IN THE MATTER OF the *Electric 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 an Order approving the capital expenditures necessary for certain capital related to the future construction of Bay d'Espoir Hydroelectric Generating Facility ("BDE") Unit 8 and the Avalon Combustion Turbine ("Avalon CT"), pursuant to Section 41(3) of the Act.

CONSUMER ADVOCATE
REQUESTS FOR INFORMATION
CA-NLH-001 to CA-NLH-039

Issued: June 19, 2026

National Energy Strategy and Clean Electricity Regulations

CA-NLH-001 On May 14, 2026, the federal government announced its new national energy strategy, "Powering Canada Strong," which includes an expanded role for natural gas. Along with that strategy, there will be a review and amendments to the federal Clean Electricity Regulations to reflect the new approach. On June 1, 2026, the provincial government announced completion of Phase II of the Natural Gas Resource Assessment of the Jeanne d'Arc Basin. In relation to that report, the CBC reported that the Holyrood TGS could be adapted for gas generation[1].

a) Will Hydro study the merits of converting the Holyrood TGS to a natural gas facility with an extended life beyond 2035?
b) Will Hydro now study the merits of constructing a new natural gas plant as a replacement for the Holyrood TGS?
c) How much capacity would a converted Holyrood TGS or a replacement natural gas plant need to be to ensure that expected load can be met?
d) Could a converted Holyrood TGS or a replacement be supplied directly by piped natural gas from the offshore natural gas fields?
e) Can the proposed Avalon CT use natural gas as its fuel?
f) Could the Avalon CT be converted to a combined cycle plant burning offshore natural gas? Would this reduce or eliminate the need for new wind turbines as anticipated in the Reference Plan?

CA-NLH-002 Under the existing federal Clean Electricity Regulations,

a) Would the proposed Avalon CT be permitted to operate after 2049?
b) Please confirm that the permissible maximum annual output of the proposed Avalon CT is limited to approximately 130 GWh (2025 Build Application, Schedule 3, Page 36).

Holyrood TGS

CA-NLH-003 With respect to the Holyrood TGS, the central question is, if the HRD TGS remains open through 2035, would the Avalon CT be needed? The bullets that follow ask for evidence around that main question.

a) Please provide a table showing the annual cost of the Holyrood TGS from 2021 to 2025 and forecasts for 2026 to 2030, assuming the current mode of operation continues. Please include forecasts for high, medium, and low fuel cost scenarios.
b) Please provide a table showing annual HRD costs and forecast system reliability criteria from 2026-2030 for the following scenarios: (1) one HRD unit retired; and (2) 2 HRD units retired.
c) Please provide a table showing the estimated annual cost to continue operation of Holyrood TGS from 2031 through 2035 if no new capacity additions are in place before 2036. Please identify the annual capital, operation, maintenance and fuel cost, and indicate how many Holyrood units are assumed to be retired

[1] CBC – NL Government pitching gas developments for future energy use

or on standby.

d) Given the current LIL assumptions, through 2035, what HRD forced outage rate would be required for the system to not the stated reliability criterion?

CA-NLH-004 Please provide tables showing NLH's hourly system generation (MW) giving the total as well as the contributions from Holyrood TGS, NLH-hydro, NLH-standby, NLH purchases, MF generation, LIL Flows, and ML Flows from 2020 to today.

CA-NLH-005 (Reference 2025 Build Application Schedule 1, Chart 1, Page 14) Demand in 2024 was roughly the same as demand in 2019. About 512 MW in capacity was added to the IIS via Muskrat Falls generation and the LIL between 2019 and 2024.

a) Please provide documentation showing that each of the 3 units at Holyrood remain "used and useful" through 2030.
b) Please provide an updated version of Chart 1.

CA-NLH-006 (Reference March 2026 and April 2026 Monthly Energy Supply Reports for the Island Interconnected System) The March 2026 report shows that each of the 3 units at Holyrood TGS were in operation for a minimum of 56% of the month. The April 2026 report shows that Holyrood TGS Unit 1 was in operation for the entire month, and Holyrood TGS Unit 2 was in operation for the first 9 days of the month.

a) Why were none of the Holyrood TGS units on standby in March 2026, and only one of the Holyrood TGS units on standby in April?
b) Why were two of the Holyrood TGS units in operation in April 2026, a non-winter month? Is Hydro considering a change in its definition of "winter months"?
c) Was the cost of keeping two Holyrood units in operation in April 2026 (Unit 1 for 30 days and Unit 2 for 9 days) approximately $11.8 million (39 days * 24 hours/day * 70,000 kW * $0.18/kWh)?

