NON-CONFIDENTIAL

Request IR-1:

Exhibit N-1, p. 4, lines 21-26:
NSPML notes it anticipated Nalcor would commence delivery of the NS Block by mid-2020, but the COVID-19 pandemic caused Nalcor to estimate a further delay of six to ten months in the completion schedule and commencement of the NS Block between late 2020 and mid-2021 (Reference: NLH – Labrador Island Link Monthly Update – July 2020).

a) Please provide a copy of the July 2020 Monthly Update and the August 2020 update when available, as well as the most recent Muskrat Falls Project Oversight Committee, Quarterly Project Update.

b) Please provide an update on the status of remedial work on the Protection & Controls (P&C) Software required to operate the LIL and the synchronous condensers at Soldiers Pond. Does this work continue to be delayed by COVID-19?

c) What were NSPML's expectations of delivery of the NS Block as of March 1, 2020?

Response IR-1:

a) Copies of the requested reports, which are public, are attached to this response as Attachments 1-3.

b) An update on the status of remedial work on the P&C Software and the synchronous condensers is provided in the August 2020 update, Attachment 2, at pages 1 and 2.

c) As of March 1, 2020, NSPML was considering the potential impact of the pandemic on Nalcor's plans and whether there would be delay in delivery of the NS Block and if so whether such delay would be material, and expected a 2020 delivery as probable.

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July 24, 2020

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

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

Dear Ms. Blundon,

Re: The Liberty Consulting Group Eighth Quarterly Monitoring Report on the Integration of Power Supply Facilities to the Island Interconnected System – Monthly Update

On November 21, 2019, the Board of Commissioners of Public Utilities ("Board") requested that Newfoundland and Labrador Hydro ("Hydro") provide further information as a result of the findings in The Liberty Consulting Group's ("Liberty") Eighth Quarterly Monitoring Report on the Integration of Power Supply Facilities to the Island Interconnected System. In its response, Hydro committed to providing Liberty and the Board with a monthly status update regarding the schedule for the Labrador-Island Link ("LIL") software development and testing, updated information in response to the specific requests detailed in the Board's November 21, 2019 correspondence, and other pertinent information with respect to the Muskrat Falls Project ("Project"). Nalcor Energy ("Nalcor") has provided Hydro with the following information on various aspects of the Muskrat Falls Project.

COVID-19 Pandemic Effects on Muskrat Falls Project Execution

All Project sites are continuing to work under procedures and work methods in alignment with Project COVID-19 hazard management guidelines. Nalcor continues to assess the impact of the COVID-19 pandemic ("Pandemic") on the Project and is evaluating its consequences on Project schedule and cost. Given the duration of the COVID-19 work suspension, it is known there will be both Project schedule and cost impacts; Project completion is delayed at least four months, with the potential that final completion could be delayed an additional two to six months.[1] The Integrated Project Schedule will be updated when greater certainty on the path forward is available.

Labrador-Island Link Software Development and Testing Schedule (Board Request #2)

The Board requested the schedule for LIL software development and testing and for Hydro to advise the Board on any future changes to this schedule, the reason for the change, and the implications of any delay for delivery of power and energy to the Island Interconnected System over the LIL.

[1] "The Liberty Consulting Group Eighth Quarterly Monitoring Report on the Integration of Power Supply Facilities to the Island Interconnected System – Monthly Update," Newfoundland and Labrador Hydro,, May 26, 2020.

GE Grid commenced a second round of Factory Acceptance Testing ("FAT") for the Interim Bipole Software on July 13, 2020. FAT is expected to take 12 days. GE Grid will provide an updated schedule for Dynamic Commissioning and Trial Operations based on the outcome of the FAT. As the schedule reflected in Hydro's prior monthly reports requires updating based on the above noted information, it is not included in this report. Hydro will reflect updated schedule information in a future update once it is available.

Synchronous Condenser Binding/Vibration (Board Request #4)

The Board referenced Liberty's discussion of binding/vibration issues with the Soldiers Pond Synchronous Condensers ("SC"). The Board required Hydro to report on these two issues, including details of the problems and the investigation into their root causes, as well as a plan and schedule to address them.

GE Renewable Energy ("GE Power") is continuing to commission SC Unit 2. SC Unit 2 was successfully balanced and commissioning of the hydrogen cooling system started in late June 2020. During hydrogen filling of SC Unit 2, a sensor identified an issue and hydrogen flow was stopped. The emergency alarm and stop system worked as designed; the cause of the alarm is under investigation. To avoid unnecessary delay, commissioning of SC Unit 2 continued without hydrogen. On-Grid Load testing for SC Unit 2 was successful up to 45 MVAR. Vibration data has been collected and is being analyzed to determine if the unit can be successfully operated for extended periods.

With respect to the lateral vibration remediation work, GE Power has proposed an elliptical design modification to the bearing face that has the potential to resolve the lateral vibration issue without requiring foundation remediation. The elliptical design modification to the SC Unit 3 bearings is ongoing and the bearings and housing are scheduled to be at the Soldiers Pond Site for installation starting in mid-August 2020. Commissioning of SC Unit 3 is scheduled to start in early October 2020. If the redesigned elliptical bearings resolves the lateral vibration then the SC Unit 1 bearings will undergo the same redesign.

To mitigate any potential impact to the schedule, the foundation design work will continue while the bearing redesign work is being undertaken such that if the bearing modification proves unsuccessful, the foundation modification will proceed as scheduled. GE Power's foundation design-build contractor has started work on the design phase. A design review is planned for early August 2020 after which it is anticipated that a preliminary schedule will be provided. Nalcor will be in further contact with Liberty early next week on their outstanding foundation remediation work impact question.

Muskrat Falls Unit 1 Update

Limited construction activity resumed at Muskrat Falls in Labrador in late May 2020. Contractor mobilization has slowly ramped up their work force since restart with approximately 280 workers on site as of mid-July. Senior personnel for Andritz Hydro, the turbine and generator contractor, completed self-isolation in mid-June and resumed work in early July 2020.

The primary focus is completing all of the activities required to commission and run Unit 1. Unit 1 is presently going through mechanical commissioning tests and wet testing restarted in July 2020.

On July 8, 2020, during the Unit 1 test run, movement was noted between the radial arms of the lower bracket and the lower bracket sole plates. Commissioning was halted and a root cause analysis indicated that the radial keys did not fit snugly allowing movement which caused cracking in the weld between the keys. Redesign of the key arrangement has been completed to ensure a proper fit, as well, the weld detail between the keys has been improved. Rework has commenced and is estimated to take approximately 14 days. Due to this rework, the forecast for completion of Unit 1 commissioning and Ready for Operation[2] has moved from August 2020 into September 2020. Hydro is assessing whether this delay will impact the Muskrat Falls-Happy Valley interconnection in 2020 and expects to make a determination on this matter before the end of the third quarter 2020.

An inspection of the upstream water passage for Unit 1[3] was undertaken during the pause in wet testing, and some concrete debris was observed in the water passage. Based on its shape, it appears to be secondary concrete from the intake sill (lower sealing surface) and lintel (upper sealing surface). A remotely operated vehicle inspection was undertaken to survey the extent and location of the issue. The results of the survey have been assessed and this issue will not delay Unit 1 commissioning.

Further inspection will be undertaken during the next planned dewatering of the unit in August 2020.

If you have any questions, please contact the undersigned.

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young, Q.C.
Vice President, General Counsel & Corporate Secretary
GPY/sk

ecc: **Board of Commissioners of Public Utilities**
Jacqui Glynn
Maureen P. Green, Q.C.
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Newfoundland Power
Gerard M. Hayes
Regulatory Email

Consumer Advocate
Dennis M. Browne, Q.C., Browne Fitzgerald Morgan & Avis
Stephen F. Fitzgerald, Browne Fitzgerald Morgan & Avis
Sarah G. Fitzgerald, Browne Fitzgerald Morgan & Avis
Bernice Bailey, Browne Fitzgerald Morgan & Avis

[2] Released for service.

[3] Each of the four turbine and generating units has an intake area where the water flows through as it enters the powerhouse before reaching the turbine. Various gates are in place to provide a barrier between the river and the turbine and the gate are inserted into a gate guide so it can move up and down to let water into the intake area or to block water from entering the intake area.

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Sheryl E. Nisenbaum

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August 25, 2020

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

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

Dear Ms. Blundon,

Re: The Liberty Consulting Group Eighth Quarterly Monitoring Report on the Integration of Power Supply Facilities to the Island Interconnected System – Monthly Update

On November 21, 2019, the Board of Commissioners of Public Utilities ("Board") requested that Newfoundland and Labrador Hydro ("Hydro") provide further information as a result of the findings in The Liberty Consulting Group's ("Liberty") Eighth Quarterly Monitoring Report on the Integration of Power Supply Facilities to the Island Interconnected System. In its response, Hydro committed to providing Liberty and the Board with a monthly status update regarding the schedule for the Labrador-Island Link ("LIL") software development and testing, updated information in response to the specific requests detailed in the Board's November 21, 2019 correspondence, and other pertinent information with respect to the Muskrat Falls Project ("Project"). Nalcor Energy ("Nalcor") has provided Hydro with the following information on various aspects of the Muskrat Falls Project.

COVID-19 Pandemic Effects on Muskrat Falls Project Execution

Nalcor and its contractors continue to follow all COVID-19 Health and Safety measures as per the established guidelines. An update of the forecast schedule and estimate of costs to complete, including COVID-19 related impacts, is ongoing. An update of the Integrated Project Schedule ("IPS") and any Authorization for Expenditure updates will be complete by the end of September 2020.

Labrador-Island Link Software Development and Testing Schedule (Board Request #2)

The Board requested the schedule for LIL software development and testing and for Hydro to advise the Board on any future changes to this schedule, the reason for the change, and the implications of any delay for delivery of power and energy to the Island Interconnected System over the LIL.

Factory Acceptance Testing ("FAT") for the Interim Bipole Software concluded on July 24, 2020 followed by the release of the software to site on July 30, 2020 to commence dynamic commissioning. A number of deficiencies were identified during FAT; however, the number and severity of the deficiencies were small enough that Nalcor, in agreement with the Independent Third Party, granted GE Grid permission to send the "Release A" version of interim software to site to proceed with the next stage of on-site testing. Outstanding deficiencies identified during FAT, as well as any identified during dynamic commissioning of "Release A," that are required to be resolved before the start of trial operations will be corrected in "Release B." A schedule from GE Grid for "Release B" and start of trial operations is pending.

As part of the dynamic commissioning process, energization of Pole 2 of the LIL commenced on August 13, 2020; however, during energization, an equipment failure in the Soldiers Pond Pole 2 Valve Hall triggered a trip on the LIL. While GE Grid initially believed that the issue was limited to Pole 2 and commissioning could proceed on Pole 1, it was later discovered that the same issue appears to exist on Pole 1. LIL commissioning is paused until a root cause analysis is complete.

Synchronous Condenser Binding/Vibration (Board Request #4)

The Board referenced Liberty's discussion of binding/vibration issues with the Soldiers Pond Synchronous Condensers ("SC"). The Board required Hydro to report on these two issues, including details of the problems and the investigation into their root causes, as well as a plan and schedule to address them.

At the Soldiers Pond Synchronous Condenser Site, SC Unit 2 has been operating at low output (up to 45 MVar) since August 3, 2020 in support of LIL commissioning. Vibration data is being collected and analyzed by GE Renewable Energy ("GE Power"). Overall levels are below alarm set points at the current MVar levels. A full vibration analysis will be undertaken when commissioning loading is complete in September. The hydrogen system issue reported in July 2020 has been investigated and it has been determined that a sensor inside SC Unit 2 was not registering the correct hydrogen concentration due to its location. To finish commissioning, the unit will be taken offline at the end of August 2020 to relocate the sensor.

The elliptical bearings for SC Unit 3 have been delivered to the Soldiers Pond site. Preparation for installation is underway. It is anticipated to take approximately six weeks to complete. The bearing redesign may address the observed lateral vibration and eliminate the requirement for the foundation remediation work discussed below. Testing to determine whether this is the case will take place beginning in October 2020. If the elliptical bearings resolves the lateral vibration for SC Unit 3 then the bearings for the other units will undergo the same redesign.

With respect to the foundation remediation work intended to address the lateral vibration issue, work is ongoing in parallel with the bearing redesign work discussed above to preserve schedule to the greatest degree possible. GE consultants, Vector and SGH, completed the 25% design review phase on August 5, 2020, and presented pros and cons for the two most promising foundation remediation concepts. Based on the current design stage and selected concepts, GE has provided possible construction sequences and a range of schedule durations for the foundation remediation work, as follows:

- Three units in parallel – 21 to 25 weeks to complete;
- Three units in series – 41 to 60 weeks to complete; and
- Test one unit before proceeding with other two units – 31 to 46 weeks to complete.

The selection of a construction sequence will be based on a decision matrix that includes SC Unit 3 elliptical bearing performance, SC Unit 2 vibration analysis, LIL commissioning status, and the requirement to have synchronous condensers online for the transfer of available power from Labrador. Remediation options and schedule will be refined as the design review progresses and the key factors of the decision matrix evolve. The design review stage is scheduled to be complete in November 2020;

however, contractor mobilization can start in September 2020 upon completion of the 60% design review phase. The earliest start date for construction is October 2020.

Muskrat Falls Unit 1 Update

Andritz Hydro ("Andritz") is responsible for the turbines and generator contract. Andritz is progressing its work scope under the contract in accordance with its 2020 work plan, which was developed to respect COVID-19 conditions. Andritz has advanced commissioning of Unit 1, pre-commissioning of Unit 2, and assembly of Units 3 and 4.

Mechanical commissioning of Unit 1 has been completed with the successful 150% overspeed test on the unit. With the completion of the overspeed test, Unit 1 was dewatered for a planned inspection. The duration of the inspection is expected to be approximately two weeks and should be finished by the end of August 2020. Unit 1 commissioning is expected to resume by the end of August, with completion of Unit 1 commissioning and Ready for Operation[1] forecast for September 2020.

The issue with the Unit 1 lower bracket keys reported to the Board in July 2020 was addressed prior to completion of the 150% overspeed test. Additionally, the extent of the issue with secondary concrete of the upstream water passage for Unit 1, which was also reported in the July 2020 update, has been assessed and a repair method has been presented by Andritz. Repairs are underway.

