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 ADDENDUM REPORT OF VINCENT MUSCO AND COLLIN CAIN

June 5, 2026

Confidential

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Abbreviations and defined terms used in report

AACE – Association for the Advancement of Cost Engineering

Avalon CT – Avalon Combustion Turbine

Batess White – Bates White Economic Consulting, LLC

BDE Unit 8 – Bay d'Espoir Unit 8

BESS – Battery Energy Storage Systems

Board – Newfoundland and Labrador Board of Commissioners of Public Utilities

CAMS – Consolidated Asset Management Services

CT – Combustion Turbine

ELCC – Electric Load Carrying Capability

EPCM – Engineering, Procurement and Construction Management

EqFOR – Equivalent Forced Outage Rates

FEED – Front End Engineering and Design

Gruner – Gruner Stucky AG

GT – Gas Turbine

Holyrood TGS – Holyrood Thermal Generating Station

Hydro – Newfoundland Labrador Hydro

IDC – Interest During Construction

IIS – Newfoundland Island Interconnected System

IRs – Information Requests

kV – Kilovolt

LIL – Labrador Island Link

Muskrat Falls – Muskrat Falls Generating Station

MW – Megawatts

NLIS – Newfoundland and Labrador Interconnected System

NP – Newfoundland Power

NPV – Net Present Value

O&M – Operating and Maintenance

QRA – Quantitative Risk Analysis

RAP – Resource Adequacy Plan

RAS – Remedial Action Scheme

UFLS – Underfrequency Load Shedding

I. Introduction and Background

(1) 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"),[1] including advising the Board on the Build Application's relation to the 2024 Resource Adequacy Plan ("2024 RAP").[2]

(2) 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.[3] 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 used the information 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.[4]

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[1] 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").

[2] 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 ("2024 RAP").

[3] 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").

[4] *See:* Build Application, Schedule 2.

(3) 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 review all inputs pertaining to the 2024 RAP and Long-Term Load Forecast Report ("2024 Load Forecast"),[5] 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").[6] This report provided an assessment of the modeling and planning efforts led by Hydro to determine new resource needs and selections.

(4) 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.[7] 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.[8] Hydro was also asked to address possible inconsistencies on items such as: (1) fuel burn-off requirements;[9] (2) management reserve calculations;[10] and (3) load forecasts.[11] The Board also asked Hydro to: (4) reply to Bates White's recommendation of a competitive solicitation for energy and capacity needs;[12] (5) provide further information on the proposed life extension and capacity increase to BDE Unit 7;[13] (6) justify the depreciable lifespans used for the Avalon Combustion Turbine ("Avalon CT") and Bay d'Espoir Unit 8 ("BDE Unit 8");[14] (7) provide a *pro forma* incremental customer rate impact analysis from 2030 through 2040;[15] (8) provide an update on the status of ongoing studies which are expected to be filed in 2025;[16] (9) consider bifurcation of the projects while the Transmission Expansion Feasibility Study remains in progress;[17] (10) address the impact on

[5] *See:* Build Application, Schedule 3, Appendix A.

[6] "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").

[7] 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").

[8] Board July Letter, page 2, items 2, 3, and 4.

[9] Board July Letter, pages 1 and 2, item 1.

[10] Board July Letter, page 3, item 6.

[11] Board July Letter, page 3, item 7.

[12] Board July Letter, pages 2 and 3, item 5.

[13] Board July Letter, page 3, item 8.

[14] Board July Letter, page 3, item 9.

[15] Board July Letter, page 3, item 10.

[16] Board July Letter, pages 3 and 4, item 11.

[17] Board July Letter, page 4, item 12.

costs and in-service dates should approval be delayed to after the year's end;[18] and (11) to confirm if Hydro has a Constitutional obligation to consult and accommodate indigenous communities in the development of the new generation resources.[19]

(5) On September 11, 2025, Hydro provided responses to each of the fourteen requests made by the Board ("Hydro September Reply"),[20] and reported the results of an additional nine capacity expansion sensitivities and four additional LIL Shortfall Analyses.[21] 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").[22] 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.

(6) 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 protocols, among other items. To address these outstanding items, along with other topics which have arisen through communications with Hydro and the Board, Bates White 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.

(7) The resulting report was filed by Bates White on February 3, 2026 ("Bates White Phase Two Expert Report").[23] The report assessed both the BDE Unit 8 and Avalon CT projects, including costs,

[18] Board July Letter, page 4, item 13.

[19] Board July Letter, page 4, item 14.

[20] 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%20Addtional%20Information%20-%202025-09-11%20-%20REDACTED.pdf ("Hydro September Reply").

[21] 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.

[22] "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").

[23] "Expert Report of Vincent Musco and Collin Cain," February 3, 2026, available at: http://www.pub.nf.ca/applications/NLH2025AvalonCombustionMarch/report/Bates%20White%20Economic%20Consulting%20-%20Expert%20Report%20-%20Phase%20Two%20-%20REDACTED%20-%202026-02-03.PDF ("Bates White Phase Two Expert Report")

schedules, design, and fuel/hydrology considerations, among others. The report also provided a review of 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 reviewed 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 kilovolt ("kV") system and a review of Hydro's analysis of its synchronous condenser needs. The resulting conclusions and recommendations from the Bates White Phase Two Expert Report were 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.

(8) The evidence in the record supports the need for the Avalon CT as necessary to accommodate the retirement of the Holyrood Thermal Generating Station ("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.

(9) 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 megawatts ("MW") of firm capacity produce a significant cost advantage in selecting BDE Unit 8 first is not adequately supported.

(10) 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.

(11) 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* Remedial Action Scheme ("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.

(12) The Newfoundland Island Interconnected System ("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 ("GTs") (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.

(13) We also provided the below findings and conclusions relating to the two projects independently:

Avalon CT

1. 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 CAMS technical review concluded that Avalon CT project is sound and that it is consistent with the stated system need.

2. 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%.

3. 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.

4. 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

1. 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.

2. 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 Electric Load Carrying Capability ("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.

3. BDE Unit 8 is subject to distinct, project-specific risks, including hydrological sufficiency, cost overruns, and schedule challenges.

(14) On March 12, 2026, Hydro provided a response ("Hydro Response to Identified Issues for Avalon CT") focused on the concerns which Bates White raised in our Phase Two report related to the Avalon CT.[24] In its report, Hydro discussed (1) the sufficiency of water supply during Holyrood concurrent operation; (2) fuel management and logistics; (3) CT delivery and specifications; and (4) management reserve and project governance.

(15) Hydro further supplemented the record when filing a revision and evidentiary update on April 16, 2026 ("Hydro Evidentiary Update").[25] This update was primarily the result of an updated assessment

[24] Hydro, "Newfoundland and Labrador Hydro – 2025 Capital Budget Supplemental Application – Application for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine – Bates White Economic Consulting Expert Report – Phase Two – Hydro's Response to Identified Issues for Avalon Combustion Turbine," March 12, 2026, ("Hydro Response to Identified Issues for Avalon CT").

[25] Hydro, "Newfoundland and Labrador Hydro – 2025 Capital Budget Supplemental Application – Application for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine – Revision 1 and Evidentiary Update," April 16, 2026 ("Hydro Evidentiary Update").

of the Avalon CT project "following the execution of the CT supply contract in December 2025 at a cost materially higher than originally estimated."[26] The report also included results from updated expansion planning analyses and LIL shortfall analyses. On May 15, 2026, Hydro also provided responses to eight Board information requests submitted on May 5, 2026.[27]

(16) This addendum report to the Bates White Phase Two Expert Report responds to the additional information received from Hydro in its Response to Identified Issues for Avalon CT and Hydro Evidentiary Update, as well as responses to information requests and other related documents filed by Hydro with the Board.

[26] Hydro Evidentiary Update, page i lines 2 to 4.

[27] Hydro, "Newfoundland and Labrador Hydro – 2025 Capital Budget Supplemental Application – Application for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine – Further Information," May 15, 2026 ("Phase Two Additional Information Request").

II. Executive Summary

(17) As described above, this addendum report to the Bates White Phase Two Expert Report responds to the additional information received from Hydro in its Response to Identified Issues for Avalon CT and Evidentiary Update, as well as responses to information requests and other related documents filed by Hydro with the Board.

(18) In this report we address issues addressed by Hydro in the referenced documents, including:

- The updated costs of the Avalon CT Project, based on the significantly higher contracted cost of the CT packages
- Updated Contingency and Management Reserve amounts, and the associated quantitative risk analysis
- Project governance related to the Management Reserve
- Hydro responses regarding fuel and water supply for the Avalon CT
- Additional capacity expansion modeling results based on updated costs for the Avalon CT and other model assumptions
- Results and implications of five additional "LIL Shortfall Analysis" model runs
- Other evidentiary considerations relating to Bay d'Espoir Unit 8, refurbishment of Newfoundland Power's Greenhill and Wesleyville gas turbines, and ongoing assessment of Island system transmission and voltage constraints

(19) Broadly, we find that the Avalon CT cost updates, additional model runs, further sensitivities, and additional information provided by Hydro in its Evidentiary Update, Response to Identified Issues for Avalon CT, and Phase Two Additional Information Request filings have materially improved the evidentiary record.

(20) Our observations, conclusions, and recommendations are, in summary:

Avalon CT cost update

- The largest cost component of the Avalon CT Project has now been largely fixed by contracting the CT packages, with a substantial increase to the Base Cost of the project of approximately $102.3 million.
- The updated Avalon CT cost estimates improve the record, and Hydro should continue to issue updated cost estimates while advancing towards the "Commitment-to-Build" decision to keep Board and stakeholders updated on project progress.

Management Reserve and Contingency

- While the largest component of cost for the Avalon CT Project has now been largely fixed, the Evidentiary Update shows counter-intuitive changes in budget components associated with ongoing cost risk, with Contingency simply growing proportionately with Base Cost, and Management Reserve declining only modestly. Hydro has provided explanations and calculation results supporting these results, but we find these to reinforce our concerns regarding the basis and reliability of the methodology used to derive the Contingency and Management Reserve amounts.
- The risk assessment methodology does not sensibly capture the effect of fixing the cost of the CT packages, and Contingency as a percentage of Base Cost is essentially unchanged at 11%. A Contingency of 11% on Base Cost excluding the $280 million CT contract cost would come to approximately $45 million, rather than the $75 million in the updated Authorized Budget Request.

Management Reserve and project governance

- There is a trade-off between the objective of the management reserve to facilitate quick action, and the ability of the Board to exercise detailed oversight of the use of reserve funds. We reiterate our recommendation in our Phase Two Report that 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.
- We also continue to recommend the burden of prudence 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.

Quantitative Risk Analysis (QRA) and Monte Carlo simulation

- While we acknowledge that QRA and Monte Carlo simulation are relatively common in project cost risk assessment, and that the general approach can provide useful information, we also conclude that the particular methods for the analysis must be selected to conform appropriately to the specific project context.
- Hydro has not presented a clear basis for the selection of the Hybrid Methodology for the QRA of Avalon CT costs, and particularly why the methodology applied for the Avalon CT should be different than that used for Bay d'Espoir Unit 8 (and the Bay d'Espoir Unit 7 Life Extension) based on QRA principles.
- The Avalon CT Project consists of a mature, widely deployed technology, well-understood by Hydro (based on its experience with the Holyrood CT), modest in size and complexity relative to many other utility generation projects, and now reasonably well-advanced in terms of costing. These characteristics would seem to be consistent with the application of a QRA

method using estimate ranging, which would inherently accommodate a significant project event such as the contracting of the CT packages.

- The fact that the Hybrid Method does not sensibly capture the effect of fixing the cost of the largest single project deliverable indicates that this approach may not be "fit-for-use" in this application.

Water, fuel and other Avalon CT issues

- Hydro has adequately shown that the water usage limit does not appear likely to impose output restrictions on joint output of Holyrood TGS and the Avalon CT during a prolonged LIL outage. However, we agree with Hydro that refined estimates remain appropriate and needed in the detailed design phase.
- Hydro's response to fuel management concerns was adequate and should continue to pursue efforts to find fuel solutions during extended operations.
- While delay risks remain, Hydro continues to make commitments to remain on schedule with development of the Avalon CT.
- The CT package synchronous condenser capability and cost are confirmed to have been included in the contracted CT package.

