underway with respect to operational studies associated with the Integration of assets into the Newfoundland and Labrador transmission system. With the support of TGS, Hydro has established a plan for the completion of operational studies sufficiently in advance of equipment in-service dates. Analysis associated with the integration of the Maritime Link is nearing completion and studies relating to the integration of Soldiers Pond synchronous condensers, the Labrador Transmission Asset, and the Labrador-Island Link are on pace for on time completion.

The plan, as specified above, has been communicated to Newfoundland Power by Hydro as part of the mandate of the Inter-Utility Integration Subcommittee, which was established in 2016. Hydro is committed to working with Newfoundland Power and all of its customers to ensure safe and reliable operation through the stages of asset integration and beyond. This cooperation is critical, particularly in consideration of aspects such as the modification of underfrequency load schemes in advance of high power operation.

Hydro is committed to providing the Newfoundland and Labrador Board of Commissioners of Public Utilities with updates pertaining to operational studies and submitting all completed reports upon receipt. It is Hydro's objective that all outcomes the operational studies be incorporated to ensure the safe and reliable operation of the transmission system.

Resources	% Complete Actual UPDATE GREEN %'s	Expected	WBS L1	WBS L2	WBS L3	WBS L4	Baseline Dates Baseline Start Date (Q)	Baseline End Date (Q)	Actual/Forecast Actual/Forecast Start Date (Q)	Actual/Forecast End Date (Q)	Project Priority	Critical Path	LCP In Service Date (Q)	Float Watch	people/ process/ system/ delivery
	38.0%	44.2%	RFI SCOPE												
	30.8%	30.8%		Governance & Oversight			Q4 16	Q4 18	Q2 16	Q3 19					
RFI Mgr	26.7%	26.7%				Manager @ 25% (Mtgs, Reporting, Interfaces, Dependencies, Risks)	Q1 17	Q4 18	Q1 17	Q4 18					
RFI Studies Lead	39.4%	39.4%				Lead @ 40% (Mtgs, Misc Study Reviews/Inputs/ Updates)	Q4 16	Q3 18	Q4 16	Q3 19					
RFI Admin	20.3%	20.3%				Admin Support @25% (Admin, Interface Management)	Q1 17	Q4 18	Q1 17	Q4 18					
	74.1%	77.6%	RFI SYSTEM STUDIES - FIRST POWER PREPARDNESS												
	91.8%	98.5%		GE Grid (Alstom) Studies Support & Review			Q1 15	Q4 17	Q1 15	Q3 17	P2	Q3 18 LIL In Service Minus 3 mths	Q3 18	181	Delivery
RFI Studies Lead	100.0%	100.0%				Common - Main Scheme Parameter Design Report	Q3 15	Q3 15	Q3 15	Q3 15					
RFI Studies Lead	100.0%	100.0%				Common - Circuit Current Requirement - Report	Q3 15	Q3 15	Q3 15	Q3 15					
RFI Studies Lead	100.0%	100.0%				Common - Basic Insulation Coordination - Design Report	Q4 15	Q4 15	Q4 15	Q4 15					
RFI Studies Lead	95.0%	100.0%				Common - DC Filter Transient Overvoltage Study	Q3 16	Q4 16	Q3 16	Q3 17					
RFI Studies Lead	100.0%	100.0%				Common - Converter Station Radiated interference - Design Report	Q1 16	Q1 16	Q1 16	Q1 16					
RFI Studies Lead	100.0%	100.0%				Common - Reactive Power Management Design Report	Q3 15	Q3 15	Q3 15	Q3 15					
RFI Studies Lead	100.0%	100.0%				Common - Equivalent AC Network Derivation - Outline Report	Q3 15	Q4 15	Q3 15	Q4 15					
RFI Studies Lead	100.0%	100.0%				Common - Equivalent AC Network Derivation Report	Q2 16	Q2 16	Q2 16	Q2 16					
RFI Studies Lead	100.0%	100.0%				Common - Harmonic Impedence Study - Report	Q1 15	Q1 15	Q1 15	Q1 15					
RFI Studies Lead	100.0%	100.0%				Common - Transient Stability, Dynamic Multi Interaction, GSE and FFTOV - Outline Report	Q1 15	Q2 15	Q1 15	Q2 15					
RFI Studies Lead	100.0%	100.0%				Common - Reactive Power Capacity - Study Report	Q1 15	Q2 15	Q1 15	Q2 15					
RFI Studies Lead	100.0%	100.0%				Common - PSCAD™ Dynamic Performance Outline Report	Q2 15	Q2 15	Q2 15	Q2 15					
RFI Studies Lead	100.0%	100.0%				Common - Subsynchronous Oscillation - Outline Report	Q2 15	Q2 15	Q2 15	Q2 15					
RFI Studies Lead	100.0%	100.0%				Common - Sub-Synchronous Oscillation Study Report	Q3 15	Q3 15	Q3 15	Q3 15					
RFI Studies Lead	100.0%	100.0%				Common - System Studies Summary Report	Q2 15	Q2 15	Q2 15	Q2 15					
RFI Studies Lead	100.0%	100.0%				Common - Harmonic Impedance Sectors Study Report	Q1 15	Q2 15	Q1 15	Q2 15					
RFI Studies Lead	100.0%	100.0%				Common - Assessment of the impact of AC Lines in Parallel with DC Lines Study Report	Q3 15	Q3 15	Q3 15	Q3 15					
RFI Studies Lead	100.0%	100.0%				Common - Block / De-block Sequence Strategy Report	Q2 16	Q3 16	Q2 16	Q3 16					
RFI Studies Lead	100.0%	100.0%				Common - Thyristor Valve Design Description - Design Report	Q4 15	Q4 15	Q4 15	Q4 15					
RFI Studies Lead	100.0%	100.0%				Common - DC Smoothing Reactor Study Report	Q1 16	Q2 16	Q1 16	Q2 16					
RFI Studies Lead	74.3%	100.0%				Common - Transient Stability, Dynamic Multi Interaction, GSE and FFTOV Study Report	Q1 16	Q4 16	Q1 16	Q3 17					
	98.0%					Original Base Cases (4) for Bipole	Q1 16	Q4 16	Q1 16	Q3 17					
	75.0%					Peak/Intermediate "Phased Approach Cases	Q1 17	Q3 17	Q1 17	Q3 17					
	50.0%					Light Load "Phased Approach Case"	Q1 17	Q3 17	Q1 17	Q3 17					
RFI Studies Lead	80.0%	100.0%				Common - PSCAD™ Dynamic Performance Study Report	Q4 16	Q1 17	Q4 16	Q3 17					
RFI Studies Lead	100.0%	100.0%				Common - RTDS™ Dynamic Performance Study Outline Report	Q1 16	Q1 16	Q1 16	Q1 16					
RFI Studies Lead	0.0%	67.7%				Common - RTDS™ Dynamic Performance Study Report	Q4 16	Q4 17	Q4 16	Q3 17					
RFI Studies Lead	100.0%	100.0%				Common - Transient Overvoltage Study Outline Report	Q1 16	Q2 16	Q1 16	Q2 16					
RFI Studies Lead	100.0%	100.0%				Common - Transient Overvoltage Study - Report	Q2 16	Q2 16	Q2 16	Q2 16					
RFI Studies Lead	100.0%	100.0%				Common - Converter Station -AC Circuit Breaker - TRV study	Q1 16	Q2 16	Q1 16	Q2 16					
RFI Studies Lead	100.0%	100.0%				Common - AC Filter Rating Report	Q4 15	Q4 15	Q4 15	Q4 15					
RFI Studies Lead	100.0%	100.0%				Common - AC Filter Performance Report	Q3 15	Q3 15	Q3 15	Q3 15					
RFI Studies Lead	100.0%	100.0%				Common - Load Flow & Short Circuit Level Studies - Outline Report	Q3 16	Q3 15	Q3 16	Q3 15					
RFI Studies Lead	100.0%	100.0%				Common - Load Flow & Short Circuit Level Studies Report	Q3 15	Q3 15	Q3 15	Q3 15					
RFI Studies Lead	100.0%	100.0%				Common - Equivalent AC Network Derivation Report	Q2 16	Q2 16	Q2 16	Q2 16					
RFI Studies Lead	100.0%	100.0%				Common - HVDC Models For Use In PSS®E - Report	Q3 15	Q3 15	Q3 15	Q3 15					
	0.0%	0.0%		GE Grid (Alstom) Studies Support & Review Post Commissioning			Q3 18	Q3 18	Q3 18	Q3 18	P2				
RFI Studies Lead	0.0%	0.0%				Common - Predicted Noise Study Report	Q3 18	Q3 18	Q3 18	Q3 18					
RFI Studies Lead	0.0%	0.0%				Common - Converter Station Losses Report	Q3 18	Q3 18	Q3 18	Q3 18					
	100.0%	99.8%		ABB Studies Support & Review			Q3 14	Q3 17	Q3 14	Q3 17	P2	Q4 17 ML In Service Minus 3 mths	Q4 17	60	Delivery
RFI Studies Lead	100.0%	100.0%				ABB Main Circuit Parameters Study Outline	Q4 14	Q4 14	Q4 14	Q4 14					
RFI Studies Lead	100.0%	100.0%				ABB Insulation Coordination Study Outline	Q4 14	Q4 14	Q4 14	Q4 14					
RFI Studies Lead	100.0%	100.0%				ABB Transient Currents Study Outline	Q4 14	Q4 14	Q4 14	Q4 14					
RFI Studies Lead	100.0%	100.0%				ABB Models of Operation Study Outline	Q4 14	Q4 14	Q4 14	Q4 14					

Resources	Actual UPDATE GREEN %'s	Expected		WBS L1	WBS L2	WBS L3	WBS L4	Baseline Start Date (Q)	Baseline End Date (Q)	Actual/Forecast Start Date (Q)	Actual/Forecast End Date (Q)	Project Priority	Critical Path	LCP In Service Date (Q)	Float Watch	people/ process/ system/ delivery
RFI Studies Lead	100.0%	100.0%					ABB AC Filter Perfromance Study Outline	Q4 14	Q4 14	Q4 14	Q4 14					
RFI Studies Lead	100.0%	100.0%					ABB DC Harmonic Performance Study Outline	Q4 14	Q4 14	Q4 14	Q4 14					
RFI Studies Lead	100.0%	100.0%					ABB Insulation Coordination for HVdc System - Technical Report	Q4 14	Q4 14	Q4 14	Q4 14					
RFI Studies Lead	100.0%	100.0%					ABB Main Circuit Parameters Technical Report	Q4 14	Q1 15	Q4 14	Q1 15					
RFI Studies Lead	100.0%	100.0%					ABB Transient Currents	Q1 15	Q2 15	Q1 15	Q2 15					
RFI Studies Lead	100.0%	100.0%					ABB Black Start Study, Study Outline	Q2 16	Q2 16	Q2 16	Q2 16					
RFI Studies Lead	100.0%	100.0%					ABB Emergency Power Control Study, Study Outline	Q2 16	Q2 16	Q2 16	Q2 16					
RFI Studies Lead	100.0%	100.0%					ABB Load Flow and Stability Study, Study Outline	Q1 15	Q1 15	Q1 15	Q1 15					
RFI Studies Lead	100.0%	100.0%					ABB Dynamic Performance Study, Study Outline	Q1 15	Q1 15	Q1 15	Q1 15					
RFI Studies Lead	100.0%	100.0%					ABB Multi-Infeed Screening Study, Study Outline	Q1 15	Q1 15	Q1 15	Q1 15					
RFI Studies Lead	100.0%	100.0%					ABB Multi-Infeed Screening Study	Q2 15	Q2 15	Q2 15	Q2 15					
RFI Studies Lead	100.0%	100.0%					ABB Frequency Control Study (Includes Plots)	Q1 15	Q1 15	Q1 15	Q1 15					
RFI Studies Lead	100.0%	100.0%					ABB Frequency Control Study, Study Outline	Q1 15	Q1 15	Q1 15	Q1 15					
RFI Studies Lead	100.0%	100.0%					ABB SSTI Screening Study	Q2 15	Q2 15	Q2 15	Q2 15					
RFI Studies Lead	100.0%	100.0%					ABB Network Data Summary	Q1 15	Q1 15	Q1 15	Q1 15					
RFI Studies Lead	100.0%	100.0%					ABB SSTI Screening Study, Study Outline	Q1 15	Q2 15	Q1 15	Q2 15					
RFI Studies Lead	100.0%	100.0%					ABB Transient Overvoltage Study	Q3 15	Q4 15	Q3 15	Q4 15					
RFI Studies Lead	100.0%	100.0%					ABB Transient Overvoltage Study Study Outline	Q1 15	Q1 15	Q1 15	Q1 15					
RFI Studies Lead	100.0%	100.0%					ABB PreInsertion Resistor Study	Q3 15	Q4 15	Q3 15	Q4 15					
RFI Studies Lead	100.0%	100.0%					ABB PreInsertion Resistor Study, Study Outline	Q2 15	Q2 15	Q2 15	Q2 15					
RFI Studies Lead	100.0%	100.0%					ABB Fundamental Frequency Overvoltages	Q3 15	Q4 15	Q3 15	Q4 15					
RFI Studies Lead	100.0%	100.0%					ABB Fundamental Frequency Overvoltages, Study Outline	Q1 15	Q1 15	Q1 15	Q1 15					
RFI Studies Lead	100.0%	100.0%					ABB AC Filter Rating, Study Outline	Q3 15	Q4 15	Q3 15	Q4 15					
RFI Studies Lead	100.0%	100.0%					ABB Influence of Parallel AC Lines, Study Outline	Q2 15	Q2 15	Q2 15	Q2 15					
RFI Studies Lead	100.0%	100.0%					ABB Influence of Parallel AC Lines, Study	Q4 15	Q4 15	Q4 15	Q4 15					
RFI Studies Lead	100.0%	96.2%					ABB DC Harmonic Performance	Q2 16	Q3 17	Q2 16	Q3 17					
RFI Studies Lead	100.0%	100.0%					ABB SSTI Study, Study Outline	Q2 16	Q2 16	Q2 16	Q2 16					
RFI Studies Lead	100.0%	100.0%					ABB General requirements for main circuit apparatus	Q3 14	Q3 14	Q3 14	Q3 14					
RFI Studies Lead	100.0%	100.0%					ABB HVDC Switches, Study Outline	Q1 15	Q1 15	Q1 15	Q1 15					
	70.0%	**70.8%**					**ABB Studies Ongoing Support & Review as required**	**Q2 16**	**Q4 17**	**Q2 16**	**Q4 17**					
	76.5%	**82.2%**					**Operational System Studies & Support of Operating Limits/Instructions**	**Q1 16**	**Q4 17**	**Q1 16**	**Q4 17**	**P3**				
RFI Studies Lead	100.0%	100.0%					Sync Relay Check for MFA prior to LIL	Q1 17	Q1 17	Q1 17	Q1 17		**Q3 18 LIL In Service Minus 3 mths**	**Q3 18**		**Delivery**
RFI Studies Lead	100.0%	100.0%					Minimum Equipment Study including cases for 0, 1 or 2 Sync Condensors at SOP	Q1 17	Q1 17	Q1 17	Q1 17		**Q1 18 SOPSC Energize Minus 3 mths**	**Q1 18**		**Delivery**
RFI Studies Lead	100.0%	100.0%					LIL Steady State & Dynamic Transfer Limits without MFA - Phase1	Q3 16	Q2 17	Q3 16	Q4 17		**Q3 18 LIL In Service Minus 3 mths**	**Q3 18**	**151**	**Delivery**
NLH	100.0%	100.0%					MATPC Reserve and Emergency Sharing	Q2 16	Q1 17	Q2 16	Q1 17		**Q3 18 LIL In Service Minus 3 mths**	**Q3 18**		**Delivery**
RFI Lead / HQT	95.0%	100.0%					NLH-HQT Study CHF Interconnection	**Q1 16**	**Q2 17**	**Q1 16**	**Q3 17**		**Q4 17 LTA In Service Minus 3 mths**	**Q4 17**	**22**	**Delivery**
	100.0%						Deliver models inputs to HQT	Q1 16	Q2 16	Q1 16	Q1 17					
	90.0%						HQT to Deliver Final Report	Q1 16	Q2 17	Q1 16	Q3 17					
							Stage I Low Power Study - Addition of the Maritime Link (ML Only Study)	**Q4 16**	**Q1 17**	**Q1 17**	**Q3 17**		**Q4 17 ML In Service Minus 3 mths**	**Q4 17**	**16**	**Delivery**
TGS	90.0%	100.0%					Identification of Maritime Link Import Export Limits	Q4 16	Q1 17	Q1 17	Q3 17					
TGS	90.0%	100.0%					Identification of transfer limits in transmission corridors for n-0 and n-1 operating conditions	Q4 16	Q1 17	Q1 17	Q3 17					
TGS	90.0%	100.0%					Impacts of the Maritime Link frequency controller	Q4 16	Q1 17	Q1 17	Q3 17					
TGS	90.0%	100.0%					Review of underfrequency load shedding with the existing scheme in place	Q4 16	Q1 17	Q1 17	Q3 17					
							Stage II Low Power Study - Addition of Soldiers Pond Synchronous Condensers	**Q3 17**	**Q4 17**	**Q3 17**	**Q4 17**		**Q1 18 SOPSC Energize Minus 3 mths**	**Q1 18**	**45**	**Delivery**
TGS		11.5%					Update of Maritime Link import and export limits	Q3 17	Q4 17	Q3 17	Q4 17					
TGS		11.5%					Update of transfer limits in transmission corridors for n-0 and n-1 operating conditions	Q3 17	Q4 17	Q3 17	Q4 17					
TGS		11.5%					Review of underfrequency load shedding with the existing scheme in place	Q3 17	Q4 17	Q3 17	Q4 17					
		0.0%					Stage III Low Power Study - Addition of the LIL and LTA (ML+LIL+LTA Study)	**Q4 16**	**Q4 17**	**Q3 17**	**Q4 17**		**Q3 18 LIL In Service Minus 3 mths**	**Q3 18**	**91**	**Delivery**
TGS	65.0%	72.7%					Identification of Labrador Island Link import and export limits	Q4 16	Q4 17	Q3 17	Q4 17					
TGS	65.0%	72.7%					Update of Maritime Link import and export limits	Q4 16	Q4 17	Q3 17	Q4 17					

