Newfoundland and Labrador Hydro
Hydro Place. 500 Columbus Drive
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 I f. 709.737.1800
nlhydro.com

April 16, 2026

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

Attention: Mike McNiven
Board Secretary

Re: 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

Newfoundland and Labrador Hydro ("Hydro") filed its application for the purchase and installation of Bay d'Espoir ("BDE") Unit 8 and Avalon Combustion Turbine ("CT") ("2025 Build Application") on March 21, 2025. In December 2025, Hydro executed a contract for the procurement of the CT package for the Avalon CT project at a cost materially higher than originally estimated. Hydro filed the updated actual costs for the Avalon CT project with the Board of Commissioners of Public Utilities ("Board") on December 19, 2025, and, on March 9, 2026, Hydro filed revised cost estimates for the project, including updated contingency and management reserve informed by a refreshed Monte Carlo analysis. Hydro later confirmed that a supplementary evidentiary filing would follow, providing further detail on the Monte Carlo analysis, and updated analytical scenario and sensitivity modelling.

Attached hereto is a revised application updating the total capital expenditures for which Hydro requests approval. Hydro has also attached its Avalon CT Evidentiary Update, providing the results of an updated expansion plan analysis, Labrador-Island Link ("LIL") shortfall analysis, and updated Basis of Estimate and cost impact analysis. Based on the updated expansion plan analysis and the LIL shortfall assessment, Hydro continues to recommend the Avalon CT project, together with the development of BDE Unit 8, as the near-term capacity additions best suited to allow Hydro to ensure service and facilities that are reasonably safe and adequate, and just and reasonable. Together, these projects represent the recommended Minimum Investment Expansion Plan required to maintain reliable service under a range of future conditions and enable the retirement of the Holyrood Thermal Generating Station.

The revised Basis of Estimate and the attachments thereto contain commercially sensitive information. Hydro has applied the Board's recent decision regarding confidential information related to the 2025 Build Application, as contained in the Bates White Economic Consulting, LLC report, in determining the scope of redactions. Attachments previously filed with the original Basis of Estimate are refiled for completeness; however, where the Board has determined certain information should be publicly available, Hydro has removed redactions as appropriate.

An unredacted version of this correspondence is being provided to the Board, and to those parties who have executed non-disclosure agreements, on a confidential basis. Hydro requests that this information be kept confidential and not be made publicly available, and that the Board use the redacted version for posting to its website.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Shirley A. Walsh
Senior Legal Counsel, Regulatory
SAW/kd

Encl.

ecc:

Board of Commissioners of Public Utilities
Jacqui H. Glynn
Ryan Oake
Board General

Island Industrial Customer Group
Paul L. Coxworthy, Stewart McKelvey
Denis J. Fleming, Cox & Palmer
Glen G. Seaborn, Poole Althouse

Newfoundland Power Inc.
Dominic J. Foley
Douglas W. Wright
Regulatory Email

Consumer Advocate
Adrienne H.Y. Ding, O'Dea Earle
Justin W. King, O'Dea Earle

IN THE MATTER OF the *Electrical Power Control Act, 1994*, SNL 1994, Chapter E-5.1 ("*EPCA*") and the *Public Utilities Act*, RSNL 1990, Chapter P-47 ("*Act*"), and regulations thereunder; and

IN THE MATTER OF an application by Newfoundland and Labrador Hydro ("Hydro") for approval of capital expenditures for the purchase, construction, and installation of Unit 8 at the Bay d'Espoir Hydroelectric Generating Facility ("Bay d'Espoir") and a combustion turbine ("CT") located on the Avalon Peninsula.

To: The Board of Commissioners of Public Utilities ("Board")

THE APPLICATION OF HYDRO STATES THAT:

A. Background

1. Hydro is a corporation continued and existing under the *Hydro Corporation Act, 2024*, is a public utility within the meaning of the *Act,* and is subject to the provisions of the *EPCA.*

2. Through substantial analysis completed within the *Reliability and Resource Adequacy Study Review* proceeding (*"RRA Study Review"*), and in particular as pertaining to the 2024 Resource Adequacy Plan[1] as part of the *RRA Study Review*, Hydro determined that a minimum investment is necessary to ensure Hydro can continue to provide service that is safe and adequate, and just and reasonable, as required by Section 37 of the *Act*.

3. The 2024 Resource Adequacy Plan assessed the integration of new assets, system reliability, and the effects of electrification and decarbonization across various scenarios. The analysis highlighted that, in all modelled scenarios, urgent investment in increased electrical supply is essential and justified to maintain a reliable power supply for customers.

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[1] "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024). http://www.pub.nl.ca/applications/NLH2018ReliabilityAdequacy/correspondence/From%20NLH%20-%202024%20Resource%20Adequacy%20Plan%20-%20REVISION%202%20-%20REDACTED%20-%202024-08-26.PDF.

4. In Hydro's updated Reference Case Expansion Plan scenario (the scenario most likely to occur), Hydro's analysis determined that approximately 525 MW of new generation is required by 2034 to address the additional Island demand and to allow for the retirement of aging thermal assets, including the Holyrood Thermal Generating Station ("Holyrood TGS").

5. The Minimum Investment Required Expansion Plan, as described in the 2024 Resource Adequacy Plan and the enclosed application, is based on a high level of Labrador-Island Link reliability and the lowest load growth (2024 Slow Decarbonization forecast) that can be reasonably anticipated for the Island Interconnected System. The Minimum Investment Required adds 385 MW of new capacity on the Island Interconnected System.

6. Hydro's evidence, as enclosed with this application, supports the construction of two new capacity resources, specifically:

   (i) An additional 150 MW unit at Bay d'Espoir ("BDE Unit 8"); and

   (ii) A new approximately 150 MW CT with renewable fuel capabilities located on the Avalon Peninsula ("Avalon CT") (collectively, the "2025 Build Application").

7. The parties to the *RRA Study Review*, more specifically Hydro, the Consumer Advocate, Newfoundland Power Inc., and the Island Industrial Customers Group, came to an agreement on certain facts and principles within that proceeding ("Settled Issues") that have implications for the 2025 Build Application. The Settlement Agreement is attached to this application as Schedule 2.[2]

8. Through the Settlement Agreement, the parties recommend that the Board accept their agreement regarding the Settled Issues during the Board's evaluation of the 2025 Build Application, and the parties' further consent to the admission in the record of matter of all pre-filed testimony, exhibits, and responses to requests for information pertaining to the Settled Issues.

[2] The Labrador Interconnected Group would be signing only to the extent to reflect agreement to item 1 in the Settled Issues List that forms part of the Settlement Agreement. That item does not have implications for the proposals in the attached application; the fully executed Settlement Agreement will be filed once received.

B. Application

9. Bay d'Espoir is located on the south coast of Newfoundland and Labrador and is the largest hydroelectric generating facility in the Island Interconnected System. Bay d'Espoir currently provides 613 MW of electrical capacity and 2,560 GWh of energy annually via seven existing units and includes a reservoir, a spillway, and two powerhouses.

10. The proposed BDE Unit 8 will supplement the existing Bay d'Espoir Hydroelectric Development, via the use of the existing reservoir and will be located with Powerhouse 2. BDE Unit 8 is expected to have a capacity of approximately 150 MW, which will help meet the system's requirement for additional capacity. There is no appreciable expected additional energy from this addition.

11. The Avalon CT will supplement system capacity by adding a new multi-unit 150 MW generating facility that will provide peaking power support and standby generation and enable reduced generation from the Holyrood TGS. The location identified for the Avalon CT is the Holyrood TGS site.

12. The 2025 Build Application requests approval of a total overall Authorized Budget of $2.08 billion for both of the necessary proposed projects, inclusive of the planned project budgets and a management reserve. In acting on recommendations from the Muskrat Falls Inquiry and consistent with best practices in major projects, Hydro established a Management Reserve to assist with the management of strategic risks. The Management Reserve is further discussed in Section 5.4 of Schedule 1.

13. The total requested Authorized Budget for BDE Unit 8 is $1.08 billion, with anticipated completion in 2031. The capital cost estimates, planned project budgets which include interest during construction and escalation, and the management reserve for each project are described in Schedule 4 and Appendix A thereto.

14. The total requested Authorized Budget for the Avalon CT is $995.9 million with anticipated completion in early 2030. The capital cost estimates, planned project budgets which include interest during construction and escalation, and the management reserve for each project are described in Schedule 5 and Appendix B thereto, along with Hydro's Evidentiary Update dated April 16, 2026.

15. Schedules 1 to 5 to this application are the 2025 Build Application Overview, Settlement Agreement, Expansion Plan Update, BDE Unit 8 Project Evidence, and Avalon CT Project Evidence.

16. Schedule 1: The 2025 Build Application Overview provides:

a) The background to the 2025 Build Application;

b) A summary of Hydro's Expansion Plan Update;

c) A summary of the 2025 Build Application;

d) A discussion of the development of the proposed projects;

e) A synopsis of the BDE Unit 8 evidence;

f) A synopsis of the Avalon CT evidence;

g) A description of Hydro's organizational readiness, including Hydro's Major Projects Governance Framework and execution capability; and

h) A customer rate impact analysis.

17. Schedule 2: Settlement Agreement provides a copy of the Settlement Agreement entered into between Hydro and the parties to the *RRA Study Review* which requests that the Board accept the settlement in its review of the 2025 Build Application.

18. Schedule 3: Expansion Plan Update provides an update to the Expansion Plan Hydro had completed in the *RRA Study Review* to incorporate the latest available information, including an updated load forecast (Schedule 3, Appendix A).

19. Schedule 4: BDE Unit 8 Project Evidence provides detailed evidence in support of BDE Unit 8, including the Basis of Estimate and Basis of Schedule (Schedule 4, Attachments 1 and 2, respectively).

20. Schedule 5: Avalon CT Project Evidence provides detailed evidence in support of Avalon CT, including the Basis of Estimate and Basis of Schedule (Schedule 5, Attachments 1 and 2, respectively).

C. Reason for Approval

21. The proposed capital expenditures for BDE Unit 8 and the Avalon CT as set out in the 2025 Build Application are necessary to allow Hydro to continue to provide to its customers service and facilities that are reasonably safe and adequate, and just and reasonable, as required by Section 37 of the *Act*.

D. Newfoundland and Labrador Hydro's Request

22. Hydro requests that the Board make an Order as follows:

    (i) Approving the requested Authorized Budget for the BDE Unit 8 in the amount of $1.08 billion as set out in Appendix A of Schedule 4, pursuant to Section 41(1) of the *Act*; and

    (ii) Approving the requested Authorized Budget for the Avalon CT in the amount of $995.9 million as set out in the Evidentiary Update dated April 16, 2026, pursuant to Section 41(1) of the *Act*.

E. Communications

23. Communications with respect to this Application should be forwarded to Shirley A. Walsh, Senior Legal Counsel, Regulatory for Hydro.

DATED at St. John's in the province of Newfoundland and Labrador on this 16th day of April 2026.

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh
Shirley A. Walsh
Counsel for the Applicant
Newfoundland and Labrador Hydro
500 Columbus Drive, P.O. Box 12400
St. John's, NL A1B 4K7
Telephone: (709) 685-4973

2025 Build Application

Avalon Combustion Turbine Evidentiary Update

April 16, 2026

A report to the Board of Commissioners of Public Utilities

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") has completed an updated assessment of the Avalon Combustion Turbine ("CT") project following the execution of the CT supply contract in December 2025 at a cost materially higher than originally estimated. This update evaluates the impact of the revised cost estimate on expansion planning, system reliability, and resource adequacy, and confirms that the Avalon CT remains a prudent component of Hydro's recommended Minimum Investment Expansion Plan.

The updated project estimate of $995.9 million represents an increase of $104.5 million relative to the estimate presented in Hydro's application for the purchase and installation of Bay d'Espoir ("BDE") Unit 8 and Avalon CT ("2025 Build Application").[1] The increase is primarily attributable to the CT supply contract, reflecting a change in global market conditions that occurred subsequent to the development of the original estimate. These changes include supply chain constraints, increased demand for CT equipment, and broader market factors affecting pricing and delivery timelines. These conditions were not reflected in the supplier information available during the feasibility and FEED[2] phases and have materially altered the market for CT procurement.

Hydro completed updated expansion planning analysis to assess the impact of the increased CT cost across a range of scenarios reflecting variations in load growth, Labrador-Island Link ("LIL") equivalent forced outage rates ("EqFOR"), fuel burn-off requirements, and capital-cost assumptions. The results demonstrate that the Avalon CT continues to be selected in the majority of scenarios as a least-cost supply addition within the planning period. The analysis consistently demonstrates that CT capacity on the Avalon Peninsula is required to meet system needs.

The LIL shortfall analysis, simulating the loss of the LIL bipole over a six-week period during the highest demand period in the winter, provides additional context for this requirement. In scenarios where the Avalon CT is not selected, the system experiences significant capacity shortfalls during a prolonged LIL outage, with peak shortfalls exceeding 200 MW during average conditions and shortfalls occurring over a substantial portion of the outage period. In contrast, scenarios that include the Avalon CT in conjunction with BDE Unit 8 demonstrate a material reduction in both the magnitude and duration of

[1] "2025 Build Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 21, 2025.
[2] Front-End Engineering Design ("FEED").

shortfalls, reducing reliance on rotating outages and improving overall system performance under contingency conditions.

In addition to its contribution to system capacity, the Avalon CT provides important operational benefits. As a dispatchable resource located on the Avalon Peninsula, it supports voltage levels on the transmission system and mitigates transmission constraints, following the retirement of the Holyrood Thermal Generating Station ("Holyrood TGS"). Alternative expansion pathways that rely on off-Avalon generation do not address these requirements and would necessitate additional system investments.

The expansion planning analysis also confirms that BDE Unit 8 remains a consistent and least-cost initial supply addition across the majority of scenarios and represents a foundational component of Hydro's Minimum Investment Expansion Plan. However, the analysis demonstrates that hydro additions alone are not sufficient to address system reliability and operability requirements, particularly under LIL shortfall conditions. Dispatchable generation on the Avalon is required to complement all off-Avalon development and ensure reliable system operation.

Taken together, the results of the updated cost assessment, expansion planning analysis, and LIL shortfall analysis demonstrate that the Avalon CT continues to be a necessary and appropriate investment. The project provides a timely and flexible source of dispatchable generation that addresses both system-wide and on-Avalon reliability requirements and supports Hydro's ability to provide safe and adequate service under a range of future conditions.

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1.0 Introduction

Hydro filed its 2025 Build Application on March 21, 2025. Hydro had previously applied on March 12, 2025, for authorization to proceed with early execution capital expenditures related to both the BDE Unit 8 and Avalon CT projects. The early execution application was approved in the Board of Commissioners of Public Utilities ("Board") Order No. P.U. 17(2025); Hydro has been reporting monthly to the Board since that approval. Hydro received approval for additional early execution expenditures related to the Avalon CT on March 13, 2026, in Board Order No. P.U. 7(2026).

In December 2025, Hydro executed a contract for the procurement of the CT packages. The cost associated with that contract, as communicated to the Board in December and in the monthly reports thereafter regarding early execution expenditures, is higher than originally estimated. This update evaluates how higher project costs affect least-cost planning, reliability, and resource adequacy, and confirms that the Avalon CT remains a prudent project for providing safe, adequate, and reasonable service under Section 37 of the *Public Utilities Act*.

To support this assessment, Hydro has undertaken updated expansion planning analysis and LIL shortfall analysis across a range of scenarios. The scenarios provided reflect varying assumptions related to load growth, LIL EqFOR, fuel burn-off requirements, and capital-cost assumptions. Hydro is also providing further details and explanations for the updated cost estimate and Monte Carlo analysis, previously provided on March 9, 2026.

2.0 Avalon CT Cost Update

Hydro conducted an impact assessment in early 2026 to quantify the effect of increased CT pricing on the estimated cost of the Avalon CT project. This assessment followed the execution of a CT supply contract in December 2025 at a price materially higher than the value included in the approved FEED estimate that formed the basis for the requested approval in the 2025 Build Application.

At the time the CT cost assumptions were developed and assessed in 2024, Hydro considered the risk of material cost escalation to be low based on the information available and prevailing market conditions. Multiple OEM[3] and suppliers were actively engaged throughout the feasibility and FEED phases and did not indicate any substantive or imminent pricing increases, and the June 2024 quote that underpinned

[3] Original Equipment Manufacturer ("OEM").

the Hatch Ltd. ("Hatch") estimate reflected current market intelligence at that time. This period also followed a phase of significant post-COVID-19 inflation, during which CT pricing had already increased relative to earlier estimates; the project team reasonably interpreted this as the market having absorbed the effects of that hyper-inflation, with pricing trends stabilizing. This view was further supported by Hatch's broader market experience on other CT projects, where no abnormal pricing pressures were identified, and by an independent review from Daymark Energy Advisors, which concluded that Hydro's cost assumptions were reasonable, albeit higher than industry benchmarks due to site-specific considerations. Subsequent cost increases are now understood to have been 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. These developments materially altered market dynamics, particularly with respect to equipment availability and schedule-driven pricing pressures, and do not reflect a deficiency in the original cost assessment, but rather a fundamental and unforeseen change in external market conditions.

The executed CT contract price of approximately $280 million exceeds the FEED estimate allowance of approximately $173 million, representing a substantial change in project cost assumptions. With regards to the cost increase, Bates White Economic Consulting, LLC concluded that "the supply risks identified by Hydro reflect the reality of the current market. Increased costs and delivery times are likely unavoidable."[4]

Hydro's impact analysis was completed using the same hybrid parametric and expected-value quantitative risk methodology applied during FEED, incorporating Monte Carlo Simulation. The analysis updated the base estimate to reflect the executed CT contract price and included an allowance for Canadian Registration Number certification. In addition, residual cost uncertainties within the CT contract, such as foreign exchange exposure, transportation costs, onsite OEM support, and potential design-related changes, were quantified and incorporated as a specific project risk within the simulation.

[4] "Expert Report of Vincent Musco and Collin Cain," Bates White Economic Consulting, LLC, February 3, 2026, p. 23, item (55).

As part of the assessment, Hydro reviewed other major project cost elements, including EPCM[5] services, transformers, civil works, transmission scope, early execution activities, and detailed design. While 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. Consequently, no additional adjustments were included beyond those directly associated with the CT package. Hydro also assessed how the risk of CT cost increases would have impacted the management reserve had the risk been known during FEED and determined that, due to the stochastic nature of the Quantitative Risk Analysis, this risk would have resulted in a management reserve increase of approximately $10 million, rather than the approximate $100 million increase in CT cost.

The results of the updated analysis are provided in Table 1. For additional information on the impact analysis and associated changes to the project estimate, please refer to Attachment 2.

Table 1: Avalon CT Project Estimate Update ($ Millions)[6]

Item	Original BOE[7]	Revised Recommendation	Change	Notes
Base Estimate	586.6	689.0	+102.3	Base price has been adjusted as a result of the change to the CT price. Indications are that other elements are within expected estimate bounds. As detailed design has not yet commenced, several unknowns remain.
Escalation	44.8	33.7	-11.2	Escalation has been adjusted as the CT contract has been awarded, thus fixing escalation rates within the contract.
IDC[8]	66.6	76.1	+9.6	IDC has been adjusted as the CT contract has been awarded with a higher base estimate.
Contingency (mean at P55)	65.1	75.5	+10.4	Project contingency has been adjusted as a result of the price increase of the CT package, as well as the added specific risks on the variable portions of the scope in the contract, as listed above.
Management Reserve (P85)	128.2	121.6	-6.6	Management reserve has been adjusted slightly due to changes in the certainty of the CT components.
Total	**891.4**	**995.9**	**+104.5**	

[5] Engineering, Procurement, and Construction Management ("EPCM").
[6] Numbers may not add due to rounding.
[7] Basis of Estimate ("BOE").
[8] Interest During Construction ("IDC").

Based on the analysis, Hydro has revised the authorized Avalon CT project cost estimate from $891.4 million to $995.9 million, representing a net increase of $104.5 million. Over 97% of this increase is attributable to direct cost impacts associated with the CT procurement. The estimate classification remains an AACE[9] Class 3 estimate, and the probabilistic cost range has narrowed slightly relative to the FEED estimate due to increased certainty in CT pricing.[10]

This analysis was focused on the CT price increase and associated contract-specific risks. 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.[11]

3.0 Expansion Plan Analysis

To reflect the material increase in the proposed Authorized Avalon CT project cost estimate on the previously completed alternatives analysis, Hydro ran a total of ten scenarios. These reflected a range of sensitivities related to load growth, LIL EqFOR, fuel burn-off requirements, and capital cost assumptions for both hydro and CT resources. Given the reduced contribution of Battery Energy Storage Systems ("BESS") during a LIL shortfall scenario, and alignment that BESS resources are not to be pursued as part of the Minimum Investment Portfolio,[12] Hydro has not included BESS resources as a factor in these scenarios, but will continue to include BESS resources in future *Reliability and Resource Adequacy Study Review*.

All scenarios incorporate the 2025 load forecast update and the updated wind Effective Load Carrying Capability ("ELCC") assumptions, reflecting the latest assessment of wind's contribution to system reliability.[13] In addition, the scenarios reflect revised firm energy requirements arising from Hydro's updated Under Frequency Load Shedding ("UFLS") scheme.[14] The full expansion plan analysis is provided in Appendix A. The results of the updated expansion planning analysis are summarized in Table 2, which presents the key capacity additions through the year 2035, and associated assumptions for each

[9] Association for the Advancement of Cost Engineering ("AACE").
[10] Project Estimate Range for Base Cost + Contingency is now -19.6%/+22.0%, compared to -22.8%/+25.7% for the original estimate.
[11] "2025 Build Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 21, 2025, sch. 1, att. 1, p. 31.
[12] "Expert Addendum Report of Vincent Musco and Collin Cain," Bates White Economic Consulting, LLC, November 6, 2025, p. 18, item (40).
[13] "Newfoundland & Labrador Hydro ELCC Study: Evaluating Effective Load Carrying Capability," Energy and Environmental Economics, Inc., November 2025. Provided in "Evaluating Effective Load Carrying Capability – Overview," Newfoundland and Labrador Hydro, December 9, 2025, att. 1.
[14] "LCP Operational Study: Final LCP Operational Study ("Stage 4F") Report," TransGrid Solutions Inc., June 26, 2025. Provided in "Final LCP Operational (Stage 4F) Study – Overview," Newfoundland and Labrador Hydro, August 11, 2025, att. 1.

1 scenario evaluated. For scenarios including Newfoundland Power CTs, these units were forced in the
2 model, and no costs were included.

Table 2: Expansion Plan Analysis to 2035

Scenario	Assumptions	First Capacity Addition	Second Capacity Addition	Total Installed Wind	Net Present Value ($ Billions)
4AE[15]	•2025 Slow Electrification Load Forecast •1% LIL EqFOR	BDE Unit 8 (2031)	CAT[16] Unit 3 (2034)	200 MW	3.4
4AEC	•2025 Slow Electrification Load Forecast •1% LIL EqFOR •No Fuel Burn-Off	**Avalon CT (2031)**	BDE Unit 8 (2034)	200 MW	3.2
4AEDC	•2025 Slow Electrification Load Forecast •1% LIL EqFOR •No Fuel Burn-Off •P85 Hydro Cost	**Avalon CT (2031)**	Additional CT (2034)	200 MW	3.3
4AEHC	•2025 Slow Electrification Load Forecast •1% LIL EqFOR •No Fuel Burn-Off •P85 CT Cost	BDE Unit 8 (2031)	CAT Unit 3 (2034)	200 MW	3.3
4AEDHC	•2025 Slow Electrification Load Forecast •1% LIL EqFOR •No Fuel Burn-Off •P85 CT and Hydro Cost	**Avalon CT (2031)**	BDE Unit 8 (2034)	200 MW	3.4
4AEKC	•2025 Slow Electrification Load Forecast •1% LIL EqFOR •NP[17] CT Uprate[18] •No Fuel Burn-Off	**Avalon CT (2031)**	N/A[19]	200 MW	2.9[20]

[15] As the model is not selecting CT resources, scenario 4AE is equivalent to scenario 4AEF for the purposes of this analysis. Scenario 4AEF is equivalent to scenario 4AE, with the exception of limiting the total number of CTs to one, 150 MW option.
[16] Cat Arm ("CAT").
[17] Newfoundland Power Inc. ("NP" or "Newfoundland Power").
[18] The NP CT uprate refers to Newfoundland Power's planned refurbishment and uprate of its Wesleyville and Greenhill CTs, totalling 48 MW.
[19] No additional capacity resource requirements identified within the planning period.
[20] Excludes the cost of Newfoundland Power CTs.

Scenario	Assumptions	First Capacity Addition	Second Capacity Addition	Total Installed Wind	Net Present Value ($ Billions)
1AE	•2025 Reference Load Forecast •5% LIL EqFOR	BDE Unit 8 (2031) **Avalon CT (2031)** Additional CT (2031)	N/A	300 MW	5.8
1AEC	•2025 Reference Load Forecast •5% LIL EqFOR •No Fuel Burn-Off	BDE Unit 8 (2031) **Avalon CT (2031)** Additional CT (2031)	N/A	300 MW	5.3
1AEK	•2025 Reference Load Forecast •5% LIL EqFOR •NP CT Uprate	BDE Unit 8 (2031) **Avalon CT (2031)**	Additional CTs (2034)	300 MW	5.4[21]
1AEKC	•2025 Reference Load Forecast •5% LIL EqFOR •No Fuel Burn-Off •NP CT Uprate	BDE Unit 8 (2031) **Avalon CT (2031)**	Additional CTs (2034)	300 MW	4.9[22]

The results of the expansion plan analysis are discussed in conjunction with the LIL Shortfall analysis and other system considerations in Section 5.0.

4.0 Labrador-Island Link Shortfall Analysis

To assess the performance of the expansion plans in a six-week LIL shortfall scenario, Hydro conducted five LIL Shortfall Analyses based on a 2032 test year, each at Average (50th percentile) and Severe (90th percentile) system conditions:

- Slow Electrification Load Forecast with BDE Unit 8 in 2031;
- Slow Electrification Load Forecast with Avalon CT in 2031;
- Slow Electrification Load Forecast with BDE Unit 8 in 2031 and Avalon CT in 2031;
- Slow Electrification Load Forecast, NP CTs Included, Avalon CT in 2031; and

[21] *Supra*, f.n. 20.
[22] *Supra*, f.n. 20.

- Reference Load Forecast with BDE Unit 8, Avalon CT, and an additional CT in 2031.

The analysis was completed on a probabilistic basis[23] and results are presented as 50th and 90th percentiles representing average and severe scenarios. The amount of shortfall is defined as the amount of load shedding required to restore to a minimum regulating reserve of 70 MW.[24] The average and severe shortfall cases are described as follows:

- **Average Case (50th Percentile):** Represents a generation shortfall that reflects a combination of average probabilistic outcomes, such as typical weather and unit availability, that would be expected to be exceeded 50% of the time in the analysis.
- **Severe Case (90th Percentile):** Represents a generation shortfall that reflects a combination of severe probabilistic outcomes, such as severe weather and poor unit availability, that would be expected to be exceeded 10% of the time in the analysis.

This analysis does not consider on-Island transmission constraints but generation (supply) constraints only. The results of each analysis are presented in Table 3, Table 4, Table 5, Table 6, and Table 7, respectively. Additional charts and duration curves are provided in Appendix C.

Table 3: Slow Electrification Load Forecast, BDE Unit 8 in 2031

	Average (50th Percentile)	Severe (90th Percentile)
Peak shortfall (MW)	309	392
Total shortfall (GWh)	19	48
Hours of shortfall (hr)	219	445
% of all hours	22%	44%
% Hours > 100MW	7%	20%

[23] The probabilistic analysis considers 2,400 random combinations of weather-driven loads, unit outage profiles, and renewable generation.
[24] Please refer to “2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study,” Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024), app. B, sec. 5.1.5.

Table 4: Slow Electrification Load Forecast, Avalon CT in 2031

	Average (50th Percentile)	Severe (90th Percentile)
Peak shortfall (MW)	304	391
Total shortfall (GWh)	18	45
Hours of shortfall (hr)	210	409
% of all hours	21%	41%
% Hours > 100MW	7%	19%

Table 5: Slow Electrification Load Forecast, BDE Unit 8 and Avalon CT in 2031

	Average (50th Percentile)	Severe (90th Percentile)
Peak shortfall (MW)	174	266
Total shortfall (GWh)	3	11
Hours of shortfall (hr)	45	147
% of all hours	4%	15%
% Hours > 100MW	1%	4%

Table 6: Slow Electrification Load Forecast; NP CTs Included, Avalon CT in 2031

	Average (50th Percentile)	Severe (90th Percentile)
Peak shortfall (MW)	264	347
Total shortfall (GWh)	11	30
Hours of shortfall (hr)	145	310
% of all hours	14%	31%
% Hours > 100MW	4%	12%

Table 7: Reference Load Forecast; BDE Unit 8, Avalon CT, and An Additional 150 MW Nominal CT in 2031

	Average (50th Percentile)	Severe (90th Percentile)
Peak shortfall (MW)	32	136
Total shortfall (GWh)	0	1
Hours of shortfall (hr)	5	24
% of all hours	0%	2%
% Hours > 100MW	0%	0%

Under the slow electrification load forecast, where only BDE Unit 8 **or** the Avalon CT is constructed by 2032, significantly larger shortfalls are observed. Peak shortfalls exceed 300 MW under average conditions and approach 400 MW under severe conditions. Total energy shortfalls increase materially, with shortfalls occurring in up to 44 percent of outage hours. A notable portion of these hours exceeds 100 MW, indicating a substantial reliance on load shedding to maintain system stability.

Hydro's Minimum Investment Expansion Plan, which includes the slow electrification load forecast with BDE Unit 8 and the Avalon CT both available in 2031, demonstrates improved system performance relative to the hydro-only expansion case. Peak shortfalls are reduced to approximately 174 MW under average conditions and 266 MW under severe conditions. Both the duration and magnitude of shortfalls are significantly reduced, although some hours with higher magnitude shortfalls remain.[25]

In the case reflecting the slow electrification load forecast with the Avalon CT and Newfoundland Power CT uprates available in 2031, demonstrates improved system performance relative to only BDE Unit 8 or the Avalon CT expansion case, but reduced performance relative to the Minimum Investment Required Expansion Plan. Peak shortfalls are approximately 264 MW under average conditions and 347 MW under severe conditions. Total energy shortfalls remain material at approximately 11 GWh and 30 GWh, respectively. Shortfalls occur over 145 hours under average conditions and 310 hours under severe conditions, representing up to 31 percent of the outage period. While the inclusion of Newfoundland Power CT uprates contributes to a reduction in both the magnitude and duration of shortfalls, a notable portion of these hours continues to exceed 100 MW, indicating increased reliance on load shedding.

Under the reference load forecast, where sufficient dispatchable capacity is available in 2031, the system experiences minimal shortfall conditions. Peak shortfalls are limited to approximately 32 MW under average conditions and 136 MW under severe conditions. Total energy shortfalls remain low, and shortfall events occur over a limited number of hours, representing up to two percent of the outage period under severe conditions. No hours of shortfall exceeding 100 MW are observed under average conditions.

[25] Shortfall analysis results differ from those provided in the 2025 Build Application due to the reduction in wind capacity required to meet the firm energy requirements as a result of the implementation of the full UFLS scheme on the Island Interconnected System.

The results of the LIL shortfall analysis are discussed in conjunction with the expansion plan analysis and other system considerations in Section 5.0.

5.0 Analysis of Results

A discussion of the results of the expansion plan analysis and the LIL shortfall analysis is presented below, organized by key system components and constraints.