Additional capacity expansion modeling

- Hydro's capacity expansion modeling was executed reasonably and demonstrates the need for and economic advantages of the Avalon CT relative to other options. This is particularly true when the fuel burn-off requirement is not included in the modeling assumptions. Many modeling assumptions appropriately remained unchanged from the Build Application, while others (such as wind ELCCs and fuel price forecasts) were appropriately updated. While not all changed assumptions were highlighted and/or explained by Hydro in its Evidentiary Update, we identified no fatal flaws that would change our recommendation, which is to accept the modeling results as demonstrating the need for the Avalon CT.

New LIL Shortfall Analysis model runs

- Hydro's LIL Shortfall Analysis model runs support the proposed Avalon CT project for development in time for a 2031 commercial operations date. On its own, the Avalon CT cannot ensure resource adequacy during a prolonged bipole outage of the LIL but is shown to provide a substantial contribution, one that exceeds that of alternatives, including Bay d'Espoir Unit 8.

Other evidentiary considerations

- Should Hydro pursue an evidentiary update for Bay d'Espoir Unit 8, we recommend Hydro include one additional LIL Shortfall Analysis run: Expansion Plan 6, which uses the same assumptions as Expansion Plan 5, but replaces the 150 MW of proxy CTs with the ~50 MW of Newfoundland Power GT uprates.

- Hydro should continue to include the Newfoundland Power GTs in its capacity expansion and LIL Shortfall Analysis modeling as it should for any thermal resource under consideration for life extension, refurbishment, or uprate (including its own thermal resources), including in any evidentiary updates for Bay d'Espoir Unit 8. Those updates should include the cost estimates of those projects, if available, and progress of any joint planning or review efforts by Hydro with Newfoundland Power.
- While the reactive power study is not yet completed or provided in Hydro's Evidentiary Update, preliminary results seem to provide support for the Avalon CT's value in providing reactive power and voltage support for the Island Interconnected System. Hydro should provide the Board with the completed study as soon as practicable.

III. Reply to Hydro's Response to Bates White's Phase Two Report

(21) Hydro's Response to Identified Issues for Avalon CT addressed certain findings and recommendations from the Bates White Phase Two Expert Report regarding the Avalon CT component of Hydro's 2025 Build Application.[28] Our observations and comments on Hydro's response, provided below, also draw on information from both the Hydro Evidentiary Update and Hydro's March 9, 2026 estimate refresh, which was responsive to the Board's request for information regarding the impact of updated costs on Contingency and Management Reserve.[29]

A. Management Reserve and Project Governance

(22) In our Phase Two Report, we addressed at some length the background, purpose and representative applications of a Management Reserve within utility project costing procedures.[30] We also assessed the methodologies used to develop the Management Reserve components included in the authorized budget requests for the Avalon CT and BDE Unit 8. In summary, our conclusions included the following:

- Incorporation of a budget component for Contingency is standard practice, but inclusion of Management Reserve, while not unprecedented, is not widespread among regulated utilities.
- There is no single accepted methodology for determining Management Reserve, and the methodologies applied with respect to Hydro's Build Application were reasonable.
- Hydro potentially underestimated high-impact strategic risks.
- Management Reserve should only be accessed in situations where the strategic risks manifest themselves and negatively impact the project(s).[31]

(23) Our concluding recommendation was that:

> [I]f 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

[28] Hydro Response to Identified Issues for Avalon CT.

[29] Hydro, "Newfoundland and Labrador Hydro – 2025 Capital Budget Supplemental Application – Application for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine – Avalon Combustion Turbine Estimate Refresh," March 9, 2026 ("March 2026 Estimate Refresh").

[30] Bates White Phase Two Expert Report, Section VII.

[31] Bates White Phase Two Expert Report, Section VII.D.

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]

(24) In its March 12, 2026 response to the Phase Two Report, Hydro affirms its position that incorporation of a management reserve in addition to contingency (1) is an accepted practice used by other regulated utilities for major capital projects;[33] (2) provides value in facilitating timely action in response to "unanticipated events that fall outside the range of foreseeable project risks";[34] and (3) allows the Board to exercise oversight in Hydro's use of funds from the management reserve.[35]

(25) With respect to Hydro's proposed governance processes, our Phase Two Report addressed several issues, including:

- That Hydro has not yet defined what would constitute a material difference for the purposes of reassessing project costs and schedules at the end of the detailed design and procurement;[36]
- How the Board's oversight role fits within Hydro's existing governance pathway, such as how significant project changes will be escalated and reviewed;[37]
- Composition of Hydro's committees responsible for project oversight, and the need for participation outside of the Major Projects Department;[38]
- Potential value of additional external expertise in project monitoring, risk review, or performance assessment.[39]

(26) In response, Hydro provides additional detail on its project management processes with respect to change management, risk assessment, committee participation and external expertise.[40] Hydro affirms its position that its processes adequately cover the governance considerations addressed in our Phase Two Report, while also stating that "the addition of further external governance layers would increase project cost without delivering clear incremental value to customers."[41]

[32] Bates White Phase Two Expert Report, paragraph 172.
[33] Hydro Response to Identified Issues for Avalon CT, page 12 lines 23 to 27.
[34] Hydro Response to Identified Issues for Avalon CT, page 12 lines 20 to 22.
[35] Hydro Response to Identified Issues for Avalon CT, page 13 lines 12 to 27.
[36] Bates White Phase Two Expert Report, paragraph 215.
[37] Bates White Phase Two Expert Report, paragraph 214.
[38] Bates White Phase Two Expert Report, paragraphs 128 and 129.
[39] Bates White Phase Two Expert Report, paragraph 130.
[40] Hydro Response to Identified Issues for Avalon CT, page 16 line 12 to page 17 line 12.
[41] Hydro Response to Identified Issues for Avalon CT, page 17 lines 15 to 16.

(27) While Hydro agrees that it should notify the Board when it has determined that the use of the Management Reserve is likely required, Hydro makes clear its position that approval by the Board is not required but is already affected by the Board's approval of the Authorized Budget.[42]

(28) We take no particular issue with Hydro's response regarding its governance procedures, and each of the elements we identified in our Phase Two Report is addressed to an extent. However, we do not agree fully with Hydro's assertion that "the Board's review at the time of the use of the Management Reserve [determines] that the access of the funds was prudent…."[43] As we addressed in our Phase Two Report, there is a trade-off between the objective of the management reserve to facilitate quick action, and the ability of the Board to exercise detailed oversight of the use of reserve funds.[44] We disagree with the language of Hydro's response to the extent that it implies that Board review at the time of a report by Hydro on the intended use of the management reserve establishes prudence, with no further recourse. We stand by the recommendation in our Phase Two Report:

> 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.[45]

B. Sufficiency of Water Supply During Holyrood TGS Concurrent Operation

(29) In the Phase Two Report, we summarized the finding by CAMS that it was unclear whether existing water supply would be adequate to support the simultaneous operation of the Avalon CT and the Holyrood TGS if those units were to remain in service after the Avalon CT was commissioned. We concluded that Hydro might need to conduct further review to determine the adequacy of the water supply in this circumstance.[46]

(30) In its response, Hydro provides reasonable basis to conclude that water supply is not a substantial concern, while stating an intention to evaluate and refine the estimates from the Front End

[42] Hydro Response to Identified Issues for Avalon CT, page 14, lines 3 to 6.
[43] Hydro Response to Identified Issues for Avalon CT, page 14, lines 6 to 7.
[44] Bates White Phase Two Expert Report, paragraph 31.
[45] Bates White Phase Two Expert Report, paragraph 214.
[46] Bates White Phase Two Expert Report, paragraph 11.

Engineering and Design ("FEED") study during the detailed design phase. Specifically, Hydro describes:

- The Quarry Brook water use license permits a maximum withdrawal of 450,000 m³ per year.[47]
- Historical high-water usage at Holyrood TGS from the 2017-2025 period, peaking at 394,217 m³/year, occurred with three-unit operation for the full winter period prior to the commissioning of the LIL. Water usage by two Holyrood TGS units during a 6-week LIL outage is expected to be significantly lower.[48]
- The worst-case water demand associated with Avalon CT operation was estimated by Hatch to be approximately 100,000 m³ over a six-week period assuming operation at full capacity 24 hours/day, 7 days/week. However, expected operating of the CT during a LIL outage is expected to be significantly lower, at 400 hours (out of approximately 1,000 during a 6-week period), and water usage of around 40,000 m³.[49]

(31) While we agree based on these estimates, that the water usage limit does not appear likely to impose output restrictions on joint output of Holyrood TGS and the Avalon CT during a prolonged LIL outage, the margin is not so great as to eliminate concern. Refined estimates are appropriate and needed.

C. Fuel Management and Logistics

(32) In the Phase Two Report, we described the finding by CAMS that the addition of liquid fuel recirculation and filtration equipment would eliminate the need for burning off excess stored fuel, thereby providing substantial operating cost savings.[50] As addressed in our prior reports relating to the Build Application, the assumed fuel burn-off cost was a significant element of CT cost reflected in Hydro's conclusions regarding the order of selection of the Avalon CT relative to Bay d'Espoir Unit 8.[51]

(33) In its response, Hydro notes that the 2024 FEED included conceptual design for fuel recirculation and filtration, and that detailed design will include such equipment "to aid in the reduction or elimination of burning off excess fuel."[52]

[47] Hydro Response to Identified Issues for Avalon CT, page 2 line 3.
[48] Hydro Response to Identified Issues for Avalon CT, page 2 lines 3 to 9.
[49] Hydro Response to Identified Issues for Avalon CT, page 2 lines 12 to 20.
[50] Bates White Phase Two Expert Report, paragraph 201.
[51] For example, *see:* Bates White Phase One Expert Report, Section III.E.iii.
[52] Hydro Response to Identified Issues for Avalon CT, page 3 lines 6 to 7.

(34) Hydro's response also addresses the broader fuel supply and management concerns raised in our Phase Two Report, which are related to fuel storage and the ability to mitigate or eliminate uneconomic fuel burn-off.[53] Hydro has assessed the planned CT fuel tank storage capacity as sufficient for normal CT operation with regular, planned fuel deliveries.[54] Hydro acknowledges challenges to adequate fueling during extended operation, and describes several ongoing efforts to identify solutions, including:

- Upgrades to the Holyrood Marine Terminal;[55]
- Interconnecting the existing Holyrood CT fuel tanks with the proposed Avalon CT fuel tanks;[56]
- Conversion of the Holyrood TGS fuel storage tanks 3 and 4 to diesel storage in conjunction with the installation of a truck fuel offloading station;[57]
- Industry engagement to identify solutions to "Hydro's fuel supply requirements, delivery options, and strategies to optimize fuel inventory management."[58]

(35) Hydro states that, "[i]f further infrastructure or supply chain solutions are determined to be justified, Hydro may bring forward a separate capital application for the option best suited to support reliable system operations."[59]

(36) Hydro's response is consistent with the findings, conclusions, and recommendations in our Phase Two Report.

D. Combustion Turbine Delivery and Specifications

(37) With respect to potential equipment delivery schedule challenges noted in our Phase Two Report, Hydro has previously determined a revised Commercial Operation Date of March 2030 based on agreed-upon delivery dates for the CTs.[60] Hydro states that it "will make best efforts with the support of the Engineering, Procurement and Construction Management ("EPCM") contractor and all long-lead suppliers to optimize the overall project schedule."[61] Hydro's response is a helpful commitment

[53] Bates White Phase Two Expert Report, paragraphs 13 and 64.
[54] Hydro Response to Identified Issues for Avalon CT, page 5 lines 12 to 14.
[55] Hydro Response to Identified Issues for Avalon CT, page 6 lines 5 to 23.
[56] Hydro Response to Identified Issues for Avalon CT, page 6 line 24 to page 7 line 8.
[57] Hydro Response to Identified Issues for Avalon CT, page 7 lines 9 to 19.
[58] Hydro Response to Identified Issues for Avalon CT, page 7 line 20 to page 8 line 21.
[59] Hydro Response to Identified Issues for Avalon CT, page 8 lines 17 to 18.
[60] Bates White Phase Two Expert Report, paragraph 52.
[61] Hydro Response to Identified Issues for Avalon CT, page 10 lines 14 to 15.

to keep the project on schedule, though the schedule is only partially in Hydro's control. Risk of delay remains.

