

**PREPARED FOR THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES OF  
NEWFOUNDLAND AND LABRADOR**

In response to Newfoundland Labrador  
Hydro's 2025 "Application for Capital  
Expenditures for the Purchase and Installation  
of Bay d'Espoir Unit 8 and Avalon  
Combustion Turbine"

**EXPERT REPORT OF VINCENT MUSCO AND COLLIN CAIN**

**February 3, 2026**

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## Abbreviations and defined terms used in report

**2024 Load Forecast Report** – Long-Term Load Forecast Report

**2024 RAP** – 2024 Resource Adequacy Plan

**AACE** – Association for the Advancement of Cost Engineering

**Avalon CT** – Avalon Combustion Turbine

**Bates White** – Bates White Economic Consulting, LLC

**BC Hydro** – British Columbia Hydro and Power Authority

**BCUC** – British Columbia Utilities Commission

**BDE** – Bay d’Espoir Hydroelectric Power Station

**BDE Unit 8** – Bay d’Espoir Unit 8

**BDE-SOP** – Bay d’Espoir to Soldiers Pond 230 kV transmission system

**BESS** – Battery Energy Storage Systems

**Board** – Newfoundland and Labrador Board of Commissioners of Public Utilities

**BoQ** – Bill of Quantities

**Build Application** – Application for Capital Expenditures for the Purchase and Installation of Bay d’Espoir Unit 8 and Avalon Combustion Turbine

**CAMS** – Consolidated Asset Management Services

**Change Control Committee** – Major Projects Change Control Committee

**Commission** – Commission of Inquiry Respecting the Muskrat Falls Project

**CPCN** – Certificate of Public Convenience and Necessity

**CSA** – Contractual Service Agreement

**CT** – Combustion Turbine

**DDA** – Design Development Allowance

**DLR** – Dynamic Line Rating

**E&M** – Electro-Mechanical

**ELCC** – Electric Load Carrying Capability

**EPCM** – Engineering, Procurement and Construction Management

**FEED** – Front-End Engineering Design

**GE** – General Electric

**Governance Framework** -- Major Projects Governance Framework

**Gruner** – Gruner Stucky AG

**GSU** – Generator Step-Up

**GT** – Gas Turbine

**Hatch** – Hatch Ltd.

**Hydro** – Newfoundland Labrador Hydro

**IBR** – Inverter-based resources

**IDC** – Interest During Construction

**IIS** – Newfoundland Island Interconnected System

**IR** – Information Request

**LIL** – Labrador Island Link

**LLWLT** – Lower Low Water, Large Tide

**LM6000** – LM6000PC Sprint

**LTMA** – Long Term Maintenance Agreement

**LTSA** – Long Term Service Agreement

**MCS** – Monte Carlo Simulation

**Muskrat Falls** – Muskrat Falls Generating Station

**NERC** – North American Electric Reliability Corporation

**NLIS** – Newfoundland and Labrador Interconnected System

**NLSO** – Newfoundland and Labrador System Operator

**RAS** – Remedial Action Scheme

**RAS Study** – Avalon Remedial Action Scheme Feasibility Study

**RFEOI** – Request for Expressions of Interest

**RFP** – Request for Proposals

**Risk Working Group** – Major Projects Risk Working Group

**SC** – Synchronous Condensing

**SCL** – Short Circuit Levels

**SSD** – Sunnyside Terminal Station

**Steering Committee** – Major Projects Steering Committee

**TGS** – Thermal Generation Station

**TransGrid** – TransGrid Solutions

**WECC** – Western Electric Coordinating Council

## I. Executive Summary<sup>1</sup>

- (1) This Phase 2 Expert Report addresses outstanding items and presents our conclusions concerning Hydro's Build Application for the Avalon CT and Bay d'Espoir Unit 8, following on the Bates White Phase One Expert Report (June 26, 2025) and Phase One Addendum Report (November 6, 2025).
- (2) Our primary conclusions and recommendations are the following:
  1. Bates White recommends that the Board consider approving the Avalon CT component of Hydro's Build Application, with a current estimated in-service date in March 2030.

The evidence in the record supports the need for the Avalon CT as necessary to accommodate the retirement of the Holyrood TGS. Bringing the Avalon CT into service as early as feasible will allow for the orderly, and possible progressive, retirement of the Holyrood units, mitigating cost while supporting system reliability. The evidence supports the need for the Avalon CT to address generation capacity needs on the Avalon Peninsula when Holyrood is no longer in service, including easing potential overload conditions on transmission during a LIL bipole outage.

2. The Board should defer approval of the BDE Unit 8 component of the Build Application until several critical unresolved issues are addressed.

Hydro's analyses supporting BDE Unit 8 as being preferred in sequence of addition to the Avalon CT are marginal and sensitive to assumptions such as the requirement to burn-off fuel uneconomically at the Avalon CT. Appropriate fuel management equipment and procedures would likely eliminate any uneconomic fuel burn-off at the Avalon CT, making it more economic than BDE Unit 8. Hydro's conclusion that BDE Unit 8's additional 12.8 MW of firm capacity produce a significant cost advantage in selecting BDE Unit 8 first is not adequately supported.

Evidence Hydro has provided to date does not adequately demonstrate the sufficiency of hydrology on the Bay d'Espoir reservoir system to support the full incremental generation capacity of BDE Unit 8 during an extended LIL bipole outage.

Evidence has not demonstrated that transmission is sufficient to deliver the full incremental generation capacity of BDE Unit 8 to the Avalon Peninsula during a LIL bipole outage. The Remedial Action Scheme approach advanced by Hydro has been determined to be a *feasible* alternative to a costly transmission upgrade, but details of an *actual* RAS remain to be developed. These items in flux include the specifics of the scheme, the requirements and

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<sup>1</sup> For readability, this Executive Summary uses summary terms defined in Section II of this report.

schedule for implementation, commissioning and testing, the expected impact on pre-contingency transmission utilization, and estimation of associated costs.

The IIS does not need both the Avalon CT and BDE Unit 8 by 2031, as long as Hydro's existing thermal assets remain operational. The timing of need for additional capacity beyond the Avalon CT has not been determined. Future build plans will be based on contemporary information, including: Newfoundland Power's plan to extend the lives of two gas turbines (totaling 48 MW of firm capacity), Hydro's most recent load forecast (2025), and Hydro's recent update to its effective load carrying capability which show higher capacity values for wind additions than assumed in the Build Application.

- (3) These unresolved issues, combined with the lack of immediate urgency to bring BDE Unit 8 into service, support a deferral of Board approval of BDE Unit 8 until the record can be more fully established.
- (4) The following summary addresses findings and conclusions regarding the evidence advanced for the respective projects.

#### **Avalon CT**

- (5) There is a clear, demonstrated need for new generation and synchronous condenser capability on the Avalon Peninsula that would be met appropriately by the proposed Avalon CT.
- (6) The importance and urgency of pursuing incremental generation capacity on the Avalon Peninsula is reinforced by Hydro's 2025–2026 Winter Readiness Planning Report, which describes efforts to support reservoir storage heading into the winter, and to bring Holyrood Unit 3 back online by late January 2026, following delays in the ongoing turbine and valves overhaul.<sup>2</sup>
- (7) The Avalon CT project proposal is sound, and the selection of three 50 MW LM6000 aeroderivative gas generator is appropriate to the stated reliability need to accommodate the retirement of Holyrood, providing the ability to come online quickly and to operate for an extended period, such as during a LIL outage event. The application and supporting documentation filed by Hydro indicates it to be a reasonably well-planned project at the current stage of development.
- (8) The CAMS technical review concluded that Avalon CT project is sound and that it is consistent with the stated system need. No major concerns were identified with the project design, scope, or specification of the Avalon CT project. CAMS concluded that certain outstanding project elements

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<sup>2</sup> Hydro, "2025–2026 Winter Readiness Planning Report," December 10, 2025, available at: <http://www.pub.nf.ca/indexreports/winterreadiness/From%20NLH%20-%202025%E2%80%932026%20Winter%20Readiness%20Planning%20Report%20-%20December%202025%20-%20Final%20Report%20-%202025-12-10.PDF>.

relating to fuel and water systems (noted below) remain to be addressed. While these outstanding issues do not warrant delaying the project, they should be addressed very early in the detailed project design phase.

- (9) The cost categories, and the general levels and relative magnitudes of costs in the application filed by Hydro, and as updated in December 2025, appear reasonable. Consistent with market intelligence obtained by CAMS on CT package cost trends, Hydro's December 2025 update reported a negotiated price for the three CT packages of \$280.2 million dollars, an increase relative to the Build Application value of approximately 67%.
- (10) Hydro has reported that the expected Commercial Operation Date of the Avalon CT has been delayed from January 2030 to March 2030, which is consistent with market information obtained by CAMS indicating increased lead times for major equipment delivery.
- (11) Water supply appears to be adequate to provide the needs for the CTs during extended periods of dispatch, considering the plant on a standalone basis. If the Holyrood TGS was to remain in service after the Avalon CT enters commercial operation, the adequacy of water to support simultaneous combined operation is not clear. Further review by Hydro may be needed to determine if the CTs can be operated for extended periods while the thermal units continue to operate.
- (12) The addition of liquid fuel recirculation and filtration equipment would eliminate the need for burning off excess stored fuel and would provide substantial operating cost savings to the project and reduce annual GHG emissions.
- (13) CAMS estimated the fuel needed to support extended full-load operation of the Avalon CT, in combination with the existing Holyrood TGS, and concluded that the required daily tanker truck deliveries could significantly exceed the level that Hydro has characterized as "unsustainable." CAMS concluded that the adequacy of fuel supply to the Avalon CT to support full output for an extended period, particularly in addition to full output at the Holyrood TGS, remains unresolved, and recommended that Hydro perform a full assessment of fueling options – including a dedicated diesel marine offload system – and present a recommendation to the Board for consideration.

### **BDE Unit 8**

- (14) With respect to the review of the BDE Unit 8 project, no major concerns were identified with the project design, scope, or specification. As stated in the Gruner Report, it is Gruner's opinion that the BDE Unit 8 project has been sufficiently developed and is a reasonable project overall. Still, we remain unconvinced that the BDE Unit 8 project should be approved immediately, as proposed.
  - First, the BDE Unit 8 project is, in our view, a lower priority project than the Avalon CT. As we indicated in our Phase One Addendum Report, the two projects are similar in cost, and it

is only BDE Unit 8's slightly larger capacity (+12.8 MW) that results in its earlier selection in Hydro's capacity expansion modeling. When the forced fuel burn-off requirement at the Avalon CT is removed, the Avalon CT is lower cost.

- Second, Hydro has demonstrated that the system does not require both the Avalon CT and BDE Unit 8 by 2031, as long as Hydro's existing thermal assets remain operational. Moreover, Newfoundland Power's plan to extend the lives of two gas turbines (totaling 48 MW of firm capacity) reduces and/or delays the need for additional firm capacity on the IIS, and Hydro's most recent load forecast (2025) indicates a reduction in peak demand of 14 MW and total energy of 289 GWh in 2035 compared to the load forecast used in the Build Application. Hydro's recent update to its ELCC assumptions indicate an increased ELCC assumption for incremental wind capacity, higher than what was assumed in the Build Application, suggesting that the assumed wind additions will contribute more firm capacity than modeled in the Build Application.
- Third, BDE Unit 8 is subject to distinct, project-specific risks, including hydrological sufficiency, cost overruns, and schedule challenges. Regarding hydrology, Hydro has provided evidence that the BDE system can sustain a similar level of output from BDE Units 1-8 as was modeled in the LIL Shortfall Analysis as part of the Build Application, though the results depend on certain assumptions and conditions incorporated by Hydro. Specifically, the results are conditioned on certain assumptions about average storage levels and average inflows, and also require significant spill activity which could prove less favorable than assumed, potentially increasing the risk of hydrological shortages in the BDE system either during a six-week LIL bipole outage or in the aftermath of such an event. We also acknowledge the value of the July 2024 Hatch Study, which shows that, through much higher reliance on thermal generation, and reduced BDE generation, there is hydrological sufficiency to sustain BDE Units 1 through 8's output during a six-week bipole outage of the LIL in the winter season. In sum, while Hydro has enhanced the evidentiary record on the question of hydrological sufficiency, the additional evidence is not sufficient to preclude any concerns about hydrological sufficiency during an extended bipole outage of the LIL. Other risks include potential for rapid water level reductions and impacts on ice cover and the impact of continuous operation of the Upper Salmon spillway. Hydro can address these risks through further study and identification of mitigation procedures.

- (15) Regarding cost, we identified no major concerns with the BDE Unit 8 cost estimate. As Gruner notes in its report, the project has been developed to a level of detail aligned with an AACE Class 3 estimate, which is typically used as a basis for budget authorization and appropriation, and is consistent with standard practice for hydropower projects and is based on quantities derived from a deterministic methodology. Gruner did recommend some relatively modest design changes that would reduce the overall cost estimate (see Gruner's Recommendations 6-1, 6-2, and 6-3). Gruner

also noted that the project is presently in the Front-End Engineering Design phase. If the Board approves the budget, the project will advance to the Execution Phase, which encompasses Detailed Design, Procurement, Construction, and Commissioning. Given the remaining risks associated with the current Class 3 cost estimate, Gruner recommends that the budget be revisited as the Detailed Design progresses. Hydro, which has been providing the Board with monthly updates on early execution activities and costs, could also update its budget estimates using information from its early execution activities, including engagement of turbine generator suppliers and Engineering, Procurement and Construction Management (“EPCM”) consulting services.

- (16) Further to cost, while we take no issue with Hydro’s methodological approach for calculating Management Reserve for BDE Unit 8, Hydro has ignored or understated certain strategic risks in BDE Unit 8’s Monte Carlo analysis (and Management Reserve calculation). These risks, identified by Hydro, relate in part to the potential for increased costs due to competition for contractors, labour, and equipment from other hydroelectric projects, including those to be developed by Hydro and Hydro-Quebec in a new, joint partnership. Potential tariffs of up to 25% on commodities imported from the United States also risk increasing project costs. Hydro quantified these risks across a variety of sensitivities; in total, the risks’ incremental impact on BDE Unit 8’s project cost range from a minimum of \$63.0 million to \$562.4 million. The interaction between the BDE Unit 8 project and the refurbishment of BDE Unit 7 could further exacerbate this risk. Hydro did not include these strategic risks in the determination of the Management Reserve. Timing challenges may explain the omission of these risks, but the potential cost impacts are too high to ignore. The cumulative impact of these three risks is estimated to be as high as \$562.4 million, which would represent an overall project cost increase of 52%. Hydro should address this potential in its updated calculations. The Board should consider requiring Hydro to incorporate these risks into an updated Monte Carlo analysis and Management Reserve calculation.
- (17) We note, too, that while BDE Unit 8 is likely to remain a more economic option than most supply alternatives (other than the Avalon CT), BESS become economic when the full budget of BDE Unit 8 is modeled. Moreover, Hydro has recently updated its ELCC assumptions for BESS resources. We also note that Hydro has received robust responses from interested third-party developers in its recent Request for Expression of Interest to provide up to 150 MW of new firm capacity (plus up to 500 GWh/year in firm energy). These facts suggest that alternatives to BDE Unit 8 do exist and can be further considered.
- (18) Regarding schedule, we identified no major concerns, with Gruner noting that the overall project layout and work sequencing are realistic while providing some suggested enhancements to reduce schedule risks. However, Hydro is separately pursuing refurbishment, and potential uprate, of BDE Unit 7, which would share certain facilities with BDE Unit 8. Schedule delays suffered by one project may negatively impact the schedule of the other.

- (19) Collectively, these updated circumstances and risks suggest that expedited action on BDE Unit 8 may not be necessary and that the project would benefit from additional evidentiary support and analytical review. Accordingly, we recommend that Hydro: (1) update its project cost estimate and Management Reserve calculation using updated information, applying Gruner’s related recommendations, and addressing our concerns with the Management Reserve calculation; (2) further assess the hydrological sufficiency and risks of the Bay d’Espoir system to address the concerns we raise here, in our Phase One Addendum Report, and in Gruner’s Report; and (3) confirm through capacity expansion modeling that BDE Unit 8 as proposed remains the optimal resource selection for further capacity expansion when considering (a) the updated (and lower) load forecast, (b) the Newfoundland Power firm generation refurbishment plans, and (c) updated BESS ELCC assumptions, or whether an alternative, smaller, or deferred (beyond 2031) supply resource addition would be more optimal.

### **Remedial Action Scheme**

- (20) Based on our review of the RAS to address transmission constraints on the BDE-SOP corridor, we conclude that the TransGrid RAS Study demonstrates that an RAS could be an effective alternative to construction of a new transmission line on the BDE-SOP corridor, albeit subject to additional observations and caveats.
- (21) The RAS would aim to increase system transfer capability to the Avalon Peninsula during a LIL bipole outage. Consistent with the application of RAS in other power systems, and with NERC guidelines, an Avalon RAS would be an automated load shed mechanism that would be “armed” during a LIL bipole outage, providing for immediate response to a further 230 kV line contingency that threatens the integrity of the power system. Such an immediate, automated response mechanism would allow the transmission system to be utilized at greater capacity during a LIL bipole outage prior to further contingency, and would thereby reduce the need for any pre-contingency load shed As discussed in Section VIII, in the absence of an RAS, or additional transmission investment, a LIL bipole outage would likely require pre-emptive shedding of load in order to protect the system against the impact of an additional contingency – i.e., transmission outage.
- (22) The study is explicitly a feasibility study, which, as characterized by Hydro, confirms “the technical viability of the Avalon RAS.”<sup>3</sup> The critical next step identified by Hydro is to “continue to engage Newfoundland Power on how the RAS can be implemented on its electrical system” with consideration given “to balancing the complexity of the implementation with refinements that would allow for reduced customer impact.”<sup>4</sup> The details of any eventual RAS, and its capability to allow greater power flows to the Avalon Peninsula during a LIL bipole outage remain to be determined. The

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<sup>3</sup> Hydro RAS Study Overview, page 10 line 21.

<sup>4</sup> Hydro RAS Study Overview, page 11 lines 18 to 20.

RAS Study does not present any cases without an RAS that would provide for an estimate of the extent of the flow increase.

- (23) It is not clear how to square the results of the RAS Study with those of the LIL Shortfall analyses that Hydro has presented, which showed a need for load shed while assuming new transmission (or equivalent) to improve deliverability of power to the Avalon Peninsula. We believe it is conservative, and appropriate, to assume that the actual RAS that is implemented would be less effective in increasing power flows to the Avalon Peninsula than a new transmission line. This implies that with a RAS some pre-contingency load shed would still be required during a LIL outage.
- (24) If an achievable, as opposed to technically feasible, RAS does not fully relieve BDE-SOP pre-contingency transmission constraints during a LIL bipole outage, then it is presumed that the full incremental capacity of BDE Unit 8 would not be deliverable to the Avalon Peninsula during a LIL bipole outage. BDE Unit 8 capacity could nonetheless reduce the volume of required load shed, but the extent of this contribution remains uncertain.
- (25) As indicated by Hydro, details of an actual RAS remain to be developed, including the specifics of the scheme, the requirements and schedule for implementation, and estimation of associated costs. Bates White finds that the results of the RAS Study support Hydro's plan to pursue the RAS in place of any near-term upgrade to transmission infrastructure.
- (26) Whether an additional transmission line on the BDE-SOP corridor will eventually be needed will depend on the details and effectiveness of the RAS, the amount of load growth on the Avalon Peninsula, and the location of further generation resources added to the system. Further information regarding potential transmission upgrades will be forthcoming in Hydro's Transmission Expansion Feasibility Study, now anticipated to be filed in February 2026.

### **Synchronous Condenser Capability**

- (27) Hydro has indicated a significant need for additional synchronous condenser capability on the IIS, particularly on the Avalon Peninsula. Incorporation of synchronous condenser capability within both the Avalon CT and BDE Unit 8 projects is reasonable and likely cost effective. Hydro reports that TransGrid is currently conducting a Reactive Power Study that will update Avalon generation and SC needs following a LIL bipole outage. The study was expected to be completed in December 2025, and Hydro intends to file it in February 2026 as part of the Reliability and Resource Adequacy Study Review proceeding.

### **Governance**

- (28) While we observe no major red flags in Hydro's proposed governance structure, we include two recommendations to enhance project governance. We recommend Hydro adjust its governance

structure to reconstitute the Risk Working Group and Change Control Committee to ensure these committees are independent of the team(s) responsible for project development. We also recommend the Board and Hydro both strongly consider adding external expertise to monitor and report on project status and risks on a regular (e.g., quarterly) basis.

### **Management Reserve**

- (29) The concept of a management reserve is not unprecedented, but it also not widespread. For example, CAMS notes that management reserve is not typically seen in the power generation industry for projects like the Avalon CT. The management reserve is a set-aside source of funds to be used only if unforeseeable, high-impact events occur that have substantial impacts on project costs. Having such funds set aside allows those high-impact events to be addressed with little or no impact on project development and schedule. In principle, a management reserve can help ease the regulatory burden of addressing unexpected or low probability events and facilitate efficient project management under such circumstances. However, an expansive initial budget approval could also blunt project management discipline, with the management reserve providing cover for poor cost estimation and poor project management. The purpose of the Management Reserve should be to provide additional, needed funds due to the manifestation of the strategic risks and should not be used as a backstop for poor cost estimates, poor contingency estimates, or poor project development and management.
- (30) The methodology approaches to calculating Management Reserve for both the Avalon CT and BDE Unit 8 projects, though differing in significant ways, are reasonable. We therefore do not take issue with Hydro's methodological approach for calculating Management Reserve for both projects, though we do note the following. Hydro's Monte Carlo analysis (and Management Reserve calculation) for BDE Unit 8 has ignored or understated certain strategic risks. Hydro did not include certain "emerging" strategic risks in the determination of the Management Reserve for BDE Unit 8, which Hydro estimates to potentially increase the project's costs by up to \$562.4 million. It is not clear if interaction between the BDE Unit 8 project and the refurbishment of BDE Unit 7 could further exacerbate this risk; Hydro should address this potential in its updated calculations. Hydro also did not capture all "unknown unknowns" in its specification of strategic risks for both projects. Further, Hydro potentially underestimated the upward cost impact of certain project risks, such as challenges in EPCM contracting. The Board should consider requiring Hydro to incorporate these risks into an updated Monte Carlo analysis and Management Reserve calculation.
- (31) Ideally, access to the Management Reserve funds would require Board review, but must be balanced against the goal of allowing project development to continue without delay when additional funds are needed. As proposed by Hydro, access to the Management Reserve fund will ultimately be controlled by the Hydro CEO, with no further approvals needed from the Board to access those funds. This approach offers little oversight, transparency, or accountability for Hydro in accessing Management Reserve funds. If the Board is to approve a Management Reserve, it is our view that the Board should

consider requiring Hydro to formally notify the Board if it anticipates tapping into the Management Reserve funds and again when those funds are accessed. The Board should request supporting information from Hydro regarding the details of the need for and amount of Management Reserve funds accessed. Moreover, even if use of the Management Review is reported to the Board, the Board should pursue a prudency review at the end of the project to test the validity of use of the Management Reserve to ensure that such funds were due to the types of “unknown unknowns” risks for which the Management Reserve is intended, and not as a general backstop for cost overruns. The burden of prudence should remain with Hydro in all cases, and the Board should review Hydro’s submissions for evidence that the strategic risks that those funds are meant to cover have materialized and driven the costs of the project higher.

- (32) Additional clarity regarding the Management Reserve is also needed. Specifically, Hydro must better define the subjective materiality threshold for changes in project schedules and budgets. Also, while Hydro commits to “report to the Board for further review if costs to complete a project are forecasted to exceed 10% of the approved project budget,”<sup>5</sup> we recommend that the 10% threshold (or any other threshold imposed by the Board) is calculated off of the project’s Authorized Budget, less the Management Reserve.

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<sup>5</sup> Build Application, Schedule 1, Attachment 1, footnote 36.

## II. Introduction and background

- (33) In November of 2023, Bates White Economic Consulting, LLC (“Bates White”) was retained by the Newfoundland and Labrador Board of Commissioners of Public Utilities (“Board”) as an Expert Consultant to support the Reliability and Resource Adequacy Review. Specifically, Bates White was retained to assess the reliability and resource adequacy of the Newfoundland and Labrador Interconnected System (“NLIS”), considering especially the impacts of electrification, clean electricity regulations, evolving resource and technological potential in the Province, and the operational uncertainty of existing supply and transmission resources in the Province, including Muskrat Falls Generating Station (“Muskrat Falls”) and the Labrador Island Link (“LIL”). Bates White was subsequently retained to provide Expert Consulting services to the Board regarding the “Application for Capital Expenditures for the Purchase and Installation of Bay d’Espoir Unit 8 and Avalon Combustion Turbine” (“Build Application”), filed on March 21, 2025 by Newfoundland Labrador Hydro (“Hydro”),<sup>6</sup> including advising the Board on the Build Application’s relation to the 2024 Resource Adequacy Plan (“2024 RAP”).<sup>7</sup>
- (34) Since being retained by the Board, Bates White has reviewed Hydro’s Long-Term Load Forecast, filed by Hydro on March 28, 2024, and Hydro’s 2024 RAP, filed on July 9, 2024. Following Information Requests (“IRs”) and calls with Hydro and Board Staff, Bates White filed an expert assessment of the 2024 RAP with the Board on August 30, 2024, providing over 60 action items for Hydro to consider before moving forward with the resource planning process.<sup>8</sup> Hydro addressed these items in Technical Conferences with Bates White and other stakeholder parties. Bates White subsequently held additional calls with Hydro to review specific matters of interest to the 2024 RAP, and would use the basis provided by these Technical Conferences, IRs, and meetings to review and provide feedback on a proposed settlement agreement between Hydro, the Board, and stakeholder parties which was filed in March of 2025.<sup>9</sup>
- (35) Bates White continued to provide expert consulting to the Board in review of Hydro’s 2025 Build Application. Following Hydro’s filing of the Build Application, Bates White hosted numerous calls to

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<sup>6</sup> Hydro, “Application for Capital Expenditures for the Purchase and Installation of Bay d’Espoir Unit 8 and Avalon Combustion Turbine – Confidential,” March 21, 2025, available at: <https://nlhydro.com/wp-content/uploads/2025/09/From-NLH-Application-for-Capital-Expenditures-for-the-Purchase-and-Installation-of-Bay-d’Espoir-Unit-8-and-Avalon-Combustion-Turbine-Redacted-2025-03-21-UPDATED-2025-05-09-compressed.pdf> (“Build Application”).

<sup>7</sup> Hydro, “Reliability and Resource Adequacy Study Review – 2024 Resource Adequacy Plan – Revision 2,” August 26, 2024, available at: [https://nlhydro.com/wp-content/uploads/2024/08/2024-08-26\\_NLH\\_RRA-Study\\_2024-RAP\\_Rev-2.pdf](https://nlhydro.com/wp-content/uploads/2024/08/2024-08-26_NLH_RRA-Study_2024-RAP_Rev-2.pdf) (“2024 RAP”).

<sup>8</sup> Vincent Musco, Collin Cain, and Nick Puga, “Assessment of Newfoundland and Labrador Hydro’s 2024 Resource Adequacy Plan,” August 30, 2024, available at: <http://www.pub.nl.ca/applications/NLH2025AvalonCombustionMarch/report/Bates%20White%20-%20Expert%20Report%20-%20Assessment%20of%20NLHs%20-%202024%20Resource%20Adequacy%20Plan%20-%202024-08-30.PDF> (“Bates White Assessment of 2024 RAP”).

<sup>9</sup> See: Build Application, Schedule 2.

review all inputs pertaining to the 2024 RAP and Long-Term Load Forecast Report (“2024 Load Forecast”),<sup>10</sup> and submitted additional IRs pertaining to the Build Application which Hydro responded to on a rolling basis through May 2025. On June 26, 2025 Bates White filed an Expert Report in review of the Build Application (“Bates White Phase One Expert Report”).<sup>11</sup> This report provided an assessment of the modeling and planning efforts led by Hydro to determine new resource needs and selections. In recognition of the findings and conclusions outlined in the Bates White Phase One Expert Report, the following recommendations were offered:<sup>12</sup>

1. Hydro should address and reconcile the potential modeling inconsistency regarding the resource selection identified by Hydro under Scenario 4AEFC.<sup>13</sup>
2. Hydro should conduct capacity expansion model runs relaxing the constraints around the Avalon Combustion Turbine (“Avalon CT”), including both the 150 MW limit and the 150 MW “blocks” modeled, to allow for smaller, 50 MW blocks, and additions beyond the 150 MW limit.
3. Hydro should conduct capacity expansion model runs that include battery energy storage systems (“BESS”) resources of 4-hour and 8-hour duration, assuming effective load carrying capabilities (“ELCCs”) of 60%, using updated capital cost estimates for BESS resources. These runs should be conducted for Scenarios 4AEF, 4AEFC, and 4AEFDH. These model runs will allow for better understanding of the economics of BESS resources relative to Bay d’Espoir Unit 8 (“BDE Unit 8”) and the Avalon CT.
  - Collectively, then, we recommend three additional capacity expansion model runs. In each run, Hydro should address our Recommendations 2 and 3 above. That is, each run should relax the Combustion Turbine (“CT”) constraints and BESS prohibition and should be conducted across the three Scenarios identified in Recommendation 3.
4. Hydro should conduct one LIL Shortfall Analysis run using BESS resources that are selected as part of expansion plans identified in the additional capacity expansion model run associated with Scenario 4AEF, identified in the prior bullet (Recommendation 3). If no

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<sup>10</sup> See: Build Application, Schedule 3, Appendix A.

<sup>11</sup> “Expert Report of Vincent Musco and Collin Cain,” June 26, 2025, available at: <http://www.pub.nl.ca/applications/NLH2025AvalonCombustionMarch/report/Bates%20White%20Economic%20Consulting%20-%20Expert%20Report%20-%20REDACTED%20-%202025-06-26.PDF> (“Bates White Phase One Expert Report”).

<sup>12</sup> Bates White Phase One Expert Report, pages 14 to 15, paragraph 13.

<sup>13</sup> For information regarding the core scenarios considered by Hydro, see Appendix C to this report. See also: “Expert Addendum Report of Vincent Musco and Collin Cain,” November 6, 2025, Appendix C, available at: <http://www.pub.nf.ca/applications/NLH2025AvalonCombustionMarch/report/Bates%20White%20Economic%20Consulting%20Expert%20Addendum%20Report%20-%202025-11-06.PDF> (“Bates White Phase One Addendum Report”).

BESS resources are selected in that model run, this additional LIL Shortfall Analysis run would be unnecessary.

5. Hydro should conduct one LIL Shortfall Analysis run that limits the output of BDE to match potential hydrological resource constraints identified in Section III.H of the Bates White Phase One Expert Report. Alternatively, Hydro should supplement the record with additional evidence that Bay d’Espoir will be able to produce at collective output levels assumed in the LIL Shortfall Analysis runs included in the Application, and that those volumes can be deliverable to the Avalon in all hours.
  6. Hydro should conduct one LIL Shortfall Analysis run that assumes Holyrood Thermal Generation Station (“TGS”), Stephenville Gas Turbine (“GT”), and Hardwoods GT are not retired, the Avalon CT is in service, and BDE Unit 8 is not in service.
    - Collectively, then, we recommend three additional LIL Shortfall Analysis runs—one for Recommendation 4, one for Recommendation 5, and one for Recommendation 6.
  7. We reiterate our August 2024 recommendation for Hydro to consider employing competitive solicitation for its energy and capacity needs.
  8. NPVs of the capacity expansion modeling runs should be recalculated accounting for the recalculated Management Reserves.
  9. Hydro should address the load forecast discrepancy identified in Section III.B of the Bates White Phase One Expert Report.
- (36) On July 22, 2025, the Board asked Hydro to provide additional information based on the conclusions and recommendations identified in the Bates White Phase One Expert Report.<sup>14</sup> Across fourteen grouped questions, the Board, relying upon feedback from Bates White, requested four additional model runs of the capacity expansion model and four additional LIL Shortfall Analysis model runs.<sup>15</sup> Hydro was also asked to address possible inconsistencies on items such as: (1) fuel burn-off requirements;<sup>16</sup> (2) management reserve calculations;<sup>17</sup> and (3) load forecasts.<sup>18</sup> The Board also asked

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<sup>14</sup> Board, “Newfoundland and Labrador Hydro - 2025 Capital Budget Supplemental Application - Application for Capital Expenditures for the Purchase and Installation of Bay d’Espoir Unit 8 and Avalon Combustion Turbine - To Parties – Request to Hydro to Provide Additional Information,” July 22, 2025 available at: <http://www.pub.nl.ca/applications/NLH2025AvalonCombustionMarch/correspondence/To%20Parties%20-%20Request%20to%20Hydro%20to%20Provide%20Additional%20Information%20-%202025-07-22.PDF> (“Board July Letter”).

<sup>15</sup> Board July Letter, page 2, items 2, 3, and 4.

<sup>16</sup> Board July Letter, pages 1 and 2, item 1.

<sup>17</sup> Board July Letter, page 3, item 6.

<sup>18</sup> Board July Letter, page 3, item 7.

Hydro to: (4) reply to Bates White’s recommendation of a competitive solicitation for energy and capacity needs;<sup>19</sup> (5) provide further information on the proposed life extension and capacity increase to BDE Unit 7;<sup>20</sup> (6) justify the depreciable lifespans used for the Avalon CT and BDE Unit 8;<sup>21</sup> (7) provide a *pro forma* incremental customer rate impact analysis from 2030 through 2040;<sup>22</sup> (8) provide an update on the status of ongoing studies which are expected to be filed in 2025;<sup>23</sup> (9) consider bifurcation of the projects while the Transmission Expansion Feasibility Study remains in progress;<sup>24</sup> (10) address the impact on costs and in-service dates should approval be delayed to after the year’s end;<sup>25</sup> and (11) to confirm if Hydro has a Constitutional obligation to consult and accommodate indigenous communities in the development of the new generation resources.<sup>26</sup>

- (37) On September 11, 2025, Hydro provided responses to each of the fourteen requests made by the Board (“Hydro September Reply”),<sup>27</sup> and reported the results of an additional nine capacity expansion sensitivities and four additional LIL Shortfall Analyses.<sup>28</sup> Bates White reviewed these responses and held additional communications with Hydro, including email exchanges and a discussion between Hydro and Bates White on October 3, 2025. Responding to the Hydro September Reply and these exchanges, Bates White filed an Expert Addendum Report on November 6, 2025 (“Bates White Phase One Addendum Report”).<sup>29</sup> The Bates White Phase One Addendum Report found that the Hydro September Reply substantially enhanced the record, and fully addressed and resolved several outstanding issues raised either in the Bates White Phase One Expert Report or the Board’s July Letter.
- (38) The review offered in the Bates White Phase One Expert Report and the subsequent Bates White Phase One Addendum Report was limited to Hydro’s planning efforts completed in 2024, and therefore excluded detailed assessments of cost estimates, project schedules, and project management

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<sup>19</sup> Board July Letter, pages 2 and 3, item 5.

<sup>20</sup> Board July Letter, page 3, item 8.

<sup>21</sup> Board July Letter, page 3, item 9.

<sup>22</sup> Board July Letter, page 3, item 10.

<sup>23</sup> Board July Letter, pages 3 and 4, item 11.

<sup>24</sup> Board July Letter, page 4, item 12.

<sup>25</sup> Board July Letter, page 4, item 13.

<sup>26</sup> Board July Letter, page 4, item 14.

<sup>27</sup> Hydro, “2025 Build Application – Request to Hydro to Provide Additional Information – Hydro’s Reply,” September 11, 2025, available at: <http://www.pub.nl.ca/applications/NLH2025AvalonCombustionMarch/correspondence/From%20NLH%20-%20Reply%20to%20Boards%20Request%20for%20Additional%20Information%20-%202025-09-11%20-%20REDACTED.pdf> (“Hydro September Reply”).

<sup>28</sup> Hydro September Reply, Transmission Letter, page 2; Hydro September Reply, Question 3a, page 5 line 5 to page 11 line 1; Hydro September Reply, Question 3c, page 1 lines 9 to 14; Hydro September Reply, Question 4, page 8 line 17 to page 11 line 12.

<sup>29</sup> Bates White Phase One Addendum Report.

protocols, among other items. This Phase Two report addresses these outstanding items, along with other topics which have arisen through communications with Hydro and the Board.

- (39) To assist in the review and assessment of the Build Application, Bates White has retained Gruner Stucky AG (“Gruner”) and Consolidated Asset Management Services (“CAMS”) to review the BDE Unit 8 and Avalon CT projects, respectively. Both firms have significant experience with their respective technologies and provide critical analyses on the efficacy of the projects presented by Hydro in the Build Application.
  
- (40) In this report, we assess both the BDE Unit 8 and Avalon CT projects, including costs, schedules, design, and fuel/hydrology considerations, among others. We review Hydro’s planned governance protocols for project development and management, as well as Hydro’s plan to implement a “Management Reserve” allowance for both projects. We also review two other issues requested by the Board: a review of Hydro’s proposed remedial action scheme to manage transmission bottlenecks across a key portion of its 230 kV system and a review of Hydro’s analysis of its synchronous condenser needs. Throughout our report, we provide recommendations that we summarize in Section IX.

### III. Summary of Phase One Findings

- (41) The Bates White Phase One Expert Report and associated Bates White Phase One Addendum Report offered a preliminary review of Hydro's Build Application, focused to the planning efforts completed in 2024. In reviewing the evidence Hydro placed on the record and exchanged via IRs, Technical Conferences (held in the Fall of 2024), email exchanges, and other calls, Bates White provided recommendations and observations on the Build Application process. Many of these recommendations were addressed and answered to in the Hydro September Reply. In review of those responses, Bates White observed:<sup>30</sup>
- Hydro's additional capacity expansion modeling demonstrates that Bay d'Espoir Unit 8 and the Avalon CT are similar in cost. When the forced fuel-burn-off requirement at the Avalon CT is removed, the Avalon CT is lower cost but is selected after BDE Unit 8 due solely to the 12.8 MW greater modeled firm capacity of BDE Unit 8. Building BDE Unit 8 first delays build of the Avalon CT by one year, providing cost savings of approximately 0.4% on a net present value basis, relative to building the Avalon CT first.
  - Hydro has provided evidence that the BDE system can sustain a level of output from BDE Units 1-8 similar to that modeled in the LIL Shortfall Analysis as part of the Build Application. Results depend on assumptions about (a) reservoir storage levels, (b) average inflows, and (c) significant spill activity that could be less favorable than assumed, which could increase the risk of hydrological shortages in the BDE system either during a six-week LIL bipole outage or in the aftermath of such an event.
  - Hydro has demonstrated that the existing transmission grid is sufficient to allow for power flows from Bay d'Espoir to the Avalon Peninsula during normal operating conditions and single contingencies, which does not include an extended LIL bipole outage.<sup>31</sup>
  - Newfoundland Power's plan to extend the lives of certain thermal generating assets would provide significant firm capacity that reduces and/or delays the need for additional firm capacity on the Newfoundland Island Interconnected System ("IIS").
  - BESS resources are shown to be economic when BDE Unit 8 and the Avalon CT are modeled at their full requested authorized budgets and provide meaningful contributions during an extended outage of the LIL bipole. (We note, too, that Hydro has subsequently updated the ELCC values assumed for BESS resources, as provided to the Board in its December 9, 2025

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<sup>30</sup> Bates White Phase One Addendum Report, pages 45 and 46, paragraph 107.

<sup>31</sup> As discussed in this Phase 2 Report, Hydro has identified a Remedial Action Scheme ("RAS") as a feasible means to improve transfer capability during a LIL bipole outage, and is continuing to pursue this approach, with details and resulting impacts yet to be determined.

filing,<sup>32</sup> demonstrating ELCCs ranging from 37 to 43% for four-hour duration BESS projects and 50 to 59% for eight-hour BESS projects on a standalone basis,<sup>33</sup> while providing higher ELCCs when paired with incremental wind capacity.<sup>34</sup>)

- The response to Hydro’s Request for Expressions of Interest (“RFEOI”) process suggests potentially robust interest in third-party willingness to supply firm energy and capacity to the province.
- Hydro has demonstrated that if the Avalon CT or BDE Unit 8 were delayed to commercial operation dates beyond 2031, the IIS would not suffer from a generation shortfall as long as Hydro’s existing thermal assets remain operational.
- Several key issues should be addressed in the remainder of the Build Application process. These include (1) the validity of the modeled fuel burn-off requirement at the Avalon CT, (2) the impact of using a remedial action scheme to manage capacity transfer limitations on the Bay d’Espoir to Soldiers Pond transmission corridor, (3) cost considerations for both the Avalon CT and BDE Unit 8 projects, including any updates to cost estimates driven by procurement activities Hydro is currently pursuing on both projects, and (4) incorporation of any updates regarding the planned refurbishment and possible uprate of BDE Unit 7.

(42) Having reviewed all materials on the record, the Bates White Phase One Addendum Report included a limited number of recommendations, namely:<sup>35</sup>

- **Recommendation 1:** Going forward, BESS resources should be considered as viable resources in future Hydro resource planning decisions, should resource needs persist (such as Hydro claims regarding the implications of applying Hydro’s Reference Case load forecast).<sup>36</sup>
- **Recommendation 2:** We continue to recommend that Hydro seek to introduce and invite competition from third parties in its future resource planning and development activities, and to do so earlier in the process to allow sufficient time for the work required to make third-party projects viable.

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<sup>32</sup> Hydro, “Effective Load Carrying Capability Study,” December 9, 2025, available at: <http://www.pub.nf.ca/applications/NLH2018ReliabilityAdequacy/study/From%20NLH%20-%20Effective%20Load%20Carrying%20Capability%20Study%20-%202025-12-09.PDF> (“Evaluating Effective Load Carrying Capability”).

<sup>33</sup> Evaluating Effective Load Carrying Capability, Table 3.

<sup>34</sup> Evaluating Effective Load Carrying Capability, Table 4.

<sup>35</sup> Bates White Phase One Addendum Report, page 46, paragraph 108.

<sup>36</sup> We note that on December 9, 2025, Hydro filed an updated study assessing the effective load carrying capability of BESS and other supply resources, as referenced above.

- **Recommendation 3**: Hydro will need prudent investment planning to balance the risk of underinvesting in its existing assets that may be needed longer than expected against overinvesting in assets about to retire.

(43) As discussed above, these conclusions and recommendations were limited in scope to the planning efforts in 2024. This Phase Two report builds on the conclusions of the Bates White Phase One Expert Report and Bates White Phase One Addendum Report, incorporates additional information provided by Hydro subsequent to the filing of our Phase One Addendum Report, and addresses an expanded scope including Hydro's detailed cost estimates, project schedules, and project management protocols, among other items.

## IV. Review of Avalon CT

- (44) In this section, we provide an assessment of the proposed Avalon CT project, developed in conjunction with CAMS, our independent subcontractor. CAMS is an integrated power infrastructure firm with particular expertise with combustion turbine power plants. CAMS has provided a separate report on the Avalon CT project, included as Appendix 1 to this report.
- (45) The CAMS report assesses (1) the proposed combustion turbines, (2) fuel system, (3) water supply (4) the potential need for annual fuel burn-off, (5) capital expenditures and spare parts, (6) operating costs, (7) contingency and management reserves, (8) consideration of major maintenance schedule and associated costs, and (8) consideration of service agreement and lease program options. In this section, we provide a high-level overview of the CAMS report, and additional narrative, conclusions, and recommendations as appropriate. This section should be read in conjunction with the CAMS report and is intended to adopt and/or reflect CAMS' findings, conclusions, and recommendations.

### A. Avalon CT Project Overview

- (46) The Avalon CT project consists of a new multi-unit 150 MW generating facility to be constructed on the site of the Holyrood TGS, and is intended to support system reliability and reduce reliance on the Holyrood TGS, ultimately facilitating retirement of Holyrood.<sup>37</sup> The planned CT site, adjacent to the Holyrood TGS, is shown in Figure 1.

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<sup>37</sup> Build Application, Schedule 1, page 40 lines 12 to 16.

Figure 1: Planned Site of Avalon CT<sup>38</sup>



- (47) The project encompasses construction of a new plant, installation of the CT generating units, and associated infrastructure and transmission interconnection, including transformers, a demineralized water plant, a compressed air system, and a black start generator. Fueling infrastructure includes a new No. 2 diesel tank farm and a truck offload delivery system.<sup>39</sup>
- (48) Hydro engaged Hatch Ltd. (“Hatch”) to develop a detailed cost estimate for the Avalon CT project. Hatch estimated costs for EPCM, equipment and materials, and construction and completions. Hatch also incorporated inputs provided by Hydro for personnel costs, project escalation, and Interest During Construction (“IDC”). Using a Monte Carlo Simulation, Hatch also calculated Contingency and Management Reserves.<sup>40</sup>
- (49) The component cost estimates for the Avalon CT that produce the requested Authorized Budget of \$891,415,257 are summarized in Table 1.

<sup>38</sup> Build Application, Schedule 1, Figure 7.

<sup>39</sup> Build Application, Schedule 1, page 41 lines 1 to 6.

<sup>40</sup> Build Application, Schedule 5, Attachment 1, page 1.

**Table 1: Avalon CT Basis of Cost Summary<sup>41</sup>**

Component		Estimated Cost
Direct Construction Costs		
Site-Wide Development	[a]	██████████
Tank Farm	[b]	██████████
CT Plant	[c]	██████████
Transformer Yard	[d]	██████████
Switchyard	[e]	██████████
Raw Water	[f]	██████████
Fuel Offloading	[g]	██████████
Transmission Lines Costs	[h]	██████████
<b>Subtotal Direct Construction Costs</b>	<b>[i] = [a] + [b] + [c] + [d] + [e] + [f] + [g] + [h]</b>	<b>367,756,014</b>
Indirect Construction Costs		
Contractor Indirect	[j]	██████████
EPCM Consultant	[k]	██████████
Hydro Project Management	[l]	██████████
Other Hydro Costs (Spare Transformer, Insurance, FEED, etc.)	[m]	██████████
<b>Indirect Construction Costs Subtotal</b>	<b>[n] = [j] + [k] + [l] + [m]</b>	<b>218,886,796</b>
<b>Subtotal Base Cost (Direct + Indirect) Estimate</b>	<b>[o] = [i] + [n]</b>	<b>586,642,810</b>
Project Contingency	[p]	65,117,352
<b>Subtotal Base Estimate (with Contingency)</b>	<b>[q] = [o] + [p]</b>	<b>651,760,162</b>
Escalation	[r]	44,845,915
Interest During Construction (IDC)	[s]	66,569,342
<b>Subtotal Planned Budget</b>	<b>[t] = [q] + [r] + [s]</b>	<b>763,175,419</b>
Management Reserve	[u]	128,239,838
<b>Total Cost Estimate (Authorized Budget upon Approval)</b>	<b>[v] = [t] + [u]</b>	<b>891,415,257</b>

(50) The Build Application anticipated major project milestones for the Avalon CT as shown in Table 2.

<sup>41</sup> Build Application, Schedule 5, Attachment 1, Table 1.

**Table 2: Build Application Avalon CT Major Milestones<sup>42</sup>**

Milestone Description	Date
Environmental Assessment Release	Q2 2025
Award Transformer Contract	Q2 2025
Award CT Contract	Q3 2025
Award EPCM contract	Q3 2025
Build Application Approval	Q4 2025
Start Main On-Site Construction Works	2026
Start of Commissioning	2029
Turbine Ready for Commercial Operation	2029

## B. Project Status

- (51) On April 25, 2025, the Board approved Hydro’s Early Execution application, intended to support activities to advance the Avalon CT project prior to approval of the Build Application itself.<sup>43</sup> The approved early execution budget was \$30,710,000, encompassing activities including transformer contract award, CT generator package award, and EPCM contract award – all initially anticipated to occur in the third quarter of 2025.<sup>44</sup> Based on the latest information reviewed, none of the contract awards has been completed.
- (52) Hydro has filed multiple Early Execution Updates. In the October 21, 2025 Early Execution Update Hydro reported that it has received all necessary permits for the early works scope.<sup>45</sup> In the January 15, 2026 Early Execution Update, Hydro reported on contracting progress:
- **Transformers** – a Request for Proposals (“RFP”) for four generator step-up transformers and one station service transformer closed on June 17, 2025, with seven proposals received. Negotiations with the highest scoring proponent are continuing, and Hydro expects an award in late January, 2026.<sup>46</sup>

<sup>42</sup> Build Application, Schedule 1, Table 3.

<sup>43</sup> Board, “An Order Of The Board No. P.U. 17(2025),” April 25, 2025, available at: [http://www.pub.nl.ca/PU/orders/2025/P.U.%2017\(2025\).PDF](http://www.pub.nl.ca/PU/orders/2025/P.U.%2017(2025).PDF) (“Early Execution Order”).

<sup>44</sup> Early Execution Order, page 4; Build Application, Schedule 1, Table 3; see: Table 2 above.

<sup>45</sup> Hydro, “Avalon Combustion Turbine Project Early Execution Update Period Ended August 31, 2025,” October 21, 2025, available at: <http://www.pub.nl.ca/indexreports/avaloncombustion/From%20NLH%20-%20Avalon%20Combustion%20Turbine%20Project%20Early%20Execution%20Update%20-%20August%202025%20-%202025-10-21%20-%20REDACTED.PDF> (“ACT October Update”).

<sup>46</sup> Hydro, “Avalon Combustion Turbine Project Early Execution Update,” January 15, 2026, page 1, lines 14 to 20, available at: <http://www.pub.nl.ca/indexreports/avaloncombustion/From%20NLH%20-%20Avalon%20Combustion%20Turbine%20Project%20Early%20Execution%20Update%20-%20November%202025%20-%202026-01-15%20-%20%20REDACTED.PDF> (“ACT January 2026 Update”).

- **CTs** – an RFP for the supply of CTs closed on July 4, 2025, with two bidders. Negotiations with the highest scoring bidder have concluded successfully, and Hydro issued a Limited Notice to Proceed (“LNTP”) on December 15, 2025.<sup>47</sup>
- **EPCM** – an RFP for EPCM services closed on August 28, 2025, with one submission, and concluded without an award. A revised RFP was issued on October 24, 2025, with a closing date scheduled for January 21, 2026, subsequently revised to March 4, 2026, with an award anticipated by July 2026. Hydro reported its assessment that sufficient schedule flexibility remains to accommodate the delayed award with no change to the project’s Commercial Operation Date (March 2030).<sup>48</sup>

(53) Other reported progress:

- Field work for the Geotechnical Investigation was completed on December 12, 2025, and a final geotechnical report is expected in the first quarter of 2026.<sup>49</sup>
- Water and wastewater tie-in investigations, awarded to Hatch;<sup>50</sup>
- Civil works, awarded to The Cahill Group.<sup>51</sup>
- Hydro is collaborating with Newfoundland Power for the development, design and execution of relocating Transmission Lines 38L and 39L (lines that are within the project footprint at the Holyrood site). The Transmission Line 38L outage was completed, and the rerouted line returned to service. Completion of the 39L work was deferred because of weather. Hydro is working with Newfoundland Power to determine a new outage date for line 39L.

(54) In the ACT January 2026 Update, Hydro repeated its identification of key risks associated with equipment supply:

- “Supply chain pressures may increase the cost of goods and increase delivery times.”<sup>52</sup>
- “CT supplier backlog as a result of competition from other projects, there may be limited supplier resources, added complexities in the international supply chain, and a potential sellers’ market resulting in higher costs and extended delivery schedules.”<sup>53</sup>

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<sup>47</sup> ACT January 2026 Update, page 1 lines 5 to 8.

<sup>48</sup> ACT January 2026 Update, page 1 line 25 to page 2 line 15.

<sup>49</sup> ACT January 2026 Update, page 2 lines 17 to 18.

<sup>50</sup> ACT October Update, page 2 lines 15 to 24.

<sup>51</sup> ACT October Update, page 2 line 26 to 28.

<sup>52</sup> ACT January 2026 Update, Table 1.

<sup>53</sup> ACT January 2026 Update, Table 1.

- (55) As discussed below, the supply risks identified by Hydro reflect the reality of the current market. Increased costs and delivery times are likely unavoidable, as such the risks are better characterized as the magnitude of increased costs and the extent of delivery delays.

## C. CAMS's Assessment

- (56) In summary, the CAMS review of Hydro's Avalon CT project proposal, design, and cost estimation supports the following conclusions:
- The Avalon CT project proposal is sound, and the selection of three 50 MW LM6000 aeroderivative CTs is appropriate to the stated reliability need to accommodate the retirement of Holyrood, providing the ability to come online quickly and to operate for an extended period, such as during a LIL outage event.<sup>54</sup> The application and supporting documentation filed by Hydro indicate that the Avalon CT is a reasonably well-planned project at the current stage of development.<sup>55</sup>
  - The cost categories, and the general levels and relative magnitudes of costs in the application filed by Hydro, and as updated in December 2025, appear reasonable.<sup>56</sup> Hydro's December 2025 update reported a negotiated price for the three CT packages of \$280.2 million dollars, an increase relative to the Build Application value of approximately 67%.<sup>57</sup>
  - Hydro has reported that the expected Commercial Operation Date of the Avalon CT has been delayed from January 2030 to March 2030. This is also consistent with market information obtained by CAMS indicating increased lead times for major equipment delivery.<sup>58</sup>
  - The major pending milestones of contracting an EPCM and CT supplier will determine and clarify the anticipated schedule and costs as well as the residual risks. Market intelligence indicates that the current availability of EPCMs and necessary equipment is constrained as a consequence of high (and still growing) demand, particularly due to the rise of data center energy demands in the U.S. market.<sup>59</sup> This imbalance of supply and demand will likely impose longer lead times and greater cost premiums than currently reflected in Hydro's estimates.

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<sup>54</sup> CAMS Report, page 1.

<sup>55</sup> CAMS Report, page 1.

<sup>56</sup> CAMS Report, page 1.

<sup>57</sup> Hydro, "Request for Further Information – Hydro's Reply," December 19, 2025, page 2, Table 1 ("December ACT Update").

<sup>58</sup> CAMS Report, page 3.

<sup>59</sup> CAMS Report, page 1.

- The Major Maintenance schedule provided in the Avalon CT proposal likely understates expected costs over the life of the project and should be reviewed and updated.<sup>60</sup>
- Water supply appears to be adequate to provide the needs for the CTs during extended periods of dispatch, considering the plant on a standalone basis. If the Holyrood TGS units were to remain in service after the Avalon CT enters commercial operation, the adequacy of water to support simultaneous combined operation is not clear.<sup>61</sup> Further review by Hydro may be needed to determine if the CTs can be operated for extended periods while the thermal units continue to operate.
- The proposal does not have the necessary details to determine the costs for the fuel storage and delivery system. The project plan should be updated with a specific design and cost for the fuel system.<sup>62</sup>
- The addition of liquid fuel recirculation and filtration equipment would eliminate the need for burning off excess stored fuel and would provide substantial operating cost savings to the project and reduce annual GHG emissions.<sup>63</sup>

## 1. Combustion Turbines

(57) CAMS states that the selection of the CTs for the project was appropriate based on Hydro's established requirements for power output, environmental requirements, cost, availability, reliability, technical support, and other factors identified in the Avalon CT Front-End Engineering Design ("FEED") Study. Hydro considered three models of CTs, each from a different manufacturer, and determined that two did not meet the requirements.<sup>64</sup> The selected General Electric ("GE") LM6000PC Sprint ("LM6000") has been in production and operation for many years and there are over 1,200 units utilized around the world for various applications.<sup>65</sup> The LM6000 is well-suited for peaking power applications. GE has a robust support program, and other third-party providers can provide support if needed. The specifications for LM6000 provided by GE indicate it will be able to meet the required dispatch and emissions requirements for this project.<sup>66</sup>

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<sup>60</sup> CAMS Report, page 1.

<sup>61</sup> CAMS Report, pages 1 and 7.

<sup>62</sup> CAMS Report, page 1.

<sup>63</sup> CAMS Report, page 1.

<sup>64</sup> CAMS Report, pages 2 to 3.

<sup>65</sup> CAMS Report, pages 2 to 3.

<sup>66</sup> CAMS Report, page 3.

- (58) Hydro's December 2025 update Hydro has reported a negotiated price for the three CT packages of \$280.2 million, an increase relative to the Build Application value of approximately 67%.<sup>67</sup> This is consistent with market intelligence obtained by CAMS on CT package cost trends.<sup>68</sup>
- (59) Market intelligence also indicated that current lead times for three LM6000 packages would likely involve delivery no earlier than 2030.<sup>69</sup> This has been confirmed in Hydro's December 2025 update to the Board, in which it reports that the expected Commercial Operation Date of the Avalon CT has been delayed from January 2030 to March 2030.<sup>70</sup> Given the continued high demand for major plant equipment, construction and management services, and the time required to install and test the CT packages prior to bringing them online, CAMS suggests a new project schedule reflecting agreed upon delivery dates is entered into the record as soon as possible.<sup>71</sup>
- (60) Recent trade press is consistent with the market intelligence reported by CAMS. For example, an article in *UtilityDive* from December 11, 2025 reported that GE Vernova (manufacturer of the LM6000) has a turbine backlog of 80 GW and expects reservations to be sold out through 2030 by the end of 2026, with new reservations priced above current orders.<sup>72</sup> A significant driver of demand is from direct sales to data centers.
- (61) CAMS confirmed that the LM6000 can accommodate, and has been installed with, synchronous condenser capability (e.g., LM6000 VELOX package solution).<sup>73</sup> The cost of incorporating the necessary overriding clutch technology is not reflected in the Avalon CT cost estimate. Hydro has reported that based on bid information it received in its RFP process, the incremental cost of synchronous condenser capability at the CT is approximately [REDACTED].<sup>74</sup> CAMS was not able to determine whether sourcing the LM6000 in a VELOX package would further delay unit delivery.<sup>75</sup>

## 2. Fuel System

- (62) The CTs are expected to be operated on #2 Fuel Oil.<sup>76</sup> The LM6000 is designed to operate on other types of fuel, such as natural gas and biofuels, which may be able to be utilized at this facility if they become available in the future. Modifications to the LM6000 may or may not be needed depending

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<sup>67</sup> December ACT Update, page 2, Table 1.

<sup>68</sup> CAMS Report, page 3.

<sup>69</sup> CAMS Report, page 3.

<sup>70</sup> December ACT Update, page 2, Table 1.

<sup>71</sup> CAMS Report, page 3.

<sup>72</sup> Brian Martucci, "GE Vernova expects to end 2025 with an 80-GW gas turbine backlog that stretches into 2029" *Utility Dive*, December 11, 2025, available at: <https://www.utilitydive.com/news/ge-vernova-gas-turbine-investor/807662/>.

<sup>73</sup> CAMS Report, pages 3 to 4.

<sup>74</sup> Phase 2 BW-NLH-009 (d), page 6 lines 1 to 3.

<sup>75</sup> CAMS Report, page 3.

<sup>76</sup> Build Application, Schedule 5, page 3, line 23.

on the type of fuel(s) being utilized. Many LM6000 are operated with more than one fuel at a time and switching between fuels, once hardware modifications have been implemented, if needed, are handled by the control systems.<sup>77</sup>

- (63) CAMS concludes that the fuel system reflected in the Build Application appears to be typical for the delivery and storage of fuel. Onsite fuel storage capacity will need to be based on the expected dispatch profile when the units are expected to be dispatched for extended hours and days. The availability of fuel from the supplier will also need to be considered to ensure fuel can be delivered as needed when the units are operated for extended periods.<sup>78</sup>
- (64) The proposed fuel system does not appear to include the equipment necessary to provide filtration and the ability to recirculate the fuel when the CTs are not in operation. These ancillary systems may have been considered and were not specifically stated in the Hydro documentation. If these systems were not included, they should be considered for the following reasons:<sup>79</sup>
- **Filtration** – Dirt and other debris can be present in pipelines, ships, barges, and tanker trucks and will need to be removed prior to the fuel being supplied to the CT units. The CT packages will include filtration, but additional filtration should be in service prior to the fuel arriving at the CT packages.
  - **Centrifuges** – Fuel oil typically has water entrained that needs to be removed. Water may be present in the fuel due to water being present in any portion of the delivery to the facility. Water can also enter the system due to high humidity and other atmospheric conditions through tank vents. The water causes corrosion in tanks and piping. The water can also cause corrosion in the CTs that can lead to increased/accelerated service needs, and potentially to catastrophic failure. The fuel should be centrifuged as it is being sent to the CT packages to ensure water is removed and not introduced into the CTs. Centrifuge will also aid in the remove of particulates.
  - **Recirculation** – The fuel storage and delivery system should include the ability to recirculate the fuel through the centrifuges and the filtration to remove water and particulates and return the fuel to the storage tank(s). This part of the system should be able to be utilized when the fuel is not being sent to the CTs to ensure the fuel is kept clean and free of water when the units are not being dispatched. Recirculation also provides the means to clean fuel if it has been delivered with high particulates and/or water content, without the need to remove the fuel and send it back to the supplier, and to help manage fuel temperature during cold weather conditions. The recirculation system, when used on a routine basis, will minimize water accumulation at the bottom of the storage tanks. This minimizes corrosion in the tank as well as the possibility to

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<sup>77</sup> CAMS Report, page 4.

<sup>78</sup> CAMS Report, page 4.

<sup>79</sup> CAMS Report, pages 4 to 5.

ingest water in the CTs. There have been many cases where enough water was delivered from the fuel storage tanks to a CT and caused it to trip offline due to flame out. Recirculation also provides means to ensure required fuel viscosity during cold weather.

- (65) CAMS also recommends that operations at the Avalon CT should include procedures for routine sampling, analysis, and conditioning of the fuel using the recirculation system.<sup>80</sup>
- (66) Regarding fuel quality management, Hydro has stated:

The use of fuel additives such as biocides and practices such as recirculation and fuel cleaning will be assessed during the detailed design phase. Newfoundland and Labrador Hydro plans to award an Engineering, Procurement, and Construction Management contract by the end of the second quarter of 2026 so that detailed design can begin and further mature the diesel fuel system.

Additionally, a fuel segregation study is underway to determine possible fueling scenarios whereby existing or new fuel tanks could be potentially managed by third-party fuel suppliers to mitigate fuel quality concerns and reduce burn-off. A new Expression of Interest for potential third-party partners could potentially help with fuel management and storage.<sup>81</sup>

### 3. Capital Expenditures (CAPEX) and Spare Parts

- (67) The CAMS review observed that there are no CAPEX items listed in the proposal beyond the initial purchase of the equipment to construct the facility and the purchase of spare parts as discussed below.<sup>82</sup> The project proposal and estimate in the Build Application does not appear to include all elements expected to be required to bring the CT to commercial operation. An example of this is the fuel system components discussed above.
- (68) The Board should be aware that the pending detailed design is likely to include additional elements and costs not reflected in the Build Application.
- (69) **General Spare Parts** – CAMS finds that the estimated cost for general spare parts [REDACTED] is high based on known costs for a facility with simple cycle gas turbines.<sup>83</sup> The detailed project plan

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<sup>80</sup> CAMS Report, page 7.

<sup>81</sup> Phase 2 BW-NLH-018 (a), page 1 lines 15 to 23.

<sup>82</sup> CAMS Report, page 8.

<sup>83</sup> CAMS Report, page 8.

and cost estimate should include a review of the spare parts to be kept at the site to determine exactly what is needed and not having items that can be easily obtained kept in inventory to minimize costs.<sup>84</sup>

- (70) **CT Spare Parts** – As with general spare parts, the detailed plan and cost estimate should review the CT spare parts that need to be kept at the site.<sup>85</sup>
- (71) **Spare Transformer** – The project proposal includes the purchase of a spare generator step-up (“GSU”) transformer. Having a spare transformer on site is highly recommended and will minimize down time for a unit if the spare is needed. Lead time to obtain a replacement transformer can be as high as 24 months.<sup>86</sup>

#### 4. Operating Costs

- (72) The CAMS assessment addressed several aspects of estimated operating costs:
- **Fixed Operating Costs** – According to CAMS, the Fixed Operating Costs appear to be reasonable for a facility of this type, size, major equipment, and location.<sup>87</sup>
  - **Administrative, Labour and Variable Operating Costs** – According to CAMS, these costs appear to be reasonable for a facility of this type, size, major equipment, and location.<sup>88</sup>
  - **Escalation** – Consideration should be given to include the expected escalation of all costs for implementation, development, etc. for this project due to the number of years from the time the proposal is approved and the time the facility commences operation.<sup>89</sup> Costs for parts and services have increased significantly over the last year and may continue to escalate over the next several years, which could take the project well above budget, more than the stated contingencies will cover. This should be addressed in the detailed project plan.

#### 5. Reserves

- (73) CAMS finds that the project contingency reserve amount, representing approximately 11.1% of total project costs is slightly higher than expected for a project of this type and size. Typically, contingency is 10%.<sup>90</sup>

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<sup>84</sup> CAMS Report, page 8.

<sup>85</sup> CAMS Report, page 8.

<sup>86</sup> CAMS Report, page 8.

<sup>87</sup> CAMS Report, page 9.

<sup>88</sup> CAMS Report, page 9.

<sup>89</sup> CAMS Report, page 9.

<sup>90</sup> CAMS Report, page 9.

- (74) Regarding Management Reserve, representing an additional reserve on top of contingency of approximately 17%,<sup>91</sup> CAMS's experience is that this type of reserve is not typically seen in the power generation industry for projects of this type.<sup>92</sup>

## 6. Plant Maintenance

- (75) With respect to the reported schedule of significant maintenance activities and costs, CAMS's findings included the following:<sup>93</sup>
- Maintenance costs are likely understated for the life of the project, as such costs have increased significantly over the year since the estimates were developed. These costs should be updated and escalated into the future.
  - CAMS finds that the maintenance schedule does not appear to conform to expected operation, and reflects maintenance intervals that are likely not correct, and may exclude required activities and costs.
- (76) CAMS concludes that the maintenance schedule and cost estimates reflected in the Build Application as likely to be minimum, and possibly understated, requirements. A more complete assessment of likely maintenance costs would incorporate a range of operational cases.

## 7. Service Agreement and Lease Program

- (77) **Service Agreement** – CAMS recommends that a form of Service Agreement with GE should be considered with the number of CT units in the project and the critical nature of the facility for supporting system reliability. A Contractual Service Agreement (“CSA”) would be appropriate for the Avalon CT. The CSA would likely include provisions for GE to conduct all CT related work including annual borescope inspections, repairs, and Major Maintenance events, when they are needed or due, and would provide discounts to the facility for parts and services provided by GE with GE as the preferred vendor for the parts and services. CAMS does not believe the typical Long-Term Service Agreement (“LTSA”) or Long-Term Maintenance Agreement (“LTMA”) would be appropriate for the Avalon CT facility, given the type of equipment and the low dispatch hours per year.<sup>94</sup>

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<sup>91</sup> Management Reserve is equal to \$128.2 million; subtotal before Management Reserve is equal to \$763.2.  $128.2 \div 763.2 = 16.8\%$ . See: Build Application, Schedule 5, Attachment 1, Table 1.

<sup>92</sup> CAMS Report, page 9.

<sup>93</sup> CAMS Report, page 10.

<sup>94</sup> CAMS Report, pages 11.

- (78) **Spare Gas Turbine** – Consideration should be given for the purchase of a spare gas turbine to be kept at the facility to be utilized when one of the turbines needs to be removed from the CT package for repairs or major maintenance events. Installation of an onsite spare can typically be completed in three to four days, maximizing availability for the unit.<sup>95</sup>
- (79) **Lease Program** – GE offers a gas turbine lease program where GE provides a gas turbine to install in a unit when that unit’s turbine has to be removed for repairs, or during major maintenance events which take an extended amount of time to complete. Participation in a gas turbine lease program, in conjunction with or in lieu of owning a spare gas turbine, should be considered.<sup>96</sup>

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<sup>95</sup> CAMS Report, page 11.

<sup>96</sup> CAMS Report, page 11.

## V. Gruner Review of Bay d'Espoir Unit 8

- (80) In this section, we provide an assessment of the proposed BDE Unit 8. Our assessment is made in conjunction with Gruner Gruner, our independent subcontractor, a leading engineering and design company specialized in the dam and hydropower engineering and energy sectors since its founding in 1926.<sup>97</sup> Gruner has provided a separate report on the BDE Unit 8 project, included as Appendix 2 to this report.
- (81) Gruner's report assesses (1) hydrology and project operations, (2) the cost methodologies, (3) project cost estimates, (4) the water conveyance system (which includes assessment of the headrace channel, intakes, penstock, and tailrace), (5) the power generation extension, (6) the transmission line and terminal station expansion, (7) the project's constructability and construction program, and (8) project governance. In this section, we provide a high-level overview of Gruner's report. We include additional narrative, conclusions, and recommendations as appropriate. This section should be read in conjunction with Gruner's report and is intended to adopt Gruner's findings, conclusions, and recommendations.

### A. Project Design, Specification, and Scope Assessment

- (82) The existing Bay d'Espoir hydroelectric power plant consists of seven generating units. The first six, 75 MW each, were commissioned in 1967 (units 1-4) and 1970 (units 5-6) and share a powerhouse (Powerhouse 1). A single headrace canal supplies water to three intakes for the six units, each connected to a penstock. Water for these intakes is discharged through a 4.5-kilometer tailrace channel.<sup>98</sup> Powerhouse 2 currently houses a single unit, the 150 MW BDE Unit 7, commissioned in 1977. Powerhouse 2 receives water through a dedicated headrace canal, intake, and penstock. Its tailrace channel connects to the tailrace channel of Powerhouse 1.<sup>99</sup>
- (83) The BDE Unit 8 project is proposed as a 150 MW hydroelectric generating unit to be located in Powerhouse 2. Hydro explains that Powerhouse 2 "was built with provisions for adding a second 150 MW unit (Unit 8) in the future."<sup>100</sup> BDE Unit 8 will also not require a new powerhouse forebay, nor will it require the construction of new dams or modifications to existing dams, relying on the existing Long Pond reservoir.<sup>101</sup> Hydro explains that "rock excavation for BDE Unit 8 was completed and the downstream portion of the draft tube, including the draft tube gate guides, was constructed."<sup>102</sup>

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<sup>97</sup> More about Gruner is available here: <https://www.gruner.ch/en/discover/stucky-ltd>.

<sup>98</sup> Build Application, Schedule 1, page 34 lines 21 to 28.

<sup>99</sup> Build Application, Schedule 1, page 35 lines 1 to 3.

<sup>100</sup> Build Application, Schedule 1, page 35 lines 3 to 4.

<sup>101</sup> Build Application, Schedule 1, page 35 lines 21 to 23.

<sup>102</sup> Build Application, Schedule 1, page 35 lines 4 to 6.

However, other components, including the headrace canal, intake, penstock, and downstream section of the tailrace channel “were designed and built exclusively for BDE Unit 7.”<sup>103</sup>

- (84) Hydro proposes to extend Powerhouse 2 to accommodate BDE Unit 8, construct an enlarged headrace canal, install a new water intake and penstock, and install a new generating unit.<sup>104</sup> The project also includes a new high voltage 230 kV line, which will connect to the new BDE Unit 8 generator step-up transformer (“GSU”) to an existing Terminal Station at the site (Terminal Station 2),<sup>105</sup> with Terminal Station 2 being modified to accept the additional interconnection.<sup>106</sup>
- (85) The project scope “will include the engineering, procurement, construction, installation, commissioning, and testing of all works associated with the project,”<sup>107</sup> including: (1) excavation of new headrace canal, (2) new intake, intake building, and ancillary services, (3) new penstock, (4) new turbine generator (150 MW) to be installed in the existing Powerhouse 2, (5) new GSU transformer and isolated phase bus, (6) new auxiliary mechanical, electrical, protection and control, telecontrol, and telecommunications and communications equipment, (7) modifications to Powerhouse 2, as required, to support BDE Unit 8 installation, operation, and maintenance, (8) tailrace channel enhancements, (9) a new 230 kV transmission line, which will include optical ground wire, from the new BDE Unit 8 GSU transformer to the existing Terminal Station 2, and (10) expansion and modifications to Terminal Station 2 to accept transmission line interconnection.<sup>108</sup> Figure 2 shows the proposed intake and penstock area for the project.

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<sup>103</sup> Build Application, Schedule 1, page 35 lines 6 to 7.

<sup>104</sup> Build Application, Schedule 1, page 35 lines 10 to 19.

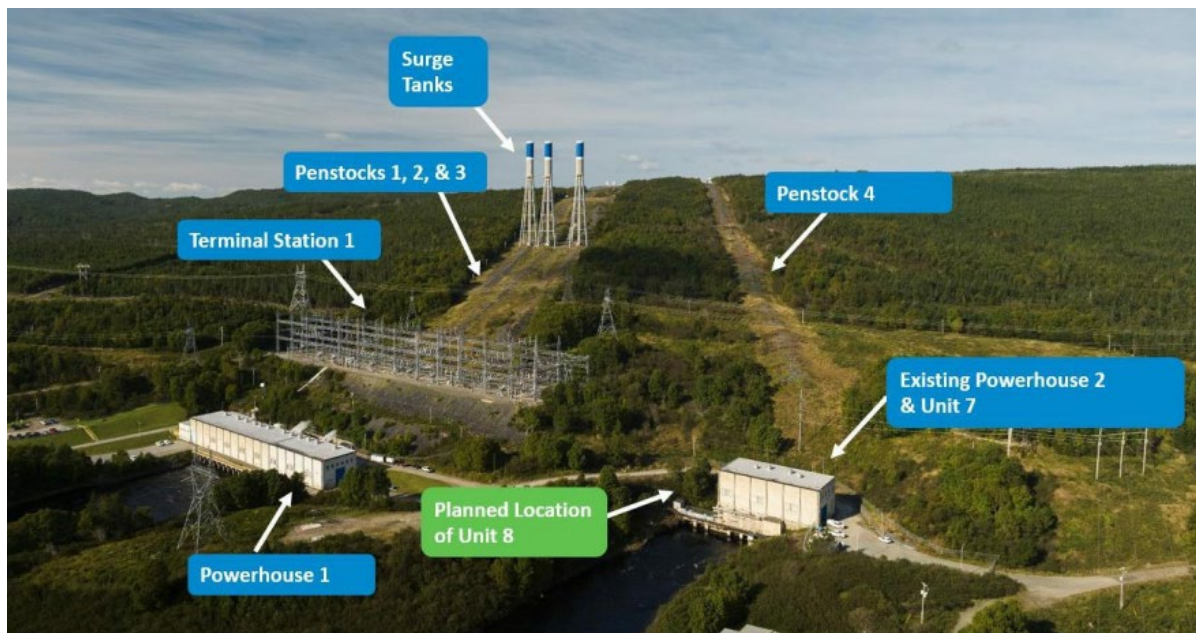
<sup>105</sup> Build Application, Schedule 1, page 35 lines 19 to 21.

<sup>106</sup> Build Application, Schedule 1, page 37 lines 1 to 3.

<sup>107</sup> Build Application, Schedule 1, page 36 lines 3 to 4.

<sup>108</sup> Build Application, Schedule 1, page 36 line 5 to page 37 line 3.

**Figure 2: Proposed Intake and Penstock Area (BDE Unit 8)<sup>109</sup>**



- (86) Gruner identifies no red flags or major concerns with the project design, scope, or specification. Regarding the water conveyance system components (e.g., the headrace, intake, penstock, and tailrace), Gruner does identify certain key risks, such as that of frazil ice,<sup>110</sup> corrosion of penstocks,<sup>111</sup> and less developed designs for the penstock bridge<sup>112</sup> and tailrace channel widening work.<sup>113</sup> Gruner provides several recommended actions Hydro can take as it proceeds in project development. The recommendations include the “priority” level of the recommendations, ranging from high priority,<sup>114</sup> to medium,<sup>115</sup> to low priority.<sup>116</sup>
- (87) Regarding the power generation extension components (e.g., the powerhouse extension, mechanical components, and electric components), Gruner notes that its review, which is based on the FEED design materials, necessarily addresses the project at a “conceptual level.”<sup>117</sup> Gruner identifies no major red flags. Gruner does identify key risks, such as the fact that the project is located near an active seismic zone<sup>118</sup> and the need to ensure the structural integrity and code compliance of the

<sup>109</sup> Build Application, Schedule 1, Figure 6.

<sup>110</sup> Gruner Report, Risk 6-1.

<sup>111</sup> Gruner Report, Section 6.4 and Recommendation 6-3.

<sup>112</sup> Gruner Report, Section 6.5 and Recommendation 6-4.

<sup>113</sup> Gruner Report, Section 6.7 and Recommendation 6-5.

<sup>114</sup> No high priority recommendations were included for the water conveyance system.

<sup>115</sup> Medium priority recommendations include Recommendations 6-1 through 6-9.

<sup>116</sup> Low priority recommendations include Recommendations 6-10 through 6-13.

<sup>117</sup> Gruner Report, Section 7.6.

<sup>118</sup> Gruner Report, Recommendation 7-8.

powerhouse.<sup>119</sup> Gruner underscores that “the design documentation currently available is at the concept design stage and therefore more accurate and detailed comparisons will only be feasible upon completion of the Final/Detailed Design phases.”<sup>120</sup>

- (88) Gruner also provides a series of recommendations along with the “priority” level of those recommendations. Gruner includes two “high” priority recommendations. First, Gruner recommends that because the project is located near an active seismic zone, Hydro should assess and address potential seismic activity to mitigate potential adverse impacts.<sup>121</sup> Second, Gruner recommends that since Unit 8’s planned steel superstructure will be extension of the 45-year old BDE Unit 7, BDE Unit 8’s design should be verified against current structural codes and updated loads (and Unit 7’s should be assessed for required refurbishment).<sup>122</sup> Gruner includes several additional recommendations, including medium priority<sup>123</sup> and low priority recommendations.<sup>124</sup>

## B. Hydrology

- (89) An important consideration for the BDE Unit 8 project is whether there is sufficient hydrology to support expansion of the Bay d’Espoir plant. Hydro has put forth several studies and analyses as evidence of the hydrological capability of the system to support BDE Unit 8. These included a 2020 study by Hatch,<sup>125</sup> and a 2025 update also performed by Hatch.<sup>126</sup> The 2020 and 2025 studies assess the hydrological sufficiency for the addition of BDE Unit 8 under normal conditions.<sup>127</sup> Hydro also provided analyses in support of hydrological sufficiency during a prolonged bipole outage of the LIL, including a 2024 Hatch Report<sup>128</sup> and a supplemental study (completed by Hydro) in October 2025, which we explain in our Phase One Addendum Report.<sup>129</sup>

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<sup>119</sup> Gruner Report, Section 7.2.2.

<sup>120</sup> Gruner Report, Conclusion 7-1.

<sup>121</sup> Gruner Report, Recommendation 7-8.

<sup>122</sup> Gruner Report, Recommendation 7-13.

<sup>123</sup> Medium priority recommendations include Recommendations 7-1, 7-2, and 7-12.

<sup>124</sup> Low priority recommendations include Recommendations 7-3 through 7-7 and 7-9 through 7-11.

<sup>125</sup> Hatch, “Final Report for Hydrology and Feasibility Study for Potential Bay d’Espoir Hydroelectric Generating Unit No. 8,” December 11, 2020, included in the Hydro 2022 RRA Update as Volume III, Attachment 7 at: <http://www.pub.nl.ca/applications/NLH2018ReliabilityAdequacy/correspondence/From%20NLH%20-%20Reliability%20and%20Resource%20Adequacy%20Study%20-%202022%20Update%20-2022-10-03.PDF> (“Hatch 2020 Report”).

<sup>126</sup> Hatch, “Hydrology and Feasibility Study for Potential Bay d’Espoir Hydroelectric Generating Unit No. 8 – Addendum Report,” March 19, 2025, included in Build Application, Schedule 1, Attachment 2 (“2025 Hatch Study”).

<sup>127</sup> 2025 Hatch Study, page 1.

<sup>128</sup> Hatch, “Impact of Prolonged Loss of LIL on Island Reservoir Levels,” July 2, 2024, included in the 2024 RAP, Appendix C, Attachment 5 (“July 2024 Hatch Report”).

<sup>129</sup> Bates White Phase One Addendum Report, paragraph 50.

- (90) Regarding hydrological sufficiency during normal operations, the evidence suggests that the system is hydrologically sufficient during normal operations. The primary evidence of hydrological sufficient comes from the 2025 Hatch Study, which concludes that the “simulated hourly optimized generation capacity increase at the Bay d’Espoir plant is 150.1 MW.”<sup>130</sup> Still, it should be noted that with the addition of BDE Unit 8, the plant and system produce only slight increases in annual energy: the simulated average annual energy of the BDE plant increases by 1.26%, and the average annual energy from the entire Bay d’Espoir hydro system (which includes the Granite Canal and Upper Salmon generator units) increases by just 0.64%.<sup>131</sup> Plant efficiency increases with the addition of BDE Unit 8 by an average of 0.76%.<sup>132</sup> Additionally, there is a slight increase in usage of the Upper Salmon spillway, which increases from 2.5% (without BDE Unit 8) to 3.0% (with BDE Unit 8).<sup>133</sup>
- (91) Gruner took no issue with the conclusions of the 2025 Hatch Study regarding hydrological sufficiency of the system during normal operating conditions. Gruner did conclude that the use of the Vista software model and the subsequent reporting limits the amount of detail that can be reviewed in assessing hydrological results and conclusions.<sup>134</sup> We note that the Vista model is a long-standing tool owned by Hatch,<sup>135</sup> though agree with Gruner’s point regarding the limited transparency of complex modeling tools, despite their merits.
- (92) Regarding hydrological sufficiency of the hydrology during an extended bipole outage of the LIL, uncertainty remains. We addressed this issue in our Phase One Addendum Report, noting:

We conclude, therefore, that Hydro has provided evidence that the BDE system can sustain a similar level of output from BDE Units 1-8 as was modeled in the LIL Shortfall Analysis as part of the Build Application, though the results depend on certain assumptions and conditions made by Hydro. Specifically, the results are conditioned on certain assumptions about average storage levels, average inflows, and significant spill activity that could be less favorable than assumed, which could increase the risk of hydrological shortages in the BDE system either during a six-week LIL bipole outage or in the aftermath of such an event. We also acknowledge the value of the July 2024 Hatch Study, which shows that, through much higher reliance on thermal generation, there is hydrological sufficiency to sustain BDE Unit 1-8’s output during a six-week bipole outage of the LIL in the winter season. In sum, while Hydro has enhanced the evidentiary record on the question of hydrological

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<sup>130</sup> 2025 Hatch Study, page iv.

<sup>131</sup> 2025 Hatch Study, page 12.

<sup>132</sup> 2025 Hatch Study, section 4.1.

<sup>133</sup> 2025 Hatch Study, page 21.

<sup>134</sup> Gruner Report, Section 3.4.

<sup>135</sup> See: Hatch, “Next Gen Vista,” available at: <https://www.hatch.com/Expertise/Services-and-Technologies/Vista-Decision-Support-System>.

sufficiency, the additional evidence is not sufficient to preclude any concerns about hydrological sufficiency during an extended bipole outage of the LIL.<sup>136</sup>

(93) Gruner shared our concerns, stating:

Studies indicate that the system has adequate storage and hydraulic capacity to supply the required water during a prolonged LIL outage. However, certain hydrological risks require further clarification, including the potential effects of rapid water level reductions in Long Pond on ice cover during winter outages. Additionally, achieving full generation capacity during a LIL outage may necessitate continuous operation of the Upper Salmon spillway, and further assessment of associated risks and constraints is recommended.<sup>137</sup>

(94) Gruner therefore identifies a series of risks, two of which are “high” priority. First, Gruner explains that the hydrological study results make it clear that for BDE Unit 8 to increase firm generation in a LIL outage scenario, spill activity will need to occur on Upper Salmon to feed Long Pond and the Bay d’Espoir plant.<sup>138</sup> Second, Gruner states that there may be environmental concerns associated with the use of the spillway.<sup>139</sup> Gruner also noted a “medium” risk, that a rapid lowering of water levels at Long Pond is a risk associated with BDE Unit 8.<sup>140</sup>

(95) Gruner included three recommendations related to hydrology. These included an assessment of the impact of rapid reductions in water levels on ice cover (and the development of mitigation measures if that assessment identifies concerns), additional reporting on the risks and constraints of using the Upper Salmon spillway for extended periods of time, and provision of more detailed hydrologic and hydraulic properties of the system occur in any future due diligence studies of Bay d’Espoir’s hydrology.<sup>141</sup>

## C. Transmission Assessment

(96) As noted, the proposed BDE Unit 8 project also includes a new high voltage 230 kV line, which will connect via a new BDE Unit 8 GSU to existing Terminal Station 2,<sup>142</sup> with Terminal Station 2 being modified to accept the additional interconnection.<sup>143</sup> The transmission line will be a hybrid design of

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<sup>136</sup> Bates White Phase One Addendum Report, paragraph 61.

<sup>137</sup> Gruner Report, Section 11.

<sup>138</sup> Gruner Report, Section 3.3.

<sup>139</sup> Gruner Report, Risk 3-2.

<sup>140</sup> Gruner Report, Risk 3-1.

<sup>141</sup> Gruner Report, Section 3.4.

<sup>142</sup> Build Application, Schedule 1, page 35 lines 19 to 21.

<sup>143</sup> Build Application, Schedule 1, page 37 line 3.

wood and steel pole construction, will have a design life of 60 years, and will run approximately 1.9 km, parallel to the existing line running from BDE Unit 7 to Terminal Station 2.<sup>144</sup> The expansion to Terminal Station 2 will install electric equipment with a minimum design life of 30 years.<sup>145</sup> The figure below shows the proposed transmission line route.

**Figure 3: Transmission Line Route (BDE Unit 8)<sup>146</sup>**



- (97) Gruner notes that its review, which is based on the FEED design materials, necessarily addresses the project at a “conceptual level.”<sup>147</sup> Gruner identifies no major red flags. Again, Gruner notes that “the design documentation currently available is at the concept design state and therefore more accurate and detailed comparisons will only be feasible upon completion of the Final/Detailed Design phases.”<sup>148</sup>

<sup>144</sup> Build Application, Schedule 4, page 11 lines 1 to 7, Gruner Report, page 64.

<sup>145</sup> Build Application, Schedule 4, page 11 lines 13 to 14.

<sup>146</sup> Build Application, Schedule 4, Figure 4.

<sup>147</sup> Gruner Report, Section 8.2.

<sup>148</sup> Gruner Report, Conclusion 8-1.

- (98) Gruner also provides a series of recommendations for the expansion of Terminal Station 2. The recommendations are all considered “low” priority recommendations.<sup>149</sup>
- (99) We note here that transmission issues related to the retirement of on-Avalon generation and additions of off-Avalon generation (i.e., BDE Unit 8) are addressed later in our report (Section 1.A). There, we discuss Hydro’s plan for addressing transmission “bottlenecks” on the Bay d’Espoir to Soldiers Pond (“BDE-SOP”) 230 kV transmission system in the event of a bipole outage on the LIL.

## D. Project Cost Assessment

- (100) Hydro’s base cost estimate for the BDE Unit 8 project is \$706,890,904.<sup>150</sup> Hydro explains that the base cost estimate is an Association for the Advancement of Cost Engineering (“AACE”) Class 3 estimate, with an accuracy of -20%/+30%.<sup>151</sup>
- (101) The base cost estimate included Design Development Allowances (“DDA”) and Contingency Reserve of \$60,725,359.<sup>152</sup> (Hydro did not provide values for DDA and Contingency separately). Monte Carlo analysis for BDE Unit 8 was then used to derive an additional contingency amount, corresponding to the difference between the simulated P50 value (which for BDE Unit 8 also corresponds to the average or mean value for the resulting distribution) and the base estimate, which amounts to \$37,555,691.<sup>153</sup>
- (102) Escalation (\$75,795,944) and IDC (\$113,799,040) was next added “based on a cost profile developed from the project schedule.”<sup>154</sup> Escalation was derived from The Conference Board of Canada statistics and Hydro’s own estimates, and applied to an annual cost expenditure profile.<sup>155</sup> IDC was calculated based on Hydro’s “expected annual borrowing rate” as of the date of the cost estimate (November 2024), which is ██████████ and which was applied to the same annual cost expenditure profile as that used in calculation escalation.<sup>156</sup> Added last was the Management Reserve of \$145,179,352, which was calculated via Monte Carlo simulation<sup>157</sup> (and as discussed in Section V of this report). Hydro’s cost estimate for BDE Unit 8 is shown in the table below.

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<sup>149</sup> The low priority recommendations include Recommendations 8-1 through 5-7.

<sup>150</sup> Build Application, Schedule 4, Attachment 1, page 6.

<sup>151</sup> Build Application, Schedule 4, Attachment 1, page 6.

<sup>152</sup> Build Application, Schedule 4, Attachment 1, page 27.

<sup>153</sup> Build Application, Schedule 4, Attachment 1, page 27.

<sup>154</sup> Build Application, Schedule 4, Attachment 1, page 24.

<sup>155</sup> Build Application, Schedule 4, Attachment 1, pages 25 and footnote 26.

<sup>156</sup> Build Application, Schedule 4, Attachment 1, page 26.

<sup>157</sup> Build Application, Schedule 4, Attachment 1, pages 6 to 7.

**Table 3: Project Cost Estimate (BDE Unit 8)<sup>158</sup>**

Component		Estimated Cost
Direct Construction Costs	[a]	378,684,509
Indirect Construction Costs	[b]	193,265,409
EPCM Consultant	[c]	████████
Hydro Project Management	[d]	████████
<b>Subtotal: Base Cost</b>	<b>[e] = [a] + [b] + [c] + [d]</b>	<b>706,890,904</b>
Project Contingency	[f]	37,555,691
<b>Subtotal Base Estimate (with Contingency)</b>	<b>[g] = [e] + [f]</b>	<b>744,446,595</b>
Escalation	[h]	75,795,944
Interest During Construction	[i]	113,799,040
<b>Subtotal: Planned Budget</b>	<b>[j] = [g] + [h] + [i]</b>	<b>934,041,579</b>
Management Reserve	[k]	145,179,352
<b>Total Authorized Budget</b>	<b>[l] = [j] + [k]</b>	<b>1,079,220,931</b>

- (103) Gruner reviewed the project cost estimate methodology and concluded that “[t]he methodology followed by [Hydro] is in line with the AACE Class 3 Estimate recommendations and in line with what is normally done in international hydropower projects.”<sup>159</sup> Gruner found the use of Monte Carlo analysis appropriate, stating that “the Monte-Carlo analysis on risk scenarios is a valuable tool to have a solid bottom-up contingency estimation.”<sup>160</sup> Gruner further stated that “[o]verall, the quality of the deliverables seems to be in line with the common practice for AACE Class 3 Estimate.”<sup>161</sup>
- (104) Gruner reviewed the direct and indirect cost components for the project, “intend[ing] to identify whether the submitted cost studies contain major inconsistencies, omissions, or skipped items, rather than to provide a fully definitive validation of the estimate.”<sup>162</sup> Gruner further noted that “the design documentation currently available is at the concept design stage; therefore, more accurate and detailed comparisons will only be feasible upon completion of the Final/Detailed Design phases.”<sup>163</sup> Gruner identified several areas of the estimates that require adjustment, though the cumulative impact of these adjustments is expected to be low. These recommendations included two “medium” priority recommendations<sup>164</sup> and several “low” priority recommendations.<sup>165</sup>

<sup>158</sup> Build Application, Schedule 4, Attachment 1, Table 1.

<sup>159</sup> Gruner Report, Conclusion 4-3.

<sup>160</sup> Gruner Report, Conclusion 4-3.

<sup>161</sup> Gruner Report, Conclusion 4-3.

<sup>162</sup> Gruner Report, Section 5.6.2.

<sup>163</sup> Gruner Report, Section 5.6.2.

<sup>164</sup> Medium priority recommendations included Recommendations 5-9 through 4-11.

<sup>165</sup> Low priority recommendations included Recommendations 5-4 through 5-8.

- (105) Regarding the calculated Contingency reserve, Gruner observes that “as this is a risk allowance, the total factored contingency stands at \$98.3 million, corresponding to 13.9% of the base estimate.”<sup>166</sup> Gruner also concludes that though the project’s design and development stage “would typically require contingencies of approximately 30% of the project budget (compared with the current 13.9%),” a “lower contingency can be justified” due to (1) the largely standard design of the project, which is essentially “a replica” of BDE Unit 7, (2) Hydro’s familiarity with the area, (3) the operational history of the BDE plant, and (4) the existence of the Management Reserve.<sup>167</sup>
- (106) Regarding the overall cost estimate and calculation of the Management Reserve, Gruner concludes that “the final amount appears generally consistent with – and slightly conservative relative to – the scale of the project in the region.”<sup>168</sup> Gruner does offer four recommendations, one of which is “high” priority and recommends that Hydro publish the final cost per unit of installed items to allow for benchmarking against other international projects.<sup>169</sup> Gruner also included two medium items<sup>170</sup> and one low priority recommendation.<sup>171</sup>
- (107) To supplement Gruner’s discussion, we make a few additional points. First, and as we discuss in Section V, we are concerned that the Management Reserve will be used to backstop cost overruns that are unrelated to the strategic risks it was intended to address. Gruner did not review the regulatory and economic aspects of Management Reserve, but only considered Management Reserve from the perspective of budget estimate sufficiency. Therefore, when Gruner concludes that the existence of the Management Reserve is a contributing mitigant to concerns about the low Contingency reserve amount, Gruner is considering those two reserve funds as accomplishing the same goal. Our review factors in regulatory and economic considerations, and thus we include certain recommendations related to the Management Reserve, explained further in Section V.
- (108) Second, in recognition that the cost estimates are now over a year old, we reviewed relevant commodity price and labor price data to roughly determine if costs may have significantly shifted since the cost estimate was developed. Our conclusion is that any broader price movement since the finalization of Hydro’s price estimate has been under 10%. For example, the Handy-Whitman Index of Public Utility Construction Costs, an industry-standard index of the costs utilities face in constructing new assets, is up by about 9.1% year-over-year.<sup>172</sup> We also observed no compelling, major price movements in commodities (e.g., primary ferrous metal products and cement) or labor.

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<sup>166</sup> Gruner Report, Conclusion 4-1.

<sup>167</sup> Gruner Report, Conclusion 4-2.

<sup>168</sup> Gruner Report, Conclusion 5-3.

<sup>169</sup> Gruner Report, Recommendation 5-1.

<sup>170</sup> The medium priority items included Recommendations 5-2 and Conclusion 5-4.

<sup>171</sup> The only low priority recommendation was Recommendation 5-3.

<sup>172</sup> The Handy-Whitman Index data since 2016 is available at: [“FCM—Multiyear Rate Elections,” ISO New England, available at: https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/fcm-multiyear-rate-elections.](https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/fcm-multiyear-rate-elections)

Still, despite no major price movements in relevant commodity or labor markets, the BDE Unit 8 project could face more localized cost pressures for more particular project components.

- (109) Third, owner’s costs (IDC and escalation) are substantial, adding to \$189.6 million. Delays in the development process (once underway) will likely cause these two cost categories to increase, potentially significantly so.
- (110) Fourth, the Board should consider a recommendation that Hydro updates its entire requested Authorized Budget for the BDE Unit 8 project before approval. It is our understanding that Hydro has been pursuing contracts for key components of the project, including EPCM services and a GSU.<sup>173</sup> If those costs are known now or are soon to become known, the overall project budget would be substantially improved by using those known costs. Hydro could then update its Contingency, Escalation, IDC, and Management Reserve amounts to reflect the more certain project costs, and could address our recommended revisions to the Monte Carlo analysis explained in Section V of this report.

## E. Project Schedule Assessment

- (111) Hydro explains that its development schedule for BDE Unit 8 “was built by combining the Bay d’Espoir Unit 8 FEED Basis of Project Level 3 Schedule with a Hydro internal project schedule.”<sup>174</sup> Hydro provided its project control schedule for the BDE Unit 8 project, shown in Table 4 below.

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<sup>173</sup> See, for example: Hydro, “Bay d’Espoir Unit 8 Project Early Execution Update,” December 17, 2025, available at: <http://www.pub.nl.ca/indexreports/baydespoir8EarlyExecution/From%20NLH%20-%20Bay%20d%E2%80%99Espoir%20Unit%208%20Project%20Early%20Execution%20Update%20-%20October%202025%20-%202025-12-17%20-%20REDACTED.PDF>.

<sup>174</sup> Build Application, Schedule 4, Attachment 2, page 8.

**Table 4: Project Control Schedule (BDE Unit 8)<sup>175</sup>**

Activity Name	Start Date	Finish Date
<b>BDE Unit 8 Project Control Schedule</b>	<b>1/3/2023</b>	<b>1/29/2031</b>
<b>Project Milestones</b>	<b>12/27/2024</b>	<b>5/10/2031</b>
<b>Front End Planning</b>	<b>1/9/2023</b>	<b>12/31/2024</b>
Project Management	1/13/2023	4/24/2024
Procurement	1/9/2023	4/5/2024
Complete Field Program	1/5/2023	1/25/2024
Internal Engineering	1/26/2023	6/28/2024
Geotech Investigation	1/24/2023	5/29/2024
FEED	1/8/2024	12/31/2024
<b>Regulatory</b>	<b>1/3/2023</b>	<b>12/31/2025</b>
PUB Report Development	1/3/2023	12/31/2025
Environmental Assessment	4/12/2024	8/18/2025
Stakeholder Relations	5/5/2023	2/14/2025
<b>Execution</b>	<b>12/16/2024</b>	<b>4/30/2031</b>
Hydro Managed	12/16/2024	
EPCM Services RFP	1/13/2025	1/12/2026
Contract Package 2 Turbine Generator	12/16/2024	
Early Works / Existing Site Infrastructure Modifications	1/13/2025	
Contract Package 3.0 -- 230 kV Transmission Line	1/5/2026	
EPCM Consultant Managed	7/29/2025	
Project Management	7/30/2025	9/15/2025
Pre-Sanction Engineering & Construction Planning	7/29/2025	2/13/2026
Contract Package 1.0 - Heavy Civil Scope	8/13/2025	
Contract Package 2 - Turbine Generator - Manufacture & Install	10/22/2025	
<b>Project Closeout</b>	<b>12/18/1930</b>	<b>6/29/2031</b>

(112) The Gruner Report assesses the BDE Unit 8 project construction plan and schedule and identifies no major concerns or red flags. Gruner states:

The overall construction plan for the BDE Unit 8 project is considered sound, making good use of the existing facilities, site access, and work structure. The recent decision to combine the management and contracting for [BDE] Unit 8 construction, [BDE] Unit 7 life extension, and penstock refurbishment should help reduce scheduling conflicts and management risks.<sup>176</sup>

(113) However, Gruner does identify certain risks to the construction plan and schedule, two of which considered medium priority. These include risks associated with complex work activities (specifically

<sup>175</sup> Build Application, Schedule 4, Attachment 2, page 10.

<sup>176</sup> Gruner Report, Conclusion 9-1.

building the powerhouse extension alongside BDE Unit 7),<sup>177</sup> and needed scope of work clarifications.<sup>178</sup>

- (114) Gruner also includes three multi-part recommendations, each of which Gruner identifies as “high” priority. These recommendations include verifying component installation times and adding detailed milestones to the schedule,<sup>179</sup> making certain scope of work clarifications,<sup>180</sup> and taking certain actions to minimize constructability risks.<sup>181</sup>
- (115) Regarding the interaction between the planned development of BDE Unit 8 and the planned life extension of BDE Unit 7, Gruner concludes that “[t]he planned works for the life extension of [BDE] Unit 7 are mostly consisting of the major overhaul of the E&M equipment already installed at [BDE] Unit 7 with no major interface with the intended civil works for the additions of [BDE] Unit 8.”<sup>182</sup> However, because “the works within the powerhouse building will have an intense interface between [BDE] Unit 7 life extension and [BDE] Unit 8 installation,” Hydro would be well-advised to combine the contract packages for these two work scopes for both the EPCM and construction and installation tasks.<sup>183</sup> Gruner explains that doing so could offer advantages, such as (1) enhanced interaction, training, and continuity of the project team, (2) reduce management costs, and (3) produce savings on common indirect costs between the two projects.<sup>184</sup> Gruner therefore agrees with Hydro’s recent decision to revise the EPCM scope of work to include both the BDE Unit 8 development project and the BDE Unit 7 life extension (and potential uprate) project.<sup>185</sup>
- (116) Regarding the potential for scheduling conflicts between BDE Unit 8 and the BDE Unit 7 life extension (and potential uprate) projects, Gruner concludes that while some works between the two projects will be “overlapping,” schedule conflicts “within the powerhouse can be managed with a careful planning.”<sup>186</sup>

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<sup>177</sup> Gruner Report, Conclusion 9-2.

<sup>178</sup> Gruner Report, Conclusion 9-4.

<sup>179</sup> Gruner Report, Recommendation 9-1.

<sup>180</sup> Gruner Report, Recommendation 9-2.

<sup>181</sup> Gruner Report, Recommendation 8-3.

<sup>182</sup> Gruner Report, Section 9.5.2.

<sup>183</sup> Gruner Report, Section 9.5.2.

<sup>184</sup> Gruner Report, Section 9.5.2.

<sup>185</sup> Gruner Report, Section 9.5.2.

<sup>186</sup> Gruner Report, Section 9.5.2.

## VI. Project Governance

- (117) The project governance framework proposed by Hydro for the Build Application is new. Hydro explains that it developed its “Major Projects Governance Framework” (“Governance Framework”) for inclusion with the Build Application.<sup>187</sup> This Governance Framework consists of three new committees, which “will advise Hydro’s Board of Directors of the status of the projects and ensure an appropriate level of engagement throughout the project lifecycle, including regular checkpoints within the phased approval process.”<sup>188</sup>
- (118) First, the Major Projects Steering Committee (“Steering Committee”), which is comprised of Hydro’s entire executive leadership team, “provides a forum for obtaining executive-level approvals, providing updates related to current progress, identifying challenges, raising issues, and seeking guidance and advice on matters of high significance.”<sup>189</sup> Second, the Major Projects Risk Working Group (“Risk Working Group”), which is to be primarily comprised of the Major Projects Department’s Management Team, “provides a forum for comprehensive evaluation of risks” and “enable[s] two-way communication from the Major Projects Department to the rest of Hydro about project and program activity that may affect Hydro’s corporate activities and operations.”<sup>190</sup> Third, the Major Projects Change Control Committee (“Change Control Committee”) is to be primarily composed of members of the Major Projects Department’s Management Team and Hydro’s Corporate Legal and Finance teams, providing for “a forum for comprehensive evaluation of proposed project and program changes” and “effective management and approval of such changes.”<sup>191</sup> The governance structure of the Major Projects group is shown in Figure 4 below.

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<sup>187</sup> Build Application, Schedule 1, page 22 lines 5 to 7.

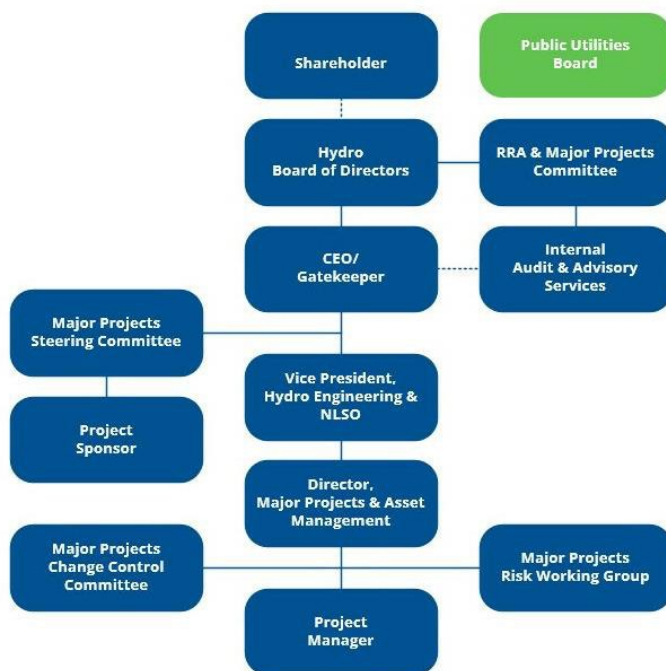
<sup>188</sup> Build Application, Schedule 1, page 22 line 23 to page 23 line 1.

<sup>189</sup> Build Application, Schedule 1, page 47 lines 2 to 7.

<sup>190</sup> Build Application, Schedule 1, page 47 lines 8 to 14.

<sup>191</sup> Build Application, Schedule 1, page 47 lines 15 to 19.

**Figure 4: Major Projects Governance Structure**<sup>192</sup>



- (119) Another aspect of Hydro’s proposed governance process is the “phased approval process,” which refers to “the high-level roadmap for Major Projects from the time a need is identified, through planning and execution, and into project handover and integration into Hydro’s operation.”<sup>193</sup> Hydro also has included a “long-term auditing strategy” for both the BDE Unit 8 and Avalon CT projects, with a focus on “project governance and project management.”<sup>194</sup>
- (120) Hydro appropriately recognizes the relationship between the size and complexity of a major project and the associated risk (and need for stronger governance controls).<sup>195</sup> Hydro also concludes – based on a “complexity assessment” completed by its internal audit team – that both projects are considered “very high complexity,” therefore requiring “a high degree of governance resources and effort.”<sup>196</sup>
- (121) Hydro claims that it has incorporated lessons from the Muskrat Falls Inquiry, including the establishment of a governance framework “that is founded on industry-accepted principles and

<sup>192</sup> Build Application, Schedule 1, Figure 8.

<sup>193</sup> Build Application, Schedule 1, page 48 lines 2 to 4.

<sup>194</sup> Build Application, Schedule 1, page 49 line 11 to page 50 line 2.

