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November 13, 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
Senior Regulatory Advisor & Board Secretary

**Re: 2026 General Rate Application – Requests for Information on Expert Reports**

Please find enclosed Newfoundland and Labrador Hydro's ("Hydro") requests for information NLH-PUB-001 to NLH-PUB-029 in relation to Hydro's 2026 General Rate Application.

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**
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**Iron Ore Company of Canada**
Gregory A.C. Moores, KC, Stewart McKelvey

**Newfoundland and Labrador Hydro External Counsel**
Daniel W. Simmons, KC, McInnes Cooper

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

**IN THE MATTER OF** a general rate application by Newfoundland and Labrador Hydro to establish customer electricity rates for 2027.

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**Newfoundland and Labrador Hydro**

**Requests for Information**

**NLH-PUB-001 to NLH-PUB-029**

**November 13, 2026**

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***Island Industrial Customer Rate Design***

**NLH-PUB-001** **Reference: The Brattle Group Inc. Report, Section III: Assessment of Proposed Island Industrial Rates, Finding 2, p. 35.**

Can costs classified as demand-related be reasonably recovered through a first-block energy charge where the structure remains revenue sufficient and improves marginal energy signals?

**NLH-PUB-002** **Reference: The Brattle Group Inc. Report, Section III: Assessment of Proposed Island Industrial Rates, Finding 2, p. 35.**

Provide further explanation as to how the level of demand price "*weakens the direct relationship between cost causation and the billing determinant used for recovery*."

**NLH-PUB-003** **Reference: The Brattle Group Inc. Report, Section III: Assessment of Proposed Island Industrial Rates, Subsection B. Hydro's Proposed Rate Design for Industrial Customers, p. 38.**

Please explain the position that demand being based on Power on Order "*implies that the incentives for customers to reduce their demand, and benefit from the Hours of Use rate by quickly accessing the Block 2 price is also limited."*? Does the current Industrial rate design contain a similar constraint arising from the use of Power on Order? If not, please explain why. Further, how does the proposed Hours of Use rate reduce customers' ability to benefit from lower demand relative to the current rate design?

**NLH-PUB-004** **Reference: The Brattle Group Inc. Report, Section III: Assessment of Proposed Island Industrial Rates, Subsection B. Hydro's Proposed Rate Design for Industrial Customers, pp. 38–40.**

The report says the $5.50/kW-month charge recovers about 31% of demand-related costs. Is there a generally accepted requirement that rate-design demand charges recover the same share of costs classified as demand in a Cost of Service Study?

**NLH-PUB-005** **Reference: The Brattle Group Inc. Report, Section III: Assessment of Proposed Island Industrial Rates, Subsection B. Hydro's Proposed Rate Design for Industrial Customers, p. 40.**

The report criticizes the 300-Hours of Use threshold because it is not directly linked to an underlying supply-cost boundary. What physical or economic threshold would you use instead, and how would it be calculated?

**NLH-PUB-006** **Reference: The Brattle Group Inc. Report, Section III: Assessment of Proposed Island Industrial Rates, Subsection B. Hydro's Proposed Rate Design for Industrial Customers, p. 40.**

Please explain why the Hours of Use design's recovery of demand-based cost through the Block 1 energy charge, relative to the current design's demand recovery, "*makes it harder to target volumetric reductions or peak reductions individually as needed by the system*"?

**NLH-PUB-007** **Reference: The Brattle Group Inc. Report, Section III: Assessment of Proposed Island Industrial Rates, Subsection B. Hydro's Proposed Rate Design for Industrial Customers, p. 40.**

The report states that Power on Order under the proposed Hours of Use rate design "*undermines the incentives to improve load factors and active management of peak demand.*" Please explain the basis for this conclusion. Does The Brattle Group Inc. consider Power on Order to provide customers with an incentive to manage peak demand on an all-hours basis? If not, please explain why.