Resources	Actual UPDATE GREEN %'s	Expected	WBS L1 / WBS L2 / WBS L3 / WBS L4	Baseline Start Date (Q)	Baseline End Date (Q)	Actual/Forecast Start Date (Q)	Actual/Forecast End Date (Q)	Project Priority	Critical Path	LCP In Service Date (Q)	Float Watch	people/ process/ system/ delivery
TGS	65.0%	72.7%	Identification of transfer limits in Labrador transmission corridors for n-0 and n-1 operating conditions	Q4 16	Q4 17	Q3 17	Q4 17					
TGS	65.0%	72.7%	Update of transfer limits in Newfoundland transmission corridors for n-0 and n-1 operating conditions	Q4 16	Q4 17	Q3 17	Q4 17					
TGS	65.0%	72.7%	Review of underfrequency load shedding with the existing scheme in place	Q4 16	Q4 17	Q3 17	Q4 17					
TGS	65.0%	72.7%	Impacts of the Labrador Island Link frequency controller and coordination with the Maritime Link frequency controller	Q4 16	Q4 17	Q3 17	Q4 17					
	76.9%	**74.1%**	**Energization System Studies**	**Q2 17**	**Q4 17**	**Q2 17**	**Q4 17**	**P3**				
TGS	90.0%	86.8%	LTA and LIL GEP's (Original GEP 1 to 8)	Q2 17	Q3 17	Q2 17	Q3 17		**Q3 18 LIL In Service Minus 3 mths**	**Q3 18**	**241**	**Delivery**
TGS	0.0%	0.0%	GEP 13 Study (Integrated Tests Low Power w/LIL monpole and ML bipole)	Q3 17	Q4 17	Q3 17	Q4 17		**Q3 18 LIL In Service Minus 3 mths**	**Q3 18**	**121**	**Delivery**
	0.0%	**0.0%**	**RFI SYSTEM STUDIES - FULL POWER PREPARDNESS**									
	0.0%	**0.0%**	**GE Grid (Alstom) Studies Support & Review**	**Q1 18**	**Q3 18**	**Q1 18**	**Q3 18**	**P4**	**Q3 19 MFG First Power Minus 6 mths**	**Q4 19**	**270**	**Delivery**
RFI Studies Lead	0.0%	0.0%	Common - Transient Stability, Dynamic Multi Interaction, GSE and FFTOV Study Report	Q1 18	Q3 18	Q1 18	Q3 18					
RFI Studies Lead	0.0%	0.0%	Update to Bipole design studies - Reduced LIL import to monitor frequency controller action	Q1 18	Q3 18	Q1 18	Q3 18					
	0.0%	**0.0%**	**Operational System Studies**	**Q1 18**	**Q3 18**	**Q1 18**	**Q3 18**	**P4**	**Q3 19 MFG First Power Minus 6 mths**	**Q4 19**	**270**	**Delivery**
			Stage IV High Power Study - Addition of Muskrat Falls Generation (ML+LIL+LTA Study)	Q1 18	Q3 18	Q1 18	Q3 18					
TGS		0.0%	Update of Labrador Island Link import and export limits	Q1 18	Q3 18	Q1 18	Q3 18					
TGS		0.0%	Update of Maritime Link import and export limits	Q1 18	Q3 18	Q1 18	Q3 18					
TGS		0.0%	Update of transfer limits in Labrador transmission corridors for n-0 and n-1 operating conditions	Q1 18	Q3 18	Q1 18	Q3 18					
TGS		0.0%	Update of transfer limits in Newfoundland transmission corridors for n-0 and n-1 operating conditions	Q1 18	Q3 18	Q1 18	Q3 18					
TGS		0.0%	Development of a new underfrequency load shedding scheme	Q1 18	Q3 18	Q1 18	Q3 18					
TGS		0.0%	Review of Power System Stabilizer applications for generators and HVdc links for improved system damping	Q1 18	Q3 18	Q1 18	Q3 18					
TGS		0.0%	Update to coordination of the Labrador Island Link frequency controller and the Maritime Link frequency controller	Q1 18	Q3 18	Q1 18	Q3 18					
TGS		0.0%	Review of coordinated runbacks of HVdc links and operating restrictions with links out of service	Q1 18	Q3 18	Q1 18	Q3 18					
TGS		0.0%	Consideration of re-strikes on the Labrador Island HVdc Link	Q1 18	Q3 18	Q1 18	Q3 18					
TGS		0.0%	Review of reactive power requirements for high power transfer on the Labrador Island Link and evaluation of dynamic reactive additions at Soldiers Pond and Holyrood	Q1 18	Q3 18	Q1 18	Q3 18					
TGS		0.0%	Review of Bay d'Espoir instabilities under a three-phase fault condition	Q1 18	Q3 18	Q1 18	Q3 18					
	0.0%	**0.0%**	**Energization System Studies**	**Q2 18**	**Q3 19**	**Q2 18**	**Q3 19**	**P4**	**Q3 19 MFG First Power Minus 6 mths**	**Q4 19**	**-9**	**Delivery**
TGS		0.0%	GEP 9 Study (Muskrat Falls G1)	Q2 18	Q3 18	Q2 18	Q3 18					
TGS		0.0%	GEP 10 Study (Muskrat Falls G2)	Q3 18	Q4 18	Q3 18	Q4 18					
TGS		0.0%	GEP 11 Study (Muskrat Falls G3)	Q4 18	Q2 19	Q4 18	Q2 19					
TGS		0.0%	GEP 12 Study (Muskrat Falls G4)	Q1 19	Q3 19	Q1 19	Q3 19					
TGS		0.0%	GEP 14 Study (Integrated Tests - fullpower performance tests)	Q4 18	Q2 19	Q4 18	Q2 19					
	47.9%	**59.1%**	**RFI OTHER ITEMS - FIRST POWER PREPARDNESS**									
	100.0%	**100.0%**	**NLH Equipment Tagging and Single Line Diagrams**	**Q1 15**	**Q2 17**	**Q1 15**	**Q1 20**	**P3**				
RFI Studies Lead	100.0%	100.0%	CHFTS Extension	Q1 15	Q1 15	Q1 15	Q1 15		**Q4 17 CFTS Energize Minus 6 mths**	**Q4 17**		**Delivery**
RFI Studies Lead	100.0%	100.0%	CHFTS2 (735/315 kV station)	Q1 15	Q1 15	Q1 15	Q1 15		**Q4 17 CFTS Energize Minus 6 mths**	**Q4 17**		**Delivery**
RFI Studies Lead	100.0%	100.0%	MFATS2 (315 kV station)	Q1 15	Q3 15	Q1 15	Q3 15		**Q4 17 MFTS Energize Minus 6 mths**	**Q4 17**		**Delivery**
RFI Studies Lead	100.0%	100.0%	MFAGS (Generating station)	Q1 15	Q2 15	Q1 15	Q2 15		**Q3 19 MFG First Power Minus 6 mths**	**Q4 19**		**Delivery**
RFI Studies Lead	100.0%	100.0%	MFACS (Muskrat Converter station)	Q1 15	Q3 15	Q1 15	Q3 15		**Q1 18 MFCS Energize Minus 6 mths**	**Q1 18**		**Delivery**
RFI Studies Lead	100.0%	100.0%	FPTCABLE (Forteau Point Transition Compound)	Q1 15	Q4 15	Q1 15	Q4 15		**Q4 17 LTA In Service Minus 6 mths**	**Q4 17**		**Delivery**