5.1 Avalon Combustion Turbine

Across the expansion planning scenarios, the Avalon CT is selected by the model in the majority of cases, specifically in eight of ten scenarios, as a least-cost supply addition within the planning period. These outcomes are generally observed in scenarios that reflect the removal of the fuel burn-off requirement, and in all reference case scenarios, which are characterized by expected load growth and a higher LIL equivalent forced outage rate.

These results consistently demonstrate that CT capacity on the Avalon is a required component of the least-cost expansion plan. The expansion plan analysis incorporates known changes since the 2025 Build Application, such as the updated wind ELCC and the final UFLS scheme. Hydro's analysis has largely assumed fuel burn-off requirements are removed, which influences the selection of BDE Unit 8 versus Avalon CT as the first resource option within select scenarios. Hydro continues to recommend the advancement of both solutions within its Minimum Investment Required Expansion Plan for the reasons described within the 2025 Build Application proceeding.

Importantly, the LIL shortfall analysis provides additional context for the timing of this requirement. The results demonstrate that the presence of dispatchable thermal generation on the Avalon Peninsula in conjunction with a significant additional generating resource, such as BDE Unit 8, materially reduces both the magnitude and duration of capacity shortfalls during a prolonged LIL outage during the winter period. In scenarios with only one resource constructed in 2031, peak shortfalls exceed 200 MW under average conditions, with shortfalls occurring in up to 44 percent of outage hours. By contrast, the inclusion and advancement of both the Avalon CT and BDE Unit 8 significantly reduces both peak and total shortfalls, as well as the frequency of high magnitude events.

These findings indicate that, while the model may defer one of the first capacity builds under certain assumptions based on least-cost optimization, such outcomes do not fully capture the reliability risks associated with a LIL shortfall scenario or transmission requirements. As a result, Hydro's recommended Minimum Investment Required Expansion Plan continues to recommend that the Avalon CT and BDE Unit 8 be constructed by 2031 to ensure dispatchable capacity is available to manage these risks. In addition to its role in mitigating shortfall risk, the Avalon CT provides important benefits to the system once Holyrood TGS is retired by providing reactive power support to maintain system voltages on the Avalon, as further discussed in Section 5.5.

These results demonstrate that the increased CT cost does not alter the conclusion that the Avalon CT remains a required component of Hydro's Minimum Investment Expansion Plan.

5.2 Bay d'Espoir Unit 8

Across the expansion planning scenarios, the addition of BDE Unit 8 within the planning period is consistently identified as a least-cost supply addition, being selected in eight of the ten scenarios evaluated. This result indicates that the expansion of existing hydro capacity at BDE is robust to changes in input assumptions, including variations in load growth, LIL EqFOR, and capital cost assumptions.

The only exceptions to this outcome occur in low load scenarios where hydro capital costs are increased in combination with the fuel burn-off requirement is removed, as well as in the scenario where incremental capacity is assumed from Newfoundland Power CT uprates and the fuel burn-off requirement is removed. In these scenarios, CT capacity is selected prior to the addition of BDE Unit 8. However, as demonstrated in the LIL shortfall analysis, scenarios that include the Avalon CT without a second significant generation resource such as BDE Unit 8 continue to experience material capacity shortfalls during a prolonged LIL outage, and additional capacity would be required to mitigate, highlighting the need for both resources to be constructed by 2031 to enable the retirement of the Holyrood TGS.

BDE Unit 8 provides further benefits to the system, particularly in conjunction with the Avalon CT. The addition of Unit 8 provides important flexibility with regards to generation outage planning, and can reduce the operation of standby generation, reducing fuel consumption.

Accordingly, BDE Unit 8 is best characterized as a necessary but not the sole component of the expansion plan, forming a key component of future supply additions while requiring complementary resources, **particularly dispatchable generation on the Avalon**, to ensure reliable system operation under contingency conditions.

5.3 Cat Arm Unit 3

The expansion planning analysis demonstrates that CAT Unit 3 is selected as the next least-cost supply addition beyond BDE Unit 8 in scenarios reflecting minimum investment assumptions and higher CT capital costs (with base case hydro costs) or when the fuel burn-off requirement is included. In these cases, CAT Unit 3 is selected in 2034. However, the analysis also highlights that the timing and selection of CAT Unit 3 relative to the Avalon CT are sensitive to changes in cost assumptions and system requirements, as the Avalon CT is selected in all other scenarios.

Importantly, scenarios that result in the addition of BDE Unit 8 and CAT Unit 3 without the inclusion of the Avalon CT introduce additional system considerations. In such cases, with the retirement of the Holyrood TGS, additional reactive power support would be required on the Avalon to maintain acceptable voltage levels on the transmission system. While the costs associated with such reactive power solutions are not yet known and have not been included in the analysis, they would likely involve options such as synchronous condensers or STATCOMs[26] and represent an additional system requirement, as discussed in Section 5.5.

Furthermore, as CAT Unit 3 is only in the feasibility study phase of development, it is highly unlikely that this asset could enter service in advance of 2034, necessitating the continued reliance on the Holyrood TGS at a cost of over $140 million annually. As a result, CAT Unit 3 would not be available in 2032 and therefore does not contribute to the LIL Shortfall Scenario Analysis

These results indicate that CAT Unit 3 remains an important resource consideration, particularly as a potential incremental resource option to meet expected load growth under the reference case, following the addition of the Avalon CT and BDE Unit 8.

5.4 Newfoundland Power Combustion Turbines

Three scenarios evaluate the impact of a planned uprate of Newfoundland Power CTs. Under these scenarios, considering the slow electrification expansion plan and the combination of incremental capacity from these assets and the removal of the fuel burn-off requirement results in the Avalon CT

[26] Static Synchronous Compensator (“STATCOM”).

being selected as the first capacity addition, with no further capacity additions required within the study period. Under reference case scenarios with expected load growth, both BDE Unit 8 and the Avalon CT are selected in addition to the uprated Newfoundland Power CTs, and additional CT resources are selected in 2034, regardless of whether fuel burn-off is considered or when the fuel burn-off requirement is removed.

However, Hydro notes that the uprate of Newfoundland Power CTs has not yet been proposed for review and approval by the Board. As a result, Hydro requires further information to adequately assess these upgrades as least-cost capacity options within the Island Interconnected System. Key information requirements include details regarding the class and accuracy of cost estimates, an assessment of project execution and operational risks, including fueling logistics, and other feasibility considerations associated with the proposed upgrades, including transmission considerations. Market analysis indicates that CT prices could increase by almost 200% by 2027, highlighting the challenges in adequately considering additional CT resources beyond the Avalon CT and their associated costs in resource planning.[27]

Accordingly, 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.

5.5 Transmission and Voltage Constraints

Hydro is in the process of completing an assessment of reactive power requirements and resource options for the Island Interconnected System.[28] The underlying analysis has determined that in scenarios where BDE 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,

[27] Diana DiGani, "Gas turbine supply crunch set to raise prices 195% by 2027: WoodMac," Utility Dive, April 9, 2026, https://www.utilitydive.com/news/gas-turbine-supply-crunch-set-to-raise-prices-195-by-2027-woodmac/816904/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202026-04-09%20Utility%20Dive%20Newsletter%20%5Bissue:83702%5D&utm_term=Utility%20Dive.

[28] The Reactive Power Study will be filed with the Board within 45 days of finalization.

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.

These considerations 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. Further information on transmission and voltage constraints is provided in Appendix B.

6.0 Conclusion

Based on the results of the updated expansion plan analysis and the LIL shortfall assessment, **Hydro continues to recommend the development of BDE Unit 8 and the Avalon CT project** as the near-term capacity additions best suited to allow Hydro to continue to provide service and facilities that are reasonably safe and adequate, and just and reasonable. **Together, these projects represent the recommended Minimum Investment Expansion Plan required to maintain the minimum reliable service under a range of future conditions and enable the retirement of the Holyrood TGS.**

The expansion plan analysis demonstrates that the addition of BDE Unit 8 in 2031 is a consistent and least-cost outcome across the majority of scenarios evaluated, confirming its role as a foundational component of Hydro’s resource supply plan. The analysis further indicates that CT capacity on the Avalon is selected in the majority of scenarios, particularly under conditions of removal of fuel burn-off requirements, higher hydro costs, and reduced reliability of the LIL. While hydro expansion through the development of CAT Unit 3 later in the study period is selected under certain assumptions, these outcomes are limited and do not reflect the full range of system considerations, such as the need for additional reactive power support on the Avalon and the requirement for the timely addition of supply resources to enable the retirement of the Holyrood TGS. Furthermore, when considering the Reference Case Load Forecast and higher LIL EqFOR, the Avalon CT continues to be selected over CAT Unit 3.

The LIL shortfall analysis reinforces the need for dispatchable generation in addition to BDE Unit 8 or the Avalon CT. Scenarios relying on only one major capacity addition exhibit significantly higher shortfall risk during a prolonged LIL outage during the winter period, with substantial increases in both the magnitude and duration of rotating outages, particularly under severe system conditions. In contrast, scenarios incorporating, at a minimum, both the Avalon CT and BDE Unit 8 in 2031 demonstrate materially improved system performance, reducing both peak and total shortfall impacts and enhancing overall system resilience.

Taken together, the results of the expansion planning analysis, the demonstrated performance under LIL bipole outage conditions, and broader system and project considerations indicate that **BDE Unit 8 and the Avalon CT project, together, represent the most prudent and reliable Minimum-Investment Expansion Plan.** The Avalon CT provides a timely, flexible, and dispatchable source of generation that complements the capacity benefits of BDE Unit 8, ensuring that Hydro can meet reliability requirements at the lowest reasonable cost to customers.

Appendix A

Expansion Plan Analysis

1 # Expansion Plan Analysis Results

Table A-1: Scenario 4AE Expansion Plan

Scenario 4AE	Slow Electrification Load Forecast, 1% LIL EqFOR							
Resource	**Firm Capacity (MW)**	**Firm Energy (GWh)**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
BDE Unit 8	154.4	0		1	1	1	1	1
CT	141.6	0						
CAT Unit 3	68.2	0					1	1
Wind	Varies	350		2	2	2	2	2
Wind Firm Capacity (MW)				73	73	73	73	73
Total Firm Capacity (MW)				227	227	227	295	295
Firm Energy (GWh)				700	700	700	700	700

Table A-2: Scenario 4AEC Expansion Plan

Scenario 4AEC	Slow Electrification Load Forecast, 1% LIL EqFOR, No Fuel Burn-Off							
Resource	**Firm Capacity (MW)**	**Firm Energy (GWh)**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
BDE Unit 8	154.4	0					1	1
CT	141.6	0		1	1	1	1	1
CAT Unit 3	68.2	0						
Wind	Varies	350		2	2	2	2	2
Wind Firm Capacity (MW)				73	73	73	73	73
Total Firm Capacity (MW)				214	214	214	369	369
Firm Energy (GWh)				700	700	700	700	700

Table A-3: Scenario 4AEDC Expansion Plan

Scenario 4AEDC	Slow Electrification Load Forecast, 1% LIL EqFOR, P85 Hydro, No Fuel Burn-Off							
Resource	**Firm Capacity (MW)**	**Firm Energy (GWh)**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
BDE Unit 8	154.4	0						
CT	141.6	0		1	1	1	2	2
CAT Unit 3	68.2	0						
Wind	Varies	350		2	2	2	2	2
Wind Firm Capacity (MW)				73	73	73	73	73
Total Firm Capacity (MW)				214	214	214	356	356
Firm Energy (GWh)				700	700	700	700	700

Table A-4: Scenario 4AEHC Expansion Plan

Scenario 4AEHC **Slow Electrification Load Forecast, 1% LIL EqFOR, P85 CTs, No Fuel Burn-Off**

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034	2035
BDE Unit 8	154.4	0		1	1	1	1	1
CT	141.6	0						
CAT Unit 3	68.2	0					1	1
Wind	Varies	350		2	2	2	2	2
Wind Firm Capacity (MW)				73	73	73	73	73
Total Firm Capacity (MW)				227	227	227	295	295
Firm Energy (GWh)				700	700	700	700	700

Table A-5: Scenario 4AEDHC Expansion Plan

Scenario 4AEDHC **Slow Electrification Load Forecast, 1% LIL FOR, P85 Hydro & CTs, No Fuel Burn-Off**

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034	2035
BDE Unit 8	154.4	0					1	1
CT	141.6	0		1	1	1	1	1
CAT Unit 3	68.2	0						
Wind	Varies	350		2	2	2	2	2
Wind Firm Capacity (MW)				73	73	73	73	73
Total Firm Capacity (MW)				214	214	214	369	369
Firm Energy (GWh)				700	700	700	700	700

Table A-6: Scenario 4AEKC Expansion Plan

Scenario 4AEKC **Slow Electrification Load Forecast, 1% LIL EqFOR, NP CT Uprate, No Fuel Burn-Off**

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034	2035
BDE Unit 8	154.4	0						
CT	141.6	0		1	1	1	1	1
CAT Unit 3	68.2	0						
Wind	Varies	350		2	2	2	2	2
Wind Firm Capacity (MW)				73	73	73	73	73
Total Firm Capacity (MW)				214	214	214	214	214
Firm Energy (GWh)				700	700	700	700	700

Table A-7: Scenario 1AE Expansion Plan

Scenario 1AE **Reference Load Forecast, 5% LIL EqFOR**

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034	2035
BDE Unit 8	154.4	0		1	1	1	1	1
CT	141.6	0		2	2	2	2	2
CAT Unit 3	68.2	0						
Wind	Varies	350		2	3	3	3	3
Wind Firm Capacity (MW)				73	95	95	95	95
Total Firm Capacity (MW)				510	533	533	533	533
Firm Energy (GWh)				700	1,050	1,050	1,050	1,050

Table A-8: Scenario 1AEC Expansion Plan

Scenario 1AEC **Reference Load Forecast, 5% LIL EqFOR, No Fuel Burn-Off**

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034	2035
BDE Unit 8	154.4	0		1	1	1	1	1
CT	141.6	0		2	2	2	2	2
CAT Unit 3	68.2	0						
Wind	Varies	350		2	3	3	3	3
Wind Firm Capacity (MW)				73	95	95	95	95
Total Firm Capacity (MW)				510	533	533	533	533
Firm Energy (GWh)				700	1,050	1,050	1,050	1,050

Table A-9: Scenario 1AEK Expansion Plan

Scenario 1AEK **Reference Load Forecast, 5% LIL EqFOR, NP CT Uprate**

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034	2035
BDE Unit 8	154.4	0		1	1	1	1	1
CT	141.6	0		1	1	1	2	2
CAT Unit 3	68.2	0						
Wind	Varies	350		2	3	3	3	3
Wind Firm Capacity (MW)				73	95	95	95	95
Total Firm Capacity (MW)				369	391	391	533	533
Firm Energy (GWh)				700	1,050	1,050	1,050	1,050

Table A-10: Scenario 1AEKC Expansion Plan

Scenario 1AEKC	**Reference Load Forecast, 5% LIL EqFOR, NP CT Uprate, No Fuel Burn-Off**							
Resource	**Firm Capacity (MW)**	**Firm Energy (GWh)**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
BDE Unit 8	154.4	0		1	1	1	1	1
CT	141.6	0		1	1	1	2	2
CAT Unit 3	68.2	0						
Wind	Varies	350		2	3	3	3	3
Wind Firm Capacity (MW)				73	95	95	95	95
Total Firm Capacity (MW)				369	391	391	533	533
Firm Energy (GWh)				700	1,050	1,050	1,050	1,050

Appendix B

LIL Shortfall Analysis

LIL Shortfall Analysis Results

Slow Electrification Load Forecast, BDE Unit 8 in 2031

Table B-1: Shortfall Analysis Results

	Average (50th Percentile)	Severe (90th Percentile)
Peak shortfall (MW)	309	392
Total shortfall (GWh)	19	48
Hours of shortfall (hr)	219	445
% of all hours	22%	44%
% Hours > 100MW	7%	20%

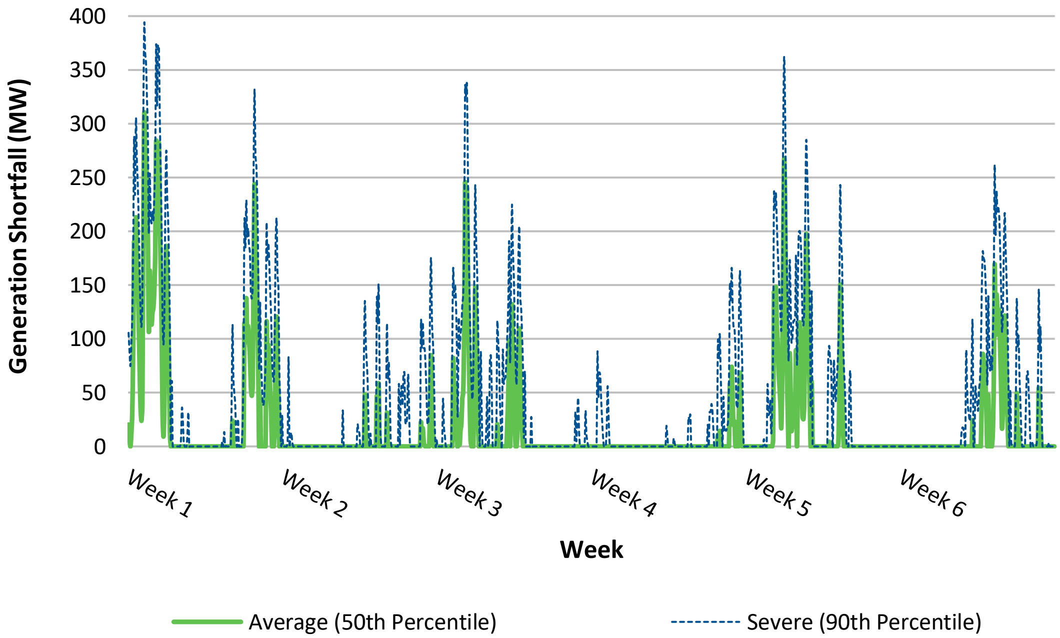

Figure B-1: Generation Shortfall Time Plot (6-Weeks)

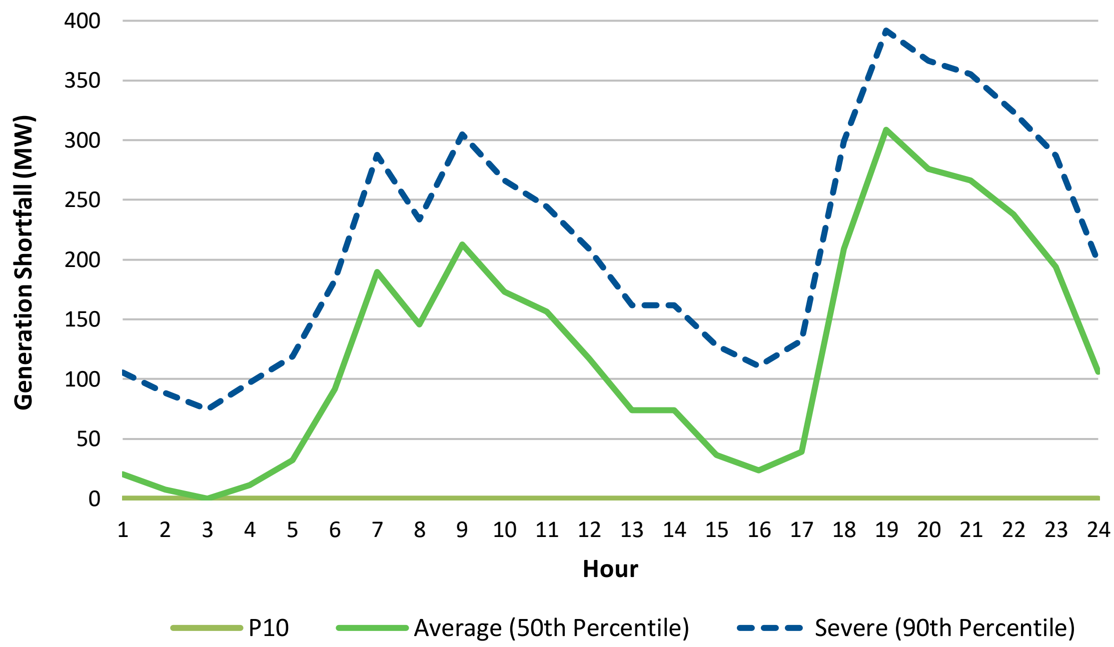

Figure B-2: Generation Shortfall Time Plot (Peak Day)

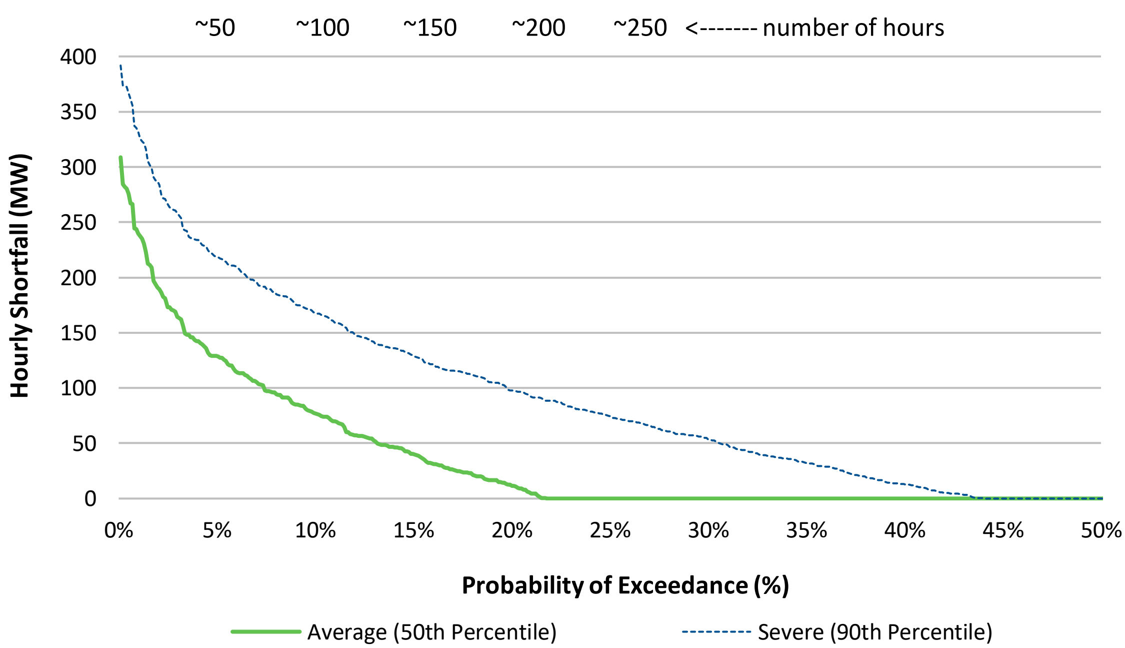

Figure B-3: Hourly Shortfall Duration Curve

1 # Slow Electrification Load Forecast, Avalon CT in 2031

Table B-2: Shortfall Analysis Results

	Average (50th Percentile)	Severe (90th Percentile)
Peak shortfall (MW)	304	391
Total shortfall (GWh)	18	45
Hours of shortfall (hr)	210	409
% of all hours	21%	41%
% Hours > 100MW	7%	19%

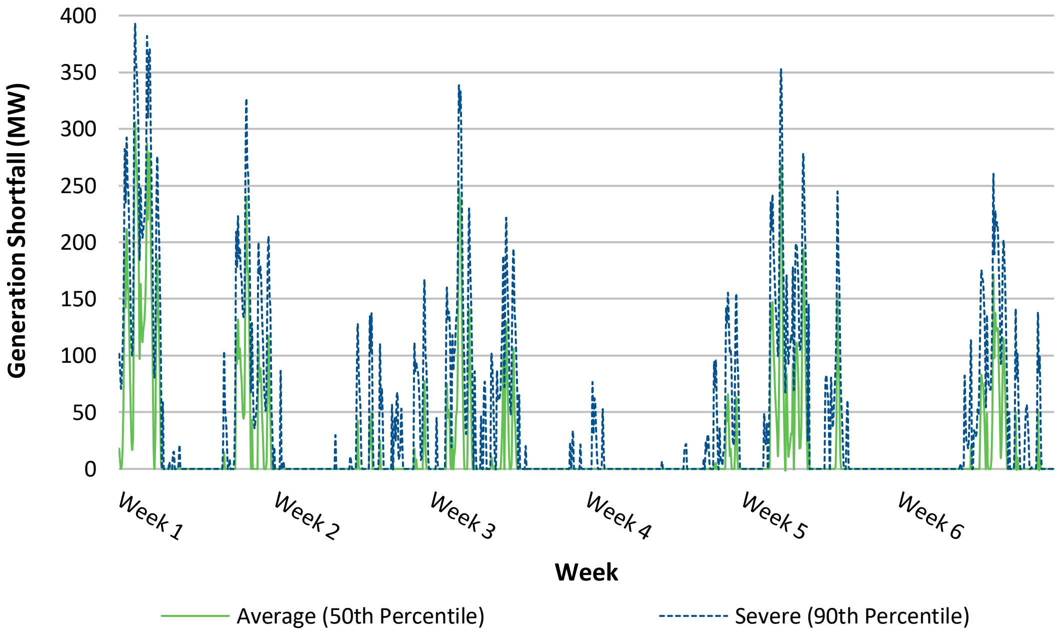

Figure B-4: Generation Shortfall Time Plot (6-Weeks)

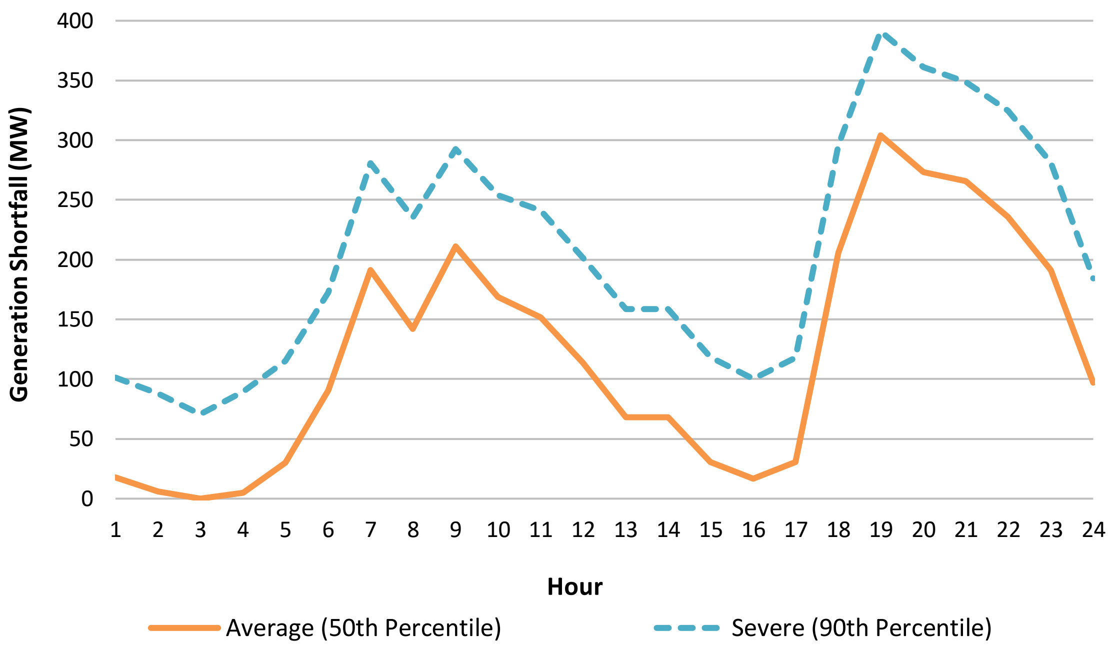

Figure B-5: Generation Shortfall Time Plot (Peak Day)

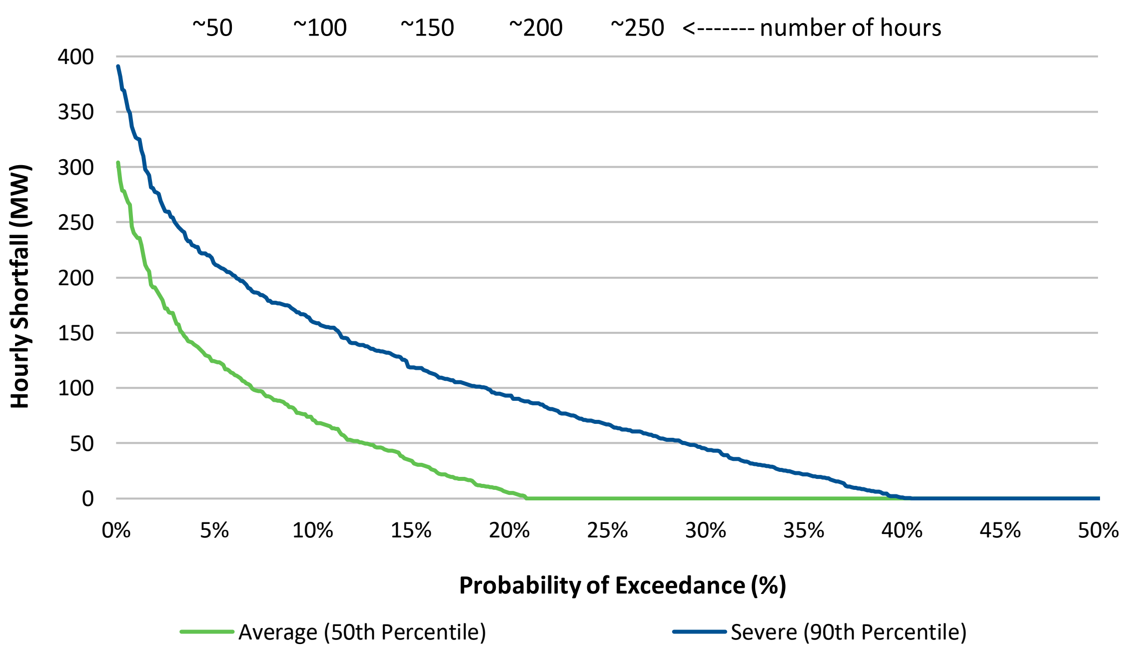

Figure B-6: Hourly Shortfall Duration Curve

Slow Electrification Load Forecast, BDE Unit 8 in 2031, Avalon CT Advanced to 2031

Table B-3: Shortfall Analysis Results

	Average (50th Percentile)	Severe (90th Percentile)
Peak shortfall (MW)	174	266
Total shortfall (GWh)	3	11
Hours of shortfall (hr)	45	147
% of all hours	4%	15%
% Hours > 100MW	1%	4%

