Public Utilities Board
NEWFOUNDLAND & LABRADOR
120 Torbay Road • Prince Charles Building, Suite E210 • St. John's, Newfoundland and Labrador • A1A 2G8

2026-11-13

Industrial Customer Group
Dana Constantine
Email: drconstantine@stewartmckelvey.com

Dear Ms. Constantine:

Re: Newfoundland and Labrador Hydro - 2026 General Rate Application - To IIC - Requests for Information

Enclosed are Requests for Information PUB-IIC-001 to PUB-IIC-009 regarding the above-noted application.

If you have any questions, please do not hesitate to contact the Board's Legal Counsel, Ms. Jacqui Glynn, by email, jglynn@pub.nl.ca or by telephone 709-726-6781.

Sincerely,

Mike McNiven
Board Secretary

MM/cj

ecc **Newfoundland and Labrador Hydro**
Shirley Walsh, Email: shirleywalsh@nlh.nl.ca
Dan Simmons, Email: dan.simmons@mcinnescooper.com
NLH Regulatory, Email: nlhregulatory@nlh.nl.ca

Newfoundland Power Inc.
Dominic Foley, Email: dfoley@newfoundlandpower.com
Liam O'Brien, Email: lobrien@curtisdawe.com
Douglas Wright, Email: dwright@newfoundlandpower.com
NP Regulatory, Email: regulatory@newfoundlandpower.com

Consumer Advocate
Adrienne Ding, Email: ading@odeaearle.ca
Justin King, Email: jking@odeaearle.ca
General Email: consumeradvocate@odeaearle.ca

Industrial Customer Group
Denis Fleming, Email: dfleming@coxandpalmer.com
Glen G. Seaborn, Email: gseaborn@poolealthouse.ca

Labrador Interconnected Group
Nick Kennedy, Email: nkennedy@oktlaw.com

Iron Ore Company of Canada
Greg Moores, Email: gmoores@stewartmckelvey.com

Public Utilities Board
Michael Collins, Email: mcollins@scllaw.ca

IN THE MATTER OF the **Public Utilities Act**, (the "**Act**"); and

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

PUBLIC UTILITIES BOARD
REQUESTS FOR INFORMATION

PUB-IIC-001 to PUB-IIC-009

Issued: November 13, 2026

PUB-IIC-001 **Bowman Evidence, page 20, lines 11-20; page 23, lines 8-15 and footnote 50; Recommendations 4 and 5; Brattle Report, page 10.**

Mr. Bowman states that, for the 2027 Test Year, "Holyrood is solely a capacity resource," and recommends that Holyrood fuel be classified consistent with Holyrood plant costs, which he would classify 100 percent to demand. Of the 455.2 gigawatt hours (GWh) of forecast 2027 Holyrood generation, 423.6 GWh is the minimum output required to keep committed units online, and 31.6 GWh is dispatched above that minimum. Footnote 50 refers to a scenario that classifies 6.94 percent of Holyrood fuel to energy.

a) state whether the fuel used to generate the 31.6 GWh dispatched above minimum stable output is, in Mr. Bowman's view, incurred to maintain unit availability or to supply energy, and state how that fuel should be classified;

b) state how fuel consumed at Holyrood to supply energy under low-inflow (drought) conditions should be classified, and whether that classification should differ from the classification of fuel consumed at minimum stable output; and

c) state whether Recommendation 5 is intended to apply only while Holyrood operates in its current reliability role, and state the classification he would recommend if Holyrood returned to regular energy production before its retirement.

PUB-IIC-002 **Bowman Evidence, page 21, lines 23–29; page 23, Table 4.2 and footnote 51; Response to CA-NLH-152, Attachment 1; Derksen Evidence, page 29; Brattle Report, page 7, Table ES-1.**

Mr. Bowman states that "[n]o COS scenario has been run" for a 100 percent demand classification of Holyrood plant costs and estimates its effect by scaling the results of response to CA-NLH-152, Attachment 1 linearly. His estimate and Table 4.2 use an energy classification of 11.19 percent. The Application, as reported by Ms. Derksen and in the Brattle report, uses 11.16 percent.

a) reconcile 11.19 percent with 11.16 percent and state which figure each of his estimates uses;

b) provide the calculation supporting the estimated $352,000 reduction for Island Industrial customers, and state whether the estimate is before or after rate mitigation; and

c) state whether the linear scaling holds over the full change from 11.19 percent energy to zero, and identify any step in the cost-of-service study at which it would not.

PUB-IIC-003 **Bowman Evidence, page 25, lines 15–21 and footnote 59; page 28, lines 11-21; page 29, lines 6-14; Recommendations 7, 9 and 10; Response to NP-NLH-104; Response to PUB-NLH-181, Table 1; Response to PUB-NLH-183; Response to PUB-NLH-188; Brattle Report, pages 21-22.**

Mr. Bowman states that Newfoundland Power thermal generation is dispatched for system purposes "only 4 times in the last 5 years," citing NP-NLH-104. He recommends replacing the 39.3 megawatt (MW) thermal credit and the 12 MW curtailable credit with payments of $3.921 million and no more than $336,000, respectively, classified 100 percent to demand. Response to PUB-NLH-183 records eight thermal requests from January 2020 through December 2025. Response to PUB-NLH-181, Table 1 reports thermal output less than 39.3 MW in six of the ten finalized generation tests since December 2015. Response to PUB-NLH-188 reports about 21.7 MW of curtailable capacity at the Memorial University of Newfoundland (MUN) electric boilers that the cost-of-service study does not credit.

a) identify the four dispatch events, the five-year period, and the definition of "dispatched for system purposes" on which the statement rests, and reconcile it with the eight requests recorded in response to PUB-NLH-183;
b) state whether the proposed $3.921 million payment would depend on output demonstrated in the annual generation test, and how a test result of less than 39.3 MW would affect the payment;
c) state whether the curtailable payment would rest on 12 MW or on the curtailable capacity available to Newfoundland Power in the Test Year, including the MUN boilers, and provide the payment on the latter basis; and
d) provide the effect of Recommendations 9 and 10 on class revenue requirements, before and after rate mitigation, or state that no such estimate has been prepared.