(38) With respect to CT package synchronous condenser capability and cost, Hydro confirms that the contracted CT package includes this capability, and that the associated cost was incorporated in Hydro's CT cost estimate, though not itemized.[62] This is an important acknowledgment to better understand the value of the Avalon CT project.

[62] Hydro Response to Identified Issues for Avalon CT, page 11 lines 5 to 8.

IV. Review of Avalon CT Cost Estimate Updates

(39) In its Evidentiary Update, Hydro increases its "total requested Authorized Budget for the Avalon CT" to $995.9 million.[63] Hydro describes the significant increase estimated for the Avalon CT resulting from much higher CT package pricing in the finalized contract with General Electric than initially estimated in the Build Application. Hydro states: "The executed CT contract price of approximately $280 million [CDN] exceeds the FEED estimate allowance of approximately $173 million, representing a substantial change in project cost assumptions."[64]

(40) Hydro characterizes the cost increase relative to the estimate in the initial Build Application as "driven by factors that were not reasonably foreseeable at the time, including shifts in U.S. energy policy following a change in administration, the introduction of new and compounding tariffs affecting global supply chains, and a rapid and unanticipated surge in demand for generation equipment associated with the expansion of AI-driven data infrastructure."[65] These factors are (now) known cost drivers over the past three years, and Bates White has observed significant cost increases across the industry over this time period. Hydro's explanation reasonably captures the reality of recent market for new generation infrastructure.

(41) Below, we note related observations regarding the incorporation of cost uncertainty in the risk analyses used to derive the Contingency and Management Reserve components of the updated requested Authorized Budget.

A. Updated Base Estimate

(42) Table 1 summarizes the Avalon CT cost components from the initial Build Application, the April 2026 Evidentiary Update, and the cost change by component. We note that it is not possible to align the values in Table 1 exactly with Hydro's summary values referenced above. That is, the $107 million CT package increase from $173 million to $280 million as summarized by Hydro does not correspond to the Table 1 values for either the change in "CT Plant" cost of $[redacted] million or the change in "Base Cost" of $102 million.[66] Possibly the discrepancy is explained by timing differences in the estimates, including exchange rates, given that the CT packages are contracted in US dollars. In any case, the discussion below is applicable with respect to the approximately $100 million cost increase reflected in the Evidentiary Update.

[63] Hydro Evidentiary Update, Application, paragraph 14.

[64] Hydro Evidentiary Update, page 2, lines 16 to 17.

[65] Hydro Evidentiary Update, page 2, lines 8 to 12.

[66] Hydro Evidentiary Update, page 2, lines 16 to 17; Hydro Evidentiary Update, Attachment 2, Table 1.

Table 1: Avalon CT Cost Change – Evidentiary Update Versus Initial Build Application[67]

	Estimated Cost (Rev B0, March 2025)	Estimated Cost (Rev B1, April 2026)	Cost Change
Direct Construction Costs			
Site-Wide Development	[redacted]	[redacted]	
Tank Farm	[redacted]	[redacted]	
CT Plant	[redacted]	[redacted]	[redacted]
Transformer Yard	[redacted]	[redacted]	
Switchyard	[redacted]	[redacted]	
Raw Water	[redacted]	[redacted]	
Fuel Offloading	[redacted]	[redacted]	
Transmission Lines	[redacted]	[redacted]	
Subtotal Direct Construction Costs	**367,756,014**	**462,748,525**	**94,992,511**
Indirect Construction Costs			
Contractor Indirect	[redacted]	[redacted]	
Increase in cost for freight and supplier representation for the CTs		[redacted]	[redacted]
EPCM Consultant	[redacted]	[redacted]	
Hydro Project Management	[redacted]	[redacted]	
Other Hydro Costs (Spare Transformer, Insurance, FEED, etc.)	[redacted]	[redacted]	
Subtotal Indirect Construction Costs	**218,886,796**	**226,222,903**	**7,336,107**
Subtotal Base Cost (Direct + Indirect)	**586,642,810**	**688,971,428**	**102,328,618**
Project Contingency	65,117,352	75,455,117	10,337,765
Subtotal Base Estimate (with Contingency)	**651,760,162**	**764,426,545**	**112,666,383**
Escalation	44,845,915	33,683,583	(11,162,332)
Interest During Construction ("IDC")	66,569,342	76,137,030	9,567,688
Subtotal Planned Budget (with escalation and IDC)	**763,175,419**	**874,247,158**	**111,071,739**
Management Reserve	128,239,838	121,628,000	(6,611,838)
Authorized Budget Request (with Management Reserve)	**891,415,257**	**995,875,158**	**104,459,901**

(43) As indicated in Table 1, only the direct CT package cost and indirect CT freight costs change relative to the Base Cost in the initial Build Application. Hydro reviewed other major cost elements and concluded that, "[w]hile several of these elements remain subject to ongoing procurement and design development, no material variances from the original estimate were identified at the time of the updated analysis."[68] However, Hydro also states that "[a] more comprehensive estimate update is planned as the project advances toward the Commitment-to-Build decision, following engagement of the EPCM contractor and progression of detailed engineering."[69]

[67] Hydro Evidentiary Update, Attachment 2, Table 1.

[68] Hydro Evidentiary Update, page 3, lines 2 to 4.

[69] Hydro Evidentiary Update, page 4, lines 6 to 8.

B. Updated Contingency and Management Reserve

(44) In response to a request from the Board, Hydro revised its Quantitative Risk Analysis ("QRA") and associated Monte Carlo simulation determining the Contingency and Management Reserve components of the requested authorized budget.[70] For the purposes of discussion here, Table 2 provides a focused summary of the changes in Avalon CT cost by component relative to the initial Build Application.

Table 2: Avalon CT Cost Changes Relative to Initial Build Application[71]

	Change from Initial Application ($mm)
Base estimate	102.3
Escalation	-11.2
Interest During Construction	9.6
Contingency	10.4
Management Reserve	-6.6
Total authorized budget	**104.5**

(45) The main impact of the new (higher) cost certainty for the contracted CT packages is that Escalation has been reduced consistent with escalation rates within the contract.[72] This is a reasonable and intuitive outcome.

(46) Updates to Contingency and Management Reserve are less intuitive. Despite the contracted cost certainty for the CT packages relative to the estimates incorporated in the initial Build Application, the Management Reserve decreases only slightly (by $6.6 million), while the updated value for Contingency actually *increases*. Hydro asserted explanations for these results:

1. In the original QRA, "a significant increase in CT pricing was not identified as a material risk requiring management reserve,"[73] and "[b]ecause this risk was not a major component of the management-reserve assessment, the subsequent increase in CT price certainty did not substantially reduce the proposed management reserve."[74]
2. "[P]roject maturity has not advanced such that other risks identified in the original QRA have significantly changed," and so "the contingency (mean at P55) has adjusted to account for the variable portions of the CT contract."[75]

[70] Hydro Evidentiary Update, transmittal letter, page 1;
[71] Hydro Evidentiary Update, Table 1; Hydro Evidentiary Update, Attachment 2, Table 1.
[72] Hydro Evidentiary Update, Table 1.
[73] March 2026 Estimate Refresh, page 2.
[74] March 2026 Estimate Refresh, page 2.
[75] March 2026 Estimate Refresh, page 2.

3. Hydro incorporated "newly identified specific risk items related to variable portions of the CT contract," including:
    a. Foreign exchange rates
    b. Onsite vendor support
    c. Transportation
    d. Design changes during detailed design
    e. Tariff impacts
    f. Factory acceptance testing and training
    g. Certification for pressure-containing components.[76]

(47) While all these factors may in some sense "explain" the somewhat counter-intuitive result that Contingency simply grows with package cost and Management Reserve declines only modestly despite a substantial reduction in project cost uncertainty, this draws into question the basis and reliability of the QRA Hydro has applied to determine Contingency and Management Reserve amounts.

(48) We appreciate that in December 2024 the full extent of impacts from demand for new generation capacity to serve prospective data center loads was not fully clear. However, the extensive supply shocks associated with the Coronavirus-19 pandemic were then in the very recent past, and may not even have been fully resolved, while inflation associated with the demand rebound continued to be evident. It is difficult to understand how supply and/or demand driven cost shocks were not identified as a material risk for incorporation in the QRA, at least as a "known unknown." The pandemic and subsequent supply chain disruptions concretely demonstrated that unanticipated factors could have substantial price effects – it would have been nonsensical to assume away in the QRA any other comparable risk factors just because those particular ones had been mostly resolved. As such, it would be expected an updated QRA following CT contract execution would be subject to less of the "known unknown" price risks facing project development.

(49) In preparing the Evidentiary Update, Hydro "recalculated" the Contingency amount for the Avalon CT project (performed in-house, rather than through Hatch).[77] However, rather than reassess the same set of specific risks following contract execution for the CT component, Hydro *added* to the existing contingency calculation the "newly identified specific risk items" (shown above) which ostensibly result from the executed contract.[78] These new risk items under the contract produce an additional $10.338 million in Contingency.[79]

[76] March 2026 Estimate Refresh, pages 1 to 2; Hydro Evidentiary Update Attachment 5, Table 2.

[77] Hydro Evidentiary Update, Attachment 5, page 9 of 20.

[78] Hydro Evidentiary Update, Attachment 5, pages 9 to 12 of 20, Table 2, and Table 3.

[79] Hydro Evidentiary Update, Attachment 2, Table 1, and Attachment 5, Table 3.

(50) The new Contingency amount is 11.0% of the revised Base Cost estimate, compared to 11.1% of Base Cost in the Build Application. While the uncertainty captured by Contingency may remain for a range of project costs, the CT package cost is now known with high (if not exact) certainty, since this is contracted. A Contingency of 11% on Base Cost excluding the $280 million CT contract cost would come to approximately $45 million,[80] rather than the $75 million in the updated Authorized Budget Request.

(51) With respect to the intent of a Management Reserve, as supported based on recommendations stemming from the Muskrat Falls Inquiry, our view is that it is specifically to capture the extremity of potential project costs for consideration by the Board prior to approval.[81] Hydro's Evidentiary Update effectively demonstrates that the prior estimate of Management Reserve did not provide this. The potential for significant CT package cost increases was not reflected in the QRA and associated Monte Carlo simulation, so fixing a significantly higher cost with certainty had little effect on the updated Management Reserve result.[82] Meanwhile, a number of other risk factors were added or updated such that contingency is effectively inflated proportionately to the increase in base cost.

(52) It is reasonable to conclude that if the original Management Reserve value had functioned as intended, the *revised* Management Reserve amount should simply be reduced by the CT package cost increase. As stated by Hydro, "Management Reserve is intended to address unanticipated events that fall outside the range of foreseeable project risks."[83] Or, as we noted in our Phase Two Report, "Management Reserve addresses risk of unknown, uncontrollable costs."[84] The CT package cost increase was just such an unknown, uncontrollable cost. If the requested Authorized Budget for the CT had already been approved, then presumably Hydro would now be reporting the anticipated need to access the Management Reserve. Instead, Hydro is leaving the Management Reserve component of the budget request largely intact in its Evidentiary Update.

(53) In combination, Contingency plus Management Reserve increases by more than $3.7 million relative to the initial Build Application.

[80] $688,971,728 - $280,698,546 = $408,272,882 × 11% = $44,910,017. Hydro Evidentiary Update, Attachment 2, Table 1.

[81] Bates White Phase Two Expert Report, paragraph 171 and 172.

[82] March 2026 Estimate Refresh, page 2.

[83] Hydro Response to Identified Issues for Avalon CT, page 12 lines 21 to 22.

[84] Bates White Phase Two Expert Report, paragraph 132.

C. QRA and Monte Carlo Simulation

(54) The Evidentiary Update includes detail on the updated QRA and Monte Carlo simulation used to derive the Contingency and Management Reserve amounts discussed above.[85] The conclusions and recommendations in our Phase Two Report relating to these methods remain applicable and indeed are reinforced by the very muted effect on Contingency and Management Reserve despite the greater cost certainty for the contracted CT packages.[86]

(55) As we observed in our Phase Two Report, the QRA and Monte Carlo implementations applied with respect to the Avalon CT and BDE Unit 8 were performed by different contractors using different methodologies and proprietary tools.[87] Further, the analysis performed by Hatch incorporated proprietary probabilistic distributions that were not made available for more than half the strategic risks identified for the Avalon CT.[88] Bates White concluded that the strategic risks considered were not comprehensive, and that potentially significant "unknown unknown" factors are inherently impossible to identify in advance.[89]

(56) While we acknowledge that QRA and Monte Carlo simulation are relatively common in project cost risk assessment, and that the general approach can provide useful information, we also conclude that the particular methods for the analysis must be selected to conform appropriately to the specific project context.