**NLH-PUB-008** **Reference: The Brattle Group Inc. Report, Section III: Assessment of Proposed Island Industrial Rates, Subsection B. Hydro's Proposed Rate Design for Industrial Customers, p. 40.**

Please clarify the basis for the view that the absence of an "*intra-day temporal rate component*" does not align with cost causation principles?

**NLH-PUB-009** **Reference: The Brattle Group Inc. Report, Section III: Assessment of Proposed Island Industrial Rates, Subsection B. Hydro's Proposed Rate Design for Industrial Customers, p. 40.**

Do you agree that, as long as the utility includes in the rate's revenue requirement the cost to serve customers of the class, the absence of a time-of-use price signal does not prevent the rate from satisfying Bonbright's cost reflectivity principle?

**NLH-PUB-010** **Reference: The Brattle Group Inc. Report, Section III: Assessment of Proposed Island Industrial Rates, Subsection B. Hydro's Proposed Rate Design for Industrial Customers, p. 40.**

Please clarify the meaning of the last paragraph on page 40:

"*Additionally, the threshold at which customers move from embedded system costs to marginal energy costs has no relationship with the underlying energy supply and may not align with the energy costs Hydro pays to serve that energy. If low-cost hydro energy is plentiful and customers are moved onto a rate that reflects an export opportunity cost to quickly, this will not result in an economically efficient level of energy consumption.*"

**NLH-PUB-011** **Reference: The Brattle Group Inc. Report, Section III: Assessment of Proposed Island Industrial Rates, Subsection B. Hydro's Proposed Rate Design for Industrial Customers, p. 41.**

Please explain the benefit of making Newfoundland and Labrador Hydro's revenue recovery of embedded costs more seasonal in pattern. Given that Newfoundland and Labrador Hydro's fixed costs, including payments for Muskrat Falls Supply Costs, do not vary significantly by season, please explain why a more seasonal pattern of cost recovery is appropriate

**NLH-PUB-012** **Reference: The Brattle Group Inc. Report, Section III: Assessment of Proposed Island Industrial Rates, Subsection B. Hydro's Proposed Rate Design for Industrial Customers, p. 41.**

Please explain why the incentive to control load factor would not apply in winter months?

**NLH-PUB-013** **Reference: The Brattle Group Inc. Report, Section III: Assessment of Proposed Island Industrial Rates, Subsection B. Hydro's Proposed Rate Design for Industrial Customers, pp. 41–42.**

Please explain why the choice of demand price dilutes the price signal to limit peak demand?

**NLH-PUB-014** **Reference: The Brattle Group Inc. Report, Section III: Assessment of Proposed Island Industrial Rates, Subsection B. Hydro's Proposed Rate Design for Industrial Customers, p. 42.**

The report states that the "*stickiness*" of billing demand would "*mute incentives to improve load factor*" and "*make it harder to take advantage of Block 2 prices.*" Please explain the basis for this conclusion. In the response, please explain how the billing-demand formulation under the proposed Hours of Use rate design reduces these incentives relative to the current rate structure.

**NLH-PUB-015** **Reference: The Brattle Group Inc. Report, Section III: Assessment of Proposed Island Industrial Rates, Subsection B. Hydro's Proposed Rate Design for Industrial Customers, p. 43.**

The report characterizes the proposed Hours of Use rate design as "*complex.*" Please explain the basis for this characterization. Given that the proposed Hours of Use rate includes defined billing-demand determinants, block boundaries, and seasonal price signals, which aspects of the design does The Brattle Group Inc. believe create complexity for customers?

**NLH-PUB-016** **Reference: The Brattle Group Inc. Report, Section III: Assessment of Proposed Island Industrial Rates, Subsection C. Recommendations, p. 43.**

Please quantify the recommended demand charge. Is it $17.54/kW-month, another embedded-cost value, a marginal-capacity value, or a hybrid?