Unit 2 pre-commissioning and dry commissioning activities, along with commissioning of the generator step-up and station service transformers, are ongoing. Water up and commencement of wet commissioning is expected in the coming weeks. Modifications to Unit 1, including rotor rim keys and lower bracket keys, have been incorporated in Unit 2 in parallel with other work. Unit 2 intake concrete will be assessed at an appropriate time during wet commissioning. Completion of Unit 2 commissioning and Ready for Operation is forecast for November 2020.

Assembly of Units 3 and 4 is ongoing. The schedules for Unit 3 and 4 are under evaluation and will be incorporated in the IPS to be updated in September 2020.

If you have any questions, please contact the undersigned.

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young, Q.C.
Vice President, General Counsel & Corporate Secretary
GPY/sk

ecc: **Board of Commissioners of Public Utilities**
Jacqui Glynn
Maureen P. Green, Q.C.
PUB Official Email

[1] Released for service.

Newfoundland Power
Gerard M. Hayes
Regulatory Email

Consumer Advocate
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Sarah G. Fitzgerald, Browne Fitzgerald Morgan & Avis
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Sheryl E. Nisenbaum

Teck Resources Limited
Shawn Kinsella

Muskrat Falls Project Oversight Committee

Quarterly Project Update

Period Ending March 31, 2020

June 15, 2020

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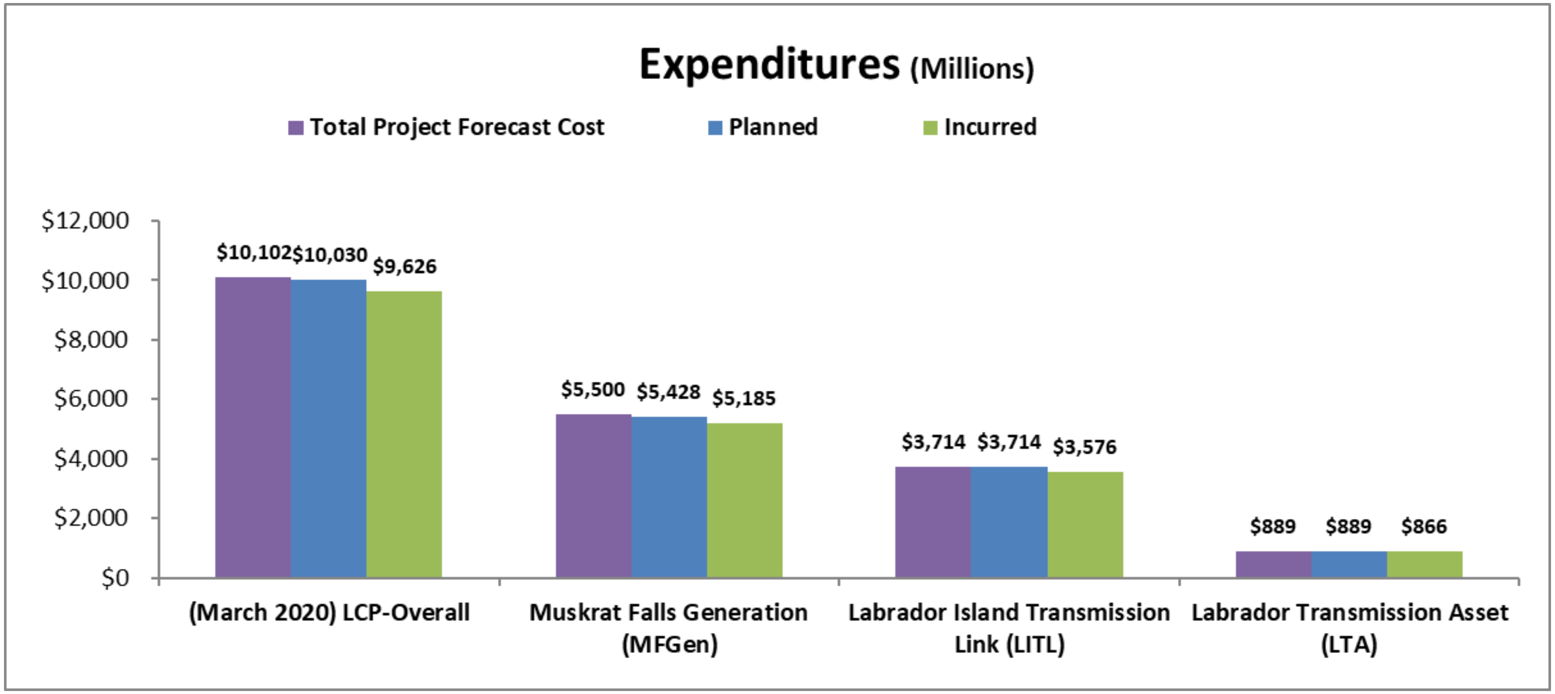
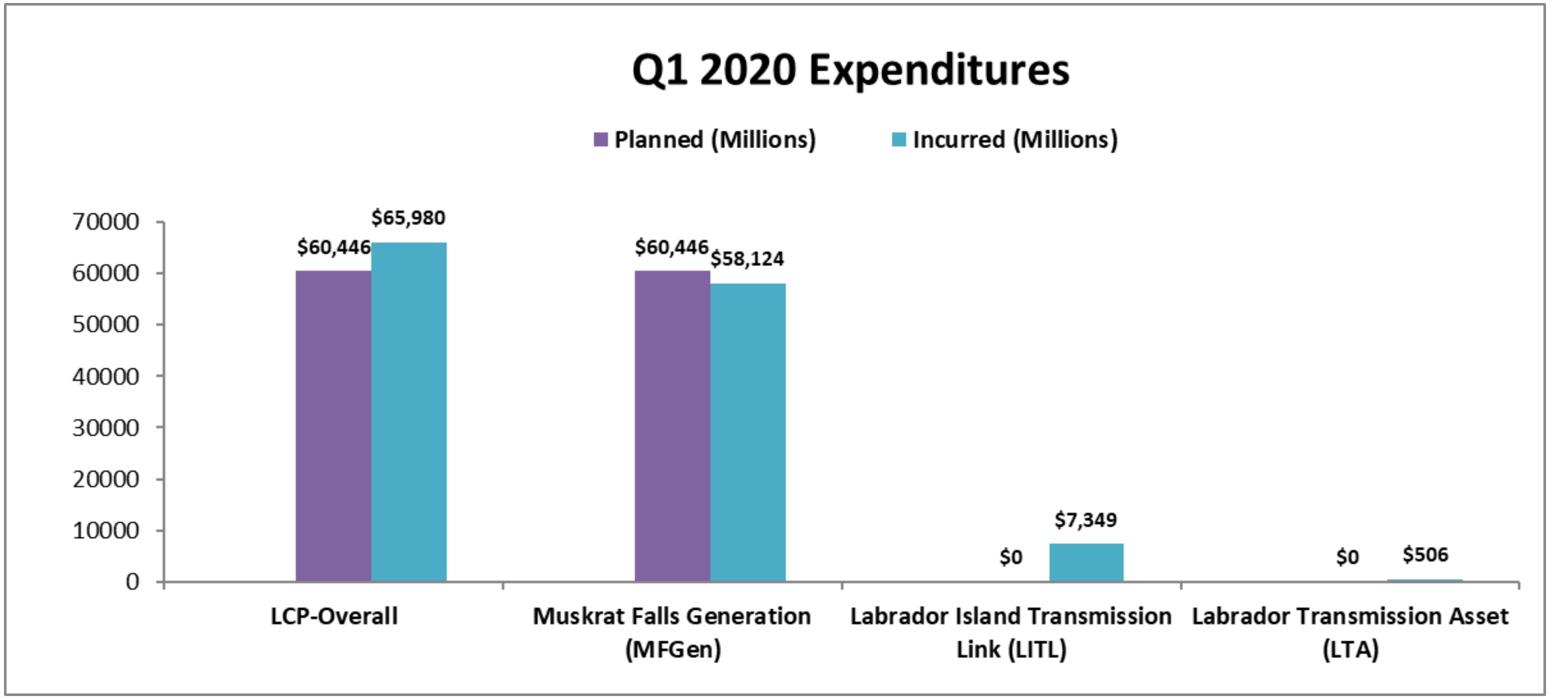
1. Q1 2020 Cumulative Costs



2. Q1 2020 Planed and Incurred Costs



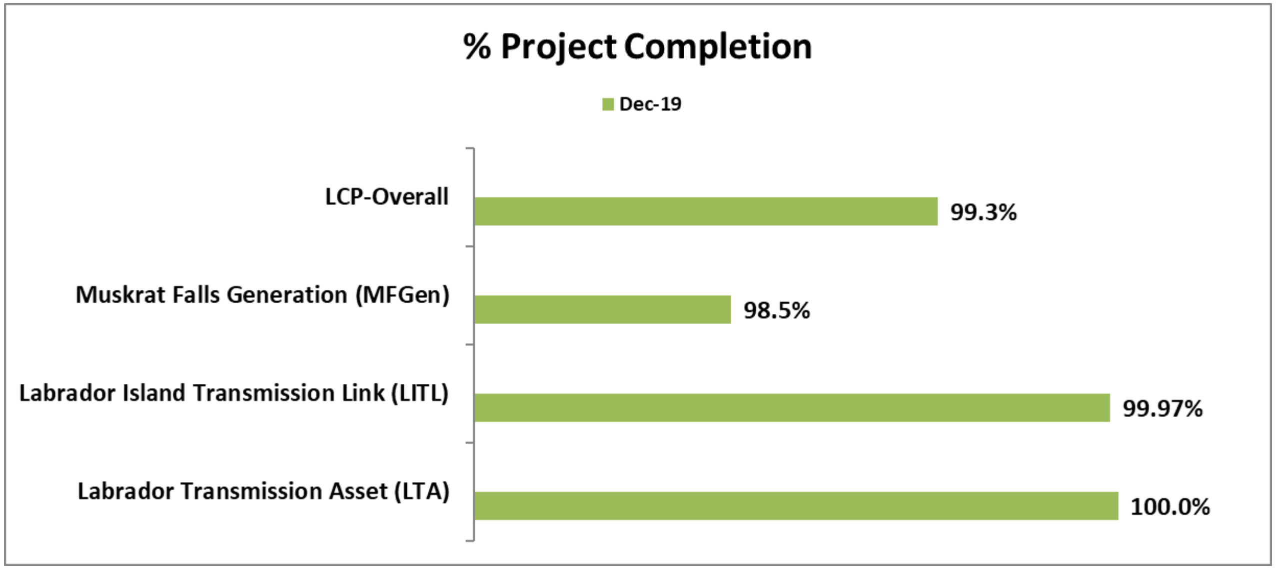
Newfoundland Labrador

3.0 Oversight Committee Reporting

3.1 Overview
3.2 Committee Activities
3.3 Independent Engineer Activities
3.4 Risks and Issues Being Monitored by the Committee
3.5 Subsequent Events to Q1 and Other Notable Activity

3.1 Overview

- The Oversight Committee (Committee) receives details on project costs incurred, schedule progress, changes in costs and milestone schedule, the status of construction, and manufacturing and installation contracts.
- The Committee identifies risks and issues and follows up with Nalcor to obtain more detail and explanation.
- This report covers the January to March 2020 period (Q1) and includes information on other notable project activity up to the date of drafting of this report.
- In December 2019, the project achieved > 99% construction complete. This progress was reported as follows:



3.1 Overview

- With earned progress overall above 99.3%, commencing in January 2020, the Project discontinued reporting earned progress and has shifted reporting to focus on remaining construction and commissioning work to be completed under remaining material contracts.
- This change impacts the reporting template for the Committee and in this report it will be noticeable that construction progress in terms of percentages complete will no longer be included.
- Reporting on planned and incurred costs will continue, however. Remaining installation and commissioning work will be reported upon by individual contracts or work activity going forward.
- Section 3 of this report contains information developed by the Committee. Section 4 contains project cost and schedule information provided by Nalcor. The Annexes contain a more detailed accounting of the information provided in this report.
- The next Committee Report will cover the period April 2020 - June 2020.

3.2 Committee Activities

- The Committee met on two occasions during the period to receive project updates and conduct other Committee business. Committee meeting minutes and reports are available on the Committee website @ Click here and Click here.
- The Committee Chair and Natural Resources Director participated as an observer in 3 monthly calls on Nalcor project reporting to the IE and NRCan and two calls with the NRCan and the IE separate from Nalcor.
- Planned visits to project sites were put on hold due to COVID-19 pandemic travel and physical distancing restrictions.

3.3 Independent Engineer Activities

- A planned March-April 2020 Muskrat Falls project site visit and Stafford HVdc protection and Controls (P&C) software development site visit were impacted by COVID-19 travel restrictions.
- Nalcor has advised that in the intervening timeframe, the Independent Engineer (IE) has been receiving project information as requested from the Nalcor and that the IE has been able to remotely observe P&C software Factory Accepted Testing (FAT) for interim bipole software. Arrangements will be made again to do so during the second phase of FAT.

3.4 Risk and Issues being Monitored by the Committee

- In its project reporting, Nalcor identifies risks which may impact project cost and schedule. The Committee reviews these and other project information to assess project risks. These risks can be found on pages 11-14 of this report.
- Over the reporting period the Committee noted:
  - The COVID-19 pandemic has resulted in the suspension of construction and commissioning work at both Muskrat Falls and Soldiers Pond in March 2020, with the sites being placed into care and maintenance mode;
  - Reservoir rim stability remained consistent over the Quarter;
  - Litigation and Arbitration proceedings continue with Astaldi;
  - Protection and Controls (P&C) software completion for the HVdc system and schedule remains a key project risk. P&C software completion has placed the LITL on the critical path for the overall project schedule. Testing has advanced from Factory System Testing (FST) to Factory Acceptance Testing (FAT);
  - Soldiers Pond synchronous condensers vibration and binding issues root cause and remediation remain ongoing. When Unit 3 bearings and housing were removed corrosion and damage was observed;
  - Official forecast completion of key milestones under the Integrated Project Schedule (IPS) have not been updated since the reporting period ending January 2020 due to the suspension of construction and commissioning work at both Muskrat Falls and Soldiers Pond in March 2020, with the sites being placed into care and maintenance mode and cessation of contractor reporting and uncertainty as to when and how operations can re-start; and
  - Nalcor/NLH preparedness for interconnection and operations following transfer of power and final completion of bipole remains a key focus area.