Resources	Actual UPDATE GREEN %'s	Expected	WBS L1 / WBS L2 / WBS L3	WBS L4	Baseline Start Date (Q)	Baseline End Date (Q)	Actual/Forecast Start Date (Q)	Actual/Forecast End Date (Q)	Project Priority	Critical Path	LCP In Service Date (Q)	Float Watch	people/ process/ system/ delivery
RFI Studies Lead	100.0%	100.0%		SOCCABLE (Shoal Cove Transition Compound)	Q1 15	Q3 16	Q1 15	Q3 16		Q4 17 LTA In Service Minus 6 mths	Q4 17		Delivery
RFI Studies Lead	100.0%	100.0%		SOPCS (Soldiers Pond Converter station)	Q1 15	Q1 15	Q1 15	Q1 15		Q1 18 SOPCS Energize Minus 6 mths	Q1 18		Delivery
RFI Studies Lead	100.0%	100.0%		SOPSC (Soldiers Pond Synchronous Condenser station)	Q1 15	Q3 15	Q1 15	Q3 15		Q1 18 SOPSC Energize Minus 6 mths	Q1 18		Delivery
RFI Studies Lead	100.0%	100.0%		SOPTS (230 kV station)	Q1 15	Q3 15	Q1 15	Q3 15		Q1 18 SOPTS Energize Minus 6 mths	Q1 18		Delivery
RFI Studies Lead	100.0%	100.0%		BBKCS (Bottom Brook Converter station)	Q1 15	Q2 15	Q1 15	Q2 15		Q4 17 ML In Service Minus 6 mths	Q4 17		Delivery
RFI Studies Lead	100.0%	100.0%		BBKTS1 (existing Bottom Brook 230 kV station)	Q1 15	Q2 15	Q1 15	Q2 15		Q4 17 ML In Service Minus 6 mths	Q4 17		Delivery
RFI Studies Lead	100.0%	100.0%		BBKTS2 (new ENL Bottom Brook 230 kV station)	Q1 15	Q2 15	Q1 15	Q2 15		Q4 17 ML In Service Minus 6 mths	Q4 17		Delivery
RFI Studies Lead	100.0%	100.0%		GCTTS (Granite Canal Tap 230 kV station)	Q1 15	Q3 15	Q1 15	Q3 15		Q4 17 ML In Service Minus 6 mths	Q4 17		Delivery
NLH	100.0%	100.0%		USLTS (Upper Salmon 230 kV station breaker addition)	Q1 17	Q2 16	Q1 17	Q2 16		Q1 18 SOPTS Energize Minus 6 mths	Q1 18		Delivery
NLH	100.0%	100.0%		BDETS1 & 2 (Bay d'Espir 230 kV line re-termination and TL267)	Q1 17	Q2 16	Q1 17	Q2 16		Q1 18 SOPTS Energize Minus 6 mths	Q1 18		Delivery
NLH	100.0%	100.0%		WAVTS (Western Avalon 230 kV station, TL267 addition)	Q1 17	Q2 16	Q1 17	Q2 16		Q1 18 SOPTS Energize Minus 6 mths	Q1 18		Delivery
NLH	100.0%	100.0%		MFATS2 for 315 kV shunt reactor	Q3 16	Q2 17	Q3 16	Q2 17		Q4 17 MFTS Energize Minus 6 mths	Q4 17		Delivery
	86.3%	**100.0%**		**Support Delivery of Final Points Lists (ECC Control & Monitoring)**	**Q1 16**	**Q2 17**	**Q1 16**	**Q4 17**	**P3**				
RFI Mgr	100.0%	100.0%		SOPTS	Q1 16	Q4 16	Q1 16	Q2 17		Q1 18 SOPTS Energize Minus 2 mths	Q1 18		Delivery
RFI Mgr	50.0%	100.0%		SOPCS	Q1 16	Q2 17	Q1 16	Q4 17		Q1 18 SOPCS Energize Minus 2 mths	Q1 18	22	Delivery
RFI Mgr	70.0%	100.0%		SOPSC	Q1 16	Q1 17	Q1 16	Q4 17		Q1 18 SOPSC Energize Minus 2 mths	Q1 18	75	Delivery
RFI Mgr	95.0%	100.0%		FPTCABLE	Q1 16	Q1 17	Q1 16	Q3 17		Q4 17 LTA In Service Minus 2 mths	Q4 17	51	Delivery
RFI Mgr	95.0%	100.0%		SOCCABLE	Q1 16	Q1 17	Q1 16	Q3 17		Q4 17 LTA In Service Minus 2 mths	Q4 17	51	Delivery
RFI Mgr	95.0%	100.0%		CHFTS2	Q1 16	Q4 16	Q1 16	Q4 17		Q4 17 CFTS Energize Minus 2 mths	Q4 17	-31	Delivery
RFI Mgr	100.0%	100.0%		CHF	Q1 16	Q4 16	Q1 16	Q2 17		Q4 17 CFTS Energize Minus 2 mths	Q4 17		Delivery
RFI Mgr	50.0%	100.0%		MFACS	Q1 16	Q2 17	Q1 16	Q4 17		Q1 18 MFCS Energize Minus 2 mths	Q1 18	52	Delivery
RFI Mgr	95.0%	100.0%		MFATS2	Q1 16	Q4 16	Q1 16	Q4 17		Q4 17 MFTS Energize Minus 2 mths	Q4 17	-5	Delivery
RFI Mgr	90.0%	100.0%		BBKCS	Q1 16	Q2 16	Q1 16	Q3 17		Q4 17 ML In Service Minus 4 mths	Q4 17	0	Delivery
RFI Mgr	100.0%	100.0%		BBKTS2	Q1 16	Q4 16	Q1 16	Q2 17		Q4 17 ML In Service Minus 6 mths	Q4 17		Delivery
RFI Mgr	95.0%	100.0%		GCTTS	Q1 16	Q2 16	Q1 16	Q2 17		Q4 17 ML In Service Minus 6 mths	Q4 17		Delivery
	45.8%	**56.4%**		**Support Delivery of Grid Energization Procedures**	**Q2 16**	**Q3 19**	**Q2 16**	**Q3 19**	**P2**				
RFI Mgr	100.0%	100.0%		GEP Overview	Q2 16	Q4 16	Q2 16	Q4 16					Delivery
RFI Mgr	100.0%	100.0%		GEP1: Churchhill Falls TS and TS Ext	Q4 16	Q2 17	Q4 16	Q2 17		Q4 17 CFTS Energize Minus 1 mth	Q4 17		Delivery
RFI Mgr	90.0%	100.0%		GEP2: Muskrat Falls TS	Q4 16	Q2 17	Q4 16	Q3 17		Q4 17 MFTS Energize Minus 1 mth	Q4 17	56	Delivery
RFI Mgr	0.0%	55.7%		GEP3: MF Converters & Filters	Q1 17	Q4 17	Q3 17	Q4 17		Q1 18 MFCS Energize Minus 1 mth	Q1 18	82	Delivery
RFI Mgr	0.0%	55.7%		GEP4: FT Pt TC, Subsea Cable & LAD Electrode	Q1 17	Q4 17	Q3 17	Q4 17		Q1 18 MFCS Energize Minus 1 mth	Q1 18	82	Delivery
RFI Mgr	0.0%	36.4%		GEP5: SC TC, Subsea Cable & DP Electrode	Q2 17	Q3 17	Q3 17	Q3 17		Q1 18 MFCS Energize Minus 1 mth	Q1 18	112	Delivery
RFI Mgr	0.0%	36.4%		GEP6: Soldiers Pond CS	Q2 17	Q3 17	Q3 17	Q3 17		Q1 18 SOPCS Energize Minus 1 mth	Q1 18	82	Delivery
RFI Mgr	100.0%	100.0%		GEP7: Soldiers Pond TS	Q4 16	Q2 17	Q4 16	Q2 17		Q1 18 SOPTS Energize Minus 1 mth	Q1 18		Delivery
RFI Mgr	25.0%	36.4%		GEP8: Soldiers Pond SC	Q2 17	Q3 17	Q3 17	Q3 17		Q1 18 SOPSC Energize Minus 1 mth	Q1 18	135	Delivery
RFI Mgr	0.0%	0.0%		GEP9: MFG Unit1	Q2 18	Q4 18	Q2 18	Q4 18		Q4 19 MFG First Power Minus 1 mth	Q4 19	360	Delivery
RFI Mgr	0.0%	0.0%		GEP10: MFG Unit2	Q3 18	Q1 19	Q3 18	Q1 19		Q4 19 MFG First Power Minus 1 mth	Q4 19	270	Delivery
RFI Mgr	0.0%	0.0%		GEP11: MFG Unit3	Q4 18	Q2 19	Q4 18	Q2 19		Q4 19 MFG First Power Minus 1 mth	Q4 19	180	Delivery
RFI Mgr	0.0%	0.0%		GEP12: MFG Unit4	Q1 19	Q3 19	Q1 19	Q3 19		Q4 19 MFG First Power Minus 1 mth	Q4 19	90	Delivery
RFI Mgr	0.0%	7.7%		GEP13: Low Power Transfer	Q3 17	Q4 17	Q3 17	Q4 17		Q3 18 LIL In Service Minus 1 mths	Q3 18	151	Delivery
RFI Mgr	0.0%	0.0%		GEP14: High Power Transfer	Q4 18	Q3 19	Q4 18	Q3 19		Q3 20 MFG In Service Minus 1 mth	Q3 20	358	Delivery
	0.0%	**18.6%**		**Support RTDS Testing and System Commissioning and Witnessing**	**Q2 17**	**Q2 18**	**Q3 17**	**Q2 18**	**P3**				
RFI Studies Lead	0.0%	48.4%		RTDS Simulation Testing (Stafford)	Q2 17	Q3 17	Q3 17	Q3 17		Q3 18 LIL In Service Minus 10 mths	Q3 18	-29	Delivery
RFI Studies Lead		0.0%		SOP SC1 Testing	Q4 17	Q4 17	Q4 17	Q4 17					
RFI Studies Lead		0.0%		SOP SC2 Testing	Q1 18	Q1 18	Q1 18	Q1 18					
RFI Studies Lead		0.0%		SOP SC3 Testing	Q2 18	Q2 18	Q2 18	Q2 18					
RFI Studies Lead		0.0%		LIL - Witness and verify filter bank switching tests SOP	Q3 17	Q4 17	Q3 17	Q4 17					
RFI Studies Lead		0.0%		LIL - Witness and verify filter bank switching tests MFA	Q3 17	Q4 17	Q3 17	Q4 17					
RFI Studies Lead		0.0%		LIL - Witness and verify performance of low power tests	Q1 18	Q2 18	Q1 18	Q2 18					
RFI Studies Lead		0.0%		ML - Witness and verify performance of low power tests	Q3 17	Q4 17	Q3 17	Q4 17					

Resources	Actual UPDATE GREEN %'s	Expected	WBS L1	WBS L2	WBS L3	WBS L4	Baseline Start Date (Q)	Baseline End Date (Q)	Actual/Forecast Start Date (Q)	Actual/Forecast End Date (Q)	Project Priority	Critical Path	LCP In Service Date (Q)	Float Watch	people/ process/ system/ delivery
	0.0%	0.0%	RFI OTHER ITEMS - FULL POWER PREPARDNESS												
	0.0%	0.0%		**Support Delivery of Final Points Lists**			**Q1 18**	**Q3 19**	**Q1 18**	**Q3 19**	**P4**				
RFI Mgr					MFAGS		Q1 18	Q3 19	Q1 18	Q3 19		**Q4 19 MFG First Power Minus 2 mths**	**Q4 19**	**62**	**Delivery**
	0.0%	0.0%		**RTDS Testing and System Commissioning and Witnessing**			**Q1 19**	**Q1 20**	**Q1 19**	**Q1 20**	**P3**				
RFI Studies Lead		0.0%			LIL - Witness and verify performance of high power tests		Q1 19	Q2 19	Q1 19	Q2 19					
RFI Studies Lead		0.0%			ML - Witness and verify performance of high power tests		Q1 19	Q2 19	Q1 19	Q2 19					
RFI Studies Lead		0.0%			MFAG1 - Muskrat Falls Generator G1 Testing		Q2 19	Q2 19	Q2 19	Q2 19					
RFI Studies Lead		0.0%			MFAG2 - Muskrat Falls Generator G2 Testing		Q3 19	Q3 19	Q3 19	Q3 19					
RFI Studies Lead		0.0%			MFAG3 - Muskrat Falls Generator G2 Testing		Q4 19	Q4 19	Q4 19	Q4 19					
RFI Studies Lead		0.0%			MFAG4 - Muskrat Falls Generator G2 Testing		Q1 20	Q1 20	Q1 20	Q1 20					
	46.8%	67.5%	RFI NERC - FIRST POWER PREPARDNESS												
	46.8%	67.5%		**Key NERC Reliability Standards (Assess, Define and Develop Voluntary Standards)**			**Q1 15**	**Q1 18**	**Q1 15**	**Q1 18**	**P4**	**Q3 18 LIL In Service Minus 3 mths**	**Q3 18**	**56**	**Delivery**
RFI NERC Lead	100.0%	100.0%			External Validation of NLH Reliability Standards		Q1 15	Q4 16	Q1 15	Q4 16					
RFI NERC Lead	100.0%	100.0%			Complete Gap Analysis of Reliability Standards		Q3 15	Q1 17	Q3 15	Q1 17					
RFI NERC Lead	100.0%	100.0%			Assist with Legislative Change, market structure, service request design		Q1 15	Q3 16	Q1 15	Q3 16					
RFI NERC Lead	80.0%	65.2%			Define Bulk Electric System for application of standards		Q3 16	Q4 17	Q3 16	Q4 17					
RFI NERC Lead	100.0%	65.2%			Develop Phase 1 Reliability Standard adoption criteria		Q3 16	Q4 17	Q3 16	Q4 17					
RFI NERC Lead	100.0%	100.0%			Assess NERC Reliability Standards for immediate voluntary adoption		Q4 16	Q2 17	Q4 16	Q2 17					
RFI NERC Lead	25.0%	100.0%			Rationalization of existing operations and planning practices with selected voluntary standards		Q1 17	Q2 17	Q1 17	Q2 17					
RFI NERC Lead	100.0%	100.0%			Document NLH standards, guidelines and criteria for non-BES elements		Q1 17	Q2 17	Q1 17	Q2 17					
RFI NERC Lead	100.0%	100.0%			Develop implementation plan for Phase 1 voluntary NLH Reliability Standards		Q2 17	Q2 17	Q2 17	Q2 17					
					Complete Phase 1 implementation of voluntary Reliability Standards		**Q1 17**	**Q1 18**	**Q3 17**	**Q1 18**					
RFI NERC Lead	100.0%	100.0%				AESI - KickOff	Q1 17	Q2 17	Q3 17	Q3 17					
RFI NERC Lead		100.0%				AESI - Site Visits & Assessment	Q1 17	Q1 17	Q3 17	Q3 17					
RFI NERC Lead		38.3%				AESI - Issue Batch1 Draft Documents (20 Documents)	Q2 17	Q4 17	Q3 17	Q3 17					
RFI NERC Lead		38.3%				AESI - Issue Batch1 Final Dcouments (20 Documents)	Q2 17	Q4 17	Q3 17	Q4 17					
RFI NERC Lead		38.3%				AESI - Issue Batch2 Draft Documents (9 Documents)	Q2 17	Q4 17	Q3 17	Q4 17					
RFI NERC Lead		38.3%				AESI - Issue Batch2 Final Dcouments (9 Documents)	Q2 17	Q4 17	Q4 17	Q4 17					
RFI NERC Lead		38.3%				AESI - Issue Batch3 Draft Documents (10 Documents)	Q2 17	Q4 17	Q3 17	Q4 17					
RFI NERC Lead		38.3%				AESI - Issue Batch3 Final Documents (10 Documents)	Q2 17	Q4 17	Q4 17	Q4 17					
RFI NERC Lead		0.0%				AESI - Issue Batch4 of Optional Draft Documents (6 Documents)	Q4 17	Q4 17	Q4 17	Q4 17					
RFI NERC Lead		0.0%				AESI - Issue Batch4 of Optional Final Documents (6 Documents)	Q4 17	Q1 18	Q4 17	Q1 18					
RFI NERC Lead		0.0%				AESI - Issue Batch5 of Optional Draft Documents (5 Documents)	Q4 17	Q1 18	Q4 17	Q1 18					
RFI NERC Lead		0.0%				AESI - Issue Batch5 of Optional Final Documents (5 Documents)	Q1 18	Q1 18	Q1 18	Q1 18					
	0.0%	0.0%	RFI NERC - FULL POWER PREPARDNESS												
	0.0%	0.0%		**Reliability Standards**			**Q4 17**	**Q4 19**	**Q4 17**	**Q4 19**	**P4**	**Q4 19 MFG First Power Minus 6 mths**	**Q3 20**		**Delivery**
RFI NERC Lead		0.0%			Develop Phase 2 Reliability Standard adoption criteria		Q4 17	Q4 17	Q4 17	Q4 17					
RFI NERC Lead		0.0%			Assess NERC Reliability Standards for Phase 2 voluntary adoption		Q4 17	Q1 18	Q4 17	Q1 18					
RFI NERC Lead		0.0%			Rationalzation of existing operations and planning practices with selected Phase 2 voluntary standards		Q1 18	Q2 18	Q1 18	Q2 18					
RFI NERC Lead		0.0%			Develop implementation plan for Phase 2 voluntary NLH Reliability Standards		Q2 18	Q3 18	Q2 18	Q3 18					
RFI NERC Lead		0.0%			Complete Phase 2 implementation of voluntary Reliability Standards		Q3 18	Q4 19	Q3 18	Q4 19					