(57) Hydro was asked by the Board to provide the high and low ranges for Avalon CT cost components used for the QRA, similar to information provided in the Life Extension Application for Bay d'Espoir Unit 7.[90] In response, Hydro describes that the QRA process for the Avalon CT was distinctly different than that used for the BDE Unit 7 Life Extension Project, which applied a "line-item ranging approach" (sometimes referred to as "estimate ranging" or "risk ranging").[91] This is the same methodology applied with respect to BDE Unit 8.[92] In this process, project cost components are assigned range values (in this case, specified by Hydro for the project) which are then used in a Monte Carlo simulation step. Hydro explains that, in contrast, the QRA for the Avalon CT applied a Hybrid Parametric and Expected Value Method that modeled systemic risks "by using industry-wide historical data from many completed projects to understand how these broader factors affect costs."[93]

[85] Hydro Evidentiary Update Attachment 3; Attachment 4; and Attachment 5.
[86] *See:* Bates White Phase Two Expert Report, Section VII.
[87] Bates White Phase Two Expert Report, paragraph 133.
[88] Bates White Phase Two Expert Report, Table 7.
[89] Bates White Phase Two Expert Report, paragraph 146.
[90] Additional Information Request 6.
[91] Additional Information Request 6, page 3, lines 1 to 2.
[92] Build Application, Schedule 4, Attachment 1.
[93] Additional Information Request 6, page 3, lines 10 to 12.

The hybrid method also incorporated consideration of specific risk events, but only where there are "clear, significant uncertainties."[94]

(58) In support of the "Hybrid Method" applied in the QRA for the Avalon CT, Hydro cites the Association for the Advancement of Cost Engineering ("AACE"), and specifically its Professional Guidance Document No. 02 *Guide to Quantitative Risk Analysis*.[95] This document addresses a range of QRA principles and method types. Notably, the AACE emphasizes that "QRA is an evolving field of practice and not settled science."[96] The document describes QRA methods including estimate ranging, parametric, expected value, and hybrid approaches, and selecting particular methods based on "fit-for-use" considerations with respect to a particular project. Considerations relevant to selecting a QRA methodology include: project details such as scope, size, complexity, and level of technology; systemic versus project-specific risks; and how far advanced development of the project is.[97]

(59) Based on our review of the Build Application record, including Hydro's Response to Identified Issues for Avalon CT, the Evidentiary Update, and Hydro's Phase Two Additional Information Request responses, we find that Hydro has not presented a clear basis for the selection of the Hybrid Methodology for the QRA of Avalon CT costs, and particularly why the methodology applied for the Avalon CT should be different than that used for BDE Unit 8 (and the BDE Unit 7 Life Extension) based on QRA principles. The Avalon CT Project consists of a mature, widely-deployed technology, well-understood by Hydro (based on its experience with the Holyrood CT), modest in size and complexity relative to many other utility generation projects, and now reasonably well-advanced in terms of costing. These characteristics would seem to be consistent with the application of a QRA method using estimate ranging. We note, in particular, that estimate ranging would inherently accommodate a significant project event such as the contracting of the CT packages – i.e., there would no longer be a cost range for this project component but, rather, the contracted cost would be used as a fixed value in the Monte Carlo simulation. The fact that the Hybrid Parametric Expected Value Method does not sensibly capture the effect of fixing the cost of the largest single project deliverable indicates that this approach may not be fit-for-use in this application.

(60) We do not see a basis for high confidence in determining a Management Reserve for the Avalon CT using the Hybrid Method and the resulting 85th percentile result from the Monte Carlo simulation. In our Phase Two Report, we did not "take issue with Hydro's methodological approach for calculating Management Reserve" for the Avalon CT, but we did identify several concerns.[98] After reviewing the

[94] Additional Information Request 6, page 3, lines 14 to 16.

[95] Additional Information Request 6, page 3, footnote 17.

[96] Association for the Advancement of Cost Engineering, Professional Guidance Document No. 02 *Guide to Quantitative Risk Analysis*, available at: https://library.aacei.org/pgd02/pgd02.shtml ("AACE Guide to Quantitative Risk Analysis")

[97] AACE Guide to Quantitative Risk Analysis.

[98] Bates White Phase Two Expert Report, paragraph 170.

Evidentiary Update, our confidence in the use of the Hybrid Method and Monte Carlo simulation for setting the Management Reserve has not increased. As addressed above, the updated analysis using this methodology does not sensibly capture the effect of fixing the cost of the CT packages. We also remain concerned that "the Management Reserve, as proposed, could potentially serve as a backstop for poor cost estimation and poor project management" and should "only be applied in situations where the strategic risks – the 'unknown unknowns' – manifest themselves and negatively impact the project."[99]

[99] Bates White Phase Two Expert Report, paragraph 171.

V. Expansion Plan Results

(61) In its Evidentiary Update, Hydro provides results for ten additional capacity expansion model runs using the updated Avalon CT project cost estimate of $995.9 million.[100] In addition to the Avalon CT project costs, Hydro updated (1) the costs of the other capacity expansion options, (2) ELCC assumptions contained in a November 2025 ELCC update study,[101] (3) firm energy requirements, which were reduced following Hydro's June 2025 adoption of an updated underfrequency load shedding ("UFLS")[102] scheme,[103] and (4) its load forecast.[104]

(62) In the ten model runs, Hydro considered a range of sensitivities, including those related to load growth; equivalent forced outage rates ("EqFOR") of the LIL; fuel burn-off requirements at the Avalon CT, and capital costs for modeled hydroelectric resources (e.g., Bay d'Espoir unit 8 and CAT Arm 3) and combustion turbine resources, including the Avalon CT.[105] Hydro precluded battery energy storage systems ("BESS") as a resource option in all ten model runs.[106]

(63) Hydro provides "names" for its scenarios that are similar to those used in the Build Application. While there are similarities between the named scenarios, enough variables have changed that make direct comparisons of Hydro's results in its Evidentiary Update to those in the Build Application less useful. To assess Hydro's modeling in its Evidentiary Update, we instead focused on the reasonableness of the assumptions and the implications of the results. For reference, the ten scenarios modeled by Hydro are in Table 3 below.

[100] Hydro Evidentiary Update, page 4 lines 1 to 2 and 10 to 11.

[101] 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 ("ELCC Update Study").

[102] Hydro, "Final Lower Churchill Project Operational (Stage 4F) Study," August 11, 2025, available at: http://www.pub.nf.ca/applications/NLH2025AvalonCombustionMarch/report/From%20NLH%20-%20Final%20Lower%20Churchill%20Project%20Operational%20(Stage%204F)%20Study%20-%202025-08-12.PDF.

[103] Hydro Evidentiary Update, page 4 lines 17 to 20.

[104] Hydro Evidentiary Update, page 4 line 17.

[105] Hydro Evidentiary Update, page 4 lines 11 to 13 and Table 2.

[106] Hydro Evidentiary Update, page 4 lines 13 to 16.

Table 3: Ten capacity expansion scenarios modeled by Hydro[107]

Scenario	Capacity Planning Criteria (LOLH)	Load Forecast	LIL Bipole EqFOR (%)	Planning Reserve Margin (%)	Additional Assumptions
4AE	2.8	Slow Decarbonization	1	17.1	-
4AEC	2.8	Slow Decarbonization	1	17.1	No fuel burn-off at CT
4AEDC	2.8	Slow Decarbonization	1	17.1	No fuel burn-off at CT; High capital cost for hydro resources (P85)
4AEHC	2.8	Slow Decarbonization	1	17.1	No fuel burn-off at CT; High capital cost for CT (P85)
4AEDHC	2.8	Slow Decarbonization	1	17.1	No fuel burn-off at CT; High capital cost for hydro resources (P85); High capital cost for CT (P85)
4AEKC	2.8	Slow Decarbonization	1	17.1	No fuel burn-off at CT; Newfoundland Power will uprate its CTs by 48 MW in 2031
1AE	2.8	Reference Case	5	25.8	-
1AEC	2.8	Reference Case	5	25.8	No fuel burn-off at CT
1AEK	2.8	Reference Case	5	25.8	Newfoundland Power will uprate its CTs in by 48 MW in 2031
1AEKC	2.8	Reference Case	5	25.8	No fuel burn-off at CT; Newfoundland Power will uprate its CTs by 48 MW in 2031

(64) Before turning to the results, we first assess the adequacy and reasonableness of Hydro's modeling. Overall, Hydro has provided a useful set of scenarios to assess the Avalon CT as a resource option, given changes in variables essential to its economic viability relative to alternatives.

(65) Hydro has appropriately used its "Slow Electrification" load forecast in the majority of cases to encourage selection of projects that are demonstrably needed, and not subject to potentially aggressive load growth assumptions.[108] As we pointed out in our Phase One Report, the Slow Decarbonization forecast is not the lowest plausible load scenario over the planning horizon—lower population growth, lower electric vehicle adoption rates, and lower industrial load growth are all possible and may coincide.[109] Still, the Slow Decarbonization load forecast is the lowest available load forecast future available, and thus is appropriate for the majority of capacity expansion model runs.

[107] Hydro Evidentiary Update, Table 2.

[108] Hydro Evidentiary Update, Table 2. Hydro has previously referred to this forecast sensitivity as the "Slow Decarbonization" forecast in filings related to its 2024 load forecast. We use the terms interchangeably in this report insofar as both represent the lowest load growth case developed by Hydro.

[109] Bates White Phase One Expert Report, paragraph 12.

(66) Hydro has also appropriately removed the assumption of required fuel burn-off at the Avalon CT in seven of ten cases.[110] We pointed out in our Phase Two Report that "[a]ppropriate fuel management equipment and procedures would likely eliminate any uneconomic fuel burn-off at the Avalon CT."[111] We demonstrated in our Phase Two Report that the fuel-burn off assumption had a material impact on the results; removing it resulted in the Avalon CT becoming the most economic resource addition, including over Bay d'Espoir Unit 8.[112]

(67) Hydro has also appropriately included cases in which Newfoundland Power extends the lives of its Wesleyville and Greenhill GTs for an additional 48 MW of firm capacity in 2031.[113] Hydro's Build Application assumed the Newfoundland Power GTs would retire in 2030.[114] In our Phase One Addendum Report, we noted that Newfoundland Power planned to extend the lives of both Wesleyville and Greenhill by 2029,[115] which offer a combined firm capacity of 48 MW.[116] We noted that the capacity expansion modeling results completed in Phase One by Hydro demonstrated that "the firm capacity contribution of the Newfoundland Power GTs directly offsets the need for additional capacity from other resources, which both reduces the total firm capacity built by the model from other sources and delays those builds."[117] Most useful of these runs is scenario 4AEKC, which is the only scenario that assumes the Newfoundland Power ("NP") GT uprates and the Slow Decarbonization load forecast. We confirmed that Hydro appropriately modeled the 48 MW of firm capacity from the Newfoundland Power GTs in 2031 and beyond in this scenario.[118]

(68) Hydro has also included high capital cost cases for hydroelectric resources only (scenario 4AEDC), CT resources only (scenario 4AEHC), and both high cases combined (scenario 4AEDHC).[119] These scenarios allow for consideration of any changes to the optimal portfolio as assumed capital costs for these resources increase to P85 levels.

(69) Regarding Hydro's decision to not allow its capacity expansion model to consider or select BESS resources in any of its ten model runs, we reiterate our position as previously stated and as based on all capacity expansion modeling to date. Specifically:

[110] Hydro Evidentiary Update, Table 2. Scenarios 4AEC, 4AEDC, 4AEHC, 4AEDHC, 4AEKC, 1AEC, 1AEKC do not include fuel burn-off.

[111] Bates White Phase Two Expert Report, paragraph 2.

[112] Bates White Phase Two Expert Report, paragraph 2.

[113] Hydro Evidentiary Update, Table 2. Scenarios 4AEKC, 1AEK, and 1AEKC include the NP uprate.