**NLH-PUB-017** **Reference: The Brattle Group Inc. Report, Section III: Assessment of Proposed Island Industrial Rates, Subsection C. Recommendations, p. 43.**

How would a materially higher demand charge affect the behavior of customers whose billing demand is based largely on contracted PO and therefore cannot be changed quickly?

**NLH-PUB-018** **Reference: The Brattle Group Inc. Report, Section III: Assessment of Proposed Island Industrial Rates, Subsection C. Recommendations, p. 44.**

Has The Brattle Group Inc. calculated how much greater seasonal bill volatility there would be under its proposed seasonal Block 1 pricing? If so, please provide the analysis, assumptions, and results. If not, please explain the basis for recommending a more seasonal pricing structure.

**NLH-PUB-019** **Reference: The Brattle Group Inc. Report, Section III: Assessment of Proposed Island Industrial Rates, Subsection C. Recommendations, p. 44.**

Regarding creating a seasonal Block 1 price, the non-seasonal proposed design already increases bills in the winter period substantially. Is there a cost justification for such a pattern?

**NLH-PUB-020** **Reference: The Brattle Group Inc. Report, Section III: Assessment of Proposed Island Industrial Rates, Subsection C. Recommendations, p. 44-45.**

Does The Brattle Group Inc. have a preferred billing-demand definition as an alternative to Hydro's existing definition? If so, please describe the alternative definition and explain how it would better achieve the objectives identified in the report.

***Long-Term Supply Cost Variance Deferral Account***

**NLH-PUB-021** **Reference: The Brattle Group Inc. Report, Section II: Assessment of Long-Term Supply Cost Variance Deferral Account, Finding 3, p. 29.**

The Brattle Group Inc. states: "*Hydro's illustration of a 10 percent reduction in Island Industrial load records a load variation of $3,135,690 but an export revenue gain of only $1,144,599, because it values the gain at $39.88/MWh and counts as exported only the reduction in second-block sales. Hydro's forecast monthly export prices span a much wider*

*range. These are not interchangeable measures, particularly in winter, when the second-block price is 8.889 cents/kWh.*"

In response to CA-NLH-290, Hydro valued the revenue gain associated with reduced Island Industrial sales using an export value of $39.88/MWh. If, instead, the revenue gain is valued using the applicable seasonal second-block energy rate, the value of the export opportunity would be equal to the $3,135,690 recorded in the load variation, representing the incremental value that would be achieved if the energy were exported rather than sold to Island Industrial customers at that time. Does this address the concern expressed in the recommendation?

**NLH-PUB-022** **Reference: The Brattle Group Inc. Report, Section II: Assessment of Long-Term Supply Cost Variance Deferral Account, Finding 4, p. 30-33.**

In recommending the use of Newfoundland and Labrador Hydro's short-term borrowing rate for the Long-Term Supply Cost Variance Deferral Account, please explain whether the principle of aligning the carrying-cost rate with the nature and duration of the financing requirement would also support the use of Weighted Average Cost of Capital, or another rate reflecting both debt and equity financing, for long-duration financing requirements associated with capital assets under construction. Please explain the basis for your response.

**NLH-PUB-023** **Reference: The Brattle Group Inc. Report, Section II: Assessment of Long-Term Supply Cost Variance Deferral Account, Finding 4, pp. 30–33.**

Please explain how Government's rate mitigation plan is relevant to determining the appropriate carrying-cost rate applicable to the Long-Term Supply Cost Variance Deferral Account. In your response, please explain whether the rate mitigation plan affects Newfoundland and Labrador Hydro's cost of financing amounts recorded in the Long-Term Supply Cost Variance Deferral Account or, alternatively, relates to the manner in which the resulting costs are ultimately recovered from customers.