3.4 Risk and Issues being Monitored by the Committee

- The project is now largely in the installation, integration and static and dynamic commissioning phases which inherently carry associated risks.
- Risks that are being tracked by the Committee include:

A) Safety Performance

- Risk associated with simultaneous operations across multiple work sites, impact on project delivery particularly in the powerhouse, energized yards and other assets. This risk will continue through construction into operations.

B) Contractor Management and Productivity

- Nalcor ability to manage contractors and contractor ability to meet schedule;
- Contractor management and performance in the powerhouse;
- Potential commercial negotiations to settle claims; and
- Potential for new claims as construction nears completion.

3.4 Risk and Issues being Monitored by the Committee

C) Phased Commissioning

- Completion of P&C system to enhance functionality and reliability; associated warranty considerations with early asset handover during commissioning and completion;
- Final completion and testing of HVdc system under low and full power, in-service system reliability, and timing of contractor release and effective warranty period; and
- P&C software delivery and final commissioning completion to maintain project critical path and power delivery.

D) Astaldi

- Astaldi arbitration/litigation outcomes and potential impact on project costs.

E) Synchronous Condensers

- Remediation of vibration (Unit 3) and binding (Unit 1) issues; and new corrosion and damage issues identified this quarter on Unit 3 and potential impact on transmission project schedule.

3.4 Risk and Issues being Monitored by the Committee

F) Insurance Claims and Coverage

- Potential coverage: Preservation/re-preservation of Turbine and Generator parts - investigations ongoing - claim is still active, and resolutions are part of ongoing commercial discussions with Andritz.
- Potential coverage: Spillway secondary concrete and gate guide heater tubulars repairs – repair proposals received with some details to follow, and resumption of site activities to implement repairs are now being planned. Potential coverage still being pursued.

G) LITL and Powerhouse Commissioning

- Commissioning of LITL and powerhouse generation Units 1 through 4 and future revised schedule.

H) Reservoir Rim Stability

- Impact of reservoir full supply level on reservoir shoreline/slope stability.

I) Project Integration and Operations Readiness

- Nalcor/NLH readiness to connect the Muskrat Falls Project to the Island and North American electricity grid and operate facilities effectively.

3.4 Risk and Issues being Monitored by the Committee

J) Project Delivery Team Retention

- Project Team personnel departures and potential impact on project completion.

K) Additional Risks (above the June 2017 Project Budget)

- COVID-19 cost and schedule impacts;
- Astaldi arbitration/litigation; and
- Alternate HVdc P&C software development.
- Funds are not held within the June 2017 Project Budget for these additional risks.

3.5 Subsequent Events to Q1 2020 and Other Notable Activity

- On March 10, 2020 the Government of Newfoundland and Labrador released the Commission of Inquiry Respecting the Muskrat Falls Project Commissioner’s Report.
- In April 2020, Astaldi filed an application to amend its Statement of Claim (which Nalcor is objecting to) seeking an increase in damages claimed.
- In response to the COVID-19 Pandemic in March 2020, Nalcor declared Force Majeure under it major construction contracts and commenced the suspension of construction and commissioning work at both Muskrat Falls and Soldiers Pond in March 2020, with the sites being placed in care and maintenance mode.
- In April 2020, Nalcor declared Force Majeure under the Project Financing Agreements, the Power Purchase Agreement with Newfoundland and Labrador Hydro, the Energy and Capacity Agreement and Development Agreement with Emera.
- In March, April and May 2020, Nalcor provided the Public Utilities Board (PUB) with the Liberty Consulting Group Quarterly Monitoring Reports on the Integration of Power Supply Facilities to the Island Interconnected System – Monthly Updates.
- On May 14, 2020 the Committee Chair and Committee solicitor met with Nalcor and its external counsel to receive an update on the Astaldi arbitration.

3.5 Subsequent Events to Q1 2020 and Other Notable Activity

- In May 2020, Nalcor provided the Committee an update on potential impacts of COVID-19 and other risks on project cost and schedule as a **risk management exercise only**. **This update was not based on an updated Integrated Project Schedule (IPS).** The IPS will be updated upon return of contractors to work and progress productivity being analyzed and reported.
  - Potential milestone dates that were provided are an estimate of the impacts on schedule related to COVID-19, and other known project schedule risks (namely, HVdc P&C software development, synchronous condenser binding and vibration remediation and powerhouse units commissioning)**. These outcomes do not represent an official forecast. Significant variability and risk is associated with schedule potential outcomes.**
    - Overall, various project milestones could be delayed by approximately 4-10 months from those reported by Nalcor in the Committee's February 26, 2020 - 2019 Quarter 4 report, placing project completion beyond Date Certain (February 2021). See table on next slide for further schedule details. It is also important to note that while project completion is estimated to be 4 months beyond the current Date Certain, final high power testing of the complete bipole may not be able to be completed until fall 2021 when demand is such to transfer > 800 megawatts on the system. Nalcor advises it anticipates that each pole can likely be tested to maximum thermal rating prior to then.
- Potential capital costs associated with COVID-19 only (exclusive of costs associated with other known project risks noted above and financing and interest charges) were also estimated. **This outcome does not represent an official cost estimate. Significant variability and risk is associated with COVID-19 cost potential outcomes.**
  - Project capital costs will increase in the range of $150 to $200 million.
- Financing and Other Costs
  - Under the existing Project Financing Agreement and Transmission Funding Agreement, interest payments on bonds and AFUDC on the LITL are to be paid by ratepayers following commissioning. With commissioning not occurring now until 4 months past Date Certain, approximately $400 million in financing and other costs would be required to be funded.
- In preparation for not being able to meet the Date Certain requirements as noted above, a waiver has been granted by the Government of Canada and the Collateral Agent.

3.5 Subsequent Events to Q1 2020 and Other Notable Activity

Potential Outcomes COVID-19 and Other Schedule Risks (To be confirmed post resumption of work)

Milestone	Date - Post-COVID
Generation	
Commercial Power Unit 1	Q3 2020[1]
Commercial Power Unit 2	Q4 2020[1]
Commercial Power Unit 3	Q1 2021[1]
Commercial Power Unit 4	Q2 2021[1]
Transmission	
LIL Interim Software (trial operations complete)	Q4 2020[2]
LIL Final Software (high power testing complete)	Q2 2021[2]
SC Unit 1 Commissioned	Q2 2021[3]
SC Unit 2 Commissioned	Q2 2021[3]
SC Unit 3 Commissioned	Q1 2021[3]

[1]Includes potential late delivery of commissioned powerhouse generating units

[2]Includes potential late delivery of Interim and Final software

[3]Includes potential late delivery of synchronous condensers due to lateral vibration remediation

- Nalcor advises that a more robust cost and schedule update will be provided in Quarter 3, 2020 following the post COVID-19 work suspension and care and maintenance program and resumption of work and contractor progress reporting.

4.0 Nalcor Reporting

4.1 Summary – Quarter Ending March 2020

- March 2020 Summary:
  - Overall construction progress is at 99.3% (December 2019);
  - $9,626 Million in incurred costs; and
  - $9,681 Million in committed costs.
- As a result of the evolving COVID-19 pandemic, the Project took specific steps to ensure the health and safety of all of its workers, as well as the public, and in that regard, construction work at both the Muskrat Falls Site and the Soldiers Pond Site was paused, both Sites placed into care and maintenance mode; and the Project office at Torbay Road was closed, with majority of the Project Delivery Team working remotely from home as per guidance from the Government of Newfoundland and Labrador. A Force Majeure was declared and letters were issued to all active contractors.
- As a result of the above, the Project is unable to provide a reliable forecast date for the key milestones that have not yet been achieved in both Power Development and Power Supply; and the Integrated Project Schedule will not be updated until there is greater certainty on the path forward. The full impact on both the final forecast cost and the key schedule milestones is unknown at this time.
- A more robust cost and schedule update will be provided in Quarter 3, 2020 following the post COVID-19 work suspension and care and maintenance program and resumption of work and contractor progress reporting.

4.1 Summary – Quarter Ending March 2020

- As of March 2020, the June 2017 budget final forecast cost remains unchanged.
  - While the overall budget and final forecast cost remains unchanged, variances between the project budget and final forecast costs have occurred within and among expenditure categories. Most variances are related to the transfer of budget between allocations from the contingency budget to the procurement and construction budget. As well, there are transfers of unused budget from procurement and construction to the contingency budget to be used in other areas of the project.
  - Does not include Additional Risks as reported on slide 14, which at the end of March 2020 totaled approximately $850 Million. If these risks are realized, they may become project costs.
  - The current forecast contingency budget at March 2020 is $129.2 Million, a decrease of $5.5 Million from the previous Quarter. For further detail see Section 4.3.

4.1 Summary – Quarter Ending March 2020

Quarterly Planned vs Incurred Cost Variances:

MFGen	
Cumulative Planned: $5,428M	Q1 2020 Planned: $60M
Cumulative Incurred: $5,185M	Q1 2020 Incurred: $58M
Variance: -$242.3M (-4.5%)	Variance: $2M (-3.3%)

- Planned expenditure by month was set in June 2017.
- During Q1 2020, the variance in planned vs. incurred cost is primarily due to lower than planned incurred in March due to the site ramp down to care and maintenance mode due to the COVID-19.
- See Section 4.2 and Annex B for further detail.

4.1 Summary – Quarter Ending March 2020

Quarterly Planned vs Incurred Cost Variances:

LITL	
Cumulative Planned: $3,714M	Q1 2020 Planned: $0M
Cumulative Incurred: $3,575M	Q1 2020 Incurred: $7M
Variance: -$139 (-3.7%)	Variance: $7M

LTA	
Cumulative Planned: $889M	Q1 2020 Planned: $0M
Cumulative Incurred: $865M	Q1 2020 Incurred: $0.5M
Variance: -$24M (-2.7%)	Variance: $0.5M

- The planned expenditure by month was set in June of 2017.
- During Q1 2020, incurred was higher than planned due to extension of work scope into 2020, whereas work scope was planned to be substantially complete in 2018.
- See Section 4.2 and Annex B for further detail.

4.1 Summary – Quarter Ending March 2020

Planned vs Earned Progress:

- MFGen
  - >98.5 complete
- LITL
  - > 99% complete
- LTA
  - Complete
- See Section 4.2 and Annex C for further detail.

4.1 Summary – Quarter Ending March 2020

Power Development[1]:

Project actions in response to the COVID-19 Pandemic:

- On March 17, Construction work at the Muskrat Falls Site was paused and the Site placed into a care and maintenance mode; The project also enacted its work-from-home policy and the majority of the Project Delivery Team is working remotely from home;
- Force Majeure was declared on major contracts;
- The Muskrat Falls Site continues to operate in care and maintenance mode; 80 +- essential workers on site maintaining essential systems and operations; all workers are housed at the camp; and the site team is rotated at the completion of each turnaround; a small crew is in place to respond problems and to monitor operation of equipment;
- COVID-19 screening and monitoring measures have been implemented at the Site, including daily temperature testing of all workers, social distancing, and enhanced sanitization;
- All normal project functions and activities are working in the LCP 'virtual' project office; protocols and procedures have been implemented to facilitate safe operation of the Muskrat Falls site while operating the site in care and maintenance mode;

[1] Some actions in this and the following slide were performed since March 2020

4.1 Summary – Quarter Ending March 2020

- Since March 2020, guidelines have been developed and issued to Contractors for resuming work at the project sites during the COVID-19 pandemic; Contractors are tasked with developing site restart plans for their work scopes;
- Unit 1 commissioning is an immediate priority;
- Lack of information regarding contractor productivity and progress rates has precluded the development of a reliable forecast date for upcoming milestones; the Integrated Project Schedule (IPS) will be updated when there is greater certainty on the path forward and COVID-19 costs are being tracked;
- While Construction is paused, the CH0030 (Turbines and Generators), CH0031 (Balance of Plant), and CH0032 (Supply and Installation of Hydro-Mechanical Equipment) Contractors remain engaged and supporting the Project;
  - By ensuring all engineering issues and technical documents are complete and up to date; advancing essential administrative work and closeout activities with respect to completed work scopes; and
  - As part of the Site restart plan, timing of other priority work at site, including completion of remaining base scope, punchlist items, and site remediation scope under Contract CH0011-002; and remaining and repair work under Contract CH0032, will be assessed.

4.1 Summary – Quarter Ending March 2020

Major Contracts Status Update

Following reflects work status prior to ramp down of operations on March 17, 2020:

- Turbines and Generators

Unit	Status
1	Water up complete; wet commissioning commenced 28-Jan-2020; replacement of generator rotor rim keys complete; initial mechanical runs up to synchronous speed completed; and completion of off-line exciter and generator testing by commissioning team ongoing.
2	Rotor rim key installation complete; welding oil head piping and lower bracket sole plates installation ongoing. (88% complete)
3	Installation of runner tower assembly in pit complete; rotor assembly and air admission piping preparations ongoing and rotor rim key installation commenced. (70% complete)
4	Stator cleaning and installation of brake track plates complete; runner assembly and preparation for high potential testing ongoing; rotor rim key installation not commenced. (49% complete)

4.1 Summary – Quarter Ending March 2020

- Intake Powerhouse Transition Dams and Spillway - Remaining Construction
  - Finalization of handover documentation and demobilization ongoing; and
  - Remaining work scope - remaining base scope, punchlist items and site remediation scope - currently under review; work forecast to be executed in Summer / Fall 2020.
- Hydro Mechanical Installation
  - Base Spillway scope is complete;
  - Work necessary to enable spillway operation during Spring freshet 2020 complete; and
  - Remaining work and repair work to be completed post Spring freshet 2020.
- Balance of Plant
  - Mechanical Completion and commissioning activities throughout Powerhouse ongoing;
  - Fire detection system installation and seismic and electrical supports ongoing; and
  - Systems to support Ready to Turn Unit 2 continue as work fronts from Andritz are available.
- Arbitration with Astaldi continues; payment of Astaldi related liens against the project continues; Nalcor intends to recover any costs associated from Astaldi or the contract’s securities; in April 2020, Astaldi filed an application to amend its Statement of Claim (which Nalcor is objecting to) seeking an increase in damages claimed; witness statements have now been exchanged. Other project residual contingency, funds are not held within the June 2017 budget should net damages be awarded in Astaldi’s favour.
- Focus areas for Q2, 2020 include work restart, commissioning of Unit 1. Forecast expenditure for Q2, 2020 is estimated at approximately $60 Million.