	% Complete						Baseline Dates		Actual/Forecast						
Resources	Actual UPDATE GREEN %'s	Expected	WBS L1	WBS L2	WBS L3	WBS L4	Baseline Start Date (Q)	Baseline End Date (Q)	Actual/Forecast Start Date (Q)	Actual/Forecast End Date (Q)	Project Priority	Critical Path	LCP In Service Date (Q)	Float Watch	people/ process/ system/ delivery
	19.8%	**20.4%**	**BTPO SCOPE**												
	34.2%	**34.2%**		**Governance & Oversight - Workstream Manager**			**Q1 16**	**Q2 20**	**Q2 16**	**Q2 20**					
BTPO Mgr	34.2%	34.2%			Mgmt, Mtgs, Reporting, Review (50% for BTPO Manager)		Q1 16	Q2 20	Q1 16	Q2 20					
	45.5%	**44.9%**	**BTPO: PEOPLE SCOPE**												
	33.0%	**33.0%**		**Team Lead - People**			**Q1 16**	**Q2 20**	**Q2 16**	**Q2 20**					
People Lead	34.2%	34.2%			Mgmt, Mtgs, Reporting, Review (18% for People Lead)		Q1 16	Q2 20	Q1 16	Q2 20					
People Lead	30.3%	30.3%			Labor Agreement/Committment Administration (7% for People Lead)		Q2 16	Q2 20	Q2 16	Q2 20					
	56.8%	**58.7%**	**BTPO: PEOPLE - FIRST POWER PREPARDNESS**												
	100.0%	**100.0%**		**Labour Negotiations & Agreements**			**Q1 15**	**Q1 17**	**Q1 15**	**Q1 17**	**P2**	**Q3 18 LIL In Service Minus 12 mths**	**Q3 18**		**People**
People Lead	100.0%	100.0%			CBA - Initial FY17 Collective Bargaining Agreement, Negotiations & Mtgs		Q4 16	Q1 17	Q4 16	Q1 17					
People Lead	100.0%	100.0%			ELAC Considerations - Negotiations, Meetings, Documents		Q1 15	Q4 16	Q1 15	Q4 16					
People Lead	100.0%	100.0%			IBA LTA Considerations - Roles, Strategy, MOU, HROE Support, Priorities		Q1 16	Q4 16	Q1 16	Q4 16					
People Lead	100.0%	100.0%			IBA MFG Considerations - Roles, Strategy, MOU, HROE Support, Priorities		Q1 16	Q4 16	Q1 16	Q4 16					
	62.7%	**68.8%**		**Staffing Strategy and Recruitment**											
	71.2%	**73.5%**			**Strategy & Planning**		**Q1 16**	**Q1 18**	**Q1 16**	**Q1 18**	**P2**				**People**
People Lead	100.0%	100.0%				Plant Operations Support Considerations	Q1 16	Q4 16	Q1 16	Q4 16					
People Lead	100.0%	100.0%				Holyrood Change Management Considerations	Q1 16	Q4 16	Q1 16	Q4 16					
People Lead	65.0%	68.4%				LCP Staff Transition Considerations	Q1 16	Q1 18	Q1 16	Q1 18					
BTPO Mgr	80.0%	80.5%				GE GRID & ATCO Operations Support Strategy	Q3 16	Q3 17	Q3 16	Q3 17					
People Lead	40.0%	44.6%				Recruitinng Approach, Marketing, Planning	Q1 17	Q4 17	Q1 17	Q4 17					
People Lead	100.0%	100.0%				Develop & Present HR Plan	Q1 16	Q4 16	Q1 16	Q4 16					
	66.2%	**82.1%**			**BTPO - Secure Team Resourcing**		**Q1 16**	**Q3 17**	**Q1 16**	**Q4 17**	**P2**	**Q3 18 LIL In Service Minus 6 mths**	**Q3 18**	**60**	**People**
People Lead	100.0%	100.0%				Requirements, Strategy, Job Scopes & Org Charts	Q1 16	Q4 16	Q1 16	Q4 16					
People Lead	100.0%	100.0%				Review & Seek Approval for BTPO Staffing Plan	Q1 17	Q1 17	Q1 17	Q1 17					
People Lead	100.0%	100.0%				Post Requisitions	Q1 17	Q1 17	Q1 17	Q2 17					
People Lead	46.2%	69.1%				Recruit, Screen, Interview and Select Candidates	Q2 17	Q3 17	Q2 17	Q3 17					
People Lead	38.5%	69.1%				Offers Finalized	Q2 17	Q3 17	Q2 17	Q4 17					
People Lead	30.8%	69.1%				Onboarding & Coordination	Q2 17	Q3 17	Q2 17	Q4 17					
	42.0%	**51.7%**			**CFLCo - Secure O&M Resourcing**		**Q4 16**	**Q1 18**	**Q4 16**	**Q1 18**	**P2**	**Q4 17 LTA In Service Plus 3 mths**	**Q4 17**	**-8**	**People**
People Lead	100.0%	100.0%				Requirements, Strategy, Job Scopes & Org Charts	Q4 16	Q4 16	Q4 16	Q3 17					
People Lead	100.0%	100.0%				Review & Seek Approval for LTA & LIL O&M Staffing Plan	Q4 16	Q1 17	Q4 16	Q3 17					
Rec Coord	0.0%	41.0%				Post Requisitions	Q2 17	Q4 17	Q2 17	Q4 17					
Rec Coord	0.0%	14.5%				Recruit, Screen, Interview and Select Candidates	Q2 17	Q1 18	Q2 17	Q1 18					
Rec Coord	0.0%	14.5%				Offers Finalized	Q2 17	Q1 18	Q2 17	Q1 18					
Rec Coord	0.0%	14.5%				Onboarding & Coordination	Q2 17	Q1 18	Q2 17	Q1 18					
	52.3%	**64.1%**			**LTA & LIL - Secure O&M Team Resourcing (Supervisor, Operator, Maintainer)**		**Q1 16**	**Q1 18**	**Q1 16**	**Q1 18**	**P2**	**Q3 18 LIL In Service Minus 3 mths**	**Q3 18**	**1**	**People**
People Lead	100.0%	100.0%				Requirements, Strategy, Job Scopes & Org Charts	Q1 16	Q4 16	Q1 16	Q3 17					

Resources	Actual UPDATE GREEN %'s	Expected	WBS L1	WBS L2	WBS L3	WBS L4	Baseline Start Date (Q)	Baseline End Date (Q)	Actual/Forecast Start Date (Q)	Actual/Forecast End Date (Q)	Project Priority	Critical Path	LCP In Service Date (Q)	Float Watch	people/ process/ system/ delivery
People Lead	100.0%	100.0%				Review & Seek Approval for LTA & LIL O&M Staffing Plan	Q4 16	Q1 17	Q4 16	Q3 17					
Rec Coord	75.9%	77.8%				Post Requisitions	Q1 17	Q3 17	Q1 17	Q3 17					
Rec Coord	13.8%	34.4%				Recruit, Screen, Interview and Select Candidates	Q1 17	Q1 18	Q1 17	Q1 18					
Rec Coord	13.8%	34.4%				Offers Finalized	Q1 17	Q1 18	Q1 17	Q1 18					
Rec Coord	0.0%	34.4%				Onboarding & Coordination	Q1 17	Q1 18	Q1 17	Q1 18					
	68.0%	57.2%			Contractor (ATCO & GE Grid) - Secure O&M Supports		Q2 16	Q4 17	Q2 16	Q4 17	P2	Q3 18 LIL In Service Minus 3 mths	Q3 18	91	People
BTPO Mgr	90.0%	89.7%				Requirements, Strategy, Job Scopes & Org Charts	Q2 16	Q3 17	Q2 16	Q3 17					
BTPO Mgr	60.0%	16.3%				Review & Seek Approval for Contractor Supports	Q2 17	Q3 17	Q2 17	Q3 17					
BTPO Mgr	50.0%	9.2%				Contract Negotiations	Q3 17	Q4 17	Q3 17	Q4 17					
BTPO Mgr		0.0%				Contracting Signing	Q3 17	Q4 17	Q3 17	Q4 17					
BTPO Mgr		0.0%				Onboarding & Coordination	Q4 17	Q4 17	Q4 17	Q4 17					
	19.0%	11.1%		Training Assessment, Schedule and Execution											
	22.5%	11.3%			CFLCo - Deliver O&M Training Requirements		Q1 17	Q4 19	Q1 17	Q4 19	P2				People
Trg Coord	80.0%	43.0%				CFLCo - Assess training requirements for equipment	Q1 17	Q1 18	Q1 17	Q1 18					
Trg Coord	70.0%	28.8%				CFLCo - Develop training strategy, plan, schedule & cost	Q2 17	Q1 18	Q2 17	Q1 18					
Trg Coord		5.1%				CFLCo - Assess training requirements for individuals	Q3 17	Q1 18	Q3 17	Q1 18					
Trg Coord		0.0%				CFLCo - Coordinate custom courses, vendor offerings	Q3 17	Q4 19	Q3 17	Q4 19					
TBD		0.0%				CFLCo - Deliver Training to Resources	Q3 17	Q4 19	Q3 17	Q4 19					
	22.5%	11.3%			LTA & LIL - Deliver O&M Training Requirements		Q1 17	Q4 19	Q1 17	Q4 19	P2				People
Trg Coord	80.0%	43.0%				LTA & LIL - Assess training requirements for equipment	Q1 17	Q1 18	Q1 17	Q1 18					
Trg Coord	70.0%	28.8%				LTA & LIL - Develop training strategy, plan, schedule & cost	Q2 17	Q1 18	Q2 17	Q1 18					
Trg Coord		5.1%				LTA & LIL - Assess training requirements for individuals	Q3 17	Q1 18	Q3 17	Q1 18					
Trg Coord		0.0%				LTA & LIL - Coordinate custom courses, vendor offerings	Q3 17	Q4 19	Q3 17	Q4 19					
TBD		0.0%				LTA & LIL - Deliver Training to Resources	Q3 17	Q4 19	Q3 17	Q4 19					
	12.0%	10.8%			CORPORATE - Deliver Standard Corporate Training Requirements		Q1 17	Q4 18	Q1 17	Q4 18	P2				People
Trg Coord	50.0%	43.0%				CORP - Assess training requirements	Q1 17	Q1 18	Q1 17	Q1 18					
Trg Coord	30.0%	28.8%				CORP - Develop training strategy, plan, schedule & cost	Q2 17	Q1 18	Q2 17	Q1 18					
Trg Coord		0.0%				CORP - Coordinate custom courses, vendor offerings	Q3 17	Q4 18	Q3 17	Q4 18					
TBD		0.0%				CORP - Deliver Training to O&M Resources	Q3 17	Q4 18	Q3 17	Q4 18					
	27.1%	17.6%	BTPO: PEOPLE - FULL POWER PREPARDNESS												
	28.9%	22.3%		Staffing Strategy and Recruitment											
	34.8%	28.4%			Recruiting - MFG O&M		Q2 16	Q2 19	Q2 16	Q2 19	P2	Q4 19 MFG First Power Minus 3 mths	Q4 19	90	People
People Lead	85.0%	73.6%				Requirements, Strategy, Job Scopes & Org Charts	Q2 16	Q4 17	Q2 16	Q1 18					
People Lead	50.0%	26.3%				Review & Seek Approval for MFG O&M Staffing Plan	Q1 17	Q3 18	Q1 17	Q3 18					
Rec Coord		0.0%				Post Requisitions	Q3 18	Q4 18	Q3 18	Q4 18					
Rec Coord		0.0%				Recruit, Screen, Interview and Select Candidates	Q3 18	Q2 19	Q3 18	Q2 19					
Rec Coord		0.0%				Offers Finalized	Q3 18	Q2 19	Q3 18	Q2 19					
Rec Coord		0.0%				Onboarding & Coordination	Q3 18	Q2 19	Q3 18	Q2 19					

Resources	Actual UPDATE GREEN %'s	Expected	WBS L1 / WBS L2 / WBS L3 / WBS L4	Baseline Start Date (Q)	Baseline End Date (Q)	Actual/Forecast Start Date (Q)	Actual/Forecast End Date (Q)	Project Priority	Critical Path	LCP In Service Date (Q)	Float Watch	people/ process/ system/ delivery
	22.0%	**15.2%**	**Recruiting - Corporate Supports**	**Q1 17**	**Q4 19**	**Q1 17**	**Q4 19**	**P2**	**Q3 20 MFG In Service**	**Q3 20**	**238**	**People**
People Lead	50.0%	44.6%	Requirements, Strategy, Job Scopes & Org Charts	Q1 17	Q4 17	Q1 17	Q3 17					
People Lead	50.0%	0.0%	Review & Seek Approval for Corporate Staffing Plan	Q4 17	Q1 18	Q4 17	Q3 17					
Rec Coord	2.9%	11.2%	Post Requisitions	Q2 17	Q2 18	Q2 17	Q2 18					
Rec Coord	2.9%	1.5%	Recruit, Screen, Interview and Select Candidates	Q3 17	Q4 19	Q3 17	Q4 19					
Rec Coord	2.9%	1.5%	Offers Finalized	Q3 17	Q4 19	Q3 17	Q4 19					
Rec Coord	0.0%	1.5%	Onboarding & Coordination	Q3 17	Q4 19	Q3 17	Q4 19					
	22.5%	**4.9%**	**Training Assessment, Schedule and Execution**									
	22.5%	**4.9%**	**MFG - Deliver O&M Training Requirements**	**Q2 17**	**Q4 19**	**Q2 17**	**Q4 19**	**P2**	**Q3 20 MFG In Service**	**Q3 20**	**238**	**People**
Trg Coord	80.0%	14.5%	Assess training requirements for equipment	Q2 17	Q1 18	Q2 17	Q3 19					
Trg Coord	70.0%	14.5%	Develop training strategy, plan, schedule & cost	Q2 17	Q1 18	Q2 17	Q3 19					
Trg Coord		5.1%	Assess training requirements for individuals	Q3 17	Q1 18	Q3 17	Q3 19					
Trg Coord		0.0%	Coordinate custom courses, vendor offerings	Q1 18	Q4 19	Q1 18	Q4 19					
TBD		0.0%	Deliver Training to MFG O&M Resources	Q2 18	Q4 19	Q2 18	Q4 19					
	4.4%	**5.8%**	**BTPO: ASSET MANAGEMENT SCOPE**									
	18.9%	**26.9%**	**Team Lead - Assets**	**Q2 16**	**Q2 20**	**Q2 16**	**Q2 20**					
Rel Engineer	28.9%	28.9%	Mgmt, Mtgs, Reporting, Review	Q2 16	Q2 20	Q2 16	Q2 20					
Rel Engineer	10.0%	28.8%	Support Finance with asset value breakdown	Q2 17	Q1 18	Q1 17	Q3 18					
Rel Engineer	5.0%	22.5%	Critical Failure Modes & Effects Analysis (FMEA)	Q2 17	Q1 18	Q1 17	Q3 18					
	20.3%	**21.4%**	**BTPO: ASSETS - FIRST POWER PREPARDNESS**									
	8.8%	**11.0%**	**HVac TERMINAL STATION ASSETS**									
	8.8%	**11.0%**	**Soldiers Pond TS (Hierachies, Criticality, Spares & Program)**	**Q2 16**	**Q1 18**	**Q2 16**	**Q1 18**	**P3**				
Rel Engineer	95.0%	100.0%	Develop High Level Asset Hierarchies	Q2 16	Q3 16	Q2 16	Q2 17					
IBS	0.0%	55.7%	Extract Data & Compile Contractor Documentation	Q1 17	Q4 17	Q2 16	Q4 17					
			Leverage OEM Maintenance Program	**Q3 17**	**Q4 17**	**Q3 17**	**Q4 17**		**Q1 18 SOPTS and SOPCS In Service**	**Q1 18**	**82**	**Processes**
TS Specialist		15.4%	Identify & Review Applicable OEM Maintenance Routines & Procedures	Q3 17	Q3 17	Q3 17	Q3 17					
TS Specialist		0.0%	Implement Interim Weekly/Monthly OEM Maintenance Routines & Procedures	Q3 17	Q4 17	Q3 17	Q4 17					
			Build Out Corporate Maintenance Program	**Q3 17**	**Q1 18**	**Q3 17**	**Q1 18**		**Q3 18 LIL In Service**	**Q3 18**	**91**	**Processes**
TS Specialist		11.5%	Perform Full Asset Criticality Assessment & Prioritize	Q3 17	Q4 17	Q3 17	Q4 17					
TS Specialist	25.0%	0.0%	For Priority Assets Perform Critical Spares & Speciality Tools Analysis	Q4 17	Q4 17	Q4 17	Q4 17					
TS Specialist		0.0%	For Priority Assets Complete JDE Load Sheets (Assets, Maintenance)	Q4 17	Q1 18	Q4 17	Q1 18					
TS Specialist		0.0%	For Priority Assets Develop Asset Maintenance Program	Q4 17	Q1 18	Q4 17	Q1 18					
	8.8%	**11.0%**	**Churchill Falls & Muskrat Falls TS (Hierachies, Criticality, Spares & Program)**	**Q2 16**	**Q1 18**	**Q2 16**	**Q1 18**	**P2**				
Rel Engineer	95.0%	100.0%	Develop High Level Asset Hierarchies	Q2 16	Q3 16	Q2 16	Q2 17					
IBS	0.0%	55.7%	Extract Data & Compile Contractor Documentation	Q1 17	Q4 17	Q2 16	Q4 17					
TS Specialist			Leverage OEM Maintenance Program						**Q4 17 CFTS and MFTS In Service**	**Q4 17**	**26**	**Processes**
TS Specialist			Build Out Corporate Maintenance Program						**Q3 18 LIL In Service**	**Q3 18**	**91**	**Processes**