<u>Planning Criteria and Need for Capacity Additions</u>

CA-NLH-007 (Reference 2025 Build Application-Revision 1 and Evidentiary Update) In the April 16, 2026 cover letter, Hydro reiterated that the Avalon CT and BDE Unit 8 "*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*."

a) Is the retirement of Holyrood TGS in 2031 driving the need for additional capacity in 2031? If Holyrood TGS were to remain in service indefinitely, when would there be a need for new capacity and energy additions on the IIS?
b) Is the need for additional capacity by 2031 being driven by Hydro's probabilistic LOLH criterion or the LIL shortfall event criterion, or both?Pease provide a comparison the criteria both with and without the proposed capacity additions from 2030 through 2035.
c) It is understood that Hydro is proposing the second capacity addition be moved forward from 2034 to 2031 on the basis of the LIL shortfall event

criterion. i) Is the LIL shortfall event criterion "hypothetical", or a legitimate criterion that Hydro uses to justify the need for capacity additions? ii) What is the cost of moving the second capacity addition forward from 2034 to 2031?

CA-NLH-008 Regarding the chances of LIL shortfalls:

a) Does a LIL Shortfall Event assume an outage of both poles of the LIL simultaneously (an n-2 event) with the outage located on the most remote section of the LIL requiring 6 weeks to repair, and occurring at the most critical time of the year, the winter period, and a loss of additional generation determined by Hydro's probabilistic loss of load simulations during the 6 week outage period?
b) Is the LIL Shortfall Event equivalent to operating the IIS with an effective load meeting capacity of the Muskrat Falls assets of 0 MW during a six-week winter period?
c) Please provide an assessment of the probability of a six-week LIL shortfall event in winter. Please include a quantitative assessment, e.g., the probability over the next five years or next 10 years, or in terms of whether such a shortfall is a once in so-many-years event.
d) Is it common practice in North America to commit large expenditures for new resources to satisfy deterministic criterion such as a LIL Shortfall Event? Please provide examples.
e) Are there any other deterministic criterion that Hydro considers such as the loss of the transmission corridor over the Isthmus of the Avalon?

CA-NLH-009 Regarding the consequences of LIL shortfalls:

a) Please provide a list of the ten most serious LIL shortfall-type events (i.e., bipole failures of material durations) including dates and duration of the events, and describe mitigation measures that were put in place, as well as any adverse effects on IIS customers.
b) If a six-week LIL shortfall in winter were to occur between now and 2030, (i) what plans do Hydro and Newfoundland Power have in place to minimize the impact on consumers, (ii) what would that impact be, and (iii) what, if any, lessons were learned from dealing with significant generation and transmission outage events in recent years that could be applied?
c) Is the number of IIS residential and general service utility customers with oil furnaces, propane heaters and fireplaces, and wood stoves and fireplaces considered a resource that could help manage a six-week LIL shortfall?

CA-NLH-010 (Reference Evidentiary Update, Page 7) It is stated that "*The amount of shortfall is defined as the amount of load shedding required to restore a minimum regulating reserve of 70MW*."

a) What is the relationship between that statement and the 100 MW threshold used in Tables 3 to 7?
b) What would be the implications of changing that minimum regulating reserve (e.g., using 35 MW instead of 70 MW)?

CA-NLH-011 (Reference 2024 Resource Adequacy Plan, Appendix B, Page 40 of 57) It is stated "*Given the continued uncertainty pertaining to LIL reliability, Hydro believes it to be prudent to maintain a minimum regulating reserve of 70 MW within the Island Interconnected System, whether or not the LIL is in service. This is subject to further review once operational experience is gained with the LIL*." In the time that has passed since that statement was made, has Hydro undertaken further review of that minimum regulating reserve and, if so, what are its conclusions?

CA-NLH-012 Regarding reserve margins:

a) What capacity reserve margin does Hydro need to meet its LOLH reliability criterion through 2035?
b) What capacity reserve margin does Hydro need to meet its LIL shortfall event criterion through 2035?
c) What was Hydro's capacity reserve margin used for planning purposes before the commercial in-service date of the Muskrat Falls project?