4.1 Summary – Quarter Ending March 2020

Power Supply:

Project Actions in Response to the COVID-19 Pandemic:

- Multiple measures have been taken to protect the health and safety of workers and the public;
- On March 13, 2020, LCP declared Force Majeure on the GE Power 534 contract and the GE Grid 501 contract;
- On March 17, 2020, operations at the MF site, including the C3 yard, ramped down; it is now in care and maintenance mode;
- On March 17, 2020 Nalcor’s work-from-home policy as per its Business Continuity Plan was enacted. The project office at Torbay Road was closed and the majority of the project delivery team, with the exception of essential services at sites, are now working remotely from their homes;
- On March 28, 2020, the Soldiers Pond site ramped down operations and is now in care and maintenance mode;
- As part of the 90-day continuity plan, all non-construction project functions and activities are working from the 'virtual' project office;
- Lack of information regarding contractor productivity and progress rates has precluded the development of a reliable forecast date for upcoming milestones; and
- The Integrated Project Schedule will be updated when there is greater certainty on the path forward and COVID-19 costs are being tracked.

4.1 Summary – Quarter Ending March 2020

Project Restart Plans

- Since March, 2020 Guidelines have been developed for resuming work on all project work sites during the COVID-19 pandemic;
- The guidelines detail precautions necessary to protect the health and safety of all personnel performing work on project sites; the guidelines have been issued to contractors to assist with COVID-19 hazard management at work sites;
- Contractors are expected to amend existing, or create new, procedures and/or work methods to ensure COVID-19 hazard controls are implemented in their worker start and recovery protocols; and
- GE Power submitted a restart plan to Nalcor for work at the Soldiers Pond synchronous condenser site. Nalcor worked with GE Power to finalize their restart plan. On April 29, 2020, Nalcor provided GE Power with notice to start remobilization to site.

4.1 Summary – Quarter Ending March 2020

Protection and Controls (P&C) Transmission Bipole Software

- Software Progress During COVID-19
  - GE Grid has implemented their work from home policy for non-essential personnel; however, software development continues and a core team of personnel remain on site to support those working from home and complete testing work in the lab;
  - Nalcor and GE Grid have established a process to ensure software development;
  - Testing and witnessing continues during this period of work and travel restrictions; technology to allow remote participation is being used to enable witnessing of Factory Accepted Testing (FAT) by Nalcor and Independent Third Party (ITP) personnel;
  - To date no issues have been identified with remote participation;
  - Systematic and Amplitude continue to monitor GE Grid’s progress from their home offices in Australia and Denmark and are witnessing and reviewing test results from the FAT daily; and
  - The ITP’s next progress audit is planned for May 4, 2020.

4.1 Summary – Quarter Ending March 2020

- Bipole Status [1]
  - Onsite testing of the OCT/OLT version of software is complete; testing concluded successfully in March with minor issues noted that have either been resolved or are in the process of being resolved;
  - GE Grid has re-run all previously failed test cases for the Factory System Test (FST);
  - A number of FST test cases were unsuccessful. Nalcor and the Independent Third Parties (ITP) reviewed the FST results and GE Grid's proposed operating restrictions, and agreed to a limited number of non-service affecting operating restrictions in the Interim version of software in order to allow Factory Acceptance Testing (FAT) to proceed;
  - Nalcor is in alignment with the ITP and approved GE Grid to proceed with FAT on April19, 2020;
  - FAT is being executed by two shifts per day, seven days per week;
  - At date of reporting, the FAT is proceeding as per the current testing schedule; however, bugs have been identified, which will require fixing; due to the software bugs found, GE Grid will provide a revised schedule for bug fixing and software delivery;
  - As of May 25, 2020 this revised schedule has not been received, nor has the schedule for final bipole software delivery; and
  - Power Supply see further schedule slippage risk as high based on historical and current performance of GE Grid.

[1] Some actions in this and the following slide were performed since March 2020

4.1 Summary – Quarter Ending December 2019

- Synchronous Condensers (SC)

- COVID-19 Essential Work at Soldiers Pond
  - As of March 28, 2020, only essential LCP and Power Supply personnel are reporting to the Soldiers Pond site for care and maintenance related activities; and
  - Approximately 10-15 people are on site daily to maintain essential operations, health, safety, and security.

- Status of Synchronous Condenser Units at Time of COVID-19 Work Suspension
  - SC Unit 3 bearings and housing were removed and shipped to a refurbishment facility for a circumferential slot modification; the same modification as Unit 2 which has resolved Unit 2 binding;
  - When the SC Unit 3 bearings and housings were removed, corrosion and damage was observed on both; root cause analysis has commenced. SC Unit 2 balancing was ongoing in March but was not complete before the site ramp down; no vibration measurements were collected;
  - SC Unit 1 refurbished bearing housing and the modified single oil pocket bearing are on site ready for installation. Installation was planned to start the last week of March but is on hold during the COVID-19 work suspension;
  - GE Power RFP award for lateral vibration remediation is planned to be completed by June 2020; and
  - Power Supply see further schedule slippage risk as high.

- The focus for Q2 2020 is on work restart, continued completions, commissioning and integration of operations; and the forecast expenditure for Q2 2020 is estimated at approximately $26 Million.

4.2 Project Expenditures

March 2020 ($000)	Project Budget June 2017 AFE amended November 2019	Cumulative $			Cumulative %		
		Plan	Incurred	Variance	Plan	Incurred	Variance
Description	*A*	*B*	*C*	*C-B*	*D=B/A*	*E=C/A*	*E-D*
NE-LCP Owners Team, Admin and EPCM Services	$1,115,235	$1,128,245	$1,054,227	($74,018)	101.2%	94.5%	-6.6%
Feasibility Engineering	$37,072	$37,073	$35,847	($1,226)	100.0%	96.7%	-3.3%
Environmental & Regulatory Compliance	$42,699	$42,561	$39,333	($3,228)	99.7%	92.1%	-7.6%
Aboriginal Affairs	$17,478	$17,059	$46,038	$28,979	97.6%	263.4%	165.8%
Procurement & Construction	$8,475,290	$8,719,626	$8,366,630	($352,996)	102.9%	98.7%	-4.2%
Commercial & Legal	$90,423	$85,289	$83,920	($1,369)	94.3%	92.8%	-1.5%
Contingency	$324,162	$0	$0	$0	0.0%	0.0%	0.0%
TOTAL	$10,102,328	$10,029,853	$9,625,995	($403,858)	99.3%	95.3%	-4.0%

March 2020 ($000)	Project Budget June 2017 AFE amended November 2019	Incurred Cumulative Costs March 2020	Project Final Forecast Cost March 2020	Variance PFC from Budget
Description	*A*	*B*	*C*	*D=A-C*
NE-LCP Owners Team, Admin and EPCM Services	$1,115,235	$1,054,227	$1,164,522	($49,287)
Feasibility Engineering	$37,072	$35,847	$35,847	$1,225
Environmental & Regulatory Compliance	$42,699	$39,333	$40,408	$2,291
Aboriginal Affairs	$17,478	$46,038	$50,960	($33,482)
Procurement & Construction	$8,475,290	$8,366,630	$8,572,939	($97,649)
Commercial & Legal	$90,423	$83,920	$108,453	($18,030)
Contingency	$324,162	$0	$129,200	$194,962
TOTAL	$10,102,328	$9,625,995	$10,102,329	($0)

Columns in tables may not total due to rounding

4.3 Contingency

Q1 2020 ($000)	Project Budget June 2017 AFE	March 2018 AFE Adjustment	November 2019 AFE Adjustment	Project Forecast Cost December 2019	Project Forecast Cost March 2020	Change from Previous Quarter	Variance PFC from Budget
	A	-		*B*	*C*	*C - B*	*C - A*
Total Project	$339,162	$339,162	$324,162	$134,679	$129,200	($5,479)	($194,962)

Columns in tables may not total due to rounding

4.4 Earned Progress (December 2019)

Cumulative to end of December 2019	Weight Factor %	December 2019 Cumulative % Earned
Sub-Project	A	C
Muskrat Falls Generation (MFGen)	46.3%	98.5%
Labrador Island Transmission Link (LITL)	43.9%	99.97%
Labrador Transmission Asset (LTA)	9.8%	100.0%
Muskrat Falls Project - Overall	100.0%	99.3%

Columns in tables may not total due to rounding

Annex A

I. Project Capital Budget
II. Project Milestone Schedule

Columns in tables may not total due to rounding

I. Project Capital Budget

Muskrat Falls Generating Facility (in $ thousands)	June 2017 AFE
Expenditure Category	
NE-LCP Owners Team, Admin and EPCM Services	$655,850
Feasibility Engineering	$17,543
Environmental & Regulatory Compliance	$27,125
Aboriginal Affairs	$16,395
Procurement & Construction	$4,501,984
Commercial & Legal	$54,760
Contingency	$226,400
Muskrat Falls Generation Total	$5,500,056
Labrador-Island Transmission Link (in $ thousands)	**March 2018 AFE**
Expenditure Category	
NE-LCP Owners Team, Admin and EPCM Services	$322,101
Feasibility Engineering	$19,167
Environmental & Regulatory Compliance	$14,726
Aboriginal Affairs	$1,003
Procurement & Construction	$3,233,690
Commercial & Legal	$30,280
Contingency	$92,750
Labrador-Island Transmission Link Total	$3,713,716
Labrador-Transmission Assets (in $ thousands)	**November 2019 AFE**
Expenditure Category	
NE-LCP Owners Team, Admin and EPCM Services	$137,284
Feasibility Engineering	$363
Environmental & Regulatory Compliance	$817
Aboriginal Affairs	$80
Procurement & Construction	$739,617
Commercial & Legal	$5,383
Contingency	$5,012
Labrador Transmission Assets Total	$888,556
Muskrat Falls Capital Cost Budget Total	$10,102,328

Contingency Budget (in $ thousands)	November 2019 AFE
Sub-Project:	
Muskrat Falls Generating Facility	$226,400
Labrador-Island Transmission Link	$92,750
Labrador Transmission Assets	$5,012
Total Project	$324,162

II. Project Milestone Schedule

Muskrat Falls Generating Facility	June 2017 Planned Dates
North Spur Works Ready for Diversion	Oct-16
River Diversion Complete	Feb-17
Reservoir Impoundment Complete	Nov-19
Powerhouse Unit 1 Commissioned - Ready for Operation	Dec-19
First Power from Muskrat Falls	Nov-19
Powerhouse Unit 2 Commissioned - Ready for Operation	Mar-20
Powerhouse Unit 3 Commissioned - Ready for Operation	Jun-20
Powerhouse Unit 4 Commissioned - Ready for Operation	Aug-20
Full Power from Muskrat Falls	Aug-20
Commissioning Complete - Commissioning Certificate Issued	Sep-20

Labrador-Island Transmission Link	June 2017 Planned Dates
SOBI Cable Systems Ready	Dec-16
Soldiers Pond Switchyard Ready to Energize	Aug-17
Ready for Power Transmission (LTA)	Dec-17
Muskrat Falls Converter Station Ready to Energize (Pole 1)	Jun-18
HVdc Transmission Line Construction Complete	Dec-17
Soldier's Pond Converter Station Ready to Energize (Pole 1)	Jun-18
1ST Power Transfer (Pole 1)	Jul-18
Soldiers Pond Synchronous Condenser Ready for Operation	Jun-18
Ready for Power Transmission (Low Load Testing Complete Pole 1)	Dec-18
Muskrat Falls and Soldiers Pond Converter Stations - Bipole Dynamic Testing Complete	Mar-19
Commissioning Complete - Commissioning Certificate Issued	Sep-20

Labrador Transmission Assets	June 2017 Planned Dates
HVac Transmission Line Construction Complete	May-17
Churchill Falls Switchyard Ready to Energize	Nov-17
Muskrat Falls Switchyard Ready to Energize	Nov-17
Ready for Power Transmission	Dec-17
Commissioning Complete - Commissioning Certificate Issued	Sep-20

Annex B

Project Expenditures

I. Muskrat Falls Generation

II. Labrador Island Transmission Link

III. Labrador Transmission Assets

Columns in tables may not total due to rounding

I. Muskrat Falls Generation

March 2020 ($000)	Project Budget June 2017 AFE	Cumulative $			Cumulative %		
		Planned	Incurred	Variance	Planned	Incurred	Variance
Description	*A*	*B*	*C*	*C-B*	*D=B/A*	*E=C/A*	*E-D*
NE-LCP Owners Team, Admin and EPCM Services	$655,850	$656,510	$565,427	($91,083)	100.1%	86.2%	-13.9%
Feasibility Engineering	$17,543	$17,543	$16,865	($678)	100.0%	96.1%	-3.9%
Environmental & Regulatory Compliance	$27,125	$27,018	$26,957	($61)	99.6%	99.4%	-0.2%
Aboriginal Affairs	$16,395	$15,976	$45,245	$29,269	97.4%	276.0%	178.5%
Procurement & Construction	$4,501,984	$4,660,907	$4,477,106	($183,801)	103.5%	99.4%	-4.1%
Commercial & Legal	$54,760	$49,626	$53,637	$4,011	90.6%	97.9%	7.3%
Contingency	$226,400	$0	$0	$0	0.0%	0.0%	0.0%
TOTAL	$5,500,056	$5,427,580	$5,185,237	($242,343)	98.7%	94.3%	-4.4%

March 2020 ($000)	Project Budget June 2017 AFE	Incurred Cumulative Costs March 2020
Description	*A*	*B*
NE-LCP Owners Team, Admin and EPCM Services	$655,850	$565,427
Feasibility Engineering	$17,543	$16,865
Environmental & Regulatory Compliance	$27,125	$26,957
Aboriginal Affairs	$16,395	$45,245
Procurement & Construction	$4,501,984	$4,477,106
Commercial & Legal	$54,760	$53,637
Contingency	$226,400	$0
TOTAL	$5,500,056	$5,185,237

II. Labrador Island Transmission Link

March 2020 ($000)	Project Budget March 2018 AFE	Cumulative $			Cumulative %		
		Plan	Incurred	Variance	Plan	Incurred	Variance
Description	*A*	*B*	*C*	*C-B*	*D=B/A*	*E=C/A*	*E-D*
NE-LCP Owners Team, Admin and EPCM Services	$322,101	$332,101	$357,860	$25,759	103.1%	111.1%	8.0%
Feasibility Engineering	$19,167	$19,167	$18,679	($488)	100.0%	97.5%	-2.5%
Environmental & Regulatory Compliance	$14,726	$14,726	$11,564	($3,162)	100.0%	78.5%	-21.5%
Aboriginal Affairs	$1,003	$1,003	$625	($378)	100.0%	62.3%	-37.7%
Procurement & Construction	$3,233,690	$3,316,440	$3,162,981	($153,459)	102.6%	97.8%	-4.7%
Commercial & Legal	$30,280	$30,280	$23,417	($6,863)	100.0%	77.3%	-22.7%
Contingency	$92,750	$0	$0	$0	0.0%	0.0%	0.0%
TOTAL	$3,713,716	$3,713,716	$3,575,126	($138,590)	100.0%	96.3%	-3.7%