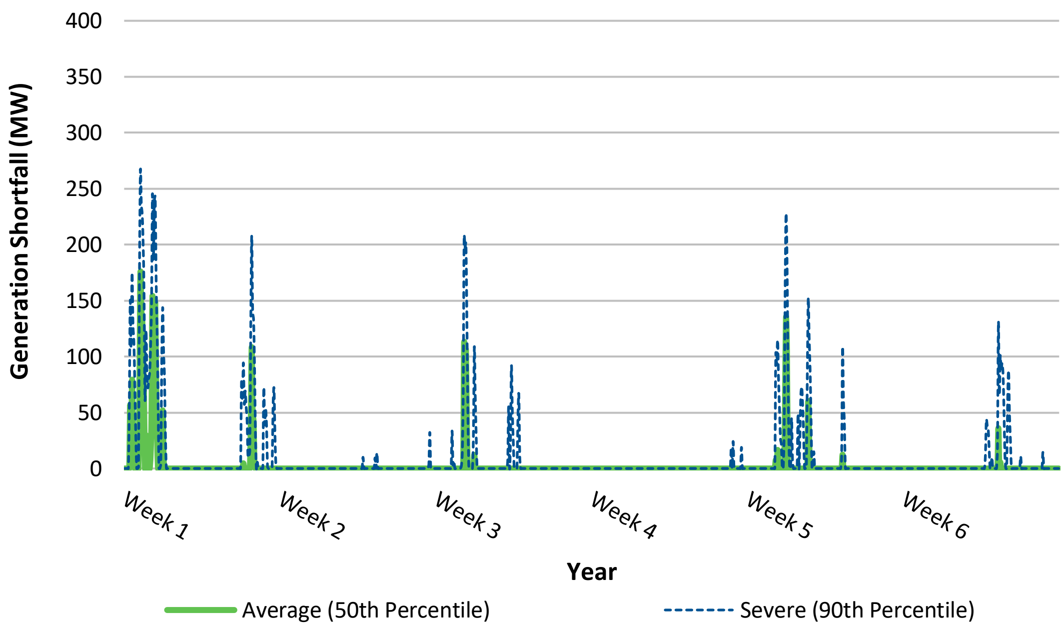

Figure B-7: Generation Shortfall Time Plot (6-Weeks)

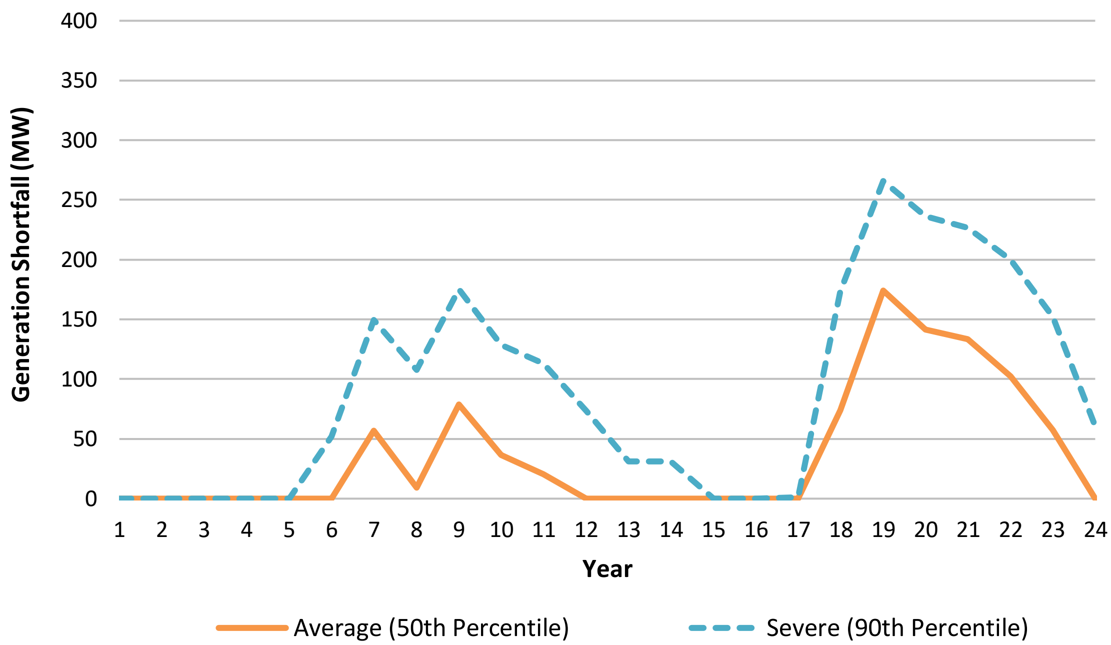

Figure B-8: Generation Shortfall Time Plot (Peak Day)

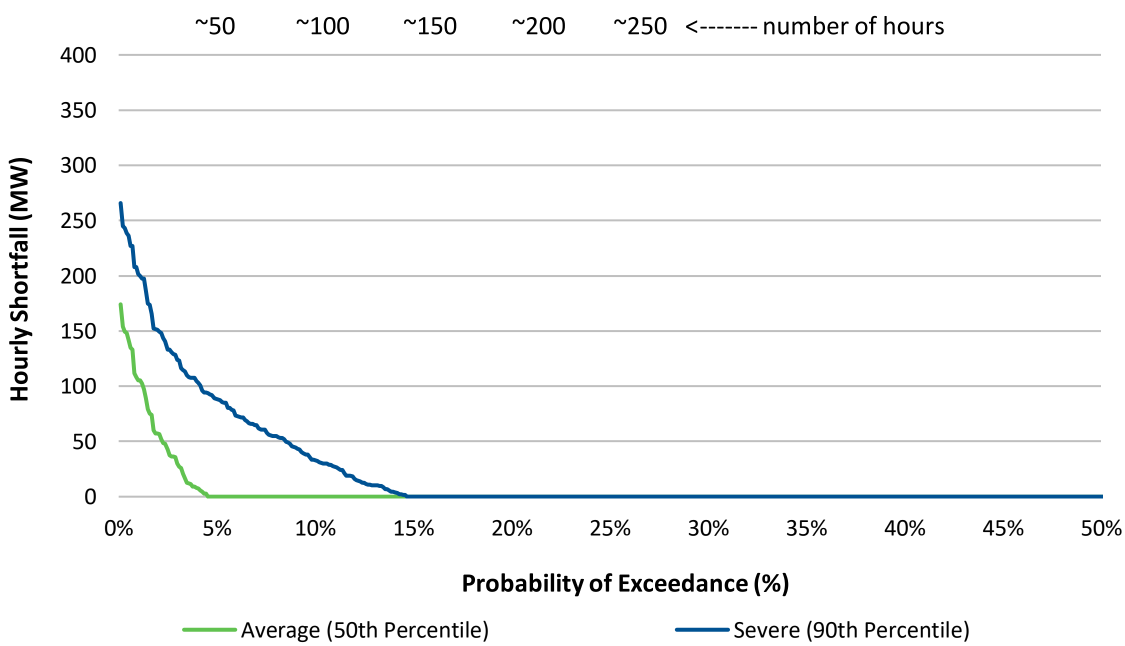

Figure B-9: Hourly Shortfall Duration Curve

1 ## Slow Electrification Load Forecast, NP CTs Included, Avalon CT in 2031

Table B-4: Shortfall Analysis Results

	Average (50th Percentile)	Severe (90th Percentile)
Peak shortfall (MW)	264	347
Total shortfall (GWh)	11	30
Hours of shortfall (hr)	145	310
% of all hours	14%	31%
% Hours > 100MW	4%	12%

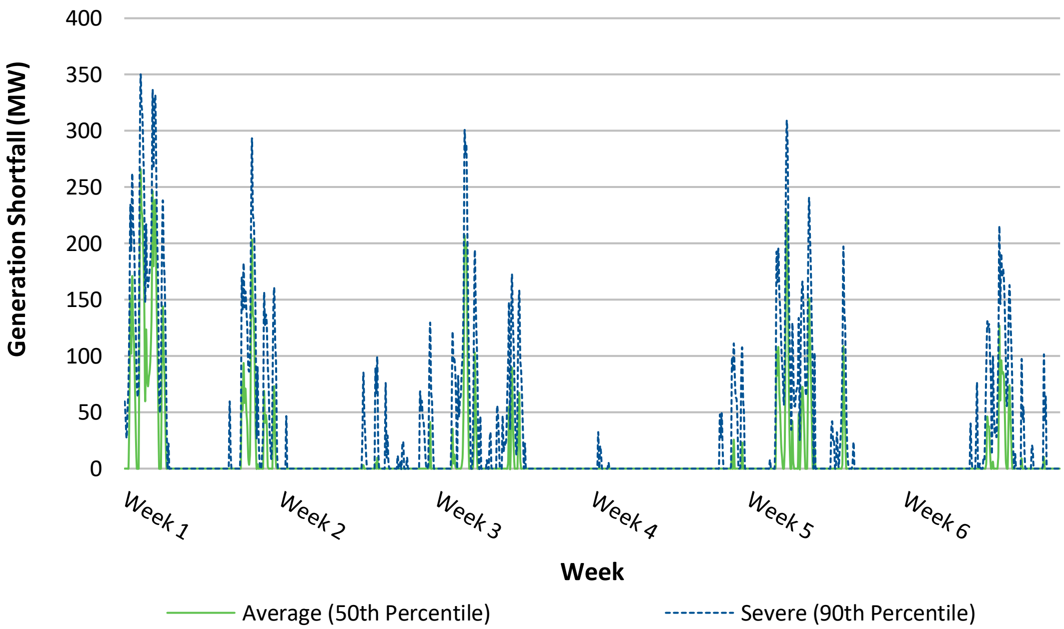

Figure B-10: Generation Shortfall Time Plot (6-Weeks)

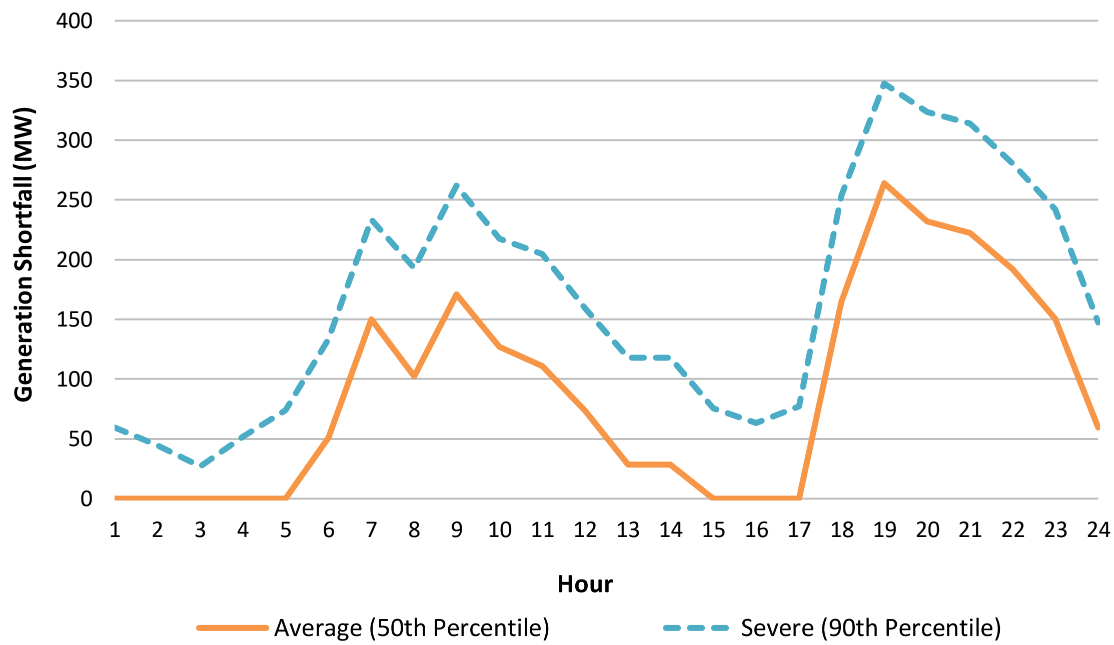

Figure B-11: Generation Shortfall Time Plot (Peak Day)

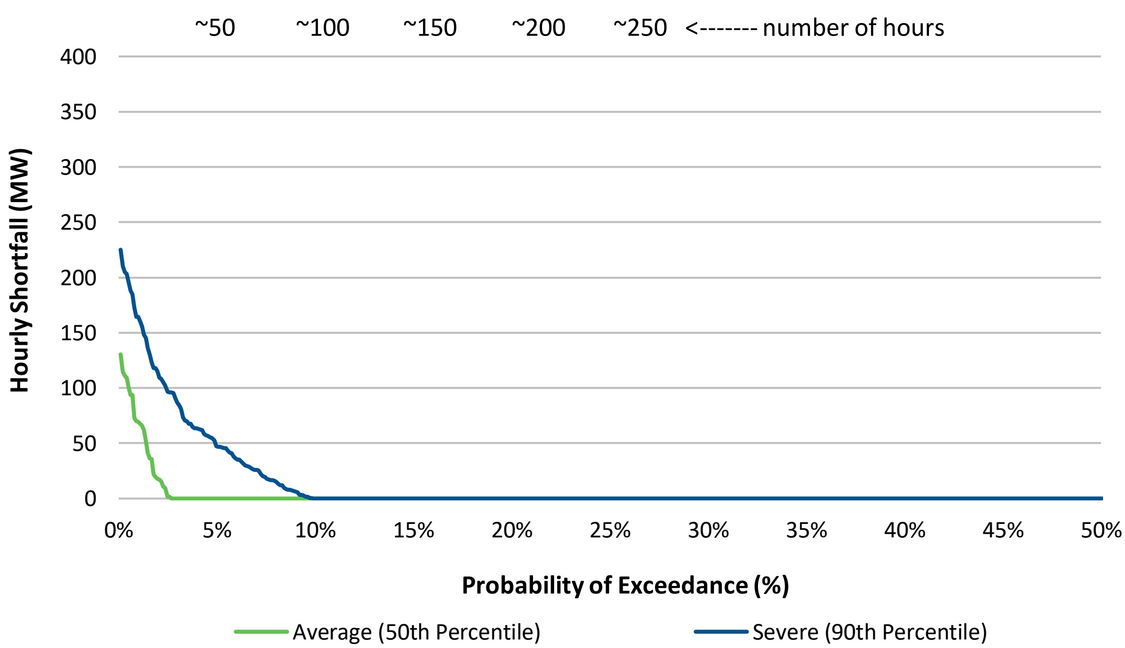

Figure B-12: Hourly Shortfall Duration Curve

Reference Load Forecast with BDE Unit 8, Avalon CT, and an Additional 150 MW Nominal CT in 2031

Table B-5: Shortfall Analysis Results

	Average (50th Percentile)	Severe (90th Percentile)
Peak shortfall (MW)	32	136
Total shortfall (GWh)	0	1
Hours of shortfall (hr)	5	24
% of all hours	0%	2%
% Hours > 100MW	0%	0%

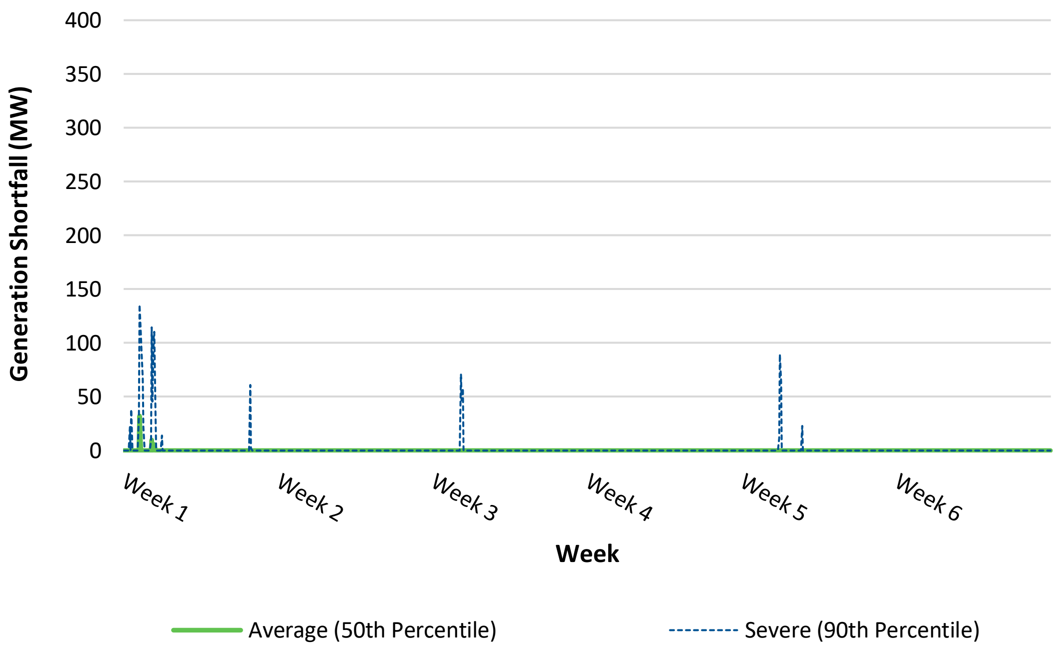

Figure B-13: Generation Shortfall Time Plot (6-Weeks)

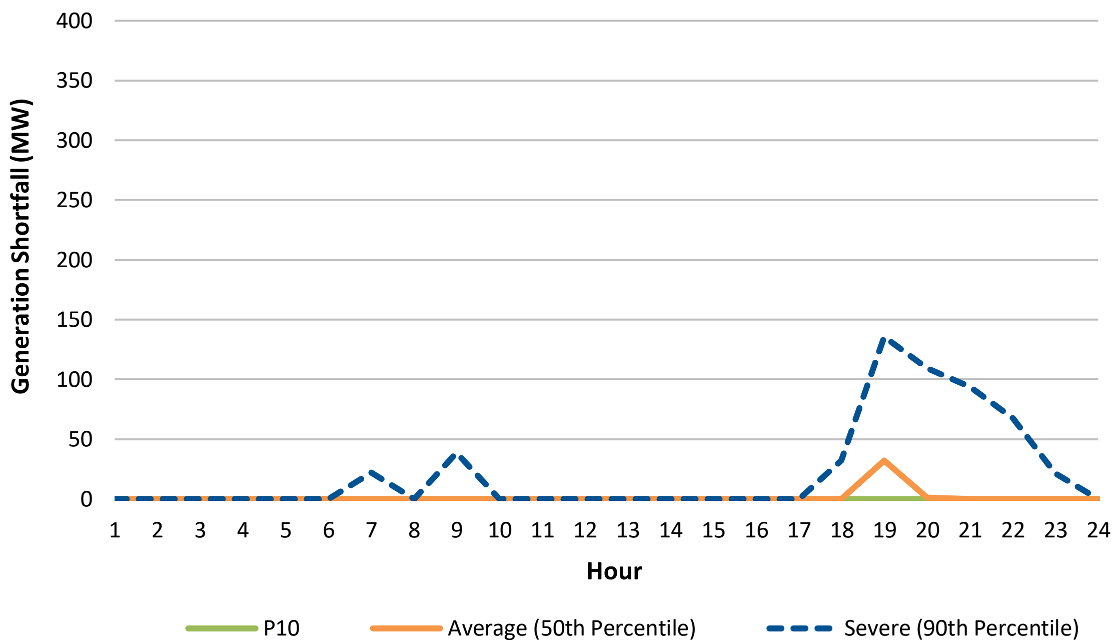

Figure B-14: Generation Shortfall Time Plot (Peak Day)

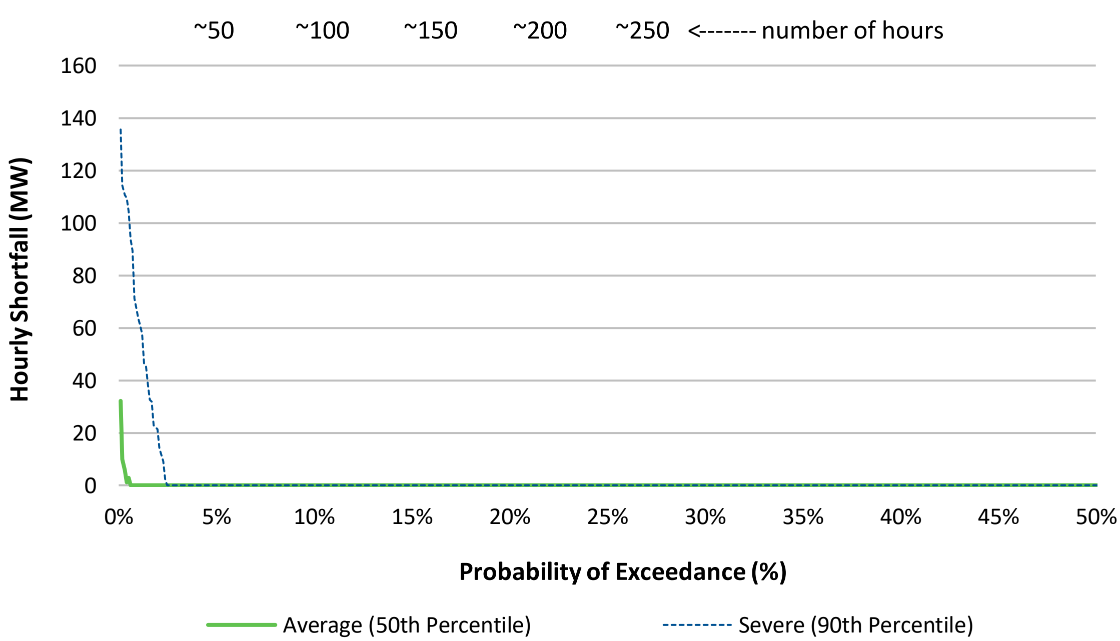

Figure B-15: Hourly Shortfall Duration Curve

Appendix C

Avalon Transmission Considerations for Generation Expansion

newfoundland labrador hydro

Avalon Transmission Considerations for Generation Expansion

The requirement for transmission upgrades on the Avalon Peninsula arises from two distinct operating scenarios. The first pertains to reactive power support requirements to maintain voltage stability and will be presented in further detail in the *Avalon Reactive Power Study* scheduled for filing within 45 days of finalization. The second scenario involves the potential for transmission line thermal overloads and abnormal voltage levels during a LIL bipole outage, which has been addressed in previous submissions[1] to the Board. A summary of both scenarios follows.

LIL Bipole Trip – Voltage Collapse

Under high Island load conditions, a LIL bipole trip results in a sudden increase in power flow from BDE to Soldiers Pond ("SOP"). The magnitude of this power flow could lead to a voltage collapse in the Sunnyside area. An external consultant, TransGrid Solutions Inc., has completed the analysis[2] quantifying the minimum Avalon generation that must be dispatched to offload BDE–SOP power transfers and prevent voltage collapse. This analysis is currently being updated within the *Avalon Reactive Power Study* by examining a range of operating and load scenarios and assessing reactive power compensation options.

At present, Holyrood TGS operation naturally eliminates the concern of a voltage collapse as it is needed to meet demand and reliability requirements, which consequently offloads the BDE–SOP transmission system. After the retirement of the Holyrood TGS, maintaining acceptable BDE–SOP flows will require dispatching a minimum level of Avalon generation, including the Hardwoods and Holyrood gas turbines and/or any new proposed generation located on the Avalon Peninsula.

The results from the analysis underlying the forthcoming *Avalon Reactive Power Study* will demonstrate that, with the proposed Avalon CT, normal gas turbine dispatch levels on the Avalon Peninsula are sufficient to mitigate voltage collapse following a LIL bipole trip. In the absence of Avalon CT,

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[1] "Assessment of the BDE/SOP Transmission Constraints," TransGrid Solutions Inc., October 25, 2023. Provided in "Avalon Supply (Transmission) Study – Overview," Newfoundland and Labrador Hydro, October 31, 2023, att. 1, sec. 2.3.
"Avalon Remedial Action Scheme (RAS) Feasibility Study," TransGrid Solutions Inc., October 7, 2025. Provided in "Avalon Remedial Action Scheme Feasibility Study – Overview," Newfoundland and Labrador Hydro, October 14, 2025, att. 1.
"LCP Operational Study: Final LCP Operational Study ("Stage 4F") Report," TransGrid Solutions Inc., June 26, 2025. Provided in "Final LCP Operational (Stage 4F) Study – Overview," Newfoundland and Labrador Hydro, August 11, 2025, att. 1, sec 7.1.

[2] "Assessment of the BDE/SOP Transmission Constraints," TransGrid Solutions Inc., October 25, 2023. Provided in "Avalon Supply (Transmission) Study – Overview," Newfoundland and Labrador Hydro, October 31, 2023, att. 1, sec. 2.3.

replacement with off-Avalon generation does not resolve the voltage stability issue, necessitating reactive power compensation, such as a synchronous condenser or STATCOM. Holyrood TGS is currently finalizing analysis to quantify the reactive power requirements to address the scenario outlined and eliminate the requirement for minimum Avalon generation.

LIL Bipole Outage Scenario – 230 kV Line Trips between BDE–SOP

During a LIL bipole outage at high load conditions, Avalon demand is supplied by increased eastward power flow across the BDE–SOP transmission system. In this operating state, a contingency involving the loss of a 230 kV line between BDE and SOP line results in unacceptable thermal overloads and/or low voltage levels. At present, Holyrood TGS operation naturally reduces BDE–SOP flow as it is needed to meet demand and reliability requirements during high load conditions. After the retirement of Holyrood TGS, there would not be enough downstream generation to avoid the thermal overloads and/or low voltage conditions following 230 kV line trips. As a result, mitigation would require either upgrades to the 230 kV transmission system or an instant post-contingency reduction in BDE–SOP transfers through downstream load shedding (i.e., the Avalon Remedial Action Scheme). These upgrade requirements exist regardless of the generation expansion plan and are driven by Holyrood TGS retirement.

Attachment 1

GE Contract Milestone Payment Schedule

GE Contract Payment Milestone Schedule

	Pmt Schedule			Contract Currency (USD)	
Payment Event/Milestone	**% Contract Price**	**Cumulative Payment %**	**Estimated Milestone Date**	**Value**	**Cumulative**
LNTP	[redacted]	[redacted]	15-Dec-25	$ [redacted]	$ [redacted]
FNTP	[redacted]	[redacted]	23-Mar-26	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Apr-26	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-May-26	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Jun-26	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Jul-26	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Aug-26	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Sep-26	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Oct-26	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Nov-26	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Dec-26	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Jan-27	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Feb-27	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Mar-27	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Apr-27	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-May-27	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Jun-27	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Jul-27	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Aug-27	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Sep-27	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Oct-27	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Nov-27	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Dec-27	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Jan-28	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Feb-28	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Mar-28	$ [redacted]	$ [redacted]
4% Pmt when 1st package is Ready to Ship	[redacted]	[redacted]	16-Mar-28	$ [redacted]	$ [redacted]
4% Pmt when 2nd package is Ready to Ship	[redacted]	[redacted]	29-Mar-28	$ [redacted]	$ [redacted]
4% Pmt when 3rd package is Ready to Ship	[redacted]	[redacted]	14-Apr-28	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Apr-28	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-May-28	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Jun-28	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Jul-28	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Aug-28	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Sep-28	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Oct-28	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Nov-28	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Dec-28	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Jan-29	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Feb-29	$ [redacted]	$ [redacted]
Progress Calendar Payment	[redacted]	[redacted]	15-Mar-29	$ [redacted]	$ [redacted]
3% Pmt when 1st Engine is Ready to Ship	[redacted]	[redacted]	1-Apr-29	$ [redacted]	$ [redacted]
3% Pmt when 2nd Engine is Ready to Ship	[redacted]	[redacted]	30-May-29	$ [redacted]	$ [redacted]
3% Pmt when 3rd Engine is Ready to Ship	[redacted]	[redacted]	30-May-29	$ [redacted]	$ [redacted]
1.5% upon unit reaching substantial completion	[redacted]	[redacted]	23-Jun-29	$ [redacted]	$ [redacted]
1% upon unit achieving final completion	[redacted]	[redacted]	23-Jul-29	$ [redacted]	$ [redacted]
1.5% upon unit reaching substantial completion	[redacted]	[redacted]	21-Aug-29	$ [redacted]	$ [redacted]
1.5% upon unit reaching substantial completion	[redacted]	[redacted]	4-Sep-29	$ [redacted]	$ [redacted]
1% upon unit achieving final completion	[redacted]	[redacted]	20-Sep-29	$ [redacted]	$ [redacted]
1% upon unit achieving final completion	[redacted]	[redacted]	4-Oct-29	$ [redacted]	$ [redacted]
Total	[redacted]			$ [redacted]	

Note: The total contract value noted above is in USD currency and is exclusive of transportation, tariffs and provisional items estimated to be an additional [redacted] USD.

Attachment 2

Basis of Estimate and Impact Analysis

newfoundland labrador hydro

Basis of Estimate

Avalon Combustion Turbine

NLH Doc. No. HRDCT2-NLH-49100-ES-BOE-0001-01

Comments:	Total # of Pages (including Cover):
Comments: The Avalon Combustion Turbine Basis of Estimate presents the cost estimate and basis for the project, and methodologies used to estimate project elements including direct costs, indirect costs, escalation, and borrowing. This document has been prepared in alignment with AACE International Recommended Practices	**Total # of Pages (including Cover):** 150
INTERNAL USE ONLY	

B1	10-April-26	Use	Glenn Whalen	Ryan Cooper	Neil Martin	Marc Cullen
Revision	**Date** (DD-MMM-YYYY)	**Issue Reason**	**Prepared By** Sr. Estimator Major Projects	**Checked By** Project Manager Major Projects	**Approved by** Sr. Project Manager Major Projects	**Approved by** Program Manager Major Projects

These signatures are required to confirm compliance with Major Projects procedures. This document cannot be finalized or distributed without this approval. Any version of this document without these signatures is not considered final.

Additional Approvals

Position	Name	Signature	Date (DD-MMM-YYYY)
Director, Major Projects & Asset Management	John Walsh	[signature]	9-Apr-2026
Senior Manager, Major Projects & Engineering	Stephen Parsons	[signature]	10-APR-2026
Senior Manager, Major Projects Commercial	John Skinner	[signature]	10-Apr-2026
Manager, Major Projects Project Controls	Tony Scott	[signature]	10 APR 2026

Endorsements

Position	Name	Signature	Date (DD-MMM-YYYY)
Senior Cost Controller, Major Projects Project Controls	Lisa Hobbs	Lisa Hobbs	10-Apr-2026.

Revision History

Changes to the content of this document are recorded in the Revision History table below. Minor or immaterial edits—such as formatting adjustments or typographical corrections—may not be listed.

Revision No.	Revision Date	Location	Reason
B1	*27-Mar-2026*	*Section 1.0*	*Describe the overall cost changes resulting from the new cost for the CTs.*
B1	*27-Mar-2026*	*Throughout Document*	*All references to "Hydro" have been changed to "NL Hydro".*
B1	*9-April-2026*	*Table for "List of Attachments"*	*Attachment 5: "Briefing Note – Impact Analysis of CT Price Increase on Project Cost," NL Hydro, Rev. B1 has been added as a new attachment.*
B1	*27-Mar-2026*	*Section 3.0 – Reference Documents*	*Briefing Note – Impact Analysis of CT Price Increase on Project Cost, listed as one of the reference documents.*
B1	*27-Mar-2026*	*Section 4.0*	*Stating the issuance of the RFP for the CTs was completed in 2025.*
B1	*27-Mar-2026*	*Section 5.0*	*Stating the purpose for issuing revision B1 of this basis of estimate document.*
B1	*27-Mar-2026*	*Section 7.4*	*Summary of the cost changes to escalation and IDC as a result of the new cost for the CTs, and update of the cost profile Tables 3 and 4.*
B1	*27-Mar-2026*	*Section 9.1*	*Update Table 5.*
B1	*27-Mar-2026*	*Section 12*	*Identify the change to contingency as a result of the new CT procurement cost.*
B1	*27-Mar-2026*	*Section 13*	*Identify the change to Management Reserve as a result of the new CT procurement cost.*
B1	*27-Mar-2026*	*Section 14*	*Identify the change to estimate classification as a result of lower uncertainty related to the CT procurement costs.*
B1	*27-Mar-2026*	*Section 16.1.1*	*Note the change to the related risk.*

Contents

List of Attachments

Attachment 1: "Objective 1 Deliverable 2 – Avalon Combustion Turbine Sanction Readiness Maturity of Deliverables (MoD) Gap Analysis," Newfoundland and Labrador NL Hydro (Internal Audit & Advisory Services), February 19, 2025

Attachment 2: "150 MW Combustion Turbine FEED Study Basis of Estimate," Hatch Ltd., Rev B0, November 11, 2024

Attachment 3: "Parametric QRA Report," Hatch Ltd., Rev B1, November 29, 2024

Attachment 4: "Risk and Assumption Register," Hatch Ltd., Rev. B0, November 18, 2024

Attachment 5: "Briefing Note – Impact Analysis of CT Price Increase on Project Cost," NL Hydro, Rev. B1, April 9, 2026

1.0 Executive Summary

Newfoundland and Labrador Hydro (NL Hydro) plans to build a new 150 MW Combustion Turbine (CT) Power Generation Plant near the Holyrood Thermal Generation Station, which is referred to as the Avalon Combustion Turbine (ACT) Project.