Resources	Actual UPDATE GREEN %'s	Expected	WBS L1	WBS L2	WBS L3	WBS L4	Baseline Start Date (Q)	Baseline End Date (Q)	Actual/Forecast Start Date (Q)	Actual/Forecast End Date (Q)	Project Priority	Critical Path	LCP In Service Date (Q)	Float Watch	people/ process/ system/ delivery
	8.6%	8.9%	TRANSMISSION ASSETS												
	8.8%	9.7%		AC Transmission Labrador (Hierachies, Criticality, Spares & Program)			Q2 16	Q1 18	Q2 16	Q1 18	P3				
Rel Engineer	95.0%	100.0%			Develop High Level Asset Hierarchies		Q2 16	Q3 16	Q2 16	Q2 17					
IBS	0.0%	55.7%			Extract Data & Compile Contractor Documentation		Q1 17	Q4 17	Q2 16	Q4 17					
Trans Specialist					Leverage Existing Nalcor/NLH/CFLCo/NSP Maintenance Program		Q3 17	Q4 17	Q3 17	Q4 17		Q4 17 LTA In Service	Q4 17	-8	Processes
Trans Specialist					Build Out Corporate Maintenance Program		Q3 17	Q1 18	Q3 17	Q1 18		Q3 18 LIL In Service	Q3 18	91	Processes
	8.8%	9.3%		DC Subsea Transmission - Straight of Bell Isle (Hierachies, Criticality, Spares & Program			Q2 16	Q1 18	Q2 16	Q1 18	P3				
Rel Engineer	95.0%	100.0%			Develop High Level Asset Hierarchies		Q2 16	Q3 16	Q2 16	Q2 17					
Trans Specialist	0.0%	55.7%			Extract Data & Compile Contractor Documentation		Q1 17	Q4 17	Q2 16	Q4 17					
Trans Specialist					Leverage Existing SOBI Team Recommendations for Maintenance Program		Q3 17	Q1 18	Q3 17	Q1 18		Q3 18 LIL In Service	Q3 18	91	Processes
Trans Specialist					Build Out Corporate Maintenance Program		Q3 17	Q1 18	Q3 17	Q1 18		Q3 18 LIL In Service	Q3 18	91	Processes
	8.2%	7.9%		DC Overland Transmission - Muskrat Falls to Soldiers Pond (Hierachies, Criticality, Spai			Q2 16	Q1 18	Q2 16	Q1 18	P3				
Rel Engineer	95.0%	100.0%			Develop High Level Asset Hierarchies		Q2 16	Q3 16	Q2 16	Q2 17					
Trans Specialist	0.0%	55.7%			Extract Data & Compile Contractor Documentation		Q1 17	Q4 17	Q2 16	Q4 17					
Trans Specialist					Leverage Existing Nalcor/NLH/CFLCo Maintenance Program		Q3 17	Q1 18	Q3 17	Q1 18		Q3 18 LIL In Service	Q3 18	91	Processes
Trans Specialist					Build Out Corporate Maintenance Program		Q3 17	Q1 18	Q3 17	Q1 18		Q3 18 LIL In Service	Q3 18	91	Processes
	9.1%	9.1%	HVdc TRANSITION COMPOUND AND CONVERTER ASSETS												
	8.8%	9.3%		Transition Compounds (Hierachies, Criticality, Spares & Program)			Q2 16	Q1 18	Q2 16	Q1 18	P3				
Rel Engineer	95.0%	100.0%			Develop High Level Asset Hierarchies		Q2 16	Q3 16	Q2 16	Q2 17					
TS Specialist	0.0%	55.7%			Extract Data & Compile Contractor Documentation		Q1 17	Q4 17	Q2 16	Q4 17					
TS Specialist					Leverage OEM Maintenance Program		Q3 17	Q1 18	Q3 17	Q1 18		Q3 18 LIL In Service	Q3 18	91	Processes
TS Specialist					Build Out Corporate Maintenance Program		Q3 17	Q1 18	Q3 17	Q1 18		Q3 18 LIL In Service	Q3 18	91	Processes
	9.5%	8.8%		Converter Stations - Muskrat Falls & Soldiers Pond (Hierachies, Criticality, Spares & Prc			Q2 16	Q1 18	Q2 16	Q1 18	P3				
CS Specialist	95.0%	100.0%			Develop High Level Asset Hierarchies		Q2 16	Q3 16	Q2 16	Q2 17					
CS Specialist	20.0%	55.7%			Extract Data & Compile Contractor Documentation		Q1 17	Q4 17	Q2 16	Q4 17					
CS Specialist					Leverage OEM Maintenance Program		Q3 17	Q4 17	Q3 17	Q4 17		Q1 18 MFCS and SOPCS In Service	Q1 18	22	Processes
CS Specialist					Build Out Corporate Maintenance Program		Q3 17	Q1 18	Q2 17	Q1 18		Q3 18 LIL In Service	Q3 18	91	Processes
	8.8%	9.3%		DC Transmission Yards & Grounding Stations - Muskrat Falls & Soldiers Pond (Hierachie			Q2 16	Q1 18	Q2 16	Q1 18	P3				
Rel Engineer	95.0%	100.0%			Develop High Level Asset Hierarchies		Q2 16	Q3 16	Q2 16	Q2 17					
TS Specialist	0.0%	55.7%			Extract Data & Compile Contractor Documentation		Q1 17	Q4 17	Q2 16	Q4 17					
TS Specialist					Leverage OEM Maintenance Program		Q3 17	Q1 18	Q3 17	Q1 18		Q3 18 LIL In Service	Q3 18	91	Processes
TS Specialist					Build Out Corporate Maintenance Program		Q3 17	Q1 18	Q3 17	Q1 18		Q3 18 LIL In Service	Q3 18	91	Processes
	8.8%	10.2%	OTHER ASSETS												
	8.8%	10.2%		Synchronous Condenser Plant at Soldiers Pond			Q2 16	Q1 18	Q2 16	Q1 18	P3				
Rel Engineer	95.0%	100.0%			Develop High Level Asset Hierarchies		Q2 16	Q3 16	Q2 16	Q2 17					
TS Specialist	0.0%	72.2%			Extract Data & Compile Contractor Documentation		Q2 16	Q4 17	Q2 16	Q4 17					

Resources	Actual UPDATE GREEN %'s	Expected	WBS L1	WBS L2	WBS L3	WBS L4	Baseline Start Date (Q)	Baseline End Date (Q)	Actual/Forecast Start Date (Q)	Actual/Forecast End Date (Q)	Project Priority	Critical Path	LCP In Service Date (Q)	Float Watch	people/ process/ system/ delivery
TS Specialist					Leverage OEM Maintenance Program		Q3 17	Q1 18	Q3 17	Q1 18		Q1 18 SOPSC In Service	Q1 18	15	Processes
TS Specialist					Build Out Corporate Maintenance Program		Q3 17	Q1 18	Q3 17	Q1 18		Q3 18 LIL In Service	Q3 18	91	Processes
	70.0%	72.3%	HYDRO GENERATION ASSETS												
	70.0%	72.3%		MF Intake & Spillway Hydraulic Structures (Hierachies)			Q2 16	Q4 17	Q2 16	Q4 17	P2	Q4 19 MFG First Power	Q4 19	690	Processes
Rel Engineer	100.0%	100.0%			Develop High Level Asset Hierarchies		Q2 16	Q1 17	Q2 16	Q2 17					
IBS	40.0%	44.6%			Extract Data & Compile Contractor Documentation		Q1 17	Q4 17	Q2 16	Q4 17					
	70.0%	72.3%		MF Equipment (Hierachies)			Q2 16	Q4 17	Q2 16	Q4 17	P4	Q4 19 MFG First Power	Q4 19	690	Processes
Rel Engineer	100.0%	100.0%			Develop High Level Asset Hierarchies		Q2 16	Q1 17	Q2 16	Q2 17					
IBS	40.0%	44.6%			Extract Data & Compile Contractor Documentation		Q1 17	Q4 17	Q2 16	Q4 17					
	70.0%	72.3%		MF Balance of Plant (Hierachies)			Q2 16	Q4 17	Q2 16	Q4 17	P4	Q4 19 MFG First Power	Q4 19	690	Processes
Rel Engineer	100.0%	100.0%			Develop High Level Asset Hierarchies		Q2 16	Q1 17	Q2 16	Q2 17					
IBS	40.0%	44.6%			Extract Data & Compile Contractor Documentation		Q1 17	Q4 17	Q2 16	Q4 17					
	0.3%	0.0%	JDE DATA IMPORT & SETUP												
	0.3%	0.0%		JDE Data Migration & Linkage (Critical BOM's, Drawings, Spares, Methods Linkages)			Q4 17	Q2 18	Q4 17	Q2 18	P3				Systems
Rel Engineer	1.0%	0.0%			Priority BOM's created		Q4 17	Q2 18	Q4 17	Q2 18					
Rel Engineer		0.0%			Priority Assembly drawings linked		Q4 17	Q2 18	Q4 17	Q2 18					
Rel Engineer		0.0%			Priority Maintenance Tactics linked		Q4 17	Q2 18	Q4 17	Q2 18					
Rel Engineer		0.0%			Priority Critical spares linked		Q4 17	Q2 18	Q4 17	Q2 18					
Rel Engineer		0.0%			Priority Work Methods linked		Q4 17	Q2 18	Q4 17	Q2 18					
Rel Engineer		0.0%			Priority Mapped to Nalcor Asset Management Methodologies		Q4 17	Q2 18	Q4 17	Q2 18					
	0.0%	0.0%	BTPO: ASSETS - FULL POWER PREPARDNESS												
	0.0%	0.0%	HVac TERMINAL STATION ASSETS												
	0.0%	0.0%		Soldiers Pond TS (Detailed Hierachies, Criticality, REMAINING Spares & Program)			Q1 18	Q4 19	Q1 18	Q4 19	P3				
TS Specialist		0.0%			Develop Detailed Level Asset Hierarchies		Q1 18	Q1 18	Q1 18	Q1 18					
TS Specialist		0.0%			Remaining Critical Spares Analysis		Q2 18	Q3 18	Q2 18	Q3 18					
TS Specialist		0.0%			Critical Spares Review & Spares Stocking		Q3 18	Q1 19	Q3 18	Q1 19					
TS Specialist		0.0%			Remaining Load Sheets (Assets, Maintenance)		Q3 18	Q4 19	Q3 18	Q4 19					
TS Specialist		0.0%			Remaining Asset Maintenance Program		Q3 18	Q4 19	Q3 18	Q4 19					
	0.0%	0.0%		Churchill Falls & Muskrat Falls TS (Detailed Hierachies, Criticality, REMAINING Spares 8			Q1 18	Q4 19	Q1 18	Q4 19	P2				
	0.0%	0.0%	TRANSMISSION ASSETS												
	0.0%	0.0%		AC Transmission Labrador (Detailed Hierachies, Criticality, REMAINING Spares & Progr			Q1 18	Q4 19	Q1 18	Q4 19	P2				
	0.0%	0.0%		DC Subsea Transmission - Straight of Bell Isle (Detailed Hierachies, Criticality, REMAINI			Q1 18	Q4 19	Q1 18	Q4 19	P2				
	0.0%	0.0%		DC Overland Transmission - Muskrat Falls to Soldiers Pond (Detailed Hierachies, Critica			Q1 18	Q4 19	Q1 18	Q4 19	P3				
	0.3%	0.0%	HVdc TRANSITION COMPOUND AND CONVERTER ASSETS												
	0.0%	0.0%		Transition Compounds (Detailed Hierachies, Criticality, REMAINING Spares & Program)			Q1 18	Q4 19	Q1 18	Q4 19	P3				
	0.6%	0.0%		Converter Stations - Muskrat Falls & Soldiers Pond (Detailed Hierachies, Criticality, REM			Q1 18	Q4 19	Q1 18	Q4 19	P3				
	0.0%	0.0%		DC Transmission Yards - Muskrat Falls & Soldiers Pond (Detailed Hierachies, Criticality,			Q1 18	Q4 19	Q1 18	Q4 19	P3				