March 2020 ($000)	Project Budget March 2018 AFE	Incurred Costs Cumulative March 2020
Description	*A*	*B*
NE-LCP Owners Team, Admin and EPCM Services	$322,101	$357,860
Feasibility Engineering	$19,167	$18,679
Environmental & Regulatory Compliance	$14,726	$11,564
Aboriginal Affairs	$1,003	$625
Procurement & Construction	$3,233,690	$3,162,981
Commercial & Legal	$30,280	$23,417
Contingency	$92,750	$0
TOTAL	$3,713,716	$3,575,126

III. Labrador Transmission Assets

March 2020 ($000)	Project Budget November 2019 AFE	Cumulative $			Cumulative %		
		Plan	Incurred	Variance	Plan	Incurred	Variance
Description	*A*	*B*	*C*	*C-B*	*D=B/A*	*E=C/A*	*E-D*
NE-LCP Owners Team, Admin and EPCM Services	$137,284	$139,634	$130,940	($8,694)	101.7%	95.4%	-6.3%
Feasibility Engineering	$363	$363	$303	($60)	100.0%	83.5%	-16.5%
Environmental & Regulatory Compliance	$817	$817	$812	($5)	100.0%	99.4%	-0.6%
Aboriginal Affairs	$80	$80	$168	$88	100.0%	210.0%	110.0%
Procurement & Construction	$739,617	$742,279	$726,543	($15,736)	100.4%	98.2%	-2.1%
Commercial & Legal	$5,383	$5,383	$6,866	$1,483	100.0%	127.5%	27.5%
Contingency	$5,012	$0	$0	$0	0.0%	0.0%	0.0%
TOTAL	$888,556	$888,556	$865,632	($22,924)	100.0%	97.4%	-2.6%

March 2020 ($000)	Project Budget November 2019 AFE	Incurred Costs Cumulative March 2020
Description	*A*	*B*
NE-LCP Owners Team, Admin and EPCM Services	$137,284	$130,940
Feasibility Engineering	$363	$303
Environmental & Regulatory Compliance	$817	$812
Aboriginal Affairs	$80	$168
Procurement & Construction	$739,617	$726,543
Commercial & Legal	$5,383	$6,866
Contingency	$5,012	$0
TOTAL	$888,556	$865,632

Newfoundland Labrador

Annex C

Earned Progress

I. Overall Construction

II. Muskrat Falls Generation

III. Labrador Island Transmission Link

IV. Labrador Transmission Assets

Columns in tables may not total due to rounding

I. Overall Construction

- >99.3% complete

II. Muskrat Falls Generation

- >98.5% complete

III. Labrador Island Transmission Link

- >99.97% complete

IV. Labrador Transmission Assets

- 100% complete

Annex D

Project Milestone Schedule Forecast

I. Muskrat Falls Generation

II. Labrador Island Transmission Link

III. Labrador Transmission Assets

I. Muskrat Falls Generation

March 2020	Planned Date June 2017	March 2020 Actual/Forecast
Project Sanction	17-Dec-12	Complete
North Spur Works Ready for Diversion	31-Oct-16	Complete
River Diversion Complete	15-Feb-17	Complete
Reservoir Impoundment Complete	1-Nov-19	Complete
Powerhouse Unit 1 Commissioned - Ready for Operation	19-Dec-19	TBD
First Power from Muskrat Falls	2-Nov-19	TBD
Powerhouse Unit 2 Commissioned - Ready for Operation	3-Mar-20	TBD
Powerhouse Unit 3 Commissioned - Ready for Operation	9-Jun-20	TBD
Powerhouse Unit 4 Commissioned - Ready for Operation	14-Aug-20	TBD
Full Power from Muskrat Falls	14-Aug-20	TBD
Commissioning Complete - Commissioning Certificate Issued	1-Sep-20	Not to be achieved
Date Certain	28-Feb-21	28-Feb-21

II. Labrador Island Transmission Link

March 2020	Planned Date June 2017	March 2020 Actual/forecast
Project Sanction	17-Dec-12	Complete
SOBI Cable Systems Ready	9-Dec-16	Complete
Soldiers Pond Switchyard Ready to Energize	31-Aug-17	Complete
Ready for Power Transmission (LTA)	31-Dec-17	Complete
Muskrat Falls Converter Station Ready to Energize (Pole 1)	1-Jun-18	Complete
HVdc Transmission Line Construction Complete	31-Dec-17	Complete
Soldier's Pond Converter Station Ready to Energize (Pole 1)	1-Jun-18	Complete
1ST Power Transfer (Pole 1)	1-Jul-18	Completion of 45 megawatt heat run
Soldiers Pond Synchronous Condenser Ready for Operation	1-Jun-18	TBD
Ready for Power Transmission (Low Load Testing Complete Pole 1)	1-Dec-18	Complete
Muskrat Falls and Soldiers Pond Converter Stations - Bipole Dynamic Testing Complete	31-Mar-19	TBD
Commissioning Complete - Commissioning Certificate Issued	1-Sep-20	Not to be achieved
Date Certain	28-Feb-21	28-Feb-21

III. Labrador Transmission Assets

March 2020	June 2017 Budget Planned Date	March 2020 Actual/Forecast
Project Sanction	17-Dec-12	Complete
HVac Transmission Line Construction Complete	31-May-17	Complete: Turnover of HVac TL and all subsystems complete
Churchill Falls Switchyard Ready to Energize	30-Nov-17	Complete
Muskrat Falls Switchyard Ready to Energize	30-Nov-17	Complete
Ready for Power Transmission	31-Dec-17	Complete
Commissioning Complete - Commissioning Certificate Issued	1-Sep-20	Not to be achieved
Date Certain	28-Feb-21	28-Feb-21

Newfoundland Labrador

End of Report

NON-CONFIDENTIAL

Request IR-2:

Exhibit N-1, p. 5, line 17 to p. 6, line 10 and p. 22, line 16 to p. 23, line 16:
In light of the challenges caused by the COVID-19 pandemic, NSPML outlined an arrangement with the Government of Canada for a mechanism to enable the long-term deferral of recovery of up to $22.75 million depreciation expense from NS Power if the NS Block is delayed into 2021.

a) Please provide the documentation from the Government of Canada confirming their approval of this mechanism.

b) Except for the delay in the delivery of the NS Block into 2021 and the provision of a letter of credit, are there any other conditions that apply to the application of this mechanism? If so, please provide the details.

c) Please explain why the above mechanism does not apply to the recovery of amortization of deferred financing charges.

d) Please confirm that under the terms of the ML Credit Agreement a minimum cash balance of $22.75 million is required in the Debt Service Reserve Account (DSRA) after payment of the semi-annual debt principal payments up to and including June 1, 2021, in order to maintain NSPML's Debt to Equity Ratio (DER) of 70:30 (and a minimum of $42.75 million for payments after December 1, 2021).

e) Under the ML Credit Agreement, why was a low-cost letter of credit not allowed to be substituted for the minimum cash balance outlined in the preceding subsection (d), even prior to the COVID-19 pandemic?

NON-CONFIDENTIAL

f) Assuming the NS Block is delayed into 2021, will the minimum required cash balance in the DSRA have to be restored once the NS Block commences? Or, alternatively, will the letter of credit remain in place for the remainder of the project debt until all payments are completed under the ML Credit Agreement?

g) On page 6, lines 8-10, NSPML states that it has estimated the above arrangement would have a net present value for the benefit of ratepayers of up to approximately $13 million. Assuming the NS Block is delayed beyond May 1, 2021, please provide the calculation in support of this statement.

h) Assuming the $13 million has considered both the delay of the payment until 2052 and the interest accrued in the FAM, please indicate what assumption was made related to the FAM. For example, would the funds need to remain in the FAM until the end of the term of the Federal Loan Guarantee (2052) to achieve $13 million in benefit to ratepayers? If so, what is the forecast benefit to customers of the funds remaining in the FAM only until January 2023?

Response IR-2:

a) Please refer to Attachments 1 and 2.

b) All details respecting the conditions applicable to this mechanism are contained in the IRs filed pursuant to this Application and the attachments thereto.

c) NSPML focused this proposal, in its discussions with Canada, as a continuation of a deferral of Depreciation as was the primary focus of deferrals in prior years. This Application continues the intra-year deferral of the recovery of Amortization, consistent with 2020.

d) The ML Credit Agreement ("MLCA") requires that the combination of cash in the DSRA and any letter of credit ("LC") on deposit with the Collateral Agent equal the Minimum DSRA Requirement as at the most recent Fixing Date. The MLCA does not specify what proportion of the Minimum DSRA Requirement is necessary to be met with cash or LC. The calculation of the Debt to Equity Ratio is independent from the DSRA requirements.

e) Prior to this arrangement with the Government of Canada, NSPML was not permitted to arrange its own Letter of Credit ("LC") to fulfill its Minimum DSRA Requirement (the MLCA only permitted Emera or an Emera affiliate other than NSPML to arrange a LC on behalf of NSPML). NSPML had sufficient cash on hand to meet the DSRA requirement to date and so it did not require a LC until 2020. After the COVID-19 pandemic, NSPML began exploring the proposal now put forward, which among other things resulted in Canada allowing NSPML to arrange its own LC. In addition, NSPML required agreement with the Government of Canada in relation to the calculation of its Debt Service Coverage Ratio ("DSCR") as outlined in Attachments 1 and 2.

f) No, the MLCA does not require a minimum cash balance in the DSRA. The alternative is correct; the letter of credit will remain in place for the duration of the repayment term, although reducing in the later years as the Minimum DSRA Requirement decreases as principal is repaid.

g) Please refer to Attachment 3 for the Excel spreadsheet that supports this calculation.

h) The calculation of the approximated net present value benefit of up to $13 million does not directly include the interest customers will earn on monies left in the FAM however the discount rate of 6% that is used for illustrative purposes is a proxy for that benefit to customers. If the FAM weighted average cost of capital (6.62% in effect in 2020) was used rather than the 6% discount rate for 2020-2022, the net present value benefit to customers would be greater. The benefit that customers receive is a combination of the interest on the

FAM during the period up to the end of 2022 and then the benefit of having the amount deferred remain on account in the FAM when the next FAM true up occurs (i.e. the amount reduces any future FAM liability). The benefit to customers is forecasted at a singular rate of 6% throughout the entire period. The net present value is essentially the value to customers derived from deferring payment of up to $22,750,000 to 30-35 years from now rather than in the first half of 2021, even after accounting for foregone interest earned on cash withdrawn from the DSRA and the cost of maintaining a letter of credit through the duration of the repayment period.

Emera Newfoundland & Labrador

125 Kelsey Drive, Suite 102 ● St. John's, NL ● Canada ● A1B0L1

July 30, 2020

André Bernier
Senior Director
Renewable and Electrical Energy Division
Natural Resources Canada
580 Booth St., 17 floor
Ottawa, ON, K1A 0E4

Sent via email

The following is NSPML's request of Natural Resources Canada with respect to satisfying the Minimum DSRA Requirement of the ML Credit Agreement ("MLCA") through the use of a Letter of Credit ("LC") obtained by NSPML.

As you know, the Minimum DSRA Requirement will increase by August, 24 2020 from the current $22.75 million to a total of $42.75 million. This ensures that the DSRA is funded to the amount of 6 months interest plus the semi-annual $20 million principal payment, in accordance with Section 8.3.2 of the MLCA. To date, the DSRA Minimum Requirement is satisfied through cash held in trust with TD Bank under the control of the Collateral Agent.

Nova Scotia customers have been and continue to be affected by the economic impact of the COVID-19 pandemic. Among other things, NSPML had expected Nalcor to deliver the NS Block by mid-2020 but, unfortunately, the unprecedented and severe impact of the pandemic has rendered Nalcor unable to safely meet that expectation. We want to do what we can to assist customers in these challenging times and, to that end, believe we have identified a meaningful way to mitigate the extended delay in delivery of the NS Block.

Specifically, NSPML proposes to replace the cash presently held in trust with TD Bank with an LC, thereby freeing up those funds for application to NSPML's semi-annual principal and interest payment. On or about the beginning of May 2021, we would withdraw the equivalent of approximately $4.55 million per month for every month the NS Block is delayed in 2021, up to the full amount of $22.75 million held in trust. An equivalent amount will remain in NS Power's Fuel Adjustment Mechanism account held for the benefit of customers, where that amount will earn interest for customers and help defray

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Newfoundland & Labrador

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the cost of replacing Muskrat Falls power. If we were to withdraw the full $22.75 million from the DSRA, we estimate the net present benefit to customers is in the range of $13 million.

To attain this outcome, we need to deliver to the Collateral Agent an LC in an amount of up to $42.75 million: $20 million in August 2020 with the final amount determined in May 2021 based on when the NS Block flows.

Section 8.3.5 of the MLCA requires Emera or a Subsidiary of Emera other than NSPML to arrange any LC used to meet the Minimum DSRA Requirement. For the following reasons, we request that Natural Resources Canada consent to NSPML arranging its own credit facility:

1. To abide by Section 8.3.5, NS Power is the logical Emera Subsidiary to arrange the credit facility. Both NS Power and NSPML are regulated by the NS UARB, both serve the same end customers, and NSPML recovers its costs from those customers via NS Power. That said, NS Power must manage its cash and credit in the most helpful way for customers during these challenging times and taking on an additional credit facility on behalf of an affiliate company is not in the best interest of customers in respect of ongoing financing and liquidity arrangements, particularly at this time when cash liquidity is so important to utilities.

2. Our discussions with Scotiabank confirm that the cost of the LC would be no greater if arranged by NSPML rather than NS Power so there is no additional cost to the customer resulting from this approach.

Therefore, we request that NSPML be permitted to arrange its own LC up to a total amount of $42.75 million on the understanding that the cash from the DSRA (up to $22.75 million) will be used to provide rate relief for NS customers.

As a corollary matter, NSPML must also ensure it continues to meet its covenants under the MLCA after implementing the proposed measure and we wish to confirm our understanding with respect to the two below-noted covenants.