The initial ACT Project Build Application was issued to the PUB in March of 2025. Since the initial Build Application was submitted NL Hydro had received updated pricing for the procurement of the CTs, in response to a formal request for quotation. The new price for CTs is significantly greater than the estimated cost documented in Revision B0 of this Basis of Estimate. NL Hydro are updating this BoE and reissuing as revision B1 to formally document the incremental cost impact on the overall cost of the ACT Project due to the increased purchase price for the CTs. It is important to note that all other estimated costs, other than the incremental cost changes noted below, remain unchanged as there has not been enough project progress or new costing information made available to suggest the remaining costs need to be reassessed at this time.

The purchase price for the CTs is approximately $102.3 million greater than the budgetary pricing (cost basis for March 2025 Build Application) that was received during the FEED phase. The cost impacts on contingency, escalation, cost of the borrowing (IDC) and management reserve were assessed, and determined to be:

- Contingency: +$10.3 million.
- Escalation: -$11.2 million.
- IDC: +$9.6 million.
- Management reserve: -$6.6 million.

The overall cost change due to the increased procurement cost of the CTs by $102.3 million, plus the incremental cost changes to contingency, escalation, cost of the borrowing (IDC) and management reserve, is a net increase of approximately +$104.4 million.

NL Hydro engaged Hatch Ltd. (Hatch) to develop a detailed contractor cost estimate during the project's Front-End Planning (FEP) phase. Hatch's cost estimate and basis of estimate are detailed in the Capital Cost Estimate and the 150 MW Combustion Turbine FEED Study Basis of Estimate, respectively. The estimated costs for the Hydro personnel, project escalation, and Interest During Construction (IDC) were completed by Hydro.

Table 1 contains a cost summary for the Total Installed Cost, which includes the estimated costs for:

- Engineering, Procurement and Construction Management (EPCM);
- Equipment and materials (including the increased cost of the CT units)
- Construction and completions;
- Hydro's costs;

- Escalation and Interest During Construction (including the changes induced from the increased cost of the CT units);
- Contingency (including the changes induced from the increased cost of the CT units); and
- Management Reserve (including the changes induced from the increased cost of the CT units).

Due to the increased purchase price for the CTs, the revised base cost estimate for the Avalon Combustion Turbine (ACT) Project is $688,971,428[1] (Base Year of 2024), with an expected accuracy range of -19.6/+22.0% about the Pmean value, for an 80% confidence interval, according to the Association for the Advancement of Cost Engineering International (AACE) Recommended Practice (RP) No. 96R-18 for a Class 3 cost estimate. The accuracy range has narrowed slightly due to the purchase price for the CTs becoming largely fixed now that NL Hydro have a signed contract with General Electric Vernova (GE). How the revised accuracy range was derived is explained in attachment 5 to this document.

Escalation and IDC were calculated based on a cost profile developed from the project schedule.

Contingency and Management Reserve for all cost elements, other than the purchase price for the CTs, is unchanged and are based on Monte Carlo Simulation (MCS) that was performed during FEED. The mean value of the MCS output (P55 value) was selected for the Contingency budget and the P85 value was selected for the Management Reserve. The Contingency budget, listed in Table 1, is the difference between the P55 value and the estimated cost. The Management Reserve budget, listed in Table 1, is the difference between the P85 value and the P55 value on the cumulative distribution graph of the MCS output. A summary of estimated costs is provided in Table 1.

The incremental cost increase and cost reduction in the Contingency and Management Reserve allowances, respectively, were derived from quantitative risk assessment (QRA) that was performed on the procurement contract for the CTs. The complete details of the risks that were considered and the results of the MCS that was performed is detailed in the briefing note contained in Attachment 5.

[1] All costs referenced herein are expressed in Canadian dollars unless noted otherwise.

Table 1: Cost Summary ($)

Component	**Estimated Cost (Rev B0)**	**Changed Cost (Rev B1)**
Direct Construction Costs		
CWP-0000: Site-Wide Development	[redacted]	
CWP-1000: Tank Farm	[redacted]	
CWP 2000: CT Plant	[redacted]	
Increase in the purchase price for the CTs	[redacted]	[redacted]
CWP-3000: Transformer Yard	[redacted]	
CWP-4000: Switchyard	[redacted]	
CWP-5000: Raw Water	[redacted]	
CWP-6000: Fuel Offloading	[redacted]	
CWP-7000: Transmission Lines	[redacted]	
Subtotal Direct Construction Costs[2]	**367,756,014**	**462,748,525**
Indirect Construction Costs		
Contractor Indirect	[redacted]	
Increase in cost for freight and supplier representation for the CTs	[redacted]	[redacted]
EPCM Consultant	[redacted]	
Hydro Project Management	[redacted]	
Other Hydro Costs (Spare Transformer, Insurance, FEED, etc.)	[redacted]	
Indirect Construction Costs Subtotal	**218,886,796**	**226,222,903**
Subtotal Base Cost (Direct + Indirect) Estimate	**586,642,810**	**688,971,428**
Project Contingency	65,117,352	
Increase in contingency due to non-fixed terms of the CT contract		10,337,765
Subtotal Base Estimate (with Contingency)	**651,760,162**	**764,426,545**
Escalation	44,845,915	
Decrease in escalation due to the CT contract being awarded		(11,162,332)
Interest During Construction (IDC)	66,569,342	
Increase in IDC due to greater costs to purchase the CTs		9,567,688
Subtotal Planned Budget	**763,175,419**	**874,247,158**
Management Reserve	128,239,838	
Decrease in Management Reserve due to increased certainty pertaining to the CT costs		(6,611,838)
Total Cost Estimate (Authorized Budget upon Approval)	**891,415,257**	**995,875,158**

[2] The totals for each CWP, as presented, do not total exactly $462,748,525, due to rounding.

2.0 Abbreviations and Definitions

Term	Description
AACE	Association for the Advancement of Cost Engineering International
ACT or Avalon CT	Avalon Combustion Turbine
AI	Artificial Intelligence
CAD	Canadian dollars
Contingency	An amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs.[3]
Contractor's All Risk	A non-standard insurance policy that covers financial risks related to property damage and third-party injury when caused by such things as fire, flood, wind, earthquakes, and construction faults at the construction site during a project.
CPI	Consumers Price Index. A measure of time-to-time fluctuations in the price of a quantitively constant market basket of goods and services, selected as representative of a special level of living.[4]
CT	Combustion Turbine
CT1	Combustion Turbine 1. The existing Industrial Frame Combustion Turbine that was installed at the Holyrood Thermal Generation Station in 2014.
Escalation	A provision in costs or prices for uncertain changes in technical, economic, and market conditions over time.[5]
EPCM	Engineering, Procurement, Construction and Management
FAT	Factory Acceptance Test
FEED	Front-End Engineering Design. A major part of FEP; it includes sufficient field investigations and engineering to establish a contracting strategy and Class 3 cost estimate.

[3] As per AACE RP 10S-90.
[4] As per AACE RP 10S-90.
[5] As per AACE RP 10S-90.

Term	Description
FEP	Front-End Planning. A stage in project planning that includes project execution planning, environmental management planning, FEED, supply chain management planning, and construction planning.
GDP	Gross Domestic Product
GE	General Electric Vernova
Hatch	Hatch Ltd.
Holyrood TGS	NL Hydro Thermal Generating Station. A Thermal Generating Power Plant located in Holyrood, Newfoundland and Labrador.
IDC	Interest During Construction. The cost for the use of capital; sometimes referred to as the time value of money.[6]
Level of Effort	Percentage of a full-time equivalent resource.
LTAP	Long-Term Asset Planner
Major Projects	Regulated projects and programs with an anticipated cost of $50 million or greater under the accountability of the Major Projects Department.
Major Projects Department	A department that is dedicated to and responsible for the planning, execution, monitoring, and delivery of major projects for NL Hydro.
Management Reserve	An amount added to a cost estimate to allow for discretionary management purposes outside of the defined scope of the project, as otherwise estimated. This may include amounts within the defined scope, but for which management does not want to fund as Contingency, or that cannot be effectively managed using Contingency.[7] Management Reserve, as it applies to the ACT Project, is the difference between the expected 85% underrun cost for the project and the 55% underrun cost for the project.
MCS	Monte Carlo Simulation
MOU	Memorandum of Understanding. A tentative agreement between NL Hydro and Hydro-Québec to increase the power output of the existing Churchill Falls assets and execute the Gull Island Project.

[6] As per AACE RP 10S-90.
[7] As per AACE RP 10S-90.

Term	Description
NL Hydro	Newfoundland and Labrador Hydro and its affiliates, successors, and assigns.
PMean	The probability of underrunning the Mean value of all probable project cost outcomes, calculated using MCS software.
Project Management Teams	All Project Managers and their delegates.
Pollution Liability Insurance	Insurance to cover third-party bodily injury, property damage, and environmental damage due to both gradual and sudden pollution events that occur on a covered job site.
PPE	Personal Protective Equipment
PUB	Public Utilities Board Newfoundland and Labrador
QRA	Quantitative Risk Assessment
Risk	An uncertain event or condition that, if it occurs, has a positive or negative effect on a project's objectives.
RP	Recommended Practice
SME	Subject Matter Expert
Total Installed Cost	The total installed cost refers to the final cost of designing, fabricating and building a capital project or industrial asset.
USCPI	United States Consumer Price Index
USD	United States dollars

3.0 Reference Documents

The following is a list of documents that either are referenced in this Avalon Combustion Turbine Basis of Estimate document or are relevant to the subject matter contained within.

Reference No.	Document Title
12972390-NLH-NLH-MEM-0001	Avalon Combustion Turbine Sanction Readiness Maturity of Deliverables (MoD) Gap Analysis[8]
AACE RP 31R-03	Reviewing, Validating, and Documenting the Estimate[9]
AACE RP 10S-90	Cost Engineering Terminology[10]
AACE RP 17R-97	Cost Estimate Classification System[11]
AACE RP 18R-97	Cost Estimate Classification System - As Applied in Engineering, Procurement, and Construction for the Process Industries[12]
AACE RP 34R-05	Basis of Estimate[13]
AACE RP 96R-18	Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Power Transmission Line Infrastructure Industries[14]

[8] "Objective 1 Deliverable 2 – Avalon Combustion Turbine Sanction Readiness Maturity of Deliverables (MoD) Gap Analysis," Newfoundland and Labrador Hydro (Internal Audit & Advisory Services), February 19, 2025., included as Attachment 1 to this Basis of Estimate.

[9] AACE International. (May 12, 2009) Recommended Practice 31R-03, *Reviewing, Validating, and Documenting the Estimate*. <https://www.pathlms.com/aace/courses/2928/documents/3815>.

[10] AACE International. (July 24, 2024) Recommended Practice 10S-90, Cost Engineering Terminology. <https://www.pathlms.com/aace/courses/2928/documents/3796>.

[11] AACE International. (August 7, 2020) Recommended Practice 17R-97, *Cost Estimate Classification System.* <https://www.pathlms.com/aace/courses/2928/documents/3802>.

[12] AACE International. (August 7, 2020) Recommended Practice 18R-97, Cost Estimate Classification System - As Applied in Engineering, Procurement, and Construction for the Process Industries. <https://www.pathlms.com/aace/courses/2928/documents/3803>.

[13] AACE International. (October 5, 2021) Recommended Practice 34R-05, Basis of Estimate. <https://www.pathlms.com/aace/courses/2928/documents/3819>.

[14] AACE International. (August 7, 2020) Recommended Practice 96R-18, Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Power Transmission Line Infrastructure Industries. <https://www.pathlms.com/aace/courses/2928/documents/12530>.

Reference No.	Document Title
Early Execution Application	Application for Early Execution Capital Work for Bay d'Espoir Unit 8 and Avalon Combustion Turbine – Refile[15]
HRDCT2-HAT-49100-EP-EST-0001-01	150 MW Combustion Turbine FEED Study Basis of Estimate[16]
HRDCT2-HAT-49100-EP-EST-0004-01	Capital Cost Estimate[17]
HRDCT2-HAT-49100-PC-EST-0001-01	Parametric QRA Report[18]
HRDCT2-NLH-49100-EN-BOD-0001-01	Avalon Combustion Turbine Basis of Design[19]
HRDCT2-NLH-49100-ES-EST-0001-01	Avalon Combustion Turbine Project Cost Estimate[20]
HRDCT2-HAT-49100-RI-REG-0001-01	Risk and Assumption Register[21]
HRDCT2-NLH-40000-PM-CHT-0001-01	Avalon Combustion Turbine Project Charter[22]
HRDCT2-NLH-49100-PC-BOS-0001-01	Avalon Combustion Turbine Basis of Schedule[23]
HRDCT2-NLH-49100-PM-MEM-0001-01	Avalon Combustion Turbine Major Projects - Internal Decision Support Memorandum[24]
MOU	Memorandum of Understanding Between Newfoundland and Labrador Hydro and Hydro Quebec[25]

[15] "Application for Early Execution Capital Work for Bay d'Espoir Unit 8 and Avalon Combustion Turbine – Refile," Newfoundland and Labrador Hydro, March 12, 2025. <http://pub.nl.ca/applications/NLH2025AvalonCombustion/index.php>.
[16] "150 MW Combustion Turbine FEED Study Basis of Estimate," Hatch Ltd., Rev B0, November 11, 2024, included as Attachment 2 to this Basis of Estimate.
[17] "Capital Cost Estimate," Hatch Ltd., Rev B1, November 22, 2024.
[18] "Parametric QRA Report," Hatch Ltd., Rev B1, November 29, 2024, included as Attachment 3 to this Basis of Estimate.
[19] "Avalon Combustion Turbine Basis of Design," Newfoundland and Labrador Hydro, Rev A0, January 2025.
[20] "Avalon Combustion Turbine Project Cost Estimate," Newfoundland and Labrador Hydro, Rev B0, (excel support file).
[21] "Risk and Assumption Register," Hatch Ltd., Rev. B0, November 18, 2024, included as Attachment 4 to this Basis of Estimate.
[22] "Avalon Combustion Turbine Project Charter," Newfoundland and Labrador Hydro, September 4, 2024.
[23] "Avalon Combustion Turbine Basis of Schedule," Newfoundland and Labrador Hydro, March 14, 2025.
[24] "Avalon Combustion Turbine Major Projects - Internal Decision Support Memorandum," Newfoundland and Labrador Hydro, Rev. B0, April 10, 2024.
[25] "Memorandum of Understanding for a New Long-Term Energy Purchase and Development Initiative Between Newfoundland and Labrador Hydro and Hydro Quebec," Newfoundland and Labrador Hydro and Hydro-Québec, December 12, 2024. <https://www.ourchapter.ca/files/NewfoundlandLabrador-Quebec-MOU-English-Dec12-2024.pdf>.

Reference No.	Document Title
12972590-NLH-NLH-BRI-0001	Avalon Combustion Turbine Briefing Note – Impact Analysis of CT Price Increase on Project Estimate

4.0 Introduction

In 2023, NL Hydro completed a conceptual design review to build a new 150 MW CT Generation Plant next to the existing Holyrood TGS. The main purpose of the study was to complete an order of magnitude cost estimate for the implementation of a new 150 MW CT Generation Plant. The cost estimate completed at the end of the study was conducted in accordance with AACE guidelines for the completion of a Class 5 cost estimate, with an expected accuracy range of -30%/+50%.

In 2024, NL Hydro proceeded with the FEED phase to mature the design and to improve the accuracy of the cost estimate for the project. A contract was awarded to Hatch to perform the FEED work and complete a Class 3 cost estimate, for the design and build of a new 150 MW CT Plant in Holyrood. Hatch chose to complete the Class 3 cost estimate in accordance with the guidelines documented in AACE RP 96R-18.[26] At the end of FEED, the maturity level of the project definition was assessed by NL Hydro's ACT Project Management Team and determined to have a design definition of 88%. The full assessment of the maturity level of the project definition is detailed in Attachment 1.

NL Hydro estimated the costs for NL Hydro's ACT Project Management Team and other NL Hydro indirect costs, described herein, to be added to the estimate completed by Hatch. Therefore, the Total Installed Cost for the ACT Project is the summation of Hatch's cost estimate and the cost estimate completed by NL Hydro. NL Hydro's cost estimate is considered a Class 3 cost estimate, according to AACE RP 17R-97.

As it relates to the project cost estimate, at the end of the FEED phase, Hatch provided the following key deliverables all of which have been reviewed and accepted by NL Hydro's ACT Project Management Team at the end of 2024:

- Preliminary engineering design drawings to demonstrate the maturity of design;
- Basis of Estimate and associated Class 3 cost estimate;
- Quantitative Risk Assessment Report;
- Basis of Schedule and associated Project schedule; and
- Project Execution Plan.

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[26] In the Hatch Basis of Estimate, AACE RP 96R-18 is referenced; however, AACE RP 18R-97 was recommended as the more suitable document. While there are industry-specific differences, particularly in the maturity matrix used to assess design progress, the estimate classification tables are identical across both documents. The project was assessed using the maturity matrix from AACE RP 18R-97, ensuring alignment with the appropriate estimation methodology. Please refer to Attachment 1 to this Basis of Estimate for the results of the assessment. Additionally, Hatch's Parametric QRA Report, provided as Attachment 3 to this Basis of Estimate, includes the Scope Development/Maturity Worksheet, reinforcing that the structured estimation approach followed AACE RP 18R-97. The reference to AACE RP 96R-18 does not affect the applied estimation framework and its inclusion has no material impact on the overall methodology.

In 2025, NL Hydro issued a formal request-for-purchase (RFP) to combustion turbine vendors to supply the CTs. The purchase price for the CTs had significantly increased above the budgetary pricing that was obtained during the FEED phase, which was the cost basis for the proposed budget in Revision B0 of this Basis of Estimate. Therefore, NL Hydro decided to reassess the overall cost impact on the project, and to update this basis of estimate in order to formally document and communicate the results of the assessment.

5.0 Purpose

The purpose for revising this basis of estimate is to formally document the cost impact of the new purchase price for the CTs, on the overall project cost, and to provide a basis for the newly proposed ACT Project budget. It is important to note that the estimated costs, and associated risks, for all other cost elements of the project have not changed. There is no new costing information available to suggest other costs elements need to be reassessed at this time.

NL Hydro have estimated the following project costs:

- NL Hydro's ACT Project Management Team;
- Project Indirect costs that will be incurred by NL Hydro directly, such as insurance, FEED, etc.; and
- Expected escalation costs and costs of borrowing (Interest During Construction) for the Total Installed Cost.
- Incremental cost adjustments resulting from the increased purchase price for the CTs.

Hence, the purpose of this Basis of Estimate is to describe the cost basis and estimating methodologies that were used by NL Hydro to estimate the costs listed above.

The information provided herein does not replace or supersede the information found in Hatch's documentation; rather, it supplements the information contained therein. Hatch's Basis of Estimate and QRA Report must be read with this Basis of Estimate to understand the cost basis and estimate methodologies that were used to estimate the total Installed cost for the ACT Project.

This Basis of Estimate has been prepared using AACE RP 34R-05 and AACE RP 31R-03 as a general guide.

6.0 Project Scope

The ACT Project is a critical component of NL Hydro's Minimum Investment Required Expansion Plan, ensuring a reliable, cost-effective, and environmentally responsible electricity supply. A CT has consistently been identified as a technically viable, cost-competitive supply option, as outlined in *NL Hydro's Reliability and Resource Adequacy Study Review* proceeding[27] and further documented in the Avalon Combustion Turbine Major Projects - Internal Decision Support Memorandum.

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[27] *Reliability and Resource Adequacy Review* proceeding. <http://pub.nl.ca/applications/NLH2018ReliabilityAdequacy/index.php>

NL Hydro proposes to construct a new CT Plant at the Holyrood TGS site to serve as a peaking facility, supporting power generation when required and maintaining overall grid reliability. The project will support system reliability as aging assets are retired, while also providing backup to support future renewable integration. By strategically integrating a new CT Plant into the system, NL Hydro aims to maintain system resiliency, particularly during peak demand periods and emergency conditions.

The overall plant capacity will be a nominal 150 MW, consisting of multiple CT units of the same size. The ACT Project will include the engineering, procurement, construction, and commissioning of all works associated with the ACT Project, including but not limited to:

- Standalone CT generating units, including all necessary auxiliary systems and controls equipment;
- A dedicated switchyard connection with 13.8 kV/230 kV transformers and standard terminal structures and facilities for connecting 230 kV transmission lines and standard 600 V and 120 V station service utilized for auxiliaries and building services; and
- Fuel storage and supply infrastructure, with 10 days of on-site fuel storage. Fuel deliveries will be via road truck; however, a new line between the new CT Plant and the existing Marine Jetty is also included as a future option to supply fuel. The refurbishment and/or modification and/or replacement of the existing Marine Jetty is not included in the scope of work for this project, hence the associated costs are also excluded.

6.1 Direct Scope

The direct scope is detailed in the 150 MW Combustion Turbine FEED Study Basis of Estimate, included as Attachment 2 to this Basis of Estimate.

6.2 Indirect Scope

The remaining indirect scope, other than the indirect scope listed in Section 5.0, is detailed in Attachment 2 to this Basis of Estimate.

7.0 Estimate Methodology

This Basis of Estimate describes the estimate methodologies for the indirect costs estimated by NL Hydro, listed in Section 5.0.

7.1 Direct Costs

The estimate methodologies that were used to estimate the direct costs for the ACT Project are described in Attachment 2 to this Basis of Estimate.

7.2 Other Indirect Costs

The estimate methodologies that were used to estimate other indirect costs, not described herein, are described in Attachment 2 of this Basis of Estimate.

7.3 NL Hydro's Indirect Costs

During the next five to ten years, NL Hydro is planning to execute multiple, relatively large, capital projects. Due to the size and complexity of those projects, NL Hydro determined that it required additional capacity and resources to manage the execution of major projects in addition to managing the ongoing operations and maintenance of existing NL Hydro assets. Therefore, a dedicated Major Projects Department was created, consisting of both NL Hydro employees and contractors with specific skill sets needed for projects of this nature.

NL Hydro's indirect costs for the ACT Project include the following:

- Employment income and burdens for members of NL Hydro's Major Projects Department;
- Personnel expenses;
- Sunken costs;
- Insurances:
  - Contractor All Risk;
  - Wrap-Up; and
  - Pollution Liability;
- Spare Transformer;
- Studies and Third-Party Consultants:
  - Fire Water System Analysis;
  - Geotechnical Study;
  - Baseline Noise Study; and
  - Emissions Study.
- Land Surveys

For estimating purposes, and as it applies to the ACT Project, the Major Projects Department was divided into the following personnel groups because their roles and responsibilities differ.

- NL Hydro's Major Projects Department Management Team;
- NL Hydro's ACT Project Management Personnel;
- NL Hydro's Engineering Personnel;
- NL Hydro's Construction and Commissioning Oversight Site Personnel; and
- NL Hydro's Personnel Expenses;
- Sunk Costs;
- Insurance; and
- Other minor costs, such as safety incentive programs and team building.

7.3.1 NL Hydro's Major Projects Department Management Team

NL Hydro's Major Projects Department Management Team are responsible for managing all major projects, not just the ACT Project. They will assign members of their teams to the different major projects and support the ACT Project Management Personnel and the Director of Major Projects & Asset Management with reporting project updates to NL Hydro's internal and external stakeholders.

As it applies to the estimated cost for the ACT Project, the Major Projects Department Management Team:

- Will be budgeted a certain number of hours per year for the full duration of the ACT Project;
- Are not expected to need any overtime for the ACT Project;
- Will not travel to the ACT Project site often; and
- Will not have to travel outside the province for the ACT Project.

The total estimated hours per year for the group are based on:

- Regular hours of 7.5 hours per day;
- 5 days per week for 52 weeks of the year, less an average of 2 weeks vacation and 14 statutory holidays per year; and
- Continuously supporting the project, from start to finish.

NL Hydro's ACT Project Management evaluated the roles and responsibilities of each position; to estimate the expected level of effort that each position would have to dedicate to the ACT Project for each year.

The only exception will be the Director of Major Projects & Asset Management. This position will primarily work at the portfolio and corporate level and will not charge directly to projects. No costs have been included in the ACT Project cost estimate for this position.

7.3.2 NL Hydro's ACT Project Management Personnel

The ACT Project Management Personnel will manage and perform specific ACT Project tasks and report project updates to NL Hydro's Major Projects Department Management Team. Unlike the Major Projects Department Management Team, the estimated hours and costs for the ACT Project Management Personnel:

- Are based on the expected level of effort required to perform project-specific tasks;
- Hours are tied to start and finish dates in the schedule to complete project-specific tasks;
- Are expected to need an average number of hours per week for overtime;
- Will travel to and from the ACT Project site often; and
- Some personnel may need to travel to Supplier facilities for kick-off meetings, etc.

The total estimated hours per year for those personnel are based on:

- Regular hours of 7.5 hours per day plus, an average number of overtime hours per week;
- 5 days per week for 52 weeks of the year, less an average of 2 weeks for vacation and 14 statutory holidays per year; and
- The start and finish dates in the schedule for project-specific tasks.

NL Hydro's ACT Project Management evaluated the roles and responsibilities of this group to decide whether or not the tasks being performed by a particular position would justify a full-time resource. If a full-time resource was not expected to be required, an expected level of effort was estimated.

7.3.3 NL Hydro's Engineering Personnel

NL Hydro's Engineering Personnel will provide the technical support. The expected level of effort for engineering is based on NL Hydro's Engineering Personnel performing the following tasks for the ACT Project:

- Reviewing engineering drawings and other technical documents from the EPCM Consultant, Contractors, and Suppliers for acceptance on behalf of NL Hydro;
- Managing contracts for the procurement of the CTs and transformers;
- Answering technical queries; and
- Traveling out of province to Supplier facilities to participate in FAT, etc.

NL Hydro's ACT Project Management evaluated the roles and responsibilities of each engineering discipline that would be required to decide whether or not a full-time or partial resource would be required. From this assessment, a full-time equivalent resource weighting was estimated, which then was applied to the following criteria.

The total estimated hours per year for the ACT Project Engineering Personnel are based on:

- Regular hours of 7.5 hours per day plus, an average number of overtime hours per week;
- 5 days per week for 52 weeks of the year, less an average of 2 weeks for vacation and 14 statutory holidays per year; and
- Start and finish dates in the schedule for engineering-related tasks.

7.3.4 NL Hydro's Construction and Commissioning Oversight Site Personnel

The expected level of effort for NL Hydro's ACT Project Construction and Commissioning Oversight Site Personnel is based on performing the following tasks at the ACT Project site:

- Overseeing construction and commissioning work activities, including the EPCM Consultant;
- Ensuring Contractors adhere to project safety practices;
- Monitoring construction and commissioning progress;
- Answering site-related queries;

- Ensuring Construction and Commissioning Contractor(s) are adhering to project specifications and standards; and
- Managing the Turnover to NL Hydro Operations.

NL Hydro's ACT Project Management evaluated the roles and responsibilities of each construction and commissioning role to decide whether or not a full-time or partial resource would be required.

From this assessment, a full-time equivalent resource weighting was derived, which then was applied to the following criteria:

- Regular hours of [redacted] hours per day, for [redacted] days per week to match the expected work schedule of the EPCM Consultant;
- Working 52 weeks of the year, less an average of 2 weeks for vacation and 14 statutory holidays per year, and
- According to the start and finish dates in the schedule for construction and commissioning-related tasks.

7.3.5 NL Hydro's Personnel Expenses

NL Hydro personnel expenses include costs for business travel and safety incentives/events. Expenses for PPE (such as hard hats, steel-toed boots, gloves, safety glasses, and hearing protection) are not included as a separate cost under expenses because it is built into the hourly rates for both Employees and Contractors.

Travel Expenses, as it applies to NL Hydro's estimated costs, comprise of the following different cost types:

- Modes of transportation, e.g., flights, taxis, rental cars, fleet vehicles, and personal vehicles;
- Meal per diems; and
- Accommodations, such as hotels.

Travel expenses include costs for travelling outside the province as well as to and from the construction site in Holyrood. The out-of-province travel expenses are for NL Hydro Engineering and Operations personnel to check on Supplier progress, attend FAT, and complete checkpoint inspections. The expenses for travelling to and from Holyrood are for the NL Hydro Construction and Commissioning Oversight Personnel and periodic meetings and reviews performed by NL Hydro's ACT Project Management Team.

If in-province travel is required, other than travel to and from Holyrood, it will be due to some of the equipment being sourced within the province. If this is the case, some of the estimated costs for travelling outside the province will be reallocated to the costs for in-province travel expenses.

7.3.6 Sunken Costs

Sunken costs are the actual NL Hydro expenditures incurred for the completion of conceptual study works and FEED, inclusive of all costs for NL Hydro personnel and the FEED contract with Hatch.

The sunken costs (actual FEED expenditures) equated to approximately $2.3 million.

7.3.7 Insurance

As advised by NL Hydro's Senior Manager of Operations Risk and Insurance, NL Hydro's existing general liability insurances will not cover project values in excess of [redacted] Since the ACT Project does exceed the minimum of [redacted] additional project-specific insurance is recommended and is included in NL Hydro's cost estimate for Contractor All Risk, Wrap-Up Liability, and Pollution Liability.

The estimated cost for insurance is based on a budgetary quote obtained by NL Hydro's Senior Manager of Operations Risk and Insurance from a reputable insurance company. The insurance company based their quote on the estimated amounts for each phase of the ACT Project. The pricing provided is approximately [redacted]

7.3.8 Spare Transformer

A new transformer will be purchased to be used as a spare.

7.3.9 Studies and Third-Party Engagement

At the end of FEED, NL Hydro's ACT Project Management Personnel completed scheduled review sessions and multiple risk sessions. Management concluded that certain studies and analyses would have to be completed prior to the planned EPCM contract award date, to derisk the project. Therefore, the costs for the following studies listed were excluded from the EPCM cost estimate and added to NL Hydro's cost estimate.

- Fire Water System Analysis;
- Geotechnical Study;
- Baseline Noise Study;
- Emissions Study;
- Land Survey; and
- Black Start Options

The estimated costs for each of these studies are based on historical pricing, for the same type of studies, that were completed by NL Hydro for other projects. The historical pricing was scaled based on the size of the study relative to what is required for the ACT Project and then escalated to 2024 pricing. The estimated cost equates to approximately [redacted]

7.4 Escalation and IDC

NL Hydro has a standard method of calculating IDC, which is applied to capital expenditures. This method was applied to this cost estimate.

The estimated escalation cost has been reduced from $44.9 million (Revision B0) by approximately $11.2 million, to $33.7 million, which takes into consideration the CT contract has been awarded, which means most of the procurement costs for the CTs are fixed.