Resources	Actual UPDATE GREEN %'s	Expected	WBS L1 / WBS L2 / WBS L3 / WBS L4	Baseline Start Date (Q)	Baseline End Date (Q)	Actual/Forecast Start Date (Q)	Actual/Forecast End Date (Q)	Project Priority	Critical Path	LCP In Service Date (Q)	Float Watch	people/ process/ system/ delivery
	0.0%	0.0%	OTHER ASSETS									
	0.0%	0.0%	Sync Plant (Detailed Hierachies, Criticality, REMAINING Spares & Program)	Q1 18	Q4 19	Q1 18	Q4 19	P3				
	0.0%	0.0%	Communication Equipment - Churchill Falls to ECC, A and B paths (Detailed Hierachies,	Q3 17	Q4 19	Q2 16	Q4 19	P3				
	0.0%	0.0%	HYDRO GENERATION ASSETS									
	0.0%	0.0%	MF Intake & Spillway Hydraulic Structures (Detailed Hierachies, Criticality, Spares & Pr	Q1 18	Q4 19	Q1 18	Q4 19	P4				
	0.0%	0.0%	MF Equipment (Detailed Hierachies, Criticality, Spares & Program)	Q1 18	Q4 19	Q1 18	Q4 19	P4				
	0.0%	0.0%	MF Balance of Plant (Detailed Hierachies, Criticality, Spares & Program)	Q4 17	Q4 19	Q4 17	Q4 19	P4				
	0.0%	0.0%	JDE DATA IMPORT & SETUP									
	0.0%	0.0%	JDE Data Migration & Linkage (REMAINING BOM's, Drawings, Spares, Methods Linkage	Q4 18	Q2 19	Q4 18	Q2 19	P4				
Rel Engineer		0.0%	Remaining BOM's created	Q4 18	Q2 19	Q4 18	Q2 19					
Rel Engineer		0.0%	Remaining Assembly drawings linked	Q4 18	Q2 19	Q4 18	Q2 19					
Rel Engineer		0.0%	Remaining Maintenance Tactics linked	Q4 18	Q2 19	Q4 18	Q2 19					
Rel Engineer		0.0%	Remaining Critical spares linked	Q4 18	Q2 19	Q4 18	Q2 19					
Rel Engineer		0.0%	Remaining Work Methods linked	Q4 18	Q2 19	Q4 18	Q2 19					
Rel Engineer		0.0%	Remaining Mapped to Nalcor Asset Management Methodologies	Q4 18	Q2 19	Q4 18	Q2 19					
	18.4%	20.1%	BTPO: FINANCE SCOPE									
	28.9%	28.9%	Team Lead - Finance	Q2 16	Q2 20	Q2 16	Q2 20					
	30.5%	39.5%	FINANCE - FIRST POWER PREPARDNESS									
	30.6%	39.0%	LTCo (Budgets, Asset Records, Operational Structures & Setup)	Q2 16	Q1 18	Q2 16	Q1 18	P2	Q3 18 LIL In Service Minus 1 mth	Q3 18	61	Process
	30.6%	39.0%	LILGPCo (Budgets, Asset Records, Operational Structures & Setup)	Q2 16	Q1 18	Q2 16	Q1 18	P3	Q3 18 LIL In Service Minus 1 mth	Q3 18	61	Process
	25.0%	57.3%	MFCo (Budgets)	Q4 16	Q4 17	Q2 16	Q3 17	P4	Q3 18 LIL In Service Minus 1 mth	Q3 18	241	Process
	1.8%	3.5%	BTPO: FINANCE - FULL POWER PREPARDNESS									
	6.3%	12.0%	LTCo	Q2 17	Q2 18	Q2 17	Q2 18	P2				Process
	0.0%	0.0%	LILGPCo	Q3 17	Q3 18	Q3 17	Q3 18	P3				Process
	0.0%	0.0%	MFCo	Q1 18	Q1 19	Q1 18	Q1 19	P4				Process
	2.4%	2.0%	BTPO: EMERGENCY RESPONSE AND RESTORATION SCOPE									
	7.0%	6.0%	BTPO: EMERGENCY RESPONSE & RESTORATION - FIRST POWER PREPARDNESS									
	1.1%	0.0%	Soldier's Pond (Risk Assessment & Response Strategy)	Q3 17	Q1 18	Q3 17	Q1 18	P3	Q1 18 SOPTS & SOPCS In Service	Q1 18	-8	Processes
ERR Lead	5%	0.0%	Identify operational risks	Q3 17	Q4 17	Q3 17	Q4 17					
ERR Lead		0.0%	Determine and secure options to leverage Hydro & GE Construction Team	Q3 17	Q4 17	Q3 17	Q4 17					
ERR Lead		0.0%	Develop & Document the Response Strategy	Q4 17	Q1 18	Q4 17	Q1 18					
	12.2%	11.3%	Overland Transmission (Risk Assessment & Response Strategy)	Q2 17	Q1 18	Q2 17	Q1 18	P3	Q3 18 LIL In Service	Q3 18	160	Processes
BTPO Mgr	100%	86.8%	Develop, release and award contract to preferred contractor	Q2 17	Q3 17	Q2 17	Q3 17					
			Develop the OHTL Response Strategy	Q3 17	Q1 18	Q3 17	Q1 18					
EPLA		100.0%	EPLA - KickOff	Q3 17	Q3 17	Q3 17	Q3 17					
EPLA		0.0%	EPLA - Complete Site Visit and Risk Workshop	Q3 17	Q3 17	Q3 17	Q3 17					

Resources	Actual UPDATE GREEN %'s	Expected	WBS L1 / WBS L2 / WBS L3 / WBS L4	Baseline Start Date (Q)	Baseline End Date (Q)	Actual/Forecast Start Date (Q)	Actual/Forecast End Date (Q)	Project Priority	Critical Path	LCP In Service Date (Q)	Float Watch	people/ process/ system/ delivery
EPLA		0.0%	EPLA - Deliver Risk Severity Matrix	Q3 17	Q3 17	Q3 17	Q3 17					
EPLA		0.0%	EPLA - Design Solutions & Present/Select Repair Approach	Q3 17	Q4 17	Q3 17	Q4 17					
EPLA		0.0%	EPLA - Develop and Deliver ERP and Incident Response Plan	Q4 17	Q1 18	Q4 17	Q1 18					
	1.1%	0.0%	**SOBI-Marine Cable (Risk Assessment & Response Strategy)**	**Q3 17**	**Q1 18**	**Q3 17**	**Q1 18**	**P3**	**Q3 18 LIL In Service**	**Q3 18**	**121**	**Processes**
ERR Lead	5%	0.0%	Identify operational risks	Q3 17	Q4 17	Q3 17	Q4 17					
ERR Lead		0.0%	Develop & Document the Response Strategy	Q4 17	Q1 18	Q4 17	Q1 18					
	0.0%	0.0%	**BTPO: EMERGENCY RESPONSE & RESTORATION - FULL POWER PREPARDNESS / POST CONSTRUCTION**									
	0.0%	0.0%	**Soldier's Pond (Switchyard, Converter Station & Sync Plant)**	**Q2 18**	**Q4 18**	**Q2 18**	**Q4 18**	**P3**				**Processes**
ERR Lead		0.0%	Develop overall ERM for SOP (site-specific)	Q2 18	Q4 18	Q2 18	Q4 18					
ERR Lead		0.0%	Determine Fire/Emergency Response capability (contract/internal)	Q2 18	Q4 18	Q2 18	Q4 18					
ERR Lead		0.0%	Contract for provision of fire suppression/fire alarm maintenance	Q2 18	Q4 18	Q2 18	Q4 18					
ERR Lead		0.0%	Emergency services tested and validated	Q2 18	Q4 18	Q2 18	Q4 18					
	0.0%	0.0%	**Overland Transmission**	**Q1 18**	**Q3 18**	**Q1 18**	**Q3 18**	**P3**				**Processes**
ERR Lead		0.0%	Develop overall ERM for HVDC (site-specific)	Q1 18	Q3 18	Q1 18	Q3 18					
ERR Lead		0.0%	Emergency work at the crew level	Q1 18	Q3 18	Q1 18	Q3 18					
	0.0%	0.0%	**SOBI-Marine Cable**	**Q1 18**	**Q3 18**	**Q1 18**	**Q3 18**	**P3**				**Processes**
ERR Lead		0.0%	Spare cable, storage identified, vessels requirements etc	Q1 18	Q3 18	Q1 18	Q3 18					
ERR Lead		0.0%	Develop overall ERM document for SOBI (site-specific)	Q1 18	Q3 18	Q1 18	Q3 18					
	0.0%	0.0%	**MF Generation**	**Q3 18**	**Q4 19**	**Q3 18**	**Q4 19**	**P4**				**Processes**
ERR Lead		0.0%	Identify operational risks	Q3 18	Q4 18	Q3 18	Q4 18					
ERR Lead		0.0%	Develop overall ERM document for MF (site-specific)	Q4 18	Q3 19	Q4 18	Q3 19					
ERR Lead		0.0%	Fire/Emergency Response capability determined (contract/internal)	Q3 19	Q4 19	Q3 19	Q4 19					
ERR Lead		0.0%	Contract for provision of fire suppression/fire alarm maintenance	Q3 19	Q4 19	Q3 19	Q4 19					
	0.0%	0.0%	**Emergency Response Plans - Post Construction Demobilization**	**Q2 18**	**Q1 19**	**Q2 18**	**Q1 19**	**P3**				**Processes**
ERR Lead		0.0%	ERMs written and communicated	Q2 18	Q1 19	Q2 18	Q1 19					
ERR Lead		0.0%	Support agencies "engaged"/contractors	Q2 18	Q1 19	Q2 18	Q1 19					
ERR Lead		0.0%	Incorporated with Corporate Emergency Response Plan (CERP)	Q2 18	Q1 19	Q2 18	Q1 19					
ERR Lead		0.0%	Have tested highest exposure(s)	Q2 18	Q1 19	Q2 18	Q1 19					
ERR Lead		0.0%	Permits issued from NL agencies (where applicable)	Q2 18	Q1 19	Q2 18	Q1 19					
ERR Lead		0.0%	Supporting resources/equipment acquired	Q2 18	Q1 19	Q2 18	Q1 19					
	36.7%	37.2%	**BTPO: O&M CONTRACTS SCOPE**									
	58.8%	59.6%	**BTPO: O&M CONTRACTS - FIRST POWER PREPARDNESS**									
	65.3%	66.4%	**Operational & Maintenance Contracts (HVdc Expertise, NLH/CF Service Contracts)**	**Q4 16**	**Q4 17**	**Q3 16**	**Q4 17**	**P3**				**Systems**
BTPO Mgr	75%	65.0%	O&M GE GRID (Converter Stations, GIS, Sync Plant)	Q4 16	Q4 17	Q3 16	Q4 17	P3	**Q3 18 LIL In Service**	**Q3 18**	**181**	Systems
BTPO Mgr	60%	65.0%	O&M ATCO (Operations, Maintenance, Support, Mentoring)	Q4 16	Q4 17	Q1 17	Q4 17	P3	**Q3 18 LIL In Service**	**Q3 18**	**181**	Systems

Resources	Actual UPDATE GREEN %'s	Expected		WBS L1	WBS L2	WBS L3	WBS L4	Baseline Start Date (Q)	Baseline End Date (Q)	Actual/Forecast Start Date (Q)	Actual/Forecast End Date (Q)	Project Priority	Critical Path	LCP In Service Date (Q)	Float Watch	people/ process/ system/ delivery
BTPO Mgr	65%	80.6%				Service Contract NLH		Q1 17	Q3 17	Q1 17	Q4 17	P3	**Q1 18 SOPTS & SOPCS In Service**	**Q1 18**	**22**	Systems
BTPO Mgr	50%	58.6%				Service Contract CF		Q1 17	Q4 17	Q1 17	Q4 17	P3	**Q4 17 LTA In Service**	**Q4 17**	**-8**	Systems
	27.0%	**26.1%**			**Maintenance Support Contracts (Key Maintenance Contracts)**			**Q3 16**	**Q1 18**	**Q3 16**	**Q1 18**	**P3**	**Q3 18 LIL In Service**	**Q3 18**	**91**	**Systems**
BTPO Mgr	100%	100.0%				SOBI Cable Storage		Q3 16	Q2 17	Q3 16	Q2 17	P3				Systems
Contacts Lead		0.0%				Fibre Repair & Splice		Q3 17	Q1 18	Q3 17	Q1 18	P3				Systems
BTPO Mgr	80%	74.3%				Gases		Q1 17	Q3 17	Q1 17	Q3 17	P3				Systems
Contacts Lead		0.0%				Trash Removal		Q3 17	Q1 18	Q3 17	Q1 18	P3				Systems
Contacts Lead		0.0%				Fire Panels, Alarms, Supression		Q3 17	Q1 18	Q3 17	Q1 18	P3				Systems
Contacts Lead		0.0%				Snow Clearing		Q3 17	Q1 18	Q3 17	Q1 18	P3				Systems
Contacts Lead		0.0%				Janitorial		Q3 17	Q1 18	Q3 17	Q1 18	P3				Systems
	0.0%	**0.0%**		**BTPO: O&M CONTRACTS - FULL POWER PREPARDNESS**												
	0.0%	**0.0%**			**Maintenance Support Contracts**			**Q3 17**	**Q2 20**	**Q3 17**	**Q2 20**	**P3**				**Systems**
Contacts Lead		0.0%				Diesel Generators		Q3 17	Q1 18	Q3 17	Q1 18	P3				Systems
Contacts Lead		0.0%				Communications & Security		Q3 17	Q1 18	Q3 17	Q1 18	P3				Systems
Contacts Lead		0.0%				Site Manned Security		Q3 17	Q2 18	Q3 17	Q2 18	P3				Systems
Contacts Lead		0.0%				Road Mtn (Access Roads)		Q3 17	Q2 18	Q3 17	Q2 18	P3				Systems
Contacts Lead		0.0%				Road Mtn (Right of Way)		Q3 17	Q1 19	Q3 17	Q1 19	P4				Systems
Contacts Lead		0.0%				Pest Control		Q3 17	Q2 18	Q3 17	Q2 18	P3				Systems
Contacts Lead		0.0%				Trucking & Transportation		Q3 17	Q2 18	Q3 17	Q2 18	P3				Systems
Contacts Lead		0.0%				SOBI Cable (ROV, Diving)		Q3 17	Q2 18	Q3 17	Q2 18	P3				Systems
Contacts Lead		0.0%				SOBI Cable (Storage Equipment)		Q3 17	Q2 19	Q3 17	Q2 19	P4				Systems
Contacts Lead		0.0%				Elevator		Q3 17	Q4 18	Q3 17	Q4 18	P4				Systems
Contacts Lead		0.0%				Inventory		Q3 17	Q2 18	Q3 17	Q2 18	P4				Systems
Contacts Lead		0.0%				Crane & Hoist		Q3 17	Q2 18	Q3 17	Q2 18	P3				Systems
Contacts Lead		0.0%				HVAC		Q3 17	Q1 18	Q3 17	Q1 18	P3				Systems
Contacts Lead		0.0%				Pressure Vessels		Q3 17	Q2 18	Q3 17	Q2 18	P3				Systems
Contacts Lead		0.0%				Oil Removal		Q3 17	Q2 18	Q3 17	Q2 18	P3				Systems
Contacts Lead		0.0%				Vehicle Maintenance		Q3 17	Q2 19	Q3 17	Q2 19	P4				Systems
Contacts Lead		0.0%				Helicopter Service		Q3 17	Q2 19	Q3 17	Q2 19	P4				Systems
Contacts Lead		0.0%				Fish Monitoring		Q3 17	Q2 19	Q3 17	Q2 19	P4				Systems
Contacts Lead		0.0%				Overhead Doors		Q3 17	Q2 20	Q3 17	Q2 20	P4				Systems
Contacts Lead		0.0%				Vegetation Management		Q3 17	Q2 20	Q3 17	Q2 20	P4				Systems
Contacts Lead		0.0%				Dams & Dykes		Q3 17	Q2 20	Q3 17	Q2 20	P4				Systems
Contacts Lead		0.0%				Office Space 33 Corp EES		Q3 17	Q1 18	Q3 17	Q1 18	P3				Systems
Contacts Lead		0.0%				Office Space 40 Eng EES		Q3 17	Q1 18	Q3 17	Q1 18	P3				Systems
Contacts Lead		0.0%				Office Space Ops Staff		Q3 17	Q1 18	Q3 17	Q1 18	P3				Systems
Contacts Lead		0.0%				Other		Q3 17	Q2 20	Q3 17	Q2 20	P3				Systems
	1.2%	**1.3%**		**BTPO: INVENTORY AND SPARES SCOPE**												
	3.8%	**4.0%**		**BTPO: INVENTORY - FIRST POWER PREPARDNESS**												