CA-NLH-013 (Reference 2025 Build Application) Based on the assumptions used to develop the Minimum Investment Plan (i.e., relating to LIL forced outage rate, load forecast, etc.) please complete the following table. The last two rows correspond to the LIL shortfall event criterion. In this case, the IIS-LIS transmission capacity would be zero and the generation shortfalls would reflect the need to maintain a 70 MW regulating reserve for a 50th percentile scenario. Please complete the table for the following scenarios: 1) No retirements and no new facilities, 2) Holyrood Unit 1 retired in 2026, no other retirements and no new facilities, 3) Holyrood Units 1 and 2 retired in 2026, no other retirements and no new facilities, 4) Holyrood Units 1 and 2 retired in 2026, no other retirements and Avalon CT in-service in 2031, 5) all three Holyrood units retired in 2031, the Avalon CT in-service in 2031, the Newfoundland Power gas turbines in service in 2031 (48 MW) and Bay d'Espoir Unit 8 in-service in 2034, 6) all three Holyrood units retired in 2031, the Avalon CT, Newfoundland Power gas turbines and Bay d'Espoir Unit 8 in-service in 2031.

	2027	*2028*	*2029*	*2030*	*2031*	*2032*	*2033*	*2034*	*2035*
IIS Firm Capacity									
IIS-LIS Transmission Capacity									
Total Island Capacity									
Total Peak Load (including losses)									
Reserve Margin (%)									
Target Reserve Margin (%)									
LOLH									
Target LOLH									
Percent of Hours that generation shortfalls exceed 100 MW									

Target Percent of Hours that Generation Shortfalls exceed 100 MW									

CA-NLH-014 (Reference CA-NLH-001, Attachment 1 pertaining to the Bay d'Espoir Penstock 3 Weld Refurbishment and Section Replacement Application) Hydro provides a table showing capacity resources, peak load and resulting capacity reserve margins for the winter peak periods from 2026 through 2032. The table shows that the LIL can deliver 484.2 MW to the Island System at time of system peak. Further, the table shows that system losses at peak are 47 MW throughout the period.

a) Is the LIL delivery figure net of losses on the LIL (delivery measured at Soldier's Pond) and commitments relating to the Nova Scotia block?
b) Is the LIL delivery figure based on a 900 MW transfer capacity of the LIL?
c) Please reconcile the LIL delivery figure with the 785 MW (measured at Muskrat Falls) transferred during the frazil ice event (Hydro April 30, 2026 report entitled Frazil Ice at Bay d'Espoir Hydroelectric Generating Station, page 20).
d) Why do losses remain constant at 47 MW throughout the period even though the system peak demand is increasing?
e) Is Hydro planning to submit a 2026 and/or a 2027 Build Application?

CA-NLH-015 (Reference Evidentiary Update, Table 2, Pages 5 and 6) In the expansion plan analysis, the LIL EqFOR is 1% in the scenarios where the 2025 Slow Electrification Load Forecast is assumed, but 5% in the scenarios based on the 2025 Reference Load Forecast.

a) What was the reason for using different EqFORs in the two sets of scenarios?
b) According to Hydro's 2026 General Rate Application, Volume I, Company Evidence (pages 2.9 and 2.10), the LIL has recently been released to operate at its full capacity of 900MW and its performance has steadily improved since commissioning, and from Chart 2-6 its 2025 EqFOR appears only slightly more than 1% at 900MW and about 1% at 700 MW. (i) What are the reasons for the improvement? (ii) Is Hydro now confident that it can achieve an EqFOR at or close to 1% over the planning horizon?

CA-NLH-016 (Reference Schedule 3, Expansion Plan Update, Page 50) Regarding the recommended $150 million transmission upgrade option, it is stated "*This option is the least-cost option to reliably meet Island demand in combination with the Expansion Plans applied during a LIL bipole outage to keep Avalon load shed requirements below 100 MW*."

a) Does Hydro consider the loss of a LIL bipole to be an n-2 criterion?
b) Is Hydro planning its transmission system to meet an n-3 criterion; e.g., in addition to a LIL bipole loss (n-2), the loss of a transmission line between Bay d'Espoir and Soldiers Pond during a LIL bipole outage?
c) Why is Hydro considering the loss of only one of the transmission lines between Bay d'Espoir and Soldiers Pond during a LIL bipole outage?