NL Hydro estimated the Escalation costs by applying the NL Hydro Corporate Escalation Rates shown in Table 2 to the committed cost profile shown in Table 3. The costs listed in Table 3 include Contingency; therefore, the Planned Budget, shown in Table 1, is based on an escalated Pmean (P55) value.

Table 2: Escalation Factors[28]

Year	GDP	CT Plant Construction	Transmission Line Construction	Transformer Station Construction
2024	1.000	1.000000	1.000000	1.000000
2025	1.020	1.025976	1.038243	1.027471
2026	1.037	1.050436	1.075731	1.053503
2027	1.056	1.075646	1.114744	1.080361
2028	1.074	1.101314	1.155020	1.107758
2029	1.093	1.127415	1.196561	1.135667
2030	1.112	1.154134	1.239597	1.164279
2031	1.131	1.181486	1.284181	1.193613
2032	1.150	1.209486	1.330368	1.223685
2033	1.170	1.238150	1.378216	1.254515
2034	1.191	1.267494	1.427785	1.286122
2035	1.211	1.297532	1.479137	1.318525
2036	1.232	1.328283	1.532336	1.351744
2037	1.254	1.359762	1.587448	1.385801
2038	1.275	1.391988	1.644542	1.420715
2039	1.297	1.424977	1.703690	1.456509
2040	1.320	1.458748	1.764965	1.493205
2041	1.343	1.493319	1.828444	1.530825
2042	1.366	1.528710	1.894206	1.569393
2043	1.389	1.564939	1.962334	1.608933
2044	1.414	1.602027	2.032911	1.649469
2045	1.438	1.639994	2.106027	1.691027
2046	1.463	1.678861	2.181773	1.733631
2047	1.488	1.718649	2.260243	1.777309
2048	1.514	1.759380	2.341535	1.822087
2049	1.540	1.801076	2.425751	1.867994
2050	1.567	1.843760	2.512996	1.915057

[28] Source: GDP, CPI, and USCPI as per The Conference Board of Canada, Canadian - 5 Yr Forecast, September 18, 2024. Other factors as per NL Hydro's Escalation Forecast Methodology.

Table 3: Committed Cost Profile to Calculate Escalation ($ Million)

	2024[29]	2025	2026	2027	2028	2029
Cost	[redacted]					

IDC is the cost of borrowing throughout the duration of the project. The annual borrowing rate of 4.96% was used to calculate the IDC for the cost estimate referenced in both Revision B0 and Revision B1 of this Basis of Estimate. The revised estimated cost for IDC equates to approximately $76.2 million, which is $9.6 million greater than the previously estimated IDC amount of $66.6 million (Revision B0). IDC has increased because the contract for the CTs has been awarded earlier than originally planned, to mitigate the delivery risk, and the cost of the CTs is greater.

To estimate the IDC, the above annual interest rate was applied to the expected annual expenditures (spend profile) referenced in Table 4, escalations and contingency included.

Table 4: Spend Profile to Calculate IDC ($ Million)

	2024[30]	2025	2026	2027	2028	2029
Cost	[redacted]					

8.0 Design Basis

The design basis for the ACT Project is described in the Avalon Combustion Turbine Basis of Design

9.0 Planning Basis

The planning basis for the ACT Project is described in NL Hydro's Avalon Combustion Turbine Basis of Schedule.

9.1 Planned Spend Profile

The planned spend profile, referenced in Table 5, is based on the schedule provided in NL Hydro's Avalon Combustion Turbine Basis of Schedule and equals the "Planned Budget" referenced in Table 1.

Table 5: Planned Spend Profile ($ Million)

	2024	2025	2026	2027	2028	2029
Planned Spend Profile	[redacted]					

[29] Escalation not applied to 2024 committed costs because it is actual cost expended.
[30] Actual cost expended in 2024.

10.0 Cost Basis

This Basis of Estimate describes the cost basis for indirects estimated by NL Hydro only. However, references are made to the cost basis of direct costs and other indirect costs that were estimated by Hatch, for the convenience of the reader.

This cost estimate is stated in 2024 dollars, with escalation and IDC calculations based on cost profiles which follow the project plan.

10.1 Construction

Pricing for labour, equipment, and materials in the estimated scope are described in Section 4 of Attachment 2 to this Basis of Estimate.

10.1.1 Direct Cost

The cost basis for all direct costs is described in Section 4 of Attachment 2 to this Basis of Estimate.

10.1.2 Productivity

The basis for labour productivity is described in Section 4.4.3 of Attachment 2 to this Basis of Estimate.

10.1.3 Other Costs

The cost basis for other costs such as freight, third-party services, commissioning spares, etc. is described in Section 5 of Attachment 2 to this Basis of Estimate.

10.1.4 Indirect Costs

The cost basis for all indirect costs, other than NL Hydro's indirect costs described herein, is described in Section 5 of Attachment 2 to this Basis of Estimate.

10.2 NL Hydro's Indirect Costs

The basis for the NL Hydro indirect costs, listed in Section 7.0, is described in Sections 10.2.1 to 10.2.4.

10.2.1 NL Hydro's ACT Project Management Team

The ACT Project Manager developed the roster for NL Hydro's ACT Project Management Team and assigned hours for each position based on their expected engagement on the project. The makeup of NL Hydro's ACT Project Management Team and the applied assumptions are described in Section 7.3.

10.2.2 Hourly Rates for NL Hydro Personnel

All-inclusive hourly rates were used to develop the costs for NL Hydro's ACT Project Management Team:

- The hourly rates for NL Hydro employees are [redacted] per hour for regular time and [redacted] per hour for overtime.
- For Contractors, a rate of [redacted] per hour was used for both regular time and overtime.

The all-inclusive costs include all burden costs such as vacation, office expenses, PPE, etc.

10.2.3 NL Hydro Personnel Expenses

For travel and accommodations, the following rates were used to estimate costs:

- For out-of-province trips, a cost of [redacted] for a typical 5-day trip was assumed, with costs as follows:
  - Flight: [redacted]
  - Accommodations: [redacted]
  - Meals: [redacted]
  - Transportation: [redacted]
- For in-province trips, [redacted] trips were assumed, with costs as follows:
  - Meals: [redacted]/day (lunch only)
  - Transportation: [redacted]/day

Other items such as safety incentives/events and insurance are also included.

10.2.4 EPCM Consultant Costs

The basis for the estimated EPCM costs is provided in Attachment 2 to this Basis of Estimate.

10.3 Exchange Rates

Some of the budgetary pricing Hatch obtained for materials and equipment during the FEED phase was provided in US dollars and it is suspected that the base currency for the transformers would be in Euros. At the time the FEED cost estimate (Revision B0) was completed, 1 USD equalled 1.34 CAD, and 1 Euro equalled 1.506 CAD. The new pricing for the CTs is based on 1 USD equalling 1.36 CAD because this is the exchange rate that was applicable to the first payment for the CTs. Additional details about the application of exchange rates to all other cost elements of the cost estimate remain unchanged from revision B0 and is described in Attachment 2.

11.0 Allowances

Allowances that were applied to the project costs, estimated by Hatch, are detailed in Attachment 2 to this Basis of Estimate.

Hatch's estimated cost for the EPCM personnel equates to approximately [redacted] of the base estimate for total direct and indirect costs. This is considered [redacted] according to Industry norms. Such EPCM costs for a project of this type should fall within the range of [redacted] Given NL Hydro's [redacted] NL Hydro decided to [redacted]

12.0 Contingency

The contingency for the total installed cost of the ACT Project was derived from a QRA that was performed by Hatch's Risk Management Lead. Members of both Hatch's and NL Hydro's FEED Teams participated in the QRA sessions. The inputs from the QRA were entered into @Risk MCS software to determine the probability distribution values for the project.

The Contingency value is the difference between the PMean value and the base estimate value as determined through the QRA.

The contingency value is approximately $76.4M, which includes the change in contingency determined from the changed price of the CT units (+10.3M) combined with the originally determined value of contingency ($65.1M).

13.0 Management Reserve

The Management Reserve is the difference between the P85 and PMean project values, resulting from the QRA.

The management reserve value is approximately $121.6M, which includes the change in management reserve determined from the changed price of the CT units (-6.6M) combined with the originally determined value of management reserve ($128.2M).

The value for management reserve has decreased due to the increased certainty of the CT components, as this contract is now in place.

Included in the total Management Reserve is approximately $16.3 million of Management Reserve for the indirect costs estimated by NL Hydro.

14.0 Estimate Classification

Cost Estimate classification and accuracy are considered to depend primarily on the maturity level of project definition deliverables. The design maturity is described in detail in the Project Definition Maturity Worksheets contained in Attachment 1 to this Basis of Estimate.

The scope development and maturity worksheets contained in Appendix A of Attachment 1 to this Basis of Estimate, formed the basis for qualifying the estimate classification of the ACT Project cost estimate. The results of the QRA were then used to classify the cost estimate in accordance with the AACE Estimate Classification Matrix, found in AACE RP 96R-18.

The expected accuracy range of the ACT project estimate is determined to be -19.6%/+22.0% (changed from the assessed range of -23%/+26% in Rev B0 of this BoE), at an 80% confidence interval. This falls within the accuracy range for a Class 3 cost estimate, according to the AACE Estimate Classification Matrix, found within AACE RP 96R-18.

A detailed description of how the new accuracy range was determined is explained in the briefing note contained in Attachment 5.

15.0 Assumptions and Exclusions

For a list of project assumptions created during FEED, refer to Attachment 4 to this Basis of Estimate

NL Hydro Corporate Support Services such as Information Systems, Human Resources, Long-Term Asset Planning, etc. are excluded, as it is expected those resources can support major projects within the scope of their current duties for NL Hydro.

16.0 Risks and Opportunities

There are many types of project risks, safety risks, etc., but the only risks that are discussed herein are those risks that could potentially result in a cost increase. The only opportunities discussed herein are those that could potentially result in a project cost reduction.

16.1 Cost Risks

During the FEED phase, risk workshops were held to create risk registers for the project. The register was continuously reassessed and updated by both the FEED Contractor and NL Hydro's ACT Project Management Team, to ensure FEED efforts were focused on the right areas. The registers were also the basis for the QRA that was performed at the end of FEED and to highlight those design elements that need to be focused on early in the next phase of the project, primarily to mitigate schedule delays.

16.1.1 LM6000 CT

In Rev B0 of this BOE, there was uncertainty as to which CT vendor and model would be selected from the competitive bid process. If a product other than the LM6000 were selected, the plant design would likely have to change to accommodate the specific unit sizing and/or utility requirements. As NL Hydro have now entered in a contractual agreement with GE for the supply of the LM 6000 CTs this risk is effectively retired.

16.1.2 Foreign Exchange Exposure

Approximately $170 million of the direct estimated costs, referenced in Hatch's cost estimate, are based on USD. As stated in Section 10.3, 1.34 was the USD to CAD exchange rate at the time Hatch completed the cost estimate. As of February 4, 2025, the USD to CAD exchange rate is 1.43, a potential currency exposure of approximately $18 million.

16.1.3 Wars in Gaza and Ukraine

If either, or both, the wars in Gaza and Ukraine end and there are immediate efforts and funding available to start rebuilding infrastructure in either or both countries, the cost of bulk materials and equipment will increase.

16.2 Emerging Risks

Emerging risks, as defined herein, are new risks that became apparent after the ACT Project QRA was completed in October 2024; as such, emerging risks were not considered in the QRA, and may not be fully covered by Contingency and Management Reserves.

Sections 16.2.1 to 16.2.3 list the emerging risks and describe how they could potentially impact the ACT Project.

16.2.1 Competing Projects (Churchill Falls and Gull Island)

In December 2024, the Government of Newfoundland and Labrador announced a new tentative agreement for the execution of the following major projects. Details are provided in the MOU:

- Gull Island Project: The design and construction of a 2250 MW NL Hydro Production Plant;
- Churchill Falls Expansion Project: A new 1100 MW NL Hydro Power Plant;
- Churchill Fall Units Upgrade: The upgrade of all 11 existing NL Hydro Power generators to obtain an additional 550 MW;
- NL Hydro's Transmission Asset Project; and
- Hydro-Québec's Transmission Asset Project.

Based on publicly released information at the time the MOU was announced, the aforementioned projects will be approximately $30+ Billion Canadian in value. These projects are planned to start around the second quarter of 2026 and be completed sometime in 2035, with the only exception being the Churchill Falls Units Upgrades Project, which is planned to be completed around 2038. This is a very aggressive timeline for projects of this size and complexity; therefore, the demand on professional resources, particularly the trades, will be great, possibly resulting in:

- Increased labour rates;
- Dilution of available professional experience; and
- Poor construction productivity, due to high ratios of Journeypersons to Apprentices, Worker retention, etc.

Lastly, this will certainly increase the demand for materials and equipment. All will have a high potential of increasing project costs. To assess the potential impact, high-level schedules for the Churchill Falls and Gull Island Projects were created to identify potential overlaps between the ACT Project and the other major projects planned for execution by NL Hydro during the next 5 to 10 years. As currently planned, each of the engineering, procurement, construction, and commissioning phases for the ACT Project will start and finish before each of the corresponding phases for the projects listed in the MOU will begin (based on an assumed schedule for the MOU projects). However, a delay in the ACT Project or a faster implementation of the MOU projects could result in schedule overlap, therefore resulting in increased ACT Project costs.

16.2.2 AI Industry

AI is another factor that poses a cost risk to the project. Multiple online articles talk about the significant increase in power that will be needed to power current and future AI developments.[31] For example, on January 21, 2025, US President Donald Trump announced on CNBC Television that three AI companies are planning to invest $500 Billion USD in the construction of 20 computer server buildings, each building having an estimated footprint of 500,000 square feet.

It is safe to assume these AI Projects, albeit significant, are just a few of many across the globe but worth highlighting, as they are North American projects that will put a demand on the same equipment, such as CTs, transformers, and other electrical equipment, etc. being considered for the ACT Project.

16.2.3 US Tariffs

Current tariff threats from the US will likely cause material costs to increase. It is difficult to qualify at this time which materials and equipment will be impacted; however, it is almost certain that some materials and equipment will increase in cost. If all items typically sourced from the US incur a 25% tariff, the cost impact could be on the order of a $42 million increase.

16.3 Cost Saving Opportunities

The following is a list of potential cost-saving opportunities identified for assessment:

- Utilize the CT1 black start generator for the new CTs instead of purchasing new black start generator(s). The cost of new black start generator(s) versus the additional electrical infrastructure and controls required to integrate with the existing infrastructure will be assessed during the next phase of the project.
- The FEED Contractor assumed structural pilings would be required to support major equipment at the site. A more extensive geotechnical study will be completed in the next phase to confirm whether or not pilings are required.
- During FEED, it was noted that there may be a way to optimize the transformer setup and terminal station arrangement to reduce costs. This will be focused on early in the detailed design phase before progressing efforts to purchase equipment and materials.
- Optimize the building configuration and layout to assess cost savings versus impacts on Operations.

[31] Multiple reputable sources have reported on the anticipated rise in energy demands required to support both current and future AI developments, a trend that could contribute to escalating project costs, including NPR <www.npr.org>, Scientific American <www.scientificamerican.com>, Springer Nature Limited <www.nature.com>, and the BBC <www.bbc.com>.

17.0 Estimating Team

The estimating team consisted of:

- Hatch, who prepared the Capital Cost Estimate and 150 MW Combustion Turbine FEED Study Basis of Estimate for the project, including direct costs, indirect costs associated with construction, and EPCM costs.
- NL Hydro's Major Projects Department members, who reviewed the estimate prepared by the consultant and estimated NL Hydro's indirect costs, total project escalation and IDC, and prepared this Basis of Estimate.

Avalon Combustion Turbine

Basis of Estimate

Attachment 1: Avalon Combustion Turbine Sanction Readiness Maturity of Deliverables (MoD) Gap Analysis

Document No.: 12972390-NLH-NLH-MEM-0001

Date: February 19, 2025

Newfoundland and Labrador Hydro
Hydro Place. 500 Columbus Drive
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 | f. 709.737.1800
nlhydro.com

To:	John Walsh, Sr. Manager, Major Projects & Engineering
Cc:	Gail Randell, Director, Major Projects & Asset Management
	John Skinner, Sr. Manager, Commercial
	Robert Collett, VP Engineering & NLSO
	David Billard, Project Manager
From:	Jackie Borden, Director, Internal Audit
Date:	February 19, 2025
Re:	Objective 1 Deliverable 2 – Avalon Combustion Turbine Sanction Readiness Maturity of Deliverables (MoD) Gap Analysis
Team Lead:	Douglas Woodford, Team Lead, Internal Audit
Director:	Jackie Borden, Director, Internal Audit

John,

Internal Audit will be performing an audit[1] engagement related to the planning phase of the Avalon Combustion Turbine (ACT) major project. This focus of this engagement will be on 18R-97 - Cost Estimating Classification System (CECS) for the Process Industries. This engagement has 4 objectives, however, due to the schedule, Internal Audit will be issuing communication as each objective(s) is completed to allow the project management to address. A consolidated summary will be completed as all 4 objectives are completed. This communication is related to Objective 1 only.

Internal Audit Objectives:

1) To assess the maturity of project deliverables, which includes:
    b. Determining if the maturity of deliverables are aligned with the class three cost estimate requirements as outlined in the *Association of Advanced Cost Engineering (AACE) Recommended Practice 18R-97, Cost Estimate Classification System - As Applied in Engineering, Procurement, and Construction for the Process Industries.*

18R-97 Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries.

"The maturity level of project definition is the sole determining (i.e., primary) characteristic of class. In Table 1, the maturity is roughly indicated by a percentage of complete definition; however, **it is the maturity of the defining deliverables that is the determinant, not the percent. The other characteristics are secondary and are generally correlated with the maturity level of project definition deliverables**. Based on an examination of the maturity level of project definition the ACT Project is within the parameters of a Class 3 Estimate. See table 1 below:

1 Some components of this engagement may be considered consulting/advisory. As per the IIA and NL Hydro Internal Audit Charter, Consulting Services and are defined as, "Advisory and related client service activities, the nature and scope of which are agreed with the client, are intended to add value and improve an organization's governance, risk management, and control processes without the internal auditor assuming management responsibility. Examples include counsel, advice, facilitation, and training."

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Hydro Place. 500 Columbus Drive
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 I f. 709.737.1800
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	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges at an 80% confidence interval
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

Table 1 – Cost Estimate Classification Matrix for Process Industries

Internal Audit completed 5 Tests to that of the MoD:

Test A: To identify if some, all, or more items from the AACE MoD will be included within the PUB Build Application. The PUB Build Application is expected to be submitted March 2025.

Test B: Identify ACCE MoD to that of the Project MoD Tracker. Determine if some, all, or more are being used.

Test C: Identify any AACE MoD not being used. For those not being used document the justification and or risk.

Test D: For each MoD used validate supporting documentation. Sample document (e.g. from Project Manager or via SharePoint) and validate if is approved and issued for use.

Test E: From the Earned Dashboard in Table 1 (see Appendix A – MoD Gap Analysis) determine what level of detail is present.

Test Results:

TEST A:

- The MoD as verified within Test B will be an input into the Regulatory PUB Build Application.
- A Table of Contents has been created and is currently being worked with many stakeholders including the Hydro Major Projects Group. Other completed Audit Procedures previously suggested that the PUB Build Application may be behind schedule; but as of Feb 10/25 the schedule has been recovered and continues to be worked according to the changing risk environment.

TEST B:

Newfoundland and Labrador Hydro
Hydro Place. 500 Columbus Drive
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 I f. 709.737.1800
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- There is no specific Project MoD Tracker; but there are a number of core registers, the NLH Master Document Register & Contractor Document Register (of note these are evergreen documents).
- The BOE does declare that AACE 18R-97 CECS for the Process Industry is used, see "150 MW Combustion Turbine FEED Study Basis of Estimate (Hatch); 2.0 Estimate Classification & Table 2-1: AACE Estimate Classification matrix, p. 7 (doc# H373979-0000-620-610-0001)." The document in its entirety summarizes the "Scope of Work."

TEST C:

- **96% of the MoD within 18R-97 are being used by the ACT Project.**
- The 2 not being used by the ACT are technical deliverables. They are: 1) Demolition Plan & Drawings: No demolition required. 2) Erosion Control Plan: This is a greenfield area on a brownfield site.

TEST D:

- A sample of 19 documents were taken to determine the reasonableness of their current status as identified by the Major Project team (either, Approved, Drafted, Substantially Complete, Conditional). All documents were deemed in conformance from a reasonableness basis. Documents continue to mature. It is suggested that the Project continue to enhance document controls (e.g. signing cover sheets, revision control etc.).

Table 2 Random Sample - 19:

Doc#	Title
HRDCT2-HAT-15000-CV-DAL-0001-01	General Civil Layout
HRDCT2-HAT-49890-EL-LST-0001-01	Electrical Load List
HRDCT2-HAT-49100-PP-DAL-0001-01	Overall Plot Plan
HRDCT2-HAT-49100-ME-TEN-0001-01	Combustion Turbine Technology Comparison
HRDCT2-NLH-49100-HR-PLN-0001-01	Staffing Management Plan
HRDCT2-HAT-49100-PM-PLN-0001-01	Project Execution Plan
HRDCT2-NLH-49100-IF-PLN-0001-01	Interface Management Plan - Avalon Combustion Turbine
NLH-MPM-00000-PC-STG-0001-01	Project Control Management Framework
NLH-MPM-00000-RM-STG-0001-01	Risk Management Framework
HRDCT2-NLH-49100-SM-PLN-0001-01	Stakeholder and Communication Management Plan
HRDCT2-HAT-49100-EV-TEN-0001-01	Community Noise Impact Assessment Report
HRDCT2-HAT-49100-ME-LST-0001-01	Mechanical Equipment List
HRDCT2-HAT-49314-PI-PFD-0001-01	Fuel System Process Flow Diagram
HRDCT2-HAT-49314-PI-PID-000-01: PID	Fuel Storage
HRDCT2-HAT-49100-PP-DAL-0001-02 (H373979-0000-203-270-0002)	A Combustion Turbine Building General Arrangement
HRDCT2-HAT-49100-EP-SCH-0001-01	Basis of Schedule
HRDCT2-NLH-49100-PC-SCH-0002-01	Project Control Schedule & Basis
HRDCT2-HAT-49100-PM-SCH-0002-01	150MW Combustion Turbine FEED Study - Basis of Schedule
HRDCT2-HAT-49100-PC-EST-0001-01	Parametric QRA Report

TEST E:

- Test E was supported by Test D, randomly sampling 19 documents from the Master Document Register (MDR). Internal Audit found no non conformances relevant to the stage of the project. Documents continue to mature and support a Class 3 Estimate.

Newfoundland and Labrador Hydro
Hydro Place. 500 Columbus Drive
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 I f. 709.737.1800
nlhydro.com

Conclusion

The MoD used by ACT aligns with AACE 18-R97 and are appropriately moving towards completion. The document status is nearing completion, as expected at this stage of the project, and continued effort will be required to reach 100% completion.

Throughout this engagement any risks, gaps/partial gaps, and/or process improvement opportunities have been identified and will continued to be communicated to Management.

Scope & Approach

The scope & approach includes; but is not limited to;

- Various interviews throughout each objective
- Conformance testing of key deliverables within the Maturity of Deliverables
- Sampling and review key documents such as the: Contracting Strategy, Human Resource Strategy, Financing Strategy, FEED Report, Constructability Review, Monte Carlo, Risk Registers etc.
- Objective 4 will be advisory and led by the Director, Internal Audit regarding Project Stewardship
- Acknowledgement of Internal Audit work completed to date to further support Sanction Readiness.

Out of Scope

This engagement does not constitute:

- An Independent Project Review (IPR)
- A Constructability Review
- Any technical assessment as this is outside the competency of the auditors
- An opinion that the Project can pass through a Phase Gate.

This engagement will be led by Douglas Woodford, Team Lead, Internal Audit. Both Douglas and/or myself can be contacted if you would like to discuss anything at this stage. Internal Audit will arrange a kick-off meeting with you in the near future. If you have additional questions, please feel free to contact me using the contact information below.

Thank you,

Jackie Borden

Jackie Borden
Dir. Internal Audit
t: 737-1201 c: 725-0280
e: JackieBorden@nlh.nl.ca

Newfoundland and Labrador Hydro
Hydro Place. 500 Columbus Drive
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 I f. 709.737.1800
nlhydro.com

Design Maturity Assessment For Avalon Combustion Turbine FEED Project
Deliverable and Letter Codes are based on AACE 18R-97

Category	Deliverable Description	AACE Prescribed Maturity	Comments	Final Assessed Maturity	FEED Phase % Complete (see Note 1)
Scope	Non-Process Facilities (Infrastructure, Ports, Pipeline, Power Transmission, etc.)	D		D	[redacted]
Scope	Project Scope of Work Description	D		D	[redacted]
Scope	Byproduct and Water Disposal	D	This is between P/D for the FEED Stage	P/D	[redacted]
Scope	Site Infrastructure (Access, Construction, Power, Camp, etc.)	D	Also covered in "Plot Plans/Facility Layouts" below.	D	[redacted]
Capacity	Plant Production/ Facility (includes power facilities)	D		D	[redacted]
Capacity	Electrical Power Requirements (when not the primary capacity driver)	D		P/D	[redacted]
Project Location	Plant and Associated Facilities	D		D	[redacted]
Requirements	Codes and/or Standards	D		D	[redacted]
Requirements	Communication Systems	D	This is between P/D for the FEED Stage	P/D	[redacted]

Newfoundland and Labrador Hydro
Hydro Place. 500 Columbus Drive
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 I f. 709.737.1800
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Category	Deliverable Description	AACE Prescribed Maturity	Comments	Final Assessed Maturity	FEED Phase % Complete (see Note 1)
Requirements	Fire Protection and Life Safety	D	This is between P/D for the FEED Stage	P/D	[redacted]
Requirements	Environmental Monitoring	P		P	[redacted]
Technology Selection	Process Technology	D		D	[redacted]
Strategy	Contracting/ Sourcing - Strategy	D		D	[redacted]
Strategy	Escalation	D		D	[redacted]
Planning	Logistics Plan	D	Concept - Via Bay Bulls from Constructability	NR	[redacted]
Planning	Integrated Project Plan	D		D	[redacted]
Planning	Project Code of Accounts	D		D	[redacted]
Planning	Project Master Schedule	D		D	[redacted]
Planning	Regulatory Approval & Permitting	D	Application Pending March 2025	D	[redacted]
Planning	Risk Register	D		D	[redacted]
Planning	Stakeholder Consultation/ Engagement/ Management Plan + Register	D		D	[redacted]

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Category	Deliverable Description	AACE Prescribed Maturity	Comments	Final Assessed Maturity	FEED Phase % Complete (see Note 1)
Planning	Work Breakdown Structure	D		D	[redacted]
Planning	Startup and Commissioning Plan	P/D	Will be included within EPCM contract. This is a post-FEED deliverable.	S	[redacted]
Studies	Environmental Impact/ Sustainability Assessment	D		D	[redacted]
Studies	Environmental/ Existing Conditions	D		D	[redacted]
Studies	Soils and Hydrology	D	[redacted]	D	[redacted]
Technical Deliverables	Block Flow Diagrams	C		C	[redacted]
Technical Deliverables	Equipment Datasheets	C		C	[redacted]
Technical Deliverables	Equipment Lists: Electrical	C		C	[redacted]
Technical Deliverables	Equipment Lists: Process/Utility/ Mechanical	C		C	[redacted]
Technical Deliverables	Heat & Material Balances	C		C	[redacted]
Technical Deliverables	Process Flow Diagrams	C		C	[redacted]
Technical Deliverables	Utility Flow Diagrams	C		C	[redacted]
Technical Deliverables	Design Specifications	C		C	[redacted]

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P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 I f. 709.737.1800
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Category	Deliverable Description	AACE Prescribed Maturity	Comments	Final Assessed Maturity	FEED Phase % Complete (see Note 1)
Technical Deliverables	Electrical One-Line Drawings	C		C	[redacted]
Technical Deliverables	General Equipment Arrangement Drawings	C		C	[redacted]
Technical Deliverables	Instrument List	C		C	[redacted]
Technical Deliverables	Piping & Instrument Diagrams (P&IDS)	C		C	[redacted]
Technical Deliverables	Plot Plans/Facility Layouts	C		C	[redacted]
Technical Deliverables	Construction Permits	P/C	Not Applicable for FEED Stage	NR	
Technical Deliverables	Civil/Site/ Structural/ Architectural Discipline Drawings	P		P	[redacted]
Technical Deliverables	Demolition Plan and Drawings	P	Not used and not applicable. No demolition required.	NR	
Technical Deliverables	Erosion Control Plan and Drawings	P	Not applicable. This is a greenfield area on a brownfield site.	NR	
Technical Deliverables	Fire Protection and Life Safety Drawings and Details	P	Some Internal to Supply Packages	P	[redacted]
Technical Deliverables	Electrical Schedules	P	FEED Deliverables at 600 V level only	P	[redacted]
Technical Deliverables	Instrument and Control Schedules	P	FEED Deliverables	P	[redacted]
Technical Deliverables	Instrument Datasheets	P	Future as part of Package Supply - Execution Phase	P	[redacted]

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Hydro Place. 500 Columbus Drive
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 I f. 709.737.1800
nlhydro.com

Category	Deliverable Description	AACE Prescribed Maturity	Comments	Final Assessed Maturity	FEED Phase % Complete (see Note 1)
Technical Deliverables	Piping Schedules Type-MTO only	P	FEED Deliverables	P	[redacted]
Technical Deliverables	Piping Discipline Drawings	S/P	FEED Deliverables	S	[redacted]
Technical Deliverables	Spare Parts Listings	P	Part of Package supply next Phase	NR	
Technical Deliverables	Electrical Discipline Drawings	S/P	FEED Deliverables	P	[redacted]
Technical Deliverables	Facility Emergency Communication Plan and Drawings	S/P	FEED Deliverables high level details in next Phase	P	[redacted]
Technical Deliverables	Information Systems/Telecommunication Drawings	S/P	FEED Deliverables high level details in next Phase	P	[redacted]
Technical Deliverables	Instrumentation/ Control System Discipline Drawings	S/P	FEED Deliverables high level details in next Phase	S	[redacted]
Technical Deliverables	Mechanical Discipline Drawings	S/P	FEED Deliverables high level details in next Phase	P	[redacted]
Management (Other Project Deliverables)	Estimate and Basis of Estimate		FEED Deliverables	D	[redacted]
Management (Other Project Deliverables)	Schedule and Basis of Schedule		FEED Deliverables	D	[redacted]

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Hydro Place. 500 Columbus Drive
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 I f. 709.737.1800
nlhydro.com

Category	Deliverable Description	AACE Prescribed Maturity	Comments	Final Assessed Maturity	FEED Phase % Complete (see Note 1)
Management (Other Project Deliverables)	QRA Report/ Monte Carlo Analysis		FEED Deliverables	D	[redacted]
Management (Other Project Deliverables)	Fuel System PFD		FEED Deliverables	D	[redacted]
Management (Other Project Deliverables)	Best Available Controller Technology (BACT) Memorandum		FEED Deliverables	D	[redacted]
Management (Other Project Deliverables)	Mechanical Equipment List (MEL)		FEED Deliverables	D	[redacted]
Management (Other Project Deliverables)	Risk and Assumptions Register		FEED Deliverables	D	[redacted]
Management (Other Project Deliverables)	Stakeholder Mgmt. Plan and Register		FEED Deliverables	D	[redacted]

Avalon Combustion Turbine

Basis of Estimate

Attachment 2: 150 MW Combustion Turbine FEED Study Basis of Estimate

Document No.: HRDCT2-HAT-49100-EP-EST-0001-01, Rev B0

Date: November 11, 2024

150 MW Combustion Turbine FEED Study

Basis of Estimate

			[redacted]		
2024-11-22	0	Issued for FEED	Spollen A.	O'Brien K.	Savoury K.
Date	**Rev.**	**Status**	**Prepared By**	**Checked By**	**Approved By**
HATCH					

NOTICE TO READER

This report was prepared by Hatch Ltd. (“**Hatch**”) for the sole and exclusive benefit of Newfoundland and Labrador Hydro (the "**Owner**") for the purpose of documenting the basis for the estimate for the Front-End Engineering Design of a 150 MW Combustion Turbine facility (the "**Project**").