The first is NSPML's covenant to maintain a DSCR of no less than 1.40. The DSCR is the ratio between Base Cash Flow and Total Debt Service. The proposed measure would result in NSPML recovering up to $22.75 million less from NS Power in 2021. However, the recovery of monies from the DSRA (up to $22.75 million) in the proposed manner

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means that practically speaking, NSPML will remain in the exact same cash position as it would have been in had it recovered such monies from NS Power rather than the DSRA.

Accordingly, as to the DSCR we request that Canada confirms that it is its understanding that the Collaboration clause set out in s. 10.25 of the MLCA has the result that Canada will instruct the Collateral Agent to work collaboratively with the Company to work out a suitable resolution of any needed rectification of a DSCR shortfall following the process outlined in Section 10.25 should such an event arise. Section 10.25 of the ML Credit Agreement provides for a DSCR Consultation Process in the event that the calculation of the Prospective and Retrospective DSCR is less than 1.40. In the event that such calculation falls below 1.40, we request Canada's agreement that measures to address the issue that would be considered may involve the recognition of sources of cash available to service NSPML's debt for the purpose of calculating the DSCR, which sources may include, without limitation, monies withdrawn from the DSRA in order to service NSPML's debt (as described above). We note that this approach is consistent with the covenants contained under the ML Credit Agreement and as noted above, would reflect an accurate and practical calculation of NSPML's true cash position in such circumstances.

The second is the DER. We want to confirm that all parties share a consistent view on the exclusion of the LC from the definition of "Additional Debt". We understand that Additional Debt relates specifically to debt incurred for Cost Overruns and Sustaining Capital. Since the LC will be used to meet the Minimum DSRA Requirement, it does not fall within the definition of Additional Debt and is therefore excluded from the DER. We ask that our interpretation be confirmed.

To summarize, we request that Canada:

(i) **permit NSPML to arrange its own LC for the purpose of funding the Minimum DSRA requirement under Section 8.3.5 of the MLCA**;

(ii) **confirm that the intent of Section 10.25 is such that Canada would instruct the Collateral Agent to work collaboratively with the Company to identify ways to rectify a DSCR shortfall, should one arise, following the process outlined in Section 10.25 and in a manner consistent with that outlined above; and**

(iii) **confirm that our interpretation of the definition of Additional Debt as it relates to the DER are consistent with those held by Canada.**

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We would be pleased to discuss at your convenience. Thank you for your consideration.

Sincerely,

Brian Rendell, CPA, CA
VP Finance and Commercial

July 30, 2020

Brian Rendell
VP Finance and Commercial
Emera Newfoundland and Labrador
125 Kelsey Drive, Suite 102
St. John's NL A1B 0L1

Sent via email

Mr. Rendell,

Thank you for your correspondence of July 30, 2020 outlining the proposed use of a letter of credit to satisfy the Debt Service Reserve Account (DSRA) requirement per the Maritime Link Credit Agreement (MLCA).

In response to the request outlined in your letter, I, on behalf of the Government of Canada:

(i) consent to NSPML arranging its own letter of credit for the purpose of funding the Minimum DSRA requirement under Section 8.3.5 of the MLCA;
(ii) confirm that the intent of Section 10.25 is such that Canada would instruct the Collateral Agent to work collaboratively with the NSPML to identify ways to rectify a DSCR shortfall, should one arise, following the process outlined in Section 10.25 and in a manner consistent with that outlined in your letter; and
(iii) confirm that Canada's interpretation of the definition of Additional Debt as it relates to the DER is consistent with the interpretation outlined in your letter.

Sincerely yours,

André Bernier
Senior Director, Renewable and Electrical Energy Division
Natural Resources Canada
580 Booth St., 17th floor
Ottawa ON K1A 0E4

NSP Maritime Link Incorporated
Net Present Value Analysis
September 4, 2020

INPUTS

Months	5
Discount Rate (Annual)	6.00%
LC Fee (Annual)	0.60%
Account Interest Rate (Annual)	1.00%

NET PRESENT VALUE	**13,463,942**

Period	Payment Date	Minimum DSRA Requirement	DSRA Cash	DSRA LC	Revenue Change (Depreciation)	Reduced Interest	Additional LC Fee	Total Benefit (Cost)	NPV
0	Dec-20	42,750,000	22,750,000	20,000,000					
1	Jun-21	42,400,000	-	42,400,000	22,750,000	(113,750)	(68,250)	22,568,000	21,910,680
2	Dec-21	42,050,000	-	42,050,000	-	(113,750)	(68,250)	(182,000)	(171,552)
3	Jun-22	41,700,000	-	41,700,000	-	(113,750)	(68,250)	(182,000)	(166,556)
4	Dec-22	41,350,000	-	41,350,000	-	(113,750)	(68,250)	(182,000)	(161,705)
5	Jun-23	41,000,000	-	41,000,000	-	(113,750)	(68,250)	(182,000)	(156,995)
6	Dec-23	40,650,000	-	40,650,000	-	(113,750)	(68,250)	(182,000)	(152,422)
7	Jun-24	40,300,000	-	40,300,000	-	(113,750)	(68,250)	(182,000)	(147,983)
8	Dec-24	39,950,000	-	39,950,000	-	(113,750)	(68,250)	(182,000)	(143,672)
9	Jun-25	39,600,000	-	39,600,000	-	(113,750)	(68,250)	(182,000)	(139,488)
10	Dec-25	39,250,000	-	39,250,000	-	(113,750)	(68,250)	(182,000)	(135,425)
11	Jun-26	38,900,000	-	38,900,000	-	(113,750)	(68,250)	(182,000)	(131,481)
12	Dec-26	38,550,000	-	38,550,000	-	(113,750)	(68,250)	(182,000)	(127,651)
13	Jun-27	38,200,000	-	38,200,000	-	(113,750)	(68,250)	(182,000)	(123,933)
14	Dec-27	37,850,000	-	37,850,000	-	(113,750)	(68,250)	(182,000)	(120,323)
15	Jun-28	37,500,000	-	37,500,000	-	(113,750)	(68,250)	(182,000)	(116,819)
16	Dec-28	37,150,000	-	37,150,000	-	(113,750)	(68,250)	(182,000)	(113,416)
17	Jun-29	36,800,000	-	36,800,000	-	(113,750)	(68,250)	(182,000)	(110,113)
18	Dec-29	36,450,000	-	36,450,000	-	(113,750)	(68,250)	(182,000)	(106,906)
19	Jun-30	36,100,000	-	36,100,000	-	(113,750)	(68,250)	(182,000)	(103,792)
20	Dec-30	35,750,000	-	35,750,000	-	(113,750)	(68,250)	(182,000)	(100,769)
21	Jun-31	35,400,000	-	35,400,000	-	(113,750)	(68,250)	(182,000)	(97,834)
22	Dec-31	35,050,000	-	35,050,000	-	(113,750)	(68,250)	(182,000)	(94,984)
23	Jun-32	34,700,000	-	34,700,000	-	(113,750)	(68,250)	(182,000)	(92,218)
24	Dec-32	34,350,000	-	34,350,000	-	(113,750)	(68,250)	(182,000)	(89,532)
25	Jun-33	34,000,000	-	34,000,000	-	(113,750)	(68,250)	(182,000)	(86,924)
26	Dec-33	33,650,000	-	33,650,000	-	(113,750)	(68,250)	(182,000)	(84,392)
27	Jun-34	33,300,000	-	33,300,000	-	(113,750)	(68,250)	(182,000)	(81,934)

NSP Maritime Link Incorporated
Net Present Value Analysis
September 4, 2020

Period	Payment Date	Minimum DSRA Requirement	DSRA Cash	DSRA LC	Revenue Change (Depreciation)	Reduced Interest	Additional LC Fee	Total Benefit (Cost)	NPV
28	Dec-34	32,950,000	-	32,950,000	-	(113,750)	(68,250)	(182,000)	(79,548)
29	Jun-35	32,600,000	-	32,600,000	-	(113,750)	(68,250)	(182,000)	(77,231)
30	Dec-35	32,250,000	-	32,250,000	-	(113,750)	(68,250)	(182,000)	(74,982)
31	Jun-36	31,900,000	-	31,900,000	-	(113,750)	(68,250)	(182,000)	(72,798)
32	Dec-36	31,550,000	-	31,550,000	-	(113,750)	(68,250)	(182,000)	(70,677)
33	Jun-37	31,200,000	-	31,200,000	-	(113,750)	(68,250)	(182,000)	(68,619)
34	Dec-37	30,850,000	-	30,850,000	-	(113,750)	(68,250)	(182,000)	(66,620)
35	Jun-38	30,500,000	-	30,500,000	-	(113,750)	(68,250)	(182,000)	(64,680)
36	Dec-38	30,150,000	-	30,150,000	-	(113,750)	(68,250)	(182,000)	(62,796)
37	Jun-39	29,800,000	-	29,800,000	-	(113,750)	(68,250)	(182,000)	(60,967)
38	Dec-39	29,450,000	-	29,450,000	-	(113,750)	(68,250)	(182,000)	(59,191)
39	Jun-40	29,100,000	-	29,100,000	-	(113,750)	(68,250)	(182,000)	(57,467)
40	Dec-40	28,750,000	-	28,750,000	-	(113,750)	(68,250)	(182,000)	(55,793)
41	Jun-41	28,400,000	-	28,400,000	-	(113,750)	(68,250)	(182,000)	(54,168)
42	Dec-41	28,050,000	-	28,050,000	-	(113,750)	(68,250)	(182,000)	(52,591)
43	Jun-42	27,700,000	-	27,700,000	-	(113,750)	(68,250)	(182,000)	(51,059)
44	Dec-42	27,350,000	-	27,350,000	-	(113,750)	(68,250)	(182,000)	(49,572)
45	Jun-43	27,000,000	-	27,000,000	-	(113,750)	(68,250)	(182,000)	(48,128)
46	Dec-43	26,650,000	-	26,650,000	-	(113,750)	(68,250)	(182,000)	(46,726)
47	Jun-44	26,300,000	-	26,300,000	-	(113,750)	(68,250)	(182,000)	(45,365)
48	Dec-44	25,950,000	-	25,950,000	-	(113,750)	(68,250)	(182,000)	(44,044)
49	Jun-45	25,600,000	-	25,600,000	-	(113,750)	(68,250)	(182,000)	(42,761)
50	Dec-45	25,250,000	-	25,250,000	-	(113,750)	(68,250)	(182,000)	(41,515)
51	Jun-46	24,900,000	-	24,900,000	-	(113,750)	(68,250)	(182,000)	(40,306)
52	Dec-46	24,550,000	-	24,550,000	-	(113,750)	(68,250)	(182,000)	(39,132)
53	Jun-47	24,200,000	-	24,200,000	-	(113,750)	(68,250)	(182,000)	(37,993)
54	Dec-47	23,850,000	-	23,850,000	-	(113,750)	(68,250)	(182,000)	(36,886)
55	Jun-48	23,500,000	-	23,500,000	-	(113,750)	(68,250)	(182,000)	(35,812)
56	Dec-48	23,150,000	-	23,150,000	-	(113,750)	(68,250)	(182,000)	(34,769)
57	Jun-49	22,800,000	-	22,800,000	(300,000)	(113,750)	(68,250)	(482,000)	(89,397)
58	Dec-49	22,450,000	-	22,450,000	(350,000)	(113,750)	(67,350)	(531,100)	(95,635)
59	Jun-50	22,100,000	-	22,100,000	(350,000)	(113,750)	(66,300)	(530,050)	(92,666)
60	Dec-50	21,750,000	-	21,750,000	(350,000)	(113,750)	(65,250)	(529,000)	(89,789)
61	Jun-51	21,400,000	-	21,400,000	(350,000)	(113,750)	(64,200)	(527,950)	(87,001)
62	Dec-51	21,050,000	-	21,050,000	(350,000)	(113,750)	(63,150)	(526,900)	(84,299)
63	Jun-52	20,700,000	-	20,700,000	(350,000)	(113,750)	(62,100)	(525,850)	(81,680)
64	Dec-52	20,350,000	-	20,350,000	(20,350,000)	(113,750)	(61,050)	(20,524,800)	(3,095,256)

NON-CONFIDENTIAL

Request IR-3:

Exhibit N-1, Total AFUDC cost, p. 17, lines 12-15:

a) NSPML reports AFUDC unchanged since 2017 at $209 million. Was any additional AFUDC recorded related to the subsea cable burial project?

b) What was the total interest and return recorded annually through December 2019 from the time the asset was placed in service (i.e., January 15, 2018)?

c) What interest and return has been recorded to date in 2020?

Response IR-3:

a) No additional AFUDC was recorded after December 31, 2017, which was prior to the remedial activity associated with the subsea cable burial work.

b) As reported in the annual audited financial statements, net interest expense and return on equity recorded in the year ended December 31, 2018 and December 31, 2019, are noted in the following table:

	Year Ending Dec 31, 2018	**Year Ending Dec 31, 2019**
Interest Expense (net)	$44.4 million	$43.8 million
Return on Equity	$45.7 million	$45.1 million

c) For the period from January 1 to June 30, 2020, NSPML has recorded net interest expense of $22.2 million and return on equity of $26.3 million.

NON-CONFIDENTIAL

Request IR-4:

Exhibit N-1, p. 18, lines 1-2:
NSPML requests an assessment and recovery of 2021 ML costs in the total amount of $172.2 million. In its Decision and Order respecting the 2020-2022 Base Cost of Fuel proceeding (M09288), the BCF approvals included a forecasted interim assessment of $164.4 million for 2021.

a) Why does the current application for $172.2 million differ from the forecasted amount of $164.4 million for 2021? Please reconcile the difference.

b) Do any COVID-19 related costs account for any of the difference in the forecasted costs? If so, please explain.

c) If the Board approves the present application, how will the revised 2021 interim assessment be reflected in customers' rates under the rate smoothing in the previously approved Fuel Stability Plan?

Response IR-4:

a) The current Application is based on the most recent forecast of NSPML's financial requirements for 2021. The $7.8 million difference between forecasted costs in the BCF and the forecasted costs included in this Application relate primarily to Depreciation ($4.6 million difference), Operating & Maintenance costs ($1.5 million) and Net Interest costs ($1.5 million).