<sup>195</sup> Build Application, Schedule 1, page 50 lines 12 to 16.

<sup>196</sup> Build Application, Schedule 1, page 50 lines 17 to 23.

standards” and “provides for transparency in decision-making and multiple governing bodies with access to all information necessary to support risk-informed and evidence-based decision-making.”<sup>197</sup>

- (122) Here, we assess the project governance protocols proposed by Hydro and summarized above. We include conclusions and recommendations by Gruner, which undertook a review of Hydro’s project governance protocols, and whose conclusions and recommendations we endorse, subject to our discussion at the end of this section.
- (123) Gruner concludes that “[t]he project’s governance framework is aligned with standard practices for major projects.”<sup>198</sup> Gruner notes that the Major Projects Governance Framework appropriately includes structured oversight, phased approvals, and expenditure and audit controls.<sup>199</sup> Gruner notes several “good practices” that “are key for successful project delivery”:<sup>200</sup>
- Project budget authorization uses a P85 scenario for estimating the total project budget. The management reserve was estimated as the difference between the project costs with a P50 scenario and a P85 scenario. This looks appropriate to compensate for optimism bias.
  - Aiming to tender work based on a competitive bidding and on a fixed price basis.
  - Ensuring the Board is updated via quarterly reports.
- (124) Gruner also includes several recommendations to enhance the governance and project management process going forward. To enhance transparency and accountability, Gruner recommends that Hydro adopt an electronic procurement system,<sup>201</sup> and that any decisions of the Major Projects Control Committee be well documented and made available to the public at regular intervals.<sup>202</sup> Gruner also recommends that project management staff receive training on the specific contract types being used (such as measurement-based or EPCM/turnkey contracts) and on the contractual mechanisms that contractors may rely on to pursue additional payments or time extensions.<sup>203</sup>
- (125) In addition to Gruner’s conclusions and recommendations (with which we agree, subject to discussion here), we offer the following additional conclusions and recommendations.

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<sup>197</sup> Build Application, Schedule 1, page A-1 lines 17 to 20.

<sup>198</sup> Gruner Report, Section 11.

<sup>199</sup> Gruner Report, Section 10.1.

<sup>200</sup> Gruner Report, Conclusion 10-1.

<sup>201</sup> Gruner Report, Recommendation 10-1.

<sup>202</sup> Gruner Report, Recommendation 10-2.

<sup>203</sup> Gruner Report, Recommendation 10-3.

- (126) Hydro explains that “[a]t the end of the Detailed Design & Procurement stage, project costs will be re-forecasted and an updated project schedule will be available.”<sup>204</sup> If the re-forecasted costs or project schedule “is materially different” from the budget and/or schedule previously approved by the Board of Directors, the Major Projects Team is tasked with “reassess[ing] and reaffirm[ing] the decision to proceed.”<sup>205</sup> The Major Projects Team would then seek approval from the Board of Directors, giving the Steering Committee, CEO, and Board of Directors “the ability to make a decision that is informed by a more current and accurate forecast of the cost, an updated risk assessment, and an understanding of the project activities completed to date and those remaining.”<sup>206</sup> The Steering Committee and CEO will then be required to endorse a “Commitment to Build” that is sent to the Board of Directors for their approval.<sup>207</sup> Only then would the project go forward, and at that point “Hydro will communicate the Commitment to Build decision to the Board.”<sup>208</sup> From our perspective, it is not clear whether the Board would have any oversight authority in this process, and the Board may wish to clarify its role in the change management process.
- (127) The “Commitment to Build” process is an important step, though is left to subjective interpretation by Hydro. What constitutes a “materially different” project budget or schedule is not obvious and could benefit from additional clarity. Also, while Hydro commits to “report to the [Board] for further review if costs to completion are forecasted to exceed 10% of the approved project budget,”<sup>209</sup> additional clarity may be needed on this threshold as well. The Board’s Capital Budget Guidelines may not have anticipated Management Reserve allowances, as is requested in this proceeding. We would recommend that the 10% threshold (or any other threshold imposed by the Board) is calculated off of the project’s Authorized Budget, less the Management Reserve.
- (128) One aspect of Hydro’s proposed governance structure does raise some concern. As noted above, there is significant overlap between the newly-created “Major Projects Department,” which is “dedicated to and responsible for the planning, execution, and delivery of Major Projects” including both the Avalon CT and BDE Unit 8 projects,<sup>210</sup> and two of the three newly-created governance committees. Specifically, both the Risk Working Group and Change Control Committee will be “primarily comprised of members of the Major Projects Department’s Management Team.”<sup>211</sup> The Risk Working Group, intended to evaluate project risks, and the Change Control Working Group, intended to allow for continual evaluation of proposed project and program changes, are strong additions to Hydro’s project management governance protocols. However, it is our view that these committees

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<sup>204</sup> Build Application, Schedule 1, Attachment 1, page 36.

<sup>205</sup> Build Application, Schedule 1, Attachment 1, page 36.

<sup>206</sup> Build Application, Schedule 1, Attachment 1, page 36.

<sup>207</sup> Build Application, Schedule 1, Attachment 1, pages 36 to 37.

<sup>208</sup> Build Application, Schedule 1, Attachment 1, page 37.

<sup>209</sup> Build Application, Schedule 1, Attachment 1, footnote 36.

<sup>210</sup> Build Application, Schedule 1, page 45 lines 11 to 13.

<sup>211</sup> Build Application, Schedule 1, page 47 lines 8 to 19.

may be harmed in executing their important functions if they are primarily comprised of management-level employees in the Major Projects Department. Independence of these committees will be important, since risk reviews and considerations of change orders are challenging endeavors that often require rigorous – and sometimes unflattering – reflections on decisions made by the Major Projects Department. Should these committees lack independence from the Major Projects Department, the committees might struggle to provide objective, unbiased, consistent advice on prudent next steps.

- (129) We note that it is a best practice to separate project planning and execution from project monitoring (including monitoring risk, cost, and work scope) and controls. For example, the Project Management Institute, a non-profit organization that develops standards and provides research and education regarding project management, defines a disparate group for “monitoring and controlling” with focused roles such as tracking, reviewing, and regulating the project’s progress and performance continuously or at regular intervals.<sup>212</sup> That is, the group tasked with monitoring and controlling changes in work scope, schedules, costs, quality, and risks is separate from groups responsible for initiating, planning, and executing the project.<sup>213</sup> We recommend Hydro adjust its governance structure to reconstitute the Risk Working Group and Change Control Committee to ensure these committees are independent of the team(s) responsible for project development.
- (130) Lastly, we wish to address the use of external experts in Hydro’s proposed governance structure. Specifically, Hydro explains that its internal project team “will be supplemented by external experts as necessary.”<sup>214</sup> Hydro later states that it has partnered with “leading engineering firms to ensure the successful execution of major capital projects,” with AtkinsRealis providing support on BDE Unit 8 and Hatch providing support on the Avalon CT.<sup>215</sup> We note that the external expertise provided by these two firms relates to project development (cost estimates, FEED, etc.). This is appropriate, but we did not observe any instance of Hydro committing to use outside expertise in the oversight of the project, including ongoing risk management and project assessment as the scope of work progresses relative to planned budgets and schedules. The Muskrat Falls Inquiry noted the usefulness of external expertise in providing ongoing assessments of project progress and risks.<sup>216</sup> We recommend the

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<sup>212</sup> Project Management Institute, “A Guide to the Project Management Body of Knowledge (Sixth Edition),” pages 532 to 534 and 589 to 608, available at: <https://trainupinstitute.com/wp-content/uploads/2022/03/Project-Management-Institute-A-Guide-to-the-Project-Management-Body-of-Knowledge-PMBOK%C2%AE-Guide%E2%80%93Sixth-Edition-Project-Management-Institute-2017.pdf> (“PMBOK”).

<sup>213</sup> PMBOK, page 532.

<sup>214</sup> Build Application, Summary, page 3.

<sup>215</sup> Build Application, Schedule 1, page 51 line 28 to page 52 line 13.

<sup>216</sup> See, for example: Commission of Inquiry Respecting the Muskrat Falls Project, “Muskrat Falls: A Misguided Project,” March 5, 2020, Volume 4, pages 20 and 88, available at: <https://www.gov.nl.ca/em/muskrat-falls-a-misguided-project/> (“Muskrat Falls Inquiry”).

Board and Hydro both strongly consider adding external expertise to monitor and report on project status and risks on a regular (e.g., quarterly) basis.

## VII. Management Reserve

### A. Background

- (131) In the Build Application, Hydro requests approval of a total Authorized Budget of \$1.97 billion for both the Avalon CT and BDE Unit 8.<sup>217</sup> Of that, about \$273.4 million (or 13.9%) is “Management Reserve.”<sup>218</sup> Hydro notes that it has never previously sought or used a Management Reserve.<sup>219</sup> Hydro defines Management Reserve as:

...an industry-standard tool that is used to manage strategic risk and to address issues that may arise that are outside the control of Hydro. It serves as additional funds in a project budget that is set aside for strategic risks and potential external, uncontrollable factors that may arise throughout the course of the project. It is not intended to be used to accommodate foreseeable changes in scope, schedule, and cost that are within Hydro’s control. Considered ‘unknown unknowns’ that are within the project scope (e.g., government policy changes).<sup>220</sup>

- (132) Management Reserve is not reserves set aside for contingencies. Hydro’s Authorized Budgets for both projects include both DDA, which accounts for anticipated growth in scope of work as engineering on the project advances,<sup>221</sup> and a Contingency Allowance, which is “funds allocated to address foreseeable but uncontrollable events” related to a project.<sup>222</sup> Thus, DDA addresses risk of known, controllable costs; Contingency Reserve addresses risk of known, uncontrollable costs; and Management Reserve addresses risk of unknown, uncontrollable costs. The table below provides

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<sup>217</sup> Build Application, Application, page 3.

<sup>218</sup> Build Application, Schedule 4 Attachment 1, Table 1; Build Application, Schedule 5 Attachment 1, Table 1. Management reserve for BDE Unit 8 is proposed at \$145.2 million; for Avalon CT, \$128.2 million.

<sup>219</sup> Phase 1 BW-NLH-018 (f), page 3 lines 17 to 26.

<sup>220</sup> Build Application, Schedule 1, footnote 35.

<sup>221</sup> Build Application, Schedule 4, Attachment 1, page 68. DDA is an “amount (typically a percentage) applied to account for anticipated growth in Scope of Work in a particular Work Item as engineering advances, e.g., from front-end engineering to detailed engineering stage. Scope of Work growth is foreseeable and controllable when a project advances to the next stage.” (Emphasis in original.)

<sup>222</sup> Build Application, Schedule 4, Attachment 1, page 68. “Contingency is considered to be ‘funds allocated to address foreseeable but uncontrollable events related to a Work Item.’ This does not mean simply adding a percentage to try to make up for poor project definition or make a Cost Estimate ‘more accurate’ than it is. In this estimate, Contingency is thought of in the same way as a ‘Contingency Plan’, i.e., a plan designed to address the impact of a possible future event. It is not about ‘unforeseen events’ (which, by definition, cannot be predicted) or ‘controllable events,’ like improved project definition project definition or natural scope growth as the project advances (this is covered in DDA).” (Emphasis in original.)

details for the fund allowances in the requested Authorized Budgets for both the Avalon CT<sup>223</sup> and BDE Unit 8.<sup>224</sup>

**Table 5: Reserve Fund Detail**

Reserve Fund	Intended Risk Coverage	Avalon CT Value (\$mm) <sup>225</sup>	BDE Unit 8 Value (\$mm) <sup>226</sup>	Total Build Application Value (\$mm)	Share of Total Authorized Budget (%)
DDA	Known, controllable costs	\$65.1	\$98.3	\$163.4	8.3%
Contingency Reserve	Known, uncontrollable costs				
Management Reserve	Unknown, uncontrollable costs	\$128.2	\$145.2	\$273.4	13.9%

- (133) To develop the Management Reserve amounts for each project, Hydro applied different approaches. This was at least partially the result of the fact that the respective Monte Carlo simulations for BDE Unit 8 and the Avalon CT were performed by different contractors with different proprietary tools.<sup>227</sup>
- (134) For BDE Unit 8, AtkinsRealis conducted the Monte Carlo simulation modeling, but it was Hydro that determined the Management Reserve.<sup>228</sup> Hydro determined the Management Reserve in two components. The first is the Management Reserve on base costs, equal to the difference between the P85 and P50 levels of the Monte Carlo distribution of total costs (the P85 value itself calculated as the average of P80 and P90 values).<sup>229</sup> This component is estimated at \$26.2 million.<sup>230</sup> The second component of the Management Reserve was based on strategic risks, which is based on a separate Monte Carlo of strategic risk factors, with the corresponding Management Reserve component being equal to the full P85 value (again, taken as the average of P80 and P90 values).<sup>231</sup> The strategic risks component is entirely additive – i.e., it is not the difference between the P85 value and a P50 value

<sup>223</sup> For the Avalon CT, Contingency Reserve was determined using Monte Carlo analysis. Contingency equals the difference between the P55 value and the base cost estimate. DDA was not a specific component of the Avalon CT cost estimate. Build Application, Schedule 5, Attachment 1, Table 1.

<sup>224</sup> For BDE Unit 8, the base cost estimate included DDA and Contingency Reserve of \$60.7 million. (Hydro did not provide values for DDA and Contingency separately). Monte Carlo analysis for BDE Unit 8 was then used to derive an additional contingency amount, corresponding to the difference between the simulated P50 value (which for BDE Unit 8 also corresponds to the average or mean value for the resulting distribution) and the base estimate, which amounts to \$37.6 million. Thus, \$60.7 million plus \$37.6 million equals the total DDA + Contingency Reserve of \$98.3 million. Build Application, Schedule 4, Attachment 1, page 22.

<sup>225</sup> Build Application, Schedule 5, Attachment 1, Table 1.

<sup>226</sup> Build Application, Schedule 4, Attachment 1, Table 1.

<sup>227</sup> Phase 1 BW-NLH-019, page 1 lines 8 to 21.

<sup>228</sup> Build Application, Schedule 4, Attachment 1, page 89.

<sup>229</sup> Build Application, Schedule 4, Attachment 1, page 28.

<sup>230</sup> Build Application, Schedule 4, Attachment 1, page 29.

<sup>231</sup> Build Application, Schedule 4, Attachment 1, page 28.

assumed to be reflected in the base cost. This second Management Reserve component is estimated at \$119.0 million, and the combined Management Reserve for BDE Unit 8 equals \$145.2 million.<sup>232</sup>

- (135) For the Avalon CT, Hatch also used Monte Carlo simulation though the Management Reserve amount simply equals the difference between the P85 value and the P55 value of the base cost Monte Carlo distribution.<sup>233</sup> There is no separate, additional Management Reserve component for strategic risks, as applies for BDE Unit 8.<sup>234</sup> As we noted in our Phase One Expert Report, while there is a methodological inconsistency in the treatment of cost allowances and the application of Monte Carlo simulation between the two projects, the total cost risk allowances for BDE Unit 8 and the Avalon CT are roughly comparable.<sup>235</sup> Management Reserve as a percentage of the base project cost plus DDA and/or Contingency Reserve for BDE Unit 8 (19.5%) is about equal to that of the Avalon CT (19.7%).<sup>236</sup>
- (136) Hydro explains that the Management Reserve funds will not be immediately accessible to the project teams.<sup>237</sup> Accessing the Management Reserve will “require justification and prior approval of the CEO,” and that “[r]elease of Management Reserve funds requires those funds to be added to the Authorization for Expenditure form and signed by the CEO.”<sup>238</sup> Hydro explains that “[s]trategic risks that increase or materialize should be escalated through the risk management process and the Steering Committee and CEO should have an understanding of the rationale for using the Management Reserve and the risk management strategies that are being used to address it.”<sup>239</sup> Hydro’s “Major Projects Steering Committee,” which “provides oversight, guidance, and approvals for all major projects,” has authority in “[a]pproving project changes,” such as use of the Management Reserve funds,<sup>240</sup> with the Hydro CEO serving as “Gatekeeper” for any use of the Management Reserve through the issuance of “supplemental Authorizations for Expenditure.”<sup>241</sup>
- (137) We undertook a review to determine whether and how Management Reserve is applied in the utility industry, for budgeting and/or regulatory approvals of major projects, and the appropriateness of a Management Reserve as incorporated by Hydro in its Application. As noted above, Hydro states that inclusion of management reserve in project cost estimates, “especially large complex projects,” was a “key finding within the Muskrat Falls Inquiry.”<sup>242</sup> Hydro also claims that management reserve funds

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<sup>232</sup> Build Application, Schedule 4, Attachment 1, page 29.

<sup>233</sup> Build Application, Schedule 5, Attachment 1, pages 6 and 25.

<sup>234</sup> Build Application, Schedule 5, Attachment 1, page 25.

<sup>235</sup> Bates White Phase One Expert Report, paragraph 94.

<sup>236</sup> Bates White Phase One Expert Report, Table 7.

<sup>237</sup> Build Application, Schedule 1, Attachment 1, pages 38 to 41.

<sup>238</sup> Build Application, Schedule 1, Attachment 1, page 39.

<sup>239</sup> Build Application, Schedule 1, Attachment 1, page 41.

<sup>240</sup> Build Application, Schedule 1, Attachment 1, page 25.

<sup>241</sup> Build Application, Schedule 1, Attachment 1, page 26.

<sup>242</sup> Build Application, Schedule 1, page 31 lines 17 to 20.

are “industry standard.”<sup>243</sup> We assess those claims and the appropriateness of a Management Reserve fund allowance in the following section.

## **B. Management Reserve recommendations from the Muskrat Falls Inquiry**

- (138) On November 20, 2017, the Government of Newfoundland and Labrador established the Commission of Inquiry Respecting the Muskrat Falls Project (“Commission”) in response to the cost overruns and other issues related to the execution of the Muskrat Falls project.<sup>244</sup> On March 5, 2020, the Commission issued its report, authored by the Honourable Richard D. LeBlanc.<sup>245</sup> The Muskrat Falls Inquiry summarized its purpose:

It is hoped that this Report will serve both as an accurate account of what has transpired related to the Muskrat Falls Project and as a resource that can be used to identify areas for improvement in the consideration, initiation, evaluation, development, construction and oversight of any and all future large-scale projects or megaprojects in this province.<sup>246</sup>

- (139) To that end, the six-volume Muskrat Falls Inquiry contained extensive details about the events that occurred both prior to and following sanctioning of the project, as well as a series of “key findings” and recommendations.<sup>247</sup> The Muskrat Falls Inquiry was critical of Nalcor’s project cost estimate for failing to include reserves to cover strategic risks.<sup>248</sup> For example, the Muskrat Falls Inquiry noted that even though the project management team recommended establishment of a “management reserve” of \$497 million to cover strategic risks in December 2012 (which was the time the project was sanctioned),<sup>249</sup> Nalcor’s chief executive “rejected this recommendation.”<sup>250</sup> Accordingly, “there was nothing in the...cost estimate to cover strategic risks.”<sup>251</sup> The Muskrat Falls Inquiry included as one of its key findings:

A reasonable reserve for strategic risk should have been included in the Project’s cost estimate and made known to [the Government of Newfoundland and Labrador].

There was no reasonable basis to support [the chief executive of Nalcor’s] decisions

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<sup>243</sup> Build Application, Schedule 1, page 31 lines 17 to 18.

<sup>244</sup> Muskrat Falls Inquiry, Volume 1, page 1.

<sup>245</sup> Muskrat Falls Inquiry, Volume 1.

<sup>246</sup> Muskrat Falls Inquiry, Volume 1, page 44.

<sup>247</sup> Muskrat Falls Inquiry, Volume 1, pages 45 to 65.

<sup>248</sup> Muskrat Falls Inquiry, Volume 1, page 16.

<sup>249</sup> Muskrat Falls Inquiry, Volume 1, page 3.

<sup>250</sup> Muskrat Falls Inquiry, Volume 1, page 16.

<sup>251</sup> Muskrat Falls Inquiry, Volume 1, page 16.

to exclude strategic risk from the [cumulative present worth] analysis or the Project's cost estimates.<sup>252</sup>

(140) The Muskrat Falls Inquiry included as one of its seven “key recommendations” that:

The Government of Newfoundland and Labrador should proceed to fund large projects using a probability value of not less than P85. As well, recognizing the likelihood of bias in any cost and schedule estimate, government should require the project proponent to provide a range of cost estimates in order to establish the project's budget, so that government can determine its own risk appetite. Amounts for tactical and strategic risks should be included in the overall budget but should not be specifically identified or quantified when disclosure is made to the public. Government should authorize the release of dollar amounts for tactical and strategic risks only on pre-determined, structured and well-defined terms.<sup>253</sup>

(141) Our review of the Muskrat Falls Inquiry suggests that the Commission was clear that future large projects should use at least a P85 estimate. Moreover, it is clear to us that the Muskrat Falls Inquiry identified the need for a reserve fund for “strategic” risks, which was defined as “[i]dentified background risks that are outside the control of the project team and that typically pertain to external issues.”<sup>254</sup>

(142) In our view, and subject to the caveats and discussion below, Hydro has been responsive to the finding and recommendation related to management reserve in the Muskrat Falls Inquiry.

(143) **First, Hydro has defined a set of strategic risks for both projects and reflected those risks in its cost estimates.** As noted above, the Muskrat Falls Inquiry defined strategic risks as “identified background risks that are outside the control of the project team and that typically pertain to external issues.”<sup>255</sup> For BDE Unit 8, Hydro has identified twenty strategic risks, each identified in its “Strategic Risk Register.”<sup>256</sup> Each strategic risk had low, expected, and/or high-cost values, in dollars, related to the risk. The Monte Carlo simulations for BDE Unit 8 included the twenty strategic risks identified in its Strategic Risk Register.<sup>257</sup> (The risks are shown in Table 6 below).

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<sup>252</sup> Muskrat Falls Inquiry, Volume 1, page 53, Key Finding 41.

<sup>253</sup> Muskrat Falls Inquiry, Volume 1, pages 61 to 62, Key Recommendation 5.

<sup>254</sup> Muskrat Falls Inquiry, Volume 4, page 100.

<sup>255</sup> Muskrat Falls Inquiry, Volume 4, page 100.

<sup>256</sup> Build Application, Schedule 4, Attachment 1, pages 44 to 47.

<sup>257</sup> Build Application, Schedule 4, Attachment 1, pages 44 to 47.

**Table 6: Strategic Risks Considered (BDE Unit 8)<sup>258</sup>**

Risk	Low	Expected	High
Foreign currency exchange	█	█	█
Escalation/inflation	█	█	█
Tariffs	█	█	█
Interest during construction	█	█	█
Contractor finance costs	█	█	█
Contract terms and conditions	█	█	█
Availability & capability of EPCM contractor	█	█	█
Limited number of hydro turbine suppliers	█	█	█
Availability of experienced contractors	█	█	█
Availability, retention, and productivity of construction labor	█	█	█
Regulatory (PUB) approval timeline			
Environmental assessment process			
Change in project execution plan (e.g., due to Unit 7 overhaul)			
Continuation of FEED work during PUB review process			
Coordination with operating plant			
Cost impact of extraordinary delays	█	█	█
Lack of support from indigenous and community groups			
Transmission system constraints			
Escalation/inflation due to schedule delay			
<b>Total</b>	<b>\$4,736,360</b>	<b>█</b>	<b>\$169,863,640</b>

(144) For the Avalon CT, Hydro and Hatch developed a set of “systemic risks” across several categories, including (1) Business Ownership and team Development, (2) General Project Scope Description, (3) Project Planning, (4) Engineering Deliverables, (5) Estimate and Schedule Development, (6) Project Management and Control Effectiveness, and (7) Project Technology and Complexity.<sup>259</sup> Each systemic risk was represented in the model by probabilistic distributions (rather than low-expected-high values), though were not provided in evidence due to Hatch using probabilistic distribution inputs that “are considered proprietary by the model Owner.”<sup>260</sup> The Hatch analysis also included a set of “project-specific risk events,” including █  
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 █.<sup>261</sup> Each project-specific risk had a low, expected, and high

<sup>258</sup> Build Application, Schedule 4, Attachment 1, pages 44 to 47.

<sup>259</sup> Build Application, Schedule 5, Attachment 1, page 96.

<sup>260</sup> Phase 1 BW-NLH-018 (b), page 2 lines 13 to 14.

<sup>261</sup> Build Application, Schedule 5, Attachment 1, page 97.

delay duration or cost associated with it.<sup>262</sup> The Monte Carlo simulations for the Avalon CT also included the strategic risks.<sup>263</sup> The Avalon CT risks are shown in Table 7, with the systemic risks shown first in orange and the project-specific risks second in blue.

**Table 7: Strategic Risks Considered (Avalon CT)<sup>264</sup>**

Risk	Probability of Occurrence	Duration/Cost Impact		
		Low	Expected	High
Business ownership and team development	N/A - Subject to a proprietary probabilistic distribution			
General project scope description				
Project planning				
Engineering deliverables				
Estimate and schedule development				
Project management and control effectiveness				
Project technology and complexity				
[Redacted]	■	■	■	■
[Redacted]	■	■	■	■
[Redacted]	■	■	■	■
[Redacted]	■	■	■	■
[Redacted]	■	■	■	■

(145) **Second, Hydro has submitted P85 estimates.** Both the Avalon CT and BDE Unit 8 project budgets put forth in this proceeding represent P85 budgets.<sup>265</sup>

(146) That said, while Hydro has been responsive to the Muskrat Falls Inquiry on this issue, we caution that there are several caveats and points of context the Board should consider.

- While Hydro has provided substantial, well-considered lists of strategic risks for each project, it is unlikely Hydro has captured the full extent of the strategic risks faced by the projects.** It is unlikely that the lists of risks in Table 6 and Table 7 above are comprehensive. For example, neither project considers the risk of certain *force majeure* events, such as natural disasters (including seismic activity risk noted by Gruner), and the Avalon CT risks do not include the risk of changes in government or environmental policy.
- By definition, risks that are “unknown unknowns” cannot be identified in advance, suggesting that a reserve fund to capture such risks may be better identified through a percentage-based approach.** Hydro purports to have developed a Management Reserve for

<sup>262</sup> Build Application, Schedule 5, Attachment 1, page 97.  
<sup>263</sup> Phase 1 BW-NLH-018 (a), page 1 line 22 to page 2 line 3.  
<sup>264</sup> Build Application, Schedule 5, Attachment 1, pages 96 to 97.  
<sup>265</sup> Build Application, Schedule 1, page 21 lines 1 to 7.

both projects that captures the “unknown unknowns” that the projects could face, such as changes in government policy.<sup>266</sup> Monte Carlo simulations use identified variables with uncertain values (estimated through an assumed distribution). If a variable is undefined, the Monte Carlo simulation would not capture its risk. An alternative approach would be to specify a Management Reserve based on a percentage of the forecasted cost of the project. However, in fairness to Hydro, the Muskrat Falls Inquiry identified “strategic risks” as “identified” risks, not “unknown unknowns.” Therefore, we are not suggesting that Hydro has not been responsive to the Muskrat Falls Inquiry, only that its consideration of strategic risks may be incomplete.

3. **The purpose of the Management Reserve should be to provide additional, needed funds due to the manifestation of the strategic risks and should not be used as a backstop for poor cost estimates, poor contingency estimates, or poor project development and management.** If the cost or contingency estimates developed by Hydro are too low, or the projects face delays and higher costs due to poor project execution by Hydro and its contractors, Hydro may look to tap into the Management Reserve to complete the projects. However, doing so would not be consistent with the purpose of the Management Reserve, which is to cover strategic risks.
4. **Ideally, access to the Management Reserve funds would require Board review, but must be balanced against the goal of allowing project development to continue without delay when additional funds are needed.** As constructed, the Management Reserve allowances are part of the Authorized Budgets, so no further approvals will be needed from the Board to access those funds. Access is ultimately controlled by the Hydro CEO. This achieves a key objective of a Management Reserve, which is to allow the project development to continue without delays to obtain regulatory approval to overspend. **However, this approach offers little oversight, transparency, or accountability for Hydro in accessing Management Reserve funds.** To prevent the use of Management Reserve as a backstop mechanism for cost estimation and project execution failures, the Board should require Hydro to formally notify the Board if it anticipates accessing the Management Reserve funds and again when those funds are accessed. The Board should be able to request supporting information from Hydro regarding the details of the need for and amount of Management Reserve funds accessed. The burden of prudence should remain with Hydro in all cases, and the Board should review Hydro’s submissions for evidence that the strategic risks that those funds are meant to cover have materialized and driven the costs of the project higher. This would increase transparency in the process and accountability for Hydro and its contractors.

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<sup>266</sup> Build Application, Schedule 1, footnote 35.

5. **The Muskrat Falls Inquiry lacked some specificity regarding access to Management Reserve funds.** As suggested by the Muskrat Falls Inquiry, the Government of Newfoundland and Labrador “should proceed to fund large projects using a probability value of not less than P85.”<sup>267</sup> However, the Muskrat Falls Inquiry also stated that the government should require the project proponent “to provide a range of cost estimates in order to establish the project’s budget, so that government can determine its own risk appetite.”<sup>268</sup> This suggests that the Board has latitude in setting Authorized Budgets for the projects while incorporating the recommendation of the Muskrat Falls Inquiry.
6. **We caution against overconfidence in the P85 results.** In the Build Application, Hydro states:

The Authorized Budget of approximately \$1.08 billion for the project, set at a P85 confidence level, **ensures an 85% probability of staying within budget**, balancing cost efficiency with prudent risk management, consistent with Justice LeBlanc’s recommendations in the final report on the Muskrat Falls Inquiry.”<sup>269</sup>

We disagree that the use of P85 estimates “ensures an 85% probability of staying within budget.”<sup>270</sup> The P85 simply refers to the 85<sup>th</sup> percentile estimate of the Monte Carlo results.<sup>271</sup> The Monte Carlo analysis depends on myriad of variables, estimates, and assumptions, and if those inputs are inaccurate or biased, the Monte Carlo analysis will not provide an accurate, unbiased set of cost estimates. For example, if the cost estimate for project components is too low, the Monte Carlo value will understate the likelihood that actual project costs exceed the P85 estimate. The Muskrat Falls Inquiry made a similar finding<sup>272</sup> and concluded that “P50 is not really P50,” stating that “cost estimates often understate both the cost of the project and the risk of large overruns.”<sup>273</sup>

7. **For BDE Unit 8, the Management Reserve amounts were calculated by Hydro, not its consultants.** AtkinsRealis states:

At this stage, several key indirect costs are excluded in the current Cost Estimate produced by AtkinsRealis. These costs – escalation during

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<sup>267</sup> Muskrat Falls Inquiry, Volume 1, pages 61 to 62.

<sup>268</sup> Muskrat Falls Inquiry, Volume 1, pages 61 to 62.

<sup>269</sup> Build Application, Schedule 4, page 43 lines 5 to 8.

<sup>270</sup> Build Application, Schedule 4, page 43 lines 5 to 8.

<sup>271</sup> See, for example: definition of “P50” and “P90,” Build Application, Schedule 5, Attachment 1, page 91.

<sup>272</sup> Muskrat Falls Inquiry, Volume 2, page 201.

<sup>273</sup> Muskrat Falls Inquiry, Volume 2, page 206.

construction (EDC), interest during construction (IDC), and management reserves – are critical components that were calculated by NLH separately and included in the project budget.

...

Finally, **management reserve**, is a contingency fund to be defined by NL Hydro. The management reserve will need to be factored into future cost updates to ensure a more complete financial picture of the BDE project.<sup>274</sup>

In addition to developing the strategic risks, Hydro also developed the low, expected, and high dollar estimates for each risk. Hydro’s estimates that the strategic risk related to its EPCM contractor – i.e., that it will have “difficulty in identifying and securing the services of a capable EPCM contractor who has a strong background in all engineering, procurement and construction management activities for hydro projects,” which “could lead to project execution risk and schedule and cost impacts”<sup>275</sup> – is estimated in the “high” case to be [REDACTED].<sup>276</sup> That represents a cost increase of just [REDACTED] for the base cost estimate of the EPCM contractor cost of [REDACTED].<sup>277</sup> This may be too low. Moreover, the BDE Unit 8 strategic risk related to a limited number of hydro turbine suppliers (which could lead to higher costs), had no quantified cost associated with that risk.<sup>278</sup> Risk associated with the cost of the turbine was included in the base cost estimate and contingency reserve.<sup>279</sup> Still, Hydro should clarify the zero values for the strategic risk estimate.

8. **Moreover, for BDE Unit 8’s Monte Carlo analysis (and Management Reserve), Hydro has ignored or understated certain strategic risks.** Hydro identified three “new and emerging risks” that “occurred between the completion of the cost estimate and the finalization of [the] Basis of Estimate document.”<sup>280</sup> Each is related to “potential increases in project costs due to possible schedule overlap and increased demand for resources such as ECPM Contractors, labour, and major equipment packages” due to a new partnership between Hydro and Hydro-Quebec to develop new hydro resources in Labrador.<sup>281</sup> These risks include (1) “delays and escalation” caused by “the potential impact of competing projects,” (2) “decreased productivity” of labor, and (3) “tariffs and foreign exchange,” which

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<sup>274</sup> Build Application, Schedule 4, Attachment 1, page 89. (Emphasis in original.)

<sup>275</sup> Build Application, Schedule 4, Attachment 1, page 45.

<sup>276</sup> Build Application, Schedule 4, Attachment 1, page 45.

<sup>277</sup> Build Application, Schedule 4, Attachment 1, Table 1.

<sup>278</sup> Build Application, Schedule 4, Attachment 1, page 45.

<sup>279</sup> Build Application, Schedule 4, Attachment 1, pages 114 to 116.

<sup>280</sup> Build Application, Schedule 4, Attachment 1, page 32.

<sup>281</sup> Build Application, Schedule 4, Attachment 1, page 32.

recognize the potential for 25% import tariffs “on all potential commodities that may be procured in the United States.”<sup>282</sup> Hydro quantified these risks across a variety of sensitivities; in total, the risks’ incremental impact on BDE Unit 8’s project cost range from a minimum of \$63.0 million to \$562.4 million. It is not clear if interaction between the BDE Unit 8 project and the refurbishment of BDE Unit 7 could further exacerbate this risk; Hydro should address this potential in its updated calculations. Table 8 below shows the detail of the cost impacts of these risks, with only the lowest and highest sensitivities shown for each risk.

**Table 8: “Emerging” strategic risks for BDE Unit 8<sup>283</sup>**

Risk	Incremental Cost Impact - Low Estimate (\$mm)	Incremental Cost Impact - High Estimate (\$mm)
Delays and Escalation	█	█
Decreased Productivity	█	█
Tariffs/Foreign Exchange	█	█
<b>Total</b>	<b>\$63.0</b>	<b>\$562.4</b>

Hydro did not include these strategic risks in the determination of the Management Reserve. Hydro only states: “As noted in Section 13.0, an MCS [Monte Carlo Simulation] analysis of strategic risks was completed in November 2024 and an amount for strategic risks is included in the estimate.”<sup>284</sup> Timing challenges may explain the omission of these risks, but the potential cost impacts are too high to ignore. The cumulative impact of these three risks is estimated to be as high as \$562.4 million, which would represent an overall project cost increase of 52%.<sup>285</sup> The Board should consider requiring Hydro to incorporate these risks into an updated Monte Carlo analysis and Management Reserve calculation.<sup>286</sup>

- 9. For the Avalon CT, strategic risks were developed by Hydro in conjunction with its consultant (Hatch) using a different approach that identified key risks associated with the project.** The “systemic” strategic risks identified by Hydro and Hatch were developed by assessing Hydro, the project plans, and the project team across a variety of risks, which were then inputted into the Monte Carlo simulation model. The strategic risk “scorecard,” which is found in the Avalon CT Basis of Estimate,<sup>287</sup> underscores some of the risks Hydro faces. Hydro’s scores generally stay within industry norms. One item worth noting was that Hydro’s schedule estimate was given a score of “3” on a scale of 0-10, with 0 being “very aggressive,”

<sup>282</sup> Build Application, Schedule 4, Attachment 1, pages 32 to 34.

<sup>283</sup> Build Application, Schedule 4, Attachment 1, pages 33 to 35.

<sup>284</sup> Build Application, Schedule 4, Attachment 1, page 32.

<sup>285</sup> See: Table 7. An increase of \$562.4 million on a project estimate of \$1.079 billion is an increase of 52%. Build Application, Schedule 4, Attachment 1, Table 1.

<sup>286</sup> We note that Gruner makes a similar recommendation. See: Gruner Report, Conclusion 4-4.

<sup>287</sup> Build Application, Schedule 5, Attachment 1, pages 105 to 110.

10 being “very conservative,” and 3 being “norms, but no clear basis.”<sup>288</sup> The scorecard also noted that “[c]ost control, contract management, and document control tools not in place. Learning curve may add difficulties. Depending on the contracting strategy, EPCM tools may be used. The scoring reflects that possibility.”<sup>289</sup> Still, Hydro’s “organizational capability/competence” was judged highly, with the scorecard noting: “Staffing with experienced people on both sides. [Evidence is] still required that the teams will work well together. Considered a strong pool of talent dedicated to this project.”<sup>290</sup>

### **C. Management Reserve fund allowances are not unprecedented but their use is not widespread**

- (147) We consider in this section whether (1) Management Reserve funds are used in other regulated electric utility project budgets and (2) if Monte Carlo simulation methods are used to develop cost estimates. Both concepts are new to Hydro, which has historically not included a Management Reserve fund, instead using a percentage model for estimating contingency funds.<sup>291</sup>
- (148) Hydro provides two examples of Canadian utilities that have included “both contingency reserve and Management Reserve in project estimates.”<sup>292</sup> The first is BC Hydro. Hydro states:

In British Columbia, large capital projects that exceed specified cost thresholds (or as directed by the British Columbia Utilities Commission (“BCUC”)) are reviewed and approved separately, either through a Section 44.2 Expenditure Schedule or a Certificate of Public Convenience and Necessity (“CPCN”) process. For the CPCN process, the BCUC’s approved Major Capital Project Filing Guidelines for British Columbia Hydro and Power Authority (“BC Hydro”) require application to the BCUC for major capital projects with authorized cost estimates that exceed certain thresholds. The Authorized Cost is the requested funding for a project, inclusive of all contingencies and reserves and based on a fixed scope and in-service date.<sup>293</sup>

- (149) Hydro cites the example of BC Hydro’s CPCN proceeding related to a transmission project (the 1L243 Transmission Load Increase (Highland Valley Copper) Project). Hydro states that for that

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<sup>288</sup> Build Application, Schedule 5, Attachment 1, page 109.

<sup>289</sup> Build Application, Schedule 5, Attachment 1, page 109.

<sup>290</sup> Build Application, Schedule 5, Attachment 1, page 109.

<sup>291</sup> Phase 1 BW-NLH-018 (f).

<sup>292</sup> Build Application, Schedule 1, Attachment 1, page 41.

<sup>293</sup> Hydro, BDE Unit 7 Life Extension Application, PUB-NLH-007 (a), page 1 lines 16 to 24. IRs related to the BDE Unit 7 life extension update are hereinafter cited as “BDE Unit 7 Life Extension Application” followed by the IR number, and are available here: <http://www.pub.nf.ca/applications/NLH2025LifeExtensionUnit7/responses.php>.

project, the “Authorized Cost” was defined as the estimated cost at the P90 confidence level, plus the “Special Reserve,” which is defined as:

...an amount added to an estimate to allow for discretionary management purposes outside of the defined scope of the Project, as otherwise estimated. It may include amounts that are within the defined scope, but for which management does not want to fund as contingency or that cannot be effectively managed using contingency.<sup>294</sup>

- (150) Hydro explained that BC Hydro’s application was approved and noted the BCUC found “as reasonable BC Hydro’s Authorized Cost estimate of \$147.1 million that includes a project reserve of \$23.5 million.”<sup>295</sup>
- (151) Our review of the BC Hydro example generally supports Hydro’s characterization. The “Expected Cost” of the project was a P50 Monte Carlo estimate (and equal to \$123.6 million).<sup>296</sup> The requested budget (or, “Authorized Cost”), however, was a P90 cost estimate, plus a “Special Reserve,” collectively equal to \$147.1 million.<sup>297</sup> The \$23.5 million in additional funds beyond the Expected Cost of the project was therefore made up of (1) the difference between the P90 and the P50 estimate for the project plus (2) the Special Reserve. The breakdown between these two components is not public and is therefore redacted in the publicly available version of the BC Hydro Application.<sup>298</sup> The BCUC approved the full Authorized Cost, including the P90 Monte Carlo estimate and Special Reserve.<sup>299</sup>
- (152) It should be noted that the BC Hydro Application was made pursuant to the BC Utilities Commission’s “2015 Certificate of Public Convenience and Necessity Application Guidelines,” which are the Commission’s guidelines for utilities in making CPCN applications.<sup>300</sup> Those guidelines require the estimates to comply with applicable AACE International Cost Estimate Classification System Recommended Practices in the development of the cost estimate.<sup>301</sup> The

<sup>294</sup> BDE Unit 7 Life Extension Application PUB-NLH-007 (a), page 1 line 24 to page 2 line 12.

<sup>295</sup> BDE Unit 7 Life Extension Application PUB-NLH-007 (a), page 2 lines 13 to 15.

<sup>296</sup> BC Hydro, “British Columbia Utilities Commission (BCUC or Commission) British Columbia Hydro and Power Authority (BC Hydro) 1L243 Transmission Load Increase (Highland Valley Copper) Project,” May 23, 2024, page 1-2 line 7 to page 1-3 line 2 and footnote 4, available at: [https://docs.bcuc.com/documents/proceedings/2024/doc\\_77349\\_b-1-bch-11243-transmissionloadincrease-highlandvalleycopper-project-application-public.pdf](https://docs.bcuc.com/documents/proceedings/2024/doc_77349_b-1-bch-11243-transmissionloadincrease-highlandvalleycopper-project-application-public.pdf) (“BC Hydro Application”).

<sup>297</sup> BC Hydro Application, page 1-2 line 7 to page 1-3 line 2 and footnote 5.

<sup>298</sup> BC Hydro Application, page 3-20.

<sup>299</sup> BC Utilities Commission, “Order Number C-1-25,” February 12, 2025, available at: [https://docs.bcuc.com/documents/other/2025/doc\\_80136\\_c-1-25-bch-cpcn-11243-load-increase-highland-valley-copper-project-final.pdf](https://docs.bcuc.com/documents/other/2025/doc_80136_c-1-25-bch-cpcn-11243-load-increase-highland-valley-copper-project-final.pdf).

<sup>300</sup> BC Hydro Application, page 1-13 lines 2 to 3 and footnote 11; BC Utilities Commission, “Re: Review of 2010 Certificate of Public Convenience and Necessity Application Guidelines and the Project Reporting Process and Purposes: 2015 Certificate of Public Convenience and Necessity Application Guidelines,” February 20, 2015, available at: [https://docs.bcuc.com/documents/guidelines/2015/doc\\_25326\\_g-20-15\\_bcuc-2015-cpcn-guidelines.pdf](https://docs.bcuc.com/documents/guidelines/2015/doc_25326_g-20-15_bcuc-2015-cpcn-guidelines.pdf) (“2015 Certificate of Public Convenience and Necessity Application Guidelines”).

<sup>301</sup> 2015 Certificate of Public Convenience and Necessity Application Guidelines, Appendix A, page 7.

guidelines allowed for Monte Carlo analysis and required in such instances that applicants must provide certain information, including P50 and P90 cost estimates, contingency estimates, and reserve estimates.<sup>302</sup>

- (153) We also noted three additional, similar projects in British Columbia. In 2022, BC Hydro received approval from the BCUC to develop the Mainwaring Substation Upgrade project.<sup>303</sup> The authorized budget of \$143.3 million included a Monte Carlo P50 cost estimate which includes “contingency and reserves,”<sup>304</sup> and a “Project Reserve” of \$28.9 million<sup>305</sup> to account “for the additional financial impact of known risks to the Project.”<sup>306</sup> The Project Reserve was calculated as the difference between the P90 and P50 cost estimates.<sup>307</sup> This approach appears to differ slightly from the Highland Valley Copper project approach, where the cost included both the difference between the P90 and P50, *plus* a “Special Reserve.” Other BC Hydro cases involve similar approaches – using Monte Carlo P50 cost estimates which include contingency reserve as well as a separate reserve for additional risks, calculated as the difference between the P90 and P50 cost estimates – including the Bridge River generator replacement projects<sup>308</sup> and the John Hart Generating Station replacement project.<sup>309</sup>
- (154) A second example cited by Hydro was Manitoba Hydro’s Keeyask and Conawapa hydroelectric generation projects.<sup>310</sup> The August 2013 supporting documentation for these two projects show that

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<sup>302</sup> 2015 Certificate of Public Convenience and Necessity Application Guidelines, Appendix A, page 8.

<sup>303</sup> BCUC, “Decision and Order C-4-22,” August 16, 2022, available at: [https://docs.bcuc.com/documents/other/2022/doc\\_67475\\_c-4-22-bch-mainwaring-project-cpcn-decision.pdf](https://docs.bcuc.com/documents/other/2022/doc_67475_c-4-22-bch-mainwaring-project-cpcn-decision.pdf) (“Mainwaring BCUC Order”).

<sup>304</sup> Mainwaring BCUC Order, page 29.

<sup>305</sup> Mainwaring BCUC Order, page 29.

<sup>306</sup> BC Hydro, “Mainwaring Substation Upgrade Project,” November 5, 2021, page 4-24, available at: [https://docs.bcuc.com/documents/proceedings/2021/doc\\_64890\\_b-1-bch-cpcn-mainwaring-substation-upgrade.pdf](https://docs.bcuc.com/documents/proceedings/2021/doc_64890_b-1-bch-cpcn-mainwaring-substation-upgrade.pdf) (“Mainwaring Application”).

<sup>307</sup> Mainwaring BCUC Order, page 30.

<sup>308</sup> *See*: BC Hydro, “Bridge River Projects,” July 23, 2021, page 5-18 lines 4 to 20, available at: [https://docs.bcuc.com/documents/proceedings/2021/doc\\_63922\\_b-1-bch-bridge-river-projects-cpcn-application-public.pdf](https://docs.bcuc.com/documents/proceedings/2021/doc_63922_b-1-bch-bridge-river-projects-cpcn-application-public.pdf) (“Bridge River Application”); *see also*: BCUC, “Application for Certificates of Public Convenience and Necessity for the Bridge River Projects: Bridge River 1 Units 1 to 4 Generator Replacement Project Decision and Order C-6-22,” October 11, 2022, page 62, available at: [https://docs.bcuc.com/documents/other/2022/doc\\_68237\\_c-6-22-bch-br1-project-cpcn-decision.pdf](https://docs.bcuc.com/documents/other/2022/doc_68237_c-6-22-bch-br1-project-cpcn-decision.pdf) (“Bridge River Order”).

<sup>309</sup> *See*: BC Hydro, “John Hart Generating Station Replacement Project (Project) Application for a Certificate of Public Convenience and Necessity (CPCN),” May 25, 2012, pages 4-7 to 4-11, available at: [https://docs.bcuc.com/documents/proceedings/2012/doc\\_30734\\_b-1-bch-john-hart-gen-station-replacement-project-cpcn-application.pdf](https://docs.bcuc.com/documents/proceedings/2012/doc_30734_b-1-bch-john-hart-gen-station-replacement-project-cpcn-application.pdf) (“John Hart Application”); *see also*: BC Hydro and Power Authority, “Certificate Of Public Convenience And Necessity For The John Hart Generating Station Replacement Project,” February 8, 2013, pages 41 to 42, available at: [https://docs.bcuc.com/documents/proceedings/2013/doc\\_33518\\_c-2-13\\_bch-john-hart-dam-web.pdf](https://docs.bcuc.com/documents/proceedings/2013/doc_33518_c-2-13_bch-john-hart-dam-web.pdf) (“John Hart Order”).

<sup>310</sup> Build Application, Schedule 1, Attachment 1 page 41, footnote 43; BDE Unit 7 Life Extension Application PUB-NLH-007 (b), page 4 lines 1 to 4 and footnote 5.

Manitoba Hydro developed the cost estimates using Monte Carlo analysis.<sup>311</sup> For the Keeyask project, the total cost estimate of \$4.1 billion included a “Point Estimate”<sup>312</sup> of \$3.05 billion, another \$0.53 billion for “Contingency,”<sup>313</sup> and \$0.50 billion for “Management Reserve.”<sup>314</sup> A similar approach and set of costs was developed for the Conawapa project.<sup>315</sup>

- (155) A Panel of the Public Utilities Board of Manitoba, in a June 2014 report, recommended to the Government of Manitoba that the Keeyask project be allowed to be developed.<sup>316</sup> The Panel recommended against an authorized budget based on a P50 estimate, and instead concluded that “[b]udgeting at least for Manitoba Hydro’s ‘high’ estimate” would be prudent.<sup>317</sup> Manitoba Hydro’s “high estimate” included a management reserve as well as a contingency.<sup>318</sup> The Panel also recommended that the Conawapa Project development be discontinued.<sup>319</sup>
- (156) Manitoba Hydro’s Keeyask and Conawapa projects were put forth using Monte Carlo estimates, although the Point Estimate plus the Contingency reserve produced a P50 estimate for the projects.<sup>320</sup> Indeed, the Manitoba Board recommended against use of a P50 and instead recommended inclusion of a management reserve (which increased the budget by 10.8 percent<sup>321</sup>). The Manitoba Hydro example also included a separate management reserve, though Manitoba Hydro noted that “several management reserve funds can be developed and recommended for inclusion in a project budget depending on the specific risks it faces.”<sup>322</sup> (Manitoba Hydro proposed two management reserve funds for these two hydroelectric projects, one for labor and one for escalation.<sup>323</sup>) However,

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<sup>311</sup> Manitoba Hydro, “Needs For and Alternatives To Appendix 2.4 – Developing the Keeyask and Conawapa Capital Cost Estimates,” August 2013, page 8, available at: [https://www.pubmanitoba.ca/nfat/pdf/hydro\\_application/appendix\\_02\\_4\\_developing\\_the\\_keeyask\\_and\\_conawapa\\_capital\\_cost\\_estimates.pdf](https://www.pubmanitoba.ca/nfat/pdf/hydro_application/appendix_02_4_developing_the_keeyask_and_conawapa_capital_cost_estimates.pdf) (“Manitoba Hydro Cost Estimate”).

<sup>312</sup> “Point Estimate” is defined as “the risk-free, escalation-free (or bare) costs based on an initial set of assumptions and current market conditions (i.e., overnight cost)” with “no allowances for risk or uncertainty.” Manitoba Hydro Cost Estimate, page 1.

<sup>313</sup> “Contingency Reserve” is defined as “an amount added to the estimate to address [uncertainty associated with the Point Estimate] and to account for potential risks that could be encountered during project implementation.” Manitoba Hydro Cost Estimate, page 6.

<sup>314</sup> Manitoba Hydro Cost Estimate, Table 3; “Management Reserve” is defined as “an amount added to cover uncertainty items with very high impacts but lower likelihood of occurrence and/or substantial risk items not appropriate to be covered through contingency (e.g., major market shifts, etc.)” Manitoba Hydro Cost Estimate, page 11.

<sup>315</sup> Manitoba Hydro Cost Estimate, Table 3.

<sup>316</sup> The Public Utilities Board of Manitoba, “Report on the Needs for and Alternatives to (NFAT) Review of Manitoba Hydro’s Preferred Development Plan,” June 2014, page 18, available at: [https://www.pubmanitoba.ca/nfat/pdf/finalreport\\_pdp.pdf](https://www.pubmanitoba.ca/nfat/pdf/finalreport_pdp.pdf) (“Manitoba PUB Report”).

<sup>317</sup> Manitoba PUB Report, page 132.

<sup>318</sup> Manitoba PUB Report, page 121.

<sup>319</sup> Manitoba PUB Report, page 18.

<sup>320</sup> Manitoba Hydro Cost Estimate, page 11.

<sup>321</sup> The projected capital cost of \$6.5 billion increased to \$7.2 billion under the “high” estimate. Manitoba PUB Report, page 132.

<sup>322</sup> Manitoba Hydro Cost Estimate, page 11.

<sup>323</sup> Manitoba Hydro Cost Estimate, Table 3.

Manitoba Hydro also noted that “unlike contingency, management reserve is not always recommended as part of the estimate.”<sup>324</sup>

- (157) While the BC Hydro and Manitoba Hydro examples demonstrate that the management reserve concept is used in other jurisdictions, the Board should not conclude that usage of management reserve is widespread. It should be noted that when asked if it was “aware of whether other Canadian regulatory jurisdictions have approved management reserve in capital project budget proposals,” Hydro identified only BC Hydro and Manitoba Hydro.<sup>325</sup>
- (158) Moreover, in our experience, many North American jurisdictions do not include separate management reserve allowances in capital budgets. South Carolina Gas & Electric’s CPCN application related to its development of the V.C. Summer Nuclear Station included a contingency reserve but no management reserve.<sup>326</sup> The South Carolina Public Service Commission approved the application,<sup>327</sup> including the contingency funds (amounting to approximately 10% of the estimated costs), which were noted to be a component of the cost of the project.<sup>328</sup> Another example is Mississippi Power Company’s Kemper County Integrated Gasification Combined Cycle project, which was proposed at a total cost of \$2.2 billion, including a \$132 million contingency, but no management reserve.<sup>329</sup> The Mississippi Public Service Commission approved the project for the proposed cost, plus “a variance of 20%.”<sup>330</sup> The size of this “variance” was derived from an “acceptable range of cost caps that this Commission could expect to be possible on a Project like Kemper, but which would still make Kemper the best overall choice for customers.”<sup>331</sup>
- (159) Another example comes from Ontario. In 2016, the Ontario Energy Board approved rate base additions of about \$5.2 billion to Ontario Power Generation’s rate base related to the Darlington Refurbishment Program.<sup>332</sup> In that case, the Ontario Energy Board accepted a P90 Monte Carlo cost estimate that included contingency.<sup>333</sup> Notably, the contingency approved by the Ontario Energy

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<sup>324</sup> Manitoba Hydro Cost Estimate, page 11.

<sup>325</sup> BDE Unit 7 Life Extension Application PUB-NLH-007 (a-b).

<sup>326</sup> SCE&G, “Combined Application for Certificate of Environmental Compatibility, Public Convenience and Necessity And for a Base Load Review Order,” Docket No. 2008-196-E, May 30, 2008, Exhibit F, available at: <https://dms.psc.sc.gov/Attachments/Matter/3b3e3e6f-f48a-a3c5-50c13f96cfd6ba604>.

<sup>327</sup> The Public Service Commission of South Carolina, “Order No. 2009-104(A),” Docket No. 2008-196-E, March 2, 2009, page 119, available at: <https://dms.psc.sc.gov/Attachments/Order/5e3440fb-fc31-8115-18c5057d060bf8ef> (“South Carolina PSC Order”).

<sup>328</sup> South Carolina PSC Order, pages 47 and 96.

<sup>329</sup> Mississippi Power Company, “Kemper County IGCC Project Description,” Docket No. 2009-UA-14, Exhibit KDF-2, section 1.3, available at: <https://ctsportal.psc.ms.gov/portal/ViewFile?fileId=3yZy7APDIEk%3D>.

<sup>330</sup> Mississippi Public Service Commission, “Order,” Docket No. 2009-UA-14, May 26, 2010, page 8, available at: <https://ctsportal.psc.ms.gov/portal/ViewFile?fileId=iwdjq5rSXEY%3D> (“Mississippi PSC Order”).

<sup>331</sup> Mississippi PSC Order, page 9.

<sup>332</sup> Ontario Energy Board, “Decision and Order,” EB-2016-0152, December 28, 2017, page 36, available at: <https://www.rds.oeb.ca/CMWebDrawer/Record/595053/File/document> (“OEB Order”).

<sup>333</sup> OEB Order, pages 35 and 38.

Board was more akin to the contingency proposed by Hydro in the instant proceeding, not to management reserve. Ontario Power Generation explained that:

[Contingency] refers to amounts that [Ontario Power Generation] *anticipates spending* because there are risk items and uncertainties that will occur and cannot be entirely mitigated or avoided. Contingency is included as a cost component of a project estimate just like any other component of a project. It is not an extra amount that will not be spent if the project goes as planned, nor is it a tool to compensate for an underdeveloped project plan. It is a necessary, legitimate and thoughtfully developed part of the estimated project cost based on residual (post-mitigation) risk and uncertainty.<sup>334</sup>

- (160) In summary, our review suggests the following conclusions. First, use of Monte Carlo simulation in determining capital budgets for large, regulated utility projects is relatively common. Second, use of management reserve allowance funds is not unprecedented but is not widespread. Third, when management reserve is used, the determination of those reserves has included approaches similar to those used by Hydro in this case: that is, defining a confidence interval (e.g., P90), and subtracting the P50 estimate, with the difference being the defined management reserve.

## D. Overall assessment and conclusion

- (161) The concept of a management reserve is defensible: a set-aside source of funds to be used only if unforeseeable, high-impact events occur that have substantial impacts on project costs. Having such funds set aside allows those high-impact events to be addressed with little or no impact on project development and schedule. Such funds address low probability events that could not be forecasted to occur during early cost estimation (e.g., in developing a Class 3 AACE estimate).
- (162) In principle, a management reserve can help ease the regulatory burden of addressing unexpected or low probability events and facilitate efficient project management under such circumstances. The flip side of an expansive initial budget approval is that it could blunt project management discipline, with the management reserve providing cover for poor cost estimation and poor project management.
- (163) Given that the Build Application represents the first instance of the proposed use of Management Reserves, the Board is correct to rigorously assess the appropriateness of its application. The need for such an assessment is heightened given the ownership structure of Hydro, a Crown Corporation with a single shareholder (the Government of Newfoundland and Labrador) that recovers its costs from the same citizens that are Hydro ratepayers. Unlike investor-owned utilities, where risk and losses can be

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<sup>334</sup> OEB Order, page 34. (Emphasis added.)

offloaded to private shareholders, the risk of capital project cost overruns accrue to taxpayers and ratepayers (which are often the same individuals).

- (164) Hydro suggests that it is following the directives of the Muskrat Falls Inquiry and that use of management reserves is industry standard. Each of these positions has some truth, but both the Muskrat Falls Inquiry and experience from other jurisdictions is not prescriptive. The Muskrat Falls Inquiry does not set up a standard that the Board must follow in reviewing and approving capital budget applications. Moreover, its recommendations – to fund projects to a P85 level and to include “amounts” for strategic risks in the budget – are open to interpretation. For example, P85 estimates are subjective, as they depend on the underlying cost estimates and risk variables, as the Muskrat Falls Inquiry recognized. Moreover, while strategic risks might be “included” in a budget, it is up to the Board to decide how funds to cover strategic risks should be accessed and recovered.
- (165) Hydro is correct to point to AACE International’s guidance documents as an authoritative source for good practices in cost estimation and quantitative risk analysis. However, even AACE recognizes the challenges of quantitative risk analysis: “[Quantitative Risk Analysis] is an evolving field of practice and not settled science.”<sup>335</sup> AACE also recognizes the lack of uniformity in terminology in quantitative risk analysis:

The terminology related to QRA is extensive. One QRA text has over 170 terms in its glossary. AACE RP 10S-90, *Cost Engineering Terminology* is the recommended reference for QRA terminology. The AACE definitions evolved from its 60-plus year history and are believed to reflect ‘what works best’ for its members in general cost engineering and project control application. Other industry definitions often contain what the DRM Subcommittee feels are ambiguities (often originating from a qualitative point of view) on one hand, or over-specificity on the other (to suit specific standards that may or may not apply to one’s situation).

There are a number of terms defining the *objects* of QRA (the control accounts or activities being determined) .... there are variations in industry definitions, and they are often misunderstood.<sup>336</sup>

- (166) We agree with AACE. Our survey of other jurisdictions demonstrates that no two jurisdictions have the same *definitions* of certain concepts, risks, and reserve funds, let alone apply uniform standards.
- (167) We turn, therefore, to AACE’s definition of Management Reserve:

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<sup>335</sup> AACE, International Professional Guidance Document No. 02: Guide to Quantitative Risk Analysis, March 18, 2024, available at: <https://library.aacei.org/pgd02/pgd02.shtml> (“AACE QRA Guidance”).

<sup>336</sup> AACE QRA Guidance, Key Terminology – RP 10S-90. (Emphasis in original.)

An amount added to an estimate to allow for discretionary management purposes outside of the defined scope of the project, as otherwise estimated. May include amounts that are within the defined scope, but for which management does not want to fund as contingency or that cannot be effectively managed using contingency.

...

Key words and phrases in this definition include: *Management* which means authority lies above the project manager level. Also, *discretionary* and *outside the defined scope* allows wide latitude to that management. The phrase *cannot be effectively managed using contingency* explicitly addresses the common situation of low-probability, high-impact risk events for which partial funding (i.e., multiplying impact times probability) is illogical. It also clearly delineates management reserves from contingency and escalation. In practice, common management reserve types include “general” reserve based on risk tolerance/appetite (funding at higher confidence levels) and “specific” reserves intended for specific high impact/low probability (HILP) risk events or similar.<sup>337</sup>

- (168) We conclude, therefore, that management reserve is one approach that can be used by project management teams in cost estimation and project management. When using a management reserve, multiple approaches can be taken, such as specifying a “general” reserve to account for risk tolerance (lower risk tolerance means a higher management reserve) or a project-specific reserve fund that identifies individual risks and sets aside funds for each identified risk.
- (169) Hydro has taken a hybrid approach. For both the Avalon CT and BDE Unit 8, Hydro has identified a set of specific risks, but has then added those risks (and cost distributions) into its Monte Carlo simulation to derive all (for the Avalon CT) or a portion (for BDE Unit 8) of the Management Reserve. Monte Carlo analysis is recognized by AACE as an effective method in quantitative risk assessment.<sup>338</sup> For BDE Unit 8, Hydro then specifies and estimates a set of additional strategic risks, again using Monte Carlo analysis to derive the size of the Management Reserve contribution. As the AACE also recognizes that because “no single method that can be used to quantify all risk on a given project,” multiple tools and methods may be combined to assess project risks.<sup>339</sup>
- (170) We therefore do not take issue with Hydro’s methodological approach for calculating Management Reserve for both projects, though we do note the following. First, Hydro did not include certain “emerging” strategic risks in the determination of the Management Reserve for BDE Unit 8, which Hydro estimates to potentially increase the project’s costs by up to \$562.4 million. Second, Hydro did

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<sup>337</sup> AACE QRA Guidance, Key Terminology – RP 10S-90. (Emphasis in original.)

<sup>338</sup> AACE QRA Guidance, Hybrid or Combined Methods and Aggregation of Projects.

<sup>339</sup> AACE QRA Guidance, Hybrid or Combined Methods and Aggregation of Projects.

not capture all “unknown unknowns” in its specification of strategic risks for both projects. Third, Hydro potentially underestimated the upward cost impact of certain project risks, such as challenges in EPCM contracting. The Board should consider requiring Hydro to incorporate these risks into an updated Monte Carlo analysis and Management Reserve calculation.

- (171) That said, we are concerned that the Management Reserve, as proposed, could potentially serve as a backstop for poor cost estimation and poor project management. Management Reserve, if approved, should only be applied in situations where the strategic risks – the “unknown unknowns” – manifest themselves and negatively impact the project(s). Absent those circumstances, Management Reserve funds should remain untapped, even if the projects face higher development costs than forecasted due to risks that were covered through the base cost estimates, DDA, and contingency reserves.
- (172) Therefore, if the Board is to approve a Management Reserve, it is our view that the Board should require Hydro to formally notify the Board if it anticipates accessing the Management Reserve funds and again when those funds are accessed. The Board should be able to request supporting information from Hydro regarding the details of the need for and amount of Management Reserve funds accessed. The burden of prudence should remain with Hydro in all cases, and the Board should review Hydro’s submissions for evidence that the strategic risks that those funds are meant to cover have materialized and driven the costs of the project higher. This would increase transparency in the process and accountability for Hydro and its contractors. It would also continue to allow Hydro to benefit from a Management Reserve, which helps project development to continue without delays to obtain regulatory approval to overspend.

## VIII. Other Issues

### A. Avalon Remedial Action Scheme

- (173) In the Build Application, Hydro raised the issue that adding new Off-Avalon generation while retiring the On-Avalon Holyrood TGS and Hardwoods GT would create significant transmission “bottlenecks” on the BDE-SOP 230 kV transmission system in the event of a bipole outage on the LIL.<sup>340</sup> Such bottlenecks would result in trapped Off-Avalon generation that would not be able to mitigate load shedding during a bipole outage. In 2023, a study was performed by TransGrid Solutions (“TransGrid”) to assess the BDE-SOP constraints and potential solutions.<sup>341</sup> That study identified the least cost solution to maintain Avalon Peninsula load shed requirements below 100 MW during a bipole outage to be a third transmission line from Western Avalon to Soldiers Pond, plus dynamic line ratings for TL201, TL202, TL206, and TL203 for a total cost of approximately \$150 million.<sup>342</sup>
- (174) Hydro did not propose new transmission as part of the Build Application. Instead, Hydro stated that it “is actively trying to reduce the identified least-cost transmission upgrade through the implementation of a remedial action scheme (‘RAS’) and/or Dynamic Line Rating (‘DLR’).”<sup>343</sup>
- (175) One finding of the Bates White Phase One Expert Report was that Hydro’s “LIL Shortfall Analysis may overstate the reliability contribution of BDE [Unit] 8 during an extended bipole outage of the LIL.”<sup>344</sup> In its July Letter, the Board requested further evidence that the modeled Bay d’Espoir output levels can be deliverable to the Avalon in all hours.<sup>345</sup> In its September Reply, Hydro provided evidence that, under normal system conditions, the current transmission system would not limit the deliverability of Bay d’Espoir output, including BDE Unit 8, based on the results of load flow studies performed by the Newfoundland and Labrador System Operator (“NLSO”).<sup>346</sup> However, Hydro acknowledged that the NLSO identifies constraints on the 230 kV lines to the Avalon during a LIL bipole outage (N-2 contingency).<sup>347</sup>

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<sup>340</sup> Build Application, Schedule 3, page 49 line 12 to page 50 line 3.

<sup>341</sup> Hydro, “Avalon Supply (Transmission) Study,” October 31, 2023, available at: [http://www.pub.nl.ca/applications/NLH2025AvalonCombustionMarch/report/From%20NLH%20-%20Avalon%20Supply%20%20\(Transmission\)%20Study%20-%20REDACTED%20-%202023-10-31.PDF](http://www.pub.nl.ca/applications/NLH2025AvalonCombustionMarch/report/From%20NLH%20-%20Avalon%20Supply%20%20(Transmission)%20Study%20-%20REDACTED%20-%202023-10-31.PDF).

<sup>342</sup> Build Application, Schedule 3, page 50 lines 4 to 8.

<sup>343</sup> Build Application, Schedule 3, footnote 13.

<sup>344</sup> Bates White Phase One Expert Report, page 12.

<sup>345</sup> Board July Letter, page 2, item 3b).

<sup>346</sup> Hydro September Reply, Question 3b), page 8 line 26 to page 9, line 12.

<sup>347</sup> Hydro, “NLSO Report – 2025 Annual Planning Assessment,” May 6, 2025, page 8, available at: [https://www.oasis.oati.com/woa/docs/NLSO/NLSOdocs/TP-R-092\\_FINAL\\_Rev\\_1\\_05062025.pdf](https://www.oasis.oati.com/woa/docs/NLSO/NLSOdocs/TP-R-092_FINAL_Rev_1_05062025.pdf).

- (176) On October 14, 2025, Hydro filed a study by TransGrid regarding the viability of an RAS to address transmission limits that would exist during a LIL shortfall (“Avalon Remedial Action Scheme Feasibility Study,” henceforth “RAS Study”).<sup>348</sup> Hydro’s summary of the results of the RAS Study, provided in response to Question 12 of the Board’s July Letter, was that (1) the RAS is confirmed to be an effective solution in a LIL shortfall scenario and (2) that the RAS would eliminate the need for additional transmission upgrades associated with delivering power from Bay d’Espoir, inclusive of BDE Unit 8.<sup>349</sup>
- (177) Our review of the RAS Study follows below. As a preliminary matter, it is important to clarify that the RAS would aim to increase system transfer capability to the Avalon Peninsula during a LIL bipole outage. Consistent with the application of RAS in other power systems, and with North American Electric Reliability Corporation (“NERC”) guidelines, an Avalon RAS would be an automated load shed mechanism that would be “armed” during a LIL bipole outage, providing for immediate response to a further 230 kV line contingency that threatens the integrity of the power system. Such an immediate, automated response mechanism would allow the transmission system to be utilized at greater capacity during a LIL bipole outage prior to further contingency, and would thereby reduce the need for any pre-emptive load shed. The RAS Study states that:
- The objective of the RAS is to shed load on the Avalon in the event of a 230 kV line contingency between BDE-SOP in order to offload the lines remaining in service to avoid thermal overloads or abnormal voltage conditions. This RAS ... will only be armed to facilitate more power flow to Avalon during a LIL bipole outage.<sup>350</sup>
- (178) Having the RAS in place would *reduce* required load shed during a bipole outage *prior* to an N-2 contingency. Essentially, the RAS would be a systematic, and automatic, scheme for shedding load that would allow for *less* conservative operation of the BDE-SOP transmission system during a LIL bipole outage, while still allowing for required response to the next system contingency. This means that less load would need to be shed preemptively (i.e., to protect against a further contingency) during a LIL bipole outage.
- (179) As Hydro explains in its RAS Study overview document, in the event of a LIL bipole outage, “the system must be re-postured to guard against the next contingency.”<sup>351</sup> This means power transfer to the Avalon Peninsula must be limited to protect against thermal overloads that would occur during a

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<sup>348</sup> Newfoundland and Labrador Hydro, “Avalon Remedial Action Scheme Feasibility Study,” October 14, 2025, available at: <http://www.pub.nf.ca/applications/NLH2018ReliabilityAdequacy/correspondence/From%20NLH%20-%20Avalon%20Remedial%20Action%20Scheme%20Feasibility%20Study%20-%202025-10-14.PDF> (“Hydro RAS Study Overview”).

<sup>349</sup> Hydro September Reply, Question 12, page 1 lines 13 to 20.

<sup>350</sup> RAS Study, Attachment 1 (“TransGrid RAS Study”), page 1.

<sup>351</sup> Hydro RAS Study Overview, page 4 line 9.

230kV line contingency.<sup>352</sup> This limit on power transfer in turn necessitates preemptive load shed on the Avalon Peninsula. The RAS would aim to accommodate greater power flow, and so reduce load shed need, while the system remained under the N-1 contingency of a LIL biopole outage.

- (180) The RAS Study examined several scenarios. In all cases, it is assumed that the Holyrood TGS and Hardwoods GT are retired,<sup>353</sup> the Holyrood CT remains on the system,<sup>354</sup> and the new Avalon CT has been built.<sup>355</sup> There is no explicit reference in the RAS Study to the assumed addition of BDE Unit 8. We infer that the study emphasis on assessing feasible RAS impacts did not require such an explicit assumption.
- (181) The study considered base cases evaluated for Island peak loads of 1,835 MW (2025 peak) and 2,000 MW (2033 peak),<sup>356</sup> and sensitively cases with the Holyrood CT unavailable,<sup>357</sup> or the Avalon CT unavailable.<sup>358</sup> In summary, the study concluded that an RAS could allow peak demand to be met during a LIL bipole outage and provided estimates of the range of RAS load shed needed under the various cases in the event of a 230kV line contingency.<sup>359</sup> Load shedding required ranges from 0 MW to 302 MW, or up to 16.4% of total IIS load. depending on IIS demand and the status of the Avalon CT and Holyrood.<sup>360</sup> Table 9 reproduces the main results table from Hydro's RAS Study overview.

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<sup>352</sup> Hydro RAS Study Overview, page 4 lines 8 to 12.

<sup>353</sup> Hydro RAS Study Overview, footnote 7; TransGrid RAS Study, page 4.

<sup>354</sup> TransGrid RAS Study, page 4.

<sup>355</sup> TransGrid RAS Study, page 4.

<sup>356</sup> Hydro RAS Study Overview, page 8 lines 3 to 4; TransGrid RAS Study, Attachment 1, page 2.

<sup>357</sup> TransGrid RAS Study, Section 4.2.

<sup>358</sup> TransGrid RAS Study, Section 4.3.

<sup>359</sup> TransGrid RAS Study, pages 10 to 11. For the cases in Table 8, it was further assumed that when the Holyrood CT was unavailable, the third Soldiers Pond ("SOP") synchronous condenser was online, and when the Avalon CT was unavailable, two SOP synchronous condensers were online.

<sup>360</sup> Hydro RAS Study Overview, Table 2.

**Table 9: Avalon RAS Feasibility Study Results<sup>361</sup>**

Island Demand (MW)	Avalon CT (IN/OUT)	Holyrood CT (IN/OUT)	Range of Load Shedding Requirement for 230 kV Transmission Line Contingencies (MW)	Worst Contingency
1,835	IN	IN	0-179	TL202/TL206
		OUT	72-288	TL202/TL206
1,800 to 1,840	OUT	IN	76-302	TL202/TL206
2,000	IN	IN	41-291	TL202/TL206
		OUT	Maximum demand limited to 1835 MW due to steady state pre-contingency voltage at Sunnyside ("SSD"), with TL201 thermal loading also nearing 100%.	

(182) Hydro’s summary of the results is:

The implementation of the RAS would enable increased flows to the Avalon Peninsula to meet Island peak demand of up to 2,000 MW in the event of a LIL bipole outage with the proposed Avalon CT online, and when activated in the event of a further contingency, it would ensure that the system remains intact and that there is no risk to equipment. Such a solution could be implemented in concert with BDE Unit 8 and the Avalon CT to eliminate the need for additional transmission upgrades in the Minimum Investment Required Case.<sup>362</sup>

(183) Based on our review, Hydro’s characterization of the results assumes that an RAS corresponding to that considered in the RAS Study can actually be implemented. The RAS Study is explicitly a *feasibility* study, which Hydro describes as confirming “the technical viability of the Avalon RAS.”<sup>363</sup> The critical next step identified by Hydro is to “continue to engage Newfoundland Power on how the RAS can be implemented on its electrical system...” with consideration given “to balancing the complexity of the implementation with refinements that would allow for reduced customer impact.”<sup>364</sup> The details of any eventual RAS, and its capability to allow greater power flows to the Avalon Peninsula during a LIL bipole outage remain to be determined.

(184) Further, we note Hydro’s conclusion that an RAS would allow “increased flows of power to the Avalon Peninsula” is not quantified.<sup>365</sup> The RAS Study does not present any cases without an RAS that would provide for an estimate of the extent of the flow increase.

(185) It is also unclear how to square the results of the RAS Study with those of the LIL Shortfall analyses that Hydro has presented. For example, Hydro has reported that with the Avalon CT and BDE Unit 8

<sup>361</sup> Hydro RAS Study Overview, Table 2.

<sup>362</sup> Hydro RAS Study Overview, page 9 lines 3 to 9.

<sup>363</sup> Hydro RAS Study Overview, page 10 line 21.

<sup>364</sup> Hydro RAS Study Overview, page 11 lines 18 to 20.

<sup>365</sup> Hydro RAS Study Overview, page 9 lines 3 to 6.

in service in 2031, and the Holyrood TGS retired, an average-severity outage event would result in a maximum peak shortfall of 124 MW.<sup>366</sup> This LIL Shortfall evaluation incorporated no BDE-SOP transmission constraints, effectively assuming that such constraints would be eliminated by construction of a third transmission line, or equivalent alternative. There is no claim or indication that an RAS would allow for *superior* flows to the Avalon Peninsula compared to a new transmission line, so there remains uncertainty about the extent of required load shed during a LIL bipole outage under even a technically feasible RAS. We believe it is conservative, and appropriate, to assume that the actual RAS that is implemented would be *less* effective in increasing power flows to the Avalon than a new transmission line, and that pre-contingency load shed would still be required during a LIL bipole outage. Further information regarding potential transmission upgrades will be forthcoming in Hydro's Transmission Expansion Feasibility Study, now anticipated to be filed in February 2026.<sup>367</sup>

- (186) The RAS does not resolve the question Bates White has raised regarding deliverability to the Avalon Peninsula of the full incremental capacity of BDE Unit 8 during a LIL bipole outage. In response to issues raised in the Bates White Phase One Expert Report,<sup>368</sup> and associated questions in the Board's July Letter,<sup>369</sup> Hydro stated clearly that "[d]uring a LIL shortfall, required volumes will be deliverable through expanded transmission capacity."<sup>370</sup> As noted, Hydro's LIL Shortfall Analysis indicates that some load shed would still be required in 2032 with the Holyrood TGS retired and BDE Unit 8 and the Avalon CT in service, *assuming expanded transmission capacity*. If an achievable, as opposed to technically feasible, RAS does not fully relieve BDE-SOP pre-contingency transmission constraints during a full LIL outage, then it is presumed that the full incremental capacity of BDE Unit 8 would not be deliverable to the Avalon Peninsula. The BDE Unit 8 capacity could nonetheless reduce the volume of required pre-contingency load shed, but the extent of this contribution remains uncertain.
- (187) One clear conclusion to be drawn from the RAS Study is the critical contribution of On-Avalon generation to mitigating the need for load shed during a LIL bipole outage. The results summarized in Table 9 indicate that with the technically feasible RAS in place, an outage at either the Holyrood CT or the Avalon CT (with the Holyrood TGS retired) would limit the maximum load that could be met on the Avalon Peninsula, reported as Island demand of 1,800 MW to 2,000 MW with the Avalon CT unavailable, or 1,835 MW with the Holyrood CT unavailable.<sup>371</sup> No case was evaluated with both CT stations unavailable. This highlights both that there is a clear reliability need for the Avalon CT and that further generation capacity on the Avalon Peninsula would be an alternative, or possibly a

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<sup>366</sup> Build Application, Schedule 3, page 41 line 8.

<sup>367</sup> Hydro, "Reliability and Resource Adequacy Study Review – Semi-Annual Update for the Fourth Quarter of 2025," December 16, 2025, page 5, available at:

<http://www.pub.nf.ca/applications/NLH2018ReliabilityAdequacy/reports/From%20NLH%20-%20Q4%202025%20Semi-Annual%20Report%20-%20%202025-12-16.PDF> ("2025 Fourth Quarter RRA Review")

<sup>368</sup> See: Bates White June Report, paragraphs 12 and 182.

<sup>369</sup> See: Board July Letter, page 2.

<sup>370</sup> Hydro September Reply, Question 3(b), page 10 lines 10 to 11.

<sup>371</sup> See: Table 8; Hydro RAS Study Overview, page 9 line 16 to page 10 line 10.

complement, to increasing BDE-SOP transmission capability (acknowledging that further additions of thermal generation on the Avalon would likely require upgrades to existing fuel infrastructure). The analyses presented by Hydro have demonstrated this need and urgency, with Hydro stating that “[a]dvancing as much On-Avalon generation as possible to improve system reliability would increase the amount of load that can be reliably served.”<sup>372</sup>

- (188) Hydro indicates an intention to advance development and submittal of an RAS prior to the retirement of the Holyrood TGS, which would inherently be in advance of the addition of either the Avalon CT or BDE Unit 8.<sup>373</sup> Though not an explicit result of the RAS Study, Hydro states that advancing the RAS prior to the retirement of the Holyrood TGS “would provide some immediate value as it could reduce Hydro’s dependency on Holyrood TGS generation in helping to offload the BDE-SOP transmission system during a LIL bipole outage.”<sup>374</sup>
- (189) We conclude that the RAS Study demonstrates that an RAS could be an effective alternative to construction of a new transmission line on the BDE-SOP corridor for Avalon demand levels at least up to the 2033 peak load of 2,000 MW modeled in the RAS Study. We conclude that it is reasonable for Hydro to pursue development and implementation of such an RAS as an alternative to a near-term transmission upgrade. Whether an additional transmission line on the BDE-SOP corridor will eventually be needed depends on the details and effectiveness of the RAS, the amount of load growth on the Avalon, and the location of further generation resources added to the system. As indicated by Hydro, details of an actual RAS remain to be developed, including the specifics of the scheme, the requirements and schedule for implementation, commissioning and testing, and estimation of associated costs. Bates White finds that the results of the RAS Study support Hydro’s plan to further explore the RAS.

## B. RAS in Other Jurisdictions

- (190) Bates White reviewed implementation of RAS approaches in other jurisdictions. While not a comprehensive survey, it is clear that RAS approaches are commonly applied to address large contingencies in the context of limited transmission, and particularly as an alternative to more costly transmission upgrades. RAS implementations are notable in the Western Electric Coordinating Council (“WECC”), as shown in Figure 5.

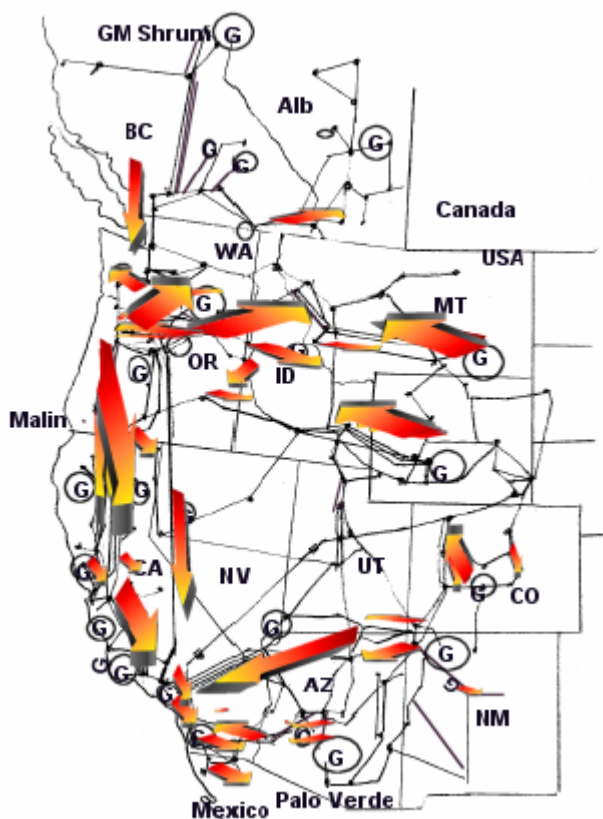
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<sup>372</sup> Build Application, Schedule 3, page 50 lines 2 to 3.

<sup>373</sup> Hydro RAS Study Overview, page 11 lines 21 to 23.

<sup>374</sup> Hydro RAS Study Overview, page 11 lines 23 to 26.

Figure 5: Major WECC RAS Applications (2006)<sup>375</sup>



(191) A 2006 assessment of RAS implementation experience and considerations in western North America noted:

Increasing demand for transmission capacity has been obstructed by increasing difficulty in obtaining funds and permits to build new transmission lines. The problem has been met with various countermeasures to allow heavier transmission system loading without increasing the risk of widespread system disturbances leading to blackouts. [RAS] are an important class of countermeasures that are becoming more widely applied due to their relatively low cost and shorter installation time compared to major equipment such as transmission lines or substation power facilities.<sup>376</sup>

<sup>375</sup> C. F. Henville and E. Struyk, “RAS and Stretched Power Systems,” October 2006, page 10, available at: [https://wprcarchives.org/wp-content/uploads/2024/07/C.-F.-Henville\\_RAS-AND-STRETCHED-POWER-SYSTEMS\\_2006.pdf](https://wprcarchives.org/wp-content/uploads/2024/07/C.-F.-Henville_RAS-AND-STRETCHED-POWER-SYSTEMS_2006.pdf) (“Henville and Struyk 2006”).

<sup>376</sup> Henville and Struyk 2006, page 1.

- (192) BC Hydro has employed multiple RASs on its system, including a load-shedding RAS on Vancouver Island to address simultaneous loss of multiple 500 kV lines.<sup>377</sup> In planning for large unit additions at its Mica and Revelstoke hydro facilities, BC Hydro evaluated RAS implementations as an alternative to building new transmission to address double contingencies: “[c]onsidering the cost and long project lead time of building new 500 kV lines, a system load shedding RAS is required to address these rare but severe double contingency events.”<sup>378</sup>
- (193) Based on this limited survey, we conclude that Hydro’s exploration of RAS viability on the IIS is appropriate.

### C. Synchronous Condenser Considerations

- (194) Hydro has identified the need for additional synchronous condensing (“SC”) capability on the IIS, and specified such capability as a requirement for the Avalon CT and at BDE Unit 8.

**Table 10: Existing Generating Assets Capable of Operating as Synchronous Condensers on the IIS<sup>379</sup>**

Unit	Reactive Power Capacity (at 0 MW)
SOP Unit 1	[REDACTED]
SOP Unit 2	[REDACTED]
SOP Unit 3	[REDACTED]
HRD Unit 3	[REDACTED]
Cat Arm Unit 1	[REDACTED]
Cat Arm Unit 2	[REDACTED]
BDE Unit 7	[REDACTED]
Hardwoods Gas Turbine	[REDACTED]
Stephenville Gas Turbine	[REDACTED]

- (195) Hydro recommends SC capability for both the Avalon CT and BDE Unit 8 to provide reactive power and increased system strength. In the absence of sufficient SC capability, “thermal units would have to operate at minimum or base load, or hydraulic units would have to be dispatched at inefficient setpoints to provide the required grid support.”<sup>380</sup> Hydro further states that the need for synchronous

<sup>377</sup> BC Hydro, “Planning Level Description of Load Shedding RAS Under 5L71 and 5L72 Double Contingency for Mica Unit 6 Transmission Integration,” 2009, page 1, available at: [https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/suppliers/transmission-scheduling/bulletins/2009/LoadsheddingRASdescriptionfinalMar16\\_R1.pdf](https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/suppliers/transmission-scheduling/bulletins/2009/LoadsheddingRASdescriptionfinalMar16_R1.pdf) (“BC Hydro Mica Unit 6 Load Shedding”).

<sup>378</sup> BC Hydro Mica Unit 6 Load Shedding, page 1.

<sup>379</sup> Phase 2 BW-NLH-009 (g), Table 3.

<sup>380</sup> BDE Unit 7 Life Extension Application PUB-NLH-001 (c), page 2 line 12 to page 3 line 3.

condensing capacity is location-specific and depends on the voltage requirements in a particular area of the system.<sup>381</sup>

(196) Hydro characterizes the primary purpose of synchronous condensers is to provide voltage regulation during steady state and transient events (i.e., electrical faults).<sup>382</sup> Hydro has limited ability to regulate voltages on the Avalon Peninsula during light load conditions when one or more of the SOP synchronous condensers are offline. Additional voltage regulation provided by SCs would also provide benefits during a LIL bipole outage at high load conditions when there is increased power flow from BDE to the Avalon Peninsula, as it provides improved system stability following a fault.<sup>383</sup>

(197) The following are other factors that drive SC need on the IIS:

- There are minimum Short Circuit Levels (“SCLs”) – the amount of current that flows on the system during a fault – required at the Soldier’s Pond 230 kV bus in order to operate the LIL reliably at its rated capacity of 900 MW. If only two large Avalon synchronous machines are online (i.e., a unit at Holyrood or Soldier’s Pond operating in generating or synchronous condenser mode), the LIL must be derated. Loss of one of the remaining two machines would require the LIL to be taken offline.<sup>384</sup>
- The amount of inverter-based resources (“IBRs”) that can be integrated on the system depends on the SCLs at the point of interconnection. As Hydro notes:

The higher the SCLs, the more IBRs can be integrated to the system. At low SCLs, there is more sensitivity to changes in voltage, which increases the risk of voltage collapse, given the increased active power variability of the IBR. Control instability with nearby control systems is currently an issue on the Island Interconnected System and limits our ability to integrate IBRs near the LIL.<sup>385</sup>

Increased system strength provided by more synchronous condensers would help facilitate more renewable energy integration on the system and would be particularly valuable in situations when active power generation from existing assets is minimized during periods of peak wind production.<sup>386</sup>

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<sup>381</sup> Phase 2 BW-NLH-009 (f), page 6 lines 13 to 15.

<sup>382</sup> Phase 2 BW-NLH-009 (b), page 3 lines 13 to 15.

<sup>383</sup> Phase 2 BW-NLH-009 (b), page 3 lines 13 to 20.

<sup>384</sup> Phase 2 BW-NLH-009 (b), page 2 lines 9 to 15 and footnote 1.

<sup>385</sup> Phase 2 BW-NLH-009 (b), page 2 lines 20 to 25.

<sup>386</sup> Phase 2 BW-NLH-009 (b), page 2 lines 16 to 29.

- The 2024 Resource Adequacy Plan identified the following related aspects of SC need and benefits:<sup>387</sup>
  - SC capability will help regulate voltages on the Avalon Peninsula during light load conditions, and reduce the requirement to burn fuel in generation mode.
  - SC capability will help improve system stability by supporting recovery from transient events, with the benefit of not having to burn fuel. SC capability could also allow greater delivery of power to the Avalon in the event of an extended LIL outage.
  - With the LIL in service, there is a requirement to dispatch Avalon Peninsula generation to make the system more stable for the sudden loss of the LIL, which requires burning fuel. Additional SC capability on the Avalon Peninsula would reduce this requirement.
  - Added SC capability will provide more inertia to the system and improve frequency stability in the event of a LIL bipole trip, without having to burn fuel. This could potentially help facilitate additional LIL imports.
  - Added SC capability on the Avalon could provide more operational flexibility for planned or unplanned outages to the existing Soldiers Pond SCs.

(198) Hydro reports that TransGrid is currently conducting a Reactive Power Study that will update Avalon generation and SC needs following a LIL bipole outage and “quantify the reduction of Avalon generation associated with the proposed Avalon CTs operating as synchronous condensers.”<sup>388</sup> Hydro estimates the study will be filed in Q2 of 2026.<sup>389</sup>

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<sup>387</sup> 2024 Resource Adequacy Plan, Appendix C, page 40 lines 1 to 25.

<sup>388</sup> Phase 2 BW-NLH-009 (b), page 4 lines 5 to 8.

<sup>389</sup> 2025 Fourth Quarter RRA Review, page 6.

## IX. Conclusions and Recommendations

- (199) Bates White recommends that the Board consider approving the Avalon CT component of Hydro's Build Application, with a current estimated in-service date in March 2030. The evidence in the record supports the need for the Avalon CT as necessary to accommodate the retirement of the Holyrood TGS. Bringing the Avalon CT into service as early as feasible will allow for the orderly, and possible progressive, retirement of the Holyrood units, mitigating cost while supporting system reliability. The evidence supports the need for the Avalon CT not because of anticipated load growth, but to address generation capacity needs on the Avalon Peninsula when Holyrood is no longer in service, including easing potential overload conditions on transmission during a LIL bipole outage.
- (200) The Avalon CT project proposal is sound, and the selection of three 50 MW LM6000 aeroderivative gas generator is appropriate to the stated reliability need to accommodate the retirement of Holyrood, providing the ability to come online quickly and to operate for an extended period, such as during a LIL outage event. The application and supporting documentation filed by Hydro indicates it to be a reasonably well-planned project at the current stage of development.
- (201) The cost categories, and the general levels and relative magnitudes of costs in the application filed by Hydro, and as updated in December 2025, appear reasonable. Consistent with market intelligence obtained by CAMS on CT package cost trends, Hydro's December 2025 update Hydro has reported a negotiated price for the three CT packages of \$280.2 million dollars, an increase relative to the Build Application value of approximately 67%. Hydro has also reported that the expected Commercial Operation Date of the Avalon CT has been delayed from January 2030 to March 2030, which is consistent with market information obtained by CAMS indicating increased lead times for major equipment delivery. The addition of liquid fuel recirculation and filtration equipment would eliminate the need for burning off excess stored fuel and would provide substantial operating cost savings to the project and reduce annual GHG emissions.
- (202) With respect to the review of the BDE Unit 8 project, no major concerns were identified with the project design, scope, or specification. As stated in the Gruner Report, it is Gruner's opinion that the BDE Unit 8 project has been sufficiently developed and is a reasonable project overall. Still, we remain unconvinced that the BDE Unit 8 project should be approved immediately, as proposed. The Board should defer approval of the BDE Unit 8 component of the Build Application until several critical unresolved issues are addressed.
- (203) Hydro's analyses supporting BDE Unit 8 as being preferred in sequence of addition to the Avalon CT are marginal and sensitive to assumptions such as the requirement to burn-off fuel uneconomically at the Avalon CT. Appropriate fuel management equipment and procedures would likely eliminate any uneconomic fuel burn-off at the Avalon CT, making it more economic than BDE Unit 8. Hydro's

conclusion that BDE Unit 8's additional 12.8 MW of firm capacity produce a significant advantage in selecting BDE Unit 8 first is not adequately supported.

- (204) Evidence Hydro has provided to date does not adequately demonstrate the sufficiency of hydrology on the Bay d'Espoir reservoir system to support the full incremental generation capacity of BDE Unit 8 during an extended LIL bipole outage.
- (205) Evidence has not demonstrated that transmission is sufficient to deliver the full incremental generation capacity of BDE Unit 8 to the Avalon peninsula during a LIL bipole outage. The RAS approach advanced by Hydro has been determined to be a *feasible* alternative to a costly transmission upgrade, but details of an *actual* RAS remain to be developed. These items in flux include the specifics of the scheme, the requirements and schedule for implementation, commissioning and testing, the expected impact on pre-contingency transmission utilization, and estimation of associated costs.
- (206) The IIS does not need both the Avalon CT and BDE Unit 8 by 2031, as long as Hydro's existing thermal assets remain operational. The timing of need for additional capacity beyond the Avalon CT has not been determined. Future build plans will be based on contemporary information. For example, Newfoundland Power plans to extend the lives of two gas turbines, which total 48 MW of firm capacity.<sup>390</sup> Additionally, Hydro's most recent load forecast (2025) indicates a reduction in peak demand of 14 MW and total energy of 289 GWh in 2035 compared to the load forecast used in the Build Application.<sup>391</sup> Further, Hydro's recent update to its assumed ELCC values shows higher capacity values for wind additions than assumed in the Build Application, reaching as high as 43%<sup>392</sup> (compared to 22% in the Build Application),<sup>393</sup> which translates to approximately 111.5 MW of firm capacity<sup>394</sup> for 400 MW of Hydro's assumed new wind generation<sup>395</sup> (vs. 88 MW of firm capacity in the Build Application).<sup>396</sup>

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<sup>390</sup> Newfoundland Power, "Newfoundland Power 2026-2030 Capital Plan," June 2025, page 1, available at: <http://www.pub.nf.ca/applications/NP2026Capital/app/From%20NP%20-%202026%20Capital%20Budget%20Application%20-%202025-06-27.PDF>.

<sup>391</sup> These values are determined by comparing the "Total Island Requirements (GWh)" and "Island Customer Coincident Peak Demand (MW)" in Table 4 of Attachment 1 of the 2025 Load Forecast and the load forecast filed with the Build Application. *See:* Newfoundland and Labrador Hydro, "2025 Island Interconnected System Load Forecast Report," Attachment 1, Table 4. *See also:* Build Application, Schedule 3, Attachment 1, Table 4.

<sup>392</sup> Evaluating Effective Load Carrying Capability, Figure 1.

<sup>393</sup> Build Application, Schedule 1, footnote 30.

<sup>394</sup> Evaluating Effective Load Carrying Capability, Figure 1. This value is calculated as a sum product of the marginal ELCCs presented in the referenced table, for each 50 MW wind addition up to 400 MW.

<sup>395</sup> Build Application, Schedule 1, Table 1.

<sup>396</sup> Build Application, Schedule 3, footnote 64.

- (207) These unresolved issues, combined with the lack of immediate urgency to bring BDE Unit 8 into service, support a deferral of Board approval of BDE Unit 8 until the record can be more fully established.
- (208) Based on our review of the RAS to address transmission constraints on the BDE-SOP corridor, we conclude that the TransGrid RAS Study demonstrates that an RAS could be an effective alternative to construction of a new transmission line on the BDE-SOP corridor, albeit subject to additional observations and caveats.
- (209) The study is explicitly a *feasibility* study, which, as characterized by Hydro, confirms “the technical viability of the Avalon RAS”. The critical next step identified by Hydro is to “continue to engage Newfoundland Power on how the RAS can be implemented on its electrical system...” with consideration given “to balancing the complexity of the implementation with refinements that would allow for reduced customer impact.” The details of any eventual RAS, and its capability to allow greater power flows to the Avalon during a LIL bipole outage remain to be determined.
- (210) It is not clear how to square the results of the RAS Study with those of the LIL Shortfall analyses that Hydro has presented, which show a need for load shed while assuming new transmission (or equivalent) to improve deliverability of power to the Avalon Peninsula. We believe it is conservative, and appropriate, to assume that the actual RAS that is implemented would be *less* effective in increasing power flows to the Avalon Peninsula than a new transmission line, and that pre-contingency load shed would still be required during a LIL outage.
- (211) As indicated by Hydro, details of an actual RAS remain to be developed, including the specifics of the scheme, the requirements and schedule for implementation, and estimation of associated costs. Bates White finds that the results of the RAS Study support Hydro’s plan to pursue the RAS in place of any near-term upgrade to transmission infrastructure.
- (212) The concept of a management reserve is defensible: a set-aside source of funds to be used only if unforeseeable, high-impact events occur that have substantial impacts on project costs. Having such funds set aside allows those high-impact events to be addressed with little or no impact on project development and schedule. In principle, a management reserve can help ease the regulatory burden of addressing unexpected or low probability events and facilitate efficient project management under such circumstances. However, an expansive initial budget approval could also blunt project management discipline, with the management reserve providing cover for poor cost estimation and poor project management.
- (213) The methodology approaches to calculating Management Reserve for both the Avalon CT and BDE Unit 8 projects, though differing in significant ways, are reasonable. We therefore do not take issue with Hydro’s methodological approach for calculating Management Reserve for both projects, though

we do note the following. First, Hydro did not include certain “emerging” strategic risks in the determination of the Management Reserve for BDE Unit 8, which Hydro estimates to potentially increase the project’s costs by up to \$562.4 million. It is not clear if interaction between the BDE Unit 8 project and the refurbishment of BDE Unit 7 could further exacerbate this risk; Hydro should address this potential in its updated calculations. Second, Hydro did not capture all “unknown unknowns” in its specification of strategic risks for both projects. Third, Hydro potentially underestimated the upward cost impact of certain project risks, such as challenges in EPCM contracting. The Board should consider requiring Hydro to incorporate these risks into an updated Monte Carlo analysis and Management Reserve calculation.

- (214) If the Board is to approve a Management Reserve, it is our view that the Board should consider requiring Hydro to formally notify the Board if it anticipates tapping into the Management Reserve funds and again when those funds are accessed. The Board should request supporting information from Hydro regarding the details of the need for and amount of Management Reserve funds accessed. Moreover, even if use of the Management Review is reported to the Board, the Board should pursue a prudence review at the end of the project to test the validity of use of the Management Reserve to ensure that such funds were due to the types of “unknown unknowns” risks for which the Management Reserve is intended, and not as a general backstop for cost overruns. The burden of prudence should remain with Hydro in all cases, and the Board should review Hydro’s submissions for evidence that the strategic risks that those funds are meant to cover have materialized and driven the costs of the project higher.
- (215) Additional clarity regarding the Management Reserve is also needed. Specifically, Hydro must better define the subjective materiality threshold for changes in project schedules and budgets. Also, while Hydro commits to “report to the Board for further review if costs to complete a project are forecasted to exceed 10% of the approved project budget,”<sup>397</sup> we recommend that the 10% threshold (or any other threshold imposed by the Board) is calculated off of the project’s Authorized Budget, less the Management Reserve. Additional clarity may be needed on this threshold as well, as the Board’s Capital Budget Guidelines may not have anticipated Management Reserve allowances, as is requested in this proceeding. Further, the “Commitment to Build” process is an important step, though is subject to subjective interpretation by Hydro. What constitutes a “materially different” project budget or schedule is not obvious and could benefit from additional clarity.
- (216) Regarding governance, we recommend Hydro adjust its governance structure to reconstitute the Risk Working Group and Change Control Committee to ensure these committees are independent of the team(s) responsible for project development. We also recommend the Board and Hydro strongly

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<sup>397</sup> Build Application, Schedule 1, Attachment 1, footnote 36.

consider both adding external expertise to monitor and report on project status and risks on a regular (e.g., quarterly) basis.

## **Appendix A. CAMS Review of Avalon CT**



**PROJECT**

**AVALON COMBUSTION  
TURBINES**

Due Diligence

Prepared for  
Bates White  
February 2026

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## 1 EXECUTIVE SUMMARY

- The project to install 150 MWs of Combustion Turbine power generation at Newfoundland Labrador Hydro's Holyrood facility is a sound project that will provide peaking power generation when the existing thermal units at the facility are shut down over the next several years. The application and supporting documentation filed by NLH indicate that the Avalon CT is a reasonably well-planned project at the current stage of development.
- The cost categories, and the general levels and relative magnitudes of costs in the application filed by Newfoundland and Labrador Hydro (NLH) appear reasonable, although some costs appear understated relative to the current market.
- The major pending milestone of securing an EPC and executed procurement contracts will determine and clarify the anticipated schedule and costs as well as the residual risks to schedule and costs. Market intelligence indicates that the current availability of EPCs and necessary equipment is constrained relative to high and growing demand particularly do to the rise of data center energy demands in the US market. This imbalance of supply and demand will likely impose longer-lead times and cost premiums.
- Although it is not currently contained in the record for the Avalon CT Project, the cost for the Combustion Turbine packages is estimated to have increased significantly over the last year driven by the increase in data center power requirements particularly in the US market (further details are provided in Section 2.2 of this report). The proposal provided by NLH for this project should be updated before being approved to reflect current costs.
- The Major Maintenance schedule provided in the proposal does not reflect the expected costs over the life of the project and should be reviewed and updated.
- The facility appears to have a good water supply for standalone operation, and the proposed treatment system should provide the needed water treatment for the water supply to the Combustion Turbines. Further review by NLH may be needed to determine if water supply is sufficient for the CTs to be operated for extended periods while the thermal units continue to operate.
- The proposal does not have the necessary details to assess the costs for the fuel storage and delivery system. The proposal should provide a specific design and cost for the fuel system.
- The addition of liquid fuel recirculation and filtration equipment, as described in Section 2.3 in this report, would eliminate the need for burning off excess stored fuel, as described in Section 2.5 of this report. Eliminating the fuel burn off would result in a substantial operating cost savings to the project.

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## 2 AVALON COMBUSTION TURBINES

### 2.1 Summary

NLH has proposed the addition of 150 MW of power production at the existing Holyrood Thermal Generation Station (TGS).<sup>1</sup> The existing thermal units at the facility will be shut down at the end of the bridging period.<sup>2</sup> To continue to provide the needed capacity on Island Interconnected System or more specifically the Avalon Peninsula, a project has been proposed to install Combustion Turbines (CTs) to generate the needed electrical power. The CTs would be fast start peaking units that will be able to be dispatched quickly when the need for additional capacity arises.<sup>3</sup> The CT units would be able to be dispatched in various increments as needed. The CTs would be able to be dispatched up to 24 hours per day for continuous operation as long as fuel and water supply is available.

### 2.2 Combustion Turbines (CTs)

The selection of the CTs for the project was based on the required power output, environmental requirements, cost, availability, reliability, technical support, and other factors.<sup>4</sup> The supplemental files provided by Hydro in June of 2025<sup>5</sup> discuss the selection of the CTs for the project and the reasoning behind the decision of which CT model to utilize.<sup>6</sup>

The NLH considered three models of CTs, each from a different manufacturer. NLH determined that two did not meet the requirements and selected the General Electric (GE) LM6000PC Sprint (LM6000) for this project.<sup>7</sup> The LM6000 has been in production and operation for many years and there are over 1,200 units

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<sup>1</sup> Hydro, “Application for Capital Expenditures for the Purchase and Installation of Bay d’Espoir Unit 8 and Avalon Combustion Turbine – Confidential,” March 21, 2025, available at: <https://nlhydro.com/wp-content/uploads/2025/09/From-NLH-Application-for-Capital-Expenditures-for-the-Purchase-and-Installation-of-Bay-dEspoir-Unit-8-and-Avalon-Combustion-Turbine-Redacted-2025-03-21-UPDATED-2025-05-09-compressed.pdf> (“Build Application”).

<sup>2</sup> Build Application, Schedule 1, page 16, footnote 27.

<sup>3</sup> Build Application, Schedule 5, page 5, line 3.

<sup>4</sup> See: Hydro, “Reliability and Resource Adequacy Study Review – 2024 Resource Adequacy Plan – Revision 2,” August 26, 2024, available at: [https://nlhydro.com/wp-content/uploads/2024/08/2024-08-26\\_NLH\\_RRA-Study\\_2024-RAP\\_Rev-2.pdf](https://nlhydro.com/wp-content/uploads/2024/08/2024-08-26_NLH_RRA-Study_2024-RAP_Rev-2.pdf) (“2024 Resource Adequacy Plan”).

<sup>5</sup> See: Hydro, “Application for Capital Expenditures for the Purchase and Installation of Bay d’Espoir Unit 8 and Avalon Combustion Turbine – Documents Placed on the Record – Hydro’s Reply,” June 13, 2025, available at: <http://www.pub.nf.ca/applications/NLH2025AvalonCombustionMarch/correspondence/From%20NLH%20-%20Documents%20Placed%20on%20the%20Record%20-%20Reply%20-%20Enclosing%20Attachments%201%20-%202025-06-13.PDF>. Documents enclosed by Hydro can be found here: <http://www.pub.nf.ca/applications/NLH2025AvalonCombustionMarch/reports.php> and are denoted in footnotes by “Hydro Correspondence dated June 13, 2025.”