This report must not be used by the Owner for any other purpose. Use or reliance upon this report or its contents by a third party is at such party's sole and exclusive risk. Hatch makes no warranty or representation of fitness and disclaims any and all liability arising out of such use or reliance. The use of this report by the Owner is subject to the terms of the relevant services agreement between Hatch and the Owner.

This report is meant to be read as a whole, and sections should not be read or relied upon out of context. The report includes information provided by the Owner and by certain other parties on behalf of the Owner. Unless specifically stated otherwise, Hatch has not verified such information and does not accept any responsibility or liability in connection with such information.

This report contains the expression of the opinion of Hatch using its professional judgment and reasonable care, based upon information available at the time of preparation. The quality of the information, conclusions and estimates contained in this report is consistent with the intended level of accuracy as set out in this report, as well as the circumstances and constraints under which this report was prepared.

As this report is a scoping study, all estimates and projections contained in this report are based on limited and incomplete data. Accordingly, while the work, results, estimates and projections in this report may be considered to be generally indicative of the nature and quality of the Project, they are not definitive. No representations or predictions are intended as to become the results of future work, and Hatch does not promise that the estimates and projections in this report will be sustained in future work.

Table of Contents

List of Tables

1. General

1.1 Overview

Newfoundland and Labrador Hydro (NLH) are part of a group of utility companies that own and operate facilities for the generation, transformation, and distribution of electricity to utility, industrial, and residential customers in the Province of Newfoundland and Labrador.

This document outlines the basis used to develop a Capital Expenditure Estimate (CAPEX) Association for the Advancement of Cost Engineering (AACE) class 3 cost estimate for the 150 MW Combustion Turbine Project. The class 3 estimate was developed in accordance with AACE 96R-18 (applied to power transmission line infrastructure industries) and has an estimate accuracy for 80% confidence interval of -22.8% to +25.7%.

The CAPEX has incorporated designs, quantity estimates, cost information and execution strategies developed as part of the Select phase.

Refer to Appendix A-1 for more details on the capital cost estimate.

1.2 Project Objectives, Critical Success Factors, Drivers, KPI's

This report was prepared by Hatch Associates Ltd. ("Hatch") for the sole and exclusive benefit of Newfoundland & Labrador Hydro (the "Owner") for the purpose of assisting the Owners to develop a class 3 for the 150 Mega watt (MW) Combustion Turbine Plant Front-End-Engineering-Design (FEED) study, in Holyrood, Newfoundland & Labrador, and may not be provided to, relied upon, or used by any third party.

1.3 Business Environment & Business Case

This report contains the expression of the professional opinions of Hatch, based upon information available at the time of preparation. The quality of the information, conclusions, estimates, and projections contained herein is consistent with the intended level of accuracy as set out in this report, as well as the circumstances and constraints under which this report was prepared. However, this is a FEED report and, accordingly, all estimates and projections contained herein are based on limited and incomplete data. Therefore, while the conclusions, estimates and projections herein may be generally indicative of the nature and quality of the Project, they are not definitive. No representations or predictions are intended as to the results of future work, nor can there be any promises that the conclusions, estimates and projections in this report will be sustained in future work.

1.4 List of Acronyms

Table 1-1 shows the list of acronyms and abbreviations for this Estimate Basis.

Table 1-1: List of Acronyms/Abbreviations

Acronyms / Abbreviations	Definitions
AACE	Association for the Advancement of Cost Engineering
CAPEX	Capital expenditure
CAD	Canadian dollars
CWP	Construction work package
EPCM	Engineering, procurement, and construction management
FBS	Facility breakdown structure
FEED	Front-end engineering design
MEL	Mechanical equipment list
MTO	Material take-off
MW	Megawatt
NLH	Newfoundland & Labrador Hydro
P&ID	Process & instrumentation drawings
QRA	Quantitative risk assessment
Q3	Third quarter
TIC	Total installed cost

1.5 Estimate Parameters

The capital estimate was prepared in alignment with AACE International Recommended Practice AACE 96R-18 (applied to power transmission line infrastructure industries), as well as the current Hatch Discipline Guide – Project Capital Cost Estimate (PLP-620-020-0001).

The AACE class 3 cost estimate is compiled based on the following parameters:

- The estimate accuracy for 80% confidence interval of -22.8% to +25.7%. The accuracy was assessed in the Quantitative Risk Assessment (QRA).
    - The estimate base date is Q3 2024.

- The estimate is presented in Canadian Dollars (CAD). Costs submitted in other currencies were converted to CAD. The exchange rates used are in Table 1-6. Hatch proposed foreign exchange rates.
  - The requirement for escalation in the CAPEX is discussed further in Section 7.
  - All units of measure are in the metric system.

1.6 Estimate Software

The Capex estimate is developed in a standard Hatch Microsoft Excel template. The Excel file includes a buildup of unit rates with estimating price coding references and all typical coding structures.

1.7 Structure and Coding of the Estimate

1.7.1 CAPEX Facility Breakdown Structure

The CAPEX Facility Breakdown Structure (FBS) is a systematically consistent method of categorizing the overall project scope by breaking it down into definable elements. The FBS is a project-oriented hierarchy of geographical/work areas or facilities that defines the total work to be performed. The FBS provides a unifying framework for planning, resource allocation, estimating, scheduling, and cost management. It allows for effective management reporting, controlling, and monitoring of scope, cost, schedule, and technical performance of the project. Each descending level represents an increasingly detailed definition of the scope. In general, all estimate line items are to be coded to the lowest level of the FBS.

Hatch coded the CAPEX FBS listed below in Table 1-2.

Table 1-2: Facility Breakdown Structure (FBS)

FBS	Description	Total Installed Cost $CAD
1000	**Site Preparation & Improvements**	[redacted]
1500	Stormwater Infrastructure	
1600	Bulk Earthworks	
1700	Site Roads and Parking Areas	
1800	Security (Fencing, Gates, etc.)	
2000	**Buildings, Structures & Foundations**	
2100	Power House Building	
2200	Gas Turbine Foundation	
2300	Electrical Foundations	
2500	Miscellaneous Foundations (Pumps, Tanks, etc.)	
2600	Pipe Rack Foundations and Structures	
2700	Permanent Cranes	
3000	**Power Generation & Auxiliaries**	
3100	Gas Turbine Generator Packages	
4000	**Fuel Storage & Handling**	
4100	Diesel Oil Tanks	
4200	Fuel Handling System	
4300	Jetty Fuel Transfer System	
4400	Vehicle Offloading System	
5000	**Electrical Power Systems**	
5100	Main Output System	
5200	Unit and Station Power Supply	
5300	AC Power Distribution Systems	
5400	Protection and Metering	
5500	UPS Power Distribution	
5600	Cabling System	
5700	Switchyard	
5800	Transmission Lines	
5900	Building and Yard Electrical Services	
6000	**Instrumentation & Control**	
6100	Central Control System	
7000	**Common Services Equipment & Systems**	
7100	Plant Water Systems	
7200	Water Treatment System	
7300	Compressed Air Systems	
7400	Fire Protection System	
7500	HVAC Systems	
7600	Oily Water Drains	
7700	Miscellaneous Equipment and Systems	
	Subtotal Direct Cost	**367,756,014**

1.7.2 Trade Codes

Trade Codes are used to collect the estimate items into groups of work of a similar nature or discipline. The standard Trade Code is an alpha character which is directly aligned with the project standard discipline descriptions. The Trade Code is defined as the first character which indicates the discipline.

The Trade Codes used in the CAPEX are listed below Table 1-3.

Table 1-3: Trade Codes

Trade Code	Trade Description
A	Site Development
C	Concrete
D	Roadworks, Drainage and Paving
E	Earthworks
F	Architectural
J	Control and Instrumentation
L	Electrical Equipment
M	Mechanical Equipment
N	Mechanical Platework and Tanks
P	Pipework and Fittings
R	Cable Ladder, Tray, and Conduit
S	Structural Steel
V	Owner's Cost
W	Wire and Cable
Y	Indirect
Z	Provisions (including Contingency)

1.7.3 Maturity Codes

Quantity maturity codes used in the CAPEX are listed below in Table 1-4.

Table 1-4: Maturity Matrix Table

Risk Code	Risk Description	Total Material + Equipment CAD	Percentage
B	Firm price - uncommitted purchase order	[redacted]	
C	From in-house data, source < 1 Year		
D	From in-house data, source > 1 Year		
X	Allowance		
EA	Budget quote - high confidence level		
EB	Budget quote – low confidence level		
	TOTAL DIRECT COST	**367,756,014**	**100.00%**

1.7.4 *Cost Codes / Resource Types*

Cost Resources are used to collect cost items into groups. All CAPEX costs are be represented in 1 of the 5 resources shown in Table 1-5.

Table 1-5: Cost Code/Resource Types Used

Resource Code	Description
L	Labour
M	Material
E	Equipment
S	Subcontract
Y	Indirect

1.7.5 *Foreign Exchange Rates*

Costs submitted in other currencies are converted to CAD according to published exchange rates for Q3 2024. No provision is included for currency fluctuation or any fees applicable to currency exchange.

FOREX used in the CAPEX are listed below Table 1-6.

Table 1-6: FOREX

Currency	Code	Rate	Inverse
Canadian Dollars	CAD	1.00	1.00
United States Dollars	USD	0.75	1.34

1.7.6 *Currency Exposure – Permanent Equipment and Materials*

Costs are recorded in the CAPEX detailed spreadsheet according to the assumed source currency. The source currencies are converted to CAD based on the agreed exchange rates.

A table was compiled listing the source currencies and the exposure of each (refer to the example presented in Table 1-7.

Table 1-7: Currency Exposure

Country	Code	Total Installed Cost CAD	Percentage
Canada	CAD	201,209,273	54,71%
USA	USD	166,546,741	45.29%
Subtotal Direct Cost		**367,756,014**	**100.00%**

2. Estimate Classification

The CAPEX was prepared in accordance with guidelines established by the Association for the Advancement of Cost Engineering (AACE) for a Class 3 estimate. The estimate accuracy for 80% confidence interval of -22.8% to +25.7%

The applicable AACE standard for this cost estimate classification and determination of its accuracy ranges is Recommended Practice AACE 96R-18 (applied to power transmission line infrastructure industries). This is a generic estimating practice standard which has been developed and published by AACE and it provides guidelines for applying the general principles of estimating and estimate classification to project cost estimates (i.e., cost estimates that are used to evaluate, approve, and/or fund projects) as it specifically relates to the process industries.

The capital cost estimate consists of four major cost groupings: Direct Costs, Indirect Costs, Contingency and Owner's Costs.

The standard AACE estimate classification matrix is shown in Table 2-1.

Table 2-1: AACE Estimate Classification Matrix

AACE Estimate Class	Primary Characteristic	Secondary Characteristic		
	Maturity Level of Project Definition (Expressed as % of complete definition)	End Usage (Purpose of estimate)	Methodology (Estimating method)	Expected Accuracy Range (Variation low / high ranges in 80% confidence interval)
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgement, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	**10% to 40%**	**Budget authorization or control**	**Semi-detailed unit costs with assembly level line items**	**L: -10% to -20%** **H: +10% to +30%**
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

CAPEX Reconciliation Table 2-2 represents the differences in accuracy ranges between the previous phase of study (class 5) and the current phase of study (class 3).

Table 2-2: CAPEX Reconciliation Accuracy Range (AACE)

Class of Estimate	Class 5	Class 3
Accuracy Range (AACE)	L: -20% to -50%	L: -22.5%
	H: +30% to +100%	H: +24.8%

Table 2-3 represents the scope changes and direct cost differences between the previous phase (class 5) and the current phase (class 3).

Table 2-3: CAPEX Reconciliation - Direct Cost

Direct Cost Reconciliation Description	Total CAD
2023 Class 5 Direct Cost	**246,369,103**
3% Escalation on Directs for 5 Quarters (Q2-2023: Q3-2024)	[redacted]
Piling was not anticipated in concept study.	
Pre-investment for Phase 2 Site Development	
Conversion Rate used in the estimate was 1 USD is 1.3 CAD to 1.34 CAD	
Turbine Quote Increase	
Larger Diesel Storage (Redundant Tank Added)	
Larger Demin Water Plant	
TL218 Field modification - Tie-in and Shielding	
Relocation of 38L & 39L lines is new.	
Cost Difference in GSU's	
Balance – Design Development (11.42%)	
2024 Class Direct Cost	**367,756,014**

A cost summary for total installed cost excluding owner's cost reconciliation is presented in Table 2-4. All in this table are in Canadian dollars.

Table 2-4: CAPEX Reconciliation - Summary

Cost Type	Previous Phase (Class 5)	Current Phase (Class 3)	Difference ($)
Directs	246,369,103	367,756,014	121,386,911
Indirects	59,836,042	144,249,048	84,413,006
Indirect on Direct Ratio	24%	39%	
Total Direct + Indirect	**306,205,145**	**512,005,063**	**205,799,918**
Contingency	73,213,000	65,117,352	(8,095,648)
Contingency (%) of Total Direct + Indirect	24%	13%	
TIC Before Owners	**379,418,145**	**577,122,415**	**197,704,270**

3. Total Installed Cost

A complete summary table of the total installed cost CAPEX including all contingencies and owner's cost values is provided below in Table 3-1.

Table 3-1: Total Installed Cost Summary

Trade	Description	TOTAL COST CAD	% of Direct Cost	% of Total Cost	EQUIP.	MATERIAL	LABOUR	SUBCONT.	Labour hours
A	Site Development	[redacted]							
C	Concrete								
D	Roadworks, Drainage & Paving								
E	Earthwork								
F	Architectural								
J	Control & Instrumentation								
L	Electrical Equipment								
M	Mechanical Equipment								
N	Mechanical Platework & Tanks								
P	Pipework & Fittings								
Q	Insulation								
R	Cable Ladder, Tray & Conduit								
S	Structural Steel								
W	Wire & Cable								
	DIRECT COSTS	**367,756,014**	**100%**	**56%**	**233,567,715**	**41,487,432**	**72,993,248**	**19,707,619**	**428,286**
Y	Indirect Cost	144,249,048	39%	22%	4,360,000	-	11,032,680	128,856,368	64,734
	INDIRECT COSTS	**144,249,048**		**22%**					
	SUBTOTAL	**512,005,063**		**79%**	**237,927,715**	**41,487,432**	**84,025,928**	**148,563,987**	**493,020**
	DIRECT + INDIRECT COSTS								
Z	**Contingency**	**65,117,352**		**10%**				**63,944,066**	
	SUBTOTAL	**577,122,415**		**89%**	**237,927,715**	**41,487,432**	**84,025,928**	**213,681,339**	**493,020**
	DIRECT + INDIRECT COSTS + CONTINGENCY								
V	**Owner's Cost**	**74,637,747**		**11%**				**74,637,747**	
	TOTAL COST	**651,760,162**		**100%**	**237,927,715**	**41,487,432**	**84,025,928**	**288,319,086**	**493,020**
	DIRECT + INDIRECT COSTS + CONTINGENCY+ OWNER'S COST								

4. Direct Costs

Direct costs are the costs of all equipment and bulk materials, together with construction and installation costs for all permanent facilities. Examples of direct costs include, but are not limited to the following:

- Supply, assembly, and installation of permanent equipment.
- Supply, fabrication, and installation of bulk materials.
- Supplemental resources for equipment and bulk material installation, such as labor and construction equipment.
- Site preparations (bulk earthworks) and the construction of roads and storm water ditching.
- Supply, fabrication and erection of permanent buildings and associated services.
- Supply, fabrication, erection of utilities and distribution systems.
- Process control systems including software programming and DCS/HMI configuration costs.
- Contractor's distributable costs such as mobilization and demobilization, overheads and profit, supervision, general construction equipment including construction cranes, small tools and consumables used in construction, etc.

Direct cost summary by discipline is provided below in Table 4-1.

Table 4-1: Direct Cost Discipline Summary

Code	Discipline	Trade Cost CAD	Source of Quantities	Source of Prices
A	Site Development	[redacted]	MTO's	Database & Allowance
C	Concrete		MTO's	Database & Allowance
D	Roadworks, Drainage & Paving		MTO's & Allowance	Database & Allowance
E	Earthworks		MTO's	Database
F	Architectural		MTO's	Database & Allowance
J	Control & Instrumentation		MTO's	Database & Allowance
L	Electrical Equipment		MTO's	Firm Price, Database & Allowance
M	Mechanical Equipment		MEL & Allowance	Firm Price, Database & Allowance
N	Mechanical Platework & Tanks		MEL	Firm Price & Database
P	Pipework & Fittings		MTO's	Database & Allowance
Q	Insulation		Allowance	Allowance
R	Cable Ladder, Tray & Conduit		MTO's	Database
S	Structural Steel		MTO's	Database & Allowance
W	Wire & Cable		MTO's	Database
	Subtotal Direct Cost	**367,756,014**		

4.1 Construction Work Packages (CWP)

Construction defines work areas around the plant, mostly based on the FBS of an area or building. The work area has physical boundaries (e.g., the walls of a building) and within that work area each trade that is required to do the work receives a specific CWP (e.g., piping, mechanical, electrical cable, cable tray, instrumentation, etc.). The CWP is a scope of work, for a specific construction contract, which describes the work within that construction work area.

All the MTO's carry the CWP (where applicable) as an attribute. The estimate is populated with CWP, which allows the estimate to be rolled up at the contract level as well. The CWP list was developed with construction execution planning and the engineering MTOs extracted from the approved for detailed design (AFDD). The CWP list that aligns to the CAPEX is described herein the basis of estimate.

The CWP list is provided in Table 4-2.

Table 4-2: CWP List

Area Number	Area Name
0000	Site Wide
1000	Tank Farm
2000	CT Plant
3000	Transformer Yard
4000	Switchyard
5000	Raw Water
6000	Fuel Offloading
7000	Transmission Lines

4.2 Quantity Development

4.2.1 Civil Site Development

Grounds Work MTO is a combination of information extracted from the OpenRoads Civil model as well as manual calculations for the FEED design's cost estimate development. The MTO includes the following:

- Clearing and Grubbing
- Mass earthworks such as:
  - Root mat removal
  - Organics removal
  - New granular materials (Fill)
- Asphalt
- Underground utility infrastructure
- Other civil infrastructure on site.

As noted, a combination of 3D modeling and manual calculations was used for determining the required take-offs. Surfaces in 3D were created using Bentley's OpenRoads Roadway Design software, Version 23.00.00.129, to obtain volumes for root mat and organics removal, other material (OM) excavation, structural fill, granular materials, and asphalt. The existing surfaces are based on open-source Light Detection and Ranging (LiDAR) data until which time the topographic survey is available for incorporation into the design. All earthworks' quantities are at a conceptual level due to the LiDAR being used.

Refer to document Appendix A-4 for more details on Grounds Work MTO.

4.2.1.1 Excavation and Backfilling

The Geotechnical Investigation (02 July 2024; File No. H373262-0000-2A0-230-0001, Rev.0) has provided 33 test pits within the site limits which detail thicknesses of root mat, organics, and other materials on site. To quantify the subsurface thicknesses throughout the site, areas outside of the test pit locations required estimated depths based on the information provided in the investigation. There are two standard approaches in which this could be achieved: through linear interpolation between adjacent test pits or through grouping of subsurface materials. For this site, linear interpolation of thicknesses resulted in an inaccurate depiction of materials between test pits. This was evident once plotted on site cross-sections during review. However, plotting the test pit logs on to the plan and cross-section views, in conjunction with the varying thicknesses of materials, illustrated areas which could be defined from subsurface conditions.

Each area was assigned a root mat and organics thickness based on geotechnical test pit data averaged within said area. The OpenRoads 3D surfaces were created based on the average subsurface material thicknesses. In addition, 3D surfaces were created where access roads and terraced pad structures were required, as well as the asphalt structure for the paved area at the northeast corner of the site (formal gravel parking area adjacent to Thermal Plant Road).

Volumes of materials were exported from the OpenRoads program for input into the MTO. For the purposes of the FEED design, there are some areas with consistent one-directional grades in which manual calculations were conducted to obtain the volumes required, rather than extensive surface modelling.

Excavation and required backfill under proposed buildings, as well as any concrete pads or other structural elements which require earthworks, fall within the battery limits of the Structural discipline. Therefore, they have not been included in the Grounds Work MTO. For this level of design, Civil removes the structural earthworks from the overall site quantities, to mitigate the duplication of quantities within the MTO.

Refer to document Appendix A-4 for more details on Grounds Work MTO.

4.2.1.1.1 Jetty Access

The existing road access from the jetty to the Holyrood Thermal Generating Facility site requires a road extension to the proposed fuel tanks, as well as reshaping of the existing surface. For the purposes of the FEED MTO, the existing road was not required to be modeled for the determination of quantities for scarifying, reshaping, and provision for a new granular surface; this was manually calculated. However, the proposed road extension to extend the fuel pipeline to the new fuel tanks requires a high-level plan and profile using the open-source LiDAR data. Similar to the method used in section 4.2.1.1, an average depth of root mat and organics is estimated based on the Geotechnical Investigation and applied as a constant for the road cross-section. Therefore, manual volumes will suffice for this new road extension.

Refer to document Appendix A-4 for more details on Grounds Work MTO.

4.2.1.2 *Stormwater Management*

The stormwater drainage areas for the proposed site are based on the open-source LiDAR. This data is utilized in the Quantum Geographic Information Software (QGIS) to assist in delineating the drainage areas which are imported into the stormwater software.

The advanced stormwater modelling software - PC SWMM (Personal Computer Storm Water Management Model; Version 7.6.3620), was used to calculate the flow contributing to the site, as well as within the battery limits, and subsequently used to size the drainage infrastructure for this design, including, but not limited to:

- Site Ditching
- Culverts
- Storm Sewers
- Manholes
- Catch Basins.

In addition, an oil grit separator, proposed within the fuel tank containment area onsite, is sized per the manufacturer's proprietary software, with inputs based on site requirements and environmental guidelines.

Upon preliminary sizing of all stormwater entities, the associated quantities were entered into the Grounds Work MTO. Trenching, bedding and backfill are accounted for with all stormwater infrastructure, as required.

Refer to document Appendix A-4 for more details on Grounds Work MTO.

4.2.1.3 *Civil Assumptions and Exclusions*

The following assumptions and exclusions were considered during preparation of the Grounds Work MTO:

- The inclusion of excavation and trenching quantities for underground infrastructure not within the civil scope shall be covered by other disciplines. This includes, but is not limited to, sanitary sewers and their associated manholes, any required water services and/or mains, fuel piping, and electrical conduits and/or duct banks.
- It is assumed that the supply of labour, materials, and equipment required to install signs on site including any excavation, placement, compaction for embedded portion of signposts is accounted for.
- Bollards are recommended around the perimeter of structural pads, such as transformer pads and tanks. Should there be structural pads in Phase 2, the same recommendation would be required.

- It is assumed that the grade/elevation at the base of live transmission or electrical poles shall not be modified within 300 mm of the existing grade.
- The cost estimate includes pricing for redesigning TL-218. Redesign of TL-218 will occur during detailed design phase. NF Power lines 39L and 38L will be re-designed by NF Power prior to relocation.
- It is assumed there is no contamination onsite.
- It is assumed that excavated material (root mat, organics, and excess material not suitable for fill) is not stockpiled on site and requires all material to be trucked offsite for disposal.
- For FEED, it is assumed that all required fill is structural fill. For the next phase of design, information is required from the geotechnical team regarding distinction between structural and other material (OM) fill.
- Should construction dewatering be required, the onus will be on the Contractor to provide proper dewatering methods suitable to site.
- Thermal Plant Road is classified as a 'Municipal Road' as per the Newfoundland and Labrador Master Specifications, Drawing Number 04650 (March 2022). In the absence of a proposed asphalt structure recommendation from the Geotechnical Investigation, the asphalt structure throughout the site is consistent with the Newfoundland and Labrador Master Specifications Drawing Number 04650 (March 2022).
- The Geotechnical Investigation test pit information is used to determine the existing geotechnical conditions along the proposed jetty pipeline access road.
- It is assumed that a 2H:1V side slope is suitable for excavation and for any imported materials for fill throughout the site.
- It is assumed that topsoil and hydroseed is to be installed along ditches with a peak velocity <1.5 m/s, and Class I riprap is to be installed along ditches with a peak velocity between 1.5-3.0 m/s.
- It is assumed the existing access road from the Thermal Generating Site to the jetty will remain, however it will be scarified and reshaped in addition to placing new granular.
- As the existing access road to the jetty is a gravel road, it is assumed that the reshaped existing road, and the proposed extension of the access road will have gravel finish.
- It is assumed a gate is required at each access point connecting to Thermal Plant Road for the new site access. They are assumed to be manually operated with keyed locks; no electronic entry is accounted for.
- Once the site is commissioned, traffic control will be handled via signage (i.e. stop signs, yield signs, etc.).

- It is assumed any change in vertical elevation over 2.5 m will require a guard rail along an access road.
- Temporary snow pole delineation is not included in the MTO, however it should be discussed with the client, for the purposes of delineating roads during winter months.
- A manual gate valve is recommended downstream from the stormwater OWGS (Stormceptor EFO4 or approved equal). There is an opportunity to automate the operation of the gate valve by way of level sensing based on potential spills. This should be explored with mechanical/piping in a future design phase.

Refer to document Appendix A-4 for more details on Grounds Work MTO.

4.2.2 Structural Concrete

MTO's were developed from the foundation model and categorized based on FBS/Area and type (Equipment footings, Structural Footings, Ground Slab etc.).

Dimensions in the foundation model are based on either preliminary calculation or historical dimensions from similar projects, accounting for differences in bearing capacity.

Concrete strengths are based on capacity requirements, client standards and structural design criteria document and are identified in the item description.

An average reinforcement density is going to be assumed for all foundations/slabs (100 kg/m^3) and is identified in the item description.

Any special coatings (i.e., floor coatings) are identified in the item description.

Excavation and backfill, including granular material required below slabs, directly required for foundations have separated take-off quantities. Battery limits for excavations and backfill are coordinated with civil discipline.

Where steel piles are required under tanks, piles are included in concrete MTO.

Structural concrete MTO does not include civil infrastructure (such as manholes, septic tanks, bollard/fence/gate foundation etc.), electrical infrastructure (i.e., exterior trenches, vaults etc.,) or jersey barriers.

No concrete demolition is expected to be required.

Refer to document Appendix A-6 for more details on Structural Concrete MTO.

Quantity and cost summary for structural concrete is presented below in Table 4-3.

Table 4-3: Structural Concrete Summary

FBS	FBS Description	Unit	Final Quantity	Total CAD	Net Rate
2100	Power House Building	m3	[redacted]		
2200	Gas Turbine Foundation	m3			
2300	Electrical Foundations	m3			
2500	Miscellaneous Foundations (Pumps, Tanks, etc.)	m3			
2600	Pipe Rack Foundations and Structures	m3			
7400	Fire Protection System	m3			

4.2.3 Architectural

MTO's for powerhouse envelope are extracted from the model, such as areas for roofing and cladding. Roofing and cladding specifications are provided in item descriptions and based on materials used for similar projects. The number of overhead doors and personnel doors have been estimated.

The substation control building is assumed to be a pre-engineered steel building. The fuel-offloading, and two (2) raw-water pumphouses are assumed to be modular. The building footprint area is extracted from the model and included in the item description. The building costs are based on historical per unit area cost for similar projects, and will include envelope, structural framing, mechanical/electrical (for heat and light) and building services. Foundations are included in the concrete MTO. Interior equipment is included in the respective discipline MTO.

For finished areas in the Powerhouse (i.e., offices, meeting rooms, control rooms, kitchen, washrooms etc.) an overall area (m^2) of finished space is going to be provided. Detailed floor layouts have not been developed at this time.

Refer to document Appendix A-7 for more details on the Architectural MTO.

Quantity and cost summary for architectural is presented below in Table 4-4.

Table 4-4: Architectural Summary

FBS	FBS Description	Unit	Final Quantity	Total CAD	Net Rate
2100	Power House Building	m2 – of Cladding	[redacted]		
2300	Electrical Foundations	m2 – footprint			
4400	Vehicle Offloading System	m2 – footprint			
7100	Plant Water Systems	m2 – footprint			

4.2.4 Structural Steel

Structural Steel MTO's for primary steel (powerhouse structure, main pipe racks) are extracted from the model and categorized by FBS/Area and by type (heavy, medium, light steel, floor decking, roof decking, stairs etc.).

The steel model was based on either preliminary calculation or historical sizing from similar structures/projects, accounting for difference in environmental loading.

Secondary/miscellaneous steel was not modelled and is accounted for using allowances.

Temporary warehousing has been factored by Construction Indirects. No permanent warehouse has been identified.

Powerhouse building is assumed to be stick-built construction, and main pipe racks are assumed to be modular.

See Architectural (Section 4.2.3) for pre-engineered buildings (Substation Control Building) and Modular Buildings (Pumphouses).

Structural CAD deliverables are assumed to be limited to 3D models and design drawings are not required at this stage of submission.

No structural steel demolition is expected.

Powerline support structures within the Substation and transmission tower structures at tie-in to existing transmission lines are included in the electrical MTO.

Refer to document Appendix A-5 for more details on the Structural Steel MTO.

Quantity and cost summary for structural steel is presented below in Table 4-5.

Table 4-5: Structural Steel Summary

FBS	FBS Description	Unit	Final Quantity	Total CAD	Net Rate
2100	Power House Building	t	[redacted]		
2600	Pipe Rack Foundations and Structures	t			
	Crane Rail	m			
	Handrail (Including Stanchion and kick plate)	m			
	Ladders with Cages - Supply, Fabricate, Paint, Deliver and Erect	m			
	Miscellaneous Supports	t			
	Stairs - Complete Unit	m			

4.2.5 Mechanical

The mechanical 3D model and equipment list was updated during the 99% FEED phase as required during design development. The mechanical equipment list serves as the input for the development of the FEED estimate.

The Mechanical Equipment List (MEL) includes available or preliminary information concerning the equipment type/configuration, size, capacity, materials of construction, power requirements, etc.

Supplier budgetary pricing is used for the combustion-turbine generator packages, the water treatment package and select major auxiliary equipment (e.g., glycol heaters for inlet heating).

The remaining mechanical equipment pricing is developed using historical data from Hatch's database.