With respect to Depreciation, the BCF amount was an estimate determined by dividing the total ML construction cost plus AFUDC by 35 years on a straight-line basis. As noted in the Application, the current Depreciation, together with Deferred Financing

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Amortization and any amount transferred from the DSRA, is equal to no more and no less than the amount of funding required in 2021 to repay debt and return equity to enable the approved Debt to Equity Ratio of 70:30 to be maintained. NSPML expects that the setting of Depreciation on a future basis will be determined during the final cost assessment when final capital costs are known. Please also see response to NSUARB IR-6(c).

With respect to Operating & Maintenance costs, the current Application is the most recent and updated forecast of requirements for 2021 based on experience in operating the ML assets to date.

With respect to Net Interest Costs, the current Application is the most recent and updated forecast based on current interest rate revenues earned on NSPML bank accounts and forecasted cash balances throughout 2021 as well as a forecast of the Letter of Credit cost in 2021.

b) COVID-19 has not had a material net impact on forecasted costs for 2021.

c) As part of the 2020-2022 Fuel Stability Plan Application, the NSUARB approved inclusion of $164.4 million for the anticipated Maritime Link for 2021 as compared to NSPML's 2021 Interim Assessment application of $172.2 million. If the Board approves a higher amount than what is included in rates, the under-collection of the 2021 NSPML Interim assessment will be deferred and trued up at the conclusion of the 2020-2022 Fuel Stability Plan period. NSPML's proposal in this Application to defer collection of a component of depreciation from NS Power by $4.6 million per month to a maximum of $22.75 million, by utilizing cash from the DSRA, would serve to offset such under-collection.

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Request IR-5:

Exhibit N-1, pp. 19-20, re Operating & Maintenance (O&M) Costs, Table 2:
NSPML forecasts its 2021 Operating and Maintenance Costs at $21.5 million, about $0.9 million more than the 2020 forecasted costs.

a) Does any of the increase in 2021 O&M costs relate to anticipated COVID-19 related costs?

b) What impact has the COVID-19 pandemic had on actual O&M costs in the current year (i.e., 2020)?

c) Describe the nature of the increased Labour and Administration costs (i.e., increase of $1.4 million) over forecast 2020. Please indicate the incremental amount of operations personnel reflected in the increased Operating & Maintenance Costs, both in dollar terms and in FTEs.

d) What is the nature of the increased insurance costs, which are forecast to increase almost 30% in 2021?

e) What is the basis for applying a Contingency and Escalation amount of $1.0 million in 2021 as part of Operating & Maintenance Costs?

f) Please reconcile the actual Operating & Maintenance Costs covered by customers' rates in 2019 to the prior forecast used to set rates.

NON-CONFIDENTIAL

Response IR-5:

a) COVID-19 has not had a material net impact on 2021 forecasted O&M Costs.

b) COVID-19 has not had a material net impact on O&M costs to date in 2020 and is not expected to have a material net impact on the forecast of O&M costs for the remainder of the year.

c) NSPML has estimated approximately $0.5 million increase in labour costs due to the forecasted addition of 3 FTE's; an additional $0.3 million in shared services which includes additional support forecasted as NSPML transitions to a steady state model; an additional $0.3 million to account for potential increases in regulatory costs as NSPML prepares for post-interim rate proceedings, as well as approximately $0.3 million for associated legal and consulting fees.

d) NSPML's insurance advisor has noted that insurance premiums, particularly relating to property coverage, have been trending upward in recent years given relatively low premium rates in the recent past, a global increase in the frequency and severity of loss events, reduced investment returns for insurers and other general macroeconomic conditions.

e) NSPML has included contingency of $1.0 million to allow for the potential for weather related costs specifically associated with the marine survey work in relation to vessel delays during bad weather.

f) In early 2016, NSPML estimated O&M costs for each of 2018, 2019 and 2020 to support the Maritime Link component of NS Power's 2017-2019 Fuel Stability Plan application filed on March 7, 2016. NSPML maintained the annual amounts estimated for 2019 when it filed its 2017 Interim Cost Assessment Application on December 16, 2016 which assisted in maintaining rate stability. These estimates, prepared in 2016, were based on NSPML's knowledge at that time using common utility cost estimation procedures. The cost estimation was conducted during the beginning of the construction phase of the project and before NSPML developed its current operations and maintenance asset management program and before the assets were fully constructed and in service. These estimates assumed, for cost estimating purposes, that many activities would be outsourced rather than performed by internal resources. As noted in the 2020 interim assessment proceeding, NSPML is now using internal resources to fulfill many of these responsibilities in order to retain the knowledge and experience within the company and in order to better control costs.

Since preparing the initial estimates of O&M costs, NSPML has refined its asset management operations and maintenance program based on the installed assets and with knowledge and experience with operating the assets as well as contracts entered into with service providers. This has led to greater cost forecasting confidence. As a result, while the total annual costs have not varied significantly from the original 2016 estimate, the allocation of costs amongst the categories has changed.

A comparison of the O&M costs requested in the 2019 interim assessment and the actual costs incurred is as noted below. As discussed above, the differences are largely due to the level of detail known at the time the estimate was prepared in 2016 and how the underlying activities have evolved. While individual line amounts have certain degrees of variation, the total is not significant.

The O&M costs for 2020 that were approved in last year's Interim Assessment are noted in the far right column of the table below to reflect the similar allocation of costs in both the 2019 actual costs and the 2020 forecasted costs that were approved by the UARB last year.

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(Millions $)	**Forecast 2019 (estimated as part of BCF in 2016)**	**Actual 2019**	**Difference (between 2019 Forecast and Actual)**	**O&M Costs Approved for 2020**
Labour and Administration	$2.8	$6.3	$3.5	$6.9
Converters and Substations	5.5	5.7	0.2	4.7
Marine O&M	1.8	2.3	0.5	3.3
Vegetation Management	0.1	0.4	0.3	1.3
Insurance	4.1	2.0	(2.1)	2.2
Independent Engineer	0.3	0.2	(0.1)	0.3
Environmental Assessment	1.6	0.3	(1.3)	0.4
Contingency & Escalation	2.2	-	(2.2)	1.5
Total	**$18.4**	**$17.2**	**($1.2)**	**$20.6**

Request IR-6:

Exhibit N-1, Capital Cost Recovery via Depreciation, pp. 20-23:

a) Please confirm NSPML is proposing collecting through "depreciation" a figure that will achieve the required cash flows to repay debt and equity and this figure does not necessarily dictate what NSPML would depreciate in 2021 in accordance with GAAP.

b) Please confirm, or correct, to understand the depreciation proposal, as compared to 2020 when depreciation was limited to one repayment obligation, one has to add the individual cash payments and transfers, as follows:

	2020	2021 (Jan start)	2021 (May start)	2021 (Nov start)
Ratepayer, collected from NS Power May 1		$23.2 ($27.8-$4.6)	$5.05 ($27.8-22.75)	$5.05 ($27.8-22.75)
Ratepayer, collected from NS Power by Nov 1	$28.6	$27.8	$27.8	$27.8
DSRA		$4.6	$22.75	$22.75
Depreciation expense	$28.6	$55.6	$55.6	$55.6

c) Please explain why the total annual depreciation is $55.6 million and what caused this to increase compared to the $51 million reported in M09288 for 2021 and 2022 which aligned with what had been collected in 2018 & 2019.

d) Please explain why none of the assessments outlined in Appendix B identify $55.6 million in depreciation. If the DSRA funds are not being treated as depreciation, please explain why not.

e) NSPML is acknowledging the project may not be online in 2021, and therefore indicates depreciation will continue to be deferred monthly until needed to match

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the repayment obligations. Are there still monthly revenues or depreciation expenses recorded related to these depreciation funds recorded?

f) Please confirm the $55.6 million proposed depreciation collected will, in fact, be the equal to the accounting entry for depreciation with no other deferral or variances.

g) If the response to part f) cannot be confirmed, please provide the expected accounting entries, including regulatory deferrals, and impact to the net income for each month of 2021 and rate base for the five quarters comprising the average 2021 forecast equity.

h) Please provide a detailed explanation on how NSPML calculates and accounts for Depreciation.

Response IR-6:

a) NSPML is proposing that in 2021 the total of i) depreciation expense recovery in rates, ii) amortization of deferred financing charges expense recovery in rates and iii) cash withdrawn from the DSRA as outlined in the Application, will equal the required debt principal payments and return of equity required to maintain the approved Debt to Equity Ratio. This is further discussed in the response to (d-h) below. NSPML expects that the matter of finalizing depreciation methodology and rates throughout the remainder of the operating period will be a matter addressed in the final cost proceeding when final costs are known.

b) To the extent that funds are withdrawn from the DSRA, such amounts will reduce the amount of depreciation expense required to be recovered in rate revenue from NS Power in 2021. In the examples provided in the table in the question, the depreciation expense that is ultimately recorded on NSPML's statement of net earnings would be $51 million

(“January start”) and $32.85 million (“May start” and “November start”). See response to (d-h) below.

c) As outlined in the Application and noted in (a) above, NSPML is calculating depreciation and amortization based on the 2021 requirements to pay debt principal obligations and return equity to maintain the approved debt to equity ratio. For GAAP purposes, NSPML based its previous estimate of depreciation on the sum of budgeted capital costs and AFUDC divided by 35 years on a straight-line basis, resulting in an annual amount of $51 million. NSPML used this amount as part of its total forecasted operating cost revenue requirement when NS Power filed its FAM BCF application in 2016. NSPML maintained those estimated amounts, including depreciation, when it filed its original interim rate application for 2018 and 2019. NSPML subsequently proposed to defer collection of depreciation in 2018 and 2019 and partially in 2020 as noted in those proceedings. If NSPML had collected cash via depreciation in those years, it would have had cash on hand to fund debt and equity payments in 2020 and beyond, and the need to possibly collect a greater amount in 2021 would not have been necessary.

For 2020, the year in which NSPML has to make its first debt principal repayment, the Board approved the collection of the amounts necessary to repay debt and equity in the year (i.e. $20 million in debt and $8.6 million in equity). NSPML has carried this approach forward to 2021 (i.e. the requirement to fund $40 million in debt principal and return $17.2 million in equity). The amount of $55.6 million represents the sum of the debt and equity payments ($57.2 million) less the amortization of deferred financing costs (i.e. $1.6 million). As noted in (a), NSPML expects the matter of depreciation methodology for the remainder of the operating period to be addressed during the final cost proceeding.

(d-h) Beginning in 2018, following GAAP, NSPML has recorded estimated depreciation expense each year based on the actual capital costs incurred to the end of each year (which is less than the full amount of the forecasted project budget), including AFUDC, and depreciated that balance on a straight-line basis over the remainder of the project's life. NSPML has used, and will continue to use, this method of estimating and recording depreciation in this interim period until such time as final costs are known and a depreciation policy and methodology is confirmed. NSPML expects this to be addressed as part of its final cost proceeding.

The journal entries to reflect depreciation and amortization in 2018 and 2019 are as follows (these are simplified entries to illustrate the principles followed):

<u>2018</u>
Debit: Depreciation expense $45m
Credit: Accumulated Depreciation (Property plant & equipment) $45m
To record estimated annual depreciation (based on costs incurred to Dec. 31/18)

<u>2019</u>
Debit: Depreciation expense $47m
Credit: Accumulated Depreciation (Property plant & equipment) $47m
To record estimated annual depreciation (based on costs incurred to Dec. 31/19)

In each of 2018 and 2019, since the UARB's order was for NSPML to defer recovery of all depreciation in rates from NS Power, NSPML also recorded the following journal entries:

<u>2018</u>
Debit: Regulatory assets $45m

Credit: Depreciation expense $45m

To adjust depreciation expense and record regulatory asset to reflect the amount approved to be recovered in rates and the amount deferred.

2019

Debit: Regulatory assets $47m

Credit: Depreciation expense $47m

To adjust depreciation expense and regulatory asset to reflect the amount approved to be recovered in rates and the amount deferred.

The net impact of these journal entries in 2018 and 2019 (and as reported in its annual audited financial statements, as filed with the UARB) is no depreciation expense on the statement of net earnings and no associated revenues from NS Power. On the balance sheet, these entries result in a reduction to property plant & equipment and an offsetting increase in regulatory assets, thus no net change to total or net assets.

In 2020, to the extent that the collection of depreciation continues to be deferred, as in 2018 and 2019, NSPML will follow the same approach as in those years and record such amounts as a regulated asset. Once NSPML commences collection of depreciation from NS Power in rates later this year ($28.6 million as approved by the UARB), that amount will be reflected as a depreciation expense.

To illustrate this, in 2020 NSPML will continue to initially record depreciation in a manner determined in 2018 and 2019. For 2020, the estimated amount of depreciation based on costs incurred to date will be recorded (for illustration purposes, assume that number is $50 million - final amount to be determined by year end). NSPML also expects to collect $28.6 million from NS Power no later than November 1, 2020 as per the assessment from last year. The journal entries to reflect this are as follows:

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Debit: Depreciation expense $50m
Credit: Accumulated Depreciation (Property plant & equipment) $50m
To record estimated annual depreciation (based on costs incurred to Dec. 31/20)

Debit: Cash $28.6m
Credit: Revenues (from NS Power) $28.6m
To record cash revenues collected from NS Power in relation to depreciation

Debit: Long term debt $20m
Debit: Shareholder equity $8.6m
Credit: Cash $28.6m
To record payment of debt principal and return of equity (to maintain approved 70:30 debt: equity ratio) using cash from revenues

Debit: Regulated assets $21.4m
Credit: Depreciation expense $21.4m
To adjust depreciation expense and regulatory asset to reflect the amount approved to be recovered in rates and the amount deferred.

The net impact of these journal entries does not result in a change to net earnings (revenues of $28.6 million are offset by depreciation expense of $28.6 million). On the balance sheet, property plant & equipment is reduced by $50 million (in keeping with NSPML's approach of depreciating the Maritime Link based on costs incurred to date during the interim period before the final cost order), regulated assets are increased by $21.4 million (the portion of depreciation not collected in rates), long term debt is reduced by $20 million (reflecting the payment of the first debt principal payment by December 1) and shareholder equity is reduced by $8.6 million (reflecting a return of equity to maintain the approved debt to equity ratio of 70:30).