[114] Bates White Phase One Expert Report, paragraph 59.

[115] Bates White Phase One Addendum Report, paragraph 73.

[116] Bates White Phase One Addendum Report, paragraph 75.

[117] Bates White Phase One Addendum Report, paragraph 76.

[118] Additional Information Request, Request 2, Attachment 2, tab "4AEKC."

[119] Hydro Evidentiary Update, Table 2.

> 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.[120]
>
> …
>
> We therefore take no issue with Hydro not including BESS resources in its Minimum Investment Portfolio but reiterate that BESS resources should be included as viable resource options in all of Hydro's resource planning efforts going forward.[121]

(70) Hydro's exclusion of BESS resources, therefore, is not unreasonable, and we note that Hydro has committed to include BESS resources in future resource adequacy planning efforts.[122]

(71) We compared the PLEXOS assumptions used by Hydro in conducting these ten model runs with those used in the Build Application. Our focus was to ensure that variables that *should* change, have changed, and those that *should not* have changed were maintained. Our review identified no concerning assumptions. We highlight the following:

- No changes to capacity for all resources[123] except Newfoundland Power's combined "Avalon Hydro" and "Off-Avalon Hydro," which was reduced from 94.2 MW to 78.6 MW.[124] However, the firm capacity assumed for these two sets of resources remained unchanged at 60.1 MW,[125] so this change in installed capacity should have no impact on modeling results.
- No changes to firm capacity for all resources (including Newfoundland Power's Avalon and Off-Avalon Hydro), except wind (noted below).[126, 127]
- No changes to heat rate, fuel type, maintenance rate for CTs.[128, 129]

[120] Bates White Phase One Addendum Report, paragraph 107.

[121] Bates White Phase One Addendum Report, paragraph 40.

[122] Hydro Evidentiary Update, page 4 lines 15 to 16.

[123] Phase Two Additional Information Request, Request 2, Attachment 1, tab "Expansion Options"; PUB-NLH-324 Attachment 1, tab "Expansion Options"; Bates White Phase One Expert Report, paragraph 58.

[124] Phase Two Additional Information Request, Request 2, Attachment 1, tab "Capacity"; PUB-NLH-324 Attachment 1, tab "Capacity." Bates White Phase One Expert Report, paragraph 58.

[125] Phase Two Additional Information Request, Request 2, Attachment 1, tab "Capacity"; PUB-NLH-324 Attachment 1, tab "Capacity."

[126] Phase Two Additional Information Request, Request 2, Attachment 1, tab "Expansion Options"; PUB-NLH-324 Attachment 1, tab "Expansion Options"; Bates White Phase One Expert Report, paragraph 58.

[127] Phase Two Additional Information Request, Request 2, Attachment 1, tab "Capacity"; PUB-NLH-324 Attachment 1, tab "Capacity"; Bates White Phase One Expert Report, paragraph 58.

[128] Phase Two Additional Information Request, Request 2, Attachment 1, tab "Expansion Options"; PUB-NLH-324 Attachment 1, tab "Expansion Options"; Bates White Phase One Expert Report, paragraph 58.

[129] Phase Two Additional Information Request, Request 2, Attachment 1, tab "Unit Characteristics"; PUB-NLH-324 Attachment 1, tab "Unit Characteristics"; Bates White Phase One Expert Report, paragraph 58.

- No changes to assumed forced outage rates for modeled resources.[130, 131]

- Increased capital costs for the CT (+16.8%) and Bay d'Espoir Unit 8 (+2.5%). Note that Build Application capital costs were in 2024$ and the Evidentiary Update costs are in 2025$.[132]

- Increased capital costs for CAT Arm 3 and other hydroelectric alternative resource options (all increased by 2.5%).[133] As with Bay d'Espoir Unit 8, the Build Application capital costs were in 2024$ and the Evidentiary Update costs are in 2025$.[134]

- Resource fixed operating and maintenance ("O&M") costs and variable O&M costs have been updated to account for escalation between 2024 and 2025 dollars.[135] Fixed O&M costs and variable O&M costs were accurately represented in Hydro's modeling input files.[136]

- Asset lives have increased for the hydro resources (from 60 years to 70 years) and for the CT (from 35 years to 45 years).[137] Hydro notes that these updated asset lives are based on the 2022 Depreciation Study.[138]

- Wind ELCCs have been appropriately updated to match the November 2025 ELCC study. [139] ELCCs begin at 40.5% for the first incremental 100 MW of wind and decline to as low as 25.1% for the fifth incremental 100 MW of wind.[140] This is increased substantially from the Build Application, which assumed a 22% ELCC for wind.[141]

- Marginal loss assumptions are unchanged.[142]

[130] Phase Two Additional Information Request, Request 2, Attachment 1, tab "Expansion Options"; PUB-NLH-324 Attachment 1, tab "Expansion Options;" Bates White Phase One Expert Report, paragraph 58.

[131] Phase Two Additional Information Request, Request 2, Attachment 1, tab "Outage and Maintenance"; Bates White Phase One Expert Report, paragraph 58.

[132] Phase Two Additional Information Request, Request 2, Attachment 1, tab "Expansion Options"; Bates White Phase One Expert Report, Table 5.

[133] Phase Two Additional Information Request, Request 2, Attachment 1, tab "Expansion Options"; Bates White Phase One Expert Report, Table 5.

[134] Phase Two Additional Information Request, Request 2, Attachment 1, tab "Expansion Options"; Bates White Phase One Expert Report, Table 5.

[135] Phase Two Additional Information Request, Request 2, Attachment 1, tab "Expansion Options."

[136] Phase Two Additional Information Request, Request 2, Attachment 6; Phase Two Additional Information Request, Request 2, Attachment 7.

[137] Phase Two Additional Information Request, Request 2, Attachment 1, tab "Expansion Options"; PUB-NLH-324 Attachment 1, tab "Expansion Options"; Bates White Phase One Expert Report, paragraph 58.

[138] Phase Two Additional Information Request, Request 2, Attachment 1, tab "Expansion Options."

[139] ELCC Update Study, Figure 19.

[140] Phase Two Additional Information Request, Request 2, Attachment 1, tab "Wind ELCC."

[141] Build Application, Schedule 1, page 17 footnote 30.

[142] Phase Two Additional Information Request, Request 2, Attachment 1, tab "Loss Equations"; PUB-NLH-324 Attachment

- Fuel costs have been updated to reflect the most recent estimates for heavy fuel oil and diesel fuels.[143]

(72) Turning now to modeling results, the Avalon CT is selected in eight of ten modeled scenarios. In each case, the Avalon CT is selected to in service by 2031 and is either the first resource selected or is selected alongside other resources to be in service by 2031.[144] The only scenarios in which the Avalon CT is not selected are those in which either the fuel burn-off requirement is included (4AE) or CT capital costs are escalated (4AEHC).[145] Results are shown in Table 4 below.

Table 4: Capacity expansion model results[146]

Scenario	Avalon CT added?	Second CT added?	BDE Unit 8 added?	CAT Arm Unit 3 added?	Firm wind added?	Cumulative Firm Capacity Added (2031)	Cumulative Firm Capacity Added (2035)	NPV ($bn)
4AE	No	No	2031	2034	2031 (73 MW)	227	295	3.4
4AEC	2031	No	2034	No	2031 (73 MW)	214	369	3.2
4AEDC	2031	2034	No	No	2031 (73 MW)	214	356	3.3
4AEHC	No	No	2031	2034	2031 (73 MW)	227	295	3.3
4AEDHC	2031	No	2034	No	2031 (73 MW)	214	369	3.4
4AEKC	2031	No	No	No	2031 (73 MW)	214	214	2.9
1AE	2031	2031	2031	No	2031 (73 MW) 2032 (22 MW)	510	533	5.8
1AEC	2031	2031	2031	No	2031 (73 MW) 2032 (22 MW)	510	533	5.3
1AEK	2031	2034	2031	No	2031 (73 MW) 2032 (22 MW)	369	533	5.4
1AEKC	2031	2034	2031	No	2031 (73 MW) 2032 (22 MW)	369	533	4.9

(73) The resulting net present values ("NPVs") of the incremental revenue requirements for the portfolios remain similar to those in the Build Application. For the Slow Decarbonization sensitivities (all scenarios beginning with "4"), NPVs range from $2.9 to $3.4 billion (2025$);[147] the Build Application NPVs for all Slow Decarbonization model runs ranged from $3.2 to $3.5 billion (2024$).[148]

1, tab "Loss Equations;" Bates White Phase One Expert Report, paragraph 58.

[143] Phase Two Additional Information Request, Request 2, Attachment 1, tab "#2 Fuel Price."

[144] Hydro Evidentiary Update, Table 2.

[145] Hydro Evidentiary Update, Table 2.

[146] Hydro Evidentiary Update, Table 2 and Appendix A.

[147] Hydro Evidentiary Update, Table 2.

[148] Build Application, Schedule 3, Chart 7.

(74) The similar NPVs are due to countervailing factors. The Evidentiary Update model runs apply higher capital costs for the hydro and CT resources, but build less capacity due to higher wind ELCCs and a lower load forecast. For example, in the Build Application, scenario 4AEF built 400 MW of installed wind capacity in order to get 88 MW of firm capacity;[149] in the Evidentiary Update, the model builds no more than 200 MW of wind to achieve 73 MW of firm capacity, avoiding 200 MW of wind installation.[150] The Build Application's Scenario 4AEF also builds 384 MW of firm capacity by 2035;[151] in the Evidentiary Update, the model builds no more than 369 MW of firm capacity by 2035 in all Slow Decarbonization model runs.[152]

(75) We also note that Hydro's resource adequacy criteria are met in all ten scenarios in all years of the planning horizon,[153] with capacity reserve margins at 19.9% or higher in all modeled years.[154]

(76) The results also show that the Avalon CT will be expected to have a near-zero capacity factor. Over the ten scenarios, the Avalon CT's resulting annual capacity factor is below 1% (and close to zero) in the great majority of modeled years. Only in two Reference Case load forecast scenarios (1AE, 1AEK) does the Avalon CT reach a higher capacity factor, but still never exceeds 2.8%.[155]

(77) The results confirm that Hydro appropriately modeled the "no fuel-burn off" assumption in the correct scenarios for the Avalon CT.[156] We note that in the Reference Case load forecast scenarios, the fuel cost savings associated with solving the fuel burn-off requirement is as much as $25 million/year.[157]

(78) We note that while the results of the Build Application capacity expansion model runs are not directly comparable to the Evidentiary Update model runs, we do wish to point out some differences. First, the total resulting installed capacity in the Evidentiary Update model runs is considerably lower than in the Build Application runs. For example, Hydro's modeling forecasts about 465 MW less installed capacity in 2031 in scenario 4AE in the Evidentiary Update modeling as resulted in the "equivalent" scenario (4AEF)[158] in the Build Application for that year.[159] The primary driver of this difference is

[149] Build Application, Schedule 3, Table 5.

[150] Hydro Evidentiary Update, Table 2 and Appendix A, Table A-2. For example, in Scenario 4AEC, 200 MW of Total Installed Wind in Table 2 yields 73 MW of Firm Capacity in Table A-2.

[151] Build Application, Schedule 3, Table 5.

[152] Hydro Evidentiary Update, Appendix A, Table A-2 and Table A-5.

[153] Phase Two Additional Information Request, Request 2, Attachment 8, all tabs, row "Unserved Energy."

[154] Phase Two Additional Information Request, Request 2, Attachment 8, all tabs, row "Capacity Reserve Margin."

[155] Phase Two Additional Information Request, Request 2, Attachment 5.

[156] Phase Two Additional Information Request, Request 2, Attachment 8.

[157] Phase Two Additional Information Request, Request 2, Attachment 8, tabs "1AE," "1AEK."

[158] Hydro Evidentiary Update, footnote 15. We provide background to the scenarios modeled in this and previous iterations of Hydro's analysis in Appendix A.

[159] Phase Two Additional Information Request, Request 2, Attachment 2, tab "4AE"; PUB-NLH-325 Attachment "Max Capacity," tab "4AEF."