Table 4-6: Mechanical Commissioning and Completion

	Construction	Commissioning				
		Pre-Operational Testing		Start-up		Ramp-up
	Stage 1 Construction Inspection and Testing	Stage 2 Pre-Operational Equipment Testing	Stage 3 Pre-Operational System Testing	Stage 4a Start-up Recirculation	Stage 4b Start-up Integrated	Stage 5 Ramp-up
Activity	Equipment Inspection and Testing	Equipment Inspection and Testing	Systems Testing	Process Start-up and Testing		Ramp-up
Conditions	Non energized	Energized	Inert materials	"Non-hazardous" Process materials	Process materials	
Example Tasks	• Wiring point to point • Pipe pressure test • Motor alignment • Vessel leak check	• I/O checks • Motor bump test • Vibration check • Instruments set-ups • Limit switches adjustment • E-stop validation	• Alarm, interlock, permissives, control loop checks • Sequence checks • Pump flow check • Alignment of empty conveyors	• Run plant areas separately in recirculation with "non-hazardous" process material • Operate at or near design conditions • Test plant areas as much as possible and debug before Stage 4b	• Run complete plant • All process material introduced	• Operate continuously • Increase production • Resolve quality and KPI issues • Remove bottlenecks
Responsible	Contractor	POT Team		Operation's Commissioning Team		Operations
Support	-	Contractor, Operations, Vendors		POT Team, Contractors, Vendors		Subject Matter Experts (SME), Vendors
Milestones	Transfer to Pre-Operational Testing (Mechanical Completion)	Handover to NLH Commissioning (POT Completion)		Ready for Integrated Start-up	Start production	Nominal production

**Refer to document Appendix A-2 for more details on the Mechanical Equipment List.*

4.2.6 *Tanks and platework*

Tanks and platework are quantified in the MEL in alignment with the 3D model and equipment layouts.

Representative costing for appropriately sized tanks has been secured through budgetary costs from vendors. In some cases, where final sizing was not detailed prior to securing estimates, the tank costs are scaled based on dimensions (given material selections remain unchanged).

Refer to document Appendix A-2 for more details on the Mechanical Equipment List.

4.2.7 *Pipework and fittings*

Hatch developed Piping MTOs (including piping, fittings, supports and manual valves) from the 3D model and manual MTOs for unmodelled piping as inputs to the CAPEX estimate. A take-off is completed for each piping line number. These piping line numbers are also shown on Piping & Instrumentation Diagrams and the Piping Line List.

Painting, insulation, heat tracing and hydrotesting quantities are included based on the pipeline lengths. All valves shown on P&IDs are included in the MTO.

Allowances are included for any piping material that is required but not shown on P&IDs.

Refer to document Appendix A-8 for more details on Pipework MTO.

Quantity and cost summary for pipework and fittings is presented below in Table 4-7.

Table 4-7: Pipework and Fittings Summary

FBS	FBS Description	Unit	Final Quantity	Total CAD	Net Rate
4100	Diesel Oil Tanks	m	[redacted]		
4200	Fuel Handling System	m			
4300	Jetty Fuel Transfer System	m			
4400	Vehicle Offloading System	m			
7100	Plant Water Systems	m			

4.2.8 *Electrical*

Electrical MTOs are extracted from the 3D models, single-line diagrams, layouts, and sectional drawings for use in the project estimate development.

An electrical equipment list was developed to include major electrical equipment.

Costs are based on a combination of vendor quotes (for major electrical equipment such as large power transformers) and historical data from Hatch's database for Electrical Bulks.

The single line diagrams were used to develop the cable schedule and MTOs for the FEED estimate.

Powerline support structures within the Substation and transmission tower structures at tie-in to existing transmission lines are included in the electrical MTO.

For minor equipment such as motor control centers, small transformers, panels, etc., prices are to be obtained from historical data from Hatch's database.

Refer to document Appendix A-9 for more details on Electrical MTO.

Refer to document Appendix A-10 for more details on Terminal Station MTO.

Quantity and cost summary for the electrical discipline is presented below in Table 4-8.

Table 4-8: Electrical Summary

FBS	FBS Description	Final Quantity	Total Cost CAD	Net Rate
3100	Gas Turbine Generator Packages		[redacted]	
5100	Main Output System		[redacted]	
5200	Unit and Station Power Supply		[redacted]	
5300	AC Power Distribution Systems		[redacted]	
5400	Protection and Metering		[redacted]	
5500	UPS Power Distribution		[redacted]	
5600	Cabling System		[redacted]	
5700	Switchyard		[redacted]	
5800	Transmission Lines		[redacted]	
5900	Building and Yard Electrical Services		[redacted]	
Plantwide	Cable Tray (m)	[redacted]	[redacted]	[redacted]
Plantwide	Wire and Cable (Excluding Grounding) (m)	[redacted]	[redacted]	[redacted]
Switchyard Structural	Switchyard (t)	[redacted]	[redacted]	[redacted]
	Subtotal		[redacted]	

4.2.9 *Instrumentation and Control*

Instrumentation and Control MTO was developed from the design deliverables for use in the project estimate development.

Quantities for field instrumentation are based on FEED-issued P&ID's. The cost of instruments and materials is priced based on analogous estimating techniques from Hatch's database.

Refer to document Appendix A-3 for more details on Instrumentation and Controls MTO.

Quantity and cost summary for instrumentation and control is presented below in

Table 4-9.

Table 4-9: Instrumentation and Control Summary

Description	Qty	Unit	Total Cost CAD	Avg. Unit Rate
Field Instruments/Control Valves	[redacted]			
Control/Instrument Cable				
HMI				
PCS				
Security Camera System				
ABB Marshalling Cabinets, Factory constructed, tested, and assembled				
Misc.				
CEMS System				
Turbine- Instrument & Controls				
Subtotal			[redacted]	

4.3 Growth and Waste Allowance

4.3.1 Quantity Growth

Quantity growth (also referred to as take-off allowance) is applied in the form of an increase to the taken-off quantity and is intended to allow for the most likely final quantity (and therefore cost) in the estimate. Quantity growth allowances are applied as percentages based on historical data and estimators experience, depending on the maturity of engineering competition. Quantity growth is applied to a 'neat quantity' (or 'base quantity') to arrive at an estimated 'final quantity.' Reported costs are calculated based on final quantities.

Total Cost	% of Direct Cost	% of TIC
[redacted]		

4.3.2 *Cost Growth*

Estimates generally base their costs on quotations, price lists, estimates provided by the vendors, etc. Due to incompleteness of the project development, all those uncommitted costs rarely consider final specifications or commercial terms and conditions.

A cost growth allowance is an amount added to the activity to account for the expected increase in costs to anticipate the values of tender period or award.

Total Cost	% of Direct Cost	% of TIC
[redacted]		

4.3.3 *Wastage*

A wastage (or construction waste allowance) allows for the fact that some materials will be purchased but not installed due to unavoidable losses from over-pour, off-cutting, theft and errors. Common items where waste
allowances are applicable are the following: wire cable, cable tray and conduit, piping, concrete, grout, siding, and block work etc.

The application of both quantity and cost growth allowances were considered with the participation of engineering and procurement. Standard wastage allowances are used.

Quantity growth, cost growth, and wastage percentages are presented below in Table 4-10.

Table 4-10: Quantity, Price, and Wastage Growth

Trade	Description	Quantity Growth											Waste Growth
	Quantity Growth =	detailed	preliminary	conceptual	historical	allowance	N/a	firm price no PO	budget high	In-house < 1 year	In-house > 1 year	Allowance	(included in unit-rates)
	Cost Growth =							B	EA	C	D	X	
A	Site Development	[redacted]											
C	Concrete												
D	Roadworks, Drainage & Paving												
E	Earthwork												
F	Architectural												
J	Control & Instrumentation												
L	Electrical Equipment												
M	Mechanical Equipment												
N	Mechanical Platework & Tanks												
P	Pipework & Fittings												
Q	Insulation												
R	Cable Ladder, Tray & Conduit												
S	Structural Steel												
W	Wire & Cable												

4.4 Installation Costs

The installation labour component was calculated using the following major sub-components: (i) all-in labour rates, and

(ii) labour hours (base hours x productivity factor).

4.4.1 All-in Labour Rates

The all-in labour rates developed in this CAPEX are divided into the following portions: direct labour, contractor distributables, construction equipment, and living out allowance (LOA).

The direct labour rates used in the estimate are developed using a combination of public published base rates and Hatch in-house data from similar projects. Separate Labour rates are developed for each discipline to accommodate different crew sizes and construction equipment. Final assumptions are presented in Table 4-11.

The All-in Labour Rates include the following components:

Direct labour component:

- Direct hourly base wage
- Overtime premiums
- Nightshift premiums (if applicable)
- Fringes and benefits
- Burdens.

Contractor distributables component (These are considered contractor indirects and not construction indirects as shown in the indirect cost section):

- Small tools and consumables
- Personal protective equipment (PPE)
- Contractor - Mobilization / Demobilization
- Contractor - Temporary Site Facilities
- Supervision & Administration
- Health / Safety / Environment / Quality
- Fees and Insurances
- Head office operations
- Mark-up and profit.
- Construction equipment component.

- Living out allowance (LOA) component

Note: [redacted] not included in the labour rate and instead are included in the indirect costs section of the estimate.

Table 4-11: Labour All-In Unit Rate Breakdown in CAD

Code	Discipline	Direct Labour CAD	Contractor Distributable CAD	Construction Equipment CAD	LOA CAD	All-In Labour Rates CAD
A	Site Development	[redacted]				
C	Concrete					
D	Roadworks, Drainage & Paving					
E	Earthworks					
F	Architectural					
J	Control & Instrumentation					
L	Electrical Equipment					
M	Mechanical Equipment					
N	Mechanical Platework & Tanks					
P	Pipework & Fittings					
Q	Insulation					
R	Cable Ladder, Tray & Conduit					
S	Structural Steel					
W	Wire & Cable					

4.4.2 *Labour Hours*

The labour hours development for labour has 2 components:

i) standard man-hours; and

ii) productivity factor:

The standard man-hours (or labour-hours, or yet industrial work hours) are standard average hours estimated using historical benchmarked data, previous benchmarked projects, and estimator's experience.

4.4.3 *Productivity, Difficulty, Level of Effort*

Productivity Factor (PF) – Since the man-hours are standard factors; adjustments are necessary to reflect the specific conditions at the project site. Those adjustments are made using a Productivity Factor Scorecard, which analyses and rates the labour efficiency based on site and on working conditions.

Productivity values are assessed using Hatch's productivity factor score card. Calculations are prepared based on estimators' experience. PF includes factors such as weather at site during construction, site congestion and work access labour availability within region (site specific productivity), as well as paid breaks, safety talks, tool clean up (non-productive daily time loss). The productivity assessment is calculated in Table 4-12.

Table 4-12: Productivity Assessment

[redacted]

Installation base hours are based on Newfoundland and Labrador, Canada, and in-house databases for similar projects. Labour hours are adjusted by a productivity multiplier to take into account project specific requirements. Hatch developed the productivity based on two components, non-productive time, and site conditions.

The labor productivity factor takes into account issues that affect labor hours regardless of the environment where the work is being completed. This productivity looks at the break walk times, toolbox meetings, clean up, etc. Table 4-13 provides an example of details on the productivity factor calculated, based on initial estimates by Hatch in conjunction with experienced NLH estimator.

Table 4-13: Site Time Loss Table

[redacted]

Productivity accounts for site specific or project specific issues. A productivity factor will be assumed for the project based on input from execution specialists who are familiar with working with the North American contractors. The productivity factor used for all disciplines within the CAPEX is shown below in Table 4-14

Table 4-14: Productivity Factor

PF Factor	Value
Assessed Total	[redacted]
Productivity Assessment	
Normal Productivity	
Total Productivity Adjustment (Productivity Assessment * Normal Productivity)	
Total Efficiency Factor	

5. Indirect Costs

Indirect costs include the following:

- Any applicable temporary construction facilities including temporary worker lodgings/services, secure lay-down areas, warehouses, scaffolding, etc.
- Temporary construction services including IT, catering, camp and office cleaning services, worker transportation to the job site, etc.
- Freight and logistics.
- Vendor representatives.
- First fills of materials such as transformer oil, lubricants and other items that are not consumed by the process.
- Start-up/commissioning spares, capital spares.
- Engineering, procurement, and construction management services (including travel expenses).
- Third party engineering and other services.

Indirect costs are made up of factors and allowance. The factors and allowances are developed based on historical information from similar projects, adjusted to account for site specific factors. An indirect cost summary with basis is provided below in Table 5-1.

Table 5-1: Indirect Cost Summary

Category	MCAD	% of Direct Cost	% Total Cost Before Owner's Cost	Basis
[redacted]				
Subtotal Indirect Cost	**144.2**	**39%**	**25%**	

5.1 Engineering, Procurement, Construction Management (EPCM)

The scope of services includes the following, project control, multi-disciplinary engineering, procurement, and construction management activities. The scope of responsibility for this section is supported by the deliverables list included in the signed contract, which includes:

- Project management and services
  - Project controls deliverables, Risk management.
- **Execution Planning**
  - Project Execution strategy
  - Project Management Strategy
  - Project Controls Strategy
  - Construction Management Strategy
  - Health and Safety Strategy
  - Quality Management Strategy.
- **Detailed Engineering**
  - FEED costs, Process, Risk, Mechanical, Piping, Layout & coordination, Civil, Structural, Instrumentation & controls (I&C), Electrical, grounding studies, arc flash studies, Additional studies (fresh water supply, hydraulic modeling, early works, etc.).
- **Procurement and contracts**
  - Procurement of equipment and materials and field contracts.
- **Construction management**
  - Construction management & supervision over the site construction contractor.

5.2 Construction Indirects

Construction indirects include:

Temporary offices, warehousing, storage & preservation, sheds, furniture, bathrooms, connections, reticulation and consumption of power, sewage, and water; staff, communications, first aid, site security, site vehicles, parking and lay-down areas, summer dedusting, snow removal, etc.

[redacted] An allowance was made for heavy cranes.

5.3 Commissioning

Commissioning includes:

- Energization of Controls
- Control (PMS, Scada)
- Energization of Mian Power Supply.

Commissioning costs were taken as a percentage [redacted] of direct costs for each stage listed above.

5.4 Freight

Costs for freight are developed for all equipment and bulk material. The freight estimate is developed based on the information provided by quotations/estimates from vendors (if provided). When not available, freight is factored using percentages from other firm price and quotes as a guideline.

Bulks are factored using historical percentages or information provided by suppliers. If delivery to site is included in the supply cost, they are excluded from the freight calculation.

5.5 Vendor Representatives

Costs for vendor representatives are factored for construction, pre-commissioning, and hot-commissioning stages.

5.6 Spare Parts

Spare parts were categorized as:

- **Commissioning and Start-up Spare Parts:** Spare parts required specifically due to initial high wear, and which may fail due to abnormal operating conditions during start-up and commissioning but are not considered normal operating spares.
- **Capital Spare Parts:** Spare parts recommended to maintain plant operability in case of catastrophic failure or accident, or to replace components taken out of service for major maintenance.
    - **Spare Transformer:** (1) Generator Step-Up Transformer, Oil Filled, 13.8kV – 230kV, 50/60/75 MVA, ONAN/ONAF/ONAF, 3 Phase, 60hz.
    - **Generator Turbine:** Percentage of turbine equipment.

Cost summary for spare parts is presented below in Table 5-2.

Table 5-2: Spare Parts

[redacted]

5.7 First Fills and Oils

First fills and oils include oils, lubricants and fluids, and reagents. The costs have been factored as [redacted] of equipment supply cost, excluding first fill of diesel tanks.

5.8 Third Party Services

Third party engineering services such as surveying, laser scanning, specialty x-ray services (e.g., buried services), testing have been assessed based on information received to date. The costs have been factored as [redacted] of the direct cost.

5.9 Miscellaneous Indirect Cost

Miscellaneous indirect costs included within the CAPEX are:

[redacted]

6. Owner Costs

Estimates of owner's cost was developed by the client and provided to the Hatch management team for insertion into the final estimate.

The owner's cost provided included:

- Owner's Project Management and Engineering Team for the Entire Detailed Engineering, Procurement, Construction and Commissioning, until handover to operations.
- All travel expenses for the PM and Engineering Team listed above.
- Early site works to move existing poles, etc. in order to have everything out of the way for the EPCM contractor to start.
- [redacted]
- Interest during construction charges.
- All accrued and forecasted costs to complete FEED which is inclusive of all Hatch FEED expenditure and forecasted costs to the end of FEED.
- Insurance Costs.
- Geotech Study, EA Studies, Noise Study for work outside EPCM scope.

The owner's cost provided excluded:

- Contingency has not been applied to above costs.

Owner's cost summary is provided below in Table 6-1.

Table 6-1: Owner's Cost Summary

Discipline	Timeline	Team	Total Cost CAD
Owner's Costs	(Based on a 5 Year Project Timeline; Project Sanction to Handover to Operations)	[redacted]	[redacted]
Owner's Costs	(Based on a 1.75 Year Timeline)	[redacted]	[redacted]
Owner's Costs	(Based on a 3.25 Year Timeline)	[redacted]	[redacted]
Owner's Costs	(Independent of Time)		[redacted]
		Subtotal	[redacted]

7. Escalation

No provisions for escalation costs have been evaluated outside of Owner's Cost scope provided by the client.

8. Contingency

Contingency is a provision for unknown project costs which may occur for the known scope of the project, but which cannot be identified for estimating purposes due to the lack of complete, accurate and detailed information, as well as limited engineering knowledge.

The addition of contingency is required to capture the most likely cost of the project at execution.

Project contingency is not intended to cover scope changes or project exclusions.

A Quantitative Risk Analysis (QRA) was completed on the overall estimate assembly to determine Capital and Schedule Risk Profiles. The QRA assesses the level of cost performance variability in the project to establish an appropriate level of contingency to be applied/carried to the cost estimates at the stage of the project development.

Cost contingency is established at the P_{Mean} value, thus a contingency of 11.1% on top of the base estimate is presented.

Table 8-1: Contingency

Discipline	Contingency @ PMean ($)	Contingency @ PMean (%)
Contingency	65,117,352	11.1%

The final contingency analysis is outlined in the QRA. Refer to Appendix A-11 for more details on the QRA.

9. Estimate Reviews

To ensure consistency of the information transfer and overall estimate assembly, the following checkpoints and estimate reviews listed below were performed prior to the final issuance of the CAPEX.

9.1 Review Process

A summary of the review steps is indicated in Table 9-1.

Table 9-1: Estimate Reviews

	Review	Responsibility	Checklist
Hatch Internal Review	MTO Review	Hatch discipline leads	Quantities and completeness of MTO's prior to issue to estimate
	Multi-Discipline Review	Hatch discipline leads, Hatch estimating, Hatch engineering manager and project manager, construction	Completeness, proper transfer of MTO information and duplications, Unit pricing completeness by construction
	Management Team Review	Hatch estimating lead, project manager and sponsors	Estimate Metrics Indirect Costs
	Peer Review	Independent Senior Hatch estimator	Complete Estimate Review

10. Estimate Exclusions

[redacted]

[redacted]

11. Estimate Reference Documents

Table 11-1 includes documents referenced within the Basis of Estimate.

Table 11-1: Reference Documents

No.	Document Title	Document No.	Revision
1.	Cost Estimate	H373979-0000-620-622-0001	1
2.	Mechanical Equipment List	H373979-0000-240-216-0002	0
3.	Instrumentation MTO	H373979-0000-270-222-0002	0
4.	Grounds Work MTO	H373979-0000-220-222-0001	1
5.	Structural Steel MTO	H373979-0000-230-222-0001	0
6.	Concrete MTO	H373979-0000-230-222-0002	0
7.	Architectural MTO	H373979-0000-230-222-0003	0
8.	Pipework MTO	H373979-0000-250-222-0003	0
9.	Electrical MTO	H373979-0000-260-222-0001	1
10.	Terminal Station MTO	H373979-0000-260-222-0002	0
11.	Quantitative Risk Assessment	H373979-0000-120-066-0001	0

Avalon Combustion Turbine

Basis of Estimate

Attachment 3: Parametric QRA Report

Document No.: HRDCT2-HAT-49100-PC-EST-0001-01, Rev B1

Date: November 29, 2024

Confidential & Commercially Sensitive

Report

Parametric QRA Report

H373979-0000-120-066-0001

			[redacted]		
2024-11-29	**1**	**Approved for Use**	**L. Reny**	**K. Savoury**	**K. Meghari**
2024-11-14	**0**	**Approved for Use**	**L. Reny**	**K. Savoury**	**K. Meghari**
DATE	**REV.**	**STATUS**	**PREPARED BY**	**CHECKED BY**	**APPROVED BY**

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1. Definitions

Table 1-1: Terms and Definitions

Term	Definition
Deterministic (Base) Estimate	Estimate value excluding escalation, foreign currency exchange and contingency.
Systemic Risk	The potential for undesired impacts to project objectives taking source in the inherent context and characteristics of the project, either though the way it is organized, structured, the state of development of its required components, its size, locations, integration of organizations, etc.
Confidence Level	The probability that the results will be equal to or more favorable than the amount estimated for that level of confidence.
Maximum Cost Scenario	Outlines the circumstances that would be seen if the outcome was less desirable than assumed in the estimate. This scenario represents the absolute worst possible result for this type of project (i.e. Short of Acts of God).
High-Cost Scenario	Outlines the circumstances that would be seen if the outcome was less desirable than the estimate. This scenario represents a plausible worst- case result that can occur for this type of project.
Minimum Cost Scenario	Outlines the circumstances that would be seen if the outcome was more desirable than the estimate. This scenario represents the absolute best possible result for this type of project.
Low-Cost Scenario	Outlines the circumstances that would be seen if the outcome was more desirable than the estimate. This scenario represents a plausible best-case result that can occur for this type of project.
Mean Contingency	Weighted average of all values in the distribution. The mean contingency is the expected contingency.
P50	This is the 50th percentile value where 50% of the sampled outcomes are less than or equal to the P50 value. This can also be viewed as the value that yields a 50% Level of Confidence. There is a 50% chance that this value will be exceeded.
P90	This is the 90th percentile value where 90% of the sampled outcomes are less than or equal to the P90 value. This can also be viewed as the value that yields a 90% Level of Confidence. There is a 10% chance that this value will be exceeded.
Confidence Interval (CI)	The range of the values sampled in the analysis. An 80% CI means the spread between P10 and P90. This means that 80% of all values sampled in the analysis fall within the P10 and P90 range.
Accuracy	An estimate's predicted closeness to the final actual cost or time. Typically expressed as a low/high percentage by which actual results will be lower or above the deterministic (estimated) value. Accuracy is calculated as the cost variation around the P50 confidence level.

2. Executive Summary

A Quantitative Risk Analysis (QRA) was completed for Newfoundland and Labrador Hydro as part of the 150 MW Combustion Turbine FEED Study to assess the project schedule and capital costs risk profiles, following a parametric quantitative risk analysis model.

The results of this analysis helped the project team to determine the level of contingency and accuracy for both the project schedule and the capital cost. The QRA workshop was carried out on October 8th and 10th, 2024 with the information available at the time. The following provides a summary of the schedule and capital cost risk analysis results.

The analysis is based on a model built on a schedule with a target date of [redacted] for the Project Construction Completion milestone [redacted] and a base estimate of the to go costs at: CAD 586 M (base estimate including owner's costs).

The Table 2-1 below summarizes the results of the Schedule Risk Analysis:

Table 2-1: Schedule Risk Analysis Results – Construction Completion

Milestone	Schedule Target	Risk Profile Result at PMean	PMean Contingency
Construction Completion	[redacted]		

The Construction Completion milestone can be expected with a [redacted] spread to the deterministic date, so towards the end of [redacted] for the level of confidence of P_{Mean}.

The Table 2-2 below, summarizes the results of the capital cost risk analysis:

Table 2-2: Capital Risk Analysis Results

Description	Estimate	Risk Value at PMean	Contingency @ PMean $	Contingency @ PMean %
Total Risk Profile	**CAD 586 M**	**CAD 650 M**	**CAD 65.0 M**	**11.1%**

Should the cost contingency be established at the P_{Mean} value, the project cost would be expected to be at a value of CAD 650 M, thus requiring a contingency of CAD 65 M, or 11.1% on top of the base estimate. Other levels of confidence above P_{Mean} are presented in Section 6.5.

It should be noted that the analysis was developed by making certain schedule and cost assumptions that affect the risk profile. Details for these assumptions can be found in Section 6.1.

The major parameters driving capital cost contingency include, in order of importance:

[redacted]

The major drivers of the schedule contingency include, in order of importance:

[redacted]

3. Introduction

In accordance with Newfoundland and Labrador Hydro (NLH)'s project management team's expectations, a capital cost, and schedule parametric Quantitative Risk Analysis (QRA) was completed to determine the capital cost and schedule risk profile for the project. The QRA assessed the level of potential project and operational costs variability to allow NLH to establish appropriate levels of contingency that are congruent with the risk tolerance of the organization and its corporate guidelines.

The objectives of the analyses were to:

- Determine the probability of achieving the deterministic costs and schedule duration;
- Determine the Mean, P5, P10, P50, P70, P80, P85 and P90 cost and schedule values;
- Determine the estimate accuracy for the 80% Confidence Interval (CI);
- Identify key capital cost and schedule risk drivers;
- Develop the project capital cost and schedule risk profile, the analysis integrated the following contributing areas:

[redacted]

1

This report documents the risk analysis process and results.

4. Parametric Quantitative Risk Analysis Processes

Project capital costs can be impacted by project estimate uncertainty, project scope uncertainty, schedule uncertainty, systemic risk, and project risk events. The QRA process addresses each of these elements to develop the schedule and cost risk profiles.

The process used is based on a hybrid risk analysis process that integrates project systemic risk and project risk events as shown here in Section 6.3. The analysis follows the AACE International Recommended Practice 43R-08 and 113R-20. The John Hollmann Industrial Model developed for Hatch was used for the analysis. The Monte Carlo simulation used for the simulation of the hybrid risk model is run in the software @Risk.

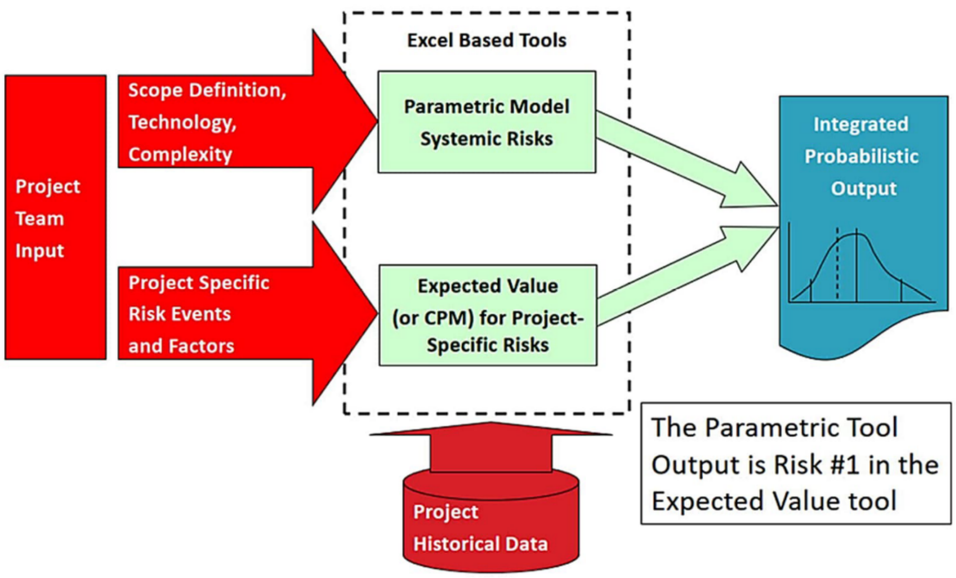

Figure 4-1: Parametric Risk Model Structure

The total project risk analysis model consisted of the following elements which is a combination of the parametric model and other project elements, such as project specific risks, not included in the parametric systemic risk analysis:

- Parametric system risk analysis for the project scope and the associated capital cost and schedule from the commencement of detailed engineering to construction completion;
- The analysis did not consider any cost or schedule uncertainty associated with the Detailed Engineering Phase;

- Project capital risk registers to quantify the capital and schedule risk events; and
- Commissioning phase schedule risks are not included in the risk profile.

The process utilized workshop and review processes that capture the full knowledge of the project study team.

The process included:

- Pre-workshop Activities, including an overview of the project's activities and assessing the project risks;
- Workshop Activities, during which the risk model was developed;
- Post Workshop Activities including review of the results and incorporating any required updates; and
- Completion of the final analysis including delivery of analysis results slides and detailed report.

5. QRA Workshops Participants

The QRA workshop was carried out on October 8th and 10th 2024, in remote arrangement. Key project team members and stakeholders (Table 5-1) attended the facilitated workshops and assessed the uncertainty ranges that were included in the analysis.

Workshop facilitation, collection of ranges, generation, interpretation and documentation of the analysis results was done by Loïc Reny, from the Hatch Risk Management practice.

Table 5-1: Parametric QRA Workshop Participants

Name	Project Role	Organization	October 8th, 2024	October 10th, 2024
David Billard	Project Manager	NLH	✓	✓
Glenn Whalen	Project Estimator	NLH	✓	✓
Ryan Cooper	Engineering Manager	NLH	✓	✓
Tony Scott	Project Controls	NLH	✓	✓
Brett Howlett	PM Coordinator	NLH	✓	✓
Doug Woodford	Compliance	NLH	✓	✓
Crystal O'Dea	Regulatory Engineer	NLH	✓	✓
Angela Vallis	Contracts Manager	NLH	✓	✓
Chris Yager	Program Manager	Hatch	✓	✓
Karim Meghari	Sponsor / Mechanical Lead	Hatch	✓	✓
Anne Stapleton	Structural Lead	Hatch	✓	✓
Kristen Gillis	Civil Lead	Hatch	✓	✓

HATCH

Name	Project Role	Organization	October 8th, 2024	October 10th, 2024
Vince Kerrivan	Instrumentation & Controls Lead	Hatch	✓	-
Kerry Savoury	Engineering Manager	Hatch	-	-
Kevin King	Electrical Lead	Hatch	✓	✓
Shem Evans	Environmental Lead	Hatch	-	✓
Adam Spollen	Project Estimator	Hatch	✓	✓
Loïc Reny	Risk Manager, Facilitator	Hatch	✓	✓

6. Capex & Schedule Risk Analysis

6.1 Schedule and Cost Risk Assumptions

The project schedule is based on the key assumptions developed in the Basis of Schedule and Basis of Estimate, as drafted at the time of review. The project did not consider self-directed delays such as decisions by the organization to modify the scope or change the execution strategy from what was developed at the time of the analysis. It is also assumed that all permits managed by NLH will be available on time for construction and other project activities. Similarly, the public procurement process is assumed to be completed on time for the CTG package award. Any change in CTG package supplier is assumed to be cost neutral (but with schedule impacts), as the costs for rework of engineering deliverables would be offset by reductions in costs associated with the package.

6.2 Systemic Risk Factors

The systemic risk factors review, and workshop information is presented in Appendix A for the project. Systemic risk factors were discussed with the team participating in the workshop and notes were developed to justify the team's selection of factors applicable to the project.

The risk factors are regrouped in major categories, being:

[redacted]

6.3 Project-Specific Risk Events

The project risk register was reviewed to identify risk events (i.e. both threats and opportunities) that would contribute to the project delay or cost overrun if they were to occur. Any risks that were considered accounted for in the reflection on systemic risk factors were not included as specific risks to prevent duplication of the risk provision.

Risk events that may negatively impact the project schedule were assessed quantitatively in terms of the two following factors: (1) probability of occurrence; (2) schedule duration impact (days) or cost impact.

The hybrid risk model developed for this analysis requires to only incorporate key critical risks, specific to the project's context, with special attention not to overlap with any items characterized in the systemic risks. The following risk events documented in the project risk register were included in the schedule risk analysis.

Table 6-1: Project Specific Risk Events

[redacted]

6.4 Schedule Risk Analysis Results

The schedule risk analysis indicates the effect of systemic risks and project-specific risks on the schedule duration.

Figure 6-1 presents the schedule duration risk profile for the *Construction Completion Milestone*.

