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

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

Requests for Information

by the Labrador Interconnected Group

LAB-IIC-001 to LAB-IIC-002

November 13, 2026

Requests for Information Regarding the General Rate Application

LAB-IIC-001 Re: Cost classification of purchases of wind generation

Citations:

GRA Volume I 6.3.1

> The 2019 Settlement Agreement for Hydro's 2018 Cost of Service Methodology Review provided for the purchase cost of wind generation on the Island Interconnected System to be classified as 22% demand and 78% energy, based on Hydro's Effective Load Carrying Capability Study conducted by Hydro's resource planning group at the time.
>
> In 2025, as part of its continued analysis associated with the Reliability and Resource Adequacy Review proceeding, Hydro engaged an external consultant to study the Effective Load Carrying Capability values for wind, solar, and battery storage as it applies to the Island Interconnected System for the purpose of system planning. Hydro filed the study with the Board on December 9, 2025, and it is attached as Exhibit 16.
>
> The 2025 study found that the marginal Effective Load Carrying Capability for 50 MW of wind is 43% demand, an increase of approximately 20% from the previous 2018 study. Effective Load Carrying Capability values are dynamic and can change as resource penetration 1 increases and as the mix of resources on the Island Interconnected System changes.
>
> Hydro is therefore proposing to classify purchases of wind generation on the Island Interconnected System as 43% demand and 57% energy. This proposal is reflected in the 2027 Test Year Cost of Service Study.

CA-NLH-147

Comparison by Class of Wind Purchases Allocation[1]

	A	B	C	A - B	A - C
	Proposed COS Wind (43%/57%)	**Amended COS Wind (22%/78%)**	**Amended COS Wind (0%/100%)**	**Variance to Proposed COS**	**Variance to Proposed COS**
Wind Purchases	**15,683,047**	**15,683,047**	**15,683,047**	-	-
Breakdown:					
Newfoundland Power	13,568,136	13,439,637	13,305,019	128,499	263,116
Industrial - Firm	1,109,329	1,230,214	1,356,855	(120,885)	(247,527)
Industrial - Non-Firm	-	-	-	-	-
Rural					
1.1 Domestic	284,840	273,711	262,052	11,129	22,788
1.12 Domestic All Electric	358,621	356,022	353,299	2,599	5,322
1.3 Special	1,018	927	831	92	188
2.1 GS 0-10 kW	162,346	168,725	175,408	(6,379)	(13,061)
2.2 GS 10-100 kW	-	-	-	-	-
2.3 GS 110-1,000 kVa	115,684	122,970	130,603	(7,286)	(14,919)
2.4 GS Over 1,000 kVa	77,642	85,621	93,979	(7,978)	(16,337)
4.1 Street and Area Lighting	5,431	5,221	5,001	210	430
TOTAL	**15,683,047**	**15,683,047**	**15,683,047**	**(0)**	**(0)**

Wind Purchases: Schedule F 4.4, line 7

[1] Numbers may not add due to rounding.

Preamble:

NLH proposes to reclassify Island wind purchase costs from 22% demand / 78% energy to 43% / 57%. The proposed change follows from the 43% marginal ELCC of a 50 MW wind increment on a 2032 system (Exhibit 16). Brattle and Ms. Derksen recommend keeping 22/78 for the 2027 Test Year, for different reasons. Mr. Bowman recommends approving 43/57 as proposed by Hydro.

The variances to the COS shown in CA-NLH-147 are modest considering the current installed wind capacity of 154 MW on the IIS. However, significant increases in installed wind capacity on both the IIS and LSS are contemplated and can be reasonably expected considering anticipated increases in future demand.

Three expert reports commented on the appropriateness of NLH's proposal for the cost classification of wind resources.

The following questions are put to each of the three experts:

a) **Purpose of the demand share.** In your view, what should the demand-classified share of a wind purchase cost represent? For example, the capacity the resource displaces, the avoided cost of capacity, or the share of the cost caused by peak demand. Is ELCC an appropriate measure of that quantity? Please explain.
b) **Marginal vs. average ELCC.** To classify the embedded cost of the *existing* 54 MW fleet, should a marginal or an average ELCC be used? Would your answer change if the Island wind fleet were to grow to several hundred MW, for example through Hydro's call for expressions of interest?
c) **Study system.** How much weight should be given to the fact that the E3 study models a 2032 system? On that system, the existing PPAs (and up to a five-year extension) have expired and Holyrood is assumed to be retired. Suppose NLH produced the average ELCC of the existing fleet on the 2027 Test Year system, as Brattle recommends. Would you support classifying wind costs on that result, whatever value it showed? If not, why not?
d) **Other experts' evidence.** Having reviewed the other two experts' evidence on this issue:
    i. Which of their points do you agree with?
    ii. Which do you disagree with, and why?
    iii. Does anything in their evidence cause you to revise or qualify your recommendation? If so, please explain.
e) **Reconsideration**. Upon reviewing the materials submitted by the other experts respecting the cost classification of purchases of wind energy, please indicate the conditions under which you would support
    i. a 43/57 classification; and
    ii. keeping a 22/78 classification.