327.5 MW less wind in the Evidentiary Update modeling, but reductions in installed capacity at Deer Lake (-22.1 MW), Exploits (-31.2), and non-utility generators (-65.7 MW) also contribute.[160] The lower installed capacity for wind can be partially explained by the higher ELCC values assigned to wind, which allow Hydro to benefit from greater firm capacity contributions for each MW of installed wind capacity.

(79) Second, with the lower wind installations, the total generated output of the wind as modeled is lower in the Evidentiary Update modeling, with some of the energy being made up by Muskrat Falls and the rest being explained by a lower overall annual load. For example, the Evidentiary Update shows 690 GWh of wind and 4,735 GWh from Muskrat Falls in 2031 (scenario 4AE),[161] while the Build Application projected 1,407 GWh from wind and 4,637 GWh from Muskrat Falls in 2031 (scenario 4AEF).[162] The lower energy output is related in part to the 2025 load forecast update, which forecasts load that is 1.9% lower than the 2024 forecast of the Slow Decarbonization case by 2035.[163]

(80) Our overall assessment of Hydro's capacity expansion modeling was executed reasonably and demonstrates the need for and economic advantages of the Avalon CT relative to other options. This is particularly true when the fuel burn-off requirement is not included in the modeling assumptions. Many modeling assumptions appropriately remained unchanged from the Build Application, while others (such as wind ELCCs and fuel price forecasts) were appropriately updated. While not all changed assumptions were highlighted and/or explained by Hydro in its Evidentiary Update, we identified no fatal flaws that would change our recommendation, which is to accept the modeling results as demonstrating the need for the Avalon CT.

[160] Phase Two Additional Information Request, Request 2, Attachment 2, tab "4AE"; PUB-NLH-325 Attachment "Max Capacity," tab "4AEF."

[161] Phase Two Additional Information Request, Request 2, Attachment 3, tab "4AE."

[162] PUB-NLH-325 Attachment "Annual Generation," tab "4AEF."

[163] Hydro, "2025 Island Interconnected System Load Forecast Report," November 5, 2025, page 33 lines 4 to 9.

VI. LIL Shortfall Analysis Results

(81) In addition to capacity expansion modeling, Hydro has submitted results of five "LIL Shortfall Analysis" model runs, which "assess the performance of the expansion plans in a six-week LIL shortfall scenario."[164] As we have pointed out, the LIL Shortfall Analysis is a necessary step given the elevated probability of an extended outage of the LIL during winter weather conditions.[165] The reliability of the LIL has a substantial impact on capacity expansion modeling results, and Hydro has appropriately continued to assess a range of LIL EqFORs (here, 1% and 5%). These LIL EqFORs translate directly into Hydro's resource adequacy criterion, which Hydro has previously specified at 2.8 LOLH.[166] However, these forced outage rates and resource adequacy criteria do not fully capture the risk of a prolonged outage of the LIL. The LIL Shortfall Analysis fills that evidentiary gap and provides an assessment of reliability outcomes of a given resource portfolio under such conditions.

(82) The LIL Shortfall Analysis runs assessed the resource adequacy of the system by tracking the hourly unserved energy during the modeled period January 1, 2032 through February 11, 2032 (six weeks).[167] Hydro assessed five portfolios, shown in the table below. For each portfolio, Hydro conducted 2,400 simulations in which weather-driven loads, unit outage profiles, and renewable generation were randomly determined.[168] All other assumptions remained the same as those in the capacity expansion model runs.[169]

Table 5: LIL Shortfall Analysis Portfolios[170]

Expansion Plan	Load Forecast	Resources Added
1	Slow Decarbonization	BDE Unit 8 (2031)
2	Slow Decarbonization	Avalon CT (2031)
3	Slow Decarbonization	BDE Unit 8 (2031) Avalon CT (2031)
4	Slow Decarbonization	Avalon CT (2031) Newfoundland Power GTs (2031)
5	Reference Case	BDE Unit 8 (2031) Avalon CT (2031) 150 MW Proxy CT (2031)

[164] Hydro Evidentiary Update, page 6, lines 4 to 5.
[165] Bates White Phase One Expert Report, Section III.C.iii.
[166] Bates White Phase One Expert Report, paragraph 37.
[167] Phase Two Additional Information Request, Request 3, Attachment 1.
[168] Hydro Evidentiary Update, page 7, line 2 and footnote 23.
[169] Phase Two Additional Information Request, Request 3.
[170] Hydro Evidentiary Update, page 6 line 7 to page 7 line 1.

(83) The LIL Shortfall Analysis runs are assessed based on the "unserved energy" metric, or the amount of load that the model was unable to supply with available generation. Unserved energy, therefore, measures resource adequacy for a given portfolio, with failure to maintain resource adequacy resulting in a "shortfall;" Hydro defines a shortfall as "the amount of load shedding required to restore a minimum regulating reserve of 70 MW."[171] Hydro assessed each portfolio across several metrics, including the hour in which the shortfall was greatest (i.e., the "peak shortfall" hour), the total shortfall across the entire six-week period, and the hours in which a shortfall occurred.[172] Hydro also identified the percentage of hours in which the shortfall exceeded 100 MW.[173] Hydro previously defined the "manageable level" of unserved energy to "rotating outages [that] are reasonably within what has been experienced on the system before."[174] Hydro defined this threshold to be a maximum of 100 MW of load shed, which Hydro states was the volume that "Newfoundland Power was able to rotate…during the 2014 loss of load event."[175] We previously opined that "Hydro's approach is a reasonable overall proxy to determine the impact of a prolonged LIL outage and to assess the benefits" of proposed expansion plan portfolios, including the Avalon CT, in mitigating that impact.[176]

(84) For each run, Hydro identifies the 50th percentile and 90th percentile results, attempting to glean the "average" and "severe" cases, respectively.[177] The results of the LIL Shortfall Analysis runs are shown in the table below for the 50th percentile.

Table 6: LIL Shortfall Analysis Results (50th Percentile)[178]

Expansion Plan	Load Forecast	Resources Added	% of Hours > 100 MW Shortfall	Peak Shortfall (MW)	Total Shortfall (GWh)	Hours of Shortfall	% of Hours with Shortfall
1	Slow Decarbonization	BDE Unit 8 (2031)	7%	309	19	219	22%
2	Slow Decarbonization	Avalon CT (2031)	7%	304	18	210	21%
3	Slow Decarbonization	BDE Unit 8 (2031) Avalon CT (2031)	1%	174	3	45	4%
4	Slow Decarbonization	Avalon CT (2031) NP GTs (2031)	4%	264	11	145	14%
5	Reference Case	BDE Unit 8 (2031) Avalon CT (2031) 150 MW Proxy CT (2031)	0%	32	0	5	< 1%

[171] Hydro Evidentiary Update, page 7 lines 3 to 4.
[172] *See,* for example: Hydro Evidentiary Update, Table 3.
[173] *See,* for example: Hydro Evidentiary Update, Table 3.
[174] 2024 RAP, Appendix C, page 141 lines 7 to 8.
[175] Build Application, Schedule 3, page 40 footnote 63.
[176] Bates White Phase One Expert Report, paragraph 54.
[177] Hydro Evidentiary Update, page 7 lines 6 to 11.
[178] Hydro Evidentiary Update, Tables 3 to 7.

(85) The results for the 50th percentile LIL Shortfall Analysis runs demonstrate the challenge that the system faces in the event of a prolonged bipole outage of the LIL. With the Avalon CT alone as an incremental addition in 2031 to Hydro's portfolio (Expansion Plan 2), the system would still face generation shortfalls in 21% of all hours during the six-week period, with peak shortfalls reaching over 300 MW.[179] Moreover, the generation shortfalls would exceed the 100 MW threshold in 7% of all hours.[180] The Avalon CT on its own performs slightly better than the scenario where Bay d'Espoir Unit 8 is the sole addition resource addition (Expansion Plan 1, also in 2031).[181] Adding Newfoundland Power's planned life extensions of its GTs by 2031 with the Avalon CT (Expansion Plan 4) materially improves the performance of the system compared to the Avalon CT-only Expansion Plan. When NP's resources are added with the Avalon CT, generation shortfalls in excess of 100 MW are reduced from 7% to 4%, and the percent of hours with shortfall is reduced from 22% to 14%.[182] The portfolio which adds the Bay d'Espoir Unit 8 project (instead of the Newfoundland Power GTs) with the Avalon CT (Expansion Plan 3) enhances results even further, reducing total shortfall hours exceeding 100 MWs to just 1% of all hours.[183]

(86) The table below shows results for all five runs across the 90th percentile, or "severe" case.

Table 7: LIL Shortfall Analysis Results (90th Percentile)[184]

Expansion Plan	Load Forecast	Resources Added	% of Hours > 100 MW Shortfall	Peak Shortfall (MW)	Total Shortfall (GWh)	Hours of Shortfall	% of Hours with Shortfall
1	Slow Decarbonization	BDE Unit 8 (2031)	20%	392	48	445	44%
2	Slow Decarbonization	Avalon CT (2031)	19%	391	45	409	41%
3	Slow Decarbonization	BDE Unit 8 (2031) Avalon CT (2031)	4%	266	11	147	15%
4	Slow Decarbonization	Avalon CT (2031) NP GTs (2031)	12%	347	30	310	31%
5	Reference Case	BDE Unit 8 (2031) Avalon CT (2031) 150 MW Proxy CT (2031)	0%	136	1	24	2%

(87) The results for the 90th percentile LIL Shortfall Analysis runs further highlight how impactful an extended bipole outage on the LIL can be, especially as assumed system conditions worsen. However, the relative performance of the individual expansion plans stay similar as in the 50th percentile cases.

[179] Hydro Evidentiary Update, Table 4.
[180] Hydro Evidentiary Update, Table 4.
[181] Hydro Evidentiary Update, Table 3.
[182] Hydro Evidentiary Update, Table 6.
[183] Hydro Evidentiary Update, Table 5.
[184] Hydro Evidentiary Update, Tables 3 to 7.

The Avalon CT slightly outperforms Bay d'Espoir Unit 8, while additional resources help enhance portfolio performance, with larger units providing more benefits than smaller ones.

(88) In reviewing the results for the LIL Shortfall Analysis, we reviewed the inputs and outputs of the five model runs.[185] We identified no concerns with the model inputs or outputs and were able to replicate Hydro's determination of its unserved energy statistics provided in its Evidentiary Update.[186]

(89) In our view, Hydro's LIL Shortfall Analysis model runs support the proposed Avalon CT project for development in time for a 2031 commercial operations date. While the Avalon CT on its own cannot ensure high resource adequacy during a prolonged bipole outage of the LIL, the Avalon CT is shown to provide a substantial contribution, one that exceeds that of alternatives, including Bay d'Espoir Unit 8. We have previously recognized that Hydro's prior LIL Shortfall Analysis runs support its Build Application proposal to bring the Avalon CT online in 2031 (as opposed to a later date suggested by the capacity expansion model runs), and that doing so "acts as a form of insurance against an extended LIL bipole outage during peak season."[187] Newfoundland Power's planned GTs would also provide additional firm capacity, and we recognize that Hydro continues to propose the Bay d'Espoir Unit 8 project in a parallel matter. Here, the addition of the Avalon CT would provide needed resource adequacy (as confirmed in the LIL Shortfall Analysis) at the lowest cost among alternatives (as confirmed in the capacity expansion modeling).

[185] Phase Two Additional Information Request, Request 3, Attachment 1; Request 2, Attachment 1 and Attachment 2.

[186] Hydro Evidentiary Update, Tables 3 to 7.

[187] Bates White Phase One Expert Report, paragraph 176.

VII. Other Evidentiary Considerations

(90) In this section, we address Hydro's Evidentiary Update as it relates to Bay d'Espoir Unit 8, the Newfoundland Power Gas Turbines, and transmission and voltage constraints on the system.

A. Bay d'Espoir Unit 8

(91) Hydro's present application is focused primarily on the Avalon CT, with most filed material addressing the revised Avalon CT cost estimate – the title of the submission is, in fact, the "Avalon Combustion Turbine Evidentiary Update."[188] However, Hydro reiterates its request to receive approval to develop its entire "Minimum Investment Portfolio," which includes Bay d'Espoir Unit 8.[189] Hydro suggests that the results of the capacity expansion model runs and LIL Shortfall Analysis support the development of Bay d'Espoir Unit 8.[190]

(92) The capacity expansion modeling runs conducted by Hydro for its Evidentiary Update may be relevant for assessing the Bay d'Espoir Unit 8 resource but are less useful than they are in assessing the Avalon CT. Hydro has provided an updated, detailed AACE Class 3 estimate for the Avalon CT,[191] but did not provide an updated cost estimate for Bay d'Espoir. For its capacity expansion modeling, Hydro only escalated Bay d'Espoir Unit 8's capital cost by one year to be stated in 2025 dollars (as it did for all resource capital costs).[192] This suggests that Bay d'Espoir Unit 8's capital cost assumptions may be stale and in need of update as Hydro proceeds on its "early execution" activities.