Avalon CT

CA-NLH-017 (Reference Evidentiary Update, Page 4) Hydro's revised authorized cost estimate of the Avalon CT is $995.9 million.

a) If there has been a further revision of the estimate, please provide it along with an explanation.
b) What are the required transmission and distribution costs associated with the Avalon CT and are they included in the estimate?

CA-NLH-018 Assuming completion in 2031, please provide the following information on the Avalon CT.

a) A tabular breakdown of expected total annual costs (annualized capital costs, fixed and variable O&M costs, fuel costs etc.) over its depreciable life.
b) The calculation of the NPV of its lifetime costs.
c) The fuel cost per MWh for the Avalon CT compared to the fuel cost per MWh at the Holyrood CT based on current fuel prices.

CA-NLH-019 (Reference Evidentiary Update, Table 2, Pages 5 and 6) Under the 2025 Slow Electrification Load Forecast, in all cases where the expansion plan analysis selects the Avalon CT as the first capacity addition there is no fuel burn-off requirement.

a) What is Hydro's assessment of the feasibility and cost-effectiveness of being able to avoid fuel burn-off in the case of the Avalon CT?
b) What has been Hydro's experience with its existing Holyrood CT regarding fuel storage and the need for burn-off?
c) Have utilities elsewhere in North America avoided fuel burn-off in a cost-effective manner?
d) If the Avalon CT is approved, is Hydro confident that it can avoid the need for fuel burn-off and is now planning accordingly?

CA-NLH-020 (Reference Newfoundland and Labrador Hydro's Response to Identified Issues for Avalon Combustion Turbine) In its March 12, 2026 response to the Bates White Phase 2 Expert Report, Hydro indicated (Page 2) that the Avalon CT would operate for 400 hours annually under normal operations and that in the event of a six-week LIL shortfall Hydro expects the Avalon CT to operate for 400 hours. For the 400 hours of usage during a six-week LIL shortfall,

a) At what capacity would the Avalon CT operate?
b) Would there be sufficient fuel in inventory or readily available?

CA-NLH-021 (Reference Schedule 1, page 53) It is stated "*Table 4 outlines the estimated incremental revenue requirement in the first full year in service associated with the Avalon CT and BDE Unit 8*" and the table indicates that incremental revenue requirement is $180 million.

a) Please provide an update of Table 4 to reflect the Revised Application's cost estimate of the Avalon CT and also include the figures for the second full year of service.

b) Please clarify whether the figures in the update of Table 4 are pre-rate mitigation. If not, please provide the total incremental revenue requirement.
c) Please identify the calendar year corresponding to the "first full year" in service.
d) For the first and second full years of service, what is the anticipated energy production (in MWh) by the Avalon CT each year and what is the forecast total energy supplied to the IIS by Hydro in each of those years?

CA-NLH-022 (Reference Bates White Phase 2 Expert Report dated February 3, 2026 by Vincent Musco and Collin Cain) This report claims that the management reserve for Bay d'Espoir Unit 8 fails to incorporate certain strategic risks. It is stated (page 5) "*The cumulative impact of these three risks is estimated to be as high as $562.4 million, which would represent an overall project cost increase of 52%.*" The three risks are identified as competition for equipment, tariffs and the Bay d'Espoir Unit 7 life extension.
a) Do two of the three identified risks, namely, competition for equipment and tariffs, also apply to the Avalon CT?
b) How much do these risks increase the management reserve for the Avalon CT?

CA-NLH-023 (Reference Evidentiary Update, Table 1, Page 3) The Bates White Phase 2 Expert Report observes that the CAMS Review of the Avalon CT, which is included as Appendix A in that report, indicated that management reserves are not typically seen for projects of this type. Hydro's March 12, 2026 response (Page 12) to Bates White states "*For large capital projects such as the Avalon CT, establishing a Management Reserve supports overall project risk tolerance by providing a mechanism to respond when unforeseen issues arise, and timely action is required to avoid additional cost or schedule impacts. The inclusion of Management Reserve to address strategic risks at a confidence level of P85 is also consistent with the findings and recommendations of the Muskrat Falls Inquiry.*"
a) Please reconcile CAMS's position that management reserves are not typical for projects of this type with Hydro's position that one is needed.
b) Did Hydro request a management reserve for its existing Holyrood CT and how did that project's risk and complexity differ from that of the Avalon CT?
c) Other than for the citation of the Muskrat Falls Inquiry to use a P85 estimate what other reasons are there for such a large management reserve?