<sup>6</sup> Hydro Correspondence dated June 13, 2025, Attachment 8, Hatch, “Best Available Control Technology Memorandum,” September 23, 2024, available at: <http://www.pub.nf.ca/applications/NLH2025AvalonCombustionMarch/report/From%20NLH%20-%20Attachment%208%20-%20Best%20Available%20Control%20Technology%20Documents%20-%20Redacted%20-%202025-06-13.PDF> (“Best Available Control Technology Memorandum”); Hydro Correspondence dated June 13, 2025, Attachment 1, Hatch, “Newfoundland and Labrador Hydro 150 MW Combustion Turbine Plant FEED Study FEED Report,” December 9, 2024, available at: <http://www.pub.nf.ca/applications/NLH2025AvalonCombustionMarch/report/From%20NLH%20-%20Attachment%201%20-%20150%20MW%20Combustion%20Turbine%20Plant%20FEED%20Study%20-%20Redacted%20-%202025-06-13.PDF> (“FEED Report”).

<sup>7</sup> Best Available Control Technology Memorandum; FEED Report, pages 3 to 4.

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utilized around the world for various applications. The LM6000 is well suited for peaking power applications. GE has a robust support program and there are other third-party providers that can provide support if needed.

The specifications for LM6000PC Sprint provided by GE indicate it will be able to meet the dispatch and emissions requirements needed for this project.

The Build Application reflected a cost for three LM6000PC Sprint packages (CT, Generator and ancillary equipment for the CT and Generator) from GE estimated at \$168.4 million (CDN).<sup>8</sup> This cost was based on an underlying capital cost estimate per CT package in U.S. dollars of \$38.1 million, with escalation and exchange rate applied.<sup>9</sup> As of December 19, 2025, Hydro has reported a negotiated price for the 3 CT packages of \$280.2 million dollars, an increase relative to the Build Application value of approximately 67%.<sup>10</sup> This is roughly consistent with market intelligence obtained by CAMS on cost increases over the past year for LM 6000 CT package costs.

Market intelligence also indicated that lead times have lengthened for delivery of newly-contracted LM6000 packages such that delivery would likely be pushed into 2030. NLH had planned to award the purchase of the CT packages in November 2025,<sup>11</sup> with construction scheduled to be completed in late 2029.<sup>12</sup> NLH's Early Execution Update of January 15, 2026 indicates an expected Commercial Operation Date (COD) in March 2030.<sup>13</sup> The updated CT package cost communicated by NLH was not accompanied by a revised schedule, but it appears unlikely that commercial operation could be achieved before 2030. A new project schedule, reflecting agreed delivery and any updates to the amount of time expected for installation and testing of the CT packages should be entered into the record as soon as available.

CAMS also queried the market regarding capability and availability of LM6000 installations with synchronous condenser capability, which NLH specified as a requirement it would pursue.<sup>14</sup> GE has provided CT packages with synchronous condensing capability to the market (i.e. LM6000VELOX package solution). NLH has reported that based on bid information it received in its initial RFP process, the incremental cost of synchronous condenser capability at the CT would be approximately [REDACTED].<sup>15</sup> This project component and cost are not reflected in the Build Application. It is unknown if supplying the LM6000 in a VELOX package would further delay unit delivery to Avalon.

The LM6000 packages could also incorporate isochronous operation capability, which could be useful for recovery of the local grid from a significant contingency such as loss of transmission lines to the Avalon Peninsula. This type of operation would require the addition of either battery or a diesel generator to

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<sup>8</sup> Build Application, Schedule 5, Attachment 1, page 50.

<sup>9</sup> Hydro Correspondence dated June 13, 2025, Attachment 2, Hatch, "Capital Cost Estimate," November 22, 2024, page 4 of 34, line 184, available at:

<http://www.pub.nf.ca/applications/NLH2025AvalonCombustionMarch/report/From%20NLH%20E2%80%93%20Attachment%202%20-%20Capital%20Cost%20Estimate%20-%20Redacted%20-%202025-06-13.PDF> ("Capital Cost Estimate").

<sup>10</sup> Hydro, "Request for Further Information – Hydro's Reply," December 19, 2025, page 2, Table 1.

<sup>11</sup> Build Application, Schedule 1, page 44, Table 3.

<sup>12</sup> Build Application, Schedule 5, pages 30 to 32, and page 31, Table 3.

<sup>13</sup> Hydro, "Avalon Combustion Turbine Project Early Execution Update," January 15, 2026, available at:

<http://www.pub.nl.ca/indexreports/avaloncombustion/From%20NLH%20-%20Avalon%20Combustion%20Turbine%20Project%20Early%20Execution%20Update%20-%20November%202025%20-%202026-01-15%20-%20%20REDACTED.PDF>.

<sup>14</sup> Hydro notes this is a requirement of the generators. See: Build Application, Schedule 5, page 5, line 15.

<sup>15</sup> Phase 2 BW-NLH-009 (d).

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provide the power needed to start a single CT (i.e. black start capable). Dominion Energy’s Bushy Park and Parr facilities in South Carolina and TVA’s Johnsonville Aeroderivative Power Plant are some examples where GE has supplied an LM6000VELOX packages that incorporate both black start/isochronous and synchronous condenser capabilities.<sup>16</sup>

## 2.3 Fueling

### 2.3.1 Fuel System

The CTs are expected to be operated on #2 Fuel Oil.<sup>17</sup> The LM6000 is designed to operate on other types of fuel, such as natural gas and biofuels, which may be able to be utilized at this facility if they become available in the future.<sup>18</sup> Modifications to the LM6000 may or may not be needed depending on the type of fuel(s) being utilized. Many LM6000 are operated with more than one fuel at a time and switching between fuels, once hardware modifications have been implemented, if needed, are handled by the control systems.

The proposed fuel system, as outlined in supplemental documents provided by Hydro and in Bates White Information Requests, appears to be typical for the delivery and storage of fuel.<sup>19</sup> Onsite fuel storage capacity will need to be based on the expected dispatch profile when the units are expected to be dispatched for extended hours and days. The availability of fuel from the supplier will also need to be considered to ensure fuel can be delivered as needed when the units are operated for extended periods.

The proposed fuel system does not appear to include the equipment needed to provide filtration and the ability to recirculate the fuel when the CTs are not in operation. These ancillary systems may have been considered and were not specifically stated in the NLH documentation. If these system were not included, they should be considered for the following reasons:

- **Filtration** – Dirt and other debris can be present in pipelines, ships, barges, and tankers and will need to be removed prior to the fuel being supplied to the CT units. The CT packages will include filtration, but additional filtration should be in service prior to the fuel arriving at the CT packages.
- **Centrifuges** – Fuel oil typically has water entrained that needs to be removed. Water may be present in the fuel due to water being present in any portion of the delivery to the facility. Water can also enter the system due to high humidity and other atmospheric conditions through tank vents. The water causes corrosion in tanks and piping. The water can also cause corrosion in the CTs that can lead to increased/accelerated service needs, and potentially to catastrophic failure. The fuel should be centrifuged as it is being sent to the CT packages to ensure water is removed and not introduced into the CTs. Centrifuge will also aid in the remove of particulates.
- **Recirculation** – The fuel storage and delivery system should include the ability to recirculate the fuel through the centrifuges and the filtration to remove water and particulates and return the fuel to the storage tank(s). This part of the system should be able to be utilized when the fuel is

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<sup>16</sup> See: “Improving gas turbine installation & commissioning costs with the first LM6000VELOX\* DLE package,” available at: <https://www.governova.com/gas-power/resources/case-studies/lm6000velox>.

<sup>17</sup> Build Application, Schedule 5, page 3, line 23.

<sup>18</sup> Build Application, Schedule 5, page 3, lines 1 to 8.

<sup>19</sup> FEED Report; Phase 2 BW-NLH-018.

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not being sent to the CTs to ensure the fuel is kept clean and free of water when the units are not being dispatched. Recirculation also provides the means to clean fuel if it has been delivered with high particulates and/or water content, without the need to remove the fuel and send it back to the supplier, and to help manage fuel temperature during cold weather conditions. The recirculation system, when used on a routine basis, will minimize water accumulation at the bottom of the storage tanks. This minimizes corrosion in the tank as well as the possibility to ingest water in the CTs. There have been many cases where enough water was delivered from the fuel storage tanks to a CT and caused it to trip offline due to flame out.

The fuel system should include the ability to add additives to the fuel when needed. Fuel additives may be required if the fuel has contaminants or if it is to be stored for an extended period – e.g., in excess of 6 to 12 months – and is not utilized. Degradation of untreated fuel oil from oxidative instability can be exacerbated by high temperature, water and particulate contamination, and bacterial and fungal growth.

There are many power generation facilities located in North America that participate in winter reliability programs or are curtailed from using natural gas and utilized #2 fuel oil. Many of these facilities will ensure their fuel tanks are full prior to the winter season and may or may not use the fuel. They will have fuel left in the tank at the end of the season and will leave it in the tank until the next winter season. During that time, microbial growth may occur, and additives are added to minimize the microbe growth. The microbes can foul the CT fuel systems. Use of the additives provides the means to minimize the growth and remove the microbes with the filtration.

It is our understanding that the Avalon CT and the existing Holyrood CT would likely share a common fuel system. Incorporation of systems and procedures to maintain fuel quality would consequently provide benefits for both facilities. We note that fuel contamination in the Holyrood Storage Tank 3 was reported in NLH’s 2025-2026 Winter Readiness report.<sup>20</sup>

### 2.3.2 Fuel Supply

The Avalon CT is expected to consume roughly 1.2 million liters of No. 2 fuel oil per day at full load. Combined with the fuel consumption of approximately 969,000 liters per day at full load of the existing Holyrood GT, full load operation of the two units would total approximately 2.15 million liters per day.<sup>21</sup>

Under normal (minimal) operation, there are no fuel supply or storage concerns with respect to the Avalon CT or the Holyrood GT. However, extended high operation during a prolonged LIL bipole outage would present significant fueling challenges. NLH has reported that that combined operation of both the Avalon CT and the Holyrood GT beyond 5 days would require fuel deliveries by 44 truck per day, and that this would be “unsustainable”.<sup>22</sup> Assuming a net heat rate for the Avalon CT of 8,600 Btu/kWh burning No. 2

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<sup>20</sup> Hydro, “2025–2026 Winter Readiness Planning Report,” December 10, 2025, pages 11-12, available at: <http://www.pub.nf.ca/indexreports/winterreadiness/From%20NLH%20-%202025%E2%80%932026%20Winter%20Readiness%20Planning%20Report%20-%20December%202025%20-%20Final%20Report%20-%202025-12-10.PDF>.

<sup>21</sup> 2024 Resource Adequacy Plan, Appendix C, Attachment 4, page 16.

<sup>22</sup> Hydro, “2024 Resource Adequacy Plan, Technical Conference #2, Issue #4: Resource Supply Options,” October 2, 2024, slide 25.

fuel oil, consistent with manufacturer specifications for the LM6000 Sprint,<sup>23</sup> and standard tanker truck capacity of approximately 35,000 liters, we estimate required fuel delivery to support full output at around 24 trucks per day. At offload times of 35-40 minutes per standard tanker, this delivery volume would require 14 to 16 hours per day.<sup>24</sup> This is in addition to an even greater volume of fuel needed for the existing Holyrood GT. As summarized in Table 1, maintaining full output at both facilities for an extended period would require daily deliveries by more than 50 trucks, significantly more than the “unsustainable” level of 44 trucks per day described by NLH.

**Table 1: Estimated Daily Fuel Delivery Requirements at Full Output**

	Full load daily fuel, liters	Trucks per day
Avalon CT	853,000	24.4
Existing Holyrood GT	969,000 <sup>25</sup>	27.7
<b>Total</b>	<b>1,822,000</b>	<b>52.1</b>

Hydro reports “plans to leverage a Request for EOI to explore potential partnerships that may help mitigate fuel risks,” and that it has been considering options for the Holyrood Marine Terminal, including refurbishment, upgrade, or potential replacement, to improve long-term fuel security.<sup>26</sup> Our understanding is that no partnerships, new supply arrangements or decisions regarding options for the Marine Terminal have been made.

Based on available documentation reviewed by CAMS, the adequacy of fuel supply to the Avalon CT to support full output for an extended period, particularly in addition to full output at the Holyrood GT, remains unresolved. NLH should perform a full assessment of fueling options – including a dedicated diesel marine offload system – and present a recommendation to the Board for consideration.

## 2.4 Fuel Burn-off

The NLH proposal includes discussion of an annual fuel burn-off to eliminate unused fuel that would otherwise be degraded below required standards. If fuel remained at the end of an annual cycle, the CTs

<sup>23</sup> See: GE Vernova, LM6000 aeroderivative gas turbine, available at: <https://www.governova.com/gas-power/products/gas-turbines/lm6000>.

<sup>24</sup> Offload times based on: Hydro Correspondence dated June 13, 2025, Attachment 4, Hatch, “Newfoundland and Labrador Hydro 150 MW Combustion Turbine Plant FEED Study Fuel Unloading Options,” September 20, 2024, available at: <http://www.pub.nf.ca/applications/NLH2025AvalonCombustionMarch/report/From%20NLH%20-%20Attachment%204%20-%20Fuel%20Unloading%20Options%20Memo%20-%20Redacted%20-%202025-06-13.PDF>.

<sup>25</sup> Holyrood daily fuel consumption at full load as reported in: 2024 Resource Adequacy Plan, Appendix C, Attachment 4, page 16.

<sup>26</sup> Hydro, “Reliability and Resource Adequacy Study Review – Semi-Annual Update for the Fourth Quarter of 2025,” December 16, 2025, available at: <http://www.pub.nf.ca/applications/NLH2018ReliabilityAdequacy/reports/From%20NLH%20-%20Q4%202025%20Semi-Annual%20Report%20-%20202025-12-16.PDF>.

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would be operated to burn remaining fuel and free up storage for the next winter season. <sup>27</sup> Inquiry was made with several CT facilities in North America regarding the storage of liquid fuel when it is not being utilized either due to utilizing other fuels or low dispatch. All of these facilities stated they do not burn off any excess fuel following a dispatch period. Rather, they store the fuel for use at a later time, obtain samples of fuel and send them for analysis, and process the fuel as needed using the fuel transfer and recirculation systems, to ensure the fuel is ready for use when needed in the future. The previously discussed fuel storage and delivery system should be highly considered before needlessly consuming fuel when it is not economic or needed to provide power during non-peak periods. The high cost of fuel burn would be eliminated with the installation of a fuel recirculation system.<sup>28</sup> Operations at the Holyrood facility for both the new and existing CTs should include the procedures for routine sampling/analysis and conditioning of the fuel using the recirculation system.

## 2.5 Water Supply

The water supply for the CTs is discussed in supplemental filings from Hydro.<sup>29</sup> The information provided indicates the water supply for the CTs would be the same source of water currently providing water to the thermal units at the site.<sup>30</sup> The water supply appears to be adequate to provide the water needs for the CTs during extended periods of dispatch, considering the plant on a standalone basis.<sup>31</sup> If the Holyrood thermal units were to remain in service after the Avalon CT enters commercial operation, the adequacy of water to support simultaneous combined operation is not clear. Further review by NLH may be needed to determine if the CTs can be operated for extended periods while the thermal units continue to operate. As each thermal unit is shutdown/decommissioned, the water supply available to the CTs will increase.

Water supplies to the CTs will need to be treated to meet the GE specification for water injection. The NLH proposal appears to address this with the equipment needed to meet the specifications.<sup>32</sup> Given potential challenges of water adequacy in operating the Avalon CT simultaneously with the Holyrood thermal units, we recommend that NLH consider including a method of back up water treatment. Backup water treatment can utilize trailer mounted system that can be rented only when needed and connected to the water system. We recommend that the Avalon CT water treatment system include the means to connect backup treatment systems.

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<sup>27</sup> 2024 Resource Adequacy Plan, Appendix C, page 57, lines 7 to 13; Build Application, Schedule 3, page 20 line 24 to page 21 line 3.

<sup>28</sup> For discussion on the excessive fuel burn-off costs, see: "Expert Report of Vincent Musco and Collin Cain," June 26, 2025, Section III.E.iii, available at:

<http://www.pub.nf.ca/applications/NLH2025AvalonCombustionMarch/report/Bates%20White%20Economic%20Consulting%20-%20Expert%20Report%20-%20REDACTED%20-%202025-06-26.PDF> ("Bates White Phase One Expert Report").

<sup>29</sup> FEED Report; Hydro Correspondence dated June 13, 2025, Attachment 9, Hatch, "Newfoundland and Labrador Hydro 150 MW Combustion Turbine Plant FEED Study Water Supply Analysis & Environmental Review Report," September 26, 2024, available at: <http://www.pub.nf.ca/applications/NLH2025AvalonCombustionMarch/report/From%20NLH%20-%20Attachment%209%20-%20Water%20Supply%20Analysis%20and%20Environmental%20Review%20Report%20-%20Redacted%20-%202025-06-13.PDF> ("FEED Water Supply and Environmental Report").

<sup>30</sup> FEED Water Supply and Environmental Report, page 13.

<sup>31</sup> FEED Water Supply and Environmental Report, page 18.

<sup>32</sup> FEED Water Supply and Environmental Report, pages 18 to 19.

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## 2.6 Capital Expenditures (CAPEX) and Spare Parts

The filings from Hydro list the proposed costs for the CAPEX and spare parts for the project.<sup>33</sup>

- **CAPEX** – There are no CAPEX items listed in the proposal beyond the initial purchase of the equipment to construct the facility and the purchase of spare parts as discussed below.<sup>34</sup> The NLH proposal does not appear to include all aspects of the proper construction of the facility. The most significant example of this, as discussed above, is the lack of a fuel management system to maintain fuel quality for extended periods of CT operation and to mitigate the potential need for burning off degraded fuel..
- **General Spare Parts** – The Build Application reports a cost of [REDACTED] for general spare parts.<sup>35</sup> This seems high for a facility with simple cycle gas turbines. A comparison of the spare parts cost was made to a facility with three of the same model combustion turbines that are being proposed for the Avalon CT. The major difference for the turbines at the other facility is they utilize natural gas as the fuel, which would not materially affect the spare parts needed. That facility carries approximately \$1 Million (USD) of spare parts, which includes consumables. Another difference, which could be a factor, is the location of the facility. It may be more difficult to obtain spare parts in a timely manner in Newfoundland and Labrador, which could justify having more items and/or higher quantities on site, to minimize down time. A review of the spare parts to be kept at the site should be made to determine exactly what is needed and not having items that can be easily obtained kept in inventory to minimize costs.
- **CT Spare Parts** - The Hydro proposal includes [REDACTED] for CT spare parts.<sup>36</sup> The same comparison was made as was done for the General Spare Parts and the other facility has approximately \$1 Million in CT parts. A review of the CT spare parts to be kept at the site should be made to determine exactly what is needed and not having items that can be easily obtained kept in inventory to minimize costs.
- **Spare Transformer** – The Hydro proposal includes the purchase of a spare main transformer, sometimes referred to as a Generating Station Units (GSU), with CAPEX at [REDACTED] (CDN).<sup>37</sup> Having a spare transformer on site is highly recommended and will minimize down time for a unit if the spare is needed. Lead time to obtain a replacement transformer can be as high as 24 months or more.
- **Spare Parts Costs** – Spare parts CAPEX costs were current to the associated reporting in 2024,<sup>38</sup> and do not reflect any escalation from that time. Updated costs estimates should be developed based on expected contracted delivery.<sup>39</sup>

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<sup>33</sup> Hydro Correspondence dated June 13, 2025, Attachment 5, Hatch, “CAPEX Estimate for Incremental 50 MW Size Increase, Class 5,” November 28, 2024, available at:

<http://www.pub.nf.ca/applications/NLH2025AvalonCombustionMarch/report/From%20NLH%20-%20Attachment%205%20-%20Capex%20Estimate%20for%20Incremental%2050%20MW%20Size%20Increase,%20Class%205%20-%20Redacted%20-%202025-06-13.PDF>.

<sup>34</sup> Build Application, Schedule 5, Attachment 1, pages 49 to 56.

<sup>35</sup> Build Application, Schedule 5, Attachment 1, page 81, Table 5-2.

<sup>36</sup> Build Application, Schedule 5, Attachment 1, page 81, Table 5-2.

<sup>37</sup> Build Application, Schedule 5, Attachment 1, page 81, Table 5-2.

<sup>38</sup> Build Application, Schedule 5, Attachment 1, page 81, Table 5-2.

<sup>39</sup> Hydro does provide an estimate of the major escalation factors associated with the Avalon CT project. Build Application, Schedule 5, Attachment 1, pages 21 to 22.

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## 2.7 Operating Costs

There are five categories of operating costs to consider over the service life of the facility.<sup>40</sup>

**Fixed Operating Costs** – The Fixed Operating Costs are reasonable for a facility of this type, size, major equipment, and location.

**Administrative Costs** – The Administrative Costs are reasonable for a facility of this type, size, major equipment, and location.<sup>41</sup>

**Labour Costs** – The Labour Costs are reasonable for a facility of this type, size, major equipment, and location.<sup>42</sup>

**Variable Operating Costs** - The Variable Operating Costs are reasonable for a facility of this type, size, major equipment, and location.<sup>43</sup>

**Escalation** – the cost estimates incorporated in the Build Application reflect assumed escalation for equipment, materials, implementation, etc. There is no evidence that operating costs are escalated in the same way. Hydro should provide updated operating cost estimates inclusive of escalation.

## 2.8 Reserves

The NLH proposal includes two Reserves to be used in case the actual costs exceed the proposed costs.

- **Contingency** – There is a Reserve described as Contingency identified by Hydro.<sup>44</sup> The amount is \$65,177,352 (CAN) and represents an 11.1% reserve.<sup>45</sup> This is slightly higher than expected for a contingency for a project of this type and size. Typically, contingency is 10%. An additional 1.1% could be needed with the ever-increasing cost of materials.
- **Management** – There is a Management Reserve of \$128,239,838 (CAN).<sup>46</sup> This type of reserve is not typically seen in the power generation industry for projects of this type. This represents an additional reserve of approximately 17%.

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<sup>40</sup> Hydro Correspondence dated June 13, 2025, Attachment 6, Hatch, “Newfoundland and Labrador Hydro 150 MW Combustion Turbine Plant FEED Study O&M and Lifecycle Cost Estimate,” December 6, 2024, available at: <http://www.pub.nf.ca/applications/NLH2025AvalonCombustionMarch/report/From%20NLH%20-%20Attachment%206%20-%20O%20and%20M%20and%20Lifecycle%20Cost%20Estimate%20-%20Redacted%20-%202025-06-13.PDF> (“O&M and Lifecycle Cost Estimate”).

<sup>41</sup> O&M and Lifecycle Cost Estimate, pages 3 and 4.

<sup>42</sup> O&M and Lifecycle Cost Estimate, page 3, Table 1-4; Build Application, Schedule 5, Attachment 1, page 56, Table 3-1 and pages 73 to 77.

<sup>43</sup> O&M and Lifecycle Cost Estimate, pages 4 and 5.

<sup>44</sup> Capital Cost Estimate, line 1995.

<sup>45</sup> Build Application, Schedule 5, Attachment 1, page 7, Table 1. As shown in the referenced table, the Subtotal Base Cost is \$586,642,810.  $\$65.2\text{mm} \div \$586.6\text{mm} = 11.1\%$ .

<sup>46</sup> Build Application, Schedule 5, Attachment 1, page 7, Table 1. As shown in the referenced table, the Subtotal Planned Budget is \$763,175,419.  $\$128.2\text{mm} \div \$763.2\text{mm} = 16.8\%$ .

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## 2.9 Plant Maintenance

The filings from Hydro included an schedule of significant maintenance activities and associated cost estimates.<sup>47</sup> The following are comments about the Avalon CT maintenance schedule presented in the O&M and Lifecycle Cost Estimate prepared by Hatch, Ltd.

- Hatch stated they did not include any escalation in the costs.<sup>48</sup> Without an escalation the costs are understated for the life of the project.
- The cost shown are stated to be as of the date of the report which is from 2024. CT and other maintenance costs have increased significantly in the last year.
- The maintenance schedule does not appear to conform to expected operation:
  - The stated run hours for each unit are 2,000 per year.<sup>49</sup> It is assumed that during a LIL bipole outage, the units could be required to operate at high output for upwards of 6 weeks.<sup>50</sup> Making the assumption that the high dispatch would be twelve hours per day, seven days per week, for 6 weeks, that would come to 504 hours per CT. To reach the 2,000 hour threshold, the units would need to be dispatched another 1,500 hours per year, which does not seem likely to occur. Further, a LIL bipole outage is assumed to have a low annual probability.
  - Intervals –
    - Hatch states the interval for the Major Inspection/Overhaul for the CT and Generator is 50,000 hours.<sup>51</sup> This is for a unit utilizing natural gas for fuel.
    - Hatch used 16,000 hours for a Hot Section and 30,000 hours for the Major Inspection.<sup>52</sup>
  - The Major Inspection/Overhaul would be due at year 25. The Hatch schedule shows these at year 15 or 30,000 hours.
  - In the years when the first unit Combustor/Hot section or a Major Inspection/Overhaul are shown in the Hatch schedule, they did not include the annual costs which would still be due, at likely a lower amount since the other work would preclude an inspection being due, but the remote monitoring would still be a cost. The cost for monitoring is not broken out.
  - Hatch did not include annual borescope inspections. While the number of annual run hours would be low, conducting the annual inspection is considered Industry Standard to ensure the unit is in proper operating conditions and will be ready to perform as needed during the peak periods.

Based on our review of the maintenance schedule and cost estimates reflected in the Build Application, we conclude that costs could be significantly higher than estimated over an assumed 26 year period, inclusive of the first major inspection of the CT electric generators. The maintenance schedule, and associated costs, will depend significantly on the actual run time of the facility, which is uncertain. We

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<sup>47</sup> O&M and Lifecycle Cost Estimate.

<sup>48</sup> O&M and Lifecycle Cost Estimate, page 1.

<sup>49</sup> O&M and Lifecycle Cost Estimate, page 1.

<sup>50</sup> 2024 Resource Adequacy Plan, Appendix C, Attachment 5, page 21, Figure 3-3.

<sup>51</sup> O&M and Lifecycle Cost Estimate, page 4.

<sup>52</sup> O&M and Lifecycle Cost Estimate, page 2, Table 1-2.

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view the maintenance schedule and cost estimates reflected in the Build Application as likely to be minimum, and possibly understated, requirements. A more complete assessment of likely maintenance costs would incorporate a range of operational cases.

## 2.10 Service Agreement and Lease Program

- **Service Agreement** - It is not clear if the NLH proposal includes costs associated with a Service Agreement with GE. Documents from Hydro indicate that a proposal for a Service Agreement was not obtained from GE.<sup>53</sup> A form of Service Agreement with GE should be considered with the number of CT units in the project and the critical nature of the facility for providing capacity during peak periods. The type of Service Agreement will need to be determined. The typical Long Term Service Agreement (LTSA) or Long-Term Maintenance Agreement (LTMA) may not be appropriate for this facility, given the type of equipment and the low dispatch hours per year. Those types of Agreements are typically suited for facilities utilizing Industrial Gas Turbines and Steam Turbines that operate at much higher dispatch profiles where they will operate 6,000 to 8,000 hours per year, per unit. A Contractual Service Agreement (CSA) may be the type of Agreement utilized for this facility. A CSA typically will not have any monthly, quarterly, annual or milestone payments, which would be applied to the cost of major maintenance events. The CSA would likely include provisions for GE to all conduct all CT related work including annual borescope inspections, repairs, and major maintenance events, when they are needed or due. The CSA would provide discounts to the facility for parts and services provided by GE with GE as the preferred vendor for the parts and services. The cost for major maintenance events would be determined at the time they are due, which would include any CSA related discounts.
- **Spare Gas Turbine** – Consideration should be given for the purchase of a spare gas turbine to be kept at the facility to be utilized when one of the turbines needs to be removed from the CT package for repairs or major maintenance events.<sup>54</sup> Installation of an onsite spare can typically be completed in three to four days, maximizing availability for the unit.
- **Lease Program** – GE offers a gas turbine lease program where GE provides a gas turbine to install in a unit when that unit’s turbine has to be removed for repairs or major maintenance events that will take an extended amount of time to complete. To be eligible to obtain a lease gas turbine, the facility has to be a member of the GE Lease Program. Membership typically has an annual fee, based on the number of covered units. That fee may be able to be negotiated with GE for a lower rate, especially if the facility has a spare gas turbine, which would be utilized first, prior to obtaining a lease gas turbine. When a lease gas turbine is installed, the facility will pay a Fired Hour Fee for only the hours when the unit is in operation. The Fired Hour Fee is a published rate that GE can provide, and it varies based on the expected number of fired hour for the unit. The NLH proposal does not include participation in a gas turbine lease program.<sup>55</sup> The participation in a lease program, in conjunction with or in lieu of owning a spare gas turbine, should be considered.

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<sup>53</sup> Feed Report, page 14.

<sup>54</sup> Build Application, Schedule 5, Attachment 1, page 39.

<sup>55</sup> Phase 2 BW-NLH-017b.

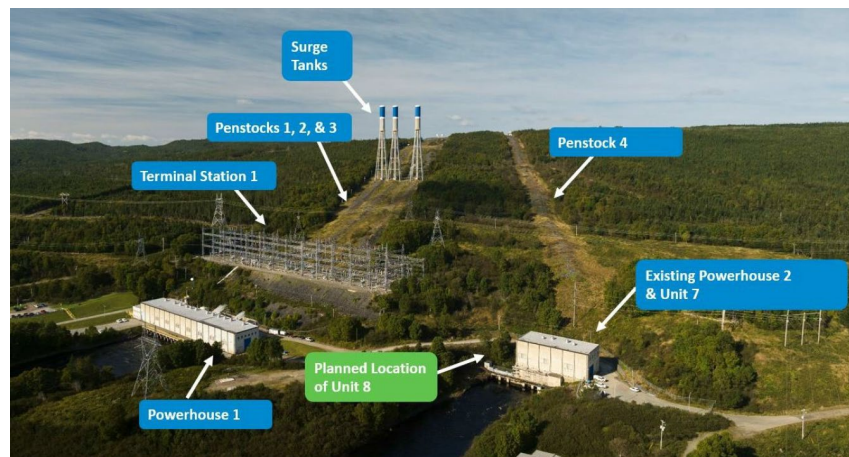
## **Appendix B. Gruner Review of Bay d'Espoir Unit 8**

Bates White Economic Consulting

E2501566.001

## Bay d'Espoir (BDE) Unit 8 Project

### Due Diligence



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Bay d'Espoir (BDE) Unit 8 Project

## Control Sheet

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## History of Revisions

*The latest version supersedes and replaces all previous one.*

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## 2 Introduction

### 2.1 Context

Gruner Stucky was engaged from Bates White Economic Consulting as independent consultant to undertake a due diligence on the on the Bay D'Espoir Unit 8 (BDE Unit 8) project proposed by Newfoundland and Labrador Hydro (aka *the Utility*). The due diligence was commissioned by the Newfoundland Board of Commissioners of Public Utilities (aka *the Board*),.

Gruner Stucky's review is based on the following assumptions, that have been validated by the information supplied by the Utility and the Board:

- > The BDE Unit 8 was identified as one of the most cost/beneficial options to install additional 150 MW of power, to address the additional Island demand of 525 MW by 2034[1].
- > BDE Unit 8 will not provide significant additional energy and will run as a capacity-only project[3].
- > BDE Unit 8 is aimed to shift generation from the off-peak hours and non-winter period to the on-peak hours and winter period[2]. It is also aimed to provide operational capacity during a potential 6-week outage on the Labrador-Island Link (LIL).

### 2.2 Scope of the Report

The purpose of the report is to:

- > Review and assess the quantities estimates for the project and highlight if there are items that have not been considered.
- > Review constructability, programme and the design of the scheme.
- > Undertake a high-level risk assessment on the items whose cost could be impacted by exogenous factors (e.g. tariffs).
- > Review the Newfoundland and Labrador Hydro project management governance to ensure it is appropriate for delivering the project.
- > Identify additional risks or opportunities for the project.

The following topics are not covered in this report:

- > Cost benefit analysis of the project and financial viability: as the project is not meant to provide additional revenues, our review will be focussed on validating the quantities, overall costing approach and provide engineering judgement.
- > Assessment of the unitary costs: unit costs are highly dependent on local market conditions specific to the geographic location of the project. Due to Gruner Stucky's limited experience in the North American region, our review will be focused on the quantities and on those items more vulnerable to price fluctuations due to exogenous factors.
- > Design detailed verification: the overall design is reviewed based on engineering judgment and Gruner Stucky's experience, in a high-level manner.
- > Operational costs: as the purpose of the due diligence is to advise the Board on the capital expenditure of the project, operational costs will be reviewed based on engineering judgement.

### 2.3 Risk, Opportunities and Conclusions Traffic Lights

Three categories of risk, opportunities and conclusions are identified throughout this report and summarised in the attached register as a means of informing the Board and the Utility for the next stage of the project. The following colour code is used to highlight:

- ▶ High Impact: A major issue of concern or key recommendation to the project, with the advise to carefully consider this aspect and take action during the next stage of the project as it may lead to significant improvements.
- ▶ Medium Impact: A moderate issue or recommendation. This has potential to improve the project, with a limited impact.
- ▶ Low Impact: A minor issue or recommendation which would be normally industry -standard and picked up by experienced project management team or contractor.

### 2.4 Short Data Sheet

The key features of the project are shown in *Table 2-1*.

*Table 2-1: Main proposed characteristics of the Project*

Feature	Unit	Quantity
<b>Number and type of generating units</b>	-	1 Francis Turbine
<b>Unit power (turbine)</b>	MW	150
<b>Unit rated discharge</b>	m <sup>3</sup> /s	102
<b>Net head (turbine)</b>	m	174.17
<b>Minimum tailwater level</b>	m a.s.l.	1.22
<b>Reservoir Maximum Flood Level (M.F.L)</b>	m a.s.l.	184.2
<b>Reservoir Maximum Operating Level (M.O.L)</b>	m a.s.l.	182.7
<b>Reservoir Low Supply Level (L.S.L)</b>	m a.s.l.	178.3
<b>Reservoir storage volume at MOL</b>	Mm <sup>3</sup>	839
<b>Waterway internal diameter</b>	m	5.18, reducing to 4.72m, 4.42m and finally to 3.76m at the powerhouse.
<b>Intake</b>	m	2 bays, 7.9m wide by 12.8m high
<b>Length of waterway</b>	m	1070
<b>Draft tube size</b>	m	3.6
<b>Tailrace Channel size</b>	m	To be enlarged from Station 2250 to 2590 by 9.15m.

### 2.5 Technical Documentation Reviewed

The list of documents reviewed as part of this report is provided in Appendix A: Document List.

## 3 Hydrology Review and Project Operation

### 3.1 Introduction

Hydrology is the science of predicting the flow of water through a watershed using statistical methods based on records of rainfall, ground conditions, land use, and flow measurements in rivers. With the proposed addition of a new turbine the facility will, quite simply, require more water to operate. In reviewing the records provided by the Utility this assessment seeks to identify any risks that have been overlooked in the documentation provided. This review also seeks to confirm that the question of water supply has been addressed satisfactorily in the Unit 8 proposal.

This section offers a high level presentation of the watershed; a summary of the hydrology aspect of the reviewed documents; and a summary of any risks identified of the Unit 8 project and its later operation.

### 3.2 Summary of the Watershed

The Newfoundland and Labrador Hydro Bay d'Espoir Development is located near the centre of the island of Newfoundland (see Figure 3-1). It consists of 10 primary water bodies, with an estimated total storage volume of 2.3 billion m<sup>3</sup> and a total watershed area of 5'903 km<sup>2</sup>. Inflow records are available at 7 locations since 1950. A summary of the hydrologic data provided (Ref [15]) is given in Table 3-1. A broader schematic of the full development can be found in the drawing included in Appendix B. Two excerpts of this schematic are shown in Figure 3-2 and Figure 3-3. Of the 10 lakes in the development, 3 have power generation stations:

- > Granite Canal Plant on Granite Lake,
- > Upper Salmon Power Plant on Cold Spring Pond, and
- > Bay d'Espoir Power Plant on Long Pond Reservoir.

These facilities are marked in the schematic in Figure 3-3 and Appendix B.

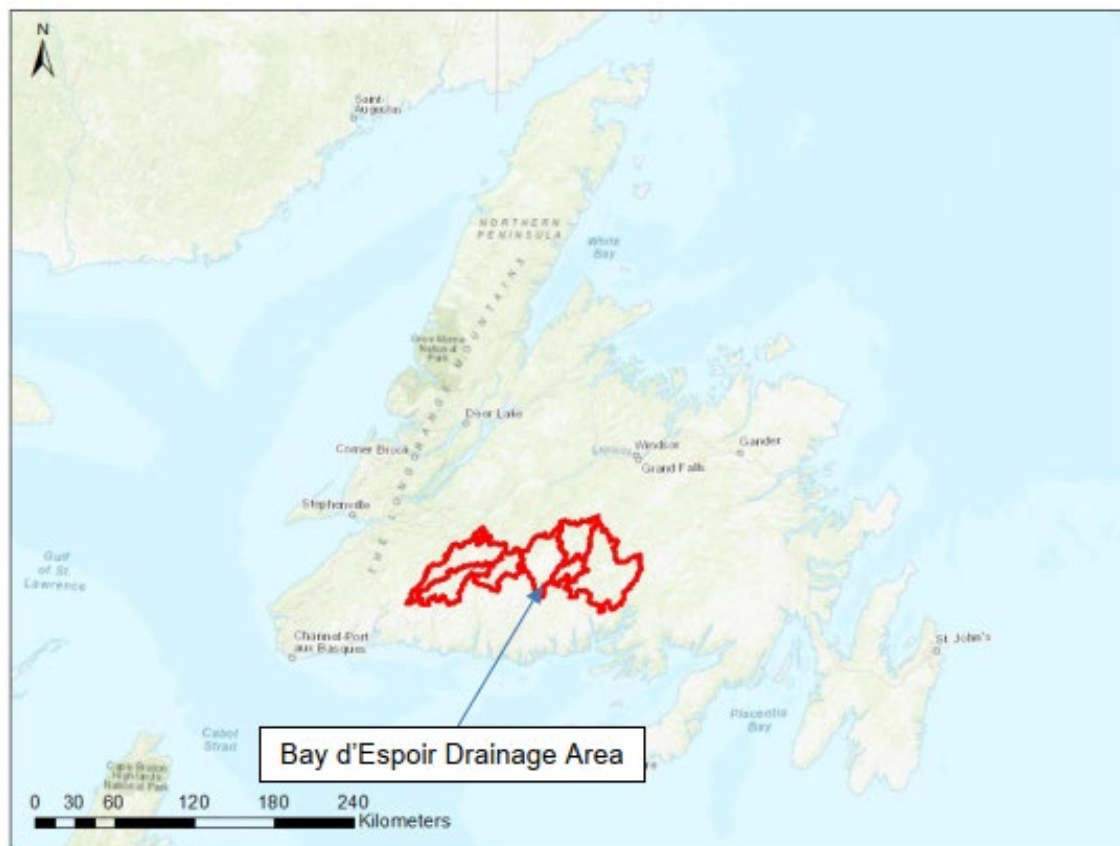









Figure 3-1 – Location of the Bay d'Espoir Development

Table 3-1 – Summary of hydrologic information provided

Name	Catchment area (km <sup>2</sup> )	Maximum Operating Level (MOL) (m)	Storage at MOL (Mm <sup>3</sup> )	LSL (m)
Victoria Reservoir	1058	326.05	1062	318.15
Burnt Pond	679	314.8	-	312.49
Granite Lake	503	312.5	82	311.37
Meelpag Reservoir	969	272.45	272.45	266.98
Crooked and Great Burnt Lakes	920	247.31	20	247.11
Cold Spring Pond		247.31	27	246.11
Godaleich Pond	1774	Not detailed in records		
Round Pond		Not detailed in records		
Long Pond Reservoir		182.7	839	178.3

**HYDROLOGY SYMBOLS**

-  INTAKE TO TURBINE
-  CONTROL GATE  
SPILLWAY GATE
-  VALVE
-  FREE FLOW WEIR
-  NATURAL INFLOW  
(NOT METERED)
-  GENERATOR
- N.I. NATURAL INFLOW
- L.S.L. LOW SUPPLY LEVEL
- M.O..L. MAXIMUM OPERATING LEVEL
- M.F.L. MAXIMUM FLOOD LEVEL
-  DRAINAGE AREA BOUNDARY

**HYDROLOGY FLOW DIAGRAM**

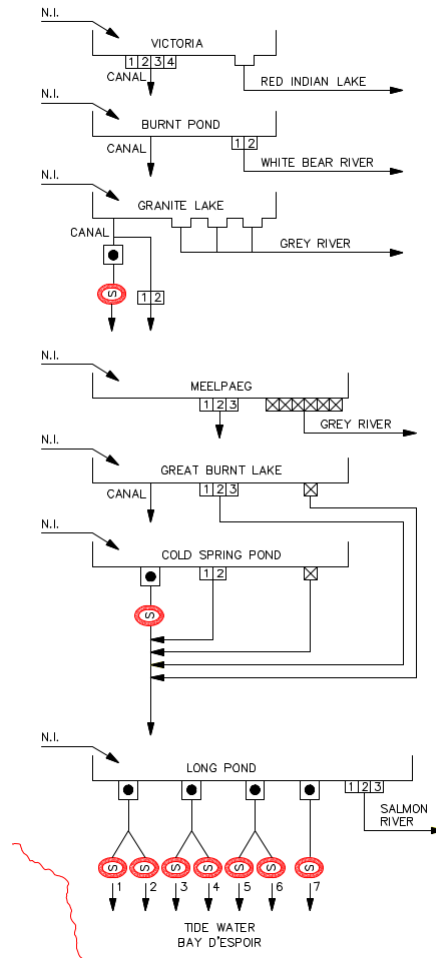


Figure 3-2 – Hydrology flow diagram taken from the Hydrology Schematic (ref [16])

One important clarification within the nomenclature of this system is the distinction between the North Salmon Spillway/bypass and the West Salmon Spillway. The North Salmon spillway is used to bypass flow to Bay d'Espoir without it passing through Upper Salmon power plant. The North Salmon Spillway is referred to as the "Upper Salmon Bypass" in some of the records. West Salmon Spillway is located immediately next to the Upper Salmon Power Plant and used sparingly see Figure 3-3.

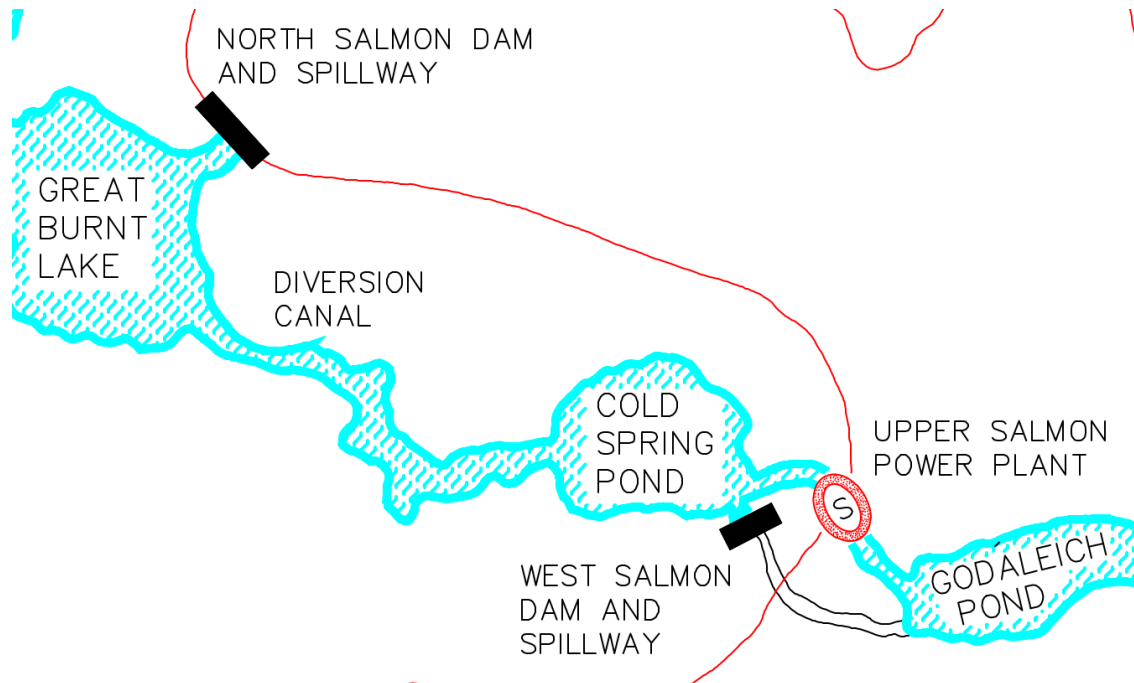


Figure 3-3 – Excerpt from Hydrology Flow Diagram (Ref [16]) showing arrangement of the Cold Spring Spillways

### 3.3 Summary of Records Provided

This section provides a summary of hydrologic information from the Utility.

#### 3.3.1 Hydrology and Feasibility Study BDE 8 [2], [15]

Hydrologic information in Attachment 2 to Schedule 1[2] is an updated version of the 2020 hydrology report [15].

The hydrology map [16] is the original version of a diagram shown in 2020 hydrology report.

The two versions of the hydrology report are very similar, with the earlier version providing more background information and the later version applying slightly different datasets.

Among the records provided this is the first mention of the *Vista Decision Support System (DSS)* (hereafter "Vista model"), a proprietary analytical model that allows the application of hydrological records to power generation scenarios. The modelling applied in this study was based on 73 years (1950-2023) of flow data records. The interpretation of these records was revised in a separate report completed by Hatch in 2023<sup>1</sup>. This report was not provided and therefore not reviewed.

It is noted that this is the only one of the hydrology studies undertaken that considers constraints caused by frazil ice in the upper power plants. See below text cited from section 5.1 of the 2020 report[15]:

<sup>1</sup> Hatch (2024). 2023 Hydrology Review. H372150-0000-2B0-230-0001, Rev. B. Prepared for Newfoundland and Labrador Hydro, April 5, 2024

Plant operation to manage frazil ice formation was considered in both phases based on the following operational assumptions at Granite Canal and Upper Salmon plants:

Granite Canal Plant:

- December: three nights in a row, 8 h/night, when the plant is limited to 30 MW.

Upper Salmon Plant:

- December: four nights in a row of shutdown for 12 h/night.
- January and February: one week in each month during which the plant is limited to 50 MW.

In this study Hatch undertook a critical period analysis to choose the period within the available records where there was the least amount of storage available. (see Figure 3-4 and Figure 3-5 below).

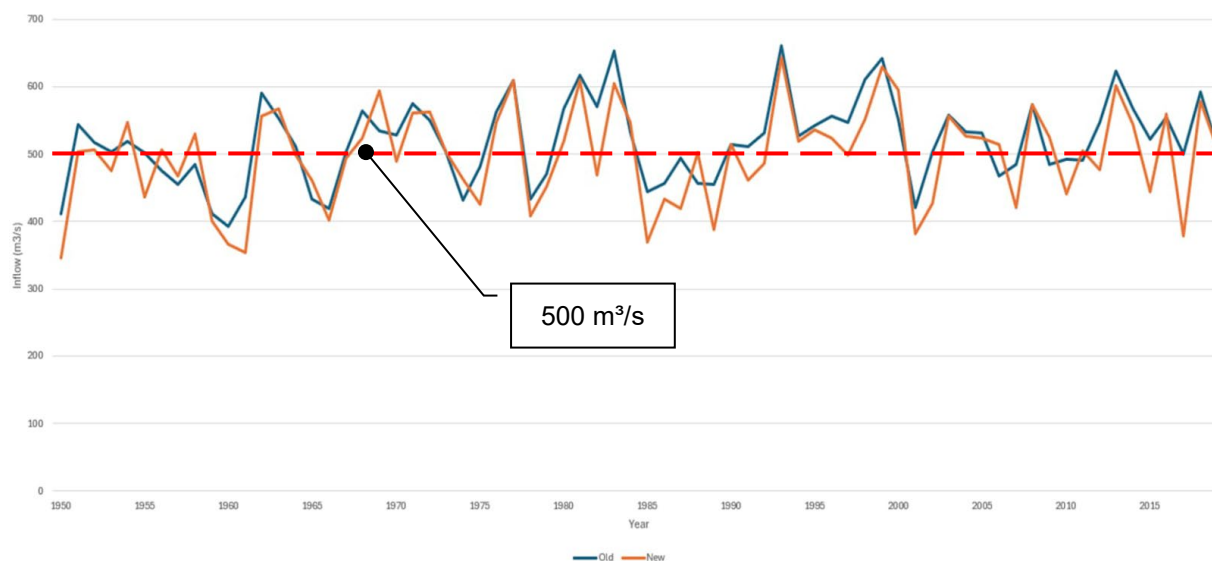


Figure 3-4 BDE total Inflow Comparison used in the latest study[2]. Adopted flow series is in orange. Superseded flow series is in Blue. Vertical scale is in 100 m³/s and horizontal scale is 5 years window, for a total period of 70 years.

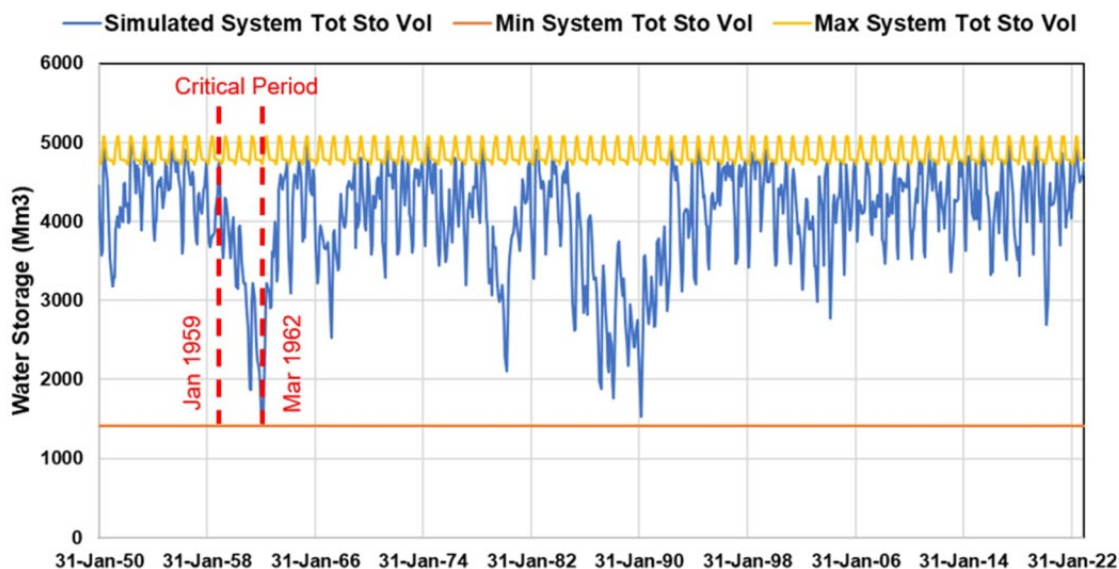


Figure 3-5 Identification of critical period[2]

Having selected the appropriate period of inflows Hatch then assessed four scenarios comparing the existing system and the addition of Unit 8 with and without the use of the North Salmon Bypass. The report drew the following conclusions from the model:

- Granite Canal plant average annual energy remains approximately 245 GWh for all four scenarios.
- There is only a very slight reduction in average annual energy for the existing system without Upper Salmon bypass.
- There is a similar level of increase, 0.64 percent, in the system average annual energy with the addition of Unit 8 with the Upper Salmon bypass.
- The average annual energy contributed by the Upper Salmon plant dropped by 2.32 percent and 1.71 percent with addition of Unit 8, with and without Upper Salmon bypass respectively.
- The average annual energy contributed by the Bay d'Espoir plant increased by 1.26 percent and 1.25 percent with addition of Unit 8, with and without Upper Salmon bypass respectively.
- The North Salmon bypass spillway is used only 2.5 percent of the time in the simulation of the existing system, and 3.0 percent of the time with addition of Unit 8. The bypass may be used during periods of high inflow that exceed the capacity flow at the Upper Salmon plant and cannot be stored; periods when the Upper Salmon plant is shut down; and when necessary to delay water from reaching the Long Pong reservoir to provide more time to generate water out of the Long Pong reservoir when the Long Pong water level is high.
- This study also re-examined the end-of-November elevation ranges and reconfirmed the range from the earlier study, that is, the large storage reservoirs in the system to optimize Bay d'Espoir system generation in the winter months while allowing room for possible early winter high flow.
  - Victoria: 323.59 m to 325.39 m
  - Meelpaeg: 271.72 m to 272.18 m

- o Long Pond: 182.22 m to 182.25 m.

### 3.3.2 June 2025 – Attachment 12 - BDE 8 Basis of Design [14]

As the title suggests this document [14] presents the basis of design for the project outlining key design criteria and constraints. Section 4.3.1 of that report includes a table that summarizes the operating water levels for Long Pond as well as an explanation of the terms used (see Figure 3-6 below). This helps to better understand the hydrological parameters outlined in *Table 2-1* and Appendix B.

Constraint		Abbr.	Elevation (m CGVD28)	Notes
Turbine Runner Center Line Level		TCL	0.93	Assumed to be impractical to change given existing powerhouse geometry.
Headrace (Reservoir Intake)	Maximum Flood Level	MaxFL	184.20	Extreme high design level. System must be safely operable at this level for extended but infrequent periods.
	Spring/Summer Maximum Operating Level	MOL	182.70	Normally expected high design level. System should be efficient at this level and capable of operating for extended periods.
	Normal Operating Level	NOL	180.94	Expected average level to which system should be optimized.
	Low Supply Level	LSL	178.01	Normally expected low design level. System should be efficient at this level and capable of operating for extended periods.
Tailrace	Maximum Tailwater Level	MaxTL	3.21	Normally expected high design level. System should be efficient at this level and capable of operating for extended periods.

Figure 3-6 Operational Water Levels at Long Pond Reservoir

### 3.3.3 Attachment 18 - BDE 8 Hydraulic Analysis of the Conveyance (SNC-Lavalin 2018)[10]

Upon review of this report no content directly related to hydrology was found. It is noted however that this report highlights the issues related to ice cover over the winter months and the importance of insuring that ice cover forms on the intake channel. The report discusses at length the low velocities required to allow ice to cover a "few inches" thick to form and the risk of high flow velocities deteriorating that ice cover.

► **Risk 3-1 – Medium:** It was not in the scope of this report to address the possibility of a rapid lowering during winter months and how that would affect ice cover. However, the findings of the assessments of the 6-week outage show a substantial drop in Long Pond's water level over a short period of time (discussed below). Given that this prolonged loss of LIL over a winter period is the primary reason for the proposed addition of Unit 8, the issue of ice cover in this scenario should be addressed, and additional measures to mitigate ice at the intakes may be required.

### 3.3.4 Appendix C Attachment 5 – Impact of Prolonged Loss of LIL on Island Reservoir

*The purpose of this study was to assess the impact of an unexpected 6-wk outage on the Labrador Island Link (LIL) on the Island Interconnected system. The outage impact on hydro generation and the effects on reservoir levels are of particular interest. ([17] section 1.1.)*

This is the second of 3 studies seeking to address this question of how Unit 8 would benefit production during a 6-week outage of the LIL. This analysis was again undertaken using the Vista model.

Two distinct scenarios were applied one under the current arrangement including the Holyrood Thermal generation system but without Unit 8; and the other with Unit 8, a 150 MW combustion turbine and 300 MW of additional wind generation. Each scenario was run with no outage, an outage starting on Jan 1<sup>st</sup>, and an outage starting March 1<sup>st</sup>. The runs with no outage were necessary to set a baseline to be forced on the model to prevent it from "preparing" for the outage. It is noted that Frazil ice reducing the capacity of the upper reservoirs is not considered in this study. The results are summarised in Table 3-2 below.

Table 3-2 Summary of Results of the 2024 LIL outage study [17]

	2025 January		2025 March		2032 January		2032 March	
	MW	%	MW	%	MW	%	MW	%
Increase in hydro production during outage*	76	9%	117	16%	129	17%	159	23%
Increase in thermal production during outage*	259	357%	181	241%	149	n/a <sup>†</sup>	77	n/a <sup>†</sup>
Average additional storage drawdown	Mm <sup>3</sup>	%**	Mm <sup>3</sup>	%**	Mm <sup>3</sup>	%**	Mm <sup>3</sup>	%**
Victoria	-26	-2.4%	-38	-3.6%	-49	-4.6%	-57	-5.4%
Meelpeg	-27	-2.5%	-15	-1.4%	-31	-2.9%	-24	-2.3%
Long pond	-74	-7.0%	-136	-12.8%	-95	-8.9%	-240	-22.6%

\* Taken from Table 1-1 in Hatch 2024 report [17]

<sup>†</sup> There was no thermal generation in the reference simulation

\*\* Expressed as a % of the total storage of the reservoir provided in the Hydrology flow diagram [16] see also Table 3-1

The results summarised in Table 3-2 show that this run of the Vista Model substantially favours the use of thermal energy. In 3 out of 4 scenarios more of the required increase in production is provided using thermal rather than hydro. The one scenario where hydro showed a higher increase in production than thermal was the 2032 March outage; comparing this to the 2025 March outage (without Unit 8 installed), average production over the outage is increased by 42MW.

The results discussed above were averaged across all the hydrological record. However, the report also shows the reservoir storage results across the full 65 year period (1958-2023) ([17] Section 1.2 p.1) in the form of graphs. These graphs for Long Pond are shown below in Figure 3-7, Figure 3-8, Figure 3-9, and Figure 3-10.

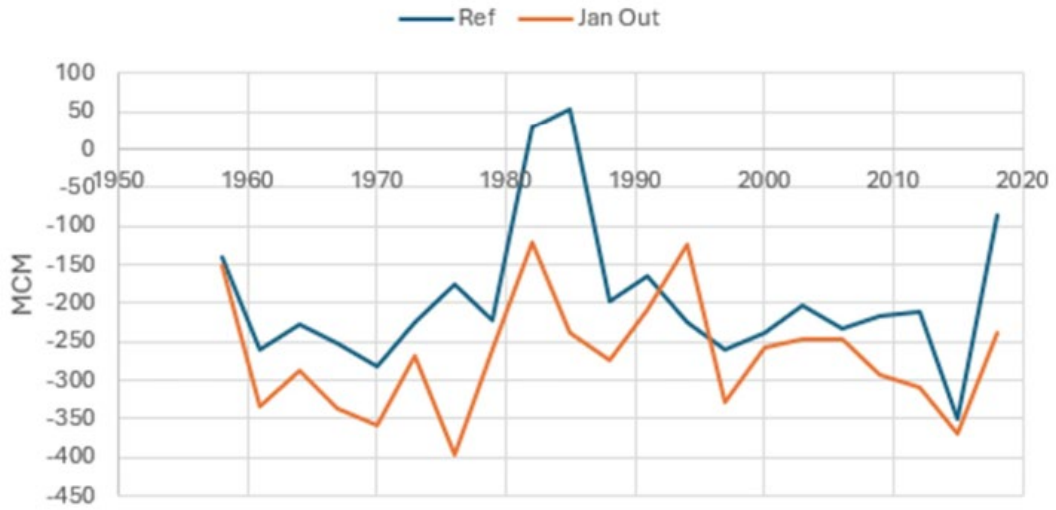


Figure 3-7 Long Pond storage for 2025 January Outage

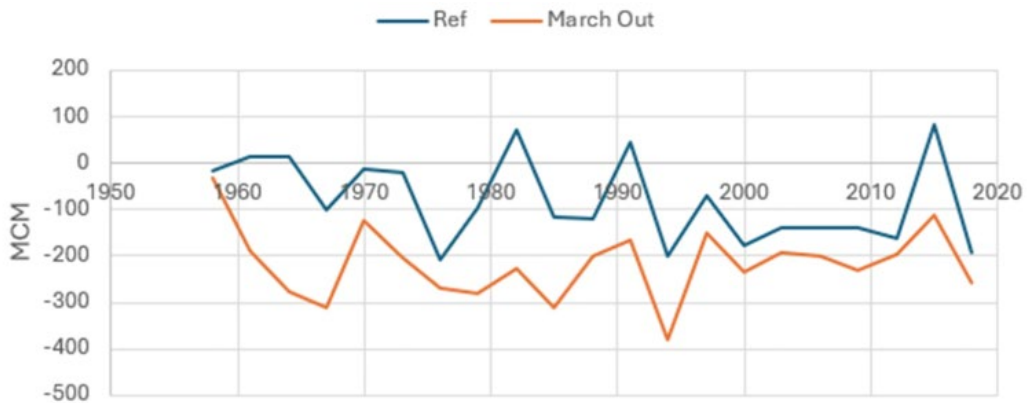


Figure 3-8 Long Pond storage for 2025 March Outage

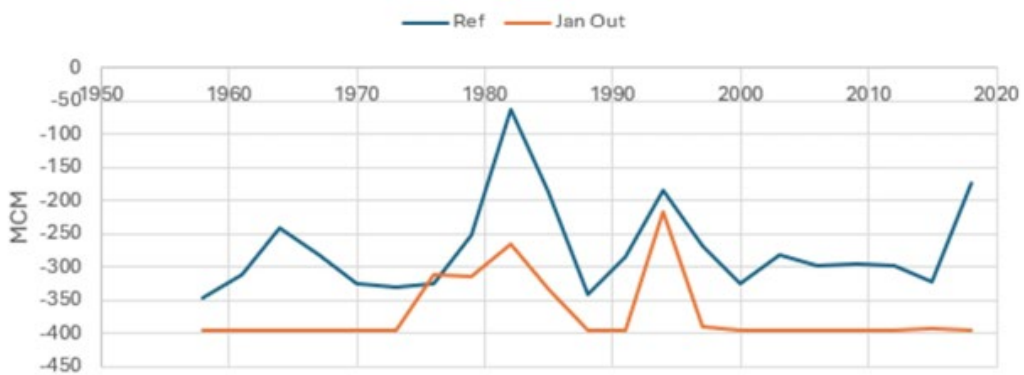


Figure 3-9 Long Pond storage for 2032 Jan Outage

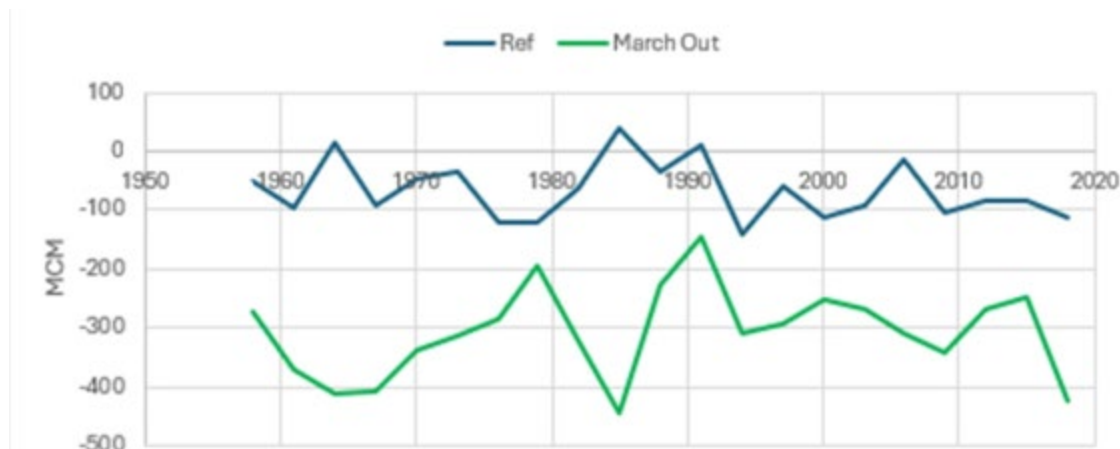


Figure 3-10 Long Pond storage for 2032 March Outage

In each of these scenarios there is one or more calendar year where the storage reached -400 Mm<sup>3</sup>. In the 2032 January outage scenario, this happened approximately half the time as read off. Section 4 p.26 of the report [17] discusses this issue as cited below:

*The Long Pond Reservoir is of particular importance, because The Bay d'Espoir plant is the largest plant in the system. Also moving water from Meelpeg is subject to about 48-hour routing delay through Great Burnt Lake and Cold Springs Pond. In addition, the capacity at rated head, of the Upper Salmon plant is 200 m<sup>3</sup>/s, and the Bay d'Espoir plant has 440 m<sup>3</sup>/s capacity and with the addition of unit 8, it goes up to 550 m<sup>3</sup>/s. If more than 200 m<sup>3</sup>/s needs to move to Long Pond, flow must be spilled past the Upper Salmon plant.*

*Long Pond has upper and lower rule curves and for January 1st the range is 181.94 m to 180.34 m, respectively. In all the simulation Long Pond is at or close to the upper rule curve, to keep the head high on the plant, and to have enough water for the winter drawdown.*

*At the end of the March outage, Long Pond was drawn down to minimum rule curve levels of 178.978 metres for many of the inflow sequences, or about 40 cm lower than in the reference case. This shows that Long Pond levels are a concern during the prolonged outages, but in an emergency, it could be drawn lower.*

*For the 2032 simulations, unit 8 at Bay d'Espoir is added. It improves the overall efficiency of the plant and provides additional capacity, but operations of the plant are subject to the same storage and flow routing limitations, discussed above. All the simulations for the 2032 show that Long Pond follows the lower rule curve for most inflow sequences. The additional unit has an impact on Long Pond storage.*

*No spilling past the Upper Salmon plant was needed during these outages in 2024 or 2032*

These conclusions suggest that this particular application of the Vista model favoured the use of thermal power generation over the use of the spillways that bypass Upper Salmon Power Plant.

These results make clear that in order for Unit 8 to serve its intended purpose of increasing peak generation capacity in a LIL outage scenario the Upper Salmon bypasses will need to be used to supply Long Pond and the Bay d'Espoir Power Plant.

### 3.3.5 Bay d'Espoir Plant Production during a Prolonged LIL Outage (Vista Analysis) [18]

#### Meeting held on 3 October 2025

On October 3<sup>rd</sup> 2025 a meeting between the Utility, Gruner Stucky, Bates White, and the Board was held to enable the Utility to explain to all parties the distinction and limitation of their PLEXOS model and their Vista model. Gruner Stucky and Bates White acted as technical reviewer and independent experts to scrutinise and consider the points raised by the Utility. The Board's staff participated as observer and facilitators for the workshop.

In the simplest terms, the PLEXOS model represents the entire electrical supply grid and each power generation facility on it. It runs at shorter time steps and better captures the need for peak production. PLEXOS does not however, consider "fuel" for those generation units (i.e. volume of water in the case of hydro) or the relationship between the passage of water between the reservoirs and the power generation of each station (e.g. bypassing at North Salmon spillway can affect production and Upper Salmon Power Plant). In contrast the Vista model captures the passage of water and the manner in which the Granite Canal, Upper Salmon and Bay d'Espoir are connected, however it operates on longer timesteps, usually 1 day or longer and therefore does not capture the peaking demand periods of each day, only the average.

As a result of this discussion it was agreed that the Utility would produce a new study applying the peak demands for production from BDE produced by the PLEXOS model to the Vista model with a restriction on thermal generation to determine if there was any issue with the routing of water to maintain desired production levels at each facility during the 6 week LIL outage.

During this meeting the use of the available spillways to bypass Upper Salmon Power Plant was discussed.

► **Risk 3-2 – High:** The Utility's team expressed concern at use of spillways highlighting associated environmental concerns that needed to be addressed each time the bypass is used. These environmental concerns were never detailed in a written record. In hindsight there may have been some confusion between the West Salmon Spillway and the North Salmon Spillway (see Figure 3-3) with one posing greater environmental consequence than the other but again there are no written records to clarify this.

#### Report delivered on 19 October 2025

On October 19<sup>th</sup> Gruner received the report [18], Gruner and Bates White reviewed the report and submitted some follow-up questions and received responses on October 22<sup>nd</sup> 2025. This section discusses the report and clarifications made in the follow-up responses.

This report is much shorter than the other studies [2], [15], [17] however this is to be expected given it addresses a single specific scenario and was prepared in just 2 weeks.

Unlike the studies discussed previously this simulation simply starts on the same day as the outage (Jan 1<sup>st</sup>) and ends after 7 months on July 31<sup>st</sup> when the reservoirs are typically at their highest levels. This run of the Vista model seeks to show that the system can supply enough water for BDE to operate at full capacity over 6 weeks totalling a production of 690 GWh.

The initial conditions are shown in the first row of Table 3-4. Section 5 p.8 of the report [18] states this to be "*aggregate starting storage level less than a 50th percentile level*". Given that the start levels are each 75% or higher further explanation of this was requested in the follow up. The Utility's explanation is cited below [19].

*Aggregate starting storage level in this instance refers to the sum of the Long Pond Reservoir, Meelpaeg Reservoir, and Victoria Reservoir storages.*

Hydro has a high measure of control over the water level in the Long Pond Reservoir from September to December before customer load reaches peak winter levels. This is achieved through the dispatch of its other hydro assets and power deliveries to the island from the LIL. Hydro's normal target range for the Long Pond Reservoir in preparation for winter is 90-92% of maximum operating level; however, operational decisions are at all times a balance of cost and reliability. The Holyrood Thermal Generating Station historically provided a reliable contingency for low water levels in Long Pond throughout the winter period which permitted flexibility in the Long Pond Reservoir storage level. In a future with an eighth generating unit at the Bay d'Espoir Hydro Generating Station and concerns over the reliability of the LIL, ensuring the reliability of energy production from the BDE HGS will be imperative for Hydro. This change to Hydro's operations will mean the 90-92% target storage range for the Long Pond Reservoir leading into winter will be pursued more aggressively than in the past. The addition of Unit 8 renders this more achievable due to the additional discharge which reduces spill risk.

Though it is counter intuitive to think these reservoirs are 75% to 90% full more than half the time, the explanation is thorough and clear, and the Utility's practice in preparation for winter is accepted.

	<b>Victoria Reservoir</b>	<b>Meelpaeg Reservoir</b>	<b>Long Pond Reservoir</b>
<b>Start Level (% MOL)</b>	75%	75%	92%
<b>End of Outage Level (% MOL)</b>	78%	32%	72%
<b>End of Winter (March 31) Level (% MOL)</b>	65%	18%	11%
<b>End of Simulation (July 31) Level (% MOL)</b>	81%	73%	71%

Table 3-3 Long Pond Inflows Jan 1 to Feb 11 in the 2025 Prolonged LIL Outage model [18]

To Gruner's understanding of the report the Vista Model was not given the option to engage thermal production (contrary to the 2024 study [17]) but the Plexos model had been allowed to engage thermal to a limited extent. The text in this report [18] is however somewhat ambiguous on this matter and cited below (Section 2 item 2 p.3)

*A simulation start date on Jan 1 that coincides with the start of the outage to avoid any storage optimization leading up to the outage. Earlier start dates would allow Vista to optimize the reservoirs levels leading into the outage, which would significantly alter the timing and quantity of hydro and thermal generation. The most simple and effective way to make the model treat the LIL outage as an unforeseen event is to start the simulation and the outage on the same date.*

The final input that is of interest in this model is the inflow chosen over the 7 months.

Section 1 item 7 of the report states:

*An inflow series with a 50th percentile total inflow volume for the island system from January 1 to July 31 and a 50th percentile total inflow volume for Long Pond from January 1 to March 31 will be used to demonstrate BDE HGS can achieve the production target under average conditions. This may be a single historic inflow series or a combination of multiple historic inflow series to achieve a P50 inflow volume for both elements.*

Section 2 then states: *A historic inflow series was selected that is approximately equal to the 50th percentile annual inflow volume for Hydro's historic inflow records from 1950-2024.*

Finally in the follow up questions the following exchange was made (Question 2)

*Question: In Figure 3, which shows the three sources of Long Pond inflows, we noted the significant natural inflow starting around January 15 and lasting through early February. What is being assumed here—a significant precipitation event that directly feeds Long Pond? Any detail on this would be appreciated to help us better understand.*

*Answer: Inflows simulated in the software are actual inflows from Hydro's records. The inflows series in this study which corresponds to a 50th percentile inflow volume is from January to March 2019.*

*On January 21, 2019, an average daily temperature of +4.9 degrees Celsius and total precipitation of 75 mm was recorded at the Long Pond Intake station.*

*On January 25, 2019, an average daily temperature of +3.1 degrees Celsius and total precipitation of 18 mm was recorded at the Long Pond Intake station.*

With Newfoundland's direct exposure to weather arriving off the Atlantic it is reasonably common to have rain events over the winter months that lead to substantial snowmelt and runoff. Upon first reading of the report it was thought that a consistent median inflow determined using the entire dataset would have been applied; expressed in volume due to the 1 day time steps in the Vista model, contrary to what was shown in Figure 3-11. The follow up clarified that this was rather the median total volume which occurred in 2019 and the recorded inflows in that period.

Figure 3-11 Shows a graph of all inflows to long pond over the course of the Vista model.

It is noted that Frazil ice reducing the capacity of the upper reservoirs is not considered in this study

Table 3-4 Reservoir Storage change in the 2025 Prolonged LIL Outage model [18]

	<b>North Salmon Bypass Flow</b>	<b>Upper Salmon Turbine Flow</b>	<b>Long Pond Natural Inflow</b>	<b>Total Long Pond Inflow</b>
<b>Volume (MCM)</b>	592	614	225	1432

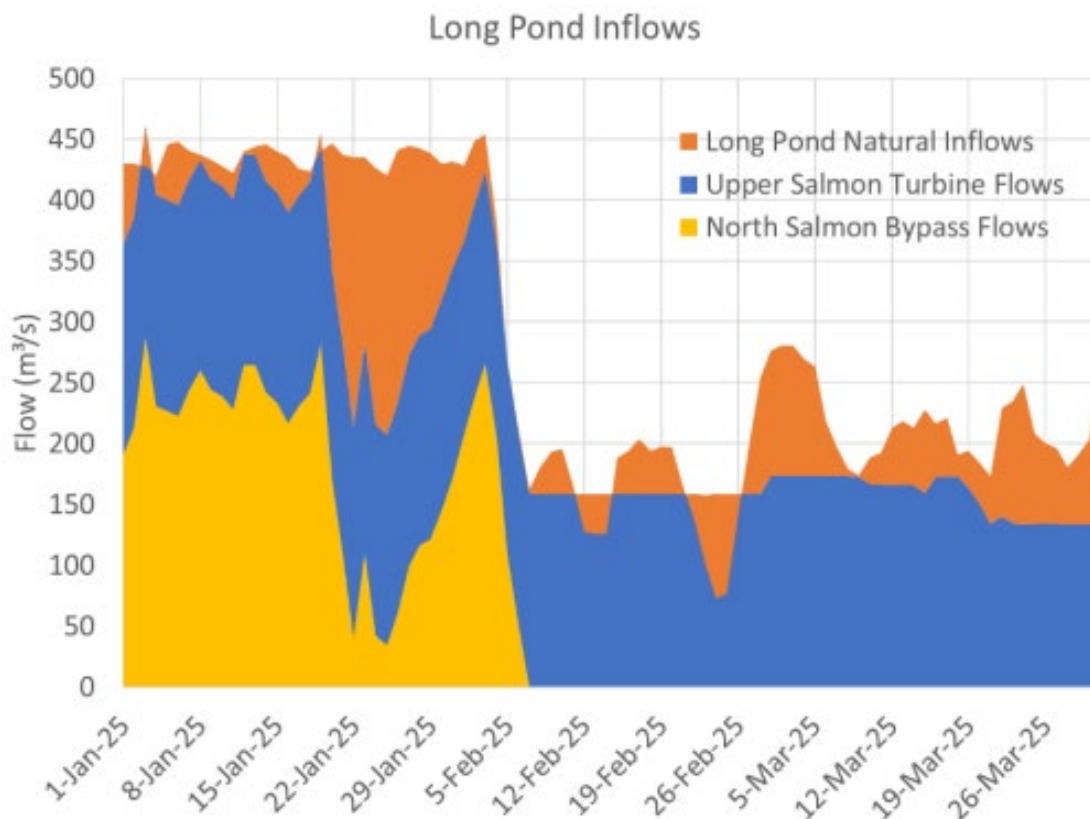


Figure 3-11 Long Pond Inflows Jan 1 to Feb 11 in the 2025 Prolonged LIL Outage model [18]

- > As can be seen in Figure 3-11 the increased inflow between January 21st and 25th relieves the flow over the Upper Salmon Spillway during that period. This raises the question of whether the higher bypass flow of approximately 250 m<sup>3</sup>/s could have been maintained for the full 6 week LIL outage.
- > The report [18] states that Long Pond requires a total inflow of 420-450 m<sup>3</sup>/s over the 6 week period (section 4 p.5) and that the control structure at Meelpag reservoir can pass up to 525m<sup>3</sup>/s.
- > As stated in Table 3-3 there is 32% of Meelpeag storage remaining at the end of the LIL outage period which corresponds to 491 Mm<sup>3</sup>. As stated in Table 3-4 the total natural inflow to Long Pond across the entire 7 months period is 225 Mm<sup>3</sup>. In spite the peak flow caused by rain and snowmelt in late January in the chosen inflow sequence, it does appear that the system has adequate storage to supply Long Pond during the LIL outage and adequate hydraulic conveyance to get the water too Long Pond continuously. See the diagram in Appendix B as a visual aid to the discussion in the last two paragraphs.
- > Even with the high flows in late January the North Salmon Spillway is actively in use with flows between 50-300m<sup>3</sup>/s (taken from Figure 3-11) over the full 6 week period (11.5% of the year). This lies in sharp contrast to the studies discussed in Section 3.3.1 which found the bypass spillway to be used "3% of the time with the addition of unit 8" ([2] page v), and in Section 3.3.4 which found that " No spilling past the Upper Salmon plant was needed during these outages in 2024 or 2032" ( [17] Section 4 p.29). This disparity between the findings of these three studies in the matter of the use of the spillways makes the conclusion of this

report [18] cited below rather surprising given the concern expressed by the Utility's staff during the call on October 3rd

- > Production from the Upper Salmon HGS and flow releases at controls structures and spillways are within their normal operational capability.([18], Section 5, Item 3, p.8)
- > Unit 8's intended purpose is to increase capacity during the 6 week outage of LIL. In order for it to achieve its intended purpose the Upper Salmon bypass will need to be used at high capacity possibly for the full 6 weeks. It is recommended that the Board seek additional reporting on the risks and constraints relating to the use of the Upper Salmon spillway for an extended period of time from the Utility.

▶ **Conclusion 3-1 – High:** This report [18] addresses the question of refill of the reservoir satisfactorily. As shown by the bottom row of Table 3-3 all three major storage reservoirs will be refilled to at least 71% capacity by the end of July.

### 3.4 Conclusions and Recommendations

In conclusion, this review of the hydrological aspects of this project has found criticalities in the hydrologic model inputs and parameters. All of the hydrological modelling was done via the proprietary Vista software and the reporting does not include enough detail of the hydrological parameters applied to the models to offer an informed opinion of their application. This section has sought to objectively review the results of these studies as best as possible with the information available and makes the following recommendations:

- > Given that this prolonged loss of LIL over a winter period is primary reason for the proposed addition of Unit 8, the issue of ice cover in this scenario should be addressed, additional measures to mitigate ice at the intakes may be required.
- > It is recommended that the Board seek additional reporting on the risks and constraints relating to the continuous use of the Upper Salmon spillway for an extended period of time from the Utility.
- > Upon any later due diligence or peer-review of matters relating to the hydrology of Bay d'Espoir Development more detailed information on the hydrologic and hydraulic properties of the system would be beneficial.

## 4 Project Cost Estimate Methodology Review

### 4.1 Introduction

It is common in the Hydropower industry to develop cost estimates and deliverables according to the requirements of the Association for the Advancement of Cost Engineering (AACE), which outline 5 classes depending on the project stages.

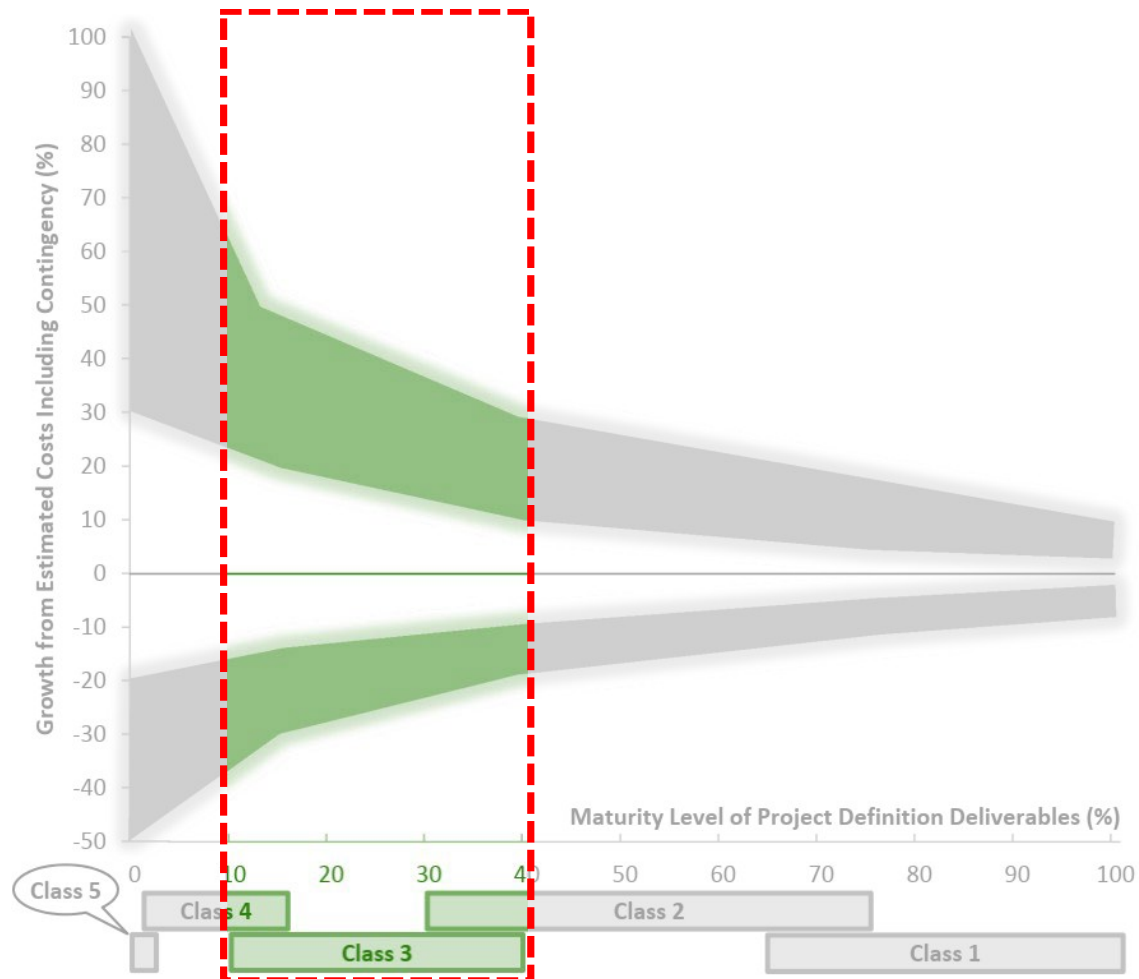
The present project was developed to meet Class 3 Estimate recommendations, which is the basis for budget authorization, appropriation, and/or funding.

### 4.2 AACE Class 3 Estimates

A short summary of the AACE Class 3 Estimates is outlined below[5].

- > Class 3 estimates are generally prepared to form the basis for budget authorization, appropriation, and/or funding. They typically become the initial control estimate against which all actual costs and resources are monitored for variations to the budget. In many owner organizations in the process industries, a Class 3 estimate may be the final estimate required and could form the only basis for cost/schedule control.
- > A Class 3 estimate typical involves a Maturity Level of typically 10% to 40% of full project definition. This typically translates to cost factoring of around -10% to 30% depending on project definition. A visual representation is shown in Figure 4-1.

Figure 4-1: Example of the Variability in Accuracy Ranges for a Hydropower Industry Estimate



#### 4.2.1 Typical Basis for AACE Class 3 Estimate

Typical Key Deliverables (Hydropower) for the hydropower industry for this estimate class are outlined below:

- > Preliminary design report complete with project description.
- > Preliminary general arrangement drawings, powerhouse, intake, and spillway drawings and specifications.
- > Essentially complete geotechnical investigations and hydrotechnical studies.
- > Preliminary earthwork drawings defining unclassified and rock excavation, rock support, and foundation treatment.
- > Complete one-line diagrams.
- > Equipment performance specifications complete for major items like turbines, generators, governors, and excitors.
- > Procurement strategy identifying long lead items of equipment.

## 4.2.2 Methodology for AACE Class 3 estimates

To provide an AACE Class 3 estimate the following approach is expected:

- > Costs are normally estimated with a deterministic approach based on quantities, with some degree of stochastic methods.
- > Normally, costs are calculated from quantities and unit cost line items.
- > Costs are quantified on an assembly level of detail.
- > Stochastic factoring is normally applied to take into account less-known areas.

## 4.3 Review of the Utility Approach for AACE Class 3 estimates

The utility followed an approach based on a deterministic approach for the quantities, based on a bottom-up approach from a design developed by Atkins Realis and presented in Schedule 4[4].

The breakdown of the estimate is provided in Table 4-1.

A Monte-Carlo analysis was undertaken to determine the appropriate level of contingency, assigning the following probabilities:

- > For project contingency to cover usual project risks a P50 value was considered. This corresponded to \$37 million (p.22 of the Basis of Estimate[4]). However, in the same Chapter of the document additional \$60 million were identified throughout the project as Design Development Allowance (DDA), which is meant to cover "*anticipated foreseeable and controllable growth in a particular work item as engineering*".
- ▶ **Conclusion 4-1 – High:** as this is a risk allowance, the total factored contingency stands at \$98.3 million, corresponding to 13.9% of the base estimate.
- > To determine additional contingency to cover risks outside the control of the Project, a P85 was chosen as a risk threshold, corresponding to \$145 million – or other 20% of the base estimate. This amount is designated as a Management Reserve, and its expenditure must be authorised by the Utility's CEO with appropriate justification and oversight[23].

The quality of the design deliverables was reviewed to confirm that they meet the minimum requirements for an AACE Class 3 estimate.

▶ **Conclusion 4-2 – High:** Although the design appears to be developed only to a feasibility level (as discussed in the following sections)—which would typically require contingencies of approximately 30% of the project budget (compared with the current 13.9%)—a lower contingency can be justified based on:

- > the largely standard design of the project, which is essentially a replica of the Unit 7 design;
- > the existence of the Management Reserve;
- > the good knowledge of the area from the utility; and
- > the operational history of the existing plant

The approach followed by Atkins Realis is appropriate for an AACE Class 3 and is in line with common practice for budget authorisation for Hydropower plants.

Table 4-1: Cost Summary from the Basis of Estimate[4]

Component	Estimated Cost (\$)
<b>Direct Construction Costs</b>	378,684,509
<b>Indirect Construction Costs</b>	193,265,409
<b>EPCM Consultant</b>	██████████
<b>Hydro Project Management</b>	██████████
<b>Subtotal Base Cost (Direct + Indirect) Estimate</b>	<b>706,890,904</b>
<b>Project Contingency</b>	37,555,691
<b>Subtotal Base Estimate (with Contingency)</b>	<b>744,446,595</b>
<b>Escalation</b>	75,795,944
<b>Interest during Construction</b>	113,799,040
<b>Subtotal Planned Budget</b>	<b>934,041,579</b>
<b>Management Reserve</b>	<b>145,179,352</b>
<b>Total Cost Estimate (Authorized Budget)</b>	<b>1,079,220,931</b>

#### 4.4 Exogenous Factor

The following exogenous factors have been considered in the Basis of Estimate [4], but their associated risk was not incorporated into the Monte Carlo Analysis to estimate Management Reserve.

- > **Delays and Escalation:** This category assesses cost increases resulting from project schedule deviations, both internal (decision-making) and external (regulatory), amplified by inflationary trends. 4 Risks scenarios are foreseen, with varying escalation factors, which could significantly increase the cost by up to ██████████
- > **Decreased Productivity:** This risk relates to labour market challenges resulting from competition, which can negatively influence the efficiency of the workforce, increasing time and material usage per task. The utility evaluated a single scenario of reduced productivity to 75% of the assumed capacity and linearly interpolated to obtain intermediate scenarios. The analysis revealed that impact on full estimate costs could reach up to approx. ██████████
- > **Tariffs and Foreign exchange** these are included to cover the consequences of likely geo-political turmoil to the market, such as potential disputes with key commercial partners for Canada (e.g. United States of America). An assessment was made by the utility, with an impact of up to ██████████.

The impact of Competing projects (like Churchill Falls Expansion and Upgrades, and the Gull Island project) was not evaluated in detail, as ultimately, their effect is deemed to be included in the Delays and Escalation.

#### 4.5 Conclusions and Recommendations

The following conclusions are made:

- ▶ **Conclusion 4-3 – High:** The methodology followed by the Utility is in line with the AACE Class 3 Estimate recommendations and in line with what is normally done in international hydropower projects.
- > In particular, the Monte-Carlo analysis on risk scenarios is a valuable tool to have a solid bottom-up contingency estimation.

- > Overall, the quality of the deliverables seems to be in line with the common practice for AACE Class 3 Estimate.

The following recommendations and risk were identified:

- > The 13.9% contingency – corresponding to \$97 million includes:
  - > \$37 million from the Monte-carlo P50 scenario
  - > \$60 million from Design Development Allowance (DDA).
- ▶ **Risk 4-1 – High:** The approach is reasonable, but to prevent misuse it is important to ensure appropriate oversight, budgeting and activation of those contingencies for covering their original purpose. More details are provided in Section 10.
- > From a top-down perspective, the 13.9% contingency (not including the Management Reserve) applied to this AACE Class 3 estimate is appropriate given the Utility's familiarity with the site and the nature of the installation.
- ▶ **Conclusion 4-4 – High:** The amount of Management Reserve seems appropriate for the project and the process to estimate is in line with the Muskrat Falls inquiry, which prescribes a probability of 85%, which prescribe to calculate it to cover a probability of 85%. However, it seems that the sensitivity analysis undertaken in Chapter 16 of the Basis of Estimate[4] is not linked to the Management Reserve. As the purpose of the Management Reserve is ultimately to ensure adequate resources are available to deliver the project, it is recommended to integrate the monte-carlo analysis to cover the emerging risks scenarios from the Basis of Estimate[4]. This could be done by introducing them separately in the monte carlo analysis with a reasonable probability to be estimated by the Utility. In particular, the scenario of 1 year of delay to completion is plausible considering the type of project.

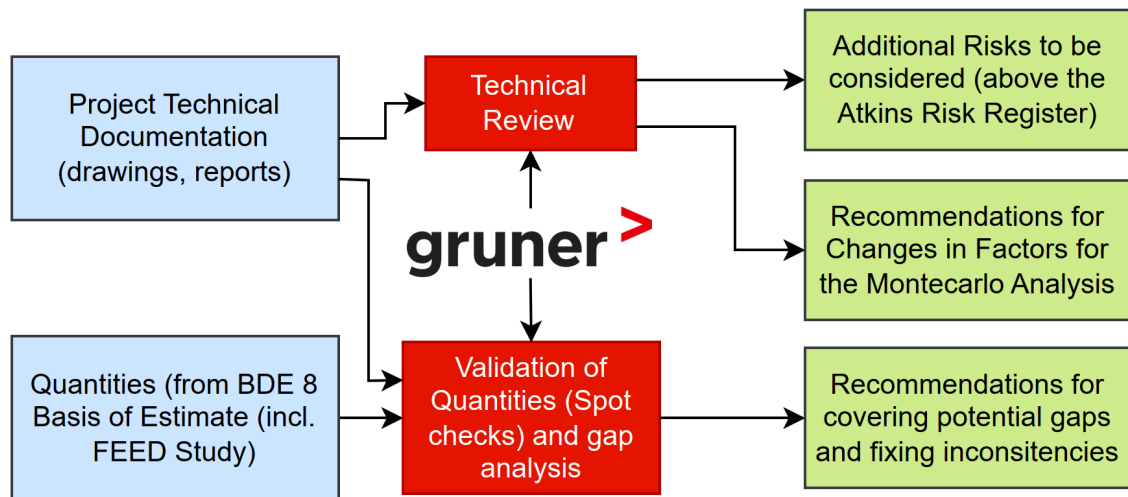
## 5 Project Costs Review

### 5.1 Gruner's Due Diligence Methodology

The methodology followed is shown in Figure 5-1. A technical review of the project based on experience is undertaken, with the aim of identifying and flagging:

- > Additional risks respect those identified in the risk register[7].
- > Identify additional scenarios for the Monte Carlo Analysis.

Figure 5-1: Methodology flow chart



- > A quantity validation exercise is undertaken aimed to cover potential gaps and fixing inconsistencies based on:
  - > Spot checks to ensure robustness of the quantities.
  - > Engineering based analysis aimed to identify if some items have been missed or neglected.

### 5.2 Monte Carlo Analysis Review

Monte-Carlo analysis is a quantitative simulation method that evaluates the range and likelihood of potential outcomes by repeatedly sampling from defined probability distributions representing key uncertainties.

Within a costing framework, it requires the explicit specification of the probability of adverse events (such as technical issues, quantities under-estimation, etc...) together with their associated financial consequences. By integrating these uncertainties across thousands of simulated scenarios, the method produces a probabilistic cost profile that provides a rigorous view of expected costs and risk. As the result of the analysis is highly dependent on probabilities and financial consequences, a review of Appendix B of the Basis of Estimate[4] is undertaken.

The following costing structure was proposed by the Utility:

- > CWA 1: Water Conveyance System (WCS)

- > CWA 2: Power Generation (PG)
- > CWA 3: Transmission Line (TL)
- > CWA 4: Terminal Station (TS2) Expansion
- > CID 1: Contractor Indirect costs
- > CWP 3.1: Owner's work

These scenarios in the monte-carlo analysis cover items such as cost increases due to more work than expected, adverse weather scenario, market price fluctuations for the lump sum items. In particular, it was observed that:

- > uncertainties in the quantity estimation were considered by increasing the amount of time for the crews to complete the work items.
- > price increase for the items to be supplied to site (for example the electro/hydro mechanical items) were covered by lump sum increases from the quotes obtained by potential suppliers.

Although the utility's approach appears sufficiently described thorough for the project, it is not clear where the probabilities of adverse events for each project element are presented. For transparency and effective sense-checking, it would be helpful if the utility provided the contingency and management Reserve results for the P85 scenario broken down by work package (CWA 1 to CWP 3.1). This would allow the financial risks associated with each work package to be compared directly with its estimated value.

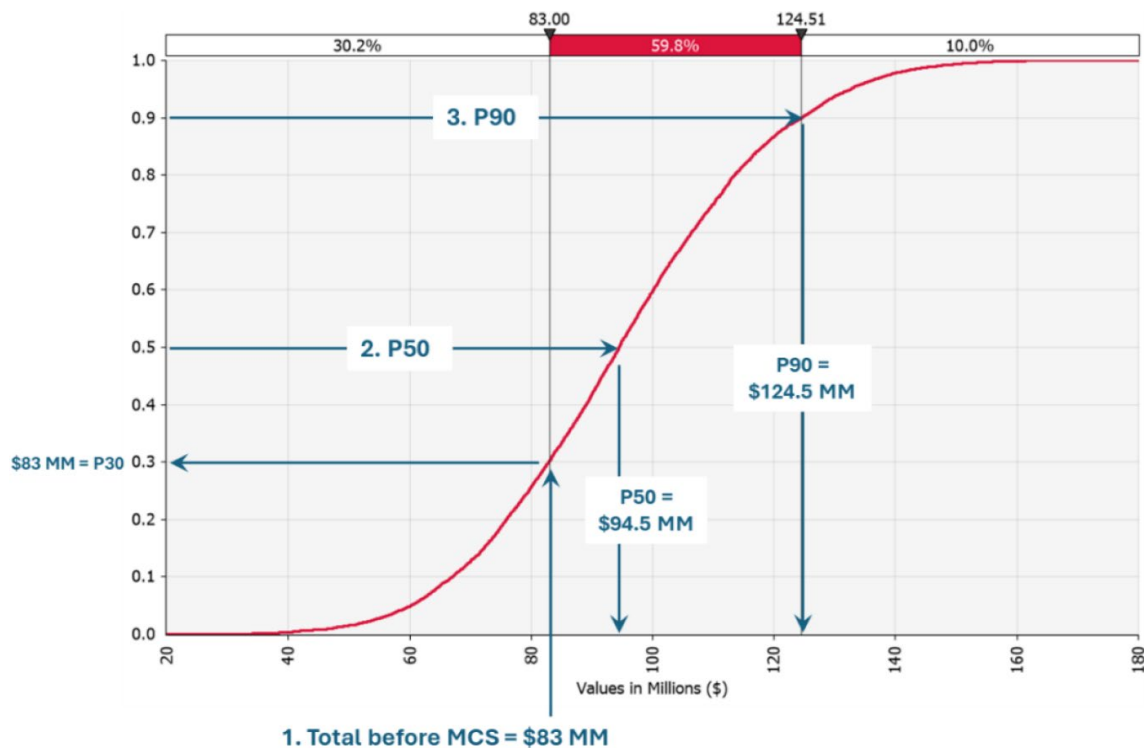


Figure 5-2: Monte-Carlo distribution for Estimating Management Reserve[4].

### 5.3 Exogenous Factors Review

Chapter 3 discussed the Utility's approach to quantifying exogenous effects and concluded that the Management Reserve (determined via the monte-carlo analysis) should be sufficient to reasonably cover any excessive project budget requirements. However, as probabilities of adverse impacts and their financial consequences were not presented in detail, a few considerations are made hereafter that could be implemented on a review of the monte-carlo analysis

#### 5.3.1 Risk Scenarios

The Utility identified the following risk scenarios:

- > Foreign currency fluctuations;
- > Escalation and inflationary risks;
- > Extension of the approval process;
- > Availability, retention and productivity of construction labour; and
- > Project coordination with an operating plant.

In particular, the Trade Disputes with the United States and fluctuations in currency exchange rates were assessed to have a potential impact of approximately [REDACTED]. This estimate was introduced as a sensitivity-testing scenario to ensure that the Management Reserve would be set at a sufficiently higher level to cover these risks.

Although the approach followed by the Utility is reasonable and conservative, a more detailed analysis of the exogenous factors could help reducing the perception of the Inflationary and Trade Disputes risks on the project.

#### 5.3.2 Inflationary Risks

The project was initially developed in 2018 and re-assessed in 2024. According to data regularly published by the International Monetary Fund (IMF), commodity and energy prices increased substantially over this period. Because the effects of these price increases are already reflected in the 2024 cost re-estimate—and given the current easing trend—it is likely that the estimates provided by suppliers and contractors are already sufficiently conservative, hence inflationary risks are expected to be low.

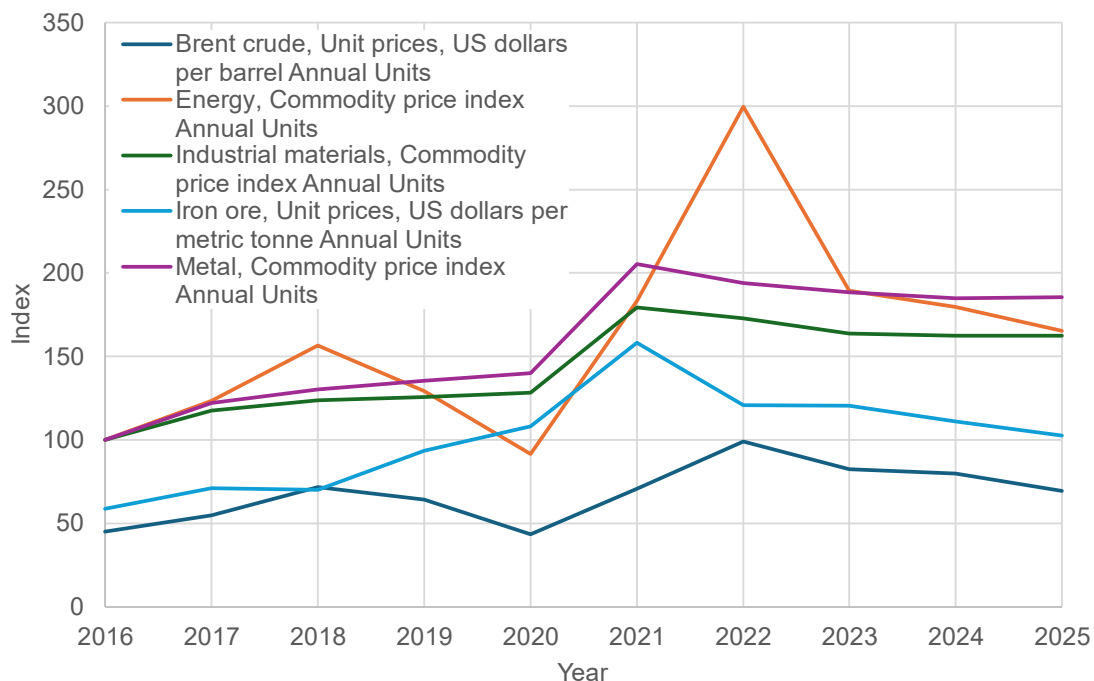


Figure 5-3: Commodity prices index according to IMF Data (<https://data.imf.org>).

### 5.3.3 Trade Disputes

Because trade disputes between the USA and Canada pose a risk to the project—particularly since hydro-mechanical and electro-mechanical equipment may be classified as steel-derivative goods—a cost increase of around 25% for these items is likely.

Unless this issue is addressed by adapting the procurement strategy and liaising directly with identified suppliers, it is recommended to include a corresponding risk scenario in the Monte Carlo analysis to account for this possibility.

## 5.4 BoQ Verification

Verification of the Bill of Quantity (BoQ) and corresponding section cost estimates was conducted based on the input data and design drawings contained in “Attachment 19 – BDE 8 Class 3 Cost Estimate and Project Execution Schedule (SNC-Lavalin, 2018).”

As a general methodology, the attached drawings for each project section—headrace channel, intake structure, penstock, powerhouse, tailrace channel, and Terminal Station 2 modifications—were reviewed against the provided cost estimate. Given the drawings are not fully detailed, expected quantities were derived using assumptions consistent with standard industry practice.

### 5.4.1 Headrace Channel

- > All calculated quantities are consistent with BoQ WBS 3.1 (44 - June 2025 - Attachment 19 - BDE 8 Class 3 Cost Estimate and Project Execution Schedule (SNC-Lavalin 2018)), with no major deviations identified.
- > The BoQ item 3.1.10 (Fencing) includes fencing works; however, no corresponding fencing layout, alignment, or structural detail are provided with the available drawings. Since the

design package does not provide any indication of fence type, length, or location, this item could not be verified or quantified. A clarification of the intended fencing scope is therefore required. The BoQ item of concern forms only [REDACTED] i.e. [REDACTED] / [REDACTED] of the overall direct cost and therefore the above-mentioned inconsistencies are evaluated to be negligible.

#### 5.4.2 Intake Structure

- > The quantities for concrete and formwork in the BoQ align with the drawings provided, with no major discrepancies noted. However, the BoQ significantly underestimates reinforcement steel, listing 148.5 t compared to an expected 320 t based on typical reinforcement ratios ( $\approx 120 \text{ kg/m}^3$ ). Despite this, the cost impact is negligible, as the reinforcement item constitutes only [REDACTED] of the total direct cost [REDACTED] even if the quantity doubles.
- > For the grout curtain (item 4.1.8), the BoQ estimates an area of 100 m<sup>2</sup>, but design drawings lack clarity on its layout and extent. A realistic estimate, based on a 100 m perimeter and 10 m depth, suggests a treated area of 1,000 m<sup>2</sup>. Despite this underestimation, the cost impact remains negligible, as the grout curtain item forms only [REDACTED] of the total direct cost [REDACTED] even if the quantity increases tenfold.

#### 5.4.3 Penstock

- > The excavation volumes for the penstock were recalculated using updated drawings, resulting in a significantly lower volume (24,297.70 m<sup>3</sup>) compared to the BoQ quantity (41,443.00 m<sup>3</sup>). This discrepancy reflects outdated alignment data in the BoQ. Financially, the BoQ excavation cost is [REDACTED] whereas the recalculated volume corresponds to approximately [REDACTED] indicating a cost difference of [REDACTED] ([REDACTED] of the total project cost of [REDACTED]). While the impact is minor at the project level, the BoQ should be updated to align with the revised design.
- > The backfill system was assessed based on trench details, with the layer labelled as riprap interpreted as a protective cover and included in the total backfill volume. Additionally, the provided reports reference sheet piling between the penstocks, but no supporting drawings or design details are available. As such, this item was excluded from the quantity calculations but should be addressed during BoQ reconciliation to ensure consistency.

#### 5.4.4 Powerhouse

- > Excavation, overburden removal, slope excavation, riprap protection, concrete demolition, wire mesh, and dowels align with the powerhouse footprint and show no discrepancies with BoQ quantities. Concrete quantities for Phase 1, Phase 2, and Phase 3, as well as formwork areas, are consistent with the structural drawings for the powerhouse.
- > Reinforcement steel in the BoQ appears to be calculated with a ratio of 100 kg/m<sup>3</sup>. However, given the powerhouse configuration (turbine pits, generator slabs, draft tube regions, and crane-supporting elements), a more realistic ratio of 120 kg/m<sup>3</sup> should be adopted to reflect the expected reinforcement demand.
- > Structural steel quantities in the BoQ for the powerhouse superstructure and embedded components seem high based on preliminary geometric reviews. Anchor bolts listed in the BoQ (e.g., Ø63.5 mm, Ø44.45 mm, Ø38.1 mm) represent minor cost impacts ([REDACTED] and [REDACTED] of the total direct cost, respectively). However, the drawings do not clearly indicate their locations, structural elements, or installation requirements. Design

clarifications or the calculation basis are needed to confirm the scope and necessity of these structural steel components.