PUB-IIC-004 **Bowman Evidence, page 11, lines 21-27; page 12, lines 23-29; page 19, lines 6-11; Recommendations 1, 2 and 3; Response to IIC-NLH-036(a).**

Mr. Bowman states that "[h]aving the LTSCVDA and GRA COS methods match ensures such outcomes do not occur." He recommends that capacity-related LTSCVDA balances be allocated at year-end on the measured class share of the coincident peak for the year (Recommendation 2), and that demand-related costs in the cost-of-service study be allocated on class peaks at a P90 load condition, which reflects weather more severe than average (Recommendation 3).

a) reconcile Recommendations 2 and 3 with the statement that the two methods should match, and state which peak measure he recommends for the LTSCVDA if the Board adopts Recommendation 3;

b) provide the class demand allocation factors and class revenue requirements, before and after rate mitigation, under P90 class peaks, or identify the response in which Hydro has provided them; and

c) confirm that, under Recommendation 1, LTSCVDA components would follow whatever classification the Board approves in the cost-of-service study, including a wind classification other than 43 percent demand and a classification of off-island purchases other than the system load factor.

PUB-IIC-005 **Bowman Evidence, page 31, lines 15-19; Recommendation 11; Response to IIC-NLH-033, Attachment 1; Brattle Report, pages 22-24.**

Mr. Bowman states that the updated effective load-carrying capability (ELCC) approach "is also consistent with the methods adopted when the parties negotiated the 2019 negotiated settlement." The 43 percent figure is the marginal ELCC of the first 50 MW of wind on a 2032 system. Both existing wind purchase agreements expire in 2029. Hydro's 2018 study measured the existing 54 MW fleet at approximately 12 MW, or 22 percent.

a) explain how the 43 percent marginal ELCC is consistent with that method in the 2019 negotiated settlement;

b) state whether the marginal ELCC of a 50 MW increment on the 2032 system measures the capacity contribution of the existing 54 MW fleet on the 2027 Test Year system, and provide support.

PUB-IIC-006 **Bowman Evidence, Section 5.3.2, pages 39-41.**

Mr. Bowman states that Hydro's proposed rate is inconsistent with its stated objective of encouraging higher customer load factors because lower-load-factor customers tend to receive larger bill reductions while higher-load-factor customers experience larger increases, and because the winter Block 2 price can discourage incremental winter consumption. Has Mr. Bowman considered introducing seasonally varying Block 1 rate as a potential solution to this adverse incentive problem? Please discuss.

PUB-IIC-007 **Bowman Evidence, Sections 5.3.2 to 5.3.3, pages 40-45.**

Mr. Bowman recommends that a broader Industrial rate-design process consider electrification opportunities and states that access to lower-cost off-peak or non-firm energy may support economically beneficial incremental Industrial consumption.

a) identify the types of Industrial electrification loads contemplated in this recommendation;

b) explain the criteria that should be used to determine whether incremental Industrial load is beneficial to other customers;

c) explain whether such incremental loads should be required to demonstrate that they do not contribute materially to Hydro's winter capacity requirements;
d) identify the rate components Mr. Bowman would recommend for an electrification rate, including any demand, energy, minimum-bill, contract-term, or interruptible provisions;
e) explain how any such rate would ensure recovery of incremental costs caused by the participating customer; and
f) explain whether existing Industrial load shifted from firm service to an electrification or non-firm rate should be eligible for the same pricing as genuinely incremental load.

PUB-IIC-008 **Bowman Evidence, Section 5.3.3, pages 44-45.**

Mr. Bowman recommends that a future rate-design process consider self-generation as part of the broader Industrial rate offering. His recommendation does not specify the rate treatment that should apply to customers that reduce grid purchases through self-generation while continuing to rely on Hydro for firm backup service.

a) describe the rate structure Mr. Bowman recommends for Industrial customers with self-generation;
b) explain how such a structure should recover generation and transmission capacity costs associated with maintaining backup service;
c) state whether a standby demand charge, reservation charge, minimum bill, or another mechanism should apply;
d) explain how the rate should distinguish between customer generation that reduces coincident system peak demand and generation that reduces energy purchases without reducing peak capacity requirements; and
e) explain how the proposed treatment would avoid shifting embedded capacity costs from self-generating Industrial customers to other customer classes.

PUB-IIC-009 **Bowman Evidence, Section 5.3.2, pages 41-42.**

Mr. Bowman cites Industrial rate offerings in New Brunswick, Nova Scotia and British Columbia as examples of broader options involving surplus or interruptible energy, real-time pricing, electrification rates and critical-peak pricing, while acknowledging that those rate designs reflect different system circumstances.

a) identify the specific tariffs or rate schedules relied upon for each jurisdiction;

b) describe the principal system characteristics that make each example relevant to Hydro, including generation mix, marginal energy costs, capacity conditions and system peak characteristics;
c) identify any material differences between those systems and Hydro that limit the applicability of the cited examples; and
d) explain which specific design features Mr. Bowman believes are transferable to Hydro and which are not.

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

BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

Per _____
Mike McNiven
Board Secretary