<u>Scenario Analysis</u>

CA-NLH-024 (Reference Evidentiary Update, Table 2, Pages 5 and 6)
a) Please list the categories of costs included in the calculation of NPVs for the various expansion plans.
b) What is the time period over which the NPVs are calculated for the expansion paths and what is the rationale for that choice of time period?
c) Please provide a table showing cumulative nominal undiscounted cost for each of the scenarios.

d) Do NPVs include the cost of transmission and distribution upgrades associated with each expansion plan? If not, how much are those transmission and distribution upgrades for each plan?

CA-NLH-025 (Reference Evidentiary Update, Table 2, Pages 5 and 6) For the scenario 4AEC, please provide a table that gives the annual costs associated with the expansion plan and the calculation of its NPV of $3.2 billion.

CA-NLH-026 (Reference Evidentiary Update, Table 2, Pages 5 and 6) In the expansion plan analysis, the LIL EqFOR is 1% in the scenarios where the 2025 Slow Electrification Load Forecast is assumed, but 5% in the scenarios based on the 2025 Reference Load Forecast. Please provide the expansion plan analysis for scenarios similar to 1AE, 1AEC, 1AEK and 1AEKC with the only difference being a LIL EqFOR of 1% rather than 5%. Please present the results in the same format as Table 2.

CA-NLH-027 (Reference Evidentiary Update, Table 2, Pages 5 and 6) So that the impact of load can be better ascertained, please provide expansion plan analysis for scenarios similar to 4AE, 4AEC, 4AEDC, 4AEHC, 4AEDHC and 4AEKC with the only difference being the assumption that IIS load remains constant at the 2025 load. Please present the results in the same format as Table 2.

CA-NLH-028 (Reference Evidentiary Update, Appendix B) Regarding the LIL shortfall analysis, please provide new versions of Table B-2, and Figures B-4, B-5 and B-6 based on the assumption of a load in 2032 that is the same as the load in 2025.

CA-NLH-029 (Reference Bates White Expert Addendum Report of Vincent Musco and Collin Cain, June 5, 2026) It is stated (page 41) with respect to the Newfoundland Power gas turbine refurbishments "*capacity expansion modeling has shown that just 48 MW of firm capacity can materially impact the constitution of the selected portfolio*."

a) Have Newfoundland Power and Hydro been in discussion regarding the fate of the two gas turbines in question? What is the current status of this matter?
b) Does Newfoundland Power need to either retire or replace these CTs before 2031, i.e., is continued operation not an option?
c) If the Avalon CT and refurbishment of Newfoundland Power's gas turbines can provide adequate reliability to the IIS if Holyrood TGS is retired, does this suggest that part of Holyrood TGS is no longer used and useful and should be retired before 2031?

CA-NLH-030 (Reference Bates White Expert Addendum Report of Vincent Musco and Collin Cain, June 5, 2026) It is observed (page 40) that Newfoundland Power plans to file a supplemental capital budget application later this year to refurbish its Greenhill and Wesleyville GTs and *"The refurbishment project is estimated to account for a total of approximately $231 million, though NP notes this estimate is subject to change in the forthcoming application*."

a) Does the $231 million cost estimate equate to $4812/kW, and compare to $6667/kW for Hydro's Avalon CT?

b) Hydro has suggested that CT prices could increase by almost 200% by 2027 (2025 Build Application - Avalon Combustion Turbine Evidentiary Update, page 13). Does Hydro have an opinion on the reasonableness of this estimate, and if refurbishment of the gas turbines is favourable compared to other alternatives such as Bay d'Espoir Unit 8 and battery storage?

CA-NLH-031 What is the Hydro and Newfoundland Power "integrated vision of the power system" and what behind-the-meter alternatives including rate design, and in what amounts, are included in the Reference Case?