#### 5.4.5 Tailrace Channel

- > The overburden excavation volumes (dry and wet) computed from the tailrace geometry align with the quantities provided in the SNC-Lavalin Class 3 estimate.
- > Similarly, slope protection areas (riprap in both wet and dry conditions) are consistent with the BoQ entries provided. Since the original BoQ aggregates excavation volumes as total values, the comparison was conducted on a combined basis (dry + wet), which matches the recalculated results.

#### 5.4.6 Modifications for Terminal Station 2 and the New Control Building

- > **▶ Conclusion 5-1 – Medium:** For the modifications planned for the Terminal Station 2, calculated civil works quantities do not justify the high costs in the BoQ, as the drawings indicate a much more limited scope.
- > Concrete quantities for switchyard foundations are consistent with the BoQ.
- > **▶ Conclusion 5-2 – Low:** The scope of structural steel is unclear due to insufficient details in the drawings regarding gables or supporting structures, requiring BoQ clarification.
- > Concrete and service-related quantities for the control building align with the BoQ.
- > For the control building, the cost listed under the Architectural Scope appears elevated relative to the expected value. If the figure is intended to be all inclusive—covering civil, structural, architectural, and associated works—it still trends higher than anticipated, though it may be acceptable within a conservative Class 3 estimate range. However, if the amount reflects only architectural works, it is disproportionate to the defined scope and should be considered excessive. Clarifying the cost breakdown (civil, structural, architectural, services) and the pricing basis is recommended to confirm scope coverage and reconcile the BoQ.

The total price for the Control Building (defined as Architectural Works) is [REDACTED] accounting for [REDACTED] of the total direct costs.

### 5.5 Benchmark sense-check

Since the base project estimate was developed through direct engagement with subcontractors and the assessment of production rates, it was not possible to verify the cost rates of individual components in the Bill of Quantities (BoQ) by comparison with other international projects. However, a top-down sense-check was conducted using estimates from similar infrastructure schemes in North America. Specifically, some comparable projects found in Canada are shown in Table 5-1.

Name	Budget	Scope
John Hart Dam Seismic Upgrade Project	\$923 million	The project work will include upgrades to the earthfill and concrete sections of the dam; creating an overflow spillway under the road deck near the spillway; and replacing the three spillway gates and related works.

Carillon Generating Station Refurbishment Project	\$750 million	Replacement of six generating units of a run-of-river power plant consisting of 14 generating units with a total installed capacity of 753 MW.
Rapide-Blanc Generating Station Refurbishment Project	\$613 million	Complete replacement of removable turbine (6 units of 34 MW each) and generator parts, refurbishment of all embedded components and installation of digitally controlled governor units.

Table 5-1: Comparable Hydro projects[25]

In addition to that, according to the International Renewable Energy Agency (IRENA) the North American Region had a weighted average total installed costs in the 2018–2024 period of USD 11'658/kW[26] driven by a few projects with substantial over-expensed costs.

## 5.6 Conclusions and Recommendations

### 5.6.1 Final Price, Contingency, and Management Reserve

The Utility developed the final project cost by actively liaising with potential suppliers and providing figures for lump-sum items for each work package.

► **Conclusion 5-3 – High:** While the final amount appears generally consistent with—and slightly conservative relative to—the scale of the project in the region, the following recommendations are proposed:

- > ► **Recommendation 5-1 – High:** To facilitate benchmarking against other international projects, it is recommended that the final cost per unit of installed items, as per the BoQ, be published.
- > ► **Recommendation 5-2 – Medium:** The results of the P85 Monte Carlo analysis for each Construction Work Area should be made available to support comparative assessment.
- > ► **Recommendation 5-3 – Low:** The Monte Carlo analysis did not account for potential fluctuations in international commodity markets or the effects of trade disputes. Nevertheless, from a probabilistic perspective, these factors are likely to offset each other, having minimal impact on the overall magnitude of the analysis.
- > ► **Conclusion 5-4 – Medium:** Although the Management Reserve appears relatively generous at 13.5% of the total project cost, allocating a substantial budget is consistent with recommendations from the Muskrat Falls Inquiry. Provided further details are supplied regarding its determination, the reserve allocation appears reasonable and prudent.

### 5.6.2 BoQ Verification

In this section, comments and recommendations are presented based on the BoQ verifications carried out by comparing the quantities derived from the review of the provided drawings with those contained in the report “BDE 8 Class 3 Cost Estimate and Project Execution Schedule” (SNC-Lavalin, 2018). It should be recognized that the design documentation currently available is at the concept design stage; therefore, more accurate and detailed comparisons will only be feasible upon completion of the Final/Detailed Design phases.

Within this limitation, the present comparison is intended to identify whether the submitted cost studies contain major inconsistencies, omissions, or skipped items, rather than to provide a fully definitive validation of the estimate.

- > **▶ Recommendation 5-4 – Low:** For the headrace channel, clarification of the intended fencing scope (type, alignment, length, and location) for BoQ item 3.1.10 is recommended; however, given that this item represents only [REDACTED] of the total direct cost, the associated uncertainty is considered negligible in terms of overall project cost impact.
- > **▶ Recommendation 5-5 – Low:** For the Intake Structure, the reinforcement steel quantities in the BOQ appear significantly underestimated relative to expected typical ratios; however, because the associated item represents only about [REDACTED] of the total direct cost—even if doubled—the potential cost impact is assessed as negligible, and no major corrective action is required at this stage. This case must be taken into account in the detailed design phase.
- > **▶ Recommendation 5-6 – Low:** The BOQ excavation quantity for the penstock should be revised to reflect the updated alignment and recalculated volume (24,297.70 m<sup>3</sup> instead of 41,443.00 m<sup>3</sup>); although the resulting cost reduction of approximately [REDACTED] represents only about [REDACTED] of the total project cost and is therefore minor at project level, the BOQ should be corrected to maintain consistency with the current design.
- > **▶ Recommendation 5-7 – Low:** For the powerhouse structure, the reinforcement steel quantity in the BOQ should be recalculated using a more appropriate reinforcement ratio of 120 kg/m<sup>3</sup>—rather than the apparent 100 kg/m<sup>3</sup> currently applied—to better reflect the expected reinforcement demand for turbine pits, generator slabs, draft tube areas, and crane-supporting elements.
- > **▶ Recommendation 5-8 – Low:** Design clarification is recommended for the structural steel quantities and anchor bolts in the powerhouse superstructure and embedded components, as the BOQ values appear high relative to preliminary geometry and the drawings do not clearly define their locations or functional requirements; however, given their very low contribution to total direct cost, the issue is not considered material at project level.
- > **▶ Recommendation 5-9 – Medium:** For the proposed modifications at Terminal Station 2, the BOQ civil works costs appear disproportionately high relative to the limited scope indicated in the drawings, and a revision or clarification of the cost basis is therefore required.
- > **▶ Recommendation 5-10 – Medium:** The scope and quantities of structural steel for Terminal 2 Modifications cannot be reliably verified due to insufficient detail in the drawings regarding gantries and supporting structures; clarification of the corresponding BOQ items is therefore required.
- > **▶ Recommendation 5-11 – Medium:** For the control building, the Architectural Scope cost should be clarified and its breakdown (civil, structural, architectural, and services) explicitly defined, as the current lump sum appears elevated relative to the expected scope and may be excessive if it covers architectural works only, despite being potentially defensible as a conservative Class 3 estimate if fully all-inclusive.

## 6 Water Conveyance System (WCS)

### 6.1 Headrace Channel

Three alternatives were evaluated in the BDE Unit 8 FEED – Concept Design Update Report [8] in adequate detail, named as alternative 1, alternative 2 and adjusted alternative 1.

- > Alternative 1 – entrance on south side at approx. 200m upstream of intake 3
- > Alternative 2 – entrance on north side at approx. 345m upstream of intake 4
- > Adjusted Alternative 1 – entrance on south side at approx. 200m upstream of intake 3 and providing an improved flow dynamics option.

Adjusted Alternative 1 was identified as the most feasible option as it minimizes the risk to Intake 4 and avoids the potential for an unscheduled outage of Unit 7.

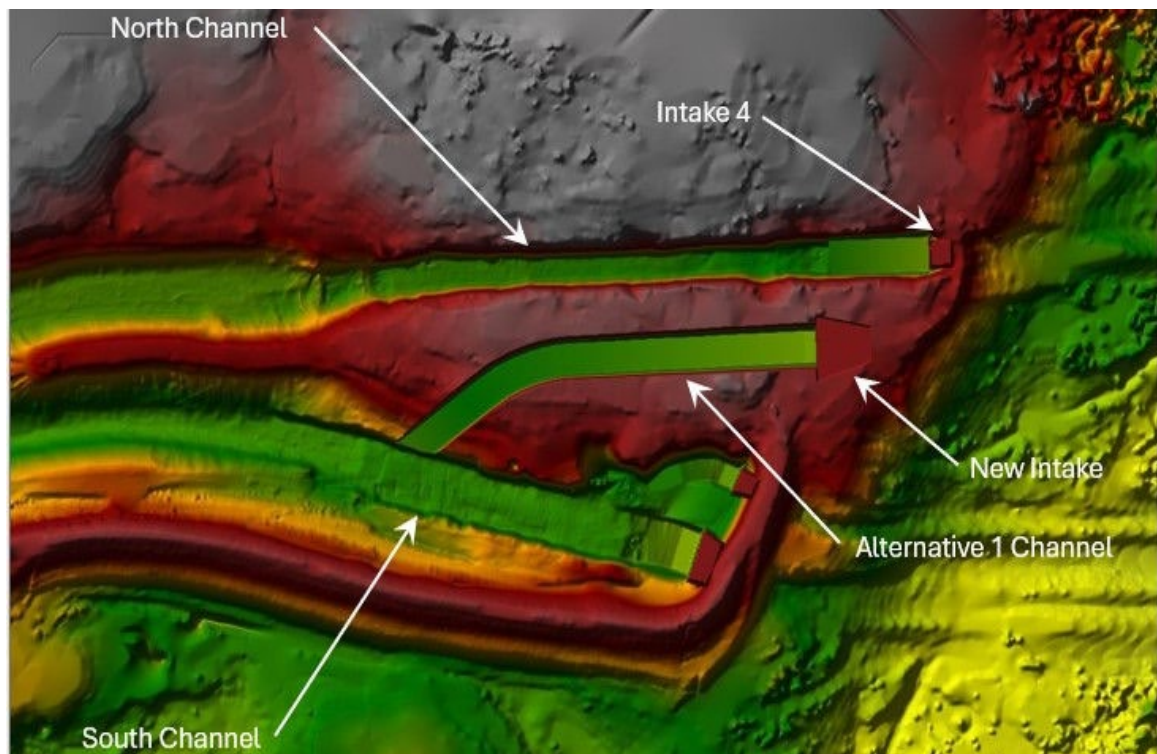


Figure 6-1 Headrace channel excavation Alternative 1, optimized.

- > The Geotechnical Investigation Report [9] primarily examines the headrace excavation along the axis of Alternative 2, but the conclusions are deemed applicable to Alternative 1 Optimized considering the proximity. According to the report, the headrace channel area features very shallow bedrock with a compact and dense thin till, implying that excavation down to the rock should be easy with some localized blasting for harder areas of the bedrock. The risk of overburden settlement is expected to be minimal, with the primary concerns being the stability of cuts and effective drainage management at the canal interface. These factors should be carefully evaluated to ensure safe and efficient excavation operations.
- > The temporary rock plug consists of fractured siltstone with zones of moderate permeability, which is expected to result in significant seepage during drilling and installation activities. To control

leakage and achieve the target seepage limits, a comprehensive grouting program will likely be required. The design of the grout curtain, including its depth and spacing, should be guided by packer test intervals to ensure effective sealing and mitigation of seepage through the fractured rock. As the works have been costed on a lump sum basis for the individual works, it is not clear whether these elements are considered.

> The hydraulic performance of the proposed channels is initially addressed in the Hydraulic analysis of the conveyance system report[10] and addressed further in the FEED Report [8]. The former identified some key risks that informed and drove the latter, namely:

- Flow velocity control: these should stay under 1.0 m/s to enable formation a stable ice cover (and avoid Frazil ice). Above 1.0 m/s there is a high probability that the ice cover would breakup and accumulate and the intake.
- It is foreseen by the Utility's consultant that velocities should be maintained under 0.65 m/s at minimum water level in the upstream part of the canal in periods when ice cover should form.

The risk of frazil is therefore fundamental for determining the shape and size of the headrace channel velocities, but risk mitigation options could be installed (e.g. Ice booms).

> In terms of wider hydraulic performance of the headrace channel / intake, although it is agreed that the quantities are reasonable and not likely to change, 2D hydrodynamic simulations are recommended between the head pond to the intakes, aimed to study:

- The effects of additional 102 m<sup>3</sup>/s on the south channel: the channel was originally designed to feed the penstocks to Unit 1 to 6 in Powerhouse 1, for a capacity of approximately 300 m<sup>3</sup>/s. Adding an additional third of capacity could have detrimental impacts on the performance of south channel, potentially reducing head and increasing erosion.
- The hydrodynamics at the connection between the South channel and the Alternative 1 Channel: a high turbulence area due to flow separation is expected at full capacity, due to preferential flow heading to the intakes to unit 1 to 6: localized erosion protection may be required.
- The effects of the additional surge in the head pond originating from the sudden operation of Unit 8.

## 6.2 Intake Civil Works

> The intake is a reinforced-concrete structure with an approximate plan footprint of 21.5 m in length by 16.8 m in width, configured as two bays whose entrance widths taper from about 12.5 m toward 6.5 m into the interior. Elevations extend from a lowest level of EL 162.4 up to a crest/operating level of EL 184.000. The installation includes a trash rack for debris interception and downstream equipment protection, a stoplog for maintenance isolation, and a service gate for operational control. The trash rack application at the entrance section is supported by a concrete pier with a thickness of 1.2 m.

> In the figures below, the plan and section views of the structure are presented.

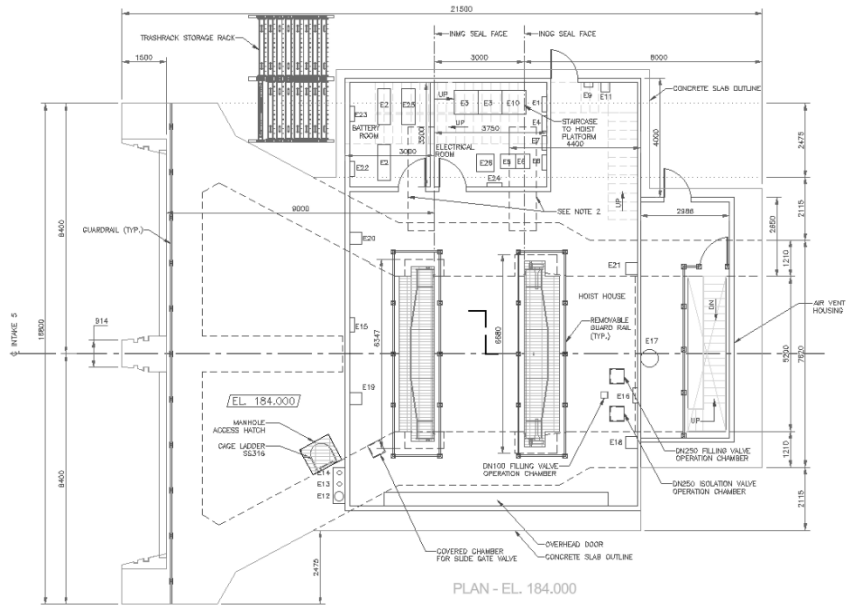


Figure 6-2 Intake structure plan view

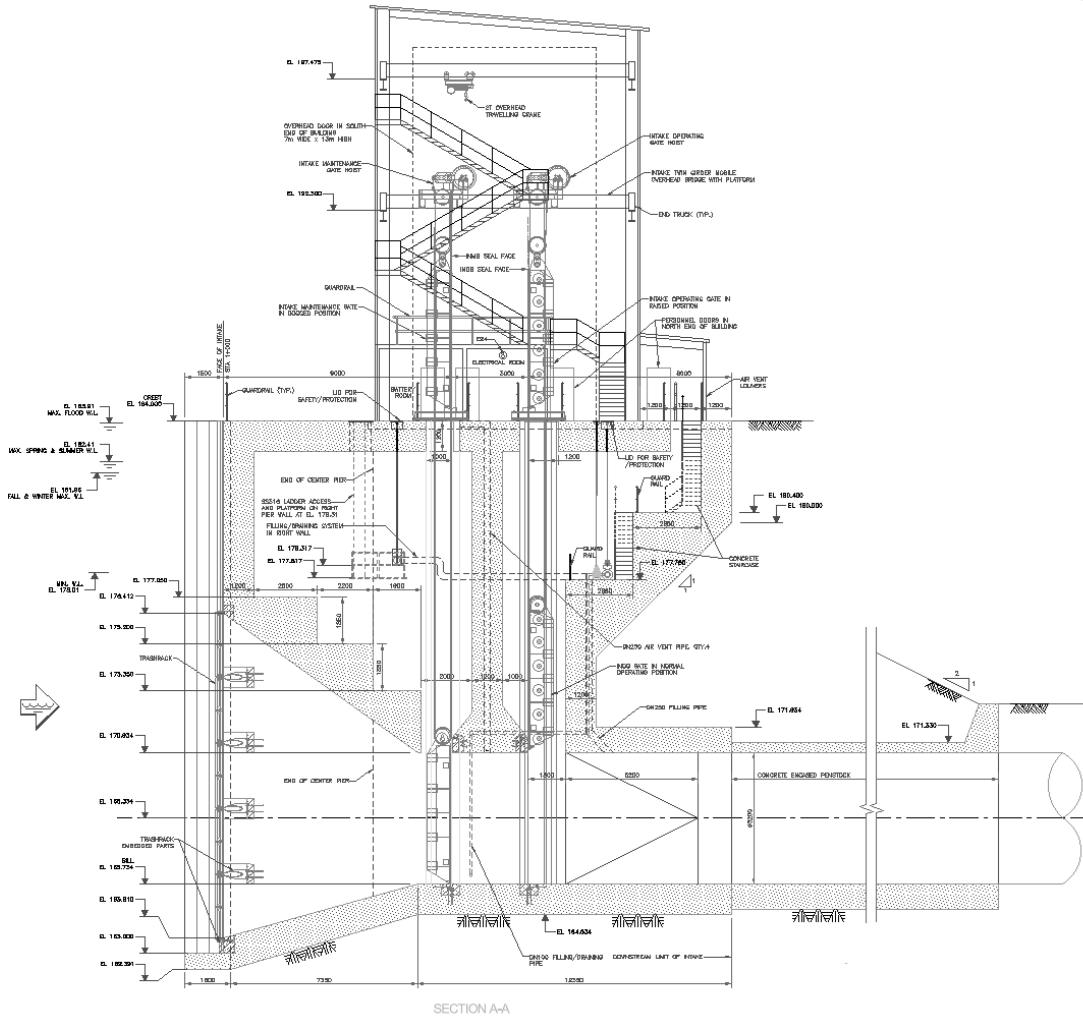


Figure 6-3 Intake structure sectional view

> Technical remarks on the structure and key items for emphasis are presented as follows:

- The intake trash rack is presumed to operate without routine cleaning; this assumption should be validated against site debris load, bar spacing, and allowable head loss.
- The gate hydraulic system should use oil that maintains functional performance at ambient temperatures down to  $-35^{\circ}\text{C}$ , with attention to viscosity grade, pour point, and seal compatibility.
- Uplift stability requires verification, particularly given the intake's elevation being 692 mm lower than comparable intakes, which may increase hydrostatic uplift and seepage; flotation factors of safety for both reservoir-full and dewatered conditions must be assessed.
- Geotechnically, the subsurface conditions at Intake Structure 5 reveal shallow bedrock with moderate weathering observed in certain areas. The foundation design should account for these conditions by anchoring the structure directly into the bedrock to ensure stability.

- The rock foundation is recommended to be established on near-surface siltstone, with acceptance criteria defined by Rock Quality Designation (RQD) and fracture mapping. Weak laminae or weathered seams should be removed and replaced with dental concrete to enhance foundation integrity. For contact grouting, fractured zones identified in core samples should be targeted, and their effectiveness verified through water pressure tests at critical elevations.

### 6.3 Steel Penstock

The project comprises a buried steel penstock approximately 1,100 m in length—about 55 m longer than Penstock 4 due to the intake's upstream relocation—with a diameter tapering from 5.20 m at the intake to 3.76 m at the spiral case connection; the alignment and profile have been reviewed and are being optimized, and the line will be routed in parallel with a centre-to-centre spacing of roughly 18.5 m. The design is specified to withstand load-rejection-induced transient pressures without reliance on a surge tank or pressure relief valve, with no resultant damage or fatigue that would compromise service life.

Technical remarks on the structure and priority considerations are as follows.

- > Without a main inlet valve or surge tank, the steel liner and global penstock design should be verified for hydraulic transients and steady-state pressures to preclude damage or fatigue in the detailed design phase
- > In a freeze-susceptible climate, burial depth should extend below the local design frost line with any additional cover and freeze-protection provisions required by code and site conditions. Where burial below the frost line is impractical or uneconomical, alternative measures—such as operational adaptations (e.g., drainage during shutdowns or maintaining a minimum flow couple hours per day) and supplemental pipe insulation—may be implemented, subject to engineering justification. These details should be taken into consideration on the detailed design phase and necessary verifications are to be addressed in reference to contemporary guidelines and standards.
- > Trench excavation and controlled blasting should be engineered to prevent adverse effects on the existing penstock at approximately 18 m centre-to-centre; recognizing bedrock constraints, controlled blasting is preferred, with sheet piles deployed only where geologic conditions make them practical.

From an engineering geology standpoint, these findings are documented. The Penstock E alignment is divided into two main sections with specific recommendations.

#### 6.3.1 Western Segment (Shallow Rock)

- > The western segment features shallow bedrock (0.4–1.8 mbgs) overlain by variable thicknesses of till (0.2–28.5 m), which transitions from loose to very dense with depth. Rootmat/topsoil and fill are present at the surface in some areas, with fill containing occasional cobbles, boulders, and construction debris.
- > Controlled blasting with pre-splitting is recommended to minimize overbreak. A bedding layer of well-graded crushed aggregate is advised to be placed over the trimmed rock.

#### 6.3.2 Central–Eastern Segment (Dense Till):

- > The central-eastern segment is dominated by thick till layers (up to >28.4 m), with bedrock encountered only in select locations or not at all in some boreholes. Surface layers include rootmat/topsoil and fill, with the fill containing similar materials as in the western segment.

- > Excavation is expected to encounter boulders and areas of refusal, where mechanical breaking may be necessary. Over-excavation is advised in areas where grade control is compromised. It is important to remove any loose or organic material from the subgrade and either recompact it or replace it with engineered granular material. Local Weak Rock (Near BH-17-23): In areas with laminated, micro-fractured rock, it is recommended to increase embedment lengths for anchors or supports. Using resin or grout with verified bond tests is suggested.

#### 6.4 Penstock Protection Works

Steel penstock design and installation should be engineered to buried-pipeline standards, explicitly accounting for soil–pipe interaction, geotechnical and hydrogeologic conditions, frost/thermal effects, corrosion control, and trench/backfill performance.

- > Given the buried configuration, the penstock must incorporate corrosion protection—external coatings and cathodic protection—integrated into both design and O&M. In the current design documents, detailed prescriptions are not existent. In detailed design phase, corrosion protection and cathodic protection must be addressed in reference to contemporary standards.
- > Settlement joints and flexibility must be provided at structure crossings; expansion joints or slip couplings should accommodate thermal and ground movements. It is evident that the existing penstock alignment withstands the movements and time-dependent deformations, but the new penstock design must also account for these factors, adhering to modern standards and design methodologies.

#### 6.5 Penstock Bridge

A concrete penstock bridge is referenced; however, detailed design data are not provided. The following points outline key technical requirements to be incorporated during definition and design.

- > The penstock–structure interface should be defined with fixed and guided supports to manage axial thrusts, with anchor blocks where needed. Local shell stress and ovalization at saddles should be verified, using wear pads or continuous saddles as appropriate.
- > Cold-region provisions should be adopted: air-entrained, low-permeability concrete; increased cover and corrosion-resistant reinforcement; sealed joints, drainage to prevent ice jacking.
- > Bearings and joints should be rated for low temperatures and sized for thermal movements. Snow/ice accretion and ice/debris impacts should be included, and de-icing or heat tracing at critical drains should be considered.
- > The penstock drawings indicate that a riprap layer, 30 cm in thickness, will be installed as the topmost layer, as illustrated in the figure below. However, the placement of large riprap rocks over the penstock may result in unforeseen consequences, such as ovalization of the penstock or potential damage to the protective layers. It is essential to implement necessary precautions, and the layering process above the penstock section must be executed with meticulous care.

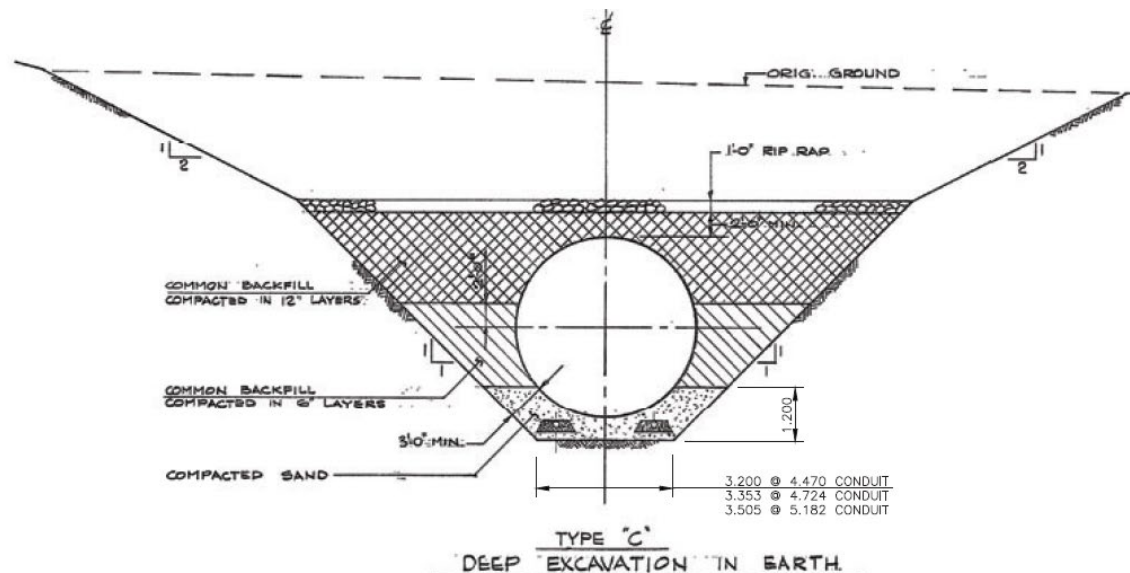


Figure 6-4 Sample penstock excavation / filling section

## 6.6 Surge Shaft or Pressure Release Valve

Similarly to the Unit 7 waterway, the Unit 8 waterway is designed without a pressure shaft. This is a reasonable design decision considering the local topography, weather conditions, and waterway length. The option will be a trade-off between installing a surge tower against foreseeing steel lining the waterway, and considering the site it will not provide significant savings to the project.

In contrast with Unit 7, Unit 8 will not be equipped with a pressure relief valve. The FEED Design recommended to avoid it by adjusting the wicket gate closing time to 16 seconds manage the water hammer pressure rise[11].

## 6.7 Tailrace Channel Widening

The current design of the tailrace excavation for Powerhouse 2 is explained to be insufficiently detailed and requires further study due to several critical factors, referring to the Bay d'Espoir Unit 8 FEED – Concept Design Update Report.

- > Firstly, the existing tailrace channel was not originally intended to accommodate the simultaneous operation of two 150 MW units, necessitating a widening that is still under review and optimization. The extent of this widening was confirmed in Report BDE-AKR-40000-CV-CAL-0001-01, received as part of RFI. However, it is to be noted that in the same report a number of recommendations are provided shared by Gruner, that need to be addressed at the early stages of Detailed Design.
- > Additionally, the expanded tailrace dimensions will need to account for backwater effects during flood conditions, ensuring the powerhouse floor remains protected during extreme hydrological events, such as a 1:1000-year inflow combined with Higher High Water Large Tide (HHWLT).
- > Furthermore, downstream flow impacts, including conditions extending to the Highway 361 bridge, have not been fully investigated, highlighting gaps in previous studies. These unresolved factors underscore the necessity for more comprehensive modelling and analysis to optimize the tailrace design and ensure operational reliability under varying conditions.

- > For tailrace expansion region, where soft, cohesive, fine-grained soils are experienced it can be better to prioritize controlled consolidation and stability by using preload/surcharge with wick drains where the schedule permits.
- > Dewatering should be managed through staged excavation with perimeter drains and sumps, and it might be better to avoid aggressive drawdown to limit softening.

## 6.8 Conclusions and Recommendations

The following Conclusions and Recommendations are made:

- > The evaluations conducted for the project components emphasize critical considerations and preferred approaches for successful implementation.
- > **Conclusion 6-1 – Medium:** For the headrace channel excavation, the adjusted version of Alternative 1 is deemed the most feasible option by the previous studies carried out by AtkinsRéalis [11] and also approved by Gruner due to its improved flow dynamics, reduced underwater work, and minimized risks to existing infrastructure. This alternative also avoids potential disruptions to Unit 7 operations and ensures a safer construction process.
- > **Risk 6-1 – Medium:** The risk of frazil ice formation is a key consideration in defining the headrace channel geometry and operating velocities; however, this risk can be mitigated through the implementation of appropriate ice-management measures (e.g., ice booms or similar control structures). Although the BoQ quantities for the headrace channel and intake are considered reasonable,
- > **Recommendation 6-1 – Medium:** 2D hydrodynamic simulations from the head pond to the intakes are recommended to:
  - (i) assess the impact of the additional 102 m<sup>3</sup>/s on the south channel (including potential head losses and erosion),
  - (ii) evaluate turbulence and localized erosion risk at the junction between the south channel and the Alternative 1 Channel, and
  - (iii) investigate the effects of surge in the head pond arising from sudden operation of Unit 8, so that any required hydraulic or erosion protection measures can be defined.
- > **Recommendation 6-2 – Medium:** The intake civil works require careful attention to trash rack functionality, hydraulic system performance under extreme temperatures, and uplift stability to address hydrostatic and seepage risks. Proper validation and design adjustments are essential to ensure operational efficiency and structural safety.
- > **Recommendation 6-3 – Medium:** The steel penstock design must account for transient and steady-state pressures without relying on surge tanks, while also addressing burial depth requirements and controlled blasting to prevent damage in freeze-prone conditions. Corrosion protection, settlement joints, and flexibility for ground movements are vital for the penstock's long-term reliability and performance.
- > **Recommendation 6-4 – Medium:** For the penstock bridge, provisions for cold-region conditions, stress management at supports, and measures to mitigate snow and ice impacts are critical for maintaining structural integrity. Additionally, proper layering and precautions are necessary to prevent damage to protective layers during riprap installation
- > **Recommendation 6-5 – Medium:** Finally, the tailrace channel widening requires further modelling and analysis to optimize its design. This includes addressing backwater effects,

ensuring compliance with submergence requirements, and protecting the powerhouse floor during extreme hydrological events. Comprehensive studies are needed to ensure operational reliability under varying conditions. The existing tailrace channel, not originally designed for concurrent operation of two 150 MW units, requires widening that remains under review; the final extent should be confirmed through hydraulic modelling to minimize head losses while maintaining adequate submergence for Units 7 and 8 at Lower Low Water Large Tide (LLWLT), currently defined using the average minimum yearly tide from 19 years of data, combined with a typical plant load and typical stream inflows. In case concerns are present regarding sufficient submergence, operational rules could be evaluated to mitigate the issue (such as using the other units during extremely low tides). The widened tailrace must be sized to account for backwater effects under flood conditions, ensuring the powerhouse floor remains protected for events up to at least the 1:1000-year inflow in combination with the Higher High Water Large Tide (HHWLT). Downstream hydraulic impacts, including conditions up to the Highway 361 bridge, remain insufficiently assessed, indicating gaps in prior studies and necessitating more comprehensive modelling to optimize the tailrace design and ensure reliable operation across a full range of flow conditions [7]. For the tailrace expansion, preload/surcharge with wick drains should be used where schedule allows to promote consolidation and stability in soft, fine-grained cohesive soils, and dewatering should rely on staged excavation with perimeter drains and sumps, avoiding aggressive drawdown to limit softening.

- > ► **Recommendation 6-6 – Medium:** For the temporary rock plug, a comprehensive grouting program (including a grout curtain with depth and spacing informed by packer test results) should be explicitly defined and confirmed in the scope, as significant seepage through fractured siltstone is anticipated; given that the related works are priced on a lump-sum basis, clarification is required to verify that all necessary seepage control measures are adequately covered in the BoQ.
- > ► **Recommendation 6-7 – Medium:** The powerhouse rock foundation should be established on near-surface siltstone meeting defined RQD and fracture-mapping criteria, with weak laminae and weathered seams removed and replaced with dental concrete, and contact grouting targeted to fractured zones identified in core logs, with post-grouting water pressure tests at critical elevations used to verify seepage control and foundation integrity.
- > ► **Recommendation 6-8 – Medium:** In the absence of a main inlet valve or surge tank, the steel liner and penstock must be verified for hydraulic transients and steady-state pressure envelopes during detailed design to avoid overstress and fatigue.
- > ► **Recommendation 6-9 – Medium:** In a freeze-susceptible climate, pipeline burial depth should extend below the local design frost line, with any additional cover and freeze-protection measures required by applicable codes and site conditions verified and incorporated during detailed design in accordance with current guidelines and standards.
- > ► **Recommendation 6-10 – Low:** Trench excavation and controlled blasting must be engineered to avoid adverse effects on the existing penstock ( $\approx 18$  m centre-to-centre), with controlled blasting adopted as the primary method and sheet piles used only where geologic conditions render their installation practical. For the penstock alignment, controlled blasting with pre-splitting should be adopted to limit overbreak, and a bedding layer of well-graded crushed aggregate should be placed over the trimmed rock surface. Penstock excavation should account for boulders and refusal, with over-excavation where grade control is lost and loose/organic subgrade replaced with engineered fill; in weak laminated or micro-fractured rock (e.g., near BH-17-23), anchors and supports should have increased embedment and use resin or grout with verified bond strength.
- > For the penstock bridge, for which no details are prepared in this stage, as general recommendations,

- > ► **Recommendation 6-11 – Low:** (i) The penstock–structure interface should be detailed with fixed and guided supports to manage axial thrusts, with anchor blocks where required, and local shell stresses and ovalization at saddles verified, incorporating wear pads or continuous saddles as needed.
- > ► **Recommendation 6-12 – Low:** (ii) Cold-region detailing should include air-entrained, low-permeability concrete, increased cover with corrosion-resistant reinforcement, sealed joints, and drainage to prevent ice jacking; bearings and joints must be rated for low temperatures and sized for thermal movements, with snow/ice accretion, ice/debris impacts, and potential de-icing or heat-tracing at critical drains addressed.
- > ► **Recommendation 6-13 – Low:** A 30 cm riprap cover over the penstock should be detailed with an appropriate cushioning and backfill layering system, and installed with controlled placement methods, to prevent ovalization of the steel shell and damage protective coatings.

## 7 Power Generation (PG) Extension

### 7.1 Powerhouse Extension Major Works

#### 7.1.1 General Evaluation

The project entails a Powerhouse #2 extension to accommodate the new unit, integrating the existing draft tube gate infrastructure originally constructed for Unit #8 and providing a dedicated maintenance bay of comparable size to the current Powerhouse #2 bay. Material and structural systems will mirror the existing facility—reinforced concrete foundations, a steel superstructure, and concrete panel cladding—to ensure continuity of performance and detailing. Existing overhead crane rails and the draft tube deck monorail will be extended to service the new unit, supplemented by a new service elevator to support construction, operations, and maintenance for both units within Powerhouse #2.

The extension is to be designed for a 100-year service life, with durability, maintainability, and asset-integration provisions aligned to that horizon.

Plan and section views are furnished as representative depictions of the structural layout; elements shown in green denote new construction, while elements in grey indicate existing structures.

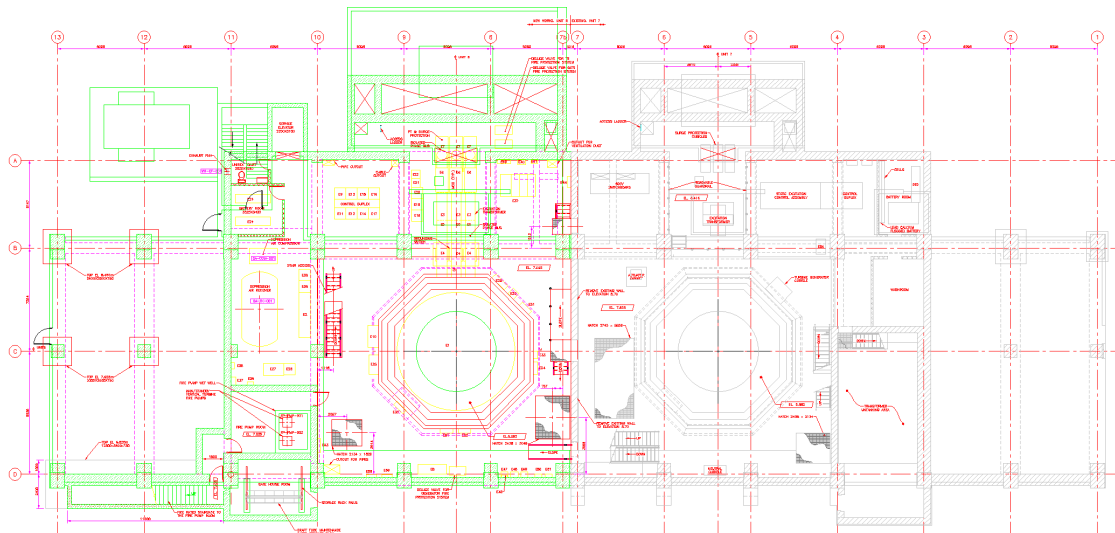


Figure 7-1 Powerhouse plan view

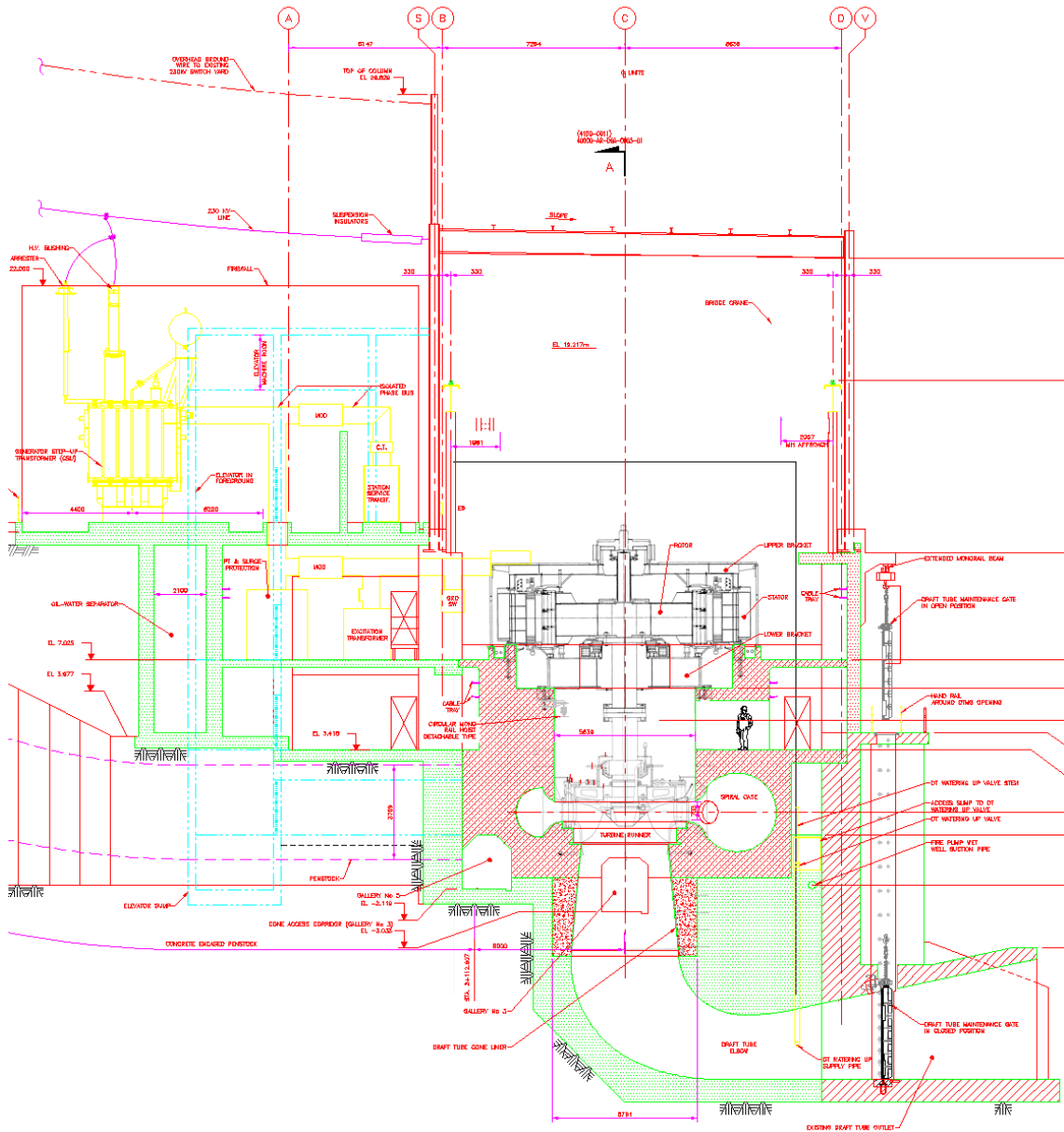
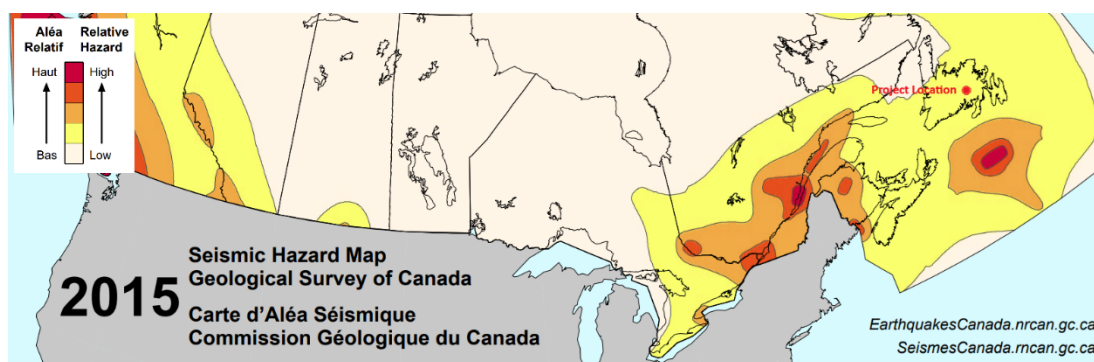


Figure 7-2 Powerhouse sectional view

- > The following optimisations are suggested with the aim of reducing costs, as they are redundant:
  - An existing erection bay is available for Unit 7; therefore, a dedicated erection bay for the planned Unit 8 may not be required, and the planned Unit 8 erection bay should be cancelled, subject to confirmation that lifting capacity, access clearances, and schedule logistics are satisfactorily met using the Unit 7 facility.
  - The previous powerhouse unit (Unit 7) operated without an elevator; accordingly, the elevator for the new Unit 8 may be omitted, provided that regulatory and safety requirements are met.

- A new dedicated fire pump for Unit 8 may not be required provided the existing Unit 7 fire pump system is evaluated and, if necessary, upgraded to meet the combined design demand (flow, pressure, and duration) for Units 7 and 8.
- > While the Bay d'Espoir Unit 8 Project Evidence targets a 100-year design service life for the new Powerhouse, the Infrastructure Assessment Report sets a practical 25-year refurbishment horizon for the 45-year-old existing structure. Accordingly, sustaining performance over this refurbishment period relies on periodic condition monitoring and timely repairs, with particular focus on legacy structural elements.
- > A Powerhouse finite-element model capturing the existing structural parts must be prepared and analysed to verify the capacity and deformation characteristics of the new, combined structure.
- > The cut next to the Powerhouse shows variable bench widths with some talus; differential weathering zones are visible. Overall slope and excavation stability for the construction area under operational and transient conditions must be taken into consideration (construction stages, drawdown, seismic, and extreme rainfall) using updated material parameters and groundwater regimes.
- > Time-dependent deformations in the existing structural part of the planned Powerhouse (creep, shrinkage) and prior differential movements are expected to have introduced minor interface geometry deviations; small misalignments at connection surfaces can be anticipated. These misalignments and geometrical differences must be followed, and the construction process detailing should be progressed accordingly.
- > In cases of misalignments or differential movements, injection grouting can be applied as necessary following appropriate monitoring and evaluation.
- > One vertical crack through draft-tube divider wall ( $\leq 6.5$  mm ROV manipulator could not enter; likely  $< 6.5$  mm, interpreted as construction shrinkage). Divider is not a primary pressure boundary; limited structural implication but should be monitored and mapped.
- > The site is a seismically low-intensity area; the peak ground acceleration (PGA) for a 2% in 50-year event (return period 2475 years) is  $0.085g$ .<sup>2</sup>
- > On the other hand, it is still important to highlight that the project site is located near an active seismic zone. Consequently, heightened seismic activity should be considered in the assessment to mitigate potential adverse outcomes. The proximity of the site to the seismic region is illustrated in the figure below. For the tailrace concrete wall, it is recommended to verify that seismic design standards have not changed over time, as any changes may require the existing structure to be upgraded during retrofitting works, resulting in extra costs.



<sup>2</sup> Geological Survey of Canada Open File 4459 - Seismic hazard design values, [www.earthquakescanada.nrcan.gc.ca](http://www.earthquakescanada.nrcan.gc.ca)

Figure 7-3 Seismic Map of Project Location (T: 2475 years)

- > Investigations near the existing excavation for the Unit 8 Powerhouse reveal shallow overburden transitioning quickly to competent sedimentary bedrock. The overburden consists of thin layers of fill or till with variable composition and limited thickness. Standard Penetration Test (SPT) results indicate high resistance or refusal at shallow depths, consistent with near-surface bedrock. Groundwater data is limited but suggests potential perched water or shallow seepage along excavation faces and local drainage paths.
- > The bedrock consists of slightly weathered, dark grey to black metamorphosed siltstone with pervasive quartz and calcite veining. It exhibits significant deformation characterized by extensive micro-fractures and millimetre-scale laminations, resulting in a disc-like pattern in the recovered core samples. Due to the insufficient length of intact core in BH-18-23, unconfined compression strength testing could not be performed. Strengthening measures and deformation mitigation techniques should be carefully evaluated during the detailed design phase and deformation evacuation techniques must be evaluated in detailed design.
- > It is recommended to design foundations to bear directly on competent bedrock where possible, avoiding reliance on the thin and variable overburden near excavation edges.
- > Where overburden cannot be avoided, it is advisable to place a layer of properly compacted, high-quality structural fill over a geotextile separation layer, with working platforms verified by plate load or CBR testing in areas of expected construction traffic.
- > For temporary excavation support, it is suggested to adopt conservative slope angles or employ rock support measures (such as rock bolts, mesh, or shotcrete) in areas with jointed or weathered zones, incorporating benching to interrupt potential sliding planes.

## 7.2 Mechanical Components

### 7.2.1 Crane Rails

The crane rail currently installed in the Unit 7 powerhouse will be extended to the newly constructed Unit 8 powerhouse. An expansion joint is provided between the two structures to allow independent movement of their superstructures; however, this cannot be applied to the crane rail to ensure continuous operation. Therefore, the design must account for the differential movement between the old and new structures, both horizontally and vertically (including differential settlement), and appropriate precautions must be implemented. Additionally, the bearing systems on the corbels must be designed accordingly.

### 7.2.2 Powerhouse Structural Steel Superstructure

The steel superstructure consists of a series of vertical columns, horizontal beams, and diagonal bracing elements arranged in a grid-like framework. It is designed with multiple bays supported by evenly spaced vertical members, which are connected by horizontal beams at various levels to provide structural stability. The diagonal bracing within each bay enhances rigidity and resistance to lateral forces. The structure includes designated openings and access points, with provisions for staircases and platforms. The layout follows a modular design, ensuring uniformity and ease of assembly. The figure below illustrates the structural framework of the superstructure (red).

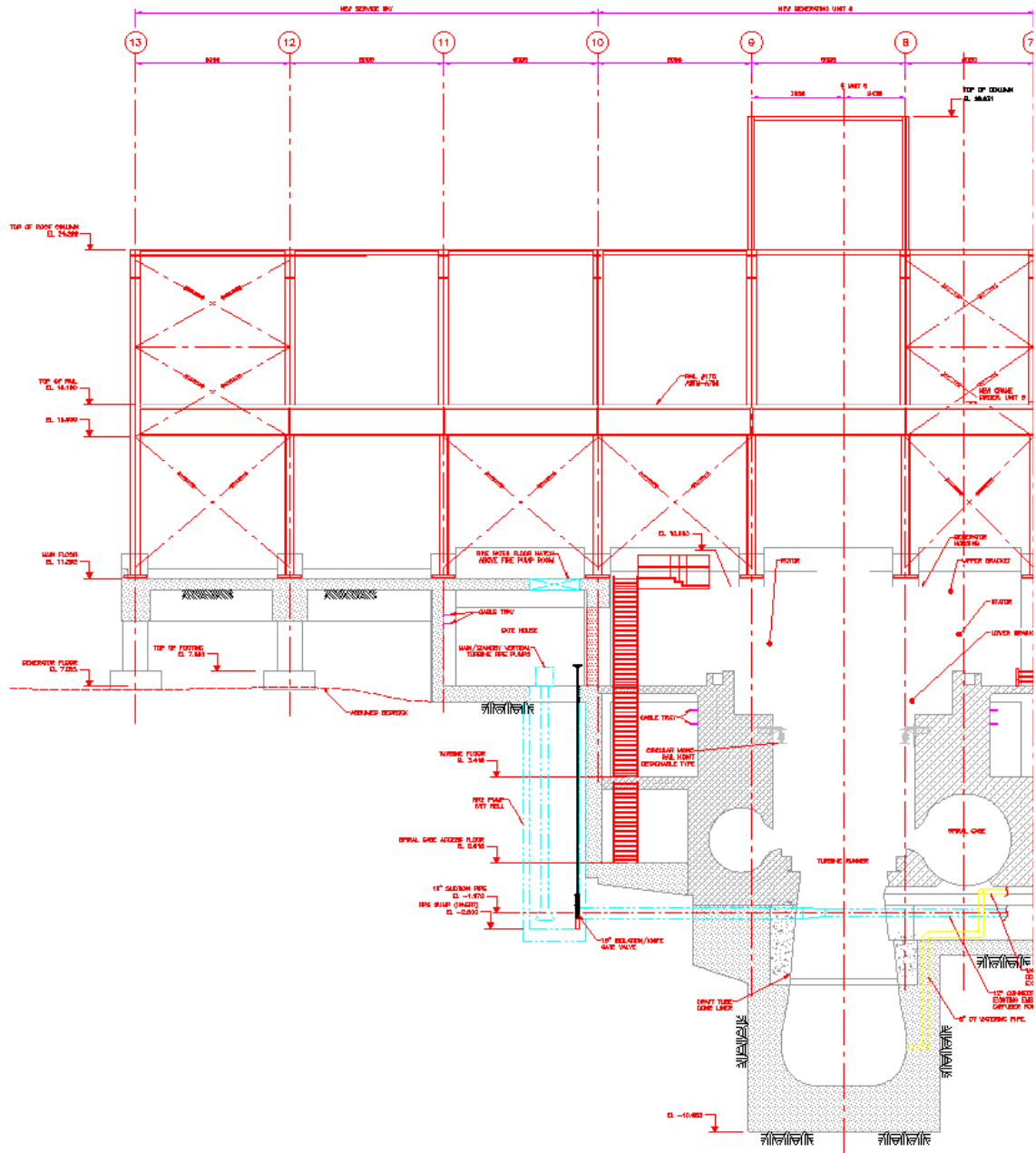


Figure 7-4 Powerhouse steel superstructure presentation

The steel superstructure of Unit 8 is planned as an extension of the existing Unit 7, which has been in service for over 45 years since its construction in 1977. Given the satisfactory performance of the existing structure under operational conditions, this approach is both logical and expected. It should be noted that any details about the structural design calculations are not present in this phase, the design is to be verified.

However, the new structure must be designed and evaluated in compliance with modern structural codes, particularly the updated loading requirements. Additionally, the structural integrity of the

existing Unit 7 must be assessed to identify any areas requiring refurbishment. The design of the new superstructure should incorporate the latest data on climatic conditions in the Newfoundland region, with particular emphasis on cold weather performance and resilience.

### 7.2.3 Draft Tube, Spiral Case

#### Draft Tube

The downstream portion of the draft tube for Unit 8, including the draft tube outlet, the division pier, the downstream wall up to the draft tube deck, and the embedded guide slots for the draft tube gates, was constructed during the original Powerhouse 2 development. This pre-built section was intentionally completed to enable future expansion without disrupting Unit 7 operation. As a result, the fundamental geometry of the draft tube, comprising the outlet dimensions, invert elevation, and overall passage configuration is fixed and cannot be altered without major demolition and extensive rock excavation. Modern hydraulic assessments indicate that the inherited geometry generates additional head losses compared to contemporary draft tube designs; however, modifying it is not feasible due to structural risks, potential destabilization of the existing unit, and the need for a large downstream cofferdam.

For Unit 8, the new draft tube works will consist primarily of the steel-lined cone section and the elbow transition connecting the circular turbine discharge to the rectangular pre-constructed outlet. These components will be embedded in second-stage concrete designed to align precisely with the existing draft tube structure and maintain hydraulic continuity. Limited improvements, such as adding downstream concrete panels to reduce recirculation through the gate slots, may be implemented to mitigate part of the inherited head loss. The installation sequence must ensure proper fit-up with the previously constructed outlet while avoiding any loading or vibration that could compromise Unit 7. All new components must maintain compatibility with the embedded parts installed in the earlier construction phase and be detailed to accommodate differential settlement between the old and new powerhouse structures.

#### Spiral case

Available documentation provides only limited information regarding the spiral case. The 2018 Unit 8 Summary Report describes the installation method, noting that the steel spiral case is designed for 100% service pressure, tested at 125% including water hammer, and embedded in second stage reinforced concrete, which is placed under approximately 60% of the maximum internal pressure. The hydraulic analysis further indicates that the penstock tapers to a diameter of 3.76 m at the spiral case inlet, implying the entry size of the scroll case.

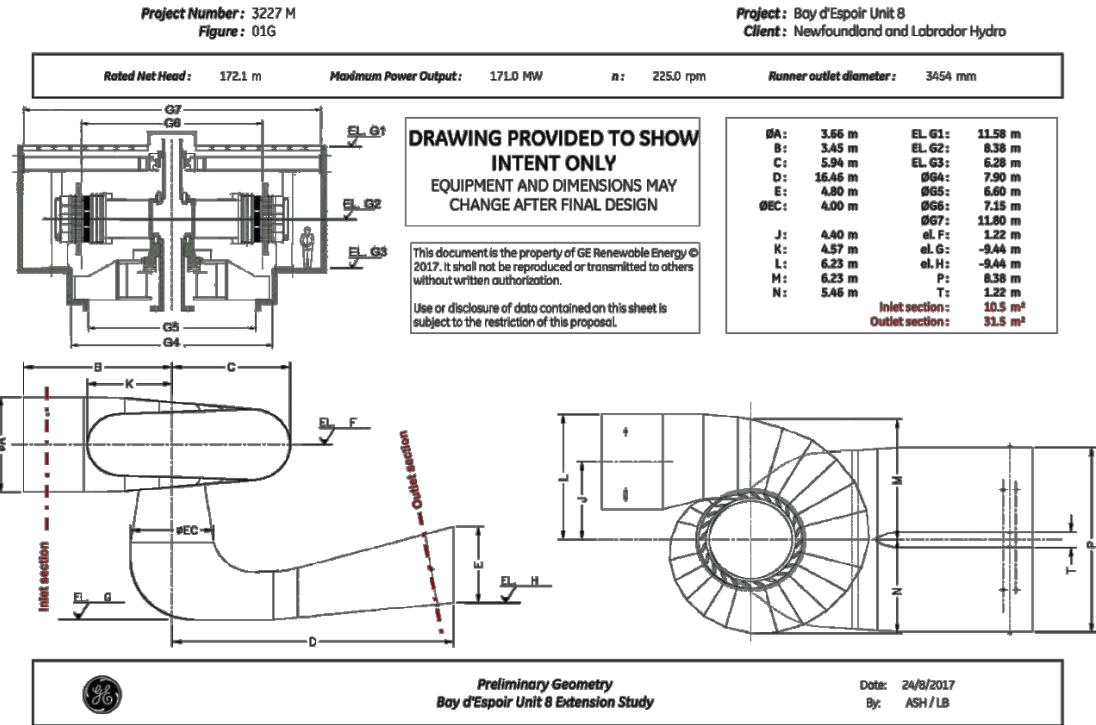


Figure 7-5: Draft tube and spiral case main dimensions (Class 3 cost estimate and project execution schedule, client's documentation)

The drawing presents the principal dimensions of the spiral case and draft tube.

For the spiral case, the key parameters include the inlet cross-section (4.40 m, 4.57 m), spiral case Inlet diameter 3.66m, the maximum outer radial width of the spiral case is 6.23 m. The total axial length of the draft tube including the outlet transition is 8.38 m.

For the draft tube, the drawing specifies the total draft tube length (16.46 m), as well as the draft tube outlet diameter of 4.80 m. Elevation levels EL.G1, EL.G2 and EL.G3 define the vertical positioning of the draft tube relative to the turbine pit.

These dimensions represent the standard geometric parameters required for describing the hydraulic envelope and installation layout of both components.

### 7.2.4 Draft tube Gates

Two new vertical-lift draft tube gates shall be provided for Unit 8, utilizing the pre-constructed embedded guides and structural components installed during the original Phase 3 works. These guides shall enable full isolation and safe watering-up of the draft tube, while the new pipework and valves shall ensure balanced-pressure conditions during gate insertion and removal. Earlier studies considered different sealing arrangements and gasket configurations; however, the latest design documentation confirms the adoption of a downstream-sealing gate consistent with operational requirements and the established Unit 7 concept.

The system shall require an extension of the monorail hoist to service both units, along with a dedicated storage room, dogging devices, and lifting provisions sized to safely handle the gates under submerged-load conditions. The design must ensure proper alignment with the existing concrete

geometry and maintain reliable operation while accommodating differential movement between the new powerhouse extension and the existing Unit 7 structure.

## 7.3 Electric Components

### 7.3.1 Synchronous Generators

The new Unit 8 is planned to be equipped with a Francis type turbine directly connected to a synchronous generator with the generator rated output of 154.4 MW at rated net head.

The generator is planned to be a vertical axis type with an output of 172 MVA, power factor of 0.90, 60 Hz, 13.8 kV, 3 phases, star connected, with a high resistance grounded neutral.

Stator windings are planned to be of the bar type, with bus bars transposed by the Roebel method. Bar lifting and replacement will be possible without removing the rotor or other major component

The stator and rotor insulation is planned to be class F and the operating temperature will be less than 105°C. The cooling will be provided through air-water heat exchangers.

The generator is planned to be a synchronous machine capable of being operated as a synchronous condenser.

BDE Unit 8 is expected to add an additional 150 MW of capacity to the provincial grid. However, the rated capacity of the generator may be improved through design optimizations during the engineering/procurement phases.

It is planned to be incorporated into the existing IIS (Island Interconnected System) and comply with NERC (North American Electrical Reliability Corporation) and the Utility's standards for grid-connected generating equipment.

Unit 8 is planned to be designed to be operated in a regime analogous to the historical operating patterns of Unit 7 between April 2023 and April 2025. This period was chosen as one when the LIL (Labrador Island Link) was in reliable operation and COVID effects were negligible.

Synchronous condenser capability is planned to be added to the Unit 8 to allow the generator to export or import the full range of reactive power within the capability of the generator. Unit Control System is planned to interface with the excitation system to start, operate, and stop the synchronous condenser mode operation. The air depression system is planned to be provided to depress the water in the draft tube and run the generator in the condenser mode.

The generator is planned to have a minimum design life of 65 years.

### 7.3.2 Excitation System

The excitation system is planned to be of the static type, with manual and automatic modes of operation and designed to satisfy the generator's excitation requirements. The system is planned to include an excitation transformer and a Unitrol type voltage regulator. The excitation system and excitation transformer is planned to be located on the generator floor.

The system is planned to utilize common spare parts and design similarities with the existing Unit #7 exciter wherever feasible and practical.

The system is planned to comply with the current relevant industry and the Utility's standards.

The exciter is planned to have a minimum design life of 32 years.

### 7.3.3 Generator Voltage Equipment and Connections

An isolated phase busducts (IPBD) assembly is planned to connect the generator to the power transformers. The IPBD and associated equipment is planned to be located on the generator floor. The physical arrangement is planned to be like Unit #7 equipment with the generator grounding switch, taps to the excitation transformer, main disconnect switch, potential transformer and surge protection cubicle located on the generator floor.

The IPBD is planned then to go up to the level of the generator step-up transformers outside the powerhouse, with also a tap connection to the station service transformer disconnect switch and station service transformer.

The IPBD is planned to be rated at 13.8kV, 8000A, 100kA short-circuit, app 38m/phase and are planned to be of the natural cooling type.

The potential and surge protection cubicle is also planned to include a grounding switch and a main disconnect switch for the surge arresters and the surge capacitors.

### 7.3.4 Generator-Step-up (GSU) Transformer

The GSU transformer is planned to be an oil filled, three-phase, 129/172 MVA (ONAN/ONAF), 13.8 kV/230 kV, bushing type power transformer for outdoor installation, with a wye connected cooper winding on the high voltage side and a delta connected cooper winding on the low voltage side.

The transformer will also be equipped with a de-energized type of tap changer on the high voltage side, an oil expansion tank and a compartment on the low voltage side to connect to the IPBD.

The GSU transformer will be located outside on the upstream side of the powerhouse. An oil recovery basin will be provided under the transformer with fire walls on two sides between Unit #7 GSU transformer and station service transformers.

The GSU transformer is planned to be designed to meet current relevant industry and the Utility standards for outdoor Power Transformers.

The exterior dimensions are planned to be essentially the same as the existing Unit 7 GSU transformer to facilitate interchangeability of spares.

The GSU transformer is planned to have a minimum design life of 55 years.

## 7.4 Mechanical Balance of Plant

### 7.4.1 Cooling System

Cooling water for Unit 8 is planned to be supplied from the raw water system, with the raw water tap taken from the top of the makeup piece between the Unit 8 pressure conduit and the spiral case. The tap is equipped with an isolating valve, two pressure-reducing valves, a self-cleaning motorized strainer and a bypass with a manually cleaned strainer, with the raw water filtered to retain particles larger than 0.8 mm; the backwash from the self-cleaning strainer is planned to be re-routed to the Unit 7 powerhouse drainage sump.

The raw water system is planned to supply the T/G cooling water system and the shaft seal water system, while the cooling water system shall provide water to the generator air coolers and the generator guide and thrust bearings via independent branches. Cooling water supply to Unit 8 is planned to be controlled by a motorized shut-off valve located on the main cooling water discharge of the T/G unit, and flow meters with associated motorized valves, provided by the T/G supplier, are

planned to be installed downstream of each bank of generator air coolers to modulate cooling water flow.

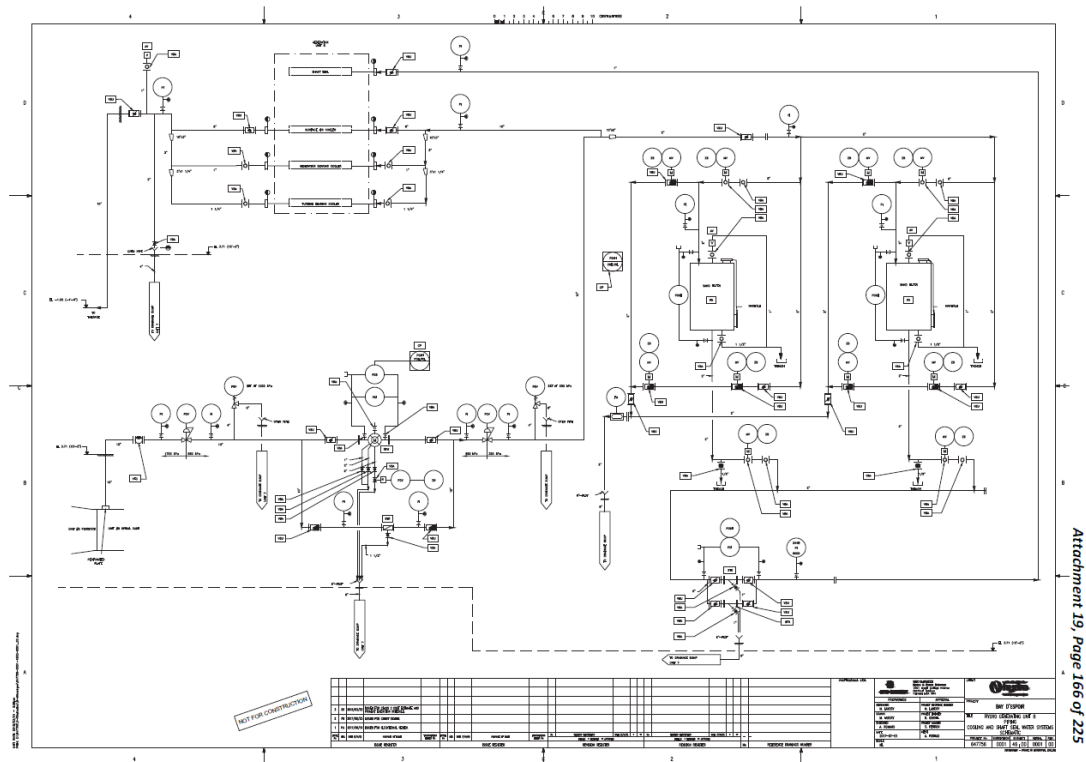
In normal operation, the raw water system for Unit 8 is planned to incorporate two stages of pressure reduction, with the first stage reducing pressure from 1 750 kPa to 860 kPa to allow proper operation of the filtration system and the second stage reducing pressure from 860 kPa to 350 kPa to provide adequate pressure to the T/G cooling water system.

For the shaft seal water system, two sand filters are planned to be provided, each capable of handling 100% of the water requirements and designed to retain particles 25 µm and larger, ensuring suitable quality for shaft seal lubrication.

The 2024 Options Analysis confirms that pressure-reducing valves remain the preferred solution over dedicated cooling water pumps for Unit 8, while noting that cooling water pumps cannot be completely ruled out and it is recommended further evaluated in the next design phase.

The new PRV system is planned to be equipped with redundant bypasses for the pressure-reducing control valves and parallel pressure-relief valves and it is recommended consider the use of safety pins instead of rupture discs for the relief devices to allow rapid replacement without removal of piping, maintain pipework integrity, and reduce disc replacement cost, labour, and associated outages.

Cooling water and raw water piping for Unit 8 is planned to be treated as part of the Balance of Plant systems and shall, wherever practical, utilize plastic and stainless-steel materials to minimize fouling and corrosion, in accordance with the latest the Utility's Basis of Design requirements.



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Figure 7-6: Cooling water system fluid diagram (Class 3 cost estimate and project execution schedule, client's documentation)

## 7.4.2 Powerhouse Crane

The powerhouse extension for Unit 8 is planned to utilize the existing 270-ton overhead travelling crane, which is already installed in Powerhouse 2 and equipped with two auxiliary hoists of 40 t and 10 t. The crane runway is planned to be extended into the new powerhouse bay, with the rails installed at Elevation 18.479 m, forming a continuous lifting system capable of servicing both Unit 7 and the new Unit 8.

The crane beam supporting structure is planned to maintain the same design characteristics as the existing arrangement, including a 1.1 m deep built-up crane girder, ensuring consistency with current load-bearing requirements.

The structural framing supporting the extended crane runway is planned to utilize W360×162 columns for the crane-beam supports and shall be fully integrated into the new steel superstructure of the powerhouse extension. The crane system is foreseen to rely on the lateral and longitudinal stability provided by rigid frames and roof bracing, ensuring full compliance with modern structural standards. The extended rails and bus bars is planned to preserve uninterrupted crane travel between the existing and new service bays, enabling lifting of major components such as the generator rotor, turbine parts, and draft tube elements during installation and future maintenance activities.

## 7.4.3 Fire Protection and Fire Fighting System

Fire protection and fire-fighting for Unit 8 is planned to be provided by a water-based system supplied from a tap on the makeup piece between the Unit 8 pressure conduit and the spiral case, equipped with an isolating valve, two pressure-reducing valves and a manually cleaned strainer capable of retaining particles larger than 0.8 mm.

The fire protection system is planned to protect the generator pit, oil-filled transformers T8 and SST5, governor areas (HPU), fire hose stations and wall hydrants, with generators and transformers protected by automatic water-spray fixed (deluge) systems and the generator HPU protected by an automatic wet-pipe sprinkler system; portable fire extinguishers shall be installed at strategic locations throughout the powerhouse.

In normal operation, a jockey pump installed in Unit 7 is planned to maintain system pressure for Units 7 and 8, with two pressure-reducing valves of different diameters provided so that the larger valve supplies high fire-protection flows (generator deluge system) and the smaller valve supplies low flows (fire hose stations); when Unit 8 is shut down, fire-protection water shall be supplied from Unit 7 via an interconnection pipe.

Fire protection systems for the powerhouse extension is planned to be independent of the existing Powerhouse 2 systems, of the same type as the existing systems to minimize additional spare-parts requirements, and is planned to meet all relevant current industry and the Utility's standards; the fire detection and alarm system shall use a single-stage, zoned, addressable, fully supervised, software-controlled, microprocessor-based fire alarm control panel.

The planned use of a water-spray deluge system is acceptable for this type of application; however, since the current design does not incorporate water-mist technology, it is recommended that the feasibility of a water-mist system as an alternative should be assessed. Water mist may provide reduced water damage, improved fire control in enclosed generator spaces, and enhanced safety for electrical equipment compared to conventional deluge systems.

The fire-fighting water distribution concept described above is consistent with the fire pump arrangement discussed earlier in this report, whereby the existing Unit 7 fire protection system is intended to serve the combined demand of Units 7 and 8, subject to verification of required flow, pressure, and duration.

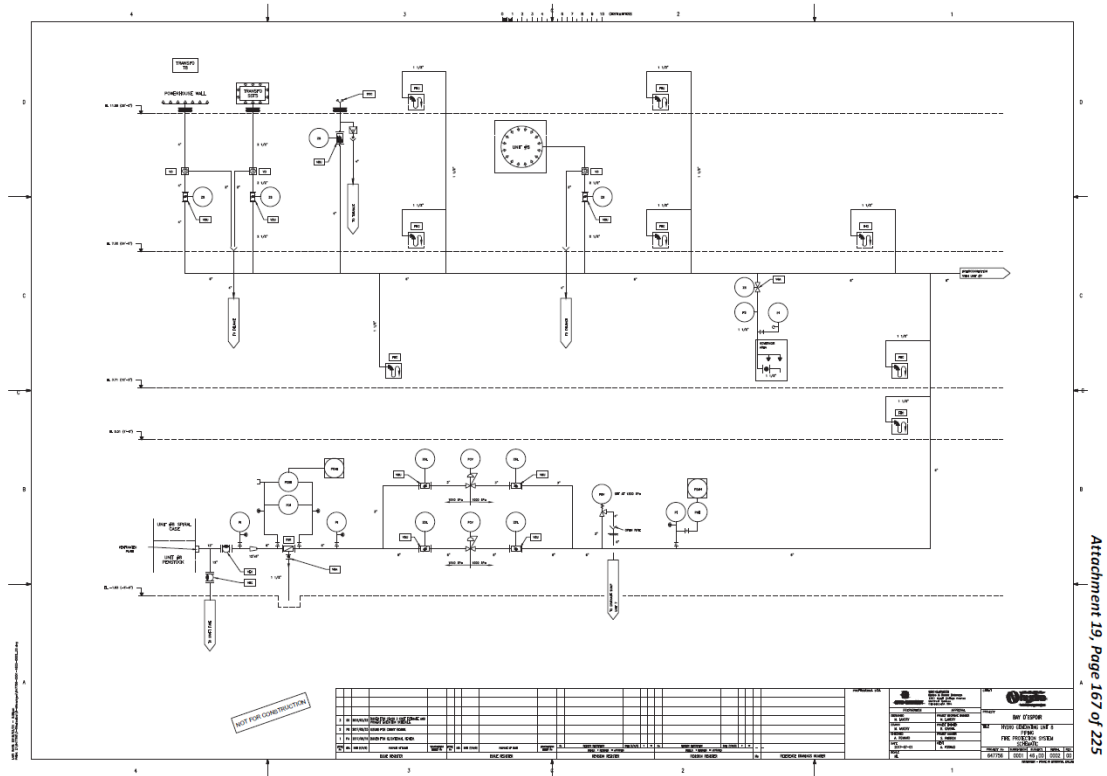
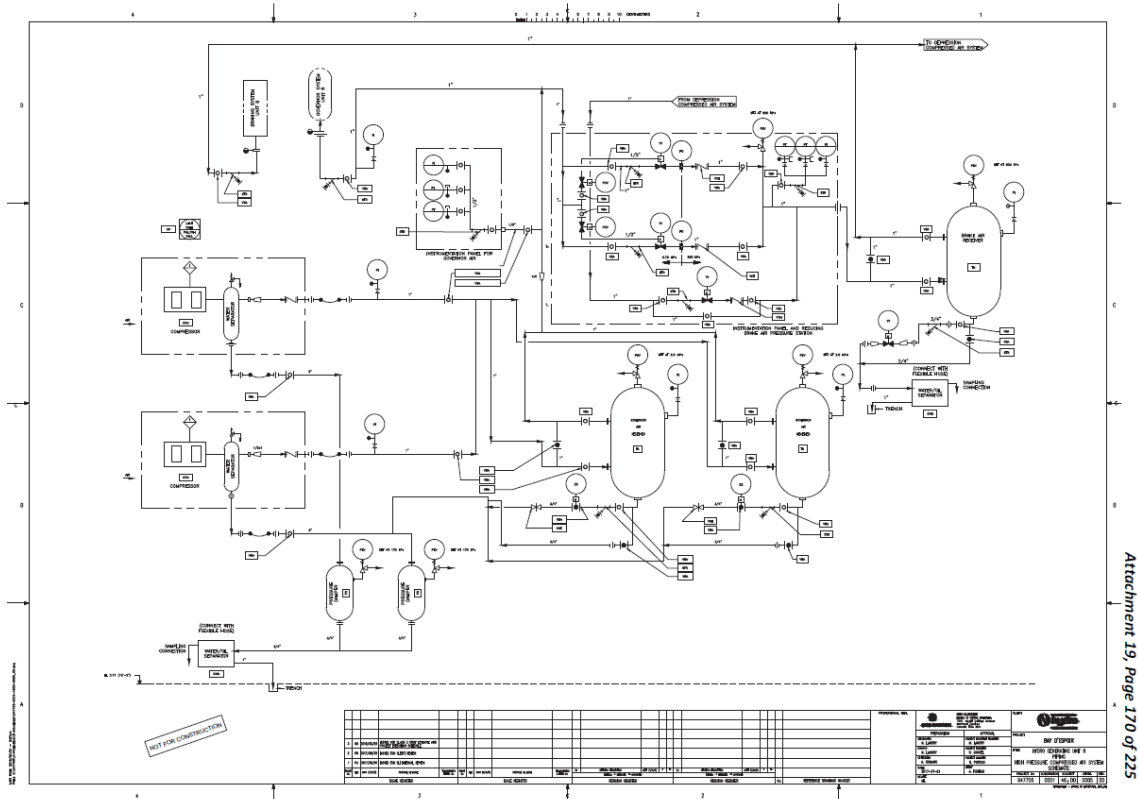


Figure 7-7: Fire Protection and Fire Fighting System fluid diagram (Class 3 cost estimate and project execution schedule, client's documentation)

### 7.4.4 Drainage and Dewatering System

The drainage water system for the powerhouse extension is planned to be designed to collect, drain and evacuate all water from all sources, both uncontaminated and containing oil, including permanent, intermittent, emergency or accidental flows from the interior and exterior of the powerhouse. Clear water from roof drains is planned to be discharged by gravity below the minimum downstream water level to a location where there is no risk of freezing, while clear water from all internal drains inside the powerhouse is planned to be routed by gravity to the existing drainage sump pit of Unit 7, in accordance with the schematic on drawing 647756-0001-46DD-0003.

Oily drainage water from transformers T8 and SST5 is planned to be directed to a concrete oil-water separator, where oil is planned to be retained on the surface and the treated water shall be discharged to the tailrace; a sampling cock shall be installed at the outlet of the separator to allow monitoring of residual oil concentration in the discharged water. Backwash from the self-cleaning motorized strainer in the raw water system is planned to be routed to the Unit 7 powerhouse drainage sump, ensuring that all such process drainage is collected and handled through the common drainage and de-oiling facilities.



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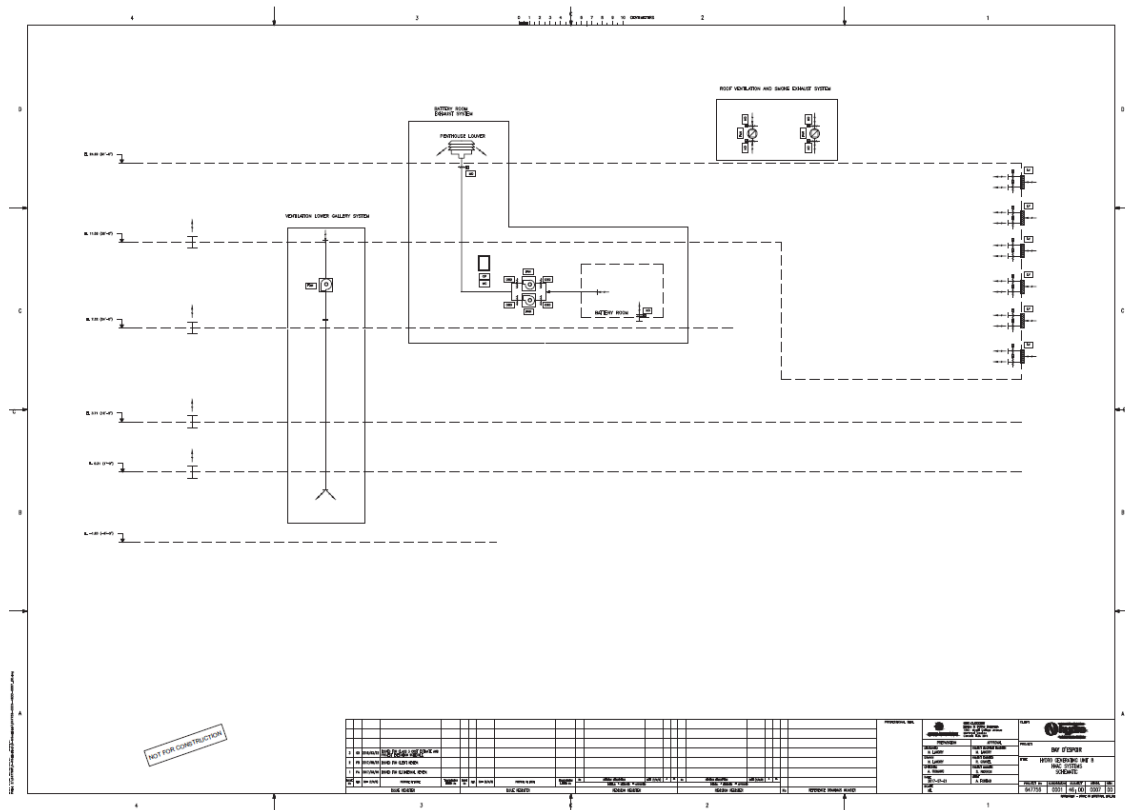
Figure 7-8: Drainage and Dewatering System fluid diagram (Class 3 cost estimate and project execution schedule, client's documentation)

**7.4.5 Heating, Ventilation and Air Conditioning (HVAC) systems**

Heating, Ventilation and Air Conditioning (HVAC) systems for the Powerhouse #2 extension are planned to be provided as part of the Balance of Plant and auxiliary mechanical systems and are planned to be generally similar to those in the existing powerhouse.

Heating systems is planned to utilize electric-resistance heating elements and is planned to be designed to ensure freeze protection of piping and other temperature-sensitive components during outages only. Ventilation systems is planned to consist of roof-top exhaust fans with passive intake louvers and shall be sized in accordance with applicable ASHRAE standards.

Three HVAC systems are planned to supply and exhaust air for Unit 8: two roof-mounted fans with louvers shall provide general ventilation for the powerhouse and is planned to also function as smoke exhaust fans in the event of fire, dedicated battery-room exhaust fans is planned to be belt-driven centrifugal in-line units configured for 100% redundancy, and a lower-galleries ventilation fan is planned to supply fresh air to the lower galleries, with air transfer from Floor Elevation 7.32 providing additional ventilation of the space.



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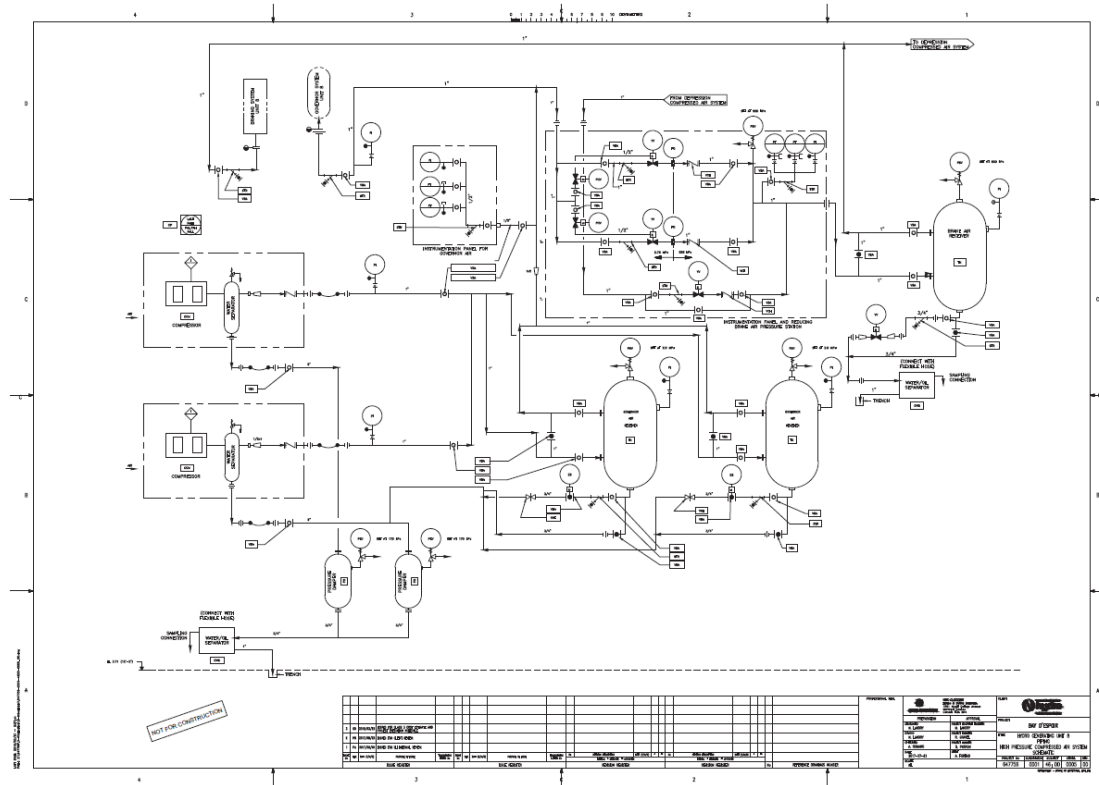
Figure 7-9: HVAC systems fluid diagram (Class 3 cost estimate and project execution schedule, client's documentation)

### 7.4.6 Compressed Air (Low Pressure) (High Pressure)

The high pressure compressed air system for Unit 8 shall supply air to the governor accumulator tank and to the brake air system, as defined in the auxiliary mechanical systems design.

Two compressors (one operating and one on standby) are planned to be provided to ensure reliable air distribution, with two high-pressure air tanks supplying the governor and brake air systems in normal operation. A pressure reduction station is planned to be used to reduce the pressure for the brake air system, and when the low-pressure set point is reached on the governor air regulator tank or on the air brake tank, the compressor or pressure-reduction station is foreseen to rebuild the pressure accordingly; in emergency operation, if one compressor is out of service the standby compressor is planned to start automatically, and if the pressure-reduction station fails, the brake air system is planned to be supplied from the depression compressed air system.

The depression compressed air system is planned to be provided to dewater T/G Unit 8 to enable operation of the unit as a synchronous condenser. The system shall consist of one compressor and two air tanks, sized to supply sufficient air to displace the draft tube water and clear the turbine runner under normal operating conditions. After dewatering, the compressor shall rebuild and maintain system pressure so that the water level in the draft tube remains between the specified minimum and maximum levels.



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Figure 7-10: Cooling water system fluid diagram (Class 3 cost estimate and project execution schedule, client's documentation)

**7.5 Electrical Balance of Plant (BOP)**

Electrical BOP systems are planned to be like those existing in Powerhouse #2.

**7.5.1 Station service transformer, 600V switchboard and low voltage equipment**

25 kV emergency power supply for Unit 8 is planned to be provided by the existing powerhouses without interrupting operations.

The station service transformer #5 is planned to be three phase, 750/1000kVA (ONAN/ONAF), with copper windings, 13.8/0.6 kV, with a delta connected winding on the high voltage side and a wye connected winding on the low voltage side, solidly grounded. The transformer is planned to be of a sealed tank construction and is also planned to be equipped with a de-energized type of tap changer on the high voltage side. The high voltage side is planned to be connected directly to the IPB. The low voltage side is planned to be connected to the 600V switchgear with Teck cables. The station service transformer is planned to be installed outside, upstream of the powerhouse with a physical arrangement like the station service transformer #3.

The 600V, 1200A switchboard is planned to consist of four cells, with two cells for the withdrawable incoming and tie breaker, one cell to include the power panel with moulded case circuit breaker and one transition cell to connect to the existing station service switchboard. The new incoming and tie breakers is planned to be electrically interlocked with the existing mains and tie breaker to provide redundancy.

The new system proposed is planned to be solidly grounded on the 600V side, to follow the Utility's standard practice. It is not recommend installing an ungrounded system like the existing system for safety reasons. It is therefore recommended that the existing ungrounded system to be modified and upgraded to a solidly grounded distribution system to allow the tie-in of the new 600V system for Unit 8 to the existing system.

The existing station service transformers station service transformer #3 and station service transformer #4 is recommended to be replaced with new transformers with a solidly grounded secondary to be compatible with station service transformer #5.

Four 600V power distribution panel boards are planned to be provided like the existing system, with each panel board provided with a manual transfer switch. One incoming side of the transfer switch is planned to be connected to the new switchboard, and the other incoming side is planned to be connected to the existing circuit breakers. Unit 8 panel board is planned to also be provided with an additional automatic transfer switch, connected to the existing Emergency Supply Panel, as it is provided for Unit 7 panel board. Local starters are planned to be provided to the motorized loads.

The other low voltage generation and powerhouse auxiliary systems are planned to be supplied from the four distribution panel boards, 600/347 V and 208/120 V distribution panels and associated distribution transformers connected to the distribution panel boards.

### 7.5.2 UPS and Battery System

This package includes 125VDC system of 2 battery banks, 2 chargers with associated DC panels, 48VDC system of 1 battery bank and charger for Communication, and 100A UPS system for the Powerhouse.

New 125 VDC and 48 VDC supply systems (battery and battery charger) is planned to be provided to supply the new protection, control, telemetering and communication systems that will be housed in the new control building.

125 VDC system is planned to contain redundant backup battery banks and chargers with AC power from both the normal and emergency station service panels.

### 7.5.3 Diesel Generator Set

An outdoor emergency 450 kW diesel generator is planned to be provided to supply emergency and black start power to Units 7 and 8.

The diesel generator set will be complete with all accessories for local and remote control starting and stopping, as well as metering and protection functions.

The diesel generator set is planned to be a stand-alone type inclusive of its own enclosure, engine, generator, governor, cooling, fuel tank, air, protection and control system.

The diesel generator is planned to be integrated with station services supply. On loss of station service supply, an undervoltage relay is planned to start the diesel generator set to supply the essential loads for periods when the auxiliary power supply is not available. The diesel generator set is planned to be installed at the proposed service floor elevation.

### 7.5.4 Power Supply of Water Intakes

An existing 25 kV aerial distribution line coming from the powerhouse with 25 kV/600 V transformers ensures the electrical supply of the existing water intake for Unit 7.

For the new water intake, the 25 kV line is planned to be extended to the new intake and a new set of 25 kV/600 V pole-mount transformers is to be installed. The transformers are planned to supply a 600 V distribution panel used as an electrical supply source for the various loads of the water intake.

A distribution transformer is planned to lower the supply voltage of the water intake to permit a distribution at 208/120 V.

The motor and heating loads are planned to be supplied from the 600 V distribution panel.

### 7.5.5 Earthing and Lightning Protection System

The powerhouse shall be provided with its own earthing system in accordance with the regulations and layout conditions.

The earthing system is designed for the following normal and fail-safe functions:

- > Ensure the earthing of the neutral points of the powerhouse equipment;
- > Ensure the reference potential for control signals and measurement;
- > Allow the dissipation of the phase to ground fault current, atmospheric discharges and overvoltage to the soil;
- > Ensure the protection of people and equipment in case of accidental contact of live parts with a metal mass.

The Terminal Station No 2 (TS-2) will be extended by one bay approximately 25 m. Earthing system will be extended accordingly.

A lightning protection system shall be used in the powerhouse and TS-2. It shall consist of air-termination system, down-conductor system and earth-termination system. Together with the metal parts of the structure they form a closed electric cage in relation to the earth, providing efficient electrical protection from lightning.

### 7.5.6 Lighting and Small Power Installations

The lighting system is planned to ensure an illumination sufficient for powerhouse operation and for performing maintenance works, while ensuring personnel security.

Outside illumination is planned to be provided on the building extension, like the existing lighting.

Emergency lighting is planned to be provided and exit signs will be used to indicate the emergency exits in case of personnel evacuation.

600 V and 120 V receptacles is planned to be placed in the new building extension and outside to satisfy operation and maintenance needs.

The Terminal Station No 2 (TS-2) will be extended by one bay approximately 25 m. Lighting system will be extended accordingly.

### 7.5.7 Control, Signalling, Protection and Measurement Systems

New fibre optic line and teleprotection systems are planned to follow the Utility's design standards.

SCADA communications between PH2 and TS2 are planned to be via fibre-optic cable.

Redundant protection or primary and backup protection systems are planned to be used as appropriate to the voltage level and specific equipment to be protected.

The protection single line diagram has been proposed for the connection of generating Unit 8 to a new extension of the TS2 at BDE.

It is proposed that the various protection, measurement and control systems is to be located in the Powerhouse 2 and in a new control building in TS2. The protection systems is planned to be separated in zones to minimize the lengths of secondary wiring from CTs. Fiber optic cable is planned to be used to reduce the required hardwired cabling.

The design and all work for protection and control systems is planned to be designed to all current relevant industry and the Utility's standards.

To ensure full functionality the designs, components and materials used are planned to be compatible with existing plant PCC (Protection, Control, and Communication) systems which include some proprietary systems.

Protection, control, alarm and telemetering is planned to be powered by 125 V DC with redundant backup battery banks and chargers with AC power from both the normal and emergency station service panels.

Intake SCADA communication and teleprotection is planned to follow the Utility's Standards and utilize fibre-optic cable between Powerhouse #2 and Intake #5. This fibre-optic communication cable is planned to be used for transmission of important status signals, like forebay elevation, intake gate position and remote control signals.

Control, Signalling, Protection and Measurement Systems are planned to have a minimum design life of 20 years.

### **7.5.8 Communication and Security Systems**

This package includes items such as Communication cabinet, fibre optical cabinet, CCTV system, public address system and communication cables.

The main communication and LAN systems for the generating Unit 8 and the new equipment at BDE is planned to be by fibre optic cables. The short line between PH2 and TS2 BDE is planned to be provided with OPGW link for the connection of PH2 to the FO network being implemented at BDE.

The main communication for the protection of the 230 kV short transmission line between PH2 and TS2 BDE is planned to be by OPGW link.

Within the Powerhouse 2 and the new control building in TS2 direct fibre optic cable pairs are planned to be used to provide station LAN. Non-redundant GPS clock will also be provided to generate a central time reference, using IRIG-B, for all protection, metering and control devices.

Telecommunication for Unit 8 is planned to be provided by the existing powerhouses without interrupting operations

The Security Video Monitoring System is planned to be similar in design to the existing Powerhouse # 2 system.

Fire detection and alarm systems are planned to be designed in accordance with all current relevant industry and the Utility's (Newfoundland and Labrador Hydro) standards.

The Fire alarm control panel is planned to be single stage, zoned, addressable, fully supervised, software controlled and microprocessor-based system.

Communication systems are planned to be powered by 48VDC with a single backup battery bank and charger.

### 7.5.9 Cable System

Power and control cables is planned to be of the TECK FT-4 type. The cables are planned to be installed in cable trays.

Re-commissioning of protection and control cables for Unit 7 is to be carried out.

The openings in walls and floors are planned to be sealed against fire propagation. The fire-resistance rating is planned to be equivalent to that of the wall and floor.

## 7.6 Conclusions and Recommendations

The evaluation of the Power Generation Extension Works is based on the FEED design documents, which address the project at a conceptual level; the recommendations outlined below are intended for incorporation during the final and detailed design phases.

- > **▶ Recommendation 7-1 – Medium:** As an erection bay already exists for Unit 7, a separate erection bay for Unit 8 is likely unnecessary and should be removed from the scope, provided that lifting capacity, access clearances, and scheduling requirements can be adequately met using the Unit 7 facility.
- > **▶ Recommendation 7-2 – Medium:** As Unit 7 has operated without an elevator, the elevator proposed for Unit 8 could be omitted, provided that all applicable regulatory and safety requirements are still fully satisfied.
- > **▶ Recommendation 7-3 – Low:** A dedicated fire pump for Unit 8 may be unnecessary if the existing Unit 7 fire pump system is assessed and, where required, upgraded to satisfy the combined flow, pressure, and duration demand for both Units 7 and 8.
- > **▶ Recommendation 7-4 – Low:** While the Bay d'Espoir Unit 8 Project Evidence targets a 100-year design life for the new powerhouse, the Infrastructure Assessment Report adopts a practical 25-year refurbishment horizon for the 45-year-old existing structure. To sustain performance over this period, a program of periodic condition monitoring and timely repairs is recommended, with particular focus on legacy structural elements.
- > **▶ Recommendation 7-5 – Low:** A finite element model of the powerhouse, including the existing structural components, should be developed and analyzed to verify the capacity and deformation behavior of the combined structure.
- > **▶ Recommendation 7-6 – Low:** Overall slope and excavation stability in the construction area should be evaluated for both operational and transient conditions (including construction stages, drawdown, seismic loading, and extreme rainfall), using updated material parameters and groundwater conditions.
- > **▶ Recommendation 7-7 – Low:** Time dependent deformations and past differential movements in the existing powerhouse are likely to have caused minor interface misalignments; these should be identified and accommodated in the construction detailing, Injection grouting can be applied as necessary following appropriate monitoring and evaluation.
- > **▶ Recommendation 7-8 – High:** The project site lies near an active seismic zone; accordingly, elevated seismic demands should be explicitly considered in the assessment to

mitigate potential adverse impacts, as illustrated by the site's proximity to the seismic region in the figure below.

- > **▶ Recommendation 7-9 – Low:** The bedrock is a slightly weathered, dark grey to black metamorphosed siltstone with pervasive veining, microfracturing, and millimeter scale laminations, yielding disc-shaped core fragments; insufficient intact core in BH1823 precluded UCS testing. Appropriate strengthening and deformation control measures should be defined during detailed design.
- > **▶ Recommendation 7-10 – Low:** Foundations should, where feasible, be designed to bear directly on competent bedrock, avoiding reliance on the thin and variable overburden near excavation edges.
- > **▶ Recommendation 7-11 – Low:** For excavation support, conservative slope angles or rock reinforcement (e.g., rock bolts, mesh, shotcrete) should be used in jointed or weathered zones, with benching provided to interrupt potential sliding planes.
- > **▶ Recommendation 7-12 – Medium:** The existing Unit 7 crane rail will be extended into the new Unit 8 powerhouse. Because an expansion joint separates the two superstructures but cannot interrupt the continuous crane rail, the design must explicitly accommodate horizontal and vertical differential movements (including differential settlement) between the old and new structures, with appropriate precautions and corbel bearing systems detailed accordingly.
- > **▶ Recommendation 7-13 – High:** The Unit 8 steel superstructure, planned as an extension of the 45 years old Unit 7, should be verified against current structural codes and updated loads, with the existing Unit 7 assessed for any required refurbishment. The final design should reflect current Newfoundland climatic data, with particular attention to cold weather performance.
- > Comments and recommendations in this section are presented based on the Bill of Quantities (BoQ) verifications carried out by comparing the quantities derived from the review of the provided layout drawings and single line diagrams with those contained in the report “BDE 8 Class 3 Cost Estimate and Project Execution Schedule” (SNC-Lavalin, 2018).
- > **▶ Conclusion 7-1 – Medium:** It should be recognized that the design documentation currently available is at the concept design stage and therefore more accurate and detailed comparisons will only be feasible upon completion of the Final/Detailed Design phases.
- > The overall design of main electrical equipment and electrical BOP is reviewed based on engineering judgment and Gruner's experience from similar projects in recent years. Review and assess are focused on validating the quantities estimate and provide highlight if there are items that have not been considered.
- > **▶ Conclusion 7-2 – Medium:** It is found that quantities for main electrical equipment and electrical BOP are consistent with the BoQ and align with the total direct cost for these items.
- > **▶ Conclusion 7-3 – Medium:** It is found that costs for energy for construction activities have been included in the cost estimate, but concept of power supply for construction sites is not provided. The separate detailed design of power supply for construction sites should be prepared in due time, i.e. before starting of construction works. This design should contain main technical data of equipment, calculations, appropriate drawings showing power supply sources and cable routes, etc.

## 8 Transmission Line (TL) and Terminal Station (TS) Expansion

This chapters covers the review of the short transmission line on site and the expansion of the on-site terminal stations. It does not cover a review of potential new transmission lines between BDE Unit #8 to the load center on the Avalon Peninsula.

### 8.1 Capital Works and associated CAPEX

#### 8.1.1 230kV Transmission Line

A high voltage line is planned to be built from Unit 8 step-up transformer to Terminal Station No 2 (TS-2), as well as the addition of a new breaker-and-a-half scheme in the switchyard to receive the new line.

The new transmission line is planned to be a 230 kV line that will be routed from Powerhouse #2 to BDE Terminal Station #2. The line route selected is planned to minimize environmental impacts and interference with other lines.

The first transmission line pole of Unit 7 is located within the excavation footprint of the new penstock. Therefore, it is required to permanently relocate this transmission line pole before starting penstock and powerhouse excavation.

The line route is planned to be parallel to the existing line between Unit 7 and Terminal Station 2. The line length is approximately 1.9 km, with five transmission line crossings and one river crossing. For the proposed line route, ten towers are to be needed. The selected conductor is an 804 kcmil AACR-TW.

Transmission line is planned to be equipped with insulator chains and dead-end assemblies.

Transmission line is planned to include an Optical Ground Wire (OPGW) fibre line providing communications between Power House 2 to TS2.

The transmission line is planned to be a hybrid design of wood and steel pole construction and will be designed to all current relevant industry and the Utility's standards.

The transmission line is planned to have a minimum design life of 60 years.

#### 8.1.2 Terminal Station Expansion

TS-2 connects to TS-1 and directly to the GSU transformer of Unit 7. TS-2 also connects to transmission line 267 (TL-267) connecting Bay d'Espoir to Western Avalon Terminal Station (WAV).

TS-2 has a breaker-and-a-half bus configuration and is directly connected to the network. It has been decided that the new Unit 8 is to be connected to TS-2, as is Unit 7.

Initially, the scheme is planned to contain two circuit breakers and their isolating switches. Space is to be provided for the third breaker which can be added in the future.

The substation will be extended by approximately 25 m. The main busses B7 and B9 will be extended by one bay each, by adding two new spans, thereby avoiding demolition of the existing dead-end structures and minimizing shut down time.

A new control building will be provided to house the protection and control equipment and power supplies.

The expansion is planned to be designed to all known environmental, climatic, and geotechnical design conditions.

The design is planned to comply with all current relevant industry and the Utility's standards for design guides and terminal stations.

All electrical equipment for the terminal station expansion is planned to be designed with a minimum design life of 40 years.

### 8.1.3 Substation extension

- > ► **Recommendation 8-1 – Low:** For Terminal Station No. 2, the foundations for equipment structures, cable trenches, and the new extension area should be designed on the basis of site specific geotechnical parameters, with explicit allowance for frost depth, frost heave, and freeze–thaw degradation under Newfoundland climatic conditions.
- > ► **Recommendation 8-2 – Low:** Foundations should, where practical, bear on competent native soils or rock below frost penetration or incorporate suitable frost protected shallow foundation details and granular, free draining backfill to limit heave and differential settlement between existing and new structures.
- > ► **Recommendation 8-3 – Low:** The arrangement and specification of internal access roads and trafficable surfaces around the new terminal station extension are not adequately defined in the current design. A coherent internal road network and surfacing standard should be developed in the next phase, providing all-weather vehicular access for construction and maintenance to all bays and equipment, appropriate turning radii for large vehicles, drainage grading away from foundations, and clear separation between access routes and live yard areas for operational safety. New control building in TS2
- > ► **Recommendation 8-4 – Low:** The control building is not clearly defined in the current drawings; only an indicative footprint of approximately 6.1 m × 16.5–16.8 m (plus a small annex) is shown, together with schematic drain and cable connections. From a civil/structural standpoint, the building should be located on a raised, well drained platform above the design flood level, with finished grades sloping away from the perimeter and coordinated with the adjacent riprap protection and site drainage (including the 200 mm drain line shown).
- > ► **Recommendation 8-5 – Low:** Foundations should be designed on the basis of a site specific geotechnical investigation, with due allowance for Newfoundland frost depth and freeze–thaw, and with particular attention to controlling differential settlement at the building extension and at all incoming/outgoing cable and pipe penetrations.
- > ► **Recommendation 8-6 – Low:** A simple, robust structural system (reinforced concrete or steel frame with suitable wall and roof systems) should be designed to current wind, snow and seismic codes, with adequate overhead clearance for cable routing and maintenance.
- > ► **Recommendation 8-7 – Low:** Underground duct banks and/or cable trenches between the control building, the switchyard bays and the powerhouse should be fully coordinated with the structural layout, made watertight where they enter the building, and sized to allow for future circuits and spare conduits. Fire resistance rating of the primary structure, internal compartmentation for control, battery/UPS and LV/MV rooms, safe access and emergency exits, all weather vehicular access for maintenance, and basic perimeter security (fencing, controlled entry) should be incorporated and clearly defined in the next design stage.

## 8.2 Conclusions and Recommendations

The evaluation of the Transmission Line and Terminal Station #2 is based on the FEED design documents, which address the project at a conceptual level. The conclusions outlined below are intended for incorporation during the final and detailed design phases.

- > Comments and recommendations in this section are presented based on the Bill of Quantities (BoQ) verifications carried out by comparing the quantities derived from the review of the provided layout drawings and single line diagrams with those contained in the report “BDE 8 Class 3 Cost Estimate and Project Execution Schedule” (SNC-Lavalin, 2018).
- > **▶ Conclusion 8-1 – Medium:** It should be recognized that the design documentation currently available is at the concept design stage and therefore more accurate and detailed comparisons will only be feasible upon completion of the Final/Detailed Design phases.
- > The overall design of High Voltage equipment is reviewed based on engineering judgment and Gruner's experience from similar projects in recent years. Review and assessment are focused on validating the quantities estimate and provide highlight if there are items that have not been considered.
- > **▶ Conclusion 8-2 – Medium:** It is found that quantities for High Voltage equipment are consistent with the BOQ and align with the total direct cost for these items.
- > **▶ Conclusion 8-3 – Medium:** The 230 kV line route between Unit 8 and Terminal Station 2 was proposed with line length of approximately 1.9 km. Having in a mind that conceptual design can contain several variants, it is not clear whether the other variant solutions were also considered.