LAB-IIC-002 Re: Coincident Peak Calculation

Citations:

CA-NLH-009

Table 1: Forecasted and Actual Demand and Energy by Customer Group for the Island Interconnected System

Newfoundland Power Inc.	2017	2018	2019	2020	2021	2022	2023	2024	2025
Forecasted Energy (GWh)	5,914.8	5,870.7	5,800.7	5,813.2	5,674.3	5,577.2	5,689.3	5,825.1	5,857.4
Actual Energy (GWh)	5,895.1	5,839.1	5,926.0	5,529.0	5,432.4	5,508.8	5,858.3	5,701.6	5,829.4
Difference (GWh)	(19.7)	(31.6)	125.3	(284.2)	(241.9)	(68.4)	169.0	(123.5)	(28.0)
Difference (%)	(0.3)	(0.5)	2.2	(4.9)	(4.3)	(1.2)	3.0	(2.1)	(0.5)
Forecasted Peak (MW)	1,337.9	1,339.3	1,322.7	1,334.6	1,315.1	1,280.8	1,336.8	1,366.9	1,394.0
Actual Peak (MW)	1,344.1	1,288.7	1,405.7	1,280.1	1,201.0	1,258.3	1,365.9	1,423.4	1,367.3
Difference (MW)	6.2	(50.6)	83.0	(54.5)	(114.1)	(22.5)	29.1	56.5	(26.7)
Difference (%)	0.5	(3.8)	6.3	(4.1)	(8.7)	(1.8)	2.2	4.1	(1.9)
Island Industrial	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Forecasted Energy (GWh)	619.9	658.1	647.3	663.2	699.3	683.9	493.4	664.5	584.2
Actual Energy (GWh)	586.6	622.6	617.9	452.1	421.9	387.4	334.3	448.8	506.7
Difference (GWh)	(33.3)	(35.5)	(29.4)	(211.1)	(277.4)	(296.5)	(159.1)	(215.7)	(77.5)
Difference (%)	(5.4)	(5.4)	(4.5)	(31.8)	(39.7)	(43.4)	(32.2)	(32.5)	(13.3)
Forecasted Peak (MW)	74.7	94.1	92.2	92.7	89.2	86.7	70.7	85.3	80.0
Actual Peak (MW)	95.7	97.5	92.0	90.0	71.3	68.2	66.8	91.0	97.5
Difference (MW)	21.0	3.4	(0.2)	(2.7)	(17.9)	(18.5)	(3.9)	5.7	17.5
Difference (%)	28.1	3.6	(0.2)	(2.9)	(20.1)	(21.3)	(5.5)	6.7	21.9
Island Rural Interconnected	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Forecasted Energy (GWh)	460.4	471.2	470.2	463.9	453.0	453.3	468.8	444.1	446.3
Actual Energy (GWh)	474.4	478.6	477.7	446.6	442.7	454.9	445.9	434.9	458.9
Difference (GWh)	14.0	7.4	7.5	(17.3)	(10.3)	1.6	(22.9)	(9.2)	12.6
Difference (%)	3.0	1.6	1.6	(3.7)	(2.3)	0.4	(4.9)	(2.1)	2.8
Forecasted Peak (MW)	96.6	99.9	98.5	97.3	95.2	94.1	96.9	91.2	91.5
Actual Peak (MW)	96.4	93.6	95.4	93.6	83.2	91.4	101.2	94.8	97.2
Difference (MW)	(0.2)	(6.3)	(3.1)	(3.7)	(12.0)	(2.7)	4.3	3.6	5.7
Difference (%)	(0.2)	(6.3)	(3.1)	(3.8)	(12.6)	(2.9)	4.4	3.9	6.2

IIC-NLH-036a)