[redacted]

Figure 6-1: Schedule Risk Profile – Construction Completion

The analysis is performed over the duration of the construction phase of the project, which spans from the mobilization for work at site [redacted] to the Construction Completion [redacted] or a deterministic duration of [redacted]

The profile above shows the P_{Mean} completion date was obtained with a [redacted] thus requiring a contingency at the mean of [redacted] beyond the deterministic duration. Note that calculated contingency includes specific risks that are unrelated to the construction phase (risks that may materialize prior to mobilization), therefore, the ratio of contingency to the construction duration phase may not compare well with other projects depending on the inclusions/exclusions. The schedule risk profile is also summarized in Table 6-2 below, providing the various confidence levels.

Table 6-2: Summary Schedule Risk Profile – Mechanical Completion

[redacted]

Table 6-3: Levels of Confidence for Schedule Results

[redacted]

6.5 Cost Risk Analysis Results

The parametric model developed with the project's characteristics provides the following results for cost contingency. The output of the cost contingency simulation is shown in Table 6-4 below:

Table 6-4: Cost Simulation Output

ESTIMATE SUMMARY (EXCLUDES RESERVES) (Based on probabilities selected above)			
	Cost (thousands)	%	Confidence of underrun
Base Estimate	$586 643		33.8%
Contingency	$65 000	11.1%	
Ref. Estimate	**$650 040**		**55%**
Range:	$502 000	-22.8%	10%
	$817 000	25.7%	90%

Table 6-5: Levels of Confidence for Cost Results

Base Estimate: **$586 643** Currency: CAN$

Probability of Underrun	Indicated Funding Amount	Contingency	
		Costs (thousands)	Percent of Base Est.
5%	470 000	(117 000)	-20%
10%	502 000	(85 000)	-14%
15%	524 000	(63 000)	-11%
20%	543 000	(44 000)	-8%
25%	560 000	(27 000)	-5%
30%	576 000	(11 000)	-2%
35%	590 000	3 000	1%
40%	607 000	20 000	3%
45%	621 000	34 000	6%
50%	637 000	50 000	9%
55%	652 000	65 000	11%
60%	668 000	81 000	14%
65%	685 000	98 000	17%
70%	704 000	117 000	20%
75%	725 000	138 000	24%
80%	748 000	161 000	27%
85%	780 000	193 000	33%
90%	817 000	230 000	39%
95%	876 000	289 000	49%

1

At a P_{Mean} level of confidence, the project funding should be CAD 650 M, thus requiring a contingency of CAD 65.0 M, or 11.1% on top of the base estimate. For an 80% confidence of underrunning, the contingency should be CAD 161 M (27% on top of the base estimate). For a 90% confidence of underrunning, the contingency should be CAD 230 M (39% on top of the base estimate). 1

Note that the base estimate (without contingency, but including Owner's costs) or CAD 579 M, has a confidence of underrun of 33.8%.

The Figure 6-2 shows the overall project capital cost risk profile for the project:

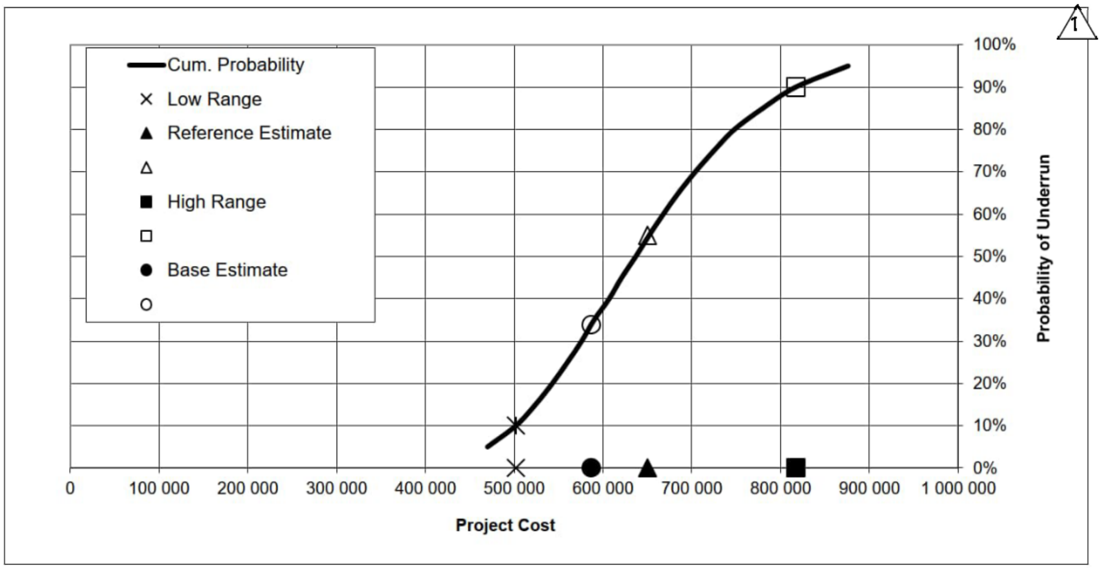

Figure 6-2: Project Capital Cost Risk Profile

6.5.1 Estimate Accuracy

Accuracy is calculated as the amount of variability of the profile around the P50 for the given Confidence Interval. Accuracy for the 80% confidence interval was calculated for the project.

For the 80% Confidence Interval, the accuracy is calculated as the percentage difference between P50 and P10 and the percentage difference between P50 and P90.

For this risk analysis, the contingency was calculated at the mean value. Additionally, P5, P10, P50, P90 and P95 were calculated to show the range of potential costs and, therefore, assess the estimate accuracy for the 80% Confidence Interval.

Using the confidence interval, the level of estimate accuracy was calculated, and the results are presented in Table 6-6 below.

Table 6-6: Estimate Accuracy

	P10	P90
Estimate Accuracy for 80% CI	-22.8%	+25.7%

6.6 Risk Drivers Analysis

The key systemic risk factors are shown in Figure 6-3. These items represent the main uncertainty sources that may require allocation of cost and schedule contingency or for which the project team should allocate mitigation efforts during project development.

[redacted]

Figure 6-3: Systemic Risk Influence Diagrams

The major drivers of the contingency include, in order of importance, for costs:

[redacted]

The major drivers of the schedule contingency include, in order of importance:

[redacted]

7. Next Steps

With the results from this integrated cost and schedule risk analysis, NLH is able to select appropriate levels of contingency for the project as well as to establish appropriate management reserve to protect the organization from potential unfavorable project performance as well as to account for enterprise risks, not developed into this analysis.

In parallel, by looking at the risks highlighted in this report, the project team is able to target efforts on specific activities that can bring the most benefits in reducing the potential for schedule slippages and potential additional costs. These results should be considered when planning and prioritizing efforts for the upcoming project development phase.

Appendix A
Systemic Risks Modeling

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

newfoundland labrador hydro

Avalon Combustion Turbine

Basis of Estimate

Attachment 4: Risk and Assumption Register

Document No.: HRDCT2-HAT-49100-RI-REG-0001-01, Rev B0

Date: November 18, 2024

ATTENDANCE

Name	Organization	6/11/2024	6/12/2024	7/5/2024	10/29/2024
Christopher Yager	Hatch	✔	✔	✔	✔
George Cooper	Hatch		✔		
Vince Kerrivan	Hatch		✔		
Valerie Shepard	Hatch		✔	✔	
Jeremy Jones	Hatch				
Melissa Martin	Hatch				
Shem Evans	Hatch		✔		
Joseph MacLean	Hatch	✔			
Andrew Peach	Hatch	✔	✔		
Miguel Rosales	Hatch	✔			
Kirsten Gillis	Hatch	✔	✔		
Anne Stapleton	Hatch	✔	✔		
Lauren Boers	Hatch		✔		
Loïc Reny	Hatch	✔	✔	✔	
Karim Meghari	Hatch			✔	
Kerry Savoury	Hatch				
Kevin King	Hatch				

HATCH

PROJECT RISK LIKELIHOOD AND IMPACT MATRIX								
Likelihood Description and Indicative Frequency	Risk Probability (Qualitative Descriptor)	Indicative Probability (%)	Probability Descriptor (P)					
Incident is very likely to occur on this project, possibly several times.	Almost Certain	>80%	P5	Low 5	Medium 10	High 15	Extreme 20	Extreme 25
Incident is likely to occur on this project.	Likely	50% to 80%	P4	Low 4	Medium 8	Medium 12	High 16	Extreme 20
Incident has occurred on a similar project.	Possible	20% to 50%	P3	Low 3	Low 6	Medium 9	Medium 12	High 15
Given current practices and procedures, this incident is unlikely to occur on this project.	Unlikely	5% to 20%	P2	Low 2	Low 4	Low 6	Medium 8	Medium 10
Highly unlikely to occur on this project.	Rare	<5%	P1	Low 1	Low 2	Low 3	Low 4	Low 5
	Consequence (C) Descriptor			C1	C2	C3	C4	C5
	Consequence Severity Qualitative Descriptor			Insignificant	Minor	Moderate	Major	Extreme
	Health & Safety			First Aid Case.	Minor injury, medical treatment case with/or restricted case Work.	Serious injury or lost Work case.	Major or multiple injuries, permanent injury or disability.	Single or multiple fatalities.
	Environment			No impact on baseline environment. Localized to point source. No recovery required.	Localized within site boundaries. Recovery measurable within 1 month of impact.	Moderate harm with possible wider effect. Recovery in 1 year.	Significant harm with local effect. Recovery longer than 1 year.	Significant harm with widespread effect. Recovery longer than 1 year. Limited prospect of full recovery.
	Financial			3% to 5% of project value	5% to 7% of project value	7% to 10% of project value	10% to 20% of project value	> 20% of project value
	Schedule			1 day to 3 days delay	3 days to 2 weeks delay	2 weeks to 1 month delay	1 to 6 months delay	> 6 months delay
	Production			1 day to 3 days Loss of availability	3 days to 2 weeks Loss of availability	2 weeks to 1 month Loss availability	1 to 6 months Loss of Availability	> 6 months Loss of Availability
	Business Impact			Impact can be absorbed through normal activity.	An adverse event which can be absorbed with some manageable effort.	A serious event which requires additional manageable effort.	A critical event which requires extraordinary management effort.	Disaster with potential to lead to collapse of the project.
	Reputation			Localized, temporary impact.	Localized, short term impact.	Localized, long term impact, but manageable.	Localized, long term impact with unmanageable outcomes.	Long term, regional impact.

Level	Timing of Risk Treatment
Extreme	Proceeding at this risk level is not permitted under any circumstance. Mitigate risk to a Low or Moderate level or Avoid activity altogether.
High	Proceeding at this risk level is not permitted under any circumstance. Mitigate risk to a Low or Moderate level or Avoid activity altogether.
Moderate	Mitigate or avoid if possible. Proceed only with Company's approval.
Low	Monitor. Take action if conditions change and raise risk grade above acceptable levels.

Note: Any risks that have been scored at the upper end of the probability and consequence ranges need to be carefully considered for moving up a risk level given that the "boundaries" between the risk levels actually overlap slightly.

Categories

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

HATCH

Parking Lot			
No	Item	Responsible	Due Date
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
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26			
27			

newfoundland labrador hydro

Basis of Estimate

Avalon Combustion Turbine

Attachment 5: Briefing Note – Impact Analysis of CT Price Increase on Project Cost

Document No.: 12972590-NLH-NLH-BRI-0001-01, Rev B1

Date: April 9, 2026

Briefing Note: Impact Analysis of CT Price Increase on Project Estimate

Avalon Combustion Turbine

NLH Doc. No. 12972590-NLH-NLH-BRI-001

Comments: This document explains the approach and methodology used to determine the impact of the change in price of the Combustion Turbines on the Avalon Combustion Turbine Project. This document contains confidential and commercially sensitive information. Access to this document and the information contained within is restricted and should only be shared with the written approval of the Manager, Project Controls for Major Projects.	**Total # of Pages (including Cover):** **19**

B1	09-Apr-2026	Use	Tony Scott	Ryan Cooper	Neil Martin	Stephen Parsons
Revision	**Date** (DD-MMM-YYYY)	**Issue Reason**	**Prepared By** Manager, Project Controls Major Projects	**Checked By** Project Manager Major Projects	**Approved By** Sr. Project Manager Major Projects	**Approved By** Sr. Manager, PM & Eng. Major Projects

These signatures are required to confirm compliance with Major Projects procedures. This document cannot be finalized or distributed without this approval. Any version of this document without these signatures is not considered final.

newfoundland labrador hydro	Briefing Note – Impact Analysis of CT Price Increase on Project Estimate Avalon Combustion Turbine				
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Additional Approvals

Additional approvals required for further authorization due to document contents, complexity, prescribed requirements, or multi-departmental involvement.

Position	Name	Signature	Date (DD-MMM-YYYY)
Director, Major Projects and Asset Management	John Walsh	[signature]	9-Apr-2026

Endorsements

Endorsements indicate support or acknowledgement of this document's contents but do not imply formal approval. Endorsements are used to represent subject matter experts who have provided input but do not hold final decision-making authority for this document.

Position	Name	Signature	Date (DD-MMM-YYYY)
Senior Estimator, Major Projects	Glenn Whalen	[signature]	09-Apr-2026
Senior Estimator, Major Projects	Doug Maloney	[signature]	09-APR-2026

Revision History

Changes to the content of this document are recorded in the Revision History table below. Minor or immaterial edits—such as formatting adjustments or typographical corrections—may not be listed.

Revision No.	Revision Date	Location	Reason
1	09-Apr-26	General	General addition of content to add more information about the specifics of the analysis process used as well as including outcomes of the simulation results as an Appendix.

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1.0 Executive Summary

In early 2026, the estimating group within the Major Projects Project Controls Department performed an analysis of the impact of the price increase of the Combustion Turbine (CT) units on the Avalon Combustion Turbine (ACT) project.

To perform this analysis, given the modeling tool that the FEED consultant used, specific software had to be utilized. The results indicate that the project estimate value (authorized cost in the application to the Public Utilities Board) should be revised to $995.9M, from $891.4M, to incorporate this price increase. This increase is significantly driven by the increased price of the CT units ($102.3M of the total $104.5M project increase).

2.0 Purpose

This briefing note is prepared to explain the approach and methodology used to determine the impact of the change in price of the CTs on the ACT project.

3.0 Terms and Definitions

Term	Description
AACE	Association for the Advancement of Cost Engineering. An international industry organization that publishes many Recommended Practices (RPs) to aid in guiding project management professionals in many aspects of project execution. AACE RPs provide useful guidance but are not standards.
ACT	Avalon Combustion Turbine
BDE	Bay d'Espoir Hydroelectric Generating Facility
CAD	Canadian Dollar
CRN	Canadian Registration Number. This is a mandatory certification for boilers, pressure vessels and fittings, and is necessary to ensure that the design meets the CSA B51 code
CT	Combustion Turbine
EPCM	Engineering, Procurement and Construction Management
FEED	Front End Engineering and Design
GSU	Generator Step Up Transformer

IDC	Interest During Construction The cost of for the use of capital, sometimes referred to as the time value of money.
Major projects	Regulated projects and programs with an anticipated cost of $50 million or greater under the accountability of the Major Projects Department.
Major Projects Department	The Major Projects Department is dedicated to and responsible for the planning, execution, monitoring, and delivery of major projects for NL Hydro
MCS	Monte Carlo Simulation
Newfoundland and Labrador Hydro (NL Hydro)	Newfoundland and Labrador Hydro and/or a consolidated entity, affiliate, or subsidiary.
QRA	Quantitative Risk Analysis
USD	United States Dollar

4.0 Impact Analysis

4.1 Background

The Avalon Combustion Turbine (ACT) project went through Front End Engineering and Design (FEED) in 2024. This work was performed by Hatch, on behalf of NL Hydro. As part of the FEED work, an estimate was developed[1], as well as a Quantitative Risk Assessment (QRA) performed[2]. The QRA report was issued in November 2024.

For the QRA, Hatch used a hybrid risk analysis process, which uses a parametric analysis model and expected value analysis model, and then combined these into an integrated Monte Carlo Simulation (MCS) model, which provides an overall probabilistic set of outcomes.

Hatch's parametric model is a proprietary system built on a spreadsheet provided by a recognized estimating Subject Matter Expert, John Hollmann, CCP, CEP, DRMP[3].

Based on the results of Hatch's QRA, the P_{mean} and P_{85} values were selected as the basis for contingency and management reserve, respectively. The contingency budget equals 11.1%[4] and management reserve equates to 21.9% (33% at P_{85} less 11.1% at P_{mean})[5] of the base estimate.

[1] HRDCT2-HAT-49100-EP-EST-0001-01, Rev. B0, *150MW Combustion Turbine FEED Study Basis of Estimate*
[2] HRDCT2-HAT-49100-PC-EST-0001-01, Rev. B1, *Avalon Combustion Turbine – Parametric QRA Report*
[3] HRDCT2-HAT-49100-PC-EST-0001-01, Rev. B1, Avalon Combustion Turbine – Parametric QRA Report, Section 4. This is aligned with AACE RPs 43R-08 and 113R-20.
[4] HRDCT2-HAT-49100-EP-EST-0001-01, Rev. B0, *150MW Combustion Turbine FEED Study Basis of Estimate*, section 12
[5] HRDCT2-HAT-49100-EP-EST-0001-01, Rev. B0, *150MW Combustion Turbine FEED Study Basis of Estimate*, section 13

Hatch identified the risk of higher than estimated costs for major equipment but had rated the risk as 'low' based on the identified mitigating actions, which included "Firm proposal received from GE, budgetary from others…" and that "…QRA performed to allocate contingency.".[6] There was no specific risk ranging completed on the price of the CT units. Following a review of the FEED estimate as part of this analysis, this resulted in a lower reserve value than could have been applied[7], as the potential for price increases to the CT package was considered low at the time.

Subsequently, NL Hydro issued an RFP for the supply of CT units, and in December 2025 came to a contractual agreement with GE for the CTs. The price in this contract was significantly above the value included in the Hatch estimate ($272M vs $173M). This change in the contracted price compared to the estimated price during FEED are a direct result of the active market for CTs in North America since the 2024 FEED, which has caused a large increase in the supplier prices[8]. This market demand is driven by a surge in demand for data centres to support the Artificial Intelligence boom, as well as overall electrification efforts.

NL Hydro completed this review using a hybrid (parametric + expected value) method, similar to that performed during the FEED phase. As NL Hydro does not have access to the propriety tool used by Hatch, NL Hydro used a demonstration version of ValidRisk[9], a new risk quantification system based on the work of John Hollmann, CCP, CEP, DRMP. This system is an evolution of the proprietary tool used by Hatch (but without any of Hatch's internal calibration) during FEED. While engaging Hatch to update the analysis using their tool was considered, as they are in the bidding process for the ACT Engineering, Procurement and Construction Management (EPCM) contract, this was deemed to not be a preferred solution due to the potential conflict that this would raise.

In preparing this impact analysis, the Project Controls team reviewed other project elements to determine if there is any other known information that could be added to this analysis. Table 1 identifies these items. It was determined that while there are indications (generally of alignment with estimated values), there were no additional items to be considered in the analysis beyond the CT price increase.

Table 1 - Items evaluated for the impact analysis

No.	Item	Context regarding impact analysis
1	Engineering, Procurement and Construction Management (EPCM) Consultant	The EPCM bid period has been extended, at the request of bidders. Accordingly, no formal contract values are available. However, indications from the initial EPCM bid, as well as bids for the BDE scope, indicated being generally within the expected estimate bounds.

[6] HRDCT2-HAT-49100-EP-EST-0001-01, Rev. B0, *150MW Combustion Turbine FEED Study Basis of Estimate*, Attachment 4, Risk ID 012

[7] Without the exact tool that Hatch used, and the assessment of the risk that would have been assigned at the time of Hatch's QRA, this cannot be exactly quantified. From NL Hydro evaluation, it is believed that this would have been in the order of $10M.

[8] Refer to the PUB filed monthly report, "Avalon Combustion Turbine Project Early Execution Update – December 17th, 2025", for additional details surrounding the market-induced CT price increases.

[9] ValidRisk.com

No.	Item	Context regarding impact analysis
2	Geotechnical Investigation	The geotechnical field investigation program was conducted during the 2025 construction season, and the interpretation and analysis of the results are ongoing. These results need to be evaluated by the EPCM and incorporated into the site design to determine any impacts as the project progresses through detailed design.
3	Generator Step Up (GSU) Transformer	While bids for the transformer have been received, negotiations with the vendor are ongoing. [redacted]
4	Circuit Breakers	Evaluation of bids for the circuit breakers is underway, and as such the impacts are unknown. [redacted]
5	Civil Scope	Civil design is pending design by the EPCM consultant. As noted above, the EPCM contract has not yet been awarded.
6	Early Transmission Scope	Early works transmission scope has been partially completed, and indications are that this element is within the expected estimate bounds for this item.
7	Detailed Design	As the EPCM consultant has yet to be engaged, detailed design has not significantly changed to factor into any impact analysis.
8	Early Execution Scope	Some specific items included in early execution are noted above. In general, early execution scope has been proceeding within the expected costs for those items.

4.2 Analysis

NL Hydro conducted this analysis in-house, using a methodology and software like that used by Hatch during the FEED phase.

Other potential impacts to the CT contract were evaluated (see table 2) and based on the estimated value and assessed probability of these impacts, a project specific risk item, with a value of $10.25M, was added to the MCS analysis.

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Table 2: Potential Contract Changes

No.	Item	Estimated Value	Assessed Probability of Increase	Calculated Increase
1	Contract is in USD. FX can impact the cost (+/-). The contract pricing is $272,328,326 CAD, based on an FX rate of 1.3605. FX has varied up to 1.41.	[redacted]		
2	Onsite OEM (Vendor) support is essentially structured as time and materials. Values can vary based on execution.	[redacted]		
3	Transportation is included in contract price as an estimate. The final price will be actual cost [redacted]	[redacted]		
4	As the design for the plant is not finalized, there is a possibility that a design change may lead to change in the CT to avoid a greater cost increase in another area of the plant.	[redacted]		
5	Tariff impact has been assessed and included in the contract. The included value is an estimate based on a model but will be at actual cost.	[redacted]		
6	The number of operations personnel travelling for FATs and participation in training is estimated and could change.	[redacted]		
7	CRN Certification for pressure retaining components. *Assumed a very high probability item and thus added* [redacted] *to base cost, rather than as a risk item.*	n/a	n/a	n/a
8	**Combined items included as a specific risk item in the model for simulation**			**$10,254,154**

[10] Based on the difference between FX rates of 1.3605 and 1.41 on contract value of $200,167,825 USD

The project was analyzed with adjusted parameters, reflecting new pricing from the vendor, as well as an estimated allowance for CRN Certification[11]. An extra $102M was added to the base estimate for the CT contract price, including the allowance for CRN certification [redacted]

The simulation model was run five times with the revised base cost value, and with the addition of the new specific risk as noted in Table 2. This risk was modeled as a triangular distribution, with the low and high ranges being at [redacted] of the midpoint (i.e. Low: [redacted] High: [redacted] and with the probability set to 'medium' in the software (which equates to a [redacted] probability).

Each of the five model runs (iterations) was independently executed, with each model iteration executing the MCS 1,000 times. NL Hydro took the average of the results of the iterations to be certain that the results remained statistically consistent with each other. This was felt to be important as NL Hydro had limited experience with this simulation tool (ValidRisk), and NL Hydro wanted to select a reasonable and balanced approach to the analysis of the impacts of the CT price. As can be seen in Table 3, the results of the five iterations are generally similar. The output of these five iterations is included as Appendix A.

The average calculated contingency was $75.45M, as shown in Table 4. As a percentage of base cost, the revised recommended values for contingency (11.0%) and Management Reserve (17.7%) are generally consistent with, but lower than, the values as originally calculated in the FEED study (11.1% and 21.9% respectively). In terms of absolute value of reserves (contingency and management reserve combined), however, the number has increased, in part due to the increased base cost, and in part due to the addition of a specific risk item to account for items within the CT contract that remain variable.

Table 3: Simulation results with updated values[12]

	Original BOE	ACT Full Evaluation (CT Cost increase + new specific risk)						
Item	($k)	Iteration 1 ($k)	Iteration 2 ($k)	Iteration 3 ($k)	Iteration 4 ($k)	Iteration 5 ($k)	Average ($k)	Change from Original ($k)
Base Estimate	**586,643**	688,971	688,971	688,971	688,971	688,971	**688,971[13]**	**+102,328**
Contingency (P_{mean})	**65,117**	74,388	73,589	74,934	77,313	77,049	**75,455**	**+10,338**
Escalation	**44,846**	--	--	--	--	--	**33,684**	**-11,162**
Interest During	**66,569**	--	--	--	--	--	**76,137**	**+9,568**

[11] Canadian Registration Number (CRN) is a mandatory certification for boilers, pressure vessels and fittings, and is necessary to ensure that the design meets the CSA B51 code. As this is not a standard practice for non-Canadian supplied equipment, there are typically additional costs required for meeting this requirement.
[12] Values may not total due to rounding
[13] Base estimate was increased by $102M based on CT contract plus [redacted] for CRN certification as noted earlier.

	Original BOE	ACT Full Evaluation (CT Cost increase + new specific risk)						
Item	($k)	Iteration 1 ($k)	Iteration 2 ($k)	Iteration 3 ($k)	Iteration 4 ($k)	Iteration 5 ($k)	Average ($k)	Change from Original ($k)
Construction (IDC)								
Management Reserve (P_{85} – P_{mean})	**128,239**	125,225	117,679	117,300	121,502	126,436	**121,628**	**-6,611**
Total Planned Cost	**891,415**	--	--	--	--	--	**995,875**	**+104,460**

The simulation provides outcomes related to project reserves – contingency and management reserve. Escalation and IDC are calculated based on the time phasing of the base cost and the reserve values. For the calculation of these items, the original estimate cost profiling has been used, but with the updated base and reserve values.

As can be seen from Table 3, less than 3% of the change in the planned total cost is in non-direct categories.

5.0 Estimate Class and Range

This analysis does not modify the estimate class (i.e. it is still considered an AACE Class 3 estimate). The maturity level of definition is the sole determining characteristic of class[14].

As there has been little progression on detailed design to date, the maturity level has not changed materially, and the maturity level has not been reassessed.

The project estimate had an estimate range of -22.8%/+25.7%[15]. A representative result from the current analysis[16] indicates a range of -19.6%/+22.0%, which indicates a slight narrowing or tightening of the estimate range (a delta of -3.2% on the lower end and -3.7% on upper end). However, this analysis only considered the impacts of the price increase of the CT units as a part of this estimate impact analysis.

6.0 Conclusion

It is recommended that the project estimate, for the ACT project, be revised to $995.9M, based on the significant increase in the price of the CTs over that originally estimated. This increase is made up of changes in the various major estimate categories as shown in Table 5.

---

[14] AACE RP 17R-97, *Cost Estimate Classification System.*

[15] HRDCT2-HAT-49100-PC-EST-0001-01, Rev. B1, *Avalon Combustion Turbine – Parametric QRA Report,* Table 6-6.

[16] Model Run 3 of 5. Given the nature of MCS, each model run generates slightly different outcomes. This can be seen in tables 2 and 4 as well in Appendix A. The average of the five model iterations had a range of -19.9% / +22.1%.

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Table 4: Recommended Estimate Change[17]

Category	Project BOE ($M)[18]	Recommendation ($M)[19]	Change ($M)
Base Cost (Note 1)	586.6	**689.0**	+102.4
Project Contingency (Note 2)	65.1	**75.5**	+10.4
Escalation (Note 3)	44.8	**33.7**	-11.1
Interest During Construction (IDC) (Note 4)	66.6	**76.1**	+9.5
Sub-total (Planned Budget)	**763.1**	**874.7**	**+111.2**
Management Reserve (Note 5)	128.2	**121.6**	-6.6
Total (Authorized Cost)	891.4	**995.9**	**+104.5**

Note 1: Base price increase as the result of the change to the CT price. Indications are that other elements are within expected estimate bounds. As detailed design has not yet commenced, several unknowns remain. Refer to Table 2 for more information.

Note 2: Project contingency has increased because of the price increase of the CT package, as well as the added specific risks to the variable portions of the scope in the contract.

Note 3: Escalation has decreased as the CT contract has been awarded, thus fixing escalation rates within the contract.

Note 4: IDC has increased as the CT contract has been awarded, and financing charges start accumulating on a higher cost for the CTs.

Note 5: Management reserve has decreased slightly due to the increased certainty of the CT components. This change was only driven by the systemic elements of the MCS analysis, as it was discovered during this analysis that the estimate developed during FEED for the CT did not consider CT price change as a specific risk item.

It is further recommended that a more comprehensive estimate update be performed as a precursor to the Commitment to Build point[20]. For this to be effective, this would occur after the EPCM consultant is engaged and the project design progresses from FEED level into Detailed Engineering and Design.

[17] Values may not total due to rounding
[18] HRDCT2-HAT-49100-EP-EST-0001-01, Rev. B0, *150MW Combustion Turbine FEED Study Basis of Estimate*, Table 1
[19] Table 3
[20] The likely time for this decision point would follow the evaluation of the major civil construction contract but should other major procurement or engineering results indicate a major project cost increase before the Commitment to Build, an impact review, such as the analysis in this briefing note, would be conducted.

7.0 Reference Documents

Ref.	Document Title	Document Number
1	AACE PGD-02	Professional Guidance Document 02 – Guide to Quantitative Risk Analysis
2	AACE RP 113R-20	Integrated Cost and Schedule Risk Analysis and Contingency Determination using combined Parametric and Expected Value
3	AACE RP 17R-97	Cost Estimate Classification System
4	AACE RP 40R-08	Contingency Estimating – General Principles
5	AACE RP 43R-08	Risk Analysis and Contingency Determination using Parametric Estimating – Example Models as Applied for the Process Industries
6	AACE Technical Paper RISK.1721	Variability in Accuracy Ranges: A Case Study in the Canadian Hydropower Industry
7	AACE Technical Paper RISK-4240	Case Study: Use of the Hybrid Parametric and Expected Value QRA Method on the Keeyask Hydropower Megaproject
8	HRDCT2-HAT-49100-EP-EST-0001-01	150MW Combustion Turbine FEED Study Basis of Estimate
9	HRDCT2-HAT-49100-PC-EST-0001-01	Avalon Combustion Turbine – Parametric QRA Report
10	No reference	BC Hydro Site C Project, Lessons Learned Report to Inform Future Major Capital Projects

Briefing Note – Impact Analysis of CT Price Increase of Project Estimate

Avalon Combustion Turbine

Appendix A: Output of Simulation Iterations

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Affidavit

IN THE MATTER OF the *Electrical Power Control Act, 1994,* SNL 1994, Chapter E-5.1 ("*EPCA*") and the *Public Utilities Act*, RSNL 1990, Chapter P-47 ("*Act*"), and regulations thereunder; and

IN THE MATTER OF an application by Newfoundland and Labrador Hydro ("Hydro") for approval of capital expenditures for the purchase, construction, and installation of Unit 8 at the Bay d'Espoir Hydroelectric Generating Facility ("Bay d'Espoir") and a combustion turbine ("CT") located on the Avalon Peninsula.

AFFIDAVIT

I, Gail Randell, of St. John's in the province of Newfoundland and Labrador, make oath and say as follows:

1) I am Vice President, Major Projects for Newfoundland and Labrador Hydro, the applicant named in the attached application.

2) I have read and understand the foregoing application.

3) To the best of my knowledge, information, and belief, all of the matters, facts, and things set out in this application are true.

SWORN at St. John's in the province of Newfoundland and Labrador, this 16th day of April 2026, before me:

Barrister, Newfoundland and Labrador

Gail Randell