## 9 Constructability, Construction Programme

The overall layout of the project structures makes sense and no major issues in terms of the access, logistics and constructability is expected. Further refinement and fine tuning for the final position of the access and site layout will be presented by the corresponding contractors before the initiation of the physical work on site.

The main access to site is already provided to both powerplants and to the dam as they have been operational for a considerable duration and no major issues in terms of access was reported in the documentation from the Utility.

The main access to site is deemed to be sufficient for the transportation of large elements such as transformers and E&M parts as equipment of similar dimensions were already transported to site during the construction and installation of Unit 7.

The overall layout of the CWAs does not result in significant interference between work areas. The defined boundaries and the sequencing of activities, as outlined in the work schedule, should allow construction and installation tasks to proceed smoothly with minimal overlap.

Detailed comments on the related physical work activities are provided in the sections below.

### 9.1 Constructability Review and Early and Support Civil Works CAPEX

#### 9.1.1 Roads and Access Roads Upgrade

No major road works are anticipated on the existing access roads leading to the project site, including those serving both powerhouses and the dam structure. Minor improvements may be required in localized sections—such as adjustments to horizontal and vertical alignment—to facilitate the safe and efficient transport of heavy or oversized equipment, including transformers and other large E&M components.

Potential E&M and transformer suppliers should assess the access conditions and identify any required upgrades during the tendering phase.

#### 9.1.2 Temporary access Roads

The requirements for the temporary access roads are minimal as the major working areas are already accessible. The potential temporary access facilities would be the access to batching plant area, intermediate access points to the penstock route as well as some temporary access for the construction around the powerhouse in limited length.

A final and permanent access road needs to be provided for the power intake area for construction and installation purposes where the same access would be utilised as the permanent access during the operation of the plant where the powerhouse will be reached through the existing access during the operation.

#### 9.1.3 Laydown Areas

No permanent laydown areas will be required for the plant operations where the temporary laydown areas would be required for the in-site stock items such as the penstock pipes before being installed in their final positions.

The powerhouse equipment may need temporary storage on site however most of the installations are scheduled after the conclusion of the superstructure of the powerhouse therefore a long-term storage on site for the E&M equipment is deemed to be on minimal basis.

#### 9.1.4 Utilities Reroute

The re-routing of the utilities is given with a broader planning in the schedule of the works and considering the rather small amount of the works of concern, the re-routing works do not present a major risk or red-flags at this stage. As already mentioned in the planning documentation, some of the routing works needs to be coordinated and harmonised with the power production program of the plant however given the considerable time spared in the schedule, such coordination is evaluated to be non-problematic at this stage.

#### 9.1.5 Site Preparation

The site preparation works to be undertaken by the Heavy Civil Contractor for the camps and technical installations (such as batching plant, camps, workshops etc) is spread along a quarter in the schedule and such duration is deemed to be enough in the case of a proper planning by the contractor of concern.

The available areas for the installations at the preliminary planning stage as presented with the available documents does not pose a critical issue at this stage neither from spacing nor from accessibility perspective.

#### 9.1.6 Intake Channel

The intake channel is composed of an excavated channel in between the existing two intakes and the preliminary planning of the activities in terms of the staged excavation by leaving an un-excavated dyke at the upstream extremity of the channel makes sense to avoid flooding of the channel by the water in the dam's reservoir. On the other hand, such excavation needs to be protected by means of a temporary grout curtain or similar at the perimeter of the channel to avoid the seepage water coming into the channel during the excavation works. Alternatively, the channel could also be excavated under submerged conditions by careful planning of the equipment and corresponding methods.

The access to the intake excavation does not pose any problematic issues at this stage while some temporary ramps would be required for the machinery to be utilised for the excavation of the tunnel and these would be easily handled by the Heavy Civil Contractor.

#### 9.1.7 Intake structure

The intake structure is a concrete structure and the concrete casting works would start after the conclusion of the excavation works. The construction pit for the intake structure shall be kept under dry conditions to avoid the flooding of the pit as well as to avoid the flooding of the further downstream sections of the penstock route. Therefore, an adequate grouting campaign needs to be performed prior to the initiation of the pit excavation and finally the pit shall be equipped with drainage pumps and sumps to pump out the limited amount of seepage water into the pit through the reservoir.

No major issues are expected for the concrete structure of the intake structure during the construction where the logistics in terms of formwork, reinforcement etc. would probably be considered from the top of the pit by means of a mobile crane to limit the construction pit (therefore the grout curtain) as narrow as possible.

The intake structure is connected to the penstock on its downstream extremity where a sort of trench excavation would be needed. The trench of concern would probably create an opening on the grout curtain of the existing structure triggering a risk of seepage or uncontrolled release of water from the reservoir. Therefore, the final sequencing of the excavation and re-construction activities shall be carefully considered in the next detailed design stages with respect to the existing curtain and dam and or its extension on the abutments to overcome the above-mentioned risks.

### 9.1.8 Penstock

The penstock is a buried steel pipe all along its route and the trench within which the penstock will be installed will be excavated partially in rock at the upstream and downstream sections where the middle portion will be excavated in loose ground and/or weathered rock. No major issues are expected in terms of the excavation and stability of the slopes of the trench as the depth will be relatively shallow and sheet piling and/or a similar protection method is already foreseen for the sections in the loose ground in order not to damage the existing penstock route connected to Unit 7 although a considerable distance between the two alignments exists. Therefore, the necessity and extend of the protection measures of concern needs to be re-evaluated in the next design stages.

As far as the constructability of the penstock is concerned, no major issues are expected as the whole trench route is planned to be accessible during the construction and no issues for the logistics in terms of pipe delivery, welding in the trench and further backfilling are expected.

### 9.1.9 Powerhouse

The powerhouse construction is expected to be the most delicate and complex part of the project due to the fact that the construction and installation works are needed to be performed adjacent to the existing unit which is expected to be under operation during a considerable amount of the construction duration.

As per the existing reports and condition assessment documentation, no major rock excavation works are to be undertaken for the foundations of the structure as these were already performed in advance during the construction of unit 7.

The areas on which the Unit 8 foundations will be built will require clearing out of the vegetation and removal of the loosened ground to a certain extent while these works will be performed within the pit with limited access and therefore probably crane access will be considered on the downstream right-hand side of the future unit 8.

The major excavation works would be the trenching excavation on the upstream side of the Unit 8 to accommodate the penstock coming into the spiral casing and such excavation will need to be carried out with limited heavy equipment and with special blasting techniques in order not to damage the structures and equipment already running at Unit 7. Therefore, a rather slow pace for these would be considered. Apart from the rather slow pace, no major technical issues are expected for the excavation of the powerhouse block for Unit 8.

The concrete works would be handled in a similar manner (i.e. within the pit) as the intake structure and once a certain elevation is reached the superstructural works for the closure of the building will take place. Considering the expected slow pace in excavation and partially in concreting works, it is likely that the civil construction works on the powerhouse would be extended over 2 construction seasons interrupted by the winter. However, a winter break is not deemed necessary, based on anecdotal evidence from the local construction industry. Moreover, a winter break would have not posed a major issue with the overall planning of the project.

## 9.2 Programme Review

The overall schedule of the project as presented with Hydro's documentation within the available set are as follows:

- > Schedule 4 Attachment 2 - BDE 8 Basis of Schedule [12]
- > Bay d'Espoir Unit 8 Project Early Execution Update Dated November 17, 2025 [13]

A high-level review of the project's schedule as well as the assumptions and conditions set forth in the Hydro's documents were performed and the comments of the reviewer are presented under the following paragraphs separated as the main assumptions and the scheduling aspects.

### 9.2.1 Main Assumptions Considered

The main assumptions considered during the preparation of the overall schedule of the project is presented with [12].

### 9.2.2 Section 5 Schedule Structure

As mentioned in Hydro's above mentioned [12] document, the presented schedule is a combination of the Level 3 Schedule of the FEED study and the Hydro's internal project schedule that includes the administrative and commercial activities in addition to the construction, installation and commissioning activities and such combination makes sense considering the administrative and commercial steps to be followed and ensured during the execution of the project.

The structure of the construction and installation works are based on an approach that divides the project area to logical geographic portions of the work called CWAs. Within each CWA there are one or more CWP's. A CWP defines a specific scope of work such that it does not overlap with other CWP's.

With this approach and presentation, the activities related to the early stages of the project before the construction is clearly defined and referenced to each other that forms a sound basis of the early-stage activities.

On the other hand, the activities related to the construction and installation works are provided in a broader manner where it is understood that the detailed schedules in more detailed levels are considered to be presented and agreed with the contractors and vendors to take place in the execution of the project.

Such approach makes sense at this stage of the works and in general the overall durations spared for the major work fronts considered in the project makes sense in general terms where a more detailed review of the items of concern is presented in the proceeding sections of the review report.

A summary of the Schedule Structure is presented with Hydro's [12] Document under Table 1 of Section 5.0 as per the following table:

WBS Level 1	WBS Level 2	Items/Description
Milestones	-	Start and finish milestones marking key activities from the schedule. These will be expanded to include select Consultant and Contractor contractual dates.
FEP	Project Management	Activities related to the FEP stage of the project. Hydro documents and studies, procurement of Contractors and Consultants to assist with the study and project development, and FEED activities executed by the consultant (AtkinsRéalis)
	Procurement	
	Complete Field Program	
	Internal Engineering	
	Geotech Investigation	
	FEED	
Regulatory	PUB	Activities related to the government and PUB review and approval.
	Environmental	
	Stakeholder Consultation	
Execution	Hydro Managed	Activities being managed by Hydro's Major Projects Department, such as existing site utility relocations, construction power provisions, and early execution
		works associated with procurement of long lead equipment.
	EPCM Managed	Activities managed and performed by the EPCM Consultant. These activities will include detailed items related to engineering, procurement, construction management, and commissioning.
Closeout	Closeout	In this schedule, the Execution Phase ends with the "Acceptance for Commercial Operation." The Close-Out Phase contains the activities associated with documentation close out (As-Built), lessons learned, and a final "Post Implementation Report."

The overall definition of the WBS (Work Breakdown Structure) Levels as well as the distribution and sequencing of the works are appropriate for this stage till the execution stage where it is understood that the execution stage activities by Hydro and the EPCM Consultant will be defined in detail in further steps.

The calendars considered within the schedule are presented in detail under Section 5.1.3 and no major comments are generated for these calendars at this stage.

The schedule structure presented uses the Total Float method for the determination of the critical path which is a standard practice in the industry.

### 9.2.3 Section 6 Schedule Development Basis

The schedule's target for the completion of the project is defined as the "Acceptance for Commercial Operation" which is in line with the project's defined target.

The key milestones defined at this stage makes sense while a more detailed set of milestones would be required to set the dependencies and sequencing of the activities to be performed by different contractors in terms of battery limits and coordination of different disciplines of works like intermediate milestones for the draft tubes installation, civil readiness for HM (Hydro-Mechanical) and EM (Electro-Mechanical) installations, crane being ready for installation, water available for wet test etc.

However, as already mentioned in the documentation, the further steps will undergo a more detailed planning including the potential and preferred contractors and the schedule is understood to be refined as per the final requirements of the project and to be closely followed up and updated throughout the realization period of the project.

### 9.3 Scheduling Aspects Project Milestones:

No major comments at this stage apart from the intermediate milestones to be added as mentioned in the above sections with respect to the interface management.

#### 9.3.1 Front End Planning (FEP)

The provided schedule considers that the studies related to this item are already concluded.

#### 9.3.2 Regulatory

Some unfinished items at the run date of the schedule presented with [12] are falling within the period of 2025 and an updated version to see the progress and further consequences in case of delays could be useful.

The status of the following activities under the regulatory items is updated with Hydro's reference [13] document sub-chapter 3.0 project schedule:

- > The milestone "Environmental Assessment Release" under activity # 12942301-EA-50 of the Work Schedule presented under [12] is delayed from August 2025 to November 2025 with no effect on the overall critical path of the project as this activity already had a quite comfortable float.
- > The Activity #PUB-200 allocated for "PUB Review Approval Process" is reportedly be delayed and the process will be delayed to 2026 instead of the previously announced completion date of end of 2025 which is shifting the previously planned date of end of the year 2025 towards 2026 for the full project approval while such delay is estimated to have some budgetary effects requiring the re-allocation of a portion of the early execution budget towards the year 2026. Such re-allocation is reported to be under development for the Board approval as per [13].

### 9.4 Execution:

#### 9.4.1 Hydro Managed

- > EPCM Services for RFP are mentioned to be planned within 2025 and an update of the schedule on the status of these would be useful for a better understanding as the Ref. [13] document delivered later reports that certain variances related to the schedules for the EPCM Consultant Selection had occurred recently.
- > Engineering and procurement activities that are on the critical path for Contract 2 Turbine and Generator are shown to be executed within 2025 and an update on these items will be helpful as defined above as a result of the changes mentioned in [13].
- > Similarly, some non-critical items are mentioned under Early Execution works within 2025 and an update on these would also be helpful while the activities of concern have a large float and therefore are not considered to be critical.

- > The Ref [13] document provides an update on the EPCM Consultant Selection due to the changes contracting approach to combine the EPCM services for the major projects planned for execution in Bay d'Espoir between 2025 and 2031 to include BDE Unit 8 construction, BDE 7 life extension and penstock 2 and 3 life extension. The reasoning behind this approach change in terms of having the above mentioned project to be managed from one management group present major potential benefits in terms of interface management, scheduling aspects and reducing the cost risk for each project while the re-packaging would be more attractive for the potential contractors and vendors. Therefore, although the delays as a result of such contracting approach change affect the early execution activities slightly, no impact on the estimated CoD is foreseen so far.

#### 9.4.2 EPCM Managed

- > A large number of Project Management and Pre Sanction Engineering and Construction planning activities are planned to be executed by the EPCM within 2025 including the critical works affecting the long lead items such as GSU performance specification and an update on these items would be helpful to make a meaningful assessment on the status of the overall schedule as the schedule for the EPCM selection is already delayed by about 3 months as per the information provided by [13]. In this respect minor to moderate delays in the EPCM managed activities as explained below are also expected.

##### Contract Package 1 Heavy Civil Scope:

- > Quite a number of preparatory activities are planned to be performed starting with 2026 in terms of engineering, permitting and approvals etc.
- > Some semi critical items in terms of procurement are initiated and concluded in the last quarter of 2025 such as the proposal periods for the GSU and Circuit breakers and an update on these items would be helpful to figure out the current status with an update on the contracting approach as referenced with [13].

##### Contract Package 2 Turbine Generator – Manufacture and Install

- > Phase 1 Design and Modelling works are planned to be initiated at the last quarter of 2025 and an update on the status would give the reviewers a better vision of the status of the project especially considering the delays in the EPCM selection as per [13].
- > As mentioned in the above sections, the schedule considers a period of about 2 quarters at the end of 2026 and at the beginning of 2027 between the finalization of the design and modelling and manufacturing due to the considered 2 Phased approach and the combination of both phases could provide a better flexibility on these critical path activities.
- > The activities such as the draft tube installation and stay ring installation are planned for rather short durations (i.e. draft tube [REDACTED], stay ring [REDACTED]) and these needs to be checked and verified with the supplier as the works of concern are on the critical path and a longer installation duration could likely happen in case of welding these large parts on site.

##### Contract Package 3 230 kV Transmission Line

- > The works of concern are planned to be executed by Hydro within 2029 and are planned to be concluded before the wet tests and commissioning of the unit. Therefore, no major flags are raised on these at this stage.

## 9.5 Key interfaces and Risks Management

### 9.5.1 Unit 8 Works

Minor to moderate issues that could require further attention and/or clarifications are as follows:

- > Early Execution / Existing Site Infrastructure Modifications shall be clearly mentioned and defined in the RfP to the Contractors and any modifications required by the Contractors shall be coordinated in due time.
- > Provision of power to different sites are considered under Early execution works however such requirements may differ from Contractor to Contractor therefore such works needs to be coordinated with them and/or the end terminal locations and conditions shall be clearly defined in the RfP.
- > Some relocation and reconstruction activities may result in short or long terms stoppage of Unit 7 – This needs to be coordinated properly in terms of water in the reservoir and timing according to the grid requirements.
- > Turbine and Generator procurement is considered in two stages. Phase 1 is the early design and modelling and the proposal for Phase 2 will follow the Phase 1 with a sort of lag. This may result in an increased price from the vendors as the technologies and know how considered in Phase 1 by the vendor will not be allowing other competitors to enter in the project. We would recommend having the Phase 1 not limited to only one vendor with a staged execution.
- > The Table 3 in the document summarizes the activity lead times for the turbine and generator where a period of 12 months is considered for design and modelling which is evaluated to be comfortable in case of physical modelling and this period includes the proposal for Phase 2 (see above for the comments on this)
- > Final Design and Manufacturing: 29 months is deemed to be comfortable. Shipment of 8 weeks will be staggered as per the requirements (i.e. draft tubes earlier, spiral case earlier than followed by the runner, shaft generator etc. -The delivery schedule shall be coordinated with the civil works advancement in the powerhouse.
- > Section 6.4.4.2 dedicated for the early works mentions that the material will be procured by Hydro and will be given to the Construction Contractor. It is not clear whether the works are planned to be performed by Hydro or just the material procurement. Also, there is a confusion for the reader Differentiate between the "Construction Contractor" and "Heavy Civil Contractor
- > Section 6.4.5.1 mentions that the GSU and 230 kV circuit breakers are under the Heavy Civil Contractor's scope. On the other hand, as per our experience the E&M Contractor should be more familiar with these items and their network of the available vendor will be much more compared to a civil contractor. This would also provide a better distribution of the works and responsibilities between the contractors.

### 9.5.2 Interaction with Unit 7 Life Extension

In addition to constructing the new Unit 8, Hydro is considering a "Life Extension" for the existing Unit 7, located in the same powerhouse building. The life extension work primarily focuses on rehabilitating or performing major overhauls on electrical and mechanical (E&M) equipment, rather than heavy civil works. These upgrades aim to extend the operational life of Unit 7's generating equipment by an additional 25 years, as explained in detail below[24].

A summary of the works to be performed under Unit 7 Life Extension as defined with Ref. [24] "Appendix A, 6.1 Direct Scope" are as follows:

- > Turbine and Generator Major Refit to include:
  - > Replacement of runner and bottom ring
  - > Replacement of stator windings
  - > Re-insulation of rotor poles
- > Refurbishment and/or replacement based on the Turbine & Generator Supplier design and inspections including the following works:
  - > Thrust collar and thrust ring
  - > Head cover
  - > Bottom ring
  - > Facing plates
  - > Turbine shaft
  - > Generator shaft
  - > Wicket gates
  - > Servo motors and dashpot
  - > Operating ring
  - > Links, levers. and pins
- > Refurbishment, replacement, modernization and/or installation of the following items:
  - > Stator core (refurbish)
  - > Rotor pole bodies, rotor spider and hub (refurbish)
  - > Relief valve (refurbish)
  - > Governor controls (modernization)
  - > Exciter controls (modernization)
  - > Unit controls (modernization)
  - > Turbine bearing and shaft seal replacement
  - > Synchronous condenser level controls (refurbish)
  - > Turbine pit hoist (install)
  - > Generator dust collector (install)
  - > Cooling water piping (modernize)
  - > High-pressure lift system (refurbish)

- > Site Works to include:
  - > Address spiral case leakage
  - > Line boring of head cover and bottom ring
  - > Machining of stay ring flanges
  - > Asbestos and lead abatement
- > Spare Parts provision to include the following items:
  - > Brake shoes and seals
  - > Bearing pads and springs
  - > Set of seals
  - > Slings
  - > Miscellaneous tooling

The intended schedule of the works as per [24] (Appendix A, Section 9.0 Planning Basis) are as follows:

- > Approval by the PUB in Q4 2025
- > Preliminary Engineering in 2025, to support long lead equipment procurement
- > Detailed Engineering starting in Q1 2026 following the PUB approval
- > Mobilization, construction and commissioning from Q1 to Q4 2028

The planned works for the life extension of Unit 7 are mostly consisting of the major overhaul of the E&M equipment already installed at Unit 7 with no major interface with the intended civil works for the additions of Unit 8.

On the other hand, the works within the powerhouse building will have an intense interface between Unit 7 life extension and Unit 8 installation and having these two contract packages in terms of both the management (EPCM) as well as the construction and installation will, at least, present the following advantages:

- > Interaction, training and continuity of the team
- > Hydro's Management Costs
- > Potential savings/optimisation on Camps and other common indirect cost items for the construction and installation works

As far as the schedule is concerned, some works will be overlapping with the Heavy Construction activities of Unit 8 that is targeted to start in [REDACTED], however the initiator activities are considered to be the ones that are geographically located in the upstream sections of the project (i.e. intake, penstock) therefore the avoidance of the clashing of the works within the powerhouse can be managed with a careful planning.

Consequently, the recent updated planning of Hydro in terms of managing the two projects in the same package with respect to EPCM and Hydro's internal management as well as the Contracting strategy of combining the E&M works for the new Unit 8 and Life Extension of Unit 7 makes sense in terms of technical, commercial and schedule aspects.

## 9.6 Conclusions and Recommendations

▶ **Conclusion 9-1 – Medium:** The overall construction plan for the BDE Unit 8 project is considered sound, making good use of the existing facilities, site access, and work structure. The recent decision to combine the management and contracting for Unit 8 construction, Unit 7 life extension, and penstock refurbishment should help reduce scheduling conflicts and management risks,

However, the analysis highlights several key challenges:

- > ▶ **Conclusion 9-2 – Medium:** Complex Powerhouse Work: The most difficult part of the project will be building the powerhouse extension right next to the currently operating Unit 7. Excavation activities, especially trenching and blasting near the penstock entrance, must be done slowly and carefully using specialised methods to avoid damaging Unit 7. This necessary caution means the main civil construction work for the powerhouse will likely require two full years, forcing a break during the cold winter months.
- > ▶ **Conclusion 9-3 – Low:** The scheduled times for critical installations like the draft tube [REDACTED] and stay ring [REDACTED] seem too short and must be checked with the equipment supplier.
- > ▶ **Conclusion 9-4 – Medium:** Contracting Confusion: The scope needs clarifying, specifically regarding the assignment of major equipment like the GSU transformer and 230 kV circuit breakers. These items are currently assigned to the Heavy Civil Contractor, but they should be moved to the Electro-Mechanical (E&M) Contractor, who has the appropriate expertise

The following actions are recommended to address risks in the construction schedule and constructability plan:

- > ▶ **Recommendation 9-1 – High:** Refine the Construction Schedule:
  - > Verify Critical Durations: Immediately check and confirm the short durations set for critical path items, such as the draft tube installation [REDACTED] and stay ring installation [REDACTED] with the equipment supplier.
  - > Add Detailed Milestones: Implement a more detailed set of checkpoints in the schedule to clearly manage dependencies and handoffs between different contractors (e.g., setting dates for civil work readiness before Hydro-Mechanical or Electro-Mechanical installations begin).
- > ▶ **Recommendation 9-2 – High:** Clarify Contractor Scopes and Strategy:
  - > Reassign Electrical Equipment (Medium Risk): Reassign the procurement and installation of the GSU transformer and 230 kV circuit breakers from the Heavy Civil Contractor to the E&M Contractor. This will better match the work with the correct specialized contractor.
  - > Expand T/G Competition: The initial design and modelling phase (Phase 1) for the Turbine and Generator contract should not be limited to only one vendor. Keeping options open prevents a potential price increase and ensures competition for the final contract.
  - > Define Power Needs: The Request for Proposals (RFP) for contractors must clearly define the power supply requirements for different construction sites, including the exact location and condition of the end terminals.

- > Clarify Contractor Titles: Ensure consistency by clearly defining the difference between the "Construction Contractor" and the "Heavy Civil Contractor" in all project documents.
- > ► **Recommendation 9-3 – High: Mitigate Constructability Risks:**
  - > Address Seepage Risk at Intake: The final plan for excavation and reconstruction near the intake must carefully address the risk that trenching could create an opening in the existing dam's grout curtain, potentially leading to uncontrolled water release or seepage.
  - > Re-evaluate Sheet Piling: The necessity and scope of using sheet piling or other protection measures for the penstock trench should be re-evaluated.
  - > Coordinate Unit 7 Outages: Clearly define and coordinate any planned short- or long-term outages of Unit 7 needed for early execution or modification activities, aligning them with water management and grid requirements. Successfully managing the construction phase of the BDE Unit 8 project requires precise coordination, where the new extension (Unit 8) must be built without disrupting the essential function of the adjacent, operating unit (Unit 7) and requires careful planning around the strict rhythm of the seasons.

## 10 Project Governance

This section aims to:

- > Describe the proposed project governance framework.
- > In the conclusion highlight good practices, as well as potential risks and strengths in the proposed governance based on Gruner's project delivery experience and common international practice.

### 10.1 Proposed Project Governance

The project will be delivered under the Major Projects Governance Framework[23], which aims to outline how large-scale capital investments projects are justified, planned, authorized, and managed effectively throughout their life cycle. The objectives of the of the Governance Framework are ultimately to introduce appropriate levels of scrutiny and accountability to control costs, deliver on time and with the sufficient quality.

The project governance relies essentially on the following pillars:

- > Introduction a governance mechanism based on three distinct groups to provide a single function between the following: oversight, risk management and change management respectively.
- > Introducing a governance structure including defined functions, powers to authorise expenditure and appropriate internal audit.
- > Introduction of a structured and phased approval process for developing the projects.
- > A defined Contracting and Procurement Strategy.

The governance document introduces a Major Projects Department, with a defined structure[22], guiding principles and governance mechanisms.

#### 10.1.1 Governance Mechanism

The following mechanisms are foreseen:

- > Oversight (Major Projects Steering Committee): This committee, comprised of Hydro's entire Executive Leadership Team including the President and CEO, provides strategic oversight, guidance, and approvals for all major projects. Its responsibilities include ensuring the Major Projects Portfolio remains aligned with Hydro's mandate and strategic goals, and reviewing all risks ranked as high and greater.
- > Risk Management (Major Projects Risk Working Group): This group, primarily composed of the Major Projects Department's Management Team, provides a forum for the comprehensive evaluation of risks. It proactively identifies and ranks risks, including corporate risks, that could impact the Major Projects Portfolio, and develops risk management strategies.
- > Change Management (Major Projects Change Control Committee): This committee evaluates proposed project and program changes that impact budget, scope, schedule, and quality. It ensures the effective management and approval of these changes (subject to defined authorization levels) and communicates the impacts to Hydro's corporate interfaces.

### 10.1.2 Governance Structure

The governance structure proposed by the Utility is shown in Figure 10-1. The role and responsibilities associated with each role are described in the Major Projects Governance Framework[23].

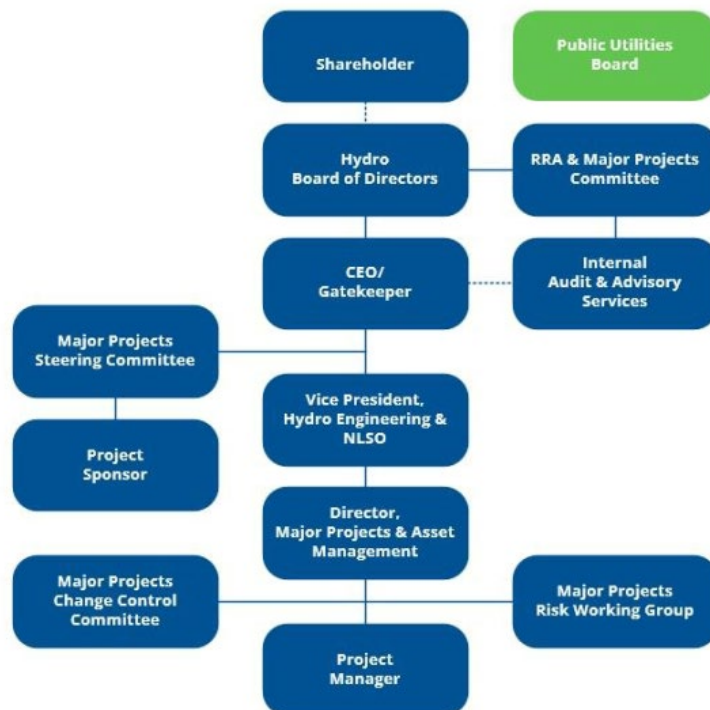


Figure 10-1: Major Projects Governance Structure

A budget differentiation and levels of approvals are defined in the governance structure as follows:

- > The Planned project budget, aimed to cover the Project Capital Cost Estimate plus Interest during Construction and Escalation. The Project Manager has the authority to manage within the approved baseline project budget.
- > The contingency budget, aimed to cover the "known unknowns" (uncertainties within the project scope). Use of Contingency requires the prior approval of the Director of Major Projects & Asset Management.
- > The Management Reserve, aimed to cover "strategic risks" or "unknown unknowns". Accessing any amount of the Management Reserve requires justification and prior approval of the CEO (Gatekeeper).

### 10.1.3 Major Projects Phased Approval Process

The major projects Phased Approval Process outlines how projects are developed and progressed by the Utility. The stages are:

- > Front-End Planning (FEP): This establishes project need, strategy, scope, cost, and schedule for early decision-making. It involves the following sub-phases:

- > Conceptual Design: Confirm need and identify alternatives (via RRA, asset programs, or customer requests).
- > Feasibility Design: Assess viable options technically, financially, environmentally, and regulatorily; refine to an AACE Class 4 estimate.
- > FEED: Refine scope and preliminary engineering; develop Class 3 estimate, schedule, risks, stakeholder input, and quality standards. Ensure operability and maintainability requirements. The end of the FEED phase coincides with the application to the Board, and this due diligence is part of the applications' review.
- > Phase 2: Execution: this includes detailed preparation and physical delivery of the asset, coordinated with Operations. It involves the following sub-phases:
  - > Detailed Design & Procurement: Finalize engineering, produce construction drawings/specs, and conduct vendor qualification, tendering, and contracting.
  - > Construction & Commissioning: Build, test, and commission the asset. Construction team maintains site presence; contractors provide operational readiness and handover documentation.
- > Phase 3: Close Out: this transitions to operations and formally close the project. It involves the following sub-phases:
  - > Transition to Operations: Transfer readiness deliverables, integrate systems, complete handover, finish construction close out, monitor performance, and shift risk ownership to Operations.
  - > Project Closure: Remove temporary works, confirm deliverables, complete financial/administrative closure, archive lessons learned, and finalize the closure report.

#### 10.1.4 Contracting and Procurement Strategy

The Utility aims to manage the project and award contract based on the following principles:

- > Minimize interface issues as they could result in legal claims regarding delays.
- > Award contracts based on Competitive Bidding: procurement activities are primarily conducted through competitive bidding unless a justification has been approved. The competitive bidding process is designed to achieve the best value for Hydro, taking into consideration technical quality, functionality, cost-effectiveness, health, safety, and environmental factors.
- > Fixed Price Basis: Where possible and economical, the strategy encourages awarding work on a fixed price basis.

#### 10.2 Conclusions and Recommendations

▶ **Conclusion 10-1 – High:** The suggested governance is compliant in several aspects to similar projects in the hydropower industry. The following good practices are key for successful project delivery:

- > Project budget authorization uses a P85 scenario for estimating the total project budget. The management reserve was estimated as the difference between the project costs with a P50 scenario and a P85 scenario. This looks appropriate to compensate for optimism bias.

- > Aiming to tender work based on a competitive bidding and on a fixed price basis.
- > Introducing supervisory bodies with separate and independent functions.
- > Ensuring the Board is updated via quarterly reports[1].

However, the following recommendations are made to address outstanding risks for the project's success:

- > ► **Recommendation 10-1 – High:** To enhance transparency and accountability adoption of e-procurement systems is recommended. After work is assigned, it is recommended to publish tender documents, evaluation criteria, winning bids, and contract terms.
- > ► **Recommendation 10-2 – High:** Decision of the Major Projects Change Control Committee should be well documented and made publicly accessible at regular intervals.
- > ► **Recommendation 10-3 – High:** Project management staff should receive training on the specific contract types being used and on the contractual mechanisms that contractors may legitimately rely on to pursue additional payments or time extensions. For instance, when using FIDIC contracts:
  - > Under the Red Book (measurement-based), contractors may have an incentive to identify and claim variations that increase measured quantities or introduce additional works.
  - > Under the Silver Book (EPC/turnkey), contractors may have an incentive to highlight deficiencies or ambiguities in the employer's requirements in order to claim compensation or time for design-related changes.
  - > Although in the Canadian market Canadian Construction Documents Committee (CCDC) are normally used, it is essential that the Project Management staff is aware and well trained on their mechanisms and how risk is allocated between the parties.

## 11 Conclusion

It is Gruner's opinion that the BDE Unit 8 Project has been developed to a level of detail consistent with the current stage and provides a sufficient basis for proceeding toward the Execution phase as identified in the Governance Framework[23].

The following conclusions are made:

1. The project has been developed to a level of detail aligned with an AACE Class 3 estimate, which is typically used as a basis for budget authorization and appropriation. This approach is consistent with standard practice for hydropower projects and is based on quantities derived from a deterministic methodology.
2. The project's technical solution largely replicates the existing Unit 7 configuration and provides a low risk profile from the Utility's familiarity with the site.
3. Studies indicate that the system has adequate storage and hydraulic capacity to supply the required water during a prolonged LIL outage. However, certain hydrological risks require further clarification, including the potential effects of rapid water level reductions in Long Pond on ice cover during winter outages. Additionally, achieving full generation capacity during a LIL outage may necessitate continuous operation of the Upper Salmon spillway, and further assessment of associated risks and constraints is recommended.
4. The project's governance framework is aligned with standard practices for major projects.
5. The Utility's use of a P85 scenario to estimate the total project budget and establish a Management Reserve (\$145 million) provides a mechanism to address potential optimism bias and aligns with recognized guidance.
6. The project budget is generally consistent with the scale of the project in the region, including a substantial Management Reserve. Additional details on the Monte Carlo analysis are recommended to support transparency and coverage of strategic risks. Incorporating sensitivity analysis for major exogenous risks, such as a one-year schedule delay, into the Monte Carlo analysis is advised.
7. The overall project layout and work sequencing are realistic; however, certain programme and design elements require further definition, in particular:
  - a. Key durations for critical path activities (e.g., draft tube and stay ring installation) should be verified with suppliers.

Gruner's review is limited by the following exclusions:

- > Gruner did not evaluate the need for the project, as it is driven by Utility-defined capacity targets.
- > Gruner did not evaluate the project timing or the potential to defer it in favour of other projects.

A summary of the Risks and Recommendations with High Impact rating is shown in the table below. All the items with lower impact rating are in Appendix B: Risk, Recommendations and Conclusions Register.

ID	Long description of the risk	Risk Title	Category	Impact
Risk 3-2	For Unit 8 to achieve its purpose of increasing peak generation capacity during a Labrador-Island Link (LIL) outage, the Upper Salmon bypasses will need to be used to supply Long Pond and the Baie d'Espoir Power Plant. [2]	Unit 8 reliance on Upper Salmon bypass	Hydrology/Operation	High
Conclusion 3-1	The issue of reservoir refill is addressed satisfactorily, as all three major storage reservoirs are projected to be refilled to at least 71% capacity by the end of July. [3]	Bypass spillway environmental concerns	Hydrology/Operation	High
Conclusion 4-1	The total factored contingency, which includes the Design Development Allowance (DDA), amounts to 98.3 mCAD, corresponding to 13.9% of the base estimate. [4]	Major reservoir refill satisfactory	Hydrology/Operation	High
Conclusion 4-2	A lower contingency of 13.9% is justified despite the feasibility-level design (which usually requires 30%), owing to the standard design, the management reserve, the utility's knowledge of the area, and operational history. [5, 6]	Factored contingency amount is 13.9%	Cost/Methodology	High
Conclusion 4-3	The methodology used by the Utility aligns with AACE Class 3 Estimate recommendations and common practice for international hydropower projects. [7]	Lower contingency of 13.9% justified	Cost/Methodology	High
Risk 4-1	Appropriate oversight, budgeting, and activation protocols must be ensured for the 13.9% contingency (including the DDA) to prevent misuse of funds intended for design development and usual project risks. [8]	AACE Class 3 methodology compliance	Cost/Methodology	High
Conclusion 4-4	The Management Reserve amount is appropriate (P85 threshold); however, integrating sensitivity scenarios (like a 1-year delay) into the Monte Carlo analysis is recommended. [9]	Oversight needed for contingency use	Cost/Governance	High
Conclusion 5-3	The final project price appears generally consistent with, and slightly conservative relative to the scale of similar projects in the region. [11]	TS 2 structural steel scope unclear	Cost/BOQ	High
Recommendation 5-1	The final cost per unit of installed items should be published to facilitate benchmarking against other international projects. [12]	Final project price acceptable	Cost/Benchmark	High
Recommendation 7-8	Elevated seismic demands must be explicitly considered in the assessment to mitigate potential adverse impacts, given the project site's proximity to an active seismic zone. [46, 48]	Accommodate interface misalignments	PG/Civil Works	High
Recommendation 7-13	The Unit 8 steel superstructure extension must be verified against current structural codes and loads, and the existing Unit 7 structure assessed for refurbishment needs and cold weather performance. [54, 55]	Crane rail differential movement design	PG/Crane/Structure	High

Recommendation 9-1	The construction schedule must be refined by clearly defining the winter break, verifying critical path durations with suppliers, and implementing detailed intermediate milestones. [73]	Refine schedule: winter break/durations	Constructability/Schedule	High
Recommendation 9-2	Contractor scopes must be clarified by reassigning electrical equipment to the E&M Contractor, ensuring the Turbine/Generator Phase 1 competition is not limited to one vendor, and clearly defining power supply requirements in the Request for Proposals (RFP). [72, 74]	Clarify scopes, expand T/G competition	Constructability/Contracting	High
Recommendation 9-3	Constructability risks must be mitigated by carefully planning excavation near the intake to avoid opening the existing dam's grout curtain, re-evaluating the use of sheet piling, and coordinating all planned stoppages of Unit 7. [75, 76]	Mitigate intake excavation seepage risk	Constructability/Risk Mitigation	High
Conclusion 10-1	The suggested governance aligns with international hydropower projects notably by using a P85 scenario for budget/Management Reserve estimation and promoting competitive fixed-price bidding. [77-79]	Project Governance	Governance	High
Recommendation 10-1	Adoption of e-procurement systems and public disclosure of tender documents, evaluation criteria, winning bids, and contract terms is recommended to enhance transparency and accountability. [80]	Adopt e-procurement and publish tenders	Governance/Transparency	High
Recommendation 10-2	Decisions made by the Major Projects Change Control Committee should be well documented and made publicly accessible at regular intervals. [80]	Document, publish change committee decisions	Governance/Transparency	High
Recommendation 10-3	Project management staff should receive training on the specific contract types used (e.g., CCDC) and the contractual mechanisms that contractors may use for time or payment claims. [81, 82]	Remote location bidder risk controlled	Governance/Risk Mitigation	High

## 12 Appendix A: Document List

NO	FILE NAME	DATE RECEIVED
1	01 - Schedule 1 - Application Overview.pdf	2 September
2	02 - Schedule 1 Appendix A - Lessons Learned Overview.pdf	
3	03 - Schedule 1 Appendix B - Governing Bodies Overview.pdf	
4	04 - Schedule 1 Appendix C - Major Projects Team Overview.pdf	
6	06 - Schedule 1 Attachment 1 - Governance Framework.pdf	
7	07 - Schedule 1 Attachment 2 - Hydrology and Feasibility Study BDE 8 - Addendum Report.pdf	
11	11 - Schedule 4 - BDE 8 Project Evidence.pdf	
12	12 - Schedule 4 Appendix A - BDE 8 Project Budget Breakdown.pdf	
13	13 - Schedule 4 Appendix B - BDE 8 Critical Path Schedule.pdf	
14	14 - Schedule 4 Appendix C - BDE 8 Engagement Summary.pdf	
15	15 - Schedule 4 Attachment 1 - BDE 8 Basis of Estimate (incl. FEED Study).pdf	
16	16 - Schedule 4 Attachment 2 - BDE 8 Basis of Schedule.pdf	
36	36 - June 2025 - Attachment 11 - BDE 8 FEED Report Introduction (AtkinsRéalis 2024).PDF	
37	37 - June 2025 - Attachment 12 - BDE 8 Basis of Design.PDF	
38	38 - June 2025 - Attachment 13 - BDE 8 Scope of Work, AtkinsRealis.PDF	
39	39 - June 2025 - Attachment 14 - BDE 8 Options Analysis Report (AtkinsRealis).PDF	
40	40 - June 2025 - Attachment 15 - BDE 8 Concept Design Update Report (AtkinsRéalis 2024).PDF	
41	41 - June 2025 - Attachment 16 - BDE 8 Monte Carlo Simulation Documents.PDF	
42	42 - June 2025 - Attachment 17 - BDE 8 FEED Risk and Assumption Register (AtkinsRealis).PDF	
43	43 - June 2025 - Attachment 18 - BDE 8 Hydraulic Analysis of the Conveyance (SNC-Lavalin 2018).PDF	
44	44 - June 2025 - Attachment 19 - BDE 8 Class 3 Cost Estimate and Project Execution Schedule (SNC-Lavalin 2018).PDF	
45	45 - June 2025 - Attachment 20 - BDE 8 Unit 8 Summary Report (2018).PDF	
46	46 - June 2025 - Attachment 21 - BDE 8 Unit 8 Summary Report (2022).PDF	
47	47 - BDE 7 Life Extension Application.pdf	
53	53 - Hatch 2020 Hydrology Report from 2022 RRA Update.pdf	23 September
54	54 - BDE Hydrology Map.pdf	
55	55 - Impact of Prolonged Loss of LIL on Island Reservoir - Appendix C Attachment 5 from 2024 RRA.pdf	
1001	2025-10-15 Bates White Vista Analysis Report rev0_Final.pdf	19 October
1002	Follow-up re: today's call on hydrology – Matthew Halloran	22 October
101	Response to RFI #001. BW-NLH-001.pdf	1 November
102	Response to RFI #002. BW-NLH-002.pdf	2025
103	Response to RFI #003. BW-NLH-003.pdf	
104	Response to RFI #004. BW-NLH-004.pdf	
105	Response to RFI #005. BW-NLH-005.pdf	
106	Response to RFI #006. BW-NLH-006.pdf	
107	Response to RFI #007. BW-NLH-007.pdf	
108	Response to RFI #008. BW-NLH-008.pdf	

- 109 | Response to RFI #009. BW-NLH-009.pdf
- 110 | Response to RFI #010. BW-NLH-010.pdf
- 111 | Response to RFI #011. BW-NLH-011.pdf
- 112 | Response to RFI #012. BW-NLH-012.pdf
- 113 | Response to RFI #013. BW-NLH-013.pdf
- 114 | Response to RFI #014. BW-NLH-014.pdf
- 115 | Response to RFI #015. BW-NLH-015.pdf
- 116 | Response to RFI #016. BW-NLH-016.pdf
- 117 | Response to RFI #017. BW-NLH-017.pdf
- 118 | Response to RFI #018. BW-NLH-018.pdf

## **13 Appendix B: Risk, Recommendations and Conclusions Register**

No	ID	Long description of the risk	Risk Title	Category	Impact
1	Risk 3-1	The possibility of a rapid lowering of Long Pond's water level during winter months could affect ice cover, requiring additional mitigation measures at the intakes. [1]	Winter water level/ice risk	Hydrology/Operation	Medium
2	Risk 3-2	For Unit 8 to achieve its purpose of increasing peak generation capacity during a Labrador-Island Link (LIL) outage, the Upper Salmon bypasses will need to be used to supply Long Pond and the Baie d'Espoir Power Plant. [2]	Unit 8 reliance on Upper Salmon bypass	Hydrology/Operation	High
3	Conclusion 3-1	The issue of reservoir refill is addressed satisfactorily, as all three major storage reservoirs are projected to be refilled to at least 71% capacity by the end of July. [3]	Bypass spillway environmental concerns	Hydrology/Operation	High
4	Conclusion 4-1	The total factored contingency, which includes the Design Development Allowance (DDA), amounts to 98.3 mCAD, corresponding to 13.9% of the base estimate. [4]	Major reservoir refill satisfactory	Hydrology/Operation	High
5	Conclusion 4-2	A lower contingency of 13.9% is justified despite the feasibility-level design (which usually requires 30%), owing to the standard design, the management reserve, the utility's knowledge of the area, and operational history. [5, 6]	Factored contingency amount is 13.9%	Cost/Methodology	High
6	Conclusion 4-3	The methodology used by the Utility aligns with AACE Class 3 Estimate recommendations and common practice for international hydropower projects. [7]	Lower contingency of 13.9% justified	Cost/Methodology	High
7	Risk 4-1	Appropriate oversight, budgeting, and activation protocols must be ensured for the 13.9% contingency (including the DDA) to prevent misuse of funds intended for design development and usual project risks. [8]	AACE Class 3 methodology compliance	Cost/Methodology	High
8	Conclusion 4-4	The Management Reserve amount is appropriate (P85 threshold); however, integrating sensitivity scenarios (like a 1-year delay) into the Monte Carlo analysis is recommended. [9]	Oversight needed for contingency use	Cost/Governance	High
9	Conclusion 5-1	For Terminal Station 2 modifications, the calculated civil works quantities do not justify the high costs presented in the BOQ, as the scope indicated in the drawings is more limited. [10]	Integrate delay scenario into Monte Carlo	Cost/Methodology	Medium
10	Conclusion 5-2	The scope of structural steel for Terminal Station 2 is unclear due to insufficient detail in the drawings regarding gantries or supporting structures. [10]	TS 2 civil works costs high	Cost/BOQ	Low
11	Conclusion 5-3	The final project price appears generally consistent with, and slightly conservative relative to the scale of similar projects in the region. [11]	TS 2 structural steel scope unclear	Cost/BOQ	High
12	Recommendation 5-1	The final cost per unit of installed items should be published to facilitate benchmarking against other international projects. [12]	Final project price acceptable	Cost/Benchmark	High
13	Recommendation 5-2	The results of the P85 Monte Carlo analysis for each Construction Work Area should be made available to enable comparative assessment. [12]	Publish unit cost for benchmarking	Cost/Transparency	Medium
14	Recommendation 5-3	While not included in the Monte Carlo analysis, fluctuations in commodity markets and trade disputes are likely to offset each other, resulting in minimal impact on the overall analysis magnitude. [12]	Provide P85 Monte Carlo results	Cost/Methodology	Low
15	Conclusion 5-4	The Management Reserve (13.5% of total cost) is consistent with goor practices from hydropower projects; its allocation is considered reasonable and prudent provided further determination details are supplied. [13]	Commodity fluctuations negligible impact	Cost/Exogenous Factors	Medium
16	Recommendation 5-4	Clarification is recommended for the fencing scope (type, length, location) for the headrace channel (BOQ item 3.1.10), though the uncertainty is negligible (0.1% of direct cost). [14]	Management Reserve is reasonable	Cost/Methodology	Low
17	Recommendation 5-5	Although reinforcement steel quantities for the Intake Structure appear underestimated (0.5% of direct cost), the potential cost impact is negligible, but this should be addressed in the detailed design phase. [15]	Clarify headrace channel fencing scope	Cost/BOQ	Low
18	Recommendation 5-6	The penstock excavation quantity in the BOQ should be revised to reflect the updated alignment and recalculated volume, correcting a minor financial impact (0.18% of total cost) for consistency. [15]	Intake steel underestimated, negligible impact	Cost/BOQ	Low
19	Recommendation 5-7	The reinforcement steel quantity for the powerhouse structure should be recalculated using a ratio of 120 kg/m <sup>3</sup> (instead of the apparent 100 kg/m <sup>3</sup> ) to better reflect the expected reinforcement demand. [16, 17]	Revise penstock excavation quantity	Cost/BOQ	Low
20	Recommendation 5-8	Design clarification is needed for the structural steel quantities and anchor bolts in the powerhouse superstructure, as BOQ values seem high, though their contribution to total direct cost is very low. [16]	Recalculate powerhouse steel ratio (120kg/m <sup>3</sup> )	Cost/BOQ	Low
21	Recommendation 5-9	The BOQ civil works costs for Terminal Station 2 modifications appear disproportionately high compared to the limited scope in the drawings, requiring cost basis revision or clarification. [18]	Clarify powerhouse steel/anchor bolts	Cost/BOQ	Medium
22	Recommendation 5-10	The scope and quantities of structural steel for Terminal 2 Modifications cannot be reliably verified due to insufficient detail in the drawings regarding gantries and supporting structures. [18]	TS 2 civil costs disproportionately high	Cost/BOQ	Medium
23	Recommendation 5-11	The cost and breakdown of the Control Building's Architectural Scope must be clarified, as the lump sum appears elevated relative to the expected scope if it only covers architectural work. [19, 20]	Cannot verify TS 2 structural steel	Cost/BOQ	Medium
24	Conclusion 6-1	The adjusted version of Alternative 1 for the headrace channel excavation is the most feasible option, offering improved flow dynamics and minimized risk to existing Unit 7 operations. [21, 22]	Clarify Control Building Architectural Scope	Cost/BOQ	Medium
25	Risk 6-1	Frazil ice formation is a key risk affecting headrace channel geometry and operating velocities, but it can be mitigated through appropriate ice-management measures. [23]	Adjusted Alternative 1 most feasible	WCS/Design	Medium
26	Recommendation 6-1	2D hydrodynamic simulations are recommended to assess the impact of additional flow on the south channel, evaluate erosion risk at the channel junction, and investigate surge effects from sudden Unit 8 operation. [23, 24]	Frazil ice formation risk key	WCS/Design Risk	Medium
27	Recommendation 6-2	Intake civil works require careful attention to trash rack functionality, hydraulic system performance in extreme temperatures, and uplift stability to address hydrostatic and seepage risks. [24]	Conduct 2D hydrodynamic simulations	WCS/Hydraulic Modelling	Medium
28	Recommendation 6-3	The steel penstock design must handle transient/steady-state pressures without reliance on surge tanks, incorporate corrosion protection, and address burial depth requirements for freeze-prone conditions. [25-27]	Intake civil works require attention	WCS/Intake	Medium

No	ID	Long description of the risk	Risk Title	Category	Impact
29	Recommendation 6-4	For the penstock bridge, provisions for cold-region conditions, stress management at supports, and mitigation of snow/ice impacts are critical; precautions are needed during riprap installation to protect coatings. [25, 28, 29]	Verify penstock pressure and protection	WCS/Penstock	Medium
30	Recommendation 6-5	Further modelling and analysis are required for tailrace channel widening to optimize design, address backwater effects, and ensure protection of the powerhouse floor during extreme hydrological events. [30-32]	Address penstock bridge cold conditions	WCS/Penstock Bridge	Medium
31	Recommendation 6-6	A comprehensive grouting program for the temporary rock plug must be explicitly defined and confirmed in the scope due to anticipated significant seepage through fractured siltstone. [33, 34]	Further tailrace widening modelling needed	WCS/Tailrace	Medium
32	Recommendation 6-7	The powerhouse rock foundation should be established on competent siltstone, with weak zones replaced by dental concrete and contact grouting verified by water pressure tests. [26, 33]	Define rock plug grouting program	WCS/Civil Works	Medium
33	Recommendation 6-8	The steel liner and penstock must be verified for hydraulic transients and steady-state pressure envelopes during detailed design, given the absence of a main inlet valve or surge tank. [27, 35]	Powerhouse foundation on competent siltstone	PG/Foundation	Medium
34	Recommendation 6-9	Pipeline burial depth must extend below the design frost line, and additional cover/freeze-protection measures verified and incorporated during detailed design in the freeze-susceptible climate. [27, 35]	Verify penstock hydraulic pressures	WCS/Penstock	Medium
35	Recommendation 6-10	Trench excavation and controlled blasting must be engineered to avoid adverse effects on the existing penstock, prioritizing controlled blasting and limiting sheet pile use to geologically suitable areas. [36, 37]	Verify pipeline burial depth/frost line	WCS/Penstock	Low
36	Recommendation 6-11	The penstock-structure interface at the bridge should include fixed and guided supports to manage axial thrusts and local shell stresses. [28, 38]	Controlled blasting near existing penstock	WCS/Penstock	Low
37	Recommendation 6-12	Cold-region detailing for the penstock bridge, including air-entrained concrete, increased cover, sealed joints, and drainage, is required to prevent ice jacking. [28, 38]	Penstock bridge needs fixed supports	WCS/Penstock Bridge	Low
38	Recommendation 6-13	The 30 cm riprap cover over the penstock should be detailed with appropriate cushioning and backfill layering, installed with controlled placement to prevent damage to the steel shell or coatings. [29, 39]	Cold-region detailing for bridge	WCS/Penstock Bridge	Low
39	Recommendation 7-1	A separate erection bay for Unit 8 is likely unnecessary and should be removed from scope if the existing Unit 7 facility meets lifting capacity, access, and scheduling needs. [40, 41]	Detailing riprap cover over penstock	WCS/Penstock	Medium
40	Recommendation 7-2	The elevator proposed for Unit 8 could be omitted, provided all regulatory and safety requirements are met (as Unit 7 operates without one). [40, 42]	Remove separate Unit 8 erection bay	PG/Powerhouse Design	Medium
41	Recommendation 7-3	A dedicated fire pump for Unit 8 may be unnecessary if the existing Unit 7 fire pump system is assessed and upgraded to meet the combined system demand. [42, 43]	Omit Unit 8 elevator if safe	PG/Powerhouse Design	Low
42	Recommendation 7-4	A program of periodic condition monitoring and timely repairs is recommended for legacy structural elements to sustain performance over the 25-year refurbishment period. [43, 44]	Dedicated fire pump likely unnecessary	PG/BOP	Low
43	Recommendation 7-5	A finite element model of the combined powerhouse structure (existing and new) should be developed and analyzed to verify capacity and deformation behavior. [44, 45]	Monitor legacy structural elements	PG/Structure	Low
44	Recommendation 7-6	Overall slope and excavation stability in the construction area should be evaluated for operational and transient conditions (e.g., drawdown, seismic, rainfall). [44, 45]	FE model for combined powerhouse structure	PG/Structure	Low
45	Recommendation 7-7	Interface misalignments due to time-dependent deformations in the existing powerhouse should be accommodated in construction detailing, with injection grouting used if necessary. [46, 47]	Evaluate slope/excavation stability	PG/Civil Works	Low
46	Recommendation 7-8	Elevated seismic demands must be explicitly considered in the assessment to mitigate potential adverse impacts, given the project site's proximity to an active seismic zone. [46, 48]	Accommodate interface misalignments	PG/Civil Works	High
47	Recommendation 7-9	Appropriate strengthening and deformation control measures should be defined during detailed design for the fractured siltstone bedrock. [49, 50]	Explicitly consider elevated seismic demands	PG/Structure Risk	Low
48	Recommendation 7-10	Foundations should be designed to bear directly on competent bedrock where feasible, avoiding reliance on thin overburden layers. [49, 51]	Define bedrock strengthening measures	PG/Foundation	Low
49	Recommendation 7-11	Conservative slope angles or rock reinforcement (bolts, mesh) should be used for excavation support in jointed or weathered zones. [51, 52]	Bear foundations on competent bedrock	PG/Foundation	Low
50	Recommendation 7-12	The crane rail must be continuous across the expansion joint between the old and new powerhouses, requiring the design to explicitly accommodate horizontal and vertical differential movements. [52, 53]	Use rock reinforcement for excavation	PG/Civil Works	Medium
51	Recommendation 7-13	The Unit 8 steel superstructure extension must be verified against current structural codes and loads, and the existing Unit 7 structure assessed for refurbishment needs and cold weather performance. [54, 55]	Crane rail differential movement design	PG/Crane/Structure	High
52	Conclusion 7-1	The current design documentation is at the concept stage, meaning accurate and detailed comparisons will only be feasible upon completion of the Final/Detailed Design phases. [54]	Verify superstructure against current codes	PG/Structure	Medium
53	Conclusion 7-2	Quantities for main electrical equipment and electrical Balance of Plant (BOP) are consistent with the BOQ and align with the total direct cost. [56]	Accurate comparisons need detailed design	PG/Design Status	Medium
54	Conclusion 7-3	The concept for power supply for construction sites is missing, although the energy costs are included in the estimate; a separate detailed design for this is needed before construction starts. [57]	Electrical BOP quantities consistent	PG/Electrical BOP	Medium
55	Recommendation 8-1	Terminal Station No. 2 foundations must be designed based on site-specific geotechnical parameters, explicitly allowing for frost depth, heave, and freeze-thaw degradation. [58]	Construction power supply concept missing	PG/Construction Planning	Low
56	Recommendation 8-2	Foundations should bear on competent ground below frost penetration or incorporate suitable frost-protected shallow foundation details and free-draining backfill. [58]	Design TS 2 foundations for frost	TS/Foundation	Low
57	Recommendation 8-3	The arrangement of internal access roads and trafficable surfaces around the new terminal station extension must be clearly defined in the next design phase. [59]	Foundations below frost penetration	TS/Foundation	Low

No	ID	Long description of the risk	Risk Title	Category	Impact
58	Recommendation 8-4	The control building should be located on a raised, well-drained platform above the design flood level, coordinated with site drainage. [60]	Define TS 2 internal access roads	TS/Civil Works	Low
59	Recommendation 8-5	Control building foundations require site-specific geotechnical investigation, considering frost depth and controlling differential settlement at penetrations. [61]	Control building above flood level	TS/Civil Works	Low
60	Recommendation 8-6	A simple, robust structural system for the control building must be designed to current wind, snow, and seismic codes. [61]	Control building foundation investigation	TS/Foundation	Low
61	Recommendation 8-7	Underground duct banks and cable trenches between the control building, switchyard, and powerhouse must be fully coordinated, made watertight at building entry, and sized for future circuits. [62]	Control building robust structural design	TS/Structure	Low
62	Conclusion 8-1	Design documentation for the Transmission Line and Terminal Station #2 is currently at the concept stage; accurate comparisons require completion of Final/Detailed Design. [63, 64]	Coordinate underground cabling/duct banks	TS/Design Status	Medium
63	Conclusion 8-2	Quantities for High Voltage equipment are consistent with the BOQ and align with the total direct cost. [64]	TL/TS 2 design at concept stage	TS/Electrical BOP	Medium
64	Conclusion 8-3	It is unclear whether variant solutions were considered for the proposed 1.9 km 230 kV line route between Unit 7 and Terminal Station 2. [65]	Variant solutions for 230 kV line unclear	TL/Design	Medium
65	Conclusion 9-1	The overall construction plan is sound, and the decision to combine management/contracting for Unit 8, Unit 7 life extension, and penstock refurbishment should reduce schedule conflicts and risks. [66]	Combined project management is sound	Constructability/Planning	Medium
66	Conclusion 9-2	Powerhouse civil construction is complex, adjacent to operating Unit 7, requiring careful excavation/blasting over two construction seasons and a likely winter break. The PUB approval process is delayed to 2026. [67]	Complex powerhouse work and PUB delay	Constructability/Schedule	Medium
67	Conclusion 9-3	The schedule needs refinement, including clear delineation and verification of short durations programmed for critical installations (e.g., draft tube: ██████ stay ring: ██████). [68-70]	Schedule needs further definition	Constructability/Schedule	Low
68	Conclusion 9-4	The assignment of major electrical equipment (GSU transformer, 230 kV circuit breakers) to the Heavy Civil Contractor is inappropriate and should be clarified and moved to the E&M Contractor. [68, 71, 72]	Reassign electrical equipment from Civil Contractor	Constructability/Contracting	Medium
69	Recommendation 9-1	The construction schedule must be refined by clearly defining the winter break, verifying critical path durations with suppliers, and implementing detailed intermediate milestones. [73]	Refine schedule: winter break/durations	Constructability/Schedule	High
70	Recommendation 9-2	Contractor scopes must be clarified by reassigning electrical equipment to the E&M Contractor, ensuring the Turbine/Generator Phase 1 competition is not limited to one vendor, and clearly defining power supply requirements in the Request for Proposals (RFP). [72, 74]	Clarify scopes, expand T/G competition	Constructability/Contracting	High
71	Recommendation 9-3	Constructability risks must be mitigated by carefully planning excavation near the intake to avoid opening the existing dam's grout curtain, re-evaluating the use of sheet piling, and coordinating all planned stoppages of Unit 7. [75, 76]	Mitigate intake excavation seepage risk	Constructability/Risk Mitigation	High
72	Conclusion 10-1	The suggested governance aligns with international hydropower projects notably by using a P85 scenario for budget/Management Reserve estimation and promoting competitive fixed-price bidding. [77-79]	Project Governance	Governance	High
73	Recommendation 10-1	Adoption of e-procurement systems and public disclosure of tender documents, evaluation criteria, winning bids, and contract terms is recommended to enhance transparency and accountability. [80]	Adopt e-procurement and publish tenders	Governance/Transparency	High
74	Recommendation 10-2	Decisions made by the Major Projects Change Control Committee should be well documented and made publicly accessible at regular intervals. [80]	Document, publish change committee decisions	Governance/Transparency	High
75	Recommendation 10-3	Project management staff should receive training on the specific contract types used (e.g., CCDC) and the contractual mechanisms that contractors may use for time or payment claims. [81, 82]	Remote location bidder risk controlled	Governance/Risk Mitigation	High

## **14 Appendix C: RFI and Responses**

1 Q. Throughout the reports we found references to the Muskrat Falls Key Findings and  
2 Recommendations as if it was two different Reports. Do both refer to this particular report?  
3 [https://www.muskratfallsinquiry.ca/files/Volume-1-Executive-Summary-Key-Findings-and-](https://www.muskratfallsinquiry.ca/files/Volume-1-Executive-Summary-Key-Findings-and-Recommendations-FINAL.pdf)  
4 [Recommendations-FINAL.pdf](https://www.muskratfallsinquiry.ca/files/Volume-1-Executive-Summary-Key-Findings-and-Recommendations-FINAL.pdf)

5

6

7 A. It is confirmed that both refer to the referenced Volume 1 report.

1 Q. In Schedule 4 Attachment 1 - BDE 8 Basis of Estimate, the cost breakdowns are presented in  
2 tabular form from pages 37-42. Please provide in .xls or .csv format.

3

4

5 A. The spreadsheet provided as BW-NLH-002, Attachment 1 in Microsoft Excel .xls format, includes  
6 these tables in four separate worksheets within the workbook. The information has been  
7 highlighted in grey for redaction in any public-facing documents or reports, consistent with the  
8 treatment of similar information submitted in the 2025 Build Application.

1 Q. Schedule 4 Attachment 1 mentions that “[t]he Bill of Quantities (BOQ) or Material Takeoff  
2 (MTO) was generated by a number of methods, e.g., Computer Aided Three-Dimensional  
3 Interactive Application (Catia 3D), AutoCAD 3D, Two-Dimensional (2D) model and sections  
4 utilizing the updated 2024 model, FEED (current) drawings, Google Earth mapping, manual hand  
5 calculations, site visit information, and previous project ratios, all of which were reviewed and  
6 vetted by experienced Subject Matter Experts (SMEs).” Please provide digitized versions of  
7 those data (in particular the FEED drawings and any CAD model).

8

9

10 A. Relevant digital files provided by the front-end engineering design (“FEED”) consultant are  
11 attached, including drawings and associated native CAD<sup>1</sup> files. Manual hand calculations  
12 performed by the FEED consultant were not supplied to Newfoundland and Labrador Hydro.

---

<sup>1</sup> Computer-Aided Design (“CAD”).

1 Q. Regarding the Unit 8 Tailrace Wall built in 1977, which will be used for the new unit: Please  
2 provide any surveys/assessments of the current condition of this wall now. If no such surveys or  
3 assessments exist, does Hydro have any evidence that the wall is not in poor condition? Please  
4 explain.

5

6

7 A. BW-NLH-004, Attachment 1, "*BDE Unit 8 Infrastructure Assessment Report*" (Document #  
8 259284-0000-BA10-RPT-0001) was completed by Wood Canada Limited in January 2024 to  
9 assess the condition of the existing Unit 8 tailrace wall, draft tube deck, draft tube passages,  
10 opening slots, guides, and embedded parts. The condition assessment showed that the existing  
11 concrete infrastructure is generally in good condition with only minor refurbishments, such as  
12 sealing and painting, recommended. It was also recommended to complete a dimensional  
13 survey of the gate guides to verify straightness and plumbness and confirm that they will  
14 provide adequate sealing when required for use. This follow-up dimensional survey is currently  
15 underway and is scheduled to be completed by the first quarter of 2026. The cost estimate for  
16 the project includes costs for the expected refurbishments and allowances for gate guide repairs  
17 should the dimensional survey indicate that they are necessary.



# Document Front Sheet

Contract Number and Description: **7969**  
**Condition Assessment of Unit 8 Existing Infrastructure**  
 Project Number: **07969**

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REVIEW DOES NOT CONSTITUTE APPROVAL OF DESIGN DETAILS, CALCULATIONS, TEST METHODS OR MATERIAL DEVELOPED AND/OR SELECTED BY THE CONTRACTOR, NOR DOES IT RELIEVE THE CONTRACTOR FROM FULL COMPLIANCE WITH CONTRACTUAL OR OTHER OBLIGATIONS.

- 01 – REVIEWED AND ACCEPTED – NO COMMENTS**
- 02 – REVIEWED – INCORPORATE COMMENTS, REVISE AND RESUBMIT**
- 03 – REVIEWED - NOT ACCEPTED**
- 04 – INFORMATION ONLY**
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NLH Project Manager:

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General Comments:

# BDE Unit 8 Infrastructure Assessment

wood.



## BDE UNIT 8 INFRASTRUCTURE ASSESSMENT REPORT

259284-0000-BA10-RPT-0001

**Prepared for:**

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B	2023-11-24	Issue for Review	BT	EO	BT	
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REV.	DATE	REVISION(S)	PREPARED BY	CHECK	APP	CLIENT

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## 1.0 Introduction

### 1.1 Summary

During the early 1970s, NL Hydro planned the addition of Powerhouse No.2 in the Bay d'Espoir (BDE) Hydro facility containing two (2)-150MW Turbine Generators, referred to as Unit 7 and Unit 8. At that time, only the installation of Unit 7 was completed but components in the region of the draft tube for Unit 8 were built in anticipation of a future development.

Newfoundland and Labrador Hydro (NL Hydro) is now planning the installation of the Unit 8 turbine. Wood was retained in 2023, to assess the existing Unit 8 Infrastructure in Powerhouse #2 of the BDE Hydro Station. The assessment included review of existing drawings, visual inspection of above water components, Remotely Operated Vehicle (ROV) inspection of the below water components, and laboratory testing of 5 concrete cores.

The existing infrastructure is generally in good condition. Some refurbishment is recommended to provide the desired 25-year service life when the Powerhouse is expanded to install the Unit 8 Turbine.

## 2.0 Scope of Assessment

The following items are included in the assessment:

- Downstream Powerhouse Wall
- Tailrace Deck
- Draft Tube Passages (including base slab, top slab, divider wall, side walls and piers, South wingwall)
- Opening Slots, Guides and Embedded Parts in Concrete

The assessment consisted of the activities described in the following sections.

### 2.1 Review of Existing Information

Wood has reviewed the As-Built drawings of the Unit 8 infrastructure provided by NL Hydro. These drawings are listed in Section 3.0. Apart from the original As-Built drawings, it appears that no other records of the Unit 8 infrastructure (such as inspection reports, or maintenance logs) are available.

### 2.2 Inspection of Above-Water Infrastructure

A visual inspection was conducted Aug. 21 and 22, 2023 by Bill Tucker, a senior structural engineer for Wood, accompanied on site by Kathleen Wadden, Project Engineer for NL Hydro. The inspection consisted of a walkthrough without using any special means of access. Some hammer soundings were performed at selected locations on the Tailrace Deck to test if there were any areas of delamination. Photographs were taken to document the current condition of the various infrastructure components. Locations for concrete coring for laboratory testing were selected.

### 2.3 Inspection of Below-Water Infrastructure

For the underwater inspection, Wood used the services of a subcontractor, Advanced Access Engineering (AAE) who performed the work on Aug. 21, 2023, using an ROV equipped with a camera. Wood monitored the inspection via the video transmitted to a screen on the deck level, while the ROV operator controlled the movements of the ROV and the orientation of its camera. AAE provided a summary report of the underwater inspection, which is given in Appendix D. The underwater inspection findings are included in this report's overall assessment of the Unit 8 infrastructure.



## 2.4 Concrete Coring and Laboratory Testing

While at site, Wood and NL Hydro selected five (5) locations for concrete coring. The purpose of the coring was to obtain samples for laboratory testing to provide information about the concrete that would be useful in estimating its remaining service life. The cores were taken by WSP, as a subcontractor to NL Hydro, on Aug. 22 and 23, 2023. Their concrete test report is included in Appendix E and forms part of this report's overall assessment of the Unit 8 infrastructure.

## 3.0 References

### 3.1 Existing Drawings

#	Number		Description	Issued	Comments
1	F-3107-C-9	2	Powerhouse Layout / Sectional Elevation Sheet 4 of 4	1978-01-11	As-built
2	C-3107-C-15	0	Powerhouse Unit 8 / Temporary Cover for Tower & Exposed Reinforcing	1977-08-08	Plywood cover over wall
3	F-3107-C-20	4	Powerhouse / Rock Excavation Plan	1978-01-11	As-built
4	F-3107-C-87	0	Powerhouse Unit 8 / General Arrangement	1976-08-01	
5	F-3107-C-90	4	Powerhouse Unit 8 / Concrete Details / Sht 1 of 2	1978-01-04	As-built
6	F-3107-C-91	3	Powerhouse Unit 8 / Concrete Details / Sht 2 of 2	1978-01-10	As-built
7	F-3107-C-92	0	Powerhouse Unit 8 / Timber Bulkhead to Draft Tube	1978-01-10	As-built
8	F-3107-C-93	1	Powerhouse Unit 8 / Reinforcing Details - Sht 1 of 4	1978-01-10	As-built
9	F-3107-C-94	2	Powerhouse Unit 8 / Reinforcing Details - Sht 2 of 4	1978-01-10	As-built
10	F-3107-C-95	2	Powerhouse Unit 8 / Reinforcing Details - Sht 3 of 4	1978-01-10	As-built
11	F-3107-C-96	0	Powerhouse Unit 8 / Reinforcing Details - Sht 4 of 4	1978-01-10	As-built
12	F-3107-C-97	0	Powerhouse Unit 8 / Draft Tube Outline Dimensions	1978-01-10	As-built
13	F-3107-C-98	0	Powerhouse Unit 8 / Draft Tube Gate Embedded Parts	1978-01-10	As-built

### 3.2 Drone Video

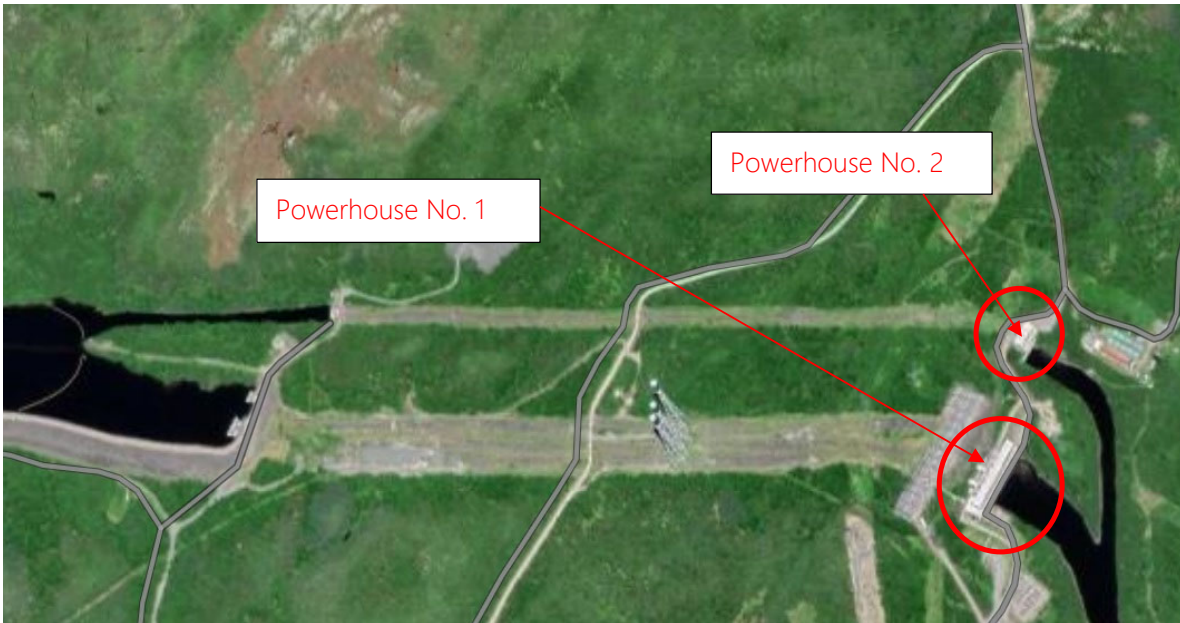
NL Hydro provided a video taken by a drone equipped with video camera that flew across the tailrace on Aug. 17, 2023. Wood has reviewed this video to supplement the observations that were made from the tailrace deck during the site visit. Photos created from frame captures of the video are given in Appendix B.



## 4.0 Unit 8 Infrastructure Descriptions and Observations

### 4.1 General

The location of Powerhouse No. 2 in the BDE Hydro Facility is shown in the following satellite photo.



**Figure 1 Location of Powerhouse No. 2**

An enlarged satellite view showing the location of the Unit 8 Infrastructure in relation to Powerhouse No. 2 is given in the following photo.



**Figure 2 Unit 8 Infrastructure**



The existing infrastructure for Unit 8 consists of the lower portion of the downstream powerhouse wall, the double passage where the draft tube discharges into the tailrace, the tailrace deck, and gate slots, complete with secondary concrete and embedded guides. The construction drawings were issued at various dates in 1976 and the As-Built drawings were issued in January of 1978, so the construction was completed circa 1977.

The components of the Unit 8 infrastructure are shown in the following figures.

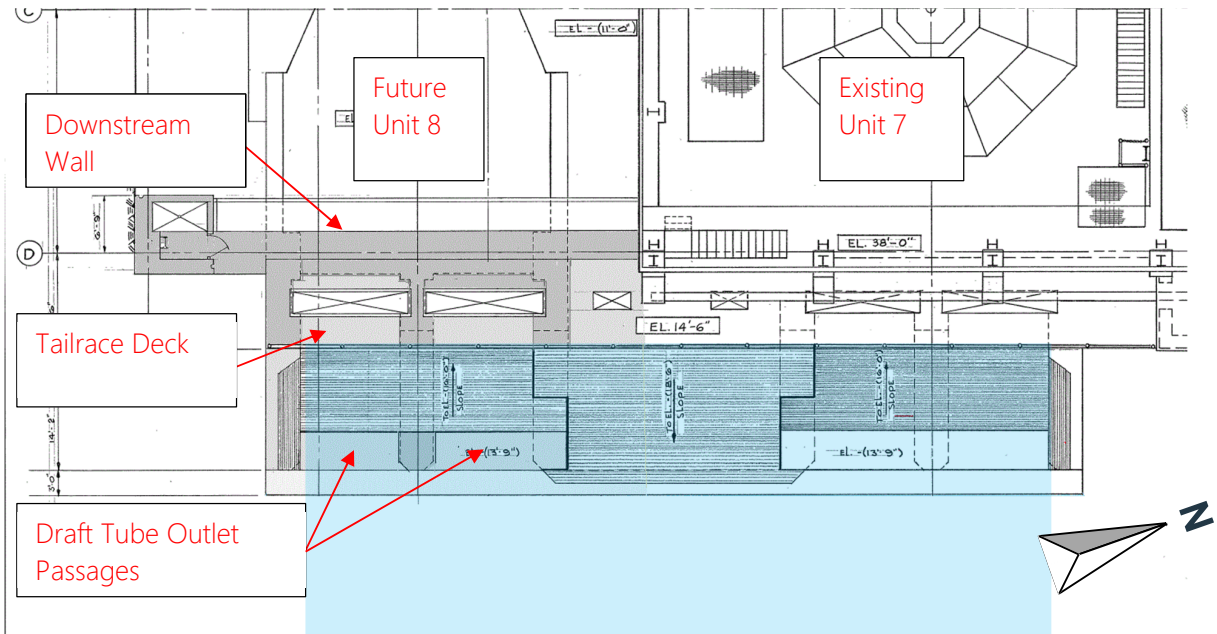
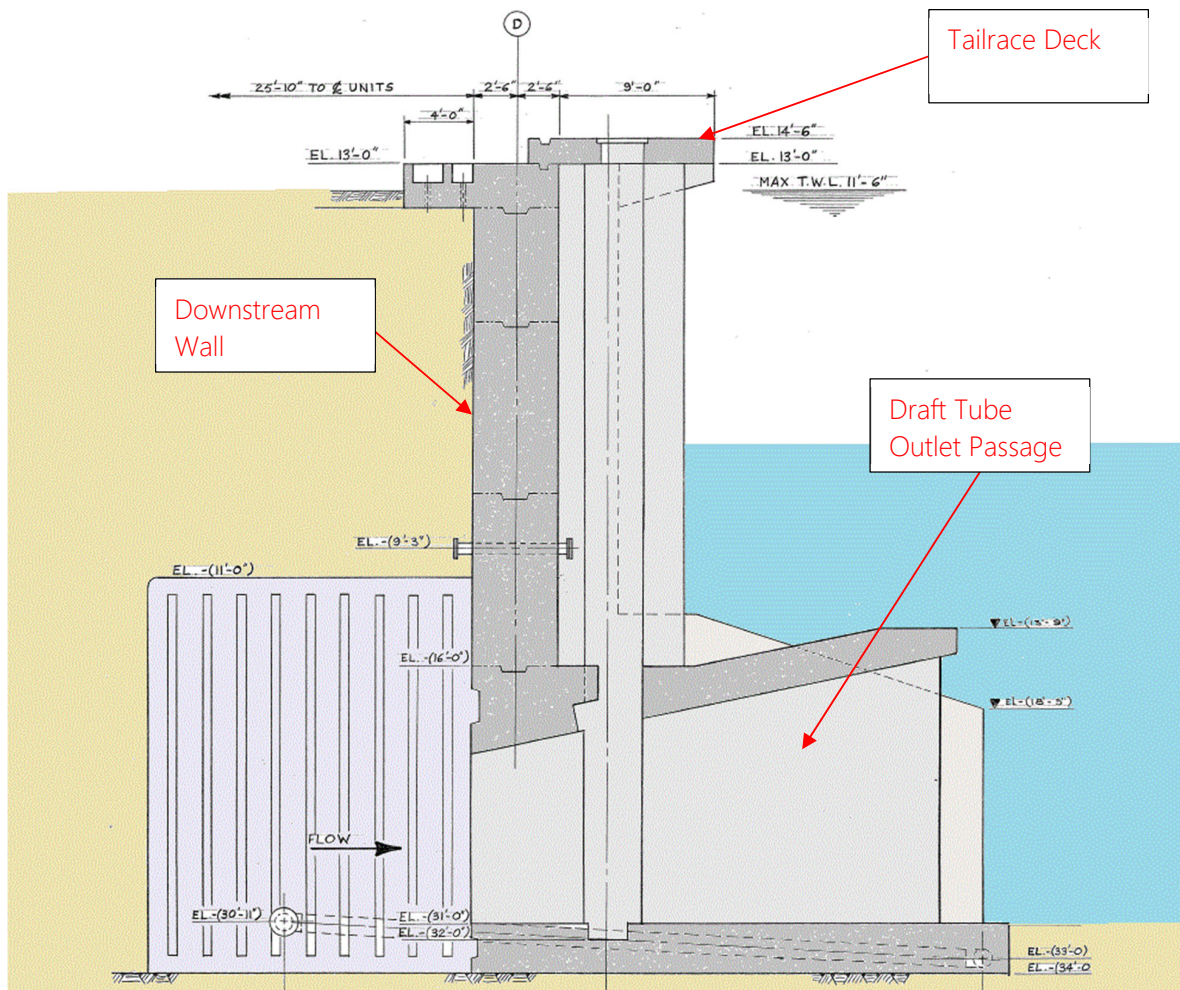


Figure 3 Plan View



**Figure 4 Cross-Section of Unit 8 Infrastructure**

#### 4.2 Downstream Powerhouse Wall

The downstream powerhouse wall is a 5ft (1.524m) thick reinforced concrete wall. The wall extends to Elev. 13ft (3.962m) as shown in the figure, with vertical bars projecting above the top surface to overlap with the reinforcing bars in the upper part of the wall when it is constructed. The projecting bars have been protected with a plywood cover (painted grey – as shown in photographs in Appendix A) that extends to Elev. 20ft (6.096m) as shown on Ref. Dwg. C-3107-C-15.

A section of plywood on the north end of the wall (towards Unit 7) was removed by NL Hydro, so the top of wall in this area and the projecting rebar could be observed during the site visit. The concrete appears to be in good condition and the projecting rebar has surface corrosion but appears to be serviceable with no significant loss of bar area. The feasibility of taking a concrete core from the wall by drilling downwards



into the top of wall was considered, but a WSP representative on site indicated that the template for mounting the drill could not fit between the projecting vertical rebar.

The above water portion of the downstream face (west face) of the powerhouse wall was observed through the gate slots from the tailrace deck level. The walls were also assessed using the drone video footage (see Appendix B for frame capture photographs from this video). Horizontal construction joints in the wall were visible. There are indications of efflorescence at the joints, but the joints generally appear to be in good condition. There is some erosion of the concrete in a region extending from the water level over approximately 6ft in height. The aggregates in this zone are exposed, but no visible rebar was detected.

According to Ref. Dwg. F-3107-C-93, the original concrete cover to the main reinforcing was 4 inches. Based on the visual inspection, the depth of erosion of the concrete near the waterline varies, with the maximum being approximately 2 inches. Since the depth of erosion does not exceed the concrete cover, the rebar has not been exposed.

The below water portion of the powerhouse wall was inspected by an ROV equipped with video camera. On the downstream face of the wall, the concrete generally appeared to be in good condition with no significant erosion or concrete defects.

The upstream face of the powerhouse wall is covered by fill material and could not be observed during the inspection.

### 4.3 Tailrace Deck

The tailrace deck is a 1ft-6in (0.457m) thick reinforced concrete slab. Photographs were taken along the entire length of the deck to document the condition (see Appendix C). The aggregate that was visible was generally well sized and distributed in the concrete matrix. The concrete was generally sound as confirmed with hammer soundings. There were some small hairline cracks with indications of efflorescence (see Photo 16 in Appendix C), but only in a limited area of the deck.

### 4.4 Concrete Piers and Draft Tube Passages

The deck is supported on piers that run all the way to the base slab of the draft tube outlets. There was erosion of the concrete on the piers in a 6 ft zone above the water level, similar to that observed on the downstream powerhouse wall. The deepest erosion occurred on the corners of the piers, which are likely subjected to the most abrasion (see Photo 7 in Appendix A). However, no exposed rebar was detected.

The draft tube outlet for Unit 8 bifurcates into two draft tube passages. These passages are below the tailrace water level and so inspection of this portion of the concrete was performed by ROV. The ROV could only enter the passage as far as the timber bulkhead to the downstream wall (which is shown in Ref. Dwg. F-3017-C-92).

The base slab of the passages was covered with a layer of silt and gravel, and so the condition of the concrete below this material could not be determined by the ROV. The sill beam, based on the ROV inspection appears to be in good condition.

The piers which form the side walls of the passages were inspected by the ROV. The ROV images show a crack in the central pier that divides the draft tube into two passages (see Page 28 of 81 in the AAE report in Appendix D). The crack runs generally in the vertical direction, starting at the base slab of the draft tube



passage all the way to the top of the divider wall and appears on both sides of the wall. Since the divider wall is not subject to significant differential pressure, it is likely to be a shrinkage crack dating from the original construction, rather than a crack caused by applied loads.

It was difficult for the ROV to inspect the underside of the top slab of the passage since the camera was not configured to aim straight up. However, based on what could be observed, there were no significant defects in the concrete. It was likewise difficult to assess the condition of the lintel beam.

The top surface of the top slab of the passage also had a covering of silt and gravel, although less thick than on the base slab. The ROV's arm was able to scrape away this debris in places, and no significant defects were observed.

#### **4.5 Gate Slot Covers**

The cover plates to the opening slots (three covers per slot) have mild corrosion but paint is generally intact. The cover plates are bolted to the deck (with two bolts per cover plate). In the two southernmost cover plates of the South Draft Tube Passage Slot, the bolts had been previously removed and the cover plates were lifted by NL Hydro personnel to permit visual observation of the guides and the concrete below the deck. In the North Draft Tube Passage Slot, all covers were fastened with bolts that were too corroded to remove. The bolts on the center cover plate were drilled out, so that the plate could be lifted to permit visual observation of the structure below and the guides.

The perimeter edge angle around the opening for seating of the cover plates is moderately corroded, but its primary purpose is to protect the edge of the concrete and the corrosion does not affect this function.

#### **4.6 Gate Guides**

The secondary concrete and the embedded steel channels stoplog guides were inspected. The joint between the primary and secondary concrete appears to be in good condition with no erosion or widening of the joint. For the embedded steel, there is some corrosion and flaking at the top of the channel, but below this level, there only appears to be surface corrosion, with no significant loss of steel thickness. From the visual inspection, it is not possible to determine if the sealing face of the guide channels is vertical within the tolerance required to achieve a good seal.

### **5.0 Concrete Testing**

#### **5.1 Core Locations**

Concrete cores were taken on August 22 and 23, 2023 from six (6) locations indicated in the following figure. Drilling of the cores, filling of holes with non-shrink grout, and testing of cores in the laboratory was performed by WSP under separate contract to NL Hydro. The WSP report is given in Appendix E and has been used by Wood in the overall assessment of the Unit 8 Infrastructure and the final recommendations in this report. Cores 1, 2, 3 and 6 were drilled vertically from the tailrace deck. Cores 4 and 5 were drilled horizontally into the center pier from a boat in the tailrace.

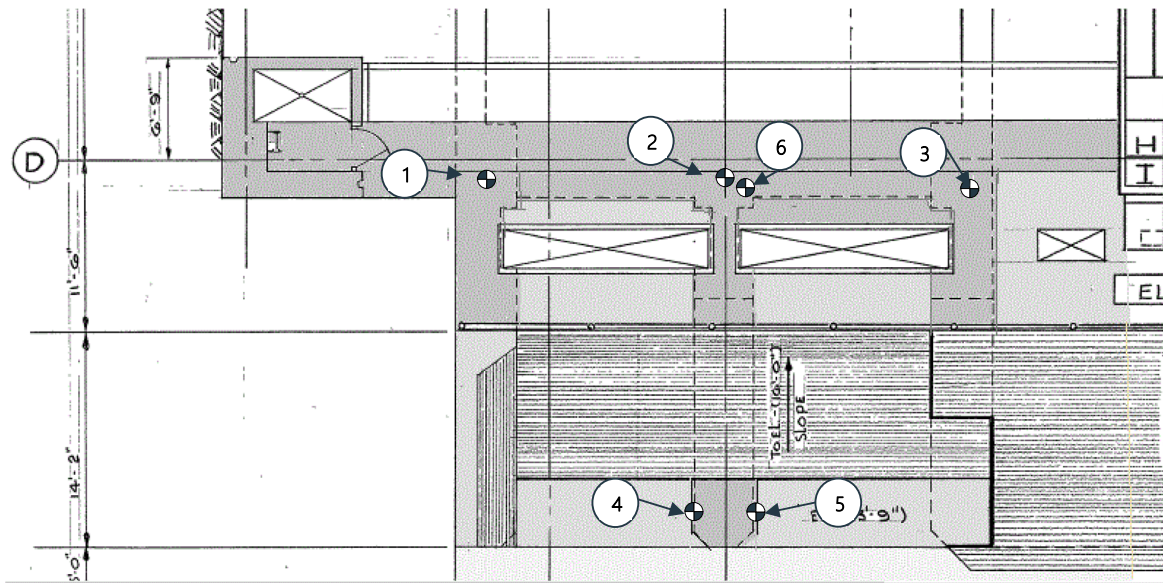


Figure 5 Plan showing Locations of Cores

## 5.2 Test Results

Cores #1, #2 and #3 were held for possible follow-up testing. The tests performed on Cores #4, #5 and #6 are shown in the following table. The following sections provide a summary of the test results. For more details, refer to the WSP test report in Appendix E.

Table 1 Concrete Tests

Core	Tests
#4	Compressive strength, density
#5	Density, petrographic analysis, hardened air void analysis and water-soluble chloride ion content
#6	Compressive strength, density



## 5.2.1 Basic Concrete Tests

**Table 2 Concrete Density**

Core	Concrete Density [kg/m <sup>3</sup> ]	Compressive Strength [MPa]
#4	2377	42.9
#5	2420	N.A.
#6	2363	37.0

## 5.2.2 Advanced Concrete Tests

The advanced concrete tests conducted on Core #5 yield the following information (this is a summary – for full discussion, see Appendix E).

### Analysis of the Hardened Air-Void System

This indicated the concrete sample tested had an air content of 3.2% and a spacing factor of 0.204 mm which *'marginally meets the requirements for a frost resistant concrete'*.

### Chloride Ion Test

The water-soluble chloride ion content, at 45 mm depth of core and at the base of the core, was measured at 0.004% and 0.006% respectively. This *'indicates no significant ingress of chloride ions in the cover concrete'*.

### Petrographic Examination

The core had moderate erosion at the surface (consistent with the visual observation of the concrete near the water line. The core presented *'minor to moderate deleterious effects from alkali aggregate reactivity evidenced by reaction rims around aggregate particles, and network of cracks within aggregates'*.

## 5.3 Discussion

Based on the site visit observations and the laboratory concrete tests, the Unit 8 concrete is generally structurally sound. Given that it has been in service for 45 years, some deterioration is to be expected, and the mechanisms that have contributed to the deterioration are discussed in this section.

### 5.3.1 Erosion of Concrete

Erosion of the concrete has occurred in the portions of the concrete structure near the waterline. The following mechanisms have likely contributed to this erosion:

#### **Freeze-Thaw Action**

The tailrace water level varies. Concrete can be submerged when the water level rises and then exposed to air when the water level drops. In cold weather, the resulting temperature fluctuations create cycles of freezing and thawing. The repeated cycles of wetting and drying / freezing and thawing contribute to deterioration of the concrete over time.



### Exposure to Chlorides

Since the tailrace connects to the head of Bay d'Espoir, the water may be brackish. At the waterline, there is evaporation of water, which would increase the concentration of chlorides in this zone. Such exposure can contribute to deterioration of concrete. *Note: testing of concrete taken from the central pier does not show a large concentration of chloride ions (see Section 5.2.2), so this mechanism may not be too significant.*

### Ice Abrasion

Sheet ice in the tailrace during winter would adhere to the concrete, particularly as there is no water flowing through Unit 8 that would break up the ice. As the water level in the tailrace fluctuates, the adhesion of the sheet ice to the structure would exert friction forces that contribute to erosion of the concrete.

## 5.3.2 Alkali Aggregate Reactivity

There are some indications of alkali aggregate reactivity (AAR) in the concrete. As indicated in the Concrete Testing Report by WSP given in Appendix E, this has resulted in '*reaction rims around aggregate particles, and network of cracks within aggregates*'. The damage is generally mild and, in most areas, hasn't progressed to visible cracking or spalling of concrete at the surface. The ROV photographs given in Appendix D show some regions of map cracking in the splash zone on the piers and the visible face of the downstream wall.

AAR is a slow acting reaction between certain forms of silica in the aggregates and alkali hydroxide in the cement paste that causes expansion in the concrete over time. In mass concrete structures, the expansion is restrained which may create significant secondary stresses in the concrete. The existing BDE Unit 8 infrastructure elements are not considered to be mass concrete elements so secondary stresses caused by AAR will be less significant. However, the expansion in the concrete matrix also may cause micro-cracking that allows infiltration of moisture and contributes to freeze-thaw damage. This is because when water in the crack freezes, it expands, widening the crack. The widening allows more water to enter the crack and leads to a cycle of progressive damage.

For the design of new Unit 8 infrastructure, consideration should be given to specifying aggregates that minimize susceptibility to AAR, as well as lowering the alkali content of the concrete. Also, it may be beneficial to inspect the mass concrete in the Unit 7 Powerhouse to determine if it has been subject to AAR, as this could affect the proposed Unit 8 powerhouse extension, especially if it is constructed monolithically with the foundation of the existing powerhouse.

Given the age of the concrete in the existing Unit 8 infrastructure, most of the reaction will have already taken place. In areas where there are visible surface cracks, one method of limiting future damage is to provide a coating to reduce or eliminate the infiltration of water, since freezing of water in the crack contributes to freeze-thaw damage.

## 6.0 Recommendations

This Section presents Wood's recommendations for refurbishment and repairs to the existing Unit 8 infrastructure to achieve a target service life of 25 years. The recommendations are based on the findings of the site visit, Wood's review of available information taken from drawings and video provided by NL



Hydro, the underwater ROV inspection/report (included in Appendix D) and the concrete testing results (included in Appendix E).

The recommendations are based on the condition of the existing infrastructure and assessment of the refurbishment required (if any), to meet the future required service life. The assessment does not include detailed structural analysis of existing or future infrastructure components and assumes that the original design was fit for purpose. Similarly, it does not include determination of whether the arrangement of the current infrastructure is suitable for the new Unit 8. These items should be addressed in the design of the Unit 8 Project.

Costs given in this section are based on the methodology for Association for the Advancement of Cost Engineering (AACE) Class 3 estimate. This class of estimates is typically used for budget allocation purposes. They are therefore referred to in the discussion as 'Budget Costs'.

## 6.1 Note on Service Life

The target service life for the refurbishment is set to 25 years. During the "service life" of infrastructure, normal maintenance may be performed. It is anticipated, however, that once the service life is reached, some significant further repairs or refurbishment beyond what is considered as normal maintenance will be required for it to continue in service. Specifying a longer service life for refurbishment of a 45-year-old structure is not considered practical. One consideration is that repairs typically have a shorter service life than new structures due to such factors as:

- Possible incompatibility between the repair materials and the original construction materials,
- Difficulty of ensuring that all deterioration is removed prior to performing the repairs. If concrete in the vicinity of the repair continues to deteriorate, it may affect the service life of the repairs,
- Interfaces between repair and original materials are a weak point where delamination or infiltration of water may occur leading to deterioration over time.

For these reasons, repairs on the existing infrastructure, using current best practice techniques, may provide a nominal service life of approximately 25 years. The proposed refurbishments and repairs are based on this assumption.

## 6.2 Summary of Observations

The summary table gives the following information:

- 'Component' is the portion of the existing Unit 8 infrastructure being inspected;
- 'Observation' is a short summary of the condition of the component;
- 'Example Photos' gives the Appendix and Photo number(s) of the relevant photographs for the component;
- 'Action' indicates whether Wood recommends an action be implemented for refurbishment of the component [Y=yes, N=no];
- '#' is the Section number in this report describing the recommended action.



Component	Observation	Example Photos	Action [Y/N]	#
<b>.1 Downstream Powerhouse Wall</b>	Generally good condition. Some loss of concrete cover due to erosion in splash zone.	App A: 1, 5, 6 App B: 2, 3, 6	Y	6.3
<b>.2 Tailrace Deck</b>	Sounded with hammer – no significant delamination. There are some hairline cracks with efflorescence over a small portion of the deck.	App C: 1-16	Y	6.4
<b>.3 Draft Tube Passages</b>	Below water portion generally good condition. Some loss of concrete cover due to abrasion and deterioration in splash zone especially at corners of piers.	App A: 1, 6, 7 App B: 2, 3, 4, 5, 6, 7	Y	6.3
<b>.4 Gate Slots and Guides Embedded Parts Concrete in Gate Wells</b>	Several covers were removed for inspection.	App. A: 4, 6, App. B: 7	Y	6.4

### 6.3 Recommendations for Concrete below the Deck Level

The condition of the concrete is discussed in Sections 4.2 and 4.4. There is some surface erosion of the concrete near the waterline, exposing some of the coarse aggregate. The depth of erosion varies locally but no exposed rebar was observed, so the erosion is within the concrete cover zone. However, when Unit 8 is brought into service, water will pass through the draft tubes at high velocity, and the rate of erosion in the downstream draft tube passages is expected to increase.

The following repair options for this concrete can be considered, in ascending order of cost.

1. No repair.
2. Improve the durability of the concrete surface by cleaning of concrete and applying a sealer.
3. Repair by sandblasting (to remove both dirt and weak carbonized layer and expose aggregate for bonding to a repair material) and coating with repair grout above waterline at low tide.

#### Cost

A significant cost component for Options 2 and 3 is providing construction access to the concrete. If the work on the powerhouse extension for Unit 8 is done using gates or stoplogs in the existing slots, then some of the downstream portions of the draft tube passages will be below water and difficult to access. Work might have to be performed from scaffolding, an articulated boom truck or by boat, if above the water level, or by divers or ROV where below water. Further study would be required to select the best option, based on the scope of work required and resources available. Therefore, the costs presented are an order of magnitude estimate for the purpose of selecting the preferred option and would need to be



re-assessed based on whether the work is executed as part of the Unit 8 installation, or as a stand-alone project. Since the construction methodology is not currently known, the budget costs do not include construction of a cofferdam.

Option 1: Budget Cost N.A.

Option 2: Budget Cost [REDACTED]

Option 3: Budget Cost [REDACTED]

### Discussion

The future work to install the new Unit 8 infrastructure may present opportunities to perform refurbishment on the existing components. Further constructability reviews may be required for sequencing with other works for Unit 8 before selecting the final refurbishment option aligned with the overall project budget and schedule. However, since the construction plan is still under development, the recommendation in this assessment report is based on the information currently available.

The case for 'no repair' is that the concrete is structurally sound after 45 years of service. Based on this, it could possibly provide an additional 25 years of service, although some local repairs may be required over that time. The submerged concrete is in good condition based on video images provided by the ROV. It has not been subject to freeze thaw action, and no repair is recommended for this concrete. A through-crack was observed in the center pier between the draft tube outlets, but it does not show any sign of freeze-thaw damage.

The concrete in the 'splash zone' (considered to extend about 6 ft above the low water level), which is subject to both freezing and thawing and to cycles of wetting and drying, has some patterns of fine cracks at the surface. This may be related to the presence of alkali reactivity identified in the laboratory concrete tests. The concern is that this deterioration may progress over the 25-year service period. The fine surface cracks can facilitate infiltration of water into the concrete. When the water freezes, it expands which may further widen the cracks. To slow the rate of deterioration, remedial action is recommended.

**Option 2** involves sealing the surface of the concrete to reduce water infiltration, thereby prolonging the life of the concrete. Before applying the sealant, the concrete surface should be cleaned, but the surface preparation is nominal to remove loose material and debris. The disadvantage of Option 2 is that the erosion forces from flowing water and floating ice in the splash zone will reduce the service life of the sealer. It may therefore be necessary to re-apply the sealer periodically to maintain its effectiveness.

One option is to use a silane sealer. This type of sealer creates a barrier to water infiltration into the concrete to protect it from future freeze thaw damage. However, it would need to be reapplied after about 10 years, since erosion will cause it to deteriorate over time.

Silicate sealers are another option that may provide more durability than a silane sealer. The silicate sealer induces a chemical reaction in the concrete, causing it to crystallize and hardening the surface. This would be beneficial in increasing the resistance of the concrete to abrasion. However, silicate sealers are sometimes not recommended in concrete has experienced AAR, and so some further work would be required to determine if this type of sealer was suitable.

Since a major component of the cost would be preparation of the concrete surface, access, and application of the sealer, rather than the cost of the sealer itself, a budget cost can be set for this option,



and selection of the type of sealer would be performed during the detailed refurbishment design.

**Option 3** is based on bonding a new coating, over the surface of the existing concrete. The surface preparation would be more extensive than Option 2, as it would be necessary to expose clean aggregate to achieve a good bond between the repair material and the existing concrete. Possible repair materials are polymer grout or epoxy-based grout. Although epoxy is more wear resistant, polymer-based grout is generally more compatible with the original concrete. The selection of the most appropriate repair material could be done during the detailed refurbishment design.

One disadvantage of applying a new coating is that it may trap moisture within the existing concrete, which can lead to debonding of the coating.

### **Preferred Option**

The concrete outside the splash zone has minimal erosion, and since the existing concrete cover is 4 inches, no action is required to provide the target 25 service life.

In the 'splash zone' repair Options 2 and 3 should be considered. Option 2 requires less disturbance of the existing concrete and has therefore been selected as the preferred option. However, depending on how the access issues are resolved, the final repair methodology can be finalized during the detailed refurbishment design.



## 6.4 Recommendations for Tailrace Deck Slab

The condition of the Tailrace Deck was discussed in Section 4.3. The concrete surface of the deck is generally in good condition, although there are some fine crack patterns in local areas.

The following refurbishment options for this concrete are (in ascending order of cost):

1. No repair.
2. Repair by cleaning of concrete and applying a silane sealer, (a product often used for bridge decks)
3. Repair by sandblasting (to remove both dirt and weak carbonized layer and expose aggregate for bonding to repair material) and coating with polymer grout above waterline at low tide.

### Cost

Budget Cost (Option 1) N.A.

Budget Cost (Option 2) [REDACTED]

Budget Cost (Option 3) [REDACTED]

### Discussion

The case for 'no repair' is that the concrete is still structurally sound, and the deck is not very wide, and is therefore not required to support heavy equipment. It will continue to perform adequately for normal operational loads over the additional 25 years of service.

Option 2 consisting of cleaning the deck and applying a sealer would help prevent any future spalling or deterioration of the concrete surface. Given the relative accessibility of the deck, it can be implemented at a reasonable cost.

Option 3 would be appropriate if the deck were subject to large abrasive forces or extreme environmental conditions.

### Preferred Option

Based on the current generally good condition of the Tailrace Deck and its anticipated service requirements Option 3 appears excessive. For Option 1 (no action), some refurbishment of the deck may be required at some point in the future. Therefore, to help meet the target of a 25-year service life for the refurbishment, Option 2 is recommended.



## 6.5 Recommendations for Gate Slot Covers

This condition of these items was discussed in Section 4.5. The gate slot covers and embedded edge angle support are structurally sound but with moderate corrosion.

The following refurbishment options for this concrete are (in ascending order of cost):

1. No repair.
2. Refurbishment by removing rust from steel, repainting the edge angle supports and covers and replacing the steel bolts that hold the covers in place. Note that it may be easier to simply fabricate new covers, but this can be determined during the detailed refurbishment design.

### Cost

Budget Cost (Option 1) N.A.

Budget Cost (Option 2) [REDACTED]

### Discussion

The case for Option 1 'no repair' is that the covers are structurally sound.

Option 2 will prolong the life of the existing covers. In addition, the bolts holding the covers in place are corroded which prevents the covers from being opened.

### Preferred Option

To help meet the target of a 25-year service life for the refurbishment, and for the covers to be removable, Option 2 is recommended.



## 6.6 Recommendations for Gate Guides

This condition of these items was discussed in Section 4.6. The guides have moderate corrosion but are structurally sound. A survey of the guides should be conducted to determine if any of the guides are out-of-plumb or out-of-straight.

The following refurbishment options for the guides are (in ascending order of cost):

1. No repair.
2. Perform a dimensional survey of the guides to determine they are out-of-plumb or out-of-straight. The surfaces of the guides that are in contact with the stoplogs to be ground smooth to ensure they are as watertight as possible.

### Cost

Budget Cost (Option 1) N.A.

Budget Cost (Option 2) [REDACTED]

### Discussion

The case for Option 1 'no repair' is that the guides are structurally sound.

Option 2 would ensure the functionality of the guides. Even under this option, there may be some leakage when gates/stoplogs are installed. However, the work performed on the guides would ensure that fit was sufficient that using a sealing material such as slag or cinder ash would provide adequate watertightness.

### Preferred Option

Option 2 is recommended since any deficiencies in the guides would be identified and could be remediated. Option 1 would introduce uncertainty that is not recommended, given the significant effort of installing the planned new Unit 8 infrastructure.



## 6.7 Summary of Recommendations

The recommendations discussed in the previous sections are summarized in the following table:

Existing Infrastructure Component	Recommendation	Budget Cost (see Notes)
<b>Concrete below the Deck Level</b>	Repair by cleaning of concrete and applying a silane sealer formulated for application on vertical surfaces. Apply to all elements above the low water level.	█
<b>Tailrace Deck Slab</b>	Repair by cleaning of concrete and applying a silane sealer.	█
<b>Gate Slot Covers</b>	Refurbishment by removing rust from steel, repainting the edge angle supports and covers and replacing the steel bolts that hold the covers in place.	█
<b>Gate Guides</b>	Dimensional survey to determine they are out-of-plumb or out-of-straight. The surfaces that contact the stoplogs/gates to be ground smooth.	█
<b>Total Budget Cost</b>		█

Notes:

[1] Assumes no significant misalignment of sealing surfaces.

[2] Cost of a cofferdam not included in budget (since work method has not been determined).