(93) In its most recent monthly execution update (May 2026), Hydro notes that it is in contract negotiations with hydroelectric turbine suppliers.[193] Hydro continues to point out the risks in securing timely supply of its needed Bay d'Espoir Unit 8 project components, including the risk of higher costs.[194] The Avalon CT, on the other hand, is further along in securing contracts for its needed equipment, which enhances the certainty of its costs (and lends itself to project cost updates).[195]

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[188] Hydro Evidentiary Update, PDF page 8.

[189] Hydro Evidentiary Update, page 14 lines 9 to 14.

[190] Hydro Evidentiary Update, page 14 lines 15 to 17.

[191] Hydro Evidentiary Update, page 4 lines 3 to 5.

[192] Phase Two Additional Information Request, Request 2, Attachment 1, tab "Expansion Options"; Bates White Phase One Expert Report, Table 5.

[193] Hydro, "Bay d'Espoir Unit 8 Project Early Execution Update," May 22, 2026 ("May 2026 BDE Unit 8 Early Execution Update"), Sections 1.1 and 1.2, available at: http://www.pub.nf.ca/indexreports/baydespoir8EarlyExecution/From%20NLH%20-%20Bay%20d%E2%80%99Espoir%20Unit%208%20Project%20Early%20Execution%20Update%20-%20March%202026%20-%202026-05-22%20-%20REDACTED.PDF.

[194] May 2026 BDE Unit 8 Early Execution Update, Table 1.

[195] Hydro, "Avalon Combustion Turbine Project Early Execution Update," April 16, 2026 ("April 2026 Avalon CT Early Execution Update"), Sections 1.1 and 1.2, available at: http://www.pub.nf.ca/indexreports/avaloncombustion/From%20NLH%20-

Hydro's execution of the CT supply contract in December 2025 represents a material portion of the project's overall costs, and its higher-than-expected cost led Hydro to complete its updated assessment of the Avalon CT's overall project cost estimate.[196] As Bay d'Espoir Unit 8 advances in its early execution activities to a degree already reached by the Avalon CT, its cost estimate will likely change and could lead to an updated cost assessment as well. At that point, we would expect Hydro to provide supporting capacity expansion modeling to support the Bay d'Espoir Unit 8 project with its updated project cost, as it has in its Evidentiary Update for the Avalon CT.

(94) As it relates to Bay d'Espoir Unit 8, nothing in the Hydro Evidentiary Update changes our conclusions on the project as already explained in our Phase One, Phase One Addendum, and Phase Two reports. For example, we noted the similarity of the resources' modeled cost,[197] the lower total cost of the Avalon CT (but higher levelized cost due to the longer assumed asset life of Bay d'Espoir Unit 8),[198] and the outsized impact of Bay d'Espoir's 12.8 MW size advantage in driving its selection over the Avalon CT in some scenarios.[199] Those conclusions are unaffected by the Hydro Evidentiary Update.

(95) There are two LIL Shortfall Analysis runs contained in the Hydro Evidentiary Update that are worth noting and may be useful in informing a Hydro evidentiary update specific to Bay d'Espoir Unit 8 (should one be forthcoming). Expansion Plan 4 – which models the Avalon CT and the Newfoundland Power GTs – and Expansion Plan 5 – which models the Avalon CT, Bay d'Espoir Unit 8, and a 150 MW proxy CT – are illuminating, but beg a further analysis. Specifically, Expansion Plan 4 models approximately 200 MW of incremental firm capacity assuming the Slow Decarbonization load forecast,[200] while Expansion Plan 5 models approximately 450 MW of incremental firm capacity assuming the Reference Case load forecast.[201] Expansion Plan 5 performs materially better, but it is difficult to glean the importance of the 250 MW of additional incremental capacity in Expansion Plan 5 due to its use of the Reference Case load forecast.

(96) Should Hydro pursue an evidentiary update for Bay d'Espoir Unit 8, we recommend Hydro include one additional LIL Shortfall Analysis run: Expansion Plan 6, which uses the same assumptions as Expansion Plan 5, but replaces the 150 MW of proxy CTs with the approximately 50 MW of

%20Avalon%20Combustion%20Turbine%20Project%20Early%20Execution%20Update%20-%20February%202026%20-%20REDACTED%20-%202026-04-16.PDF.

[196] Hydro Evidentiary Update, page i lines 2 to 4.

[197] Bates White Phase One Addendum Report, paragraph 23.

[198] Bates White Phase One Addendum Report, paragraph 23.

[199] Bates White Phase One Addendum Report, paragraph 18.

[200] Newfoundland Power's refurbishments and uprates account for 48 MW; Avalon CT accounts for 141.6 MW, for a total of 189.6 MW of incremental firm capacity. *See:* Hydro Evidentiary Update, footnote 18; Phase Two Additional Information Request, Request 2, Attachment 1, tab "Expansion Options."

[201] In addition to the 141.6 MW from the Avalon CT, BDE Unit 8 provides 154.4 MW, and the proxy CT an additional 150 MW for a total firm capacity of 446 MW. *See:* Phase Two Additional Information Request, Request 2, Attachment 1, tab "Expansion Options."

Newfoundland Power GT uprates. This run would better identify the incremental impact of Bay d'Espoir Unit 8 on resource adequacy during an extended bipole outage of the LIL during peak season. This is particularly useful given the probability of the Newfoundland Power gas turbine uprates, which were not included in Hydro's Expansion Plan 5. We address the Newfoundland Power GTs next.

B. Newfoundland Power Gas Turbines

(97) The Greenhill and Wesleyville GTs, owned by Newfoundland Power, currently provide a combined 28 MW of firm capacity.[202] In its Build Application, submitted in March 2025, Hydro modeled both units to be retired in 2030.[203] On May 29, 2026, Newfoundland Power submitted its 2027 Capital Budget Application, which included its 2027-2031 Capital Plan, in which Newfoundland Power stated: "[Newfoundland Power] is anticipating filing a supplemental application in the third quarter of 2026 for the refurbishment of thermal generation facilities at Greenhill and Wesleyville over the next five years," with refurbishment work to be complete by 2031.[204] The refurbishment project is estimated to account for a total of approximately $231 million, though NP notes this estimate is subject to change in the forthcoming application.[205]

(98) The Board issued a letter in July 2025 directing Hydro to "[p]rovide an additional capacity expansion model run and LIL Shortfall Analysis which incorporates Newfoundland Power's plans to extend the lives of its gas turbines in 2028 and 2029."[206] Hydro did so, and in September 2025, provided the results. Hydro assumed that the total firm capacity for the Newfoundland Power GTs would be 48 MW.[207] The results of the model runs showed that "the firm capacity contribution of the Newfoundland Power gas turbines directly offsets the need for additional capacity from other resources, which both reduces the total firm capacity built by the model from other sources and delays those builds."[208]

(99) As we explain above, Hydro appropriately modeled three cases in which the Newfoundland Power GTs provide 48 MW of firm capacity during the planning horizon. Hydro's modeling shows that in scenario 4AEKC, which assumes the Newfoundland Power GTs, no fuel-burnoff requirement, and

[202] 2024 RAP, Appendix B, page 38 lines 21 to 25.

[203] Bates White Phase One Expert Report, paragraph 59; Build Application, Schedule 3, page 34 lines 1 to 2.

[204] Newfoundland Power, "Newfoundland Power 2027-2031 Capital Plan," May 2026 ("Newfoundland Power 2027-2031 Capital Plan"), page 1, available at: http://www.pub.nl.ca/applications/NP2027Capital/app/From%20NP%20-%202027%20Capital%20Budget%20Application%20-%202026-05-29.PDF.

[205] Newfoundland Power 2027-2031 Capital Plan, page 21.

[206] Bates White Phase One Addendum Report, paragraph 74.

[207] Bates White Phase One Addendum Report, paragraph 75; Hydro Evidentiary Update, footnote 18.

[208] Bates White Phase One Addendum Report, paragraph 76.

uses the Slow Decarbonization load forecast, only the Avalon CT is selected by the model.[209] In our view, both the inclusion of the Newfoundland Power GTs and the removal of the fuel burn-off requirement[210] to be higher likelihood assumptions, making scenario 4AEKC of higher value.

(100) In its Evidentiary Update, Hydro states that "while these uprates may represent a viable means of providing incremental capacity, they remain subject to further evaluation and cannot currently be relied upon as a component of the Minimum Investment Expansion Plan."[211] We recognize that Hydro's capacity expansion modeling has not, to date, included the Newfoundland Power GTs as an *economic option* for its model to select, but rather has manually inserted 48 MW of additional firm generation into the existing resource portfolio prior to determining which incremental resources would be needed to meet projected needs. Still, capacity expansion modeling has shown that just 48 MW of firm capacity can materially impact the constitution of the selected portfolio.

(101) Moreover, with Newfoundland Power including its GTs in its capital expenditure plans, these projects are not speculative. Newfoundland Power noted that the Wesleyville and Greenhill GTs are required to mitigate certain transmission planning contingencies on two 230 kV loops on Hydro's system.[212] In its 2027 Capital Budget Application, Newfoundland Power states that it "is anticipating filing a supplemental application in the third quarter of 2026 for the refurbishment of thermal generation facilities at Greenhill and Wesleyville over the next five years" at an estimated cost of "approximately $231 million."[213] Hydro should continue to include the Newfoundland Power GTs in its capacity expansion and LIL Shortfall Analysis modeling as it should for any thermal resource under consideration for life extension, refurbishment, or uprate (including its own thermal resources), including in any evidentiary updates for Bay d'Espoir Unit 8. Those updates should include the cost estimates of those projects, if available, and progress of any joint planning or review efforts by Hydro with Newfoundland Power.

[209] Hydro Evidentiary Update, Table 2 and page 12 line 25 to page 13 line 2.

[210] In our Phase Two Report, we stated: "Appropriate fuel management equipment and procedures would likely eliminate any uneconomic fuel burn-off at the Avalon CT." Bates White Phase Two Expert Report, paragraph 2.

[211] Hydro Evidentiary Update, page 13 lines 15 to 17.

[212] Newfoundland Power, "Newfoundland Power 2026-2030 Capital Plan," June 2025 ("Newfoundland Power 2026-2030 Capital Plan"), page 12, available at: http://www.pub.nf.ca/applications/NP2026Capital/app/From%20NP%20-%202026%20Capital%20Budget%20Application%20-%202025-06-27.PDF.

[213] Newfoundland Power 2027-2031 Capital Plan, page 1.

C. Transmission and Voltage Constraints

(102) Hydro indicates that it "is in the process of completing an assessment of reactive power requirements and resource options for the Island Interconnected System."[214] While the assessment is ongoing, Hydro states:

> The underlying analysis has determined that in scenarios where [Bay d'Espoir] Unit 8 and/or CAT Unit 3 are added without corresponding Avalon-based generation, and with the retirement of the Holyrood TGS, additional reactive power support would be required to support voltage levels on the Avalon transmission system.
>
> Although the costs of such reactive power support have not been explicitly included in the analysis, they would likely include solutions such as synchronous condensers or STATCOM installations. Conversely, the inclusion of dispatchable generation on the Avalon mitigates these risks by offloading transmission to the Avalon while providing crucial reactive power support to maintain voltage levels on the Avalon, improving system resilience.[215]

(103) Hydro concludes the preliminary results of its reactive power study "highlight that transmission and voltage constraints are key factors in evaluating expansion alternatives and reinforce the importance of considering both generation location, diversity, and system operability in long-term planning."[216]

(104) We agree, and while the reactive power study is not yet completed or provided in Hydro's Evidentiary Update, preliminary results seem to provide support for the Avalon CT's value in providing reactive power and voltage support for the Island Interconnected System. Hydro should provide the Board with the completed study as soon as practicable.