Table 1: Forecast System Peak at P90

	Non-Coincident Peak (MW)	Coincident Factor (%)	Coincident Peak (MW)	P90 Addition (MW)	Total P90 (MW)
Newfoundland Power	1450.3	99.44%	1,441.8	57.0	1,498.8
Island Industrial	91.3	86%	78.5	-	78.5
Hydro Rural	94.9	98%	93.0	3.0	96.0
Total Deliveries			**1,613.3**	**60.0**	**1,673.3**
Transmission Losses			70.4	70.4	70.4
System Electricity Requirement			**1,683.7**	**130.4**	**1,743.7**

Pre-filed Testimony of P. Bowman

S.4.2 Coincident Peak Calculation

> As outlined in Table [1] above, industrial customers cause no material load forecast uncertainty associated with weather. But other classes, who rely on electricity frequently for space heating, do cause such effects and costs.
>
> …
>
> Consistent with the need for Hydro to plan to meet load conditions of more extreme than average weather, it is appropriate to allocate demand-related costs on the basis of P90 peak loads, as shown in IIC-NLH-036 (a).
>
> **Recommendation 3: Allocation of demand-related costs should reflect class peaks consistent with a P90 load condition, consistent with Hydro's need to plan for weather conditions more extreme than average.**

Footnote 81:

> Where relevant, the contracts also provide for Generation Outage Demand and Energy, e.g., in PUB-NLH-047, Attachment 3.

Preamble:

Recommendation 3, if implemented, would move generation demand costs from Island Industrial customers to Newfoundland Power and Rural Island Interconnected customers.

Mr. Bowman states that "industrial customers cause no material load forecast uncertainty associated with weather" and recommends allocating demand-related costs on P90 class peaks. CA-NLH-009 shows Island Industrial actual peaks differed from forecast by +21.0 MW (2017), −17.9 MW (2021), −18.5 MW (2022) and +17.5 MW (2025), or roughly ±20–28% of forecast. Over the same period, Newfoundland Power's peaks differed from forecast by −8.7% to +6.3%. Hydro attributes the industrial variances to customers' operational requirements. Mr. Bowman also notes that Hydro embeds load forecast uncertainty in its planning reserve margin.

a) Please confirm that Mr. Bowman's conclusion on industrial load forecast uncertainty is limited to weather-related uncertainty. Did he analyze any non-weather sources of industrial peak uncertainty, such as production changes, shutdowns or restarts, changes to Power on Order, customer generation outages, or new and expanding loads? If so, please provide the analysis. If not, please explain why such sources are not relevant to his recommendation.

b) Does Mr. Bowman agree that the CA-NLH-009 variances show material non-weather uncertainty in Island Industrial peak demand, relative to the industrial class's size? If not, please explain.

c) Please describe Mr. Bowman's understanding of which sources of load forecast uncertainty (e.g., weather, economic, industrial) Hydro embeds in its Island planning reserve margin,

and the basis for that understanding. If it includes industrial or economic uncertainty, how should Recommendation 3 recognize the industrial class's contribution to required reserves?

d) Please explain Mr. Bowman's understanding of whether Hydro plans capacity for Island Industrial customers at Power on Order, at forecast operational demand, or at P50 coincident demand. How does that planning basis affect his conclusion that industrial customers do not contribute to capacity needed for load uncertainty?

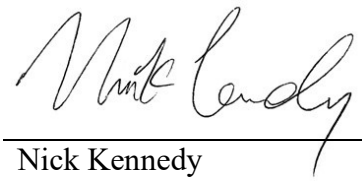
e) Please explain how capacity that Hydro must hold to supply Generation Outage Demand under the industrial contracts (footnote. 81) should be reflected in the industrial class's allocated demand.

f) Under Recommendation 3, a weather-only P90 increment would be allocated to Newfoundland Power and Rural Island Interconnected, with no non-weather increment for any class. Does Mr. Bowman agree this treatment is asymmetric? Please describe an alternative that allocates reserve-related costs on each class's share of total peak forecast uncertainty, whatever its source, and explain why it is or is not preferable to Recommendation 3.

g) Please identify any generation capacity, such as new combustion turbines, battery storage or wind, that Mr. Bowman understands Hydro plans or proposes to meet the P90 or reserve-margin requirement. Please give the MW amount and timing, and Mr. Bowman's view on whether any part of it is driven by industrial load uncertainty.

h) Please estimate the effect of Recommendation 3 on costs allocated to Rural Island Interconnected, on the total Rural Deficit, and on the share of the Rural Deficit allocated to Rural Labrador Interconnected.

All of which is respectfully submitted this November 13, 2026



Nick Kennedy
For the Labrador Interconnected Group