## **7.0 Appendix A General Photos**



**APPENDIX A**

Client: NL Hydro  
Project: BDE Unit 8 Assessment Date: Various  
Data For: General Photos Work Order: 259284  
Prepared By: BT Checked By: \_\_\_\_\_ FileNo: \_\_\_\_\_



Photo 1 View of Unit 8 Tailrace Infrastructure  
([2023-08-17.jpg](#))



Photo 2 View looking South towards Unit 7  
([2023-08-21\\_12h-26m.jpg](#))



Photo 3 ROV on Tailrace Deck  
([2023-08-21\\_12h-35m.jpg](#))



Photo 4 South Gate Slot - Embedded Steel Guide  
([2023-08-22\\_08h-21m.jpg](#))



**APPENDIX A**

Client: NL Hydro  
Project: BDE Unit 8 Assessment Date: Various  
Data For: General Photos Work Order: 259284  
Prepared By: BT Checked By: \_\_\_\_\_ FileNo: \_\_\_\_\_



Photo 5 South Gate Slot - View of Back Wall  
([2023-08-22\\_08h-21mB.jpg](#))



Photo 6 North Gate Slot - Embedded Steel Guide  
([2023-08-22\\_09h-26m.jpg](#))



Photo 7 North Gate Slot - View of Center Pier  
([2023-08-22\\_09h-27mA.jpg](#))



## **8.0 Appendix B Photos taken by Aerial Drone**



**APPENDIX B**

Client: NL Hydro  
Project: BDE Unit 8 Assessment  
Data For: Drone Survey  
Prepared By: BT Checked By: \_\_\_\_\_

Date: August 17, 2023  
Work Order: 259284  
FileNo: \_\_\_\_\_



Photo 1 Unit 8 Tailrace Deck (from above)  
[\(DJI\\_0187 - frame at 0m0s.jpg\)](#)



Photo 2 Unit 8 South Draft Tube Bay  
[\(DJI\\_0187 - frame at 0m19s.jpg\)](#)



Photo 3 Unit 8 Central Pier between Draft Tube Bays  
[\(DJI\\_0187 - frame at 0m36s.jpg\)](#)



Photo 4 Unit 8 South Wingwall  
[\(DJI\\_0187 - frame at 0m38s.jpg\)](#)



Photo 5 Unit 8 Wingwall, South and North Draft Tube Bays  
[\(DJI\\_0187 - frame at 0m7s.jpg\)](#)



Photo 6 Unit 8 Central Pier  
[\(DJI\\_0187 - frame at 1m36s.jpg\)](#)



**APPENDIX B**

Client: NL Hydro

Project: BDE Unit 8 Assessment

Data For: Drone Survey

Prepared By: BT Checked By: \_\_\_\_\_

Date: August 17, 2023

Work Order: 259284

FileNo: \_\_\_\_\_



Photo 7 Unit 8 Looking Towards Unit 7  
[\(DJI\\_0187 - frame at 1m9s.jpg\)](#)



Photo 8 Unit 8 Side View of Deck Slab  
[\(DJI\\_0187 - frame at 2m15s.jpg\)](#)



## **9.0 Appendix C Detailed Photos of Tailrace Deck**



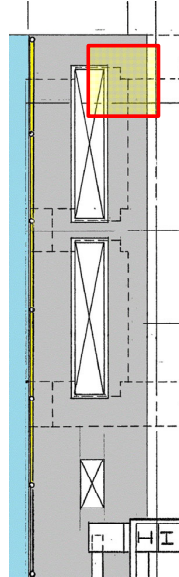
**APPENDIX C**

Client: NL Hydro  
Project: BDE Unit 8 Assessment  
Data For: Tailrace Deck  
Prepared By: BT Checked By: \_\_\_\_\_

Date: August 22, 2023  
Work Order: 259284  
FileNo: \_\_\_\_\_



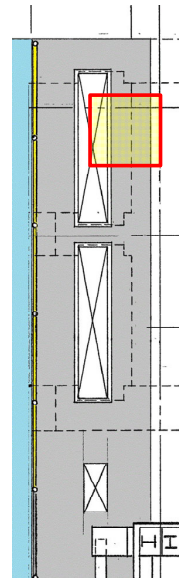
Photo 1 Unit 8 Tailrace Deck - Upstream Side  
([2023-08-22\\_08h-36m.jpg](#))



Key Plan



Photo 2 Unit 8 Tailrace Deck - Upstream Side  
([2023-08-22\\_08h-36mA.jpg](#))



Key Plan



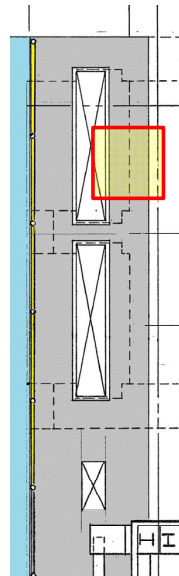
**APPENDIX C**

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Project: BDE Unit 8 Assessment  
Data For: Tailrace Deck  
Prepared By: BT Checked By: \_\_\_\_\_

Date: August 22, 2023  
Work Order: 259284  
FileNo: \_\_\_\_\_



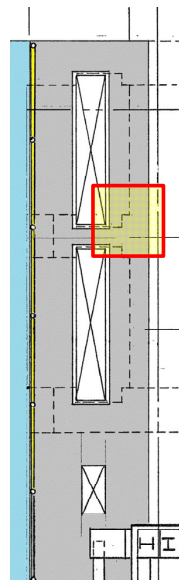
Photo 3 Unit 8 Tailrace Deck - Upstream Side  
([2023-08-22\\_08h-36mB.jpg](#))



Key Plan



Photo 4 Unit 8 Tailrace Deck - Upstream Side  
([2023-08-22\\_08h-36mC.jpg](#))



Key Plan



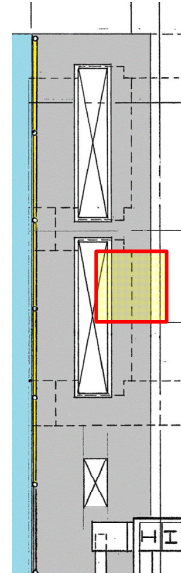
**APPENDIX C**

Client: NL Hydro  
Project: BDE Unit 8 Assessment  
Data For: Tailrace Deck  
Prepared By: BT Checked By: \_\_\_\_\_

Date: August 22, 2023  
Work Order: 259284  
FileNo: \_\_\_\_\_



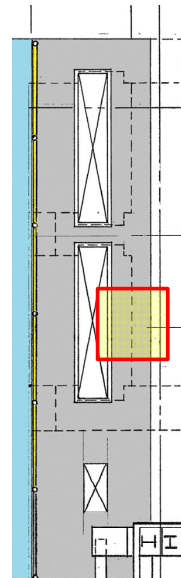
Photo 5 Unit 8 Tailrace Deck - Upstream Side  
([2023-08-22\\_08h-37m.jpg](#))



Key Plan



Photo 6 Unit 8 Tailrace Deck - Upstream Side  
([2023-08-22\\_08h-37mA.jpg](#))



Key Plan



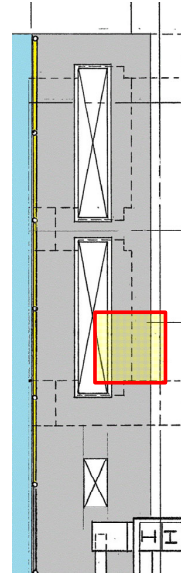
**APPENDIX C**

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Project: BDE Unit 8 Assessment  
Data For: Tailrace Deck  
Prepared By: BT Checked By: \_\_\_\_\_

Date: August 22, 2023  
Work Order: 259284  
FileNo: \_\_\_\_\_



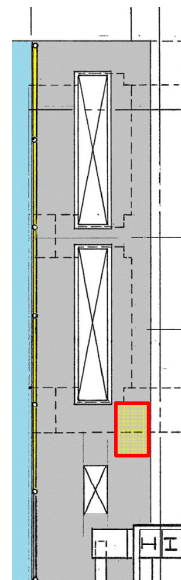
Photo 7 Unit 8 Tailrace Deck - Upstream Side  
([2023-08-22\\_08h-37mB.jpg](#))



Key Plan



Photo 8 Unit 8 Tailrace Deck - Upstream Side  
([2023-08-22\\_08h-37mC.jpg](#))



Key Plan



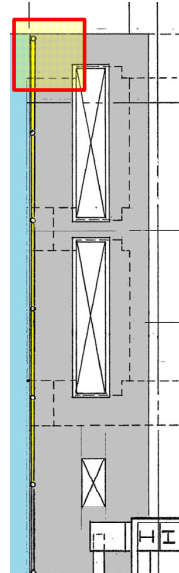
**APPENDIX C**

Client: NL Hydro  
Project: BDE Unit 8 Assessment  
Data For: Tailrace Deck  
Prepared By: BT Checked By: \_\_\_\_\_

Date: August 22, 2023  
Work Order: 259284  
FileNo: \_\_\_\_\_



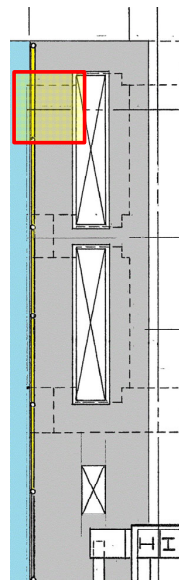
Photo 9 Unit 8 Tailrace Deck - Downstream Side  
([2023-08-22\\_08h-37mD.jpg](#))



Key Plan



Photo 10 Unit 8 Tailrace Deck - Downstream Side  
([2023-08-22\\_08h-38m.jpg](#))



Key Plan



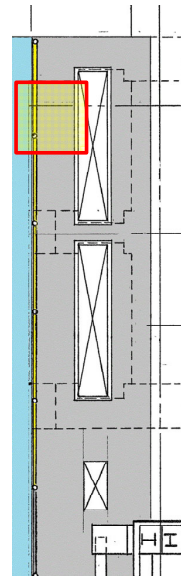
**APPENDIX C**

Client: NL Hydro  
Project: BDE Unit 8 Assessment  
Data For: Tailrace Deck  
Prepared By: BT Checked By: \_\_\_\_\_

Date: August 22, 2023  
Work Order: 259284  
FileNo: \_\_\_\_\_



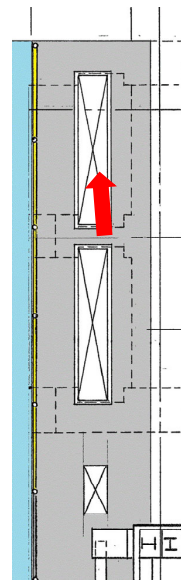
Photo 11 Unit 8 Tailrace Deck - Downstream Side  
([2023-08-22\\_08h-38mA.jpg](#))



Key Plan



Photo 12 Unit 8 Tailrace Deck - Downstream Side  
([2023-08-22\\_08h-38mB.jpg](#))



Key Plan



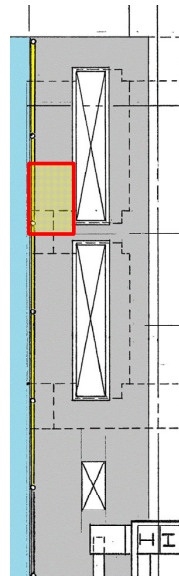
**APPENDIX C**

Client: NL Hydro  
Project: BDE Unit 8 Assessment  
Data For: Tailrace Deck  
Prepared By: BT Checked By: \_\_\_\_\_

Date: August 22, 2023  
Work Order: 259284  
FileNo: \_\_\_\_\_



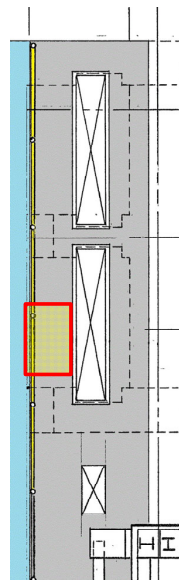
Photo 13 Unit 8 Tailrace Deck - Downstream Side  
([2023-08-22\\_08h-39m.jpg](#))



Key Plan



Photo 14 Unit 8 Tailrace Deck - Downstream Side  
([2023-08-22\\_08h-39mA.jpg](#))



Key Plan



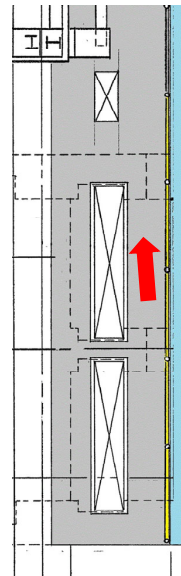
**APPENDIX C**

Client: NL Hydro  
Project: BDE Unit 8 Assessment  
Data For: Tailrace Deck  
Prepared By: BT Checked By: \_\_\_\_\_

Date: August 22, 2023  
Work Order: 259284  
FileNo: \_\_\_\_\_



Photo 15 Unit 8 Tailrace Deck - Downstream Side  
([2023-08-22\\_08h-39mB.jpg](#))



Key Plan

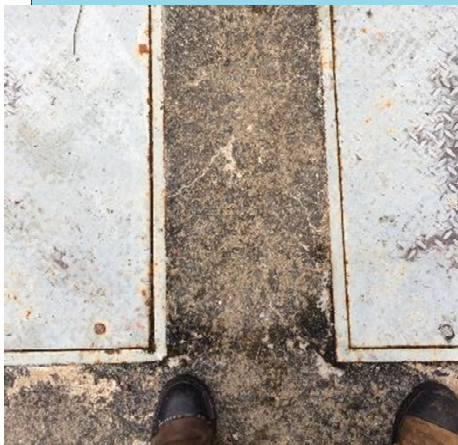
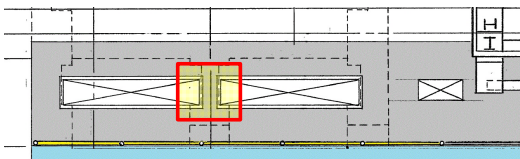


Photo 16 Unit 8 Tailrace Deck - Between Gate Slots  
([2023-08-22\\_08h-39mC.jpg](#))



Closeup of concrete between gate slots



## **10.0 Appendix D UAV Report by AAE**

## Bay d' Espoir - Unit 8 - ROV Assessment



23-178-03



**Advanced Access**  
ENGINEERING

Site: Bay d' Espoir Damsite  
 Asset Description: Unit 8 Concrete  
 Asset Number: Unit 8  
 AAE ID: 23-178-03  
 Client ID: PO#306400002951  
 Inspection Date: 21 August 2023

**WOOD.**

**INSPECTION REPORT**

**Scope of work**

Advanced Access Engineering were contracted to perform an internal ROV inspection of the current concrete structure in preparation for the Unit 8 construction project where a new turbine will be installed at the Bay d'Espoir generating station. The inspection took place from the draft tube deck, utilizing existing access hatches for the ROV deployment. This operation was executed with a strong focus on safety and professionalism, encompassing a thorough assessment of the working environment and safety precautions.

The primary objective of the inspection is to provide an all-encompassing evaluation of the concrete condition, with specific attention directed towards gate guides, pre-existing concrete structures, coatings, and other pertinent areas. The insights gained from this inspection will be useful for the asset owner in determining the readiness of the asset for the forthcoming Unit 8 construction project.



**Acceptance**

Name	Shelly Leighton	Bill J tucker	
Signature			
Organization	Advanced Access Engineering Inc	Wood	
Date			

Inspection Team: M.Sibley J. Wade

Signature: *M.Sibley J. Wade*

Date: 14 August 2023

Author: M.Sibley

Signature: *M.Sibley*

Date: 22 August 2023

This report is for the owner's independent use. Information contained within can be disseminated as needed but should not be relied upon for any other purposes other than the intended use. Advanced Access Engineering Inc will not be liable for any claims, losses or any nature coming from the use of the information provided. Advanced Access Engineering will not be liable for any recommendations, opinion or other advice provided or obtained as part of inspection campaigns. Inspections should be carried out at intervals as per the facility inspection and integrity plans if one exists.

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<b>Reporting - Unit 8 ROV site assessment</b> .....	<b>6</b>
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## Introduction

Advanced Access Engineering were contracted to provide a ROV inspection as part of the Wood condition assessment for the existing underwater infrastructure located at the Unit 8 site at the Bay d'Espoir generating site. This inspection consisted of the existing concrete structure below the waterline as directed by the onsite Wood Engineer. This inspection was carried out with the Canadian Dam Association (CDA) guidelines for visual inspections taken into consideration (2013 edition).

The Inspection Shall:

- Capture meaningful data which can be used to determine the overall condition of the structure, i.e., equivalent to a "General Visual Inspection" (GVI). A "Close Visual Inspection" (CVI) will be included where required for a more in-depth look at areas of interest.
- Determine the extent of additional close-up surveys if any.
- Collect visual data at specified locations for condition assessments of known anomalies, temporary repairs and/or other notable anomalies.

Inspection Guidance:

The purpose of the GVI is to visually identify items such as gross deformation, gross damage, significant variance from "as-built" specification and breakdown of internal areas. All findings will be reported accordingly. This report will include photographs with accompanying text throughout. Photographs are only be added where it will assist or add clarity to the reporting. Re-inspect areas that have a known anomaly and report findings accordingly.

## Summary

The ROV inspection was carried out on 21 August 2023. The water is noted to be brackish with some sediment present in the water column along with a high turbidity value due to the short field of vision while at depth. It was noted that some marine growth is visible on the upper sections of the concrete structure with most of the structure below -5m depth in good condition with little growth present. A silt layer present in most flat to low grade locations. The tide was rising during the inspection. The areas inspected included:

- (a) Existing areas located below the waterline
- (b) Existing below water concrete
- (d) Concrete embedment's (Guides and sill)
- (e) 12" drain as identified on drawings
- (f) Other pertinent areas including additional piping, general concrete condition as observed during the GVI

Anomaly register and previous reference.

Anomaly No.	Description	Page(s)	Previous report reference & Page #
1	Crack located along DT dividing column	28	-
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			

Reporting - Unit 8 ROV site assessment

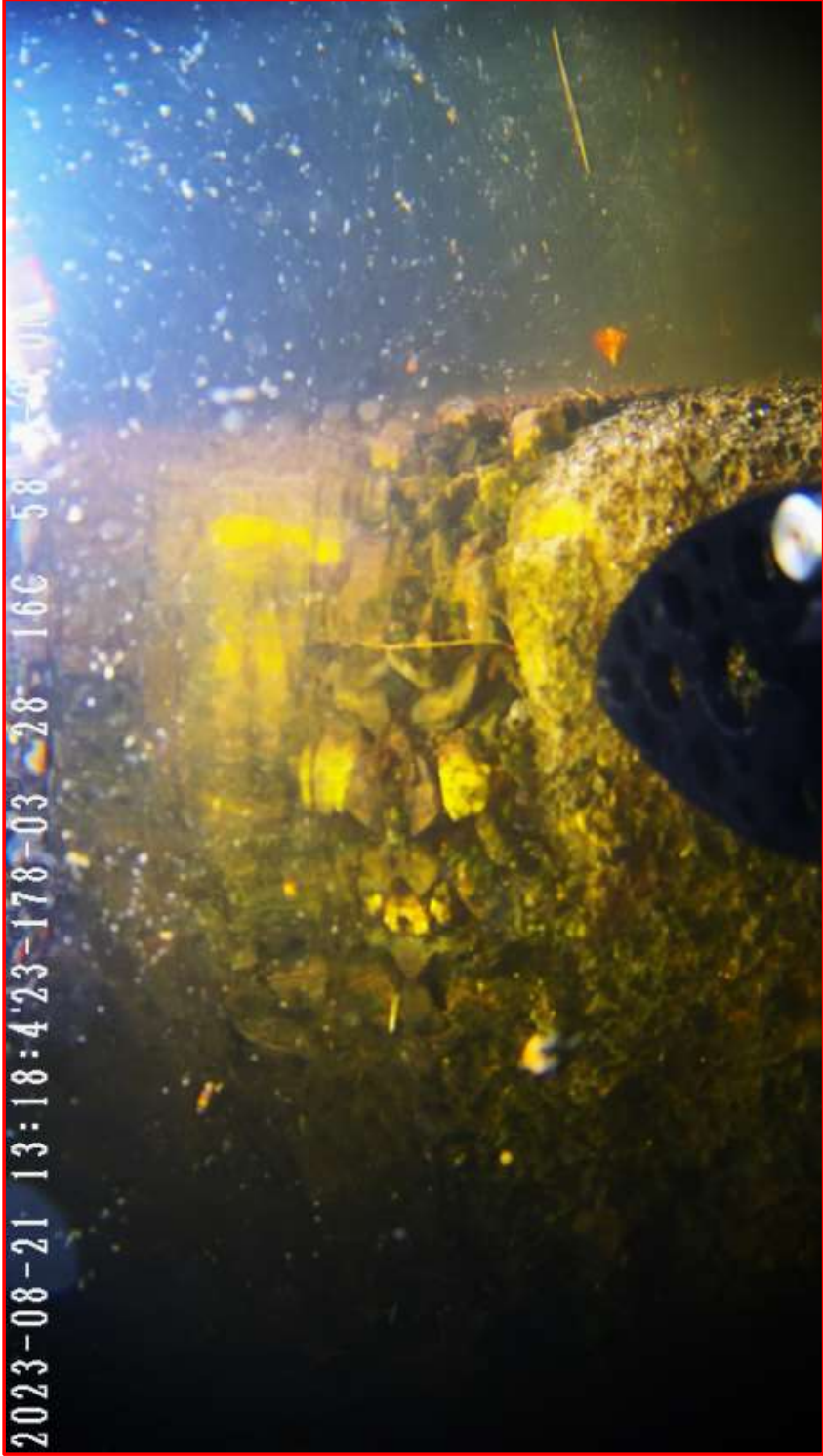
Client: Wood  
 Report Description: Unit 8 Rov Inspection  
 AAE Job ID: 23-178-03



Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: 0M	Water line on structure	-	Typical of what was seen along the waterline of the existing structure. Light marine growth was present throughout.



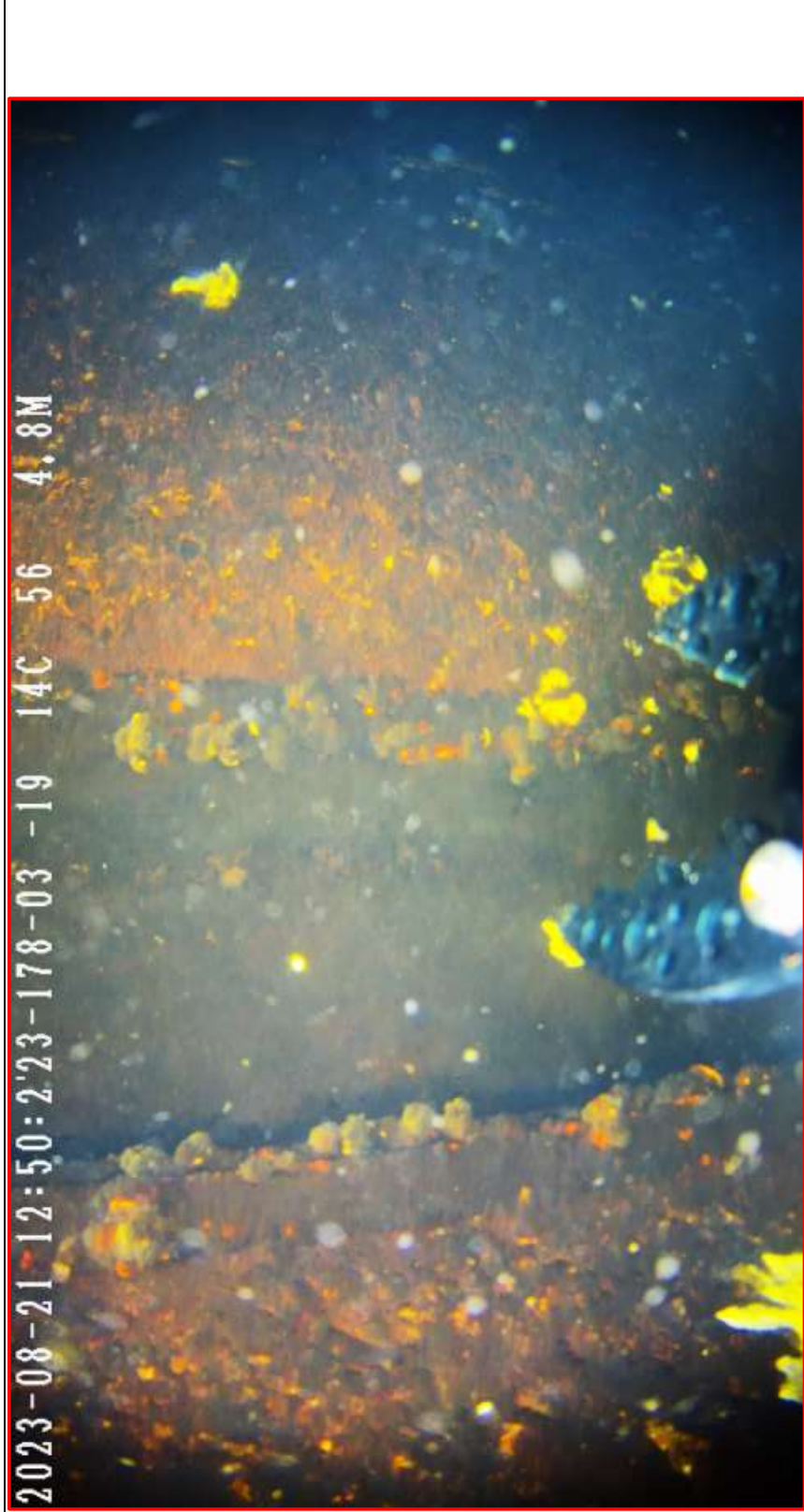
Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
Y	EL: 0M	Water line on structure	-	Some areas showing exposed aggregate at the waterline likely from winter ice conditions. This was also visible from the operating deck.



Client: Wood  
 Report Description: Unit 8 Rov Inspection  
 AAE Job ID: 23-178-03



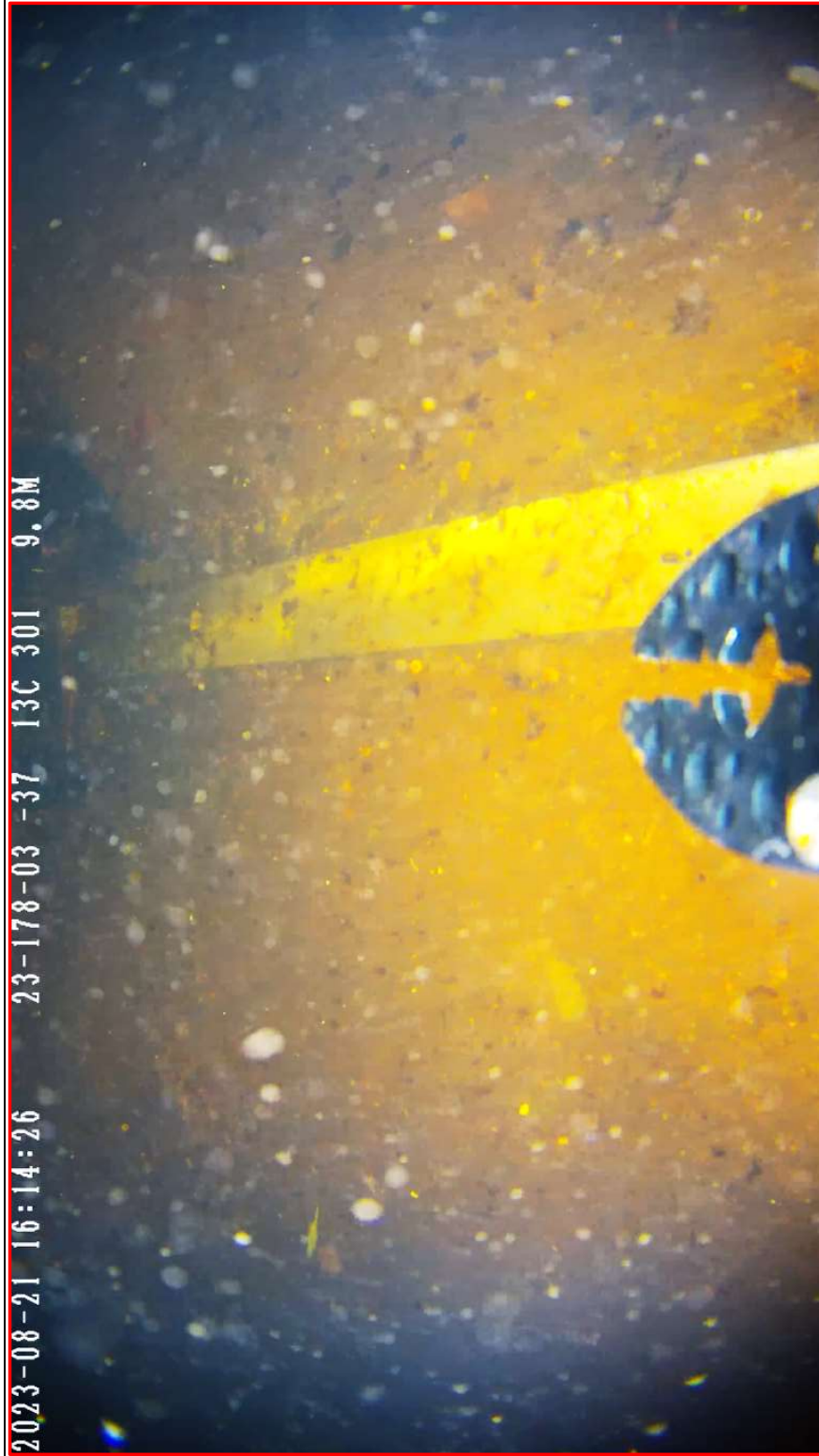
Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: -4.8M	Gate guide	-	Typical of what was seen along the gate guides of the existing structure. Light marine growth was present throughout.



Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: -9.0M	Gate guide	-	Typical of what was seen along the gate guides of the existing structure. Light marine growth was present throughout but reduced near the -10M mark.

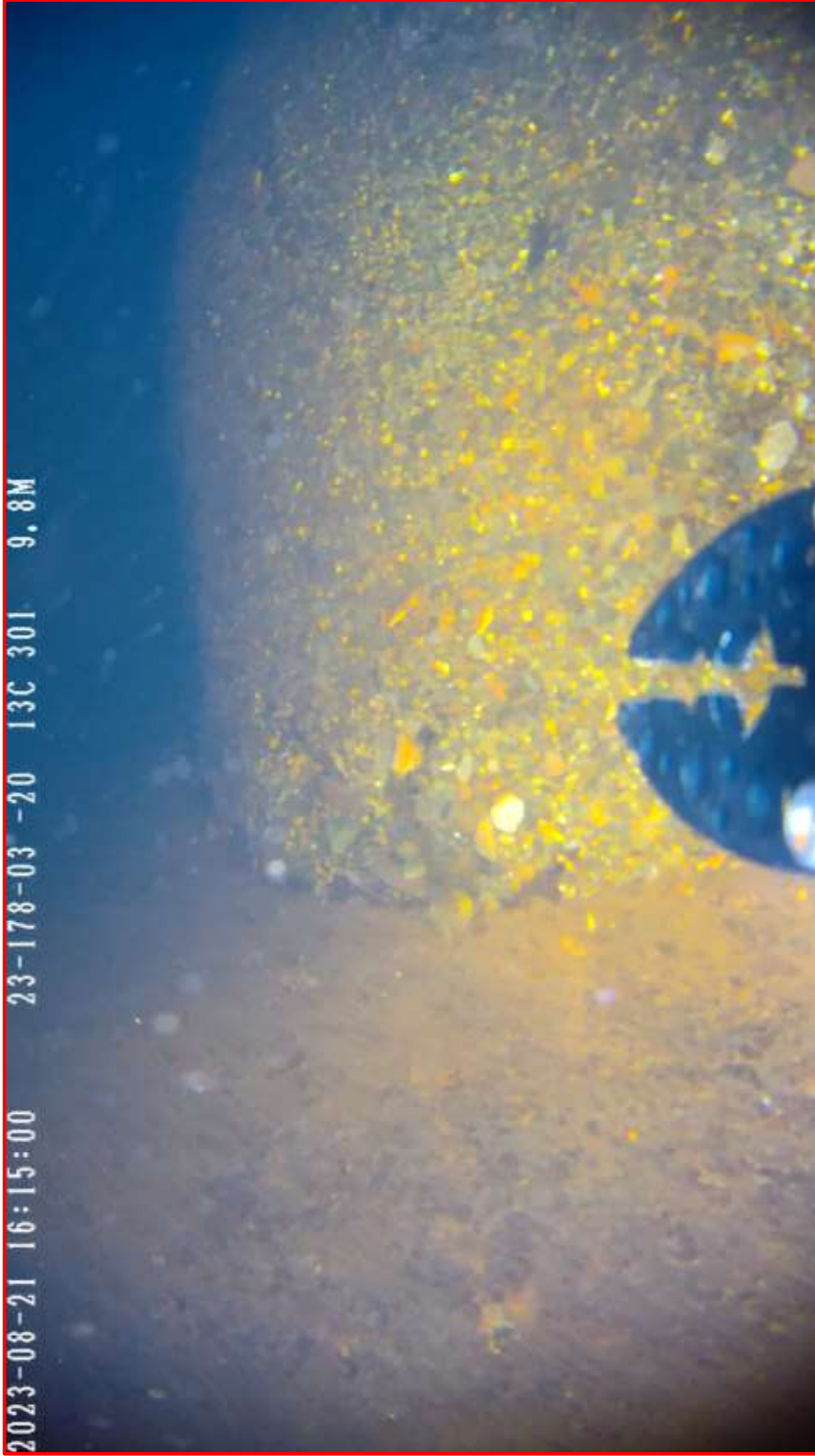


Client: Wood  
 Report Description: Unit 8 Rov Inspection  
 AAE Job ID: 23-178-03



Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: -9.8M	Lower sill	-	Typical of what was seen along the lower sill. Some small boulders were noted in the area along the bottom sill area, no damage was noted.

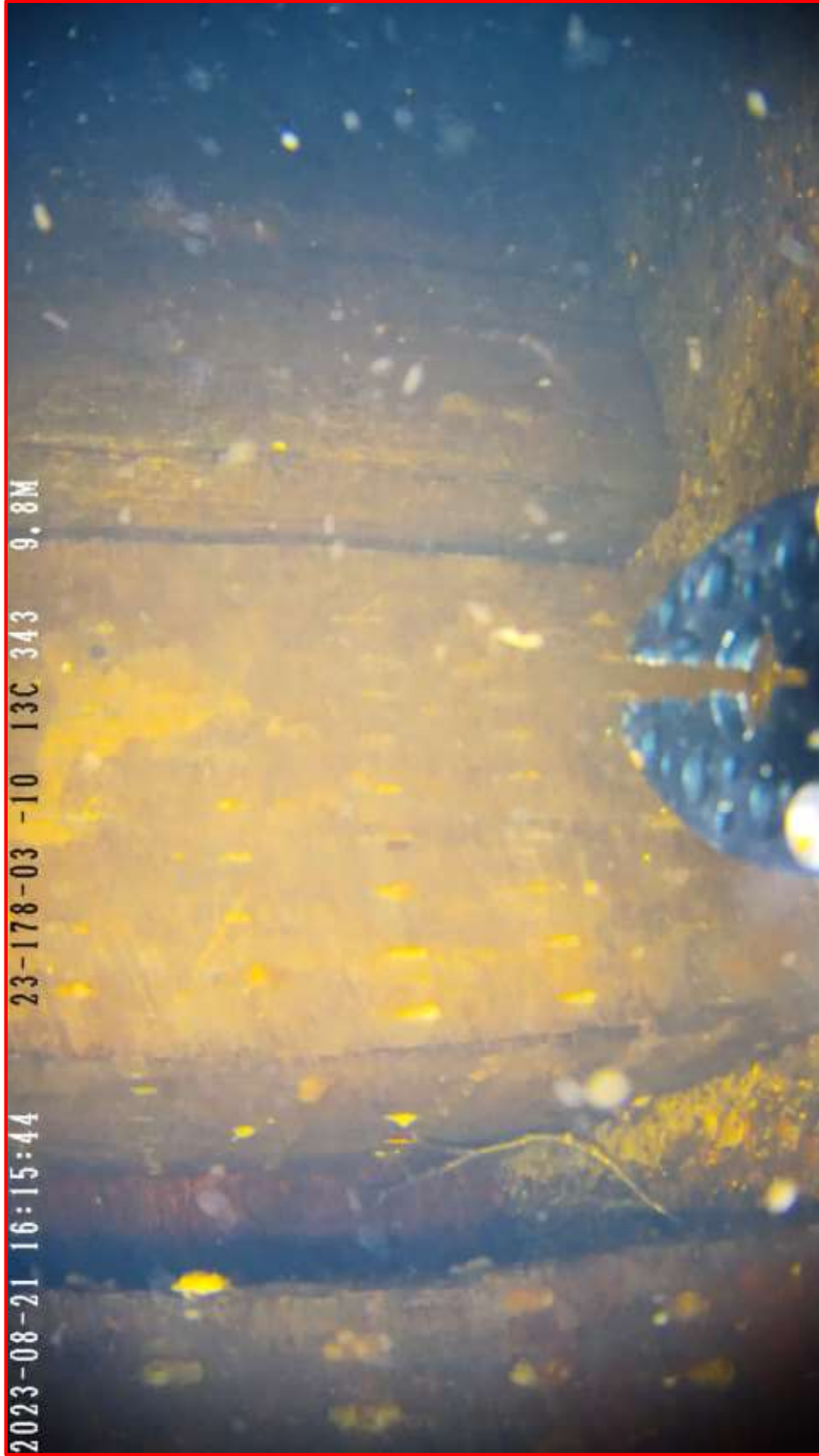
Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: -9.8M	Bottom of existing Draft Tube	-	The bottom of the draft tube has a layer of small stone built up, an attempt to dig with the ROV estimated that there is approx 6"+ present.



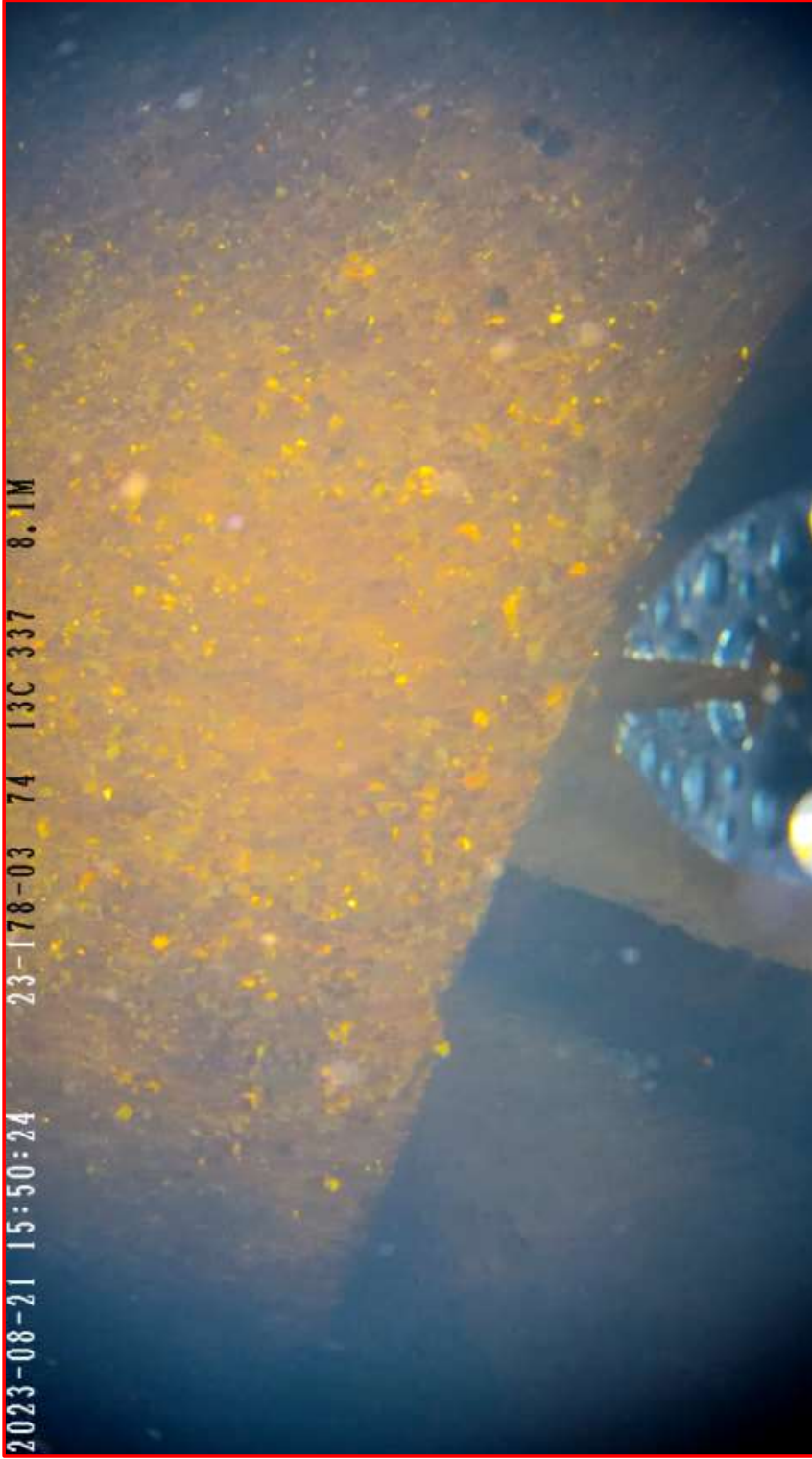
Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: -9.8M	Bottom of Draft Tube near permanently installed timbers	-	The bottom of the draft tube along the back wall where the timbers are installed showed as being in good condition with no damage or notable anomalies present.

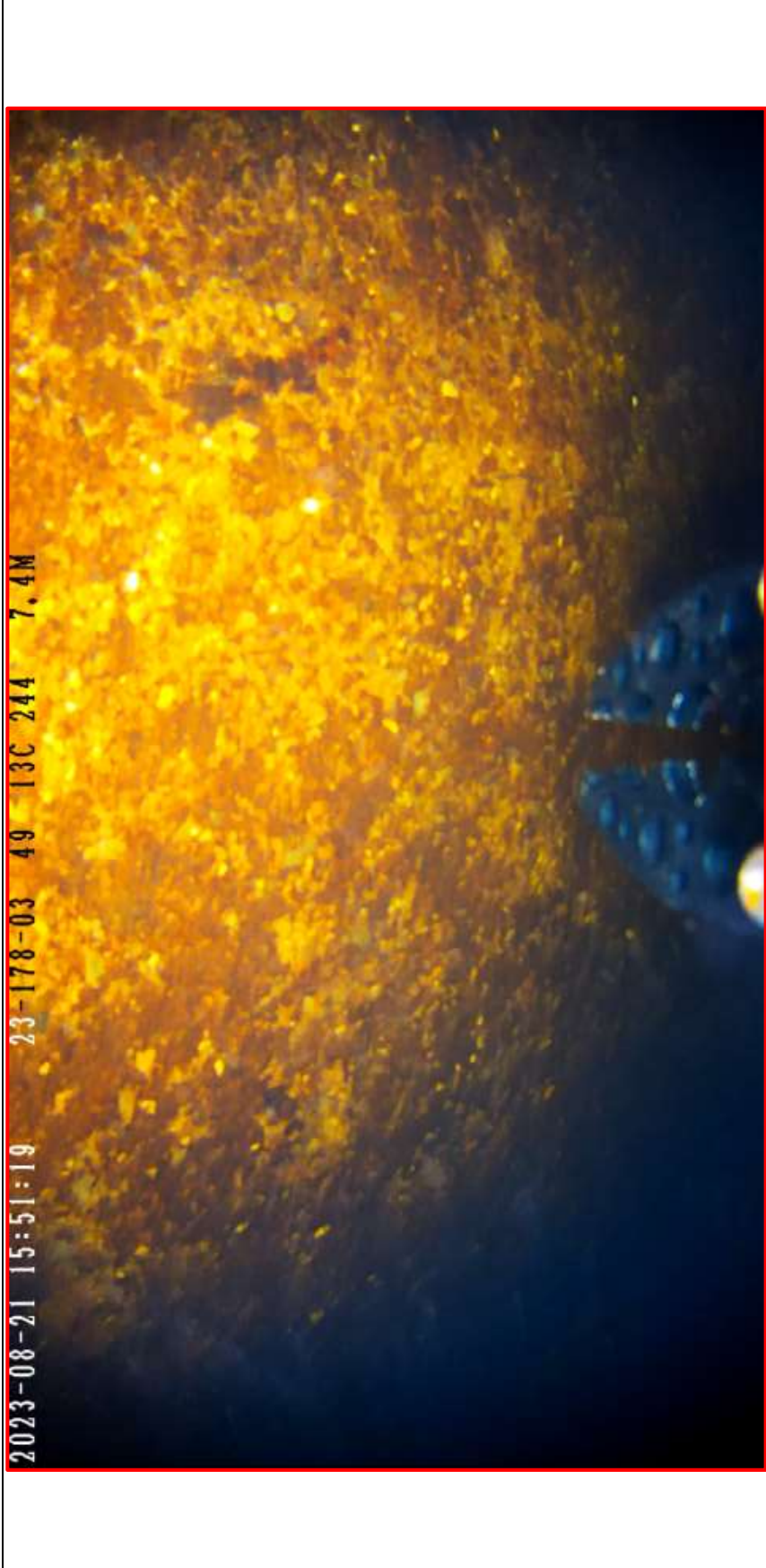


Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: -9.8M	Bottom of Draft Tube near timber bulkhead	-	The bottom of the draft tube along the back wall where the timbers are installed showed as being in good condition with no damage or notable anomalies present.



Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: -8.1	Top of Draft Tube near timber bulkhead	-	The top of the draft tube along the back wall where the timbers are installed showed as being in good condition with no damage or notable anomalies present.



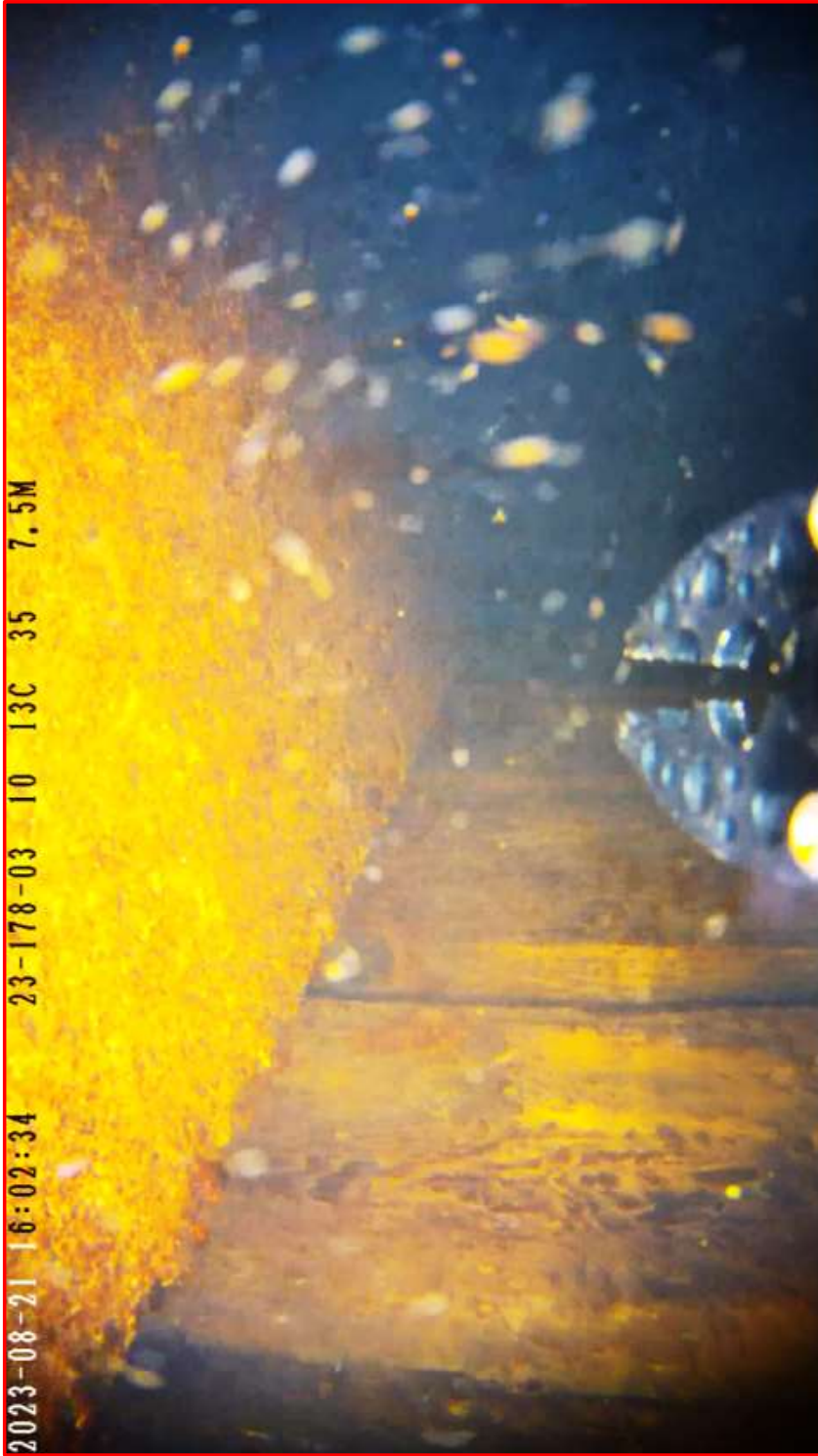


Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: -7.4	Top of Draft Tube	-	The top of the draft tube showed as being in good condition with no damage or notable anomalies present.

Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: -8.8M	Top radius area of Draft Tube near timber bulkhead	-	Start of top radius along the back wall where the timbers are installed showed as being in good condition with no damage or notable anomalies present.



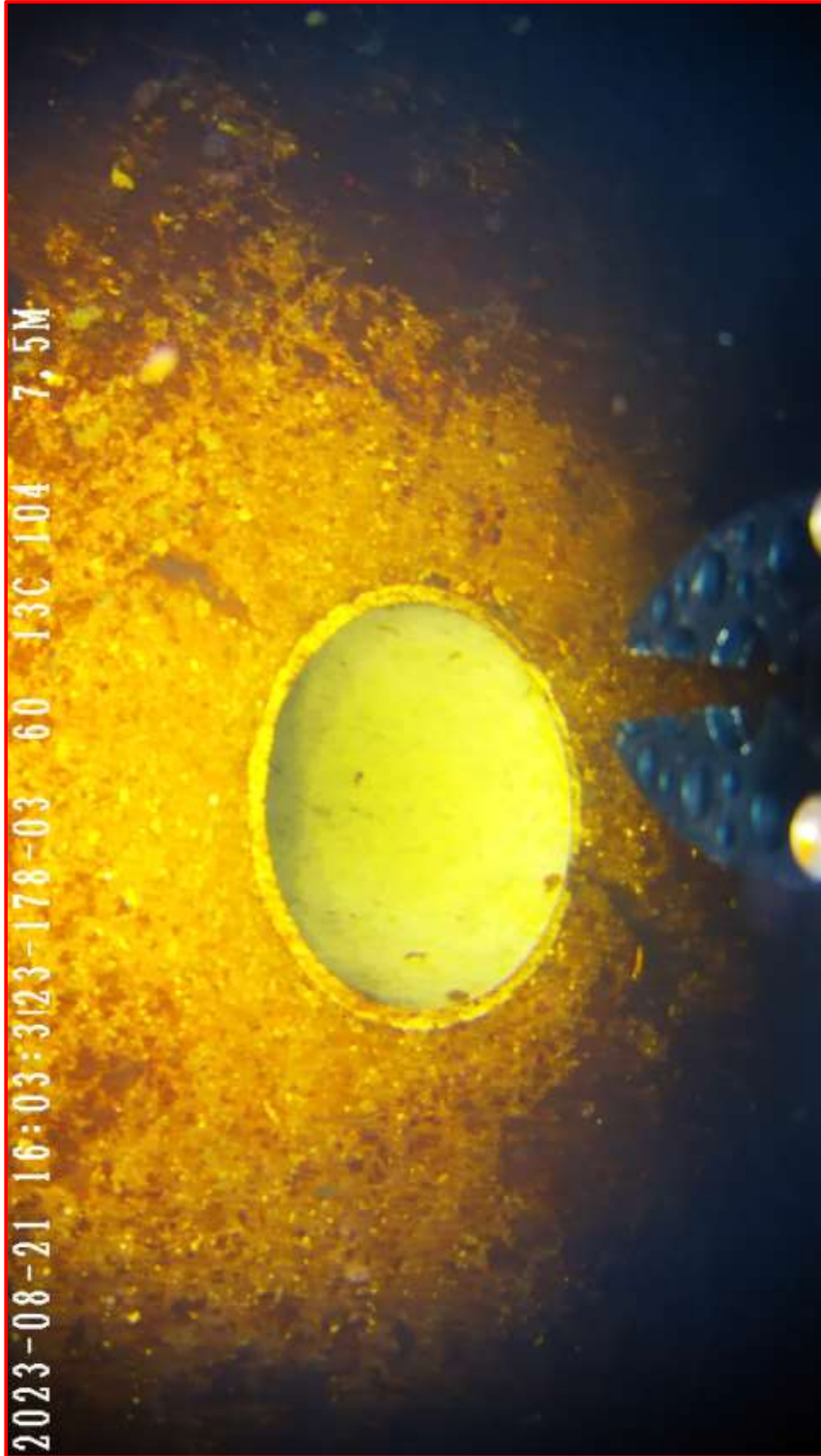
Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: -7.5M	Top radius area of Draft Tube near timber bulkhead	-	Start of top radius along the back wall where the timbers are installed showed as being in good condition with no damage or notable anomalies present.



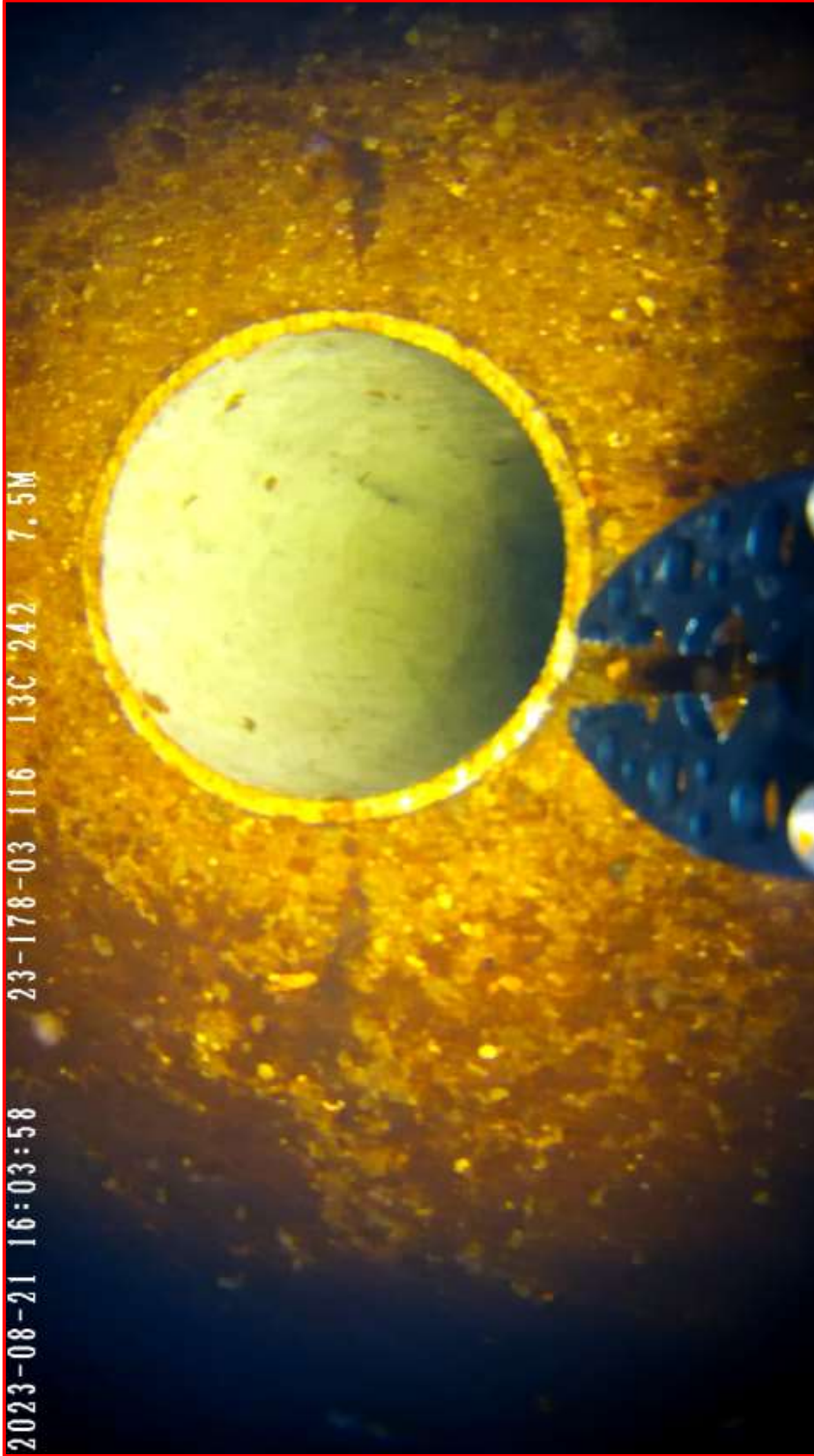
Client: Wood  
 Report Description: Unit 8 Rov Inspection  
 AAE Job ID: 23-178-03



Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: -7.5M	12" line	-	12" line into the top of the draft tube concrete. This is assumed to be the 12" line identified in the inspection document. There was another line noted in the unwatering sump.



Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: -7.5M	12" line	-	12" line into the top of the draft tube concrete. This is assumed to be the 12" line identified in the inspection document. There was another line noted in the unwatering sump.

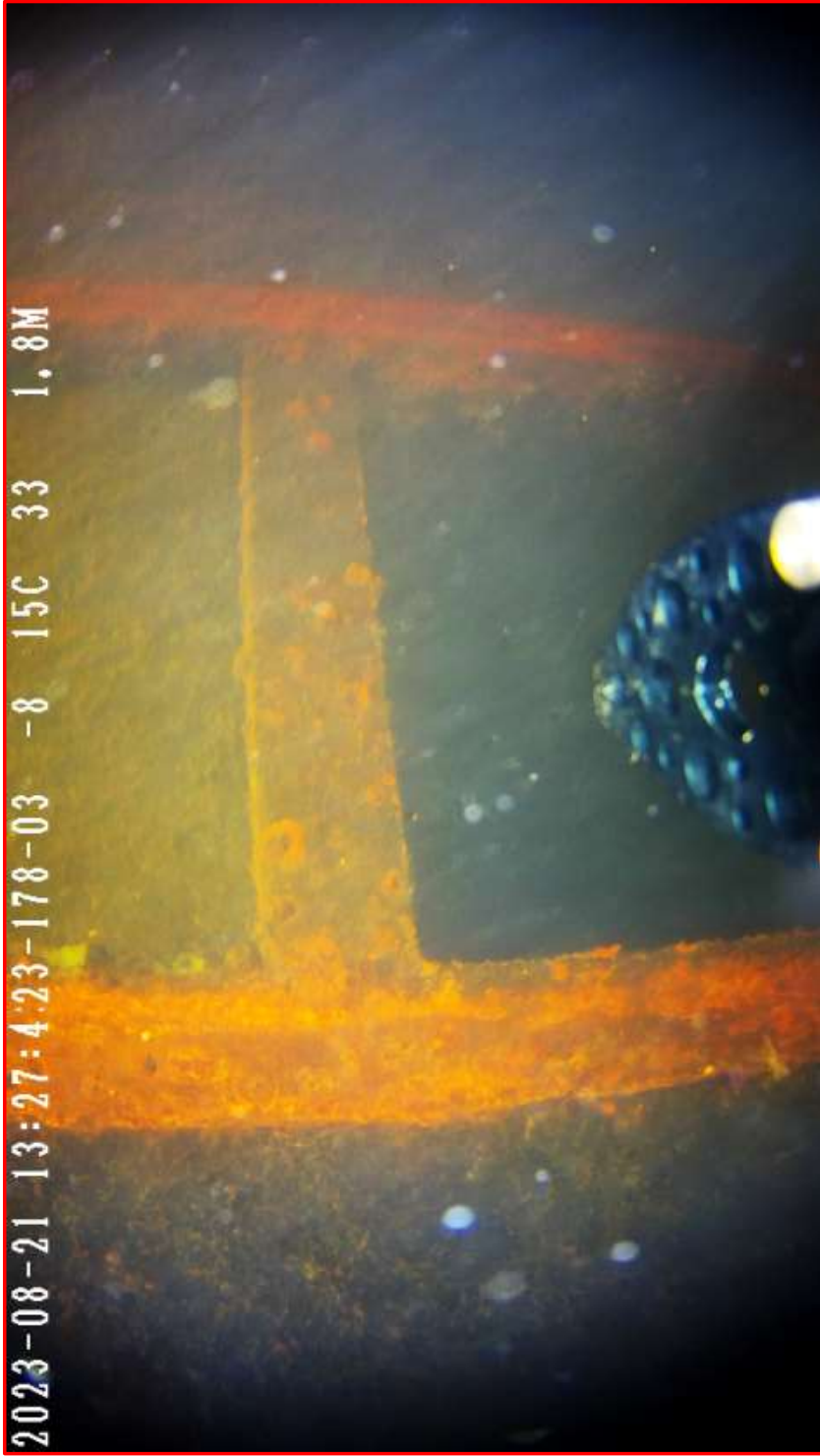


2023-08-21 16:03:58 23-178-03 116 13C 242 7.5M

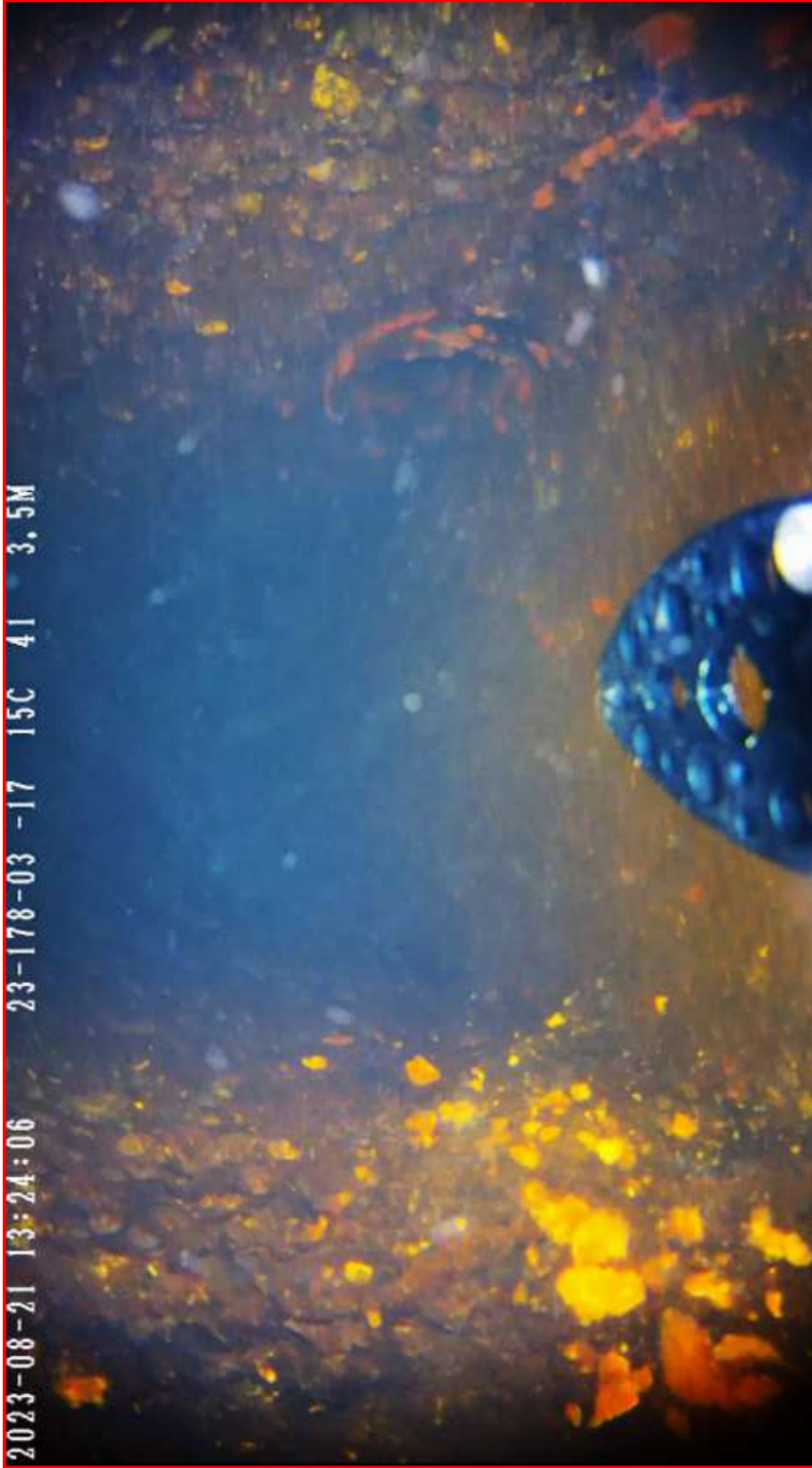
Client: Wood  
 Report Description: Unit 8 Rev Inspection  
 AAE Job ID: 23-178-03



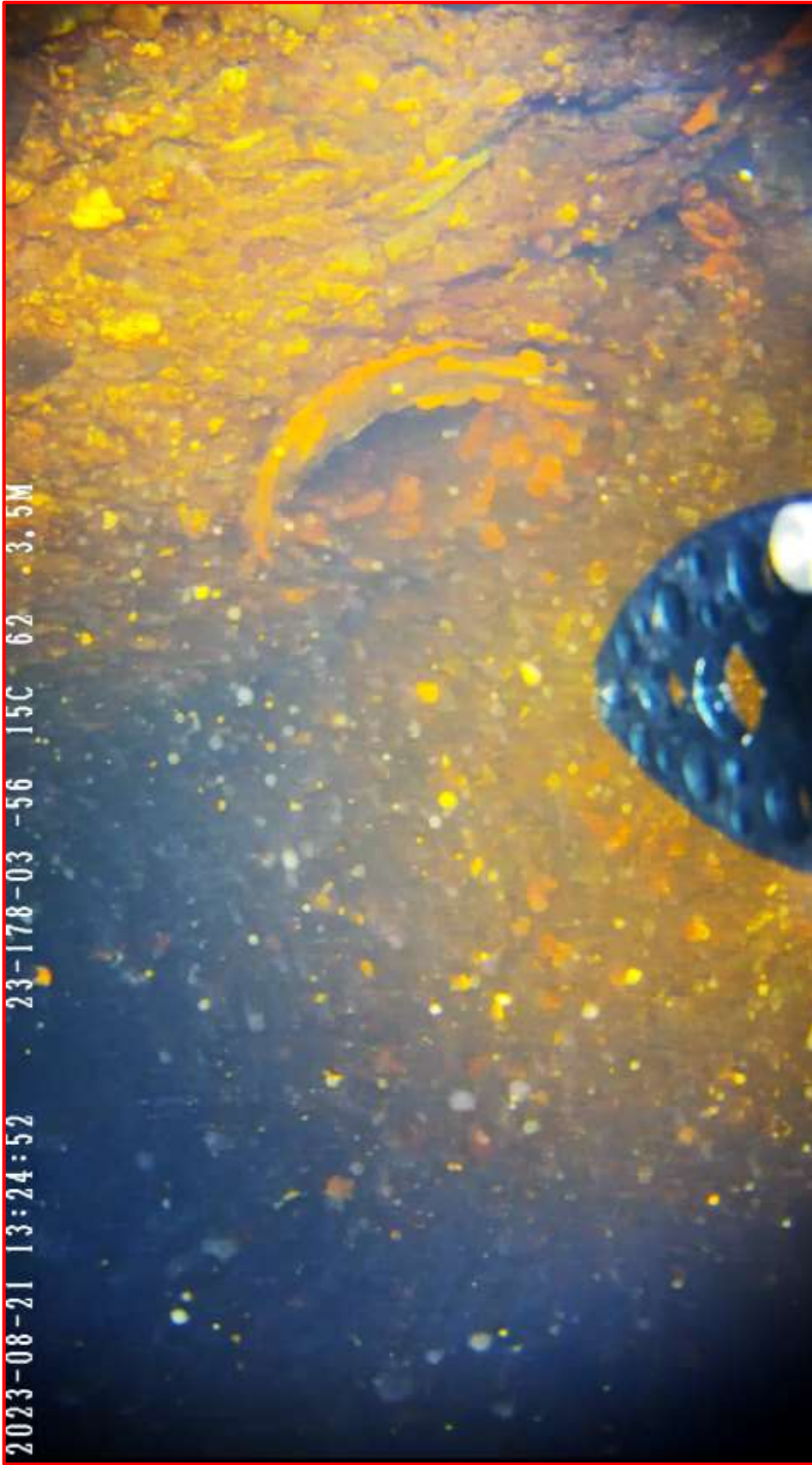
Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: -1.8M	Unwatering Sump external steel work	-	Unwatering sump has the appearance of being corroded but intact.



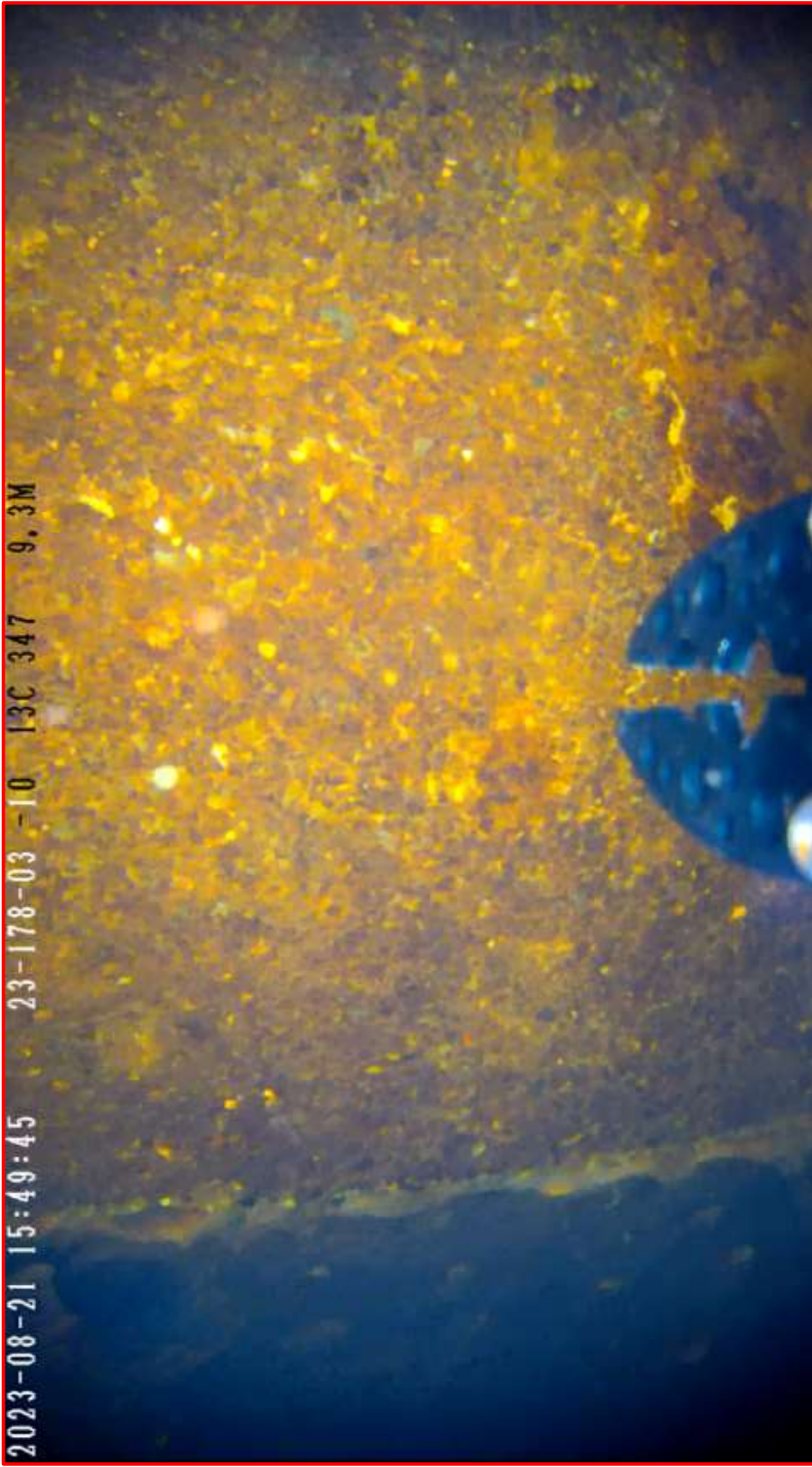
Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: -3.5M	Internal Unwatering Sump	-	General view of sump internal.



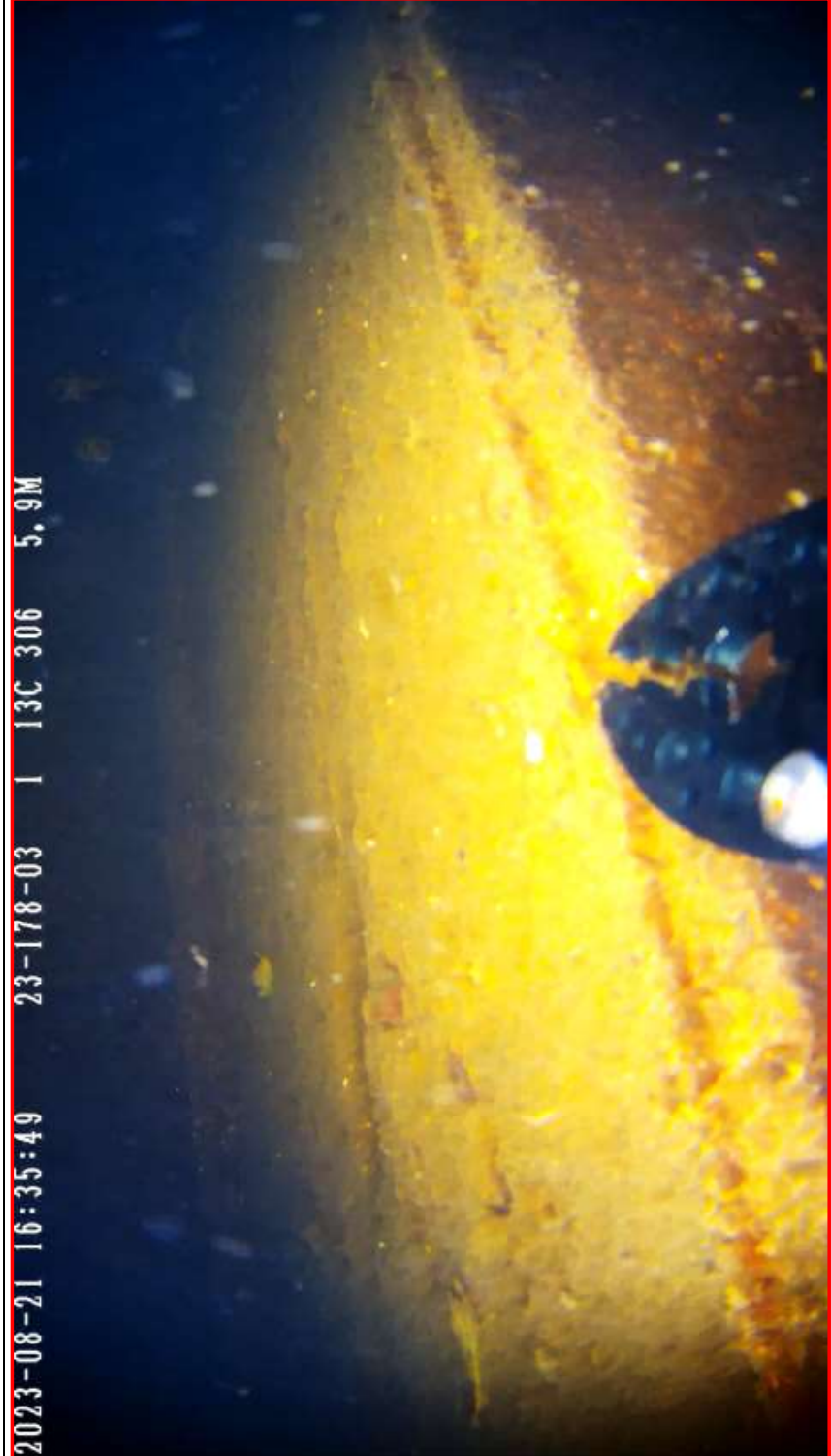
Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: -3.5M	Internal Unwatering Sump line	-	Line in unwatering sump, appears to have marine growth and likely corroded.



Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: -9.3M	Draft tube	-	Typical condition of draft tube area into the timber wall.



Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: -5.9M	Sloping structure edge	-	The sloped structure appeared to be in good condition with a layer of silt present throughout. No anomalies were observed.

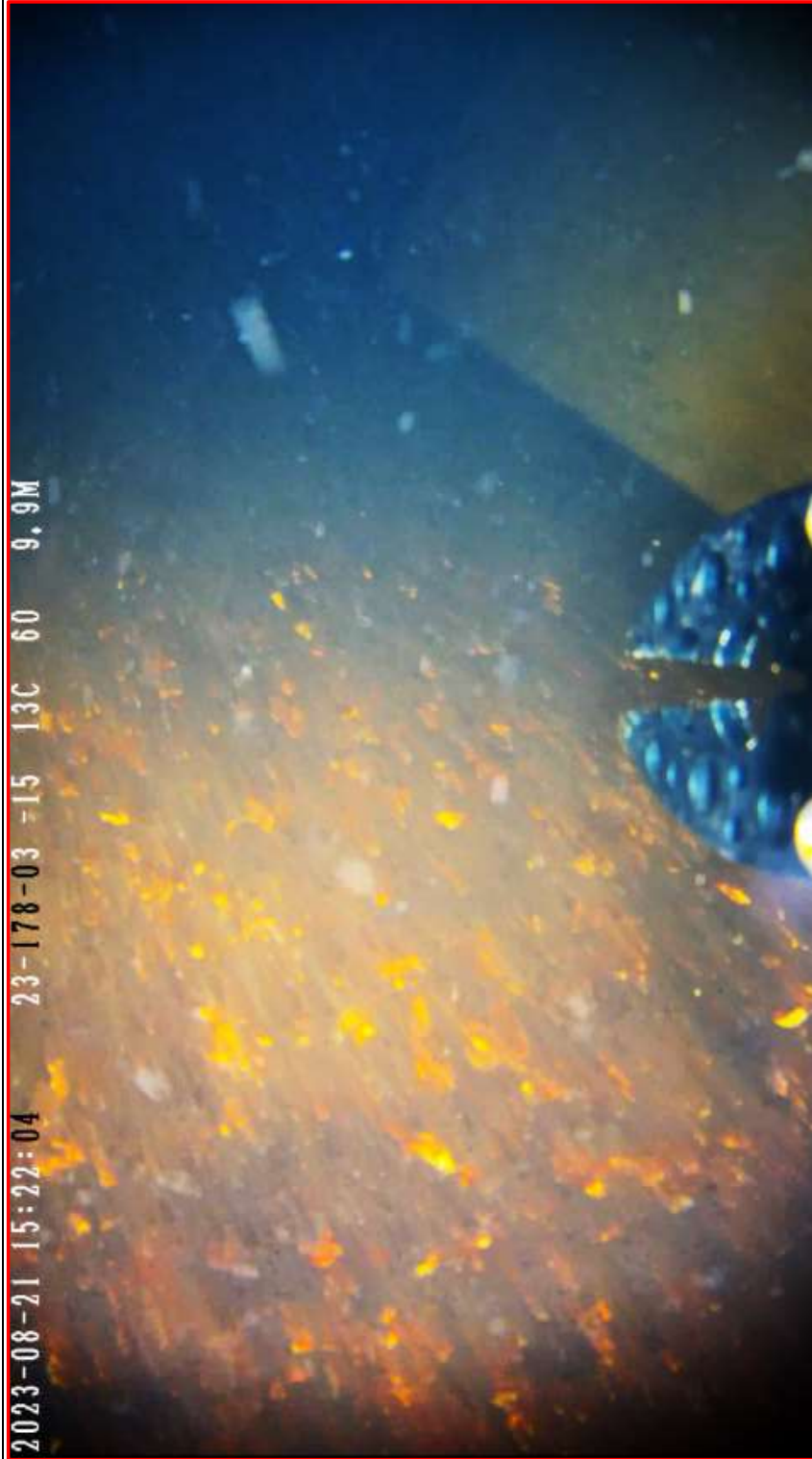


Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: -5.6	Leading edge of sloping roof	-	Typical condition along the leading edge of the sloping roof.

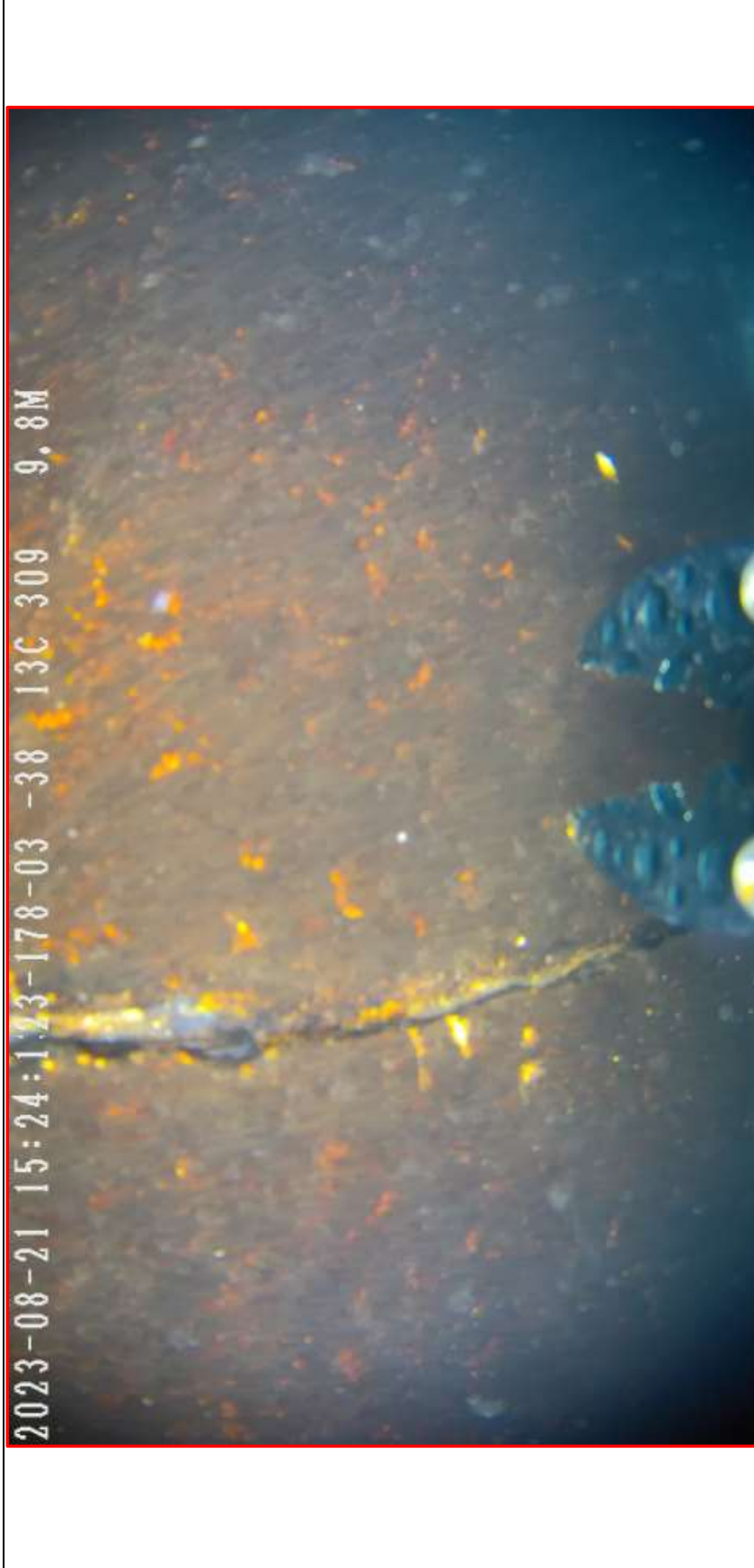


2023-08-21 16:37:47 23-178-03 -19 13C 319 5.6M

Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: -9.9M	Lower structural concrete	-	Lower structural concrete, no anomalies noted.

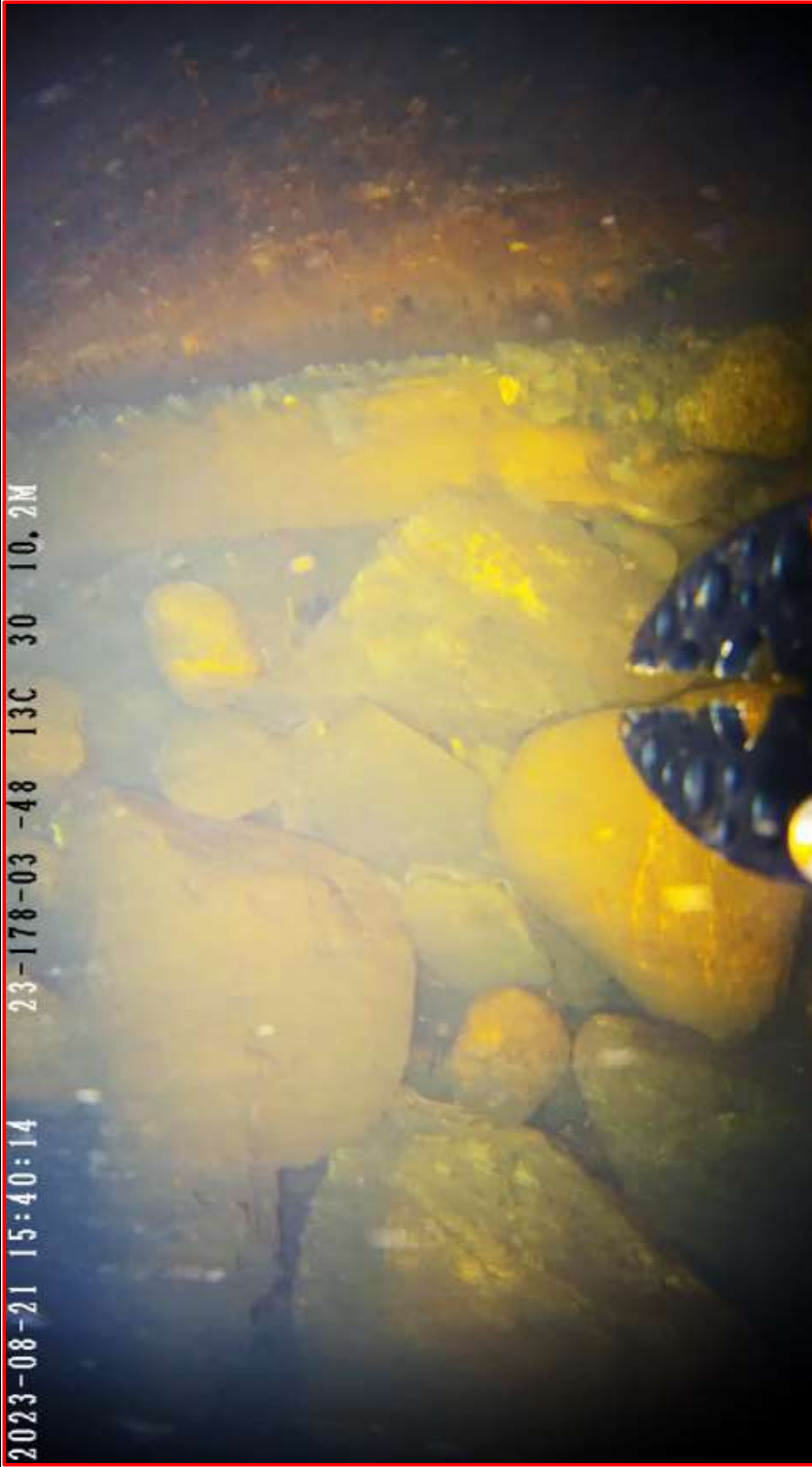


Client: Wood  
 Report Description: Unit 8 ROV Inspection  
 AAE Job ID: 23-178-03



Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
Y	EL:-9.8	Structural Divider on Unit 8	Crack	A crack was noted that extended from EL:-9.8 to the surface. It appears on both sides of the unit 8 divider. The crack appears to be less than 6.5mm in width as the ROV manipulator was used and could not fit into the crack. It is abnormally shaped and was deemed to not be an expansion joint.

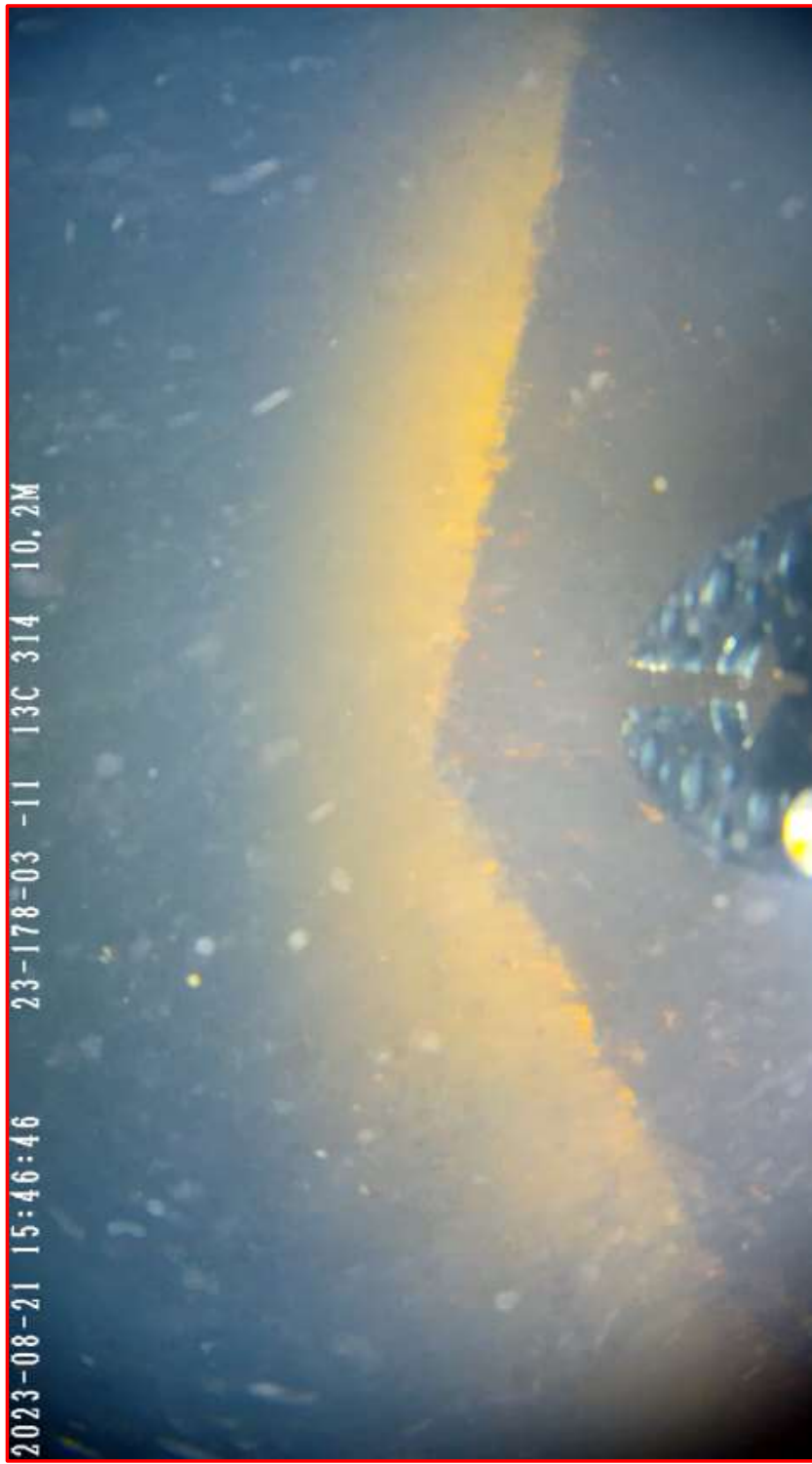
Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: -10.2	Lowest concrete foundation	-	Typical condition along the leading edge of the deepest structural concrete. Appearance of small boulders and loose stone/silty conditions, no undermining noted.



Client: Wood  
 Report Description: Unit 8 Rov Inspection  
 AAE Job ID: 23-178-03



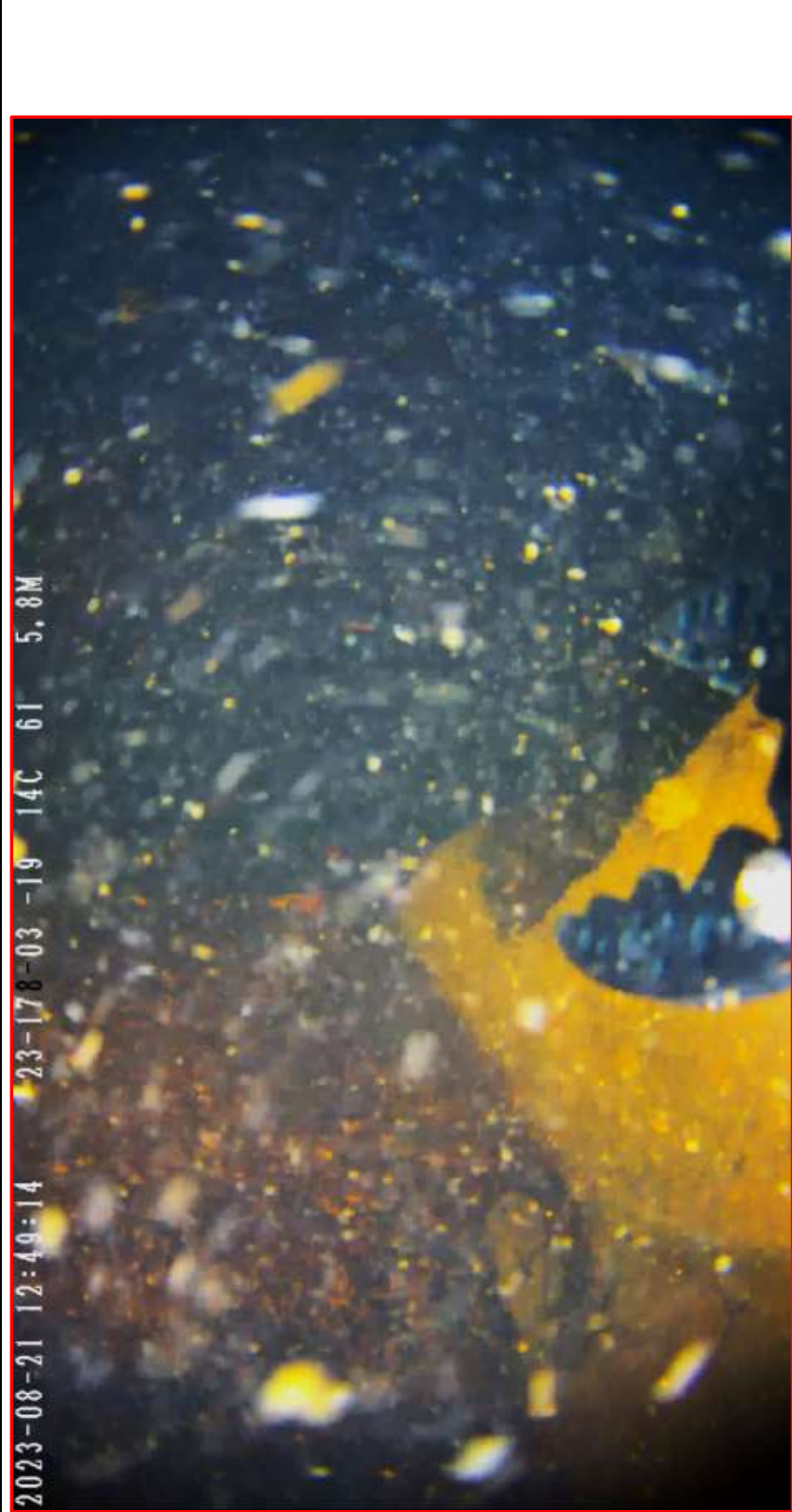
Anomaly (V/N)	ID	Component	Type of Anomaly	Comments
N	EL: -10.2	Lowest concrete foundation	-	Typical condition along the leading edge of the deepest structural concrete. The face and condition was good with no anomalies noted.



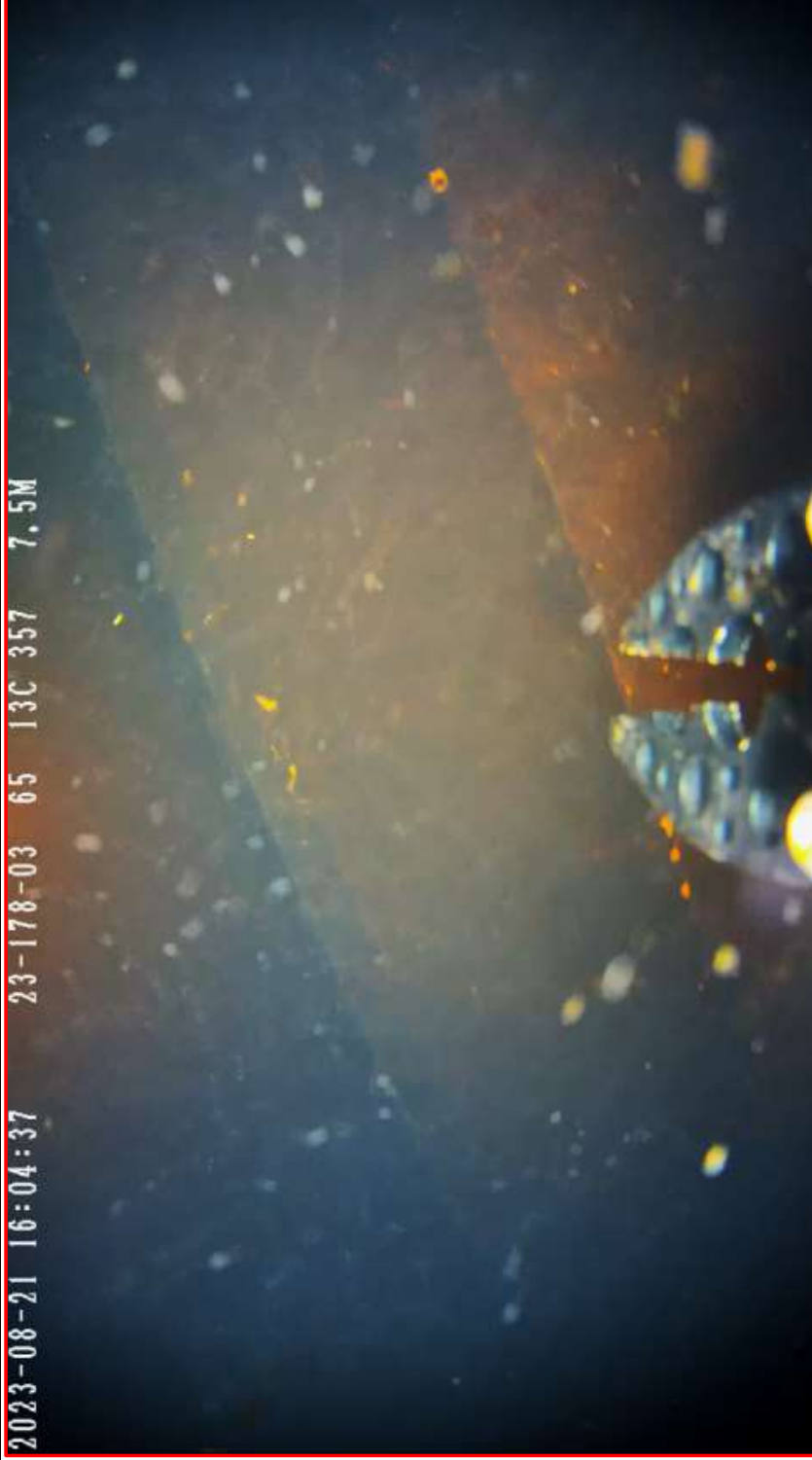
Client: Wood  
 Report Description: Unit 8 Rov Inspection  
 AAE Job ID: 23-178-03



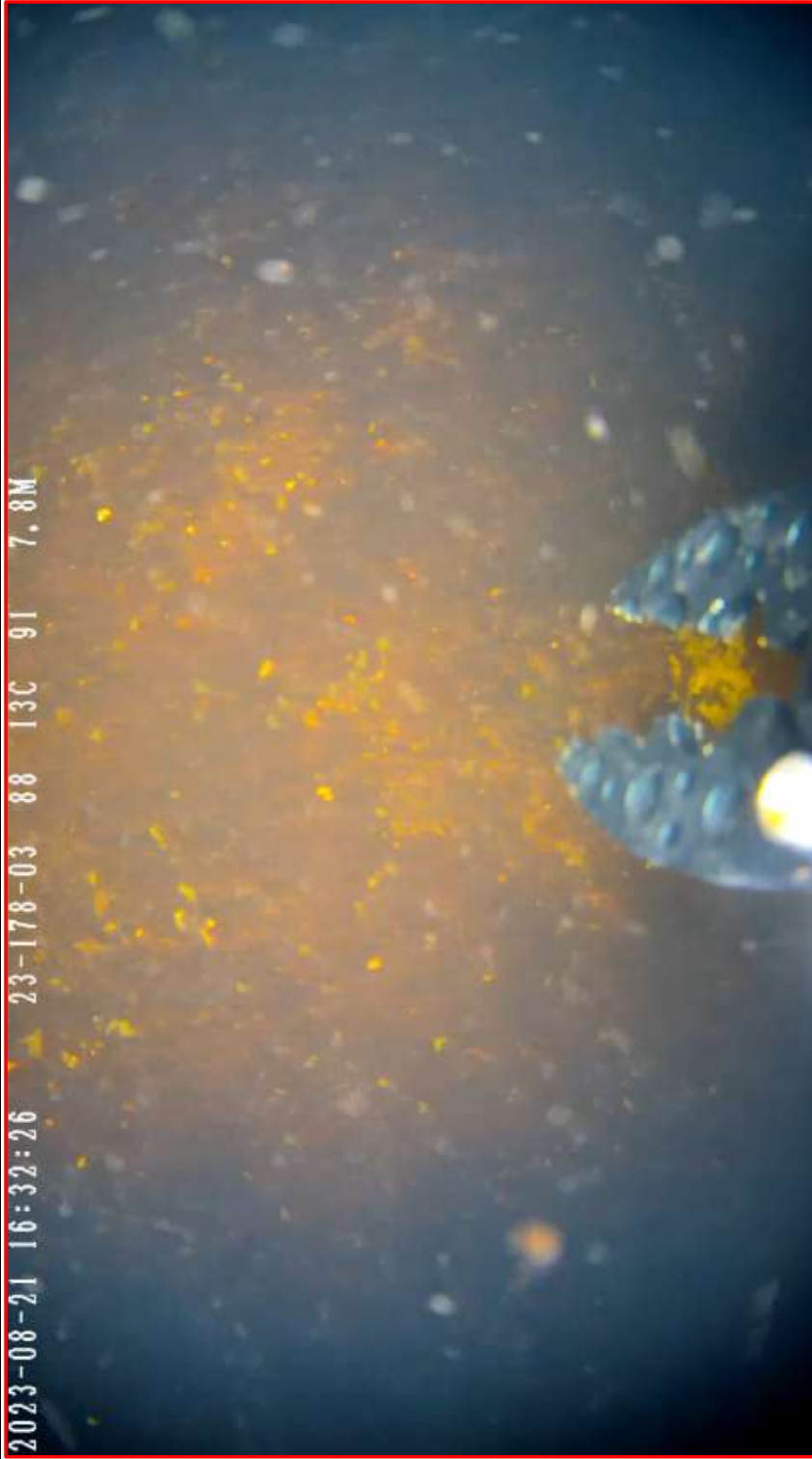
Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: -5.8	Roof slab connection point	-	The roof slab connection areas was in good condition showing no animalies.



Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: -7.5	Roof slab	-	The roof slab connection areas was in good condition showing no animalies.