Resources	Actual UPDATE GREEN %'s	Expected		WBS L1	WBS L2	WBS L3	WBS L4	Baseline Start Date (Q)	Baseline End Date (Q)	Actual/Forecast Start Date (Q)	Actual/Forecast End Date (Q)	Project Priority	Critical Path	LCP In Service Date (Q)	Float Watch	people/ process/ system/ delivery
	3.8%	**4.0%**			**Interim Inventory & Spares Storage Arrangements**			**Q1 17**	**Q1 18**	**Q1 17**	**Q1 18**	**P3**	**Q3 18 LIL In Service**	**Q3 18**	**91**	**Systems**
BTPO Mgr	75%	80.6%				Perform Foundational Assessment for Interim Arrangements		Q1 17	Q3 17	Q1 17	Q3 17					
Spares Lead		0.0%				Review existing construction storage locations		Q3 17	Q1 18	Q3 17	Q1 18					
Spares Lead		0.0%				Catalog existing infrastructure in terms of attributes		Q1 18	Q1 18	Q1 18	Q1 18					
Spares Lead		0.0%				Secure interim storage arrangements (plans/facilities) for inventory/spares in each loc		Q1 18	Q1 18	Q1 18	Q1 18					
	3.8%	**4.0%**			**Long Term Inventory & Spares Storage Arrangements**			**Q1 17**	**Q1 18**	**Q1 17**	**Q1 18**	**P4**	**Q3 18 LIL In Service**	**Q3 18**	**91**	**Systems**
Spares Lead	75%	80.6%				Perform Foundational Assessment for Long Term Arrangements		Q1 17	Q3 17	Q1 17	Q3 17					
Spares Lead		0.0%				Obtain recommendations on spares storage for SOP from GE		Q3 17	Q4 17	Q3 17	Q4 17					
Spares Lead		0.0%				Develop recommendations/options for the long term		Q4 17	Q1 18	Q4 17	Q1 18					
	0.0%	**0.0%**		**BTPO: INVENTORY - FULL POWER PREPARDNESS**												
	0.0%	**0.0%**			**Long Term Inventory & Spares Storage Arrangements**			**Q1 18**	**Q4 19**	**Q1 18**	**Q4 19**	**P4**				**Systems**
Spares Lead		0.0%				Develop & Document Storage Strategy for Churchill Falls		Q1 18	Q2 18	Q1 18	Q2 18					
Spares Lead		0.0%				Develop & Document Storage Strategy for LTA		Q1 18	Q2 18	Q1 18	Q2 18					
Spares Lead		0.0%				Develop & Document Storage Strategy for LIL (Island)		Q1 18	Q3 18	Q1 18	Q3 18					
Spares Lead		0.0%				Develop & Document Storage Strategy for LIL (Labrador)		Q1 18	Q3 18	Q1 18	Q3 18					
Spares Lead		0.0%				Develop & Document Storage Strategy for SOBI		Q1 18	Q3 18	Q1 18	Q3 18					
Spares Lead		0.0%				Develop & Document Storage Strategy for Soldiers Pond		Q1 18	Q3 18	Q1 18	Q3 18					
Spares Lead		0.0%				Develop & Document Storage Strategy for Telecom		Q1 18	Q3 18	Q1 18	Q3 18					
Spares Lead		0.0%				Analyze potential long term storage locations beyond existing locations		Q1 18	Q3 18	Q1 18	Q3 18					
Spares Lead		0.0%				Develop & Document Storage Strategy for Muskrat Falls		Q2 18	Q4 19	Q2 18	Q4 19					
Spares Lead		0.0%				Preservation routines for capital spares		Q2 18	Q4 19	Q2 18	Q4 19					
	1.8%	**1.9%**		**BTPO: WORK PROTECTION & SAFETY SCOPE**												
	1.8%	**1.9%**			**Work Protection & Safety**			**Q1 17**	**Q4 19**	**Q1 17**	**Q4 19**	**P2**				**Process**
Safety Lead	75%	80.6%				Perform Foundational Activities for Work Protection & Safety for First Power		Q1 17	Q3 17	Q1 17	Q3 17	**P3**	**Q1 18 SOPTS & SOPCS In Service Minus 4 mths**	**Q1 18**	**22**	**Process**
Safety Lead	0%	0.0%				Limits of Approach		Q3 17	Q4 18	Q3 17	Q4 18	**P3**				**Process**
Safety Lead	0%	0.0%				Live Line Work Ready		Q3 17	Q4 19	Q3 17	Q4 19	**P3**				**Process**
Safety Lead	0%	0.0%				Electronic Work Protection		Q3 17	Q4 18	Q3 17	Q4 18	**P3**				**Process**
Safety Lead	0%	0.0%				Haz Ops (converters,GIS stations,sync plant, +20m heights)		Q3 17	Q4 18	Q3 17	Q4 18	**P4**				**Process**
Safety Lead	0%	0.0%				WHIMIS Standard/Labelling (Assessments for all Sites)		Q3 17	Q3 19	Q3 17	Q3 19	**P4**				**Process**
Safety Lead	0%	0.0%				Evacuation Plans (Developed for all Sites)		Q3 17	Q4 19	Q3 17	Q4 19	**P4**				**Process**
Safety Lead	0%	0.0%				Operations First Aid Readiness (Assessment completed for all Sites)		Q3 17	Q3 19	Q3 17	Q3 19	**P4**				**Process**
Safety Lead	0%	0.0%				Integrate Emergency Response Plans into CERP (all sites)		Q3 17	Q3 19	Q3 17	Q3 19	**P4**				**Process**
Safety Lead	0%	0.0%				Special Safety Systems (Developed for all Sites)		Q3 17	Q3 19	Q3 17	Q3 19	**P4**				**Process**

	% Complete					Baseline (by Q)		Forecast (by Q)						
Resources	Actual UPDATE GREEN %'s	Expected	WBS L1	WBS L2	WBS L3	Baseline Start Date (Q)	Baseline End Date (Q)	Forecast (by Q)	Actual/Forecast End Date (Q)	Project Priority	Critical Path	LCP In Service Date (Q)	Float Watch	people/ process/ system/ delivery
	72.5%	**82.2%**	RFCI SCOPE											
	51.2%	**51.2%**		**RFCI Governance & Oversight**		**Q1 16**	**Q4 18**	**Q1 16**	**Q4 18**	**P4**				**Process**
RFCI Mgr	51.2%	51.2%			Mgmt, Mtgs, Reporting, Review for RFCI Lead	Q1 16	Q4 18	Q1 16	Q4 18					
	76.6%	**88.0%**		**Agreements - Sumamry Level (Commercial, Regulatory, Open Acess, Legislative)**		**Q1 15**	**Q4 18**	**Q1 15**	**Q4 19**	**P4**				**Process**
RFCI Mgr	**79.3%**	98.2%			**Commercial - Generation Production Optimization**	**Q1 15**	**Q4 18**	**Q1 15**	**Q4 19**	**P4**				**Process**
RFCI Mgr	**88.7%**	99.6%			**Emera Agreements**	**Q2 15**	**Q4 18**	**Q2 15**	**Q4 18**	**P4**				**Process**
RFCI Mgr	**63.5%**	60.0%			**Government Legislation Support**	**Q1 15**	**Q3 17**	**Q1 15**	**Q2 18**	**P4**	**Q3 18 LIL In Service**	**Q3 18**	1	**Process**
RFCI Mgr	**96.8%**	98.0%			**Rates & Regulatory Preparation**	**Q1 15**	**Q4 17**	**Q1 15**	**Q3 17**	**P4**	**Q3 18 LIL In Service**	**Q3 18**	271	**Process**
RFCI Mgr	**81.4%**	99.8%			**Transmission Regime and Open Access**	**Q1 15**	**Q3 17**	**Q1 15**	**Q4 17**	**P4**	**Q3 18 LIL In Service**	**Q3 18**	181	**Process**
RFCI Mgr	**2.5%**	19.0%			**CF Commercial Arrangements**	**Q3 17**	**Q3 17**	**Q3 17**	**Q3 17**	**P4**	**Q3 18 LIL In Service**	**Q3 18**	271	**Process**
	76.6%	**88.0%**		**Agreement Listing (from RFCI Mgr deliverables listing)**		**Q1 15**	**Q4 18**	**Q1 15**	**Q4 19**	**P4**				**Process**
RFCI Mgr	20.0%	100.0%			Power Supply Power Purchase and Optimization Agreement	Q1 15	Q4 15	Q1 15	Q2 18					
RFCI Mgr	75.0%	100.0%			Heads of Agreement - Power Supply Power Purchase and Optimization Agreement	Q4 15	Q1 16	Q4 15	Q3 17					
RFCI Mgr	100.0%	100.0%			Metering and Measuring Standards - Transmission Losses	Q2 15	Q4 15	Q2 15	Q3 15					
RFCI Mgr	75.0%	100.0%			Regulation Service Agreement	Q2 15	Q3 15	Q2 15	Q4 17					
RFCI Mgr	100.0%	100.0%			Strike Interconnection Operators Committee - mandate to deliver IOA related deliverables	Q2 15	Q1 15	Q2 15	Q1 16					
RFCI Mgr	99.0%	100.0%			IOA - ML Transmission Procedures	Q2 15	Q2 16	Q2 15	Q3 17					
RFCI Mgr	85.0%	100.0%			IOA - Reserve Sharing Agreement / Arrangement	Q2 15	Q3 15	Q2 15	Q3 17					
RFCI Mgr	99.0%	100.0%			IOA - Description of Interconnection Facilities	Q2 15	Q2 16	Q2 15	Q3 17					
RFCI Mgr	99.0%	100.0%			IOA - Functional Operating Relationship	Q2 15	Q2 16	Q2 15	Q3 17					
RFCI Mgr	70.0%	100.0%			IOA - Operating Instructions	Q2 15	Q2 16	Q2 15	Q3 17					
RFCI Mgr	100.0%	100.0%			IOA - Participation in Reliability Assessment Program (Transmission)	Q2 15	Q2 16	Q2 15	Q3 17					
RFCI Mgr	10.0%	0.0%			IOA - Participation in Reliability Assessment Program (Generation)	Q2 18	Q4 18	Q2 18	Q4 18					
RFCI Mgr	95.0%	100.0%			ML TSA Scheduling Process	Q2 16	Q2 16	Q2 16	Q3 17					
RFCI Mgr	30.0%	100.0%			Develop Scheduling Protocol - MF PPA	Q4 15	Q1 17	Q4 15	Q3 17					
RFCI Mgr	0.0%	0.0%			Determination of Service Life of LIL by PUB or Authorized Authority (per LIL Partnership Agreement)	Q1 18	Q4 18	Q1 18	Q4 18					
RFCI Mgr	75.0%	100.0%			Pre-Muskrat Falls Power Arrangements with Hydro	Q4 15	Q2 16	Q4 15	Q4 17					
RFCI Mgr	100.0%	100.0%			Commercial arrangement to access power - Nova Scotia - for 2017 prior to in-service of Muskrat and upon in-service of new transmission	Q4 15	Q3 16	Q4 15	Q2 17					
RFCI Mgr	100.0%	100.0%			Identification of Operational Accountability (RFCI Agreements)	Q4 15	Q1 16	Q4 15	Q2 16					
RFCI Mgr	100.0%	100.0%			Assign Execution Accountables for RFCI Deliverables	Q4 15	Q2 16	Q4 15	Q2 16					
RFCI Mgr	80.0%	88.6%			Compliance Action List - MPPA, AIA and TOA	Q1 17	Q3 17	Q1 17	Q3 17					
RFCI Mgr	100.0%	100.0%			NERC/NPCC MOU Decision	Q3 15	Q2 16	Q3 15	Q2 16					
RFCI Mgr	50.0%	100.0%			NERC - Gap analysis and gap closure plan	Q2 15	Q2 15	Q2 15	Q2 17					
RFCI Mgr	100.0%	100.0%			C.A. Energy Review of Nalcor contract package	Q1 15	Q2 15	Q1 15	Q2 15					
RFCI Mgr	100.0%	100.0%			C.A. Energy illustration of transmission transactions	Q2 15	Q2 15	Q2 15	Q4 16					
RFCI Mgr	100.0%	100.0%			Marginal Cost Study - Part 1	Q3 15	Q4 15	Q3 15	Q4 15					
RFCI Mgr	100.0%	100.0%			Marginal Cost Study - Part 2	Q1 16	Q1 16	Q1 16	Q1 16					
RFCI Mgr	100.0%	100.0%			COS Methodology Study	Q4 15	Q1 16	Q4 15	Q1 16					
RFCI Mgr	100.0%	100.0%			Rate Design Review	Q1 16	Q2 16	Q1 16	Q2 16					
RFCI Mgr	100.0%	100.0%			Supply Cost Recovery Mechanisms Report	Q1 16	Q2 16	Q1 16	Q2 16					