**NLH-PUB-024** **Reference: The Brattle Group Inc. Report, Finding 4, Section II: Assessment of Long-Term Supply Cost Variance Deferral Account, pp. 30–33.**

If the Long-Term Supply Cost Variance Deferral Account carrying-cost rate is determined using Newfoundland and Labrador Hydro's short-term borrowing cost rather than Newfoundland and Labrador Hydro's Weighted Average Cost of Capital, please explain whether the short-term debt assumed to finance the Long-Term Supply Cost Variance Deferral Account balances should be excluded from the debt balances and financing costs used in the calculation of Hydro's Weighted Average Cost of Capital. Please explain how the proposed treatment avoids attributing the same short-term financing both specifically to the Long-Term Supply Cost Variance Deferral Account and more generally to Newfoundland and Labrador Hydro's overall capital financing.

**NLH-PUB-025** **Reference: The Brattle Group Inc. Report, Finding 4, Section II: Assessment of Long-Term Supply Cost Variance Deferral Account, pp. 30–33.**

The Long-Term Supply Cost Variance Deferral Account could take 15 months to recover the outstanding balances in a period of rate mitigation. In the absence of rate mitigation, this recovery period could be 30 months. Please explain how the assessment of risk and the duration of the outstanding balance were considered in the recommendation to retain short-term borrowing costs for the Long-Term Supply Cost Variance Deferral Account. If the recovery period is a deciding factor, is there an accepted guideline for outstanding balances to attract different financing rates? In your response, please address whether recurring amounts recorded in the Long-Term Supply Cost Variance Deferral Account could result in an ongoing financing requirement notwithstanding the shorter duration of individual amounts recorded in the account.

***Cost of Service Methodology***

**NLH-PUB-026** **Reference: The Brattle Group Inc. Report, Executive Summary, Table ES-1: Recommendations, p. 7.**

The Brattle Group Inc. recommends that Holyrood fuel classification be approved with the following modification: "*classify the minimum output portion as demand-related for the Bridging Period.*"

Given that Holyrood's minimum-output generation also produces energy that serves customer load, please explain how The Brattle Group Inc. accounts for the associated energy benefit was considered in formulating the recommendation. Specifically, please explain why the fuel costs associated with minimum-output generation should be classified entirely as demand-related rather than, in whole or in part, as energy-related.

**NLH-PUB-027** **Reference: The Brattle Group Inc. Report, Executive Summary, Table ES-1: Recommendations, p. 7.**

The Brattle Group Inc. recommends classifying 93.06% of forecast Holyrood No. 6 fuel costs as demand-related because 423.6 GWh of the 455.2 GWh forecast generation represents minimum stable output associated with unit commitment for reliability.

Identify any Canadian or United States cost-of-service decisions in which minimum-generation fuel was classified as demand-related because a generating unit was committed for reliability.

**NLH-PUB-028** **Reference: The Brattle Group Inc. Report, Section I: Assessment of Cost of Service Matters, Subsection B: Classification and Allocation of the Remaining Holyrood Costs, p. 18.**

The report states "*Unit 3's operating costs in the months it operates as a synchronous condenser should be functionalized as transmission, and its remaining costs should be classified as demand-related*."

The Brattle Group Inc. recommends treating Holyrood Thermal Generating Station Unit 3's operating costs during synchronous-condenser service as transmission costs and its remaining costs as demand-related. How should shared annual fixed costs, such as depreciation and maintenance, be treated? Should any portion be allocated to transmission and, if so, using what method? Please provide a worked example.

**NLH-PUB-029** **Reference: The Brattle Group Inc. Report, Section I: Assessment of Cost of Service Matters, Subsection B: Classification and Allocation of the Remaining Holyrood Costs, p. 14, Table 1.**

Please provide the supporting calculations for the Capacity Factors presented in Table 1, excluding the 11.16% Capacity Factor previously filed in Newfoundland and Labrador Hydro's 2026 General Rate Application.

**DATED** at St. John's, in the province of Newfoundland and Labrador, this 13th day of November 2026.



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