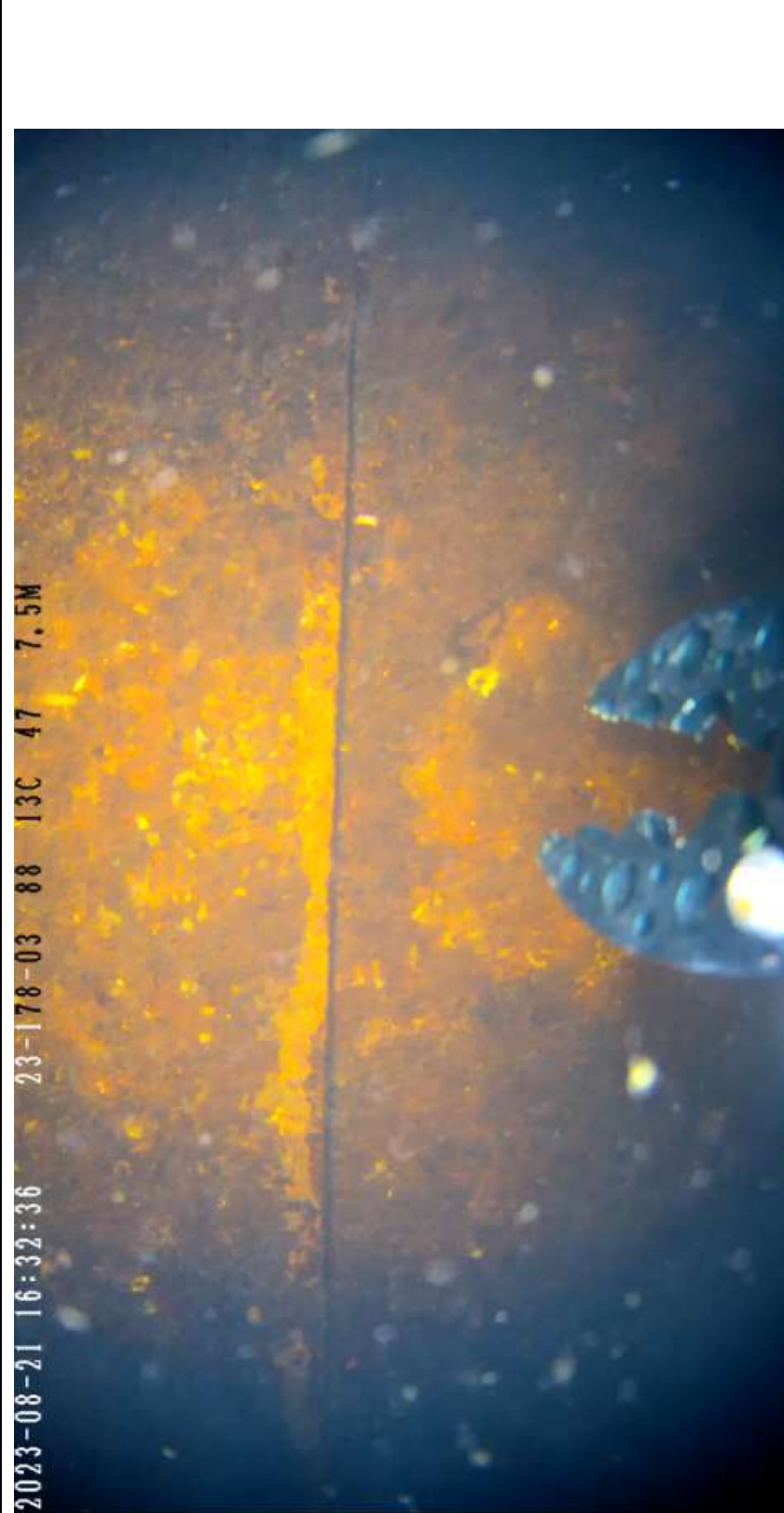
Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: -7.8	Roof slab	-	General condition of the roof slab. Looking up from below. No anomalies noted.



Client: Wood  
 Report Description: Unit 8 Rov Inspection  
 AAE Job ID: 23-178-03



Anomaly (Y/N)	ID	Component	Type of Anomaly	Comments
N	EL: -7.5	Roof slab	-	General condition of the roof slab connection point. Looking up from below. No anomalies noted.



## Appendices

The following reference material was provided as part of the inspection, where reasonable these appendices have been attached and where size limitations became an issue they will be submitted digitally.

### Included Appendices:

- Work Package Request MSO - BDE 8 Existing Infrastructure Condition Assessment Final.pdf

## Recommendations

Recommendations from the inspection team would be to keep monitoring the area at intervals identified in the asset integrity plan if one exists. Advanced Access Engineering Inc has in similar asset integrity monitoring situations developed asset integrity monitoring workflows that identify critical areas and provide visual comparison overtime. If this maybe of interest please let us know.



Client: Wood  
Report Description: Unit 8 Rev Inspection  
AAE Job ID: 23-178-03

## Appendices

Work Package Request MSO - BDE 8 Existing Infrastructure Condition Assessment Final

## ***Work Package Request***

Note: This portion of the AAE report contained NL Hydro's Work Package Request for BDE Unit 8 Assessment - has been removed by Wood to reduce file size.

### **Appendix A: Photos**

Note: this is Appendix A of the AAE Report on the ROV inspection, which is contained in Appendix D of the Wood Assessment Report

































Note: The following appendices of the AAE report in have been removed by Wood to reduce the size of the report file.

**Appendix B drawings** - contained scanned copies of existing drawings received from NL Hydro

**Appendix C Subcontractor form** - removed since not relevant to the infrastructure assessment

Advanced Access Engineering provides Specialized Access and Engineering services. As a multidiscipline Engineering and inspection services firm we support,

- Class Approved Inspection Services including,
  - o UAV inspections
  - o UAV LIDAR Surveys
  - o ROV inspections
  - o Crawler inspections
  - o Third Party Inspectors and Surveyors
  - o Hydrographic & Survey Services
  - o Digital Solutions
  - o Cloud Asset and Information viewer
  - o Mooring and Marine Support
  - o Procedure development
  - o Vendor Surveillance
  - o Drawing Packages
  - o Marine Surveys
  - o Mooring Equipment

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## **11.0 Appendix E Concrete Testing Report by WSP**



## Document Front Sheet

Contract Number and Description: 07965; Bay D'Espoir Geotechnical Investigation for Unit 8 and LD-1

Contractor Name: WSP Canada Inc

Address: 36 Pippy Place St. John's, NL, A1B 3X4

Project Number: 07965

Document Title: GEOTECHNICAL INVESTIGATION AT THE BAY D'ESPOIR GENERATING STATION - CONCRETE CORING PROGRAM

Total Number of Pages  
 Incl. Front Sheet: 37

Contractor Document Number: CA0010449.7949

Revision Number: Rev 0

Contractor Signature/Stamp:

Sterling Parsons, WSP Project Manager

NLH Document Number: 07965-A99-0005

NLH Revision Number :01

Date on Document (mm-dd-yyyy): 01-18-2024

Comments:

Equipment Tag

REVIEW DOES NOT CONSTITUTE APPROVAL OF DESIGN DETAILS, CALCULATIONS, TEST METHODS OR MATERIAL DEVELOPED AND/OR SELECTED BY THE CONTRACTOR, NOR DOES IT RELIEVE THE CONTRACTOR FROM FULL COMPLIANCE WITH CONTRACTUAL OR OTHER OBLIGATIONS.

- 01 – REVIEWED AND ACCEPTED – NO COMMENTS
- 02 – REVIEWED – INCORPORATE COMMENTS, REVISE AND RESUBMIT
- 03 – REVIEWED - NOT ACCEPTED
- 04 – INFORMATION ONLY
- 05 – NOT REVIEWED

NLH Lead Reviewer:

Date (mm-dd-yyyy):

NLH Project Manager:

Date (mm-dd-yyyy):

General Comments:

NEWFOUNDLAND AND LABRADOR HYDRO  
REPORT NUMBER: CA0010449.7949

# GEOTECHNICAL INVESTIGATION AT THE BAY D'ESPOIR GENERATING STATION CONCRETE CORING PROGRAM

JANUARY 18, 2024





# GEOTECHNICAL INVESTIGATION AT THE BAY D'ESPOIR GENERATING STATION

## CONCRETE CORING PROGRAM

## FINAL REPORT

NEWFOUNDLAND AND LABRADOR HYDRO

PROJECT NO.: CA0010449.7949  
CLIENT REF: 2023-95503 MG  
DATE: JANUARY 18, 2024

WSP  
36 PIPPY PLACE  
ST. JOHN'S, NL A1B 3X4

T: 709-771-4706  
WSP.COM



January 18, 2024

Newfoundland and Labrador Hydro  
Hydro Place 500 Columbus Drive  
PO Box 12400  
St. John's, NL A1B 4K7

**Attention: Kathleen Wadden, Main Contract Manager**

Dear Madam/Sir:

**Subject: Final Report for Concrete Core Program**  
**Client ref.: 2023-95503 MG**

Enclosed please find the final report for the concrete coring program for Unit #8 Generation Facility construction project. We understand that further testing may be required based on the results of the testing to date. We are available to discuss at a mutually convenient schedule.

Yours sincerely,

A handwritten signature in black ink, appearing to read 'Yvette Hughes', written over a horizontal line.

Yvette Hughes, MASc, PEng  
Senior Principal Materials Engineer  
36 Pippy Place, St. John's, NL

YH  
Encl.  
cc:  
WSP ref.: CA0010449.7949

# REVISION HISTORY

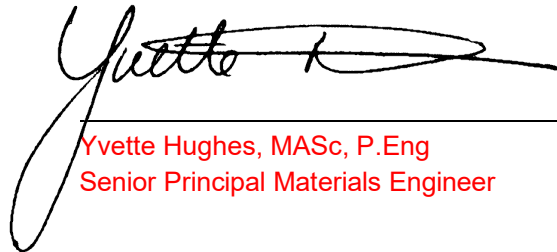
## FIRST ISSUE

October 9, 2023				
Prepared by	Reviewed by	Approved By		
Yvette Hughes, Senior Principal Materials Engineer	Chris Barnes Principal Materials Engineer	Sterling Parsons Senior Project Manager		
REVISION 1				
January 18, 2024	Revised to address comments from NL Hydro			
Prepared by	Reviewed by	Approved By		
Yvette Hughes	Chris Barnes	Sterling Parsons		
REVISION 2				
Prepared by	Reviewed by	Approved By		

---

# SIGNATURES

PREPARED BY



---

Yvette Hughes, M.ASc, P.Eng  
Senior Principal Materials Engineer

January 18, 2024

---

Date

APPROVED<sup>1</sup> BY



---

Sterling Parsons, M.Eng., P.Eng., PMP  
Senior Project Manager

January 18, 2024

---

Date

WSP prepared this report solely for the use of the intended recipient, Newfoundland and Labrador Hydro, in accordance with the professional services agreement. The intended recipient is solely responsible for the disclosure of any information contained in this report. The content and opinions contained in the present report are based on the observations and/or information available to WSP at the time of preparation. If a third party makes use of, relies on, or makes decisions in accordance with this report, said third party is solely responsible for such use, reliance or decisions. WSP does not accept responsibility for damages, if any, suffered by any third party as a result of decisions made or actions taken by said third party based on this report. This limitations statement is considered an integral part of this report.

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<sup>1</sup> Approval of this document is an administrative function indicating readiness for release and does not impart legal liability on to the Approver for any technical content contained herein. Technical accuracy and fit-for-purpose of this content is obtained through the review process. The Approver shall ensure the applicable review process has occurred prior to signing the document.

---

# CONTRIBUTORS

## CLIENT

Main Contract Manager                      Kathleen Wadden

## WSP

Senior Field Technician                      Tyler Bloom, CET

Senior Geoscientist                              Martin Little, MSC, PGeo

Senior Principal Materials Engineer              Oliver Gepraegs, MASC, PEng



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1	INTRODUCTION.....	1
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1.2	Concrete Core Program.....	1
1.2.1	Field/Lab work program.....	1
2	CORE PROGRAM TEST RESULTS .....	2
2.1	Record of Cores.....	2
2.2	Petrographic Examination of hardened concrete Report.....	3
3	CONCLUSION .....	4



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*TABLES*

TABLE 2.1	RECORD OF CORES AND TEST RESULTS.....	2
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*APPENDICES*

APPENDIX A	PHOTO RECORD
APPENDIX B	PETROGRAPHIC REPORT

# 1 INTRODUCTION

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## 1.1 BACKGROUND

Newfoundland and Labrador Hydro (NLH) is currently assessing the option of proceeding with the construction and commissioning of Unit #8 at the Bay D’Espoir Generation Facility. WSP understands that the Unit #8 Generation Facility will consist of a new powerhouse built as an extension to Powerhouse No. 2. The new unit will be constructed within the existing excavation, upstream of the Unit #8 Draft Tube concrete that was built as part of the original Powerhouse No. 2. WSP was contracted by NLH to conduct a Geotechnical and Concrete Core Program to obtain detailed site information for the planned construction of Unit #8. NLH also engaged Wood as a consultant to provide input to the concrete core program and assess the condition of the existing structure. This report documents the findings of the Concrete Core Program. The findings of the Geotechnical Investigation will be issued under a separate cover.

---

## 1.2 CONCRETE CORE PROGRAM

---

### 1.2.1 FIELD/LAB WORK PROGRAM

As part of the assessment to move forward with the completion of Unit #8, cores were extracted from concrete constructed as part of the original Powerhouse No. 2 in approximately 1977. The core locations were identified by Wood/NLH with WSP representative, Howard Kearley, Senior Technician present onsite, on August 21, 2023. The original core program plan consisted of five concrete cores, 6” diameter by 12” long, with three cores taken from land access and two cores from the downstream face of the existing concrete. Due to the presence of reinforcing steel in some cores, WSP discussed with NLH the option to extract a sixth core, with the intent to retrieve a full-length concrete core for testing. NLH located the sixth core in the draft tube deck in the proximity of Core 2. Reinforcing steel was encountered in the core, however, the core was suitable for testing.

The six cores were drilled on August 22 and 23, 2023. The WSP field team consisted of Senior Technicians, Tyler Bloom and Howard Kearley. The cores were wet drilled using an electric core drill with a diamond tip core barrel mounted securely at the core location. The actual diameter of the cores is 143 mm. NLH provided boat access to obtain the cores from the downstream concrete pier. A Photo Record of the core locations (Photos 1 to 6) is presented in Appendix A. The cores were wrapped in a water-proof bag and transported to the WSP laboratory at 36 Pippy Place, St. John’s, NL.

The original laboratory test program as identified in the RFP, consisted of a Petrographic Examination and Analysis, Compressive Strength & Density, Modulus of Elasticity & Poisson’s Ratio, Pulse Velocity, Resistance of Concrete to Rapid Freezing and Thawing, Microscopical Determination of Parameters of the Air-Void System in Hardened Concrete and Water-Soluble Chloride Content. In discussion with Wood, NLH instructed WSP to conduct compressive strength testing on two cores (one from the deck and one from the pier), and petrographic examination over the full length of one core to detect symptoms of Alkali Aggregate Reactivity (AAR). Based on the results of the petrographic examination, further testing may be required to investigate AAR, if observed.

The laboratory test program was conducted from August 25 to October 3, 2023. Cores 4, 5 and 6 were selected for the initial test program. Compressive strength and density testing was conducted on Core 4 (cored from the pier) and Core 6 (cored from the draft tube deck). Core 5 was submitted to the WSP Burlington, ON advanced testing laboratory for petrographic analysis, hardened air void analysis and water-soluble chloride ion content. The test results are presented in the attached WSP report “Petrographic Examination of Hardened Concrete” and are summarized below.

# 2 CORE PROGRAM TEST RESULTS

## 2.1 RECORD OF CORES

The cores were received in the WSP St. John’s laboratory on August 25, 2023. Photos 7 to 18 of the core samples in Appendix A show the condition of the concrete at the exposed surface for each core and the condition of the concrete in the core with depth. A visual description of the cores and test results on select cores are presented in Table 2.1 below.

**Table 2.1 Record of Cores and Test Results**

CORE ID (LAB ID)	LENGTH (MM)	DENSITY (KG/M <sup>3</sup> )	COMPRESSIVE STRENGTH (MPA)	COMMENTS
1 (17335)	335	NA	NA	Core held/not tested. Cored vertically in draft tube deck. Rebar intercepted ~ 185mm from face of concrete. Moderate weathering on exposed face. No visible deterioration of concrete in core.
2 (17336)	330	NA	NA	Core held/not tested. Cored vertically in draft tube deck. Rebar intercepted at 180mm and 220mm from face of concrete. Moderate weathering on surface of concrete with some exposed coarse aggregate. No visible deterioration of concrete in core.
3 (17337)	350	NA	NA	Core held/not tested. Cored vertically in draft tube deck. No rebar intercepted through depth of core. Moderate weathering on surface of concrete with some exposed coarse aggregate. No visible deterioration of concrete in core.
4 (17338)	320	2377	42.9	Cored horizontally near surface of water in concrete pier. Severe weathering with loss of fine aggregate. Rebar intercepted at 90mm and 120mm from face of concrete.
5 (17339)	250	2420	NA	Cored horizontally near surface of water in concrete pier. Rebar intercepted at 205mm depth from face of concrete. See the WSP Petrographic Report in Appendix B for a full detailed report, hardened air-void analysis test and water-soluble chloride ion test results.
6 (17340)	350	2363	37.0	Cored vertically in draft tube deck. Rebar intercepted at 210mm from face of concrete. Slight weathering on surface of concrete with minor exposed coarse aggregate. No visible deterioration of concrete in core.

---

## 2.2 PETROGRAPHIC EXAMINATION OF HARDENED CONCRETE REPORT

The WSP report “Petrographic Examination of Hardened Concrete Original Powerhouse No. 2 – Unit 8 Bay D’Espoir, NL” is included in Appendix B. Core 5 was chosen as a representative core to conduct the testing. The report gives a detailed description of the findings. As a summary, the concrete in the core appeared well consolidated, well proportioned and of acceptable durability and overall quality.

The analysis of the hardened air-void system indicated an air content of 3.2% and a spacing factor of 0.204 mm. In accordance with the CSA A23.1 standard for concrete materials, this result marginally meets the requirements for a frost resistant concrete.

The water-soluble chloride ion content, at 45 mm depth of core and at the base of the core, was measured at 0.004% and 0.006% respectively, which indicates no significant ingress of chloride ions in the cover concrete over the approximate 46 years in service.

The petrographic examination revealed distress attributed to:

- Moderate erosion of the surface of the core exposing coarse aggregate to an ~ depth of 5 mm
- A weak carbonated layer to 4 mm from the eroded surface with deeper zones around shallow cracks
- Minor to moderate deleterious effects from alkali aggregate reactivity evidenced by reaction rims around aggregate particles, network of cracks within aggregates
- Cracking within the cement paste and around select coarse aggregates
- Evidence of reaction products in voids or pores of the cement paste.

## 3 CONCLUSION

---

WSP conducted a coring program to support the construction of the Unit 8 Generating Facility at Bay D'Espoir. Six cores were obtained from the structure and three cores were tested. Remaining three cores were held for further testing if required.

The concrete in the cores appeared well consolidated and of adequate quality given the existing service life of the structure. Concrete compressive strengths were adequate for exposure conditions and densities were in the expected range for aggregates from the local area. Water-soluble chlorides were low indicating minimal ingress of chlorides in the concrete. Evidence of alkali aggregate reactivity in the form of microcracking of aggregates and the presence of reaction products was observed in the detailed petrographic examination. Evaluating the potential for continued alkali-aggregate activity of the concrete will require further examination and predictive testing.

This report presents the scope of work completed to date. We are available to discuss a test program to further investigate the evidence of alkali-aggregate reactivity present in the concrete cores.

# APPENDIX

# A PHOTO RECORD





**Photo Record**  
**Concrete Core Program Bay D'Espoir Generating Station**



Photo 1 Core 1 location, SW side of Draft Tube Deck



Photo 2 Core 2 location (Core 1 in background)



Photo 3 Core 3 location



Photo 4 Repaired corehole at Core 4 location, SW side of central column



Photo 5 Coring drill setup at Core 5 location, NE side of central column



Photo 6 Core 6 location near Corehole 2

Project No.: CA0010449.7949



**Photo Record**  
**Concrete Core Program Bay D'Espoir Generating Station**



Photo 7 Core 1 exposed surface



Photo 8 View of Core 1 for length of core



Photo 9 Core 2 exposed surface



Photo 10 View of Core 2 for length of core

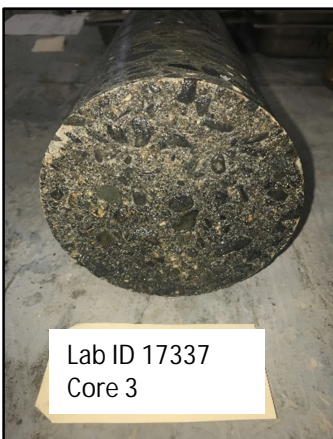


Photo 11 Core 3 exposed surface



Photo 12 View of Core 3 for length of core

Project No.: CA0010449.7949



**Photo Record**  
**Concrete Core Program Bay D'Espoir Generating Station**



Photo 13 Core 4 exposed surface



Photo 14 View of Core 4 length of core



Photo 15 Core 5 exposed surface



Photo 16 View of Core 5 length of core



Photo 17 Core 6 exposed surface

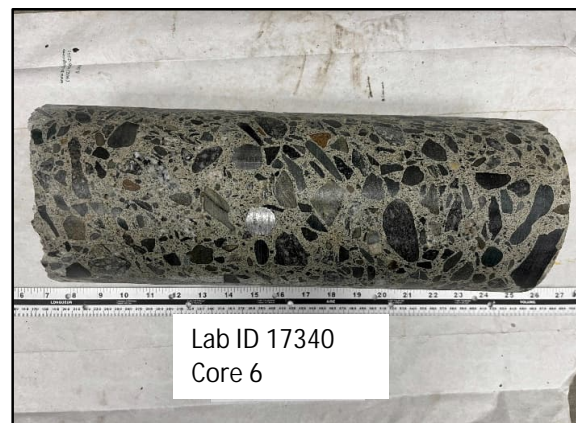


Photo 18 View of Core 6 length of core

## APPENDIX

# B PETROGRAPHIC REPORT



## PETROGRAPHIC EXAMINATION OF HARDENED CONCRETE

### ORIGINAL POWERHOUSE NO. 2 - UNIT 8

### BAY D'ESPOIR, NEWFOUNDLAND AND LABRADOR

NEWFOUNDLAND AND LABRADOR HYDRO  
Hydro Place, 500 Columbus Drive  
P.O. Box 12400  
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A1B 4K7

Attention: Kathleen Wadden, Civil Engineer Engineering Services

PROJECT NO.: CA0010449.7949  
DATE: OCTOBER 03, 2023

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#### 1.0 Introduction

WSP E&I Canada Limited (WSP) is pleased to present petrographic findings and laboratory results conducted on a concrete core identified as Core #5 - 17339 from the pier of Unit 8 of Powerhouse No. 2, located in Bay D'Espoir, Newfoundland and Labrador. The powerhouse is owned by Newfoundland and Labrador Hydro (NLH). The core was removed from the original concrete of the powerhouse, which was constructed circa 1977.

The laboratory testing of the core is part of a larger structural evaluation of Powerhouse No. 2. The purpose of this report is to provide an understanding of the general condition of the original concrete used in construction as represented by the cores removed from Unit 8. Concerns of potential Alkali-Aggregate Reactivity (AAR) distress has been raised as a result of field observations. Compressive strength results of 37.0 MPa and 42.9 MPa with hardened densities between 2,363 and 2,420 kg/m<sup>3</sup> obtained from companion cores revealed good compressive strength for the original bulk concrete of Unit 7 and Unit 8.

Details regarding the concrete mix design, quality control test results and specification parameters such as air content, slump, and the use of admixtures (if any) for the concrete used in the original construction of Powerhouse No. 2 were not available for review by WSP. Information regarding procedures and techniques utilized for the placement, curing, finishing or repair/rehabilitation, if any, were also not available. As such, results and conclusions regarding the general condition of the concrete are limited to petrographic observations and laboratory results obtained from the concrete core provided.



## 2.0 Methodology

On August 23, 2023 representatives of WSP conducted coring operations of Powerhouse No. 2, Unit 8 at locations selected by representatives of NLH. Core #5 - 17339 was removed from a Unit 8 pier that showed evidence of periodic submergence due to variable water levels. Each core extracted from the structure was marked with a unique identifier and assigned testing in consultation with representatives of NLH.

Concrete Core #5- 17339 was assigned for petrographic examination, air void system analysis, and water soluble chloride ion content, was sealed, packaged and shipped to the WSP Burlington Materials Laboratory on August 30, 2023 where it was logged and photographed in its as-received condition. Parameters considered during core logging included the identification of general features such as core dimensions, aggregate lithologies, constituent proportions (sand, stone, cement paste, voids), and/or signs of potential distress mechanisms.

Upon completion of the core logging and photography, Core #5 - 17339 was cut parallel to the long axis in order to expose a cross-sectional face that was polished to a high finish suitable for petrographic examination based on *ASTM C856, Standard Practice for Petrographic Examination of Hardened Concrete* and *ASTM C457, Standard Test Method for Microscopical Determination of Parameters of the Air Void System in Hardened Concrete*, respectively.

As part of this petrographic examination, a thin section was prepared from the core to provide detailed insight into the overall quality of the concrete matrix, in particular micro-features typically associated with AAR. In addition, the freshly cut cross-sectional surface was tested with phenolphthalein indicator to determine if pervasive carbonation of the cementitious paste was present and if so, to what extent.

In addition, a cross-sectional cut portion of Core #5 - 17339 was prepared for water soluble chloride ion content determination. Two horizons (45 mm to 55 mm and 240 mm to 250 mm) were tested according to method *CSA A23.2-4B, Sampling and determination of water-soluble chloride ion content in hardened grout or concrete*.

## 3.0 Laboratory Results

### 3.1 Air Void System Analysis

The Air-Void System (AVS) analysis conducted on Core #5 - 17339 (Appendix A) is summarized in Table 1 and was used to assess the basic resistance of the concrete to damage from cycles of freezing and thawing.

CSA A23.1-19 requirements for the AVS are that the hardened concrete air content not be less than 3.0% and the Spacing Factor (average distance between air bubbles) in the hardened concrete not to exceed 0.260 mm for the concrete to be freeze/thaw durable. Core #5- 17339 meets current hardened concrete spacing factor (individual sample) and air content requirements. These values are summarized in Table 1 and agree with petrographic observations that the concrete represented by Core #5 - 17339 displays a marginal air void system.

**Table 1: Summary of Air-Void System (AVS) analysis Testing**

Location	Core ID	Air Content (%)	Spacing Factor (mm)	Specific Surface (mm <sup>-1</sup> )	Paste Content (%)
Core #5	17339	3.2	0.204	28.64	26.86

**Note(s)**

- CSA A23.1-19 clause 4.3.3.3 requirements:  
 Air Content, min 3%  
 Spacing factor, average <0.230 mm; no single value >0.260 mm

### 3.2 Water Soluble Chloride Ion Content

Results of the water-soluble chloride ion content determinations (Appendix B) that were cut at 45 mm to 55 mm and 240 mm to 250 mm from the scaled surface of Core #5 - 17339 revealed values for percent chlorides by mass of concrete of 0.004% and 0.006% respectively. This indicates that the concrete at these depths has not been exposed to the ingress of chlorides, from external sources or cast into the concrete as set accelerators.

### 3.3 Petrographic Examination

Enclosures 1 and 2 provide a summary of as-received core logging observations recorded for Core #5- 17339. Detailed petrographic findings from the examination conducted on the polished cross-sectional surface of the core are presented in Enclosures 3 to 6.

Overall, Core #5 - 17339 appeared well consolidated with a measured diameter of 143 mm and length that varied between 250 mm and 271 mm. Light to medium scaling (possible disintegration due to erosion) of the exposed surface was characterized by an estimated average surface loss to 5 mm depth (up to 20 mm along macrocracks open to the exposed surface), resulting in a rough, irregular, appearance of exposed coarse and fine aggregate particle perimeters. The presence of organic grey-green coloured debris (lichen), observed growing on the exposed surface, is evidence of periodic exposure to air and local climatic conditions when water levels are low.

A rough, irregular coring fracture at the core base indicates that Core #5 - 17339 represents the outer 271 mm of the Unit 8 pier concrete. The coring fracture prominently exposed the cross-sectional faces of aggregate, which revealed alteration rims around metasedimentary and volcanic lithologies, in addition to opaque white deposition.

The core log findings together with results of the petrographic examination show that both the coarse and fine aggregates used in the construction of the original concrete have a similar lithological composition (Enclosure 4) which would be consistent with stone and sand sourced from local geologic formations. The concrete was composed of well graded, evenly distributed 25 mm (maximum measured size of 29 mm) partly crushed, gravel coarse aggregate contributing an estimated 30% to 35% of the concrete by volume. The coarse aggregate was predominantly composed of greywacke and metasediment in addition to minor amounts of granite, mafic volcanic, quartzite, sandstone, carbonate, diorite, gneiss, and siltstone particles. White reaction products (RP) optically identified as ettringite with rare alkali-silica gel were commonly observed infilling cracks propagating through greywacke, metasediment, mafic volcanic, and quartzite particles.

The natural sand contributed an estimated 35% to 40% of the concrete by volume and consisted of similar lithologies of rock fragments as those identified within in the coarse aggregate, in addition to individual crystal grains of quartz, feldspar, amphibole, micaceous

minerals, and opaque minerals. The fine aggregate appeared finely graded, with an average grain size less than 2 mm (under-representation of larger grains).

Phenolphthalein Indicator showed pervasive carbonation up to 4 mm below the exposed surface corresponding to a buff white colouration. Underlying cementitious paste within body of concrete was a uniform light grey colour and appeared strong displaying a good bond with coarse and fine aggregate particle perimeters. A network of cracks was observed traversing through cementitious paste and frequently propagated through reactive aggregate (Enclosures 5 and 6). The cracks show infill of Reaction Products (RP) optically identified as ettringite ± alkali-silica gel and rare dark (gel) staining. This was confirmed by thin section examination of the concrete matrix. No evidence of the use of supplementary cementitious materials as partial replacement of Portland cement was observed.

CSA document A864-00, Guide to the Evaluation and Management of Concrete Structures Affected by Alkali-Aggregate Reaction and US Department of Transportation FHWA, Report on the Diagnosis, Prognosis, and Mitigation of Alkali-Silica Reaction (ASR) in Transportation Structures lists petrographic features commonly related to alkali-aggregate reaction:

- micro-cracks in and around aggregate particles and in the cement paste, with some of these cracks filled to various extents with secondary reaction products;
- reaction rims around aggregate particles;
- distribution of reaction products in voids or pores of the cement paste, or impregnating cement paste around reacted aggregate particles;
- cracks within the cement paste with and without reaction products;
- closed cracks as well as open or fine networks of cracks within aggregates particles with and without reaction product; and,
- de-bonding at the cement paste-coarse aggregate interface, and reactive aggregate.

The presence of features such as alteration rims, weathered particles, pattern cracking, ettringite (and in rare occasions silica gel and/or calcium carbonate) infilling cracks and voids with Core #5 - 17339 indicate that the Unit 8 concrete pier has undergone expansion due to AAR to during its service life.

#### 4.0 Conclusion

The concrete of Powerhouse No.2, Unit 8 represented by Core #5- 17339 revealed the original concrete is of acceptable durability and overall quality. The concrete appears well consolidated, well proportioned which is consistent with the high compressive strength 37.0 MPa and 42.9 MPa tested on other core samples. Petrographic examination revealed distress attributed to:

- 1) Loss of approximately 5 mm of cementitious paste at the surface caused by light to moderate scaling (possible disintegration due to erosion);
- 2) A weak carbonated cementitious paste to a depth of approximately 4 mm from the scaled surface, and extending up to 20 mm along shrinkage cracks open to the exposed surface;
- 3) Minor to moderate deleterious effects from alkali aggregate reactivity evidenced by:
  - a. reaction rims around aggregate particles;
  - b. closed cracks as well as open or fine networks of cracks within aggregate particles with and without reaction product;
  - c. cracks within the cement paste within and around aggregate particles of greywacke, metasediment, mafic volcanic, and quartzite particles;
  - d. distribution of reaction products in voids or pores of the cement paste, or impregnating cement paste around reacted aggregate particles.



## 5.0 Closure

This report has been prepared for the exclusive use of Newfoundland and Labrador Hydro for the specific application to the area within this report, based on WSP's review of laboratory studies prepared in accordance with generally accepted materials engineering practices and general knowledge and experience in concrete technology.

### WSP E&I Canada Limited,

PREPARED BY

A handwritten signature in blue ink, appearing to read 'Martin Little', written over a horizontal line.

Martin Little, M.Sc., P.Geo. (ON, BC, SK)  
Senior Geoscientist

REVEIUED BY

A handwritten signature in blue ink, appearing to read 'Oliver Gepraegs', written over a horizontal line.

Oliver Gepraegs, M.A.Sc., P.Eng. (BC, AB)  
Senior Principal Materials Engineer

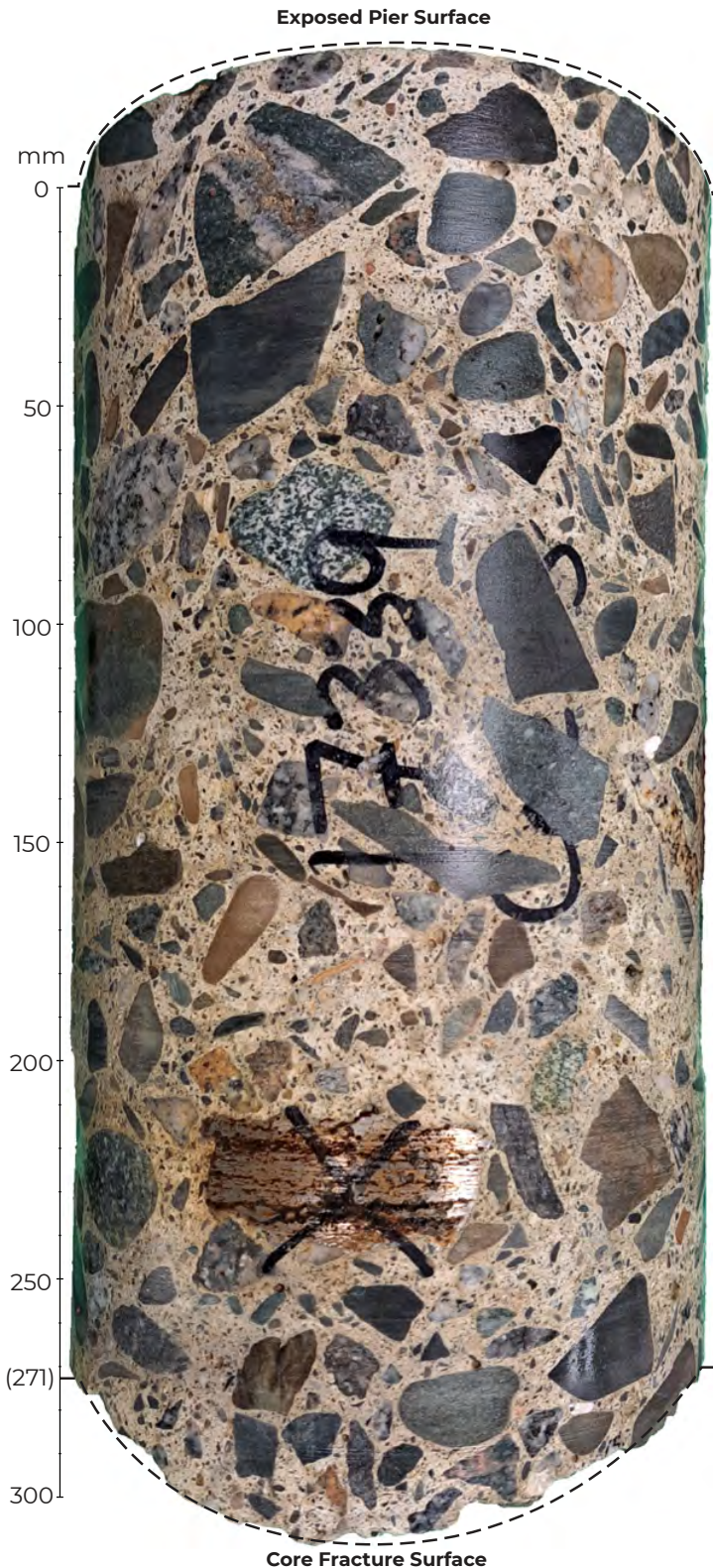
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ml/OG

Enclosures: 6

# *Enclosures*



**Core #5 - 17339**

**Dimensions:**

Length Min. 250 mm  
 Length Max. 271 mm  
 Diameter 143 mm

**Summary of Core Logging Parameters:**

**Coarse Aggregate**

Material Type	Natural
Percentage (by volume of concrete)	30 to 35%
Preferred Orientation	Not Observed
Grading	Well Graded
Distribution	Evenly Distributed
Segregation	Not Observed

**Fine Aggregate**

Material Type	Natural
Percentage (by volume of concrete)	35 to 40%
Grading	Finely Graded
Distribution	Evenly Distributed

**Air Content**


Percentage (by ASTM C475)	3.24 %
Percentage Voids (Lined/Filled)	80 to 90%

**Cement Paste**

Percentage (by ASTM C475)	26.86%
Depth of Carbonation (by Phenolphthalein Indicator)	4 mm

As-received photographs of petrographic findings for concrete Core #5 - 17339 that was cored horizontally from the Unit 8 pier at NLH Powerhouse No.2, located in Bay D'Espoir, Newfoundland and Labrador. The concrete appears well consolidated, composed of a well graded, evenly distributed 25 mm (maximum measured size of 29 mm) partly crushed, gravel coarse aggregate of various siliceous lithologies. The natural sand used in construction consisted of evenly distributed rock fragments of similar lithologies as those identified within in the coarse aggregate. However, the fine aggregate appeared finely graded, with an average grain size less than 2 mm (under representation of larger grains). Overall, the bond between aggregate and cementitious paste was strong. Reinforcing steel (marked with "X") was located approximately 205 mm (centre) from the exposed surface. Based on the cross-section of steel bar exposed, the bar appeared clean, with the minor corrosion seen attributed to coring operations. No sign of oxide staining within the adjacent cementitious paste was observed.

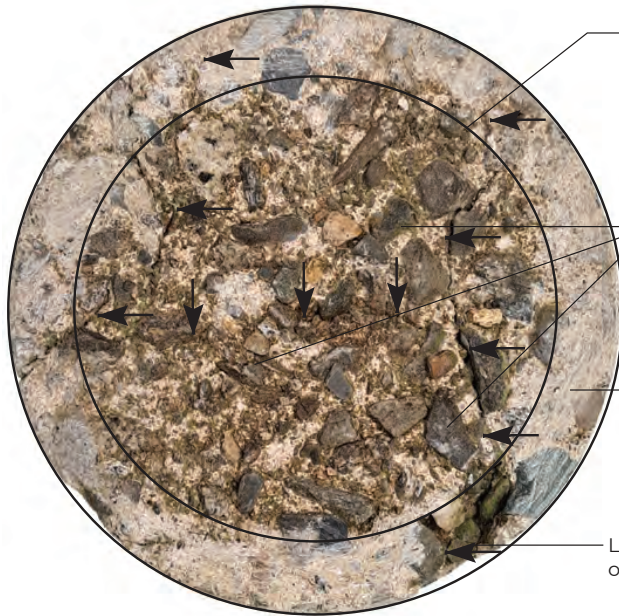
**Petrographic Examination of Hardened Concrete  
 Original Powerhouse NO. 2 - Unit 8  
 Bay D'Espoir, Newfoundland and Labrador**

ENCLOSURE 1 Core #5 - 17339		
PROJECT No: CA0010449.7949		
SCALE: As Indicated	DATE: September 2023	

**A)**

**Exposed Pier Surface**

mm  
 0  
 50  
 100  
 150



Accumulated grey-green colour organic debris (lichen) indicative of exposure to episodic drying and wetting

Light to medium scaling to approximately 5 mm depth that has exposed coarse and fine aggregate particle perimeters that protrude above the weak, carbonated cementitious paste.

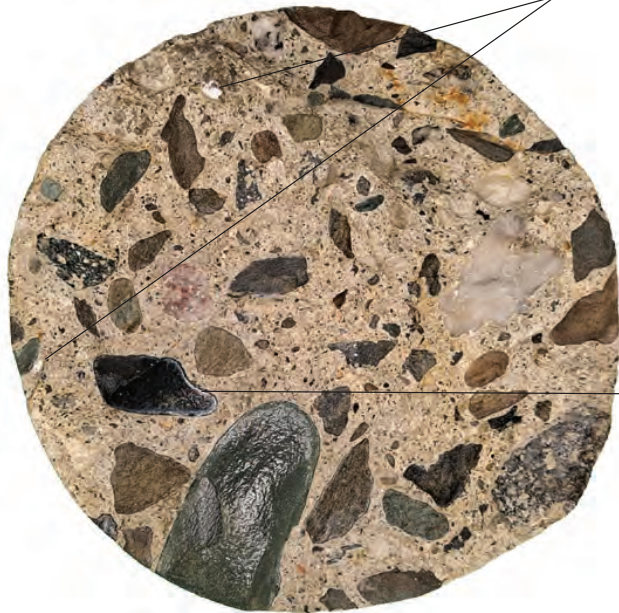
Abrasion of concrete around core circumference

Loss of up to 20 mm along macrocrack (black arrows) open to exposed surface

**B)**

**Core Fracture Surface**

mm  
 0  
 50  
 100  
 150



Opaque white deposition within larger air voids

Alteration rim and opaque white deposition of greywacke particle. Common among metasediment, mafic volcanic, and quartzite particles.

As-received photographs of concrete Core #5 - 17339 showing the exposed surface of the Unit 8 pier (A) that showed light to medium scaling that has resulted in a loss of approximately 5 mm of cementitious paste. The exposed coarse and fine aggregate particle perimeters are seen protruding from the weak cementitious paste creating a rough, irregular surface that has accumulated grey-green colour organic debris (lichen). This indicates periodic exposure to air and local climatic conditions when water levels are low. Three cracks measuring approximately 1 mm wide can be seen at the surface (black arrows). Abrasion of concrete around core circumference was attributed to coring operations.

At the core base (B) a rough, irregular coring fracture traversed through coarse and fine aggregate particles. The cross-section of aggregate particles revealed alteration rims, in addition to opaque white deposition among greywacke, metasediment, mafic volcanic, and quartzite particles and air voids.

**Petrographic Examination of Hardened Concrete  
 Original Powerhouse NO. 2 - Unit 8  
 Bay D'Espoir, Newfoundland and Labrador**

**ENCLOSURE 2**  
 Core #5 - 17339



PROJECT No: CA0010449:7949

SCALE: As Indicated

DATE: September 2023



WSP E&I Canada Limited  
3450 Harvester Road, Suite 100  
Burlington, Ontario, Canada  
L7N 3W5

**Petrographic Examination of Hardened Concrete - ASTM C856**

ENCLOSURE 3

Job No	CA0010449.7949	Exam Date	September 5, 2023
Lab No	C1110-23	Analysed by	Martin Little, P.Geo.
Sample No	Core #5- 17339	Received	August 30, 2023
Location	Bay D'Espoir, Newfoundland		

**Details of Structure**

Year of Construction	Not Specified	Description of Structure	Undisclosed Monument
Description of Deterioration / Problem			
Potential Alkali Aggregate Reactivity of Concrete Material			

**Total Concrete**

Hit with Hammer	Dull - Near Macro crack	Unusually Wet / Dry Areas	No
Strength	Strong	Cement / Coarse Aggregate Bond	Strong
Breaks with Fingers	Particles Not Dislodged	Cement / Fine Aggregate Bond	Strong
Observations	<p>Diameter: 143 mm Length (Minimum): 250 mm Length (Maximum): 271 mm</p> <p>Exposed Surface: Irregular, rough exposed core surface displaying light to medium scaling that exposed coarse and fine aggregate particle perimeters; estimated surface loss average 5 mm depth, up to 20 mm along macrocrack open to exposed surface; organic debris (lichen), grey-green colour observed on surface of cementitious paste; cementitious paste is easy to scratch and gouge using moderate pressure with a metal probe. Abrasion of concrete around core circumference due to coring operations.</p> <p>Overall the body of core appeared well consolidated, isolated entrapped air voids that measured up to 8 mm were observed throughout the length of the core; Two macrocracks open at the exposed surface observed penetrating up to 90 mm into body of concrete (persistent wetness seen along crack) ; cementitious paste within the body of the concrete can be scratched with difficulty using moderate pressure with a metal probe.</p> <p>Core Base Surface: Rough, irregular coring fracture prominently traversing through coarse and fine aggregate (occasionally traverse around the particle perimeter of smooth, hard coarse aggregate particles exposing surfaces; cross-section of aggregate reveal alteration rims around volcanic lithologies in addition to opaque white deposition. cementitious paste is difficult to scratch using moderate pressure with a metal probe.</p>		

**Coarse Aggregate**

Percent of Total	30 to 35	% estimate by volume of concrete	Distribution	Even	Grading	Well Graded
Preferred Orientation	Not Observed		Nominal Maximum Size	25 mm	Shape	Rounded
Material Type	Partly Crushed Gravel		Observations			
Maximum measured particle size 29 mm; displays good bond with cementitious paste; alteration rims (AR) frequently observed around crushed particle perimeters; white reaction products (RP) optically identified as ettringite ± alkali-silica gel commonly observed infilling cracks propagating through greywacke, metasediment, mafic volcanic, and quartzite particles.						

Lithological Types	Percentage	Alteration Rims (AR)/ Reaction Products (RP) / Fractures / Discolouration	Remarks
Greywacke	30	AR frequent; RP within fractures traversing into cementitious paste	Very fine grain, matrix supporting clasts
Metasediment	28	AR frequent; RP within fractures traversing into cementitious paste	Fine to medium grained, individual crystal grain-alignment along deformations / foliations; healed fractures, rare weathering and oxide staining Medium to coarse grained crystalline
Granite	10		
Mafic Volcanic	7	AR frequent; RP within fractures traversing into cementitious paste	Fine grained crystalline
Quartzite	6	AR frequent; RP within fractures traversing into cementitious paste	Massive, non-foliate, network of interlocking quartz crystal grains, rare weathering
Sandstone (arkose)	5		Fine to medium grained, individual crystal grain-supported, feldspar-rich
Carbonate	5		Fine to medium grained, granular texture; rare healed fractures
Diorite	4		Medium to coarse grained crystalline
Gneiss	4		Medium to coarse grained crystalline, banded/foliated texture
Siltstone	1	Recrystallization of salts on polished surface	Very fine grained, soft, weak, high absorption



ENCLOSURE 3

Job No	CA0010449.7949	Exam Date	September 5, 2023
Lab No	C1110-23	Analysed by	Martin Little, P.Geo.
Sample No	Core #5- 17339	Received	30-Aug-23
Location	Bay D'Espoir, Newfoundland		

**Fine Aggregate**

Percent of Total	35 to 40	% estimate by volume of concrete	Distribution	Even	Grading	Finely Graded
Preferred Orientation	Not Observed		Shape	Rounded		
Material Type	Natural					
Observations	Average grain size less than 2 mm (under representation of larger grains); fine aggregate greater than 2 mm commonly display alteration rims around particle perimeters and internal fractures lined with opaque, white secondary mineralization. Generally good bond with cementitious paste and displays adequate field performance					

Lithological Types	Estimated Percentage	Reaction Rims / Reaction Products / Fractures	Remarks
Greywacke	6		
Metasediment	8		
Granite	1		
Mafic Volcanic	4		
Quartzite	4		
Sandstone	1		
Quartz (Individual Crystal grains)	62		
Feldspar (Individual Crystal grains)	8		
Amphibole (Individual Crystal grains)	4		
Mica Group	1		
Opaque minerals	1		

**Cement Paste**

Percent of Total	26.86	% by ASTM C457	Colour	Light	Grey
Bleeding	Not Observed		Colour Distribution	Mostly Uniform	
Slag	Not Observed	Fly Ash	Not Observed	Appearance in Broken Concrete	Not Broken
Strength	Strong		Carbonation	Outer Skin	
Retempering	Not Observed				
Observations	<p>Phenolphthalein Indicator: Pervasive carbonation of cementitious paste was detected up to 4 mm from the scaled surface associated with pale tan colouration of the cementitious paste.</p> <p>Cementitious paste within body of concrete was a uniform light tan colour and appeared strong, difficult to scratch or gouge with metal probe using moderate pressure. Generally appeared well bonded at the interface with coarse and fine aggregate particle perimeters. Cracking observed traversing through cementitious paste frequently proximate though reactive aggregate and show infill of reaction products (RP) optically identified as ettringite ± alkali-silica gel and rare dark (gel) staining. Confirmation of secondary mineralization's and characteristics of the concrete matrix pending thin section examination.</p> <p>Examination of thin section revealed the presence of partly hydrated (remnant) grains of Portland cement grains measuring up to 0.02 mm and rare coarse unhydrated Belite nests up to 0.08 mm wide; flat, platy, equant calcium hydroxide crystals were commonly observed along cement paste-coarse aggregate interface; fine calcium hydroxide crystals disseminated within cement paste and along cement paste-fine aggregate interface.</p>				

**Voids**

Percent of Total	3.24	% by ASTM C457	Mineralization	Other - See Below	
Percent with Mineralization	70% to 80%		Interior Condition	Filled and Partly Lined	
Interior Luster	Dull		Shape	Round	Average Size
Grading	Non air-entrained				0.140 mm
Observations	Air void system characterized by predominantly poorly graded, poorly spaced, circular air voids, frequently lined or filled with well-formed, elongate, needle-like crystals optically identified as ettringite crystals +/- calcium hydroxide. Rare observation of voids lined or filled with silica gel reaction product, commonly associated with macro/micro cracks commonly emanating from greywacke, metasediment, mafic volcanic, an quartzite particles;				



ENCLOSURE 3

Job No	CA0010449.7949	Exam Date	September 5, 2023
Lab No	C1110-23	Analysed by	Martin Little, P.Geo.
Sample No	Core #5- 17339	Received	August 30, 2023
Location Bay D'Espoir, Newfoundland			

**Cracks**

Location	Within Aggregate Particles		
Orientation	Variable		
Continuity, Distribution	Through matrix or around crystal grains		
Maximum Width-micro crack (mm)	0.08	Amount	Frequent
Minimum Width-micro crack (mm)	0.01	Filling	See Below
Associated with Embedded Items	-	Describe	-

Observations:

Micro-cracks traversing through coarse aggregate greywacke, metasediment, mafic volcanic, an quartzite particles extend into adjacent cementitious paste; lined or filled with rare secondary mineralization ettringite +/-silica gel.

Location	Near Surface		
Orientation	Perpendicular to exposed surface		
Continuity, Distribution	Around aggregate (rare through aggregate)		
Maximum Width-micro crack (mm)	0.9	Amount	Rare
Minimum Width-micro crack (mm)	0.2	Filling	Not Observed
Associated with Embedded Items	-	Describe	-

Observations:

Shrinkage cracks (3) open at core exterior surface (approximately 0.9 mm wide) and penetrating up to 90 mm into the body of the concrete, narrowing with depth (approximately 0.01 mm wide); weathering of crack faces noted to 36 mm below exterior surface; no infill detected at surface. Crack traversed around cementitious paste- aggregate particle interfaces, orientation influenced by convergence with aggregate perimeters.

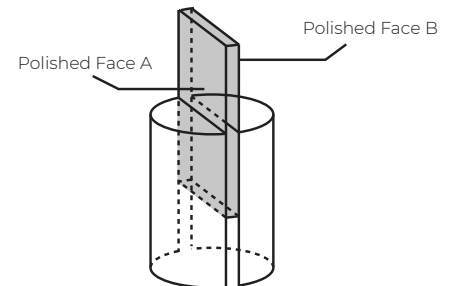
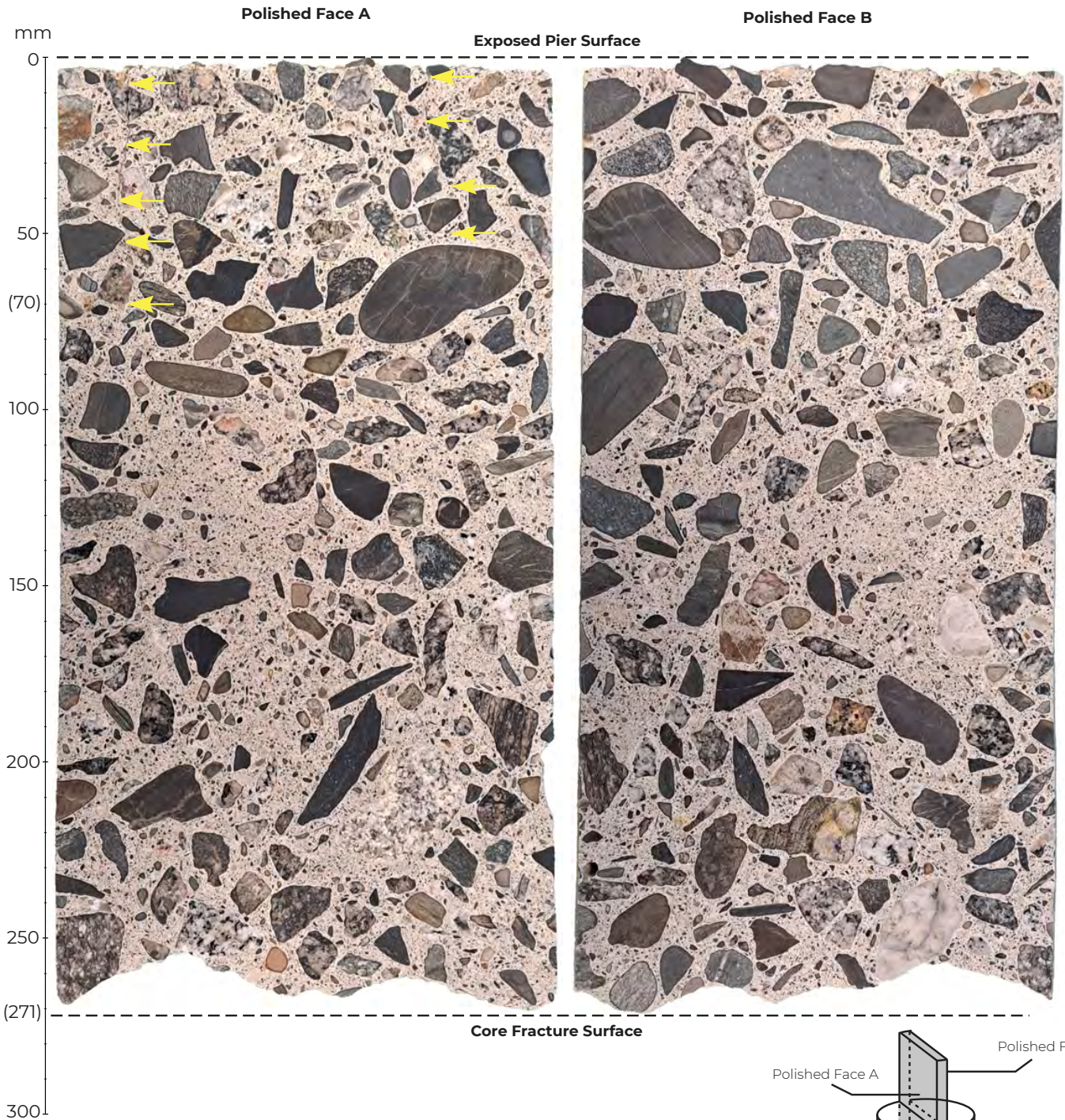
Location	Body of Concrete		
Orientation	Variable		
Continuity, Distribution	Through and Around Aggregate		
Maximum Width-micro crack (mm)	0.1	Amount	Frequent
Minimum Width-micro crack (mm)	0.005	Filling	Not Observed
Associated with Embedded Items	-	Describe	-

Observations:

Cracks measuring 0.005 mm to 0.1 mm wide observed traversing through cementitious paste; traverse around aggregate where changes in orientation was associated with convergence of aggregate particles perimeters or traverse though aggregate where propagation influenced by alignment of reactive aggregate particles. Lined or filled with rare secondary mineralization ettringite +/-silica gel. +/- calcium hydroxide.

**Embedded Items**

Description	Reinforcing Steel Bar		
Location	205 mm (Center) from exposed surface		
Size (mm)	Estimated 20MM	Condition	Clean
		Associated Features	No
Observations Reinforcing Steel shows minor corrosion (coring operations), however, cross-section is clean, no sign of oxide staining in adjacent cementitious paste.			
Description	Wood Fragment		
Location	238 mm (Center) from exposed surface		
Size (mm)	9 mm	Condition	Clean
		Associated Features	No
Observations			



Photograph of the polished cross-sectional face of concrete Core #5 - 17339 (A) showing well graded, evenly distributed 25 mm (maximum measured size of 29 mm) partly crushed, gravel coarse aggregate contributing an estimated 30% to 35% of the concrete by volume. The coarse aggregate was predominantly composed of greywacke and metasediment in addition to minor amounts of granite, mafic volcanic, quartzite, sandstone, carbonate, diorite, gneiss, and siltstone particles. White Reaction Products (RP) optically identified as ettringite ± alkali-silica gel were commonly observed infilling cracks propagating through greywacke, metasediment, mafic volcanic, and quartzite particles.

The natural sand contributed an estimated 35% to 40% of the concrete by volume and consisted of similar lithologies of rock fragments as those identified within in the coarse aggregate, in addition to individual crystal gains of quartz, feldspar, amphibole, micaceous minerals, and opaque minerals. The fine aggregate appeared finely graded, with an average grain size less than 2 mm (under representation of larger grains). Overall, coarse and fine aggregate particles display a good bond with the cementitious paste.

Analysis of the polished concrete surfaces according to ASTM C457 yielded an air content of 3.24% and a spacing factor of 0.204 mm. which agree with petrographic findings which indicated a marginal air voids system.

**Petrographic Examination of Hardened Concrete  
 Original Powerhouse NO. 2 - Unit 8  
 Bay D'Espoir, Newfoundland and Labrador**

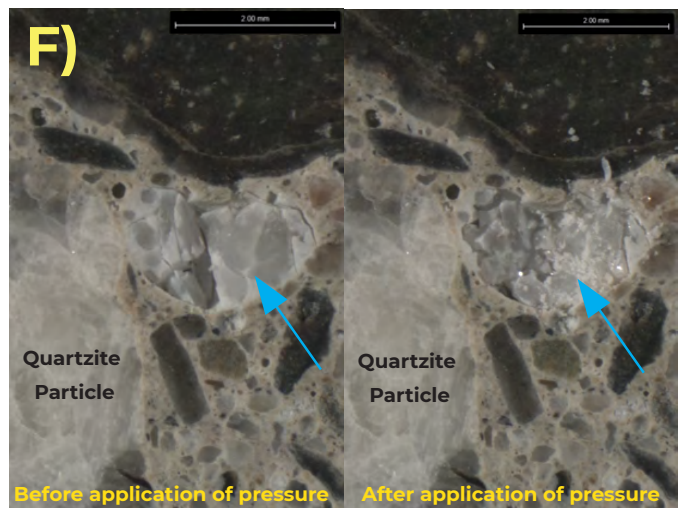
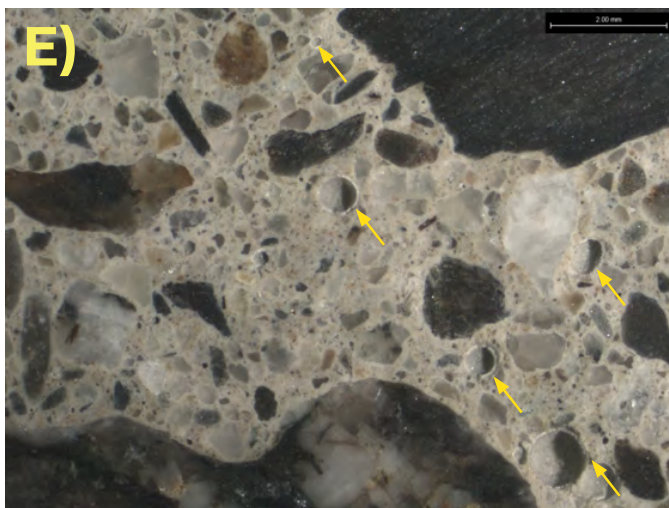
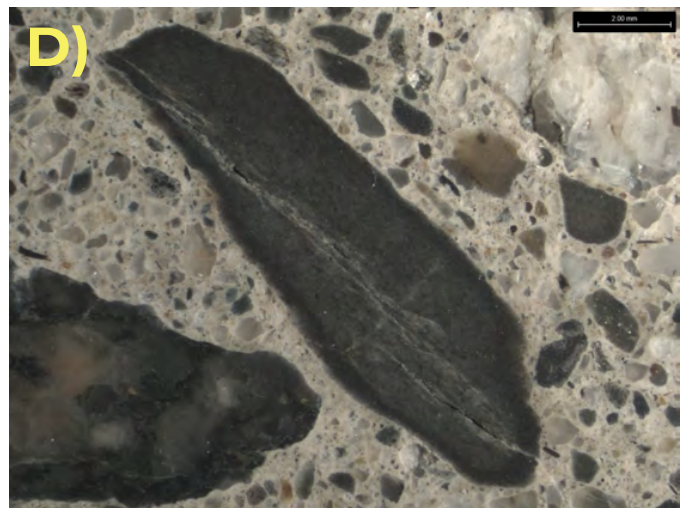
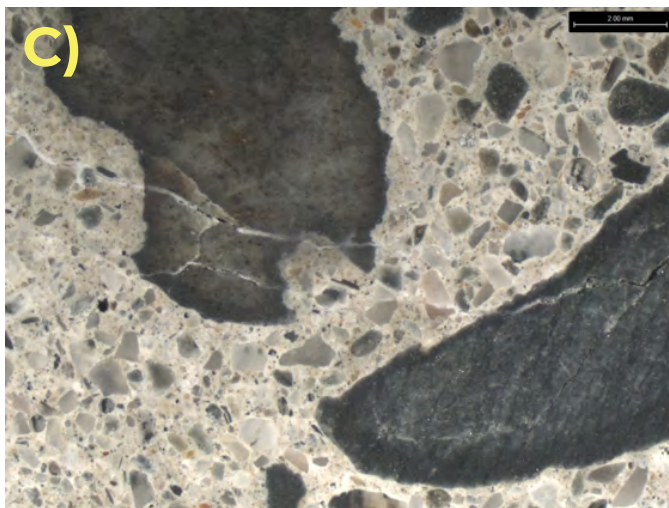
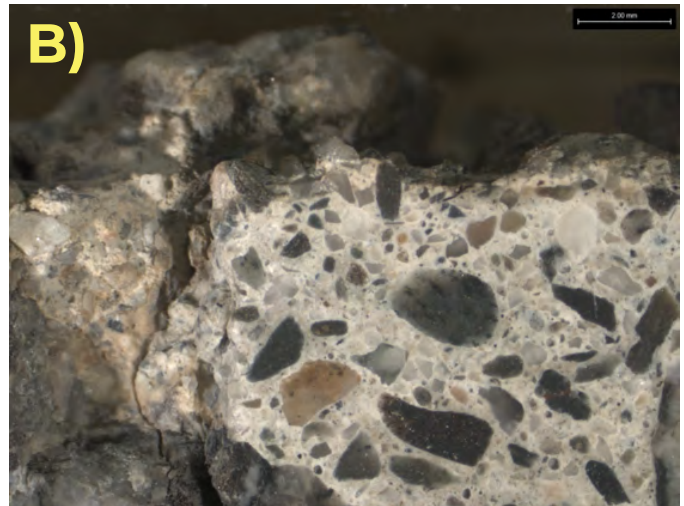
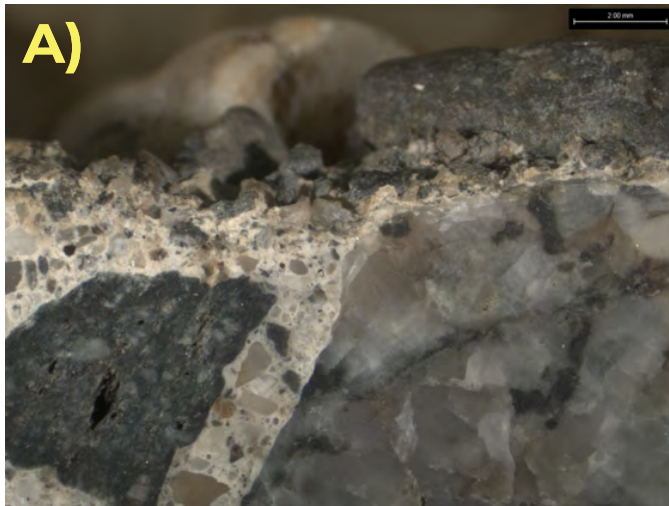
**ENCLOSURE 4**  
 Core #5 - 17339



PROJECT No: CA0010449.7949


SCALE: As Indicated

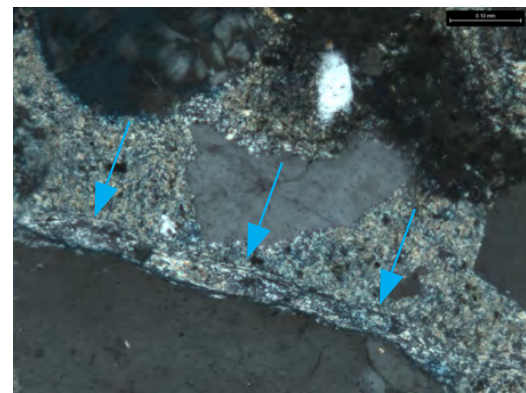
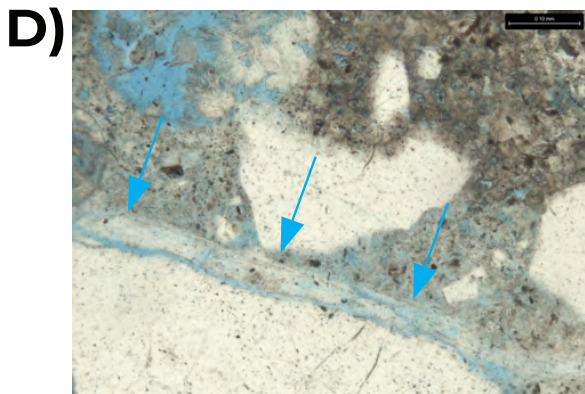
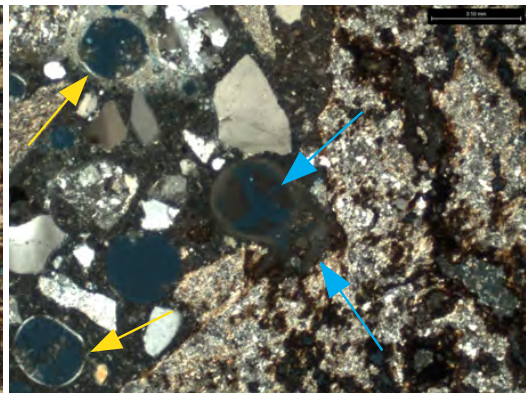
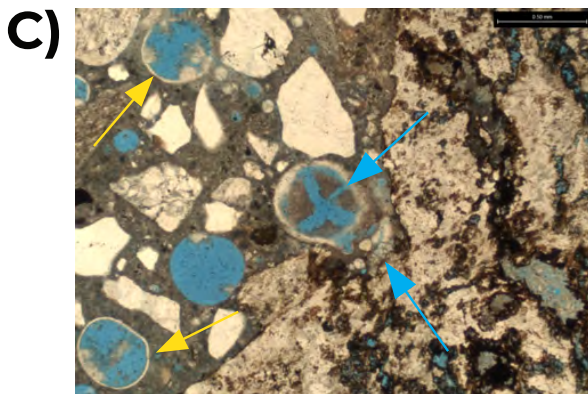
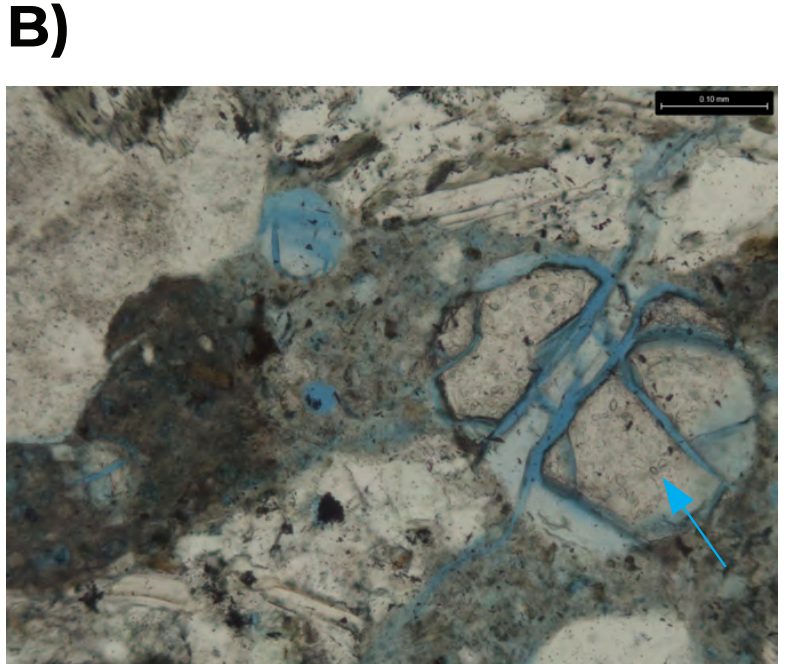
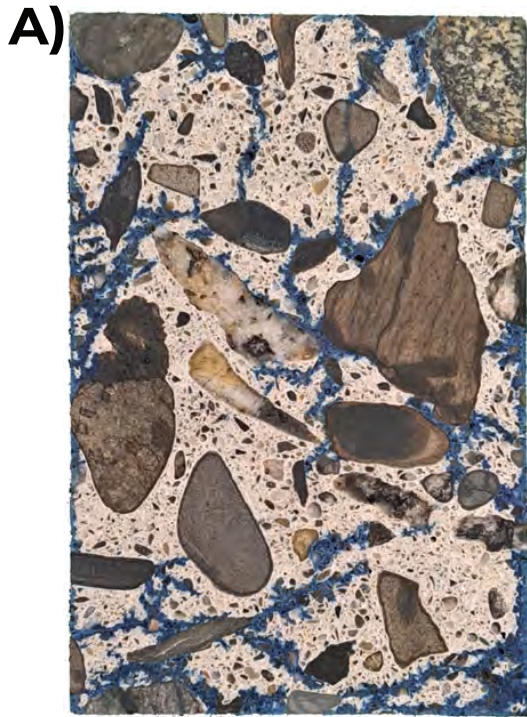
DATE: September 2023



Microphotographs of the polished cross-section face of Core #5 - 17339 showing (A and B) the loss of approximately 5 mm of weak, carbonated cementitious paste at the surface exposed surface seen as a band of buff white contrasting from the light grey colour of the body of the concrete. Also shown in (B) is a shrinkage crack, open to the surface displaying signs of weathering and oxide staining. Microphotographs C and D show examples of cracks propagating through AAR particles of greywacke and metasediment, and traversing through adjacent cementitious paste. These cracks were filled with opaque white crystals of predominantly ettringite +/- calcium hydroxide +/- silica gel. Examination of the polish face revealed a marginal air void system (E) with 80% to 90% of the bubbles lined or filled with well-formed, elongate, needle-like crystals of ettringite (yellow arrows). Air voids lined or filled with reaction product (gel) (blue arrow) seen near aggregate particle displaying alteration rims and internal cracks that extended into the surrounding cementitious paste. Note that gel deforms and cracks when slight pressure is applied in contrast to hard quartzite particle.

**Petrographic Examination of Hardened Concrete**  
**Original Powerhouse NO. 2 - Unit 8**  
**Bay D'Espoir, Newfoundland and Labrador**

<b>ENCLOSURE 5</b>		
Core #5 - 17339		
PROJECT No: CA0010449.7949		
SCALE: As Indicated	DATE: September 2023	



The polished cross-section face of Core #5 - 17339 prepared for thin section showing impregnation with blue epoxy resin. The intensity of the blue dye at the outer skin is indicative of weak cementitious paste susceptible to increased absorption. Highlighted weak foliation within aggregate particles and an interconnected network of microcracks are also shown. Image of an air void (B) partly filled with gel reaction product (blue arrow). Microphotograph C viewed in plain light (left) and cross-polarized (right) showing an air void partly filled with reaction product (gel). The differences between air voids lined with ettringite observed in 80% to 90% of bubbles (yellow arrows) versus an air void bubble containing gel reaction product (blue arrows). Thin section also confirmed that cracks (D) were partly lined with gel reaction product (blue arrows) accompanying secondary mineralization of ettringite and calcium hydroxide crystals (plain light- left and cross-polarized - right).

**Petrographic Examination of Hardened Concrete  
 Original Powerhouse NO. 2 - Unit 8  
 Bay D'Espoir, Newfoundland and Labrador**

**ENCLOSURE 6**

Core #5 - 17339



PROJECT No: CA0010449:7949

SCALE: As Indicated

DATE: September 2023

# APPENDIX

## A

### *Air Void System (AVS) Analysis Results*



Client: Newfoundland and Labrador Hydro (NLH)  
 Project No.: CA0010449.7949  
 Location: Bay D'Espoir, Newfoundland  
 Powerhouse No.2, Unit 8, Location #5

Date: September 27, 2023

SAMPLE INFORMATION			
Sample (Lab) Identification		Core #5- 17339 (C1110-23)	
Cored By		Representative of WSP	
Coring Date		23 August 2023	
Sample Obtained From		143 mm diameter concrete core	
Orientation of Test Specimen		Parallel to long axis of concrete core	
Nominal Maximum Size of Aggregate		25 mm	
Slump	Not Specified	Plastic Air Content	Not Specified

TEST PARAMETERS			
Length of Traverse	3001	Number of Stops	1482
Area Traversed	120 cm <sup>2</sup>	Magnification	105 X

TEST RESULTS		
	Results	Specified Limits
Air Content	3.2 %	Min. 3%
Void Frequency	0.232 mm <sup>-1</sup>	-
Paste Content	26.86 %	-
Paste-Air Ratio	8.292	-
Average Chord Length	0.140 mm	-
Specific Surface	28.64 mm <sup>-1</sup>	-
Spacing Factor	0.204 mm	Max. 0.260 mm

Remarks:

Test sample meets spacing factor (individual sample) and air content in hardened concrete requirements stated in CSA A23.1-19 Clause 4.3.3.3, Air Void Parameters.

Tested By: Elizabeth Hooper, Ph.D.

Reviewed By: Martin Little, P.Geo.

WSP E&I Canada Limited  
 3450 Harvester Road, Suite 100, Burlington, Ontario, L7N 3W5  
 T+1 905 335 2353

# APPENDIX

## B

### *Water Soluble Chloride Ion Content Results*



**SAMPLING AND DETERMINATION OF WATER-SOLUBLE CHLORIDE  
ION CONTENT IN HARDENED GROUT OR CONCRETE**  
CSA A23.2-4B

<b>Client:</b> WSP Canada Inc. <b>Project #:</b> CA0010449.7949 <b>Client Sample #:</b> Core #5- 17339 (C1110-23) <b>Date Received:</b> August 30, 2023 <b>Project:</b> Bay D'Espoir, Newfoundland Powerhouse No.2, Unit 8, Location #5	<b>Report Date:</b> September 18, 2023 <b>WSP Lab #:</b> C1110-23 / 17339 <b>Date Tested:</b> 15-Sep-23 <b>Date Cored:</b> 23-Aug-23
--	---

Sample Depth (mm)	Mass of chloride (g)	Chloride content by mass of concrete (%)
45-55	0.0001	0.004
240-250	0.0002	0.006

**Tested By:** Frank Grivich, P.Geo.      **Reviewed By:** Martin Little, P.Geo.

WSP E&I Canada Limited  
 3450 Harvester Road, Unit 100, Burlington, ON, L7N 3W5,  
 T: (905) 335-2353

1 Q. The justification for the extension of the tailwater channel is provided in 647756-0000-40ER-I-  
2 0001-00. The recommendation is to “enlarge the downstream portion of the canal by 9.15 m  
3 and place riprap on the left side depending on economic analysis to be done in a future phase.  
4 Not enlarging the channel would result in an average additional head loss of 0.5 m and  
5 placement of riprap would still be required.” Considering the level of uncertainty associated to  
6 this decision and the cost of this work (██████████ CAD), please provide any  
7 reports/assessments that gives more detail about the hydraulics. The decision is all based on a  
8 500mm headloss saving, which in tidal condition could be highly dependent on modelling  
9 parameters (roughness, boundary conditions, etc.).

10

11

12 A. The optimum extent of tailrace widening was further studied in BW-NLH-005, Attachment 1,  
13 “*Bay d’Espoir Unit 8 FEED - 2D Tailrace Hydraulic Analysis*” (Document # BDE-AKR-40000-CV-  
14 CAL-0001-01), completed by the front-end engineering design consultant in August 2025. The  
15 scope of this study was to support the turbine generator unit design by confirming the tailrace  
16 water level design limits and determining the extent of the Powerhouse 2 tailrace widening  
17 required to maintain operation of the proposed Unit 8 turbine within expected tailrace water  
18 level design limits. This follow-up study utilized detailed operational data not available at the  
19 time of the study referenced in the RFI (report 47756-0000-40ER-I-0001-00) to provide an  
20 incrementally higher degree of accuracy. In addition to overall efficiency, this study considered  
21 factors such as the cavitation performance of Unit 8 and Unit 7 and the flooding potential of  
22 Powerhouse 2 in extreme conditions, such as storm surges, to inform optimization of tailrace  
23 design. The findings of this study suggest that a reduced degree of tailrace widening than that  
24 assumed in the estimate may be achievable. Final optimization of the tailrace design will require  
25 additional engineering effort, which is planned to be completed in the detailed design phase of  
26 the project. Newfoundland and Labrador Hydro may realize potential cost savings through this  
27 effort.



# Document Front Sheet

Contract Number and Description: <b>Bay d'Espoir Unit 8 FEED – TGU support</b> Project Number: <b>699257</b>		Contractor Name: ATKINSRÉALIS CANADA INC. Address: 455 René-Lévesque W., Montreal, QC, H2Z 1Z3	
Document Title: 2D Tailrace Hydraulic Analysis		Total Number of Pages Incl. Front Sheet: 22	
Contractor Document Number: 699257-0000-4HCM-0003		Revision Number: 01	
Contractor Signature/Stamp:			
NLH Document Number: BDE-AKR-40000-CV-CAL-0001-01		NLH Revision Number : B1	

Date on Document (mm-dd-yyyy): 08-27-2025			
<u>Comments:</u> Comments incorporated from B0, Issued as Final		Equipment Tag	

REVIEW DOES NOT CONSTITUTE APPROVAL OF DESIGN DETAILS, CALCULATIONS, TEST METHODS OR MATERIAL DEVELOPED AND/OR SELECTED BY THE CONTRACTOR, NOR DOES IT RELIEVE THE CONTRACTOR FROM FULL COMPLIANCE WITH CONTRACTUAL OR OTHER OBLIGATIONS.

01 – REVIEWED AND ACCEPTED – NO COMMENTS  
 02 – REVIEWED – INCORPORATE COMMENTS, REVISE AND RESUBMIT  
 03 – REVIEWED - NOT ACCEPTED  
 04 – INFORMATION ONLY  
 05 – NOT REVIEWED

NLH Lead Reviewer:	Date (mm-dd-yyyy):	NLH Project Manager:	Date (mm-dd-yyyy):

General Comments:

# TECHNICAL MEMORANDUM

## Bay d'Espoir Unit 8 FEED - 2D Tailrace Hydraulic Analysis

<b>SUBJECT</b> 2D Tailrace Hydraulic Analysis for TGU support	<b>DOCUMENT NO.</b> BDE-AKR-40000-CV-CAL-0001-01, Rev B1 699257-0000-4HCM-0003, Rev 01	<b>DATE</b> August 26, 2025
<b>PREPARED BY</b> Atefeh Fazlollahi Carissa Sparkes Caline Maksad	<b>REVIEWED BY</b> Greg Snyder	<b>APPROVED BY</b> Carissa Sparkes

### Document history

Revision	Purpose description	Originated	Reviewed	Authorized	Date
B0/00	Issued as Final	CS/AF/CM	GS	CS	2025-07-14
B1/01	Issued as Revision 1	CS/AF/CM	GS	CS	2025-08-26

### Client signoff

<b>Client</b>	Newfoundland and Labrador Hydro				
<b>Project</b>	Bay d'Espoir Unit 8 FEED - 2D Tailrace Hydraulic Analysis	<b>Doc No.</b>	BDE-AKR-40000-CV-CAL-0001-01, Rev B1 699257-0000-4HCM-0003, Rev 01		
<b>Client signature / date</b>					

# TECHNICAL MEMORANDUM

## Signatures

Prepared by:

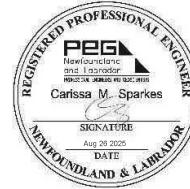
*Atefeh Fazlollahi*

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**Atefeh Fazlollahi P. Eng. Ph.D.**

Hydraulic and Hydrology Engineer  
Engineering Services Canada

*CS*



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**Carissa Sparkes, P.Eng. M.Eng.**

Senior Hydrotechnical Engineer  
Engineering Services Canada

*CM*

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**Caline Maksad, EIT**

Hydraulic and hydrology  
Engineering Services Canada

Verified by:

*GS*

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**Greg Snyder, P.Eng.**

Subject Matter Expert – Hydro  
Engineering Services Canada

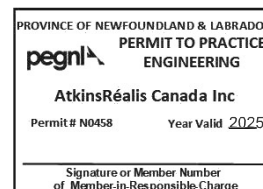
Approved by:

*CS*

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**Carissa Sparkes, P.Eng.**

Project Manager  
Engineering Services Canada



# TECHNICAL MEMORANDUM

## 1. Introduction

### 1.1 General

The Bay d'Espoir Hydroelectric Facility is composed of three primary elements: (i) a reservoir system that includes dams and a spillway, (ii) two adjacent powerhouses featuring an average gross head of 179 meters and a combined installed capacity of 600 MW, and (iii) a tailrace channel that discharges into the Bay.

Powerhouse 1 (PH 1) houses 6 units with a nominal total capacity of 450 MW. Water is supplied from Long Pond Reservoir through a power canal / headrace channel and three penstocks. Powerhouse 2 (PH 2) includes a single unit (Unit 7) with a nominal capacity of 150 MW. It receives water from a separate headrace channel, intake, and penstock. This powerhouse discharges into its own tailrace channel, which converges with the PH 1 tailrace channel, approximately 200 m downstream of the powerhouse. NL Hydro is currently planning the addition of a new unit (Unit 8) to PH 2. The addition of this unit would double the flow into the PH 2 tailrace, thus affecting tailrace water levels during operations.

During the construction of PH 2 in the 1970's, the PH 2 tailrace canal, near the powerhouse, was constructed to a width that would accommodate the installation of Unit 8. The existing PH 2 tailrace channel tapers to a narrower width. The canal at the draft tube exit is 30.5 m wide and cut into rock with vertical walls. According to construction drawings, the tailrace narrows from 30.5 m to 15.25 m, with the invert rising from an elevation of -9.5 m to -3.0 m over a distance of about 40 m, while the tailrace sidewalls remain vertical. For the next 70 m, the rock surface gradually drops below the channel invert, and the side slopes transition from vertical (in rock) to a 2H:1V side slope in till, with the invert remaining horizontal and 15.25 m wide at an elevation of -3.0 m. Approximately 110 m downstream from PH 2, the width of the channel bottom continues to narrow over the next 100 m, reducing from 15.25 m to 6.10 m wide at the confluence with the tailrace from PH 1. Unless otherwise specified, all elevation values in this report are referenced to the CGVD28 vertical datum.

### 1.2 Objectives

The objective of this study is to support the Turbine Generator Unit design by confirming the tailrace water level design limits and determining the extents of the PH 2 tailrace widening required to maintain operation of the proposed Unit 8 turbine within expected tailrace water level design limits. These limits are related to the tailrace water level limits of the existing Unit 7 located in the same powerhouse.

A 2D hydrodynamic model of the tailrace was developed during the FEED stage; however, due to insufficient reliable water level data at the powerhouses, the model could not be adequately calibrated to define the tailwater elevation range of the PH 2 tailrace with Unit 8 in place. As a result, actual water level measurements were collected at two tailrace channel cross sections for calibration purposes. The calibrated model was then used to determine the effects of adding Unit 8 to the tailrace water level response under various load and tide conditions for three PH 2 tailrace configurations.

# TECHNICAL MEMORANDUM

## 2. Data Review and Survey

A 2D hydrodynamic model of the tailrace from PH 1 and PH 2 to the tailrace canal bridge on Hwy 361 was developed as part of the FEED stage of the Unit 8 project. Bathymetric data was collected from the tailrace bridge to within 125 m of PH 1 and 95 m of PH 2. Ten years of historical tailrace water elevation data collected using gauges located at each powerhouse, were obtained from NL Hydro. Review of the data from each gauge found that there were a number of inconsistencies in the historical data sets, including a step change in 2009 as well as differences between the water levels of each tailrace that suggested each gauge was set to a different datum level. The data could not be corrected with sufficient accuracy to adequately calibrate the model. As a result, it was recommended that NL Hydro survey the tailrace gauges to set their elevations to a consistent CGVD28 datum and collect a minimum of two months of data to calibrate the 2D hydrodynamic model. The adjustment had been determined through survey during the FEED to be CGVD28 = local datum – 0.29 m.

Both gauges were surveyed and elevations established to CGVD28 using the NL provincial Geodetic network monument near the intake (81G2301) in January 2025. Additional gauge data was collected in both tailraces by NL Hydro between February and April 2025 and this information was provided to AtkinsRéalis for review and validation. The following were noted as part of the gauge data review.

**Table 1 - Summary of Data Review Observations**

Observation	Expected Behaviour	Explanation
<b>Minimum of three identical recorded gauge readings in a row</b>	Recorded gauges readings were noted to 6 significant figures. Gauge readings should be different with every reading given the significant figures.	The communications RTU only records changes in the readings so identical readings can be expected when there is no change in flow. All instances of identical readings would need to be reviewed against flow changes to determine if these are expected or not.
<b>Identical recorded gauge readings, greater than three in a row, when generation flow was noted to be changing</b>	Gauge readings should be changing when generation flows and thus tailwater levels change.	No obvious explanation. Possible communication error with the communications RTU hub.
<b>Series of identical readings over a longer period of time when generation flows are changing significantly</b>	Gauge readings should be changing when generation flows are changing significantly.	Communication hub was determined to be out of service for 6+ hours as similar behaviour was observed in other system recordings.
<b>PH 2 tailrace is higher than PH 1 tailrace when Unit 7 is not in operation</b>	When Unit 7 is not operating and Units 1-6 are in operation, it is expected that the PH 1 tailrace elevation would be marginally higher or at least similar to the PH2 tailrace; however, the PH 2 tailrace under these conditions is sometimes noted in the data to be	No obvious explanation. For similar flow conditions, the model results in the PH 2 tailrace being within a few centimetres of the PH 1 tailrace water elevation.

## TECHNICAL MEMORANDUM

	higher than the PH 1 tailrace by as much as 17 cm.	
<b>PH1 tailrace is sometimes lower than tide level at St Albans station</b>	The tailrace elevation should be the same as the tide elevation at minimum.	No explanation was found.

The identical gauge readings observed during the data review may be attributed either to the RTU system's design which only records changes in readings or to communication errors within the RTU system. All instances of identical readings would need to be reviewed against flow changes to determine if the readings are reasonable or should be removed from the data set.

Based on the above observations made on the review of the Feb to April 2025 gauged data, it was determined that the existing information could not be used for the purpose of model calibration, and it was recommended that additional tailrace water levels be collected from downstream of the powerhouses in order to calibrate the tailrace model.

### 2.1 Survey

In order to collect data for model calibration purposes, two locations were selected in areas where turbulence was anticipated to be minimal; approximately 1300 m downstream of PH 1 above the confluence with Bear Brook (location 1) and approximately 2600 m downstream of PH 1 above an observed expansion in the tailrace channel (location 2). See Figure 3 in Section 4 for the locations of the surveyed cross sections.

Water level data were collected on May 16, 2025 using stream gauges at location 1 and manual RTK-GPS survey at location 2. Flow targets during low and high tides were provided to NL Hydro for PH 1 and PH 2 for the day so that tailrace elevations could be collected at the two cross sections. The flow targets are listed in Table 2, with high tide occurring at 11:20 am and low tide occurring at 6:05 pm.

**Table 2 – Flow targets during tailrace survey**

Timing	PH1 generation (MW)	PH1 Flow (m <sup>3</sup> /s)	PH2 generation (MW)	PH2 Flow (m <sup>3</sup> /s)	Description of condition
11:20 – 12:20	300	203	143	89	High Tide, High discharge
12:20 – 1:20	107	79	0	0	High tide, Low discharge
5:05 – 6:05	273	176	141	87	Low tide, High discharge
6:05 – 7:05	148	90	0	0	Low tide, Low discharge

The above generation values are noted as the target values within each time period. Time was required to ramp up load or shed load between test conditions and the values used in the model for calibration were selected to be as close to the target values as possible. The actual flows related to the generation values used for calibration are presented in Section 4. In addition, the low tide, high discharge timing was extended to end at 6:20 pm due to difficulties obtaining the high

## TECHNICAL MEMORANDUM

discharge during the field test. Overall, the intention of measuring high and low discharges during both high and low tides was met and the data collected on May 16, 2025 were used to calibrate the tailrace model.

According to Unit 7 tailrace water level design limits, the minimum tailrace water level at PH 2 is 0.93 m. During the survey, the tailwater levels at PH 2 were observed below 0.93 m while Unit 7 was in operation (see Figure 1). The areas circled in red in the graph note the times when the unit was in operation and the tailwater level was also below the minimum tailwater level.

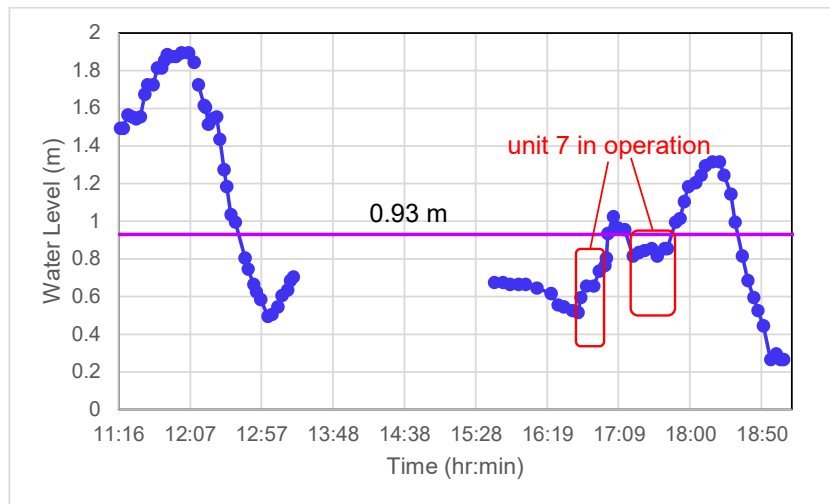


Figure 1 - Water Level at PH 2 during the May 16 2025 Survey

## 3. 2D Hydraulic Model

### 3.1 Software

HEC-RAS 2D (Hydrologic Engineering Center's River Analysis System) is developed by the U.S. Army Corps of Engineers for modelling two-dimensional (2D) hydrodynamic and floodplain processes. HEC-RAS 2D was selected for the present study, as it is widely used for simulating river flows, floodplain mapping, and water surface profiles under both steady and unsteady flow conditions and is freely available for use.

HEC-RAS 2D uses a finite volume solver to simulate shallow water equations (Saint-Venant equations), which model the movement of water with high accuracy. The software allows for flexible mesh generation and can work with both structured and unstructured grids, giving users control over spatial resolution.

# TECHNICAL MEMORANDUM

## 3.2 Terrain

The Digital Elevation Model (DEM) used in the 2D modeling was created by combining LiDAR and bathymetric data. The LiDAR was provided by NL Hydro, with a 1 m cell size resolution. Bathymetric data were collected by AtkinsRéalisis in May 2024 using multibeam sonar. The dataset has a high resolution of 0.25 m by 0.25 m and covers the channel bed from downstream of the powerhouse down to the bridge on Route 361 (St. Veronica's Bridge). The dataset coverage is shown in Figure 2.

Due to safety related issues, bathymetry data could not be collected in the tailrace channel directly downstream of the draft tubes to 125 meters downstream of PH 1 and 95 m downstream of PH 2. For these two sections the terrain is based on the drawings obtained from SNC-Lavalin (2018) for PH 2 and design basis report provided by NL Hydro for PH 1 which may not be as-constructed geometries.

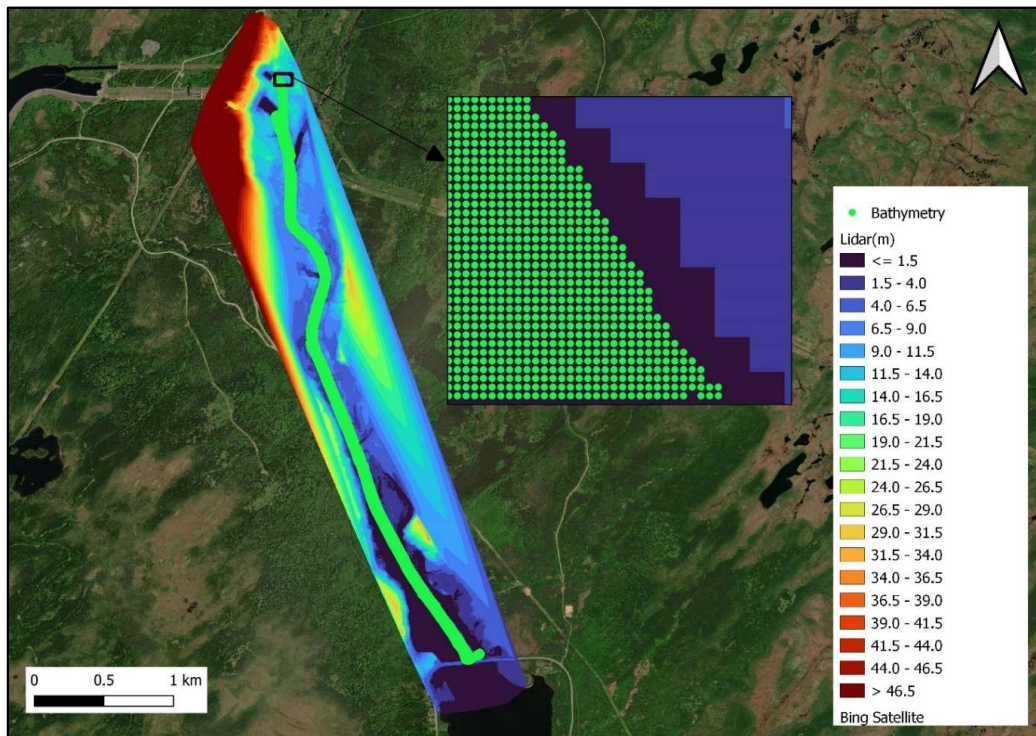


Figure 2 - LiDAR and bathymetric data

## 3.3 Geometry and boundary conditions

The 2D model developed for this study covers a domain extending from the draft tube decks of the powerhouses to St. Veronica's Bridge on Route 361, approximately 4.6 km downstream (Figure 3). The upstream boundary condition is the discharge outflow from the powerhouses, while the downstream boundary condition at St. Veronica's Bridge is the water level at high and low tide conditions.

## TECHNICAL MEMORANDUM

The high tide water level noted throughout this document corresponds to the “higher high water large tide” level as defined by Fisheries and Oceans Canada for St. Alban’s station, converted to the CGVD28 vertical datum from the chart datum. This is the average of the highest high-water levels over a 19-year period from tidal predictions. The low tide water level noted throughout this document corresponds to the “lower low water large tide” level as defined by Fisheries and Oceans Canada for St Alban’s station. This is the average of the lowest low water levels over a 19-year period of predictions (Table 3).

The model also includes inflows from Northwest Brook and Bear Brook. Under normal conditions, the 1:2-year flow from both brooks was applied to the model while under flood conditions, the 1:1000-year flow from both brooks was applied to the model. These flows are applied at the confluence locations with the main tailrace channel (Table 4).

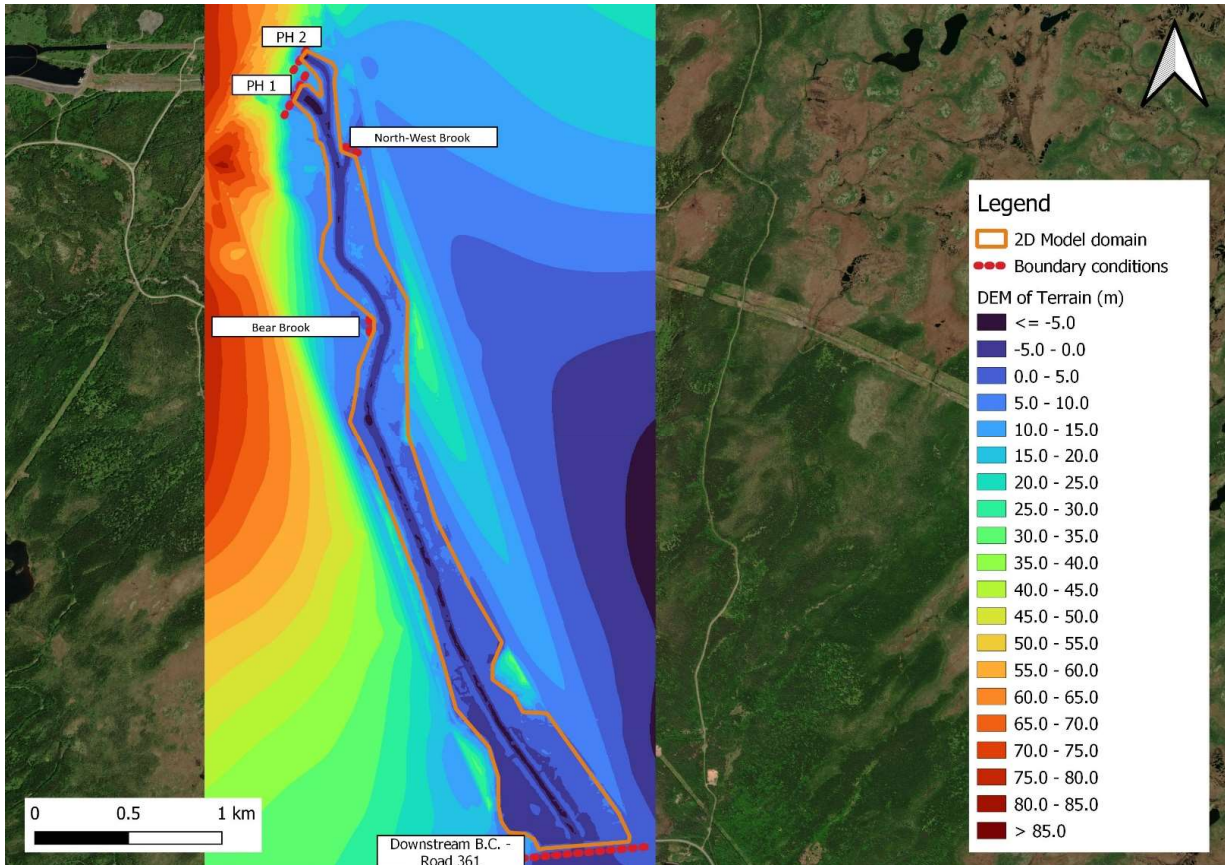
**Table 3 - Water Levels at Downstream Boundary of the 2D Model**

Scenario	Water Level (m)
Low Tide	-1.00
High Tide	1.12

**Table 4 - Flow at Upstream Boundary Locations of the 2D Model**

Scenario	Flow (m <sup>3</sup> /s)	
	Northwest Brook	Bear Brook
Normal Condition	17.4	6.8
Flood Condition	44.3	23.7

## TECHNICAL MEMORANDUM



## 4. Calibration of the Model

The calibration of the hydraulic model was performed using steady-state simulations. A number of parameters were reviewed during the FEED project as part of the calibration of the 2D tailrace hydrodynamic model for the velocity and flood review pre and post Unit 8 installation. These parameters include the mesh size of the 2D model, the program solver and Manning's roughness. For the calibration of the model as part of this study, the mesh size and solver previously tested was applied and only the riverbed roughness, represented by Manning's coefficient, was used for calibration. Four calibration scenarios were considered:

- High tide – high discharge
- High tide – low discharge
- Low tide – high discharge
- Low tide – low discharge

## TECHNICAL MEMORANDUM

To develop the calibration model, water level measurements and powerhouse outflow data from May 16<sup>th</sup> were utilized. The measurement locations and corresponding values for each scenario are illustrated in Figure 4 and Table 5. The water level at the St Alban's tidal station for the exact time of data collection was used as the downstream boundary condition. The distance between the tidal station and the tailrace bridge was reviewed to determine if there would be a significant effect on tidal lag or tide magnitude between the St. Alban's station and the tailrace bridge. It was determined that it is likely there would be a minimal difference in tidal magnitude at the bridge and the tidal lag would likely be between 15 to 30 minutes at the bridge. Therefore, the assumption that the tide timing and magnitude at the St. Alban's station is applied directly to the tide at the tailrace bridge as the boundary condition of the model is deemed to be acceptable.

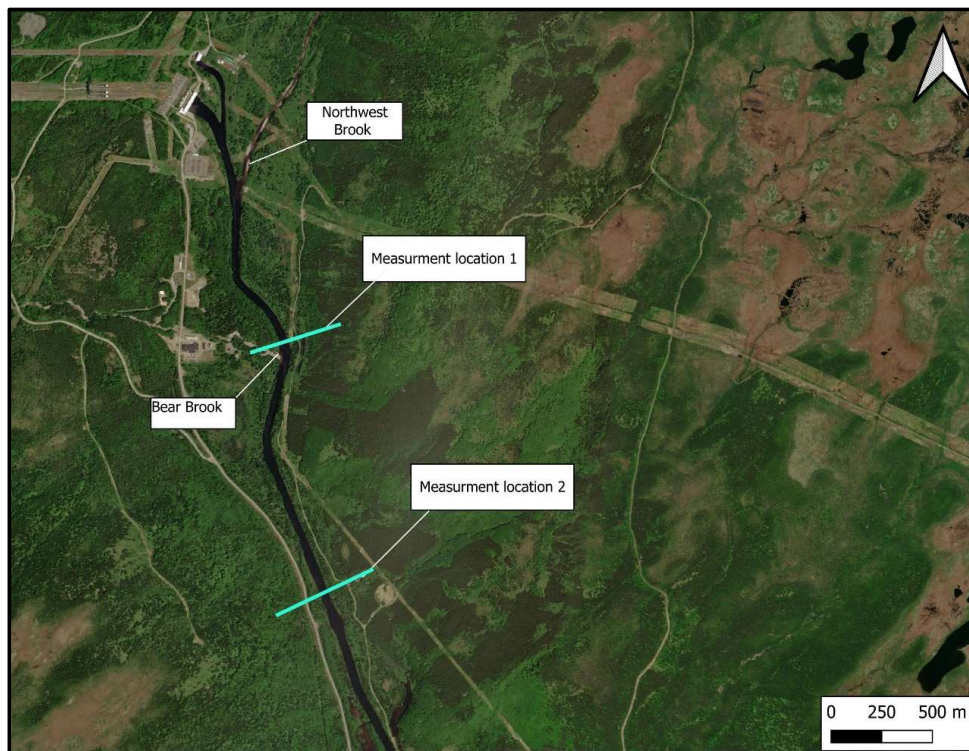


Figure 4 – Measurement Locations for Calibration Model

## TECHNICAL MEMORANDUM

The following table summarizes the tailwater levels that were observed during the May 16, 2025 survey as well as the discharges and tidal elevations that were noted during the test. Four specific times were selected from the actual data set as noted in Table 5, and each of these scenarios were modelled for calibration.

**Table 5 - Water Level and Discharge Measurements at the Time of Data Collection for Calibration Scenarios**

Scenario	Time of Data collection	Water level at location 1 (m)	Water level at location 2 (m)	PH 1 discharge (m <sup>3</sup> /s)	PH 2 discharge (m <sup>3</sup> /s)	Water level at St Alban's (m)
High Tide- High Discharge	2025-05-16 11:54 AM	1.42	0.94	199.6	89.3	0.49
High Tide- Low Discharge	2025-05-16 1:01 PM	0.48	0.56	75.3	0	0.45
Low Tide- High Discharge	2025-05-16 6:14 PM	0.84	0.14	166.0	66.0	-0.66
Low Tide- Low Discharge	2025-05-16 6:56 PM	0.09	-0.28	88.7	0	-0.60

The calibration model results indicate that a Manning roughness coefficient of 0.02 yields better agreement with observed data compared to coefficients of 0.03 and 0.025. Model calibration is based on a selected accuracy threshold whereby the model predicted values are compared to the field measured values and are found to be within a selected accuracy. An accuracy threshold of 0.15 m was selected for calibration and this value is considered acceptable practice based on modelling experience. The maximum difference between **observed/measured** and **simulated** water levels using the 0.02 coefficient was 0.14 m. As a result, a Manning roughness of 0.02 was selected for use in modeling the assessment scenarios. Table 6 provides a summary of the calibration results.

## TECHNICAL MEMORANDUM

Table 6 - Calibration Results for Three Studied Manning Roughness Values

Scenario	High Tide- High Discharge	High Tide- Low Discharge	Low Tide- High Discharge	low Tide- Low Discharge
n=0.025				
Water level at location 1 (m)	1.68	0.65	1.14	0.06
Water level at location 2 (m)	1.07	0.52	0.37	-0.31
Difference at location 1 (m)	-0.26	-0.17	-0.30	<b>0.03</b>
Difference at location 2 (m)	<b>-0.13</b>	<b>0.04</b>	-0.23	<b>0.03</b>
n=0.02				
Water level at location 1 (m)	1.53	0.62	0.98	-0.01
Water level at location 2 (m)	0.97	0.51	0.27	-0.32
Difference at location 1 (m)	<b>-0.11</b>	<b>-0.14</b>	<b>-0.14</b>	<b>0.10</b>
Difference at location 2 (m)	<b>-0.03</b>	<b>0.06</b>	<b>-0.13</b>	<b>0.04</b>
n=0.03				
Water level at location 1 (m)	1.84	0.70	1.29	0.15
Water level at location 2 (m)	1.18	0.54	0.49	-0.26
Difference at location 1 (m)	-0.42	-0.22	-0.45	<b>-0.06</b>
Difference at location 2 (m)	-0.24	<b>0.02</b>	-0.35	<b>-0.02</b>

**Bolded** values are within the acceptance criteria of 0.15 m difference between measured and modelled values

## 5. Assessment Scenarios

### 5.1 Stream inflows analysis

Both normal and flood operation scenarios were modelled using the calibrated tailrace model. The following scenarios were investigated for each tailrace configuration:

- 1) Normal Operations –
  - a) Full capacity discharge for existing PH 1 and PH 2 units during high tide conditions;
  - b) Full capacity discharge for both PH1 and PH 2 plus Unit 8 full discharge during high tide conditions;
  - c) No discharge from PH 1 and PH 2 during low tide conditions;
  - d) Full discharge of Unit 7 plus one unit at full discharge capacity in PH 1 during low tide conditions;

## TECHNICAL MEMORANDUM

2) Flood Operations -

- a) Full capacity discharge for existing PH 1 and PH 2 units during high tide conditions;
- b) Full capacity discharge for both PH 1 and PH 2 plus Unit 8 during high tide conditions;
- c) No discharge from PH1 and PH 2 during low tide conditions;
- d) Full discharge of Unit 7 plus one unit at full discharge capacity in PH 1 during low tide conditions.