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In 2021, NSPML expects to follow the same principles as noted above. For purposes of illustration, assume that the NS Block commences in May 2021 (the "May start" scenario noted in the table in question (b) above) and consequently $22.75 million is withdrawn from the DSRA and not collected in revenues from NS Power on account of depreciation. Given that scenario, the journal entries would be as follows:

Debit: Depreciation expense $51m
  Credit: Accumulated Depreciation (Property plant & equipment) $51m
To record annual depreciation (amount subject to change based on actual total costs and if a final determination of rate base and depreciation is determined in a final cost proceeding with the UARB)

Debit: Cash $32.85m
  Credit: Revenues (from NS Power) $32.85m
To record revenue collected from NS Power in relation to depreciation ($5.05m collected in May and $27.8m collected after May as noted in the table in question b)

Debit: Long term debt $40m
Debit: Shareholder equity $15.6m
  Credit: Cash (from NS Power as depreciation recovery) $32.85m
  Credit: Cash (from DSRA) $22.75m
To repay debt principal and return equity (to maintain approved 70:30 debt: equity ratio) using cash from revenues collected from NS Power and from withdrawal from the DSRA.

Debit: Regulated assets $18.15m
  Credit: Depreciation expense $18.15m

To adjust depreciation expense and regulatory asset to reflect the amount approved to be recovered in rates and the amount deferred.

The net impact of these journal entries does not result in a change to net earnings (revenues of $32.85 million are offset by depreciation expense of $32.85 million). On the balance sheet, property plant & equipment is reduced by $51 million, regulated assets are increased by $18.15 million (the amount of depreciation not recovered in rates), DSRA cash is reduced by $22.75 million, long term debt is reduced by $40 million (reflecting the payment of both debt principal payments in 2021) and shareholder equity is reduced by $15.6 million (reflecting a portion of the return of equity to maintain the approved debt to equity ratio of 70:30). The remaining portion of return of equity to enable the maintenance of the approved debt to equity ratio is funded from revenues collected as amortization of deferred charges ($1.6m).

This proposal does not result in a net difference on the balance sheet from what would be the scenario had no cash been withdrawn from the DSRA. In both cases, the reduction in long term debt and return of equity is the same: long term debt must decrease by a total of $40 million (two $20 million debt principal payments) and shareholder equity will reduce by a total of $17.1 million in order for the 70:30 debt to equity ratio to be maintained.

As noted above, NSPML expects that the setting of rate base and the determination of depreciation for the remainder of the operating period (post the interim phase) will be addressed during the final cost proceeding.

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Request IR-7:

Exhibit N-1, Operating & Maintenance costs, Section 5.1.2:

a) Please identify the updated total costs (capital and operating) expected to be incurred prior to delivery of the NS Block per the application.

b) Please identify the updated total costs (capital and operating) incurred to date and forecast through to the anticipated NS Block delivery.

c) Have additional costs been imposed on Nova Scotia ratepayers as a result of the delay of the NS Block and associated Muskrat Falls Generating Station? Please explain and quantify.

d) Have additional costs been imposed on Nova Scotia ratepayers as a result of the delay of the NS Block and associated Muskrat Falls Generating Station as a result of COVID-19 pandemic, beyond what were existing construction issues and delays? Please explain and quantify?

e) How has or will NSPML determine the costs and cause of delays for purposes of negotiations with Nalcor related to various agreements?

Response IR-7:

a) NSPML is forecasting to be within the total capital budget approved by the UARB and within the forecasted operating and maintenance costs of $21.5 million included in this Assessment. As noted in the Application, the uncertainty caused by the pandemic presently leaves NSPML unable to provide a precise update on Nalcor's project schedule

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or the timing of the NS Block, and as such, NSPML is not in a position to segregate its costs before and after the date of delivery of the NS Block.

b) As at June 30 2020, NSPML has incurred $1.557 billion in capital expenditures and is forecasting to be within the capital budget approved by the UARB. As at June 30, 2020, NSPML has incurred $7.2 million in operating and maintenance costs year to date and expects to be within the total approved budget of $20.6 million approved as part of the 2020 interim assessment.

c)-d) Until delivery of the Nova Scotia Block commences, NS Power will need to replace this energy with energy from other sources. These actions will increase fuel costs; however, due to the favourable commodity pricing experienced thus far in 2020, NS Power does not currently project a significant FAM deferral balance at the end of the 2020-2022 Fuel Stability Period if NS Block does not commence until mid-2021. From the perspective of NS Power customers, there is no difference between delays related to COVID-19 and delays related to other Muskrat Falls Project issues. NS Power has not quantified or estimated the actual replacement energy costs associated with delays in delivery of the Nova Scotia Block.

e) NSPML will address any issues regarding the Nalcor agreements as part of its Final Cost Application.

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Request IR-8:

Exhibit N-2, Appendix B scenarios:

a) **Please indicate how the proposed assessments impact the Debt Service Reserve Account and any other covenants. Please identify any changes that would exist if not for the $22.75 million DSRA cash being utilized.**

b) **Please provide this debt service ratio (including inputs) quarterly since the inception of the project.**

c) **Will any debt service ratio requirement remain? If so, please explain and forecast the debt service ratio (including inputs) through 2021 based on NSPML's application request.**

d) **Please provide the inputs required through 2021 that reflect the lowest assessment required to maintain the 1.4 times total debt service ratio.**

Response IR-8:

a) If cash was not being drawn from the DSRA and replaced with a letter of credit, then the ML Credit Agreement would not be affected by this assessment request. If cash is drawn from the DSRA as proposed, then the ML Credit Agreement covenant affected is the calculation of the Debt Service Coverage Ratio ("DSCR"), which NSPML is required to maintain at least 1.40 on both a retrospective and prospective basis. The DSCR calculation is a comparison between Base Cash Flow and Total Debt Service. NSPML's revenue received from NS Power is factored into the computation of Base Cash Flow, but monies withdrawn from the DSRA are not. As a result, the DSCR will be reduced in proportion to the total cash withdrawn from the DSRA and not collected from customers.

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This is a matter that NSPML addressed with the Government of Canada as outlined in Attachments 1 and 2 to UARB IR-2.

b) See table below for a summary of the quarterly DSCR calculations which were submitted to the Collateral Agent, representing the Government of Canada:

	2018				**2019**				**2020**	
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2
Retrospective DSCR	**NIL**	**1.96**	**2.93**	**1.82**	**1.87**	**1.88**	**1.82**	**1.87**	**2.01**	**1.99**
ML Project Revenue	23.7	46.1	70.9	95.8	100.0	102.1	102.6	103.1	109.5	108.8
Cash Operating Costs	1.2	3.1	6.7	13.1	14.9	16.4	19.6	18.1	18.0	18.1
Debt Service	0.0	21.9	21.9	45.5	45.5	45.5	45.5	45.5	45.5	45.5
Prospective DSCR	**2.09**	**1.87**	**1.81**	**1.85**	**1.85**	**1.87**	**1.78**	**1.82**	**1.70**	**1.41**
ML Project Revenue	110.0	105.5	103.5	103.1	104.0	107.5	104.2	139.9	134.6	143.1
Cash Operating Costs	14.8	20.3	21.3	19.1	19.7	22.4	23.3	20.7	23.0	23.3
Debt Service	45.5	45.5	45.5	45.5	45.5	45.5	45.5	65.5	65.5	85.2

c) Yes, the DSCR requirement will remain in effect. The Prospective DSCR calculation for Q2 2020, which reflects a twelve-month forward-looking calculation covering July 1, 2020 through June 30, 2021, as noted in the table above illustrates the impact of the proposal on the DSCR. As noted in (a) above, the DSCR will decrease to the extent that cash is withdrawn from the DSRA and not collected as depreciation from NS Power as a revenue. This can be seen in the table in (b) above where the Prospective DSCR for Q2 2020, which covers the period from July 1, 2020 to June 30, 2021 is 1.41 since the ratio does not assume, for conservatism purposes of filing with the Collateral Agent, that the NS Block has begun by May 2021 and consequently assumes that $22.75 million of rate

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revenues on account of depreciation have not been received from NS Power and rather DSRA cash has been withdrawn to meet debt service. As noted above, this matter has been addressed between NSPML and the Government of Canada.

d) The inputs needed to achieve a minimum prospective DSCR of 1.4 are shown in the table provided in response to part (b) of this request for the Prospective DSCR in Q2 of 2020. This Prospective DSCR is based on the requested rate recovery contained in this Application for 2021 and assumes as noted above that $22.75 million of depreciation revenues are not collected in the first half of 2021 but rather DSRA cash of that amount is utilized to meet debt service. As NSPML explained in the 2020 interim assessment process, the Company highlights the importance of not further reducing its rate revenues in 2021 to ensure that the minimum 1.4 DSCR is maintained.

Request IR-9:

Exhibit N-1, Equity Financing Costs totalling $49 million, p. 27:

a) **In 2019, what was the approved equity return balance and rate and what was the actual return (balance and rate) on regulated equity?**

b) **If the net income varies from the forecast equity return, how has or will NSPML account for this?**

c) **Please confirm NSPML is calculating its 9.25% earnings cap and reducing this figure by the final approved holdback to establish a revised cap to ensure ratepayers are not inadvertently paying for any portion of the holdback.**

d) **Given the explanation that these 2021 delays are the result of the COVID-19 pandemic has NSPML made any concession in its earnings ask to reflect shareholder risk of not expecting to realize a full return on an investment?**

e) **Please confirm the range of reasonable return is approved at 8.75% to 9.25%? If so, what would equity return be if NSPML's shareholders were to seek only 8.75% return due to the unprecedented circumstances?**

Response IR-9:

a) In its 2017 application, NSPML forecasted that it would have total shareholder equity of approximately $560 million at the end of construction.[1] Based on that forecast, it requested and received approval to recover $51 million of net earnings in rates from NS

[1] M07718, NSPML Interim Assessment Application, December 16, 2016, section 5.4, page 26, line 11.

Power for each of 2018 and 2019. NSPML's audited financial statements for 2019 reported net earnings of $45.7 million. During 2019, NSPML estimates its average shareholder equity was approximately $549 million. Consequently, its return on equity percentage, prior to any regulatory adjustments, was approximately 8.3%.

NSPML has not undertaken to make the necessary adjustments in order to calculate regulated equity or regulated return on equity and will do so by the earlier of the filing of its final cost assessment or the date it is required to file its 2020 financial statements, as directed by the UARB in its letter dated July 13, 2020[2] which was part of the 2019 Affiliate Code of Conduct Report.

b) NSPML does not record any difference between forecasted and actual results.

c) NSPML will consider how the holdback mechanism may impact its regulated return on equity and the approved range of return on equity when it files regulated financial statements and regulated ROE as noted in (a) above.

d) No, NSPML has pursued this Application on the basis that it will be given a reasonable opportunity to recover its costs and a return on its investments, in keeping with the Board's findings in 2017 and again in 2019 that NSPML is entitled to a recover its prudently incurred costs, including a return of and on capital[3].

e) Confirmed that NSPML's range of regulated ROE has been approved at between 8.75% and 9.25%. NSPML has not calculated the amount of allowed return at an 8.75% return since the earnings base against which an allowed return would be applied has not been determined and will not be until the final cost proceeding. In addition, see response to (d) above.

[2] M09702, Board Letter regarding NSPML 2019 Affiliate Code of Conduct Report, July 13, 2020.
[3] M09277, Board Decision regarding NSPML 2020 Interim Cost Assessment, paragraphs 21-23.

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Request IR-10:

Re: Cash on hand:

a) What are the current unrestricted and restricted cash on hand balances as of June 30, 2020?

b) Please provide a full accounting of cash in and cash out since December 31, 2018, including detail of what it related to that reconciles to the June 30, 2020 cash on hand balance.

c) Please reconcile from the current cash on hand balances, to the projected opening 2021 balance, that will require the assessment as requested.

Response IR-10:

a) As at June 30, 2020, the total restricted cash balance was $27.8 million and unrestricted cash balance was $27.4 million.

b) See below a reconciliation of cash inflow and outflows from January 1, 2019 to June 30, 2020:

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Total Restricted and Unrestricted Cash (Millions $)

Balance January 1, 2019	**$81.2**
Total revenues (NS Power)	162.2
Total operating expenses	(24.4)
Other income	0.4
Interest expense	(66.6)
Income tax recovery	0.4
Changes in working capital	(7.2)
Additions to Property Plant & Equipment	(31.1)
Dividends paid	(59.5)
Other	(0.2)
Balance June 30, 2020	**$55.2**

c) See below the forecasted cash balance as at December 31, 2020

Total Restricted and Unrestricted Cash (Millions $)

Balance June 30, 2020	**$55.2**
Total revenues (NS Power)	81.1
Operating expenses	(13.4)
Debt principal payment & return of equity	(28.6)
Interest expense	(22.8)
Estimated Dividend to be paid	(27.5)
Forecasted Cash Balance Dec. 31, 2020	**$44.0***

*The forecasted cash balance as at December 31, 2020 includes DSRA cash of $22.75 million as well as approximately $20m on hand to fund remaining construction costs thus leaving approximately $1m of cash for working capital requirements.

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Request IR-11:

Are payments of other costs, such as interest (debt financing) and return (equity financing) costs, able to be delayed in a manner similar to depreciation and recognized or paid to NSPML from NS Power only as cash is required? If so, please explain any impact to earnings or rate base. If not, please provide detail of the covenants or other impacts that would restrict this.

Response IR-11:

NSPML submits that it is not in the best interest of customers to delay or defer recovery of other costs in a manner similar to the proposed deferral of recovery of depreciation.

While NSPML's other forecast costs (operating and maintenance, annual net interest costs and equity financing costs) are presented in the current and previous assessment requests on an annualized basis and then divided into equal monthly assessment payment requests, NSPML in fact incurs operating and maintenance costs in a variable fashion throughout the year as does any other business. The equal monthly assessment payments received from NS Power are not set to match variable monthly cash requirements, and it is NSPML's responsibility to manage its cash flow to meet expenses as they come due. NSPML has not included a specific amount for working capital in its assessment applications to date, but rather has drawn debt and maintained equity and managed its cash position as necessary to manage its cash flow requirements. Attempts to design deferral mechanisms for recovery of NSPML's forecast costs other than depreciation and amortized deferred financing costs would make prudent cash management difficult. Further, NSPML pays dividends on a quarterly basis to maintain its approved debt to equity ratio which avoids an unnecessary accumulation of shareholder equity in the business.

In its decisions relating to 2018, 2019 and 2020, the UARB permitted NSPML to recover its costs, excluding depreciation, on a predictable monthly basis which has enabled the company to

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manage its working capital requirements. This Application requests that the same treatment apply in 2021.

NSPML also highlights that attempting to further restrict its cash revenues in 2021 may added further pressure on its Debt Service Coverage Ratio as explained in NSUARB IR-8.