CA-NLH-032 (Reference Electrification, Conservation and Demand Management Report for the Year Ended December 31, 2024)

a) Please confirm that the CDM program achieved savings of 1019 MWh and 161 kW (non-coincident) in 2024. Does this equate to less than 7 hours of energy production and about 0.1% of the capacity from the proposed Avalon CT?
b) How have these results affected Hydro's IIS costs?
c) In light of the more than $2 billion NPV in additional cost between the expansion paths based on the 2025 Slow Electrification Load Forecast and the 2025 Reference Load Forecast (Table 2 of Evidentiary Update), should not substantially better results be targeted?

CA-NLH-033 (Reference Bates White Phase 2 Expert Report, Page 4) It is stated that "*Hydro's most recent load forecast (2025) indicates a reduction in peak demand of 14 MW and total energy of 289 GWh in 2035 compared to the load forecast used in the Build Application*."

a) Newfoundland Power has embarked on a Rate Design Study. To the extent that the study leads to rates that better reflect marginal cost and the substantial difference in marginal cost between winter and non-winter months, (i) has Hydro studied the implications for future loads? and (ii) does Hydro accept the Christensen Associates' (September 3, 2024 Report for Newfoundland and Labrador Hydro –Application for Adjustment to Wholesale Utility Rate, Schedule 1, Attachment 1)) estimate of all-in marginal cost (2023) of $211.09 per MWh for the winter months (Dec-Mar) and $37.75 per MWh for the other months as accurate?
b) In the November 15, 2018 Marginal Cost Study Update prepared by Christensen Associates Energy Consulting encourages (page ES-4) time-of-use (TOU) pricing.
    a. Does Hydro agree that TOU rates reflecting all-in marginal-cost would improve consumption efficiency and provide substantial opportunities for reducing peak demand and the cost of supply? (ii) Could effective use of seasonal and/or TOU retail rates on the IIS, if implemented, reduce load enough to defer, or avoid the need for both, or one of, the Avalon CT and Bay d'Espoir Unit 8?

General

CA-NLH-034 (Reference Schedule 1) It is stated (Page 26) "*In line with customer expectations, Hydro's proposed projects, BDE Unit 8 and the Avalon CT continue to be the least-cost projects to provide reliable, electricity in an environmentally responsible manner.*"

a) Does that quote mean that customers are agreeable to the least-cost projects that increase reliability no matter how high "least-cost" is?
b) In its surveys of customers, has Hydro ever asked customers if they would be willing to change their consumption levels or patterns of consumption rather than support additions to capacity? If not, does Hydro have sufficient information to assess how customers would answer that question?

CA-NLH-035 (Reference Schedule 1, Appendix C, Page C-1)

a) Are all members of the Major Projects Organization shown in Figure B-1 full-time employees of Hydro?
b) Will this Organization do any work other than managing the Bay d'Espoir Unit 8 and Avalon CT projects?
c) What is the total estimated cost of project management and oversight included in the cost estimate for the Avalon CT?

CA-NLH-036 (Reference Schedule 3, Expansion Plan Update, Appendix A) It is stated (Page 16) "*In recent years, Newfoundland and Labrador has seen record-setting exploration expenditures in the mining sector and there has been activity in wind hydrogen development projects. A renewable fuels refinery also commenced commercial operations in 2024.*"

a) Please describe the "activity in wind hydrogen development" and how this might impact the proposed minimum investment plan.
b) Please describe what a renewable fuels refinery would refine. Might the renewable fuel produced by this facility be used in the Avalon CT, and for that matter, the Holyrood gas turbine or a re-purposed Holyrood TGS?

CA-NLH-037 (Reference Application) According to a recent news report, Kruger Inc., the owner of Deer Lake Power, is in talks with Hydro and the provincial government "*for a long-term power purchase agreement that would allow the construction of a wind energy farm and upgrades to its existing hydro electric assets.*" (https://www.cbc.ca/news/canada/newfoundland-labrador/kruger-newsprint-future-9.7098874).

a) What is the anticipated size of this wind farm and the associated firm energy?
b) Would the potential upgrade to Kruger's existing hydroelectric assets entail more capacity? If so, how much?
c) How would such an arrangement affect the need for Hydro to complete the two projects in its Build Application?
d) When does Hydro anticipate a conclusion to these talks?

DATED at St. John's, Newfoundland and Labrador, this 19th day of June, 2026.

Per: ______________________________________

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