Scenario numbers and associated scenario descriptions, as noted above, are summarized in Table 7, below.

**Table 7 - Description of the modeled scenarios**

Scenario #	Scenario description
NH-1	Normal Operations, High Tide, current max discharge
NH-2	Normal Operations, High Tide, max discharge incl Unit 8
NL-1	Normal Operations, Low Tide, no discharge
NL-2	Normal Operations, Low Tide, max discharge of 1 unit in each PH
NHW15-1	Normal Operations, High Tide, current max discharge – widening to 15.24m
NHW15-2	Normal Operations, High Tide, max discharge incl. Unit 8- widening to 15.24m
NLW15-1	Normal Operations, Low Tide, no discharge- widening to 15.24m
NLW15-2	Normal Operations, Low Tide, max discharge of 1 unit in each PH- widening to 15.24m
NHW20-1	Normal Operations, High Tide, current max discharge - widening to 20m
NHW20-2	Normal Operations, High Tide, max discharge incl. Unit 8 widening to 20m
NLW20-1	Normal Operations, Low Tide, no discharge- widening to 20m
NLW20-2	Normal Operations, Low Tide, max discharge of 1 unit in each PH- widening to 20m
FH-1	Flood Operations, High Tide, current max discharge
FH-2	Flood Operations, High Tide, max discharge incl Unit 8
FL-1	Flood Operations, Low Tide, no discharge
FL-2	Flood Operations, Low Tide, max discharge of 1 unit in each PH
FHW15-1	Flood Operations, High Tide, current max discharge- widening to 15.24m
FHW15-2	Flood Operations, High Tide, max discharge incl Unit 8- widening to 15.24m
FLW15-1	Flood Operations, Low Tide, no discharge- widening to 15.24m
FLW15-2	Flood Operations, Low Tide, max discharge of 1 unit in each PH- widening to 15.24m
FHW20-1	Flood Operations, High Tide, current max discharge- widening to 20m
FHW20-2	Flood Operations, High Tide, max discharge incl Unit 8- widening to 20m
FLW20-1	Flood Operations, Low Tide, no discharge- widening to 20m
FLW20-2	Flood Operations, Low Tide, max discharge of 1 unit in each PH- widening to 20m

Under the normal operating condition, the 1:2-year flood peak inflows from Northwest Brook and Bear Brook were calculated using statistical analysis and were used as inflows to the tailrace channel. Under the flood operations scenarios, the peak inflows from both Northwest Brook and Bear Brook were increased to 1:1000-year flows.

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For Bear Brook, the 1:2 year and 1:1000-year floods were estimated using the rational method. This method was selected based on the small sub-watershed area of 5.3 km<sup>2</sup> for Bear Brook and this is an accepted methodology to use for drainage areas of this size (Figure 5). For Northwest Brook, the watershed area exceeds the recommended basin limit for use of the rational method and therefore the flood estimation for Northwest Brook was based on a statistical analysis of the flows in Conne River, a nearby gauged river. The station (ID: 02ZE004) is located downstream of Conne River Pond and provides discharge data since 1989. A watershed area ratio, which is consistent with the provincial regional flood frequency methodology, was applied to estimate the 1:2 year and 1:1000-year floods in Northwest Brook.

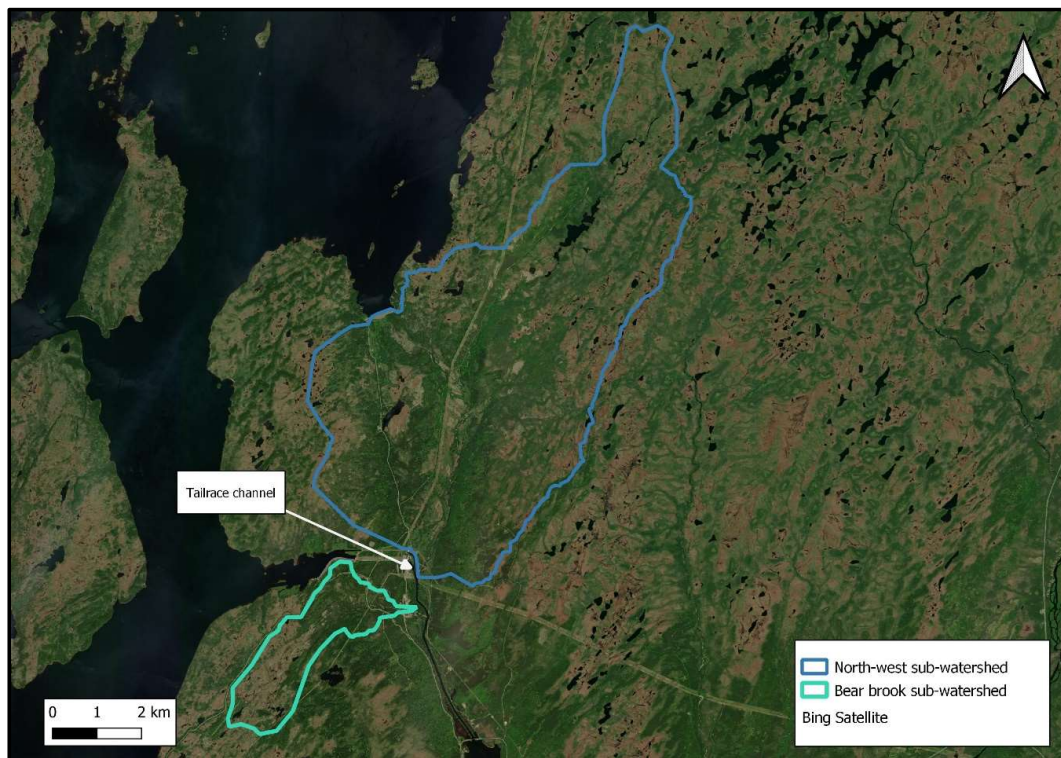


Figure 5 - Northwest Brook and Bear Brook Watersheds

## 5.2 Channel Widening

A review of the powerhouse tailrace data, from February to April 2025 indicates that the tailrace water levels were below the minimum design water level for Unit 7 approximately 9% of the time while the unit was in operation. The PH 2 tailrace water level was also observed to be below the minimum level with Unit 7 in operation during the survey that was completed on May 16, 2025 (see Figure 1). As a result, the existing tailrace width scenario was reviewed with the addition of Unit 8 to determine if tailrace water levels would increase to within design levels after installation. It should be noted that excavation would still be required for the existing tailrace width scenario to install riprap in the tailrace as is recommended in the 2018 study (SNC-Lavalin, 2018).

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Two additional widening scenarios were also considered. One scenario is based on the proposed final tailrace configuration outlined in the 2018 study (SNC-Lavalin, 2018). As illustrated in Figure 6, this excavation is proposed along the right bank and the channel bottom, expanding the bottom width to 15.24 m (50 ft). The widening would start around 430 m downstream of PH 2 and continue to the confluence of the PH 1 and PH 2 tailrace channels. The 15.24 m width would be the final tailrace dimension including riprap placement along the East side of the tailrace. The second widening scenario was similar to the first scenario except that the channel width was increased to a final dimension of 20 m. The assessment scenarios are summarized in Table 8. In the table, the N stands for normal conditions, F for flood conditions, H for high tide, L for low tide and W for widening.

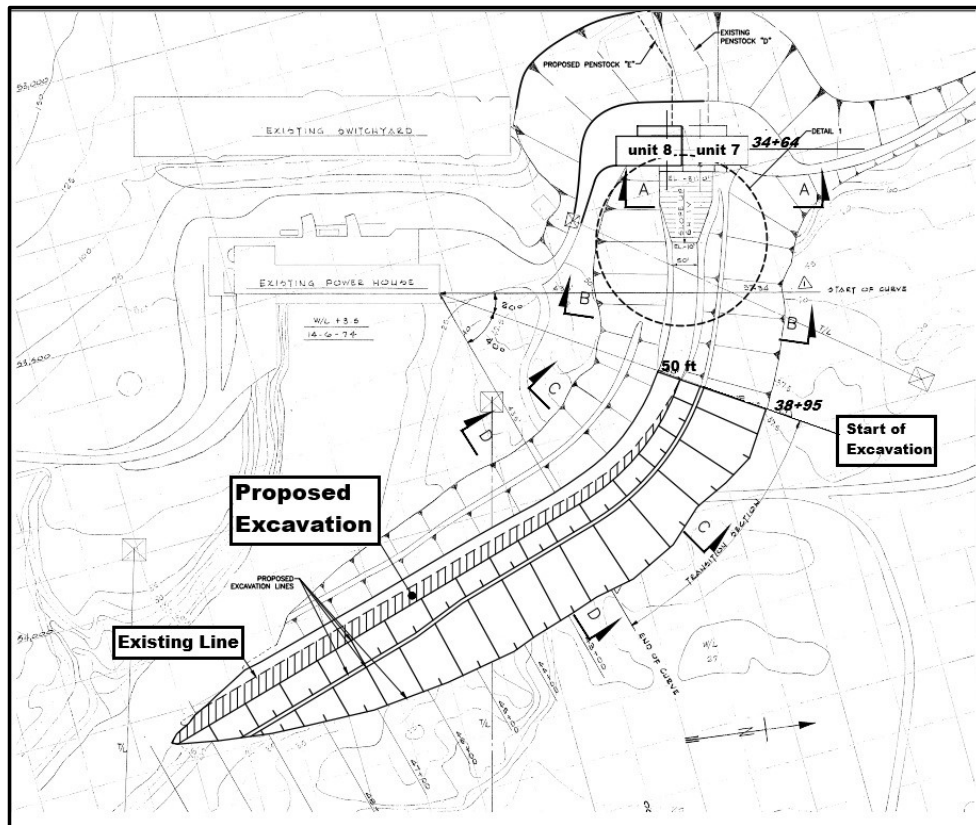


Figure 6 - Proposed Excavation in PH 2 Tailrace Channel

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Table 8 - Summary of Model Scenarios

Operating Regime	Terrain Condition	Scenario #	PH 1 discharge (m <sup>3</sup> /s)	PH 2 discharge (m <sup>3</sup> /s)	Stream inflows	Low tide	High tide
Normal	Existing Terrain	NH-1*	306	102	1:2 yr	-	Yes
		NH-2	306	204	1:2 yr	-	Yes
		NL-1	0	0	1:2 yr	Yes	-
		NL-2	49.5	102	1:2 yr	Yes	-
	Terrain with 15.24 m widening	NHW15-1	306	102	1:2 yr	-	Yes
		NHW15-2	306	204	1:2 yr	-	Yes
		NLW15-1	0	0	1:2 yr	Yes	-
		NLW15-2	49.5	102	1:2 yr	Yes	-
	Terrain with 20 m widening	NHW20-1	306	102	1:2 yr	-	Yes
		NHW20-2	306	204	1:2 yr	-	Yes
		NLW20-1	0	0	1:2 yr	Yes	-
		NLW20-2	49.5	102	1:2 yr	Yes	-
Flood	Existing Terrain	FH-1	306	102	1:1000 yr	-	Yes
		FH-2	306	204	1:1000 yr	-	Yes
		FL-1	0	0	1:1000 yr	Yes	-
		FL-2	49.5	102	1:1000 yr	Yes	-
	Terrain with 15.24 m widening	FHW15-1	306	102	1:1000 yr	-	Yes
		FHW15-2	306	204	1:1000 yr	-	Yes
		FLW15-1	0	0	1:1000 yr	Yes	-
		FLW15-2	49.5	102	1:1000 yr	Yes	-
	Terrain with 20 m widening	FHW20-1	306	102	1:1000 yr	-	Yes
		FHW20-2	306	204	1:1000 yr	-	Yes
		FLW20-1	0	0	1:1000 yr	Yes	-
		FLW20-2	49.5	102	1:1000 yr	Yes	-

\* Indicators 1 and 2 correspond to the scenarios presented in Section 5.1.

## 6. Results

The results of the widening scenarios under both normal and flood conditions are summarized in Table 9 and Table 10, respectively. Under normal operating conditions, the tailwater level at PH 2 decreases as the tailrace widening increases, which is as expected. It was also noted that the tailwater level at PH 2 decreases by as much as 0.10 m during high tide (scenario NH-2) and by as much as 0.31 m during low tide (scenario NL-2). This difference indicates the PH 2 tailrace is more sensitive to tailrace widening during low tide - low discharge conditions than during high tide - high discharge conditions.

Modelling of the existing tailrace and unit configuration under normal operating conditions results in a high tailwater level of 2.83 m. The installation of Unit 8, while still maintaining the existing tailrace configuration, results in an increase in the

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high tailwater level to 3.45 m. With tailrace widening, the high tailwater level drops to 3.35 m for high tide conditions with Unit 8 in full capacity operation (NHW-2). This decrease is considered to be minimal, as a 0.10 m difference between the maximum tailwater levels for all modelled scenarios is within the accuracy range of the model (0.15 m). Modelling of the three tailrace configurations indicates that the high tailwater level is above what was noted in the design basis for the FEED project, which was 3.21 m. This increase in high tailwater level should be noted during detailed design.

Under flood operating conditions, the tailwater level at PH 2 decreases as the tailrace widening increases, which is as expected. The existing tailrace and unit configuration results in a high tailwater level at PH 2 of 3.01 m and a high tailwater level of 3.61 m during high tide with Unit 8 at full capacity operation (scenario FH-2). This high tailwater level is approximately 0.4 m below the PH 2 draft tube deck floor that was surveyed on May 16, 2025 and was determined to be 4.116 m. Under these noted conditions, a 15.24 m wide tailrace results in a 0.09 m reduction of the high tailwater level compared to water level noted with the existing tailrace configuration. Overall, it was observed that there is a minor decrease in the high tailwater levels with increased tailrace widening. Similar to the results under normal conditions, the water level at PH 2 during high tide and flood operating conditions with Unit 8 operating at full capacity is above the 3.21 m maximum tailwater design level that was indicated in the design basis FEED document; however, this tailwater level remains below the PH 2 draft tube deck floor elevation of 4.116 m.

According to the Unit 7 tailrace water level design limits, the minimum tailrace water level at PH 2 is 0.93 m which corresponds with the centreline elevation of the Unit 7 distributor. Under normal operations and low tide conditions with 15.24 m tailrace widening (NLW15-2), the tailwater level is expected to be as low as 0.82 m, which is below Unit 7's design minimum tailwater level of 0.93 m. This indicates that tailrace widening to 15.24 m, or wider, may lead to cavitation issues with the turbine during low tide conditions unless a weir is installed in the PH 2 tailrace to maintain the minimum tailwater level at or above 0.93 m.

Overall, tailrace widening does not significantly affect high tailwater levels during high tide; however, it does have a more appreciable effect on low tailwater levels. The tailwater widening scenarios modelled show that in both the 15.24 m and 20 m widening cases, the low tailwater level during low tide with low discharge falls below the minimum design elevation of Unit 7.

Additionally, a 0.02 m increase in water level at PH 1 was observed in the model results for the widening scenarios understanding that this increase is within the 0.15 m accuracy limit of the model. This minor tailwater level rise is likely due to a backwater effect. The reduced velocity in the widened section leads to a local increase in water level at the confluence, which propagates upstream into the PH 1 tailrace. In essence, the widening of PH 2 tailrace alters the momentum distribution at the confluence, resulting in a small upstream backwater effect at PH 1. No adjustments to the PH 1 tailrace are recommended as a result of these tailrace modelling results.

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**Table 9 - Water Levels for Existing Terrain and Tailrace Widening Scenarios in Normal Conditions**

Location	Water Levels (m)											
	Existing Terrain				Terrain with 15.24 m widening				Terrain with 20 m widening			
	NH-1	NH-2	NL-1	NL-2	NHW 15-1	NHW 15-2	NLW 15-1	NLW 15-2	NHW 20-1	NHW 20-2	NLW 20-1	NLW 20-2
PH 1	2.79	3.27	-0.92	0.67	2.79	3.29	-0.92	0.69	2.79	3.29	-0.92	0.69
PH 2	2.83	3.45	-0.92	1.13	2.79	3.35	-0.92	0.82	2.79	3.33	-0.92	0.78
Confluence of Tailrace of PH 1 and PH 2	2.74	3.23	-0.92	0.67	2.74	3.23	-0.92	0.69	2.76	3.26	-0.92	0.69

Blue Highlighted cells: Maximum tailwater levels under the modelled normal operating conditions

Green Highlighted cells: Minimum tailwater level under the modelled normal operating conditions

**Table 10 - Water Levels for Existing Terrain and Tailrace Widening Scenarios in Flood Conditions**

Location	Water Levels (m)											
	Existing Terrain				Terrain with 15.24 m widening				Terrain with 20 m widening			
	FH-1	FH-2	FL-1	FL-2	FHW 15-1	FHW15 -2	FLW15 -1	FLW15 -2	FHW20 -1	FHW20 -2	FLW20 -1	FLW20 -2
PH 1	2.98	3.45	-0.56	1.02	2.98	3.47	-0.56	1.04	2.98	3.47	-0.56	1.04
PH 2	3.01	3.61	-0.56	1.34	2.98	3.52	-0.56	1.13	2.98	3.51	-0.56	1.11
Confluence of Tailrace of PH 1 and PH 2	2.94	3.42	-0.56	1.02	2.95	3.44	-0.56	1.04	2.95	3.45	-0.56	1.04

Blue Highlighted cells: Maximum tailwater levels in PH 2 tailrace under the modelled flood operating conditions

Green Highlighted cells: Minimum tailwater level in PH 2 tailrace under the modelled flood operating conditions

## 7. Conclusions and Recommendations

Three tailrace configurations were evaluated as part of this study to assess their impact on tailwater elevations relative to the design for Unit 8. These tailrace configurations are noted as final constructed widths, understanding that additional excavation will be required to install riprap protection along the invert and east side slope for all configurations.

- 1) Existing tailrace width
- 2) Widen tailrace to 15.24 m
- 3) Widen tailrace to 20 m

The findings of this study indicate that the concurrent operations of Unit 8 and Unit 7 at PH 2 will result in increased low and high tailwater elevations during both normal and flood operations. Under the existing tailrace configuration, as observed during the May 16 survey and as indicated in Section 2.1, the tailwater levels with Unit 7 in operation during low tide periodically fall below the design minimum tailwater level of 0.93 m, potentially resulting in cavitation issues with the turbine. The installation of Unit 8 will increase the minimum low tailwater level during low tide to exceed the design

## TECHNICAL MEMORANDUM

minimum and improve operational conditions during concurrent operation of the two units. The existing tailrace configuration will also result in an increase in the high tailwater level from 2.83 m, without Unit 8, to 3.45 m with both units in operation. This maximum tailwater level remains below the PH 2 draft tube deck level but will result in a reduction of net head from the 3.21 m high tailwater level that was used in the design basis report for the FEED project.

In addition, as the width of the tailrace is increased, the minimum tailwater level decreases. Widening the tailrace to 15.24 m slightly reduces the maximum tailwater level to 3.35 m (with concurrent operation of Units 7 and 8) but also lowers the minimum tailwater level to 0.82 m, which is below the minimum acceptable design threshold of 0.93 m. This minimum tailwater level could be mitigated with the installation of a weir in the PH 2 tailrace, located between the bend in the PH 2 tailrace and the confluence with the PH 1 tailrace.

Overall, the existing tailrace width is adequate to meet the design tailwater limits of Unit 7 and Unit 8; however, refinement of the tailrace model to include additional bathymetry to 100 meter downstream of PH 2 as well as transient analysis is recommended during the detailed design stage of the project to confirm this conclusion as well as the design tailrace operating range.

Considering a Low Supply reservoir elevation of 178.3 m, the difference in net head between the existing tailrace and a tailrace widened to 15.24 m is approximately 0.2%. The actual difference may be less when accounting for model accuracy. Based on the results of this study, it is concluded that the tailwater design parameters should range between a minimum of 0.93 m and a maximum of 3.45 m under normal operating conditions.

The following items should be considered during optimization of the tailrace during detailed design:

- **Operating Regime Review:** Optimum width of the tailrace to maintain the tailwater levels within the design range will be dependent on the PH 2 operating regime with Unit 8 installed. A review of operations will help inform the optimized tailrace design.
- **Outage Assessment:** During detailed design, a tailrace widening to 15.24m should be evaluated. A low minimum tailwater level with Unit 8 in operation and tailrace widening could be mitigated by the installation of a weir in the tailrace as noted above. Assess whether a weir can be installed, between the bend in the PH 2 tailrace and the confluence with the PH 1 tailrace, with a planned outage of Unit 7. If this is not possible, is a separate 6-8 week outage of Unit 7 acceptable to facilitate the installation of the weir. The outcome of this decision will affect whether the minimum tailrace water level can be achieved with a weir installation.
- **Cost Review:** An energy production loss review and associated cost comparison would be recommended during detailed design to optimize the tailrace configuration. This cost review would include the results of the aforementioned reviews as well as the cost to modify the tailrace.
- **Transient Analysis:** It is recommended that transient analyses for restart and load rejection events be conducted, during the detailed design phase, to determine the high tailwater levels under transient conditions and as part of a comprehensive transient study.
- **Bathymetry collection:** It is recommended to collect bathymetry from PH 2 to 100 m downstream of PH 2 to refine the digital terrain of the model close to PH 2. Bathymetry will need to be collected when Unit 7 is not generating.

## **TECHNICAL MEMORANDUM**

The review of gauge data and the field survey conducted on May 16, 2025, revealed multiple issues with the gauge measurements. It is recommended to carry out a detailed investigation of the gauge data, including a comparison with the water levels measured on May 16. This investigation should include the May 16, 2025 survey data as well as data since February 2025, RTU communications, and information regarding other concerns listed in Table 1, to draw a comprehensive conclusion regarding the reliability of the gauge data, including the functionality of the equipment used to collect and record the data.

## TECHNICAL MEMORANDUM

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SNC-Lavalin. 2018. "Proposed Bay d'Espoir Hydro Generating Unit 8, Class 3 Cost Estimate and Project Execution Schedule, Final Report".

1 Q. Please provide any reports/assessments that gives more detail about the new intake channel.

2

3

4 A. Section 5.1 of BW-NLH-006, Attachment 1, "*Concept Design Update Report*" (Document # BDE-  
5 SN-40000-EN-DEG-0002-01), completed by the front-end engineering design consultant in  
6 November 2024, discusses the considerations made in the design of the current iteration of the  
7 intake channel.



# Document Front Sheet

Contract Number and Description: <b>Bay d'Espoir Unit 8 FEED</b> Project Number: <b>699257</b>		Contractor Name: ATKINSRÉALIS CANADA INC. Address: 455 René-Lévesque W., Montreal, QC, H2Z 1Z3	
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General Comments:

AtkinsRéalis



## CONCEPT DESIGN UPDATE REPORT

NEWFOUNDLAND AND LABRADOR HYDRO

November 11, 2024

BDE-SN-40000-EN-DEG-0002-01

699257-3300-40EC-0001

# BAY D'ESPOIR UNIT 8 FEED

## DISCLAIMER

This report was prepared for Newfoundland and Labrador Hydro (“NL Hydro”) by AtkinsRéalis. It contains the expression of the professional judgement of AtkinsRéalis and the information herein has been prepared for the specific purpose and use as outlined in the Contract Document 2023-94590-DS. It is meant to be read as a whole, and sections or parts thereof should thus not be read or relied upon out of context. This report should be read, with the additional context provided by the existing 2018 comprehensive report titled “Class 3 Cost Estimate and Project Execution Schedule” (647756-0000-40ER-I-0002-00) for a more complete understanding of the project background and scope.

This concept design update report has been prepared based on the available data, inputs, and conditions at the time of its creation. The report captures a specific window in time of information and reflects the understanding and analysis of that moment. While this concept design update report provides valuable insights, stakeholders should recognize its limitations and understand that it may not align with the final design documents of the Bay d’Espoir Unit 8 FEED project.

# Signature Page

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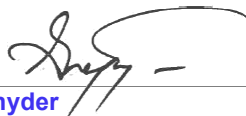
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## 1 EXECUTIVE SUMMARY

### 1.1 Objective of the Concept Update Report

In 2017-2018, AtkinsRéalis (formerly SNC-Lavalin) undertook a study for NL Hydro on the proposed Bay d'Espoir Hydro Generating Unit No. 8. Two reports were produced and issued in March 2018, a report entitled "Hydraulic Analysis of the Conveyance System" (647756-0000-40ER-I-0001-00) and a comprehensive report on the project entitled "Class 3 Cost Estimate and Project Execution Schedule" (647756-0000-40ER-I-0002-00). These will collectively be referred to as "the 2017 Study" in this report. The primary objective of the 2017 Study was to evaluate options for adding an eighth unit to the existing Bay d'Espoir Generating Station in Powerhouse 2. The study detailed the preferred option at that time, laying the groundwork for future planning.

The 2024 Bay d'Espoir Unit 8 Front-End Engineering Design (FEED) project builds upon the 2017-2018 work, reaching a level of detail necessary to support an application for project approval by the Public Utilities Board (PUB) and to advance design documentation for the subsequent project phase.

The objective of this high-level concept design update report is to supplement and enhance the existing design documentation, as well as describe revisions to the concepts presented in the 2017 Study. The report delineates the design approach, underlying assumptions, optimization strategies, and governing codes and standards that will underpin the preliminary engineering phase, including performance specifications and drawings, for the 2024 Bay d'Espoir Unit 8 FEED.

## 2 GOVERNING STANDARDS, CODES AND GUIDES

### 2.1 General

At a minimum, the design will adhere to the following codes and standards:

NBC	National Building Code of Canada
OHS NL	Occupational Health and Safety Regulations, 2012, under the Occupational Health and Safety Act, 2012-Newfoundland and Labrador
NFC	National Fire Code of Canada
NFPA	National Fire Protection Association

### 2.2 Turbine-Generator

At a minimum, the turbine-generator design will adhere to the following codes, standards and guides:

ANSI/ASME PTC29	Speed-Governing Systems for Hydraulic Turbine-Generator Units
A	Standard specification for steel forgings, carbon and alloy, for general
ASTM A668M	Standard specification for steel forgings, carbon and alloy, for general industrial use
ASTM A743M	Standard Specification for Castings, Iron-Chromium, Iron-Chromium-Nickel, Corrosion Resistant, for General Application
IEC 60193	Hydraulic turbines, storage pumps and pump-turbines - Model acceptance tests
IEC 61362	Guide to the specifications of the hydraulic turbines control system
IEC 60308	International code for testing of speed governing systems for hydraulic turbines
IEC 60041	Field acceptance tests to determine the hydraulic performance of hydraulic turbines, storage pumps and pump-turbines
IEEE 125	IEEE recommended practice for preparation of equipment specifications for speed-governing of hydraulic turbines intended to drive electric generators
IEEE 286	Recommended Practice for the Measurement of Power Factor Tip-Up of Electric Machinery Stator Coil Insulation
IEEE 421.1	IEEE Standard Definitions for Excitation Systems for Synchronous Machines
IEEE 810	Hydraulic Turbine and Generator Shaft Couplings and Shaft Runout Tolerances
IEEE 1043	Recommended Practice for Voltage-Endurance Testing of Form-Wound Bars and Coils
IEEE 1095	Guide for the Installation of Vertical Generators and Generators/Motors for Hydroelectric Applications



IEEE 1310	Recommended Practice for Thermal Cycle Testing of Form-Wound Stator Bars and Coils for Large Rotating Machines
IEEE 1553	IEEE Standard for Voltage Endurance Testing of Form-Wound Coils and Bars for Hydrogenerators
IEEE 1207	IEEE Guide for the Application of Turbine Governing Systems for Hydroelectric Generating Units
IEEE C57.32	Requirements, Terminology, and Test Procedures for Neutral Grounding Devices
IEEE C50.12	Standard for Salient-Pole 50 Hz and 60 Hz Synchronous Generators and Generators/Motors for Hydraulic Turbine Application Rated 5 MVA and above
IEEE 115	Test Procedures for Synchronous Machines
CEATI T 212700-03111	Guidance For Technical Specifications for The Procurement of Major Hydraulic Plant Equipment
CEATI T162700-0392	Hydro Generator Turbine Vibration and Balancing Field Guide
CEATI T182700-03	Guide to Ensuring Quality for Manufacturing and Installation
CEATI T122700-0381	Hydroelectric Turbine-Generator Units Guide for Erection Tolerances and Shaft System Alignment
ISO 20816-5	Mechanical Vibration - Measurement and Evaluation of Machine Vibration. Part 5: Machine sets in hydraulic power generating and pump-storage plants
ISO 21940-11	Mechanical Vibration — Rotor Balancing. Part 11: Procedures and tolerances for rotors with rigid behaviour
ASTM A343/A343M	Standard Test Method for Alternating-Current Magnetic Properties of Materials at Power Frequencies Using Wattmeter-Ammeter-Voltmeter Method and 25-cm Epstein Test Frame
ASTM A345	Standard Specification for Flat-Rolled Electrical Steels for Magnetic Applications
ASTM A677	Standard Specification for Non-oriented Electrical Steel Fully Processed Types
ASTM B48	Standard Specification for Soft Rectangular and Square Bare Copper Wire for Electrical Conductors
ASTM B187/B187M	Standard Specification for Copper, Bus Bar, Rod, and Shapes and General Purpose Rod, Bar, and Shapes
ASTM D149	Standard Test Method for Dielectric Breakdown Voltage and Dielectric Strength of Solid Electrical Insulating Materials at Commercial Power Frequencies

### **2.3 Hydromechanical Equipment**

At a minimum, trashracks, maintenance gates, the operating gate and all associated embedded parts will adhere to the following codes and standards:



CISC	Canadian Institute of Steel Construction
ASME BPV	Boiler and Pressure Vessel Code, Section VIII
CSA A23.3	Design of Concrete Structures
CSA S16	Design of Steel Structures
DIN 19704-1	Hydraulic Steel Structures– Part 1: Criteria for Design and Calculation
DIN 19704-2	Hydraulic Steel Structures– Part 2: Design and Manufacturing
USACE ETL 1110-2-584	Design of Hydraulic Steel Structures

The intake operating gate hoist and the intake maintenance gate hoist will adhere to the following codes and standards:

ASME B30.7	Base Mounted Drum Hoist
AGMA 260.02	Design of Components-enclosed gear drives, Bearings, Bolting, Keys and Shafting
FEA	FEA Rules for Design of Hoisting Appliances
CSA	CSA W59 Welded Steel Construction (Metal Arc Welding)

Other applicable technical references for hydromechanical equipment:

Erbisti, P.C.F., Design of Hydraulic Gates. 1st Edition. 2004.

Falvey, H.T., Air-Water Flow in Hydraulic Structures. USBR Engineering Monograph No. 41. 1980.

US Army Corps of Engineers, Hydraulic Design Criteria Sheet 050-1: Air Demand – Regulated Outlet Works. January 1964.

Zangar, C.N., Hydrodynamic Pressures on Dams Due to Horizontal Earthquake Effects. USBR. 1952.

Sehgal, C.K. et.al., Recommendations for the design of intake trashracks. Hydropower & Dams, Issue Six, 2005.

## 2.4 Balance of Plant Mechanical Equipment

At a minimum, the powerhouse balance of plant systems will adhere to the following codes and standards:

ASHRAE	American Society of Heating, Refrigerating and Air-Conditioning Engineers
ASME B31.1	Power Piping



HI Hydraulic Institute for Pumps

## 2.5 Civil

At a minimum, the design for the civil and structural work will adhere to the following codes, standards and guides:

AAMP	Association for Materials Protection and Performance (AAMP) (formerly SSPC)
ACI 207.1	Guide to Mass Concrete
ACI 207.2	Report on Thermal and Volume Change Effects on Cracking of Mass Concrete
ACI 224	Control of Cracking in Concrete Structures
AISE Tech Report No. 13	Guide on the Design and Construction of Mill Buildings
ASCE	Manuals and Reports on Engineering Practice No. 79 - Steel Penstocks, 2nd edition
ASCE	Water Pressure on Dams During Earthquakes, Westergaard, H.M., 1933
ASTM A759	Carbon Steel Crane Rails
CDA Guidelines	Canadian Dam Association, Dam Safety Guidelines
CISC	Handbook of Steel Construction
CSA A23.1/A23.2	Concrete Materials and Methods of Concrete Construction / Test Methods and Standard Practices for Concrete
CSA A23.3	Design of Concrete Structures
CSA A3000	Cementations Materials Compendium
CSA G40.20/G40.21	General Requirements for Rolled or Welded Structural Quality Steel/Structural Quality Steel
CSA S16	Design of Steel Structures
CSA S136	North American Specification for the Design of Cold-Formed Steel Structural Members
CSA W59	Welded Steel Construction (Metal Arc Welding)
FM DS 05-04	Factory Mutual Property Loss Prevention Data Sheet 5-4 Transformers
NFPA 851	Recommended Practice for Fire Protection for Hydroelectric Generating Plants
ASME BPV	Boiler and Pressure Vessel Code, Section VIII
DIN 19704-1	Hydraulic Steel Structures – Part 1: Criteria for Design and Calculation
USACE ETL 1110-2-584	Design of Hydraulic Steel Structures
USBR	Design of Gravity Dams
USBR	Design of Small Dams



## 2.6 Balance of Plant Electrical Equipment

At a minimum, the powerhouse balance of plant electrical equipment will adhere to the following references:

CSA 22.1	Canadian Electrical Code Part I
CSA 22.2	Canadian Electrical Code Part II
C57.13	Requirement for Instrument Transformers
CSA C9	Dry-Type Transformers
C22.2 No. 178	Automatic Transfer Switches
CSA C22.2 NO. 201:M84	Metal-Enclosed High Voltage Busways
CSA C61869-1	Instrument transformers - Part 1: General requirements
CSA C61869-2	Instrument transformers - Part 2: Additional requirements for current transformers
CSA CAN3-C108.3.1-M84	Limits and Measurement Method of Electromagnetic Noise from AC Power Systems 0.15-30 MHz
CSA G164	Hot Dip Galvanizing of Irregularly Shaped Articles
CSA W47.1	Fusion Welding of Steel
CSA W47.2	Fusion Welding of Aluminium Company Certification
CSA W59	Welded Steel Construction
CSA W59.2	Welded Aluminium Construction
C22.10	Québec Construction Code, Chapter V - Electricity, Canadian Electrical Code, Part I (Twenty-third edition) with Québec Amendments
C22.2 No. 22	Electrical equipment for flammable and combustible fuel dispensers
C22.2 No. 31	Switchgear Assemblies
C22.2 M85	Enclosed Switches
CAN/CSA-C60044-1	Instrument Transformers Part 1: Current Transformers
CAN/CSA-C60044-2	Instrument Transformers Part 2: Inductive Voltage Transformers
IEEE C37.04	IEEE Standard for Ratings and Requirements for AC High-Voltage Circuit Breakers with Rated Maximum Voltage Above 1000 V
IEEE C37.06	IEEE Standard for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis-Preferred Ratings and Related Required Capabilities for Voltages Above 1000 V



IEEE C37.09	IEEE Standard Test Procedures for AC High-Voltage Circuit Breakers with Rated Maximum Voltage Above 1000 V
IEEE C37.010	IEEE Application Guide for AC High-Voltage Circuit Breakers > 1000 Vac Rated on a Symmetrical Current Basis
IEEE C37.011	IEEE Guide for the Application of Transient Recovery Voltage for AC High-Voltage Circuit Breakers with Rated Maximum Voltage above 1000 V
IEEE C37.11	IEEE Standard Requirements for Electrical Control for AC High-Voltage (>1000 V) Circuit Breakers
IEEE C37.12	IEEE Guide for Specifications of High-Voltage Circuit Breakers (over 1000 V)
IEEE C37.013	IEEE Standard for AC High-Voltage Generator Circuit Breakers Rated on a Symmetrical Current Basis
IEEE C37.013a	IEEE Standard for AC High Voltage Generator Circuit Breakers Rated on a Symmetrical Current Basis - Amendment 1: Supplement for Use with Generators Rated 10-100 MVA
IEEE C37.20.2	IEEE Standard for Metal-Clad Switchgear
IEEE C37.20.7	IEEE Guide for Testing Metal-Enclosed Switchgear Rated Up to 38 kV for Internal Arcing Faults
IEEE C37.47	IEEE Standard Specifications for High-Voltage (>1000 V) Distribution Class Current-Limiting Type Fuses and Fuse Disconnecting Switches
IEEE C37.90	IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus
IEEE C37.110	IEEE Guide for the Application of Current Transformers Used for Protective Relaying Purposes
IEEE C57.13	IEEE Standard Requirements for Instrument Transformers
IEEE C62.11	IEEE Standard for Metal-Oxide Surge Arresters for AC Power Circuits (>1 kV)
IEEE 62271-37-013	IEEE/IEC International Standard for High-voltage switchgear and controlgear--Part 37-013: Alternating current generator circuit-breakers
IEEE C29.1	Test Methods for Electrical Power Insulators
IEEE C37.23	IEEE Standard for Metal-Enclosed Bus



IEEE C22.1	Canadian Electrical Code, Part 1 – Safety Standard for Electrical Installations
IEEE C37.13	IEEE Standard for Specifications of Low Voltage AC Power Circuit Breakers Used in Enclosures
IEEE C37.16	IEEE Guide for Specifications of Low Voltage Power Circuit Breakers and AC Power Circuit Protectors – Preferred Ratings, Related Requirements and Application Recommendations
IEEE C37.17	IEEE Standard for Trip Devices for AC and General Purpose DC Low-Voltage Power Circuit Breakers
IEEE C37.20.1	IEEE Standard for Metal-Enclosed Low-Voltage Power Circuit Breaker Switchgear
IEEE C37.50	IEEE Standard for Switchgear – Low Voltage AC Power Circuit Breakers Used in Enclosures – Test Procedures
IEEE C37.51	Metal-Enclosed Low-Voltage AC Power Circuit Breaker Switchgear Assemblies – Conformance Test Procedure
IEEE C50.12	Standard for Salient-Pole 50 Hz and 60 Hz Synchronous Generators and Generators/Motors for Hydraulic Turbine Application Rated 5 MVA and above
IEEE 115	Test Procedures for Synchronous Machines
IEEE 286	Recommended Practice for Measurement of Power Factor Tip-Up of Electric Machinery Stator Coil Insulation
IEEE 522	Guide for Testing Turn Insulation of Form-Wound Stator Coils for Alternating-Current Electric Machines
IEEE 810	Standard for Hydraulic Turbine and Generator Integrally Forged Shaft Couplings and Shaft Runout Tolerances
IEEE Std 32	Standard Requirement, Terminology, and Test Procedure for Neutral Grounding Devices
IEEE C37.30	Requirements for High Voltage Switches
IEEE 665	Guide for Generating Station Grounding
IEEE 141	Recommended Practice for Electric Power Distribution for Industrial Plants
IEEE 399	Recommended Practice for Industrial and Commercial Power Systems Analysis
IEEE 666	Design Guide for Electric Power Service Systems for Generating Stations
IEEE 946	Recommended Practice for the Design of DC Auxiliary Power Systems for Generating Stations
IEEE 1187	Recommended Practice for Installation Design and Installation of Valve-Regulated Lead-Acid Storage Batteries for Stationary Applications



IEEE 1189	Guide for Selection of Valve-Regulated Lead Acid (VRLA) Batteries for Stationary Applications
IEEE 1375	Guide for the Protection of Stationary Battery Systems
IEEE C57.12.01	General Requirements for Dry-Type Distribution and Power Transformers, Including Those with Solid-Cast and/or Resin Encapsulated Windings
IEEE C57.12.70	Standard for Terminal Markings and Connections for Distribution and Power Transformers
IEEE C57.12.91	Standard Test Code for Dry-Type Distribution and Power Transformers
IEEE C57.96	Guide for Loading Dry-Type Distribution and Power Transformers
CAN/ULC S524-06	Installation of Fire Alarm Systems
IESNA	Illuminating Engineering Society - The Lighting Handbook – 10th Edition



### 3 ASSUMPTIONS

The assumptions outlined in the following section are not exhaustive but will eventually be documented and added to the project final assumptions register.

1. The front-end engineering design for the transmission line is being addressed by NL Hydro and will not be elaborated upon in this report.
2. Design of the relocation for Unit 7 first pylon tower is included in the transmission line design that is being addressed by NL Hydro.
3. The design is to consider minimizing the outage time and impact on power production for the existing units (Units 1 to 7) as a result of construction.
4. The existing powerhouse overhead crane will be utilized for Unit 8 only if the capacity of generating unit remains at or below 155 MW. In this case, no modifications or major upgrade are required for the existing crane, except to extend the crane runway.
5. Bedrock depths in the vicinity of the penstock have been assumed based on lidar, test pit, and borehole data which have been provided by NL Hydro.
6. A new set of draft tube gates for Unit 8 will be provided to ensure that the existing set can be used for operation and maintenance of Unit 7 when required during the construction of Unit 8.
7. Vertical datum for the project will be CGVD28.
8. Horizontal datum for the project will be NAD83 original MTM Zone 2.

## 4 OPTIMIZATION STRATEGIES

The optimization strategies for Bay d’Espoir FEED Unit 8 focus on high-level approaches to enhance efficiency, minimize cost, and ensure constructability, and considered safety by design (e.g. elimination of confined spaces, gate handling methods, etc.). Detailed specifics are covered in subsequent sections in Design Approach. The following summarizes the optimization considerations by area:

### 4.1 Headrace

- Channel Routing:
  - Evaluated four (4) potential channel routes.
  - Factors considered: constructability, hydraulics including frazil ice performance of all units and vorticity review, impact on existing work and cost.
  - Reviewed two (2) of those routes in more detail for final optimized headrace canal route and selection of the recommended route.
- Log boom removed from scope because entrance will be protected by existing boom for Intakes 1 to 3.

### 4.2 Intake

- Sealing Options:
- Explored upstream vs downstream sealing with respect to emergency closure and gate cracking requirements.
- Maintenance and Operation Requirements:
  - Addressed gate and bulkhead maintenance access.
- Considered Operator needs.
- Intake Configuration - Factors considered: hydraulics including submergence and vorticity.

### 4.3 Penstock

- Penstock Routing:
  - Prioritized constructability.
  - Minimized excavation in overburden and rock.

### 4.4 Powerhouse

- Layout and Equipment:
  - Factors considered: safety, maintenance, ease of use and cost.

### 4.5 Tailrace

- Tailrace:
  - Factors considered: constructability, hydraulics (minimized headloss) and cost.



## 5 DESIGN APPROACH

### 5.1 Water Conveyance System (WCS)

#### 5.1.1 Headrace Channel Route

The headrace described in the 2017 Study included the expansion of the existing Unit 7 canal with a bifurcation of the channel near Intake 4 to accommodate the new Unit 8 intake. A constructability review highlighted that there is a high likelihood that blast rock could partially block the Unit 7 canal during the development of the new canal and that channel depth would make rock removal difficult and expensive. This route would also result in an unacceptably high risk of an unscheduled Unit 7 outage during canal construction. In addition, there was concern regarding the stability of the rock wall that would remain between the existing Unit 7 canal and the bifurcated section of the new canal to the new intake. This instability poses a risk during construction as well as during operation. AtkinsRéalis has also determined that controlled blasting should be used for bedrock removal near other infrastructure such as intakes and rock canal side walls, and the new intake and canal should be located no closer than 25 m to existing infrastructure. As a result of the risks noted above, alternative headrace channel routes were explored.

Four additional headrace layouts were reviewed:

- Alternative 1 – entrance on south side at approx. 200m upstream of intake 3
- Alternative 2 – entrance on north side at approx. 345m upstream of intake 4
- Alternative 3 – entrance on south side at approx. 50m upstream of intake 3
- Alternative 4 – entrance on south side at approx. 115m upstream of intake 3

Based on the modelled flow effects on Intake 3 as well as the inability to maintain the required 25 m rock buffer around all canal edges, Alternatives 3 and 4 were deemed to be unsuitable and were not studied further.

The two (2) remaining alternatives were further reviewed to determine the recommended option to carry forward (See Figures 5-1 and 5-2). The two options are briefly described as follows:

#### *Alternative 1: Long channel with entrance from existing south canal*

- A full rock cut is anticipated for 3/4 of the length of the channel. A rock plug may not be possible during construction if the rock profile is below the anticipated reservoir level during construction (180.5m). Alternative methods to isolate the channel during construction may be required.
- Underwater removal of granular material is required at the channel entrance.
- No widening or expansion of the forebay area is anticipated.

#### *Alternative 2: Long channel with entrance from existing north canal*

- There will be a full rock cut for the entire length of the channel. A rock plug will be used during construction to isolate the channel given the reservoir level during construction is anticipated to be at 180.5m which is the typical reservoir level in August.
- Underwater removal of granular material at the entrance is likely minor.
- No widening or expansion of the forebay area is anticipated.



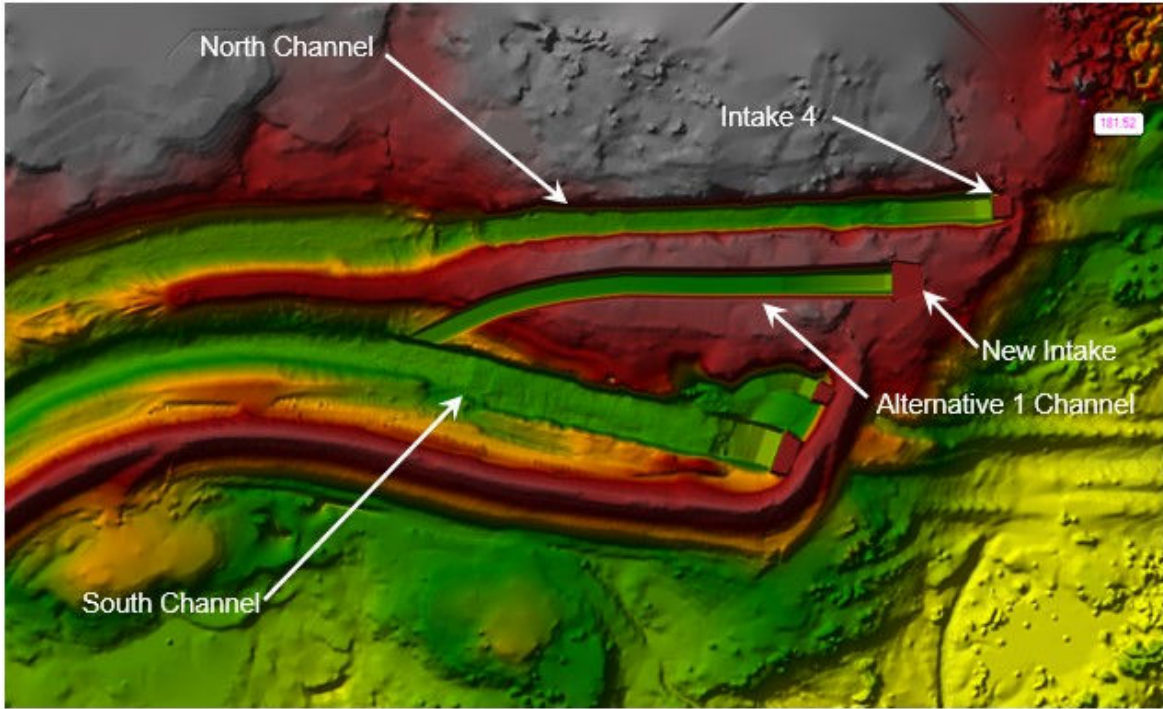


Figure 5-1 - Alternative 1

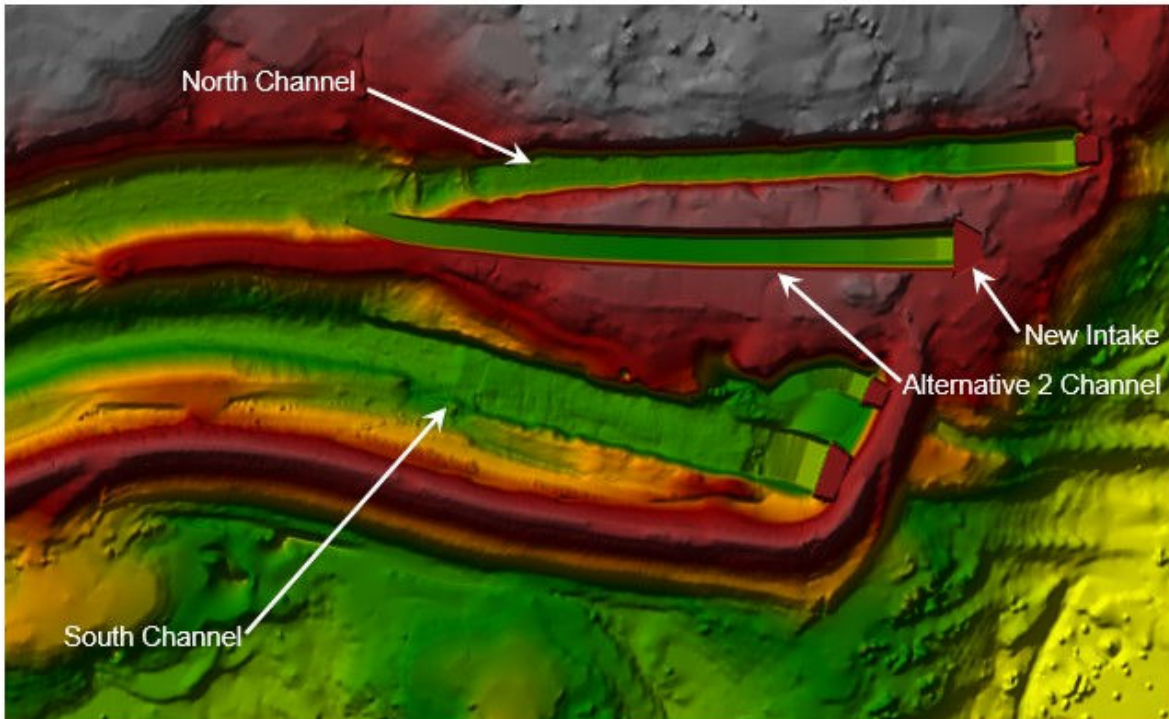
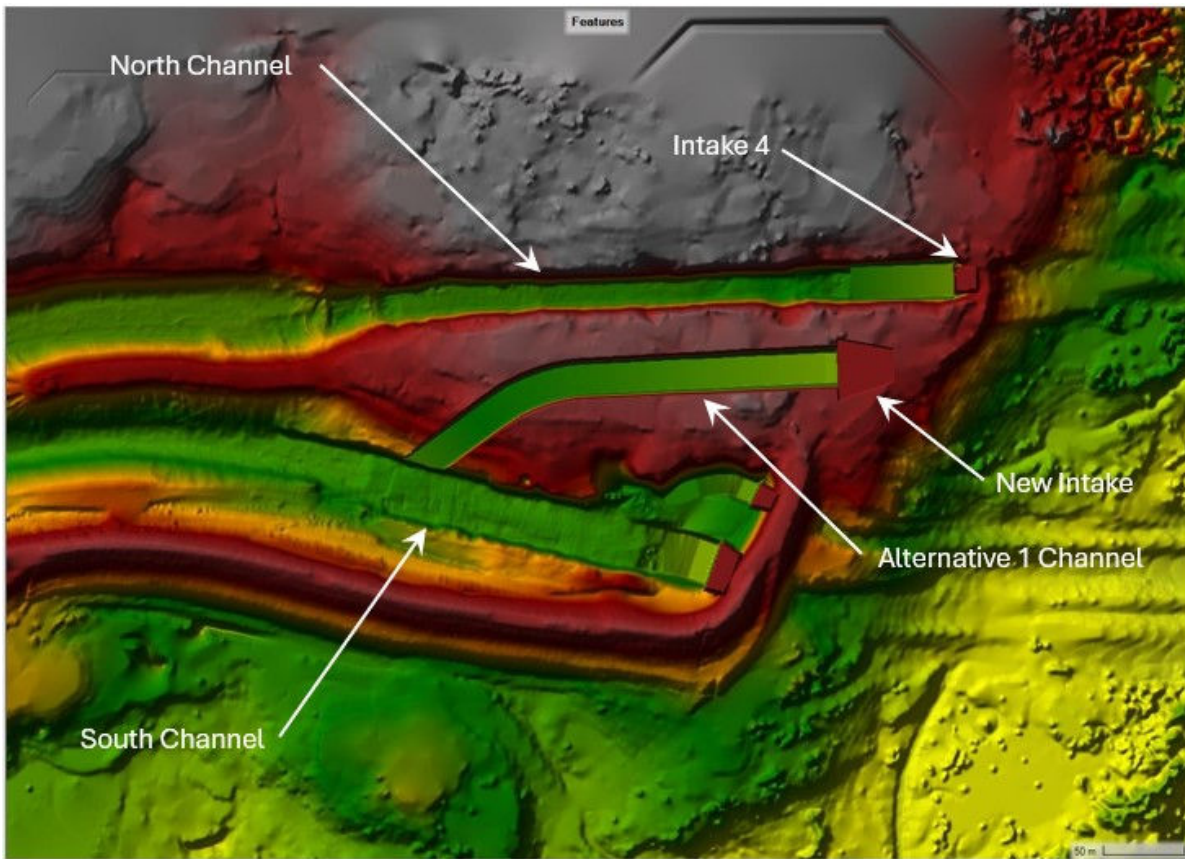


Figure 5-2 - Alternative 2



Further adjustments to Alternative 1 were made to improve flow dynamics at the entrance and along the channel as well as reduce the amount of underwater work required by widening the channel and moving the entrance towards the intakes. The following figure shows the adjusted Alternative 1 layout.



**Figure 5-3 - Alternative 1 - Adjusted**

### 5.1.2 Frazil Ice Consideration

Historically, frazil ice has not been observed at the Long Pond intakes; however, frazil ice was encountered at Intakes 3 and 4 on January 19, 2024, raising concerns that this may be an issue in the future with climate change resulting in a reduction of ice cover formation on the headpond. The normal process for design of a headrace canal incorporates review of the ice regime including frazil ice formation and this 2024 frazil ice event highlighted the importance of that review.

Adjustment to the layout of Alternatives 1 and 2 were completed to reduce velocities and minimize the effect of the new channel on the existing intakes. It was agreed with NL Hydro that the flow conditions in the south channel are preferred and should be emulated in the Unit 8 channel. Adjustments to the width of the new channel were completed to reduce velocities to be more in line with the conditions seen in the south channel. In addition, the entrances were adjusted to determine the most favorable flow conditions.

### 5.1.3 Headworks

The Unit 8 channel was initially developed in the model to match the characteristics of the bedrock section of the Unit 7 channel. According to bathymetry obtained in the headrace channel and Lidar obtained in the area, the average width at the top of the channel is 20 m, the average width at the bottom is approximately 12 m and side slopes are 1H:3V below the typical water surface. The Unit 7 channel also includes a sloped drop in the channel invert approximately 93 m upstream of the intake to meet the elevation of the intake entrance. The Unit 7 intake sill elevation is at 166.00 m (CGVD28), while the design sill elevation for the Unit 8 intake is at 163.00 (CGVD28).

Adjustments to the alternative layouts have generally included decreasing the gradient of the canal side slopes, increasing the bottom width of the channel, increasing the overall width of the new channel, and flaring the entrances in the model. This process has been iterative to mimic conditions that will reduce the likelihood of frazil ice while minimizing construction cost implications as much as possible.

### 5.1.4 Intake

A new intake location was selected to maintain access to Intake 4 via the existing access road downstream of the new intake. This location will also ensure that the canal rock walls are at or above the intake deck.

The submergence at the intake was assumed to be adequate based on Gordon's formula in the 2017 Study. As noted in the 2017 report, the submergence is acceptable at the gate, but the submergence at the trash racks appears slightly deficient at the minimum operating level. To account for this deficiency at this stage of design development, the penstock invert was lowered by approximately 692 mm compared to the penstock invert of the adjacent intakes. A flow 3D model was developed for the new intake configuration and submergence for both the gate and the trash racks were confirmed to meet submergence criteria.

### 5.1.5 Penstock

The penstock alignment and profile were reviewed and are being optimized. The length of the new penstock will be approximately 1100 m long, which is 55 m longer than Penstock 4 due to the new intake location being further upstream than Intake 4.

The overall profile of the new penstock for Unit 8 will be similar to the existing Penstock 4 profile. This design will ensure that the new penstock will not be notably higher or lower than the existing penstock to prevent any foundational loading on the existing penstock. The existing and new penstocks will be parallel from the powerhouse to approximately 320 m upstream of the powerhouse with 18.44 m center to center separation between the existing and the new penstock. Upstream of this point, the new penstock will bend horizontally away from the existing penstock to better line up with the location of the new intake, which is approximately 55 m west and 40 m south of Intake 4.

Since the pressure relief valve from the spiral case is eliminated, the pressure rise due to water hammer will increase from 30% to 50% of static head. The steel penstock thickness increases along the length of the penstock, with the maximum increment close to the powerhouse and progressively reducing for sections away from the powerhouse. The penstock steel will be required to be designed for external loading including transformer shipping loads and other vehicle loads envisaged to cross Unit 8 penstock, during the detailed design.



The ground surface elevations are available from the 2023 Lidar; however, the exact rock profiles along the new penstock are not available. Bedrock depths have been assumed based on lidar, test pit, and borehole data, as well as 1977 as-built information, in the vicinity of the penstock which have been provided by NL Hydro.

### 5.1.6 Tailrace

The existing tailrace channel linking Powerhouse 2 to the tailrace channel of Powerhouse 1 was not intended to accommodate two 150 MW units and therefore tailrace widening is currently undergoing review and optimization.

To minimize future head losses when operating both units simultaneously, widening of the tailrace channel is anticipated and the extent of the widening will be confirmed using Hec-Ras modeling. This widening will also affect the submergence of the new and existing units at Powerhouse 2. The minimum submergence requirements at Lower Low Water Large Tide (LLWLT) for Unit 8 will be determined using the expanded tailrace dimensions. The Unit 7 submergence requirements will also be confirmed given the expanded tailrace dimensions. The tailrace dimensions will be adjusted as necessary to minimize head losses while meeting submergence requirements for both units.

The back water effect in the expanded tailrace will be determined under flood conditions to ensure the powerhouse floor is not flooded during an extreme rainfall or runoff event. The tailwater level for the expanded tailrace will be evaluated with full unit capacity during a 1:1000-year inflow event from Northwest Brook, in conjunction with a Higher High Water Large Tide (HHWLT).

The scope of the tailrace analysis was expanded to include flow impacts and modeling of the tailrace conditions downstream of the Powerhouse 2 tailrace to the bridge located on Highway 361. The downstream flow conditions had not previously been investigated as part of the 2017 Study.

## 5.2 Water-to-Wire (W2W) Equipment

### 5.2.1 W2W Major Equipment

As in the 2017 Study, one vertical shaft Francis turbine of rated capacity corresponding to generator output of 172 MVA (154.4 MW) at rated net head 174.17 m and rated speed of 225 rpm, will be provided as Unit 8 in the powerhouse. The turbine generator components and other heavy components in the powerhouse will be handled by the existing overhead travelling crane with the capacity of 270 metric tons. The rails and bus bars of the existing crane will be extended to cover the Unit 8 powerhouse. The step-up transformer of capacity 172 MVA will be provided outside the powerhouse to step-up the generation voltage from 13.8 kV to line voltage 230 kV.

Numerous optimization options have been evaluated, analyzed, and reviewed for their feasibility, as documented in the Options Analysis Report 699257-2300-40ER-0001. The options retained at this time and approved by NL Hydro for this FEED are described in the subsequent sections.

#### 5.2.1.1 Oil Free Lower Guide Bearing

To prevent the contamination of tailrace water from oil, the turbine guide bearing will be an oil free type and lubricated by filtered clean water. The clean filtered water will be supplied from the cooling water system.



#### 5.2.1.2 Greaseless Wicket Gate Bushing

To prevent grease-induced tailwater pollution and reduce maintenance loads, the wicket gate bushes will be oil free self-lubricating bushing of material PTFE or other self-lubricating material.

#### 5.2.1.3 Mechanical Tensioner Type Fasteners

Mechanical tensioner type fasteners will be installed instead of heat stretch type fasteners for large size bolts in Unit 8.

#### 5.2.1.4 Dust collection System for Collector Rings

A carbon dust collection system for the collector rings will be installed. The dust collector system for the collector ring of generator will extract the carbon dust from source, to avoid dispersion over the machine and dust inhalation by the Operator.

#### 5.2.1.5 Cooling Water Supply

The water for the cooling water system is to be tapped from the penstock. See Section 5.3.7 for details.

#### 5.2.1.6 Runner Model Test

Turbine model test will be conducted by turbine generator supplier to ensure the achievement of the efficiency and the performance guarantees of the turbine.

#### 5.2.1.7 Synchronous Condenser

Synchronous condenser capability will be added to the Unit 8 to allow the generator to export or import the full range of reactive power within the capability of the generator. Unit Control System will interface with the excitation system to start, operate, and stop the synchronous condenser mode operation. The air depression system will be provided to depress the water in the draft tube and run the generator in the condenser mode.

### 5.2.2 Intake Civil Works

The new intake will be a reinforced concrete structure which will vary notably from the existing intakes and the design proposed in the 2017 Study as follows:

- The geometry for the hydraulic passage will be similar to the four existing intakes except that it will be lower in elevation by 692 mm to address submergence concerns.
- The air vent will be incorporated into the intake operating gate slot instead of a separate air vent.
- A hoist house will be provided to permit lifting of the maintenance and intake gates fully out of the guides above the intake deck for maintenance.
- A new intake will be located about 55 m upstream and 40 m to the south of the location of the Unit 7 intake. The intake location has been selected to maintain a minimum of 25 m between the new channel and the existing south edge of the Unit 7 channel.

### 5.2.3 Intake Hydro-Mechanical Equipment

The new water intake will include the following mechanical equipment:

- Two sets of intake trashracks (INTR) with embedded parts (opening dimensions to be confirmed).
- One downstream sealing intake maintenance gate (INMG) and its associated embedded parts will be provided downstream of the center pier replacing two sets of stoplogs, one each side of the center pier, for the original intakes.
- Two sets of dogging devices for INMG, the first set will be used to support the INMG above the deck for maintenance and storage purposes. The second set will be used to secure the INMG in the slot for installation and removal via a mobile crane.
- One upstream sealing intake operation gate (INOG) of the vertical fixed wheel type and associated embedded parts will be provided, as opposed to the downstream sealing gates for the existing intakes.
- Two sets of dogging devices for INOG, the first set will be used to support the INOG above the deck for maintenance purposes. The second set will be used to secure the INOG in the slot for installation and removal of the gate via a mobile crane.
- One wire-rope hoist, mounted and secured on a twin girder mobile overhead bridge structure for the operation of the INOG.
- One wire-rope hoist, mounted and secured on the same twin girder mobile overhead bridge structure for the operation of the INMG.
- One lifting beam for intake trashrack panels.
- Intake trashrack panels and lifting beam storage racks.
- A penstock filling valve system will be installed in the intake structure. The system includes a connection pipe to the upstream reservoir, a connection pipe to the downstream side of the INOG, and a connection pipe to the space between the INMG and INOG. The valves can be operated manually by a long stem actuator, which would be accessible and operable from the intake gate house floor. An alternative method of filling the penstock will be by crack opening of the INOG.

### 5.2.4 Intake Trashracks (INTR)

The concept for the intake trashracks will be generally as described in the 2017 Study Report.

Each trashrack panel can be handled with an estimated 75 metric ton rated mobile crane, and a lifting beam will be provided with the trash racks.

The trashrack panels and the lifting beam will be stored in two trashrack storage racks at the intake deck level.

### 5.2.5 Intake Maintenance Gate (INMG)

A new downstream-sealing, vertical lift slide gate will be provided for the new intake. The INMG is provided for the purpose of isolating downstream water passage for maintenance and will be operated only in balance head conditions.

A fill valve (included in the filling valve system will be provided for filling the space between INOG and INMG. The fill valve will be compliant with work protection requirements lockout/tagout (LOTO) consistent with the INMG being a single point of isolation for the penstock and INOG.

During normal facility operation and when not in use, the INMG will be dogged and stored above the intake deck elevation (connected to its wire-rope hoist). When it is required to transfer the INMG outside



of the hoist house for major overhaul, the INMG will be dogged inside its dedicated slot to be dismantled from the wire-rope hoist and be removed by a mobile crane inside the hoist house through a full height overhead door.

In the event of INMG closure for downstream water passage maintenance, the INOG will be opened in a cracked position (approximately 50 mm opening) to drain the water between the INMG and INOG. To prevent a vacuum, an air vent system with four DN250 air pipes will be used.

An alternative to crack opening of the INOG would be to operate the penstock filling valve system with the addition of a drain pump. This could be discussed and developed further in the detailed design phase.

INMG will be designed to operate as a "single point of isolation" in accordance with Newfoundland and Labrador Occupational Health and Safety (NLOHS) Regulations.

#### **5.2.6 Intake Operating Gate (INOG)**

The new Intake Operating Gate (INOG) will be an upstream sealing gate of the fixed wheel type. The INOG will be used to isolate the penstock or the generating unit from the upstream forebay for inspection or maintenance purposes. It will also be used as the emergency closing device to protect the generating unit in case of a closing fault of the turbine wicket gates and to protect the powerhouse against an eventual flooding originating from the upstream forebay.

During normal operation of the power station, the INOG will remain open hanging from its dedicated hoist right above the penstock opening. The INOG will be maintained in such a position that its bottom edge is located some 300 mm above the lintel, so as not to affect the flow, but ready to be closed in an emergency event such as a generating unit malfunction or a load rejection. A fill valve will be provided for initial filling of the penstock. The gate will also be used in the cracked position (about 200 mm opening) for filling the penstock. The fill valve will be compliant with work protection requirements lock out/tag out (LOTO) consistent with the INOG being a single point of isolation for the penstock.

INOG will be designed to operate as a "single point of isolation" in accordance with NLOHS Regulations.

#### **5.2.7 Intake Mobile Overhead Bridge Structure**

A new custom-designed mobile overhead bridge structure will be provided to support both the INMG and INOG wire-rope hoists. The INMG and INOG wire-rope hoists will be bolted on top of the mobile bridge structure. The mobile overhead bridge structure can travel on a set of runway rails. The runway rails will be installed along the length of the hoist house and will be supported by the structural columns of the hoist house building.

#### **5.2.8 Overhead Travelling Maintenance Crane**

An overhead travelling maintenance crane will be provided to assist with the maintenance of the INOG and INMG wire-rope hoist components, as well as INOG components such as wheels, rollers and seals. The overhead travelling maintenance crane will have an approximate capacity of 2 metric tons and will be located above the intake mobile overhead bridge structure.

### **5.3 Powerhouse**

The powerhouse will be generally as described in the 2017 Study Report except that a service elevator will be installed to access the sub-levels of the powerhouse, and a storage room is proposed for the Unit 8 draft tube gates.



### 5.3.1 Service Elevator

A new service elevator will be provided near the main transformer at Gridline A between Gridline 9-10 (see drawing BDE-AKR-40000-AR-DGA-0006-01). The elevator will have landings at Spiral case access floor, Turbine floor, Generator floor and Main floor. The service elevator will be used for transferring tools and equipment into lower floors. The machine room will be located on top of the elevator. Stairs will be provided to access the machine room. There will also be access provided to the adjacent Unit 7 on each floor.

### 5.3.2 Excavation

The excavation for the powerhouse will be generally as described in the 2017 Study Report except that additional detailed rock excavation will be required to accommodate a service elevator, fire pump room, and a storage room for the draft tube gates. The rock excavation will need to be performed in a manner that will not damage the existing powerhouse.

### 5.3.3 Concrete Infrastructure (under El. 12.2 m)

The concrete for the powerhouse will be generally as described in the 2017 Study Report except that additional concrete will be required to accommodate the new service elevator and the corridors between the elevator and the powerhouse, the fire pump room, and the storage room for the draft tube gates.

### 5.3.4 Steel Superstructure

The concept for the powerhouse superstructure will be generally as described in the 2017 Study Report.

### 5.3.5 Architecture

The architecture for the powerhouse will be generally as described in the 2017 Study Report. The additional elevator, including the machine room and corridors to the elevator, as well as the fire pump room and draft tube gate storage room will be of concrete construction.

### 5.3.6 Generating Unit

The new Unit 8 will be equipped with a Francis type turbine with the following characteristics:

Rated flow:	102 m <sup>3</sup> /s
Gross design head:	179.73 m
Net design head:	174.17 m
Rotating speed:	near 225 rpm

Nominal unit capacity: 154.4 MW (Generator rated output at rated net head)

The digital speed governor, supplied with the turbine, will include a hydro pneumatic reservoir, a sump, and an oil pumping system, as well as all required piping, valves, fittings, and control mechanisms. Since there is no surge tank with the penstock and no pressure relief valve system, to limit the overpressure in the penstocks at the unit to 30% of the gross head, the closing time of the wicket gates, excluding the cushioning, will be set to 16 seconds minimum.



### 5.3.7 Auxiliary Mechanical Systems

The concept for the auxiliary systems of the new powerhouse will be generally as described in the 2017 Study Report except for the following systems:

- Cooling water and raw water systems.
- Fire protection system.
- Heating, Ventilation and Air Conditioning (HVAC) systems.

#### 5.3.7.1 Cooling Water System

Water for cooling the Turbine Generator of Unit 8 will be fed from the raw water pipe with independent branches for the generator air coolers and for turbine and generator bearings.

The turbine guide bearings will be water-lubricated type and the water supply to the turbine guide bearings will be filtered to remove suspended solids of specific gravity 1.2 or higher, and any particles greater than 100 microns.

Cooling water supply to Unit 8 will be controlled by a motorized shut-off valve located on the main cooling water discharge of the Turbine Generator unit.

The flow alarm will be incorporated through flow meters to alert operator for any low flow conditions to turbine generator bearings and the generator air coolers.

#### 5.3.7.2 Raw Water System Pressure Relief Valves (PRV)

There will be two pressure reduction stages via the PRVs in the supply of cooling water to the turbine generator unit. The first stage will reduce the pressure from 1750 kPa to 860 kPa. The second stage will reduce the pressure from 860 kPa to 350 kPa.

In the 2017 Study, the first pressure reduction stage (unfiltered water) and the second pressure reduction stage (filtered water) proposed the use of spring-loaded PRVs. The spring-loaded PRVs for the unfiltered section are more prone to failure, including blockage of pilot valves under conditions of poor water quality. The new PRV system shall consider using safety pin valves over the rupture discs for the pressure relief safety valves. Safety pins can be easily replaced within a short period of time (around 15 minutes) without requirement to remove piping, therefore the integrity of piping system will remain intact. Rupture pins can save loss of valves, disc replacement cost, and labour to replace the disc. This is to be further investigated in the next design phase.

#### 5.3.7.3 Fire Protection System

The fire protection system will be generally as described in the 2017 Study Report except that the fire water for powerhouse Unit 8 is now planned to be supplied from a fire pump station, which includes both main and standby vertical turbine fire pumps. These pumps will draw water from the tailrace water source and will be located on the Generator floor.

The fire pumps will supply water into the sprinkler and hydrant system of Unit 8 as well as an interconnection to the Unit 7 fire protection system.

The design of fire pumps will conform to NFPA 20 standards. The pump will be installed in a room that is separated from the rest of the powerhouse by a barrier with a minimum fire resistance rating of 2 hours.



The fire pump station will be equipped with an isolating valve and a manual cleaning strainer, capable of retaining particles larger than 0.8 mm.

Generators and transformers will be protected by automatic water spray fixed systems (deluge).

An automatic wet pipe sprinkler system (pre-action system) will be used to protect the generator hydraulic power unit (HPU).

In normal operation, a jockey pump, installed in Unit 8 as part of the Unit 8 fire pump station design, will be used to maintain the pressure in the system.

#### 5.3.7.4 Heating, Ventilating and Air Conditioning (HVAC) Systems

The HVAC system will be generally as described in the 2017 Study Report except for the addition, to the above systems, of two roof-top exhaust fans and three louvers, typical to the existing ones, that will be installed to increase ventilation rate and address the cooling load added by Unit 8. This area will have stairway access. In addition, six Unit Heaters will be installed in the Main Floor to operate during the cold season and keep the temperature above the minimum design temperature.

### 5.4 Tailrace Hydro-Mechanical Equipment

The Powerhouse (Tailrace) will include the following hydro-mechanical equipment:

- Two new Draft Tube Gates (DTMG).
- Extended monorail to cover operation of the new DTMGs.
- Upgrade the existing monorail hoist and the rails (if required).
- One Storage Rack for draft tube gates
- Dogging devices.

Two sets of draft tube gates already exist for Unit 7. The gates are of vertical lift sliding gate types with downstream sealing arrangement (considering opposite turbine water flow direction). The Unit 8 new draft tube gates will also be of vertical lift sliding types with downstream sealing arrangement.

Two new sets of DTMGs will be provided for Unit 8. These new sets will be similar to the existing Unit 7 gates and use the existing embedded parts. The draft tube will be watered up through a new set of pipes and valves to allow the draft tube gates to operate under equal pressure.

Unit 7 existing gates are stored in a room under the existing service bay and can be maneuvered with a monorail hoist that currently services only the draft tube gates of Unit 7.

The new Unit 8 DTMGs will be provided using the existing monorail hoist via an extension of the existing monorail. The existing monorail will be extended and if required, can be upgraded to a higher capacity where possible. DTMGs will be stored inside a new storage room designated for Unit 8. New DTMGs will be designed to be interchangeable with the existing draft tube gates of Unit 7.

The new set of DTMGs for Unit 8 will be provided prior to start of Unit 8 construction to ensure that the existing set can be used for the operation and maintenance of Unit 7.

Once construction of Unit 8 is completed, the monorail beam will have to be extended to service the slots for Unit 8. To initiate the excavation of Unit 8, new DTMGs must be constructed in advance to isolate the construction area.



Embedded parts for Unit 8 DTMGs already exist although their condition needs to be verified in the next project design phase.

## 5.5 Electrical Systems

The electrical systems will be generally as described in the 2017 Study Report except for the supply and installation of a new emergency generator.

### 5.5.1 Emergency Diesel Generator

An emergency diesel generator will be provided for emergency services including black start. The diesel generator set will be complete with all accessories for local and remote control starting and stopping, as well as metering and protection.

Diesel generator set will be stand-alone inclusive of its own enclosure, engine, generator, governor, cooling, fuel tank, air, protection and control system.

The diesel generator will be integrated with station services supply. On loss of station service supply, an undervoltage relay will start the diesel generator set to supply the essential loads for periods when the auxiliary supply is not available. The diesel generator set will be installed at the proposed service floor elevation, preferably behind the battery room location.

Please refer to drawing of AC Station Service System Single Line Diagram (BDE-AKR-50000-EL-DSD-0001-01) for integration of Diesel generator with station services supply and drawing of General Arrangement Main Floor – Plan Unit 7 & 8 (BDE-AKR-40000-AR-DGA-0005-01) for location of Diesel generator in the layout.

## 5.6 Terminal Station No. 2

The Terminal Station No. 2 will be generally as described in the 2017 Study Report.

Due to change in the transmission line route provided by NL Hydro, from generating Unit 8 to Terminal Station no. 2, the single line diagram, electrical layout plan and sections drawings of Terminal station no. 2 have been modified. As a result of the transmission line route change and the buried grounding, surface grounding drawings of Terminal Station No. 2 have also been revised to incorporate the new connection point for generating Unit 8.

Surface grounding drawing of Terminal Station No. 2 have been revised to incorporate the new connection point for generating Unit 8.

Please refer to buried grounding and surface grounding drawings of Terminal Station No. 2 (BDE-AKR-51000-EL-DES-0001-01 and BDE-AKR-51000-EL-DES-0002-01).

## 5.7 Geology

### 5.7.1 Geotechnical Investigations

The Unit 8 Geotechnical Investigation program was carried out by WSP, and the final report (NLH Document Number 07965-A99-0003) was provided by NL Hydro to AtkinsRéalis in June 2024. The results of this report were used for site characterization. This program includes twenty-four (24) boreholes and sixteen (16) test pits as presented in the table below.

**Table 5-1 – Geotechnical Investigations Undertaken**

<b>Description of Test</b>	<b>No.</b>	<b>Details</b>
<i>Boreholes</i>	24	
<i>Test pit excavations (4 - 4.5 m deep)</i>	16	
<i>Standard Penetration Test SPT</i>	23	All boreholes, except Intake structure 5 (bedrock encountered near surface).
<i>Piezometer Installation</i>	10	BH-03-23, BH-05-23, BH-06-23, BH-08-23, BH-10-23, BH-12-23, BH-14-23, BH-16-23, BH-17-23, and BH-17A-23
<i>Packer Testing</i>	1	Only in BH-03-23: at area proposed in 2017 for temporary rock plug.
<i>Field Vane Shear Testing</i>	2	Only in BH-22-23 and BH-23-23: within Tailrace enlargement.
<i>Laboratory Testing for Soil samples</i>	-	Gradation, Atterberg limits and moisture content.
<i>Laboratory Testing for Rock Samples</i>	-	UCS and unit weight.

## 6 CONCLUSION

In summary, this update to the concept design report reflects a comprehensive and strategic approach to expanding the facility's generation capacity by the addition of a new Unit 8. The report reflects the concept design work completed during the Front-End Engineering Design (FEED) phase of the project, providing support for the application for project funding approval to the PUB and to advance the design documentation for the next project phase.

This update represents a step in the project's progression, ensuring that all engineering and design elements are aligned with the latest technical and regulatory requirements. With an optimized design, the Bay d'Espoir Unit 8 project is well-positioned to proceed into its next phase, ultimately enhancing the BDE facility's power generation capacity, operational efficiency, and long-term reliability.



1 Q. The scheme is adding another 100m<sup>3</sup>/s potential discharge to a 400m<sup>3</sup>/s on an 839 Mm<sup>3</sup>  
2 reservoir. This means that at full capacity of all the units working simultaneously, the reservoir  
3 could be drawn down from initial 24 days down to 19 days. We will assume for purposes of this  
4 question that this is not an issue on a water resources level (considering also the upper  
5 reservoirs). On the hydraulic level, the Min W.L. vs intake geometry seems to be appropriate to  
6 avoid vorticity issues based on a preliminary assessment. Can you confirm this is not a  
7 problem/has been already considered in the design? Please explain and provide any supporting  
8 evidence.

9

10

11 A. Please refer to BW-NLH-006, Attachment 1, "*Concept Design Update Report*" (Document # BDE-  
12 SN-40000-EN-DEG-0002-01), completed by the front-end engineering design consultant in  
13 November 2024, which confirms the adequacy of submergence and discusses the methods  
14 employed in the design of the current iteration of the intake in Section 5.1.4.

1 Q. In order to ensure continuous amount of water through the system, has the impact of  
2 potentially releasing additional 100m<sup>3</sup>/s been evaluated? Please provide the design capacity of  
3 the various control structures throughout the cascade.

4

5

6 A. An additional release of 100 m<sup>3</sup>/s is within the discharge capacity of the control structures and  
7 spillway structures upstream of the Long Pond Reservoir, based on their design rating curves,  
8 which have been validated by decades of operating experience. The North Salmon Spillway has a  
9 discharge capacity of 1,021 m<sup>3</sup>/s at the maximum operating level in Great Burnt Lake. The  
10 Ebbegunbaeg Control Structure has a discharge capacity of 525 m<sup>3</sup>/s at the maximum operating  
11 level in Meelpaeg Reservoir. The rated flow of the Upper Salmon turbine at maximum load  
12 (84 MW) is 189.5 m<sup>3</sup>/s. The Ebbegunbaeg Control Structure can release a total discharge of  
13 290 m<sup>3</sup>/s with two of its three gates approximately 75% open, which will supply the maximum  
14 turbine flow at Upper Salmon plus a 100 m<sup>3</sup>/s bypass flow at the North Salmon Spillway.  
15 Ebbegunbaeg Control Structure would have up to 235 m<sup>3</sup>/s of discharge capacity remaining after  
16 matching the flow required at Upper Salmon and the North Salmon Spillway. The North Salmon  
17 Spillway can release a discharge of 100 m<sup>3</sup>/s with one of its three gates approximately 20%  
18 open. The Bay d'Espoir Plant has a total maximum turbine flow of approximately 394 m<sup>3</sup>/s with  
19 all seven units running at rated capacity. This would increase to approximately 494 m<sup>3</sup>/s,  
20 assuming an eighth unit at the plant has similar operating characteristics to the existing Unit 7.  
21 Therefore, the discharge capacity of the Ebbegunbaeg Control Structure would still exceed the  
22 maximum flow at the Bay d'Espoir Plant with an eighth unit.

1 Q. Hydro has an active application before the Board regarding potential refurbishment of Bay  
2 d'Espoir Unit 7.

3 a) In the "Bay d'Espoir Unit 7 Additional Analysis Report" filed September 23, 2025 in that  
4 docket, NLH states on page 2 that "As a result of the system hydrology on the Bay  
5 d'Espoir system and the optimized maximized capacity addition to the system of 150  
6 MW, the uprating of Unit 7 may necessitate lowering the nominal capacity of Unit 8 by  
7 approximately 20 MW to 130 MW."

8 i. Please explain what Hydro means here by "system hydrology," with reference to  
9 how system hydrology impacts the potential capacity sizing of Unit 8 assuming  
10 Unit 7 is uprated.

11 ii. Is it Hydro's position that the system hydrology cannot support the addition of  
12 more than 150 MW at Bay d'Espoir, relative to its current capacity? If not,  
13 please explain.

14 b) In the "Bay d'Espoir Unit 7 Additional Analysis Report," at "Attachment 2" (the GE  
15 Report from 2004), filed September 23, 2025 in that docket, GE states: "As an  
16 illustration of the significance of [Figure 3], what it indicates is that we could make use  
17 of 15 MW of additional MW of capacity only 20% of the time and 5 additional MW of  
18 capacity 90% of the time. The limitations inherent in the design of the proposed runner  
19 are apparent from this curve, especially when one considers that high tide will not  
20 necessarily coincide with system peak, which is when the additional capacity offered by  
21 the proposed runner would be of most use...To summarize, although GE Hydro has  
22 offered a runner with greater capacity, tail water elevation severely limits the usefulness  
23 of this additional capacity...The amount of additional capacity offered is considered to  
24 be 5 MW."

25 i. Do the limitations discussed by GE in the referenced report have implications  
26 for the benefits and/or operational capabilities of proposed BDE 8? Please  
27 explain.

1 A. a) “System hydrology” refers to the available water resources and hydraulic capacity of the  
2 entire Bay d’Espoir System, including reservoir inflows, storage, head, and discharge limits  
3 through the power canal, penstocks, and tailrace.<sup>1</sup> It defines how much additional  
4 generation the system can support without diminishing efficiency or firm energy.

5 According to the 2025 Hydrology and Feasibility Study for Potential Bay d’Espoir Unit 8,  
6 provided in the 2025 Build Application,<sup>2</sup> Hatch Ltd. modelled 73 years of inflow and  
7 operational data to quantify the effect of adding a new unit. The study determined that the  
8 optimized increase in Bay d’Espoir Plant output was approximately 150.1 MW, even though  
9 the nameplate rating of Unit 8 is 154.4 MW.

10 The simulated hourly optimized generation capacity increase at the Bay d’Espoir  
11 plant is 150.1 MW with addition of Unit 8...because the model optimizes the  
12 total Bay d’Espoir plant output to meet the defined firm load while maximizing  
13 energy. The increase in simulated on-peak generation is at the expense of  
14 simulated off-peak generation.<sup>3</sup>

15 The report further explains that when the Bay d’Espoir System is modelled in isolation, its  
16 hydrology constrains total effective capacity. Newfoundland and Labrador Hydro’s (“Hydro”)  
17 reference to “system hydrology” therefore means that the finite water supply and hydraulic  
18 head shared among all Bay d’Espoir units limit total plant output, which defines the  
19 optimized plant capacity. The report also notes, however, that the full 154.4 MW output of  
20 Unit 8 could likely be achieved through optimization of Hydro’s broader energy resources.

21 Therefore, Hydro’s position is that the Bay d’Espoir system hydrology presently supports  
22 approximately 150 MW of additional generating capacity as an optimized limit under  
23 current operating assumptions. That figure represents the amount of incremental capacity  
24 the system can efficiently utilize without reducing firm energy or overall efficiency.

25 b) Yes. The tailwater elevation at Powerhouse 2 does have implications for the benefits and/or  
26 operational capabilities of the proposed Bay d’Espoir Unit 8. The scope of the proposed Bay

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<sup>1</sup> “Bay d’Espoir Unit 7 Additional Analysis Report,” Newfoundland and Labrador Hydro, rev. September 23, 2025 (originally filed September 22, 2025).

<sup>2</sup> “2025 Build Application – Bay d’Espoir Unit 8 and Avalon Combustion Turbine,” Newfoundland and Labrador Hydro, March 21, 2025, sch. 1, att. 2.

<sup>3</sup> “Hydrology and Feasibility Study for Potential Bay d’Espoir Hydroelectric Generating Unit No. 8,” Hatch Ltd., March 17, 2025, Executive Summary, p. iv.

1 d'Espoir Unit 8 Project includes the necessary modifications to Powerhouse 2 tailrace to  
2 maintain operation of both the existing Bay d'Espoir Unit 7 and the proposed Bay d'Espoir  
3 Unit 8 within expected tailrace water level design limits. For more information on the  
4 studies and design supporting tailrace optimization, please refer to Hydro's response to  
5 BW-NLH-005. Additionally, the runner for the proposed Bay d'Espoir Unit 8 is to be designed  
6 and guaranteed based on the technical characteristics and operational limits of the site and  
7 facility to mitigate against any negative implications.

1 Q. In Hydro’s BDE 7 Life Extension Application, Schedule 1, Attachment 1, page 14, footnote 11,  
2 Hydro states: “BDE Unit 8 Project EPCM Contractor selection process includes the opportunity to  
3 support (where needed) the various BDE facility Major Projects under consideration. For the  
4 BDE Unit 7 Project, utilizing a site-wide Construction Management Contractor would provide  
5 synergies.”

6 a) Are the costs of these support activities included in BDE 8’s cost estimate? Please  
7 provide a reference to the cost estimate line item and total cost of those support  
8 services.

9 b) According to the Build Application, Schedule 1 (“Application Overview—Bay d’Espoir  
10 Unit 8 and Avalon Combustion Turbine”), Table 2, Hydro was scheduled to “award EPCM  
11 contract” by “Q3 2025.” Is that milestone achieved, and if so, please explain the EPCM’s  
12 scope and incremental cost as it relates to any services, support, or coordination with  
13 the BDE 7 refurbishment project.

14

15

16 A. a) The Bay d’Espoir (“BDE”) Unit 8 cost estimate does not include Engineering, Procurement,  
17 and Construction Management (“EPCM”) support activities for the BDE Unit 7 Life Extension  
18 Project. EPCM support activities for the BDE Unit 7 Life Extension Project are included in the  
19 estimate for that project.<sup>1</sup> With respect to cost control during project execution, a work  
20 breakdown structure would be established to account for the EPCM contractor costs for  
21 each project separately.

22 b) The milestone has not yet been achieved. Newfoundland and Labrador Hydro (“Hydro”)  
23 issued a Request for Proposals (“RFP”) for the EPCM services for BDE Unit 8 on  
24 June 13, 2025, which closed on September 18, 2025. Proposals for the EPCM contract have  
25 been received and are under evaluation, with selection of the EPCM contractor now

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<sup>1</sup> Please refer to “Life Extension Application – Bay d’Espoir Unit 7,” Newfoundland and Labrador Hydro, June 20, 2025, sch. 1, att. 1, Table 7.

1 anticipated in the fourth quarter of 2025. The EPCM scope of services for the BDE Unit 7 Life  
2 Extension Project includes:

- 3 **1.** Engineering review and support during OEM/life extension contractor design and  
4 procurement phase.
- 5 **2.** Construction management, project management, and post-award contract  
6 administration support.
- 7 **3.** Completion, commissioning, start-up support, and ready for operations support.

8 There are no anticipated incremental costs to either the BDE Unit 7 Project or BDE Unit 8  
9 Project, as each of the project cost estimates was prepared as if they were executed  
10 independently. Also, the EPCM RFP identifies the scope of services for each project  
11 separately, so that the cost for each can be identified.

12 Integrating elements of the management of BDE Unit 7 and BDE Unit 8 scopes presents an  
13 opportunity for potential savings due to improved interface management and optimized  
14 EPCM services, which should reduce schedule risks and associated cost risks for each of the  
15 projects.

- 1 Q. In Hydro’s BDE 7 Life Extension Application, Schedule 1, Attachment 2, page 5, Hydro states:  
2 “Management of Unit 7 scope may be integrated with the Unit 8 Project, if approved. Both  
3 Projects are in Powerhouse 2 with overlap in the execution timing which will require  
4 coordination between the teams and may provide opportunities for resource sharing.
- 5       **a)** When will Hydro decide if the “management of Unit 7 scope” will be “integrated with  
6 the Unit 8 project”? Are there costs associated with this decision? Please explain.
- 7       **b)** To the extent work on the two projects becomes, even temporarily, mutually exclusive  
8 (i.e., that Hydro may only progress on one of the two projects), which project takes  
9 priority? Is it BDE 7’s refurbishment, as suggested in Schedule 1, Attachment 3, page 12  
10 of the Life Extension Application? Please explain.
- 11       **c)** The BDE 7 Life Extension project schedule specifies that the start of the outage window  
12 for BDE 7 is April 1, 2028 through October 31, 2028 (see BDE 7 Life Extension  
13 Application, Schedule 1, Attachment 3, page 13). The BDE 8 Build Application specifies  
14 April 4, 2028 as the start of construction (see Build Application, Schedule 4, Appendix B,  
15 page B-1).
- 16           **i.** Please explain the work that must be completed for the BDE 8 project by  
17 October 31, 2028 (the end date of BDE 7’s outage window).
- 18           **ii.** If the work identified in (i) is not completed by the end of BDE 7’s outage  
19 window, please explain the impacts to BDE 7’s commissioning date and the  
20 steps Hydro would take to manage both projects. Is this a material risk in  
21 Hydro’s view? For example, at BDE 7 Life Extension Application, Schedule 1,  
22 Attachment 3, page 17, Hydro states that construction durations are based on  
23 “actual daily reports from previous projects,” and that those assumptions “will  
24 be removed when the OEM Contractor is selected and detailed construction  
25 schedules are provided,” suggesting that construction schedules are uncertain  
26 and may change. Please explain.
- 27           **iii.** Please identify any impacts on BDE 8’s project schedule if BDE 7’s outage  
28 window starts later than April 1, 2028.

1           **iv.**     Please identify any impacts on BDE 8’s project schedule if work on BDE 7 is not  
2                     complete by October 31, 2028 (or, by the end of the “2028 construction season,  
3                     which has the basis that BDE Unit 7 can only be taken offline during the non-  
4                     winter load period (April 1 to October 31),” as stated at BDE 7 Life Extension  
5                     Application, Schedule 1, Attachment 3, page 18.

6  
7  
8    A.     **a)**    A final decision to integrate the management of the Bay d’Espoir (“BDE”) Unit 7 and BDE  
9                     Unit 8 projects ultimately depends on receiving Board of Commissioners of Public Utilities  
10                    approval for both proposed build applications. However, integrating the management of the  
11                    BDE Unit 7 and BDE Unit 8 projects presents a significant opportunity to improve interface  
12                    management and optimize Engineering, Procurement, and Construction Management  
13                    (“EPCM”) services, which is anticipated to reduce schedule risks and the associated cost  
14                    risks for each of the projects. The primary benefits include:

- 15                    **1)** Streamlined interface management.
- 16                    **2)** Simplified procurement process.
- 17                    **3)** Optimization of EPCM service personnel (reduced duplication of personnel  
18                    positions).
- 19                    **4)** Optimization of efforts related to specific scopes (e.g., health and safety  
20                    services, emergency services, site access, and security).
- 21                    **5)** Simplified contract administration.
- 22                    **6)** Simplified project controls coordination.
- 23                    **7)** Coordinated construction management.

24                    With respect to costs associated with this decision, there is an opportunity for cost savings  
25                    associated with the efficiencies noted above, and there should be no incremental cost to  
26                    either project, as each of the project cost estimates was prepared as if they were executed  
27                    independently.

1 To preserve this opportunity while a final decision is pending, the EPCM Request for  
2 Proposals that has been issued identifies the scope of services for each project separately,  
3 so that the cost for each project is identifiable and Hydro maintains the options for how to  
4 proceed.

5 **b)** If work on the BDE Unit 7 Life Extension Project and the BDE Unit 8 Project were to become,  
6 even temporarily, mutually exclusive, Newfoundland and Labrador Hydro (“Hydro”)  
7 confirms that the BDE Unit 7 Life Extension Project would take priority, consistent with the  
8 evidence provided in the Life Extension Application.<sup>1</sup>

9 Deferral of the BDE Unit 7 work is not a viable option. As outlined in the 2019 inspection and  
10 2023 Condition Assessment,<sup>2</sup> the unit requires significant refurbishment within the next five  
11 years to ensure the continued reliable operation of this 154 MW generating unit. Deferral  
12 presents an unacceptable risk to the reliable operation of the Island Interconnected System,  
13 as a forced outage of BDE Unit 7 could extend for up to two years, given current equipment  
14 lead times. The continued reliable operation of BDE Unit 7 is essential to support system  
15 demand, provide synchronous condenser capability, and facilitate planned outages required  
16 to complete maintenance and capital work across the remainder of the generating fleet.

17 Hydro notes that both the BDE Unit 7 Life Extension Project and the BDE Unit 8 Project are  
18 required to support the continued reliability and long-term capacity needs of the Island  
19 Interconnected System. The timing and execution of Unit 7’s life extension work must be  
20 coordinated with the commencement of Unit 8 construction in 2028 to minimize schedule  
21 and productivity impacts at Powerhouse 2. Completion of the Unit 7 refurbishment within  
22 this period reduces the risk of unplanned outages, ensures continued system reliability, and  
23 allows Unit 8 construction activities, representing necessary new capacity for the system to  
24 proceed without interference.

25 Hydro views these projects as complementary and collectively necessary. The Unit 7 Life  
26 Extension Project is required to maintain the reliability and operational flexibility of existing

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<sup>1</sup> “Life Extension Application – Bay d’Espoir Unit 7,” Newfoundland and Labrador Hydro, June 20, 2025.

<sup>2</sup> “Bay D’Espoir Unit 7 Condition Assessment Condition Report,” Hatch Ltd., Rev B0, May 3, 2024.

1 generation assets, while the Unit 8 Project is required to meet future capacity needs and  
2 enhance the overall resilience of the system.

3 c) i. The tailrace excavation and widening associated with the Unit 8 Project are planned to  
4 take place during the extended outage of Unit 7 in 2028. This will help mitigate potential  
5 environmental impacts associated with the in-stream excavation work by timing the  
6 work to take place when tailrace water flows are minimized while Unit 7 is offline.

7 ii. If work identified in item i. above is not completed within the 2028 Unit 7 outage  
8 window, it would delay final commissioning and start-up of Unit 7, as the Unit 8 scope  
9 involves work in the tailrace, which requires Unit 7 to be offline as described in item i.  
10 above. With the current execution plan, [REDACTED]

11 [REDACTED]  
12 [REDACTED]  
13 [REDACTED]

14 The Unit 7 outage window was established to coincide with the non-winter load period  
15 between April 1 and October 31. The planned construction duration for Unit 7, which  
16 was developed based on historical information, including progress reports for similar  
17 projects, was intended to provide a realistic planning baseline that would fit within the  
18 outage window. The procurement process for engagement of original equipment  
19 manufacturers contractors requires submission of execution schedules with their  
20 proposals, which will factor into the evaluation of proposals and selection of the  
21 contractor. Once the contract is awarded, which is expected in the first quarter of 2026,  
22 the contractor will prepare a detailed construction schedule, which will be constrained  
23 to the planned outage window.

24 iii. [REDACTED]  
25 [REDACTED]  
26 [REDACTED]  
27 [REDACTED]  
28 [REDACTED]

1           However, with respect to the Unit 7 schedule, should there be a delay in the  
2           commencement of the Unit 7 construction activities in 2028, there is a potential that  
3           the Unit 7 work would not be able to be completed within the non-winter load period  
4           by October 31. If a delayed start were to occur, a decision would need to be made  
5           whether to proceed in 2028 or defer the work to the non-winter load period in 2029.  
6           This decision would need to be evaluated and informed by contractor execution plans,  
7           interface considerations, risk assessments, a detailed review of the system-wide outage,  
8           maintenance plans, and system-wide generation availability. The potential impact of this  
9           on Unit 8 is described in item iv. below.

10          **iv.** The primary schedule dependency for Unit 8 related to the 2028 Unit 7 outage is the  
11          tailrace widening work. [REDACTED]

12          [REDACTED] Therefore, an extension of the Unit 7 outage window beyond  
13          October 31, 2028, should not impact the Unit 8 schedule, assuming that the work is  
14          started in 2028.

15          However, as noted in item iii. above, should there be a delay in the commencement of  
16          the Unit 7 construction activities in 2028, there is a potential that the Unit 7 work would  
17          not be able to be completed within the non-winter load period by October 31, 2028. If a  
18          delayed start were to occur, a decision would need to be made whether to proceed in  
19          2028 or defer the work to the non-winter load period in 2029. As the BDE Unit 8 Project  
20          is a multi-year project, [REDACTED]

21          [REDACTED] However, should the  
22          Unit 7 outage be moved to 2029, other interfaces with Unit 8 would be introduced.

23          For example, the current plan to have the Unit 7 work completed in 2028 allows for the  
24          work to be completed in the existing section of Powerhouse 2 with a physical separation  
25          from the Unit 8 exterior work. If the Unit 7 work is moved to 2029, it would create a  
26          physical interface with the Unit 8 Powerhouse 2 extension work, which involves the  
27          removal of the existing Powerhouse 2 wall and the extension of the existing overhead  
28          crane rails into the building expansion area. This interface would likely introduce the  
29          following issues for both projects:



1 Q. In fuel mix for the proposed CT projects, does Hydro plan to include SCR and CO Catalyst in the  
2 exhaust to reduce emission as low as possible?

3

4

5 A. Newfoundland and Labrador Hydro (“Hydro”) submitted and received approval from the  
6 Department of Environment and Climate Change for the Best Available Control Technology  
7 (“BACT”) requirements for the Avalon Combustion Turbine (“CT”) Project as part of its  
8 Environmental Release on September 9, 2025. As part of the submission, Hydro provided a BACT  
9 report developed by Independent Environmental Consultants.<sup>1</sup> The report outlines several  
10 different options available for NOx<sup>2</sup> control, including Selective Catalytic Reduction (“SCR”). The  
11 use of an SCR is less economical and requires the use of ammonia as a catalyst. Use of ammonia  
12 will pose more technical challenges for storage, capital cost, and maintenance. The use of water  
13 injection technology is more economically feasible, and Hydro currently has operating  
14 experience with this model at the existing Holyrood CT. The Avalon CT is planned as an  
15 emergency backup facility for the grid and is estimated to operate for 400 hours per year. Hydro  
16 will therefore use water injection technology for the Avalon CT facility.

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<sup>1</sup> Please refer to “Best Available Control Technology Assessment,” Independent Environmental Consultants, March 21, 2025, provided within Attachment 8 to “Application for Capital Expenditures for the Purchase and Installation of Bay d’Espoir Unit 8 and Avalon Combustion Turbine – Documents Placed on the Record – Hydro’s Reply,” Newfoundland and Labrador Hydro, June 13, 2025.

<sup>2</sup> Nitrogen oxides (“NOx”).

1 Q. Please provide the list of spare parts expected to be in inventory at the Avalon CT facility along  
2 with the details and cost. This is for all parts including CAPEX and CT.

3

4

5 A. While the estimate includes an allocation for spare components, this estimate is not based on  
6 an itemized list, which is dependent on the detailed design of the Avalon Combustion Turbine.  
7 The Engineering, Procurement, and Construction Management contractor, as part of the service,  
8 will provide detailed design and procurement package development for the project. Once the  
9 detailed design and procurement of project materials are complete, a comprehensive spare  
10 parts inventory list will be developed. At this time, Newfoundland and Labrador Hydro has  
11 identified that a spare oil-filled transformer will be provided as part of the project and  
12 confirmed in the response to BW-NLH-015.

1 Q. How many spare oil filled transformers are expected to be purchased and kept on site with the  
2 Avalon CT?

3

4

5 A. Newfoundland and Labrador Hydro will procure one spare 50/66.6/83.3 MVA Generator Step-  
6 Up Transformer for the Avalon Combustion Turbine.

1 Q. Will the Avalon CT facility have a Service Agreement with the CT provider, and if so, what is  
2 expected to be covered by the Agreement and what are the expected costs?

3

4

5 A. The Request for Proposals for the combustion turbine procurement includes the solicitation of  
6 proposals and associated pricing associated with a Long-Term Service Agreement (“LTSA”).  
7 Typical coverage includes parts, technical advisory services, inspection and repair services.  
8 Newfoundland and Labrador Hydro is continuing to evaluate proposal information, which  
9 includes the evaluation of proposed LTSA responses.

1 Q. Will the Avalon CT facility participate in a Lease CT program with the CT provider and what is the  
2 expected cost? If not is there any plan to purchase a spare CT?

3

4

5 A. The Request for Proposals for the combustion turbine (“CT”) procurement includes the  
6 solicitation of proposals and associated pricing associated with a Long-Term Service Agreement  
7 (“LTSA”). Newfoundland and Labrador Hydro does not intend to purchase a spare CT; however,  
8 is continuing to evaluate the LTSA proposal information, which includes the evaluation of lease  
9 engine options.

1 Q. Regarding fueling for the Avalon CT:

2 a) Will the fuel system at the Avalon CT have the equipment to allow the use of fuel  
3 additives, including biocides?

4 b) Will the fuel system for the Avalon CT include equipment to improve the quality of the  
5 fuel such as centrifuges and filtration?

6 c) Will the fuel system at the Avalon CT provide the means to circulate the fuel when the  
7 units have not been operating to allow for cleaning of the fuel?

8 d) As means to obviate uneconomic fuel burn off, has Hydro evaluated the use of biocides,  
9 recirculating, cleaning and sampling fuel?

10 e) Are there additional factors that would limit the applicability or effectiveness of  
11 strategies to avoid uneconomic fuel burn off, such as those noted in 19.d, and limit  
12 storage periods for fuel at the Avalon CT location?

13

14

15 A. The use of fuel additives such as biocides and practices such as recirculation and fuel cleaning  
16 will be assessed during the detailed design phase. Newfoundland and Labrador Hydro plans to  
17 award an Engineering, Procurement, and Construction Management contract by the end of the  
18 second quarter of 2026 so that detailed design can begin and further mature the diesel fuel  
19 system.

20 Additionally, a fuel segregation study is underway to determine possible fueling scenarios  
21 whereby existing or new fuel tanks could be potentially managed by third-party fuel suppliers to  
22 mitigate fuel quality concerns and reduce burn off. A new Expression of Interest for potential  
23 third-party partners could potentially help with fuel management and storage.

Gruner Stucky SA

Fadi Hachem  
Project Committee

Luca Cotterle  
Project Manager

## Appendix C. Matrix of critical scenarios tested by Hydro

Scenario	Load Forecast	Description
1AEK	Reference	Fixed wind profile to meet firm energy criteria Remove Batteries as a resource option Include Newfoundland Power GT additions
1AK	Reference	Fixed wind profile to meet firm energy criteria Include Newfoundland Power GT additions
4A	Slow Decarbonization	Fixed wind profile to meet firm energy criteria
4AC	Slow Decarbonization	Fixed wind profile to meet firm energy criteria Remove forced Avalon CT fuel burn-off
4ADH	Slow Decarbonization	Fixed wind profile to meet firm energy criteria Increase BDE Unit 8 and Avalon CT costs to P85
4AEF	Slow Decarbonization	Fixed wind profile to meet firm energy criteria Remove batteries as a resource option Restrict CT additions to maximum of 150 MW
4AEF (ADV)	Slow Decarbonization	Fixed wind profile to meet firm energy criteria Remove batteries as a resource option Restrict CT additions to maximum of 150 MW Advance second capacity resource from 2034 to 2031
4AEFC	Slow Decarbonization	Fixed wind profile to meet firm energy criteria Remove batteries as a resource option Restrict CT additions to maximum of 150 MW Remove forced Avalon CT fuel burn-off
4AEFDH	Slow Decarbonization	Fixed wind profile to meet firm energy criteria Remove batteries as a resource option Restrict CT additions to maximum of 150 MW Increase BDE Unit 8 and Avalon CT costs to P85
4AEK	Slow Decarbonization	Fixed wind profile to meet firm energy criteria Remove batteries as a resource option Include Newfoundland Power GT additions
4AK	Slow Decarbonization	Fixed wind profile to meet firm energy criteria Include Newfoundland Power GT additions