[214] Hydro Evidentiary Update, page 13 lines 19 to 20.

[215] Hydro Evidentiary Update, page 13 line 20 to page 14 line 3.

[216] Hydro Evidentiary Update, page 14 lines 4 to 6.

VIII. Key Conclusions and Recommendations

(105) Overall, we find that the Avalon CT cost updates, additional model runs, further sensitivities, and additional information provided by Hydro in its Evidentiary Update, Response to Identified Issues for Avalon CT, and Phase Two Additional Information Request filings have materially improved the evidentiary record.

(106) Our key findings, conclusions, and recommendations (noted in emphasized print) are, in summary:

Avalon CT cost update

- The largest cost component of the Avalon CT Project has now been largely fixed by contracting the CT packages, with a substantial increase to the Base Cost of the project of approximately $102.3 million.
- The updated Avalon CT cost estimates improve the record, and Hydro should continue to issue updated cost estimates while advancing towards the "Commitment-to-Build" decision to keep Board and stakeholders updated on project progress.

Management Reserve and Contingency

- While the largest component of cost for the Avalon CT Project has now been largely fixed, the Evidentiary Update shows counter-intuitive changes in budget components associated with ongoing cost risk, with Contingency simply growing proportionately with Base Cost, and Management Reserve declining only modestly. Hydro has provided explanations and calculation results supporting these results, but we find these to reinforce our concerns regarding the basis and reliability of the methodology used to derive the Contingency and Management Reserve amounts.
- The risk assessment methodology does not sensibly capture the effect of fixing the cost of the CT packages, and Contingency as a percentage of Base Cost is essentially unchanged at 11%. A Contingency of 11% on Base Cost excluding the $280 million CT contract cost would come to approximately $45 million, rather than the $75 million in the updated Authorized Budget Request.

Management Reserve and project governance

- **Recommendation #1:** There is a trade-off between the objective of the management reserve to facilitate quick action, and the ability of the Board to exercise detailed oversight of the use of reserve funds. We reiterate our recommendation in our Phase Two Report that 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.

- **Recommendation #2:** We also continue to recommend the burden of prudence 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.

Quantitative Risk Analysis (QRA) and Monte Carlo simulation

- While we acknowledge that QRA and Monte Carlo simulation are relatively common in project cost risk assessment, and that the general approach can provide useful information, we also conclude that the particular methods for the analysis must be selected to conform appropriately to the specific project context.
- Hydro has not presented a clear basis for the selection of the Hybrid Methodology for the QRA of Avalon CT costs, and particularly why the methodology applied for the Avalon CT should be different than that used for Bay d'Espoir Unit 8 (and the Bay d'Espoir Unit 7 Life Extension) based on QRA principles.
- The Avalon CT Project consists of a mature, widely deployed technology, well-understood by Hydro (based on its experience with the Holyrood CT), modest in size and complexity relative to many other utility generation projects, and now reasonably well-advanced in terms of costing. These characteristics would seem to be consistent with the application of a QRA method using estimate ranging, which would inherently accommodate a significant project event such as the contracting of the CT packages.
- The fact that the Hybrid Method does not sensibly capture the effect of fixing the cost of the largest single project deliverable indicates that this approach may not be "fit-for-use" in this application.

Water, fuel and other Avalon CT issues

- Hydro has adequately shown that the water usage limit does not appear likely to impose output restrictions on joint output of Holyrood TGS and the Avalon CT during a prolonged LIL outage. However, we agree with Hydro that refined estimates remain appropriate and needed in the detailed design phase.
- Hydro's response to fuel management concerns was adequate and should continue to pursue efforts to find fuel solutions during extended operations.
- While delay risks remain, Hydro continues to make commitments to remain on schedule with development of the Avalon CT.
- The CT package synchronous condenser capability and cost are confirmed to have been included in the contracted CT package.

Additional capacity expansion modeling

- Hydro's capacity expansion modeling was executed reasonably and demonstrates the need for and economic advantages of the Avalon CT relative to other options. This is particularly true

when the fuel burn-off requirement is not included in the modeling assumptions. Many modeling assumptions appropriately remained unchanged from the Build Application, while others (such as wind ELCCs and fuel price forecasts) were appropriately updated. While not all changed assumptions were highlighted and/or explained by Hydro in its Evidentiary Update, we identified no fatal flaws that would change our recommendation, which is to accept the modeling results as demonstrating the need for the Avalon CT.

New LIL Shortfall Analysis model runs

- Hydro's LIL Shortfall Analysis model runs support the proposed Avalon CT project for development in time for a 2031 commercial operations date. On its own, the Avalon CT cannot ensure resource adequacy during a prolonged bipole outage of the LIL but is shown to provide a substantial contribution, one that exceeds that of alternatives, including Bay d'Espoir Unit 8.

Other evidentiary considerations

- **Recommendation #3:** Should Hydro pursue an evidentiary update for Bay d'Espoir Unit 8, we recommend Hydro include one additional LIL Shortfall Analysis run: Expansion Plan 6, which uses the same assumptions as Expansion Plan 5, but replaces the 150 MW of proxy CTs with the ~50 MW of Newfoundland Power GT uprates.
- **Recommendation #4:** Hydro should continue to include the Newfoundland Power GTs in its capacity expansion and LIL Shortfall Analysis modeling as it should for any thermal resource under consideration for life extension, refurbishment, or uprate (including its own thermal resources), including in any evidentiary updates for Bay d'Espoir Unit 8. Those updates should include the cost estimates of those projects, if available, and progress of any joint planning or review efforts by Hydro with Newfoundland Power.
- **Recommendation #5:** While the reactive power study is not yet completed or provided in Hydro's Evidentiary Update, preliminary results seem to provide support for the Avalon CT's value in providing reactive power and voltage support for the Island Interconnected System. Hydro should provide the Board with the completed study as soon as practicable.

Appendix A. Matrices of scenario model runs

Table 8: Scenarios updated in Hydro Evidentiary Update

Scenario	Introduced in	Updated in Hydro Evidentiary Update	Load Forecast	Description
1AE	2024 RRA	Yes	2025 Reference	Fixed wind profile to meet firm energy criteria Removes batteries as a resource option
1AEC	2024 RRA	Yes	2025 Reference	Fixed wind profile to meet firm energy criteria Removed forced CT fuel burn-off Removes batteries as resource option
1AEK	Hydro September 2025 Response to Board letter	Yes	2025 Reference	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Included NP GT Uprates and refurbishments
1AEKC	Hydro Evidentiary Update	Yes	2025 Reference	Fixed wind profile to meet firm energy criteria Removed forced CT fuel burn-off Removed BESS as resource option Included NP GT Uprates and refurbishments
4AE	2024 RRA	Yes	2025 Slow Electrification	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option
4AEC	2024 RRA	Yes	2025 Slow Electrification	Fixed wind profile to meet firm energy criteria Removed forced CT fuel burn-off Removed BESS as resource option
4AEDC	Hydro Evidentiary Update	Yes	2025 Slow Electrification	Fixed wind profile to meet firm energy criteria Removed forced CT fuel burn-off Removed BESS as resource option P85 Hydro capital costs
4AEDHC	Hydro Evidentiary Update	Yes	2025 Slow Electrification	Fixed wind profile to meet firm energy criteria Removed forced CT fuel burn-off Removed BESS as resource option P85 CT capital costs P85 Hydro capital costs
4AEHC	Hydro Evidentiary Update	Yes	2025 Slow Electrification	Fixed wind profile to meet firm energy criteria Removed forced CT fuel burn-off Removed BESS as resource option P85 CT capital costs
4AEKC	Hydro Evidentiary Update	Yes	2025 Slow Electrification	Fixed wind profile to meet firm energy criteria Removed forced CT fuel burn-off Removed BESS as resource option Included NP GT Uprates and refurbishments

Table 9: Additional relevant scenarios introduced in the Hydro September 2025 Response to Board letter, not updated in Hydro Evidentiary Update

Scenario	Load Forecast	Description
1AK	2024 Reference	Fixed wind profile to meet firm energy criteria Included NP GT Uprates and refurbishments
4ADH	2024 Slow Decarbonization	Fixed wind profile to meet firm energy criteria P85 CT capital costs P85 Hydro capital costs
4AEK	2024 Slow Decarbonization	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Included NP GT Uprates and refurbishments
4AK	2024 Slow Decarbonization	Fixed wind profile to meet firm energy criteria Included NP GT Uprates and refurbishments

Table 10: Additional relevant scenarios introduced in the Build Application, not updated in Hydro Evidentiary Update

Scenario	Load Forecast	Description
1AEFC	2024 Reference	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Restricted CT additions to maximum of 150 MW Removed forced Avalon CT fuel burn-off
1AEFD	2024 Reference	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Restricted CT additions to maximum of 150 MW
1AEFDH	2024 Reference	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Restricted CT additions to maximum of 150 MW P85 CT capital costs P85 Hydro capital costs
1AEFG	2024 Reference	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Restricted CT additions to maximum of 150 MW Increased CT fuel costs
1AEFGH	2024 Reference	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Restricted CT additions to maximum of 150 MW P85 CT capital costs Increased CT fuel costs
1AEFH	2024 Reference	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Restricted CT additions to maximum of 150 MW P85 CT capital costs
1AEFJ	2024 Reference	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Restricted CT additions to maximum of 150 MW Reduced Hydro costs 15%
4AEFC	2024 Slow Decarbonization	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Restricted CT additions to maximum of 150 MW Removed forced Avalon CT fuel burn-off
4AEFD	2024 Slow Decarbonization	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Restricted CT additions to maximum of 150 MW P85 Hydro capital costs

4AEFDH	2024 Slow Decarbonization	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Restricted CT additions to maximum of 150 MW P85 CT capital costs P85 Hydro capital costs
4AEFG	2024 Slow Decarbonization	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Restricted CT additions to maximum of 150 MW Increased CT fuel costs
4AEFGH	2024 Slow Decarbonization	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Restricted CT additions to maximum of 150 MW P85 CT capital costs Increased CT fuel costs
4AEFH	2024 Slow Decarbonization	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Restricted CT additions to maximum of 150 MW P85 CT capital costs
4AEFJ	2024 Slow Decarbonization	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Restricted CT additions to maximum of 150 MW Reduced Hydro costs 15%

Table 11: Additional relevant scenarios introduced in the 2024 RRA, not updated in Hydro Evidentiary Update

Scenario	Load Forecast	Description
1A	2024 Reference	Fixed wind profile to meet firm energy criteria
1AB40	2024 Reference	Fixed wind profile to meet firm energy criteria BESS ELCC at 40%
1AB80	2024 Reference	Fixed wind profile to meet firm energy criteria BESS ELCC at 80%
1AC	2024 Reference	Fixed wind profile to meet firm energy criteria Removed forced CT fuel burn-off
1AD	2024 Reference	Fixed wind profile to meet firm energy criteria Increased Hydro capital costs 50%
1AEF	2024 Reference	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Restricted CT additions to maximum of 150 MW
1AEG	2024 Reference	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Increased CT fuel costs 50%
1AEH	2024 Reference	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Increased CT capital costs 50%
1AEI	2024 Reference	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Added 75 MW of NP GTs
4A	2024 Slow Decarbonization	Fixed wind profile to meet firm energy criteria
4AB40	2024 Slow Decarbonization	Fixed wind profile to meet firm energy criteria BESS ELCC at 40%
4AB80	2024 Slow Decarbonization	Fixed wind profile to meet firm energy criteria BESS ELCC at 80%
4AC	2024 Slow Decarbonization	Fixed wind profile to meet firm energy criteria Removed forced CT fuel burn-off
4AD	2024 Slow Decarbonization	Fixed wind profile to meet firm energy criteria Increased Hydro capital costs 50%
4AEF	2024 Slow Decarbonization	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Restricted CT additions to maximum of 150 MW
4AEF (ADV)	2024 Slow Decarbonization	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Restricted CT additions to maximum of 150 MW Advance second capacity resource from 2034 to 2031
4AEG	2024 Slow Decarbonization	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Increased CT fuel costs 50%

4AEH	2024 Slow Decarbonization	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Increased CT capital costs 50%
4AEI	2024 Slow Decarbonization	Fixed wind profile to meet firm energy criteria Removed BESS as a resource option Added 75 MW of NP GTs