Resources	Actual UPDATE GREEN %'s	Expected		WBS L1	WBS L2	WBS L3	Baseline Start Date (Q)	Baseline End Date (Q)	Forecast (by Q)	Actual/Forecast End Date (Q)	Project Priority	Critical Path	LCP In Service Date (Q)	Float Watch	people/ process/ system/ delivery
RFCI Mgr	100.0%	100.0%				Modeling - postage stamp rates	Q1 15	Q2 15	Q1 15	Q2 16					
RFCI Mgr	85.0%	100.0%				NL Transmission Planning Program	Q1 16	Q4 16	Q1 16	Q3 17					
RFCI Mgr	100.0%	100.0%				NL System Performance Standards	Q1 16	Q4 16	Q1 16	Q4 16					
RFCI Mgr	100.0%	100.0%				Asset Interconnection Agreement - Emera, NLH as Transmission Owner	Q1 15	Q1 15	Q1 15	Q2 15					
RFCI Mgr	100.0%	100.0%				Multi-Party Pooling Agreement	Q1 15	Q1 15	Q1 15	Q2 15					
RFCI Mgr	100.0%	100.0%				Letters for transmission owners to join MPPA	Q4 15	Q4 15	Q4 15	Q4 16					
RFCI Mgr	100.0%	100.0%				Confirmation of Operating Procedures - Existing Transmission System	Q2 15	Q2 15	Q2 15	Q4 15					
RFCI Mgr	100.0%	100.0%				Transmission Operating Agreement (NL)	Q1 15	Q1 15	Q1 15	Q2 15					
RFCI Mgr	90.0%	100.0%				NL Interconnection Agreement #1	Q3 15	Q1 16	Q3 15	Q3 17					
RFCI Mgr	10.0%	100.0%				NL Interconnection Agreement #2	Q3 15	Q1 16	Q3 15	Q3 17					
RFCI Mgr	0.0%	100.0%				NL Interconnection Agreement #3	Q3 15	Q1 16	Q3 15	Q4 17					
RFCI Mgr	99.0%	100.0%				Transmission Service Agreement #1	Q2 15	Q3 15	Q2 15	Q3 17					
RFCI Mgr	100.0%	100.0%				Transmission Service Agreement #2	Q2 15	Q3 15	Q2 15	Q2 15					
RFCI Mgr	100.0%	100.0%				Transmission Service Agreement #3	Q2 15	Q3 15	Q2 15	Q2 15					
RFCI Mgr	99.0%	100.0%				Transmission Service Agreement #4	Q2 15	Q3 15	Q2 15	Q3 17					
RFCI Mgr	100.0%	100.0%				Letter to CF(L)Co requesting participation in the MPPA	Q4 15	Q4 15	Q4 15	Q1 16					
RFCI Mgr	70.0%	100.0%				NLH system of accounts to account for NLSO costs and establish allocators for G&A costs	Q1 16	Q2 16	Q1 16	Q3 16					
RFCI Mgr	10.0%	87.5%				Interconnection Operators Agreement - HQ and NLH	Q1 16	Q3 17	Q1 16	TBD					
RFCI Mgr	30.0%	100.0%				Execution of MPPA (Tx SPVs)	Q1 17	Q2 17	Q1 17	Q4 17					
RFCI Mgr	30.0%	100.0%				Execution of MPPA (NLH as transmission owner)	Q1 17	Q2 17	Q1 17	Q4 17					
RFCI Mgr	100.0%	100.0%				Transmission Operator Agreement	Q1 15	Q4 15	Q1 15	Q2 16					
RFCI Mgr	100.0%	100.0%				Intercompany Code of Conduct	Q2 15	Q2 16	Q2 15	Q3 17					
RFCI Mgr	60.0%	100.0%				NL System Operating Procedures	Q2 15	Q4 16	Q2 15	Q4 17					
RFCI Mgr	95.0%	100.0%				Process for Obtaining and Administering Transmission Service	Q2 15	Q2 16	Q2 15	Q3 17					
RFCI Mgr	0.0%	19.0%				Modify delivery point for recall - use of LTA wires to deliver to HVGB - commercial agreement	Q3 17	Q3 17	Q3 17	Q3 17					
RFCI Mgr	5.0%	19.0%				Exchange of letters between CF(L)Co and NLH - supply of construction power (recall) - new delivery point at CF 735Kv bus	Q3 17	Q3 17	Q3 17	Q3 17					

Resources	% Complete Actual UPDATE GREEN %'s	% Complete Expected	WBS L1	WBS L2	WBS L3	WBS L4	Baseline Dates Baseline Start Date (Q)	Baseline Dates Baseline End Date (Q)	Actual/Forecast Forecast (by Q)	Actual/Forecast Actual/Forecast End Date (Q)	Project Priority	Critical Path	LCP In Service Date (Q)	Float Watch	people/ process/ system/ delivery
	30.3%	**31.4%**	RFO SCOPE												
	44.9%	**44.9%**		**RFO Governance & Oversight**			**Q2 15**	**Q1 20**	**Q2 16**	**Q1 20**	**P2**				**Delivery**
RFO Mgr	44.9%	44.9%			Mgmt, Mtgs, Reporting, Review for RFO Lead		Q2 15	Q1 20	Q2 15	Q1 20					
	26.4%	**27.8%**		**Completions & PCS Data Loading (Commissioning, Testing, As Built Drawing Records)**			**Q1 15**	**Q1 20**	**Q1 15**	**Q1 20**	**P2**				**Delivery**
LCP Team	37.9%	48.4%			PCS Data Loading		**Q3 15**	**Q4 19**	**Q3 15**	**Q4 19**					
LCP Team	74.6%	79.1%			Completion Team (Plans, Personnel, Descriptions)		**Q2 15**	**Q4 18**	**Q2 15**	**Q4 18**					
LCP Team	60.0%	82.2%			Develop turnover process		Q3 15	Q4 17	Q3 15	Q4 17					
LCP Team	0.0%	91.6%			Prepare and issue Completions Implementation Plans for Components		Q1 15	Q3 17	Q1 15	Q3 17					
LCP Team	82.0%	36.0%			Revise Completions execution plan		Q4 16	Q4 18	Q4 16	Q4 18					
LCP Team	100.0%	100.0%			Roll out the Completion process to Alstom		Q3 15	Q1 17	Q3 15	Q1 17					
LCP Team	100.0%	100.0%			PCS Start of Contractor Rollout C3		Q4 15	Q1 17	Q4 15	Q1 17					
LCP Team	91.0%	84.8%			Prepare and issue RFP for Commissioning services contract		Q1 16	Q3 17	Q1 16	Q3 17					
LCP Team	82.0%	77.3%			Revise & Re-issue Completions & Project RFO Execution Plan		Q3 16	Q4 17	Q3 16	Q4 17					
LCP Team	85.0%	81.5%			Roll out the Completion process to Andritz		Q3 15	Q4 17	Q3 15	Q4 17					
LCP Team	76.0%	58.2%			PCS Training		Q3 15	Q4 18	Q3 15	Q4 18					
LCP Team	0.0%	0.0%			Project acceptance scope handover complete		Q4 19	Q1 20	Q4 19	Q1 20					
LCP Team	0.0%	0.0%			Verification of all O&M information & As - built delivery		Q3 19	Q1 20	Q3 19	Q1 20					
LCP Team	0.0%	0.0%			All turnovers complete ready for project acceptance		Q3 19	Q1 20	Q3 19	Q1 20					

Transition To Operations 2017 Road Map

	Q2 Objectives	Action Items	Status Notes	Overall % Complete	Q2 Delivery
SUMMARY TTO	Support completion of energization pre-requisites for SOP TS (TL217/265 & TL242/268)	Points Lists for SOP finalized; Grid Energization Plan Signed off; Commissioning plan completed and reviewed; Options for SOP station service agreed and in progress. Fencing in progress; Operating Interfaces response completed.		34.3% overall completion on plan objectives at 36.9%	Q2 objectives met
	Prepare and enable NLH team to maintain & operate SOPTS	Power Supply Collective Agreement signed; O&M org chart drafted; O&M recruitment initiated; GEGrid and ATCO service offerings for O&M support evaluated and defined; Delineation of NLH/Pwr Supply O&M responsibilities at SOP in progress; Two mechanical tech positions secured; NERC training initiated; NL Gap Closures principally on track			Q2 objectives principally met NLSO indicates ~90-95% readiness TRO indicates ~95% readiness
	Deliver Remaining Q2 TTO Outcomes	RFO on track, RFI principally on track but interfaces and NERC standards development lagging; BTPO principally on track but some team hires lagging (5 of 13 BTPO team placements secured); RFCI overall progression for Q2 outcomes partially met			Q2 outcomes for remaining TTO scope partially met.
RFO	Continue to execute and deliver objectives of the FY2017 RFO plan	Complete PCS training for 'Transmission' Team and contractors	Training completion delayed - awaiting C3 & GE completions team hiring	30.5% overall completion on plan of 31.7%	Overall RFO Q2 objectives met PCS training ongoing and pending team hires
		Re-issue Completions Execution Plan	Due to project re org this item has been moved to Q3		Overall RFO Q2 objectives met Completions execution plan to be delivered in Q3 not Q2
BTPO	Continue to execute and deliver objectives of the FY2017 BTPO plan NLH ready to maintain and operate SOP AC TS	PEOPLE: Staff BTPO Team; Ratify O&M Team & Org Chart; Staff 10% of maintenance and operations personnel	All 13 BTPO positions posted, 5 offers accepted ; 2 O&M staff placed and 18 positions posted and in active recruitment	19.8% overall completion on plan of 20.5% Plan reset for phased approach objectives and BTPO team start dates	Q2 objectives partially met (BTPO recruitment lagging)
		FINANCE: Advance 35yr/50yr LTAMP; Complete draft of O&M agreements between Nalcor and NLH and Nalcor and CF(L)Co	LTAMP: 50% completed (+10% over May) Contract: Nalcor-NLH sample O&M contract drafted.		Q2 objectives partially met (LTAMP completion in Q3, NLH/CFLCo O&M contract lagging)
		ASSETS: Complete high level asset hierarchies & sanction structure	Hierachy agreed. High Level Hierachy Completed		Q2 objectives met
		ERR: Release RFP for Overland transmission and restoration support	OHTL RFP awarded and kick-off with contractor held		Q2 objectives met
		OM&A CONTRACTS: Complete 4 of 6 contract drafts required for FY2017	One contract completed and secured, one contract principally drafted, four others at 60% draft		Q2 objectives principally met (one contract ahead of schedule, remaining 3 for Q2 in draft)
RFI	Complete RFI readiness requirements for CF Ext, CF TS2, MF TS, MF CS Complete 4 of 10 operational system studies as identified in the RFI work plan for FY2017 Complete 25% of GEP studies Initiate development of NERC Readiness Standards	STUDIES: Complete operational system studies for ML + interconnected system, CF + LTA, CF+LTA+LIL, MATPC reserve and emergency sharing & under frequency load shedding	Draft of ML only operational study delivered in June and currently under review. ML+ LIL study at 70% completion and draft expected in July	38.1% overall completion on plan of 44.2%	Q2 objectives partially met. Operational studies moved to Q3 and Q4 completion. Under frequency load shedding study moved to FY2018.
		GEP STUDIES: Complete energization system studies for CFExt, CFTS2, MF TS & MF CS	Drafts delivered in June and currently under review		Q2 objectives met
		SOD's: Complete SOD's for BBKTS, GCTTS, USLTS and MFATS2 Shunt Reactor	Completed. Note, updates will be required to all SOD's for ECC.		Q2 objectives met
		NERC: Complete 3rd party review; Define development scope; Engage contractor; Complete 50% of identified NERC adoption standards for 2017 implementation	Requisition for AESI contract signed off; Project kick-off conducted (scope review, prioritization, schedule, team, next steps)		Q2 objectives partially met (standards development lagging but expected to principally recover by Q4 based on AESI schedule
Gap Closure	Enable operational readiness for an interconnected system	Define: Systems, process, procedures Deliver training	On track	20.0% overall completion	Q2 objectives met and progress at 40% complete overall
		Other Items from Q1 (not completed)	ECC tools & reporting requirements not completed and dependant on ECC procurement/implementation		Q2 objectives pending implementation of ECC Open Access Support Tools
RFCI	Achieve 50% completion of 2017 actions related to a comprehensive strategy for implementation of open access and generation production optimization	Revise RFCI Deliverables Listing as required and establish 2017 % completion required for each deliverable to achieve objective	Completed	72.3% overall completion on plan of 81.1%	Q2 objectives met
		Complete 50% of the efforts associated with the open access initiative	Transmission regime and open access items work in progress		Q2 objectives partially met
		From Q1: Present comprehensive strategy to the Province	Meeting held June 23 to discuss preparation/schedule		Q2 objectives partially met.
	Achieve 50% completion of 2017 deliverables related to commercial agreements with Emera as specified in the RFCI Deliverables Listing	Complete Q2 planned deliverables	Progress being made but challenges exist to complete all requirements.		Q2 objectives partially met

TTO Assumptions

TTO Overall

Scope divided into a) critical requirements for first power preparedness and b) remaining activities for full power preparedness

RFI Assumptions

Studies
- GE & ABB meet delivery schedules for submission of studies to review
- Review of HQT study dependent on completion of study by HQT
- Delivery of operational studies dependent on engagement with 3rd party contractor
- Delivery of grid energization studies dependent on engagement with 3rd party contractor
- Studies subject may require amendments for unforeseen system design changes

Point Lists
- Completion of points list dependent on information provided by contractor

Grid Energization Procedures
- Delivery of GEP for HVdc components subject to supply of contractor procedures

RTDS & Simulation
- Completion of RTDS simulation dependent on contractor readiness (Series V, RTDS setup)
- Witness and verification activities dependent on contractor delivery schedule

NERC
- Delivery of NERC standards dependent on engagement with 3rd party contractor

BTPO Assumptions

Overall
- Delivery of scope dependent on recruitment of BTPO Team hires/contract resources

People
- O&M recruitment dependent on CBA, ELAC, IBA agreements
- O&M recruitment based primarily on new market hires rather than internal hires
- O&M recruitment based on interim supports from 3rd party contractors (GE Grid, ATCO)

Assets
- First power preparedness scope limited to high level hierarchies, asset criticality analysis and maintenance program for priority assets only
- Interim maintenance program based on leveraging OEM, NALCOR/NLH/CFLCo/NSP/SOBI Team routines and procedures
- Maintenance program to be executed through services contracts as an interim measure as appropriate until internal resources are hired and trained
- Asset Hierarchies dependent on receipt of requisite contractor documentation
- Interim Maintenance program dependent on receipt of OEM materials (weekly/monthly routines & procedures)
- Maintenance program dependent on availability of JDE upgrade

RFCI Assumptions

Activities managed by Nalcor/Hydro resources - dotted line reporting to TTO

RFO Assumptions

Identified scope based on functional management only